Integrated distribution network expansion planning incorporating
distributed generation considering uncertainties, reliability,
and operational conditions

A. Bagheri, H. Monsef *, H. Lesani
School of Electrical and Computer Engineering, University of Tehran, Tehran, Iran

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A B S T R A C T

In this paper, an integrated methodology is proposed for distribution network expansion planning which considers most of the planning alternatives. The planning aims to determine the optimal reinforcement of existing medium voltage lines and high voltage/medium voltage substations, or installation of new ones to meet the load growth in the planning horizon subject to the technical and operational constraints. Also, to take the advantages of new technologies, the renewable and non-renewable distributed generations have been included in the problem as another alternative. The uncertainties related to renewable DGs, load demand, and energy price have been considered in the calculation of cost components. The load duration curve has been utilized for loads such that the results be more precise. The possibility of islanding and load transferring through the reserve feeders have been regarded in the problem to improve the reliability of the network. Also, the required condition for successful and safe operation of island considering all of uncertainty states have been checked out to accurately calculate the reliability. The genetic algorithm is employed to solve this integrated problem. Finally, the proposed method is applied to the 54-bus system and also a real large-scale distribution network, and the results are discussed. The results verify the effectiveness of the presented method.

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Introduction

Expansion planning of power distribution systems is one of the major activities of distribution utilities to deal with electric power demand growth.

The main objective of the distribution network expansion planning (DNEP) problem is to provide a reliable and cost effective service to consumers while ensuring that voltages and power quality are within standard ranges [1]. Traditionally, this aim is attained through the reinforcement of existing lines and substations, or by installation of new ones regarding to the technical and operational constraints [2–7].

Today, power system economic and operation environment has changed as new capacity options have emerged. Distributed Generation (DG) is one of these new options. The introduction of DG in power system changes the operating features, and has significant technical and economic advantages. Adding DG sources to the planning options is resulting in challenges in the distribution network operation, structure, design and upgrade issues. At present, there are several technologies ranging from traditional to non-traditional used in DG application. The former is non-renewable technologies such as internal combustion engines, combined cycles, gas turbines, and micro-turbines. The latter includes renewable-energy-based technologies such as wind, photovoltaic, biomass, geothermal, etc. Due to the availability of such a flexible option of DG as an energy source at the distribution voltage level, the distribution network is being transformed from a passive network to an active one. In this regard, DG brings about various benefits such as distribution capacity deferral, losses reduction, flattening of peak, improving of voltage profile, and reliability improvement [8–13].

Several researches have been implemented to illuminate the advantages of utilizing DG units in the distribution network. Optimal allocation and sizing of DGs is solved in [14] using an analytical-based method to minimize the line losses. The same problem is solved using an ordinal optimization method in [15]. In addition to line losses, the system’s reliability is included in the DG planning problem as a constraint in [16] which tries to improve the system reliability, line losses, and voltage profile using the genetic algorithm (GA). To further improve the system reliability,
switches, such as reclosers and cross-connections (CCs), are incorporated in the DG–based planning problem. An ant colony system algorithm is employed in [17] for finding the optimal placement of reclosers and DGs. This method minimizes an objective function composed of two reliability indices: system average interruption duration index (SAIDI) and system average interruption frequency (SAIFI). [18] proposes an integrated methodology for distribution network planning in which the operation of DGs and CCs is optimally planned. Distribution lines and HV/MV transformers are also optimally upgraded in order to improve system reliability and to minimize the line losses under load growth; the objective function is composed of the investment cost, losses cost, and reliability cost; the energy savings resulted from installation of DGs is also included in this function. The constraints are the buses' voltages and lines' currents; the modified discrete particle swarm optimization (PSO) method is employed to optimize the problem in different scenarios.

In the abovementioned works, the considered DG technology is non-renewable and controllable (Dispatchable DG (DDG)). On the other side, the development in technology and the importance of using clean energy resources have made the renewable energies more attractive for distribution network operators, specifically because of their inexhaustible and non-polluting features. Among these renewable energies, wind-based distributed generation (WDG) has emerged very rapidly in recent years. Reduction of capital costs, improvement of reliability, and efficiency have made the wind power able to compete with the conventional power generation [19]. The renewable DG technologies like wind have special

### Nomenclature

**Constants**
- \( n_f \): number of network’s feeders
- \( n_s \): number of HV/MV substations
- \( n_l \): number of load buses (MV/LV substations)
- \( n_n \): total number of network substations
- \( n_e \): number of existing HV/MV substations
- \( n_{ef} \): number of existing feeders
- \( n_{cf} \): number of candidate feeders for installation
- \( n_{LL} \): number of load levels
- \( n_s \): number of states
- \( \lambda \): planning horizon
- \( \delta \): failure rate of feeder \( k \) (fail/km/year)
- \( PW \): present worth factor
- \( \text{Infr} \): inflation rate (%)
- \( \text{Intr} \): interest rate (%)
- \( Y_{ij} \): magnitude of admittance between buses \( i \) and \( j \)
- \( \theta_{ij} \): angle of admittance between buses \( i \) and \( j \)
- \( r_k \): repair time of feeder \( k \) (h)
- \( T_{LL} \): duration of load level \( LL \) (h)
- \( S{i}^{\text{LL},s} \): apparent power of load demand in bus \( i \), in load level \( LL \) and state \( s \)
- \( S{i}^{\text{peak},s} \): apparent power of load demand in bus \( i \), in peak condition
- \( S{i}^{\text{LL},s} \): apparent power of DG installed in bus \( i \), in load level \( LL \) and state \( s \)
- \( S{i}^{\text{DG}} \): capacity of DG installed in bus \( i \)
- \( L_{C{i}^{\text{LL},s}} \): load level factor for load level \( LL \) and state \( s \)
- \( E_{P{i}^{\text{LL},s}} \): energy price in load level \( LL \) and state \( s \)
- \( E_{P_{\text{peak}}} \): energy price in peak condition
- \( P{i}^{\text{LL},s} \): price level factor for load level \( LL \) and state \( s \)
- \( P{i}^{\text{LL},s} \): active load demand in bus \( i \), in load level \( LL \) and state \( s \)
- \( Q{i}^{\text{LL},s} \): reactive load demand in bus \( i \), in load level \( LL \) and state \( s \)
- \( P{i}^{\text{peak}} \): active load demand in bus \( i \) in peak condition
- \( Q{i}^{\text{peak}} \): reactive load demand in bus \( i \) in peak condition
- \( V_{\text{crit}} \): upper limit of buses voltages for critical operating condition
- \( V_{\text{min}} \): lower limit of buses voltages for critical operating condition
- \( \mu_L \): degree of voltage constraint satisfaction for bus \( i \), in load level \( LL \) and state \( s \)
- \( \mu_L' \): degree of voltage constraint satisfaction for bus \( i \), in peak condition
- \( \mu_L^s \): degree of current constraint satisfaction for the whole network
- \( \mu^s \): degree of substution capacity constraint satisfaction for the whole network
- \( V_{i,LL} \): voltage magnitude of bus \( i \), in load level \( LL \) and state \( s \)
- \( V_{i,LL} \): voltage angle of bus \( i \), in load level \( LL \) and state \( s \)
- \( Q_{\text{WGD/WDG}}^{\text{LL},s} \): active power generated by WDG/DDG installed in bus \( i \), in load level \( LL \) and state \( s \)
- \( Q_{\text{WGD/WDG}}^{\text{LL},s} \): reactive power generated by WDG/DDG installed in bus \( i \), in load level \( LL \) and state \( s \)
- \( P_{\text{DDG}}^{\text{LL},s} \): generated power of DG installed in bus \( i \), in load level \( j \) and state \( s \)
- \( P_{\text{trans}}^{\text{LL},s} \): the power imported from transmission system to distribution network through the \( i \)th HV/MV substition in load level \( j \) and state \( s \)

**Functions**
- \( c_{\text{sec}}(S) \): expansion cost of \( i \)th existing HV/MV substation with the capacity of \( S \) ($/kVA)
- \( IC(S) \): installation cost of \( i \)th new HV/MV substation with the capacity of \( S \) ($/kVA)
- \( F_{C_{ij}}(k) \): cost of installing a feeder with the type of \( k \) between buses \( i \), \( j \) ($/km)
- \( MFC_{ij}(k) \): cost of installing main feeder with the type of \( k \) between buses \( i \), \( j \) ($/km)
- \( RFC_{ij}(k) \): cost of installing reserve feeder with the type of \( k \) between buses \( i \), \( j \) ($/km)
- \( DDGIC(S) \): installation cost of dispatchable DG with the capacity of \( S \) in bus \( i \) ($/kVA)
- \( WDGIC(S) \): installation cost of wind DG with the capacity of \( S \) in bus \( i \) ($/kVA)

**Variables**
- \( h_{\text{LL}} \): load level factor for load level \( LL \) and state \( s \)
- \( E_{P_{\text{LL},s}} \): energy price in load level \( LL \) and state \( s \)
- \( P_{\text{DDG}}^{\text{LL},s} \): generated power of DG installed in bus \( i \), in load level \( j \) and state \( s \)
- \( P_{\text{trans}}^{\text{LL},s} \): the power imported from transmission system to distribution network through the \( i \)th HV/MV substition in load level \( j \) and state \( s \)

characteristics due to their main source of energy. Since the wind speed is not a constant quantity during the operation of wind turbine, and it is highly dependent on the climate condition, therefore there is an uncertainty and variability in the output power of wind turbine. In other words, the WDG has intermittent output power [20].

In the literature, some methods have been proposed to model the impact of these uncertainties on distribution network performance. In [21], different scenarios are constructed based on the probability distribution function (PDF) of uncertain values and then a method is proposed to determine the optimal combination of different renewable technologies for minimizing the active losses. In [22], an effective tool was proposed based on Monte Carlo Simulation (MCS) for modeling the uncertainties in location, exported energy, penetration level, and the states (on/off) of the DG units. In [21,23], a powerful probabilistic method is proposed to handle the uncertainties of electric load and intermittent generation of renewable energy resources. In [21], the optimal location of a predetermined number of wind turbines is determined in order to minimize the active losses. In [23], a methodology is proposed for optimally allocating different types of renewable DG units including wind power, photovoltaic, solar thermal systems, biomass, and various forms of hydraulic power for loss minimization. Authors in [24] presented a hybrid possibilistic–probabilistic tool to assess the impact of DG units on technical performance of distribution network. The uncertainty of electric loads, DG operation and investments are taken into account. The objective function is active losses and technical risk, including the possibility of under/over voltage in load nodes. The proposed problem was formulated under GAMS environment and applied to a test network in different scenarios to evaluate the effectiveness of the method.

In [25], a possibilistic method was proposed to handle the uncertainties of electrical loads and energy prices considering different objective functions like cost and technical and economic risks. The study in [26], presents a stochastic dynamic multi-objective model for integration of distributed generations in distribution networks. The proposed model optimizes three objectives, namely technical constraint dissatisfaction, costs and environmental emissions, and simultaneously determines the optimal sitting, sizing and timing of investment for both DG units and network components. The uncertainties of electric loads, electricity price and wind power generations are taken into account using scenario modeling. The above survey of papers indicates that there are the following major aspects in DNEP problem:

1. Formulation of DNEP with different objective functions and solving it by using efficient methods,
2. Using renewable and non-renewable DGs as an alternative for DNEP,
3. Considering uncertainties related to renewable DGs, load demand, etc. in the planning,
4. The way that the reliability of network is modeled and the effect of renewable and non-renewable DGs on reliability.

In the following, the most recent papers in DNEP are investigated in details from these four viewpoints. Ref. [18] is the most comprehensive one which has considered almost all the planning options. However, the possibility to consider new substations installation has not been regarded. Also the utilized DGs are of non-renewable type. In [27], a multi-objective technique was developed for optimal allocation of DG considering system reliability. An algorithm to determine the optimum operating strategy for DG was presented in [27,28] incorporating reliability worth evaluation of distribution system to minimize the cost of customer interruption. However, these works assumed conventional dispatchable DG units. An approach to evaluate the economic benefits of renewable DG was proposed in [5] in which a GA based method is implemented for optimal DG allocation to maximize the deferral of system upgrade investments, reduction of the energy losses cost, and reduction of the interruption cost. The proposed methodology takes into account:

- Uncertainty and variability associated with renewable DGs’ output,
- Load variability,
- The possibility of islanding to improve the reliability of the system.

In the mentioned work, it is assumed that the substations are redundant, and there are neither new load points, nor new substations for installation. The lines are reinforced, and there is no reserve feeder to improve the reliability. For considering of islanding after occurring a fault on a feeder, it is checked that if there is a sufficient capacity of dispatchable and renewable DGs in the isolated part or not. In other words, the adequacy of generation in the island is checked. However, the load flow constraints are not checked to see if the island can operate successfully from the viewpoint of voltage and current constraints or not. In addition, the possibility of load shedding to reduce the interruption cost has not been regarded. Refs. [29–31] presented a framework to solve the problem of multistage distribution system expansion planning in which installation and/or reinforcement of substations, feeders, and DG units are taken into account as possible solutions for the system capacity expansion. The proposed formulation considers investment, operation, and outage costs of the system. The results show the positive effect of DG on the reliability improvement and reduction of outage costs. These two papers have not considered the renewable DGs.

In this paper, an integrated distribution network expansion planning is presented which modifies the shortcomings of the previous works. The MV feeders and HV/MV substations are reinforced to meet the load growth in the planning horizon. In addition, since there will be some new load points in the horizon year, there is a need to install some new feeders and possibly new substations. For improving the reliability of the network, the reserve feeders have been considered to be installed if economical. As an alternative, the renewable and non-renewable DGs are regarded in the proposed DNEP. The operation cost of DGs and the cost of energy purchased from the upward grid (transmission system) is calculated considering the load-duration curve (LDC) of load points. The uncertainty in the output power of renewable DGs, and that of load demand have been regarded in the calculation of the reliability, energy losses, and energy purchased from the upward grid. For further improvement of reliability, the islanding operation of DG units has been considered, and the required conditions for successful and safe operation of island considering all the uncertainty states have been checked out. The GA as a promising solution method is employed for optimization of the proposed DNEP. Finally, the proposed method is applied to the 54-bus test system and a real large-scale distribution network in different scenarios, and the results are discussed. The obtained results demonstrate the effectiveness of the presented method.

The main contributions of this paper can be listed as follows:

- An integrated DNEP has been proposed which considers the expansion of substations and feeders, along with the utilization of renewable and non-renewable distributed generation;
- Reliability and operational considerations are regarded;
- Uncertainties related to the wind energy, load demand, and energy price have been considered;
- Possibility of islanding has been regarded in reliability evaluation.
Problem formulation

The objective of the distribution network expansion planning is to provide a reliable and cost effective service to consumers while ensuring that voltages and power quality are within standard ranges [6,7]. The solution of DNEP will determine the following decision variables:

- Expansion capacity of existing high voltage/medium voltage (HV/MV) substations;
- Location and capacity of new HV/MV substations to be installed;
- Upgrade of existing medium voltage (MV) feeders;
- Routing and type of new MV feeders to be installed;
- Location and type of reserve feeders;
- Setting and sizing of non-renewable DGs (DDG);
- Setting and sizing of renewable DGs (here WDG);
- Determining the optimal power generation of DDG units in each load level.

Load and price model

To consider the variation of load and price during the year, and to calculate the operational costs accurately, the load duration curve (LDC) is used for the load points. In the planning studies, the continuous LDC is approximated by the discrete one. The price of purchasing energy from the transmission network is assumed to follow the same manner, which means that for each level of LDC there is a related energy price [7,29,32] as shown in Fig. 1. In this figure, the vertical axis shows the load/price level factors (the ratio of load/price to the peak value of load/price in the horizon year), and the duration of each load level (LL) is denoted by $T_{LL}$ in horizontal axis.

Uncertainty of load and energy price

The load demand and energy price are usually uncertain parameters in the planning problems; they are dependent on each other, so that an increase/decrease in electric load will lead to increase/decrease in electricity price. To model these two uncertainties, it is assumed that they follow a normal distribution around their expected values as shown in Fig. 1. For simplicity, the distribution curves are divided into some states (seven states in Fig. 1) with the related probabilities. In this regard, the load and energy price models, considering the uncertainty are as Eqs. (1) and (2).

$$S^i_{LLS} = S^i_{peak} LLF_{LLS}$$

$$EP_{LLS} = EP_{peak} PLF_{LLS}$$

Wind power generation

Since the wind speed has intermittent nature, therefore, the power generated by the wind turbine is stochastic and intermittent. Several models have been proposed for the stochastic behavior of the wind speed. The most common expression is the Rayleigh probability distribution function as Eq. (3) [23]; where, $v$ is the wind speed and $c$ is the scale factor of the Rayleigh PDF of wind speed in the zone under study.

$$PDF(v) = \left( \frac{2v}{c^2} \right) \exp \left( -\left( \frac{v}{c} \right)^2 \right)$$

The output power of the wind turbine is calculated using the wind turbine power-speed characteristic as (4), where, $P_{wind}$ and $P_{rated}$ are the output and rated power of wind turbine. Also, $V_{1s}$, $V_{co}$, and $V_{rated}$ respectively are the cut-in, cut-off, and rated speed of wind turbine.

$$P_{wind} = \begin{cases} P_{rated} \times \frac{v - V_{1s}}{V_{rated} - V_{1s}}, & \text{if } V_{1s} \leq v \leq V_{rated} \\ P_{rated}, & \text{if } V_{rated} \leq v \leq V_{co} \\ 0, & \text{if } V_{co} \leq v \end{cases}$$

For expansion planning studies, it is appropriate to use the behavior of wind during the whole year [23]. In this paper, the data of Table 1 have been used for modeling the wind behavior. Regarding to Table 1 and Eq. (4), the output power and the related probabilities are obtained as Table 2.

Combined state model

In each load level, the states of load, price, and wind speed are combined to construct the whole set of uncertainty states as follows:

$$\text{States}_{comb} = \left\{ \text{Load}(s), \text{Price}(s), \text{Wind}(s) \right\}$$

$$\text{Prob}_{comb} = \text{Prob}_L \times \text{Prob}_P \times \text{Prob}_W$$

<table>
<thead>
<tr>
<th>Wind speed limits (m/s)</th>
<th>Hours/year</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>0–4</td>
<td>1804</td>
<td>0.2059</td>
</tr>
<tr>
<td>4–5</td>
<td>579</td>
<td>0.0661</td>
</tr>
<tr>
<td>5–6</td>
<td>984</td>
<td>0.1123</td>
</tr>
<tr>
<td>6–7</td>
<td>908</td>
<td>0.1037</td>
</tr>
<tr>
<td>7–8</td>
<td>983</td>
<td>0.1122</td>
</tr>
<tr>
<td>8–9</td>
<td>799</td>
<td>0.0912</td>
</tr>
<tr>
<td>9–10</td>
<td>677</td>
<td>0.0773</td>
</tr>
<tr>
<td>10–11</td>
<td>439</td>
<td>0.0501</td>
</tr>
<tr>
<td>11–12</td>
<td>395</td>
<td>0.0451</td>
</tr>
<tr>
<td>12–13</td>
<td>280</td>
<td>0.0326</td>
</tr>
<tr>
<td>13–14</td>
<td>219</td>
<td>0.0250</td>
</tr>
<tr>
<td>14–25</td>
<td>687</td>
<td>0.0784</td>
</tr>
</tbody>
</table>

Fig. 1. Load/price duration curve and the related uncertainty model.
In (6), Prob\(_i^L\), Prob\(_i^p\), and Prob\(_i^w\) are the probabilities of load, electricity price, and wind speed states, respectively. Prob\(_i^{cont}\) is the probability of each combined state \(s\).

**Constraints**

There are two types of constraints in DNEP, hard and soft ones. The satisfaction of the former one is mandatory. However the latter one can be violated, but this violation must be calculated and minimized.

**Hard constraints**

**Network radiality constraint.** Most of the distribution systems are operated in radial topology [6,7,33]. Thus, the radiality constraint is regarded in almost all of the distribution network expansion and operation planning problems. The most well-known problems are the distribution network reconfiguration (DNR) and the distribution network expansion planning (DNEP). Distribution network topology can be considered as a graph consisting of \(n\) arcs and \(m\) nodes. According to the graph theory, a tree is defined as a graph without any loops. Thus, it is possible to compare the radial topology of a distribution network with a tree. When there is only one supply point (HV/MV substation) for the distribution network, the following conditions must be satisfied to ensure the network is radial (i.e. to ensure the graph is a tree):

- **Condition 1:** the number of network feeders must be equal to the total number of network substations (including HV/MV and MV/LV buses) minus 1 as (7) [33]:
  \[ n_f = n_s - 1 \]  
  (7)

- **Condition 2:** the network must be connected.

where \(n_f\) is the number of network feeders, and \(n_s\) is the total number of network substations.

These two conditions must be satisfied simultaneously, i.e. satisfaction of each of them solely does not ensure the radial structure of the network. Different methods have been proposed for the sake of constructing a distribution network having radial topology in DNEP and DNR problems, such as: branch exchange [34], Evolutionary algorithm [35], specialized genetic algorithm [36], algebraic relations [37], prüfer-number based GA [38]. In these methods, the network has only one feeding point (HV/MV substation), and the mentioned two conditions are adequate for satisfaction of the radiality. However, in the case the network has more than one HV/MV substation, or when there are a forest of trees instead of one tree, the condition 1 must be modified to expression (8) [33]:
  \[ n_f = n_h - n_s \]  
  (8)

where \(n_h\) is the number of HV/MV substations.

In this paper, a new criterion is introduced for checking the radiality of networks with a desired number of HV/MV substations. Satisfaction of criterion (9) ensures that the distribution network is in the structure of a forest containing several trees (satisfying the radiality constraint).

**The network must be connected**

\[ n_f = n_t \]  
(9.1)

\[ \text{rank}(A) = n_s - n_t \]  
(9.2)

where:

- \(n_t\) is the number of load buses (MV/LV substation),
- \(A\) is the incidence matrix of distribution network,
- \(\text{rank}(A)\) is the number of linearly independent rows or columns of matrix \(A\).

**Power flow equations.** The following power flow equations must be satisfied for each state in each load level [6,7]:

\[ p_{\text{net}}^{i,i+1} = p_{\text{DDG}}^{i,i+1} + p_{\text{WDG}}^{i,i+1} \]  
(10.1)

\[ q_{\text{net}}^{i,i+1} = q_{\text{DDG}}^{i,i+1} + q_{\text{WDG}}^{i,i+1} \]  
(10.2)

\[ p_{\text{net}}^{i,i+1} = V_{i,i+1} e_{\text{PP}} \sum_{j=1}^{n_b} Y_{ij} V_{j,i+1} \cos(h_{ij} - \delta_{i,i+1} - \theta_j) \]  
(10.3)

\[ q_{\text{net}}^{i,i+1} = V_{i,i+1} e_{\text{PP}} \sum_{j=1}^{n_b} Y_{ij} V_{j,i+1} \sin(h_{ij} - \delta_{i,i+1} - \theta_j) \]  
(10.4)

**DG units’ operating constraint.** The DG units’ power generation must be under their capacity limit.

\[ e_{\text{DDG}}^{i,i+1} \leq e_{\text{DDG}}^{\text{rated}} \leq e_{\text{DDG}}^{\text{peak}} \]  
(11)

**DG units’ maximum penetration.** A maximum penetration level (here 35%) is usually used for DG units in the system as (12) to prevent the reverse power flow from the distribution network to the upward grid [5,23,32].

\[ \sum_{i=1}^{n} e_{\text{DDG}}^{i,i+1} + \sum_{i=1}^{n} e_{\text{WDG}}^{i,i+1} \leq e_{\text{DDG}}^{\text{max}} \]  
(12)

**Soft constraints**

The fuzzy modeling can be used to quantify the value of satisfaction of technical constraints, including bus voltages and thermal limits of feeders and substations.

**Voltage limitation.** When the voltage magnitude of a bus is in the safe operation interval, then there is no violation. However, the planner may tolerate the violation of these limits to some extent to improve other objectives. The voltage limitation is represented by a penalization function [26,39]. For his aim, the voltage constraint satisfaction can be mathematically represented as (13). In this way, the safe operating interval is defined as \([V_{\text{min safe}}, V_{\text{max safe}}]\), in which the satisfactory value is 1. As the voltage magnitude exceeds these limits, the value of satisfaction decreases until it becomes zero beyond the critical voltage values \([V_{\text{min crit}}, V_{\text{max crit}}]\).

\[ \mu_{\text{V}}^{i,i+1} = \begin{cases} \frac{V_{i,i+1} - V_{\text{min crit}}}{V_{\text{crit}}}, & V_{\text{min safe}} \leq V_{i,i+1} \leq V_{\text{max safe}} \\ 0, & V_{\text{min crit}} \leq V_{i,i+1} \leq V_{\text{max crit}} \end{cases} \]  
(13)
The values obtained from (13) show the condition of voltage constraint satisfaction for bus $i$ in state $s$. Since there are more than one state in a real system, the planner has different satisfaction levels of voltage constraint for a given bus. To obtain an index representing the voltage condition of the whole network, the weighted average of voltage satisfaction over all buses of the network provides an information about voltage condition of the whole network as (15).

$$\mu_i = \frac{1}{8760} \sum_{l=1}^{nL} \sum_{s=1}^{ns} \text{Prob}_s^{\text{comb}} T_{ll} \mu_i^l$$

(14)

According to (14), the voltage satisfaction value of bus $i$ is dependent on the satisfaction value of each state and also, on its probability. The average value of $\mu^l$ over all buses of the network provides an information about voltage condition of the whole network as (15).

$$\mu = \frac{\sum_{i=1}^{nB} \mu_i^l}{nL}$$

(15)

**Thermal limits of feeders and substations.** The satisfaction value of feeders currents ($\mu^l$) and substations capacities ($\mu^s$) are calculated in the similar way as the voltage. The difference is that there is only an upper limit for the feeders currents and substations capacities instead of upper and lower limits.

**Objective function**

The objective function of the proposed DNEP is minimization of the total cost represented in (16).

Cost Function $= \text{SEC} + \text{SIC} + \text{FRC} + \text{FIC} + \text{DGIC} + \text{DGOC} + \text{EEC} + \text{EELC} + \text{EENSC} + \text{EMC} + \text{TDC}$

(16)

where:

- SEC is the substations expansion cost as (17):

$$\text{SEC} = \sum_{i=1}^{ns} \text{sec}_i(S)$$

(17)

- SIC is the substations installation cost as (18):

$$\text{SIC} = \sum_{i=1}^{ns} \text{IC}_i(S)$$

(18)

- FRC is the cost of feeders’ replacement as (19):

$$\text{FRC} = \sum_{i=1}^{ns} \sum_{s=1}^{ns} \left[ \text{FC}_i(k_1) - \text{FC}_i(k_2) \right]$$

(19)

- FIC is feeders installation cost as (20):

$$\text{FIC} = \sum_{i=1}^{ns} \sum_{s=1}^{ns} \left[ \text{MFC}_i(k) + \text{RFC}_i(k) \right]$$

(20)

- DGIC is installation cost of DG units as (21):

$$\text{DGIC} = \sum_{i=1}^{ns} \left[ \text{DDGIC}_i(S) + \text{WDGIC}_i(S) \right]$$

(21)

- DGOC is DG units’ operation cost as (22):

$$\text{DGOC} = \sum_{i=1}^{ns} \sum_{l=1}^{nL} \sum_{s=1}^{ns} \left[ \text{TDC}_i(S) + \text{WDGIC}_i(S) \right]$$

(22)

- PW is 1 + Infr

$$\text{PW} = 1 + \text{Infr}$$

(23)

- EEC is the expected cost of purchased energy from the transmission network as (24):

$$\text{EEC} = \sum_{i=1}^{ns} \sum_{l=1}^{nL} \sum_{s=1}^{ns} \left[ \text{PW}_i^{\text{trans}} T_{ll} \times \text{EP}_I, \times \text{Prob}_s^{\text{comb}} \right]$$

(24)

- EELC is the expected energy loss cost as (25):

$$\text{EELC} = \sum_{i=1}^{ns} \sum_{l=1}^{nL} \sum_{s=1}^{ns} \left[ \text{PW}_i^{\text{trans}} T_{ll} \times \text{LC}_I, \times \text{Prob}_s^{\text{comb}} \right]$$

(25)

- EENSC is the expected energy not supplied cost as (26):

$$\text{EENSC} = \sum_{i=1}^{ns} \sum_{l=1}^{nL} \sum_{s=1}^{ns} \left[ \text{PW}_i^{\text{trans}} T_{ll} \times \text{LNS}_I, \times \text{Prob}_s^{\text{comb}} \right]$$

(26)

- EMC is the cost of emission as (27):

$$\text{EMC} = \sum_{i=1}^{ns} \sum_{l=1}^{nL} \sum_{s=1}^{ns} \left[ \text{PW}_i^{\text{trans}} T_{ll} \times \text{GE}_I \times \text{Prob}_s^{\text{comb}} \right]$$

(27)

where:

- EM is the emission cost due to pollutant CO$_2$.

- EM is the emission cost in ($/ton$).

- $p_{i,l}^{\text{trans}}$ is the power received from the $i$th transmission substation in load level $LL$ and state $s$.

- $\text{GE}_I$ is the emission related to the power received from transmission grid in load level $LL$ and state $s$ (ton/kWh).

- TDC is the technical dissatisfaction cost as (28):

$$\text{TDC} = \text{dc} \times \max\{1 - \mu^l, 1 - \mu^s, 1 - \mu^T\}$$

(28)

where, dc is the dissatisfaction cost.

**Calculation of EENSC**

In this section, the procedure for calculating the reliability index is described in details. Most of the researches have not considered the following items in reliability calculation:

- Possibility of islanding after a fault;
- Uncertainty of load and wind power;
- Load duration curve;
- Checking the power flow and other constraints in the island.

To clarify the discussion, suppose that a fault occurs on feeder $k$. To reduce the outage cost, at first, the circuit breaker (CB), located at outgoing of the substation, disconnects all the branches (including the faulted and un-faulted sections), then the faulted section is isolated from the rest of the network using the switches and goes to repair state. Then, the circuit breaker is again closed. Here, there may be some isolated parts with some loads. If there are some DDGs with enough generation in the isolated part, and the constraints are satisfied, this part can be operated successfully as an island to supply the disconnected loads until the faulted section is repaired. Otherwise, all or a part of the loads of the island must be shed. In some cases, there may be reserve feeders that can connect the islanded part to the neighboring feeders or substations to supply the island’s loads without the voltage and current violations.

Now, it is important to see in the time that the fault occurs, and feeder goes out of service, what are the amounts of load and generated power of WDGs (as uncertain and stochastic parameters). In each outage, depending on the network condition, the result of reliability calculation would be different. In this paper, all the possibilities of network states are simulated to precisely calculate the reliability index (EENSC).

Regarding to the above explanation, the following stages are required to calculate the EENSC:
1. It is assumed that each feeder is equipped with two switches at its endings, and there is a circuit breaker at each outgoing of HV/MV substation that can disconnect the main feeder and its downstream load points (MV/LV buses) from the substation.

2. After that a fault occurs on feeder $k$, at first, the circuit breaker immediately operates and disconnects all the loads fed from the substation. Then, to reduce the outage cost, the faulted section is located and isolated from the rest of the network; finally, the

Fig. 2. Flowchart for calculation of the EENSC.
circuit breaker is again closed. By reclosing the circuit breaker, the loads of un-faulted sections are fed as fed before. However, there may be some isolated parts with some loads. In these parts, there may be some DG units, or there may be some reserve feeders that can connect the isolated part to a neighboring HV/MV substation, or an energized feeder. On this basis, three situations can be arisen:

**Case 1:** There is no DDG in the isolated part, and no reserve feeder to connect this part to the rest of the network; in this case, all the loads of isolated part will be unsupplied until the faulted section is repaired;

**Case 2:** There is reserve feeder between the isolated part and the rest of network;

**Case 3:** There is no reserve feeder between the isolated part and the rest of the network, but there is DDG in the isolated part.

In case 2, the reserve feeder connects the isolated part to the rest of the network; then the backward-forward power flow is performed [40]. If none of the constraints related to the voltage, current, and substations capacity is violated, then the loads of isolated part will be supplied. If the thermal capacities of substation or buses voltages are violated, then the loads of isolated part are shed step by step until the violation is resolved. In each step, the load of bus with the minimum voltage will be shed. If the current limitation of any feeder is violated, then the loads influencing the current of this feeder are determined, and the loads of buses which have the minimum voltage is shed step by step until the current violation is removed.

In case 3, the largest DDG is selected as the slack bus of island; then the power flow in the island is performed; if the output power of slack bus is negative (which means that the generation in the island is more than the load plus losses), the WDG and if necessary, the DDG on the bus with the highest voltage will be disconnected; then, the power flow is re-performed. This process is continued until the output power of slack bus becomes positive.

If the output power of slack bus is positive, but it exceeds the capacity of DDG, the loads of island are shed based on the lowest voltage until the output power of DDG falls under its capacity.

The flowchart of Fig. 2 shows the procedure of calculating the EENSC in details.

**Proposed solution method**

To solve the DNEP problem formulated in part 2, the genetic algorithm has been employed as the following.

**Genetic algorithm**

In the field of artificial intelligence, a genetic algorithm (GA) is a search heuristic that mimics the process of natural selection. This heuristic (also sometimes called a metaheuristic) is routinely used to generate useful solutions to optimization and search problems [41,42]. Genetic algorithm belongs to the larger class of evolutionary algorithms (EA), which generate solutions to optimization problems using techniques inspired by natural evolution, such as selection, crossover, and mutation. In genetic algorithm, a population of candidate solutions (called individuals) to an optimization problem is evolved toward better solutions. Each candidate solution has a set of properties (its chromosomes or genotype) which can be mutated and altered; traditionally, solutions are represented in binary as strings of 0s and 1s, but other encodings like real and decimal codifications are also possible [32,43].

The evolution usually starts from a population of randomly generated individuals, and is an iterative process, with the population in each iteration called a generation. In each generation, the fitness of every individual in the population is evaluated; the fitness is usually the value of the objective function in the optimization problem being solved. The more fit individuals are stochastically selected from the current population, and each individual’s genome is modified (crossed over and possibly randomly mutated) to form a new generation. The new generation of candidate solutions is then used in the next iteration of the algorithm. Commonly, the algorithm terminates when either a maximum number of generations has been produced, or a satisfactory fitness level has been reached for the population.

The GA has been used for solving many of planning problems [27,29,32,43]. Since the decision variables used in this study are of real, binary and decimal type, thus a combination of all the three methods has been employed.

**Proposed chromosome structure**

To optimize the proposed DNEP problem, the information showing the configuration of distribution network should be encoded in the genes of chromosome. The structure of the proposed chromosome is illustrated in Fig. 3. As shown in this figure, the chromosome is composed of seven parts. In the first part, the ith gene gets binary values as 0 or 1, and indicates that the feeder i has been installed or not. The number of genes in this part is equal

![Fig. 2 (continued)](image-url)
to the number of existing feeders plus candidate ones. The $i^{th}$ gene of second part shows the type of $i^{th}$ feeder and can get the discrete values between 1 and the number of conductor types. The reserve feeders which should be installed are expressed by the values 1 or 0 of the genes of the third part. Here, 1 means that the related reserve feeder is installed, and 0 means that it is not installed. The genes of 4th and 5th parts determine the installation of WDGs and DDGs on MV/LV buses. The integer values of the genes in this part are between 0 and the maximum installable DG units on the buses. The 6th part of the proposed chromosome indicates the power generation of DDG units in each load level, and its genes have real values between 0 and the related DDG's capacity. Finally, the 7th part shows the layout of the HV/MV substations including the existing and candidate ones.

Procedure of problem optimization

According to the proposed chromosome structure, when the genes of chromosome are initialized, the network configuration such as substations site and capacities, main and reserve feeders routing and their conductor type, the DGs' site, capacities and their generated power in each load level will be known. This data is sufficient for performing the backward-forward load flow to obtain the power flowing through the feeders and substations, and the voltages of buses for all the states. In this stage, the installation and operation costs of equipment, cost of losses, and the violation of constraints are determined. In the next stage, the interruption cost is calculated according to the procedure proposed in flowchart of Fig. 2. Finally, all the cost components are summed to compose the cost or objective function. The complete procedure of the proposed optimization is illustrated in flowchart of Fig. 4.

Numerical study

The proposed DNEP is programmed and executed in MATLAB programming environment and applied to the 54-bus test system and also on a real 104-bus distribution network. The data of these
systems are introduced in the next parts. By several executions of the algorithm for different values of GA parameters, it was observed that assigning the values 100, 0.75 and 0.05 respectively for the number of chromosomes, crossover rate, and mutation rate, yields the best results. In addition, the roulette wheel is used for the reproduction process [42].

Improving the GA performance

To maintain the fittest chromosomes during the optimization procedure, and to improve the performance of the GA, the “Elite Selection” (ES) process has been employed. For this purpose, the worst 10% of present generation (population) are replaced with the best 10% of previous generation. Of course, this substitution is fulfilled if the mentioned 10% of previous generation is more qualified than that of the present one from the objective function viewpoint.

54-node distribution system

The first test system, as shown in Fig. 5, is a 54-node, 33 kV network consisted of 50 load points (MV/LV buses) with the specifications of Table 3 [7,33]. The total load of the system in the horizon year is 73.22 MVA, and the power factor of loads is 0.8. There are two existing and two candidate HV/MV substations to feed the distribution network. The data related to HV/MV substations are given in Table 4. The number of existing feeders is 17, and there are 56 new feeders as candidates for installation. There are twelve types of conductors used in the feeders; their characteristics are presented in Table 5. Two DG technologies, including gas turbine and wind turbine are considered in the simulation; their characteristics are given in Table 6. The wind turbine’s cut-in, rated, and cut-off speeds are 4, 14, and 25 m/s, respectively. The data of the chosen wind turbine are used to generate the probabilistic wind output power model as Tables 1 and 2. All the MV/LV buses are candidates for DG installation. Other parameters used in the simulations are presented in Table 7.

Table 3
Specification of load points of Fig. 5.

<table>
<thead>
<tr>
<th>No.</th>
<th>Load (kW)</th>
<th>No.</th>
<th>Load (kW)</th>
<th>No.</th>
<th>Load (kW)</th>
<th>No.</th>
<th>Load (kW)</th>
<th>No.</th>
<th>Load (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4200</td>
<td>11</td>
<td>300</td>
<td>21</td>
<td>1800</td>
<td>31</td>
<td>700</td>
<td>41</td>
<td>900</td>
</tr>
<tr>
<td>2</td>
<td>1500</td>
<td>12</td>
<td>1800</td>
<td>22</td>
<td>1100</td>
<td>32</td>
<td>1700</td>
<td>42</td>
<td>1200</td>
</tr>
<tr>
<td>3</td>
<td>700</td>
<td>13</td>
<td>1100</td>
<td>23</td>
<td>1000</td>
<td>33</td>
<td>2900</td>
<td>43</td>
<td>1300</td>
</tr>
<tr>
<td>4</td>
<td>1100</td>
<td>14</td>
<td>1000</td>
<td>24</td>
<td>500</td>
<td>34</td>
<td>1200</td>
<td>44</td>
<td>1400</td>
</tr>
<tr>
<td>5</td>
<td>2600</td>
<td>15</td>
<td>1400</td>
<td>25</td>
<td>900</td>
<td>35</td>
<td>900</td>
<td>45</td>
<td>800</td>
</tr>
<tr>
<td>6</td>
<td>700</td>
<td>16</td>
<td>1900</td>
<td>26</td>
<td>1200</td>
<td>36</td>
<td>300</td>
<td>46</td>
<td>1800</td>
</tr>
<tr>
<td>7</td>
<td>1000</td>
<td>17</td>
<td>700</td>
<td>27</td>
<td>1500</td>
<td>37</td>
<td>2100</td>
<td>47</td>
<td>1000</td>
</tr>
<tr>
<td>8</td>
<td>1900</td>
<td>18</td>
<td>1200</td>
<td>28</td>
<td>700</td>
<td>38</td>
<td>1100</td>
<td>48</td>
<td>800</td>
</tr>
<tr>
<td>9</td>
<td>1200</td>
<td>19</td>
<td>1400</td>
<td>29</td>
<td>1400</td>
<td>39</td>
<td>1000</td>
<td>49</td>
<td>500</td>
</tr>
<tr>
<td>10</td>
<td>2900</td>
<td>20</td>
<td>800</td>
<td>30</td>
<td>2600</td>
<td>40</td>
<td>1400</td>
<td>50</td>
<td>800</td>
</tr>
</tbody>
</table>

Table 4
Specification of HV/MV substations.

<table>
<thead>
<tr>
<th>Substation</th>
<th>Geographical position</th>
<th>Existing capacity (MVA)</th>
<th>Expandable capacity (MVA)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>X (km)</td>
<td>Y (km)</td>
<td></td>
</tr>
<tr>
<td>S1</td>
<td>16.6</td>
<td>24.2</td>
<td>2 × 15</td>
</tr>
<tr>
<td>S2</td>
<td>10.5</td>
<td>0</td>
<td>1 × 15</td>
</tr>
<tr>
<td>S3</td>
<td>23.9</td>
<td>9.5</td>
<td>0</td>
</tr>
<tr>
<td>S4</td>
<td>2.9</td>
<td>15.8</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 5
Specification of conductors used in feeders.

<table>
<thead>
<tr>
<th>Conductor type</th>
<th>Resistance (ohm/km)</th>
<th>Reactance (ohm/km)</th>
<th>Current capacity (A)</th>
<th>Cost (k$/km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.7500</td>
<td>0.1746</td>
<td>61</td>
<td>17</td>
</tr>
<tr>
<td>2</td>
<td>0.4794</td>
<td>0.1673</td>
<td>84</td>
<td>22</td>
</tr>
<tr>
<td>3</td>
<td>0.3080</td>
<td>0.1596</td>
<td>114</td>
<td>30</td>
</tr>
<tr>
<td>4</td>
<td>0.1972</td>
<td>0.1496</td>
<td>156</td>
<td>42</td>
</tr>
<tr>
<td>5</td>
<td>0.1208</td>
<td>0.1442</td>
<td>208</td>
<td>54</td>
</tr>
<tr>
<td>6</td>
<td>0.0723</td>
<td>0.1262</td>
<td>303</td>
<td>85</td>
</tr>
<tr>
<td>7</td>
<td>0.0487</td>
<td>0.1217</td>
<td>400</td>
<td>125</td>
</tr>
<tr>
<td>8</td>
<td>0.0405</td>
<td>0.1196</td>
<td>453</td>
<td>140</td>
</tr>
<tr>
<td>9</td>
<td>0.0350</td>
<td>0.1180</td>
<td>500</td>
<td>165</td>
</tr>
<tr>
<td>10</td>
<td>0.0247</td>
<td>0.1140</td>
<td>645</td>
<td>220</td>
</tr>
<tr>
<td>11</td>
<td>0.019</td>
<td>0.11</td>
<td>700</td>
<td>270</td>
</tr>
<tr>
<td>12</td>
<td>0.017</td>
<td>0.09</td>
<td>850</td>
<td>310</td>
</tr>
</tbody>
</table>
Table 6
Characteristics of DG units used in the problem.

<table>
<thead>
<tr>
<th>DG technology</th>
<th>Size (MVA)</th>
<th>Installation cost (k$/MVA)</th>
<th>Operation cost ($/MW h)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas turbine (GT)</td>
<td>1</td>
<td>400</td>
<td>46</td>
</tr>
<tr>
<td>Wind turbine (WT)</td>
<td>1</td>
<td>800</td>
<td>10</td>
</tr>
</tbody>
</table>

Table 7
The value of parameters used in the simulation.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\rho$ ($$/MWh)$</td>
<td>60</td>
</tr>
<tr>
<td>Infr (%)</td>
<td>10</td>
</tr>
<tr>
<td>Intr (%)</td>
<td>12</td>
</tr>
<tr>
<td>$V_{min}$ (pu)</td>
<td>0.95</td>
</tr>
<tr>
<td>$V_{max}$ (pu)</td>
<td>1.05</td>
</tr>
<tr>
<td>$V_{min}$ (pu)</td>
<td>$0.95 \times V_{max}$</td>
</tr>
<tr>
<td>$V_{max}$ (pu)</td>
<td>$1.05 \times V_{max}$</td>
</tr>
<tr>
<td>$I_{max}$ (A)</td>
<td>$1.1 \times$ capacity of feeder $i$</td>
</tr>
<tr>
<td>Failure rate of feeders (fail/km/year)</td>
<td>0.2</td>
</tr>
<tr>
<td>Repair time (h)</td>
<td>2</td>
</tr>
<tr>
<td>Emission of CO$_2$ related to the received power from the transmission grid (ton/MWh)</td>
<td>0.632</td>
</tr>
<tr>
<td>Emission of CO$_2$ related to the generated power by DDGs (ton/MWh)</td>
<td>0.365</td>
</tr>
<tr>
<td>Maximum number of installable DGs on each bus</td>
<td>4</td>
</tr>
</tbody>
</table>

Scenario 1
In this scenario, the distribution network expansion planning is implemented without the presence of distributed generation. Thus, the DNEP is fulfilled through the upgrading or installation of feeders and substations. In this case, the improvement of reliability would be gained by means of reserve feeders installation, and by the load transferring between the substations during fault on the feeders. The results of this scenario are illustrated in Fig. 6 and Tables 8 and 9. Fig. 6 shows the configuration of expanded network. In this figure, the conductors with higher current capacity are depicted by the thicker lines. Also, the dashed lines are the installed feeders as the reserve ones. Tables 8 and 9 show the results of expanded substations and cost components, respectively.

![Fig. 6. Configuration of 54-bus network after expansion in scenario 1.](image)

Table 8
Results of substation expansion for 54-bus network.

<table>
<thead>
<tr>
<th>Substation</th>
<th>Existing capacity (MVA)</th>
<th>Expanded capacity (MVA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>2 × 15</td>
<td>3 × 15</td>
</tr>
<tr>
<td>S2</td>
<td>1 × 15</td>
<td>3 × 15</td>
</tr>
<tr>
<td>S3</td>
<td>0</td>
<td>3 × 7.5</td>
</tr>
<tr>
<td>S4</td>
<td>0</td>
<td>4 × 7.5</td>
</tr>
</tbody>
</table>

Table 9
Cost components for 54-bus network.

<table>
<thead>
<tr>
<th>Component</th>
<th>Value (M$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation expansion cost</td>
<td>2.40</td>
</tr>
<tr>
<td>Substation installation cost</td>
<td>11.40</td>
</tr>
<tr>
<td>Feeders cost</td>
<td>9.89</td>
</tr>
<tr>
<td>DG installation cost</td>
<td>0</td>
</tr>
<tr>
<td>DG operation cost</td>
<td>0</td>
</tr>
<tr>
<td>Energy purchase cost</td>
<td>94.39</td>
</tr>
<tr>
<td>Energy not supplied cost</td>
<td>26.71</td>
</tr>
<tr>
<td>Energy loss cost</td>
<td>3.17</td>
</tr>
<tr>
<td>Emission cost</td>
<td>56.76</td>
</tr>
<tr>
<td>Total cost</td>
<td>204.72</td>
</tr>
</tbody>
</table>

Scenario 2
In this scenario, the DNEP is solved considering the presence of DG. The results of this scenario are shown in Fig. 7 and Tables 8 and 9. Also the type and number of installed DGs on the buses are illustrated in Table 10.

Comparing the results of the two scenarios indicates the benefits of using DG in DNEP. As the results show, the installation and upgrading costs of substations and feeders have been decreased, and the energy loss and reliability costs have been diminished significantly. Also, the energy cost is lower than that without DG. As an important advantage, the emission cost in the presence of DG
is lower, and this can be very valuable from the environmental concerns viewpoint. The decrease of cost components leads to a 10% decrease in the total cost. Fig. 8 compares the cost components in the two scenarios.

The convergence trend of GA with and without elite selection process has been depicted in Fig. 9 for the second scenario. As

<table>
<thead>
<tr>
<th>Bus number</th>
<th>Type of installed DG</th>
<th>Number of installed DG</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>WDG</td>
<td>3</td>
</tr>
<tr>
<td>8</td>
<td>DDG</td>
<td>2</td>
</tr>
<tr>
<td>13</td>
<td>WDG</td>
<td>3</td>
</tr>
<tr>
<td>17</td>
<td>DDG</td>
<td>1</td>
</tr>
<tr>
<td>18</td>
<td>DDG</td>
<td>1</td>
</tr>
<tr>
<td>20</td>
<td>WDG</td>
<td>2</td>
</tr>
<tr>
<td>21</td>
<td>DDG</td>
<td>2</td>
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<td>28</td>
<td>DDG</td>
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<td>33</td>
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<td>DDG</td>
<td>1</td>
</tr>
<tr>
<td>49</td>
<td>WDG</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 10: Number and type of installed DGs on 54-bus network in scenario 2.

Fig. 7. Configuration of 54-bus network after expansion in scenario 2.

Fig. 8. Comparison of the cost components in the two scenarios.

Fig. 9. Convergence trend of GA with and without elite selection.
shown, when the GA is equipped with ES, more optimal result is obtained.

Real distribution network

The second test system is a real distribution network [44]. It is a 13.5 kV network consisted of 101 load buses, with the characteristics given in [44] and shown in Fig. 10. The total load of the system in the horizon year is 58.23 MW and 43.67 MVar. Three HV/MV substations named as HV1, HV2 and HV3 are candidate to feed the distribution network. There are 184 candidate feeders as shown in Fig. 10. The utilized conductors are the ones reported in Table 5. The ratings of gas and wind turbines are 500 kW. All the MV/LV buses are candidates for DG installation. In addition, the potential buses for WDG installation are the nodes: 10, 19, 21, 22, 27, 32, 35, 36, 37, 43, 59, 64, 89, 97, 98, 99, 102, and 103. The same scenarios defined for the 54-bus network (i.e. the scenarios without and with DG) are also implemented on this network. The simulation results are provided in Figs. 11 and 12 and Tables 11–13. As shown, when the DG units are not utilized, all the candidate substations have been expanded, while when the DGs are incorporated, there is no need to install substation HV2. The
feeders installation cost, the purchased energy cost are also decreased. Moreover, the energy not supplied cost, the emission cost, and the energy losses cost have been diminished significantly. As a whole, the total expansion cost is reduced from 194.15 M$ to 143.88 M$.

**Conclusion**

In this paper, an integrated distribution network expansion planning in the presence of renewable and non-renewable distributed generation is proposed. The reinforcement of existing feeders and substations, the installation of new feeders and substations, and also the installation of renewable and non-renewable DGs have been considered as the expansion planning options. The objective function includes all the installation and operation costs. Moreover, the reliability and environmental concerns have been regarded in the problem. The annual load variation, and also, the uncertainties of renewable DGs’ output power, load demand and energy price have been taken into account in the calculation of reliability and other cost components. To enhance the reliability and lower the interruption costs, the reserve feeders and also, the possibility of islanding operation of DG units are considered. Likewise, the required condition for successful and safe operation of island has been evaluated for all the uncertainty states. The proposed DNEP along with its constraints has been formulated as an optimization problem where the genetic algorithm is employed to solve this integrated problem. To evaluate the effectiveness of the presented DNEP problem, it has been applied to the 54-bus network and also a real large-scale distribution network. The simulation results verify the efficiency of the proposed method in the improvement of the network’s technical characteristics, the decrease of total cost and the decrease in environmental pollution.
References


