IEEE Transactions on Power Delivery, Vol. 14, No. 3, July 1999

Determining Number And Timing Of Substation Spare Transformers Using A Probabilistic Cost Analysis Approach

W. Li (IEEE SM) E. Vaahedi (IEEE SM) Y. Mansour (IEEE Fellow)
Grid Operations And Inter-Utility Affairs
BC Hydro, Vancouver, Canada

ABSTRACT: Compared to the N-1 security design principle in each substation, common spare transformers shared by multiple substations can avoid considerable capital expenditure and still assure a sufficient reliability level. Using common spare transformers has been already a practice of some utilities in distribution substation transformer planning. This paper presents a probabilistic approach to determining the number and timing of spare transformers shared in a substation group. The proposed approach is based on the aging failure model of transformers, the overall reliability analysis and the probabilistic damage cost model for a substation group, the capital cost model for spares and the present value method. The spare transformer scheme obtained using the presented approach provides both cost efficiency and sufficient reliability. A single transformer substation group in a non-urban region is given as an application example to illustrate the procedure of the method.

Keywords: Spare transformer, reliability, probabilistic cost analysis, present value

INTRODUCTION

The N-1 security principle is widely used in the substation transformer planning. Each substation is often designed to have two or more transformers in parallel so that the peak load can be still supplied when one transformer fails. This is a secure but very expensive criterion. On the other hand, using common spare transformers has been already a practice of many utilities in distribution substation transformer planning, particularly for existing single transformer substations supplying power to less important loads. This policy can be extended to multiple transformer substations and new single transformer substation design. For a two transformer substation where either one will not be able to meet the peak due to load growth, for example, the substation can become a member of the substation group with the same class of transformers to share common spares rather than a third transformer will be added in the individual substation. For moderately important loads, single transformer substations instead of two transformers in parallel can be considered with shared common spares. Compared to the N-1 security design principle in each substation, common spare transformers shared by multiple substations can avoid considerable capital expenditure and still assure a sufficient reliability level. In today's increasing competitive environment in electrical power industry, the spare policy will be more and more considered in the future.

PE-216-PWRD-0-09-1998 A paper recommended and approved by the IEEE Substations Committee of the IEEE Power Engineering Society for publication in the IEEE Transactions on Power Delivery. Manuscript submitted April 27, 1998; made available for printing October 7, 1998.

Using common spare transformers is an economic and reliable alternative. The challenging questions are: (1) How many spare transformers are needed in a region to provide sufficient reliability? (2) To avoid degrading in power supply reliability due to the transformer aging problem, what is the timing to have the first, second, third, ... spare in a long term planning? (3) How much benefits can be gained by using the spare policy?

Considerable efforts have been devoted to power system probabilistic planning for years [1-7]. However, very little attention has been paid from a viewpoint of probabilistic methods to power equipment spare planning which is tightly associated with aging failures. This paper presents a probabilistic approach including quantitative reliability evaluation and probabilistic cost analysis to answer the above questions. A computer program named SPARE has been developed in BC Hydro to conduct studies needed in the presented method. An example for a single transformer substation group in a non-urban region is given to demonstrate the approach.

MODELLING AND METHODOLOGY

There are two failure modes for a transformer: repairable and non-repairable. The installation time of a spare transformer (1 to 5 days) is comparable with the repair time (from 1 to 10 days) from a random repairable failure and much shorter than the replacement time (1.0 to 1.5 years) of buying or rebuilding a transformer in the case of non-repairable failure and no spare available. When a failure takes place, emergency measures such as using a mobile diesel station, temporary switching to other possible feeder, or/and even giving customers compensation, etc. can be considered. These measures are very costly and may not be feasible for a long time non-repairable failure which takes 1 to 1.5 years to get a new transformer replacement while they are financially and technically acceptable for a short time repairable failure. Therefore the benefits gained by using the spare policy are dominated by non-repairable failures although a quick installation like a mobile spare can also provide marginal benefits for those repairable failures longer than the installation time of a spare transformer. In other words, the spare issue is mainly associated with non-repairable failures. In this paper, only non-repairable failures are considered. Repairable failures can be modelled in a similar way if the marginal benefits justify their inclusion.

Aging Failure Model

A non-repairable failure is mainly due to insulation wear-out in the end-of-life period [8] although it can also randomly happens at any point of the life. The aging failure can be modelled using a posteriori probability associated with a normal or Weibull distribution [9-11]. A normal distribution assumption is used in the paper. There is no difficulty to use Weibull or other distribution assumption since the difference is only associated with failure density functions for different distributions . It can be proved mathematically that the failure rate function corresponding to a normal distribution is a non-linearly increasing curve with time as shown in Figure 1. Therefore this model actually covers the whole life span with the significantly increasing failure probability in the end-of-life period as the age increases. According to the definition of reliability function, the probability that a transformer will still survive in a subsequent interval t after having operated for T years is:

$$p_s = \frac{\int_{T+t}^{\infty} f(t)dt}{\int_{T}^{\infty} f(t)dt} \tag{1}$$

where f(t) is the following normal distribution failure density function:

$$f(t) = \frac{1}{\sigma\sqrt{2\pi}}\exp(-\frac{(t-\mu)^2}{2\sigma^2}) \tag{2}$$

where μ and σ are the mean life (years) of transformers and its standard deviation respectively.

The probability that a transformer will die due to the aging failure in a subsequent interval t after having operated for T years is:

$$p_f = 1.0 - p_s \tag{3}$$

If t in the integral sign of Equation (1) is one year, p_f is called annual failure probability. Note that this is a probability of transition to failure in one year but not unavailability in the year. T in Equation (1) generally should be the functional or insulation age of a transformer rather than its natural age. The functional age can be estimated by life testing [12, 13]. However, individual life testing is very expensive. If the functional age is not available, the natural age is acceptable for the purpose of long term transformer planning. An alternative can be the use of the natural age with an adjustment based on engineering understanding for the operation and utilization history of individual transformers.

Substation Group Model

For a substation group with the same class of transformers, two cumulative states are identified: loss-of-load state and no-loss-of-load state. The installation time of a spare transformer (1 to 5 days) is much shorter than the replacement time (1 to 1.5 year) of buying a new transformer. Therefore as an approximation, a spare can be assumed to be installed immediately in calculating

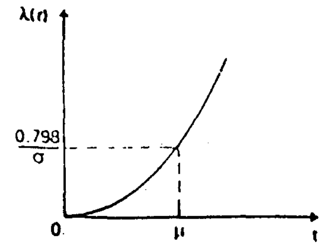

Figure 1 Failure rate function of normal distribution

the probabilities of the two cumulative states associated with long time non-repairable failures. This approximation is not used in the cost model below to make the damage cost evaluation more accurate. An enumeration technique can be used to calculate probabilities of the two cumulative states. This is based on the expansion of the following expression:

$$(p_{s1}+p_{f1})(p_{s2}+p_{f2})\cdots\cdots(p_{sm}+p_{fm}) \tag{4}$$

where p_{si} and p_{fi} are success and failure probabilities of the ith transformer respectively.

Take three single transformer substations as an example. In the case of zero spare, only the zero-transformer-failure event makes contribution to the annual probability of the cumulative no-loss-of-load state, i.e.

$$p_N = p_{s1}p_{s2}p_{s3} \tag{5}$$

The annual probability of the cumulative loss-of-load state is

$$p_L = p_{s1}p_{s2}p_{f3} + p_{s1}p_{f2}p_{s3} + p_{f1}p_{s2}p_{s3} + p_{s1}p_{f2}p_{f3} + p_{f1}p_{s2}p_{f3} + p_{f1}p_{f2}p_{s3} + p_{f1}p_{f2}p_{f3} \tag{6}$$

Each item in Equation (6) corresponds to the probability of an individual loss-of-load event.

For the case of one spare available in this example, all zero-transformer-failure and one-transformer-failure events contribute to the annual probability of the cumulative no-loss-of-load state:

$$p_P = p_{s1}p_{s2}p_{s3} + p_{s1}p_{s2}p_{f3} + p_{s1}p_{f2}p_{s3} + p_{f1}p_{s2}p_{s3} \tag{7}$$

All two- and three-transformer-failure events make contributions to the annual probability of the cumulative loss-of-load state:

$$p_L = p_{s1}p_{f2}p_{f3} + p_{f1}p_{s2}p_{f3} + p_{f1}p_{f2}p_{s3} + p_{f1}p_{f2}p_{f3} \tag{8}$$

Damage Cost Model

Any transformer failure event leading to loss-of-load causes damage costs. In the case of no spare, the expected total damage cost (TDC) for one year can be calculated by

$$TDC = \sum_{i=1}^{N} C_i p_i d U_i \quad (9)$$

where C_i and p_i are the average lost load (MW) and the annual probability for each individual loss-of-load event, d is replacement time of a new transformer (hours), U_i is the unit damage cost due to loss of 1 MW load for one hour($/MWh), and N is the number of all transformer failure events leading to loss-of-load. It is worthy to appreciate that since the annual probability is the probability of transition to the loss-of-load state and associated with an interval of one year, it should be numerically equal to the transition rate from the no-loss-of-load state to the loss-of-load state if the transition rate is assumed to be constant in the year. As mentioned earlier, the replacement time d is 1 to 1.5 years. In such a long time period, some special or emergency measures will be taken. U_i depends on these measures. If a mobile diesel station is used, for instance, U_i is the difference between the unit costs of diesel generation and normal power supply.

In the case of spares available, the expected total damage cost is calculated in two groups:

$$TDC = \sum_{i=1}^{M1} C_i p_i d U_i + \sum_{j=1}^{M2} C_j p_j d_t U_j \quad (10)$$

where C_i or C_j, p_i or p_j, U_i or U_j and d are defined as above. d_t is the installation time of a spare transformer. M1 is the number of transformer failure events leading to long time loss-of-load where the number of failed transformers is larger than that of spares. M2 is the number of transformer failure events leading to temporary loss-of-load during an installation of a spare where the number of failed transformers is equal to or smaller than that of spares. In the above example and for the case of one spare, for instance, M1 includes the four events in Equation (8) and M2 includes the events corresponding to Items 2, 3 and 4 in Equation (7).

The damage costs are calculated considering transformer annual failure probabilities. The differences between the damage costs for the no spare and one spare cases, for the one spare and two spare cases, ... are the benefits obtained using the first, the second, ... spare. The benefits are calculated on the yearly basis for many years in planning to create a benefit "cash flow".

Annual Capital & Present Value Models

Spare transformers require capital investments. The cash flow of the capital investment can be obtained using the capital return factor (CRF) [14]:

$$A = S \bullet CRF \quad (11)$$

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \quad (12)$$

where A: annual equivalent investment
S: actual capital investment in some year
i: discount rate
n: economic life of investment S

The present values of the cash flows for the benefits and the capital costs due to spares are calculated using the following formula:

$$PV = \sum_{k=1}^{L} \frac{A_k}{(1+i)^{k-1}} \quad (13)$$

where PV: present value
A_k: annual value in year k
i: discount rate
L: number of years considered in planning

Procedure of the Proposed Method

The proposed method is summarized as follows:

1. Calculate annual probabilities of the cumulative loss-of-load state for the substation group with no spare, one spare, two spares, ... for the years considered in planning.

2. Calculate total damage costs for the no spare, one spare, two spare, ... cases and obtain a damage saving table due to the first, the second, the third spare, ... for the years considered in planning.

3. Calculate the annual capital cost of a spare. If the capital cost of a spare is just smaller than the damage saving for a particular year, one spare is required to add for that year. The number and timing of added spares can be marked in the damage saving table by comparing the damage saving value due to a spare with its annual capital cost.

4. Two cash flows for the capital investment and the benefit (damage saving) due to adding the spare transformers marked in Step 3 can be obtained.

5. Calculate present values of the capital cost and the benefit and conduct benefit/cost analysis.

6. The result obtained in the above steps often provides cost efficiency with an acceptable level of reliability. However, in some case where there are relatively many aging transformers in the group, unreliability may be beyond the criterion. In this case, an adjustment on the number and timing of added spare transformers is required to satisfy the reliability criterion according to the information on the annual probabilities of the cumulative loss-of-load state for the substation group obtained in Step 1.

7. Repeat Steps 4 and 5 using the number and timing of spares adjusted in the damage saving table. A new benefit/cost ratio for the post-adjustment is obtained. The adjusted spare addition scheme will be both cost efficient and reliability sufficient.

The procedure is demonstrated in the following section using a single transformer substation group in a non-urban region as an example.

APPLICATION TO A SINGLE TRANSFORMER SUBSTATION GROUP

Data and Study Conditions

This group includes 26 single transformer substations in a non-urban region where the capacity of each transformer is smaller than 20 MVA and the load at each substation is less than 12 MW. The age of the transformers ranges between 11 and 44 years with the average of 29.6 years. There are 13 transformers beyond 30 years and 7 of them older than 40 years. In terms of statistics in North America and other parts of the world, the mean life of power transformers is around 45 years with a deviation of 10 to 15 years [10, 15]. Therefore this is a quite aging group and the end-of-life failures are a real concern, particularly for the following 10 to 20 years in planning. If we do not adopt the shared spare policy, the seven more than 40 years old transformers will be gradually replaced by new ones in 5 to 10 years while still leaving others in their end-of-life periods with high failure probability. Individual replacement around the end-of-life age but before an aging failure is an expensive and unreliable policy.

In this application, the type of spares is 25 MVA multiple voltage (138/69 to 25/12 kV) mobile transformer with +/- 12.5% OLTC. A relatively large MVA will meet the requirement of long term load growth for each substation. The multiple voltage levels at both high and low voltage sides enable a spare to be used for any substation. A mobile spare requires short time (about 24 hours) to install and thus non-repairable failures can also take advantage of it while the main purpose is to target non-repairable aging failures. The price of a mobile spare transformer was estimated to be about $ 1.6 - 1.9 million. The economic life of a mobile spare was assumed to be 45 years and a discount rate of 8% was used.

A yearly load growth rate of 1.5% was assumed for all substations based on a long term load forecast in the region. The time length in the study is 20 years from 1998 to 2017. In the case of no spare, it has been assumed that it would take one year to replace. The average unit interruption cost of $55/MWh was used in the analysis. This is based on a synthetic consideration of revenue reduction and other damages due to possible emergency measures during one year before replacement. The data for the 26 substation transformers are given in Table 1. In this application, the natural age of the transformers (service years) was used. An average load factor of 0.6 for the studied region was employed in the analysis.

Reliability Analysis of the Substation Group

The SPARE program using the proposed approach was used to conduct unreliability evaluation and probabilistic cost analysis of the substation group. Table 2 shows the annual probabilities of the cumulative loss-of-load state for the substation group with varying numbers of spares for 20 years. Again, note that the concept of the annual probability is completely different from that of availability for a repairable system which is often used in power system reliability evaluation. The annual probability is a state transition probability rather than availability. It can be seen that the annual probabilities of the cumulative loss-of-load state for the substation group without any spare are very high and increase with years. This is because of the old age of the transformers and the transformers become older and older. As mentioned earlier, half of transformers in the group exceed 30 years of service (7 transformers more than 40 year and 6 transformers more than 30 years). They are close to the end of life. On the other hand, it can also be seen that with the spare transformers, the situation of very high unreliability will never happen. The unreliability decreases dramatically as the number of spares increases. For example, with the first spare, the annual probability of the cumulative loss-of-load state for the substation group is reduced from 0.410 to 0.0917 in 1998 and from 0.930 to 0.730 in 2017. With the fifth spare, this probability will be reduced to 0.000005 in 1998 and 0.030 in 2017. The annual probabilities in the years far away generally are not a main concern. In fact, the transformers over 30 and 40 years now would be more than 50 and 60 years old respectively in 2017 and one or more actual replacements due to aging failure(s) may have taken place before that.

Table 1 Substation Data

Substation	In-Service Year	1998 Peak Load (MW)
Ahc	1966	7.0
Cin	1971	3.0
Sen	1966	1.0
Cea	1971	8.0
Vve	1976	12.0
Aol	1976	0.3
Bue	1976	2.0
Myi	1956	2.5
Mry	1978	10.0
Soo	1966	2.0
Sar	1974	6.0
Prs	1956	2.0
Rdi	1976	6.0
Ive	1980	5.0
Can	1956	0.9
Cas	1976	7.0
Mnt	1966	0.8
Hff	1976	7.0
Brr	1976	10.0
Tax	1956	0.3
Ljo	1954	2.4
Pvi	1954	0.4
Hgh	1966	4.2
Mcu	1987	0.04
Cno	1958	6.0
Wst	1966	2.9

Table 2 Annual Probabilities of the Cumulative Loss-of-load State for the Substation Group

Year	0 Spare	1 Spares	2 Spares	3 Spares	4 Spares	5 Spares
1998	0.410421	0.091724	0.013052	0.001286	0.000092	0.000005
1999	0.445581	0.110338	0.017545	0.001942	0.000157	0.000009
2000	0.481262	0.131495	0.023279	0.002884	0.000262	0.000018
1001	0.517171	0.155262	0.030488	0.004215	0.000430	0.000033
2002	0.553007	0.181655	0.039420	0.006059	0.000690	0.000060
2003	0.588466	0.210629	0.050325	0.008570	0.001086	0.000106
2004	0.623254	0.242070	0.063445	0.011929	0.002678	0.000182
2005	0.657091	0.275796	0.079002	0.016342	0.002541	0.000305
2006	0.689717	0.311558	0.097184	0.022041	0.003776	0.000502
2007	0.720903	0.349045	0.118130	0.029273	0.005506	0.000807
2008	0.750453	0.387895	0.141920	0.038295	0.007883	0.001270
2009	0.778209	0.427701	0.168561	0.049359	0.011082	0.001954
2010	0.804056	0.468030	0.197981	0.062703	0.015304	0.002946
2011	0.827918	0.508440	0.230029	0.078535	0.020770	0.004349
2012	0.849762	0.548490	0.264473	0.097019	0.027715	0.006293
2013	0.869591	0.587758	0.301007	0.119259	0.036377	0.008928
2014	0.887446	0.625861	0.339260	0.142296	0.046986	0.012428
2015	0.903394	0.662456	0.378816	0.169092	0.059755	0.016983
2016	0.917529	0.697256	0.419224	0.198535	0.074867	0.022796
2017	0.929964	0.730033	0.460018	0.230434	0.092457	0.030076

Determining the Number and Timing of Spares

The damage costs of the substation group due to transformer failures were calculated according to Equations (9) and (10). The differences between the cases with no spare and one, one and two spares, etc. provide the damage savings due to spares. The damage savings for the 20 year period are shown in Table 3. Based on this table, the number and timing of required spares can be determined by comparison between the benefit and the capital expenditure of the spare. The criterion is that when the annual saving in the damage cost (benefit) due to adding a spare is larger than its annual capital cost, an additional spare is required. The annual capital cost of a spare is calculated below using Equations (11) and (12) and the data given earlier:

$$\text{Annual Capital Cost} = 1.9k*(0.08*(1+0.08)^{45})/((1+0.08)^{45} - 1) = 156.9 \text{ k\$}$$

Comparing the annual capital cost of a spare with the saving in the damage cost due to adding the spare, it can been seen that the first spare should be required immediately in 1998, the second one in Year 2003, the third one in Year 2009 and the fourth one in Year 2014. These have been marked with flag * in Table 3. The saving in the damage cost due to adding spares increases with time because the load level grows at a rate of 1.5% and the annual failure probability of the transformers increases as they become older.

Table 3 The Savings in Damage Costs Due to Adding Spares (K$)

Year	First spare	Second spare	Third spare	Fourth spare	Fifth spare
1998	* 288.68	65.76	9.55	1.04	0.00
1999	322.98	81.36	13.20	1.49	0.13
2000	359.40	99.82	18.02	2.28	0.23
2001	398.34	121.44	24.31	3.43	0.39
2002	438.88	146.57	32.36	5.08	0.65
2003	481.77	* 175.28	42.58	7.40	1.06
2004	526.27	207.78	55.32	10.61	1.70
2005	574.07	244.21	71.15	14.98	2.37
2006	621.63	284.30	90.17	20.78	3.62
2007	670.69	328.37	112.99	28.46	5.44
2008	720.05	377.20	140.00	38.36	8.02
2009	769.40	428.65	* 171.25	50.89	11.58
2010	822.02	483.52	207.19	66.54	16.44
2011	872.53	541.07	247.78	85.70	22.92
2012	922.54	600.82	293.01	108.79	31.37
2013	971.77	662.23	342.74	136.15	42.20
2014	1020.76	725.26	396.97	* 168.16	55.85
2015	1068.55	788.82	455.06	204.90	72.68
2016	1114.97	852.35	516.52	246.43	93.07
2017	1160.70	915.92	581.15	292.88	117.40

Benefit/Cost Analysis for the Spare Transformers

According to the analysis given above, we need four spare transformers for the substation group before 2017. While we pay the capital investment for these four spare transformers, we also gain the benefit from the savings in the damage costs caused by substation transformer aging failures. The benefit/cost ratio for the 20 year's period from 1998 to 2017 is calculated as follows.

The cash flow for the capital investment of the four spare transformers over the 20 years from 1998 to 2017 is shown in Table 4. The present value (in 1998) of the capital investment is 3268.98 k$. The cash flow for the savings in the damage costs due to the four spare transformers over the same 20 years can be obtained from Table 3 and is also shown in Table 4. The present value (in 1998) of the savings is 10181.68 k$. The benefit/cost ratio is: 10181.68/3268.98 = 3.115 . This indicates that the spare scheme obtained from the above procedure is financially justifiable.

Table 4 Cash Flow for Capital Investment and Damage Cost Saving

Year	Capital (k$)	Damage Saving (k$)
1998	156.916	288.68
1999	156.916	322.98
2000	156.916	359.40
2001	156.916	398.34
2002	156.916	438.88
2003	313.832	657.05
2004	313.832	734.05
2005	313.832	818.28
2006	313.832	905.93
2007	313.832	999.06
2008	313.832	1097.25
2009	470.747	1369.30
2010	470.747	1512.73
2011	470.747	1661.38
2012	470.747	1816.37
2013	470.747	1976.74
2014	627.663	2311.15
2015	627.663	2517.33
2016	627.663	2730.27
2017	627.663	2950.65

Adjusted Scheme and its Benefit/Cost Ratio

There are two reasons for the adjustment in this particular application. First, it can be seen from Table 2 that the group unreliability still looks high after the four spares are considered in 1998, 2003, 2009 and 2014, particularly for those years just before the next spare is added. This is basically because of the old age of the transformers. Secondly, considering the situation where there are many aging transformers in the group (up to half of the total 26 transformers are over 30 years old), the spare scheme should focus on the years in the near future rather than the years far away. Transformer failures eventually will occur as time increases and one or more replacements will be in place. When that happens, the calculation process above will be repeated with new transformer(s) in the group to obtain a updated scheme.

The reliability criterion used in this application is that the annual probability of the cumulative loss-of-load state for the substation group is always kept below 2% for the years in which a spare is just added and below 5% for the years just before a spare is added. As mentioned earlier, the annual probability is numerically equal to the transition rate to the loss-of-load state. The criterion means that the average time to the cumulative loss-of-load state is 20 to 50 years. Obviously, one or more replacements will have taken place in such a long period. With the replacement(s), the reliability of the substation group will be further improved. In order to meet such a criterion, it can be seen from Table 2 that the alternative is to have the first two spares at the beginning (in 1998), the third spare in 2003, the fourth one in 2010 and the fifth one in 2015. The cash flows for the capital investment and the damage cost saving due to the five spare transformers over the 20 years were calculated. The present values (in 1998) for the capital investment and the damage cost saving are 4819.752 k$ and 11095.965 k$ respectively. The benefit/cost ratio is reduced to 11095.965/4819.75 = 2.302 which is still financially justifiable. The adjusted scheme is both cost efficient and reliability sufficient.

CONCLUSIONS

The responsibility of utilities is to supply electric power to their customers with satisfied reliability while minimizing capital investments. Common spare transformers shared by multiple substations can avoid considerable capital expenditure and still assure an sufficient reliability level. The spare policy has been already a practice of many utilities in the distribution substation transformer planning and will be more and more considered in the future.

This paper presents a probabilistic approach to determining the number and timing of spare transformers in a substation group. There are repairable and non-repairable transformer failures. A non-repairable failure requires a new transformer replacement which generally will take 1 to 1.5 years. Non-repairable failures are a dominant factor in the spare analysis. The proposed approach is based on the aging failure model of transformers, the overall reliability analysis and the probabilistic damage cost model for a substation group, the capital cost model for spares and the present value method. The spare transformer scheme obtained using the presented approach provides both cost efficiency and sufficient reliability.

A 26 single transformer substation group in a non-urban region was used as an application example to illustrate the procedure of the method. This is a quite aging group with half of the transformers over 30 years old. The adjusted spare scheme for this substation group requires five spare transformers for the 20 year's period from 1998 to 2017, with the first two in 1998, the third one in 2003, the fourth one in 2010 and the fifth one in 2015. The benefit/cost ratio of the scheme is 2.30 which is financially justifiable. The annual probability of transition to the cumulative loss-of-load state for the substation group is between 2% and 5% in the 20 years considered. This corresponds to a 20 to 50 year's average time to the loss-of-load state which indicates sufficient reliability. In fact, 7 transformers will reach 57 to 61 year's service in 2015 and one or more replacements will most likely take place before that year. The spare scheme will be updated using the proposed approach after any transformer replacement. Therefore the fifth or even the fourth spare may actually not be required if any replacement happens.

REFERENCES

[1] R.N. Allan, R. Billinton, S.M. Shahidehpour and C. Singh, "Bibliography on the Application of Probability Methods in Power system Reliability Evaluation (1982-1987)", IEEE Trans. on PS, Vol. 3, No.4, August 1988,

[2] IEEE Tutorial Course Text, Reliability Assessment of Composite Generation and Transmission Systems, 90EH0311-PWR, IEEE Publishing Services, 1990

[3] EPRI Report, Reliability Evaluation for Large Scale Bulk Transmission Systems, Report EL-5291, 1988

[4] R. Billinton and W. Li, Reliability Assessment of Electric Power Systems Using Monte Carlo Methods, Plenum Press, New York, 1994

[5] R. Billinton, "Distribution System Reliability Performance and Evaluation", Electrical Power and Energy Systems, Vol.10, No.3, 1988, pp190-200

[6] W. Li, Y. Mansour, J.K. Korczynski and B.J. Mills, "Application of Transmission Reliability Assessment in Probabilistic Planning of BC Hydro Vancouver South System", IEEE Trans. on PS, Vol. 10, No. 2, 1995, pp964-970

[7] W. Li, Y.Mansour, B.J. Mills and J.K. Korczynski, "Composite System Reliability Evaluation and Probabilistic Planning: BC Hydro's Practice", 1995 Canadian Electric Association Conference, Vancouver, March 1995

[8] W.J. McNutt, "Insulation Thermal Life Considerations For Transformer Loading Guides", 1991 IEEE Summer Meeting, Paper No.91 SM 320-2 PWRD, San Diego, July 28 -Aug. 1, 1991

[9] R. Billinton and R. N. Allan, Reliability Evaluation of Engineering Systems, Plenum Press, New York and London, 1983

[10] D. Allan C.Jones and B. Sharp, "Studies of the Condition of Insulation in Aged Power Transformers, Part I: Insulation Condition and Remnant Life Assessments for In-Service Units", Proceedings of the 3rd International Conference on Properties and Applications of Dielectric Materials, Tokyo, July 8-12, 1991

[11] G.C. Stone, "Application of Statistical Methods to the Design of Solid Insulation Systems", IEEE 1985 Annual Report Conference on Electrical Insulation and Dielectric Phenomena, October 1985, pp234-250

[12] W.J. McNutt and G.H. Kaufman, "Evaluation of a Functional Life Model for Power Transformers", IEEE Trans. on PAS, Vol.102, May, 1983, pp1151-1162

[13] J.Biernet, J.arnicki, K.Kaplon, A.Kuras and G.J.Anders, "Reliability Considerations in Accelerated Life Testing of Electrical Insulation with Generalized Life Distribution Function", IEEE Trans. on PS, Vol.7, No.2, May, 1992, pp656-664

[14] Chan S. Park, Contemporary Engineering Economics, Addison-Wesley Publishing Company, New York, 1993

[15] J. M. Eyer and R. P. Branstetter, "Replacements: units, Service Lives, Factors", Technical report of E&B Consultants, prepared for U.S. Department of Interior Bureau of Reclamation and U.S. Department of Energy Western Area Power Administration, 1982

Bibliography

Wenyuan Li: Senior Engineer of the Control Center Technologies Department of BC Hydro, IEEE senior member, the co-author of the book "Reliability Assessment Of Electric Power Systems Using Monte Carlo Methods", Plenum Press, New York, 1994

Ebrahim Vaahedi: Manager of the Control Center Technologies Department of BC Hydro, adjunct professor at the Electrical Engineering Department of University of British Columbia, IEEE senior member

Yakout Mansour: Manager of the Grid Operations and Inter-Utility Affairs Division of BC Hydro, the chairman of the IEEE PES Power System Dynamic Performance Committee, IEEE fellow