Distribution Feeder Scheduling Considering Variable Load Profile and Outage Costs

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***Abstract*—In a deregulated power market, customers would have more choices for their power service and the improvement of service quality has become a challenge to power transmission and distribution companies. Distribution system reliability that was traditionally considered within the planning activities is now incorporated in the operational environment. This paper presents study results of a multiobjective feeder operation optimization problem that considers how to balance network efficiency, switching and reliability costs in a distribution network. The proposed method divides annual feeder load curve into multiperiods of load levels and optimizes the feeder configurations for different load levels in annual operation planning. Customer load profiles and seasonal varying data of feeder section failure rates and customer interruption costs are considered. Numerical simulations demonstrate the time-varying effects on the optimal distribution feeder configuration and operation costs. A binary particle swarm optimization (BPSO) search is adopted to determine the feeder switching schedule. Test results indicate that not considering time-varying effects and using only simplified fixed load and reliability parameters could underestimate the total loss to the utility and its customers.**

***Index Terms*—Customer interruption cost, distribution feeder reconfiguration, distribution system operation, system loss, system reliability.**

I. Introduction

DISTRIBUTION networks provide the final links between the transmission systems and customers. Distribution networks are divided into subsystems of radial or loop feeders fitted with a number of switches that are normally closed or opened. Customers could be supplied from different substations or by distributed power generations through different routes each with different reliability records. These paths are characterized by different mixtures of commercial, industrial and residential customers who might impose time-varying load demands and different service reliability requirements.

Operation records have shown that most customer service interruptions are due to failures in the distribution networks. It is recognized that distribution network structure affects the system operating efficiency and effective operations of the service restoration. To improve service reliability, distribution network reinforcements and automated switches are applied to the distribution network, and many distribution applications, such as var planning, optimum switching/feeder reconfiguration, and distribution state estimation, are gradually adopted in distribution management systems (DMS) to improve reliability and hence service to the electricity customers [1]–[3].

Many algorithms have been proposed to solve the feeder reconfiguration problems. To restructure primary feeders for loss reduction, a simple formula which removes the need to conduct many load flow studies was presented in [4] as a planning and/or real-time control tool. Approximate power flow and loss reduction formula with varying degree of accuracy were developed in [5] and [6] to aid the search for optimal feeder configuration. These methods can also be applied to the load balancing problems. Using a basic current profile concept, the global optimality condition of the problem and two solution algorithms were presented in [7] to determine the open switch positions for loss reduction. One is based on the uniformly distributed load model and the other on the concentrated current (or power demand) model. A two-stage solution methodology based on a modified simulated annealing technique and ε-constraint method for general multiobjective optimization problems was developed in [8].

A systematic method to derive the optimal short term and long term switching planning for loss reduction was proposed in [9], and a critical switch concept for feeder reconfiguration was presented. Brown extended the use of feeder reconfiguration to improve distribution network reliability [10]. A predictive reliability model was used to compute reliability indices and an annealed local search algorithm was used to adjust switch positions. An interactive fuzzy algorithm and evolution programming method were proposed to solve a multiobjective function which includes minimum loss and switching operations with good voltage quality and service reliability. Artificial neural network, particle swarm optimization and heuristic methods were also proposed for solving feeder reconfiguration and distribution operation problems [11]–[15]. PSO technique has shown good potential applications in many problems although it seems sensitive to the tuning of some weights or parameters. A new meta-heuristic evolutionary self-adapting PSO was proposed in [16] to incorporate the best features of evolution strategies and the PSO technique.

Operational experiences have shown that many influences in distribution operations, such as feeder node load profiles, feeder section failure rates and service restoration times, switching costs and system losses, have time-varying characteristics. To enhance distribution service reliability and operation efficiency, these factors should be considered in operation planning. Time-sequential simulations techniques incorporating the effects of weather conditions and restoration resources in the reliability cost/worth evaluation of distribution systems were presented in [17] and [18]. The study showed that the

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time-varying failure rate and restoration time strongly affect the results of network reinforcement planning.

Balancing operation costs, network efficiency and cost of reliability is one of the important tasks for transmission and distribution companies under deregulated environment. In many traditional feeder reconfiguration methods, fixed load and parameters were used for one snap shot optimization. To achieve optimal network efficiency, switching operations can be executed periodically according to seasonal load changes, reliability records and costs of the network. In the meantime, it is desirable to minimize the number of switching operations to reduce the possibility of switching surges and minimize operating costs.

In this paper, a multiobjective sequential optimization problem considering seasonal factors is formulated and a feeder reconfiguration solution method is proposed. Reliability costs in the system operational environment along with system losses and switching operational costs are included. System load level, customer sectors characteristics, seasonal switching concept in operational practices, and reliability time-varying models are used to determine critical switches and switching times. The proposed solution procedure divides a whole year daily average load curve of a service area into multiple load level periods and determines the optimal feeder configurations for each period. Customer load profiles and practical distribution system reliability data from outage management system (OMS) are used. Load variations, starting from small changes to only a few load levels for a year, are investigated and optimal feeder switching schedule is determined. While pseudo chronological sequential simulation and its variants methods may be excellent for distribution network planning purposes, the proposed method would require less computational efforts as compared to the sequential Monte Carlo method. Test results presented in this paper show that using only simplified fixed load and reliability parameters as have done in traditional methods could underestimate the total loss to the utility and customers as a whole.

II. Time-Varying Models

In many distribution systems, automatic and metering devices are being installed to control and monitor the networks. Feeder section loadings and interruption events occurring at the distribution feeders over specific time periods are recorded and can be used to analyze the time-varying effects of distribution feeder reliability. System fault statistics have shown that failure rates and durations have cyclical patterns due to seasonal/climatic and social variations.

Customer interruption cost studies have shown time dependence of costs, and a large portion of the incidents occur in periods when the loads and interruption costs are high [19]. To make a realistic assessment of annual operation and service reliability costs, the influence of these time dependent patterns, including correlations, is investigated. Fig. 1 shows typical monthly peak loads of different types of feeders in a service area and Table I lists the average failure rate of three types of feeders during a year. It is shown that residential, commercial and industrial feeder demands and their failure rates are time varying. Various models with different complexities can be used to include the time-varying effects. The models used in this study are described in the following.

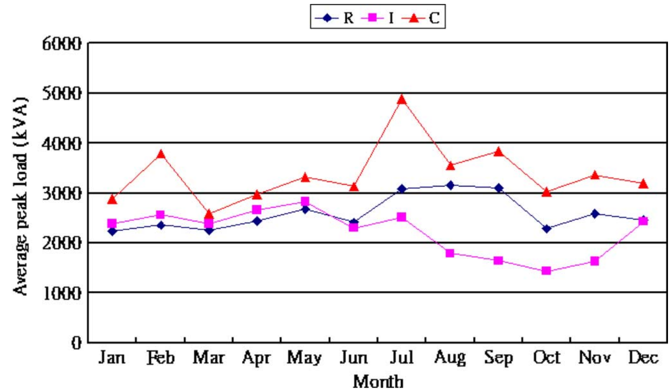

Fig. 1. Examples of monthly peak loads of different feeders.

TABLE I
Recorded Average Monthly Failure Rates in a Large Service Area (Number of Outages/Month)

Feeder type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
R	4	2	4	8	6	17	20	12	5	5	4	7
I	3	3	1	3	3	6	3	4	1	1	1	1
C	4	6	2	3	10	8	9	7	5	9	8	2

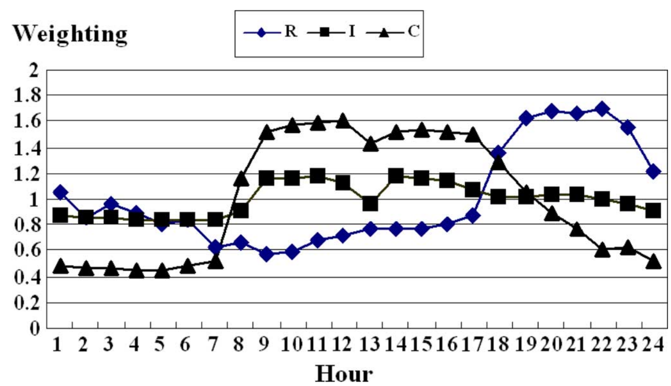

Fig. 2. Daily load profiles of three typical customer sectors.

A. Feeder Section Load Model

Each feeder section has several load points and the equivalent load of a section is obtained by summing individual loads within the section. Considering typical customer daily load profiles (as shown in Fig. 2), feeder/substation daily peak loads and proportions of customer types at individual feeder sections, feeder section load profiles can be established. The peak load for each feeder section on day (or load level) d can be determined by

$$\mathrm{L}_{\mathrm{j}}^{\mathrm{i}}(\mathrm{d}) = \sum_{\mathrm{i}\in\mathrm{R,I,C}} \mathrm{L}_{\mathrm{i}}^{\mathrm{avg}} \times \mathrm{W}_{\mathrm{j,i}}(\mathrm{d}) \tag{1}$$

where $L_j^j(d)$ and $W_{j,i}(d)$ are the estimated section peak load and the load weighting for day d, respectively. L_i^{avg} denotes the average section load for customer type i that can be obtained by using the data in the Customer Information System (CIS).

B. Failure Rate Model

Historical data show that the failure rates of distribution equipment vary with geographic location, weather and load level. Recorded data, such as those listed in Table I, can be used to estimate the failure rates with respect to system components and feeder sections. In certain areas, operation experiences have indicated a high correlation between failure rates and feeder loadings. Thus, if seasonal outage data are incomplete, the failure rate weighting factors can be determined based on the correlations between failure rate and feeder section loads. Section failure rates at one load level can be obtained by multiplying the average failure rate with the time dependent weighting factors. It can be expressed as

$$\lambda_f^i(d) = \lambda_f^{i,avg} \times W_{\lambda,f}^i(d) \quad (2)$$

where $\lambda_f^{i,avg}$ and $\lambda_f^i(d)$ are the average failure rate (failure/km) and failure rate of day (or load level) d, respectively. $W_{\lambda,f}^i(d)$ is the failure rate weighting for day (or load level) d.

C. Customer Interruption Cost Model

The average customer interruption costs (CIC) for industrial, commercial and residential customers have been studied in many countries [19]. In a practical system, the average CIC for a given load level and outage duration also changes with time. Time dependent cost weighting factors can be developed based on CIC survey data. Feeder sections with different reliability records supply power to different types of customers and usually have different lengths; therefore, each feeder structure forms a corresponding reliability profile. Considering failure rates at individual load points, expected duration of the outages and customer damage functions, the interruption costs for a particular load point, feeder or system can be calculated. To address the importance of service reliability in a deregulated market environment, daily peak load model can be used in computing the CIC, i.e., it can be assumed that the timing of interruptions coincides with the daily peak load periods. The formulations used to calculate the reliability costs are given in the next section.

III. Problem Formulation and Solution Method

A multiobjective feeder scheduling problem is formulated to identify critical switches for quasi-seasonal distribution feeder reconfiguration. The objective function is to minimize the total cost of customer interruption, line loss and switching costs

$$\text{Min TC} = \min(\text{TCLOSS} + \text{TSC} + \text{TCIC}) \quad (3)$$

where TC denotes the total annual operation cost for a distribution system. Moreover, TCIC, TCLOSS and TSC represent the total annual costs of customer service interruption, line loss and switching operations, respectively. Note that weightings can be designated to individual components if it is desired.

When examining possible system reconfigurations, it is important not to violate equipment rating and voltage drop criteria. Excessive equipment load may accelerate loss of life and unsafe line clearances. Moreover, line voltage drops may violate regulatory obligations and damage customer equipment. A power flow for each system configuration (using a current-voltage iteration algorithm) [5] is performed in the proposed procedure to identify voltage and capacity violations. The voltage and current magnitudes at each bus and branch must be within its limits, and can be expressed as

$$V^{\min} \le \left|V_f^i\right| \le V^{\max} \quad i = 1 \cdots NB(f) \quad f = 1 \cdots NF \quad (4a)$$

$$Ib^{\min} \le \left|Ib_f^l\right| \le Ib^{\max} \quad l = 1 \cdots NL(f) \quad f = 1 \cdots NF \quad (4b)$$

where $V^{\min}$ and $V^{\max}$ are the allowable minimum and maximum voltage magnitudes. $Ib^{\min}$ and $Ib^{\max}$ are the allowable minimum and maximum branch current magnitudes, respectively. Moreover, $|V_f^i|$ represents the voltage magnitude of bus i in feeder f, while $|Ib_f^l|$ is the branch current magnitude of branch l in feeder f. $\mathrm{NB}(f)$ and $\mathrm{NL}(f)$ are the numbers of buses and branches of feeder f, respectively. NF denotes the number of feeders.

A. Feeder Loss

Using the distribution system load flow solution, the power loss of a branch in feeder f at hour t of day (or load level) d can be expressed as

$$Ploss_f^l(d,t) = \left|Ib_f^l(d,t)\right|^2 R_f^l \quad (5)$$

where $Ploss_f^l(d,t)$ denotes the line loss of branch l in feeder f at hour t of day d. R_f^l is the resistance.

The cost of annual line loss can then be expressed as

$$TCLOSS = C_P \sum_{d=1}^{365} \sum_{t=1}^{24} \sum_{f=1}^{NF} \sum_{l=1}^{NL(f)} Ploss_f^l(d,t) \quad (6)$$

where $\mathrm{C_p}$ represents the energy cost (\$/kWh), and it can also be the market energy price.

B. Feeder Switching Operations Costs

By considering the costs of maintenance, switching operations, switch surge and switch lifetime, this study assumes switching operation cost (SC) to be a certain percentage of a feeder sectionalizer's installation cost. The total annual switching cost (TSC) is calculated by

$$TSC = \sum_{k=1}^{NL} SC \times NS_k \quad (7)$$

where $\mathrm{NS_k}$ denotes the total number of switch status changes from load level k to $\mathrm{k+1}$. Moreover, NL represents the number of load levels in the study.

C. Peak Load Failure Model for Calculating Customer Interruption Costs

Since service interruption incidents may occur in periods when load and interruption costs are high, to emphasize the importance of service reliability at peak load period, it is assumed that failure occurring time coincides with the system daily peak load. CIC of feeder f on day (or load level) d can be estimated by

$$CIC_f(d) = \sum_{i=1}^{NC(f)+1} IC_f^i(d) = \sum_{i=1}^{NC(f)+1} \lambda_f^i(d) l_f^i \left(\sum_{j=1}^{NC(f)+1} C_f^{ij}(d) L_f^j(d) \right) \quad (8)$$

where IC_f^i denotes the interruption cost due to outages in Section i of feeder f on day (or load level) d and $\mathrm{NC}(f)$ represents the number of switches at feeder f. Moreover, $L_f^i(d)$ and $\lambda_f^i(d)$ are the peak load and outage rate (failure/km), respectively. l_f^i represents the length of Section i of feeder f, while $C_f^{ij}(d)$ is the per kilowatt interruption cost ($/kW) of load at Section j. $C_f^{ij}(d)$ can be expressed as [3]:

$$C_f^{ij}(d) = \left(Res_f^j(\%) * fr\left(\gamma_f^{ij}\right) + Com_f^j(\%) * fc\left(\gamma_f^{ij}\right) + Ind_f^j(\%) * fi\left(\gamma_f^{ij}\right) \right) \quad (9)$$

where $Res_f^j(\%)$, $Com_f^j(\%)$, $Ind_f^j(\%)$ and $f_r(\gamma_f^{ij})$, $f_c(\gamma_f^{ij})$, $f_i(\gamma_f^{ij})$ are the load percentages and the interruption cost functions of residential, commercial and industrial customers, respectively. Meanwhile, γ_f^{ij} is the duration of service interruption of Section j for a fault at Section i.

Annual customer interruption costs can then be expressed as

$$TCIC = \sum_{d=1}^{365} \sum_{f=1}^{NF} CIC_f(d). \quad (10)$$

The distribution feeder scheduling procedure shown in Fig. 3 is used to determine the operating dates and positions of switches for feeder reconfiguration. Preliminary study has shown that distribution network reconfiguration is required when the feeder loads or failure rate indicate seasonal changes, thus, to speed up the solution process, different load variations, starting from small changes to only a few load steps for a year are investigated. The proposed feeder scheduling procedure is described as follows.

Step 1) Prepare feeder section load data, annual average failure rate, average CIC of different types of customers, switch operations cost, transformer and line ratings.

Step 2) Compute time-varying feeder section loads, failure rates, and interruption cost rate weighting factors based on the models described in Section II.

Step 3) Based on the typical daily average load curve of the studied system, specify an amount of load change to determine the number of load levels to be studied. For example, if the load difference between the maximum and minimum of the system annual load profile is, say 32% of the average value of the curve, and given a load change of 0.5% from previous load level, then 64 load levels will need to be studied.

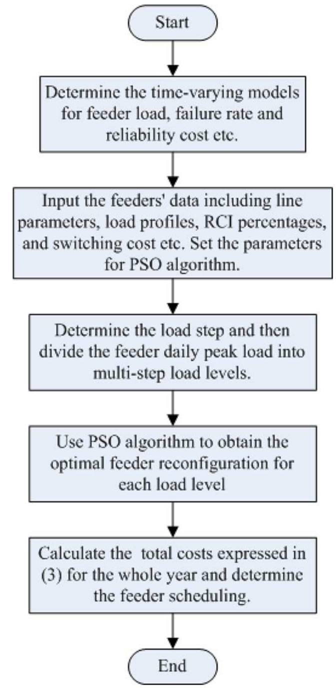

Fig. 3. Flow chart of annual feeder scheduling.

Step 4) Take the switching costs into account and use a BPSO search technique to determine the optimal feeder configuration at each load level.

Step 5) When the changes in feeder section loads and failure rates are small, the optimal feeder configuration would be the same in successive load step periods until such time as the time-varying effects are significant. At this point new normally open switches can be determined and the operating costs including system loss and CIC in the previous load level period and switching cost are added to the overall cost. Upon completion of the process, the annual switching operations dates and status of switches can be determined.

D. BPSO Solution Technique

In this study, a BPSO technique is used to determine the optimal system configuration in each load level period. Through cooperation and competition among the population, population-based optimization approaches, such as genetic algorithm (GA) and PSO, often can find good solutions. These optimization approaches update the population of individuals by applying operators according to the fitness information obtained from the environment so that the individuals of the population can be expected to move towards better solution areas [21][21]. In the BPSO method used in this study, the i^{th} particle is represented as $x_i = (x_{i1}, x_{i2}, \ldots, x_{iD})$. The particle $\mathrm{x_i}$ represents switch status, and D denotes total number of switches of the system. The best previous position (the position with the best fitness value) of the ith particle is recorded and represented as $p_i = (p_{i1}, p_{i2}, \ldots, p_{iD})$. Meanwhile, the rate of position change (velocity) for particle i is expressed as $v_i = (v_{i1}, v_{i2}, \ldots, v_{iD})$. In a binary space, a particle can move to nearer and farther corners of the hypercube by flipping various numbers of bits; velocity of the particle can be described by the number of bits changed per iteration, or by the Hamming distance between the particle at time t and $t+1$.

The moving velocity is defined in terms of the changes in the probabilities that a bit will be a particular state. Thus a particle moves in a state space restricted to 0 and 1 on each dimension, where each v_{id} represents the probability of bit x_{id} taking the value 1, since it is a probability and must be constrained to the interval [0.0, 1.0]. Different versions of PSO algorithms have been proposed to enhance the efficiency of the solution procedure. This study uses the following logistic function transformation $\mathrm{S}(v_{id})$ to update the movement :

$$\begin{aligned}&\text{if } (randNO < \mathrm{S}(v_{id})) \text{ then } x_{id} = 1\\&\text{else} = 0\end{aligned} \tag{11}$$

where $\mathrm{S}(v_{id})$ is a sigmoid limiting transformation and $randNO$ is a quasi-random number selected from a uniform distribution in [0.0, 1.0]. The following update scheme is used :

for $\mathrm{i} = 1 : \mathrm{m}$

for $\mathrm{d} = 1 : \mathrm{D}$

$$\begin{aligned}v_{id} = w * v_{id} + c_1 * randNO1 * (p_{id} - x_{id})\\+c_2 * randNO2 * (p_{gd} - x_{id})\end{aligned} \tag{12}$$

$$\text{if } (randNO1 < \mathrm{S}(v_{id})) \text{ then } x_{id} = 1 \tag{13}$$

else $x_{id} = 0$

end

end

end

where $\mathrm{p_{id}}$ denotes the best previous position of the i^{th} particle, p_{gd} represents the best among all the particles and m is the population size. Furthermore, D is the dimension size, and c_1, c_2 are learning factors, and w is the inertia weight.

For feeder reconfiguration applications, to retain the radial structure and reduce search requirements, the following modified procedure is used to update the state of x_{id}:

for $\mathrm{d} = 1 : \mathrm{D}$

$$\begin{aligned}v_{id} &= w * v_{id} + c_1 * randNO1 * (p_{id} - x_{id})\\&\quad + c_2 * randNO2 * (p_{gd} - x_{id})\\r_{id} &= \mathrm{S}(v_{id}) - randNO1\end{aligned} \tag{14}$$

end

for $\mathrm{d} = 1 : \mathrm{D}$

$$\text{if} (r_{id} < \text{the qth lowest value of all } r_i) \text{ then } x_{id} = 0 \tag{15}$$

Else $x_{id} = 1$

End

end

where q denotes the number of normally opened switches. The second loop limits the number of state changes to the number of feeders. The inertia weight, w, has the same effect of the temperature parameter in the simulated annealing technique. Notably, a larger inertia weight facilitates a global search while a smaller inertia weight facilitates a local search.

The BPSO procedure used is as follows :

Step 0: set population size (m) and stop criterion.

Step 1: randomly select m feasible solutions x, and compute p for each x, p_g is the minimum in all p's, the initial values of v's are set to zero.

Step 2: use (12) to calculate the rate of the position change (velocity), v_i for particle i (x_i).

Step 3: use (13) or (15) to update x_i.

Step 4: use (3) to calculate the objective function.

Step 5: if the evaluated value (total cost) of each particle is better than the previous p_i, p_i is set to this value. If the best p is better than p_g, p_g is replaced by this value.

Step 6: if stop criterion is satisfied, p_g is the optimal solution, otherwise, go to Step 2.

IV. Numerical Results

Several test systems were tested, to exhibit the time-varying effects in annual feeder switching planning, the test results of a simplified three-feeder system [4] and an 18-feeder system are presented here. The following parameters assumptions are used in the study.

— The cost of electricity is $6.5625 cents per kWh
— One switching cost is set to $203 which is one-twentieth of a new switch installation cost.
— The average CIC for an outage lasting for 1 h are $0.482, $9.085, and $8.552 per kW for residential, industrial, and commercial customers, respectively.
— The number of particles m in BPSO is set to 50, and the stop criterion is 50 generations.
— After tuning, the learning factors c1 and c2 are set to 2.
— Dimension sizes D are 16 and 87 for three-feeder and 18-feeder systems, respectively.
— Inertia weight w is unity.

A. Three-Feeder System

Figs. 4 and 5 show the feeder section peak loads on the second Wednesday in a month and the failure rates of six different months of the test system.

The original configuration of the three-feeder system is shown in Fig. 6, where feeder F1 is mostly a residential feeder, feeder F2 is a commercial feeder and feeder F3 is an industrial

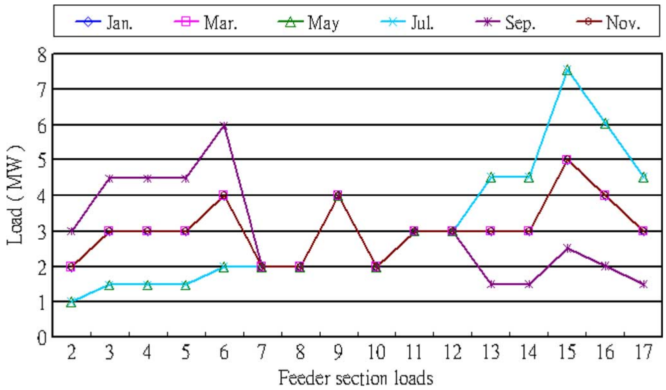

Fig. 4. Feeder section loads.

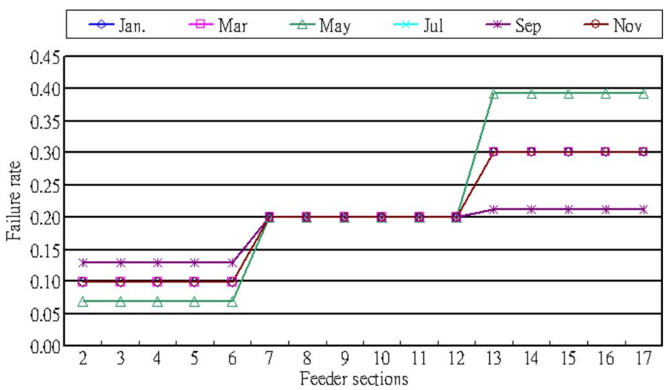

Fig. 5. Failure rates of feeder sections.

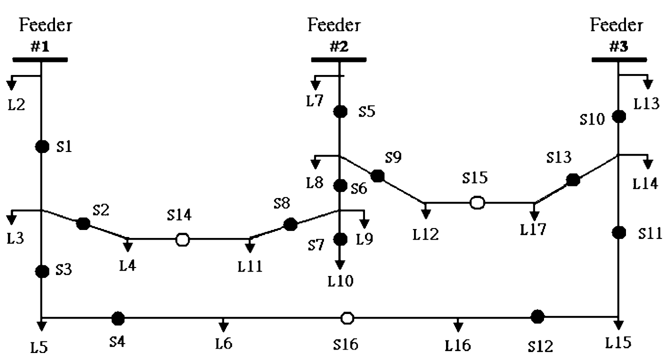

Fig. 6. Configuration of the three-feeder system.

feeder. To simply the presentation, only four fixed time periods with different load levels, outage rates, repairing times and CIC are assumed, and they are shown in Table II.

Annual Operating Costs of the Original Feeder Configuration With/Without Time Dependence of Parameters: For the configuration shown in Fig. 6, the annual total cost without considering time-varying effect (all weighting factors are set to unity) is \$609 056, including \$444 125 CIC, and \$164 931 line loss. Without reconfiguration and considering the time dependent effects, the total cost is \$833 453, including \$654 301 CIC and \$179 152 line loss for the original configuration. This result indicates the possible differences in overall costs for studies using the peak load failure model and the fixed average load, and the reliability parameter models adopted in previous studies.

TABLE II
WEIGHTING FACTORS FOR TIME-VARYING PARAMETERS

Parameters	Feeder # (Load Types)	Q1 (Day 1-90)	Q2 (Day 91-180)	Q3 (Day 181-272)	Q4 (Day 273-365)
Failure rate Repair time Load level CIC	F1 (R)	M	L	H	M
	F2 (C)	M	M	M	M
	F3 (I)	M	H	L	M

Note: $\mathrm{H} = 1.5$, $\mathrm{M} = 1$, $\mathrm{L} = 0.5$.

TABLE III
COSTS FOR THREE-FEEDER SYSTEM

In US\$

Switch Configuration	Time Varying Weightings	TC LOSS	TCIC	TSC	TC
Original Configuration	Not Included	164,931	444,125	N/A	609,056
Original Configuration	Included	179,152	654,301	N/A	833,453
Reconfiguration from original	Included	234,570	443,136	N/A	677,705
Multiple Feeder Reconfigurations	Included	215,869	388,009	2,448	606,327

Annual Minimum Operation Cost After Considering Time-Varying Effects: Table III shows the reduction of total costs by feeder reconfiguration. Using the assumptions made in the test system and considering the time-varying effects, the BPSO solution suggests that tie switches should be transferred from S14, S15, and S16 to S2, S12, and S13 respectively, to obtain improved operation if one feeder configuration for a whole year is assumed. Neglecting the switching cost, the annual cost is reduced to \$677 705. In this case, the switching operations trade saving in the line loss to achieve a large reduction in the reliability cost.

After executing the procedure shown in Fig. 3, an annual operation cost of \$606 327 is achievable. The total cost thus is \$227 000 lower than the case shown in the third row of Table III. The solution identifies two switching dates and 12 switch status changes. The optimal feeder configurations at different periods are shown in Figs. 7 and 8, respectively. In Q1 and Q4, the parameters have a mid level (M) weighting and the opened switches are S8, S12, and S13. In Q2, the optimal configuration does not change from the previous period, because weighting factors of parameters of feeder F1 change from middle (M) to low (L) and those of feeder F3 change from middle (M) to high (H). In Q3, the opened switches transferred from S8, S13, and S12 to S14, S9, and S4, respectively. Because the weighting factors changed rapidly from low (L) to high (H) in feeder F1, which discourages the connection of the load to feeder F1 to minimize the CIC. In feeder F3, the weighting factors change from high (H) to low (L), resulting in an increase of load connected to feeder F3.

B. Eighteen-Feeder System

The original configuration of the 18-feeder system is shown in Fig. 9. Feeders F1, F4, F7, F10, F13, and F16 are residential feeders. Feeders F2, F5, F8, F11, F14, and F17 are commercial feeders and the rest are industrial feeders. The test re-

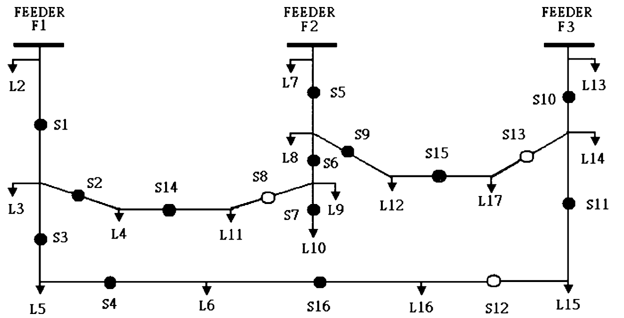

Fig. 7. Switches S8, S12, and S13 are opened from day 1 to day 180 and day 273 to day 365.

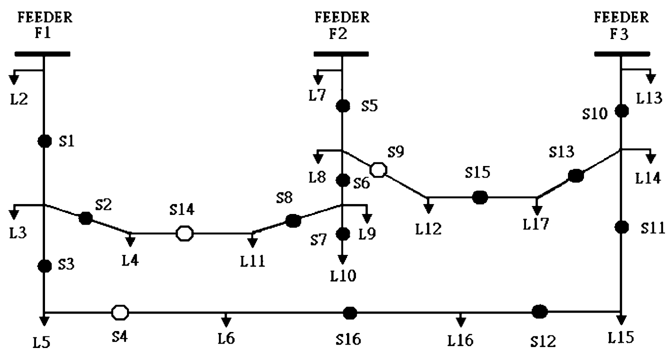

Fig. 8. Switches S4, S9, and S14 are opened during day 181 to day 272.

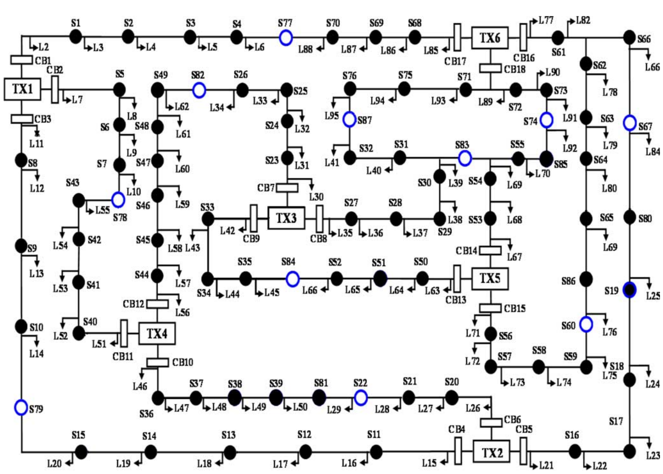

Fig. 9. Eighteen-feeder distribution system example.

sults are shown in Table IV. Original network configuration is used in Case SW0 that has either fixed parameters ($W = 1$) or time-varying weighting (TVW). After preliminary study, Case 1SW has one better switch status for the entire year if no seasonal switching is desired. PSO searches are then performed for different load level periods to considering time-varying effects in annual feeder operation planning.

As can be seen in Table IV, instead of using fixed parameters for a whole year ($\text{total cost} = \$849.155 \text{ thousand dollars}$), when time-varying effects are included for the original network configuration, the annual total cost is $1273.732 thousand dollars. If the same system data and optimal feeder configuration of the system are used, the total annual cost becomes $932.865 thousand dollars. A reduction of $340 867 (about 27%) is obtainable if the network is operated under better configuration. Based on the cost and reliability models used in this study, Table IV indicates that, for a 0.02 p.u. system load change from the beginning of previous period, a new feeder reconfiguration is desirable. As shown in Table V, the optimal solution requires eleven feeder reconfigurations over a whole year and the statuses of 94 switches are changed. The total annual cost is $859.599 thousands dollars which has a reduction of $414.133 thousand dollars (33%) reduction from the total operating cost of the original configuration. The open switches and switching timings are shown in Table V.

TABLE IV
RESULT IN DIFFERENT DELTA LOAD OF 18-FEEDER DISTRIBUTION SYSTEM

In Thousand US$

Delta Load	Switching Freq.	# of SW Changed	TSC	TCIC	TC LOSS	TC
SW0 W=1	N/A	N/A	N/A	596.296	252.859	849.155
SW0 TVW	N/A	N/A	N/A	967.852	305.880	1273.732
1SW TVW	N/A	N/A	N/A	599.737	333.128	932.865
0.32	1	16	3.248	587.675	323.847	914.770
0.16	2	28	5.684	550.647	324.203	880.534
0.08	4	52	10.556	536.017	321.329	867.902
0.04	7	74	15.022	536.191	309.622	860.835
0.02	11	94	19.082	530.130	310.465	859.599
0.01	20	104	21.112	528.039	310.634	859.785
0.005	28	116	23.548	528.757	308.727	861.032

TABLE V
OPENED SWITCHES IN THE CASE OF 0.02 p.u. LOAD CHANGE

In Thousand US$

Start Day	End Day		TCIC	TC LOSS	Open Switches										
1	70	SW1	80.632	41.328	3	14	26	30	38	52	64	67	78	85	87
71	149	SW2	176.29	87.226	3	13	25	30	32	38	51	55	63	67	78
150	173	SW3	44.122	27.405	3	14	26	30	32	38	52	55	64	67	78
174	188	SW4	25.783	17.160	4	14	26	30	32	38	52	55	64	78	80
189	227	SW5	63.018	42.626	4	15	32	39	65	78	80	82	83	84	85
228	242	SW6	18.995	13.722	4	19	32	49	78	79	81	83	84	85	86
243	254	SW7	13.690	10.193	19	30	49	60	77	78	79	81	84	85	87
255	266	SW8	12.664	9.856	19	35	48	60	74	77	78	79	81	83	87
267	278	SW9	12.450	9.243	19	22	35	48	60	74	77	78	79	83	87
279	305	SW10	28.105	19.400	10	19	22	35	48	60	74	77	78	83	87
306	328	SW11	20.569	13.619	4	22	35	48	60	74	78	79	80	83	87
329	365	SW12	33.812	18.679	3	15	30	49	67	74	76	78	81	84	86

In order to verify the results, the method proposed in [5] is implemented and used as a reference for comparison. The following is the implemented solution procedure:

1) Given a feasible configuration
2) Find all M open switches

For $i = 1 : M$

(close i-th open-switch and open only one of the N switches in the loop to maintain the radial structure of the feeders)

For $j = 1 : N$

Calculate the cost function and compare the solutions

TABLE VI
TEST RESULTS OF 100 PSO RUNS WITH DIFFERENT LOAD VARIATIONS

In Thousand US$

	Delta Load	0.005	0.01	0.02	0.04	0.08	0.16	0.32
Total Cost	Min.	861.03	859.39	859.26	860.84	867.90	880.53	914.77
	Max.	868.93	864.01	862.23	863.13	868.80	880.88	914.77
	Avg.	863.58	860.45	859.68	861.22	868.12	880.62	914.77
SW Freq.	Min.	27	20	11	7	4	2	1
	Max.	35	23	13	8	4	2	1
	Avg.	29	20	11	7	4	2	1
# of Changed	Min.	116	102	92	74	52	26	16
	Max.	154	124	106	84	56	28	16
	Avg.	128	107	94	76	53	27	16

Store optimal configuration

End

End

Store optimal configuration and use it as the new feasible configuration

3) Stop when there is no improvement in the objective function, otherwise go to 1.

Test results have shown that most of the 100 PSO trials in each load level provide the same optimal solution as that given by above procedure. However, it is noted that in some trials a few open switch positions are different and result in a slight difference in total cost. This is due to the fact that, in each outer loop of above procedure only one open switch is closed to form a loop, with other open switches remain intact, and the optimal break point of the loop is determined to minimize the cost and maintaining radial. While in the proposed BPSO method, it uses several searching points like GA and the searching points gradually get close to the optimal point. Our experiences indicate that, with proper implementation, BPSO execution time could be lower than that of the above procedure.

Since PSO is one of the stochastic optimization methods, the performance of the solution would hinge on the choice of seeds of random numbers and the search strategy adopted in each implementation. The results are evaluated statistically and Table VI shows the statistics of 100 BPSO trials for the case of 0.02 p.u. load change. As can be seen, if a lower number of seasonal network reconfiguration is required, the proposed BPSO trials would give the same solutions. On the other hand, if a smaller load change is specified for the feeder reconfiguration study, then depending on the convergence criteria adopted, a slight range of solutions could be expected from BPSO. Even with this phenomenon, experiences show that a high number of trials (75% in the delta load $= 0.02$ p.u. case) have the same solution.

The network configurations during the off-peak and peak load seasons during SW2 and SW10 periods are shown in Figs. 10 and 11, respectively. The results obtained seem reasonable and explicable, that is, when feeder load, failure rates and consequently, interruption costs of a route become higher due to seasonal changes, the proposed solution procedure would manage

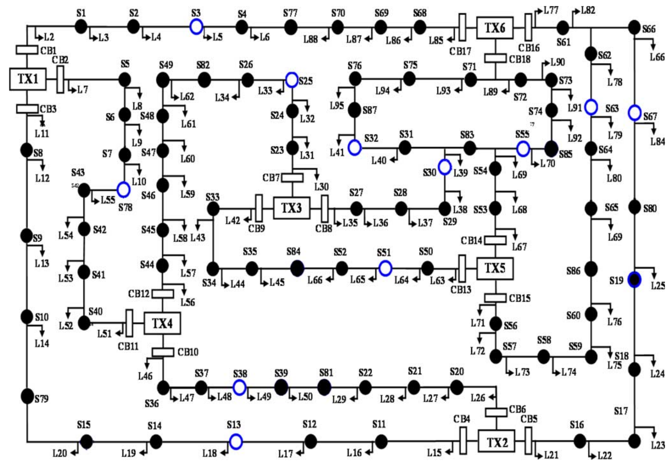

Fig. 10. Feeder configuration in off-peak load season (SW2).

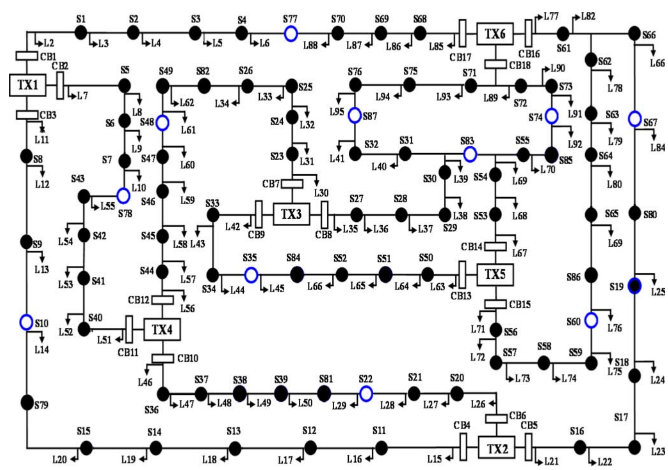

Fig. 11. Feeder configuration in peak load season (SW10).

to reduce the loads connected to this route and seek other routes having lower failure rates to share some of the load demands. This process also considers the system line loss and switching operation costs to minimize total cost. It is assumed that the expected number of interruptions in a given distribution system remains the same irrespective of the selected operational structure. The costs associated with undelivered customer demands are strongly affected by the system configuration, particularly by the structures supplying customers with high interruption sensitivity. The optimization algorithm, suggested in this paper, creates system patterns with high reliability paths supplying highest priority customers, thus explaining the reduction in total interruption costs.

V. CONCLUSION

Electric power industry has confronted many challenges in the deregulated environment since the customers may require different service quality, and the improvement of service quality and efficiency has become increasingly important. This paper addresses the assessment of interruption costs in distribution systems and the impacts of seasonal time variation effects in annual distribution feeders operation planning. The proposed sequential solution procedure can be used to model time-varying effects and find the optimal feeder reconfiguration plan to reduce system loss, switching and reliability costs. Based on the time-varying models used in this study, simulation results have indicated that using only simplified fixed load and reliability parameters as have done in previous studies could underestimate the total loss to the utility and customers as a whole.

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