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A dynamic method for feeder reconfiguration and capacitor switching in smart distribution systems

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ABSTRACT

In distribution systems, feeder reconfiguration (FR) can lead to loss reduction, reliability improvement and some other economic savings. These advantages can be intensified by proper control and switching of Capacitor Banks (CBs). In this paper, using Ant Colony Optimization (ACO) technique, a novel method is proposed for simultaneous dynamic scheduling of FR and CB switching in the presence of DG units having uncertain and variant generations over time. This method is applicable to both smart and classic distribution systems. While for the latter, state estimation method should be used to estimate the loads at different buses by employing a limited number of measurements. The objective of this method is to minimize the total operational cost of the grid, including the cost of power purchase from the sub-transmission substation, cost of customer interruption penalties, Transformers Loss of Life (TLoL) expenses, and the switching costs (CBs and disconnecting switches). To perform this study, the planning period is divided into several intervals for each of them the network topology and CBs reactive power are determined to satisfy the objective function. Additionally, due to the curse of dimensionality, a Case Reduction Technique (CRT) is proposed in order to decrease the computational burden of the proposed method. Finally, the efficiency of the proposed method is verified through its application on the IEEE 118-bus distribution test system, and evaluating its economic and operational characteristics.

1. Introduction

Distribution system may have different types of loads such as residential, commercial and industrial with different demand levels changing during a day. This brings about variations in the system operational condition according to its heavily or lightly loaded condition [1]. Reconfigurable distribution systems are capable of changing their topology under both normal and abnormal conditions based on load variations and changes in distribution generation [2]. This is an optimization procedure called reconfiguration which changes the open/close status of network switches to interconnect feeders with the objective of increasing the grid efficiency [3]. Network reconfiguration helps flatting out the peak demands, improving voltage profile, reducing power loss and enhancing power system reliability. Hence, in distribution networks which have the major contribution to power system losses and power outages, reconfiguration is growingly employed.

Besides reconfiguration, another strategy which is widely being used for improving the operational condition of power grids is the capacitor banks switching. Installing these banks limits the reactive power flow in the grid which results in real power losses and voltage drops reduction. Also, financial benefits, increased feeder capacity, congestion alleviation, etc. can be obtained using this strategy. However, after each reconfiguration process the implemented capacitor banks should be reformed and adjusted to yield the desired objectives.

On the other hand, the increased application of renewable resources in power systems has added to the complexity of this optimization problem. This originates mainly from the variant generations of many DG technologies like wind turbines. This cause distribution system reconfiguration to be faced with uncertainty in such cases [4].

The numerous advantages of reconfiguration have brought the attention of many researchers to this concept. In this regard, different objectives are defined. Many studies have been done with the objective of loss reduction [3–27]. Some have based their approaches on reliability improvement [9,11,18,19,25,26]. In [8],

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a voltage stability index has been proposed to improve voltage stability of a radial distribution system through network reconfiguration. Voltage profile improvement is also another objective function being concentrated on by the authors of [4,13,16]. Additionally, power quality issues such as load balancing and voltage sag improvement have also been investigated in [6,7,27]. Besides the operational issues mentioned, some researchers have worked on economic aspects of grids as objective functions while network reconfiguring [3,4,16–19,22–25]. Also while determining objective functions, some papers have concentrated only on one of the criteria mentioned above [5,10,12,14,15,20,21] unlike others which have used multi-objective functions [3,4,6–8,9,11,13,16–19,22–24]. Despite the fact that most of the papers have considered distribution system reconfiguration as a static problem [3,4–17,20–24], some have considered it as a dynamic one [18,19,25]. Another issue considered in [3–5,17,19,22,25] is load variations. In these references, different formulations are proposed for the problem in order to properly optimize network reconfiguration. Furthermore, simultaneous application of capacitor banks and reconfiguration is studied in [5,20–24]. Some researchers [4,7,13,16,17] also explored the incremental use of distribution generations besides network reconfiguring. The literature review of this section is briefly categorized in Table 1.

In this paper, the objective of Distribution Network Operator (DNO) is to reduce its total cost and the network power losses. This is achieved through a proper reconfiguration scheme as well as switching the capacitor banks in a smart distribution system by using Ant Colony Optimization (ACO) method. It is assumed that capacitor banks and reconfiguration switches are already installed in the network and DNO only intends to schedule their switching times.

This algorithm is used dynamically in presence of a DG unit with variant generation in order to minimize the total cost of the grid. This cost is related to: electric energy purchase, customer interruption penalty, transformer loss of life, and switching devices wear. Furthermore, due to the curse of dimensionality a case reduction method is proposed in order to increase the efficiency and reduce the complexity of the proposed method. Contributions of the proposed method are as follows:

(1) A new grid cost minimization scheme is proposed by considering system reconfiguration besides capacitor banks switching in presence of distributed generation.
(2) Reconfiguration and capacitor banks switching schemes are implemented dynamically while load is continuously varying.
(3) Stochastic methods are used for handling the uncertainty related to the generation of the distributed generation unit.
(4) The objective function considers the following costs: power purchased, energy not supplied, transformer loss of life, and switching devices loss of life.

In this paper two different optimization algorithms, i.e. ACO and Harmony Search (HS) algorithms, with completely different features are used. HS tries to find the best answers while optimizing (minimizing or maximizing) a certain objective function [28]. However, ACO is a probabilistic technique to solve a computational problem which can be reduced to finding good paths through graphs [29]. Hence, HS is more appropriate for the first part of this optimization problem or case reduction part, whereas ACO is suitable for the second part of the optimization process which looks for the best path for cost minimization.

Furthermore, in this paper it is assumed that the impact of the load uncertainty is not as much as the wind generation uncertainty impact, and therefore it is neglected. The reason for this assumption is that the time horizon for which the load should be forecasted is a week and this assumption is reasonable particularly in a smart environment equiped with advanced meters. However, in cases in which load uncertainty is required to be considered [30], a stochastic model similar to the DG unit uncertainty model can be employed for the loads.

Table 1
Summary of the reviewed literature's optimization features.

Ref. #	Loss reduction	Reliability improvement	Voltage stability	Voltage profile	Economic issues	Load balancing	Power quality	Capacitor placement/ switching	Load model	DG presence	Optimization method
[3]	✓				✓						Genetic
[4]	✓			✓	✓						AMPSO
[5]	✓							✓	✓		Mixed-integer nonlinear Programming
[6]	✓						✓				Differential evolution
[7]	✓					✓				✓	Ant colony
[8]	✓		✓								Fuzzy-based method
[9]	✓	✓									Micro-genetic
[10]	✓										Circular-updating
[11]	✓	✓									Branch-exchange (BE)
[12]	✓										Modified PSO
[13]	✓			✓						✓	Harmony search
[14]	✓										UVDA
[15]	✓										Integer coded PSO
[16]	✓			✓	✓					✓	Adaptive PSO + Fuzzy
[17]	✓				✓				✓	✓	Genetic
[18]	✓	✓			✓						Binary PSO
[19]	✓	✓			✓				✓		HS + DP
[20]	✓							✓			Ant colony
[21]	✓							✓			Adaptive genetic
[22]	✓				✓			✓	✓		BE + Discrete genetic
[23]	✓				✓			✓	✓		Dedicated genetic
[24]	✓				✓			✓			Modified PSO
[25]	✓	✓			✓				✓		Scenario theory + PSO
[26]	✓	✓									Artificial immune systems
[27]	✓						✓				Branch exchange
Proposed method	✓	✓			✓			✓	✓	✓	ACO + HS

The rest of this paper is organized as follows: the problem is formulated in Section 2; a case study in which the proposed method is applied to a sample distribution network is presented in Section 3; finally, the paper is concluded in Section 4.

2. Problem formulation

In this section, first the assumptions about the DG unit application in the proposed method will be given. Then, the optimization constraints will be introduced. In the third part, the main objective function for the proposed method will be stated. Next, a case reduction method will be proposed in order to increase the convergence speed of the proposed algorithm in an efficient way. Afterwards, calculation of transformer loss of life will be explained. In the next subsection, the uncertainty of the DG unit will be handled. Then, the flowchart of the proposed method will be explained. Finally, for a better evaluation of the operational performance of the grid some operational indices are introduced.

2.1. The DG unit application assumptions

The following assumptions about the DG unit application are taken into consideration in this paper:

- The DG unit is a wind turbine generating only active power.
- The DG unit is considered as a negative P load. Hence, the bus this unit is connected to is of PQ type.
- Since the generation of the DG unit is variant, its generation is represented through a probabilistic model.
- To reduce the amount of energy not served, under presence of DG unit in the grid, islanding operation of this unit is permitted [31].

2.2. Constraints

In this paper, the following constraints are satisfied during case reduction technique (CRT) for determining the feasible cases.

2.2.1. Distribution system radial topology constraint

The most prominent constraint of the problem is always keeping the network topology radial. Therefore, graph theory is applied in order to make sure that this constraint is complied. If the graph of the network is a tree, then the related configuration is allowable. To do so, whenever a switch is closed and a loop is created, another switch in that loop should be opened in a way that the grid remains always as a tree.

2.2.2. Bus voltage limit

The voltage values of all buses should be kept in the acceptable range shown below:

$$V_{min} \leqslant V_k \leqslant V_{max} \tag{1}$$

in which, k is the index related to the grid buses and V_k is the kth bus voltage value. Furthermore, V_{min} and V_{max} refer to the minimum and maximum allowable values of bus voltages, respectively.

2.2.3. Branch current limit

Based on the thermal limits of the grid branches, the following constraint related to branch currents is defined:

$$|I_b| \leqslant I_{b,max} \tag{2}$$

in which, I_b is the bth branch current value and $I_{b,max}$ refers to the maximum allowable amount of it.

2.2.4. Power flow constraints

In addition to the above constraints, also power flow constraints related to the active and reactive powers injected to the network buses should be taken into consideration as well:

$$P_k = V_k \sum_{j \in N_n} V_j (g_{jk} \cos(\theta_{jk}) + b_{jk} \sin(\theta_{jk})) \tag{3}$$

$$Q_k = V_k \sum_{j \in N_n} V_j (g_{jk} \sin(\theta_{jk}) - b_{jk} \cos(\theta_{jk})) \tag{4}$$

In the above equations, N_n is the total number of buses in the grid. Furthermore, g_{jk} and b_{jk} respectively refer to the conductance and susceptance of the branch connecting the jth and kth buses. θ_{jk} also indicates the impedance angle related to this branch.

2.2.5. Capacitor bank constraint

Another constraint for the minimum and maximum values of the capacitor banks output kVArs exists as follows:

$$QC_{m,min} \leqslant QC_m \leqslant QC_{m,max} \tag{5}$$

in which, m is an index referring to capacitor banks. Also, QC_m refers to the reactive power generated by the mth bank. Furthermore, $QC_{m,min}$ and $QC_{m,max}$ respectively refer to the minimum and maximum amounts of reactive power the mth bank can generate.

2.3. The main objective function

In this paper, the network reconfiguration and capacitor banks switching (in presence of a DG unit) is employed through application of the ant colony optimization algorithm [32]. Among the advantages of this algorithm, requiring less time to achieve the optimum solution is of high importance for the optimization purposes of this paper. In power system studies, this algorithm is especially used for solving the Unit Commitment Problems (UCPs) [32].

In this section, the main objective is to minimize the total cost of the grid during a specific period by simultaneous application of distribution system reconfiguration and capacitor banks switching under the uncertain generation of a DG unit. To obtain the optimal solution under a specific load curve over the planning period, this period is divided into some intervals. These intervals are developed through approximation of the grid load curve (each interval is usually equal to one hour). Then, for each interval, the network topology and capacitor banks arrangement should be determined on the basis of cost minimization over that planning period. In fact, distribution system reconfiguration and capacitor banks switching problem is employed to minimize the total costs of the grid consisting of the cost of the electric power (or energy) bought from the substation, customer's electricity interruption penalty cost, transformer loss of life, and the equivalent switching equipment loss of life cost. The objective function which should be minimized is:

$$F = \sum_{i=1}^{N-1} C_{SW}(i, i+1) + \sum_{tr=1}^{N_{TR}} C_{TLoL}(L_{tr}^{st}) + \sum_{i=1}^{N} C_{PP,i}^{st} + \sum_{i=1}^{N} C_{CI,i}^{st} \tag{6}$$

$$C_{sw}(i, i+1) = \sum_{m=1}^{N_c} SW_{c,m}(i, i+1) \times SCCS_m + \sum_{n=1}^{N_{RS}} (SW_{R,n}(i, i+1)) \times CORS \tag{7}$$

Equation (6) should be minimized subjected to constraints presented in (1)–(5). In (6), i is the index referring to intervals. Also, $\sum_{i=1}^{N-1} C_{SW}(\cdot)$ refers to the total switching cost. Additionally, $\sum_{i=1}^{N} C_{PP,i}^{st}$ and $\sum_{i=1}^{N} C_{CI,i}^{st}$ respectively refer to the total cost of

purchasing power from the substation and total customer interruption cost during the whole N intervals. Furthermore, $\sum_{tr=1}^{N_{TR}} C_{TLoL}^{st}(L_{tr}^{st})$ calculates the total cost of transformer loss of life for all N_{TR} transformers of the network in which L_{tr}^{st} is a $1 \times N$ matrix comprising the trth transformer load in all intervals of the period under study. It is noteworthy to mention that the superscript st which is used in three terms of (6) refers to the expected value of those terms which will be explained later in Section 2.6.

In (7), $C_{SW}(i, i+1)$ refers to the cost of switching between the ith and $(i+1)$th intervals. Also, N_{RS} and N_c respectively refer to the total number of reconfiguration switches and capacitor banks. Also, n is an index referring to feeder switches. $SCCS_m$ is the switching cost for each steps of the mth capacitor bank which should be either connected to or disconnected from the grid, and CORS is the cost of opening a reconfiguration switch under load. $SW_{c,m}(i, i+1)$ also refers to the number of steps of the mth capacitor bank being switched while shifting from the interval i to the interval $i+1$, and $SW_{R,n}$ refers to the state of the nth reconfiguration switch while reconfiguring from the ith interval to the $(i+1)$th. This value is considered to be 0 if switching from the open state to the closed one, and 1 vice versa.

As mentioned before, minimization of the main objective function is done by the application of ACO. To do so, considering the possible number of radial configurations (N_{RC}) and the number of steps of each capacitor bank which is between 1 and N_s, a total number of $(N_{RC} \times N_s^{N_c})$ cases in each interval should be investigated which brings about a huge amount of calculations. Hence, in order to reduce the intricacy and extent of the problem, a Case Reduction Technique (CRT) is applied to reach the best answer more rapidly and efficiently.

2.4. The proposed Case Reduction Technique (CRT)

The main goal of this section is to reduce the total number of cases by the application of harmony search algorithm and an objective function that will be discussed in (8). First, in each interval, for each generation scenario of the DG unit, without considering other intervals and states, the HS algorithm explained in [19] is used to determine the optimum grid configuration as well as capacitor banks reactive power. This is done based on minimizing the objective function defined by (8). This objective function should be minimized subjected to the defined constraints in (1)–(5).

$$f_{i,j} = C_{PP,i,j} + C_{CI,i,j} \tag{8}$$

where $f_{i,j}$ is the objective function representing the total costs of customer interruption penalties and purchasing power from substation in the ith interval for the jth scenario of the DG unit generation. Therefore, C_{PP} and C_{CI} refer to the purchased power and the customer interruption costs, respectively. More details about how to calculate this objective function will be given later in Sections 2.4.1 and 2.4.2.

It is noteworthy to mention that since the thermal time constant of power transformers are usually in the range of several hours, the transformer loss of life cost is not considered in (8). The reason is that due to the large value of this time constant, before the transformer reaches to the expected temperature, probably the transformer load has already changed (decreased or increased) several times. Therefore, it does not let the transformer operating condition to follow closely the hourly changes of the load. As a result, similar to the switching cost, the transformer loss of life cost can be determined through the main objective function by considering the load changes in previous and future intervals.

Furthermore, unlike (6), the stochastic analysis discussed later in Section 2.6 is not applied to (8). The reason is that this function is minimized separately for each scenario of the DG unit generation. Hence, if the total number of the DG unit generation scenarios is N_j, then a total number of $(N_j \times N)$ separate optimization processes will be followed in this subsection.

Considering the obtained results after applying HS to all those separate optimizations, it should be determined that opening or closing which switches will have the least effect on the optimum solution. In other words, by HS application, feeder switches which are always closed or open (or have been switched rarely in all optimizations) are kept in their former state. Also, for each capacitor bank, an effective range for its number of steps would be determined based on the maximum and minimum number of steps obtained in all optimizations. Ultimately, by considering that the topology of the grid must be radial, using the remaining feeder switches as well as the specified capacitor banks steps, all possible arrangements are combined together to form all possible cases.

For optimizing (8), the following costs should be calculated:

2.4.1. Cost of purchasing real power from the substation (C_{PP})

This cost is related to purchasing the real power demand from the substation, and is calculated using the following equations:

$$C_{PP,i,j} = P_{in,i,j} \times T_i \times CF_{PP,i}(P_{in,i,j}) \tag{9}$$

$$P_{in,i,j} = P_{Loss,i,j} + \sum_{k=1}^{N_n}\sum_{l=1}^{N_{LT}} P_{Load,i,j,k,l} - P_{DG,j} \tag{10}$$

$$P_{Loss,i,j} = \sum_{b=1}^{N_B} r_b \times I_{b,i,j}^2 \tag{11}$$

In (9), T_i refers to the ith interval duration (hours), and $P_{in,i,j}$ refers to the amount of power purchased in the ith interval for the jth scenario of the DG unit generation (MW). $CF_{PP,i}(\cdot)$ is also the cost function for purchasing power from the substation in the ith interval in terms of USD per MWh. In (10), l is the index related to the type of loads (residential, commercial or industrial), N_{LT} is the total number of load types, and $P_{Load,i,j,k,l}$ is the amount of the lth type of load demanded in the kth node, during the ith interval for the jth scenario of the DG unit generation (MW). $P_{DG,j}$ also represents the power generated in the jth scenario of the DG unit generation (MW).

Finally, in (11), b is an index referring to branches. N_B, r_b and I_b also refer to the total number of branches, the resistance, and the current of the bth branch, respectively.

2.4.2. Customer interruption cost (C_{CI})

The expected customer interruption cost is used to evaluate the reliability of a network configuration in a specific period. Since failure costs are variant for different load types, in order to calculate the cost of failures in power grid lines, the following equations are used:

$$C_{CI,i,j} = \sum_{l=1}^{N_{LT}}\sum_{b=1}^{N_B} \xi_b \times L_b \times P_{NSLi,j,l,b} \times T_{int} \times CF_{CI,i,j,l}(P_{in,i,j}) \tag{12}$$

$$P_{NSL,i,j,l,b} = \sum_{s=1}^{N_{NSL,b}} P_{NSL,i,j,l,b,s} \tag{13}$$

In (12), ξ_b and L_b are respectively the failure rate in terms of fault per kilometer and the length (km) of the bth branch. $P_{NSL,i,j,l,b}$ is also the amount of type l load which is not supplied (MW) due to a failure occurrence in the bth branch (in the ith interval for the jth scenario of the DG unit generation). T_{int} refers to the

duration of customer interruption (hours per fault). Finally, $CF_{CI,i,j,l}(\cdot)$ is the cost function of the energy not supplied for the loads of type l (USD per MWh).

In (13), $N_{NSL,b}$ refers to the total number of not supplied loads due to the fault occurrence in the bth branch. Also, subscript s in $P_{NSL,i,j,l,b,s}$ refers to the sth not supplied load (MW).

It should be mentioned that in case of having some sensitive loads in the system, the interruption cost of such loads should be defined high in order to decrease the possibility of their interruption.

2.5. Cost of transformer loss of life (C_{TLoL})

In this subsection, the transformer loss of life cost is calculated for a period comprising a specific number of intervals [33]. This cost is calculated using the following equations considering a specified ambient temperature.

$$C_{TLoL} = \sum_{t=1}^{N_{TR}} LOL_{tr} \times BP_{tr} \tag{14}$$

$$LOL_{tr} = \frac{F_{EQA,tr} \times T}{life_{nom,tr}} \tag{15}$$

$$F_{EQA,tr} = \frac{\sum_{i=1}^{N} F_{AA,tr,i} \times T_i}{\sum_{i=1}^{N} T_i} \tag{16}$$

$$F_{AA,tr,i} = e^{\left(\frac{15000}{383} - \frac{15000}{\Theta_{H,tr,i}+273}\right)} \tag{17}$$

In (14), tr is an index referring to each transformer and N_{TR} is the total number of transformers in the grid. BP_{tr} and LOL_{tr} also refer to the trth transformer price (USD) and its loss of life, respectively.

In (15)–(17), T, T_i, and $life_{nom,tr}$ refer to the duration of the period under study (hours), duration of the ith interval (hours), and the nominal insulation life of the trth transformer, respectively. Also, $F_{AA,tr,i}$ calculates the accelerated aging of the trth transformer insulation in the ith interval. Finally, $\Theta_{H,tr,i}$ refers to the trth transformer hot-spot temperature in the ith interval. According to [33], the hot-spot temperature can be calculated for the transformers with the allowable temperature rise of 65 °C as follows:

$$\Theta_{H,tr,i} = \Theta_{A,tr} + \Delta\Theta_{TO,tr,i} + \Delta\Theta_{H,tr,i} \tag{18}$$

In this equation, the trth transformer hot-spot temperature ($\Theta_{H,tr,i}$) in the ith interval consists of three parts: ambient temperature ($\Theta_{A,tr,i,j}$), top-oil temperature rise over ambient temperature ($\Delta\Theta_{TO,tr,i}$), and hot-spot temperature rise over top-oil temperature ($\Delta\Theta_{H,tr,i}$).

Top-oil temperature rise of the trth transformer after a specific interval is calculated by the following exponential equation:

$$\Delta\Theta_{TO,tr,i} = \left(\Delta\Theta_{TO,U,tr,i} - \Delta\Theta_{TO,I,tr,i}\right)\left(1 - e^{-\frac{T_i}{\tau_{TO,tr}}}\right) + \Delta\Theta_{TO,I,tr,i} \tag{19}$$

In this equation, indices U and I refer to the ultimate and initial values, respectively. Also, $\tau_{TO,tr}$ is the oil time constant (hours) at the rated load of the trth transformer. $\Delta\Theta_{TO,I,tr,i}$ is obtained from the top-oil rise calculated for the $(i-1)$th load step. Furthermore, since the ultimate temperature rise of the oil ($\Delta\Theta_{TO,U,tr}$) has an unknown value, the following empirical equation is used to estimate the value of this temperature:

$$\Delta\Theta_{TO,U,tr,i} = \Delta\Theta_{TO,R,tr}\left[\frac{\left(K_{tr,i}^2 \times R + 1\right)}{(R+1)}\right]^n \tag{20}$$

In this equation, $\Delta\Theta_{TO,R,tr}$ refers to the top-oil rise at the rated load of the trth transformer. K is the per-unit value of the transformer load. Also, R is the ratio of rated load losses to no-load losses. Furthermore, n is an empirical constant which its value is dependent to the transformer cooling technique. Finally, using the following equation $\tau_{TO,tr}$ can be calculated:

$$\tau_{TO,tr,i,j} = \tau_{TO,tr,r}\frac{\left(\frac{\Delta\Theta_{TO,U,tr,i}}{\Delta\Theta_{TO,R,tr}}\right) - \left(\frac{\Delta\Theta_{TO,I,tr}}{\Delta\Theta_{TO,R,tr}}\right)}{\left(\frac{\Delta\Theta_{TO,U,tr,i}}{\Delta\Theta_{TO,R,tr}}\right)^{\frac{1}{n}} - \left(\frac{\Delta\Theta_{TO,I,tr}}{\Delta\Theta_{TO,R,tr}}\right)^{\frac{1}{n}}} \tag{21}$$

in which, $\tau_{TO,R,tr,i}$ is the rated top-oil time constant of the trth transformer in the ith interval. Furthermore, to calculate the last term of (18), $\Delta\Theta_{H,tr,i}$, the following equation is applied:

$$\Delta\Theta_{H,tr,i} = \left(\Delta\Theta_{H,U,tr,i} - \Delta\Theta_{H,I,tr,i}\right)\left(1 - e^{-\frac{T_i}{\tau_W}}\right) + \Delta\Theta_{H,I,tr,i} \tag{22}$$

in which, $\Delta\Theta_{H,U,tr,i}$ and $\Delta\Theta_{H,I,tr,i}$ refer to the ultimate and initial values of the winding hot-spot temperature of the trth transformer in the ith interval, respectively. The following equation can be used for calculating the former:

$$\Delta\Theta_{H,U,tr,i} = \Delta\Theta_{H,R,tr} \times K_{tr,i}^{2m} \tag{23}$$

in which, m is an empirical constant. It is noteworthy to mention that due to the negligible amount of τ_W, $\Delta\Theta_{H,tr,i}$ and $\Delta\Theta_{H,U,tr,i}$ are usually equal.

To sum up on this subsection, for a period with a specific number of intervals, the transformer loss of life cost can be calculated using (14)–(23). The only required data for calculating this cost is a matrix consisting the amount of transformer load for all intervals ($L_{tr,i,c}^{st}$) which is explained in Section 2.6.

2.6. Handling the DG unit uncertainty

As generation of the DG unit is uncertain, some scenarios with specific probabilities are considered for its generation. In Section 2.4, for each interval and each scenario of the DG unit generation a separate optimization was done, and then a specific number of cases were determined by the aid of the proposed case reduction approach.

In this subsection, the expected value of each case cost as well as the expected value of transformer load will be determined and fed into ACO as inputs. Hence, for the cth case of the ith interval, the expected values of the cost of purchasing power from the substation ($C_{PP,i,c}^{st}$) and customer interruption cost ($C_{CI,i,c}^{st}$) can be calculated as follows:

$$C_{PP,i,c}^{st} = \sum_{j=1}^{N_j} P_j \times C_{PP,i,j,c} \tag{24}$$

$$C_{CI,i,c}^{st} = \sum_{j=1}^{N_j} P_j \times C_{CI,i,j,c} \tag{25}$$

in which P_j is the probability of the jth scenario of the DG unit generation. Also, $C_{PP,i,j,c}$ and $C_{CI,i,j,c}$ respectively refer to the cost of purchasing power from the substation and customer interruption cost for the jth scenario of DG unit generation in the cth case of the ith interval.

Hence, the Total Cost (TC) of the cth case in the ith interval can be calculated as follows:

$$TC_{i,c}^{st} = C_{PP,i,c}^{st} + C_{Cl,i,c}^{st} \tag{26}$$

As explained in (6), for calculating the transformers loss of life cost the expected value of their loads (L_{tr}^{st}) are needed. In fact, L_{tr}^{st} is needed for calculating the per-unit value of the *tr*th transformer load (K_{tr}) in (20) and (23). By having this parameter, the transformers loss of life cost can be calculated using (14)–(23). Therefore, the *tr*th transformer expected load in the *c*th case of the *i*th interval can be calculated as follows:

$$L_{tr,i,c}^{st} = \sum_{j=1}^{N_j} P_j \times L_{tr,i,j,c} \tag{27}$$

where $L_{tr,i,j,c}$ is the *tr*th transformer load in the *c*th case of *i*th interval for the *j*th scenario of DG unit generation.

2.6. Flowchart of the proposed method

For better deduction, the flowchart of the proposed method explained in Sections 2.6 is shown in Fig. 1.

2.7. Operational indices

In this section, two operational indices are defined in order to investigate the operational condition of the grid:

2.7.1. Total Voltage Profile Index (TVPI)

This index calculates the summation of voltage deviations from the rated value in all nodes of the grid during the whole planning period. Due to the variant output of the DG unit, this index is calculated separately for each scenario of the DG unit generation as follows [34,35]:

$$TVPI_j = \sum_{i=1}^{N} \sum_{k=1}^{N_n} |V_{rated} - V_{i,j,k}| \tag{28}$$

in which $TVPI_j$ refers to the amount of this index calculated for the *j*th scenario of the DG unit generation. Obviously, lower values of this index guarantee the flatter voltage profile of the grid.

Furthermore, $\sum_{k=1}^{N_n} |V_{rated} - V_{i,j,k}|$ is called the Voltage Profile Index (VPI) in the *i*th interval for the *j*th scenario of the DG unit Generation which is equal to the sum of deviations of all buses from 1 p.u.

The per-unit value of $TVPI_j$ is calculated as follows:

$$TVPI_j^{pu} = \frac{TVPI_j}{TVPI_j^{n}} \tag{29}$$

where $TVPI_j^{n}$ refers to the amount of $TVPI_j$ when no switching scheme is implemented in the grid.

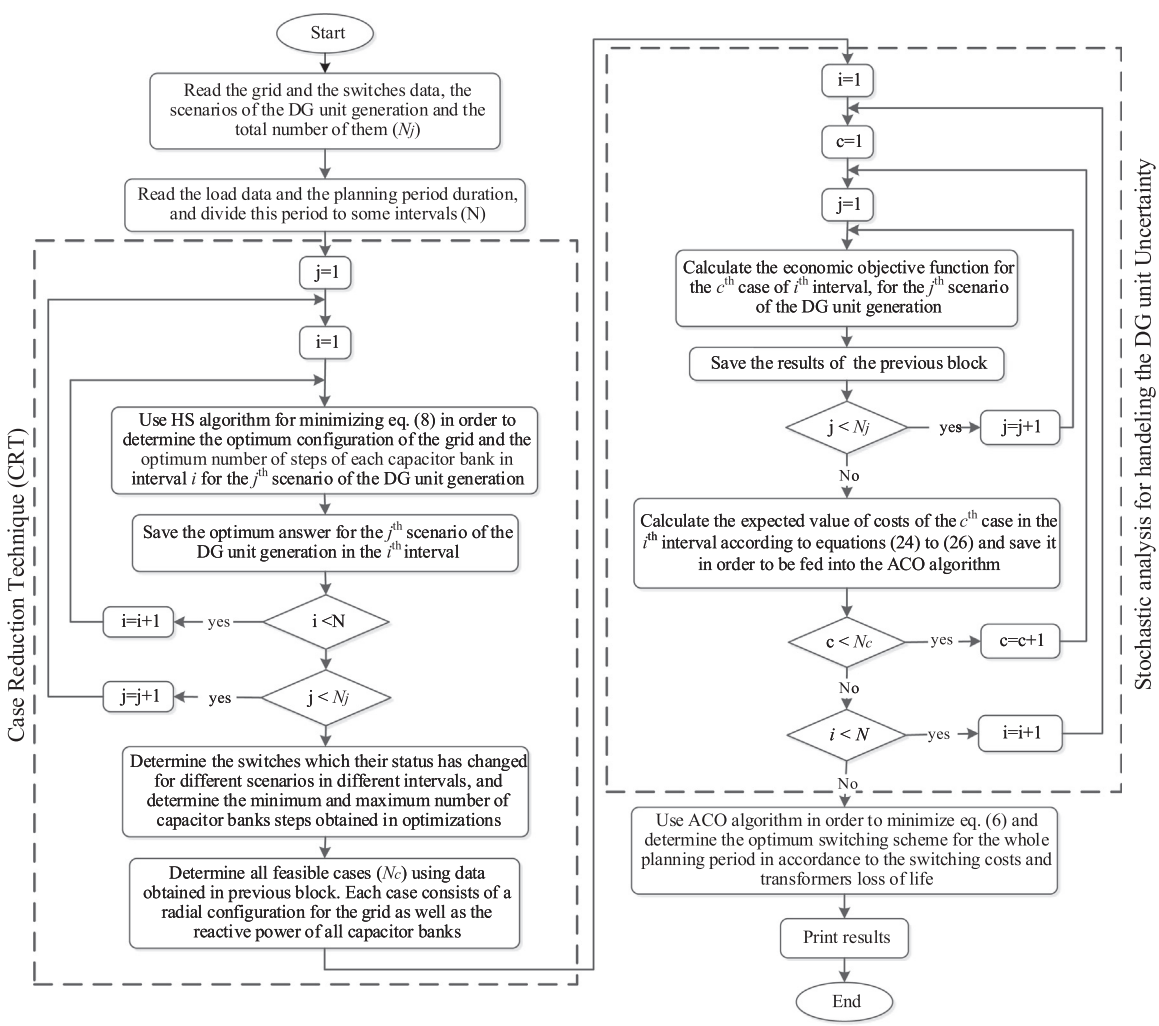

Fig. 1. Flowchart of the proposed method.

2.7.2. Total Power Loss Index (TPLI)

As power loss is one of the main issues operators concern about, this index which calculates the summation of the grid real power losses during the whole planning period is defined as follows [34,35]:

$$TPLI_j = \sum_{i=1}^{N}\sum_{b=1}^{N_b} r_b \times I_{i,j,b}^2 \tag{30}$$

$$TPLI_j^{pu} = \frac{TPLI_j}{TPLI_j^n} \tag{31}$$

in which $TPLI_j$ refers to the amount of this index calculated for the jth scenario of the DG unit generation. Also, $TPLI_j^{pu}$ is the per-unit value of $TPLI_j$ which is calculated based on the amount of the same index when no switching scheme is applied ($TPLI_j^n$).

3. Case study and simulation results

In this section, the proposed method is simulated using MATLAB. In the following subsections, first the system under study and its parameters are explained. Afterwards, the simulation results will be presented and discussed in details.

3.1. Case study

3.1.1. Power grid model

In order to evaluate the performance of the proposed method, the IEEE 118-bus distribution system is used for simulations. Data related to this system is available in [36].

3.1.2. Load model

In this paper, three different load types, i.e. residential, commercial and industrial are simulated. Also, it is assumed that the weekly load curve is available as shown in Fig. 2. In this figure, the vertical axis represents the load demand percentage at each bus in each hour. Therefore, the load demand of each bus can be obtained by multiplying the percentage represented in this curve by the related base load of that bus which is brought in [36]. For better deduction, the amounts of active and reactive load demands for all three load types are shown in Figs. 3 and 4 for the first 48 hours of the week, respectively. It is also noteworthy to mention that the period of study (one week) is divided into 168 equal intervals. As a result, each interval is equal to 1 hour.

3.1.3. DG unit generation stochastic data

In this paper, a DG unit in form of a wind turbine with variant generation of maximum 5 MW is considered. Data related to each generation scenario consisting of the amount of generation and its probability is given in Appendix A. These data are related to a real wind turbine installed in Manjil wind farm, Iran.

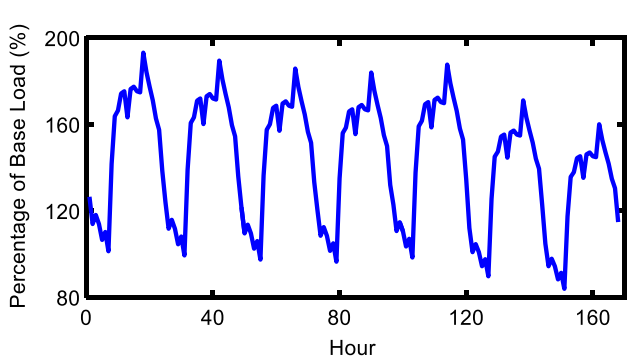

Fig. 2. Weekly load model.

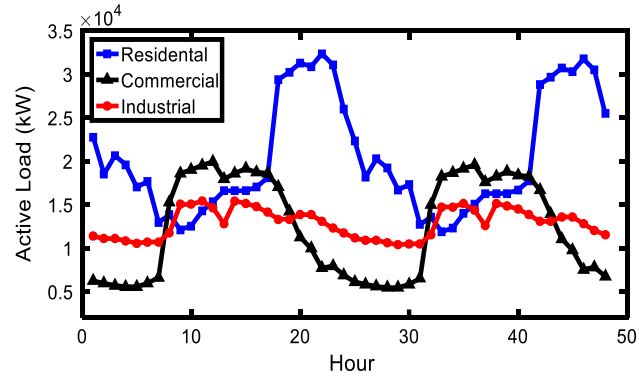

Fig. 3. Active powers demanded by each type of load during the first 2 days.

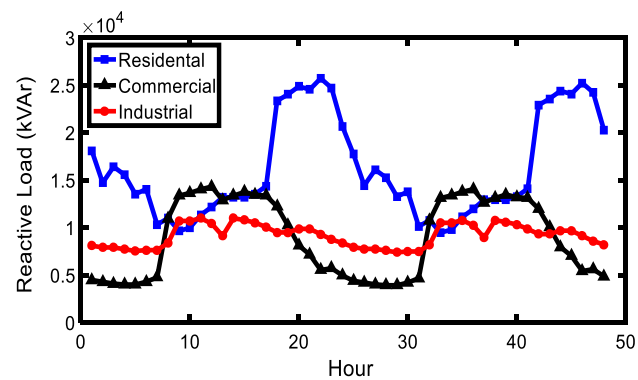

Fig. 4. Reactive powers demanded by each type of load during the first 2 days.

3.1.4. Data related to the cost of purchasing power

To calculate the cost of power purchase from the substation, three load levels, i.e., low, medium and high are considered which their data are presented in Appendix A. As it is shown in Appendix A, cost of buying power from the grid is dependent on load levels. In other words, the price of power in each hour is a function of the amount of load demand.

3.1.5. Data related to the cost of energy not supplied

In order to calculate the cost of energy not supplied, it is assumed that this cost is dependent on load types and levels [37]. The cost of unsupplied energy for each kind of load according to its level is presented in Appendix A. It is noteworthy to mention that the outage rate for each line as well as the needed time for restoration of the grid after fault occurrence can be obtained from Outage Management Systems (OMS) [38,39].

3.1.6. Data related to the cost of transformer loss of life

In this paper, as an example to show how this cost works, transformer loss of life cost is calculated only for the substation transformer. The value of this cost can be considerable when there are some high power transformers in the grid. Otherwise, this cost can be neglected. The parameters according to which this cost is calculated are given in Appendix A.

3.1.7. Data related to the cost of switching devices loss of life

In order to calculate the switching cost, it is assumed that opening each reconfiguration switch under load costs \$50.75 [40]. Also, each capacitor bank switching costs \$8.107 [41].

Table 2
Reconfiguration switches data obtained from the CRT.

Constantly open switches or those closed at very few hours	–
Constantly closed switches or those opened at very few hours	1–4, 10–17, 27–28, 31, 36–38, 53, 56, 63–64, 68–71, 78–80, 84–85, 90, 92–95, 100–103, 106–107, 111–118, 132
Switches being opened and closed regularly	5–9, 18–26, 29–30, 32–35, 39–52, 54–55, 57–62, 65–67, 72–77, 81–83, 86–89, 91, 96–99, 104–105, 108–110, 119–131, 133

3.2. Simulation and results

In this subsection, the simulation results for the IEEE 118-bus distribution systems are presented. It is assumed that five capacitor banks with the maximum capacity of 3 MVAr are installed on buses 22, 51, 82, 95, 110. These capacitor banks have 10 steps, each of which with the capacity of 300 kVArs. Furthermore, it is assumed that a DG unit with the maximum capacity of 5 MW is connected to the bus number 110.

By applying the case reduction technique, the results shown in Tables 2 and 3 are obtained for the switches and output kVArs of capacitor banks, respectively. Afterwards, based on these results, all possible cases are specified and fed as inputs into ACO. Hence, by implementing this algorithm, the optimum switching scheme for both reconfiguration and capacitor banks switches is determined which is shown in Tables 4 and 5, respectively. Using this switching scheme, the total cost breakdowns given in Table 6 will be obtained. Also, for better deduction, the output variations of capacitor banks are depicted in Fig. 5.

In order to fully judge the proposed algorithm, these scenarios are considered as well:

Scenario I: In this scenario, it is assumed that no variant capacitor bank is installed in the distribution system. Hence, only reconfiguration switching scheme can be applied in order to have a better economic and operational performance. The optimum scheme for this scenario is shown in Table 7.

Scenario II: In this scenario, it is assumed that no reconfiguration switch is installed in the distribution system. Hence, only capacitor banks switching scheme can be applied. The optimum scheme for this scenario is shown in Table 8.

In order to have a better evaluation, operational costs of the grid after implementing the proposed method, scenario I and scenario II in comparison with the case of implementing no switching scheme are shown in Table 9. As it is shown, the cost of buying power from the substation after applying the proposed method has been reduced about 12% while this cost has been decreased about 4.7% and 5.7% after applying scenarios I and II, respectively.

Furthermore, there is a further decrease in the transformer loss of life cost in the second scenario as well as the proposed method

Table 3
CBs variation ranges obtained from the CRT.

CB No.	Maximum used capacity (kVArs)	Minimum used capacity (kVArs)	Number of steps
1	3000	1500	6
2	2400	1200	5
3	2400	0	9
4	3000	600	9
5	2400	1200	5

Table 5
The optimum switching scheme obtained from the proposed method for Capacitor banks.

Hour	Capacitor banks KVar				
	Bank1	Bank2	Bank3	Bank4	Bank5
1	2700	2100	1800	1200	1800
11	1800	2100	0	600	2400
17	3000	1200	2400	2700	1500
74	1800	2100	0	600	2400
77	2700	2100	1800	1200	1800
83	1800	2100	0	600	2400
86	3000	1200	2400	2700	1500
121	2700	2100	1800	1200	1800
133	1800	2100	0	600	2400
138	3000	1200	2400	2700	1500

Table 6
Weekly costs after applying the proposed method.

Cost	Value ($)
Buying power	245824.33
Interruption	12,109
Transformer loss of life	13.10
Capacitor banks switching	1305.23
Reconfiguration switching	5125.75
Total	264377.409

Table 4
The optimum switching scheme obtained from the proposed method for reconfiguration switches.

Hour	Open reconfiguration switches														
	Sw. 1	Sw. 2	Sw. 3	Sw. 4	Sw. 5	Sw. 6	Sw. 7	Sw. 8	Sw. 9	Sw. 10	Sw. 11	Sw. 12	Sw. 13	Sw. 14	Sw. 15
1	7	24	29	30	50	57	77	88	89	104	110	120	124	125	130
11	6	18	25	30	43	49	72	75	86	96	110	120	122	129	130
17	6	20	26	45	51	59	67	76	82	86	88	96	110	123	133
74	6	18	25	30	43	49	72	75	86	96	110	120	122	129	130
77	7	24	29	30	50	57	77	88	89	104	110	120	124	125	130
83	6	18	25	30	43	49	72	75	86	96	110	120	122	129	130
86	6	20	26	45	51	59	67	76	82	86	88	96	110	123	133
121	7	24	29	30	50	57	77	88	89	104	110	120	124	125	130
133	6	18	25	30	43	49	72	75	86	96	110	120	122	129	130
138	6	20	26	45	51	59	67	76	82	86	88	96	110	123	133

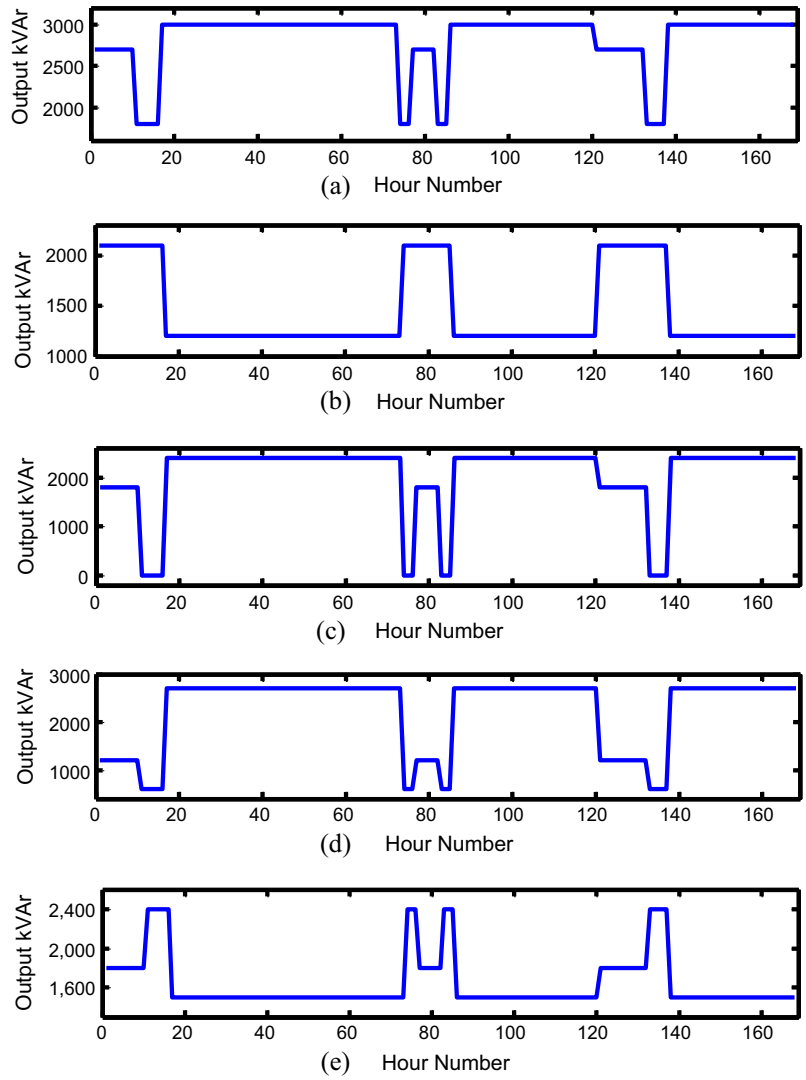

Fig. 5. Generated kVArs of capacitor banks installed on buses: (a) 22, (b) 51, (c) 82, (d) 95, (e) 110 in each hour.

Table 7
The optimum switching scheme for scenario I.

Hour	Open reconfiguration switches														
	Sw. 1	Sw. 2	Sw. 3	Sw. 4	Sw. 5	Sw. 6	Sw. 7	Sw. 8	Sw. 9	Sw. 10	Sw. 11	Sw. 12	Sw. 13	Sw. 14	Sw. 15
1	15	24	34	39	54	60	67	75	76	83	110	119	122	126	131
18	8	25	29	37	38	41	54	56	67	88	97	108	110	120	131
24	15	24	34	39	54	60	67	75	76	83	110	119	122	126	131
42	8	25	29	37	38	41	54	56	67	88	97	108	110	120	131
48	15	24	34	39	54	60	67	75	76	83	110	119	122	126	131
66	8	25	29	37	38	41	54	56	67	88	97	108	110	120	131
72	15	24	34	39	54	60	67	75	76	83	110	119	122	126	131
90	4	5	9	17	24	26	32	59	72	75	77	104	108	122	130
96	15	24	34	39	54	60	67	75	76	83	110	119	122	126	131
114	8	25	29	37	38	41	54	56	67	88	97	108	110	120	131
120	15	24	34	39	54	60	67	75	76	83	110	119	122	126	131
138	8	13	22	29	31	42	52	57	70	76	87	107	110	125	131
144	15	24	34	39	54	60	67	75	76	83	110	119	122	126	131
162	8	13	22	29	31	42	52	57	70	76	87	107	110	125	131
167	15	22	25	27	51	59	67	74	83	96	97	110	122	125	131

in comparison with the first scenario. However, the amount of savings due to this cost is small in comparison with other savings as only the substation transformer is considered. Transformer loss of life cost can be more considerable if all transformers in the grid are considered.

Finally, it can be observed that the total operational cost of the grid after implementing the proposed method has been reduced about 9.3% which shows a further improvement in comparison with the values of 1.93% and 5.3% which are obtained after applying scenarios I and II, respectively.

Table 8
The optimum capacitor banks switching scheme for scenario II.

Hour	Capacitor banks kVArs				
	Bank 1	Bank 2	Bank 3	Bank 4	Bank 5
1	1200	900	2100	2400	2100
13	900	1200	2400	3000	2700
17	1800	1500	2700	3000	3000
22	1200	900	1500	2400	1800
32	1800	1200	2100	3000	2400
36	1800	1200	2400	3000	2700
41	1200	1500	2700	2700	3000
47	1800	1200	2100	3000	2400
56	1800	1200	2400	3000	2700
68	1200	900	2100	2400	2400
73	1200	900	1500	2400	1800
80	1800	1200	2100	3000	2400
84	1200	1500	3000	2700	3000
95	900	1200	2100	3000	2400
104	1500	1200	2400	3000	2400
107	1800	1500	3000	2700	2700
115	1800	1500	2700	2700	3000
118	1200	900	1500	2400	1800
129	1200	1200	2400	2700	2700
133	1800	1500	3000	3000	2400
135	1800	1500	2700	2700	3000
141	900	1200	2100	3000	2400
150	1200	900	1500	2400	1800
152	1800	1200	2400	3000	2700
161	1800	1500	2700	2700	3000
164	1200	1200	2100	3000	2400

To evaluate the operational performance of the grid, using (28) and (30), indices $TVPI_j^{pu}$ and $TPLI_j^{pu}$ are calculated separately for each scenario of the DG unit generation which is shown in Table 10. This table shows that how much variation would occur in the operational performance of the grid in terms of voltage profile and power losses in comparison with the case of implementing no switching scheme when the DG unit generates its *j*th scenario during the whole planning period.

According to the results shown in this table, while reconfiguration (the scheme applied in scenario I) has the least effect on voltage profile improvement, capacitor banks switching (the scheme applied in scenario II) has more impact on voltage profile improvement. Meanwhile, as shown in this table, the proposed method leads to the maximum improvement of voltage profile. Furthermore, from loss reduction viewpoint, differences between the proposed method and the defined scenarios are more highlighted. In other words, power loss index varies over the interval of 38.3–39.3% using the proposed method, while it changes from 67.1 to 84.2%, and from 62.3 to 65.8% respectively for the first and second scenarios. Hence, the proposed method has a strong potential in reducing the network power losses as well. In Fig. 6, the amount of VPI for the first and the last scenarios of DG unit generation during the first 24 hours of the planning period is shown for the proposed method, scenario I, scenario II, and the case of implementing no switching scheme. This figure also verifies the results of Table 10.

Table 9
Weekly operational costs of the grid.

Costs	No switching scheme	Proposed method	Scenario I	Scenario II
Buying power	278131.90	245824.33	265005.35	262215.10
Interruption	12536.91	12,109	12286.04	12536.91
Transformer loss of life	955.06	13.10	738.60	13.94
Capacitor banks switching	–	1305.23	–	1410.618
Reconfiguration switching	–	5125.75	7967.75	–
Total	291623.87	264377.409	285997.74	276176.57

Table 10
Operational indices values calculated for each scenario.

J	DG output (MW)	Proposed method		Scenario I		Scenario II	
		$TVPI_j^{pu}$	$TPLI_j^{pu}$	$TVPI_j^{pu}$	$TPLI_j^{pu}$	$TVPI_j^{pu}$	$TPLI_j^{pu}$
1	5	0.619	0.393	0.886	0.671	0.766	0.623
2	3.5	0.617	0.387	0.872	0.720	0.772	0.632
3	2.25	0.616	0.384	0.855	0.764	0.777	0.642
4	1.25	0.614	0.383	0.837	0.804	0.780	0.650
5	0.5	0.613	0.383	0.822	0.842	0.783	0.658

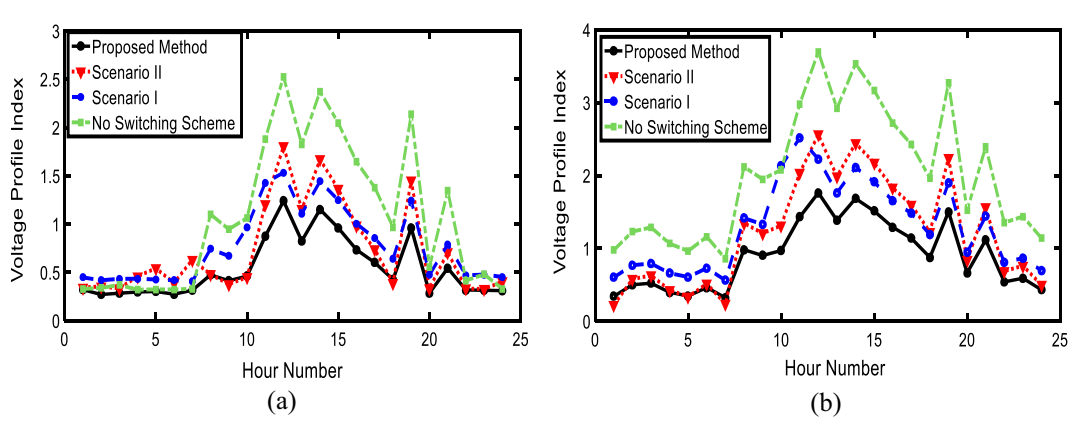

Fig. 6. Voltage profile index during the first 24 hours of the planning period: (a) for the minimum generation of the DG unit, (b) for the maximum generation of the DG unit.

4. Conclusion and further works

In this paper, realizing the presence of a DG unit whit a variant generation in a smart distribution system, a method was proposed to determine the optimum distribution system configuration and reactive power of capacitor banks for each interval of the planning period. It was assumed that the load curve and switching costs for both reconfiguration and capacitor banks switches are known. The proposed objective function which had to be minimized using ant colony optimization method included: switching costs, transformers loss of life expenses, and costs of buying power from substation as well as customers' interruption penalties. Furthermore, in order to reduce the complexity of the problem, a case reduction technique using HS algorithm was proposed. Additionally, in order to evaluate the performance of the proposed algorithm, two scenarios were studied. The simulation results revealed that the proposed method consisting of both reconfiguration and capacitor banks switching schemes has better potential for reducing the total grid cost in comparison with the schemes implemented in scenarios I and II. Also, the defined operational indices showed the superiority of the proposed method in improving the operational performance of the grid.

The algorithm developed in this work can be improved through the following points of view:

- Implementation of the stochastic load modeling to fully address the real load nature.
- Considering the continuous form of load curve and determining the proper duration of intervals by using clustering methods.
- Considering on-line tap changing transformers and investigating their effects on reconfiguration and capacitor switching schemes while a high level of fluctuations in power generation and load level exists.
- Considering the resiliency of the grid as well as its vulnerability while determining the candidate configurations in case reduction section.

Appendix A. Case study data

In this appendix the used data for the case study section is presented. Data related to the scenarios of the DG unit is shown in Table 11. Furthermore, the used data for calculating the cost of purchasing power from substation is presented in Table 12. In Table 13, data related to the price of not supplied energy for different load types and levels are provided. Data related to the transformer loss of life are provided in Table 14.

Table 11
The DG unit generation scenarios (Manjil wind turbine).

Level	DG unit output (MW)	Probability
1	5.00	0.335502
2	3.50	0.050628
3	2.25	0.056336
4	1.25	0.075570
5	0.50	0.481964

Table 12
Data used for calculating the cost of buying power [37].

Level	Percentage of peak load	Load level	Cost ($/MWh)
1	0–70	Low	35
2	70–90	Medium	49
3	90–100	High	70

Table 13
Data used for calculating energy not supplied cost [37].

Load type	Network demand	Unsupplied energy cost ($/MWh)
Residential	Low demand	53
	Average demand	73
	Peak demand	105
Commercial	Low demand	2000
	Average demand	2800
	Peak demand	3600
Industrial	Low demand	6000
	Average demand	8400
	Peak demand	11,050

Table 14
Data used for calculating transformer loss of life cost.

Parameter	Details	Parameter	Details
Transformer life	15 years	R	8
Transformer price	$1,200,000	M	0.8
Ambient temperature	25 °C	N	0.8
Rated power	70 MVA	τ_{TO}	2 h

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