OPTIMAL SPARING STRATEGY FOR SUBSTATION COMPONENTS

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Abstract: The paper suggests a method to optimize the number of spare items of substation components which have to be stored at the beginning of each year throughout a planning period. This sparing policy is conceived to provide the minimum total cost consisting of investment and load curtailment costs. The method uses the Hooke & Jeeves' direct search optimization approach. The application of the method suggested and the benefits it provides are demonstrated for two typical substation arrangements.

Keywords: substation, equipment, sparing, reliability, investment, load, curtailment, cost, optimization

1. LIST OF PRINCIPAL SYMBOLS

Z - total cost associated with sparing, during the planning period

I - sparing investment cost, during the planning period

L - load curtailment cost, during the planning period

m_{ij} - amount of spare items of substation component i stored at the beginning of year j

c_i - investment cost for a spare component i

r - discount rate

q - number of different substation components

n - duration of the planning period, expressed in years

p_i - probability that the damage of component i cannot be repaired

$\lambda'_i, \lambda'_{Ai}$ - failure and active failure transition rates for component i, per component

λ_i, λ_{Ai} - total failure and active failure transition rates for all components i associated with substation

c_L - load curtailment cost per kWh not delivered

P_{kj} - probability that deficiency situation k will occur in year j

W_{kj} - energy not delivered in deficiency situation k, in year j

C_{kj} - capacity for load supply available in deficiency situation k, in year j

r_{oi}, r_{ri}, r_{Ri} - ordering lead-, repair- and replacement-times for component i, respectively

r_{ij} - expected mean renewal time for component i in year j

r'_{ij}, r''_{ij} - expected mean renewal time for unrepairably (repairably) damaged component i

λ'_{MCB}, r_{MCB} - circuit breaker maintenance transition rate and duration

s - switching time

S_T - transformer unit installed capacity

$P\{A\}$ - probability of event A

$A + B \equiv$ either A or B or both

$A \cdot B \equiv$ both A and B

Nomenclature

functional block - group of substation components functionally associated in such a way that the repair or maintenance of any one of the components of the group interrupts the operation of all other components of the group.

critical event - event that causes a deficiency situation

maintenance - planned preventive maintenance

active failure - failure that causes immidiate operation of adjacent circuit breakers

2. INTRODUCTION

To improve the reliability of electric power supply to the consumers it is important to reduce the time that is needed for restoration of the functional ability of the supplying power system after failures of its components. For the distribution systems, the reliability of the main, generating substations are of the substantial importance. It is particularly the case if there is a low redundancy installed in such a substation itself and in the adjacent substations and/or in the associated lower voltage distribution network supplying the consumers. However, the improvement of the substation reliability has its price as it implies higher investment cost for reinforcements. A rational approach is to analyze costs and benefits achieved with reinforcements in order to establish the solution that provides minimum total cost, including both investment and load curtailment costs.

The analysis performed for a generating transformer substation with two transformer banks [1,2], has shown that spare transformer units, if available, might significantly improve the reliability indices of the substation.

This paper analyzes the effects of the sparing concept for all substation components, generally, and suggests a method

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to determine an optimal sparing strategy that provides minimum total cost for a planning period. The total cost includes both the investment cost for spare components and load curtailment costs caused by the failures of substation components. Two typical substation arrangements are analyzed using the method proposed, as an illustration. The analysis performed has shown that the optimal sparing could significantly reduce the total costs associated with a substation.

3. MATHEMATICAL MODEL

The optimal policy in ordering the number of spare substation components, during the planning period, has to provide the minimum amount of the total cost Z determined as:

$$Z = I + L \qquad (1)$$

Both the storage investment and load curtailment costs are over the entire time period for which the storage policy has to be optimized. For a proper evaluation, the present-worth costs (equivalent costs at the beginning of the first year of the planning period) have to be used [3].

The present-worth investment cost is

$$I = \sum_{j=1}^{n} \sum_{i=1}^{q} m_{ij} c_i (1+r)^{-j+1} - \sum_{j=1}^{n} \sum_{i=1}^{q} c_i u_{ij} (1+r)^{-j+1/2} \qquad (2)$$

Parameter u_{ij} in expression (2) is, by definition,

$$u_{ij} = \begin{cases} \min((p_i\lambda_i), a_{ij}) & \text{for } a_{ij}>0 \\ 0 & \text{otherwise} \end{cases} \qquad (3)$$

where

$$a_{ij} = \sum_{s=1}^{j} m_{is} - j p_i \lambda_i \qquad (4)$$

The first term in (2) yields the cost spent, during the analyzed period, for refilling the stocks of different substation components in the inventory. The items that have been taken from the inventory stocks to replace the damaged components, do not cause storage investment cost any more. This fact has been accounted for by the second term in (2). Parameter u_{ij} indicates the expected number of items of substation components i that will be taken, in year j, from the inventory stock, for replacing the damaged components i. Parameter a_{ij} is the expected number of spare items of component i in year j and $p_i\lambda_i$ is the expected number of unrepairably damaged components i per year in each year, if λ_i is expressed in 1/year units. As clearly from (2), the assumption has been made that the replacements will take place in the middle of the year j.

The load curtailment costs can be evaluated as

$$L = \sum_{j=1}^{n} L_j (1+r)^{-j+1/2} \qquad (5)$$

with

$$L_j = c_L \sum_{kj} p_{kj} W_{kj} \qquad (6)$$

where index kj covers all load deficiency situations k expected to occur in year j. The energy not supplied in deficiency situation k can be evaluated using the hourly load duration diagram , for year j, as shown in Fig.1.

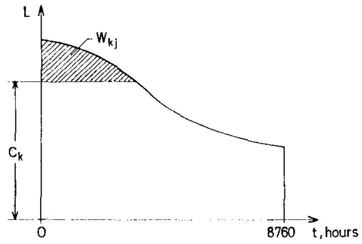

Fig.1 Hourly load duration diagram and the energy not supplied in a deficiency situation; C_k is the available substation capacity

Annual load curtailment cost L_j depends on parameters m_{ij} because these affect the duration of deficiency situations caused by substation's components failures. The expected renewal time for substation component i in year j can be evaluated using the expression

$$r_{ij} = p_i r'_{ij} + (1-p_i) r''_{ij} \qquad (7)$$

The expected renewal time, for component i, for an unrepairable damage, will be

$$r'_{ij} = r_{oi} + \alpha_{ij}(r_{Ri} - r_{oi}) \qquad (8)$$

The expected renewal time, for component i, for a repairable damage, can be determined as

$$r''_{ij} = \begin{cases} r_{ri} & r_{ri} < r_{Ri} \\ r_{ri} + \alpha_{ij}(r_{Ri} - r_{ri}) & \text{otherwise} \end{cases} \qquad (9)$$

In (8) and (9), parameter α_{ij} reflects the storage situation

$$\alpha_{ij} = \begin{cases} 1 & \text{for } a_{ij}>0 \\ 0 & \text{otherwise} \end{cases} \qquad (10)$$

If the total number of substation components i stored during j years is not less than the expected number of unrepairably damaged components i during the same period, there will be , in year j, enough spare items of component i in the stock for replacing the damaged ones. For such a situation, expressions (10) and (8) yield $\alpha_{ij}=1$ and $r'_{ij}=r_{Ri}$, respectively. Otherwise, the components i renewal time will be equal to the ordering lead time, i.e. $r'_{ij}=r_{oi}$, which is generally much longer than the replacement time r_{Ri}. In (10), it is assumed that the mean repair duration is considerably lower than the mean time between faults (MTBF) of components i and that, therefore, it is very likely that the damaged component i will be repaired before the next damage of any of the components i occurs, and, consequently, it will be a spare item for substation components i. Therefore, as far as the repairable damages are concerned, we need to have only one spare item of components i available before the first repairable damage of a component i occurs. This fact is covered by the "greater than" condition in (10). As it is observable from (9), for $\alpha_{ij}=1$, the outage duration r''_{ij} is the replacement time, which is generally much shorter than the repair time. However, if the repair time is shorter than the replacement time, the component i will be repaired whenever there are spare components i available or not, as stated by the first relationship in (9).

The load curtailment costs L_j do not include the load supply interruption cost due to the substation components active failures alone, and the cost of the interruption caused by preventive maintenance alone or by superposition of active failure upon maintenance because all these interruptions of load supply are not affected by the equipment storage conditions.

There are several efficient methods for evaluating the reliability indices of substations and the associated load curtailment cost [4-6], that can be utilized in the optimization procedure suggested in this paper. The illustrative examples presented in Section 4 have been worked by applying the approach based upon the algebra of events, that yields closed form expressions for the probabilities of substation deficiency states (Appendix A.1).

4. APPLICATION

4.1 Single-Busbar-System Substation

The single-line diagram of the sample single-busbar substation for the higher voltage side is presented in Fig.2. Substation components are merged into functional blocks, regarding their functional dependability. The relevant data for the substation are presented in Table I. All substation components are singe-phase constructions , except the busbar and the transformer. Only circuit breakers are preventively maintained.

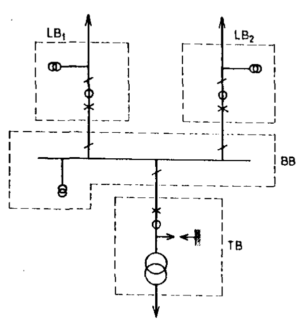

Fig.2 Single-busbar-system substation one-line diagram with components merged into functional blocks; x - circuit breaker, / - disconnector, o - current transformer, ⟶ ⟵ - surge arrester

The substation is fed from the higher voltage side by two redundant lines and it supplies a distribution network on the lower voltage side. The annual hourly load-duration diagram for the transformer is displayed in Fig.3. It is assumed that the load has reached its saturation and that there are no annual load level increments during the planning period.

Three cases have been studied concerning the capability of the distribution network in transferring the load from the subject substation to the adjacent substations:

A) There are no load transferable facilities

B) A load amount of 150 MW can be transferred

C) A load amount of 180 MW can be transferred

Table I. Substation Data

Substation component i *)	λ'_{Ai}	λ'_i	r_{0i}	r_{ri}	r_{Ri}	p_i	I_i **)
	10^{-3}/year		hours				10^3\$
T	20	20	8760	20	200	0.4	180.0
CB	8	13	2160	7	6	0.3	7.86
CT	4	4	2160	-	6	1.0	6.0
VT	8	8	2160	-	3	1.0	3.0
D	1	2	2160	-	3	1.0	0.96
B	15	15	2160	10	5	0.8	4.0
SA	4	4	2160	-	3	1.0	0.96

c_L	r	λ'_{MCB}	r_{MCB}	s	S_T	n
\$/kWh		1/year	hours		MVA	
0.315	0.05	1	6	1/6	300	20

*) T - transformer; CB - circuit breaker; CT - current transformer; VT - voltage transformer; D - disconnector; B - busbar; SA - surge arrester

**) Yugoslav market prices in Summer 1989, converted into US\$.

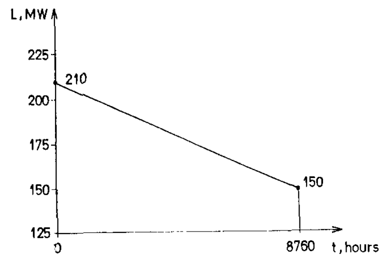

Fig.3 Annual hourly load duration diagram for the sample single-busbar-system substation

The method suggested in this paper will be used to optimize the storage of the substation's components on the higher voltage side. Clearly, the same procedure could be applied for the substation's components on the lower voltage side, separately, in the analogous way, as the storage conditions for higher and lower voltage substation equipment do not affect one another.

From Fig.2 it is clear that

$$OTC = TB + BB + LB_1 \cdot LB_2 \tag{11}$$

The events in equation 11 are the following:

OTC = outage of the substation total capacity

TB = outage of block TB

BB = outage of block BB

LB_k = outage or preventive maintenance of line k block, k=1,2

Active failures of circuit breakers in feeder's blocks, causing the substation outage, are not considered in expression (11) because the substation operation is restored after switching and the outage duration is not affected by the storage conditions, as already stated previously. The preventive maintenance of the transformer circuit breaker is also not included , as the storage situation does not affect the duration of the maintenance.

The expressions for the probabilities associated with events in equation (11) can be determined from substation component reliability indices given in Table I and from expressions (7)-(10), by applying a simple procedure (Appendix A.1). For brevity sake, these expressions will not be given.

For the example analyzed, it will be

$$p_{1j}=Pr\{OTC\}$$

$$c_{1j} = \begin{cases} 0 & \text{for case A} \\ 150\ \text{MW} & \text{for case B} \\ 180\ \text{MW} & \text{for case C} \end{cases} \qquad j=1,\ldots,20 \qquad (12)$$

In (12) k=1 because there is only one deficiency situation to be considered, for all j.

Expressions (2)-(12) completely describe all relevant circumstances that are needed to determine the optimal ordering of spares for substation components minimizing the total cost Z defined by expression (1). The optimal quantities m_{ij} have been determined by applying the Hooke & Jeeves' direct search method (Appendix A.2). For all three cases studied it was established that the optimal storage policy is to store one spare item for each substation component, including the transformer, at the beginning of the first year only. As exception, an additional spare voltage transformer has to be provided at the beginning of the 14th year. This result can be explained by the fact that the failures of all substation components cause the outage of the substation, as all these components are present in transformer and busbar blocks and such outages result in very high load curtailment cost. A spare voltage transformer has additionally to be ordered, later, in course of the study period, because it has relatively high failure rate and requires low investment.

Table II yields the present-worth costs for the sample substation for a 20-year planning period.

As it is observable from Table II, the optimal storage policy considerably decreases the total cost for all cases analyzed. The advantages provided by optimal sparing are the more remarkably the lower is the redundancy in supplying the consumers. The "restrictive" sparing , which is frequently exercised in practice, reduces the total substation cost when compared to the no-sparing concept but the benefits it provides are considerably lower than these achievable by optimal sparing. For case C, the saving achieved by the optimal sparing is relatively lower than for cases A and B because of the improved redundancy of the power supply. However, it is still substantial.

Table 2 Single-Busbar-System Substation's Present-Worth Costs For 20-year Planning Period

Sparing policy	Investment cost for reserve equipment	Load curtailment cost	Total cost
		10^6 \$	
Case A : No load transferable facilities			
Optimal	0.176	1.724	1.900
Restrictive*	0.013	60.64	60.65
No spares	-	192.5	192.5
Case B : Load amount of 150 MW can be transferred			
Optimal	0.176	0.287	0.463
Restrictive*	0.013	10.11	10.12
No spares	-	32.10	32.10
Case C : Load amount of 180 MW can be transferred			
Optimal	0.176	0.072	0.248
Restrictive*	0.013	2.527	2.54
No spares	-	8.03	8.03

*One spare for each component, except transformer, stored at the beginning of the planning period

4.2 Ring-Busbar-System Substation

The single-line diagram of the sample ring-busbar-system substation is presented in Fig.4. The parameters of the substation components are the same as for the single-busbar-system substation. The load-duration diagram for the substation has the same general shape as the diagram in Fig.3, with doubled load magnitudes.

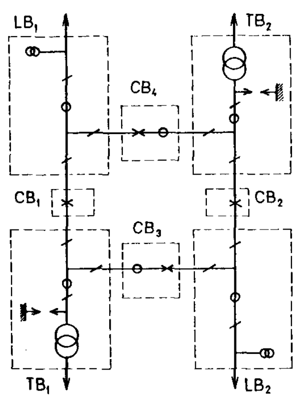

Fig.4 Ring-busbar-system substation one-line diagram with components merged into functional blocks; x - circuit breaker, / - disconnector, o - current transformer, —› ‹— - surge arrester

As it is observable from Fig.4, the outages of transformer T_1 and T_2 are determined by the following event algebra expressions

$$OT_1 = TB_1+CB_1 \cdot CB_3+CB_1 \cdot LB_2+CB_3 \cdot LB_1 \quad (13)$$

$$OT_2 = TB_2+CB_2 \cdot CB_4+CB_2 \cdot LB_1+CB_4 \cdot LB_2 \quad (14)$$

The outage of the total substation capacity can be expressed as

$$OTC = TB_1 \cdot TB_2+LB_1 \cdot LB_2+CBA_1 \cdot (TB_2+LB_2+CB_2)+CBA_2 \cdot (TB_1+ LB_1+CB_1)+CBA_3 \cdot (LB_1+CB_4+TB_2)+CBA_4 \cdot (LB_2+CB_3+TB_1) \quad (15)$$

In (13) - (15), the out-of-service events for substation blocks are, again, designated with the same symbols as the corresponding blocks. Symbols CBA_k ,k=1,...,4, denote active failures of circuit breakers. Events in equations (13) -(15) generally mean failure or maintenance of the corresponding substation's functional blocks. As the circuit breakers are the only components that are maintained, maintenance events are associated with only these functional blocks that comprise circuit breakers. The overlapping of active failures and maintenance with failures are included in equation (15) since the duration of such events depend upon the renewal time of the component which is down while there is an active failure or maintenance of another component.

Events OT_1, OT_2 and OTC cause the load interruption the duration of which can be decreased by storage of spare equipment.

Hence, we have

$$p_{1j} = P\{OT_1\} \qquad C_{1j} = 300 \text{ MW}$$
$$p_{2j} = P\{OT_2\} \qquad C_{2j} = 300 \text{ MW} \qquad j=1,\ldots,20 \quad (16)$$
$$p_{3j} = P\{OTC\} \qquad C_{3j} = 0$$

In equation (16), it is assumed that the distribution network is capable to transfer the load from the transformer that is out of service to the operating one.

The Hooke & Jevees' direct search method has established that it is optimal to store a single spare, for all components, at the beginning of the substation planning period, and to store one additional disconnector and current transformer at the beginning of the 14th year of the planning period.

Table III yields the relevant substation cost for different sparing concepts.

The benefits achieved with optimal storage planning are, again, considerable. The main reason for this is the high load curtailment cost as a single transformer outage causes a deficiency situation throughout the entire year during the whole planning period, with the interrupted load amount being up to 120 MW , in the worst case.

In order to check the validity of the approximate method used for the evaluation of the outage probabilities and durations, based upon expected mean duration of different substation's components states, the load curtailment cost, for the optimal storage policy, has been calculated by applying the Monte Carlo simulation technique. Exponential

Table III Ring-Busbar-System Substation's Present-Worth Costs For 20-year Planning Period

Sparing concept	Investment cost for reserve equipment	Load curtailment cost	Total cost
		10^6 $	
Optimal	0.152	0.968	1.120
Restrictive*	0.007	43.28	43.29
No spares	-	84.63	84.63

*One spare for each component, except transformer, stored at the beginning of the planning period

distributions for operating time of substation components have been assumed. The fault duration and circuit breaker maintenance time have been taken as random quantities determinable as:

$$r_{Ri} = \hat{r}_{Ri}(1 + \beta) \quad (17)$$

$$r_{MCB} = \hat{r}_{MCB}(1 + \gamma) \quad (18)$$

In (17) and (18), $\hat{r}_{Ri}$ and $\hat{r}_{MCB}$ are the corresponding mean values taken from Table I, β is a normally distributed random variable with zero mean and standard deviation equal to 0.25 and γ is a random variable distributed uniformly within the interval (-0.5, 0.5). The switching time has been taken as deterministic, fixed quantity. The analysis of a sample of 1200 planning 20-year periods has shown that the 95% confidence interval for the present-worth load curtailment cost is $(0.927 - 1.095)10^6$ $, which matches well with the result from Table III obtained by utilizing the approximate method. For illustration's sake, Fig.5 displays the relative frequency histogram of the present-worth load curtailement cost for optimal sparing , as obtained by the simulation.

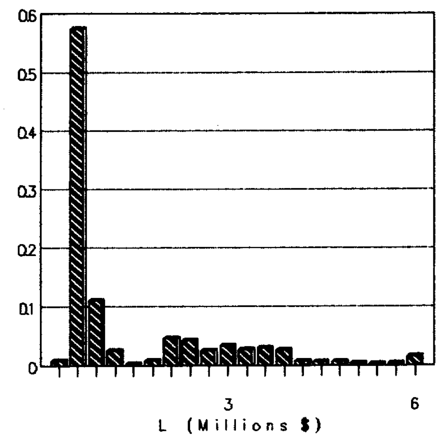

Fig.5 Relative frequency histogram of the present-worth load curtailment cost for optimal sparing

The load curtailment cost per kWh not served considerably affects the total substation cost. To investigate this effect quantitatively, the total cost for the sample substation has been calculated for different c_L values, for various sparing concepts (Fig.6.) .

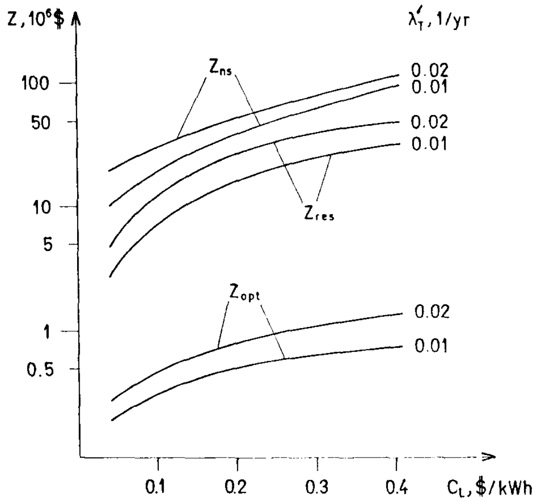

Fig.6 Total substation cost for various parameter c_L values; λ'_T - transformer unit failure rate; ns - no spares, res - restrictive sparing, opt - optimal sparing

5. CONCLUSIONS

The paper suggests a method for optimizing the sparing of substations components to provide minimal total cost, comprising the load curtailment and storage investment costs, during a planning period. The analysis performed for two typical substation arrangements has clearly shown that the application of the optimization method proposed can substantionally decrease the total cost. The comparison of different sparing concepts for substation components, carried out in the paper, has indicated that the substation costs are substantially sparing sensitive, particularly if the power supply redundancy is limited and the cost per kWh not served is high.

6. ACKNOWLEDGEMENT

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7. APPENDIX

A.1 Evaluation Of The Probability Of The Substation Deficiency States

Nomenclature

renewal - repair or replacement from storage or replacement by ordering

out-of-service - renewal or/and maintenance of a functional block

basic event - renewal or active failure or maintenance of a functional block

elementary event - renewal or active failure or maintenance of a functional block component

event direct form - event described by the mixed sum of out-of-service and basic events and their products

event basic form - event described by the sum of basic events and their products

Notation

B = out-of-service of functional block B
BR = renewal of functional block B
BM = maintenance of functional block B
BA = active failure of functional block B
E = critical event
$P\{A\}$ = probability of event A
R_i = renewal time of functional block or component i
M_i = maintenance duration for functional block or component i

All other symbols and definitions are given in Sec.1.

Basic assumptions:

a) Probabilities of coincidencies of more than two basic (elementary) events are relatively small and they can be ignored.

b) Probabilities of coincidencies of two and more active failures are relatively small and they can be ignored.

c) Two or more functional blocks cannot simultaneously be maintained.

d) The maintenance of any component cannot begin if there is a renewal activity in due course in the substation.

e) Critical events due to active failures or maintenance alone and due to the coincidence of these events are ignored.

As stated in Sec.3, assumption e) is specific for the problem being studied in this paper. Other assumptions listed are usually made in substation reliability analysis [4-6].

The critical event for a deficiency situation is described by the following general direct form, according to assumptions a) ,b) and e),

$$E = \sum_j BR_j + \sum_{i,k} B_i \cdot B_k + \sum_{p,k} BA_p \cdot B_q \tag{A.1}$$

where indices j, i, k, p and q designate relevant substation functional blocks. Expression (A.1) can directly be red from the substation scheme (see expressions (11) and (13)-(15), as examples).

By definition,

$$B_g = BR_g + BM_g \qquad \forall\ g \tag{A.2}$$

From assumption c) and expression (A.2) it follows

$$B_i \cdot B_k = (BR_i + BM_i)\cdot(BR_k + BM_k) = BR_i \cdot BR_k + BR_i \cdot BM_k + BM_i \cdot BR_k \tag{A.3}$$

as the coincidence of the maintenance of two functional blocks is an impossible event.

Regarding assumption e) and (A.2) we have

$$BA_p \cdot B_q = BA_p \cdot (BR_q + BM_q) = BA_p \cdot BR_q \tag{A.4}$$

By expressing the terms in (A.2) using (A.3) and (A.4), the relationship for E is converted into its basic form

$$E = \sum_j BR_j + \sum_{i,k} (BR_i \cdot BR_k + BR_i \cdot BM_k + BM_i \cdot BR_k) + \sum_{p,q} BA_p \cdot BR_q \tag{A.5}$$

Probability of event E is approximately equal

$$P\{E\} = \sum_j P\{BR_j\} + \sum_{i,k} (P\{BR_i \cdot BR_k\} + P\{BR_i \cdot BM_k\} + P\{BM_i \cdot BR_k\}) + \sum_{p,q} P\{BA_p \cdot BR_q\} \tag{A.6}$$

The terms in (A.6) are [1]

$$P\{BR_i \cdot BR_k\} = P\{BR_i\} \cdot P\{BR_k\}$$

$$P\{BR_i \cdot BM_k\} = P\{BR_i\} \cdot P\{BM_k\} \cdot \frac{M_k}{R_i + M_k} \qquad (A.7)$$

$$P\{BA_i \cdot BR_k\} = P\{BA_i\} \cdot P\{BR_k\}$$

Basic event reliability indices can be evaluated using the following expressions [1]

$$P\{BR_i\} = \sum_{k_i} \lambda'_{k_i} \cdot R_{k_i} \quad , \quad R_i = \frac{P\{BR_i\}}{\sum_{k_i} \lambda'_{k_i}} \qquad (A.8)$$

$$P\{BA_i\} = \sum_{k_i} \lambda'_{Ak_i} \cdot s \qquad (A.9)$$

$$P\{BM_i\} = \sum_{k_i} \lambda'_{Mk_i} \cdot M_{k_i} \quad , \quad M_i = \frac{P\{BM_i\}}{\sum_{k_i} \lambda'_{Mk_i}} \qquad (A.10)$$

In (A.8) and (A.9), index k_i is over all substation components belonging to functional blok i. Groups of components within a functional block can be maintained simultaneously. If this is the case, index k_i in (A.10) includes only the components that are representative for the simultaneously maintained component groups.

The procedure for calculating the probability of critical event can briefly be summarized in the following steps:

1. Determine the functional blocks for the substation.

2. By inspection of the substation diagram determine the critical event E and describe it using the event direct form (expression (A.1)).

3. Convert the event direct form into the event basic form (expression (A.5)) using (A.2) to (A.4).

4. Calculate the reliability indices for all basic events and products of basic events that are present in the event basic form by means of expressions (A.7) to (A.10).

5. Calculate the probability of the critical event using (A.6).

A2. Optimization Flow Using the Hooke & Jeeves' Method [7]

From Sec.1 and Appendix A.1 it is clear that the total cost Z is an explicite function of parameters m_{ij} , j=1,...n and i=1,...,q. This can be formally stated as

$$Z = F(\mathbf{M})$$

where **M** is a $n \cdot q$-dimensional vector the components of which are parameters m_{ij} . Vector **M** specifies a point in the $n \cdot q$ dimensional space of coordinates m_{ij}. Cost Z is the *objective function* for the optimization method.

The Hooke & Jeeves' method proceeds with a sequence of *exploatory* and *pattern* moves in the space of variables. In the exploatory moves the method evaluates the objective function values around a chosen point in order to find neighbouring points that yield lower objective function values. Such points, if any, are *better points* and the point among them that gives the lowest objective function value is the *best point*. The exploatory moves are performed by subsequently changing the point coordinate values by a *step length* which is chosen to be equal to 1, in this application. Besides, no negative point coordinate values have been allowed because of their nature. If a better point is found, a pattern move, "leap frog", is made in the direction of the best point determined by the exploatory moves, to speed up the calculation.

For a better understanding, the flow chart for the procedure applied in this paper is presented in Fig.7 . To check if the found solution is the absolute minimum of the objective function, the calculation procedure has to be repeated with several different sets of initial values of m_{ij} , as initial points.

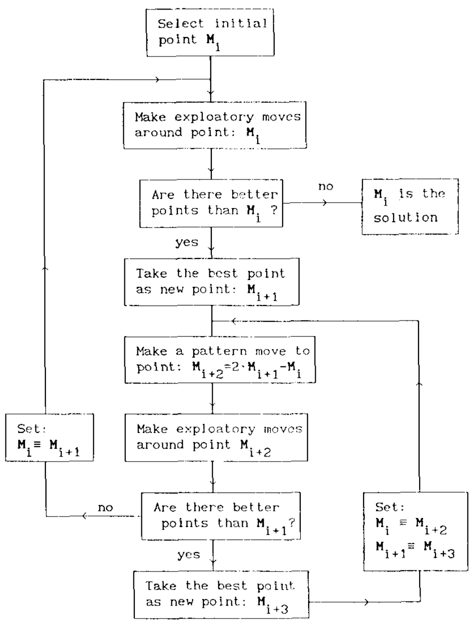

Fig.7 Flow chart for the Hooke and Jeeves' direct search method

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