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Distributed generation planning based on the distribution company's and the DG owner's profit maximization

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SUMMARY

In recent years, Distributed Generation (DG) has been utilized in electric power networks increasingly. DG units can affect the system operational conditions in different ways such as voltage profile improvement, amending voltage stability, reliability enhancement, securing power market, etc. if they are managed properly. Otherwise, they may have undesirable impacts on technical issues of power grids. A lot of studies have been done on various aspects of control and operation of DG units to find the optimal placement, sizing and also the proper technology of them. This paper proposes a novel comprehensive economic method for planning DG units which considers both the Distribution Company's (DisCo) and the DG Owner's (DGO) profits simultaneously. Multi-objective particle swarm optimization technique is used to simulate many case studies on the IEEE 33-bus distribution test system and finally find the best solution for the placement, size and contract price of the generated power of DGs. The proposed methodology not only considers operational aspects such as power loss reduction, voltage profile and stability improvement and reliability enhancement, but also leads to an accurate analysis which satisfies both the DisCo's and the DGO's economic viewpoints. Finally, an encouragement to invest more on DG technologies is proposed based on the gained results. Copyright © 2013 John Wiley & Sons, Ltd.

KEY WORDS: DG placement and sizing; distributed generation; electric distribution system; MOPSO; multi-objective optimization method

1. INTRODUCTION

The traditional ways of producing electricity were mainly focused on large-scale and centralized generations. According to recent studies, scientific interests and researches have been directed to the concept of distributed generation (DG) [1]. Large-scale generation needs huge amounts of investment for both power plants and power stations. Clearly, the large facilities of conventional technologies can't be near load centers. These problems and others in the design, construction and maintenance of large power plants and transmission lines besides the global environmental concerns have accelerated the application of DG units [2]. With the aid of renewable sources such as wind and solar energy and advances in photovoltaic cells and micro turbines, DG units can now generate power that is more reliable and cleaner [3]. Voltage profile improvement, reducing system losses and better power quality are also the advantages that can't be neglected [4]. On the other hand, traditional grids are only able to take small amounts of the power generated by DG units. Selecting the best place for DG units and their preferable sizes are two important factors that researchers are working on and should be taken seriously. If not, adverse impacts on power quality, reduced efficiency, over-voltages, unwanted harmonics, etc. are some of the negative consequences that affect the power flow, transmission lines and distribution grids. Consequently, there should be detailed analyses about the connection of DG units to power grids and its consequent influences on power stability [5]. Main concentration is on the aspects such as optimal DG placement, sizing and penetration level of DGs in order to minimize costs and losses.

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In previous studies, different objectives have been defined and considered in DG planning problems. In [6], a specialized Genetic Algorithm (GA) is proposed to determine the location and contract pricing of DG units in distribution systems that would render maximum profits to the DG Owner (DGO) subjected to the minimization of payments produced by the Distribution Company (DisCo). A population-based artificial bee colony algorithm has been offered in [7] with the objective function of minimizing the total real power losses of the system. A Particle Swarm Optimization (PSO)-based algorithm has been presented in [8] for the purpose of the optimal allocation of multiple DGs in the distribution networks. The system loss is minimized using PSO considering constant power as well as voltage-dependent load models. Unlike GA and other heuristic techniques, PSO has a flexible and well-balanced mechanism to enhance and adapt the global and local exploration abilities. It usually results in faster convergence rates than the GA [9,10]. In [9], a multi-objective version of the conventional PSO technique has been proposed to solve the environmental/economic dispatch problem which has been formulated with competing fuel cost and environmental impact objectives. The diversity and well-distribution characteristics of the non-dominated solutions by the proposed Multi-Objective PSO (MOPSO) technique have been demonstrated. Carman *et al.* [11] have evaluated DG impacts on the system reliability, losses and voltage profile. GA is combined with other methods to optimally find the DG allocation and sizing while minimizing the electrical losses and remaining at the acceptable operational level. In [12], a bilevel programming framework has been proposed to solve the optimal contract pricing of DGs. Sudipta *et al.* [13] used a simple conventional iterative search technique along with the load flow study method known as Newton–Raphson for optimal sizing and placement of generators. In [14], Tabu search method is used to find the optimum DG size as well as the reactive sources within the distribution system. An objective function that sums the total cost of active power losses, line loading and the cost of adding reactive sources was defined and then minimized to solve the constrained nonlinear optimization problem. In [15], a combined methodology is proposed. Site of DG is searched by GA and its size is optimized by PSO. The authors of [16] have used a voltage sensitivity index to determine the optimal location of DG units. Then, in order to gain maximum voltage support, active and reactive powers of DG units have been adjusted. Ref. [17] presents a dynamic multi-objective formulation of a DG planning problem and an immune-GA-based method to solve the formulated problem. The proposed two-step algorithm finds the non-dominated solutions by simultaneous profit maximization of both distribution network operators and DGO in the first stage and uses a fuzzy satisfying method to select the best solution from the candidate set in the second stage. N. Khalesi *et al.* [18] have endeavored to determine the optimal location of DGs in distribution system by defining a weighted coefficient multi-objective function to minimize power losses of the system and enhance the reliability and improve voltage profile. An approach based on dynamic programming was applied to solve the mentioned multi-objective optimization problem. Furthermore, some researchers have studied the DG planning under uncertainties. F.J. Ruiz-Rodriguez *et al.* in [19] propose a method for keeping the voltages within the desired limits at all load buses in a distribution system with biomass fueled gas engines while considering load uncertainties and random nature of lower heat value of biomass. In [20], in order to minimize power losses, the optimal placement of multiple-DG units is studied. Moreover, including load uncertainty, different DG penetration levels and reactive power of multiple-DG concept, an optimality criterion is investigated to minimize losses. The authors of [21] consider photovoltaic generators as implemented DGs in redial distribution system. Furthermore, loads and DG productions are modeled as random variables and a new method utilizing discrete PSO and probabilistic load flow are introduced. Reference [22] proposes a multi-objective optimization approach with technical and economic cost functions in order to site DG units optimally in the IEEE 37-bus test system. In this paper, Non-dominated Sorting Genetic Algorithms II (NSGA-II) is employed as widely used multi-objective dilemmas, to cope with the optimization problem. Moreover, a robust probabilistic approach, i.e. Point Estimation Method, is employed to model the unavoidable uncertainties in power systems.

Although all DG placement problems may seem different from each other, but according to their objectives, they can be categorized into two main groups: problems with operational or economic objectives. While the operational constraints include the ones related to the grid such as voltage profile and load margin improvement, active and reactive power losses reduction, etc., the economic objectives focus on the costs and profits of the DGO(s) and (or) the DisCo. It seems that a comprehensive

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work should be done that covers both the DGO's and the DisCo's viewpoints and takes into account the operational aspects of the power system, too. Considering the mentioned issues, this paper simultaneously calculates the optimum size, location and contract price of all DG units using a novel comprehensive economic approach. This multi-objective problem is formulated considering the DisCo's and the DGO's viewpoints simultaneously, unlike most of the previous studies which have solved this problem considering only one of the DGO's or DisCo's viewpoints. MOPSO technique has been used to solve this problem subjected to appropriate operational constraints. The maintenance, operation and investment costs are formulated to form the total costs of DGs. Then, the limitations of the grid and also all the profits that DGOs and DisCos seek are considered at the same time. Afterward, by proposing a novel approach for choosing the best compromised answer among the Pareto set obtained from MOPSO technique, it is endeavored to take operational issues into account. This study also tries to have a short look at encouragement strategies with the aim of developing distribution generation in power grids. As a result, the proposed method shows its superiority to the other similar works done before.

The rest of this paper is divided into four sections. In section 2, the main objective functions, their constraints and some operational indices are introduced; MOPSO technique is explained in section 3; simulation is reported in section 4 on a specific test system, and the results clarification follows; at last, a conclusion is given in section 5.

2. PROBLEM STATEMENT

The optimization problem, based on maximizing the DGO's and DisCo's profits is introduced in this section. A multi-objective optimization method must be applied to achieve the main goal which is finding the optimum parameters related to the DG's size, placement and the contract price between the DGO and the DisCo.

Some presumptions should be taken into consideration before any further action: first, there is only one DGO and DG placement model is proposed according to both the DGO's and the DisCo's points of view simultaneously in an energy market; No limitations exist about the installation of different DG technologies within the distribution system; In load flow analysis, the connection of a DG unit to a bus is modeled as a negative PQ load and the corresponding bus is considered as a PQ bus; finally, the islanding operation of DG technologies can be used to reduce the energy not served index.

This section is divided into four parts. First, the load model used in this study is introduced. Second, the operational and economic limits will be expressed. Then, the objective functions are stated and explained thoroughly. Finally, some operational indices are introduced to evaluate the efficiency of the proposed model.

2.1. Load model

Since accurate optimization is achieved when input data is correctly modeled, load pattern should be defined properly according to daily variations. Hence, considering the demand factor, β_h, and the demand growth rate, α, active and reactive powers of the load connected to the i^{th} bus in the h^{th} hour of the day in the y^{th} year are:

$$P_{Load,i,y,h} = P_{i,base} \times \beta_h \times (1+\alpha)^y \tag{1}$$

$$Q_{Load,i,y,h} = Q_{i,base} \times \beta_h \times (1+\alpha)^y \tag{2}$$

in which $S_{i,base} = P_{i,base} + jQ_{i,base}$ is the base load defined in node i.

2.2. Operational and economic limits

Some operational restrictions exist in this study that should be considered while solving the mentioned problem: Injected active and reactive powers to each node, (P_j,Q_j), should observe power flow constraints stated in Equations (3) and (4); The voltage magnitude of each bus and the branch current value are going to be kept in the safe operating limits during the planning horizon. The statements 5 and 6 are expressed to

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formulate the discussed limitations; it is also clear that DG units should be operated considering the limits of their primary resources. The minimum and maximum (*Min* and *Max*) amounts of the power that each unit is capable of generating determine the limitations shown in the inequalities 7 and 8.

Besides the operational limits mentioned, some economic limitations should be taken seriously: Electricity market conditions determine the logical range for the contract price between the DGO and DisCo. This constraint is formulated in inequality 9; DGO can afford a limited amount of capitalization (C_c) mentioned in the inequality 10; Finally, DisCo's costs in case of using DG units ($C_{DisCo,DG}$) should not exceed the case without using any DG unit (inequality 11).

$$P_j = U_j \sum_{i \epsilon N} U_i \left(G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij} \right) \tag{3}$$

$$Q_j = U_j \sum_{i \epsilon N} U_i \left(G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij} \right) \tag{4}$$

$$Min(U_i) \leq U_{i,h,y} \leq Max(U_i),\, i = 1 : N \tag{5}$$

$$I_{b,h,y} \leq Max(I_b),\, b = 1 : B \tag{6}$$

$$Min\left(P_{u,m}\right) \leq P_{u,m} \leq Max\left(P_{u,m}\right) m = 1 : M \tag{7}$$

$$Min\left(Q_{u,m}\right) \leq Q_{u,m} \leq Max\left(Q_{u,m}\right)\ m = 1 : M \tag{8}$$

$$Min(CP) \leq CP \leq Max(CP) \tag{9}$$

$$C_c \leq Max(C_c) \tag{10}$$

$$C_{DisCo,DG} \leq C_{DisCo,without\ DG} \tag{11}$$

In Equations (3) and (4), G_{ij}, B_{ij} and θ_{ij} are, respectively, the conductance (Ω^{-1}), susceptance (Ω^{-1}) and impedance angle (*rad*) of the branch that connects the i^{th} and the j^{th} nodes. *N* and *B* also denote total number of the nodes and branches, respectively. In inequalities 5 and 6, $Max(I_b)$, $Min(U_i)$ and $Max(U_i)$ are, respectively, the maximum amount of current allowed in branch *b*, minimum and maximum magnitudes of voltage allowed in node *i*. The amount of current that flows in branch *b* in the h^{th} hour of the day in year *y* is shown by $I_{b,h,y}$. $U_{i,h,y}$ is the voltage magnitude of the i^{th} node, h^{th} hour of the day and y^{th} year. In inequalities 7 and 8, $P_{u,m}$ and $Q_{u,m}$ are the active and reactive powers generated by the DG unit *m*, respectively. M also denotes total number of DG units; *CP* is the contract price between the DGO and the DisCo in inequality 9; in inequality 10, $Max(C_c)$ is the maximum amount of money that the DGO can capitalize in order to gain profit; finally, in inequality 11, $C_{DisCo,without\ DG}$refers to the total DisCo's costs in case of no DG units in the grid.

2.3. *Objective functions*

The main objective in this article is to simultaneously maximize both the DisCo's and the DGO's profits. Hence, two objective functions, one for maximizing the DisCo's profit and the other for maximizing the DGO's, are proposed. The problem should be optimized in a way that both objective functions can be achieved simultaneously. So, a multi-objective optimization technique which considers these two objectives at the same time should be applied. Two objective functions in order to find the proper placements, sizes and contract price are as follows:

$$\begin{aligned} OF_1 &= \max(R_{DGO} - C_c - C_o - C_m) \\ OF_2 &= \max\left(C_{DisCo,without\ DG} - C_{DisCo,DG}\right) \end{aligned} \tag{12}$$

Subjected to: (3)→ (11)

Components of these two functions will be explained thoroughly:

$\boldsymbol{R_{DGO}}$:Selling the generated power to the DisCo profits the DGO based on the contract price. This profit is formulated as:

$$R_{DGO} = \sum_{y=1}^{Y} \sum_{m=1}^{M} P_{u,m} \times \varphi_{u,m} \times CP \times 8760 \times \left(\frac{1}{1+RIR} \right)^y \tag{13}$$

DGO's revenue is formulated by the above equation where *Y* denotes total number of the years in the planning horizon. The number (8760) refers to the total number of the hours in a year. $\varphi_{u,m}$ is

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the capacity factor related to the DG unit m. RIR refers to the term, "real interest rate", which can be calculated by the Equation (14).

$$1 + RIR = \frac{1 + intrest\ rate}{1 + inflation\ rate} \tag{14}$$

$\boldsymbol{C_c}$: Just like every other business, a proper amount of capitalization is needed for each generation unit which covers the procurement and installation costs. These costs can be formulated as below:

$$C_c = \sum_{m=1}^{M} P_{u,m} \times \varphi_{u,m} \times C_{\frac{cap}{MW}} \tag{15}$$

where $C_{\frac{cap}{MW}}$ is the capitalization cost of DGs based on their MW ($/MW).

$\boldsymbol{C_o}$: Running a business is usually costly. In this study, operating expenses consist of fuel and generation costs. The equation for modeling these expenses is:

$$C_o = \sum_{y=1}^{Y} \sum_{m=1}^{M} P_{u.m} \times \varphi_{u,m} \times 8760 \times C_{\frac{o}{MWh}} \times \left(\frac{1}{1 + RIR}\right)^y \tag{16}$$

in which $C_{\frac{o}{MWh}}$ is the operation cost of DGs based on their generated power ($/MWh).

$\boldsymbol{C_m}$: Maintenance cost including mechanical and electrical inquiry and renovation costs is also crucial while making economic decisions. Its present worth can be formulated as follows:

$$C_m = \sum_{y=1}^{Y} \sum_{m=1}^{M} P_{u,m} \times \varphi_{u,m} \times 8760 \times C_{\frac{m}{MWh}} \times \left(\frac{1}{1 + RIR}\right)^y \tag{17}$$

in which $C_{\frac{m}{MWh}}$ is the maintenance cost of DGs based on their generated power ($/MWh).

Till now, DGO's economic viewpoints have been formulated by the calculating equations given. The DisCo is required to meet its customers demand growth. As shown in OF_2, DisCo's profit consists of two components. The first one, which is the DisCo's cost without any DG unit in the grid, is a constant value. On the other hand, the other one is the same cost after inclusion of DG units which is variable. Hence, the actual profit of the DisCo is the difference between these two costs. In the following equations, these two components are clarified:

$$C_{DisCo,without\ DG} = C_{ENS}^{without\ DG} + C_{pbs}^{without\ DG} \tag{18}$$

$$C_{DisCo,DG} = C_{pp} + C_{ENS}^{DG} + C_{pbs}^{DG} \tag{19}$$

$\boldsymbol{C_{pp}}$: In accordance with the bilateral contract between the DisCo and the DGO, all the power that DG units generate is purchased by the DisCo. The related DisCo's cost calculation can be formulated as the equation below:

$$C_{pp} = \sum_{y=1}^{Y} \sum_{m=1}^{M} P_{u,m} \times \varphi_{u,m} \times 8760 \times CP \times \left(\frac{1}{1 + RIR}\right)^y \tag{20}$$

$\boldsymbol{C_{ENS}}$: Failure and interruption occurrences are inevitable in power grids. It's an obligation for distribution companies to satisfy their customers even in such cases. In order to submit the importance of a system outage, energy not supplied (ENS) is evaluated for all customers. Consequently, customer ENS cost (in form of $C_{ENS}^{DG}\ or\ C_{ENS}^{without\ DG}$) is used to calculate the present worth of this DisCo's cost with and without using DG units which is formulated by the following equations:

$$C_{ENS}^{DG} = \sum_{y=1}^{Y} \sum_{b=1}^{B} C_F \times \xi_b \times L_b \times P_{NSL,y}^{DG} \times \left(\frac{1}{1 + RIR}\right)^y \tag{21}$$

$$P_{NSL,y}^{DG} = \sum_{nsl=1}^{NSL} P_{Load,nsl,y}^{DG} \tag{22}$$

$$C_{ENS}^{without\ DG} = \sum_{y=1}^{Y} \sum_{b=1}^{B} C_F \times \xi_b \times L_b \times P_{NSL,y}^{without\ DG} \times \left(\frac{1}{1 + RIR}\right)^y \tag{23}$$

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$$P_{NSL,y}^{without\ DG} = \sum_{nsl=1}^{NSL} P_{Load,nsl,y}^{without\ DG} \tag{24}$$

in which NSL refers to the total number of not supplied loads for each fault. ξ_b and L_b are respectively the fault rate (f/km.year) and length (km) of the b^{th} branch. $P_{Load,nsl,y}^{DG}$ and $P_{Load,nsl,y}^{without\ DG}$ are the active powers of not supplied loads connected to the nsl^{th} bus, in the y^{th} year, with and without DGs, respectively. C_F is the the fault (interruption) price which is determined according to the repairing time which is needed during failure outages. This term needs detailed information about the entire network such as network topology, used components, environmental condition, as well as different types of customers (residential, commercial or industrial).

C_{pbs}: Cost of power bought from the substation should also be considered when assessing the DisCo's costs. This cost (in form of C_{pbs}^{DG} *or* $C_{pbs}^{without\ DG}$) is used to calculate the present worth of this DisCo's cost with and without using DG units and it is formulated by the following equations:

$$C_{pbs}^{DG} = \sum_{y=1}^{Y} \sum_{h=1}^{24} P_{s,h,y}^{DG} \times 365 \times CF(P_{bs}) \times \left(\frac{1}{1+RIR}\right)^{y} \tag{25}$$

$$P_{s,h,y}^{DG} = \sum_{i=1}^{N} P_{Load,i,h,y} + \sum_{b=1}^{B} R_b \times \left(I_b^{DG}\right)^2 - \sum_{m=1}^{M} P_{u,m} \tag{26}$$

$$C_{pbs}^{without\ DG} = \sum_{y=1}^{Y} \sum_{h=1}^{24} P_{s,h,y}^{without\ DG} \times 365 \times CF(P_{bs}) \times \left(\frac{1}{1+RIR}\right)^{y} \tag{27}$$

$$P_{s,h,y}^{without\ DG} = \sum_{i=1}^{N} P_{Load,i,h,y} + \sum_{b=1}^{B} R_b \times \left(I_b^{without\ DG}\right)^2 \tag{28}$$

where $P_{s,h,y}^{DG}$ and $P_{s,h,y}^{without\ DG}$ are the active powers supplied by the substation in the h^{th} hour of the day in the y^{th} year with and without DGs (MW), respectively, (365) refers to the total number of the days in a year and CF (P_{bs}) is the cost function ($/MWh) of purchased power with the amount of power bought from substation (pbs with bs as subscript) as its variable. In Equations (26) and (28), R_b, I_b^{DG} and $I_b^{without\ DG}$ are the resistance (Ω) and current (A) of the b^{th} branch with and without DG units, respectively. It is obvious that proper determination of the locations and sizes of DGs reduces the losses in the grid and consequently C_{pbs}.

2.4. *Operational indices*

On one hand, DGO wants to obtain profit as much as possible, without caring too much about the technical issues. On the other hand, the DisCo is responsible for the power quality its customers receive and it is up to him to decide how much the operational issues should be considered when making decisions. Therefore, in this study, the operational issues weren't directly involved in the objective functions mentioned. Instead, some constraints such as voltage profile and current limits were defined for this optimization problem in the operational and economic limits section. Hence, a total operational index (TOI) showing the technical condition of the grid is defined as:

$$TOI = PLI + VDI + ENSI + VSI^{-1} \tag{29}$$

This index consists of the following components:

PLI: Technically, power losses are unavoidable in power systems and lower values of these losses are of great importance in power grids. *PLI* (Power Loss Index) is a fraction in which the nominator is the total power system losses during the planning horizon considering DG units and the denominator is the same expression without any DG in the system. This index is defined as below [15]:

$$PLI = \frac{\sum_{\mathrm{y}=1}^{\mathrm{Y}} \sum_{\mathrm{h}=1}^{24} \sum_{\mathrm{b}=1}^{\mathrm{B}} R_b \times \left(I_{\mathrm{y,h,b}}^{DG}\right)^2}{\sum_{\mathrm{y}=1}^{\mathrm{Y}} \sum_{\mathrm{h}=1}^{24} \sum_{\mathrm{b}=1}^{\mathrm{B}} R_b \times \left(I_{\mathrm{y,h,b}}^{without\ DG}\right)^2} \tag{30}$$

in which $I_{\mathrm{y,h,b}}^{DG}$ and $I_{\mathrm{y,h,b}}^{without\ DG}$ are the current values in the b^{th} branch in the y^{th} year and h^{th} hour of the day with and without the DG units, respectively.

VDI: One of the advantages of determining the proper locations and sizes of DG units is the improvement in voltage profile. *VDI* (Voltage Deviation Index) is a fraction in which the nominator is the voltage

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deviation from the nominal value (U_{nom}) for all the nodes of the system during the planning period after inclusion of DG and the denominator is the same statement without any DG unit in the system. This index is defined as [15]:

$$VDI = \frac{\sum_{y=1}^{Y}\sum_{h=1}^{24}\sum_{i=1}^{N}\left|U_{nom} - U_{y,h,i}^{DG}\right|}{\sum_{y=1}^{Y}\sum_{h=1}^{24}\sum_{i=1}^{N}\left|U_{nom} - U_{y,h,i}^{without\ DG}\right|} \tag{31}$$

in which $U_{y,h,i}^{DG}$ and $U_{y,h,i}^{without\ DG}$ are the voltage magnitude of the i^{th} node in the y^{th} year and h^{th} hour of the day with and without the DG units, respectively.

ENSI: Some loads do not get supply in failure outages. According to the failure rate in each branch and the amount of the interrupted loads in failure occurrences, Energy Not Supplied Index (*ENSI*) is calculated. This index is a fraction in which the nominator is the energy calculated for the total number of not supplied loads for each fault after inclusion of DG and the denominator is the same expression without any DG unit in the system. Lower value of this index guarantees better operational condition of the power grid in case of failures. This index is expressed as below:

$$ENSI = \frac{\sum_{y=1}^{Y}\sum_{b=1}^{B}AT_F \times \xi_b \times L_b \times P_{NSL.y}^{DG}}{\sum_{y=1}^{Y}\sum_{b=1}^{B}AT_F \times \xi_b \times L_b \times P_{NSL.y}^{without\ DG}} \tag{32}$$

in which AT_F is the average time that the corresponding load is out of service when the fault occurs.

VSI: Another technical issue which should be considered is voltage stability. In [23], *SI* (Stability Index) is defined for each node in radial distribution networks. Higher value of this index is better according to stability standpoints. Using *SI*, the voltage stability index (*VSI)*, is defined. In this fraction, the nominator is an expression calculating the total stability index for all the nodes of the system during the planning horizon after inclusion of DG and the denominator is the same statement without any DG unit in the system. This index is formulated as:

$$VSI = \frac{\sum_{y=1}^{Y}\sum_{h=1}^{24}\sum_{i=2}^{N}SI_{y,h,i}^{DG}}{\sum_{y=1}^{Y}\sum_{h=1}^{24}\sum_{i=2}^{N}SI_{y,h,i}^{without\ DG}} \tag{33}$$

It is noteworthy to mention that unlike three previous indices defined by Equations (30)–(32), higher values of *VSI* are the sign of better condition of the grid from the operational point of view. Hence, in order to make the use of this index applicable, it has been inversed in Equation (29). Also, in this paper, weighted coefficients are applied to total operational index in a way different from previous studies. In this study, first, since operational indices have different values with different ranges, the normalized values of these indices are used by dividing each one to the same index calculated in the absence of DGs. This brings about new ranges between 0 and 1 for *PLI*, *VDI*, *ENSI* and for the inverse of *VSI* which its own value is usually more than 1. Second, according to the importance of each of these indices, they can be multiplied by appropriate coefficients. But, in this paper, it is assumed that all abovementioned indices are of the same importance. So, total operational index calculates the summation of these indices with the same coefficient, 1, for all of them.

3. MULTI-OBJECTIVE PSO

PSO method is one of the most applicable heuristic optimization techniques which can be implemented when a single objective function with some constraints should be optimized. But in many cases, several objectives or attributes should be optimized simultaneously that may be in conflict with each other. Furthermore, in large grids, the DGO's and DisCo's economic equations complexity and the interconnection between them besides their dependency to variations in DG units size, location and contract price make weighted multi-objective methods less efficient. Consequently, weighted coefficient technique is not able to work properly. Instead, other

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multi-objective methods such as MOPSO are used to meet the desired results. The result of implementing MOPSO technique to solve an optimization problem is a set of optimal solutions instead of one optimal solution. This originates from the fact that none of the solutions can be better than the others regarding all the objective functions. These optimal solutions are known as Pareto solutions [24]. Considering *f(x)* to be a vector of the *N* objective functions, Pareto optimal solutions are the ones which are nondominated within the entire search space. In a maximization problem, the solution x_1 dominates x_2 if the following statements are satisfied:

$$1.\forall i \in \{1, 2, \cdots, N\} : f_i(x_2) \leq f_i(x_1) \tag{34}$$

$$2.\exists j \in \{1, 2, \cdots, N\} : f_j(x_2) < f_j(x_1) \tag{35}$$

The first inequality expresses that the solution x_1 is no worse than x_2 in all objectives and the second one states that the solution x_1 is strictly better than x_2 in at least one objective. If x_1 dominates the solution x_2, then x_1 is called the nondominated solution. The main goals of this optimization approach are to reach closer to the set of the Pareto-optimal solutions and get a set of diversified solutions.

In MOPSO, a group of swarms is used instead of a single swarm which is used in the PSO searching for an optimum solution. In this algorithm, the particle *i* in the time *t* is defined by its position vector $X_i(t) = \{x_{i,1}, x_{i,2}, \ldots, x_{i,k}, \ldots, x_{i,m}\}$ and its velocity vector $V_i(t) = \{v_{i,1}, v_{i,2}, \ldots, v_{i,k}, \ldots, v_{i,m}\}$ where *m* is the number of the optimized parameters. $x_{i,k}$ is the position of the i^{th} particle with respect to the k^{th} optimized parameter and $v_{i,k}$ is the velocity of the i^{th} particle with respect to the k^{th} dimension. Incipient particle positions and velocities are determined randomly in the first iteration and will be calculated according to the following equations in the next iterations[9]:

$$v_{i,k}(t+1) = w(t)v_{i,k}(t) + c_1 r_1 \left(l_{i,k}(t) - x_{i,k}(t)\right) + c_2 r_2 \left(g_{i,k}(t) - x_{i,k}(t)\right) \tag{36}$$

$$x_{i,k}(t+1) = v_{i,k}(t+1) + x_{i,k}(t) \tag{37}$$

where $k = 1,2,..,m$ and $i = 1,2,..,N_p$, where N_p refers to the size of population. *w(t)* is the inertia weight which is employed to control the impact of the current iteration velocity on the next one. If there is no need to include the previous history, then the inertia weight is simply eliminated. While c_1 and c_2 are two positive constant coefficients, r_1 and r_2 are two random values in the range [0,1]. Since each particle knows the position of its personal best solution and the other particles best solutions found in the previous iterations, the new velocity of this particle can be calculated by Equation (36) where $l_{i,k}(t)$ and $g_{i,k}(t)$ are respectively the local and the global best solutions up to the current iteration [9]. New position of each particle is also obtained by Equation (37) using this updated velocity. The flowchart of MOPSO technique is shown Figure 1.

4. CASE STUDY, SIMULATION, RESULTS AND DISCUSSION:

4.1. Test system

Simulations have been done using MATLAB on the 12.66 KV IEEE 33-bus distribution test system which is shown in Figure 2. Resistance and reactance of all the branches and the active and reactive base loads for all nodes of the system are given in Table I. Furthermore, the demand factor for the 24 hours of a day is depicted in Figure 3. Also, for more simplicity, the cost function of the power bought from the substation which is based on the amount of purchased power is approximated by a three-step function depicted in Figure 4. These three steps are chosen according to the three different load conditions. In this figure, the horizontal axis shows the per-unit values of the power bought from the substation based on the maximum amount of the purchased power during the day. Moreover, commercial information of DGs is given in Table II [18]. It is noteworthy to mention that faults occur only in the lines of the system and other pieces of equipment are completely reliable. Finally, the values of other parameters related to this study are given in Table III. Total number of DG units (*M*), demand growth rate (α), capacity factor ($\varphi_{u,m}$), minimum and maximum amounts of the contract price

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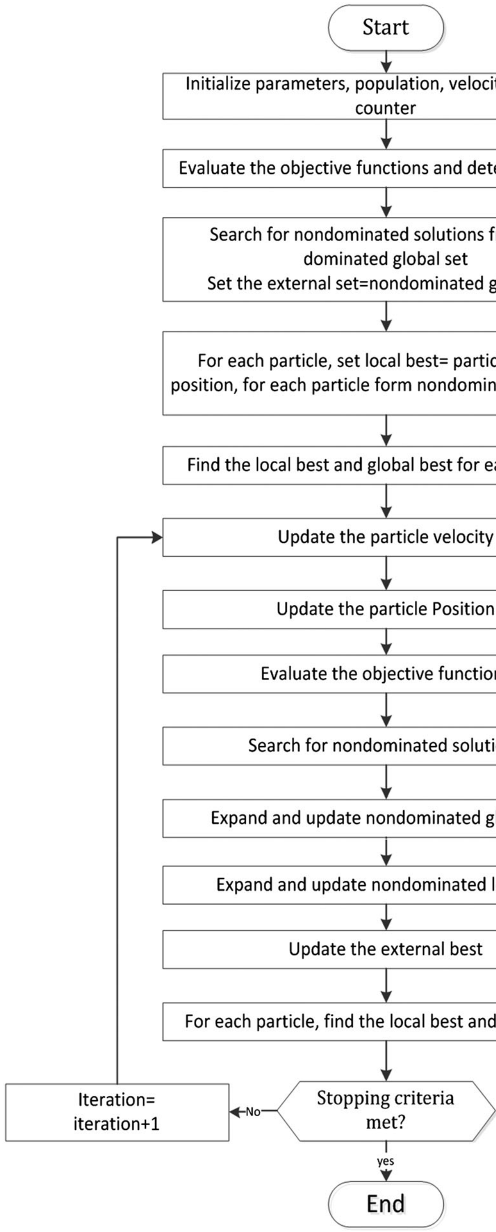

Figure 1. Flowchart of MOPSO method [9].

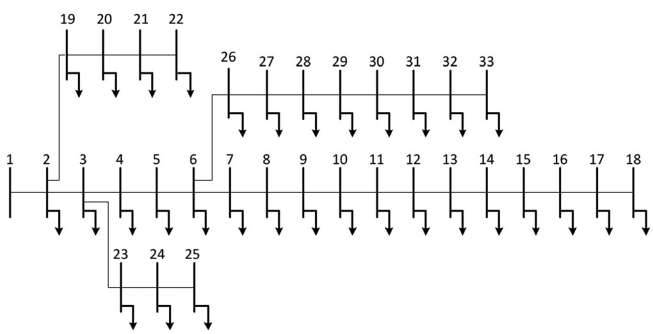

Figure 2. The IEEE 33-bus test system.

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Table I. Data of the test system.

Line Num	Send bus	Receive bus	Length (KM)	R (Ω)	X (Ω)	P_{base}, Q_{base} P(KW)	Q(Kvar)
1	1	2	2.8	0.0922	0.0477	100	60
2	2	3	2.5	0.4930	0.2511	90	40
3	3	4	1.6	0.3660	0.1864	120	80
4	4	5	0.9	0.3811	0.1941	60	30
5	5	6	1.6	0.8190	0.7070	60	20
6	6	7	2.5	0.1872	0.6188	200	100
7	7	8	0.6	1.7114	1.2351	200	100
8	8	9	1.6	1.0300	0.7400	60	20
9	9	10	0.75	1.0400	0.7400	60	20
10	10	11	0.9	0.1966	0.0650	45	30
11	11	12	3.2	0.3744	0.1238	60	35
12	12	13	2.8	1.4680	1.1550	60	35
13	13	14	0.6	0.5416	0.7129	120	80
14	14	15	3.5	0.5910	0.5260	60	10
15	15	16	1.6	0.7463	0.5450	60	20
16	16	17	2.8	1.2890	1.7210	60	20
17	17	18	3.2	0.7320	0.5740	90	40
18	2	19	2.5	0.1640	0.1565	90	40
19	19	20	3.2	1.5042	1.3554	90	40
20	20	21	1.6	0.4095	0.4784	90	40
21	21	22	0.8	0.7089	0.9373	90	40
22	3	23	2.8	0.4512	0.3083	90	50
23	23	24	2.5	0.8980	0.7091	420	200
24	24	25	3.2	0.8960	0.7011	420	200
25	6	26	2.8	0.2030	0.1034	60	25
26	26	27	2.5	0.2842	0.1447	60	25
27	27	28	0.75	1.0590	0.9337	60	20
28	28	29	1.6	0.8042	0.7006	120	70
29	29	30	3.2	0.5075	0.2585	200	600
30	30	31	2.8	0.9744	0.9630	150	70
31	31	32	3.2	0.3105	0.3619	210	100
32	32	33	1.4	0.3410	0.5302	60	40

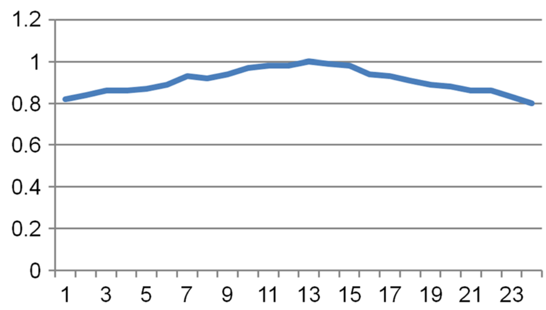

Figure 3. Demand factor (β_h) during the day.

between the DisCo and the DGO ($Min(CP)$ and $Max(CP)$), minimum and maximum amounts of the active power of each DG unit ($Min(P_{u,m})$ and $Max(P_{u,m})$), DGs power factor (PF), fault rate (ξ_b), the cost of not supplying each load during the repairing time (C_F) and the average time that the corresponding load is out of service (AT_F) are all valued in this table. Also, it should be stated that although C_F is dependent on the operational condition and load types of the network, but in this study, the average value given in Table III is considered for all loads during failure outages [25].

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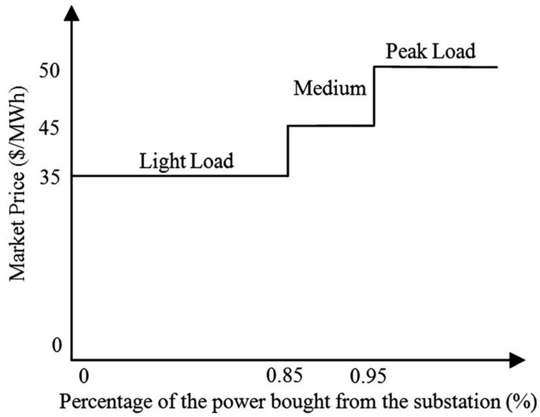

Figure 4. Market price three-step function.

Table II. Commercial information of DGs [18].

Parameter	Unit	Value
DG investment cost	*$/MW*	318 000
DG Operation cost	*$/MWh*	29
DG maintenance cost	*$/MWh*	7
Interest rate	%	12.5
Inflation rate	%	9
Planning period	Year	20

Table III. Values of the used parameters.

Parameters	Values
α	2%
ξ_b(f/km.year)	0.12
$\phi_{u,m}$	1
AT_F (h)	8
C_F ($/kw)	20
M	3
Max(CP) ($/MWh)	50
Min(CP) ($/MWh)	30
Max($P_{u,m}$) (MW)	1
Min($P_{u,m}$) (MW)	0.2
PF	0.9 lag

4.2. Simulation results and discussion

The proposed multi-objective optimization is done using MOPSO technique to calculate the local optimal solution for the DGO's and DisCo's profits. It is apparent that the two related objective functions are dependent to each other seriously, which means that reduction in one of them leads to increase in the other one and vice versa. As a result, there are various optimum points and it is imperative to use a proper methodology while choosing the best answer. The Pareto optimal set attained from MOPSO is shown in Figure 5.

It is worth mentioning that each point in the obtained Pareto set expresses two kinds of information: the contract price of selling DGs generated power to the DisCo as well as the size and location of DG units. Consequently, in addition to different profits for both the DisCo and DGO, selecting each point from the Pareto set results in different operational characteristics which are completely independent and separate from each other. Hence, to choose an optimal solution, two imperative issues should be considered: First,

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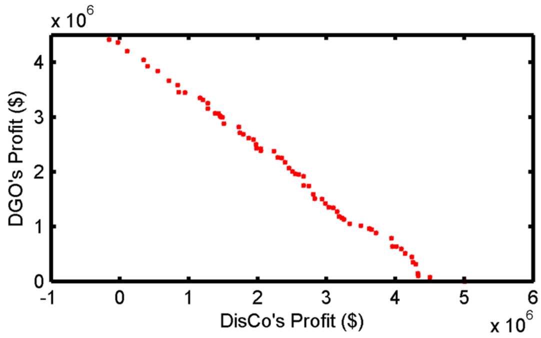

Figure 5. Pareto optimal set achieved by MOPSO.

in the optimal solution, the profit of both the DisCo and the DGO should be supplied adequately. Second, the operational indices in the optimal point should be in an acceptable levels. It should be noted that the operational issues are not used directly in the proposed multi-objective decision making method [26]. The main disadvantage of this method is that the selected solution may not be the optimum one from the DisCo's and DGO's profit standpoints. Additionally, the operational issues are not considered in the selection of the optimal point; hence, there is no guarantee that the operational indices in the chosen optimal solution are good enough. Consequently, a more rational procedure is needed.

In order to find the optimal solution, it is better to consider both the operational and economic issues. It is noteworthy to mention that all the points in the Pareto set have rates of return which are more than 12.5% for the DGO in such a way that the more the profit, the more the rate of return. The positive value of the DGO's profit means a rate of return more than 12.5%, because while calculating the present value of this profit, all the annual expenses and profits are discounted by the rate of 12.5%. Since the rates of return more than 12.5% are desirable from the DGO's point of view, all the points in the Pareto set are acceptable from the DGO's standpoint. Therefore, it would be better to choose a point which satisfies the DisCo's economic and operational issues. Hence, considering the DisCo's profits, total operational index and amount of each index separately, it is up to the DisCo to choose the most compromised solution based on the grids condition.

Taking all the above mentioned issues into consideration, in this paper, a methodology for selecting the final solution is proposed. In the first step of this method, as shown in Figure 6, the first 10% of the points in the Pareto set which have the best operational condition in regard to *TOI* index are selected which their related data are brought in Table IV. Selecting the 10% of the Pareto set points instead of the best point according to the operational issues causes higher DisCo's profit by allowing a little mismatch in the operational issues. The adjacency of *TOI* amounts and also the dispersion of DisCo's profit shown in Table IV place more emphasis on this issue. Among these candidate points, the one with the highest DisCo's profit is selected as the best solution. This point is distinguished in Figure 6 and the data about the DGs' characteristics and contract price related to this point is brought in Table V and details about the operational indices, DisCo's profit, cost and DGO's profit are given in Table VI. The flowchart of the

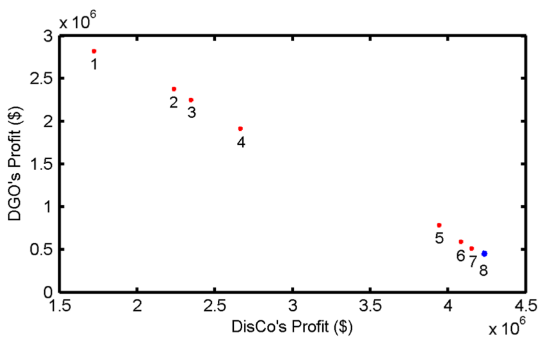

Figure 6. Candidate points and best compromised solution achieved by applying the proposed method.

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Table IV. Economic and operational characteristics of the best 10% of Pareto set.

Point num.	DisCo's cost	DGO's cost	Index				TOI
			PLI	VDI	ENSI	VSI	
1	1.723e6	2.822e6	0.147	0.131	0.249	1.219	1.349
2	2.237e6	2.374e6	0.167	0.164	0.181	1.243	1.318
3	2.348e6	2.253e6	0.172	0.154	0.213	1.237	1.348
4	2.664e6	1.917e6	0.164	0.145	0.214	1.229	1.337
5	3.942e6	0.784e6	0.128	0.160	0.173	1.190	1.302
6	4.084e6	0.587e6	0.139	0.168	0.183	1.194	1.329
7	4.151e6	0.509e6	0.141	0.182	0.179	1.184	1.347
8	4.236e6	0.446e6	0.163	0.170	0.161	1.195	1.331

Table V. DGs characteristics related to the selected point.

	Power (MW)	Location	Contract price ($)
DG number 1	1	16	39.735
DG number 2	1	33	39.735
DG number 3	0.8	24	39.735

Table VI. Technical indices, the DisCo's profit, cost and the DGO's profit for the optimum planning scheme.

VDI	0.170
PLI	0.163
VSI	1.195
ENSI	0.161
DisCo cost ($)	20 901 032.69
DisCo profit ($)	4 236 800.26
DG owner's profit ($)	446 643.19

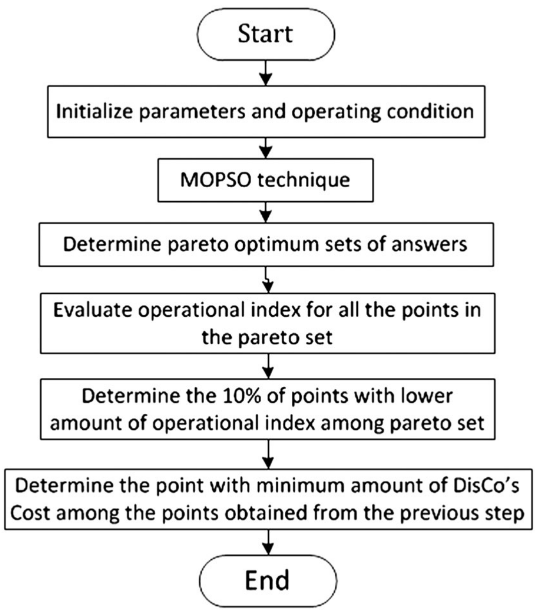

Figure 7. Flowchart of the proposed method.

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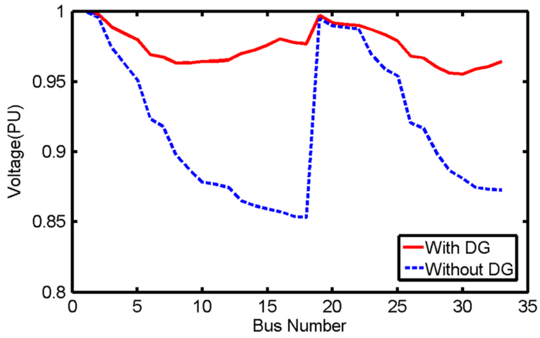

Figure 8. Voltage profile in the 20th year of planning under peak load condition.

proposed method is presented in Figure 7. To demonstrate the superiority of the proposed method, the voltage profile for the peak hours of the last year of the project is depicted in Figure 8. It is obvious that the voltage profile improves significantly when DG units are used in comparison with the condition without using DGs. The DGO's rate of return regarding to this selected point is 15.45% and it means approximately a rate of return 3% more than what was expected. Therefore, because of the higher return rate that might investors gain, it can be assigned as an encouragement for investors to spend more money on renewable energy and DG technologies. Furthermore, according to Table VI, the total cost of the DisCo is about 20.9 million dollars while this cost was about 25.13 million dollars in condition without using DGs which means the DisCo's saving is about 4.2 million dollars.

5. CONCLUSION

In this paper, a methodology based on MOPSO technique has been proposed to find the best solution for the DGs sizing and locating problem and determining their optimal generated electricity prices in a competition market between the DGO and the DisCo. The main objective functions of this optimization problem were maximizing the DGO's profit and minimizing the DisCo's cost simultaneously. Pareto set of the optimal solutions was obtained by implementing the multi-objective optimization method. In order to attain the best solution, improving the operational issues of grid such as power loss reduction, voltage profile and stability enhancement and reliability improvement were considered as auxiliary tools. The proposed methodology was implemented on the IEEE 33-bus distribution test system and the simulation results confirmed that not only the DGO obtains good enough profits but also the DisCo has his own benefits, i.e. the DisCo's cost decreases notably in comparison with the case of not using DGs. Furthermore, the operational condition of the grid improves significantly. It was finally shown that the proposed methodology has flexibility to offer the proper encouragement energy policies to DGOs in different situations.

6. LIST OF SYMBOLS AND ABBREVIATIONS

6.1. *Symbols*

AT_F	The average time that the corresponding load is out of service when the fault occurs
B_{ij}	Susceptance of the branch that connects the i^{th} and the j^{th} nodes(Ω^{-1})
B	The total number of branches
C_c	Initial investment of the DGO ($)
$C_{\frac{cap}{MW}}$	The capitalization cost of DGs based on their MW ($/MW)
$C_{DisCo,DG}, C_{DisCo,without\ DG}$	The total DisCo's costs in case of using and without using DG units ($)
$C_{ENS}^{DG}, C_{ENS}^{without\ DG}$	Total cost of energy not supplied with and without using DG units ($)

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C_m	Total maintenance cost of DG units ($)
$C_{\frac{m}{MWh}}$	The maintenance cost of DGs based on their generated power ($/MWh)
C_o	Total operating expenses of running DG units ($)
$C_{\frac{o}{MWh}}$	The operation cost of DGs based on their generated power ($/MWh)
$C_{pbs}^{DG}, C_{pbs}^{without\ DG}$	Total cost of active power bought from the substation ($)
C_{pp}	Total cost of purchased power from the DG owner ($)
C_F	The cost of not supplying each load during the repairing time
$CF(P_{bs})$	The cost function ($/MWh) of power bought from the substation based on the amount of purchased power (P_{bs})
CP	The contract price between the DGO and the DisCo ($/MWh)
G_{ij}	The conductance of the branch that connects the i^{th} and the j^{th} nodes(Ω^{-1})
$I_b^{DG}, I_b^{without\ DG}$	Current of the b^{th} branch with and without using DG units (A)
$I_{b,h,y}$	The amount of current that flows in branch b in the h^{th} hour of the day in year y (A)
$I_{\mathrm{y,h,b}}^{DG}, I_{\mathrm{y,h,b}}^{without\ DG}$	The current (A) of the b^{th} branch in the y^{th} year and h^{th} hour of day with and without the DGs
L_b	Length of the b^{th} branch
M	The total number of DG units
$Max(I_b)$	The maximum amount of current allowed in branch b (A)
$Max(C_c)$	Maximum amount of money that DGO can capitalize ($)
$Min(CP), Max(CP)$	Minimum and maximum values of contract price between the DGO and the DisCo ($/MWh)
$Min(P_{u,m}), Max(P_{u,m})$	Minimum and maximum amounts of the active power that each unit is capable of generating (MW)
$Min(Q_{u,m}), Max(Q_{u,m})$	Minimum and maximum amounts of the reactive power that each unit is capable of generating (MVAR)
$Min(U_i), Max(U_i)$	Minimum and maximum allowed amounts of bus voltage (v)
N	The total number of nodes
NSL	The total number of not supplied loads for each fault
P_j, Q_j	Injected active and reactive powers to each node (MW)
$P_{i,base}, Q_{i,base}$	Active and reactive base loads defined for node i (MW)
$P_{Load,i,y,h}, Q_{Load,i,y,h}$	Active and reactive powers of the load connected to the i^{th} bus, in the h^{th} hour of the day in the y^{th} year (MW and MVAR)
$P_{Load,nsl,y}^{DG}, P_{Load,nsl,y}^{without\ DG}$	The active powers of not supplied load connected to the nsl^{th} bus, in the y^{th} year, with and without DGs (MW)
$P_{s,h,y}^{DG},\quad P_{s,h,y}^{without\ DG}$	Active powers supplied by the substation in the h^{th} hour of the day in the y^{th} year with and without DGs (MW)
$P_{u,m}, Q_{u,m}$	Active and reactive powers generated by the DG unit m (MW and MVAR)
R_b	Resistance of the b^{th} branch (Ω)
R_{DGO}	DGO's revenue based on the selling generated power to the DisCo ($)
RIR	Real interest rate
$SI_{y,h,i}^{DG},\quad SI_{y,h,i}^{without\ DG}$	Stability index of the i^{th} node in the y^{th} year and h^{th} hour of the day with and without the DG units
U_{nom}	Nominal voltage of buses (v)
$U_{i,h,y}$	The voltage magnitude of the i^{th} node, h^{th} hour of the day and y^{th} year (v)
$U_{y,h,i}^{DG}, U_{y,h,i}^{without\ DG}$	The voltage magnitude of the i^{th} node in the y^{th} year and h^{th} hour of the day with and without using DG units (v)
Y	The total number of years in the planning horizon
A	Demand growth rate

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β_h	Demand factor
θ_{ij}	Impedance angle of the branch that connects the i^{th} and the j^{th} nodes (*rad*)
ξ_b	Fault rate in the b^{th} branch (f/km.year)
$\varphi_{u,m}$	Capacity factor related to the m^{th} unit

6.2. Abbreviations

DisCo	Distribution company
DG	Distributed generation
DGO	Distributed generation owner
MOPSO	Multi-objective particle swarm optimization
PLI	Power loss index
VDI	Voltage deviation index
ENSI	Energy not supplied index
VSI	Voltage stability index

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