Multistage Coordinated Planning of Active Distribution Networks

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***Abstract*— This paper introduces a multistage coordinated planning method for active distribution networks (ADN). The proposed methodology optimizes, in a coordinated manner, multiple planning alternatives, i.e., reinforcement of the existing substations and distribution lines, network expansion, as well as capacitor and voltage regulator placement in conjunction with the active management of distributed generation (DG). The active management considers the control of the active and reactive power output of the DG units. The proposed multistage coordinated planning methodology aims at minimizing the net present value of the network investment cost. To handle the high complexity of the planning problem, two successive planning procedures are developed. First, the location and capacity of the multiple planning alternatives are computed incorporating the active management of DG. Afterwards, using a heuristic approach, the time period for the commissioning of the computed network investments along the planning period is defined. To validate its effectiveness and performance, the proposed method is applied to a 24-bus distribution test system and a real-world 267-bus distribution system.**

***Index Terms*—Active distribution network, distributed generation, multistage planning, network expansion, power distribution planning.**

Nomenclature

A. *Sets*

Φ_{f_k}	Set of buses of feeder k.
Φ_N	Set of system buses.
Φ_{CB}	Set of candidate buses for capacitor bank (CB) placement.
Φ_L	Set of distribution lines.
Φ_{LA}	Set of candidate lines to be added.
Φ_{LR}	Set of candidate lines to be reinforced.
Φ_{LVR}	Set of candidate lines for voltage regulator (VR) placement.
Φ_{SS}	Set of substation buses.
Ψ_{CB}	Set of available capacitor banks.
Ψ_{cd}	Set of available conductors.
Ψ_{SS}	Set of available substations.
Ψ_{VR}	Set of available voltage regulators.

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B. *Parameters*

$a_{R\,\min}/a_{R\,\max}$	Minimum/maximum VR range.
$C_{CB,c}$	Cost of type c CB, \$.
$C_{cd,b}$	Cost of type b conductor, \$/km.
$C_{SS,a}$	Cost of type a substation, \$/MVA.
$C_{VR,d}$	Cost of type d VR, \$.
Inf	Inflation rate.
Int	Interest rate.
l_{ij}	Length between buses i and j, km.
N	Total number of buses.
N_f	Total number of distribution feeders.
$\overline{P_D}$	Mean active power demand of the network, MW.
$P_{D,i,t}/Q_{D,i,t}$	Active/reactive load demand of bus i at period t, MW/Mvar.
$P_{DG,i,t}$	Active power of the DG unit at bus i at period t, MW.
$P_{DGnom,i}$	Rated active power of the DG unit at bus i, MW.
$pf_{\lim}$	Power factor limit of the DG units.
$Q_{CB,j}$	Nominal reactive power of the CB at bus j, Mvar.
$Q_{DG\,\max,i}$	Maximum reactive power of the DG unit at bus i, Mvar.
$Q_{DG\,\min,i}$	Minimum reactive power of the DG unit at bus i, Mvar.
$r_{ij,b}/x_{ij,b}$	Resistance/reactance of type b conductor of line i–j, Ω/km.
$S_{DG\,\max,i}$	Maximum apparent power of the DG unit at bus i, MVA.
$S_{\max,b}$	Thermal limit of type b conductor, MVA.
$S_{SS\,\max,a}$	Thermal limit of type a substation, MVA.
$S_{VR\,\max,d}$	Thermal limit of type d voltage regulator, MVA.
T	Years of the planning period.
$V_{\min}/V_{\max}$	Minimum/maximum voltage magnitude limits, kV.
w_1, w_2, w_3	Weighting coefficients.

C. *Variables*

a_R	Voltage regulator ratio.
$I_{ij,t}$	Current magnitude of line i–j at period t, A.
P_{D,f_k}	Maximum active power demand of feeder k, MW.

$P'_{DG,i,t}$	Injected active power from the DG unit of bus *i* at period *t*, MW.
$P_{DGcurt,i,t}$	Curtailed active power of the DG unit of bus *i* at period *t*, MW.
$P_{ij,t}/Q_{ij,t}$	Active/reactive power flow of line *i–j* at period *t*, MW/Mvar.
$P_{SS,i,t}/Q_{SS,i,t}$	Active/reactive power flow of substation at bus *i* at period *t*, MW/Mvar.
$Q_{DG,i,t}$	Reactive power of the DG unit of bus *i* at period *t*, Mvar.
$V_{i,t}$	Voltage magnitude of bus *i* at period *t*, kV.
$\delta v^{+}_{i,t}/\delta v^{-}_{i,t}$	Variables associated with the voltage drop calculation of bus *i* at period *t* taking either positive or zero value.
$\delta s_{ij,t}$	Variable associated with the conductor's thermal limit of line *i–j* at period *t* taking either positive or zero value.

D. *Binary Variables*

$y_{ij,t}$	Spanning tree variable. It is equal to 1 if bus *j* is the parent of bus *i* at period *t*; otherwise it is equal to 0.
$z_{i,a,t}$	Decision variable for reinforcement of substation at bus *i* using type *a* substation at period *t*.
$z_{ij,b,t}$	Decision variable for construction of line *i–j* using type *b* conductor at period *t*.
$z^{CB}_{i,c,t}$	Decision variable for construction of type *c* CB at bus *i* at period *t*.
$z^{VR}_{ij,d,t}$	Decision variable for construction of type *d* VR in line *i–j* at period *t*.

I. Introduction

THE main goal of the power distribution network planning (DNP) is to determine the location, capacity and time period of the network investments at minimum cost in order to serve the load growth demand and the new loads, while ensuring the safe operation of the distribution network. In recent years, the active management of the increasing penetration of distributed generation (DG) units, mainly based on renewable energy sources (RES), has converted the distribution networks from passive to active distribution networks (ADN). This transition has provided a new dimension and further complexity to the DNP problem. Traditional DNP approaches, which are typically used by electric utilities, consider a given load growth forecast and no control of the generation output of the DG units to determine the installation of new distribution network assets. These "fit and forget" approaches pose barriers to the further penetration of RES in the distribution networks and they may lead to costly planning solutions. The exploitation of active management of the DG units can ameliorate the above problems.

DNP is a complex mixed integer nonlinear programming (MINLP) problem. The DNP problem can be modeled as static or multistage. In the static formulation, the DNP problem is solved in a single stage and the investment decisions are implemented at the beginning of the planning period [1]–[3]. In the multistage formulation, the network investments are determined over successive planning stages according to the requirements of each stage [1]–[3]. Therefore, the electric utilities can gradually execute the investment decisions over the planning horizon in order to deal with the increasing load demand at minimum cost [3]. The investment decisions required at the first stages of the planning period are immediately implemented; while the investment decisions determined for the later stages can be reexamined for updated values of the load forecast [2], [4]. An exhaustive review of the DNP models and strategies is provided in [1]–[3]. The objective of the typical DNP is to optimally plan the distribution network to meet the future demand and all the technical and operational constraints [1]. In the modern and future active distribution networks era, the exploitation of the control capabilities and the capacity of the distributed energy resources can provide optimal distribution neh important cost savings [2]. A detailed presentation of current DNP practices around the world and how these have evolved (or have to evolve) in the context of ADNs can be found in [3]. In [4] and [5], DNP is deterministically solved investigating the impact of dispatchable DG (DDG) units in a multistage planning method. The tradeoffs between the placement and control of dispatchable and renewable DG units and the investments on new feeders and substations for different regulatory environments are evaluated using multi-objective optimization methods in [6] and [7], and the DNP is simplified into a static (final year) planning problem. Uncertainties arising from the DG units' output power and the load response are considered for the static expansion planning of ADNs in [8]. The investment deferral and the reliability improvement of the distribution network are considered as objectives in the multistage optimization methods of [9]–[11] by utilizing conventional DG units as a reinforcement option for the Distribution System Operator (DSO). In [12], the allocation of renewable and DDG units is simultaneously co-optimized with the network reinforcement in a single objective function for cost and CO_2 emission minimization over a planning horizon. In [13], a multistage DNP considering the allocation of both conventional and wind DG units is presented. The construction of new distribution lines, capacitor banks (CBs) and voltage regulators (VRs) along with the installation of conventional DG units are considered in the multistage DNP formulation in [14].

In [4], [8], [9], [11]–[14], the DG units are considered as DSO investments and as planning alternatives, while in [6], [7], [10] it is assumed that DG units are private investments, which is the common practice in Europe. Furthermore, the distribution network investments in [4]–[8], [11]–[13] exclusively include the reinforcement and/or addition of new distribution lines and substations. Investment decisions in [9] and [10] consider the reinforcement and installation of feeders, substations and CBs. The joint reinforcement and placement of distribution lines, substations, CBs and VRs is performed in [14]. Control of the active power output of DG units [6], [7] and demand response (DR) [8], [12] are taken into account in the planning of ADNs.

All the above papers deal with several aspects of the DNP problem, however the consideration of multiple planning

TABLE I
CONTRIBUTIONS AND ATTRIBUTES OF THE REVIEWED DNP PAPERS

Ref.	MS[1]	SR[2]	LR[3]	NE[4]	CB	VR	DG	ANM
[4]	√	√	√	√			√	
[6]			√				√	√
[7]			√				√	√
[8]			√	√			√	√
[9]	√	√	√		√		√	
[11]	√	√	√				√	
[12]	√		√				√	√
[13]	√	√	√	√			√	
[14]	√	√	√	√	√	√	√	
Proposed	√	√	√	√	√	√	√	√

[1] MS = Multistage, [2] SR = Substation Reinforcement, [3] LR = Line reinforcement,
[4] NE = Network expansion

alternatives (coordinated planning) in combination with the active management of DG is an issue that has not been thoroughly examined. Although, active management of the distribution networks that includes control of both DG units and network components has been examined in [15], [16], these works mainly focus on the operational challenges brought by DG integration rather than the planning challenges of ADN.

This paper introduces a multistage coordinated planning framework of active distribution networks in the presence of high renewable DG integration. The long term DNP is modeled as a MINLP problem and multiple planning alternatives are taken into account. The planning procedure is divided into two phases. First, the maximum stress conditions of the distribution network during the planning period are identified and the reinforcement and expansion planning of the distribution network is computed considering the location and capacity of new distribution lines, substations, CBs and VRs. Afterwards, the proposed multistage network planning model determines the installation times of the network components during the planning period. Different active network management (ANM) schemes are taken into account in the proposed multistage planning method and their effects on the DNP solution are examined. In the proposed DNP formulation, the ANM schemes include the control of the reactive and active power output of the DG units. Table I presents a summary of the contributions and attributes of the reviewed papers and the proposed method. The effectiveness of the proposed method is examined using a 24-bus distribution test system and a real-world 267-bus distribution system.

The contributions and main goals of the present work are:

1) To develop a multistage planning framework that optimizes, in a coordinated manner, the capacity, location and installation time of new distribution lines, substations, CBs and VRs considering high DG integration.
2) To incorporate various ANM schemes and examine their effects on the DNP solution.

This paper is organized as follows. Section II describes the formulation of the proposed DNP model. The solution methodology is provided in Section III. The method is applied to a 24-bus distribution test system and a 267-bus real distribution network and the results are presented in Section IV. Conclusions are drawn in Section V.

II. Problem Formulation

Long-term distribution network planning is a large scale optimization problem with a large number of design variables. The proposed model considers the investment costs (*IC*) for i) the reinforcement of the substations ($IC_{SR,t}$) and the existing distribution lines ($IC_{LR,t}$), ii) the expansion of the distribution network ($IC_{LA,t}$), iii) the placement of CBs ($IC_{CB,t}$) and iv) the installation of VRs ($IC_{VR,t}$). The planning framework considers the presence of high DG penetration and its potential active management. The renewable DG units are assumed to be privately owned and their type, site, size and installation time are considered pre-determined. Furthermore, it is assumed that information and communication technology (ICT) infrastructures have already been deployed for the purpose of AMR (Automatic Meter Reading) and not for the application of the proposed method. Since smart metering installations are foreseen by European regulations and have been deployed or are in progress in several countries, their costs have not been considered in our calculations.

A. Power Distribution Planning Formulation

The DNP problem is modeled as a MINLP problem. The objective function (1) considers the net present value (NPV) of the investment costs during the planning period:

$$\min f = \sum_{t=1}^{T} \left(\frac{1 + Inf}{1 + Int} \right)^t (IC_{SR,t} + IC_{LR,t} + IC_{LA,t} + IC_{CB,t} + IC_{VR,t}) \tag{1}$$

where,

$$IC_{SR,t} = \sum_{i \in \Phi_{SS}} \sum_{a \in \Psi_{SS}} C_{SS,a} \cdot z_{i,a,t} \tag{2}$$

$$IC_{LR,t} = \sum_{ij \in \Phi_{LR}} \sum_{b \in \Psi_{cd}} C_{cd,b} \cdot l_{ij} \cdot z_{ij,b,t} \tag{3}$$

$$IC_{LA,t} = \sum_{ij \in \Phi_{LA}} \sum_{b \in \Psi_{cd}} C_{cd,b} \cdot l_{ij} \cdot z_{ij,b,t} \tag{4}$$

$$IC_{CB,t} = \sum_{i \in \Phi_{CB}} \sum_{c \in \Psi_{CB}} C_{CB,c} \cdot z^{CB}_{i,c,t} \tag{5}$$

$$IC_{VR,t} = \sum_{ij \in \Phi_{LVR}} \sum_{d \in \Psi_{VR}} C_{VR,d} \cdot z^{VR}_{ij,d,t} \tag{6}$$

The constraints associated with the steady-state operation of the distribution system in each stage *t* of the planning period are formulated as follows [17]:

$$P_{ij,t} = \sum_{k:(jk) \in \Phi_L} P_{jk,t} + I^2_{ij,t} \cdot r_{ij,b} \cdot l_{ij} + P_{D,j,t} - P_{DG,j,t} - P_{SS,j,t} \tag{7}$$

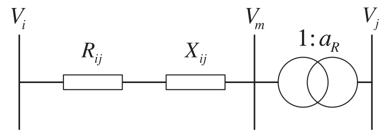


Fig. 1. Voltage regulator model.

$$Q_{ij,t} = \sum_{k:(jk)\in\Phi_L} Q_{jk,t} + I_{ij,t}^2 \cdot x_{ij,b} \cdot l_{ij} + Q_{D,j,t} - Q_{DG,j,t} - Q_{CB,j} \cdot z_{j,c,t}^{CB} - Q_{SS,j,t} \quad (8)$$

$$V_{j,t}^2 = V_{i,t}^2 - 2 \cdot (P_{ij,t} \cdot r_{ij,b} \cdot l_{ij} + Q_{ij,t} \cdot x_{ij,b} \cdot l_{ij}) + I_{ij,t}^2 \cdot \left(r_{ij,b}^2 + x_{ij,b}^2\right) \cdot l_{ij}^2 + \delta v_{j,t}^+ - \delta v_{j,t}^- \quad (9)$$

$$I_{ij,t}^2 \cdot V_{i,t}^2 = P_{ij,t}^2 + Q_{ij,t}^2 \quad (10)$$

$$V_{\min}^2 \le V_{i,t}^2 \le V_{\max}^2 \quad (11)$$

$$P_{ij,t}^2 + Q_{ij,t}^2 \le S_{\max,b}^2 \cdot z_{ij,b,t} + \delta s_{ij,t} \quad (12)$$

$$P_{SS,i,t}^2 + Q_{SS,i,t}^2 \le S_{SS\max,a}^2 \cdot z_{i,a,t} \quad (13)$$

$$y_{ij,t} + y_{ji,t} = 1, \qquad (ij) \in \Phi_L \backslash \Phi_{LA} \quad (14)$$

$$y_{ij,t} + y_{ji,t} = \sum_{t=1}^{T} \sum_{b\in\Psi_{cd}} z_{ij,b,t}, \quad (ij) \in \Phi_{LA} \quad (15)$$

$$\sum_{j\in\Omega_N} y_{ij,t} = 1, \qquad i \in \Phi_N \backslash \Phi_{SS} \quad (16)$$

$$y_{ij,t} = 0, \qquad i \in \Phi_{SS} \quad (17)$$

Equations (7) and (8) represent the active and reactive power flow from bus *i* to *j*, which is equal to the sum of the power flows of the lines that are connected to bus *j* plus the total power injection at bus *j* and the losses of line *i*–*j*. The square of the voltage magnitude of each bus is calculated according to (9). The square of the current magnitude of line *i*–*j* is computed by (10). The voltage limits of the distribution network are shown in (11). The limit of the apparent power flow of line *i*–*j* with type *b* conductor is given in (12). In (13), the apparent power flow limit of type *a* substation is considered. The terms δv^+, δv^- in (9) and δs in (12) provide a relaxation to the voltage and thermal limits violation and they are used to penalize an infeasible solution.

The radiality of the distribution network is ensured by (14)–(17) [18]. The distribution network is represented as a spanning tree with the substation considered as the root of the tree. If the line *i*–*j* is connected to the spanning tree at period *t* $(z_{ij,b,t} = 1)$, the bus *i* can be the parent of bus *j* $(y_{ji,t} = 1)$ or the bus *j* can be the parent of bus *i* $(y_{ij,t} = 1)$, as shown in (14) and (15). The buses connected to the tree have only one parent (16), except the substation bus that has no parents (17).

The VR is modeled, as shown in Fig. 1, by a line in series with an ideal transformer with ratio a_R [19] and it is described by (18)–(20). The voltage of the fictitious bus *m* is calculated according to (9). The thermal limit of a type *d* VR is given by (21). For simplicity, the tap positions of the VR are considered as continuous variables [14], [20]. This assumption can be made since this paper deals with planning issues and not with operational ones.

$$a_{R,\min}^2 \cdot V_{m,t}^2 \le V_{j,t}^2 \le a_{R,\max}^2 \cdot V_{m,t}^2 \quad (18)$$

$$a_{R,\min}^2 \le a_R^2 \le a_{R,\max}^2 \quad (19)$$

$$\left|V_{j,t}^2 - V_{m,t}^2\right| \le \left(V_{\max}^2 - V_{\min}^2\right) \cdot z_{ij,d,t}^{VR} \quad (20)$$

$$P_{ij,t}^2 + Q_{ij,t}^2 \le S_{VR\max,d}^2 \cdot z_{ij,d,t}^{VR} \quad (21)$$

The constraints associated with the investment decision variables during the planning period are given by (22)–(25).

$$\sum_{t=1}^{T} \sum_{a\in\Psi_{SS}} z_{i,a,t} \le 1 \quad (22)$$

$$\sum_{t=1}^{T} \sum_{b\in\Psi_{cd}} z_{ij,b,t} \le 1 \quad (23)$$

$$\sum_{t=1}^{T} \sum_{c\in\Psi_{CB}} z_{i,c,t}^{CB} \le 1 \quad (24)$$

$$\sum_{t=1}^{T} \sum_{d\in\Psi_{VR}} z_{ij,d,t}^{VR} \le 1 \quad (25)$$

Equation (22) ensures that there will be at most one change in the capacity of the substation. Constraint (23) is applied in order to avoid more than one conductor change, during the planning period, for the distribution lines that are candidate to be reinforced or added. According to (24) and (25), investments in CBs and VRs can be made at most once in each candidate bus and branch during the planning period. A substation capacity, a conductor type, a CB or a VR is selected to be installed if the corresponding decision variable is equal to one, while it is not selected if it is equal to zero.

The formulation described by (1)–(25) is the DNP formulation considering the passive management of renewable DG. In the following section the effect of reactive or active power output of the renewable DG units is included.

B. Implementation of Active Network Management

Overvoltage is one of the problems caused by the increasing penetration of RES [21], [22] in weak rural networks. To deal with these long term voltage problems, network investments are needed [21], [23]. Different ANM schemes are implemented in the proposed DNP model in order to test their effect on the planning of ADN. Implementation of such schemes requires complex control techniques with time response dependence [24]. However, in the planning period the time delays of control actions are neglected. The ANM schemes incorporated in the DNP method are:

1) DG reactive Power Control: The DG units can absorb or supply reactive power via their inverter interface to the network [25]–[28], as shown in Fig. 2. Thus, the DG units can operate under active power factor (APF). The capacity of the DG

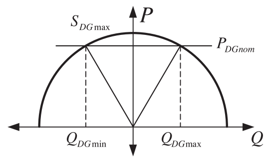


Fig. 2. Inverter reactive power capability curve.

inverters may have to be oversized in order to supply/absorb the needed reactive power. Since, the main goal of the DG units is to produce active power, their injected reactive power is limited as follows:

$$S_{DG\ \max,i}^2 = P_{DGnom,i}^2 + Q_{DG\ \max,i}^2 \tag{26}$$

$$Q_{DG\ \max,i} = P_{DGnom,i} \cdot \tan\left(\cos^{-1}\left(pf_{\lim}\right)\right) \tag{27}$$

$$Q_{DG\ \min,i} = -P_{DGnom,i} \cdot \tan\left(\cos^{-1}\left(pf_{\lim}\right)\right) \tag{28}$$

$$Q_{DG,i,t} \geq -P_{DG,i,t} \cdot \tan\left(\cos^{-1}\left(pf_{\lim}\right)\right) \tag{29}$$

$$Q_{DG,i,t} \leq P_{DG,i,t} \cdot \tan\left(\cos^{-1}\left(pf_{\lim}\right)\right) \tag{30}$$

The maximum apparent power of the DG inverter is given in (26). The maximum and minimum DG reactive power injection limits are given in (27) and (28), respectively. The DG reactive power injected at bus *i* during period *t* has a specific range, as shown in (29) and (30).

2) DG Active and Reactive Power Control: The application of active power curtailment (APC) to the DG units may solve voltage limits violations, in case these violations cannot be solved by the APF scheme [21], [23], [27], [28]. In the proposed DNP method, the APC is modeled as a negative generation added to the active power output of the DG unit:

$$P_{DG,i,t}^{prime} = P_{DG,i,t} - P_{DGcurt,i,t} \tag{31}$$

$$0 \leq P_{DGcurt,i,t} \leq P_{DGcurt}^{\max} \tag{32}$$

$$P_{DGcurt}^{\max} \leq P_{DG,i,t} \tag{33}$$

$$Q_{DG,i,t} \geq -\left(P_{DG,i,t} - P_{DGcurt,i,t}\right) \cdot \tan\left(\cos^{-1}\left(pf_{\lim}\right)\right) \tag{34}$$

$$Q_{DG,i,t} \leq \left(P_{DG,i,t} - P_{DGcurt,i,t}\right) \cdot \tan\left(\cos^{-1}\left(pf_{\lim}\right)\right) \tag{35}$$

It has to be noted that $P_{DGcurt,i,t}$ is greater than or equal to zero and is limited as shown in (32) and (33). The APC is very effective in dealing with voltage rise problems; however it has economic implications for the DG owners.

All the variables associated with the ANM are considered as continuous variables. It should be also noted that there are inverters that can inject the desirable active and reactive power according to the control scheme that is applied [28].

III. Solution Methodology

A. Overview of the Proposed Method

In this paper, a solution methodology is proposed to solve the multistage coordinated DNP problem that incorporates multiple planning alternatives and the active management of DG. The DNP problem is a MINLP problem due to the non linear constraint (10) and the binary nature of the investment variables. The proposed methodology is applied to distribution networks, in which large shares of DG are planned to be installed. The consideration of the reinforcement of existing network assets (e.g., substations, distribution lines) and the installation of new ones (e.g., CBs, VRs) leads to a more complete planning solution that efficiently handles both thermal and voltage constraints of the network.

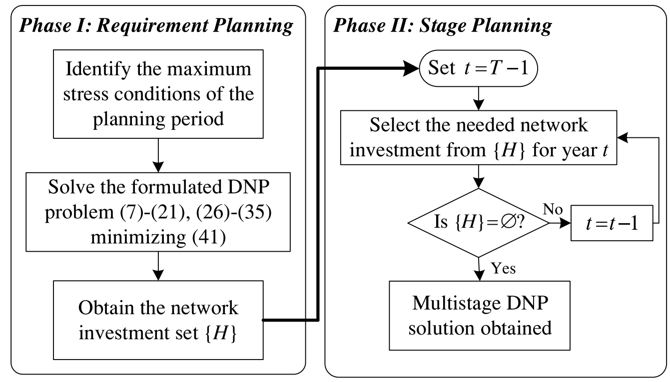


Fig. 3. Architecture of the proposed multistage DNP solution methodology.

The proposed planning framework consists of two successive optimization procedures in order to reduce the complexity of the multistage DNP problem. In the first phase, the location and capacity of the network components are evaluated for the maximum stress conditions of the planning period. In the second phase, the installation time is determined for the calculated network investments. The architecture of the proposed two-phase multistage coordinated DNP framework is illustrated in Fig. 3.

B. Definition of Scenarios

In general, distribution networks should be planned in order to cope with the maximum stress conditions of the planning period. The maximum stress conditions are: i) maximum load /no generation and ii) minimum load/ maximum generation [3]. The planning solution that satisfies these conditions also satisfies all the operating conditions of the planning period. Even though the occurrence probability of these conditions is very low, always meeting the whole demand during the planning period is considered as the most important planning priority. The stress condition that accounts for maximum load / no generation appears only once in the planning period and it accounts for the maximum load demand of the distribution network at the final year of the planning period. The number of stress conditions that account for minimum load / maximum generation is equal to the number of the time periods in which DG units are planned to be installed in the network. In these conditions, the minimum load is considered equal to the lowest yearly demand of the time period and as maximum generation the rated power of the renewable DG units. For example, in a planning period of T years, in which DG units are planned to be installed at years t_1 and t_2, the total number of the maximum stress conditions (T_{sc})

is equal to three. Phase I (see Section III-D) of the proposed planning methodology has as input these stress conditions.

C. *Definition of Criteria*

In the proposed multistage planning methodology, several criteria are considered for the evaluation of a planning solution.

The first criterion is the investment cost given by (36):

$$f_{inv} = IC_{SR,t} + IC_{LR,t} + IC_{LA,t} + IC_{CB,t} + IC_{VR,t} \tag{36}$$

Another criterion of optimal network operation is the equal distribution of the maximum demand among parallel feeders of the distribution network [29]. This criterion ensures that each feeder serves similar amounts of loads. Thus, a feeder overload is avoided and the voltage drop to the most remote buses is reduced. This criterion can be expressed as follows:

$$f_d = \sum_{k=1}^{N_f} \left(P_{D,f_k} - \overline{P_D}\right)^2 \tag{37}$$

$$P_{D,f_k} = \sum_{i \in \Phi_{f_k}} P_{D,i,T} \tag{38}$$

$$\overline{P_D} = \frac{\sum_{i \in \Phi_N} P_{D,i,T}}{N_f} \tag{39}$$

In case the APC is considered in the planning methodology, the level of DG curtailment that occurs in the maximum stress conditions should be limited. The curtailed active power of the DG units for the maximum stress conditions (T_{sc}) is given by (40):

$$f_c = \sum_{t=1}^{T_{sc}} \sum_{i \in \Phi_N} P_{DGcurt,i,t} \tag{40}$$

D. *Phase I: Requirement Planning*

Conventional optimization techniques often face convergence problems in large scale non-convex MINLP problems [1], [2]. The genetic algorithm (GA) [8], [12], [29]–[33] is therefore employed to solve the formulated DNP problem for the maximum stress conditions. Meta-heuristic optimization algorithms, particularly GA, converge in a feasible solution for problems with large number of variables and allow the consideration of all aspects of the DNP problem with regard to technical constraints and objectives. GA can provide near optimal solutions if its parameters are properly selected. The components of the adopted GA are described in Sections III-D1–D4.

1) Chromosome Structure: Every candidate solution is represented by a five-part vector. The first part of the chromosome represents the potential substation reinforcement; the second and the third part refer to the potential reinforcement and addition of distribution lines, respectively; the fourth and the fifth part represent the possible installation of CBs and VRs, respectively. Fig. 4(a) illustrates the initial topology of a 5-bus distribution network. In Fig. 4(a), the dashed routes denote the candidate lines for the connection of the future load of bus 6; all lines are considered candidate for reinforcement and

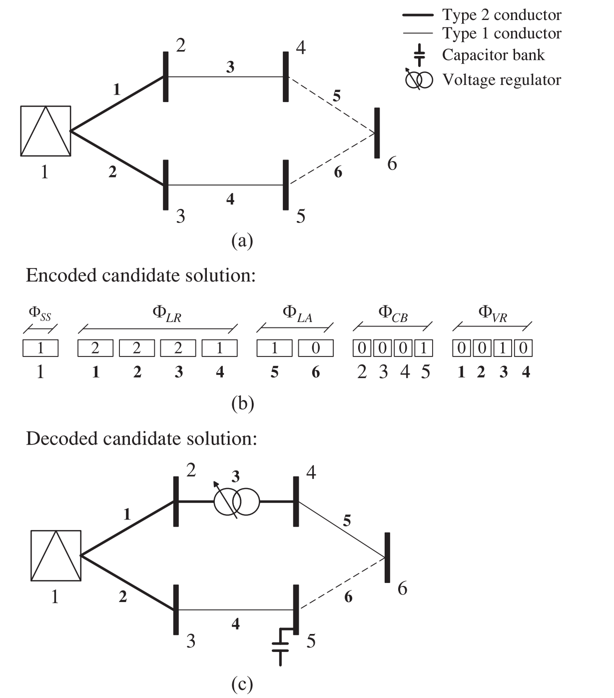


Fig. 4. (a) Illustrative 5-bus distribution network, (b) Encoded candidate solution, (c) Decoded candidate solution.

VR placement; all buses are candidate for CB placement except for bus 1, which is the substation. Fig. 4(b) illustrates an encoded candidate solution with type 1 substation at bus 1; lines 1 to 3 with type 2 conductor and line 4 with type 1 conductor; line 5 with type 1 conductor connects the new load of bus 6, and line 6 is not connected to the new load, since the gene of line 6 is equal to 0; a CB is placed at bus 5; a VR is installed in line 3. Fig. 4(c) shows the decoding of the candidate solution of Fig. 4(b).

2) Initial Population: Two procedures are employed to create high quality and diverse initial solutions. The first procedure is based on the reverse Kruskal's algorithm (a minimum spanning tree algorithm) to generate radial distribution networks [32]. Afterwards, a substation or a conductor type with the same or higher capacity is randomly assigned to the first three parts of the chromosome. The second procedure generates random radial networks. More specifically, in the first two parts of the chromosome, a substation or a line with equal or higher capacity is randomly assigned. For the connection of a new load point, first an available distribution line is randomly selected and then its conductor type is randomly chosen. In this paper, 20% of the initial population is generated by the first procedure, while the rest 80% of the initial population is generated by the second procedure.

3) Chromosome Evaluation: The fitness function (ff) of the optimization procedure is the following:

$$\min ff = w_1 \cdot f_{inv} + w_2 \cdot f_d + w_3 \cdot f_c + M \cdot \sum_{t=1}^{T_{sc}} \left(\sum_{i \in \Phi_N} \left(\delta v_{i,t}^{+} + \delta v_{i,t}^{-}\right) + \sum_{ij \in \Phi_L} \delta s_{ij,t} \right) \tag{41}$$

Each candidate DNP solution (chromosome) is decoded and the values of the investment variables $(z_{i,a,t},\ z_{ij,b,t},\ z_{i,c,t}^{CB},\ z_{ij,d,t}^{VR})$ are determined considering $t = 0$. Thus, the candidate network topology is provided and the first two terms of (41) are calculated. Afterwards, the operational feasibility of the candidate planning solution is examined. Since the network topology and the placement of CBs and/or VRs are given by the values of the investment variables, the nonlinear problem (NLP) defined by (7)–(21) and (26)–(35) is solved for the maximum stress conditions (T_{sc}), using as an objective function only the last two terms of (41). The last term of (41) acts as a penalty function and it is used to handle the constraint violation, while the GA seeks for the best solution. Since *M* is much larger than the other weighting coefficients, if a planning solution is feasible, the positive variables δv^+, δv^- and δs will be driven to their minimum value, i.e., zero. Otherwise, a penalty is assigned to an infeasible solution. Note that when the passive management of the DG or the APF is considered, the third term of (41) is equal to zero.

The analytic hierarchy process (AHP) is used to calculate the weighting coefficients w_1, w_2 and w_3 [34]. In the AHP method, a pairwise comparison between the objectives is performed by the decision maker (DM) in order to define the importance of each objective compared with the other objectives.

4) Next Generations: After the evaluation of the initial population, the best chromosomes are selected to be the parents in the next generation. The genetic operators (selection, crossover, mutation) are applied next to create a new population. The process is repeated until a maximum number of generations is reached.

The planning solution, computed by the optimization procedure, is a set $\{H\}$, which contains all the network investments that should be made in order to guarantee the safe operation of the network under the maximum stress conditions with the minimum cost by the end of the planning period.

E. Phase II: Stage Planning

In this step of the proposed multistage coordinated DNP framework, a heuristic approach is proposed to place the network investments of set $\{H\}$. The approach considers the elements of $\{H\}$ as fixed decision variables that have to be assigned during the planning period. The step by step procedure is as follows:

Step 1: Set $t = T - 1$ and consider the network configuration with all the network investments of set $\{H\}$.

Step 2: Select a network investment from set $\{H\}$. Solve the NLP problem defined by (7)–(21) and (26)–(35) minimizing (42) for the network topology without the selected network investment. If the value of (42) is equal to zero, which means that the system is feasible, the selected network investment should be made at planning period $t + 1$. Remove the selected investment from set $\{H\}$.

$$\min\ f_{st} = M \cdot \left(\sum_{i \in \Phi_N} \left(\delta v_{i,t}^{+} + \delta v_{i,t}^{-}\right) + \sum_{ij \in \Phi_L} \delta s_{ij,t} \right) \tag{42}$$

TABLE II
PAIRWISE COMPARISON OF THE OBJECTIVE TERMS OF (41)

	Investment cost	Feeders' load balance	DG curtailment	Weighting coefficients
Investment cost	1	9	7	0.772
Feeders' load balance	1/9	1	1/5	0.055
DG curtailment	1/7	5	1	0.173

Step 3: Repeat Step 2 until all the elements of set $\{H\}$ are examined for year *t*.

Step 4: If set $\{H\}$ is empty terminate the procedure, else set $t = t - 1$ and go to Step 2.

IV. RESULTS AND DISCUSSION

The performance of the proposed methodology is validated using a modified 24-bus distribution test system [35] and a 267-bus distribution network. The proposed methodology has been developed in MATLAB 2012a and GAMS. The CONOPT3 solver [36] is used for the solution of the NLP problem. All tests have been carried out on a PC with an Intel Core i7 CPU at 3.40 GHz and 4 GB of RAM.

In Table II, the pairwise comparison between the objectives of (41) and the weighting coefficients of each term of (41) are shown. The investment cost on network assets is considered 9 and 7 times more important than the load balancing of feeders and the DG curtailment, respectively. Furthermore, the DG curtailment is considered 5 times more important than the load balancing of the feeders.

A. 24-Bus Distribution Test System

The distribution system is a 20 kV network with 2 substations, 20 load buses and 34 branches, presented in Fig. 5, where the dashed lines represent the candidate lines for expansion. The planning period is divided into three stages. The detailed load and branch data can be found in [14]. Table III presents the costs and technical characteristics of the available planning alternatives. The conductor type of the initial distribution lines is type 2. Voltage limits are $\pm 5\%$ of the nominal voltage, the capacity of the existing substations is 12 MVA and the interest rate is 10%. At the first stage, 5 MW of wind DG at bus 7, 6 MW of wind DG at bus 23 and 7 MW of wind DG at bus 24 are planned. Furthermore, it is assumed that at each future load bus a solar DG unit of 0.1 MW is connected. All buses are candidate for CB placement and the lines of the initial network configuration are candidates for VR placement.

Two cases are considered as follows:

1) *Case A*: Multiple load/generation scenarios for every stage. The number of hours of each scenario during a stage is presented in Fig. 6. The planning framework consists of a single optimization procedure with investment

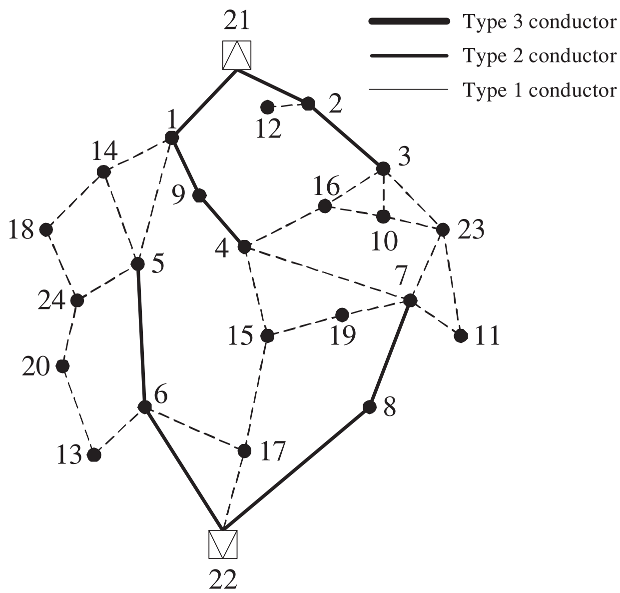


Fig. 5. Initial topology of 24-bus distribution test system.

TABLE III
AVAILABLE SUBSTATIONS, CONDUCTORS, CBS AND VRS

Substation				
Type	**Capacity (MVA)**		**Cost ($)**	
1	25		100 000	
Conductors				
Type	**R (Ω/km)**	**X (Ω/km)**	**Ampacity (A)**	**Cost ($/km)**
1	1.268	0.422	136	10 000
2	0.576	0.393	261	15 000
3	0.215	0.334	445	23 000
Capacitors				
Type	**Capacity (kvar)**		**Cost ($)**	
1	1200		12 000	
Voltage regulators				
Type	**Capacity (MVA)**		**Cost ($)**	
1	5		66 000	
2	10		85 000	

variables the location, capacity and time period of each planning alternative.

2) *Case B*: Only the maximum stress conditions are considered as described in Section III-B. The planning framework consists of two successive optimization procedures, as described in Sections III-D and III-E.

It should be noted that the size of the chromosomes in Case A is Tth times larger than in Case B, since the location and capacity of the investment variables are coupled with the time period of their commissioning. The parameters of the GA for the two cases are shown in Table IV.

The network topologies of the 24-bus distribution system, at the end of the planning period, considering different ANM schemes and the NPV of their respective investment costs for Cases A and B are shown in Fig. 7. In the APF scheme, it is assumed that the power factor of the DG units can vary from 0.95 lagging to 0.95 leading and in the APC, the maximum allowable DG active power curtailment is 5% of DG rated power.

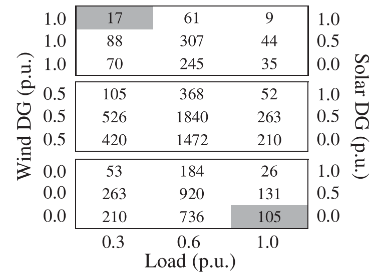


Fig. 6. Number of hours of the load/generation scenarios during a stage. The maximum stress conditions are represented by the shaded cells.

TABLE IV
PARAMETERS OF THE GA

	Case A	Case B
Population size	120	80
Number of generations	100	80
Crossover rate	0.80	0.80
Mutation rate	0.05	0.05

Case A: Fig. 7(a) presents the network topology without control of the DG units (passive management). The total investment cost is 490.27 k$ and its computational time 370 min. To meet the load demand and renewable DG of the first stage, distribution line 22–6 is reinforced with type 3 conductor; lines 3–10, 5–24 and 3–23 are constructed with type 2 conductor. For the requirements of the second stage, the capacity of the substations at bus 21 and bus 22 is upgraded to 25 MVA, line 21–1 is reinforced with type 3 conductor; line 6–13 is constructed with type 2 conductor; lines 7–11, 2–12, 1–14, 4–15 and 22–17 are constructed with type 1 conductor; one CB is installed at bus 11. To guarantee the safe operation of the network at the third stage, lines 21–1 and 22–8 are reinforced with type 3 conductor; lines 3–16, 24–18, 7–19 and 13–20 are constructed with type 1 conductor; one CB is installed at bus 7.

Fig. 7(b) presents the network topology considering the APF scheme. The total investment cost is 480.47 k$ and its computational time 383 min. The lower investment cost of the solution shown in Fig. 7(b) is due to the fact that the reinforcement of line 22–6 with type 3 conductor is deferred to the third stage.

The lowest total investment cost is achieved when DG active and reactive power control is enabled. The cost of the planning solution of Fig. 7(c) is 476.38 k$ and the computational time required is 410 min. Compared to the topology of Fig. 7(a) line reinforcement at the first stage is not required; line 22–1 is reinforced at the second stage, while lines 21–2, 22–6 and 22–8 are reinforced at the third stage. Moreover, bus 23, in which wind DG is installed, is connected with bus 7.

Case B: Application of the proposed multistage planning method provides the solution of Fig. 7(a), when passive DG management is considered. The investment cost is 492.65 k$ and its computational time 74 min. For the requirements of the

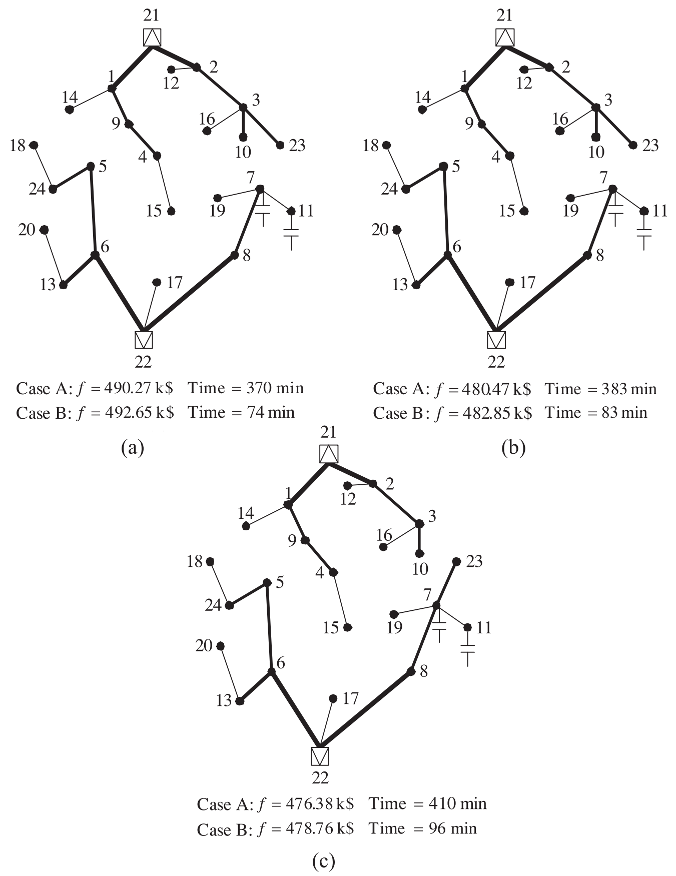


Fig. 7. Distribution network topologies of the 24-bus distribution network for Cases A and B considering: (a) passive management of DG, (b) APF and (c) APF + APC.

first stage, line 22–6 is reinforced with type 3 conductor; lines 3–10, 5–24 and 3–23 are constructed with type 2 conductor. At the second stage, the capacity of the substations at bus 21 and bus 22 is upgraded to 25 MVA; distribution lines 21–1 and 22–8 are reinforced with type 3 conductor; line 6–13 is constructed with type 2 conductor; lines 7–11, 2–12, 1–14, 4–15 and 22–17 are constructed with type 1 conductor. At the third stage, line 21–2 is reinforced with type 3 conductor; lines 3–16, 24–18, 7–19 and 13–20 are constructed with type 1 conductor; one CB is installed at bus 7 and another CB is installed at bus 11.

Fig. 7(b) illustrates the network topology considering the APF scheme. The investment cost of this solution is 482.85 k$ and its computational time is 83 min. The difference between the network topologies of Fig. 7(a) and (b) is that the reinforcement of line 22–6 is postponed for the third stage.

The solution with the lowest investment cost is achieved with APF and APC, as presented in Fig. 7(c). The cost is equal to 478.76 k$ and the computational time is 96 min. The differences between the planning solutions of Fig. 7(c) and (a) are the reinforcement of line 22–6 at the third stage instead of the first stage and the construction of line 7–23 instead of line 3–23.

As is shown in Fig. 7, the proposed method of Case B provides practically the same solutions with Case A, while it is four to five times faster. In both cases, the obtained network topologies at the end of the planning period are identical, while the small difference in investment costs is due to minor changes in the time and type of reinforcements of the same elements (line 22–8 and CB at bus 11).

TABLE V
RESULTS FOR THE 24-BUS DISTRIBUTION SYSTEM CONSIDERING APF+APC

Combination	Data modeling	Time decoupling	Cost (k$)	Time (min)
1	MLGS[1]	No	476.38	410
2	MSC[2]	No	476.38	304
3	MLGS	Yes	478.76	133
4	MSC	Yes	478.76	96

[1]MLGS = Multiple load/generation scenarios per stage.
[2]MSC = Maximum stress conditions.

TABLE VI
INVESTMENT COST OF PLANNING SOLUTIONS OF THE 24-BUS DISTRIBUTION SYSTEM FOR DIFFERENT WEIGHTING COEFFICIENTS OF (41)

Weighting Coefficients	Cost (k$)
$w_1 = 0.77,\ w_2 = 0.06,\ w_3 = 0.17$	478.76
$w_1 = 0.17,\ w_2 = 0.06,\ w_3 = 0.77$	482.85
$w_1 = 0.20,\ w_2 = 0.41,\ w_3 = 0.39$	496.26
$w_1 = 0.17,\ w_2 = 0.77,\ w_3 = 0.06$	515.13

The impact of the proposed definition of scenarios (see Section III-B) and the impact of decoupling the location and capacity of the investment variables from time are presented in Table V, where combination 4 is the proposed method. In comparison to the other three combinations of Table V, the advantage of the proposed method is that it provides practically the same solution (cost) requiring the minimum computational time. Table V refers to the planning solutions that consider APF and APC. The minor cost differences in Table V are due to the fact that the investment decisions are decoupled from time. However, the location and capacity of the investment variables are identical and they are determined by the maximum stress conditions.

Table VI presents the investment costs of the planning solutions calculated by the proposed method (Case B) considering APF and APC scheme for various values of the weighting coefficients. As is shown in Table VI, different weighting coefficient values lead to different planning solutions. Furthermore, the proposed methodology considering APF and APC scheme was executed 50 times to evaluate its effectiveness due to the stochastic nature of the GA. The best solution with an investment cost of 478.76 k$ was found 46 times out of 50 executions, while the worst planning solution had an investment cost of 479.51 k$.

B. 267-Bus Distribution Network

The proposed method is applied to a 20 kV real-world distribution network with one 25 MVA substation, two feeders and 267 buses, as shown in Fig. 8. The maximum total load demand is 10.65 MVA at the reference year and the peak load of every bus is presented in Table VII. The power factor of the loads is 0.95 lagging. The planning horizon is 20 years. The inflation

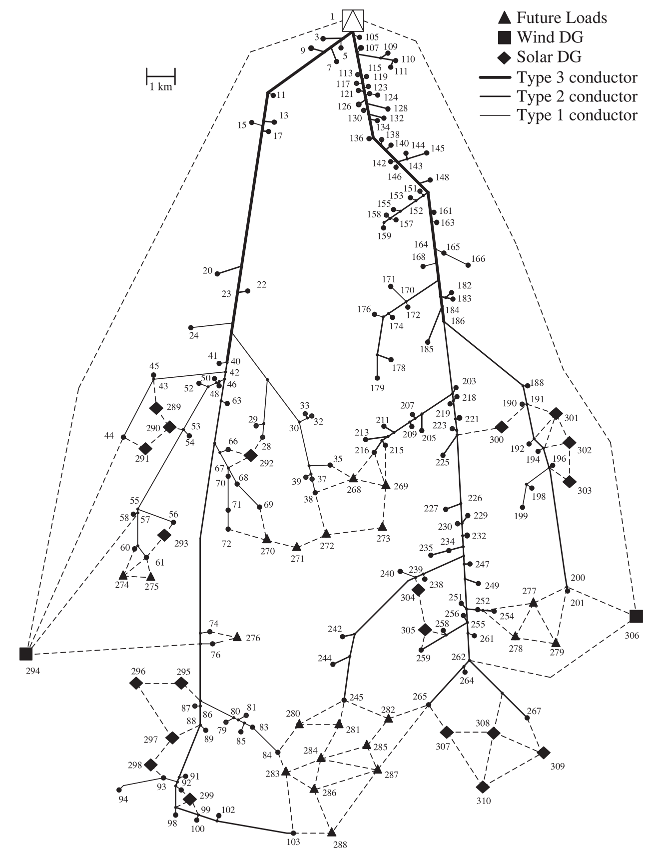


Fig. 8. The 267-bus distribution network.

TABLE VII
PEAK LOAD AT THE REFERENCE YEAR

Bus	Load (kVA)
45	640
215	580
7	480
3, 54, 81, 163, 207	200
13, 15, 29, 33, 63, 94, 105, 117, 119, 242, 254	130
50, 70, 71, 72	120
17, 22, 24, 32, 35, 38, 41, 48, 52, 74, 76, 79, 83, 85, 93, 96, 110, 111, 115, 123, 126, 130, 134, 136, 138, 144, 151, 153, 155, 157, 159, 166, 174, 178, 182, 183, 194, 221, 234, 245, 256, 265	80
5, 9, 11, 20, 28, 37, 39, 44, 56, 58, 60, 61, 66, 68, 69, 84, 87, 89, 91, 100, 102, 107, 109, 113, 124, 128, 132, 140, 163, 165, 168, 171, 172, 176, 179, 185, 190, 192, 198, 199, 205, 209, 211, 213, 216, 223, 230, 232, 235, 240, 244, 247, 249, 251, 252, 261, 264, 267	40
188, 196	20

and interest rate are 3% and 8%, respectively. Table III presents the costs and technical characteristics of the available planning alternatives. The load demand of the future loads and the year of connection are shown in Table VIII. The nominal power of the wind and solar DG to be installed by the end of the planning period is 2×5 MW and 20×0.1 MW, respectively, as shown in Table IX. The initial population and the generations of the GA are equal to 200, while the rest parameters are shown in Table IV.

Four different scenarios for the load growth demand were considered within the planning period. The scenarios are:

TABLE VIII
FUTURE LOADS OF THE 267-BUS DISTRIBUTION NETWORK

Bus	Load (kVA)	Year
269, 280	80	2
268, 270, 275, 278, 281, 282, 283	40	
286	80	4
271, 276, 279, 284	40	
274	80	5
285	130	6
272	80	
273, 287, 288	40	

TABLE IX
DATA OF THE DG UNITS OF THE 267-BUS DISTRIBUTION NETWORK

Bus	Nominal DG capacity (MW)	Year
289, 290, 291, 307, 308, 309, 310	0.1	1
292, 293, 298, 300, 301, 302, 303, 304, 305	0.1	2
294	5.0	
297, 299	0.1	3
295, 296	0.1	4
306	5.0	

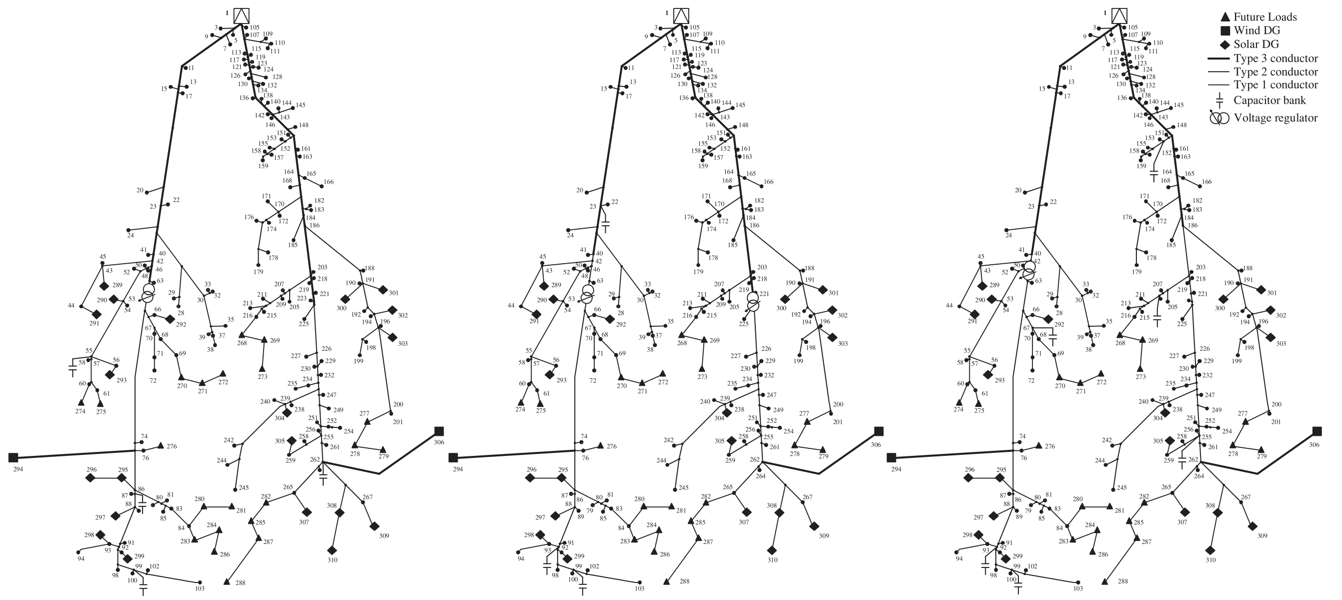
TABLE X
RESULTS OF THE 267-BUS DISTRIBUTION NETWORK FOR SCENARIO 1

Scheme	Phase I		Phase II	
	Investment Costs (k$)	Run time (h)	Investment Costs (k$)	Run time (h)
Passive management	1037	5.1	888.71	0.2
APF	1011	5.4	847.69	0.2
APF+APC	928	5.8	782.25	0.2

1) *Scenario 1*: The yearly load growth rate is 3% and 21 new loads are added at buses 268–288.
2) *Scenario 2*: The yearly load growth rate is 2% and 12 new loads are added at buses 268–279.
3) *Scenario 3*: The yearly load growth rate is 1% and 6 new loads are added at buses 268–273.
4) *Scenario 4*: The yearly load growth of the left feeder is 3% and of the right feeder is 1%. 21 new loads are added at buses 268–288 and their yearly load growth rate is 3%.

The dashed lines in Fig. 8 represent the candidate lines for expansion. The candidate lines for VR placement are all the distribution lines of the main feeder segments that connect bus 1 with bus 88 and with bus 262. The distribution lines that are candidate for reinforcement are the lines that connect the buses 40 with 88, 42 with 44, 46 with 57, 184 with 262, and 186 with 200. The candidate buses for the installation of CBs are 23, 30, 43, 53, 55, 67, 80, 86, 92, 99, 143, 152, 164, 170, 191, 208, 226, 239, 255 and 262. The effect of the ANM schemes of Section II-B is examined for the four scenarios. In the APF scheme, it is assumed that the power factor of the DG units varies from 0.95 lagging to 0.95 leading.

The DNP problem for the 267-bus distribution network includes 1036 integer (binary) variables for Scenarios 1 and 4, 876 for Scenario 2 and 772 integer (binary) variables for Scenario 3. Table X presents the results and computation time of Phase I and



(a) (b) (c)

Fig. 9. Distribution network topologies of the 267-bus distribution network for Scenario 1 considering: (a) passive management of the DG, (b) APF and (c) APF + APC.

Phase II of the proposed methodology for Scenario 1 considering the ANM schemes. The results of Phase I are the network investment cost if all the investment decisions were made in the reference year of the planning period. Phase II distributes the network investments along the planning horizon and the net present value of their cost is calculated. This is the reason why the final network investment cost, which is calculated in Phase II, is lower than the investment costs calculated in Phase I.

The network topologies, by the end of the planning period, considering different ANM schemes for Scenario 1 are shown in Fig. 9. Fig. 9(a) presents the network topology considering no control of the DG units (passive management). The feeders' segments that connect bus 40 with bus 62 and bus 186 with bus 224 are reinforced with type 3 conductor at year 2 and 4 of the planning period, respectively, due to the integration of the wind and solar generation. To solve voltage drop problems, one CB is installed at bus 262 at year 11 and three CBs are installed at buses 55, 86 and 99 at year 15. Furthermore, a VR is installed at the line that connects bus 62 with 64 at the second year of the planning period. The NPV of the network investment cost for this planning scheme is 888.71 k\$. Fig. 9(b) illustrates the network topology considering reactive power control of the DG units (APF). In this case, the feeder segments that are reinforced with type 3 conductor are the ones that connect bus 186 with bus 220. In order to guarantee the safe operation of the network, two CBs are installed at buses 92 and 99 at year 15 and one CB is placed at bus 23 at year 16. Two VRs are installed at line 62–64 at the second year of the planning period and at line 220–222 at year 11. The NPV of the total investment cost is 847.69 k\$, which is 4.62% lower than the cost of the planning solution in which the passive management of the DG was considered. The network configuration that considers APF and APC is shown in Fig. 9(c). In this case, there is no reinforcement in any of the feeders. To keep the voltage in all buses within the voltage limits during the planning period, one CB is installed at bus 255 at year 11, four CBs are installed at buses 67, 92, 99 and 208 at year 15 and one CB is installed at bus 152 at year 17. Moreover, one VR is placed between bus 46 and bus 62 at the second year of the planning period. The NPV of the investment cost of this planning solution is 782.25 k\$. Comparing all the planning solutions for Scenario 1 it can be noted that the planning scheme that simultaneously considers APF and APC has the lowest investment cost. It has a 12% lower investment cost than the planning scheme that considers no control of the DG units and it also has a 7.72% lower investment cost than the planning solution that considers only the control of the reactive power of the DG units. In this scenario, the optimal solutions include: a) line reinforcement to cope with voltage rise issues caused by the integration of DG and b) placement of CBs and VRs to face voltage drop problems. Fig. 10 illustrates the fitness function evolution of GA for Scenario 1 in the planning scheme that considers APF and APC. Due to the randomness of the GA, the proposed methodology was executed 50 times for Scenario 1

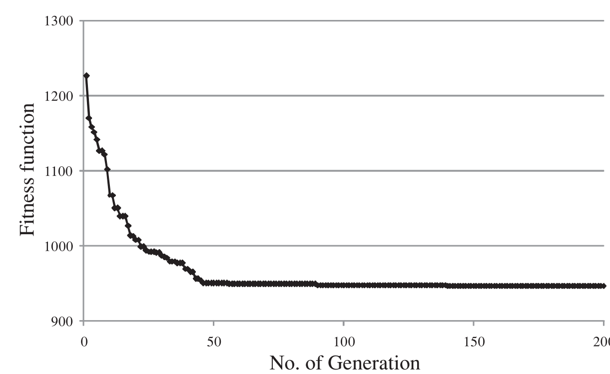


Fig. 10. Fitness function evolution of GA for Scenario 1 considering APF and APC.

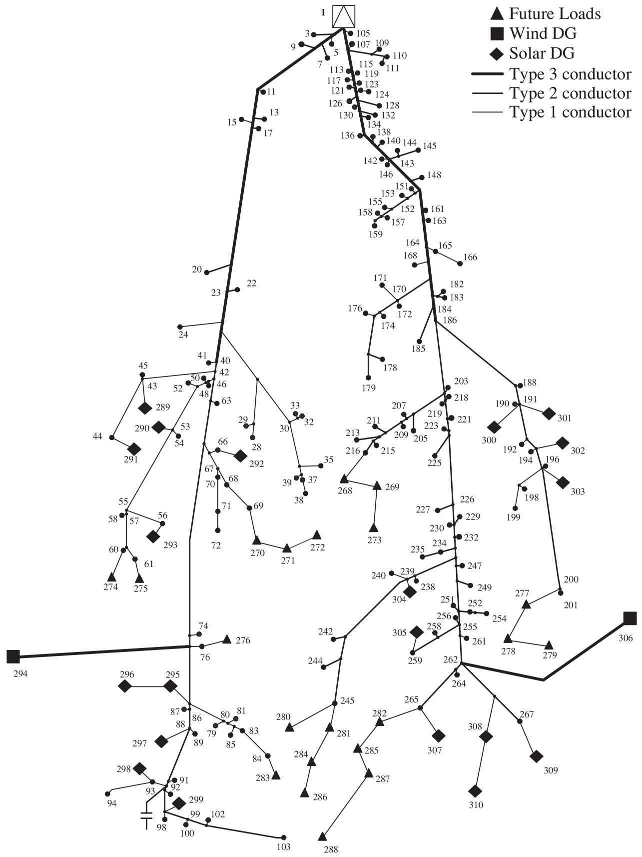


Fig. 11. Distribution network topology of the 267-bus distribution network for Scenario 4 when APF+APC are considered.

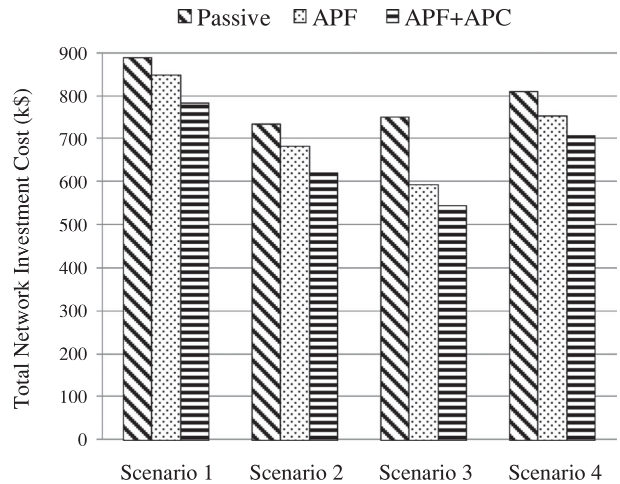


Fig. 12. Total investment cost of Scenarios 1–4 considering active and passive management of the renewable DG units.

when APF and APC schemes are considered in order to evaluate its effectiveness. The best solution with an investment cost of 782.25 k$ was found 38 times out of 50 executions; the average investment cost was equal to 783.18 k$; the worst solution had an investment cost of 788.84 k$. It should be noted that the maximum allowable DG active power curtailment is considered equal to 5% of DG rated power for all the examined scenarios.

Fig. 11 presents the network topology in case APF and APC are considered for Scenario 4. The total investment cost of this planning solution is 707.04 k$. The main difference between the network configurations of Figs. 9 and 11 is that the new loads 280, 281, 284 and 286 are connected to the right feeder in the planning solution of Fig. 11, while in Fig. 9 they are connected to the left feeder.

The total investment costs for the four scenarios for the load growth considering the passive management of the DG units and the two ANM schemes are presented in Fig. 12. As is shown, in all four scenarios the lowest investment cost is achieved when active and reactive power output of the DG units are controlled. The decrease in the investment cost varies from 12% to 27.41% compared with the cost of the planning solution without control of the output power of DG units. Furthermore, a noteworthy decrease in the investment cost is achieved when the reactive power of the DG units is controlled. The planning solutions that incorporate APF have a lower cost than the planning solutions with the passive management of the DG units that ranges from 4.62% to 21%. As expected, planning solutions that simultaneously apply APF and APC have the most cost-effective results; however this is not always possible without a proper regulatory framework.

V. Conclusion

This paper introduces a multistage coordinated planning method of active distribution networks. The proposed planning methodology simultaneously considers the reinforcement of the existing substations and distribution lines, the network expansion, and the placement of CBs and VRs in conjunction with the integration of DG. The active management of the DG units is incorporated into the formulated DNP and its effect is highlighted. The active management considers the control of the active and reactive power output of the DG units.

The formulated DNP problem is divided into two subproblems and two successive optimization procedures are developed for their solution. First, the maximum stress conditions of the planning period are identified and the DNP problem is solved using the GA. The output of the optimization procedure is a set $\{H\}$ that contains the location and capacity of the planning alternatives in order to ensure the safe operation of the network during the planning period. Next, a heuristic approach is used to define the installation period of the network investments of set $\{H\}$. The performance of the proposed planning method is validated using a 24-bus distribution test system and a realistic distribution network with 267 buses. Different scenarios of load growth were examined.

The results show that the most cost efficient planning solution was obtained when active and reactive power of the DG units were controlled. The results demonstrate the significance of incorporating active management of the DG units into the solution of the DNP, in deferring network investments. Furthermore, the inclusion of multiple planning alternatives (coordinated planning) in the DNP offers high flexibility and determines the most suitable set of network assets with the minimum cost in order to ensure safe operation of the network during the whole planning period.

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