2021-09-22

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Recommended Citation

N. Gholizadeh, S.H. Hosseinian, M. Abedi, H. Nafisi, P. Siano, Optimal placement of fuses and switches in active distribution networks using value-based MINLP, Reliability Engineering & System Safety, Volume 217, 2022, 108075, ISSN 0951-8320, DOI: 10.1016/j.ress.2021.108075.

Reliability Engineering and System Safety 217 (2022) 108075

Contents lists available at ScienceDirect

Reliability Engineering and System Safety

journal homepage: www.elsevier.com/locate/ress

Optimal placement of fuses and switches in active distribution networks using value-based MINLP

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ARTICLE INFO

Keywords:
Sectionalizing switch placement
Power distribution system reliability
Distributed generation
Customer interruption cost model

ABSTRACT

Contingency conditions in distribution networks create financial losses for different parts of the system including electricity customers, electricity retailers, distributed generation (DG) units, etc. Therefore, protective device allocation methods have been introduced in recent years to enhance the reliability of the power system. In this study, a new formulation is proposed to find the optimal places of sectionalizing switches and fuses while taking the financial loss of both electricity customers and DG units into account. The current method has the flexibility to consider DG effect on any location of the network and its islanded operation in case of contingencies. Moreover, the uncertainty in load and renewable generation is taken into account using stochastic programming. The results demonstrate that the DG units and their financial loss can change the results of switch and fuse placement dramatically when there are no tie switches in the network. Furthermore, it is found that this method can decrease the total reliability costs by 3.86% when high penetration of DG units is introduced into a modified Roy Billinton test system (RBTS). The problem is modeled as a mixed-integer nonlinear (MINLP) formulation and is handled using BARON solver in GAMS environment.

1. Introduction

The increasing need for reliable and continuous power supply to electricity customers has led to the development of quantitative analysis of distribution system reliability worth and its applications, such as value-based reliability optimization in the past few years [1]. Higher levels of reliability are associated with greater capital and operational costs. Therefore, value-based optimization helps to reach a trade-off between utility reliability costs, including costs for capital investment, maintenance, etc., and customer interruption cost [2]. An approach is proposed in [3] to assess the survivability of power systems by considering the phased-recovery of the system after fault. This method performs power flow and evaluates the system before and after fault to make investment decisions. In [4,5], the reliability of the system is assessed by studying the system before and after fault. A planner–attacker–defender model is used in [6] to develop decisions that minimize investment and operational costs in power systems. Power flow is performed for the system before and after fault to evaluate system condition and determine the amount of load shedding. However, none of these studies are value-based reliability study. In value-based reliability studies, the system condition is not studied after each single fault. Rather, the number of the failures per year in each system equipment and the outage duration and financial loss they cause to various customers is calculated and is compared to investment costs. Therefore, no power flow is needed in these types of studies.

Studies show that approximately 70% of the customer supply interruptions are due to failures in the primary distribution network [7]. Therefore, sectionalizing switches are mostly implemented in this network to help improve reliability indices by reducing customer outage duration. Extensive researches have been performed to find the optimal number and locations of these devices in the distribution network. To this end, a multi-objective memetic optimization approach was proposed in [8] to find the type and locations of the protective devices while minimizing equipment costs, system average interruption frequency index (SAIFI), and system average interruption duration index (SAIDI). To consider the uncertainties of network contingencies in switch deployment, a stochastic multi-objective model was designed in [9] which maximized the profit and minimized the financial risk. Three-point estimate method was used in [10] to consider uncertainties

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https://doi.org/10.1016/j.ress.2021.108075
Received 7 January 2021; Received in revised form 25 August 2021; Accepted 8 September 2021
Available online 22 September 2021

Nomenclature

General indices

f	Fuse place
fr	Feeder number
j	Fault places in load points
k	Type of customer
lp	Load point number
q	Fault places in lines
s	Scenario number
sc	Sectionalizing switch place
t	Time

Parameters

γ_k	Annual load increment rate [%]
λ	Average failure rate of equipment [f/yr]
μ_s	Probability of scenarios
$C_{fr,q,k,lp}$	Outage cost of customers [$/kW]
CIC_{sc}/CIC_f	Switch/fuse capital investment cost [$]
I^f/I^r	Inflation/interest rate
IC_{sc}/IC_f	Switch/fuse installation cost [$]
$L_{s,fr,lp}$	Average electricity consumption or production in load points [kW]
$MC_{t,sc}/MC_{t,f}$	Switch/fuse annual operation and maintenance cost [$]
N^{fr}	Total number of feeders
N^{lp}/N^k	Total number of load points/customer types
N^q	Total number of fault locations in lines
N^{sc}/N^f	Total number of used switches/fuses
N^s	Total number of scenarios
N^{Tsc}/N^{Tf}	Total number of available switches/fuses
P_s^{DG}	Average power output of DG units [kW]
T	Life period of switches and fuses [yr]
t^r	Total repair time [min]
t^s/t^{TS}	Switch/tie switch switching time [min]

Variables

C^{int}	Customer interruption cost [$]
C^S/C^F	Total switch/fuse costs [$]
$I_{lp,q}^{DG}$	Binary variable showing existence of DG for supplying a specific load point (1 = existence, 0 = nonexistence)
$I_{lp,q}^{sa}$	Binary variable showing existence of switch after a load point for fault separation (1 = existence, 0 = nonexistence)
$I_{lp,q}^{sb}$	Binary variable showing existence of switch before a load point for fault separation (1 = existence, 0 = nonexistence)
$I_{lp,j}^{sfa}$	Binary variable showing switch or fuse existence after a load point for fault separation (1 = existence, 0 = nonexistence)
$I_{lp,j}^{sfb}$	Binary variable showing switch or fuse existence before a load point for fault separation (1 = existence, 0 = nonexistence)
$Pr_{s,lp,q}^{DG}$	Probability of being supplied by DG unit in contingency condition
$t_{s,lp}^o$	Total outage time of load points [min]
$X_{fr,sc}$	Binary variable showing switch existence (1 = existence, 0 = nonexistence)
$Y_{fr,f}$	Binary variable showing fuse existence (1 = existence, 0 = nonexistence)

in temporary failure rates, permanent failure rates, repair rates and load data while finding optimal places of protective devices.

Genetic algorithm was used in [11] to find the optimal switch places while considering the switch malfunction possibility using the discrete Markov chain model. A multi-objective optimization approach for switch deployment was used in [12] and [13] that aimed to minimize the number of switches and customers not supplied and was handled by particle swarm optimization and differential search algorithms, respectively. Moreover, a mixed-integer nonlinear model was developed by [14] to determine the optimal placement of sectionalizing switches and fuses and was solved using the BARON solver. Other studies include using ant colony optimization to find optimal switch locations in [15], applying differential evolution to find switch and recloser locations in [16], solving the remote-controlled switch allocation problem as a mixed-integer convex programming model in [17] and as a weighed set cover (WSC) problem in [18].

A limited number of studies presented a linear formulation for the optimal switch placement problem by using some estimations or simpler network models. A two-stage and a single-stage mixed-integer linear formulation was proposed in [19] and [20], respectively, to solve the switch allocation problem by minimizing investment, maintenance and interruption costs. A mixed-integer formulation was proposed in [21,22] to solve the switch placement problem while taking switch failures into account. In [23], optimal location and number of remote-controlled switches were found using a linear model to maximize profit and minimize financial risk. Moreover, a linear model was developed in [24] to find the optimal places of sectionalizing switches and tie switches in the network.

Mathematical linear models were developed in [25,26] to optimally place fault indicators and remote-controlled switches within distribution networks. The influence of branch lines on the problem was also studied in [26]. Linearization methods were used in [27] to develop a mixed-integer linear model for simultaneous deployment of fuses, reclosers and remote-controlled switches in distribution networks. A novel mixed-integer linear method was proposed by [28] to optimize placement of fault indicators and sectionalizing switches in distribution networks while minimizing the cost of interruption, switches and fault indicators. Switch deployment was optimized in [29] as a mixed-integer linear model using a resilience-based framework.

Distributed generation (DG) resources are an inseparable part of distribution systems. Since they can supply a part of system loads during fault conditions, considering these resources while allocating protective devices is very crucial. The effect of DG units in finding the optimal location of protective devices was investigated by [7,30,31], while [30] presented a mixed-integer linear formulation and [7,31] used a mixed-integer nonlinear model for the allocation problem. However, none of these models considered different possible locations of the DG units as well as the financial loss caused to DG operators in case of faults in the system. The method used in [30,31] assumed that all DGs were placed at the end of the feeder and no tie switches and fuses were present in the system and the one in [7] did not consider the effect of DGs on decreasing customer interruption cost and did not consider the financial loss of DG units.

Two different methods were developed in [32], to take DG availability in switch placement into account. By using a multi-objective approach, system reliability indexes were improved. However, the operation of the DGs in island mode was neglected and DG units were treated as a determined number of consumers connected to a load point. Optimal switch and DG locations were found in [33] by using a methodology to solve the multi-period distribution expansion planning problem. A similar study by [34] focused on finding the optimal sizing and sitting of DGs and switches in the planning stage and performing DR in the operation stage while minimizing the total outage and investment cost of the system. However, none of these two studies considered the financial loss of DG operators, fuses and tie switches in contingency conditions. A multi-objective optimization was developed in [35] and was solved using graph-based algorithms to place switches within the distribution system consisting of DG units. The formulation in this study was not value-based and did not include the fuses. To the best of the authors' knowledge, no previous work has presented a value-based formulation to study the effect of DG units in every feeder location on the switch and fuse placement.

This paper proposes a mixed-integer nonlinear programming (MINLP) formulation to find the optimal places of the sectionalizing switches and fuses in the distribution network by taking customer outage, device installation, capital investment, annual operation and maintenance costs into account. Also, the effect of DG units in the proposed allocation problem is investigated while considering DG financial loss, outage duration and operation in island mode. In this model, DGs can be connected to any feeder section. In general, the main contributions of this paper can be summarized as follows:

- Presenting a value-based MINLP formulation for switch and fuse allocation in presence of DG units, load and renewable generation uncertainties;
- Proposing a model to consider the effect of the DGs and their operation mode in any location of the feeders;
- Introducing the DG outage duration and financial loss to the proposed formulation.

The rest of the paper is organized in the following order. Section 2 discusses the sources of uncertainty in this study and their modeling. Section 3 describes the proposed formulation in this paper for optimal switch and fuse placement problem. Section 4 presents the case study and the results. Finally, the concluding remarks are discussed in Section 5.

2. Uncertainty modeling

Different sources of uncertainties that exist in distribution networks can affect the optimal deployment of switches and fuses substantially. The uncertainty sources in this study are the electrical loads and the output power of renewable resources. Load surveys and mathematical techniques are used to calculate the amount of estimated load at each load point. However, customer loads can vary widely over time. Similarly, the output power of renewable generation units vary with many different factors such as a change in weather, solar irradiance, wind speed and so on. Several methods such as fuzzy programming, stochastic programming and scenario-based approaches can be used to model uncertainty. Fuzzy and stochastic programming methods are more complicated than the scenario-based approach and they need more detailed information about uncertain parameters. Since it is hard to obtain this detailed information about loads and renewable resources, the scenario-based approach is preferred in this study. In this approach, a number of scenarios are generated which show the possible values of uncertain parameters. Results become more reliable as the number of generated scenarios grows.

To take the stochastic nature of loads and renewable resource generation into account, various approaches and techniques have been used in literature. These techniques consist of analytical methods, approximate techniques and Monte Carlo simulation (MCS). Among these techniques, MCS is the most straight forward and accurate one with less computational burden [7]. Therefore, MCS is used in this paper to generate a large number of likely scenarios. The scenarios are separately created for each feeder using a normal distribution function with 30% standard deviation. Later, the number of scenarios is reduced using Taguchi's orthogonal array testing algorithm (TOAT). This way, similar scenarios are eliminated from the process and the most representative scenarios are selected for simulation. In doing so, the computational burden of the problem is reduced while the accuracy of the results is maintained [36].

3. Problem formulation

A mixed-integer nonlinear programming (MINLP) model is developed in this section to find the optimal switch and fuse placement in the presence of load and renewable generation uncertainties, DG operation modes, the financial loss of electricity customers and DG operators. The formulation is presented in the following subsections. The location of switches and fuses is represented by binary decision variables which are defined as (1) and (2), respectively.

$$X_{fr,sc} = \begin{cases} 1 & \text{sectionalizing switch present} \\ & \text{at location } sc \text{ of feeder } fr, \\ 0 & \text{otherwise.} \end{cases} \tag{1}$$

$$Y_{fr,f} = \begin{cases} 1 & \text{fuse present at location } f \\ & \text{of feeder } fr, \\ 0 & \text{otherwise.} \end{cases} \tag{2}$$

3.1. Objective function

To evaluate the reliability of the distribution systems, different indices can be used such as SAIDI, SAIFI, customer average interruption duration index (CAIDI), expected energy not supplied (EENS), etc. In this paper, the expected customer interruption cost (ECOST) index is used to determine the reliability of the power supply as it can characterize both customer costs and reliability. ECOST is used to determine the equipment investment required to reach and maintain an adequate reliability level in the system. The interruption cost for each customer is determined based on the amount of outage load and the duration of the outage. These values are extracted based on the experiments and surveys in literature. The objective function of this study is defined as (3). The objective function consists of total sectionalizing switch costs, total fuse costs and customer interruption costs.

$$OF = C^S + C^F + C^{int} \tag{3}$$

Total sectionalizing switch cost comprises switch installation costs, capital investment and maintenance costs and is defined as (4). This model is adopted from [14]. Since the life span of switches and fuses can be several years, the present value of each cost needs to be incorporated in the objective function. Therefore, interest and inflation rates are used similar to [37] to calculate the present value of switch maintenance cost.

$$\begin{aligned} C^S = &\sum_{fr=1}^{N^{fr}} \sum_{sc=1}^{N^{sc}} (CIC_{sc} + IC_{sc}) \times X_{fr,sc} \\ &+ \sum_{t=1}^{T} \sum_{fr=1}^{N^{fr}} \sum_{sc=1}^{N^{sc}} \frac{1}{R^t} \times MC_{t,sc} \times X_{fr,sc} \end{aligned} \tag{4}$$

$$R = (1 + I^f) \times (1 + I^r) \tag{5}$$

Fuse cost includes fuse installation, capital investment and maintenance costs and is modeled as (6) [14].

$$\begin{aligned} C^F = &\sum_{fr=1}^{N^{fr}} \sum_{f=1}^{N^{f}} (CIC_f + IC_f) \times Y_{fr,f} \\ &+ \sum_{t=1}^{T} \sum_{fr=1}^{N^{fr}} \sum_{f=1}^{N^{f}} \frac{1}{R^t} \times MC_{t,f} \times Y_{fr,f} \end{aligned} \tag{6}$$

Customer interruption cost is obtained by (7) and is calculated by considering average failure rates of the network components, customer outage duration and its respective cost and load increment rate [14]. Three types of customers are considered in this study which are industrial consumers, residential consumers and DG operators. Therefore, the interruption cost also takes the financial loss of DG units into account by calculating their outage time, average generation and energy selling price. No increment rate is considered for the generation of DG units. Note that $L_{s,fr,lp}$ also includes the different generated scenarios for loads and renewable generation units and μ_s represents the probability of each scenario. These scenarios can only alter the results of the allocation problem by changing the value of C^{int} compared to C^S and C^F.

$$C^{int} = \sum_{t=1}^{T}\sum_{s=1}^{N^s}\sum_{fr=1}^{N^{fr}}\sum_{j=1}^{N^{lp}}\sum_{q=1}^{N^q}\sum_{lp=1}^{N^{lp}}\sum_{k=1}^{N^k}\frac{1}{R^t}\times\mu_s\times\lambda_{fr,q,j} \times C_{fr,q,k,lp}(t^o_{s,lp})\times L_{s,fr,lp}(1+\gamma_k)^{(t-1)} \tag{7}$$

3.2. Outage duration

Outage duration of the customers and DG units is calculated by (8) and (9) in presence and absence of the tie switches, respectively. When a permanent fault occurs in downstream of a load point, the load point can be restored if a sectionalizing switch exists between the load point and the faulted part. Similarly, in case of a contingency in the upstream of a load point, the load point can be restored if that feeder has a tie switch and a sectionalizing switch exists between the faulty section and the load point. Also, in case of contingencies in a load point, other load points can be restored if the load point has a fuse or a sectionalizing switch exists between them and that load point. In all other conditions, the load point is lost for the duration of the repair time. Fig. 1 illustrates a sample feeder to help better understand the fault management process. It should be noted that only one fault can happen in a given time and in Fig. 1 only places of the possible fault locations have been shown.

$$\begin{aligned} t^o_{s,lp} = &\sum_{q=1}^{lp}\lambda_q t^r_q(1-Pr^{DG}_{s,lp,q})+\sum_{q=1}^{lp} I^{DG}_{lp,q}t^s \\ &+\sum_{q=lp+1}^{N^q}\lambda_q t^r_q(1-I^{sa}_{lp,q})+\sum_{q=lp+1}^{N^q}\lambda_q t^s I^{sa}_{lp,q} \\ &+\sum_{j=1}^{lp-1}\lambda_j t^r_j(1-Y_j)(1-Pr^{DG}_{s,lp,q}) \\ &+\sum_{j=1}^{lp-1} I^{DG}_{lp,q}t^s(1-Y_j)+\sum_{j=1}^{lp-1}\lambda_j t^s Y_j \\ &+\sum_{j=lp+1}^{N^{lp}}\lambda_j t^r_j(1-I^{sfa}_{lp,j})+\sum_{j=lp+1}^{N^{lp}}\lambda_j t^s I^{sfa}_{lp,j}+\lambda_{lp}t^r_{lp} \end{aligned} \tag{8}$$

$$\begin{aligned} t^o_{s,lp} = &\sum_{q=1}^{lp}\lambda_q t^r_q(1-I^{sb}_{lp,q}) \\ &+\sum_{q=1}^{lp}\lambda_q(t^s+t^{TS}(1-Pr^{DG}_{s,lp,q}))I^{sb}_{lp,q} \\ &+\sum_{q=lp+1}^{N^q}\lambda_q t^r_q(1-I^{sa}_{lp,q})+\sum_{q=lp+1}^{N^q}\lambda_q t^s I^{sa}_{lp,q} \\ &+\sum_{j=1}^{lp-1}\lambda_j t^r_j(1-I^{sfb}_{lp,j})+\sum_{j=1}^{lp-1}\lambda_j t^s I^{sfb}_{lp,j} \\ &+\sum_{j=1}^{lp-1}\lambda_j t^{TS}(1-Pr^{DG}_{s,lp,q})I^{sb}_{lp,j} \\ &+\sum_{j=lp+1}^{N^{lp}}\lambda_j t^r_j(1-I^{sfa}_{lp,j})+\sum_{j=lp+1}^{N^{lp}}\lambda_j t^s I^{sfa}_{lp,j}+\lambda_{lp}t^r_{lp} \end{aligned} \tag{9}$$

3.3. DG model

In this study, instead of finding the optimal places of DG units, it is assumed that DG places are known similar to the load points before the switch and fuse placement. Since DGs are normally small generation units (<15 MW), they can only supply a small part of system loads during contingency conditions. Therefore, to take DG presence into account, the probability of supplying each load by DG in contingencies is calculated by (10). The probability is then used, as in (8) and (9), to reduce the outage duration of each load. DGs can supply loads that are disconnected from the grid using a switch and are connected to the DG. $I^{sb}_{lp,q}$ is a binary variable which shows the existence of a switch that is able to separate the load from grid and $I^{DG}_{lp,q}$ is a binary parameter which denotes the existence of a DG in the islanded area. Since the DG units cannot supply all of the loads in the islanded area, dividing DG capacity to sum of the load values in the islanded area gives the probability of being supplied by DG. These DG units can be small micro-turbines, wind turbines, rooftop photovoltaic systems or any other small generation units.

$$Pr^{DG}_{s,lp,q} = I^{sb}_{lp,q}\times I^{DG}_{lp,q}\frac{P^{DG}_s}{\sum_{j=lp}^{N^{lp}} L_{s,fr,j}} \tag{10}$$

3.4. Constraints

The technical constraints for the current study are defined by (11) and (12) which limit the maximum available number of sectionalizing switches and fuses, respectively.

$$\sum_{fr=1}^{N^{fr}}\sum_{sc=1}^{N^{sc}} X_{fr,sc}\le N^{Tsc} \tag{11}$$

$$\sum_{fr=1}^{N^{fr}}\sum_{f=1}^{N^{f}} Y_{fr,f}\le N^{Tf} \tag{12}$$

To define the existence of any switch before a load point which can separate the load from fault place, (13) is used. Big-M method is used in (13) where parameter M shows a large number. For example, for a fault in $q = 2$ and the load point $lp = 3$ in the first feeder, the left side of this inequality is $(X_{1,3} + X_{1,4} + X_{1,5})/M$ which has a value slightly greater than zero when there is at least one switch in one of $X_{1,3}$, $X_{1,4}$ or $X_{1,5}$ locations. One the other hand, the right side of this inequality is $X_{1,3} + X_{1,4} + X_{1,5}$ which has a value greater than one. Since $I^{sb}_{lp,q}$ is a binary variable, its will be set to one to show that at least one switch exists before the third load point to disconnect it from faulty place. Similarly, (14) is used to specify the existence of any switch after a load point for fault separation.

$$\frac{\sum_{sc=2q-1}^{2lp-1} X_{fr,sc}}{M}\le I^{sb}_{lp,q}\le\sum_{sc=2q-1}^{2lp-1} X_{fr,sc} \tag{13}$$

$$\frac{\sum_{sc=2lp}^{2q-2} X_{fr,sc}}{M}\le I^{sa}_{lp,q}\le\sum_{sc=2lp}^{2q-2} X_{fr,sc} \tag{14}$$

When a fault occurs in a load point, a fuse in the faulty load point or a switch in the line can disconnect the fault from healthy points. For such conditions, (15) and (16) were defined that show the existence of a fuse or switch before and after a load point, respectively. Defining (10) to (16) enabled modeling DGs in any location of a feeder and studying their effect on switch and fuse allocation. It should be noted that this study does not attempt to find optimal DG locations at the same time. Therefore, no power flow constraints are needed.

$$\frac{Y_{fr,j}+\sum_{sc=2j}^{2lp-1} X_{fr,sc}}{M}\le I^{sfb}_{lp,j}\le Y_{fr,j}+\sum_{sc=2j}^{2lp-1} X_{fr,sc} \tag{15}$$

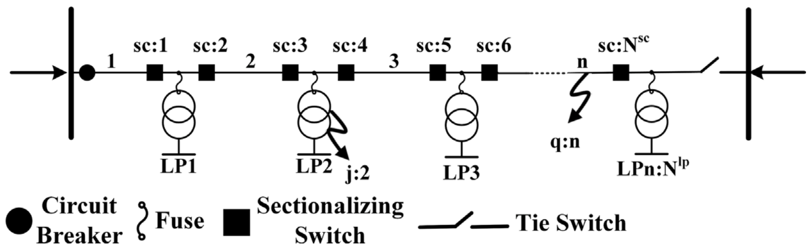

Fig. 1. Sample feeder to show fault management process.

Table 1
Minimum and maximum generation scenarios for test systems 1, 2.

Load point #	Minimum generation [kW]	Maximum generation [kW]
LP3	332.73	830
LP23	67.29	220
LP28	111.41	300
LP33	552.83	1334.84

$$\frac{Y_{fr,j} + \sum_{sc=2lp}^{2j-1} X_{fr,sc}}{M} \leq I_{lp,j}^{sfa} \leq Y_{fr,j} + \sum_{sc=2lp}^{2j-1} X_{fr,sc} \tag{16}$$

4. Numerical examples

The proposed formulation is applied to a radial distribution system connected at bus 4 of the modified Roy Billinton test system (RBTS) [38]. Two test systems are designed. The test system 1 is depicted in Fig. 2. As can be seen, the system consists of 38 load points, 51 and 38 possible sectionalizing switch and fuse locations, respectively. The required data regarding the average load, customer type, failure rates of components are derived from [38]. Normal distribution function with 30% standard deviation is used to generate 1000 likely scenarios for each load and renewable generation unit. The number of scenarios is then reduced according to the orthogonal array and TOAT method. Since the number of loads is high, it is not practical to present their generated scenarios in this paper. However, the minimum and maximum generation scenarios for renewable energy resources after applying TOAT method in both test systems are presented in Table 1.

In this study, the total number of available switches and fuses are 51 and 38, respectively. All of the switches and circuit breakers are assumed to be automatic with switching time of ten minutes. The capital investment and installation costs for sectionalizing switches and fuses are considered to be \$4700 and \$470, respectively [14]. The annual maintenance and operation cost of each switch is set equal to 2% of the capital investment cost and the maintenance cost of a fuse is calculated similar to [14]. The life span of the switches and fuses are assumed to be 15 years. Inflation and interest rates are assumed to be 2%. The outage rate and repair time of DG units are set equal to 0.01 and 44 h, respectively [7]. The load increment rate is assumed to be 3% and the customer damage function is derived from [39] and presented in Table 2. It should be noted that for any interruption duration between separate times a linear approximation is used. The outage cost of DG units is calculated by multiplying the amount of power that they cannot sell by the average electricity price. The average electricity price is considered to be 0.13 \$/kWh. Three types of DG units are considered in this study. The type and capacity of each DG unit at each location of the test systems 1 and 2 are presented in Table 3.

The model is simulated in the General Algebraic Modeling System (GAMS) environment and the problem is solved using BARON solver. The execution of BARON stopped when the value of the objective function was within 0.001% of the optimal solution and the maximum program execution time was 33 s on a 2.5 GHz processor with 6 GBs of random-access memory.

Table 2
Customer damage function.

Customer type	Interruption duration [min] & Cost [\$/kW]				
	1 min.	20 min.	60 min.	240 min.	480 min.
Industrial	3.1663	4.3217	6.5508	16.2679	30.3254
Residential	0.0002	0.0279	0.1626	1.8126	4.0006

Table 3
Location and size of DG units in test systems 1, 2.

DG location	Type	Capacity [kW]
Test system 1		
LP12	Micro-turbine	1000
LP28	Photovoltaic system	300
LP33	Wind turbine	1400
Test system 2		
LP3	Wind turbine	830
LP9	Micro-turbine	550
LP12	Micro-turbine	1000
LP23	Photovoltaic system	220
LP28	Photovoltaic system	300
LP31	Micro-turbine	1000
LP33	Wind turbine	1400

To show the necessity of considering DG units in switch and fuse allocation problem, four case studies are defined as below. Note that in cases with tie switches, the tie switches are added to the end of all feeders.

- Case 1: Switch and fuse placement without tie switches and with DG units;
- Case 2: Switch and fuse placement without tie switches and DG units;
- Case 3: Switch and fuse placement with tie switches and DG units;
- Case 4: Switch and fuse placement with tie switches and without DG units.

4.1. Test system 1 results

Each line section is assumed to have two possible locations for switch installation at the beginning and ending of the line which are shown by suffixes B and E, respectively. Table 4 presents the optimal location of switches and fuses in case 1 and case 2. Through the comparison, it can be concluded that considering DG units will change the optimal switch and fuse places dramatically. As can be seen, by taking the DG presence into account, the number of switches is changed from 16 to 22 and three additional fuses are added to the network for DG locations. The switches in locations 9E and 25E are added to the network so that DG12 and DG33 can supply the load points in case of contingencies in line 9 and line 25, respectively. Two switches that are located at both sides of the DG units (10E, 11B, 26E, 27B) are placed to prevent DG financial loss. DG unit which is present at feeder 5, has no impact on switch placement due to its lower generation capacity, lower failure rates of the lines of the feeder and lower customer damage function values.

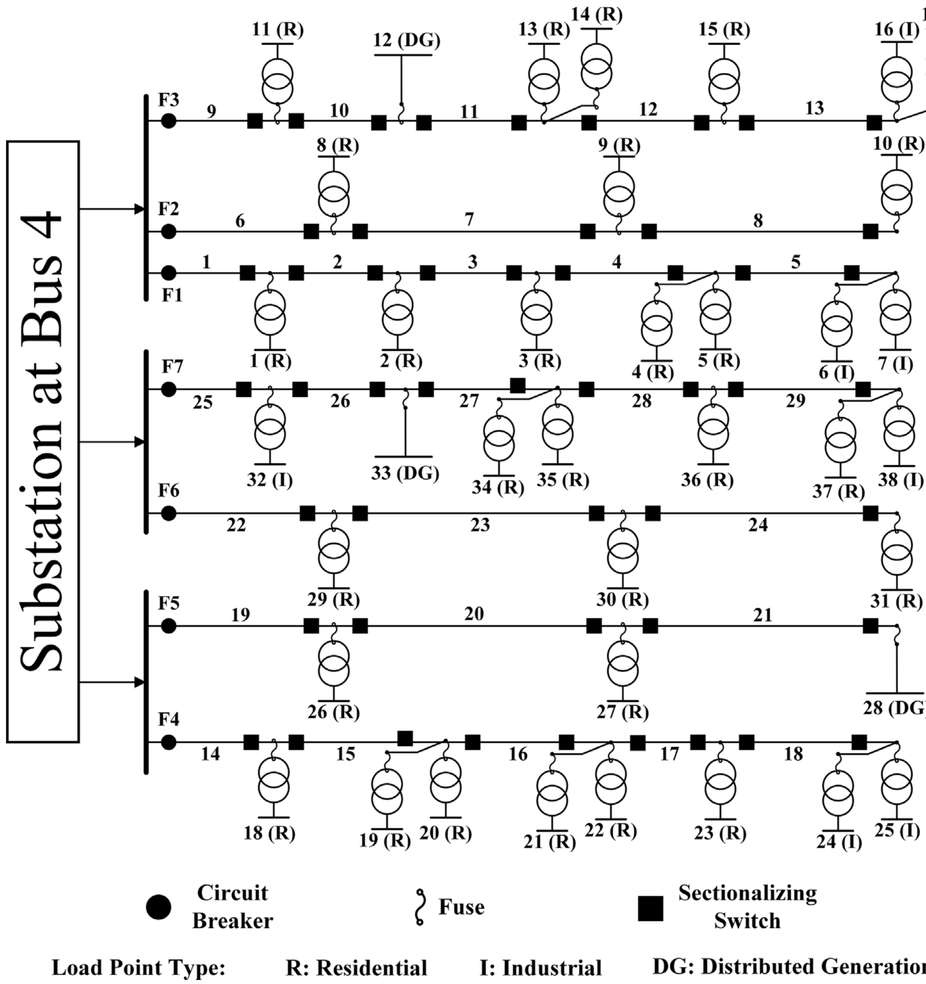

Fig. 2. Test system 1.

Table 4
Optimal equipment locations in test system 1: Case 1, 2.

Feeder	Case 1		Case 2	
	Switch	Fuse	Switch	Fuse
1	2B,3B,4B,5B	All locations	2B,3B,4B,5B	All locations
2	7B,8B	LP8,9	7B,8B	LP8,9
3	9E,10B,10E 11B,12B,13B	All locations	10B,12B,13B	LP11,13,14 15,16,17
4	15B,16B,17B 18B	All locations	15B,16B,17B 18B	All locations
5	–	All locations	–	LP26,27
6	–	All locations	–	All locations
7	25E,26B,26E 27B,28B,29B	All locations	26B,28B,29B	LP32,34,35 36,37,38
Total	22	37	16	34

Optimal places of the switches and fuses in case 3 and case 4 are given in Table 5. In the presence of tie switches in the network, DG units only alter switch places to limit DG financial loss and their islanded operation does not affect the results of allocation. Therefore, two switches are placed at both sides of the DG units (10E, 11B, 26E, 27B) to prevent their financial loss only. Presence of DG units changes the fuse placement of only feeder 5. Moreover, it can be concluded that when tie switches are available in the network, using sectionalizing switches instead of fuses is financially more feasible while without tie switches in the network, installing fuses instead of switches is more cost-effective. This is because in presence of tie-switches, sectionalizing switches can be very helpful in isolating system parts from the faulted section and connecting them to the grid via the tie switch and without tie switches, using fuses is more feasible since they are cheaper compared to switches.

Table 6 compares the values of different system costs including, total cost, customer interruption cost, switch and fuse costs in four case studies. In the absence of tie switches in the system, considering DG units increases the total system costs by 0.25% (since the financial loss of DG units has been added to the system costs as well) however, it decreases the customer outage cost by 0.21% because they can supply some loads in case of outages. On the other hand, when tie switches are available in the network, the presence of DG units causes 1.01% and 0.36% increase in total costs and customer interruption cost, respectively since in this case, tie switches can better supply loads and prevent interruption compared to DGs and DGs only increase total costs and customer interruption cost due to considering DG financial loss in the formulation.

Table 5
Optimal equipment locations in test system 1: Case 3, 4.

Feeder	Case 3		Case 4	
	Switch	Fuse	Switch	Fuse
1	All locations	LP4,5,6,7	All locations	LP4,5,6,7
2	All locations	–	All locations	–
3	All locations	LP13,14 16,17	9E,10B,11E,12B, 12E,13B,13E	LP13,14 16,17
4	All locations	LP19,20,21 22,24,25	All locations	LP19,20,21 22,24,25
5	20E	LP27,28	20B	–
6	23E	LP30,31	23E	LP30,31
7	All locations	LP34,35 37,38	25E,26B,27E,28B 28E,29B,29E	LP34,35 37,38
Total	43	22	39	20

Table 6
Costs in test system 1 in four case studies [k$].

Case #	Total Cost	C^{int}	C^{S}	C^{F}
Case 1	8416.56	8251.18	126.33	39.05
Case 2	8395.88	8268.13	91.87	35.88
Case 3	3575.73	3306.66	246.91	22.16
Case 4	3539.83	3294.77	223.95	21.11

Table 7
Optimal equipment locations in test system 2: Case 1, 2.

Feeder	Case 1		Case 2	
	Switch	Fuse	Switch	Fuse
1	1E,2B,2E 3B,5B	All locations	3B,5B	All locations
2	7B	All locations	7B	LP8,9
3	9E,10B,10E 11B,12B,13B	All locations	10B,12B,13B	All locations
4	15B,16B,17B	All locations	17B	All locations
5	20B,21B	LP26	21B	LP26,27
6	23B,24B	LP29,30	24B	LP29,30
7	25E,26B,26E 27B,28B,29B	All locations	26B,28B,29B	All locations
Total	26	35	12	35

Table 9
Costs in test system 2 in four case studies [k$].

Case #	Total cost	C^{int}	C^{S}	C^{F}
Case 1	8326.93	8146.44	143.55	36.94
Case 2	8661.24	8555.39	68.91	36.94
Case 3	4140.59	3878.31	241.17	21.11
Case 4	4104.68	3866.43	218.2	20.05

Table 10
Optimal location of switches in [7,30] and without Islanded DG operation.

	Switch location	Total
In [30]	2E,4B,5E,7E,8B,11B,12B,13E,15E,16B 17B,18E,20B,21E,23B,24E,27E,28B,29E	19
In [7]	2B,3B,4E,5B,5E,6E,7B,7E,8B,8E,10B 11E,12B,13E,15E,16B,16E,17B,18E,19E,20B,20E 21B,21E,22E,23B,23E,24B,24E,26B,27E,28B,29E	33
Case 1 w/o Islanding	2B,3B,4B,5B,7B,10B,11B,12B,13B,15B 16B,17B,20B,21B,23B,24B,26B,27B,28B,29B	20
Case 3 w/o Islanding	1E,2B,2E,3B,3E,4B,4E,5B,5E,6E,7B,8E 9E,10B,10E,11B,11E,12B,12E,13B,13E,14E,15B 15E,16B,16E,17B,18E,19E,20B,20E,21B,22E,23B 23E,24B,25E,26B,26E,27B,27E,28B,28E,29B,29E	38

4.2. Test system 2 results

To further analyze the effects of DG presence on fuse and switch placement, the formulation was applied to another test system which is depicted in Fig. 3. The differences between this test system and test system 1 are shown in red color in Fig. 3. This test system consists of DG units in all of its feeders. The type and capacity of these DG units are given in Table 3. Also, this test system includes more industrial customers compared to the first one.

Table 7 shows the locations of switches and fuses in this test system and for case 1 and case 2. It can be understood from the comparison between two cases that the number of switches in the network has risen from 12 to 26 as a result of DG presence. The extra switches are placed in locations that prevent DG financial loss or enable DG operation in islanded mode. On the other hand, the fuse placement is only slightly different in case 1 and 2.

Table 8 represents the switch and fuse placement in the presence of tie switches in the test system 2. As can be seen, there are changes in both switch and fuse number between case 3 and case 4. However, this change is less dramatic given the difference between case 1 and 2. This is because in case 3, islanded operation of DGs is less important since load points can easily connect to the grid using tie switches during faults.

Total system costs in test system 2 are given in Table 9. According to this table, DGs can reduce total system costs and customer interruption costs by 3.86% and 4.78%, respectively in case 1. Introducing DG units can, in fact, decrease the total system costs effectively despite increasing the number of installed switches in the absence of tie switches. DG presence is less noticeable when tie switches are available in the network. DGs have increased total system cost by 0.87% and customer

Table 8
Optimal equipment locations in test system 2: Case 3, 4.

Feeder	Case 3		Case 4	
	Switch	Fuse	Switch	Fuse
1	All locations	LP4,5,6,7	1E,2B,2E,3B 4E,5B,5E	LP4,5,6,7
2	6E,7B,8E	–	6E,7B	LP9
3	All locations	LP13,14 16,17	9E,10B,11E,12B 12E,13B,13E	LP13,14 16,17
4	14E,15B,15E,16B 16E,17B,18E	LP19,20,21 22,24,25	14E,15B,15E,16B 16E,17B,18E	LP19,20,21 22,24,25
5	19E,20B,20E 21B	–	19E,20B,20E 21B	–
6	22E,23B,23E 24B	–	22E,23B,23E 24B	–
7	All locations	LP34,35 37,38	25E,26B,27E,28B 28E,29B,29E	LP34,35 37,38
Total	45	18	38	19

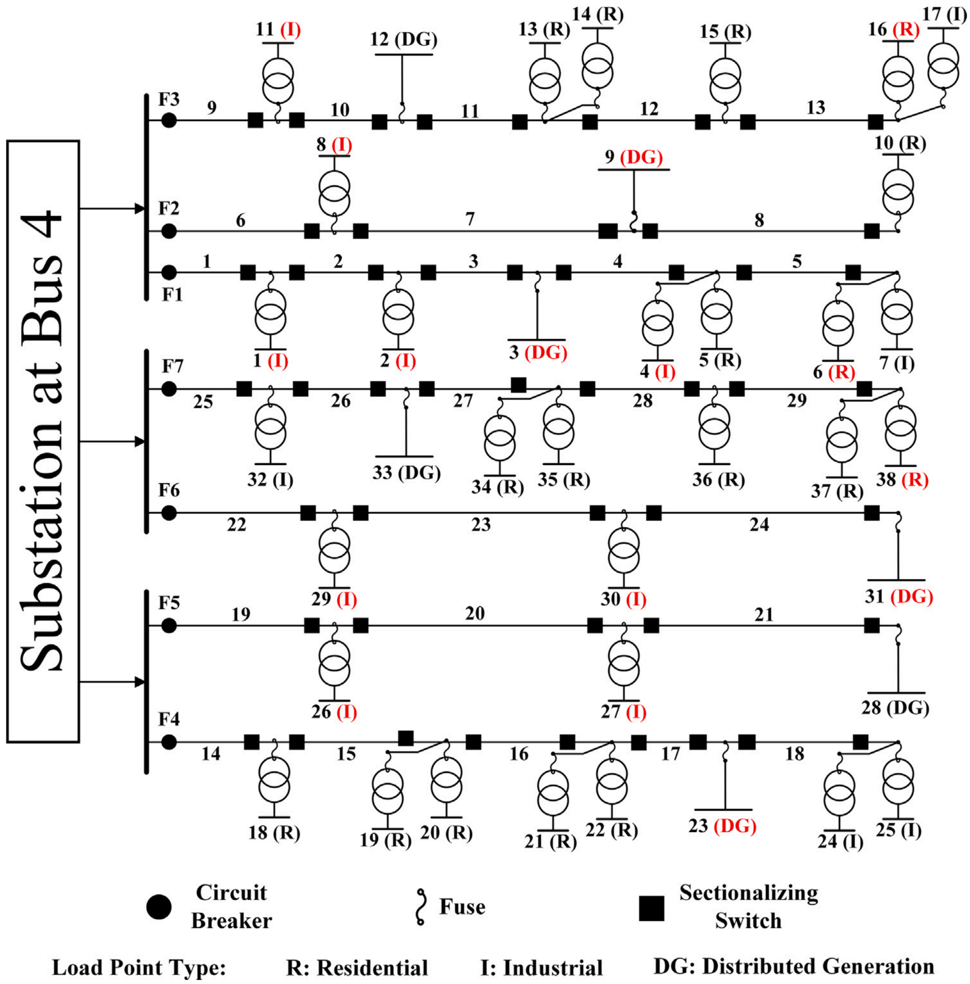

Fig. 3. Test system 2.

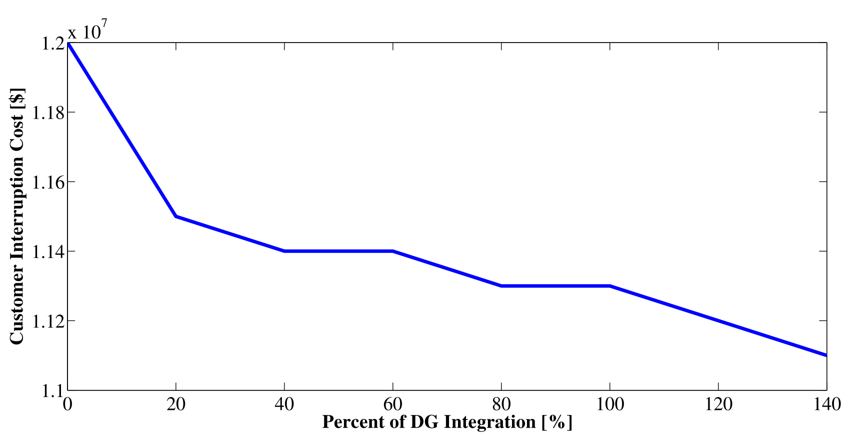

Fig. 4. Sensitivity analysis for customer interruption cost.

interruption cost by only 0.31% in the presence of tie switches in the network.

4.3. Sensitivity analysis

To assess the impact of DG penetration level on the obtained results, the study was repeated considering different DG integration levels. Fig. 4 shows the customer interruption cost as a function of DG integration level. It should be noted that the integration level is expressed as a percent of the total DG power produced in test system 2. It can be seen that as the DG penetration level increases, customer interruption cost decreases.

Fig. 5 shows the number of deployed switches and fuses for different DG integration levels. The number of fuses is not really affected by DG integration level. However, the number of switches increases as DG integration level rises.

4.4. Comparative study

To demonstrate the validity of the proposed method, the results obtained in this paper are compared with studies presented in [30]

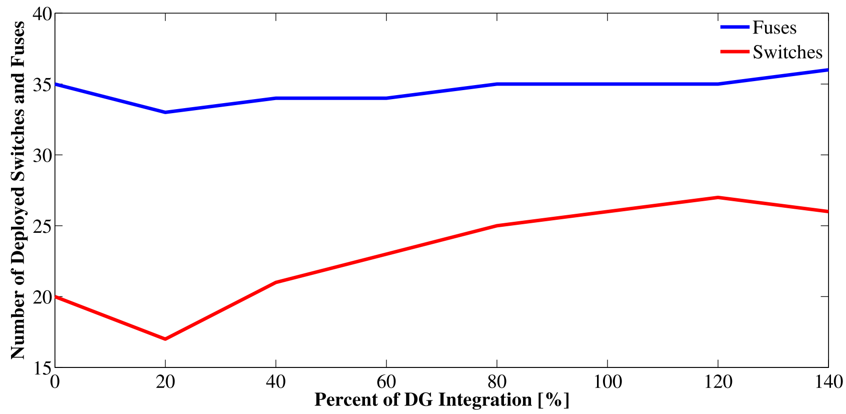

Fig. 5. Sensitivity analysis for the number of deployed switches and fuses.

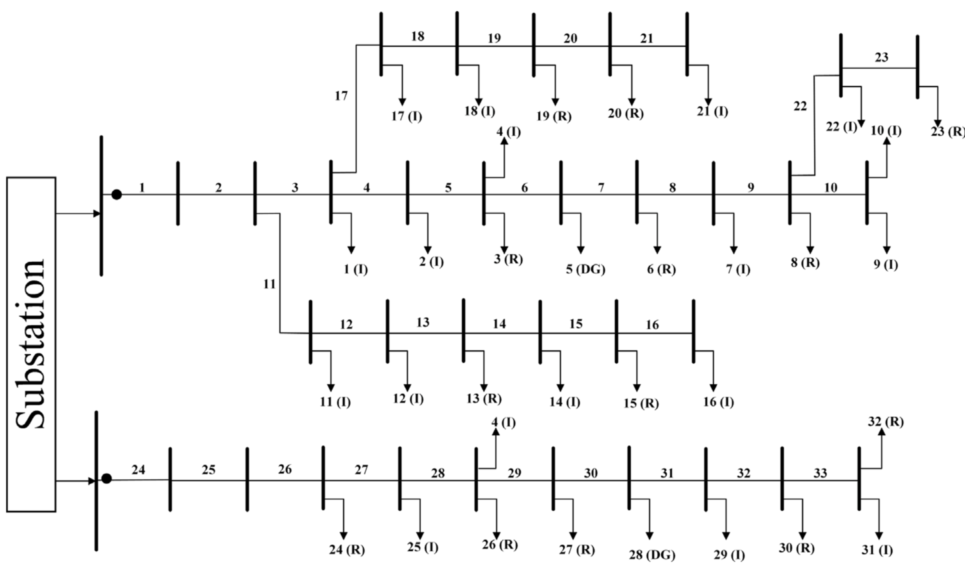

Fig. 6. Practical distribution feeder.

Table 11
Comparison of the proposed approach with other studies.

References		[7]	[10]	[14]	[40]	[20]	[21]	[23]	[25]	[30]	[32]	[33]	[34]	[35]	Proposed approach
Method	MINLP	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	✓
	MILP	×	×	×	✓	✓	✓	✓	✓	✓	×	×	×	×	×
	Heuristic	×	×	×	×	×	×	×	×	×	✓	✓	✓	✓	×
Objective function	ECOST	✓	✓	✓	✓	✓	✓	✓	✓	✓	×	✓	✓	×	✓
	Switch Cost	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	×	✓
	Fuse Cost	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	✓
DG	Location	Feeder end	×	×	×	×	×	×	×	Feeder end	Anywhere	Optimized	Optimized	Anywhere	Anywhere
	Islanded operation	✓	×	×	×	×	×	×	×	✓	×	×	×	✓	✓
	Financial loss	×	×	×	×	×	×	×	×	×	×	×	×	×	✓
	Number of DGs	No limit	×	×	×	×	×	×	×	No limit	No limit	No limit	No limit	No limit	No limit
Uncertainty modeling in load & RES		×	×	×	×	×	×	×	×	×	×	×	×	×	✓
Effect of tie switches		✓	×	✓	×	✓	×	✓	✓	×	×	×	×	×	✓
Calculation of outage duration		✓	×	✓	×	×	×	×	×	✓	×	×	×	×	✓

Table 12
Obtained results for practical distribution feeder without tie switches.

Case	Total cost [k$]	C^{int} [k$]	C^{S} [k$]	C^{F} [k$]	Number of switches	Number of fuses
With DG	129 820.81	129 625.2	160.78	34.83	28	33
Without DG	133 903.44	133 730.8	137.81	34.83	24	33

and [7]. In both of these studies, the proposed objective function is identical to that in this paper and bus 4 of the modified RBTS is used as the test system. However, they both assumed that all of the DGs are placed only at the end of the feeders and [7] took tie switch presence into account while [30] ignored it. The optimal location and number of switches obtained in [30] and [7] are summarized in Table 10. Also, to study the islanded operation of DG units better, the simulation for test system 2 is repeated while ignoring the DG islanded operation similar to [32] and the results are given in Table 10.

Results of [30] and [7] can be compared with case 1 and 3 of the test system 2, respectively. Through this comparison, it is evident that similar to this paper, more switches are used in the presence of tie switches in [7]. The reason for the switch location differences between the two studies and this paper is that test system 2 has more industrial customers than [30] and [7], DG locations are different and DGs can be connected to the feeder at the same location as a load point in [30] and [7] and DG financial loss is not involved in [30] and [7] formulations. In feeders 5 and 6 of test system 2, DGs are placed at the end of the feeder and switches are placed in 19E, 20B,20E, 21B, 22E, 23B, 23E in the presence of tie switches and in 20B, 21E, 23B, 24E in the absence of them. Similar results for these two feeders are derived in Table 10 except that two more switches are placed at 21E and 24E as well to protect the additional loads in LP28 and LP31 from faults in lines. No loads are placed in LP28 and LP31 in the present study. Also, in feeder 4, switches are allocated to 15B, 16B, 17B in case 1 of this study and to 15E, 16B, 17B, 18E in [30]. The switch in 18E in [30] can form an island for LP24 and LP25 which are important industrial customers and since in this paper the DG of feeder 4 is located in LP23, 17B does the same job here. Also, 15B is preferred over 15E here to protect LP18 from fault in line 15 as well.

In case 1, due to the absence of tie switches in the network, DGs' islanded operation can be beneficial in reducing customer interruption costs. Therefore, it is profitable to provide switches that enable it. Comparing the third row of Table 10 with Table 7, the six switches that are added in case 1 of Table 7 are provided for this mean. These switches are added to locations 1E, 2E, 9E, 10E, 25E, 26E. In the presence of tie switches, DGs are not helpful to prevent interruption costs via the islanded operation. Therefore, the fourth row of Table 10 and case 3 of Table 7 are identical.

To illustrate the advantages of the proposed MINLP formulation in this paper, a comparison has been done with the methods used in [7,10,14,20,21,23,25,30,32–35,40] and the results are presented in Table 11.

4.5. Practical distribution feeder

To demonstrate the importance of including DG availability in the decision-making process, the proposed method was validated on a more practical distribution network. The network is illustrated in Fig. 6 and is adapted from [41]. The obtained results are given in Table 12. As can be seen, DGs reduce the customer interruption cost and total system costs by 3.07% and 3.05%, respectively and increase the number of deployed switches by 4 in this test system.

5. Conclusion

This study proposed a new formulation to consider the presence of DG units and the uncertainties in load and renewable generation in switch and fuse allocation problem. The proposed method took the financial loss of DG units into account and was able to consider DG effects in any location of the network. It was found that the islanded operation of DGs could only be hugely beneficial if tie switches were unavailable in the network. In an RBTS network with significant penetration of DG units and without tie switches, DGs were able to reduce the total system cost and customer interruption cost by 3.86% and 4.78%, respectively. The number of network switches changed from 12 to 26, when DGs were added. Studies showed that six of these switches were added only to enable the islanded DG operation. On the other hand, considering the DG units in the same network with tie switches increased the total cost of the system by 0.87% and the customer interruption cost by 0.31%. Moreover, the number of switches changed from 38 to 45 by adding the DG units and none of them were added solely for DGs' islanded operation. In the same network, the location of fuses received less change compared to the switches by adding DG units.

CRediT authorship contribution statement

N. Gholizadeh: Methodology, Software, Writing – original draft, Formal analysis, Visualization, Writing – review & editing. **S.H. Hosseinian:** Supervision, Writing – review & editing. **M. Abedi:** Supervision, Writing – review & editing. **H. Nafisi:** Supervision, Investigation, Formal analysis, Visualization, Writing – review & editing. **P. Siano:** Supervision, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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