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Reliability Optimization of Automated Distribution Networks with Probability Customer Interruption Cost Model in the presence of DG units

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***Abstract*—Distribution automation systems in terms of automatic and remote-controlled sectionalizing switches allows distribution utilities to implement flexible control of distribution networks, which is a successful strategy to enhance efficiency, reliability and quality of service. The sectionalizing switches play a significant role in an automated distribution network, hence optimizing the allocation of switches can improve the quality of supply and reliability indices. This paper presents a mixed-integer nonlinear programming aiming to model the optimal placement of manual and automatic sectionalizing switches and protective devices in distribution networks. A value-based reliability optimization formulation is derived from the proposed model to take into consideration customer interruption cost and related costs of sectionalizing switches and protective devices. A probability distribution cost model is developed based on a cascade correlation neural network to have a more accurate reliability assessment. To ensure the effectiveness of the proposed formulation both technical and economic constraints are considered. Furthermore, introducing distributed generation into distribution networks is also considered subject to the island operation of DG units. The performance of the proposed approach is assessed and illustrated by studying on the bus 4 of the RBTS standard test system. The simulation results verify the capability and accuracy of the proposed approach.**

***Index Terms*—Distribution automation system, sectionalizing switch placement, power distribution system reliability, customer interruption cost model.**

NOMENCLATURE

L_{jtkfr}	Annual average load of type k at Load Point j of feeder fr at year t .
γ	Annual load increase rate.
CC_c	CB capital investment cost.
IC_c	CB installation cost.
CC_f	Fuse capital investment cost.
IC_f	Fuse installation cost.
CC_s	Sectionalizing switch capital investment cost.
C_{temp}	Interruption cost (\$/kW) of temporary faults.
ICT_{ijtkfr}	Interruption cost of Load Point j of type k because of temporary interruption in section i of feeder fr at year t.
IC_s	Sectionalizing switch installation cost.
$MC_{s,t}$	Sectionalizing switch annual operation and maintenance cost.
T	Sectionalizing switch and fuse life period.
$MC_{c,t}$	Total maintenance cost of a CB.
$MC_{f,t}$	Total maintenance cost of a fuse.
N_{CT}	Total number of customer types.
N_{LPf}	Total number of load points in feeder f.
N_{LP}	Total number of load points.
N_{ac}	Total number of available CB for installation.
N_{af}	Total number of available fuses for installation.
N_{as}	Total number of available switches for installation.
N_c	Total number of installed CBs.
N_{fr}	Total number of feeders.
N_f	Total number of installed fuses.
N_q	Total number of possible fault locations.
N_s	Total number of installed sectionalizing switches.
λ'_{ijtfr}	Temporary failure rate of Load Point j because of failure in section i of feeder fr at year t.

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I. INTRODUCTION

Nowadays, there is an increasing interest in the analysis of power distribution systems, including demands to improve the reliability of distribution networks by implementing distribution automation systems (DASs). The application of DASs in distribution networks can be defined to monitor, coordinate and operate distribution network component to restore supply to the customers during a fault. In fact, a DAS is not just a remotely control and operation of substation and feeder equipment but it can provide a reliable and self-healing distribution network that is able to rapidly react to real-time events by taking appropriate actions. Hence, an economic analysis of DASs is necessary because of its large investment cost [1].

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It has been estimated that approximately 70% of interruptions in supplying demand are related to the failure in primary distribution networks [2]. Thus, considerable effort has been devoted to reduce the effects of failures by utilizing DAS in terms of automatic protective devices such as circuit breaker (CB) and sectionalizing switches. One of the functions of DASs is to determine the placement of remote control switches to isolate fault and restore service to the customers. The proper number, location and type of such protective devices play an important role in the reliability of distribution networks by minimizing the impact of the interruption. In addition, the optimum number and location of manual and automatic switches and protective devices are important to minimize capital investment cost and maximize customer benefits [3].

Sectionalizing switches are commonly used in primary distribution networks to improve the service reliability. Recently, more attention is being paid to the use of optimization techniques to solve the sectionalizing switch placement problem. In order to solve the optimal sectionalizing switch placement problem, heuristic algorithms such as genetic algorithm [2], ant colony [4], simulated annealing [5] and immune algorithm [6] have been widely utilized. In [7], the optimal numbers and locations of two sorts of automatic switches (i.e., sectionalizer and circuit breaker) in the distribution system are determined by using a trinary particle swarm optimization method. The feeder-switch relocation problem, with the aim of customer interruption cost reduction, was solved by using a heuristic approach in conjunction with simple numerical computation in [8]. In [9], the mixed-integer linear programing was employed to model the sectionalizing switches placement problem considering the switch cost and outage of customers. An approach to solve the composition and placement problem of switches in distribution automation networks was developed in [10]. Additionally, the decomposition approach was used in [11] and the alliance algorithm was used in [12] to solve the problem of optimal allocation of switches. In [2], a solution framework based on a memetic algorithm concept with a structured population was presented for the switch allocation problem. These references considered various elements, such as the switch cost, customer outage cost, and optimal number and location of sectionalizing switches for improving the reliability of power distribution networks. However, but the dispersion of customer interruption cost data, which is important information that can have a significant effect on the accuracy of the reliability assessment, was not considered.

The accuracy of the reliability analysis can be affected directly by the customer interruption cost model. There are two different approaches to model the customer interruption cost. The customer survey approach provides customer outage cost data that could be modeled as a customer damage function (CDF) [9], [13]. This model determines the aggregate or average cost of interruption for each customer sector as a function of duration. The main disadvantage of the aggregate or average cost model (AAM) is that the dispersed nature of data within a specified customer group is neglected. The dispersed nature of customer interruption costs at specified failure duration has been designated as the probability distribution model (PDM) [14]. The results presented in [13], [14] demonstrated that the PDM had a considerable effect on predicting the expected customer interruption cost.

Until recently, grows of distributed generation (DG) has been limited due to economic reasons. However, increased attention to power quality, environmental awareness, market deregulation and reduction in the price of photovoltaic and wind driven generation have all contributed to increasingly integrate DGs into the network. In power distribution reliability analysis, DG unit can potentially improve network reliability by reducing the interruption durations and increasing the restoration speed when a fault occurs. However, such improvement depends on the operation mode of the DG units, such as islanding mode, while the protection requirements are met. On this basis, presence of DG units in distribution systems adds more complexity for finding the optimal switch and protective device placement optimization.

The main contribution of this paper is to propose a mixed-integer nonlinear programming (MINLP) formulation to solve the optimal allocation of sectionalizing switches and protective devices problem in presence of DG units. The proposed method provides the minimum reliability cost while limiting the number of installed switches and protective devices. The PDM cost model is based on a cascade correlation neural network (CCNN) that takes into account the costs associated with switches and protective devices, such as capital investment, installation, annual operation and maintenance costs. Moreover, this paper considers the interruption costs arisen from temporary faults.

II. Problem Formulation

The concepts related to distribution networks reliability, protection and operation, required to define the problem and the proposed formulation, are presented in this section.

A. *Failures and Interruptions*

An Interruption can be defined as a complete loss of service to one or a group of customers, and is categorized by its duration as either momentary or sustained [15]. According to IEEE Standard 1366 [16], the interruption with a total duration less than 5 min is classified as a momentary interruption. Otherwise, the interruption is considered as a sustained interruption. The failures that occur in the distribution networks always lead to customer interruptions and can be considered as permanent or temporary. The permanent failures will happen by the most serious events and always cause the sustained interruptions occur, which require to dispatch a repair crew to handle them. On the contrary, the temporary failure will clear themselves away after a short period of time. It should be noted that a temporary failure can cause either a momentary or a sustained interruption. In this paper, failure is considered either as the occurrence of a permanent failure on a feeder's line or transformer or occurrence of a sustained interruption due to the failure of any component of the distribution network.

B. *Network Structure*

Distribution networks can be divided as radial, spot or secondary. Radial networks are the most prevalent and the

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focus of this paper. The radial distribution network is basically served by the substation and consists of one or more distribution feeders. Each feeder is split into one or more line sections and laterals with sectionalizing switches and protective devices. This is the most frequently form of network configuration, each feeder can operate radially for effective coordination of protective devices, as presented in Fig. 3. In addition, supply can be restored from an alternative supply or neighbour feeders by tie switches (TS).

C. Sectionalizing Switches and Protective Devices

In general, to mitigate the effects of failures to a minimum acceptable level, utilities install protective devices along the distribution network feeders. The protective device considered in this paper consists of a CB with overcurrent and automatic reclosing relays at the substation, and sectionalizing switches and fuses along the feeders and on the laterals. Automatic sectionalizing switches can isolate a faulted section after the operation of an upstream CB. Fuses are low cost protective devices and can sense the fault. They have interruption capability but do not have automatic reclosing capability. In this paper, fuses are installed on laterals and a constraint is defined to avoid putting the fuses on the main feeders.

D. Basic Operation of Distribution Networks

Reliable distribution networks try to minimize the impact of failures to the customers by utilizing more switches and protective devices and minimizing the number of customers affected with protective device operations. Due to cost constrains, only a limited number of switches and protective devices can be installed on feeders and laterals. However, types and locations of these devices vary depending on utility practices and networks topology. Sectionalizing switches can be located at both sides of each line sections, and protective equipment is usually located at the beginning of line sections on the feeders or laterals. Operation of distribution networks can be evaluated according to the type, number and location of switches and protective devices.

For instance, when a fault occurs in the Line Section 3 (LS3) of the network shown in Fig. (1a), the following steps should be performed:

Step 1 (fault clearance): The fault clearance functions open the protection breaker CB1 (Fig. (1)b). Therefore, during the clearance of this fault, all load points are interrupted.

Step 2 (fault separation): Separation of sectionalizing switches, S1 and S6 open in Fig. (1)c. The separated area now contains the faulty line, LS3. There are two restorable areas following the fault separation; the area which contains the Load Point (LP1) and the area which contains the Load Point 4 and 5 (LP4 and LP5).

Step 3 (power restoration): The following switch actions are required to restore power to the two separate restorable areas: 1) Separation switch S1 is remote-controlled and has a switching time of 1 minute. Power to Load Point 1 is restored by (re)closing the protection breaker CB1 which is also remote controlled. The LP1 is therefore restored in 1 minute. 2) Power to LP4 and LP5 is restored by closing the TS. Because the tie switch (TS) has an actuation time of 30 minutes, loads 4 and 5 are restored in 0.5 hours. The network is now in the post-fault condition as illustrated in Fig. (1)d.

However, LP2 and LP3 experienced the outage duration equal to the repair time of LS3 which is much longer than the switching time.

It is worth to note that, when a fault occurs in the Lateral Section 2 (L2), as there is no protective device in this lateral, the previous switching actions will be followed to clear this fault. Thus, additional installation of protective devices on the lateral or sectionalizing switches on the main feeder will increase the reliability of the network.

Consider the fully automated network with protective devices shown in Fig. 2. When a fault occurs in LS3, all the load points can be restored after isolation of the faulty section by the sectionalizing switches. Furthermore, the outage duration of the load points was equal to the switching time of CB1 and the sectionalizing switches. In the case of fault in L2, the presence of protective devices such as a fuse or CB will lead to isolate the fault without interrupting other parts of the system. In this case, just LP2 experiences the outage equal to the repair time of L2.

Although LP2 and LP3 would experience a shorter outage time in Fig. 2 compared to Fig. 1, the switching and protective device costs in the network shown in Fig. 2 are much higher and the necessity of doing optimization is more important to balance the cost of reliability and switching devices.

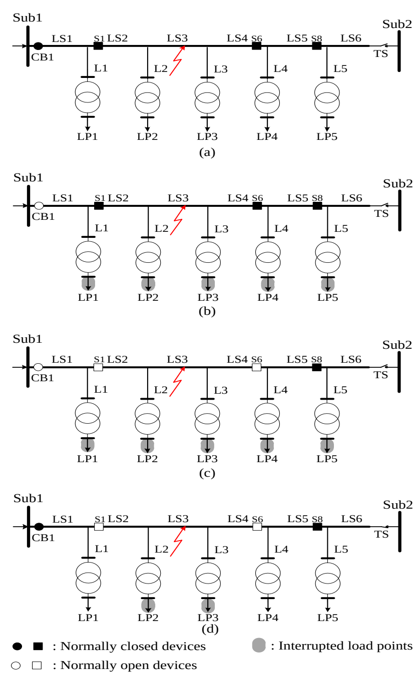

Fig. 1. Sample of radial distribution network and fault restoration steps. (a) Fault occurred in LS3, (b) fault clearance step, (c) fault separation step, and (d) fault restoration step.

E. Distribution Networks Reliability Indices

A variety of indices are defined in [17] to evaluate the reliability of distribution networks. The basic indices that normally provide service reliability data from an individual

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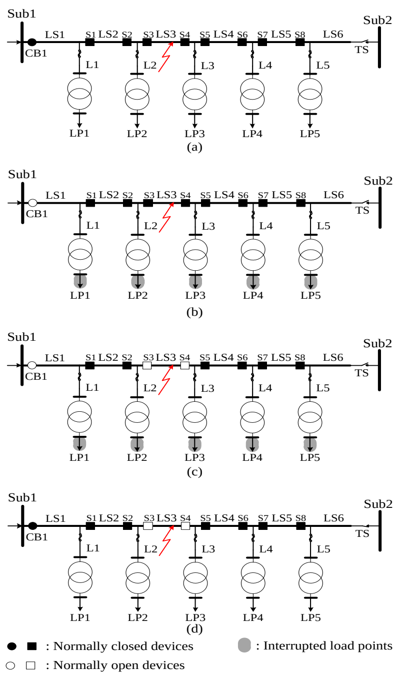

Fig. 2. Sample of fully automated radial distribution network and fault restoration steps. (a) Fault occurred in LS3, (b) fault clearance step, (c) fault separation step, and (d) fault restoration step.

customer viewpoint are called single load point indices. These include the load point average failure rate (λ), average outage duration (r), and average annual outage duration (U). The most frequently used customer oriented indices can be calculated using these three basic indices, given as the system average interruption frequency index (SAIFI), system average interruption duration index (SAIDI) and energy not supplied (ENS). These indices are not sufficient to represent the cost of reliability. The expected interruption cost (ECOST) index reflects the impacts of the interruption duration, failure rate of equipment, load variation, customer type and customer damage function [17]. On this basis, the index can be utilized to associate the reliability with the customers' cost. The contingency based analytical method, which is employed to calculate the ECOST in distribution networks for a typical feeder, is well described in [5].

$$ECOST = \sum_{i=1}^{N_q} \sum_{j=1}^{N_{LP}} \sum_{k=1}^{N_{CT}} \lambda_i \times CDF_{ijk}(r_{ij}) \times L_{jk} \quad (1)$$

where λ_i is the average failure rate of the distribution network equipment i, $CDF_{ijk}(r_{ij})$ is the customers damage function that depends on r_{ij}, r_{ij} being the failure duration of jth load point, and L_{jk} is the average load of kth type customer located at the jth load point.

F. PDM Training Data

Interruption cost evaluation demonstrates that the monetary values expose a large deviation and, in some cases, the standard deviation is more than four times the mean value [18]. Taking into consideration the dispersed customer interruption cost data in the analysis, the actual data need to be transferred into a flexible mathematical model. A normality transformation has been used to represent the full range of interruption cost data. According to this systematic procedure, the customer interruption cost data can be transformed into a normal distribution in which the PDM is developed to represent the data [18]. In this approach, the data collected from the survey for the specified duration are transformed into a group of data, which are illustrated by a normal distribution using the normality transformation. The following transformation is selected in this paper:

$$b = \begin{cases} \frac{a^{\alpha}-1}{\alpha} & \text{if } \alpha \neq 0 \\ log(a) & \text{if } \alpha = 0 \end{cases} \quad (2)$$

where a is the original data, α is the power exponent and b is the transformed value.

The distributed nature of the transformed interruption cost data for a particular customer sector and a specific outage duration can be determined by four parameters: the normality power transformation factor α, the mean of the normal transformed distribution μ, the variance of the normal transformed distribution σ^2 and the proportion of zero-valued data P_z. These parameters for industrial and residential customer sectors are taken from [18].

In this paper, regression analysis is used to predict the distribution pattern for intermediate durations. The relation between the studied duration ($d(min)$) and each of the four parameters is described by (3)-(10) which are derived by the least square method [18]:

Industrial customers:

$$\alpha = -0.487 + 0.0537\, log(d) - 0.0821\, [log(d)]^2 + 0.0256\, [log(d)]^3 \quad (3)$$

$$\mu = 0.3263 * 10^{0.3933 log(d)} \quad (4)$$

$$\sigma^2 = 3.8757 + 0.5985 log(d) - 1.7895 [log(d)]^2 + 0.5371 [log(d)]^3 \quad (5)$$

$$P_z = \begin{cases} 0.3333 - 0.1346 log(d) & \text{d} < 4 \text{ hours} \\ 0.0047 & \text{d} \geq 4 \text{ hours} \end{cases} \quad (6)$$

Residential customers:

$$\alpha = -0.4552 + 0.1709 log(d) \quad (7)$$

$$\mu = -11.8902 + 4.986 log(d) \quad (8)$$

$$\sigma^2 = 14.8429 - 10.2288 log(d) + 1.9692 [log(d)]^2 \quad (9)$$

$$P_z = 0.8771 [log(d)]^{-3.7322} \quad (10)$$

where the log base is 10. To determine the parameters of the normal distribution and the zero cost, (3)-(10) can be used as the cost models.

According to the architecture of cascade networks [19], the three input vectors related to the cascade correlation neural network for PDM are defined as I_1, I_2, and I_3. The first two inputs imply the type of customers and I_3 emphasizes the interruption duration. The output layer consists of four parameters of PDM (i.e. α, μ, σ^2 and P_z). The values sampled with 10 minutes duration are chosen as the training data for the cascade correlation neural network [13].

It should be noted that the customer interruption cost cannot be directly described by the PDM data. These data have to be transferred back to the original form to generate the actual customer interruption cost. The procedure to calculate the customer interruption cost using PDM is more complex compared to the customer damage function method [18]. The cascade correlation neural network presented in [19] is used to obtain four parameters of PDM for different types of customers.

The procedure used by PDM to compute the customer interruption cost for duration of failure d_i can be implemented by the following steps:

1) Calculate P_z, α, μ and σ^2 from d_i using CCNN for the specified type of customers.
2) A random number A_1 is generated for a customer by using a uniform random generator $R(0,1)$.
3) If $A_R \leq P_z$, the customer is assigned a zero outage cost.
4) If $A_R > P_z$, the parameters (α, μ and σ^2) are distinguished from the existing d_i and another random number A_2 is generated to sample a transformed cost b.
5) The customer outage cost a ($\$/kW$) is used to assess the reliability indices. It is calculated using the following inverse transformation:

$$a = \begin{cases} (1+\alpha \cdot b)^{1/\alpha} & \text{if } \alpha \neq 0 \\ log^{-1}(b) & \text{if } \alpha = 0 \end{cases} \tag{11}$$

III. Proposed Formulation

A. Objective Functions

In Fig. 3, a set of possible locations to install sectionalizing switches and protective devices is shown. Total cost of reliability (TCR) is formulated as explicit nonlinear function of decision variables indicating the installation of sectionalizing switches and protective devices on the sections of a radial distribution network. The binary decision variables are defined as follows:

$$X_{sfr} = \begin{cases} 1 & \text{if a sectionalizing switch is installed on location } s \text{ of feeder } fr, \\ 0 & \text{otherwise.} \end{cases}$$

$$Y_{ffr} = \begin{cases} 1 & \text{if a fuse is installed on location } f \text{ of feeder } fr, \\ 0 & \text{otherwise.} \end{cases}$$

$$Z_{cfr} = \begin{cases} 1 & \text{if a CB is installed on location } c \text{ of feeder } fr, \\ 0 & \text{otherwise.} \end{cases}$$

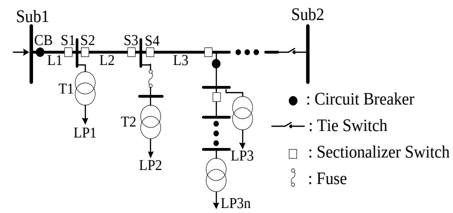

Fig. 3. Possible locations for sectionalizing switches and protective devices in a radial distribution network.

A contingency simulation based technique is used to formulate the TCR as a mathematical function of basic reliability indices and the above mentioned binary variables as follows:

$$TCR = UCR + CIC \tag{12}$$

where UCR denotes the utilities cost of reliability including costs of sectionalizing switches and protective devices and CIC represents the customer interruption cost.

$$UCR = SC + FC + CBC \tag{13}$$

where SC (switch cost) represents the sectionalizing switch cost including the costs of capital investment, installation and maintenance as follows.

$$\begin{aligned} SC = &\sum_{fr=1}^{N_{fr}} \sum_{s=1}^{N_s} (CC_s + IC_s) \times X_{sfr} \\ &+ \sum_{t=1}^{T} \sum_{fr=1}^{N_{fr}} \sum_{s=1}^{N_s} MC_{s,t} \times X_{sfr} \end{aligned} \tag{14}$$

FC (fuse cost) is defined as the fuse cost as follows:

$$\begin{aligned} FC = &\sum_{fr=1}^{N_{fr}} \sum_{f=1}^{N_f} (CC_f + IC_f) \times Y_{ffr} \\ &+ \sum_{t=1}^{T} \sum_{fr=1}^{N_{fr}} \sum_{f=1}^{N_f} MC_{f,t} \times Y_{ffr} \end{aligned} \tag{15}$$

CBC (CB cost) is defined as the CB cost as follows:

$$\begin{aligned} CBC = &\sum_{fr=1}^{N_{fr}} \sum_{c=1}^{N_c} (CC_c + IC_c) \times Z_{cfr} \\ &+ \sum_{t=1}^{T} \sum_{fr=1}^{N_{fr}} \sum_{c=1}^{N_c} MC_{c,t} \times Z_{cfr} \end{aligned} \tag{16}$$

The CIC consists of ECOST and the interruption cost due to temporary faults (ICT).

$$\begin{aligned} CIC = &\sum_{fr=1}^{N_{fr}} \sum_{t=1}^{T} \sum_{i=1}^{N_q} \sum_{j=1}^{N_{LP}} \sum_{k=1}^{N_{CT}} (ECOST_{ijtkfr} + \\ &ICT_{ijtkfr})(1+\gamma)^{t-1} \end{aligned} \tag{17}$$

where ICT_{ijtkfr} is defined by:

$$ICT_{ijtkfr} = C_{temp} L_{jtkfr} \lambda'_{ijtfr} \tag{18}$$

The objective of the proposed formulation is to accurately model the sequence of events after a contingency in the network. It is achieved by minimizing the total cost of reliability in terms of customer outage cost in conjunction with sectionalizing switch and protective device capital investment, installation, and annual operation and maintenance costs. Also, taking into consideration the load increase rate during a time horizon under study, the average load of load points is multiplied by $(1+\gamma)^{t-1}$ [9].

The objective function is minimized according to the following assumptions.

1- The feeders are operated as radial feeders.

2- The protective equipment is completely coordinated. In the case of changes in the capacity of generation units, network configuration and network's load, the protection setting should be recalculated and re-tuned [20].

3- No installation of fuses in the main feeder allowed.

B. Constraints

This section presents economic and technical constraints which are incorporated to the proposed mixed-integer nonlinear programming model. The sectionalizing switches and CBs are expensive devices. Therefore, adding more switches and protective devices in distribution system can increase the UCR cost. The following economic constraints are defined to limit the number of switches and protective devices which are available to be installed in the case of budget limitation:

$$\sum_{fr=1}^{N_{fr}} \sum_{s=1}^{N_s} X_{sfr} \leq N_{as} \tag{19}$$

$$\sum_{fr=1}^{N_{fr}} \sum_{f=1}^{N_f} Y_{ffr} \leq N_{af} \tag{20}$$

$$\sum_{fr=1}^{N_{fr}} \sum_{c=1}^{N_c} Z_{cfr} \leq N_{ac} \tag{21}$$

The technical constraints are based on network configuration and utilities practices. In fact, in the case of installing a mandatory switch in a particular section, the related binary variable should be set to one. The following constraints are defined to restrict the continuous decision variable $CDF_{ijktfr}(r_{ij})$ based on the location and number of switches and protective devices thanks to the switching time of sectionalizing switches, actuation time of fuses, and repair time of faulted equipment.

$$CDF_{ijktfr}(r_{ij}) \geq CDF_{ijktfr}^{Switching} \times (1 - Y_{ffr}) \times Z_{cfr} \tag{22}$$

$$\begin{aligned} CDF_{ijktfr}(r_{ij}) \geq [CDF_{ijktfr}^{Repair} \times (1 - \sum_{s=s_i}^{s_j} X_{sfr})] \\ \times (1 - Y_{ffr}) \times Z_{cfr} \end{aligned} \tag{23}$$

In fact, the $CDF_{ijktfr}(r_{ij})$ is a set of positive continuous variables and depends on the location and number of installed switches and protective devices. To show how the constraints (22) and (23) can restrict the customer outage cost based on the existence or in-existence of the switches and protective devices between the contingency (fault) location and load points, a simplified feeder shown in Fig. 3 consisting 2 line segments (L1, L2) and 2 load points (LP1, LP2) is considered. There is one possible location to install CB which is assumed that $Z_{cfr} = 1$. Furthermore, there are three and two possible locations to install sectionalizing switches (S1-S3) and fuses, respectively. Also, because this test system has 2 line segments and 2 transformers (T1 and T2), there are four possible fault locations (fault in L1, L2, T1 and T2). Based on the (22) and (23), for instance, if a fault occurs in transformer (T1) which is connected to the load point 1 (LP1), the following set of constraints can be defined to restrict the continuous variables. Note that, $CDF_{ijktfr}^{Switching}$ and CDF_{ijktfr}^{Repair} are the fixed values and present CDF values related to the duration of failure equal to the switching and repair times, respectively. The LP1 is assumed to be residential, thus k and fr stand for 1.

$$CDF_{2111}(r_{21}) \geq CDF_{2111}^{Switching} \tag{24}$$

$$CDF_{2111}(r_{21}) \geq CDF_{2111}^{Repair} \tag{25}$$

$$CDF_{2211}(r_{22}) \geq CDF_{2211}^{Switching} \times (1 - Y_{11}) \tag{26}$$

$$CDF_{2211}(r_{22}) \geq CDF_{2211}^{Repair} \times [1 - X_{21} - X_{31}] \times (1 - Y_{11}) \tag{27}$$

IV. Numerical Example

A. Test System

The modified low voltage test network in this study is a radial distribution network at Bus 4 of the RBTS, including 38 load points, 51, 38 and 7 possible sectionalizing switches, fuses and CB locations, respectively [21]. The modified test network without TS is presented in Fig. 4. The essential reliability data, such as customer data, equipment failure data, maximum and average load at each load point are provided in [21]. The related fix costs associated with sectionalizing switches and protective devices are presented in Table I [22]. The cost of maintenance for a switching device is considered to be 2% of the cost of capital investment. The life time of a switch device is presumed to be fifteen years [9]. The reliability data of protective devices are taken from [3]. The rate of load growth of the test network is considered to be 3%. Furthermore, the related data of the customer damage function are extracted from [13]. The proposed formulation performed in the GAMS software and the branch-and reduce optimization navigator (BARON) solver is used to work out on the problem.

Note that, the simulations performed on an Intel(R) Core(TM) i5-2500 CPU@3.30GHz with 8 GBs of random-access memory. The performance of the cascade correlation neural network in terms of root-mean square (RMS) error convergence was 0.9s for 12 epochs.

TABLE I
SECTIONALIZING SWITCH AND PROTECTIVE DEVICE FIXED COSTS.

Device	Cost($)
CB	6000
Automatic Switch	4700
Manual Switch	2500
Fuse	1500

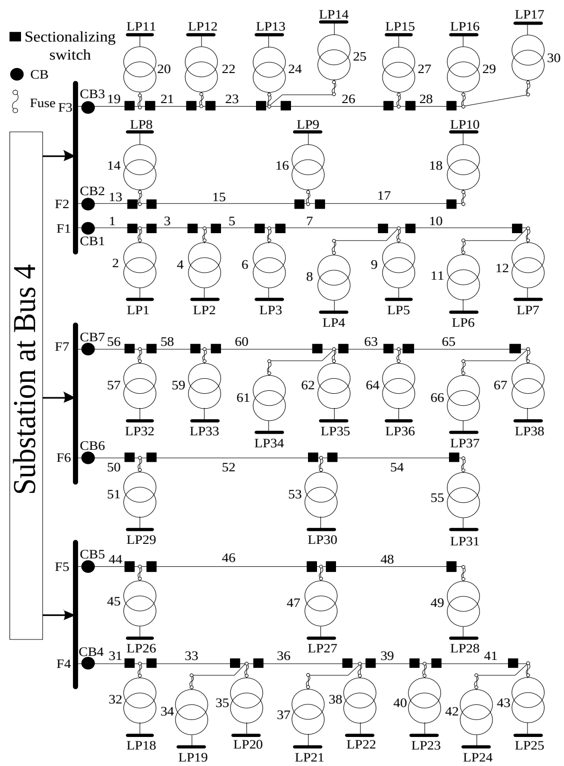

Fig. 4. Modified distribution test network (38 load points (LP), 51 sectionalizing switches, 38 fuses and 7 CBs).

B. Simulation Results

In order to proceed the proposed formulation on the test network, different case studies are performed. In Case 1, CBs, sectionalizing switches, and fuses are placed in all possible sections, as the base case. The TCR value is 92.365 (k\$/yr) (including UCR= 44.008 (k\$/yr) and CIC= 48.357 (k\$/yr)). This case might be good for the customers because of the highest reliability level. But is not a desired option for the utilities due to the higher cost. Thus, the optimal number of protective devices is a tradeoff challenge for the utilities to keep the reliability of the network at the reasonable levels while meeting cost constrains. In Case 2, the optimal location and number of manual switches and protective devices are investigated. The value of TCR is 70.676 (k\$/yr) which is 23.5% less than for the Case 1. The results obtained by the proposed formulation suggest installing seven CBs and show that the best locations to install CBs are the start section of the main feeders (CB1-CB7), confirming the performance of the proposed formulation. Note that the AAM cost model is used to evaluate the above cases.

To have a more accurate reliability analysis, in Case 3, the optimum location and number of manual sectionalizing switches and protective equipments are evaluated by considering the PDM cost model. The comparison between Case 2 and 3 is depicted in Table II. The higher CDF is made by the PDM result in the higher value for TC. Also the number of switches and fuses are increased due to the higher CDF. However, despite these higher values, the PDM cost model can provide a more realistic reliability analysis [18]. The optimal number of fuses in Case 3 is 38, and the proposed optimization formulation suggests putting fuses in all possible locations because of their lower cost compared to the cost of customer outage.

TABLE II
OPTIMAL SOLUTION RESULTS (CASE 2, 3)

Study Case		Case 2	Case 3
Number of Switches		6	14
Location of Switches*		17B,26B,39B,48B 54B,63B	5E,10B,15B,17B,21B,26B,36B 39B,46B,48B,52B,54B,60B,63B
Number of Fuses		34	38
Number of CBs		7	7
TCR	UCR	15.743	21.945
	CIC	54.933	255.570
TCR (k\$/yr)		70.676	277.515

* Every line section has two candidate locations for sectionalizing switch installation which are shown as B for the beginning of a line section and E for the end of a line section.

The automatic protective devices and sectionalizing switches can greatly enhanced the reliability of power distribution systems. The automated restorative service avoids the required acting of manual switching schedule and can provide a remarkable improvement in the reliability of the system by reduction in the outage cost. Therefore, in Case 4, the reliability worth of utilizing DAS in terms of automatic sectionalizing switches (RWDAS) based on the TC is investigated. DAS in terms of automatic and remotely controlled switches installation can provide benefits for the distribution utilities. These benefits can be quantified in terms of reduction on the customer outage duration and number of affected customers during a fault by fast restoration of service to the unfaulted parts of the network. To do this, as mentioned before, the faulted part of the network needs to be isolated by remote and automatic sectionalizing switches and the unfaulted parts will be supplied by the main substation or alternative routes. The RWDAS can be evaluated as follows:

$$RWDAS = TCR - TCR_{DAS} \tag{28}$$

where TCR_{DAS} and TCR are the network TCR with and without DAS, respectively. Note that, the PDM cost model is used in this case.

The value of RWDAS, when comparing with Case 3, is 12 351 (\$/yr) which is a major benefit for distribution utilities. It can be seen that automatic switches can decrease the objective functions (TCR and ECOST) despite the fact that the higher number of installed switches is offered. On the other hand, the more installed automatic switches provides more reductions on the interruption time of customers, consequently amending the objective functions and continuity of supply. By inspecting the results, it is important to change the manual switch devices with automatic devices to reduce the restoration time which is a crucial measure to decrease the customer outage costs. The detailed results of Case 4 are presented in

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TABLE III
OPTIMAL SOLUTION RESULTS (CASE 4)

Study Case	Case 4
Number of Switches	15
Location of Switches	5B,10B,15B,17B,21B,26B,33E,36E 39B,41E,48B,52B,54B,60B,63B
Number of Fuses	38
Number of CBs	7
TCR (k$/yr)	265.164

TableIII. Furthermore, the program execution time for Case 4 is around 8.5 seconds, which is evident for this case. To show the scalability of the proposed formulation, a distribution network comprising 420 feeders is considered which has been produced by replicating 60 times the distribution network connected to bus 4 of the RBTS. In this case, the optimal locations of protective and sectionalizing devices are the same of Case 4. The optimal solution is achieved in approximately 410 seconds which shows the applicability of the proposed formulation to the bigger system.

V. IMPACTS OF DG UNITS ON THE OPTIMAL SWITCH AND PROTECTIVE DEVICE PLACEMENT

A. DG Model

The DG operated in distribution systems can be represented by a two-state model where the generator has either full or zero capacity (Fig. 5). Since the DG is normally defined as a small generation unit (<15MW), the partial capacity state is ignored in this paper. The partial capacity state is typically used for generation units of 100MW or higher [23]. The forced outage rate (FOR) and repair time of DG are assumed to be 0.01 and 44h, respectively [21]. It should be noted that, in the case of active failure into the system, the DG should be disconnected immediately. Once the faulty sections are isolated, the DG supply the healthy parts of the system via operating in island mode.

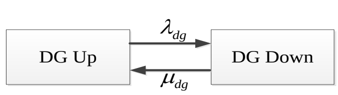

Fig. 5. Two-state model for DG units.

The probability of availability and unavailability of the two-state model for DG can be expressed by:

$$P_{available} = \frac{\mu_{dg}}{\lambda_{dg} + \mu_{dg}} \qquad (29)$$

$$P_{unavailable} = \frac{\lambda_{dg}}{\lambda_{dg} + \mu_{dg}} \qquad (30)$$

where λ_{dg} is the expected failure rate and μ_{dg} is the expected repair rate of a DG unit.

B. Results

Location and capacity of DG units are important to improve the quality of service in distribution networks [24], [25]. The level of improving depends on operation of DG systems in island mode which is adopted in this paper. Islanding will occur when a part of distribution network including DG systems becomes electrically isolated to the rest of the network and continues to be energized by the DGs. Island formation would be successful in case that the DG systems can supply the customer demand within the island. It is assumed that, after forming the island, the customers within the island will supply continuously with DG systems.

The probability of an island is given by [26]:

$$P_{IP} = (\sum_{j=1}^{N_{LPf}} (P_{GDG} \times P_{GLP_j})) \times (1 - P_f) \qquad (31)$$

where P_{GDG} presents the DGs' probability to generate power greater than or equal to a certain level, P_{GLP} presents a load point' probability to have a certain value, and P_f denotes as the forced outage rate of a DG.

The major players in renewable energy generation are photovoltaic, wind, fuel cell and biomass. The increase in fuel price has prompted distribution network operators to invest in renewable energy sources. In this paper, two DG systems are considered including a diesel generator (2 MW output rating) and two wind turbines (1 MW output rating each). The output power probability function of the wind turbines, network demands and reliability data of the DG units are extracted from [27].

As the addition of DG units into the feeders supplying the load points with high CDF and heavier load density would be more useful to reduce the TC of the network, in Case 5, feeder four (F4) is selected for adding a DG unit into the modified test network. The optimal location and number of switches and protective devices of Case 5 are presented in Table IV. Note, the DAS and PDM cost model are considered in this case.

The results demonstrate that introducing DG at the end of feeder four can decrease the TCR by about $7 675 (k$/yr) compared to Case 4. This is because of that the feeder four consisting of commercial customers with slightly high CDF and has the highest load demand of the entire test system. As can be seen, 17 switches are selected to be placed in the network by the proposed formulation. In fact, introducing DG units can decrease the objective function effectively despite of increasing in the number of installed switches. This is due to the fact that the more installed switches can provide a greater decrement of the customers interruption time.

To demonstrate how increasing in the number of DG units can affect the optimum switch placement problem, the number of introduced DG units in the system is considered to be varied from one to seven. Table IV presents the proposed location and number of switches and variation in TCR as the number of added DG units is increased. It can be evidenced that the number of sectionalizing switches increased as the number of DGs increased. For instance, by adding seven DGs, the proposed MINLP algorithm suggests to install eighteen more switches compared to the Case 4. Therefore, adding more switches enables a decrease of the customer outage cost and

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TABLE IV
NUMBER OF DGS IMPACT ON OPTIMAL LOCATION AND NUMBER OF SWITCHES

Number of DG	Location of DG	Number of Switches	Location of Switches	TCR (k$/yr)
1	F4	17	5B,10B,15B,17B,21B,26B,33E,36B,36E 39B,41E,46B,48B,52B,54B,60B,63B	257.490
2	F1,F4	20	3B,5B,7E,10B,10E,15B,17B,21B,26B,33E 36B,36E,39B,41E,46B,48B,52B,54B,60B,63B	236.609
3	F1,F3,F4	22	3B,5B,7E,10B,10E,15B,17B,21B,23E,26B,28E 33E,36B,36E,39B,41E,46B,48B,52B,54B,60B,63B	215.495
4	F1,F3,F4,F7	24	3B,5B,7E,10B,10E,15B,17B,21B,23E,26B,28E,33E 36B,36E,39B,41E,46B,48B,52B,54B,58B,60E,63B,65E	201.735
5	F1,F3,F4,F6,F7	27	3B,5B,7E,10B,10E,15B,17B,21B,23E,26B,28E,33E,36B,36E 39B,41E,46B,48B,50E,52B,52E,54B,54E,58B,60E,63B,65E	184.973
6	F1,F2,F3,F4,F6,F7	30	3B,5B,7E,10B,10E,13E,15B,15E,17B,17E,21B,23E,26B,28E,33E 36B,36E,39B,41E,46B,48B,50E,52B,52E,54B,54E,58B,60E,63B,65E	169.464
7	F1,F2,F3,F4,F5,F6,F7	33	3B,5B,7E,10B,10E,13E,15B,15E,17B,17E,21B,23E,26B,28E,33E,36B,36E 39B,41E,44E,46B,46E,48B,48E,50E,52B,52E,54B,54E,58B,60E,63B,65E	156.462

consequently reducing the objective function (TCR) relevant to the solution.

VI. COMPARATIVE STUDY

To illustrate the benefits of the proposed mixed-integer nonlinear programming (MINLP) formulation in this paper, a comparison has been done with the other methods available in the technical literatures [1], [2], [3], [4], [5], [7], [9], [10], [12], [22] and [26] and the results are presented in Table VI. The heuristic algorithms in most of the cases cannot provide the accurate results due to exploring a limited region of the search space while there is the possibility of getting stuck into a local optimum solution [9] and [26]. However, parameter tuning and lack of information in terms of the quality of solution are two drawbacks of the heuristic methods, especially if the aim is to provide a useful technique for a company. To find the exact solution to the problem, mathematically optimizing methods such as mixed integer linear programming, have proven to attain the global optimal solution in a bounded number of steps, besides providing an accurate and flexible model.

The reliability of a distribution system can directly affected by customer outage duration. Since the outages are due to both permanent and temporary faults therefore assuming the temporary faults in the proposed approach brought a more pragmatic assessment of the customer reliability which was neglected in some of the cited literatures. However, since the effects of the interruption durations, load variations, equipments failure rate and customer types and damage functions are associated with the reliability through the ECOST index, the better way to express the effects of customer interruption cost on the reliability is using this index compare to the reliability indices such as SAIDI, SAIFI, and ENS. Another important factor which has a considerable effect on the reliability of a distribution network is the customer outage cost. As mentioned before it is difficult to assess the real values of the cost and for this reason a PDM cost model based on the cascade correlation neural network is proposed in this paper to provide a more realistic assessment of the distribution systems reliability while considering the dispersed nature of data in a specified group of customers. Furthermore, as mentioned before DAS can bring remarkable benefits to the distribution systems in terms of improving reliability.

VII. CONCLUSION

This paper presented a formulation to identify the optimal number, types and locations of protective devices and sectionalizing switches in distribution networks. A MINLP formulation has been performed to assess the effects of DAS in improving the reliability indices of a distribution network. The objective was to minimize the TC while installing the minimum number of protective devices and switches. Furthermore, to have a more accurate model for the reliability assessment, which can provide better solutions to meet the utility practices, the PDM interruption cost model is considered. The advantages of the proposed formulation has been accredit in terms of case studies on Bus 4 of the modified RBTS. Numerical results have corroborated the efficient performance of the formulation. Also, in the case of adding DG units, the effects of DAS and the PDM on the optimal protective and switching devices placement have been investigated and discussed.

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TABLE V
COMPARISON OF THE PROPOSED APPROACH WITH OTHER LITERATURES

References		[1]	[2]	[3]	[4]	[5]	[7]	[9]	[10]	[12]	[22]	[26]	Proposed Approach
Method	MINLP	✕	✕	✕	✕	✕	✕	✕	✕	✓	✕	✕	✓
	MILP	✕	✕	✓	✕	✕	✕	✓	✓	✕	✕	✓	✕
	Heuristic	✓	✓	✕	✓	✓	✓	✕	✕	✓	✓	✕	✕
Objective Function	ECOST	✓	✕	✓	✕	✓	✓	✓	✕	✕	✓	✓	✓
	Switch Cost	✓	✓	✓	✓	✓	✓	✓	✓	✕	✓	✓	✓
	Fuse Cost	✕	✕	✓	✕	✕	✕	✕	✕	✕	✓	✕	✓
	CB Cost	✕	✕	✓	✕	✕	✓	✕	✕	✕	✓	✕	✓
Considering PDM cost model		✕	✕	✕	✕	✕	✕	✕	✕	✕	✕	✕	✓
Fault Type	Permanent Faults	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Temporary Faults	✕	✕	✕	✕	✕	✕	✕	✕	✕	✓	✓	✓
Protective Device	Automatic	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Manual	✓	✓	✕	✕	✕	✕	✕	✕	✕	✕	✕	✓
Load Growth		✓	✕	✕	✕	✓	✓	✓	✓	✕	✕	✓	✓
DG		✕	✕	✕	✓	✕	✕	✕	✕	✓	✕	✓	✓
Type of Customers		✓	✕	✕	✕	✓	✓	✓	✓	✕	✕	✓	✓
Test System	RBTS Bus 4	✕	✕	✕	✕	✓	✓	✓	✕	✕	✕	✓	✓

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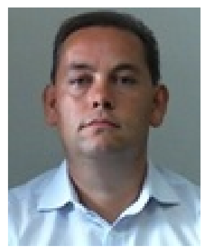

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