Determination of the Optimal Switching Frequency for Distribution System Reconfiguration

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***Abstract*—This paper shows that there is great potential for saving money when reconfiguring distribution systems at an optimal frequency. Studies are conducted on hourly, daily, weekly, monthly, and seasonal reconfiguration plans, based on the 8760 hourly loads of a year. Switches that actively participate in the reconfiguration process are first identified. These sectionalizers are substituted by smart (remotely controlled) switches. According to the results, two economic indices: total savings and return on investment are used to determine the optimal switching frequency. Numerical simulations are conducted on three distribution systems including one with 119 buses that is commonly used as a benchmark for reconfiguration of large-scale distribution systems. The results reveal that there exist large potential gains on frequent switching reconfiguration. Therefore, detailed studies must be carried out to determine the benefits of the dynamic reconfiguration for particular distribution systems.**

***Index Terms*—Distribution system reconfiguration, optimal power flow, power loss, switching frequency, voltage stability.**

I. Introduction

DISTRIBUTION system reconfiguration is a very important real-time operation task capable of optimizing the topology of modern systems. The objectives of system reconfiguration may include the following: reduce power loss [1], improve voltage security margin [2], enhance reliability [3], [4], reduce line maintenance costs [5], and improve power quality [6]. In primary distribution systems, sectionalizing switches (normally closed) and tie switches (normally open) can be used for this purpose. In this process, the configuration of the system changes with the status of the switches. Numerous switching scenarios can be considered. Thus, network reconfiguration becomes a nonlinear and complex constrained optimization problem.

In conventional distribution systems with manually controlled switches, switching operations cannot be executed frequently. Under this circumstance, constant load models (peak or mean value) are considered for most of the reconfiguration studies [7]–[9]. For example, reference [8] proposes a method to find the optimal configuration under peak load only. This static optimal configuration does not consider load variations.

For a power utility operator, it is important to perform the distribution system reconfiguration throughout the year with the objective of minimizing operational costs. Naturally, when switching operations are carried out more frequently to consider the dynamics of the loads, power losses reduce.

In the context of the smart grid, all manual switches that significantly affect the system performance can be substituted with automatic (or remote controlled) switches to facilitate dynamic (real-time) network reconfiguration [10], [11]. In practice, switching frequency can be set as hourly, daily, weekly, monthly, or seasonal. A dynamic load (time-sequence) model with variations of a specific resolution needs to be considered to perform these types of studies. However, frequent switching operations may be costly and may lead to transient disturbances that could reduce system reliability and create undesirable overvoltages [12]. Also, it is not economically feasible to substitute all manual switches with smart switches [13], [14].

There are some studies that consider variable demands for distribution system reconfiguration. For example, reference [15] concentrates on "hourly" reconfiguration during a day. Apart from the reconfiguration for one day, few studies consider the reconfiguration scheme for a complete year [16], [17]. In [16], the "daily" feeder reconfiguration is determined for the whole year. Reference [17] carries out the "weekly" reconfiguration plan for the entire year.

All aforementioned publications focus only on a single scenario (hourly, daily, or weekly). Therefore, the methods of previous publications cannot determine the best reconfiguration scheme for a given system. Today (2016), there is no comprehensive study in the literature comparing different reconfiguration plans (scenarios) establishing the optimal switching frequency in a distribution system for the full year. Comparison between different switching scenarios requires a comprehensive study based on the load profile of the entire year with hourly resolution as performed in the present paper.

The present paper, in contrast with available publications, obtains the optimal configuration for a dynamic (hourly) load model and compares different reconfiguration schemes comprehensively. This paper, for the first time compares different reconfiguration plans (hourly, daily, weekly, monthly, and seasonal) and determines the optimum scenario. The objective of

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this study is to suggest the best scenario based on the total savings and return on investment analysis.

Economic evaluation on different reconfiguration scenarios has been established based on hourly load profiles. Additionally, to introduce an economically practical approach, a few switches that need to be retrofitted for smart (or remote controlled) switches are identified. The study is based on the real annual data (8760 hours) of residential, industrial, and commercial loads from two large distribution utilities in the USA. Seasonal, monthly, weekly, daily, and hourly reconfigurations are compared and the best switching strategy is determined based on the total savings and return on investment analysis.

II. Problem Formulation

Distribution system reconfiguration is an optimization problem that involves operation constraints. In the present paper, the objective is to minimize the real power loss considering voltage limits on buses, radial topology constraints, ampacity of lines, and voltage stability index constraints.

A. Real Power Loss

The system real power loss for different configurations is obtained using power flow calculations as follow:

$$P_{\text{loss}} = \sum_{k=1}^{N_l} |I_K|^2 R_k \tag{1}$$

where P_{loss}, $|I_k|$, R_k, and N_l are the real power loss, magnitude of the kth branch current, kth branch resistance, and number of branches, respectively.

B. Topology Constraints

It is assumed (initially) that all lines in the distribution system are equipped with switches. To solve the reconfiguration problem, several loops including one tie switch and some sectionalizing switches must be defined. The network reconfiguration problem consists in opening a switch in each one of the loops, the so-called tie-switch, and closing all other switches. This method maintains the radial characteristics of the distribution system [8].

To describe the algorithm, the meshed network of Fig. 1 is analyzed in this section. Four loops and eleven branches are defined in Fig. 1. Sectionalizing switches are simulated in each branch. The loops in the network are listed here:

Loop1: $\{B1, B2, B3\}$

Loop2: $\{B4, B5, B6, B7, B8\}$

Loop3: $\{B9, B10, B11, B12\}$

Loop4: $\{B13, B14, B15, B16\}$

Some of the branches are included in different loops, for example: $\{B3, B4\}, \{B8, B11\}, \{B7, B12\}, \{B5, B14\}, \{B6, B13\}$. In [8], integer programming is used to formulate the topology constraints. However, reference [8] merely considers the situation that different loops have one common branch at most. In this part, multiple common branches between loops are also considered; for example, branches $B5$ and $B13$ between loops 2 and 4 in Fig. 1.

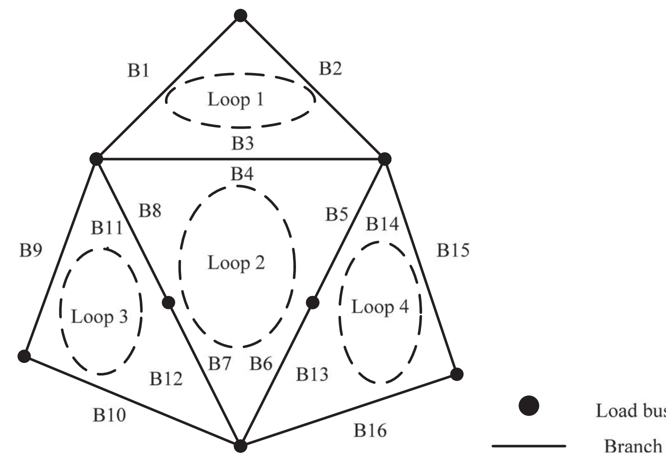

Fig. 1. Diagram of a meshed network.

To keep the network radial, one should open a branch in each loop. The state vector $y = [y_1, y_2, y_3, y_4]$ represents the integer indices of branches which are disconnected to break the loops. Since, for this example, the branches are identified in sequential order, the range of disconnected branches in the different loops could be represented by:

$$\begin{aligned} 1 \le y_1 \le 3 \\ 4 \le y_2 \le 8 \\ 9 \le y_3 \le 12 \\ 13 \le y_4 \le 16 \end{aligned} \tag{2}$$

In Fig. 1, there are common branches: $\{B_3, B_4\}, \{B_5, B_{14}, B_6, B_{13}\}$, and $\{B_7, B_8, B_{11}, B_{12}\}$. To avoid disconnecting any load from the system, and to prevent the creation of loops, none of the switches shall be selected twice from the common branches. This can be formulated as:

$$TP = \begin{cases} \infty, & \text{if open two common branches} \\ 0, & \text{otherwise} \end{cases} \tag{3}$$

where TP is the penalty factor of the radial topology constraint.

C. Other Constraints

Distribution system reconfiguration is a constrained optimization problem. Note that, the voltage magnitude of the distribution system nodes must be maintained in the permissible range:

$$V_{\min} \le |V_i| \le V_{\max}, i = 1, 2, 3, \ldots, N_b \tag{4}$$

where N_b is the total number of the buses, $V_{\min}$ and $V_{\max}$ are the minimum and maximum voltage limits given in the standards. Additionally, the current in each branch should be within its capacity limits:

$$|I_j| \le I_{\max}, j = 1, 2, 3, \ldots, N_l \tag{5}$$

where N_l is the total number of the branches and $I_{\max}$ is the current capacity of each line.

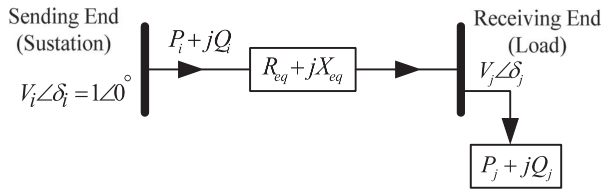

Fig. 2. Simplified two-bus system of a typical distribution system.

D. Voltage Stability Index

Voltage stability refers to the ability of a system to maintain steady voltages at all buses when the system is subjected to a disturbance such as an increase in the demand. The voltage stability index is developed for voltage stability assessment of distribution systems as discussed in [2].

To calculate the voltage stability index, the distribution system can be simplified as a load being fed by a line. Also the power loss of the distribution system can be analyzed with an equivalent two-bus system as shown in Fig. 2. In [2], it is proved that the voltage stability index of the simplified two-bus system is very close to that of the weakest bus of the radial distribution system.

In Fig. 2, P_i and Q_i are the total active and reactive powers flowing out of the substation, P_j and Q_j are the sum of the active and reactive loads in the distribution system, $V_i\angle\delta_i$ refers to the substation voltage, $V_j\angle\delta_j$ denotes the receiving end voltage, and R_{eq} and X_{eq} are the equivalent line resistance and reactance. According to the conservation of energy law:

$$P_i = R_{\text{eq}}\frac{P_i^2 + Q_i^2}{V_i^2} + P_j \tag{6}$$

$$Q_i = X_{\text{eq}}\frac{P_i^2 + Q_i^2}{V_i^2} + Q_j \tag{7}$$

It is assumed that the substation voltage $V_i = 1.0$ pu,

$$R_{\text{eq}} = \frac{P_i - P_j}{P_i^2 + Q_i^2} = \frac{P_{\text{loss}}}{P_i^2 + Q_i^2} \tag{8}$$

$$X_{\text{eq}} = \frac{Q_i - Q_j}{P_i^2 + Q_i^2} = \frac{Q_{cl}}{P_i^2 + Q_i^2} \tag{9}$$

where P_{loss} and Q_{cl} denote the total active power loss and reactive power consumed by the line in the distribution system, respectively.

According to [2], the voltage stability index of the distribution system can be computed from:

$$SI \cong 1 - \frac{4\,(P_j P_{\text{loss}} + Q_j Q_{cl})}{P_j^2 + Q_j^2} \tag{10}$$

Voltage V_j is close to collapse when the value of SI approaches zero. Therefore, SI defines the distance to voltage instability of the system.

III. Solution Method

The method to determine the annual reconfiguration plan consists of two stages. First, the hourly reconfiguration schedule is obtained for the entire year. Then, the daily, weekly, monthly,

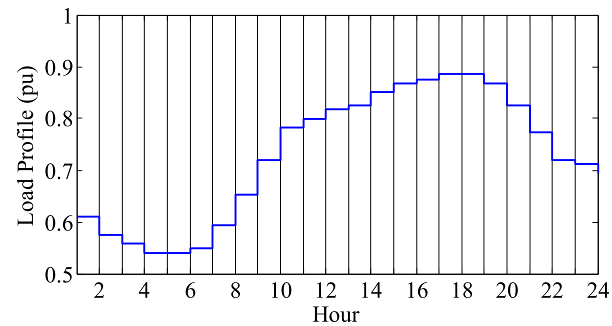

Fig. 3. Typical load variation for a day in July; note that the measurement sampling rate is one hour.

and seasonal reconfiguration scenarios are obtained based on the results obtained in the first stage. The switches that actively participate in the reconfiguration are replaced by remotely controlled switches. After determining the optimum location of switches and statuses, the ROI analysis is performed to investigate the economic feasibility of the different reconfiguration schemes. Theoretically, the problem could have been formulated to optimize ROI directly. However, as written previously, the solution can be obtained independently for each time interval, thus breaking down the reconfiguration problem into 8760 independent problems. This makes parallel computing feasible and hence reduces the computation time. The direct calculation of ROI should take into account switching operations for all time intervals together. Thus, the hourly reconfiguration problem cannot be treated as 8760 independent problems. This makes the search space very large and requires a very long simulation time.

A. Short Term Reconfiguration Scheduling (Hourly)

To explain the method presented in the paper, we select a typical commercial load data (a day in July) as an example. As shown in Fig. 3, the measurement sampling rate is one hour; thus the load curve of one day has 24 intervals. We use the Discrete Particle Swarm Optimization (DPSO) technique to perform optimal power flow at all hour intervals (24 hours a day). Extending the idea to the entire year, the method obtains the optimal configuration for every hour of the 8760 in a year. Therefore, the yearly reconfiguration plan consists of 8760 hourly optimal configuration schemes. With this information we build a matrix of switch statuses as follows:

$$\overbrace{\begin{bmatrix} S_{1,1} & S_{1,2} & \cdots\cdots & S_{1,m} & S_{1,8760} \\ S_{2,1} & S_{2,2} & \cdots\cdots & S_{2,m} & S_{2,8760} \\ \vdots & \vdots & \cdots\cdots & \vdots & \vdots \\ S_{n,1} & S_{n,2} & \cdots\cdots & S_{n,m} & S_{n,8760} \end{bmatrix}}^{8760h} \tag{11}$$

where each column $[S_{1,m} \quad S_{2,m} \quad \cdots \quad S_{n,m}]^T$ denotes the configuration at hour m. $S_{n,m}$ stands for the opened switch (tie switch) of loop n at hour m. The results of extensive simulation studies on different distribution systems revealed that many switches remain closed (or open) over the entire year and only a few switches actively participate in the reconfiguration operations. This means that the open/close status of the great majority of switches does not change during the optimization process and thus they can be excluded from the optimization process. In this paper, these switches are called nonsensitive hereafter. The switches that change their status are called sensitive switches. For system reconfiguration purposes, only the sensitive switches need to be replaced by smart (or remote controlled) switches since the insensitive switches remain closed (or open) for the entire year. Other switches may be added to the list for resiliency purposes. This reduces the investment costs, which increases the feasibility of high frequency reconfiguration schemes.

B. Long Term Reconfiguration Scheduling (Daily, Weekly, Monthly, and Seasonal)

The reconfiguration schedule for longer periods (less frequency) is derived based on the hourly optimal reconfiguration matrix (11) obtained in the previous subsection. For example, for a daily reconfiguration plan, the optimal configuration (set of switches) with the objective of minimizing the energy loss in a 24-hour period (a day) is considered. If we select a day from (11), the reconfiguration scheme in this particular day can be obtained as:

$$\overbrace{\begin{bmatrix} S_{1,1} & S_{1,2} & \cdots\cdots & S_{1,m} & S_{1,24} \\ S_{2,1} & S_{2,2} & \cdots\cdots & S_{2,m} & S_{2,24} \\ \vdots & \vdots & \cdots\cdots & \vdots & \vdots \\ S_{n,1} & S_{n,2} & \cdots\cdots & S_{n,m} & S_{n,24} \end{bmatrix}}^{24h} \Longrightarrow \overbrace{\begin{bmatrix} S_{1,l} \\ S_{2,l} \\ \vdots \\ S_{n,l} \end{bmatrix}}^{\text{Day}} \tag{12}$$

where $[\, S_{1,l} \; S_{2,l} \; \cdots \; S_{n,l} \,]^T$ denotes the optimal configuration during the 24 hours of the day l. This method is implemented for all days (365 cases) to obtain the complete daily reconfiguration plan. Therefore, a matrix with 365 columns and n (number of loops) rows is derived.

The weekly, monthly, and seasonal reconfiguration plans are determined using the same method. The flowchart of the algorithm is shown in Fig. 4.

C. Discrete Particle Swarm Optimization Technique

Discrete Particle Swarm Optimization algorithm is a stochastic evolutionary computation method inspired from flocking birds that has been widely used to solve distribution network reconfiguration problems [6], [16]. Because of its reduced computation time and effective search ability, DPSO is adopted here to determine the optimal system configuration. Note that, the objective of this paper is not to identify/test any optimization method. The results of this research are independent of the selected solver, if implemented correctly. Some methods would be faster than others, but the selection of the best optimization method is beyond the scope of this paper.

For the DPSO used in this study, the variables are a set of tie switches that have been selected to break each one of the loops. The variables of ith particle can be represented as $x_i = (x_{i1}, x_{i2}, \ldots, x_{\text{in}})$. x_{in} stands for the switch selected to be

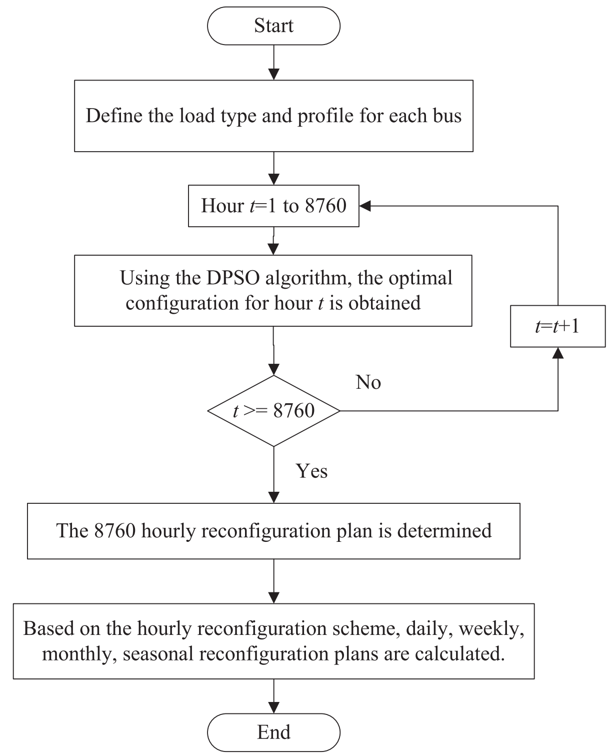

Fig. 4. Flow chart of annual reconfiguration scheduling.

opened in loop n. The objective function is to minimize (1). The search space covers all possible combinations of tie switches in the radial system. Meanwhile, the velocity of the changes in position for particle i is expressed as $v_i = (v_{i1}, v_{i2}, \ldots, v_{\text{in}})$. The most popular PSO algorithm consists of the following velocity and position equations:

$$\begin{aligned} v_{\text{in}}(k+1) = v_{\text{in}}(k) &+ \alpha_1\gamma_1(P_{\text{in}} - x_{\text{in}}(k)) \\ &+ \alpha_2\gamma_2(G_n - x_{\text{in}}(k)) \end{aligned} \tag{13}$$

and

$$x_{\text{in}}(k+1) = x_{\text{in}}(k) + v_{\text{in}}(k+1) \tag{14}$$

where i is the particle index, k is the discrete time index, P_{in} is the best position found by the ith particle, G_n is the best position found by the swarm, γ_1, γ_2 are random numbers on the interval $[0, 1]$, and α_1, α_2 are acceleration factors. Since the variables in the reconfiguration problem are discrete, (14) should be revised as follows

$$x_{\text{in}}(k+1) = \text{round}\,(x_{\text{in}}(k) + v_{\text{in}}(k+1)) \tag{15}$$

D. Return on Investment Analysis

Return on investment (ROI) is a popular financial metric to evaluate the economic consequences of individual investments. A high ROI is a sign to demonstrate that the investment gains compare favorably to investment cost. The ROI is used in the paper to evaluate and compare the economic feasibility of different reconfiguration plans.

To perform reconfiguration, some lines should be equipped with remote control switches. The investment costs include the capital cost of upgrading switches together with annual maintenance cost [14]. This can be expressed as follows:

$$IC = \sum_{k=1}^{N_s} (CC_k + CI_k) + \sum_{Y=1}^{N_y} \sum_{k=1}^{N_s} \frac{MC_k}{(1+IR)^Y} \tag{16}$$

where IC, CC_k, CI_k, and MC_k are the investment cost, capital cost of remote control switch k, construction cost of auxiliary communication infrastructure of remote control switch k, and annual maintenance cost of remote control switch k together with its auxiliary communication infrastructure. N_s, N_y, and IR are the total number of remote control switch, lifetime of remote control switch, and inflation rate.

Reconfiguration reduces the annual energy loss compared to the base case, which is the gain from the investment [14]. Power loss is the amount of energy loss per unit of time. For the hourly reconfiguration, the annual energy loss cost can be formulated as follows:

$$EL = C \cdot \sum_{t=1}^{8760} P_{\text{loss}}(t) \tag{17}$$

where EL, $P_{\text{loss}}(t)$, and C are the annual energy loss cost, real power loss at time t, and energy cost per kWh.

The gain from the investment can be formulated as follows:

$$GI = \sum_{Y=1}^{N_y} \frac{(EL_{\text{base}} - EL_{\text{scenario}})}{(1+IR)^Y} \tag{18}$$

where GI, EL_{base}, and EL_{scenario} are the gain from the investment, annual energy loss for the base case, and annual energy loss for the reconfiguration scenario, respectively. The ROI index is calculated as:

$$ROI = \frac{GI - IC}{IC} \tag{19}$$

According to data from manufacturers, the installation of an automatic switch and its auxiliary communication infrastructure costs approximately \$4,000 [16] and the maintenance cost is assumed to be 0.05% of the installation cost [14]. The lifetime of a remote control switch is 40 years and the maximum number of operations is 10,000 [26]. Note that, when a switch reaches its maximum operation within the lifetime, capital cost of a new switch will be included in the process. According to the US Bureau of Labor Statistics (BLS) reports, the inflation rate is set to be 1% on average [28].

IV. Simulation Results

This section presents the data required for the reconfiguration scenarios tested in this paper. The energy cost is considered as 18 cents/kWh in this paper [27]. Based on experience, the number of particles for DPSO is set to 40 and the acceleration constants α_1, α_2 are set to 2.

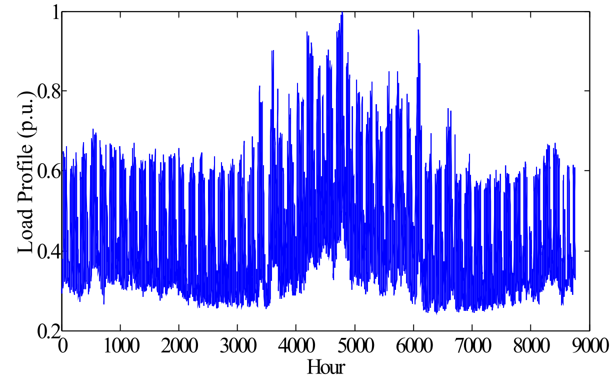

Fig. 5. Commercial load curve from utility B in per unit.

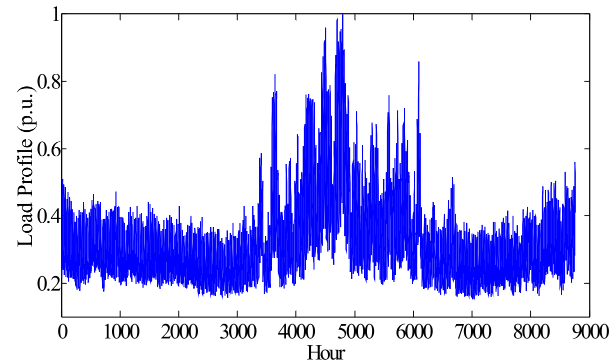

Fig. 6. Residential load curve from utility B in per unit.

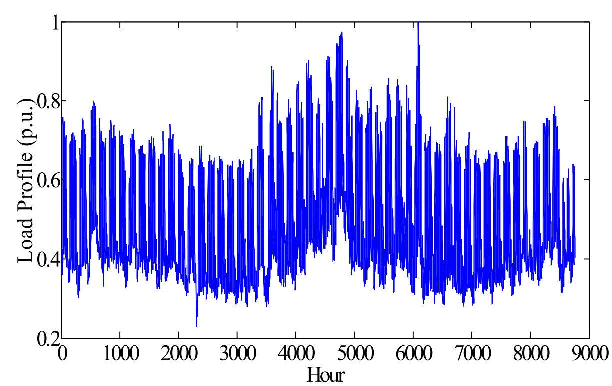

Fig. 7. Industrial load curve from utility B in per unit.

A. *Load Profiles*

The annual distribution system reconfiguration described in the previous sections is implemented on a 69-bus (single feeder) system, an 84-bus (multi-feeder) system, and a large-scale 119-bus test system. For a realistic assessment of the annual operation, the effect of the time-varying load of different types (residential, commercial, industrial, and mixed) should be investigated. To validate the effectiveness of the methodology, two groups of load curves are investigated. These annual load curves are the recorded data obtained from two distribution systems in the Northeast (say utility A and utility B). Figs. 5–9 show examples of hourly load profiles for commercial, residential and industrial loads from utility B. Due to space limitations,

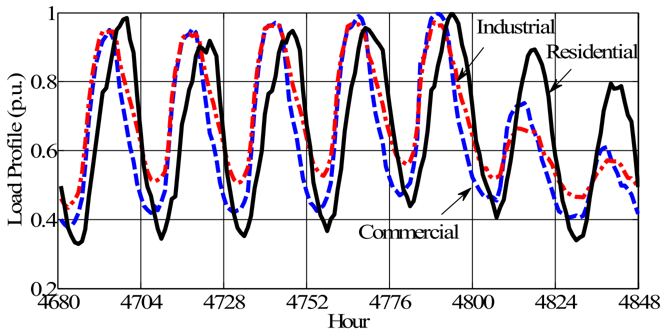

Fig. 8. Load variation for a week in a heavily loaded distribution network.

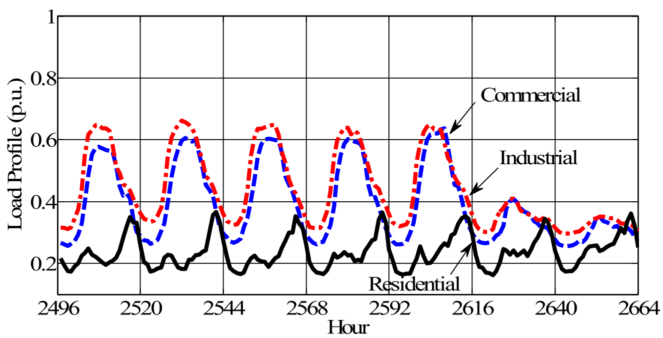

Fig. 9. Load variations for a week in a lightly loaded distribution network.

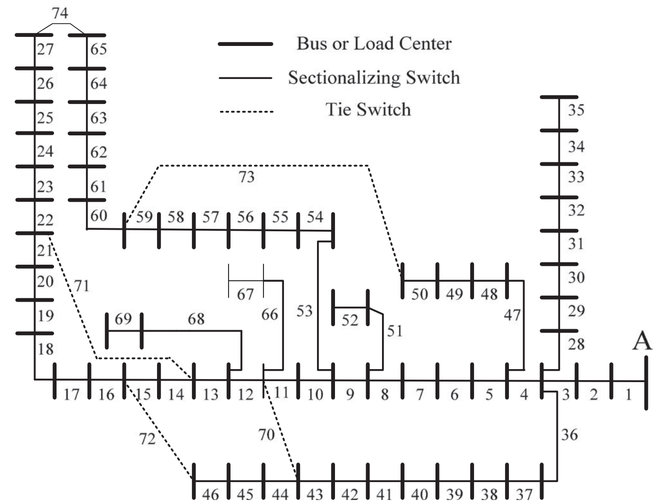

Fig. 10. 69-bus distribution system [21].

TABLE I
LOAD CHARACTERISTICS OF THE 69-BUS TEST SYSTEM

Load Type	Residential	Commercial	Mixed/Industrial
Located Bus	2–10, 16–20, 28–35, 53–58	11–15, 46–52, 59–65	21–27, 36–45, 66–69

TABLE II
SENSITIVE SWITCHES OF THE 69-BUS TEST SYSTEM UNDER HOURLY RECONFIGURATION

Sensitive Switches
13, 14, 15, 21, 24, 25, 26, 58, 59, 70, 71

the load data of utility A is not presented. Figs. 5–7 present the variation over the entire year and Figs. 8 and 9 show the load variation for the peak-week and the valley-week of the year, respectively. The illustrations highlight the difference in the behavior of the loads during a week. From Figs. 5–7 one can see that residential loads are compact during the spring, fall and winter, and spread during the summer (due to air conditioners). Fig. 8 shows that the three types of loads behave in a similar manner in July. Yet, as expected, the peaks of the residential loads are not coincidental with the peaks of commercial and industrial loads pointing to advantages on reconfiguration. Generally, commercial and industrial loads have larger deviations from weekdays to weekends.

Fig. 9 shows that residential loads follow almost the same pattern every day when the loading is light. However, the other two load types decrease on the weekend. Comparing Fig. 8 and Fig. 9 one can conclude that industrial and commercial loads patterns do not change significantly from a heavily loaded system to a lightly loaded one (but the load is reduced). The major difference in residential loads is during the summer because of air conditioners. These hourly load fluctuations and the changes on the loads patterns on the daily and seasonal basis is the key factor that makes a higher frequency reconfiguration method more effective than a constant configuration scheme. As an example the residential feeders are lightly loaded in the winter. Therefore, tie switches may change to transfer a portion of the commercial and industrial loads to the lighter loaded feeders.

In this paper, several load types are assigned to feeders based on measurement data from one of the largest utilities in Northeastern United States. The assignment of load profiles to feeders may influence the results. The method proposed in the paper determines the optimal switching frequency based on field-measured time-dependent load models. Therefore, this method is flexible and capable to adjust load models with any load curves if available to system operators. Note that, the optimal switching frequency is a system dependent problem and may vary from system to system. Here we have solved three distribution systems with available data as examples. The results presented in the paper solely correspond to the systems and data provided. However, the method is general and can be applied to any distribution system with any load data.

B. 69-Bus Distribution System

The first case study is a 12.66 kV radial distribution system with 5 tie switches and 74 branches (illustrated in Fig. 10). Different types of load (residential, commercial, mixed, and industrial) are allocated in the system as shown in Table I. The lower limit of node voltages is set to 0.95 pu and the current limit for all branches is 445 A (details are available in [21]).

It is found that not every sectionalizing switch participate in the reconfiguration process even under the high frequency reconfiguration scheme. The simulation results using utility A load curves are presented in Tables II and III. Table II lists the sensi-

TABLE III
ECONOMIC STUDY FOR THE 69-BUS TEST SYSTEM COMPARED TO BASE CASE

Operation Frequency	Investment Cost ($)	Gain From Investment ($)	Total Savings ($)	ROI
Seasonal	4,064.33	961.73	−3,102.60	−0.76
Monthly	4,064.33	6,466.79	2,402.47	0.59
Weekly	8,128.65	10,313.70	2,185.05	0.27
Daily	12,192.98	12,635.12	442.14	0.04
Hourly	32,514.61	21,655.46	−10,859.15	−0.33

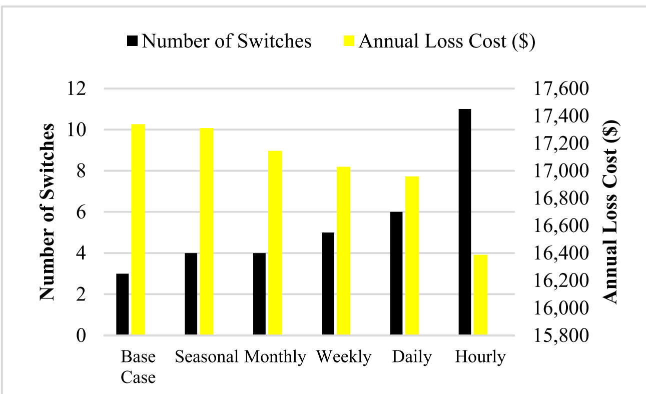

Fig. 11. Comparison between number of switches and annual loss cost of the 69-bus test system.

tive switches that participate in hourly reconfiguration process. It shows the maximum of the sectionalizers that should be replaced by remote control switches. According to this table, only 11 (out of 79) switches need to be replaced by smart switches in the hourly scenario. Note that, for less frequency scenarios, the number of switches that needs to be changed are fewer than for hourly reconfiguration. Thus, these cases need smaller initial investment. Fig. 11 shows the number of the switch that should be upgraded and annual loss cost under different scenarios. To achieve higher frequency reconfiguration, more remote control switches should be installed, which could reduce even more the loss cost for the year.

The economic comparison between different scenarios is presented in Table III. To highlight the effect of switching frequency in determining the reconfiguration plan, the optimal configuration for the peak of the load is chosen as the base configuration. Tie switches after reconfiguration for the peak load are: 70, 15, 71, 26, and 59. The system's minimum voltage over the entire year is almost the same at 0.97 pu.

High frequency switching leads to larger gains from investment. At the same time, the investment cost increases due to the replacement of more conventional switches with remote controlled ones. In terms of total savings and ROI, monthly switching is recommended for this case. The total savings and the expected ROI for the monthly switching are $2,402.47 and 0.59 when compared to the base configuration.

The voltage stability index remains almost unchanged at 0.977, which means the system is not prone to voltage instability.

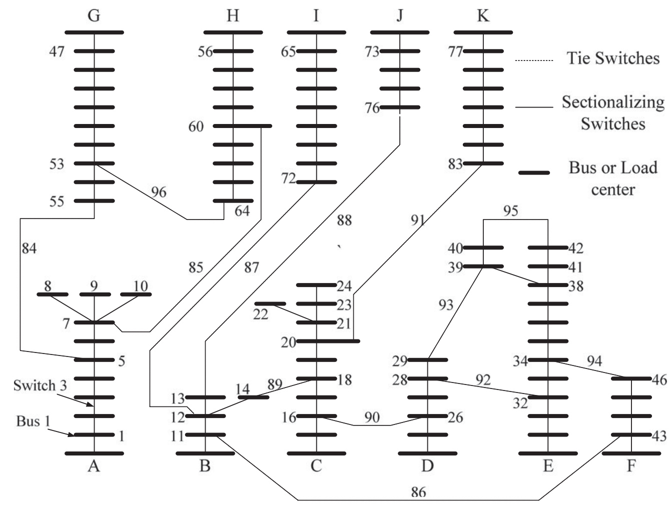

Fig. 12. Taiwan Power Company distribution system with 84 buses [7].

TABLE IV
SENSITIVE SWITCHES OF THE 84-BUS TEST SYSTEM UNDER HOURLY RECONFIGURATION

Sensitive Switches
7, 13, 29, 33, 34, 37, 38, 39, 40, 41, 42, 54, 55, 59, 60, 61, 62, 63, 72, 81, 82, 83, 84, 86, 88, 89, 90, 91, 92, 93, 95

TABLE V
ECONOMIC STUDY FOR THE 84-BUS TEST SYSTEM USING UTILITY A LOAD PROFILES COMPARED TO BASE CASE

Operation Frequency	Investment Cost ($)	Gain From Investment ($)	Totalxbrk Saving ($)	ROI
Seasonal	16,257.30	25,601.86	9,344.56	0.57
Monthly	20,321.63	58,764.89	38,443.26	1.89
Weekly	24,385.96	114,976.24	90,590.28	3.71
Daily	52,836.24	160,840.71	108,004.47	2.04
Hourly	89,415.17	228,360.65	138,945.47	1.55

C. 84-Bus Distribution System

The second case is a distribution system from the Taiwan Power Company [7]. The system consists of 83 sectionalizing and 13 tie switches. The lower limit of node voltages is set to 0.95 pu and the maximum branch current limit is 640 A. The system has 11 feeders with overhead lines and underground cables. The original configuration of the 84-bus system is shown in Fig. 12. Feeders B, D, F, G, and K are residential feeders. Feeders C, H, and I are commercial feeders and the rest are industrial/mixed load feeders.

For utility A load profiles, the simulation results are shown in Tables IV and V. The sensitive switches that participate in hourly reconfiguration process are presented in Table IV. Results demonstrate that 31 switches from the total 96 switches need to be replaced by remote controlled switches to achieve hourly reconfiguration scheme. Even in the high frequency reconfiguration plan, not every line should be equipped with remote

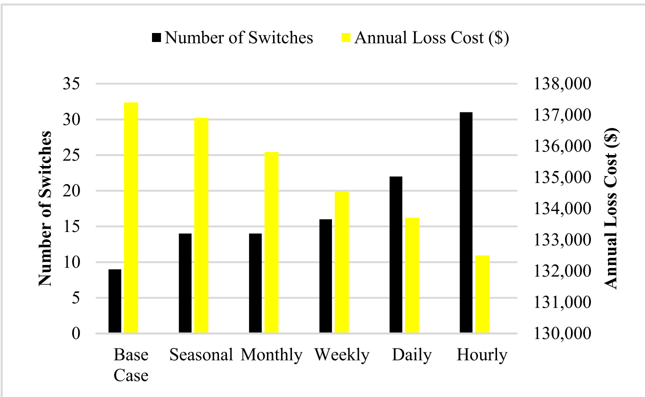

Fig. 13. Comparison between number of switches and annual loss cost of the 84-bus test system.

control switches. Fig. 13 shows that higher frequency switching reduces the cost of the power loss. However, the initial investment on switch upgrade is significant. The tie switches for the optimal reconfiguration considering peak load are: 55, 7, 62, 72, 13, 83, 42, 39, 92, 34, 90, 89, 86. The comparison between the different scenarios is given in Tables V.

The minimum system voltage over the entire year is almost constant at 0.953 pu. The results show that the total savings are maximum for the hourly reconfiguration plan. However, weekly reconfiguration has the maximum ROI (3.71) compared to the base case (optimal configuration for peak load). The average voltage stability index is far from zero, which means that the voltage keeps stable in all scenarios.

D. 119-Bus Distribution System

A large-scale 11 kV distribution system with 118 sectionalizing switches and 15 tie switches is selected as the third test case [2]. The original configuration is shown in Fig. 14. Note that, in this paper the substation voltage is set to 1.05 pu. This is so because, the minimum voltage of the system presented in [2] is below the voltage limit. Different loads (commercial, residential, and industrial) are placed in different locations in the system (see Tables VI). Simulation results are provided in Tables VII and VIII using utility B load profiles. The 43 sensitive switches (out of 133) that participate in hourly reconfiguration process are presented in VII. Therefore, only about 32% of the switches need to be substituted by smart ones to achieve highest frequency reconfiguration. The tie switches for the optimal configuration considering the peak load are: 20, 11, 39, 34, 46, 51, 124, 61, 96, 98, 72, 88, 130, 86, 110. Fig. 15 explains that higher frequency reconfiguration needs more remote control switches, which could save more annual loss cost instead. Tables VIII lists the comparison between different operation scenarios.

Although the gain from the investment is larger when increasing the operation frequency (see Tables VIII), the investment cost on switch upgrade increases significantly. In terms of total savings, the hourly reconfiguration plan is the superior strategy among all reconfiguration scenarios. However, weekly reconfiguration is more promising considering ROI index.

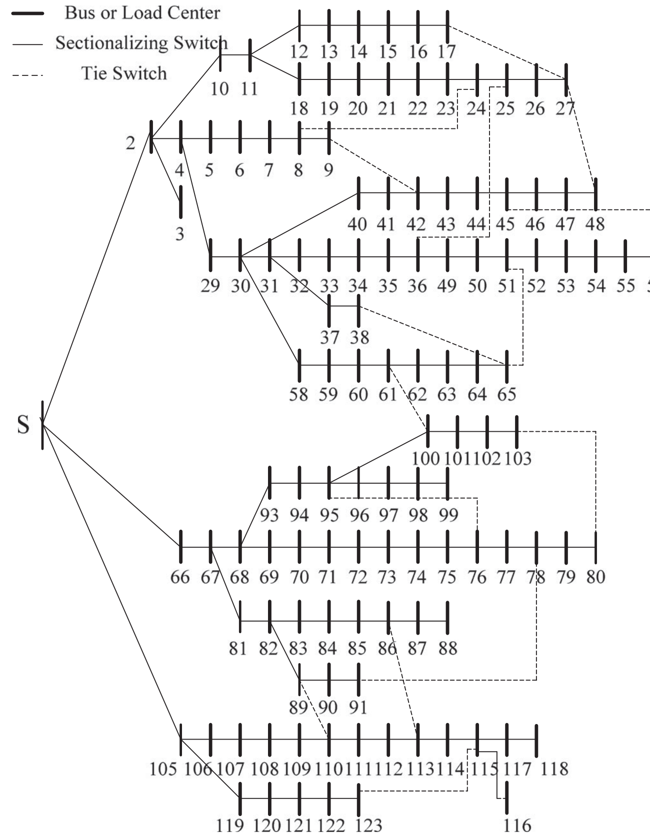

Fig. 14. 119-bus distribution system [2].

TABLE VI
LOAD CHARACTERISTICS OF THE 119-BUS TEST SYSTEM

Load Type	Residential	Commercial	Industrial
Located Bus	9,12,18,20,22,24, 25,35,40,43,46, 47,49,54,58,63,64, 65,68,69,71,74,77, 78,80,82,90,91,93, 98,101,103,106,108, 110,112,114,118,123	2,4,6,7,8,13,15, 17,19,21,23,26, 27,29,31,32,34,38, 42,45,48,50,51,52, 55,59,60,61,62,66, 70,73,76,83,84,87, 88,89,96,97,100,102, 105,109,113,121,122	3,5,10,11,14,16, 30,33,36,37,41, 44,53,56,67,72, 75,79,81,85,86,94, 95,99,107,111,115, 116,117,119,120

TABLE VII
SENSITIVE SWITCHES OF THE 119-BUS TEST SYSTEM UNDER HOURLY RECONFIGURATION

Sensitive Switches
8,11,12,13,14,18,20,25,26,27,39,40,43,44,45,46,51,52,53,59,60,61,72,73,75, 76,77,83,87,88,96,98,99,110,121,123,124,125,128,129, 130,131,133

V. DISCUSSION

One can observe from Tables II, IV, and VII, that even in the hourly reconfiguration scheme, not all switches participate in switching operations. In other words, only some "sensitive" switches have an impact on the reconfiguration plan. Therefore, there is no need to equip all lines with automatic sectionalizing

TABLE VIII
ECONOMIC STUDY FOR THE 119-BUS TEST SYSTEM USING UTILITY B LOAD PROFILES COMPARED TO BASE CASE

Operation Frequency	Investment Cost ($)	Gain From Investment ($)	Total Saving ($)	ROI
Seasonal	12,192.98	11,938.69	−254.29	−0.02
Monthly	28,450.28	59,693.46	31,243.18	1.10
Weekly	48,771.91	119,386.92	70,615.01	1.45
Daily	77,222.20	179,080.38	101,858.18	1.32
Hourly	121,929.78	253,299.25	131,369.46	1.08

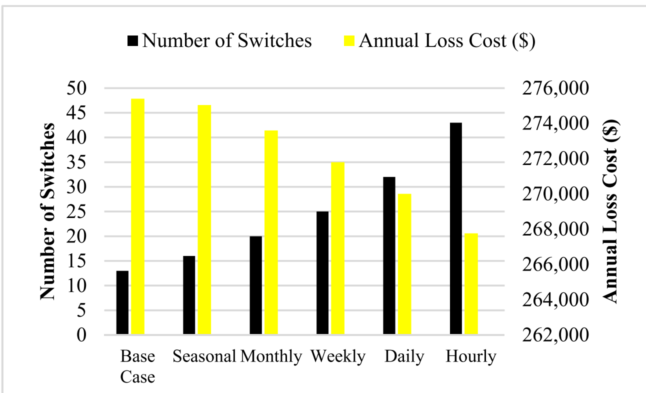

Fig. 15. Comparison between number of switches and annual loss cost of the 119-bus test system.

switches. In this way, sensitive switches that need to be replaced by smart (or remote controlled) switches are identified.

The paper provides a way to determine the optimal switching frequency. Note that the determination of the optimal switching frequency is a system dependent problem. For example, results show that the monthly reconfiguration plan is optimal for the 69-bus system. However, in terms of total saving and ROI, hourly and weekly reconfigurations are superior among all reconfiguration scenarios for the 84-bus and the 119-bus test systems, respectively. The method is general and can be applied to any distribution system.

VI. CONCLUSIONS

Comparative studies are presented in the paper for hourly, daily, weekly, monthly, and seasonal reconfiguration plans. The results demonstrate that even with the highest frequency operation, only a few switches participate in the reconfiguration process. For economic operation, there is no need to equip all lines with automatic sectionalizing switches. Therefore, utilities need to substitute only a few sectionalizers with automatic (or remote control) switches. The number of switches for replacement is dependent on the reconfiguration frequency. This fact offers a practical/economical way to optimally automate distribution networks for real-time reconfiguration operations.

The paper provides a way to determine the optimal switching frequency based on the economic indexes such as total savings and ROI. Greater energy cost reductions are achieved when system reconfigurations are carried out with higher frequency. However, this reduction is associated with large initial investment cost on switch upgrades.

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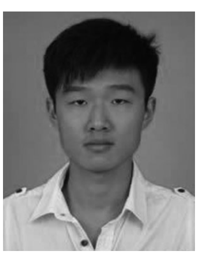

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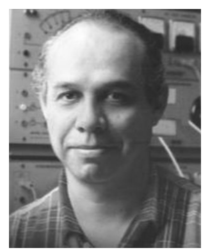

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