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Renewable power generation employed in an integrated dynamic distribution network expansion planning

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ABSTRACT

The recent developments in green energy technologies and the importance of using clean energies have made the renewable resources more attractive for distribution network operators, specifically due to their inexhaustible and non-polluting features. In this way, the present study initiates an integrated dynamic distribution network expansion planning (DDNEP) in which most of the planning alternatives along with renewable and non-renewable distributed generation (DG) are taken into account. The proposed framework considers the important cost terms, including both the investment and operational ones. The uncertainties regarding the intermittent nature of renewable DGs, load demand, and energy price have been well-regarded in calculating the cost components. With the aim of a precise calculation of operation and interruption costs, the load duration curve (LDC) has been established for modeling of the network loads. Moreover, both the possibility of operating the DG units in islanding mode, and, the load transferring through the reserve feeders have been interrogated in the problem in order to improve the network reliability. In the present research, to provide an accurate evaluation of reliability indices, and to cover all of the uncertainty states, the required conditions for the successful and safe operation of island have been suitably studied in the problem. In numerical evaluations, a combination of improved genetic algorithm (IGA) and optimal power flow (OPF) is employed to solve the integrated problem in the 54-bus test system. The obtained results are discussed in details.

1. Introduction

Distribution network expansion planning (DNEP) is one of the main tasks of distribution companies to meet the rapid growth in the load demand [1]. Traditionally, the DNEP is fulfilled either through the reinfrcement of existing lines and substations, or by installation of new ones that leads to minimum expansion cost, subjected to the technical and operational constraints [2–6]. There are two main approaches for solving the DNEP: (a) static and (b) multi-stage planning [7–14]. The static planning simply considers a single planning horizon and decides the type, location, and capacity of network equipment which require to be reinforced and/or installed to meet the load growth in the horizon year. In this way, all of the requirements for the network expansion are determined in one period of the planning horizon. In comparison with the static one, the multi-stage planning not only determines the characteristics of the network equipment, but also, decides the time of reinforcement/installation of the network required equipment. In this case, the planning horizon is divided into several time stages, each with a predicted load demand. The multi-stage planning can be fulfilled using one of the following methods:

- Successive method
  In the successive method, a static planning is conducted for each time stage to meet the peak load demand of that stage regarding to the network's layout of the previous stage [9]. Since the optimal solution of each stage depends on the result of the previous stages, the successive method commonly leads to local minima [7].
- Pseudo-dynamic method
  In the pseudo-dynamic method, the DNEP is divided into two phases [8]. In the first phase, by the use of the static planning method, a system is designed to optimally supply the load demand in the horizon year. After that, the non-selected equipment are removed from the set of candidate ones. In the second phase, the load growth is considered at each time stage using the successive method. It has been demonstrated that the pseudo-dynamic method acquires better results compared to other non-dynamic planning methods [10].

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Nomenclature

Indices

dg index for DG units
tr index for the transformers of HV/MV substations
k index for MV feeders
es index for existing HV/MV substations
cs index for candidate HV/MV substations
ef index for existing MV feeders
cf index for candidate MV feeders
s index for uncertainty states
LL index for load levels
i,j index for buses
t index for years

Constants

n_{dg} number of DG units
n_{tr} number of HV/MV transformers
n_{es} number of existing HV/MV substations
n_{cs} number of candidate HV/MV substations
n_{ef} number of existing MVfeeders
n_{cf} number of candidate MV feeders
ns number of uncertainty states
n_{LL} number of load levels during a year
λ_k failure rate of feeder k (fail/km/year)
λ_{dg} failure rate of DG unit dg (fail/year)
λ_{tr} failure rate of transformer tr (fail/year)
r_{k} repair time of feeder k (h)
r_{dg} repair time of DG dg (h)
r_{tr} repair time of transformer tr (h)
T horizon year of planning
T_{LL} time duration of load level LL (h)
Infr inflation rate (%)
Intr INTEREST rate (%)
$V_{\mathrm{safe}}^{\mathrm{min}}$ minimum safe value of bus voltage (p.u.)
$V_{\mathrm{crit}}^{\mathrm{min}}$ minimum critical value of bus voltage (p.u.)
$V_{\mathrm{safe}}^{\mathrm{max}}$ Maximum safe value of bus voltage (p.u.)
$V_{\mathrm{crit}}^{\mathrm{max}}$ maximum critical value of bus voltage (p.u.)
L_{ij} length of feeder between buses i and j (km)
$\mathrm{LC}_{\mathrm{LL}}$ loss cost in load level LL ($/kWh)
$\mathrm{RC}_{\mathrm{LL}}$ reliability cost of unsupplied energy in load level LL ($/kWh)
$\mathrm{oc}_{\mathrm{LL.s}}$ operation cost of DG in load level LL and sate s ($/kWh)
emc cost of emission ($/ton)
dc cost of dissatisfaction of constraints ($)
$S_{i,t,LL,s}^{L}$ apparent load demand of bus i in year t, load level LL, and state s (kVA)
$S_{\mathrm{peak},i,t}^{L}$ apparent load demand of bus i in year t, in peak condition (kVA)
$\mathrm{LLF}_{\mathrm{i,t,LL,s}}$ load level factor of bus i in year t, load level LL, and state s
$\mathrm{EP}_{\mathrm{i,LL}}$ price of energy purchased from the transmission network through ith HV/MV substation in load level LL ($/kWh)
$\mathrm{EP}_{\mathrm{peak.i}}$ price of energy purchased from the transmission network through ith HV/MV substation in peak condition of year ($/kWh)
$\mathrm{PLF}_{\mathrm{i,LL,s}}$ price level factor of energy purchased from the transmission network through ith HV/MV substation in load level LL, and state s
$P_{\mathrm{peak},i,t}^{L}$ active load demand of bus i in year t, in peak condition (kW)

Functions

$IC_i\left(S_i^{\mathrm{inst}}\right)$ installation cost of ith HV/MV substation with capacity of S ($)
$\mathrm{sec}_i\left(S_i^{\mathrm{exp}}\right)$ expansion cost of ith existing HV/MV substation with capacity of S ($)
$FC_{ij}(k)$ installation cost of feeder with the type of k between buses i,j ($/km)
$MFC_{ij}(k)$ installation cost of new main feeder with the type of k between buses i,j ($/km)
$RFC_{ij}(k)$ installation cost of new reserve feeder with the type of k between buses i,j ($/km)
$DGIC_i\left(S_i^{DG}\right)$ installation cost of DG unit with the capacity of S^{DG} in bus i ($)

Variables

$\mu_{i,t,LL,S}^{V}$ voltage constraint satisfaction rate for bus i, in year t, load level LL, and state s
μ_i^V voltage constraint satisfaction rate for bus i
μ^V voltage constraint satisfaction rate for the whole network
μ^I current constraint satisfaction rate for the whole network
μ^S satisfaction rate of substation capacity constraint for the whole network
$\delta_{i,t,LL,s}$ voltage angle of bus i, in year t, load level LL, and state s (rad)
$Y_{ij,t}$ magnitude of admittance between buses i and j in year t (p.u.)
$\theta_{ij,t}$ angle of admittance between buses i and j in year t (rad)
$P_{i,t,LL,s}^{\mathrm{net}}$ net active power of bus i in year t, load level LL, and state s (kW)
$P_{i,t,LL,s}^{L}$ active load demand of bus i in year t, load level LL, and state s (kW)
$P_{i,t,LL,s}^{DG}$ active power generated by the DG of bus i in year t, load level LL, and state s (kW)
$P_{i,t,LL,s}^{\mathrm{Trans}}$ power imported from the transmission grid to distribution system through ith HV/MV substation in year t, load level LL, and state s (kW)
$P_{i,t}^{DG}$ active power of DG installed on bus i in year t (kW)
$Q_{i,t,LL,s}^{\mathrm{net}}$ net reactive power of bus i in year t, load level LL, and state s (kVAr)
$Q_{i,t,LL,s}^{L}$ reactive load demand of bus i in year t, load level LL, and state s (kVAr)
$Q_{i,t,LL,s}^{DG}$ reactive power generated by the DG installed on bus i, in year t, load level LL, and state s (kVAr)
$S_{i,t,LL,s}^{DG}$ apparent power generation of DG installed on bus i, in year t, load level LL, and state s (kVA)
$S_{i,t,\mathrm{max}}^{DG}$ capacity of DG installed on bus i in year t (kVA)
$V_{i,t,LL,s}$ voltage magnitude of bus i, in year t, load level LL, and state s (p.u.)
$Loss_{i,t,LL,s}$ power loss of feeder i in year t, load level LL, and state s (kW)
$LNS_{f,t,LL,s}$ load not supplied in year t, load level LL, and state s due to outage of feeder f (kW)
$LNS_{dg,t,LL,s}$ load not supplied in year t, load level LL, and state s due to outage of DG unit dg (kW)
$LNS_{tr,t,LL,s}$ load not supplied in year t, load level LL, and state s due to outage of transformer tr (kW)
$P_{t,LL,s}^{\mathrm{Grid}}$ the power received from the transmission grid in year t, load level LL, and state s

$P^{DDG}_{t,LL,s}$ generated power by DDG units in year t, load level LL, and state s
$GE_{t,LL,s}$ emission of CO_2 corresponding to the energy received from the transmission grid in year t, load level LL, and state s (ton/kWh)
$DGE_{t,LL,s}$ emission of CO_2 corresponding to the energy provided by DDG units in year t, load level LL, and state s (ton/kWh)

- Dynamic method
  In the dynamic planning approach, the DSEP is optimized for all the stages, and the whole problem unknowns are determined simultaneously. Hence, the dynamic planning method can lead to the optimal solution. However, the problem becomes very complex, and its execution time is multiplied [7].

On the other hand, due to the emergence of distributed generation in the power systems, new capacity options have been developed. Presence of DG, as an energy source, influences the operation, design, and expansion problems of the distribution systems [9,15,16]. With respect to the potential benefits of DGs such as capacity deferment, peak cutting, losses reduction, voltage profile improvement, and reliability enhancement [15,17–19], it is expected that DGs play an important role in the future of distribution networks. Thus, modeling of expansion planning should consider the DG sources as well as the substations and feeders. DG units might be owned either by the utility or customers. In the case of utility-owned DG installation, the utility is responsible for optimal planning and operation of the DG units in order to maximize the network benefits and improve its reliability [11–14,20–22].

DG units are categorized into two main groups: non-renewable DGs and renewable ones [23]. Since the output power of the first type of DG is usually controllable, they are known as dispatchable DGs (DDGs). The second type includes the DGs which their primary energy sources are the renewables like wind, biomass, photovoltaic, geothermal, etc.

Nowadays, the developments in green energy technologies and the importance of providing clean energies have made the renewable resources more attractive for distribution network operators, specifically due to their inexhaustible and non-polluting features. The wind-based distributed generation (WDG) is one of these technologies which much attention is being paid toward it [24]. The output power of a wind turbine is dependent on the wind speed. Since the wind speed has an uncertain and stochastic nature, therefore, the output power of a WDG is also an uncertain and intermittent parameter [25]. Different studies have modeled this uncertainty and its impact on the performance of distribution networks [26–28].

Regarding the importance of distributed generation, several researches have been done in the field of distribution network expansion planning in the presence of DG. These works have formulated the DNEP as different objective functions, and have used various methods to solve the problem [29–31]. A survey of researches in the area of distribution network expansion planning reveals the following challenges:

- formalizing the DNEP by different objective functions and employing efficient methods to solve it;
- implementation of DNEP either as static or multi-stage;
- using renewable and non-renewable DGs as an alternative for DNEP;
- uncertainty consideration in the problem;
- considering the operational costs in the planning;
- regarding the reliability in the planning;
- possibility of operating the DGs in the islanding mode for enhancing the network reliability.

Subsequently, the recently published papers in the area of DNEP have been reviewed in details from the above mentioned viewpoints.

Ref. [29] has considered almost all of the planning options. However, the possibility of new substations installation has not been regarded. Also, only the non-renewable DGs have been considered. An approach to evaluate the economic benefits of renewable DGs is proposed in [32] in which a GA-based method is employed for optimal DG allocation in order to maximize the deferral of system upgrade investments, and reduce both the energy loss and interruption costs. The proposed methodology takes into account the uncertainty of renewable DGs' output power, load variability, and the possibility of islanding to improve the reliability of the system. In this work, it is assumed that the substations are redundant, and there are neither new load points nor new substations for installation. The lines are just reinforced, and there is no reserve feeder for the reliability enhancement. To improve the reliability of the network, the possibility of operating the DGs in islanding mode has been considered in the case of fault occurrence on the feeders. However, the power flow and other technical constraints are not checked in the islanded part to see if the islanding is successful or not. Refs. [9,33,34] proposed a methodology to solve the multi-stage DNEP problem in which the installation or reinforcement of substations, feeders, and DGs are considered as possible solutions for the system capacity expansion. The presented formulation has considered the investment, operation, and outage costs. The simulation results indicate the positive impact of DG on improvement of the reliability and reduction of the outage costs. The renewable DGs have not been considered in these papers. Ref. [35] presents a multi-objective tabu search algorithm to solve the multi-stage planning problem of a distribution system; the objective function of the problem includes the investment, operational, and reliability costs. This work has not considered the DG in the planning. In [36], a framework is proposed for pseudo-dynamic multi-stage planning of HV substations and MV feeders routing using an imperialist competitive algorithm (ICA); the Greedy algorithm is used to construct the minimum spanning tree problem to construct a radial configuration of the mesh network for producing initial feasible solutions. This work is in the absence of both the DG and reliability consideration. Authors in [37] presented a hybrid simulated annealing (SA) and mixed integer linear programming (MILP) approach for the static DNEP with DGs to minimize the cost of investment, cost of customers interruption due to the failures at the branches, and the cost of lost DG production due to failure at branches. This work has not implemented the DNEP as dynamic. Moreover, the renewable DGs have not been utilized. Aghaei et al. [38] presented a multi-objective optimization algorithm for multi-stage distribution expansion planning in the presence of DG using non-linear formulations. The objective functions of problem include minimization of costs, non-distributed energy, active power losses, and voltage stability index. A modified particle swarm optimization (MPSO) algorithm is developed and applied for this multi-objective optimization. This work has not considered the renewable DGs. In addition, neither the islanding mode of DGs' operation nor the LDC have been considered. In [39], a dynamic DNEP model is proposed to decide the optimal size, site and installation year of DG units in the distribution network; Binary Enhanced Particle Swarm Optimization (BEPSO) and Modified Differential Evolution (MDE) are employed to search for the optimal solution. This paper has not considered the reliability. Besides, its test networks are small and composed of only one HV/MV substation; an annual load growth has been considered for the load points; whereas, in real distribution systems, there might be some new load points added to the network during the planning periods, and there may be a need to install new HV/MV substations to properly feed the loads. In addition, this work has considered the loads as constant during each year (the LDC has not been regarded), and the DDGs have been assumed to have a fixed power generation. Finally, the renewables are not included in the problem. Munoz-Delgado et al. [11] have addressed the dynamic expansion planning of distribution system where investment in DGs and distribution network are jointly considered. The objective function to be minimized is composed of all the cost components, including: cost of reinforcing the existing feeders and substations, cost of installing new feeders and substations, DGs' operating cost, energy purchasing cost, cost of installing conventional and wind DGs, cost of energy losses, and cost of unserved energy. In this paper, by avoiding the isolation of DG units, the LDC has been considered in optimizing the power generation of DGs and the related cost components. The simulation results of two case study reveal that substantial reduction in total cost is yield when the distribution network and DG units are jointly optimized in dynamic DNEP. The study in [40] proposed a stochastic dynamic multi-objective model for the integration of DGs in distribution networks. The presented model minimizes the costs, technical constraint dissatisfaction, and environmental emissions in order to determine the optimal location, size and time of investing on the DG units and network components. This paper has not considered the islanding operation and the reliability. In [22], the researchers presented an approach to evaluate the effects of both renewable and non-renewable DGs on DNEP. The proposed method has not solved the DNEP as dynamic, but as a static model; while, the dynamic planning is more favorite than static one from the mathematical and engineering points of view. Moreover, in [22], all the load points are considered similar from the viewpoint of supply priority; whereas, in practice, the load points have different supply priority, and this fact is important in the reliability calculation of the network.

A review of papers and their features has been summarized in Table 1. As it can be seen, the previous studies in this field are not comprehensive. So, each study has addressed the DNEP from one or some limited viewpoint. In this paper, in order to resolve the shortcomings of the previous studies, a comprehensive approach is proposed for the integrated dynamic distribution network expansion planning in the presence of utility-owned renewable and non-renewable distributed generation. The aim of the presented approach is to find the following unknown parameters to meet the load growth throughout the planning years with the minimum total cost subjected to the network technical and operational constraints:

- The time and capacity reinforcement of existing MV feeders and HV/MV substations.
- The time, routing, and conductor type of newly installed main and reserve feeders.
- The time, location, and installation capacity of candidate HV/MV substations.
- The site, size, and installation year of renewable and non-renewable DGs.
- The optimal power generation of DDG units in different years and load levels.

To improve the network reliability, the installation of reserve feeders, and also the possibility of operating the DGs in the islanding mode have been regarded. In addition, the load variations during a year, the uncertainties, and the operational costs have been considered. A combination of IGA and OPF is employed to solve this integrated problem. Finally, the proposed DDNEP has been applied to the 54-bus test network, and the results are investigated.

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

- Proposing an integrated dynamic approach for distribution network expansion planning.
- Employing the renewable power generation as an alternative for the DDNEP.
- Regarding the reliability and operational costs in the problem.
- Possibility of islanding operation of DGs.

2. Problem representation

The aim of DDNEP is to determine the siting, sizing, and timing of the network equipment to supply the loads during the planning period with the minimum total cost subjected to the technical and operational constraints.

2.1. Modeling of load and energy price

To properly obtain the operational and interruption costs, the variation of load and price during the year should be regarded. For this aim, the discretized load duration curve (LDC) is utilized for the loads [9,11,13,14,41]. The similar curve is used for the price of energy purchased from the transmission network. Fig. 1a illustrates this model. In this figure, the vertical axis shows either the load or the price level factor (the ratio of the load or price to its peak value in the year), and the horizontal axis denotes the time duration of each load level (LL) as T_{LL}.

2.2. Uncertainty of load and energy price

In the expansion planning problems, the load demand and energy price are usually uncertain parameters. Their uncertainty can be expressed using normal distributions around the expected values as illustrated in Fig. 1b.

2.3. Wind power generation

Due to the stochastic behavior of the wind speed, the generated power of the wind turbine is also stochastic and intermittent. Several models have been proposed to express this stochastic behavior [27]. The Rayleigh Probability Distribution Function (PDF) as Eq. (1) is the most popular model in which v is the wind speed, and c is the scale factor of the Rayleigh PDF of wind speed in the zone under study [40].

$$\mathrm{PDF}(v) = \left(\frac{2v}{c^2}\right) \exp\left[-\left(\frac{v}{c}\right)^2\right] \tag{1}$$

By using the power-speed curve of the wind turbine, the output power of WDG can be calculated as (2) in which P^{WDG} and P_{rated} are the output and rated power of WDG, respectively. Also, v_{ci}, v_{co}, and v_{rated} are the cut-in, cut-out, and rated speeds of the wind turbine, respectively [27,42].

$$P^{\mathrm{WDG}} = \begin{cases} 0, & \text{if } v \le v_{ci} \\ P_{\mathrm{rated}} \times \dfrac{v - v_{ci}}{v_{\mathrm{rated}} - v_{ci}}, & \text{if } v_{ci} \le v \le v_{\mathrm{rated}} \\ P_{\mathrm{rated}} & \text{if } v_{\mathrm{rated}} \le v \le v_{co} \\ 0, & \text{if } v_{co} < v \end{cases} \tag{2}$$

2.4. Uncertainty handling method

Different methods can be used for handling the uncertainties of WDG output power, load, and energy price, such as Monte Carlo simulation (MCS), two-point estimation method, scenario-based

Table 1
Classification of specialized literature in the area of distribution network expansion planning.

Issue	Features	Moreira et al. [3]	Lavorato et al. [4]	Jimenez et al. [5]	Falaghi et al. [9]	Munoz-Delgado et al. [11]	Ziari et al. [15]	El-Khattam et al. [18]	Bagheri et al. [22]	Attwa et al. [26]
Planning Way	Upgrading	√	√	√	√	√	√		√	
	New installations		√	√	√	√			√	
	DG Utilization				√	√	√	√	√	√
Planning model	Static	√	√	√				√	√	√
	Multi-stage				√		√			
	Dynamic					√				
DG type	Non-renewable				√	√	√	√	√	
	Renewable					√			√	√
Uncertainty consideration									√	√
Load variation consideration					√	√			√	
Islanding	Islanding consideration						√		√	
	Checking constraints in the Island								√	
Objective Function	Investment cost	√	√	√	√	√	√	√	√	
	DG operation cost				√	√	√	√	√	
	Loss cost	√	√	√	√	√	√	√	√	√
	Reliability cost				√	√	√	√	√	

Issue	Features	Sedghi et al. [30]	Shaaban et al. [32]	Gitizadeh et al. [33]	Junior et al. [34]	Najafi et al. [36]	Popovic et al. [37]	Aghaei et al. [38]	Ahmadigorji et al. [39]	Soroudi et al. [40]
Planning Way	Upgrading	√	√	√	√	√	√	√	√	√
	New installations	√		√	√	√	√	√	√	√
	DG utilization	√	√	√			√	√	√	√
Planning model	Static		√				√			
	Multi-stage	√		√	√	√		√		
	Dynamic								√	√
DG type	Non-renewable	√		√			√	√	√	√
	Renewable		√							√
Uncertainty consideration			√				√			√
Load variation consideration		√		√				√		√
Islanding	Islanding consideration		√							
	Checking constraints in the Island									
Objective function	Investment cost	√	√	√	√	√	√	√	√	√
	DG operation cost	√	√	√			√	√	√	√
	Loss cost	√	√		√	√	√	√	√	√
	Reliability cost	√	√	√	√		√	√		

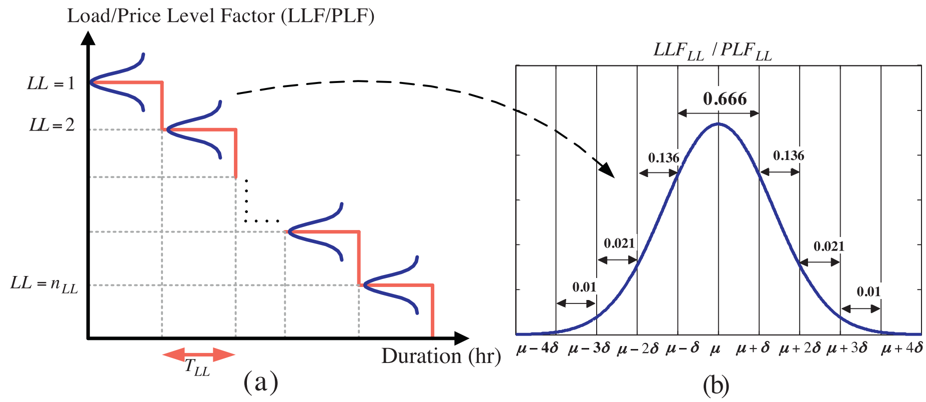

Fig. 1. (a) Load/price duration curve and (b) the related uncertainly model.

modeling, etc. [27,42]. The scenario-based modeling is usually employed in the planning problems [40]. If the number of scenarios is chosen appropriately, this method is capable of covering all the uncertainty states with an acceptable accuracy without increasing the computational burden. On this basis, the distribution curves of wind, load, and price are divided into a number of states with the related probabilities as Fig. 1b. The uncertainty states of load and energy price, and their related probabilities have been estimated based on the historical information. Consequently, the model of load and energy price, regarding the uncertainty, can be expressed as Eqs. (3) and (4).

$$S^{L}_{i,t,LL,s} = S^{L}_{i,t,\mathrm{peak}} LLF_{LL,s} \quad (3)$$

$$EP_{LL,s} = EP_{\mathrm{peak}} PLF_{LL,s} \quad (4)$$

Moreover, in the expansion planning studies, it is appropriate to use the behavior of wind during a year [27]. The data of Table 2 are used for modeling of the wind's behavior in this paper. With regard to Table 2 and Eq. (2), the output power of WDG and the associated probabilities are acquired as Table 3. It should be noted that the values of second column in Table 2 are based on the historical data of the area under study. By dividing these values to the number of hours in a year, that is 8760, the wind state probabilities are yield according to the third columns of Tables 2 and 3.

2.4.1. Combinational model for uncertainty states

In each load level, the states of wind speed, load, and energy price are combined with each other to compose the whole set of the uncertainty states according to Eqs. (5) and (6).

$$S_{comb} = S_{wlp} \;\; ; \quad w = 1, 2, \ldots, nws; \quad l = 1, 2, \ldots, nls; \quad p = 1, 2, \ldots, nps; \quad (5)$$

$$\mathrm{Prob}^{com}_{wlp} = \mathrm{Prob}^{w}_{wlp} \times \mathrm{Prob}^{l}_{wlp} \times \mathrm{Prob}^{p}_{wlp} \quad (6)$$

where S_{comb} is the combination of all uncertainty states. S_{wlp} is the uncertainty state of wind speed w, load l, and price p. Also, Prob^{w}_{wlp}, Prob^{l}_{wlp}, and Prob^{p}_{wlp} are the probabilities of wind speed, load, and energy price in state wlp. $\mathrm{Prob}^{Com}_{wlp}$ is the probability of each combined state wlp; nws, nls, and nps are the number of of wind speed, load, and energy price states, respectively.

2.5. Problem constraints

The constraints of DDNEP are classified into hard and soft ones. While the satisfaction of the hard constraints is mandatory, the soft ones may be violated; however, this violation must be calculated and minimized in the optimization process.

2.5.1. Hard constraints

2.5.1.1. Network radiality constraint. Distribution systems are usually operated in radial topology [11,13,14,43]. Therefore, the radiality constraint is regarded in the expansion and operation planning problems. Different algorithms have been proposed to construct a radial distribution network from a meshed structure, such as: branch exchange [44], evolutionary algorithm [45], specialized genetic algorithm [46], algebraic relations [47], *prufer-number* based GA [48]. The method used in this paper for checking the radiality constraint is based on the adjacency matrix of the network.

In the case that there is only one HV/MV substation in the network, the conditions (7.1) and (7.2) must be simultaneously satisfied to ensure the network is radial [49].

Network must be connected (7.1)

Table 2
Wind speed probabilities.

Wind speed Limits (m/s)	Hours/year	Probability
0–4	1804	0.2059
4–5	579	0.0661
5–6	984	0.1123
6–7	908	0.1037
7–8	983	0.1122
8–9	799	0.0912
9–10	677	0.0773
10–11	439	0.0501
11–12	395	0.0451
12–13	286	0.0326
13–14	219	0.0250
14–15	687	0.0784

Table 3
Wind power probabilities.

State no.	Output power as percentage of rated capacity %	Probability
1	100	0.0784
2	94.97	0.0250
3	84.7	0.0326
4	74.98	0.0451
5	64.8	0.0501
6	54.98	0.0773
7	44.99	0.0912
8	34.99	0.1122
9	19.9	0.1037
10	15.00	0.1123
11	5.00	0.0661
12	0.00	0.2059

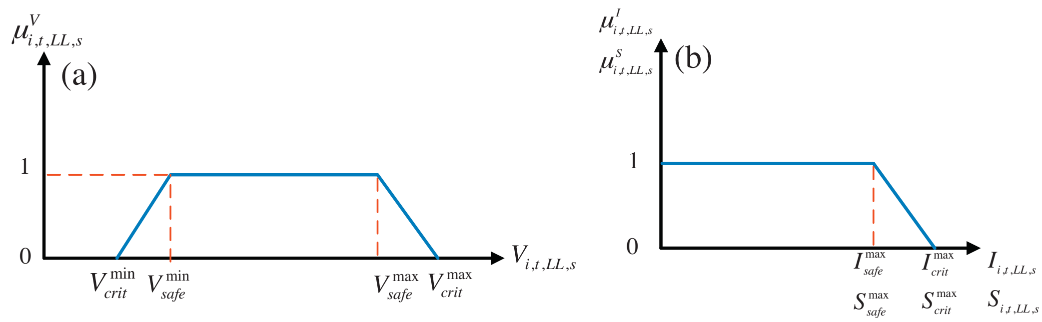

Fig. 2. Trapezoidal fuzzy model (a) for voltage limitation and (b) for feeders current/substations capacity limitation.

$$\text{rank}(A) = n_n - 1 \quad \text{or} \quad \text{trace}(A^2) = 2(n_n - 1) \tag{7.2}$$

where, n_n is the total number of network buses; A is the adjacency matrix of distribution network; *rank*(A) is the number of linearly independent rows or columns of matrix A; and, trace(A^2) is the sum of diagonal elements of the matrix A^2.

In order to check the radiality of a network consisted of several HV/MV substations, the condition (7.2) must be modified to condition (7.3) as below.

$$\text{rank}(A) = n_n - n_s \quad \text{or} \quad \text{trace}(A^2) = 2(n_n - n_s) \tag{7.3}$$

where, n_s is the number of HV/MV substations in the network.

2.5.1.2. Power flow constraints. The power flow equations must be satisfied for each uncertainty state, load level, and year as Eq. (8).

$$P^{\text{net}}_{i,t,LL,s} = -P^{L}_{i,t,LL,s} + P^{\text{DDG/WDG}}_{i,t,LL,s} \quad \forall i \in \{1, 2, \ldots, n_n\} \tag{8.1}$$

$$Q^{\text{net}}_{i,t,LL,s} = -Q^{L}_{i,t,LL,s} + Q^{\text{DDG/WDG}}_{i,t,LL,s} \quad \forall i \in \{1, 2, \ldots, n_n\} \tag{8.2}$$

$$P^{\text{net}}_{i,t,LL,s} = V_{i,t,LL,s} \sum_{j=1}^{n_n} Y_{ij,t} V_{j,t,LL,s} \cos(\delta_{i,t,LL,s} - \delta_{j,t,LL,s} - \theta_{ij,t}) \quad \forall i \in \{1, 2, \ldots, n_n\} \tag{8.3}$$

$$Q^{\text{net}}_{i,t,LL,s} = V_{i,t,LL,s} \sum_{j=1}^{n_n} Y_{ij,t} V_{j,t,LL,s} \sin(\delta_{i,t,LL,s} - \delta_{j,t,LL,s} - \theta_{ij,t}) \quad \forall i \in \{1, 2, \ldots, n_n\} \tag{8.4}$$

2.5.1.3. DG units' operating limit. The power generation of DG units must be lower than their maximum generation limit as (9).

$$S^{DG}_{i,t,LL,s} \le S^{DG}_{i,t,\max} \tag{9}$$

2.5.1.4. Penetration level of DG units. To prevent reverse power flow from the distribution network to the upward grid, a penetration level for the DG units is considered as (10) [22,32].

$$\sum_{i=1}^{n_l} P^{DG}_{i,t} \le 0.35 \times \sum_{i=1}^{n_l} P^{L}_{\text{peak},i,t} \tag{10}$$

2.5.2. Soft constraints

To calculate the satisfaction value of the technical constraints, including buses' voltages, feeders' currents and substations' capacities, the fuzzy modeling can be used as follows.

2.5.2.1. Voltage constraint. If the voltage magnitude of a bus is in the safe operating interval, then there is no voltage violation. However, the planner may tolerate the violation of these limits to some extent in order to improve other objectives. The voltage limitation is represented by a penalization function [40,50]. For this aim, the voltage constraint satisfaction can be mathematically represented as Fig. 2a. In this way, the safe operating interval is defined as $\left[V^{\min}_{\text{safe}} \quad V^{\max}_{\text{safe}}\right]$. In this interval, the satisfaction value is 1. As the voltage magnitude exceeds these limits, the satisfaction value decreases until it becomes zero beyond the critical voltage values $(V^{\min}_{\text{crit}}, V^{\max}_{\text{crit}})$. The value obtained from Fig. 2a, i.e. $\mu^{V}_{i,t,LL,s}$ shows the condition of voltage constraint satisfaction for bus *I*, in year t, load level *LL*, and the state *s*. To obtain an index representing the voltage condition of a given bus *i*, the weighted average of voltage satisfaction over all the states and load levels is obtained through (11).

$$\mu^{V}_{i,t} = \frac{1}{8760} \sum_{LL=1}^{nLL} \sum_{s=1}^{ns} Prob^{comb}_{s} T_{LL} \mu^{V}_{i,t,LL,s} \tag{11}$$

The average value of $\mu^{V}_{i,t}$ over all of the network buses and all years provides an information about the overall voltage condition of the network as (12):

$$\mu^{V} = \frac{\sum_{i=1}^{n_L} \sum_{t=1}^{T} \mu^{V}_{i,t}}{n_l} \tag{12}$$

2.5.2.2. Feeders and substations capacity limitation. In the similar way, the satisfaction values of feeders' currents (μ^{I}) and substations' capacities (μ^{S}) can be calculated. However, there is only the upper limit for the feeders' currents and substations' capacities as Fig. 2b.

2.6. Objective function

The following objective function is considered for the proposed DDNEP. The terms of objective function respectively express: expansion cost of existing substations, installation cost of candidate substations, feeders replacement cost, installation cost of main and reserve feeders, DGs installation cost, operating cost of DG units, expected cost of purchased energy from the transmission system, expected value of energy loss cost, cost of expected energy not supplied due to the failure on the feeders, cost of expected energy not supplied due to the failure on the DG units, cost of expected energy not supplied due to the failure on the HV/MV transformers, pollutants emission cost, and finally, dissatisfaction cost. All the parameters of objective function have been defined in the nomenclature. In (13), *PW* is the present worth factor represented as: $PW = (1 + Infr)/(1 + Intr)$.

$$\begin{aligned}
\mathrm{OF} = & \sum_{t=1}^{T} PW^t \sum_{i=1}^{n_{es}} \mathrm{sec}_i\left(S_i^{\exp}\right) + \sum_{t=1}^{T} PW^t \sum_{i=1}^{n_{cs}} IC_i\left(S_i^{\mathrm{inst}}\right) + \sum_{t=1}^{T} PW^t \sum_{i,j=1,i\neq j}^{n_{ef}} \left[FC_{ij}(k_1) - FC_{ij}(k_2)\right] \times L_{ij} + \\
& \sum_{t=1}^{T} PW^t \sum_{i,j=1,i\neq j}^{n_{cf}} \left[\mathrm{MFC}_{ij}(k) + \mathrm{RFC}_{ij}(k)\right] \times L_{ij} + \sum_{t=1}^{T} PW^t \sum_{i=1}^{n_l} \mathrm{DGIC}_i\left(S_i^{DG}\right) + \sum_{t=1}^{T} PW^t \sum_{i=1}^{n_l} \sum_{LL=1}^{n_{LL}} \sum_{s=1}^{ns} P_{i,t,LL,s}^{DG} \times T_{LL} \times oc_{js} \times \mathrm{Prob}_s^{comb} \\
& + \sum_{t=1}^{T} PW^t \sum_{i=1}^{n_s} \sum_{LL=1}^{n_{LL}} \sum_{s=1}^{ns} P_{i,t,LL,s}^{\mathrm{Trans}} \times T_{LL} \times EP_{i,LL} \times \mathrm{Prob}_s^{comb} + \sum_{t=1}^{T} PW^t \sum_{i=1}^{n_f} \sum_{LL=1}^{n_{LL}} \sum_{s=1}^{ns} \mathrm{Loss}_{i,t,LL,s} \times T_{LL} \times LC_{LL} \times \mathrm{Prob}_s^{comb} \\
& + \sum_{t=1}^{T} PW^t \sum_{f=1}^{n_f} \lambda_f \times r_f \sum_{LL=1}^{n_{LL}} RC_{LL} \times T_{LL} \sum_{s=1}^{ns} LNS_{f,t,LL,s} \times \mathrm{Prob}_s^{comb} + \sum_{t=1}^{T} PW^t \sum_{dg=1}^{n_{dg}} \lambda_{dg} \times r_{dg} \sum_{LL=1}^{n_{LL}} RC_{LL} \times T_{LL} \sum_{s=1}^{ns} LNS_{dg,t,LL,s} \times \mathrm{Prob}_s^{comb} \\
& + \sum_{t=1}^{T} PW^t \sum_{tr=1}^{n_{tr}} \lambda_{tr} \times r_{tr} \sum_{LL=1}^{n_{LL}} RC_{LL} \times T_{LL} \sum_{s=1}^{ns} LNS_{tr,t,LL,s} \times Prob_s^{comb} + \\
& \sum_{t=1}^{T} PW^t \times emc \times \sum_{LL=1}^{n_{LL}} \sum_{s=1}^{ns} \left[\left(P_{t,LL,s}^{Grid} \times T_{LL} \times GE_{t,LL,s}\right) + \left(P_{t,LL,s}^{DDG} \times T_{LL} \times DGE_{t,LL,s}\right)\right] \times Prob_s^{comb} + dc \times \max\{(1-\mu^V), \{(1-\mu^I), \{(1-\mu^S)\}
\end{aligned} \tag{13}$$

2.6.1. Calculation of energy not supplied (ENS)

There are several indices for measuring the reliability of distribution system, such as SAIFI, SAIDI, CAIDI, ASAI, ENS, etc. These indices are specifically studied in the problems of reliability evaluation [51–53]. However, the energy not supplied (ENS) is a common index for the network reliability in the expansion planning problems [9,11,37,54]. Since the ENS is dependent on both the failure rate of the equipment and their repair time, it provides a useful measure of network reliability for the planning problems.

The expected energy not supplied cost (*EENSC*) has been regarded in this paper as the representative of network reliability. In the following, the procedure for calculating the energy not supplied, and consequently the *EENSC*, is described in details.

2.6.1.1. ENS *due to failure on the feeders.* Improving the service reliability is an important issue for distribution companies. In this regard, the distribution systems are usually equipped with automation devices for the fault detection, isolation, and service restoration, in order to enhance the network reliability, and to reduce the customers outage cost [51,55]. When a fault occurs on a feeder, the faulted section is located and isolated from the rest of the network using the sectionalizing switches [35,37]. Then, the service is restored to as much as possible of the customers unaffected by the faulted section within a relatively short period of time. The restoration process can be fulfilled either through tie (reserve) feeders [51,55] or by operating some part of the network in the islanding mode if distributed generation exists in the islanded part [32].

As described in the introduction part, the reviewed researches:

- Have not considered the possibility of islanding after fault occurrence.
- Have not considered the load variation, and the uncertainty of load and wind in the calculation of reliability.
- Have not checked the power flow and other constraints in the island after the fault occurrence [32].

To clarify the matter, suppose that a fault occurs on feeder *k*. To reduce the outage cost, at first, the circuit breaker (CB), located at the 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 its ending switches and goes under repair. Afterwards, the circuit breaker is closed. Here, there will be some isolated parts with some loads. If there are DGs with enough generation in the isolated part, and the constraints are satisfied, this part can be operated successfully as an island, and the loads will be supplied until the faulted section is repaired. Otherwise, either all or part of the loads of the island must be shed [13,14]. In some cases, there may be reserve feeders, which can connect the isolated part to the neighboring energized feeders or substations to supply the island's loads without any voltage and current violations. A key question is arisen here:

When the fault occurs, and the faulted feeder goes out of service, what are the amount of load and wind turbines' output power?

Since the load and wind turbines' output power are variable and uncertain parameters, therefore, for the sake of precise calculation of the reliability, all the uncertainty states should be considered.

Regarding to the above explanation, after releasing of CB, three situations may be occurred:

- **Case 1**: there is no DG in the island, and there is no reserve feeder to connect the isolated part to the rest of the network. In this situation, all the loads of isolated part will remain unsupplied until the faulted section is repaired.
- **Case 2**: there are some reserve feeders between the isolated and the rest of the network.
- **Case 3**: there is no reserve feeder between the isolated part and rest of the network, but there are some DGs in this part.

In case 2, the reserve feeder connects the isolated part to the rest of the network. Then, the power flow is performed. In the event that none of the constraints, including the buses' voltages, feeders' currents, and substations' capacities are violated, the loads of islanded part will be supplied. If the thermal capacities of substations, or buses' voltages are violated, the loads of island are shed successively based on the Load Shedding Index (*LSI*), defined as (14), until the violation is resolved. In the load shedding process, at first the load having the largest value of *LSI* will be shed.

$$LSI_{i,t,LL} = \frac{SP_i}{V_{i,t,LL}} \tag{14}$$

In (14), SP_i is the supply priority of load point *i*. In this paper, from the viewpoint of supply priority, the loads have been classified into four types of 1–4. In this way, a load with the *SP* of 1 has the maximum supply priority. Also, a load having the *SP* of 4 has the minimum priority to be supplied. $V_{i,t,LL}$ is the voltage of bus *i*, in year *t*, and load level *LL*. In the case that the thermal capacity of feeders' currents is violated, the loads of buses influencing the current of this feeder are determined and shed step by step until there is no current violation. In case 3, the largest DDG is selected as the slack bus of the island. Then, the power flow in the island is

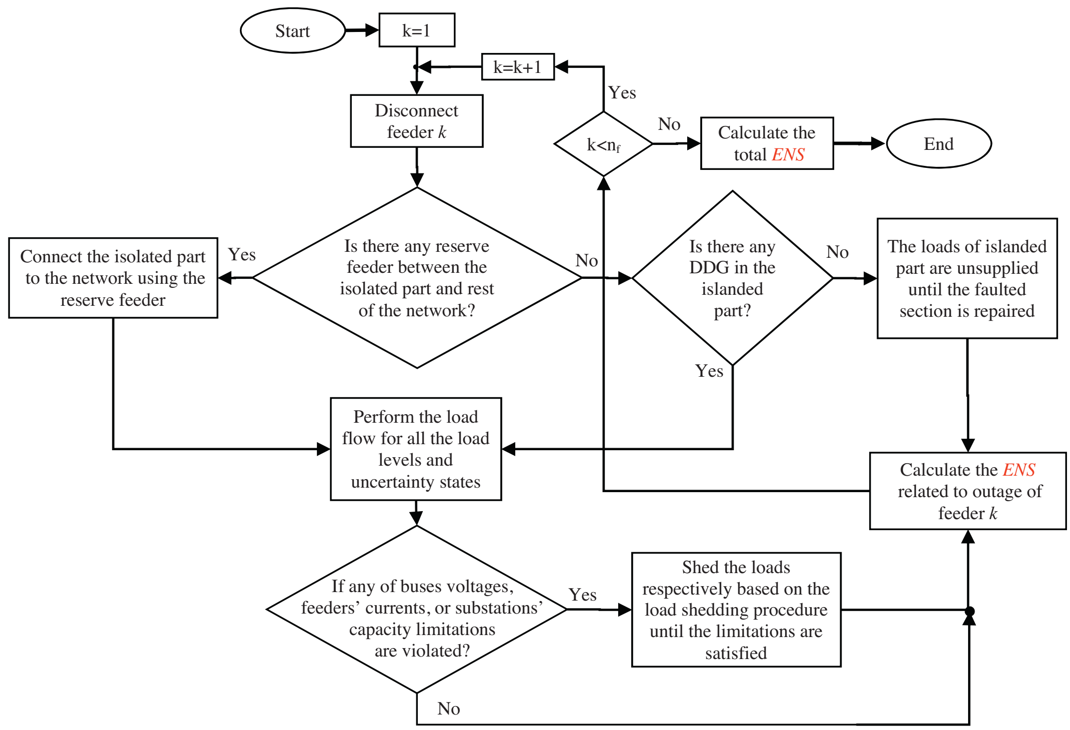

Fig. 3. Flowchart for calculation of the *ENS*.

performed. If the output power of slack bus is negative (which means that the generation on the island is more than the load plus losses), the DG on the bus having the highest voltage will be disconnected. Again, the power flow is performed. This process is continued until the output power of slack bus becomes positive. On the condition that the output power of slack bus is positive but exceeds the capacity of DG, the loads of the island will be successively shed until the output power of DG is below its capacity. The flowchart of Fig. 3 demonstrates the procedure of calculating the *ENS* in details.

2.6.1.2. *ENS due to failure on the HV/MV substations and DG units.* When a failure occurs on a transformer of the HV/MV substation or on a DG unit [33], a procedure similar to that of Section 2.6.1.1 is performed either to remove the overload of substations and feeders or to resolve the voltage drop problem of the load points. On this basis, the *ENS* is calculated.

3. Proposed solution method

For solving the proposed DDNEP problem, a genetic algorithm-based method has been applied as the following.

3.1. *Genetic algorithm (GA)*

The genetic algorithm is a meta-heuristic search method which mimics the process of natural selection. This algorithm is routinely performed to generate useful solutions in optimization and search problems. http://en.wikipedia.org/wiki/Genetic_algorithm-cite_note-FOOTNOTEMitchell19962-1. Genetic algorithm belongs to a larger class of evolutionary algorithms (EA) which generate solutions to non-linear and complex optimization problems using techniques inspired by natural evolution, such as selection, crossover and mutation [56]. As an efficient and reliable optimization algorithm, the GA has been used for solving different power system operation and planning problems [9,41,46].

3.2. *Chromosome structure of the proposed GA*

For optimizing the proposed DDNEP, the decision variables of the problem are encoded in the genes of chromosome. The structure of the proposed chromosome is illustrated in Fig. 4. As this figure shows, the chromosome is composed of eight parts. In the first part, the *i*th gene shows the replacement year of *i*th existing feeder, and gets an integer value between 1 and *T*. The conductor type of *i*th reinforced feeder is determined by the *i*th gene of part 2. The *i*th genes in parts 3 and 4 represent the installation year and conductor type of *i*th candidate feeder, respectively. Part 5 will show the status of candidate feeders. Each gene in this part takes three values, including 0, 1, or 2; where 0 means that the related candidate feeder is not installed; 1 means that the feeder is installed as a reserve feeder; and, 2 means that the feeder has been installed as a main feeder. The number of DDG and WDG units installed on the MV buses is indicated using the values of parts 6 and 7 of the chromosome, respectively. At last, the capacity of the existing and new substations in each year is indicated by the genes of 8th part of the chromosome.

3.3. *GA-OPF combination for the problem optimization*

With respect to the proposed chromosome structure, if the chromosome is decoded, the network configuration is determined for each year. However, the generated power of DDG units is still unknown. In this paper, for each configuration of the distribution network proposed by the GA, an optimal power flow is performed for each year, load level, and uncertainty state in order to determine the power generated by DG units for achieving the minimum energy cost (operation cost of DDGs plus the cost of

Reinforcement year of existing feeders	Conductor type of reinforced feeders	Installation year of new feeders	Conductor type of new feeders	Status of candidate feeders	Number of installed DDGs on buses			Number of installed WDGs on buses			Capacity of existing or new substations		
					Year 1	…	Year T	Year 1	…	Year T	Year 1	…	Year T

Fig. 4. Structure of the proposed chromosome.

energy purchased from the transmission network) subjected to the power flow, voltage, current, and substations' capacity limitations.

4. Numerical study

4.1. Test network and the IGA parameters

The test system, as shown in Fig. 5, is the modified 54-node, 33 kV system consisted of 50 load points (MV/LV buses) [35,43]. The power factor of loads is 0.85. The planning horizon is 5 years. The load data in each of the planning years is given in Table 4. There are two existing and two candidate HV/MV substations with the characteristics of Table 5. The number of existing feeders is 17. Moreover, there are 72 new feeders (as candidates for installation). There are ten types of conductors which can be used in feeders; their characteristics have been presented in Table 6. The capacity, installation cost, and operation cost of DDG units are considered as 1 MVA/unit, 400 \$/kVA and 46 \$/MWh; and those of WDG units are 0.3 MVA/unit, 800 \$/kVA and 10 \$/MWh, respectively. All the MV/LV buses are candidates for the DDG installation. Also, the potential nodes for WDG installation are the nodes 6, 13, 17, 19, 20, 28, 29, 30, 33, 41, 43, 47, 48, 49. The cut-in, rated, and cut-out speeds

Table 4
Specification of load points.

Load point no.	Geographical position		Supply priority	Value of load during the planning years (kW)				
	X (km)	*Y* (km)		Year#1	Year#2	Year#1	Year#4	Year#5
1	12.63	23.68	2	3200	3431	3673	3925	4200
2	14.47	21.32	2	1145	1225	1310	1400	1500
3	19.47	24.07	2	535	570	610	655	700
4	20.26	21.32	1	840	900	960	1030	1100
5	23.16	20	3	1985	2125	2270	2430	2600
6	24.47	17.5	4	535	570	610	655	700
7	17.37	21.05	2	765	816	874	937	1000
8	17.11	17.63	2	1450	1550	1660	1775	1900
9	9.21	22.63	2	915	978	1050	1120	1200
10	7.89	16.05	3	2215	2370	2535	2710	2900
11	8.68	3.42	2	230	245	260	280	300
12	5.79	4.87	2	1375	1470	1579	1683	1800
13	1.58	6.57	4	840	900	960	1030	1100
14	13.95	4.21	2	765	815	875	935	1000
15	13.42	7.89	1	1070	1147	1224	1311	1400
16	15.79	7.63	2	1450	1550	1660	1775	1900
17	5.26	24.87	3	0	210	420	651	700
18	3.16	21.84	3	0	0	360	840	1200
19	1.32	23.42	4	0	0	420	980	1400
20	1.05	26.58	4	0	0	240	560	800
21	1.84	18.95	4	0	0	540	1260	1800
22	6.05	19.47	3	0	330	660	1023	1100
23	9.74	19.08	3	0	300	600	930	1000
24	12.37	18.95	2	150	300	435	465	500
25	14.47	18.42	2	270	540	785	840	900
26	20.79	18.68	2	360	720	1044	1117	1200
27	20	15.79	3	0	450	900	1395	1500
28	23.42	13.42	3	0	0	210	490	700
29	0	12.36	4	0	0	420	980	1400
30	2.89	11.05	3	0	0	780	1820	2600
31	6.05	14.21	4	0	210	420	651	700
32	11.18	15.26	2	0	510	1020	1581	1700
33	13.68	13.68	3	2215	2370	2535	2710	2900
34	16.57	12.76	4	0	0	360	840	1200
35	16.68	12.11	3	0	0	270	630	900
36	21.05	11.97	3	0	0	90	210	300
37	6.05	11.71	4	0	630	1260	1953	2100
38	9.74	11.32	3	0	330	660	1023	1100
39	13.16	11.84	2	300	600	870	931	1000
40	17.63	9.34	2	420	840	1218	1303	1400
41	20.26	8.55	2	0	0	270	630	900
42	21.18	5.79	3	0	0	360	840	1200
43	4.74	8.95	3	0	390	780	1209	1300
44	9.21	7.89	2	420	840	1218	1303	1400
45	7.11	6.58	2	240	480	696	745	800
46	17.37	3.68	1	540	1080	1566	1676	1800
47	20.39	3.68	2	0	300	600	930	1000
48	22.63	2.76	4	0	0	240	560	800
49	20	0	3	0	150	300	465	500
50	18.42	1.32	2	0	240	480	744	800

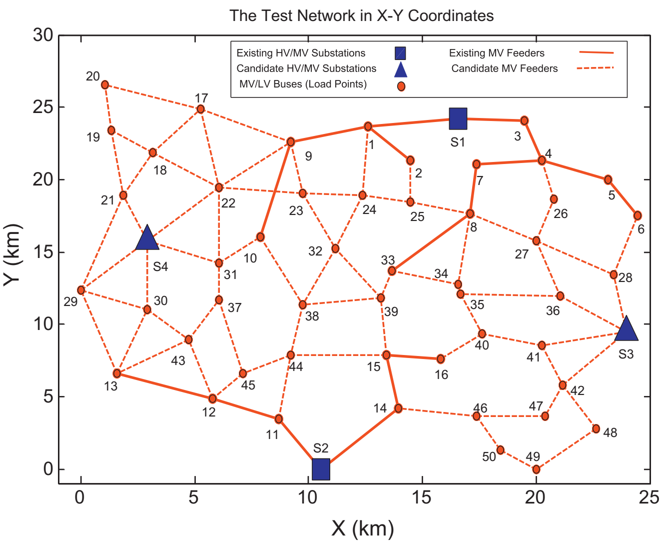

Fig. 5. The 54-node test system.

Table 7
Value of simulation parameters.

Parameter	Value
ρ($/MWh)	60
Infr(%)	10
Intr(%)	12
$V_{safe}^{min}(pu)$	0.95
$V_{safe}^{max}(pu)$	1.05
$V_{crit}^{min}(pu)$	$0.95 \times V_{safe}^{min}$
$V_{crit}^{max}(pu)$	$1.05 \times V_{safe}^{max}$
$I_{crit,i}^{max}(A)$	$1.1 \times$ current capacity of feeder i
Failure rate of feeders (f/km/year)	0.2
Repair time of feeders(h)	2
Failure rate of transformers (f/year)	0.3
Repair time of transformers (h)	72
Failure rate of DG units (f/year)	0.25
Repair time of DG units (h)	50
Emission of CO_2 corresponding to the received energy from the transmission grid (ton/MWh)	0.632
Emission of CO_2 corresponding to the energy generated by DDGs (ton/MWh)	0.365

of WDG are 4, 14, 25 m/s, respectively. The maximum number of installable DGs on each bus is 4 units. Other parameters used in the simulations are illustrated in Table 7. By several executions of the algorithm for different values of GA parameters, it was observed that by assigning the values 50, 0.75 and 0.02, respectively for the number of chromosomes, crossover rate, and mutation rate, the best result is yield. In addition, the tournament selection has been used for the reproduction process [57].

4.2. Improving the GA performance

4.2.1. Elitism strategy (ES)

To improve the performance of the genetic algorithm, the "Elitism Strategy" has been employed [58]. For this aim, the worst 20% of present generation (population) are replaced with the best 20% of previous generation if the mentioned 20% of previous generation is more qualified than that of the present one from the objective function viewpoint. This leads to preserve the fittest chromosomes in the progress of GA.

Table 5
Specification of HV/MV substations.

Substation	Graphical position		Existing capacity (MVA)	Expandable capacity (MVA)
	X (km)	Y (km)		
S_1	16.6	24.2	2 × 15	4 × 15
S_2	10.5	0	1 × 15	4 × 15
S_3	23.9	9.5	0	4 × 7.5
S_4	2.9	15.8	0	4 × 7.5

Table 6
Specification of candidate conductors.

Conductor type	Resistance (Ohms/km)	Reactance (Ohms/km)	Current capacity (A)	Cost (k$/km)
1	0.7500	0.1746	61	17
2	0.4794	0.1673	84	22
3	0.3080	0.1596	114	30
4	0.1972	0.1496	156	42
5	0.1208	0.1442	208	54
6	0.0723	0.1262	303	85
7	0.0487	0.1217	400	125
8	0.0405	0.1196	453	140
9	0.0350	0.1180	500	165
10	0.0247	0.1140	645	220

4.2.2. Archiving strategy (AS)

Since similar chromosomes are possible to be generated in the process of GA, the Archiving Strategy has been used in this paper. For this purpose, as soon as a feasible solution is found, its fitness function is calculated; then, the chromosome and its calculated fitness are stored in an archive of feasible solutions. This leads to avoid calculating of the fitness of the chromosome which has been evaluated previously. In this manner, the convergence trend and execution time of GA are improved significantly.

4.3. Simulation results

The proposed DDNEP is developed in the MATLAB programming environment as the following experiments.

4.3.1. Experiment 1

In this experiment, the distributed generation is not considered in the distribution network expansion planning. Therefore, the DDNEP is implemented either through the reinforcement of existing feeders and substations or by installation of new ones. Under this condition, the reliability of the network can be improved by the installation of the reserve feeders. In this case, when the fault occurs on the feeders, the load can be transferred between the substations/feeders to restore the loads of un-faulted sections. The results of this experiment are illustrated in Fig. 6 and Tables 8–10. Fig. 6 shows year-by-year configuration of the expanded network in which the thicker lines represent the conductors with the higher current capacity. Moreover, the installed reserve feeders have been indicated by the dashed lines. The service area of HV/MV substations in the normal condition is distinguished by different colors for the feeders. Tables 8 and 9 demonstrate the results of the expanded

Table 8
Results of substations expansion in experiment 1.

Substation no.	Expanded or installed capacity (MVA)				
	Year 1	Year 2	Year 3	Year 4	Year 5
S_1	3 × 15	4 × 15	4 × 15	4 × 15	4 × 15
S_2	2 × 15	3 × 15	3 × 15	3 × 15	3 × 15
S_3	0	0	2 × 7.5	2 × 7.5	2 × 7.5
S_4	0	0	2 × 7.5	3 × 7.5	3 × 7.5

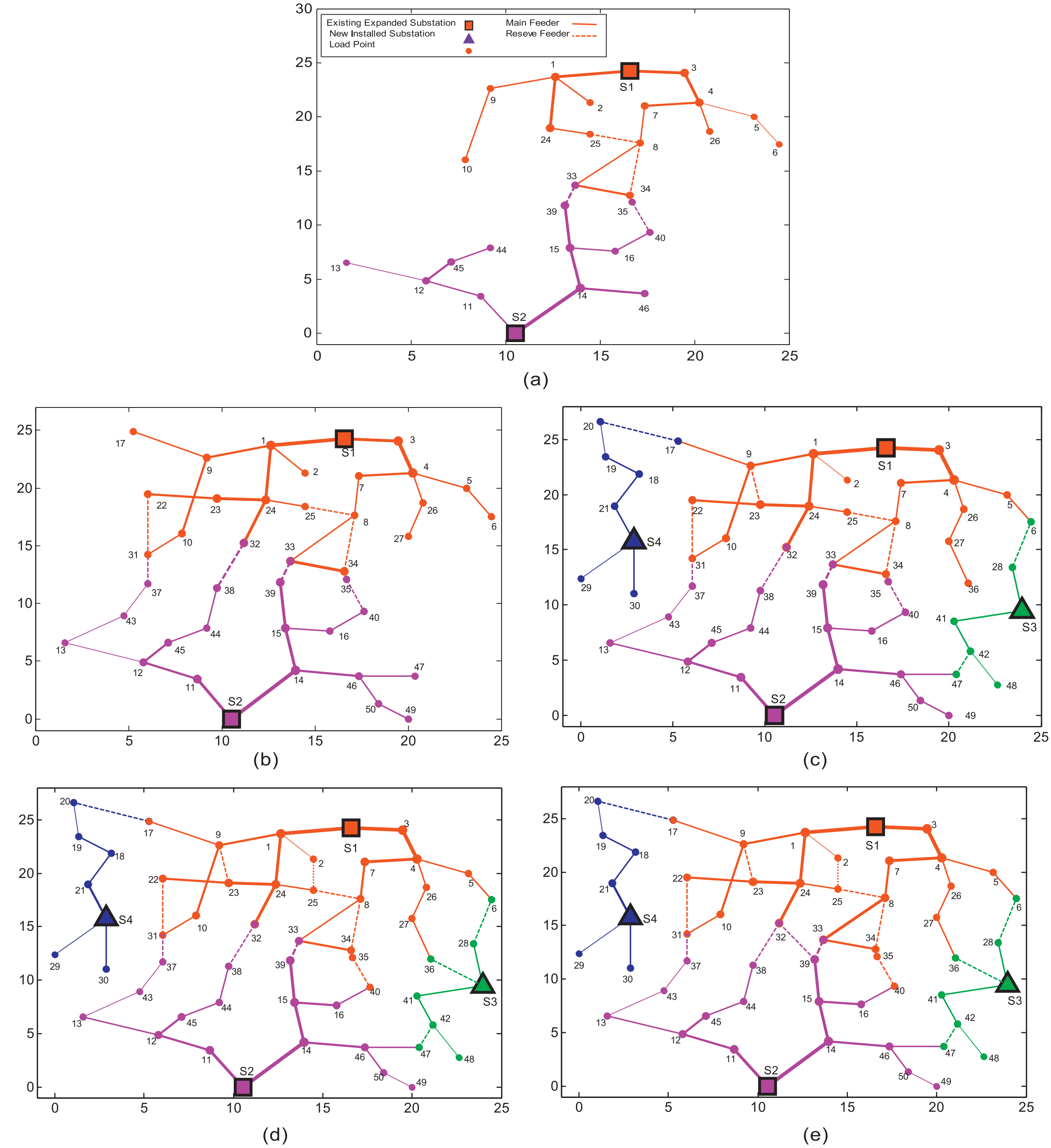

Fig. 6. (a) Network configuration after expansion in experiment 1, in year 1, (b) network configuration after expansion in experiment 1, in year 2, (c) network configuration after expansion in experiment 1, in year 3. (d) Network configuration after expansion in experiment 1, in year 4. (e) network configuration after expansion in experiment 1, in year 5.

substations and feeders, respectively. In addition, the cost components have been represented in Table 10.

4.3.2. Experiment 2

In this experiment, in addition to the feeders and substations, the DDG units are considered as another option in the dynamic distribution network expansion planning. The results of this experiment are shown in Fig. 7 and Tables 10–12. The installed DDGs on the buses are given in Table 12. The advantages of using DDG in DDNEP are illustrated by comparison of the results of experiments 1 and 2. According to the simulation results, when the DDG units are incorporated, the upgrading and installation costs of substations and feeders have been reduced. The cost of energy loss, and also the interruption cost have been considerably decreased. Likewise, the cost of energy purchased from the transmission network is lower when the DDG units are incorporated.

4.3.2.1. Evaluating the islanding operation. As stated previously, the islanding operation of DG units has been considered to improve the network reliability. In this section, an illustrative example is presented for evaluating the islanding mode of operation. Consider the expanded configuration of the network in Fig. 7. In the case of fault occurrence on the feeder between buses 14 and 46, this feeder goes out of service using its ending switches, and the load points 46, 47, 49, and 50 are isolated from their feeding HV/MV substation, that is S_2. This condition has been depicted in Fig. 8a. As shown, there

Table 9
Specifications of feeders in Experiment 1.

Feeder no.	Feeder route		Main or reserve (M/R)	Installation or replacement Year	Conductor type
	From bus	To bus			
1	S1	1	M	2	8
2	1	2	M	No change	–
3	1	9	M	2	5
4	9	10	M	2	4
5	S1	3	M	3	8
6	3	4	M	2	7
7	4	5	M	3	3
8	5	6	M	3	3
9	4	7	M	4	6
10	7	8	M	4	5
11	8	33	M	5	4
12	S2	11	M	2	6
13	11	12	M	2	6
14	12	13	M	2	4
15	S2	14	M	1	7
16	14	15	M	1	6
17	15	16	M	3	4
18	S4	21	M	3	4
19	21	18	M	3	4
20	18	19	M	3	4
21	19	20	M	3	4
22	17	9	M	2	4
23	22	23	M	2	5
24	23	24	M	2	5
25	24	25	M	1	4
26	27	26	M	2	3
27	S3	28	M	3	3
28	35	34	M	1	3
29	34	33	M	1	5
30	38	44	M	2	4
31	44	45	M	1	4
32	45	12	M	1	5
33	S3	41	M	3	3
34	40	16	M	1	3
35	41	42	M	3	3
36	47	46	M	2	3
37	46	14	M	2	5
38	42	48	M	3	1
39	49	50	M	2	1
40	S4	30	M	3	1
41	43	13	M	2	3
42	43	37	M	2	3
43	31	10	M	2	4
44	1	24	M	1	5
45	15	39	M	1	5
46	24	32	M	2	4
47	4	26	M	1	3
48	46	50	M	2	1
49	29	S4	M	3	1
50	27	36	M	3	2
51	2	25	R	4	1
52	8	25	R	1	4
53	8	34	R	3	2
54	35	40	R	1	3
55	42	47	R	3	3
56	32	39	R	5	5
57	32	38	R	2	4
58	9	23	R	3	3
59	22	31	R	2	3
60	17	20	R	3	4
61	33	39	R	1	4
62	S3	36	R	4	2
63	6	28	R	3	3

is no reserve feeder between this isolated part and rest of the network. However, according to Table 12, there are three DG units installed on bus 49. Therefore, the only way for restoring the isolated loads and reducing the interruption costs is to operate this part of the network in the islanding mode until the faulted feeder is repaired and brought back to service. For the first load level, the power flow calculation results have been depicted in Fig. 8b. As seen in this figure and in Table 13, the voltages of buses are within the safe operating interval. The conductor type of feeder between buses 46–47, 46–50, and 49–50 is 1, 2, and 2, respectively. Based on the results, the current flowing through the feeders is below their rated capacity. However, the output power from the DG of bus 49, as seen in Fig. 8b, is higher than its capacity. Therefore, some of load points must be shed. According to the load shedding process represented in Fig. 3, and based on the load shedding index given in (14), the load shedding procedure is implemented

Table 10
Cost components in the three experiments.

Cost component	Value (M$)		
	Experiment 1	Experiment 2	Experiment 3
Substation expansion cost	1.557	1.151	1.164
Substation installation cost	10.418	10.414	5.402
Feeders cost	9.321	7.156	6.233
DG installation cost	0	9.214	13.765
DG operation cost	0	7.137	5.011
Energy purchase cost	64.057	54.871	50.711
Energy not supplied cost	70.180	27.819	34.382
Energy loss cost	3.976	3.425	2.681
Emission cost	38.552	36.633	32.678
Dissatisfaction cost	2.783	2.436	2.548
Total cost	200.844	160.256	154.575

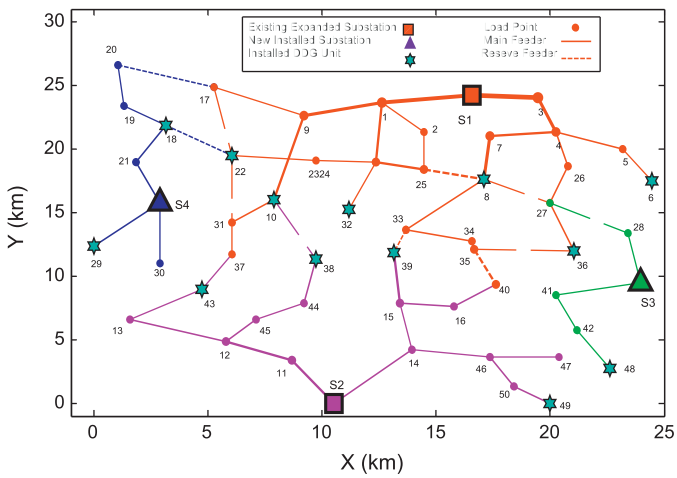

Fig. 7. Network configuration after expansion in experiment 2, in horizon year.

Table 11
Results of substations expansion in experiment 2.

Substation no.	Expanded or installed capacity (MVA)				
	Year 1	Year 2	Year 3	Year 4	Year 5
S_1	2 × 15	3 × 15	3 × 15	3 × 15	3 × 15
S_2	2 × 15	2 × 15	2 × 15	3 × 15	3 × 15
S_3	0	0	2 × 7.5	2 × 7.5	2 × 7.5
S_4	0	0	2 × 7.5	2 × 7.5	3 × 7.5

Table 12
Specifications of installed DDGs during the planning years in experiment 2.

Bus number	Number of DDG units installed on the buses				
	Year#1	Year#2	Year#3	Year#4	Year#5
6	3	3	3	3	3
8	0	1	1	2	2
10	3	3	3	3	3
18	0	0	0	1	1
22	0	0	0	1	1
29	1	1	1	1	1
32	0	1	3	3	3
36	0	0	0	0	1
38	1	1	1	1	1
39	2	3	3	3	3
43	0	0	0	0	1
48	0	0	1	1	1
49	0	1	3	3	3

until the output power of DG resides within its capacity. Table 13 summarizes this procedure. As shown, after the load shedding, the load point no. 46 which has the highest supply priority will be supplied.

4.3.3. Experiment 3

As a comprehensive case study, this experiment considers all of the planning alternatives, including the upgrade of existing feeders and substations, installation of both new feeders and substations, and installation of both types of DG, i.e. DDG and WDG units. Fig. 9 and Tables 10 and 14, and 15 represent the characteristics of the expanded network in this experiment. The results of this case verify that employing both DDG and WDG units in DDNEP results in more economical results. While the installation cost of WDG units is relatively high, their low operation cost and the key role of these units in reduction of the emission costs cause the DDNEP to be more economical when they are utilized in the planning. Likewise, from the environmental viewpoint, this experiment is the best case which achieves low emission of pollutants.

The convergence curve of GA in the third experiment has been depicted in Fig. 10 for three conditions: 1-GA, 2-GA equipped with Elitism Strategy (ES), and 3-GA equipped with Elitism Strategy and Archiving Strategy (AS). As seen, when the GA is equipped with Elitism and Archiving strategies, the convergence trend is fast, and also, the obtained result is more optimal.

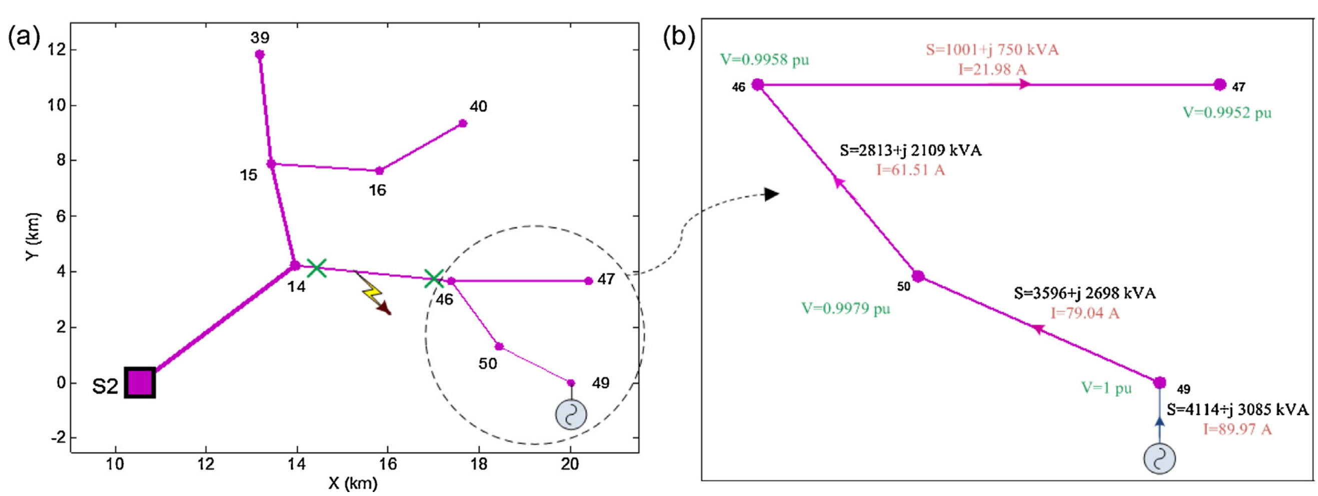

Fig. 8. (a) Fault on feeder 14–46 causing the isolation of load points 46, 47, 49, 50 (b). Islanding operation of the isolated part.

Table 13
Load shedding process for the successful operation of island.

	Shed loads	Voltage violation	Current violation	Substation capacity violation	Successful islanding
Stage 1	–	No	No	Yes	×
Stage 2	49	No	No	Yes	×
Stage 3	49, 47	No	No	Yes	×
Stage 4	49, 47, 50	No	No	No	√

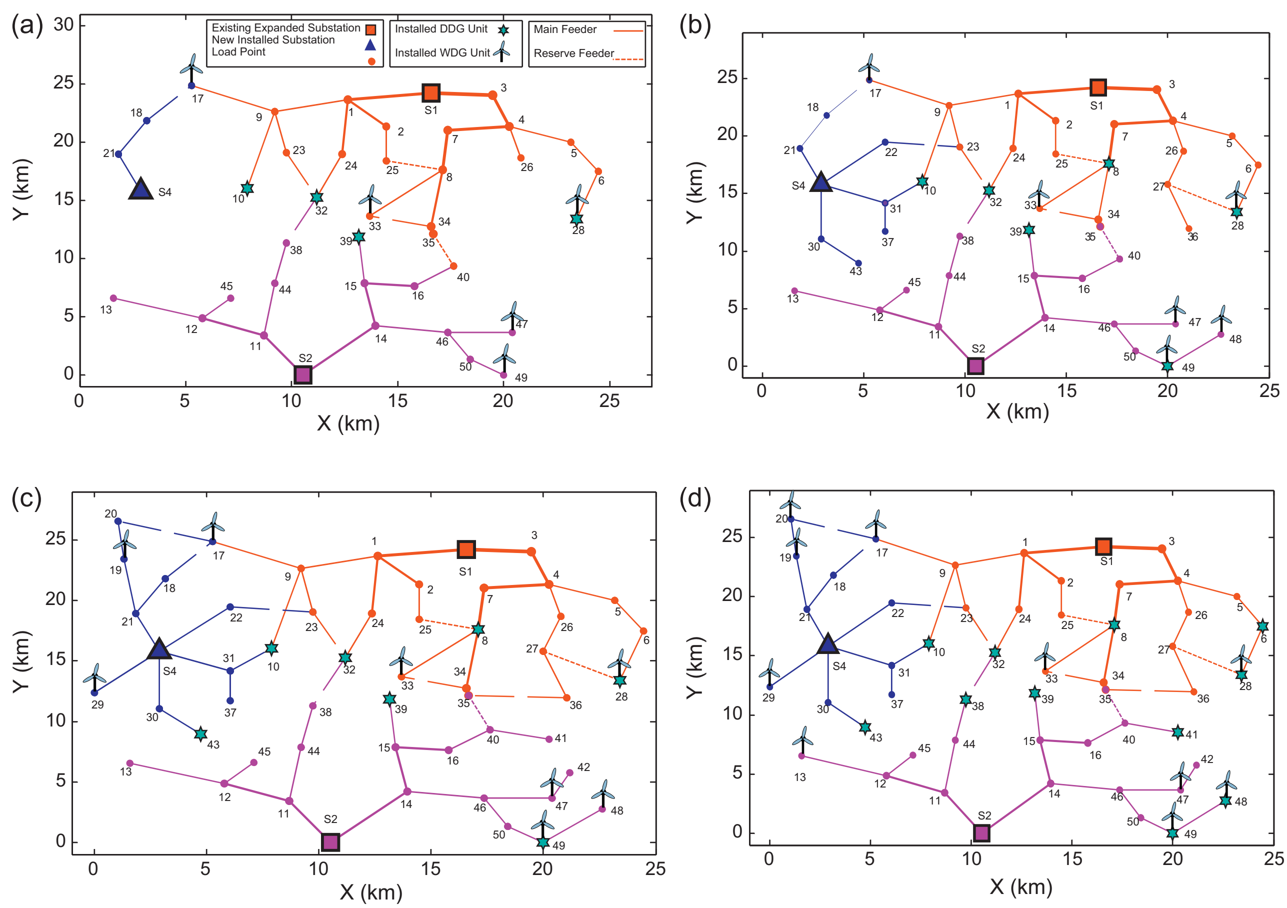

Fig. 9. (a) Network configuration after expansion in experiment 3, in year 1. (b) Network configuration after expansion in experiment 3, in year 2. (c) network configuration after expansion in experment 3, in year 3. (d) Network configuration after expansion in experiment 3, in years 4 and 5.

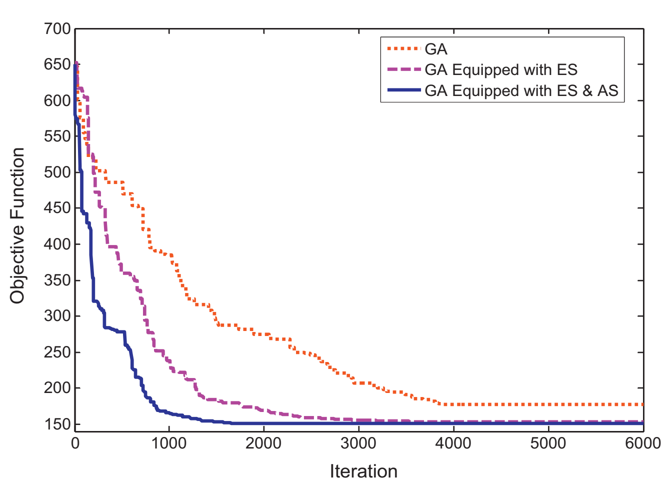

Fig. 10. Convergence trend of GA in the third experiment.

4.4. Computational aspects

In this section, the problem size, the properties of the computer used for simulations, and the solution time are described.

The arrangement of the proposed chromosome was introduced in Fig. 4. According to this figure and the test network, the number of existing feeders is 17; so, the number of genes in the first and second parts of the chromosome is $2 \times 17 = 34$. Also, the number of candidate feeders is 72; thus, the number of genes in third, fourth and fifth parts will be $3 \times 72 = 216$. The number of candidate buses

Table 14
Results of substations expansion in experiment 3.

Substation no.	Expanded or installed capacity (MVA)				
	Year 1	Year 2	Year 3	Year 4	Year 5
S_1	3×15	3×15	3×15	3×15	3×15
S_2	2×15	2×15	2×15	3×15	3×15
S_3	0	0	0	0	0
S_4	2×75	2×75	3×75	3×75	3×75

Table 15
Specifications of installed DGs during the planning years in experiment 3.

Bus number	Number of DG units installed on the buses									
	Year#1		Year#2		Year#3		Year#4		Year#5	
	DDG	WDG	DDG	WDG	DDG	WDG	DDG	WDG	DDG	WDG
6	0	0	0	0	0	0	2	0	2	0
8	0	0	2	0	2	0	2	0	3	0
10	1	0	1	0	2	0	2	0	2	0
13	0	0	0	0	0	0	0	1	0	1
17	0	3	0	3	0	4	0	4	0	4
18	0	0	0	0	0	0	0	0	1	0
19	0	0	0	0	0	2	0	3	0	3
20	0	0	0	0	0	0	0	3	0	3
28	1	2	1	2	1	2	1	2	1	2
29	0	2	0	2	0	2	0	2	0	2
32	2	0	2	0	2	0	2	0	2	0
33	0	2	0	2	0	2	0	2	0	2
38	0	0	0	0	0	0	1	0	1	0
39	1	0	1	0	3	0	3	0	3	0
41	0	0	0	0	0	0	1	0	1	0
43	0	0	0	0	1	0	2	0	2	0
47	0	3	0	3	0	3	1	3	2	3
48	0	0	0	2	0	2	0	2	0	2
49	0	3	1	3	1	3	1	3	1	3

Table 16
The solution time of problem in different experiments.

	Number of integer variables (optimized by GA)	Number of continuous variables (optimized by OPF)	Solution time (min)	
			GA	IGA
Experiment 1	270	–	67	35
Experiment 2	520	500	190	118
Experiment 3	590	6000	510	320

for DDG installation is 50, and the planning years are 5; therefore the number of genes of the sixth part is $5 \times 50 = 250$. The number of candidate buses for WDG installation is 14, and the planning years are 5; therefore, the number of genes of the seventh part of the chromosome is $5 \times 14 = 70$. The number of HV/MV buses is 4, and the planning years are 5; therefore, the number of genes of eighth part is $5 \times 4 = 20$.

In total, the number of integer variables (genes of chromosome) is $34 + 216 + 250 + 70 + 20 = 590$.

Furthermore, the power generation of dispatchable DG units in each year, load level, and uncertainty state are the other unknown variables which will be determined by the optimal power flow within GA. These are continuous variables. The planning years are 5, and the number of considered load levels is 10. Also, in each load level, seven states have been considered for the uncertainty of load and energy price according to Fig. 1. Furthermore, the number of wind speed states is 12 as shown in Table 3. With respect to the these information, the number of continuous variables equals to $5 \times 10 \times 10 \times 12 = 6000$.

As seen, the number of problem variables is high. The experiments have been performed in MATLAB software on a laptop with Core i7, 2.0 GHz processor, and 4 GB RAM. To speed up the running time of the algorithm, the parallel computing capability of MATLAB has been employed. For this aim, the cores of computer have been paralleled, and it has been used of "*parfor*" loops to do the calculations in parallel, in order to accelerate the execution time. The solution time of the algorithm in different cases have been summarized in Table 16. It should be noted that in the long-term planning problems, like dynamic DNEP, the most optimal solution is an important issue which the planners would like to tolerate the execution time to reach the best solution.

5. Conclusion

In this paper, the renewable power generation has been employed as an alternative in an integrated dynamic distribution network expansion planning (DDNEP). The proposed integrated planning problem determines the characteristics of distribution network equipment, including both the capacity reinforcement and new installations of the existing/candidate MV feeders and HV/MV substations in a dynamic manner. The renewable DGs along with the non-renewable ones are considered as another option for the DDNEP. The comprehensive objective function of the problem is composed of all the investment and operational costs as well as the interruption, losses, and emission costs. The load variation has been regarded using the LDC. Furthermore, the uncertainties related to the load demand, energy price, and wind power generation are considered in the problem. The reserve feeders and also the possibility of operating DGs in islanding mode are both considered in order to augment the network reliability and reduce the interruption costs. An optimization problem is developed based on the proposed objective function and its constraints, where, a hybrid IGA-OPF method is applied to solve this integrated problem. The 54-bus test network is used to evaluate the effectiveness of the proposed approach in several experiments. By comparing the results of the experiments, it was observed that in the presence of DG units, the technical characteristics of the network are improved. Likewise, not only the equipment cost, but also the interruption costs are reduced while utilizing DG. Moreover, the emission of environmental pollutants is decreased in the case that DGs, specially WDGs are utilized in DDNEP. In total, it is concluded that appropriate incorporation of both the DDG and WDG units in DDNEP leads to a more optimal solution from the economical and environmental points of view.

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