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Quantifying Mobile Transformers for Southern Interior and Vancouver Island Regions Using Probabilistic Risk Assessment

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Summary: This report investigates the number of mobile transformers required during the 20 years planning period (2007 – 2026) to backup a group of single transformer substations and some multi-transformer substations that cannot meet the peak load if one of transformers is out of service. Probabilistic risk assessment and benefit/cost analysis are performed to determine the number of mobile transformers for each region. In the benefit/cost analysis, two different unit interruption costs (in $/kWh) were utilized. These are the GDP-based and customer-survey based interruption costs. Southern Interior and Vancouver Island regions are focused in this study and the number of mobile transformers required for individual regions are examined as well as the timing requirement to have the mobile transformers in place.

1. Introduction

Single transformer substations do not meet the deterministic N-1 criterion. The loss of a transformer at these substations will result in total substation load curtailment. Considerably long outage duration can be expected at these substations if there is no mobile transformer available, and the outage duration constraint would depend on how quick a spare transformer can be moved to the location and be installed. Service reliability at single transformer substations could be expected to be deteriorated in particularly when transformer aging failures currently becoming a concern. Upgrading all single transformer substations to multi-transformer substations involves significant capital investment and might not be feasible. Utilization of mobile transformer as an emergency backup for single transformer substations is more economical, which can avoid considerable capital expenditure while still providing an acceptable reliability level. The challenges when utilizing mobile transformers are [1 – 3]:

- How many mobile transformers are needed in each region to provide sufficient reliability?
- To avoid degrading in power supply reliability due to the transformer aging problem, what is the timing to have the first, second, third mobile (and so on) in a long term planning?
- How much benefits can be gained by using mobile transformer policy?

This report performs risk assessment to answer the above questions in regard to mobile transformers.

2. Probabilistic Risk Assessment Methodology

The SPARE software [4] is used in this mobile transformer study. The SPARE program can incorporate both repairable (forced) and non-repairable (aging) failures of components. Normal distribution model is used in this study to represent aging failure characteristics as the fact that the retired (aging) statistical data obtained from the Asset Program Management Department tend to fit to the normal distribution better than the Weibull distribution for this particular transformer group. A mean life and standard deviation of the mean life for the 60kV and 138kV transformer groups (371 units in total) are obtained using an in-house software, designated as MeanLife program. The resulting mean life and standard deviation for this transformer group based on normal distribution model are 51.1 and 19.9 years respectively.

In practice, there might be an overlapped utilization between mobile and spare transformer strategies. For example, if a transformer at a single-transformer substation fails (N-0) due to either forced outage (requiring a major repair) or aging failure, the mobile transformer will initially be brought to the site in order to quickly bring the substation load back in service, and then a spare transformer is brought to the site and replaced the mobile transformer later. This example indicates a common use of mobile and spare transformers due to the same failure event. Such a situation can also have an influence on determining the number of both spare and mobile transformers. In the above example, if there is no spare transformer (specific type) reserved for single-transformer substations, the mobile transformer would be used at that substation until a new transformer (ordered) has arrived and this could take up to one year duration. The mobile transformer in this case is actually acting like a spare transformer. In order to calculate the number of mobile and spare transformers, the strategies in utilizing mobile and spare transformer should be clearly defined or specified. In reliability perspective, mobile and spare transformer concepts are not mutually exclusive. In other words, in order to determine the optimum number of mobile transformers, a spare transformer strategy and its optimization technique has to be initially identified. These strategies could be illustrated as follows:

Strategy 1: If the mobile transformer strategy is defined that it is undesirable to put the mobile transformer at a substation longer than 30 days, this means that there must have sufficient spare transformers (for each specific transformer type) to replace the mobile transformer within 30 days. In this strategy, the number of mobile transformers required can be minimized by assuming that there are sufficient spare transformers to backup each type of transformers.

Strategy 2: If a mobile transformer can be placed at a substation for a long time (i.e. one year) until a new transformer (being ordered) become available, the number of spare transformers in this case can be minimized as it is not necessary to have redundant spares for all types of transformers if a mobile transformer can be used as a spare transformer.

The two above strategies indicate that in order to maintain the similarly acceptable reliability level, the number of spare transformers can be reduced (minimized) if the number of mobile transformers is increased, or the number of mobile transformers can be minimized if there are more spare transformers for a backup due to the fact that the probability of requiring more than one mobile transformer within 30 days is relatively low.

One of the advantages in utilizing a mobile transformer is that a mobile transformer has multi-connection points at both high and low voltage sides, i.e. 60kV and 138kV at the high voltage side, and 25kV and 12 kV at the low voltage side. A mobile transformer is therefore more flexible in providing a backup for a wider range of transformers when compared to a spare transformer that has to be in a similar voltage level at both sides. The utilization of mobile transformer could help in optimization of spare transformers. A problem associated with a mobile transformer might be that it does not come with a load tap changer and might require some source of voltage supports for desirable operations. This issue is however beyond the scope of this report.

It is worth noting that the above strategy for mobile transformers is only applicable for some specific transformer types in particularly small transformer sizes, i.e. 60 kV and 138 kV 25 MVA transformers. The utilization of mobile transformers might not be applicable to larger transformer sizes, and therefore the sufficient number of spare transformers is still required for the large transformer categories.

2.1 Study Conditions

As previously noted, Strategy 1 tends to minimize the number of mobile transformers. This is due to the fact that the expected energy not supplied (EENS) occurs only 30 days For example, if there is no mobile transformer, a single transformer substation will encounters loss of load during 30 days until a spare transformer is installed. The damage cost associated with this event will not be significant compared to the investment cost for buying many mobile transformers. In other words, a benefit/cost ratio will be relatively small (less than 1) when considering to have many mobile transformers associated with redundantly spare transformers. Strategy 1 is, however, considerably optimistic as it is assumed that there are sufficient spare transformers for each type of transformers, which can be put in place within 30 days. In order to be relatively more conservative, Strategy 2 is utilized in this study and this implies that if there are sufficient numbers of mobile transformers, the spare transformer minimization can then be achieved later after the mobile transformer strategy and quantification technique are clearly specified. The following study conditions are therefore used:

1. If a transformer fails due to aging failure and there is a mobile transformer available, it will take 36 hours to install it. If there is no mobile transformer available in this situation, it will take one year to put a new transformer in place.

2. Both repairable and aging failures are considered in this study. In the repairable failure mode, failure frequencies and repair times for 60 kV and 138 kV transformer groups are obtained from the Reliability Database Management System (RDMS) during the past 10 year period (1996 – 2005). In an aging failure mode, the normal distribution characteristic is used to present the aging failure behaviour.

3. The major contribution of mobile transformer utilization is to backup single transformer substations. A mobile transformer can also be extended to backup multi-transformer substations that cannot meet the peak load if one of transformers is out of service. The contribution in mobile transformer utilization for these multi-transformer substations is, however, not significant as the fact that the probability of hitting the peak load during one transformer outage is very low. In this study, mobile transformers are used to backup all single transformer substations and some multi-transformer substations that cannot meet the peak load if one of transformers is out of service. The number of mobile transformers is determined for each region and will use within its own region.

4. A yearly load growth rate is obtained from BC Hydro load forecast during 2007 – 2015. The extrapolation based on the load growth rate of the year 2015 is used for forecasting loads from years 2016 – 2026.

5. In the benefit/cost analysis, two interruption cost models are utilized in order to provide a range of monetary loss impacts to the customers.

The mobile transformer analysis for each substation group includes the following steps [3]:

Step 1: Calculate the unavailability of transformers in the group.
Step 2: Evaluate the individual failure event probabilities and the total group unavailability.
Step 3: Perform the mobile transformer analysis based on a specified reliability criterion.
Step 4: Repeat Steps 1 – 3 for all the years in consideration.

2.2 Data Requirement

The data requirements for the mobile transformer study for Southern Interior and Vancouver Island regions are illustrated in Tables 1 and 2 respectively. The full list of load forecast (2007 – 2026), power factors and load factors for individual substations that are considered to use a mobile transformer as a backup are shown in Appendix A.

Table 1: Southern Interior substations data (year 2007) used in the SPARE software.

Transformer	Purchase Year	Operating Year	Failure Freq. (f/yr)	Repair Time (hours)	Load Loss (MW)
Single-Transformer Substations					
AFT-T1	1979	28	0.019	92.60	4.530
AVO-T1	1976	31	0.030	139.60	0.077
BAR-T1	1976	31	0.030	139.60	4.537
BLU-T1	1976	31	0.030	139.60	1.385
CHS-T2	1976	31	0.030	139.60	5.265
CLN-T1	1976	31	0.019	92.60	1.196
CLW-T1	1976	31	0.030	139.60	4.294
CNL-T1	1976	31	0.019	92.60	0.892
FST-T1	1976	31	0.019	92.60	0.606
HFY-T1	1976	31	0.030	139.60	8.468
HLD-T2	1976	31	0.019	92.60	2.745
INV-T4	1969	38	0.019	92.60	2.161
LAJ-T2	1986	21	0.019	92.60	0.574
MCA-T11	1976	31	0.019	92.60	0.819
MCK-T1	1963	44	0.019	92.60	0.016
MTE-T1	1976	31	0.019	92.60	0.399
MVL-T1	1979	28	0.019	92.60	6.513
MYE-T1	1976	31	0.019	92.60	0.974
PAV-T1	1978	29	0.019	92.60	0.116
PSN-T1	1976	31	0.019	92.60	0.797
RDM-T1	1981	26	0.019	92.60	4.239
SBR-T1	2006	1	0.019	92.60	2.415
SKU-T1	1984	23	0.019	92.60	1.115
SMH-T1	1976	31	0.019	92.60	4.390
SPD-T1	1979	28	0.019	92.60	2.700
TXL-T1	1976	31	0.019	92.60	0.220
VBY-T1	1976	31	0.030	139.60	3.792
VLM-T3	1979	28	0.030	139.60	4.585
WDS(12kV)-T1	1972	35	0.019	92.60	2.417
WDS(25kV)-T2	1979	28	0.019	92.60	5.854
WIN-T1	1976	31	0.019	92.60	3.214
WWD-T1	1976	31	0.019	92.60	1.355
Multi-Transformer Substations					
ATH-T1	1982	25	0.019	92.60	0.000
ATH-T2	1984	23	0.019	92.60	0.002
END-T1	1974	33	0.030	139.60	0.000
END-T2	2002	5	0.030	139.60	0.004
FMT-T1	1976	31	0.019	92.60	0.000
FMT-T2	1979	28	0.019	92.60	0.068
FNE-T1	2000	7	0.019	92.60	0.091
FNE-T2	1976	31	0.019	92.60	0.000
NAK-T1	1962	45	0.019	92.60	0.072
NAK-T2	1976	31	0.019	92.60	0.072
SCM-T1	1974	33	0.019	92.60	0.000
SCM-T2	1980	27	0.019	92.60	0.055
STO-T1	1982	25	0.030	139.60	0.000
STO-T2	1977	30	0.030	139.60	0.000
WBK-T1	1972	35	0.030	139.60	0.000
WBK-T2	1971	36	0.030	139.60	0.000
WBK-T3	1993	14	0.030	139.60	0.211

Table 2: Vancouver Island substations data (year 2007) used in the SPARE software.

Transformer	Purchase Year	Operating Year	Failure Freq. (f/yr)	Repair Time (hours)	Load Loss (MW)
Single-Transformer Substations					
GLS-T1	1976	31	0.030	139.60	3.420
OYR-T1	1998	9	0.030	139.60	9.270
WOS-T1	1988	19	0.030	139.60	0.490
Multi-Transformer Substations					
CLD-T2	1976	31	0.030	139.60	0.051
CLD-T3	1976	31	0.030	139.60	0.051
LBH-T1	1976	31	0.019	92.60	0.243
LBH-T2	1976	31	0.019	92.60	0.028
LCW-T1	1976	31	0.019	92.60	0.000
LCW-T2	1979	28	0.019	92.60	0.162
SHA-T1	1976	31	0.030	139.60	0.109
SHA-T2	1980	27	0.030	139.60	0.109

3. Study Results

The results obtained using the probabilistic risk assessment associated with the benefit/cost analysis are shown in this section. The benefit/cost analysis focuses on quantifying consequences or impacts due to power outages and interpreting it in a monetary term. An expected energy not supplied (EENS) index is normally used to indicate the magnitude or severity of unreliable power supply. The EENS can also be linked to the monetary loss impacts to the customers due to the loss of load. The benefit/cost analysis therefore establishes a balance between the costs of improving service reliability with the benefits that the improvement brings to the customer.

The reliability studies conducted in this report focus on two individual regions designated as Southern Interior and Vancouver Island. The study results are therefore divided into two separated sections based on the regions.

3.1 Southern Interior Region

32 single-transformer substations and 8 multi-transformer substations in Southern Interior are considered to use a mobile transformer as a backup. The full list of the substations required the mobile transformer as a backup is shown Table 1. There are currently two mobile transformers in Southern Interior. The study in this section is to determine whether or not the third mobile transformer is needed in order to maintain the reliability of this substation group.

An expected energy not supplied (EENS) index is normally used and is translated to the expected damage cost (EDC) by multiplying with the unit interruption cost ($/kWh). This section conducts the benefit/cost analysis for quantifying the number of mobile transformers required in the Southern Interior. The reductions in the expected energy not supplied (EENS) when adding mobile transformers are shown in Table 3.

Table 3: Reductions in EENS (MWh/year) due to mobile transformer additions to Southern Interior region.

Year	1 Mobile	2 Mobiles	3 Mobiles	4 Mobiles	5 Mobiles
2007	4442.56	570.36	48.49	3.03	0.15
2008	4742.45	657.36	60.52	4.10	0.21
2009	5066.55	743.26	72.55	5.21	0.29
2010	5396.95	836.79	86.49	6.58	0.39
2011	5726.73	937.19	102.43	8.25	0.51
2012	6066.00	1046.39	120.79	10.28	0.68
2013	6417.03	1165.27	141.89	12.75	0.89
2014	6779.68	1294.31	166.03	15.73	1.15
2015	7139.24	1396.60	183.65	17.83	1.34
2016	7499.97	1567.50	221.03	23.06	1.86
2017	7895.57	1728.71	255.94	28.06	2.38
2018	8302.40	1901.98	295.32	33.99	3.03
2019	8349.26	1957.69	311.31	36.68	3.34
2020	8763.83	2145.24	356.98	44.06	4.20
2021	9191.35	2346.14	408.11	52.70	5.25
2022	9625.22	2559.15	464.84	62.75	6.53
2023	8998.20	2429.96	448.47	61.49	6.50
2024	9411.42	2642.22	508.25	72.70	8.01
2025	9836.74	2868.05	574.44	85.63	9.82
2026	10276.88	3108.73	647.71	100.54	12.00

The reduction in the EENS shown in Table 3 can be directly translated to the reduction in the expected damage cost (EDC) when the unit interruption cost ($/kWh) is specified. There are two interruption cost models used in this report to represent the unit interruption cost ($/kWh). They are designated as the GDP-based interruption cost and customer-survey based interruption cost approaches. The interruption cost model selection can directly have a significant influence on the project justification. The following assumptions are used in the benefit/cost analysis for both GDP-based interruption cost and customer-survey based interruption cost approaches.

Assume that:

- A discount rate is 6 %
- A useful life time for a mobile transformer is 40 years
- A mobile transformer cost is $3.5 million

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

Annual capital cost of a mobile transformer is = (Mobile transformer cost)×CRF
= M$3.5×0.06646 = 0.233 M$/year

A. GDP-Based Interruption Cost Concept

In the GDP-based interruption concept, the unit interruption cost can be obtained using the ratio of the Provincial Gross Domestic Product (GDP) [5] to the annual energy consumption [6]. The unit interruption cost rate is approximately 3.07 $/kWh. 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 reductions in the expected damage cost (EDC) due to transformer additions using the GDP-based model is shown in Table 4.

Table 4: Reductions in EDC (M$/year) due to mobile transformer additions to Southern Interior region using GDP-based model.

Year	1 Mobile	2 Mobiles	3 Mobiles	4 Mobiles	5 Mobiles
2007	***13.639***	***1.751***	0.149	0.009	0.000
2008	14.559	2.018	0.186	0.013	0.001
2009	15.554	2.282	0.223	0.016	0.001
2010	16.569	2.569	***0.266***	0.020	0.001
2011	17.581	2.877	0.314	0.025	0.002
2012	18.623	3.212	0.371	0.032	0.002
2013	19.700	3.577	0.436	0.039	0.003
2014	20.814	3.974	0.510	0.048	0.004
2015	21.917	4.288	0.564	0.055	0.004
2016	23.025	4.812	0.679	0.071	0.006
2017	24.239	5.307	0.786	0.086	0.007
2018	25.488	5.839	0.907	0.104	0.009
2019	25.632	6.010	0.956	0.113	0.010
2020	26.905	6.586	1.096	0.135	0.013
2021	28.217	7.203	1.253	0.162	0.016
2022	29.549	7.857	1.427	0.193	0.020
2023	27.624	7.460	1.377	0.189	0.020
2024	28.893	8.112	1.560	0.223	0.025
2025	30.199	8.805	1.764	***0.263***	0.030
2026	31.550	9.544	1.988	0.309	0.037

Table 4 indicates that two mobile transformers can be justified in year 2007 as the fact that the savings in EDC when adding the first mobile transformer and the second mobile transformer in year 2007 are M$13.639 and M$1.751 respectively. The savings in EDC are larger than the annual capital cost of a mobile transformer (M$0.233). This indicates the benefit/cost ratios are higher than 1.0 for these two mobile transformer additions. The third mobile transformer can be justified in year 2010 when the saving in EDC reaches M$0.266, and the fourth mobile transformer can be justified in year 2025.

It is worth noting that the above conclusion focuses on the best timing to add a new mobile transformer. The third mobile transformer should therefore be added in year 2010 in order to achieve the maximum benefit/cost ratio. It is however interesting to investigate what the benefit/cost ratio is altered from the maximum benefit/cost ratio if the third mobile transformer is added in year 2007 instead of year 2010. The present value (PV) is used in this case and is described below:

Present value (PV) can be used to capture the time values of the costs during the system planning period (i.e. 20 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 of a mobile transformer in year j, m = system planning period.

A present value can also be applied to the expected damage cost (EDC), and expressed as follows [3]: $EDC = \sum_{j=1}^{m} \frac{EDC_j}{(1+0.06)^{j-1}}$.

Based on the annual capital cost of a mobile transformer of M$0.233 and the saving in EDC shown in Table 4, the present value of the mobile transformer cost is M$2.833 and the present value of the saving in EDC is M$8.126 (if the third mobile transformer is added in year 2007).

Therefore, the benefit/cost ratio when adding the third mobile transformer in year 2007 is M$8.126/M$2.833 = 2.868.

In a similar manner, if the third transformer is added in year 2010 instead of 2007, the benefit/cost ratio is reached the maximum value of 3.499.

The sensitivity analysis of the benefit/cost ratio illustrated above indicates that changing the timing of the third mobile transformer to be added in year 2007 rather than in year 2010 is still acceptable The benefit/cost ratio when adding the third mobile transformer in year 2007 is to some extent less that that when adding it in year 2010, but it is still considerably larger than 1.0.

B. Customer-Survey Based Interruption Cost Concept

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 [7]. 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 [8]. This customer damage function is shown in Table 5. The customer damage functions shown in Table 5 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 6 [9].

Table 5: 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 6: 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

Energy consumption percentages of residential, commercial and industrial customer loads at individual substations in Southern Interior are obtained from BC Hydro and are shown in Table 7. The composite unit interruption cost ($/kWh) for individual substation loads can be calculated using average values of individual customer sectors shown in Table 6 weighted by their energy consumption percentages shown in Table 7. The composite unit interruption costs for individual substation loads are presented in the last column of Table 7.

Table 7 indicates that the unit interruption cost (UIC) for individual substations varies depending on the customer load mix in each substation. The composite UIC for substations in Southern Interior are basically in a range of 3 – 21 $/kWh. The higher UIC values indicate how significant the customer monetary losses due to power outages would be.

Table 7: Customer load composition and composite unit interruption cost (UIC) for individual substations in Southern Interior.

Substation	Customer sector load composition			Composite UIC ($/kWh)
	Residential	Commercial	Industrial	
AFT	72%	1%	26%	5.67
AVO	67%	33%	0%	12.97
BAR	80%	11%	9%	6.62
BLU	36%	52%	12%	21.61
CHS	84%	14%	2%	6.69
CLN	87%	12%	1%	5.83
CLW	77%	19%	4%	8.75
CNL	84%	13%	3%	6.30
FST	84%	16%	0%	6.92
HFY	77%	19%	3%	8.69
HLD	79%	20%	1%	8.44
INV	29%	2%	69%	12.05
LAJ	59%	7%	34%	8.78
MCA	20%	17%	62%	16.48
MCK	20%	17%	62%	16.48
MTE	79%	3%	18%	5.06
MVL	77%	21%	2%	9.19
MYE	76%	23%	1%	9.65
PAV	89%	11%	0%	5.39
PSN	92%	4%	4%	3.32
RDM	39%	10%	51%	12.20
SBR	81%	18%	1%	7.93
SKU	86%	11%	3%	5.75
SMH	92%	6%	2%	3.65
SPD	68%	29%	3%	12.09
TXL	93%	7%	0%	3.98
VBY	21%	2%	76%	13.12
VLM	57%	20%	23%	11.61
WDS	80%	11%	8%	6.60
WIN	66%	12%	22%	8.77
WWD	89%	6%	5%	4.27
ATH	80%	19%	2%	8.26
END	81%	12%	7%	6.70
FMT	81%	17%	1%	7.70
FNE	50%	24%	26%	13.63
NAK	76%	20%	3%	9.06
SCM	78%	13%	9%	7.24
STO	77%	7%	16%	6.03
WBK	77%	12%	12%	7.23

The savings in EDC associated with mobile transformer additions can be calculated by the multiplication of the composite UIC shown in Table 7 and the savings in EENS shown in Table 3. The savings in EDC associated with mobile transformer additions for

Southern Interior based on customer survey interruption cost concept are shown in Table 8.

Table 8: Savings in EDC (M$/year) due to mobile transformer additions to Southern Interior region using customer-based survey model.

Year	1 Mobile	2 Mobiles	3 Mobiles	4 Mobiles	5 Mobiles
2007	***38.304***	***4.917***	***0.418***	0.026	0.001
2008	40.851	5.662	0.521	0.035	0.002
2009	43.602	6.396	0.624	0.045	0.002
2010	46.414	7.196	0.744	0.057	0.003
2011	49.207	8.052	0.880	0.071	0.004
2012	52.079	8.983	1.037	0.088	0.006
2013	55.046	9.995	1.217	0.109	0.008
2014	58.104	11.092	1.423	0.135	0.010
2015	61.215	11.974	1.574	0.153	0.011
2016	64.243	13.426	1.893	0.197	0.016
2017	67.572	14.794	2.190	***0.240***	0.020
2018	70.987	16.261	2.525	0.291	0.026
2019	72.517	17.003	2.704	0.319	0.029
2020	76.035	18.611	3.097	0.382	0.036
2021	79.653	20.331	3.536	0.457	0.046
2022	83.318	22.152	4.023	0.543	0.057
2023	77.751	20.995	3.875	0.531	0.056
2024	81.208	22.797	4.385	0.627	0.069
2025	84.756	24.710	4.949	0.738	0.085
2026	88.409	26.742	5.571	0.865	0.103

Table 8 indicates that three mobile transformers can be justified in year 2007 when using the customer-based survey interruption cost model. The savings in EDC when adding the first, second and third mobile transformers in year 2007 are M$38.304, M$4.917 and M$0.418 respectively. These savings in EDC are larger than the annual capital cost of a mobile transformer (M$0.233). This indicates the benefit (reliability improvement) of having three mobile transformers is higher than the investment cost. The fourth mobile transformer can be justified in year 2017 when the saving in EDC reaches M$0.240.

3.2 Vancouver Island Region

3 single-transformer substations and 4 multi-transformer substations in Vancouver Island are considered to use a mobile transformer as a backup. The full list of the substations required the mobile transformer to backup is shown in Table 2. One mobile transformer designated as MO4 is anticipated to use for a backup the above substations in Vancouver Island region. The MO4 is, however, not reliable and has been returned to the manufacturer for a repair process, and there is no indication that the MO4 can be used for the emergency backup at this time (MO4 is un-repairable). These substations therefore do not currently have a backup plan if contingency occurs. The study in this section is to

determine whether or not a new mobile transformer (to replace MO4) is needed in order to maintain the substation group reliability.

The reductions in the expected energy not supplied (EENS) when adding mobile transformers in Vancouver Island region are shown in Table 9.

Table 9: Reductions in EENS (MWh/year) due to mobile transformer additions to Vancouver Island region.

Year	1 Mobile	2 Mobiles	3 Mobiles
2007	411.18	11.74	0.20
2008	450.91	13.70	0.25
2009	495.84	16.01	0.31
2010	546.47	18.72	0.38
2011	604.03	21.93	0.47
2012	660.63	25.39	0.58
2013	723.71	29.41	0.71
2014	793.22	34.05	0.87
2015	871.27	39.44	1.06
2016	957.33	45.66	1.29
2017	1054.18	52.89	1.58
2018	1160.48	61.19	1.92
2019	1281.44	70.92	2.34
2020	1417.18	82.23	2.84
2021	1568.19	95.29	3.45
2022	1719.54	109.34	4.15
2023	1887.30	125.44	4.98
2024	2072.68	143.85	5.96
2025	2277.18	164.85	7.13
2026	2507.75	189.18	8.54

A. GDP-Based Interruption Cost Concept

The unit interruption cost of 3.07 $/kWh is used in this section as a multiplication factor to the savings EENS in order to obtained the saving EDC. The savings in the expected damage cost (EDC) due to transformer additions to Vancouver Island region using the GDP-based model is shown in Table 10.

Table 10 indicates that one mobile transformer can be justified in year 2007 as the fact that the saving in EDC when adding the first mobile transformer in year 2007 is M$1.262, which is higher than the annual capital cost of a mobile transformer (M$0.233). The second mobile transformer can be justified in year 2020 when the reduction in EDC reaches M$0.252.

Table 10: Reductions in EDC (M$/year) due to mobile transformer additions to Vancouver Island region using GDP-based model.

Year	1 Mobile	2 Mobiles	3 Mobiles
2007	***1.262***	0.036	0.001
2008	1.384	0.042	0.001
2009	1.522	0.049	0.001
2010	1.678	0.057	0.001
2011	1.854	0.067	0.001
2012	2.028	0.078	0.002
2013	2.222	0.090	0.002
2014	2.435	0.105	0.003
2015	2.675	0.121	0.003
2016	2.939	0.140	0.004
2017	3.236	0.162	0.005
2018	3.563	0.188	0.006
2019	3.934	0.218	0.007
2020	4.351	***0.252***	0.009
2021	4.814	0.293	0.011
2022	5.279	0.336	0.013
2023	5.794	0.385	0.015
2024	6.363	0.442	0.018
2025	6.991	0.506	0.022
2026	7.699	0.581	0.026

B. Customer-Survey Based Interruption Cost Concept

Energy consumption percentages of residential, commercial and industrial customer loads at individual substations in Vancouver Island region are obtained from BC Hydro and are shown in Table 11. The composite unit interruption costs for individual substation loads are presented in the last column of Table 11.

Table 11: Customer load composition and composite unit interruption cost (UIC) for individual substations in Southern Interior.

Substation	Customer sector load composition			Composite UIC ($/kWh)
	Residential	Commercial	Industrial	
GLS	91%	8%	1%	4.22
OYR	95%	5%	0%	3.22
WOS	58%	8%	33%	9.04
CLD	80%	17%	3%	7.82
LBH	68%	25%	6%	11.30
LCW	83%	14%	3%	6.72
SHA	88%	10%	2%	5.24

Table 11 indicates that the unit interruption cost (UIC) for individual substations varies depending on the customer load mix in each substation. The composite UIC for substations in Vancouver Island region are basically in a range of 3 – 11 \$/kWh. The reductions in EDC associated with mobile transformer additions for Vancouver Island region based on customer survey interruption cost concept are shown in Table 12.

Table 12: Reductions in EDC (M\$/year) due to mobile transformer additions to Vancouver Island region using customer-based survey model.

Year	1 Mobile	2 Mobiles	3 Mobiles
2007	***1.858***	0.053	0.001
2008	2.063	0.062	0.001
2009	2.298	0.074	0.001
2010	2.572	0.088	0.002
2011	2.890	0.104	0.002
2012	3.197	0.122	0.003
2013	3.543	0.143	0.003
2014	3.933	0.167	0.004
2015	4.379	0.197	0.005
2016	4.876	0.231	0.006
2017	5.449	***0.271***	0.008
2018	6.089	0.318	0.010
2019	6.830	0.375	0.012
2020	7.676	0.442	0.015
2021	8.632	0.520	0.019
2022	9.579	0.604	0.023
2023	10.646	0.701	0.028
2024	11.838	0.814	0.033
2025	13.171	0.945	0.040
2026	14.697	1.099	0.049

Table 12 indicates that one mobile transformer can be justified in year 2007 when using the customer-based survey interruption cost model. The saving in EDC when adding the first mobile transformer in year 2007 is M\$1.858 which is higher than the annual capital cost of a mobile transformer (M\$0.233). The second mobile transformer can be justified in year 2017 when the saving in EDC reaches M\$0.271.

4. Conclusions and Recommendations

This report presents a probabilistic risk assessment in calculating the number of mobile transformers required for Southern Interior and Vancouver Island regions. Two different interruption cost models are used in the benefit/cost analysis in order to provide an appreciation of the reliability cost and reliability worth from different perspectives. The results indicate that:

For Southern Interior region:

- When using the benefit/cost analysis associated with the GDP-based interruption cost, the best timing to have the third mobile transformer is in year 2010. However, if the third mobile transformer is added in year 2007 rather than 2010, the project can still be justified (the benefit/cost ratio slightly decreases but it is still considerably significant).
- When using the benefit/cost analysis associated with the customer-based survey interruption cost, the best timing to have the third mobile transformer is in year 2007.

For Vancouver Island:

- The benefit/cost analyses associated with both GDP-based and Customer-based interruption cost models provide the similar conclusion. One mobile transformer is required in year 2007 for Vancouver Island region, and this project can be justified based on the benefit/cost analysis.

It is worth noting that the report [2] conducted in 1995 indicated that the third mobile transformer can be justified in year 2007 for Southern Interior region. This is somewhat coincided with the results shown in this current study. There are however three major factors that should be noted when comparing the results provided in [2] and the results shown in this current report. The first factor is that the cost of a mobile transformer is almost doubled at the time of the study conducted (mobile transformer cost was M$1.8 in year 1995, but it is M$3.5 in year 2006). The second factor is the damage cost was based on the electricity rate of 0.05 $/kWh in the report [2]. The third factor is that the mean life and standard deviation of transformers have been altered compared to those data used in the report [2]. The mean life and standard deviation obtained from Asset Program Management and used in this current study are larger (longer mean life) than those used in the report [2], and therefore the impact of aging failures is relatively less than that indicated in report [2].

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Appendix A: Southern Interior and Vancouver Island Substations Load Data.

A.1 Data for Southern Interior substations that requires a backup from a mobile transformer (loads are in MVA).

Sub.	P.F.	L.F	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
AFT	0.96	0.384	12.29	12.47	12.66	12.85	12.98	13.11	13.24	13.37	13.50	13.64	13.78	13.91	14.05	14.19	14.34	14.48	14.62	14.77	14.92	15.07
AVO	0.95	0.261	0.31	0.31	0.31	0.31	0.31	0.32	0.32	0.32	0.32	0.32	0.32	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.34	0.34
BAR	0.95	0.466	10.25	10.35	10.45	10.56	10.61	10.66	10.72	10.77	10.83	10.88	10.93	10.99	11.04	11.10	11.15	11.21	11.27	11.32	11.38	11.44
BLU	0.95	0.376	3.88	3.90	3.92	3.94	3.95	3.97	3.99	4.01	4.03	4.05	4.07	4.10	4.12	4.14	4.16	4.18	4.20	4.22	4.24	4.26
CHS	0.95	0.585	9.47	9.57	9.66	9.76	9.81	9.86	9.91	9.96	10.01	10.06	10.11	10.16	10.21	10.26	10.31	10.36	10.42	10.47	10.52	10.57
CLN	0.93	0.442	2.91	2.94	2.97	3.00	3.03	3.06	3.09	3.12	3.15	3.18	3.21	3.25	3.28	3.31	3.34	3.38	3.41	3.44	3.48	3.51
CLW	0.93	0.436	10.59	10.70	10.80	10.91	10.97	11.02	11.08	11.13	11.19	11.24	11.30	11.35	11.41	11.47	11.53	11.58	11.64	11.70	11.76	11.82
CNL	0.95	0.546	1.72	1.73	1.74	1.75	1.75	1.76	1.77	1.78	1.79	1.80	1.81	1.82	1.83	1.83	1.84	1.85	1.86	1.87	1.88	1.89
FST	0.94	0.545	1.18	1.19	1.21	1.22	1.23	1.24	1.26	1.27	1.28	1.29	1.31	1.32	1.33	1.35	1.36	1.37	1.39	1.40	1.41	1.43
HFY	0.9	0.523	17.99	18.26	18.53	18.74	18.96	19.17	19.39	19.62	19.84	20.14	20.44	20.75	21.06	21.37	21.70	22.02	22.35	22.69	23.03	23.37
HLD	1	0.622	4.41	4.46	4.50	4.55	4.59	4.64	4.68	4.73	4.78	4.83	4.87	4.92	4.97	5.02	5.07	5.12	5.17	5.23	5.28	5.33
INV	0.95	0.259	8.78	8.92	9.05	9.18	9.23	9.28	9.32	9.37	9.42	9.46	9.51	9.56	9.61	9.65	9.70	9.75	9.80	9.85	9.90	9.95
LAJ	0.95	0.575	1.05	1.06	1.07	1.08	1.09	1.10	1.12	1.13	1.14	1.15	1.16	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.26	1.27
MCA	0.95	0.643	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
MCK	0.95	0.426	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
MTE	0.95	0.343	1.22	1.25	1.27	1.30	1.33	1.35	1.38	1.41	1.43	1.46	1.49	1.52	1.55	1.58	1.62	1.65	1.68	1.71	1.75	1.78
MVL	0.98	0.519	12.81	13.00	13.19	13.39	13.52	13.66	13.80	13.93	14.07	14.21	14.36	14.50	14.64	14.79	14.94	15.09	15.24	15.39	15.55	15.70
MYE	0.95	0.566	1.81	1.84	1.87	1.89	1.91	1.93	1.95	1.97	1.99	2.01	2.03	2.05	2.07	2.09	2.11	2.13	2.16	2.18	2.20	2.22
PAV	0.95	0.374	0.33	0.33	0.33	0.34	0.34	0.34	0.35	0.35	0.35	0.36	0.36	0.36	0.37	0.37	0.38	0.38	0.38	0.39	0.39	0.40
PSN	0.95	0.485	1.73	1.74	1.75	1.76	1.76	1.77	1.78	1.79	1.80	1.81	1.82	1.83	1.84	1.84	1.85	1.86	1.87	1.88	1.89	1.90
RDM	0.95	0.518	8.61	8.70	8.79	8.88	8.92	8.96	9.01	9.05	9.10	9.15	9.19	9.24	9.28	9.33	9.38	9.42	9.47	9.52	9.57	9.61
SBR	0.95	0.384	6.62	6.62	6.63	6.63	6.64	6.64	6.65	6.65	6.66	6.68	6.71	6.74	6.76	6.79	6.82	6.85	6.87	6.90	6.93	6.96
SKU	0.95	0.553	2.12	2.14	2.16	2.19	2.21	2.23	2.25	2.27	2.30	2.32	2.34	2.37	2.39	2.41	2.44	2.46	2.49	2.51	2.54	2.56
SMH	0.94	0.431	10.84	11.00	11.16	11.27	11.39	11.50	11.62	11.73	11.85	11.97	12.09	12.21	12.33	12.45	12.58	12.70	12.83	12.96	13.09	13.22
SPD	0.95	0.489	5.81	5.87	5.93	5.99	6.05	6.11	6.17	6.23	6.29	6.36	6.42	6.49	6.55	6.62	6.68	6.75	6.82	6.88	6.95	7.02
TXL	0.95	0.575	0.40	0.40	0.41	0.41	0.41	0.41	0.41	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.43	0.43	0.43	0.43	0.43
VBY	0.92	0.477	8.64	8.73	8.82	8.90	8.95	8.99	9.04	9.08	9.13	9.17	9.22	9.27	9.31	9.36	9.41	9.45	9.50	9.55	9.60	9.64
VLM	0.88	0.29	17.97	18.15	18.33	18.51	18.70	18.88	19.07	19.26	19.46	19.65	19.85	20.05	20.25	20.45	20.65	20.86	21.07	21.28	21.49	21.71
WDS(12)	0.95	0.353	7.21	7.39	7.57	7.72	7.88	8.04	8.20	8.36	8.53	8.70	8.87	9.05	9.23	9.42	9.60	9.80	9.99	10.19	10.40	10.60
WDS(25)	0.99	0.353	16.75	17.17	17.60	17.95	18.31	18.68	19.05	19.43	19.82	20.22	20.62	21.03	21.45	21.88	22.32	22.77	23.22	23.69	24.16	24.64
WIN	0.95	0.547	6.18	6.25	6.31	6.37	6.44	6.50	6.56	6.63	6.70	6.76	6.83	6.90	6.97	7.04	7.11	7.18	7.25	7.32	7.40	7.47
WWD	0.95	0.355	4.02	4.06	4.10	4.14	4.18	4.22	4.27	4.31	4.35	4.39	4.44	4.48	4.53	4.57	4.62	4.66	4.71	4.76	4.81	4.85
ATH	1	0.386	31.26	31.73	32.20	32.53	32.85	33.18	33.51	33.85	34.19	34.53	34.87	35.22	35.57	35.93	36.29	36.65	37.02	37.39	37.76	38.14
END	0.98	0.613	14.31	14.54	14.77	15.01	15.25	15.49	15.74	15.99	16.25	16.51	16.77	17.04	17.31	17.59	17.87	18.16	18.45	18.74	19.04	19.35
FMT(25)	0.95	0.466	10.77	10.88	10.98	11.09	11.21	11.32	11.43	11.54	11.66	11.78	11.89	12.01	12.13	12.25	12.38	12.50	12.63	12.75	12.88	13.01
FNE	0.99	0.503	14.29	14.51	14.73	14.95	15.10	15.25	15.40	15.55	15.71	15.87	16.03	16.19	16.35	16.51	16.68	16.84	17.01	17.18	17.35	17.53
NAK	0.95	0.382	9.37	9.46	9.56	9.61	9.65	9.70	9.75	9.80	9.85	9.90	9.95	10.00	10.05	10.10	10.15	10.20	10.25	10.30	10.35	10.40
SCM	0.98	0.276	18.64	19.32	20.01	20.72	21.34	21.96	22.29	22.63	22.97	23.31	23.66	24.01	24.38	24.74	25.11	25.49	25.87	26.26	26.65	27.05
STO	0.98	0.595	32.88	33.60	34.34	35.08	35.66	36.24	36.83	37.42	38.03	38.60	39.18	39.77	40.36	40.97	41.58	42.21	42.84	43.48	44.14	44.80
WBK	0.98	0.582	69.98	71.73	73.52	74.62	75.74	76.88	78.03	79.20	80.39	81.60	82.82	84.06	85.32	86.60	87.90	89.22	90.56	91.92	93.30	94.70

A.2 Data for Vancouver Island substations that requires a backup from a mobile transformer (loads are in MVA).

Sub.	P.F.	L.F	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
GLS	0.98	0.278	12.55	12.67	12.80	12.93	13.06	13.19	13.32	13.45	13.59	13.72	13.86	14.00	14.14	14.28	14.42	14.57	14.71	14.86	15.01	15.16
OYR	0.99	0.471	19.88	20.18	20.48	20.79	21.05	21.31	21.58	21.85	22.12	22.40	22.68	22.96	23.25	23.54	23.84	24.13	24.44	24.74	25.05	25.36
WOS	0.95	0.243	2.14	2.16	2.19	2.21	2.23	2.25	2.27	2.30	2.32	2.34	2.37	2.39	2.41	2.44	2.46	2.49	2.51	2.54	2.56	2.59
CLD	0.976	0.491	112.57	114.50	116.46	118.45	120.19	121.96	123.75	125.57	127.42	129.29	131.19	133.12	135.08	137.07	139.09	141.14	143.22	145.33	147.47	149.65
LBH	0.97	0.764	22.42	22.74	23.07	23.40	23.69	23.99	24.28	24.59	24.90	25.21	25.53	25.85	26.18	26.51	26.85	27.19	27.54	27.89	28.25	28.62
LCW	0.93	0.742	17.24	17.41	17.59	17.76	17.94	18.12	18.30	18.48	18.67	18.85	19.04	19.23	19.43	19.62	19.82	20.01	20.21	20.42	20.62	20.83
SHA	0.98	0.48	46.07	46.88	47.70	48.53	49.14	49.75	50.38	51.00	51.64	52.29	52.94	53.60	54.27	54.95	55.64	56.33	57.04	57.75	58.47	59.20