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Toward a Smart Distribution System Expansion Planning by Considering Demand Response Resources

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ABSTRACT
This paper presents a novel concept of "smart distribution system expansion planning (SDEP)" which expands the concept of demand response programs to be dealt with the long term horizon time. The proposed framework, integrates demand response resources (DRRs) as virtual distributed generation (VDG) resources into the distribution expansion planning. The main aim of this paper is to develop and initial test of the proposed model of SDEP to include DRRs which are one of the most important components to construct smart grid. SDEP is modeled mathematically as an optimization problem and solved using particle swarm optimization algorithm. The objective function of the optimization problem is to minimize the total cost of lines' installation, maintenance, demand response persuasion, energy losses as well as reliability. Furthermore, the problem is subject to the constraints including radiality and connectivity of the distribution system, permissible voltage levels, the capacity of lines, and the maximum penetration level of demand response. Based on two sample test systems, the simulation results confirmed that the consideration of DRRs simultaneously with distribution system expansion can have economical profit for distribution planners.

KEYWORDS: Demand response resources, Distribution expansion planning, Smart grids.

1. INTRODUCTION

The expansion problem of electricity delivery chain components is necessary due to the incremental electricity consumption in the whole levels of the power systems [1-3]. Expansion of the distribution network is one of the activities of the planners to cope with the electricity demand growth [4,5]. Among them, the distribution system expansion planning is selected as the main point of interest of this paper.

Distribution system expansion planning (DEP) problem consists of siting, sizing, and timing of installation of distribution equipment while all the system and equipment restrictions are satisfied [6]. The expansion problem methods have been investigated through different studies. Optimization algorithm should be employed for the best allocation of the limited financial resources [7]. Dynamic planning [8], graph-theory models [9] and heuristic algorithms such as genetic algorithm, ant colony, and the particle swarm optimization (PSO) are examples of the introduced optimization methods [6]. Network expansion planning is a difficult optimization problem due to the nonlinear and the combinatorial nature of the problem [10]. This fact leads various studies to utilize some methods with random nature. However, the main drawback of these methods is that they cannot guarantee the optimal solution [11].

The distribution system development, poses new challenges and problems related to the electrification levels and the desired reliability level [12]. Changes in the designing, planning and operation of the distribution network are necessary to adopt with the new challenges and requirements of the developing system [12].

Demand response programs can dramatically change the forecasted demand pattern in a horizon year. Demand response (DR) is enabled by end-users to motivate changes in power consumption

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patterns. Based on the type of loads, a specified percentage of loads can transfer to other periods, when they are called by DR. These types of loads are called multi-period loads, while single-period loads cannot be shifted to other hours and should be turned off. DRPs are attractive programs for both system operators and electricity customers due to the high increases in electricity demand [13-15]. Aalami et al. have elaborated comprehensive investigations on the DRPs and their modeling [16]. Reducing electricity price, security enhancement, resolving lines congestion and the improvement of market liquidity are some of the benefits of DR [16]. Because of the potential benefit of the demand side activities; these programs are introduced as the first choice in all energy policy decisions according to the strategic plan of international energy agency (IEA) [17]. Implementing demand side management programs have many other benefits such as: cost and emission reduction, reliability enhancement, and decreasing the fuel dependency [17-19].

Reference [20] has classified DRPs into two basic categories as depicted in Fig. 1. Each of these classes consists of several programs. Time-based programs include: time of use (TOU), real time pricing (RTP), and critical peak pricing (CPP). These programs expose customers to varying levels of price exposure; the least with TOU and the most with RTP [14]. Incentive based programs include: direct load control (DLC), emergency demand response program (EDRP), interruptible/curtailable service (I/C), capacity market program (CAP), demand bidding (DB) and ancillary service (A/S) programs. DLC and EDRP are voluntary programs and customers are not penalized if they do not response to the DR calls. However, I/C and CAP are mandatory programs and they use of penalties when enrolling customers if they do not participate when directed. Moreover, DB programs encourage large customers to provide load reductions at a price at which they are willing to be curtailed, or to identify how much load they would be willing to curtail at posted prices. Furthermore, customers are allowed to bid load curtailment in electricity markets as operating reserves in A/S programs.

The role of DRPs in the smart grid is illustrated in Fig. 2 [21]. The Smart grid can be defined as the combination of general concepts to enhance the overall functionality of the electric power delivery system [22]. The future vision of the smart grid has been investigated in [23]. Smart grids provide suitable infrastructure to enable DRPs [22].

The backbone of smart grid concentrates on environmental driven programs incorporating various clean generations, demand response and distributed generation, for the sake of the best utilization of facilities, and to enhance the customer choice [21].

However, the potential of DRPs is not considered in this area of research. Indeed, DRRs are one of the most essential components to lead the conventional distribution system planning toward a smart planning of distribution systems. By following the trends of studies in this area of knowledge, importance and necessity of considering DRPs as virtual resources to be modeled in the planning of distribution systems can be justified.

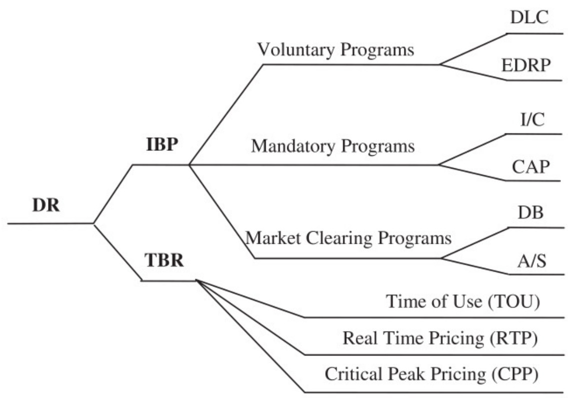

Fig. 1. Classification of DR programs [20]

This paper integrates the long term concept of DRRs with the conventional DEP to lead this area of study toward a "SDEP". As it can be observed from Fig. 2, DG units (especially renewable units) are one of the components of the smart grid. However, this paper strives to expose the effect of DR in the planning of distribution grids. Hence, the investigation of the presence of DG units is out of the scope of this paper and could be modeled in the future researches. According to Fig. 1, incentive based programs are considered in this paper. Among them, the DLC programs are focused in this paper as a DR contract to avoid the probabilistic nature of customers' behavior. The cost of DR is provided for DR participants to encourage customers to response when they are called by DR. In this paper, the influence of DRPs is applied to load duration curve (LDC) that has direct effect on the expansion studies. However, the main aim of this paper is to investigate the effect of DR in the planning of the distribution systems and initial test of the proposed problem.

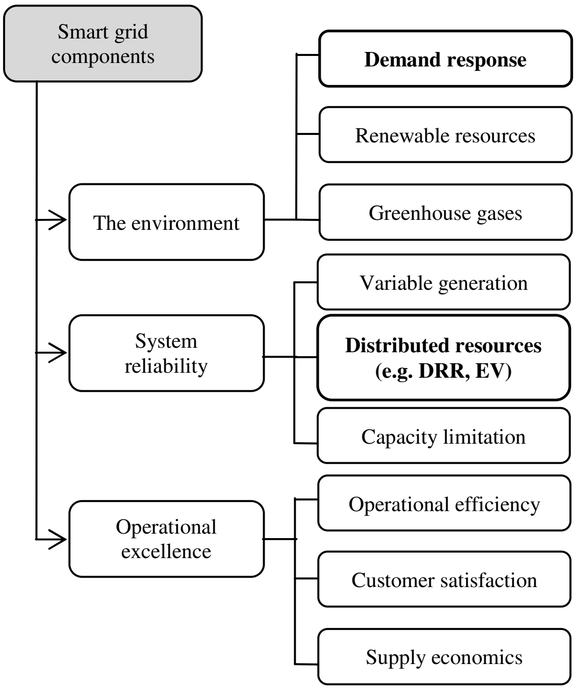

Fig. 2. The role of demand response resources in smart grid

Hence, the DLC programs are modeled in which the incentives are provided to encourage customers for participating in DRPs. Therefore, for the sake of simplicity and without loss of generality, the cost of DR is considered as a constant value. The consideration of other types of DR is out of the scope of this paper and can be investigated in future researches.

The main contribution of this paper is to open a new vision in distribution expansion planning in which DRRs are taken into account in planning the distribution system. The proposed framework includes DRRs as one of the most important components of the smart grid to lead toward the smart expansion scheme. Implementing DRPs in the planning stages can have some advantages in comparison with the traditional expansion planning models such as economic and environmental profits.

The mathematical model incorporates the distribution expansion variables and facilities as well as the variables corresponding to the demand response penetration level, while all the constraints related to the distribution system, measures, and DRPs are satisfied. The objective function of the optimization problem is to minimize the total costs of lines' installation, maintenance (corrective and preventive costs), DR enabling, energy losses and reliability (cost of curtailed load per fault and energy cost per hour of fault).

To the best of the authors' knowledge, in despite of the numerous studies, the role of optimum determination of DRRs in the distribution system and the concept of SDEP has not been considered until now. Integration of DRRs as the most necessary part of the smart grid to extend the problem of distribution expansion toward the smart distribution system planning is the main aim of this paper. Indeed, this paper extends the concept of DR as a virtual and flexible distributed generation to be considered in a long term planning schemes. VDGs (DRRs) are integrated into distribution expansion planning to lead toward a smart distribution system planning where DRRs should be optimally specified among the system nodes. In this study, the PSO method is used to find the desired optimum solution of the proposed problem.

The main contributions of this paper with respect to the published paper in the area are as follows.

- A new framework for smart distribution expansion planning (SDEP);
- Integrating DRRs into the long-term SDEP model.

The rest of the paper is organized as follows. The formulation of SDEP problem is explained in details in section 2. The procedure of optimization tool is elaborated in section 3. Section 4 conducts the numerical simulations. Finally, concluding remarks are drawn in section 5.

2. SDEP FORMULATION

Distribution network components are designed to deliver the required peak demand [24]. The proposed version of distribution system planning problem considers DRPs as virtual distributed resources that will change the electricity demand profile.

This study provides a framework in which operational issues are considered as well as investment alternatives. Indeed, while expansion requirements are considered to be minimized, operational costs such as energy losses must be optimized. Hence, on one hand, constraints such as the capacity of lines and system voltage levels must be satisfied to ensure the proper expansion plan (without operational deficiencies). On the other hand, expansion requirements must optimally be invested, due to the economic considerations.

The problem formulation of the paper which consists of the mathematical definition of the objective function, constraints and the optimization tool are presented in this section.

2.1. Objective function

The objective function of the proposed SDEP is to minimize the total planning costs while the system, components and DR constraints are satisfied. The route (optimal connections) and type of lines, in addition to DR specifications, are the optimization variables.

The objective function of the SDEP problem which is developed in this study consists of the following parts and should be minimized through the optimization tool:

- Lines' installation costs;
- Lines' maintenance costs;
- DR enabling costs;
- Cost of power losses;
- Costs corresponding to failure rates and repair times.

The solution of the optimization problem is a radial system that minimizes the total cost of SDEP problem. The objective function can be stated mathematically as Eq. (1). Since, single-stage expansion planning is considered in this paper, the consideration of monetary specifications such as inflation and interest rates will not affect the expansion results and planning schemes. Such considerations must be considered in multi-stage planning problems and could change the timing of expansion alternatives. Therefore, such monetary parameters can be ignored here for the sake of simplicity and without loss of validity of the results.Considering the results of power flow and the required injected power from the distribution substation to the system as well as the nominal rated power of the distribution facilities, the expansion requirements can be obtained for other distribution equipment. However, in this paper, the expansion of distribution lines is mainly considered as an alternative to evaluate the investment costs.

$$
\begin{aligned}
&OF = fixed\ \ cost + variable\ \ cost + fault\ \ cost \\
&fixed\ \ cost = \sum_{n_f}\sum_{LT}\left\{\begin{bmatrix}\left(l_{n_f}\times IC^{LT}\right)+\left(l_{n_f}\times PC^{LT}\right)\\ +\left(l_{n_f}\times CC^{LT}\right)\end{bmatrix}\times \upsilon_{n_f}^{LT}\right\} \\
&variable\ \ cost = DR\ \ \cos t + loss\ \ cost \\
&DR\ \ cost = \sum_{lp}\sum_{per}\left[C_{lp}^{DR}(per)\times p_{lp}^{DR}(per)\times T^{DR}(per)\right] \\
&loss\ \ cost = \sum_{n_f}\sum_{per}\left[p_{n_f}^{l}(per)\times LC(per)\times t(per)\right] \\
&fault\ \ cost = \sum_{n_f}\sum_{per}\sum_{LT}\begin{bmatrix}\left(\left(\lambda^{LT}\times\dfrac{t(per)}{8760}\right)\times CCLF\right)\\ \times l_{n_f}\times pf_{n_f}(per)\times T^{P}\times\upsilon_{n_f}^{LT}\end{bmatrix} \\
&\qquad +\sum_{n_f}\sum_{per}\sum_{LT}\begin{bmatrix}\left(rp^{LT}\times\lambda^{LT}\times\dfrac{t(per)}{8760}\times HEC\right)\\ \times l_{n_f}\times pf_{n_f}(per)\times T^{P}\times\upsilon_{n_f}^{LT}\end{bmatrix} \\
&\qquad \forall\ \ n_f\in\Pi\ \ \ LT\in\Gamma,\ \ ,lp\in\Delta,\ \ per\in\Upsilon
\end{aligned}
\tag{1}
$$

The important feature of the mathematical model of SDEP problem which is considered here is the integration of DRRs with the DEP model. DRRs can dramatically mitigate the distribution constraints and therefore change the network topology. It should be mentioned that DRPs will change the LDC and consequently the load level in each period. Hence, the modified LDC after the implementation of DRPs should be considered. Indeed, all the characteristics such as fault cost will be affected due to the changes in the load levels and network structure.

2.2. Constraints

The constraints of the proposed SDEP problem are described in the following paragraphs. These constraints include radiality and connectivity of the distribution system, permissible voltage ranges, the maximum capacity of lines, load balance, and the maximum penetration level of DR.

a) Radiality and connectivity

Distribution systems are tree shape graphs and must be operated radially. Furthermore, islanded buses should not appear for providing the system loads. Therefore, all the nodes in a fully connected tree shape distribution networks must be connected to the root of the graph [25, 26]. The approach represented in [27] is utilized in this paper to guarantee the radiality and connectivity of the network.

b) Voltage limits

The voltage levels of distribution buses should be within the maximum and minimum permissible thresholds. These constraints are represented by Eq. (2).

$$U^{min} \le U_n(per) \le U^{max}, \ \forall \ n \in \Psi, \ per \in \Upsilon \tag{2}$$

c) Line capacities

Considering the type of installed lines, Eq. (3) represents the capacity constraint of the feeders.

$$-\sum_{LT}\left(pf^{LT,max} \times \upsilon^{LT}_{n_f}\right) \le pf_{n_f}(per) \le \sum_{LT}\left(pf^{LT,max} \times \upsilon^{LT}_{n_f}\right) \\ , \ \forall \ n_f \in \Pi, \ per \in \Upsilon \tag{3}$$

d) Load balance

Total injected power from the distribution substation must be equal with the total required loads.

$$P_{sub}(per) = \sum_{lp} p_{lp}(per) + \sum_{n_f} p^l_{n_f}(per) \\ , \ \forall \ per \in \Upsilon, \ lp \in \Delta, \ n_f \in \Pi \tag{4}$$

$$Q_{sub}(per) = \sum_{lp} q_{lp}(per) + \sum_{n_f} q^l_{n_f}(per) \\ , \ \forall \ per \in \Upsilon, \ lp \in \Delta, \ n_f \in \Pi \tag{5}$$

e) Maximum DR capacity

DR penetration level is limited to the maximum value at each load point and can be represented as follows.

$$p^{DR}_{lp}(per) \le p^{DR,max}_{lp}(per) \ \forall \ lp \in \Delta, \ per \in \Upsilon \tag{6}$$

DRPs are contracts between the distribution system planner and customers. According to these contracts, customers will be persuaded to become ready to participate in DR when they are called. Furthermore, according to the type of DR, the customers may be paid for becoming ready to participate even if they are not called. DLC programs are focused in this paper as a DR contract. As it is mentioned in section 1, DLC and EDRP are voluntary programs and customers are not penalized if they do not response to the DR calls. Moreover, for the sake of simplicity and without loss of generality, a constant cost term per kW is assumed here as incentives for participants. So, DR incentives are provided to encourage customers to be ready to participate in DRPs when they are called by DR.

Furthermore, it should be noted that, the cost of construction of an advanced metering infrastructure (AMI) is not considered in this paper. As it is obvious, the AMI is vital in smart grid to satisfy its aims. DR can utilize this pre-constructed infrastructure; so this assumption will not affect the validity of the results and conclusions. Furthermore, it is obvious that the benefits of AMI will overcome its costs in the long term horizon and is considered as the basic assumption in all the smart grid studies. Hence, the cost of AMI is not considered in this paper.

It should be mentioned that, the backward/forward sweep method is utilized in this paper for power flow calculation. The process of this method is represented in Appendix section with Table A.1 [28] and formulated by (A.1)-(A-7) in Table A.2.

3. OPTIMIZATION TOOL

The PSO technique is implemented to solve the optimization problem. The PSO is a population-based optimization algorithm introduced by Eberhart and Kennedy [29]. It is based on the number of particles and inspired by the behavior of insects' swarm or birds' flock [30]. Each particle denotes a solution of the problem. The PSO has some important advantages in comparison with other heuristic methods like GA. The PSO has more effective memory capacity, more diversity to search the optimum solution and also faster search speed [31].

The first decision variables are corresponding to the state of lines' installation. After each iteration of the PSO method, lines decision vectors (DV_i) will be updated regarding to Eq. (7) for the i^{th} particle:

$$DV_i(j+1) = DV_i(j) + vel_i(j+1) \tag{7}$$

where, *"j"* represents the number of iterations. Furthermore, *"vel_i"* in Eq. (7) is the velocity of changes in DV_i and is calculated by Eq. (8):

$$vel_i(j+1) = vel_i(j) + \\ r1 \times (G(j) - DV_i(j)) + r2 \times (P_i(j) - DV_i(j)) \tag{8}$$

"*r1*" and "*r2*" are random numbers in the interval [0-1]. "$G(j)$" is the global best decision vector until the "j^{th}" iteration; while "$P_i(j)$" represents the individual best result for the "i^{th}" particle until iteration "j".

Decision vectors for determining DRRs' specifications are the second decision variables in the optimization problem. Similarly, after each iteration, DR decision vectors (DV_i^{DR}) will be updated as the following:

$$DV_i^{DR}(j+1) = DV_i^{DR}(j) + vel_i^{DR}(j+1) \quad (9)$$

vel_i^{DR} is the velocity function of the "i^{th}" particle and can be represented by Eq. (10).

$$\begin{aligned} vel_i^{DR}(j+1) = vel_i^{DR}(j) + r3\times\left(G^{DR}(j) - DV_i^{DR}(j)\right) \\ + r4\times\left(P_i^{DR}(j) - DV_i^{DR}(j)\right) \end{aligned} \quad (10)$$

"$r3$" and "$r4$" are also random coefficients between [0-1]. "$G^{DR}(j)$" and "$P_i^{DR}(j)$" are related to DR decision vectors to indicate the global and individual optimal solutions until the "j^{th}" iteration.

The optimization procedure for solving the proposed problem is depicted in Fig. 3. It should be noted that in Fig. 3 $P^b(p,j)$ refers to the best solution of swarm "p" until the iteration number "j". Furthermore, $G^b(j)$ indicates the best solution of all the swarms until j^{th} iteration. Moreover, $iter^{max}$ denotes the maximum number of the PSO iterations. If generated particles face with a violation of the system constraints, a penalty factor will be applied to them. Hence, unacceptable solutions will be avoided due to the high value of objective functions.

4. NUMERICAL RESULTS

In this section, the main input data, simulation results and the necessary comparisons are provided to investigate the performance of the proposed SDEP problem. Two sample test systems include 7 and 18-node networks are examined for the sake of numerical analysis.

The LDC is considered as shown in Fig. 4 for each of the system nodes. Both primary and modified LDCs after considering the effect of DRPs are depicted in Fig. 4. Horizontal dashed lines are corresponding to the modified LDC. Changes in the level of demand in each time period by implementing the DRPs are shown using vertical arrows. According to Fig. 4, three load levels are assumed as the primary segments of the LDC that include: peak, shoulder and off-peak periods. Peak, Shoulder and Off-peak periods in Fig. 4, are assumed equal to 360, 4900 and 3500 hours during a year, respectively.

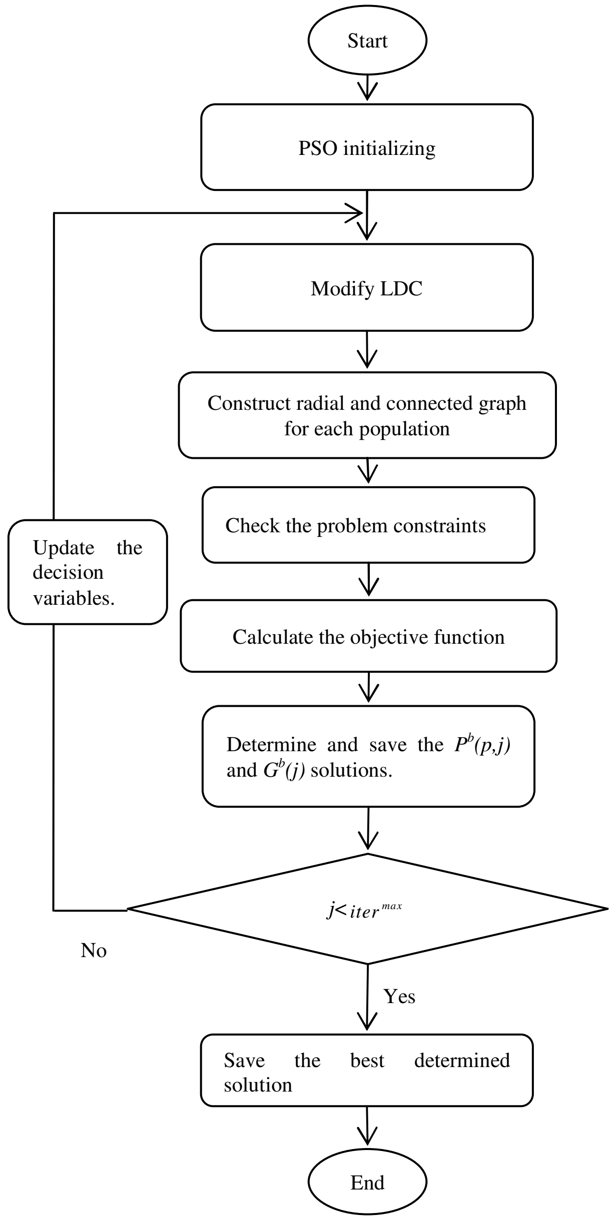

Fig. 3. Overall scheme of the optimization process

Furthermore, load demands in shoulder and off-peak periods are considered to be 75 and 60 percent of the peak load for each load point. Also, as aforesaid, DLC programs are considered as DRPs. By considering the effect of DRRs on LDC curve, 3-segment curve will break to 5-segment curve as shown in Fig. 4. Intervals [T1-T2] and [T3-T4] are equal to [0-T1]; total hours that DR should be enabled in the network. The maximum penetration level of DR in responsive load points is considered equal to 15 percent of the active loads. This assumption can be realistic from the practical point of view. As aforesaid, some parts of participated load will shift to other periods. It is assumed that 20 percent of the curtailed load (enabled DR) will be transferred to the shoulder hours and 50 percent of that will be shifted to off-peak area. Residual loads are considered to be single period and could not be transferred to other periods.

Most of input data for lines and system characteristics are taken from [10]. The candidate lines' specifications for upgrading the system are listed in Table 1. Other assumptions are available in Table 2. Furthermore, the voltage of substation is assumed to be 1.04 per-unit for both the test systems. The PSO population size is considered equal to 40 and the maximum iteration number is 80. It should be mentioned that, as the problems of this paper are modeled as a single-stage expansion problems for the specific horizon time, the timing of expansion planning is for the next horizon year (here the planning horizon time is 1 year). Furthermore, the siting of the distribution lines is done with the consideration of candidate feeders. Indeed, siting and sizing of the distribution lines are determined among the candidate feeder and line types.

4.1. The 7-node network

A sample 7-node distribution system is assumed as a case study of this subsection to explore the planning results. Table 3 explains the characteristics of the load points in peak times.

The planning results are presented in two cases: 1) DEP problem; in which DR capacity is not considered, and 2) SDEP problem; in which DR capacity is applied to the distribution expansion planning. The simulation results are compared to each other to analyze the performance of the proposed framework.

Table 1. Candidate lines' specification [10]

Lines' type	Nominal current (A)	Impedance (Ohm/km)	Reactance (Ohm/km)	Cost ($/km)
1	118	0.16118	0.24	145000
2	158	0.10145	0.22	150000
3	179	0.0822	0.2	160000
4	210	0.06	0.13	175000

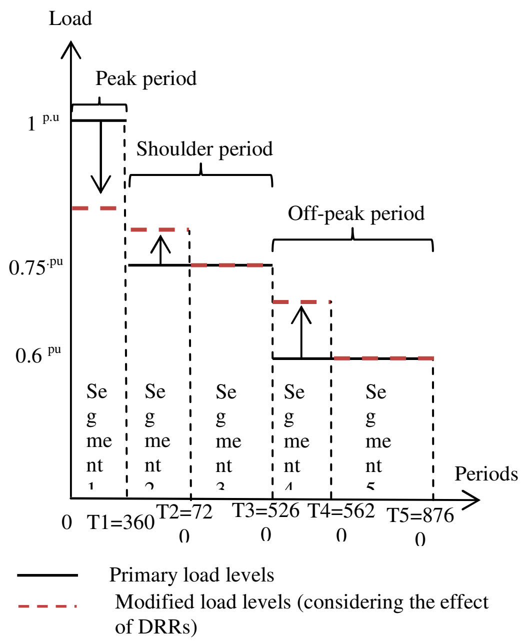

Fig. 4. Load duration curve for each load point

Table 2. System characteristics [10]

Specification	Dimension	Value
Voltage base	(kV)	13.8
Energy cost	($/MW.hr)	60
Cost of curtailed load	($/MW.fail)	13.7
Energy cost per hour of fault	($/MW.hr)	21.7
Cost of DR	($/MW.hr)	200

Table 3. 7-node test system specifications

Load points	Active load (kW)	Reactive load (kVAr)
2	750	200
3	900	200
4	900	200
5	850	150
6	850	150
7	525	110

Figure 5 depicts the network configurations in both predefined cases. Fig. 5-a, corresponds to the network design in the absence of DR, while Fig. 5-b, portrays the network structure by solving the proposed SDEP. Network structure and feeders' current in both cases are represented in Table 4.

It can be concluded from Fig. 5 and Table 4, in addition to the changes in the types of installed lines, network configuration is changed after the implementation of DR in the network.

The total planning cost is evaluated equal to 10.3 (M$) and 9.8 (M$) in case 1 and 2, respectively, that shows 0.5 (M$) reduction when DRRs are incorporated into the DEP programs. As it is illustrated in Fig. 5, the integration of DRRs in the distribution system planning, results a dramatic changes in system design while decreasing the planning costs.

The total amount of energy losses during the one-year horizon time is equal to 571.4 (*MW.hr*) and 472.8 (*MW.hr*) in case 1 and 2, respectively, that shows 17.3 percent reduction in the energy losses after enabling DR in the network.

Table 5, represents the amount of enabled DR in each bus. Furthermore, the changes in the amount of enabled DR with respect to its price are illustrated in Fig. 6 for the 7-node test system. The maximum value of DR capacity is considered as the base value to normalize the enabled DR. It can be observed from Fig. 6, considering the price of DR equal to 0 will enable all the capacitor of DR. Furthermore, DR will not be enabled when the price of DR is extremely increased. In this case, the amount of the objective function for SDEP is equal to the objective function of the DEP. Moreover, bus voltages are described in Table 6. As it is obvious in Table 6, enabling DR in the network will improve the network condition by decreasing the amounts of voltage drops in the peak hours. In summary, the comparison results between DEP and SDEP are provided in Table 7 for more clarification.

The optimization process of the PSO method is shown in Fig. 7. Figure 7-a, corresponds to the total cost minimization process in the absence of DR. However, Fig. 7-b is related to the total cost optimization in the presence of DR. It should be mentioned that these optimization processes are with the aim of minimizing the total planning cost.

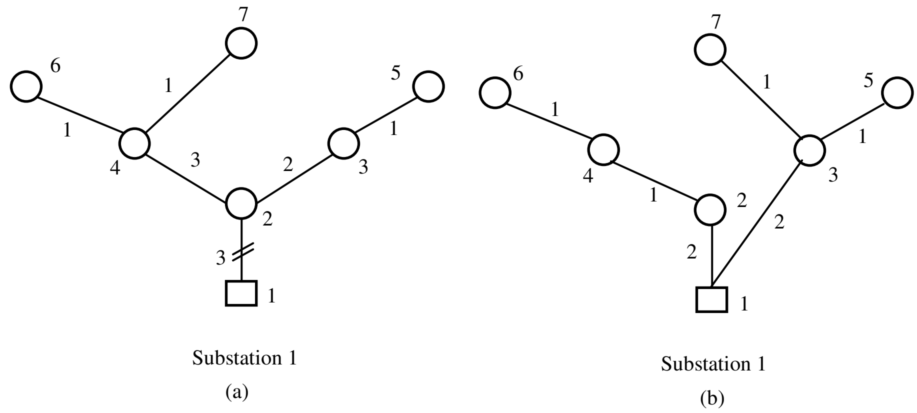

Fig. 5. 7-node test system design: a) in the absence of DRRs b) in the presence of DRRs

Table 4. Optimization results for network configuration and line currents of the 7-node system

Selected lines	Type and number of lines	Line current (A)				
		Peak	Shoulder		Off-peak	
		Segment 1	Segment 2	Segment 3	Segment 4	Segment 5
Case 1	*Distribution system expansion planning*					
1-2	3 (× 2)	349.1	260.1	260.1	207.2	207.2
2-3	2 (× 1)	128.8	95.7	95.7	76.2	76.2
2-4	3 (× 1)	167.7	124.6	124.6	99.1	99.1
3-5	1 (× 1)	62.7	46.5	46.5	37.0	37.0
4-6	1 (× 1)	62.7	46.6	46.6	37.0	37.0
4-7	1 (× 1)	38.9	28.9	28.9	23.0	23.0
Case 2	*Smart distribution system expansion planning*					
1-2	2 (× 1)	158.0	140.8	135.9	120.4	108.4
1-3	2 (× 1)	157.9	124.8	123.3	101.9	98.3
2-4	1 (× 1)	108.6	99.4	95.5	85.7	76.0
3-5	1 (× 1)	60.6	46.5	46.2	37.5	36.8
3-7	1 (× 1)	32.7	29.8	28.7	25.7	22.8
4-6	1 (× 1)	52.8	48.3	46.4	41.6	36.9

Table 5. Optimization results for Enabled DR in case 2

Load points	Time periods	
	Peak (kW)	Other periods (kW)
2	64.1	-
3	0	-
4	135	-
5	20.4	-
6	127.50	-
7	78.8	-

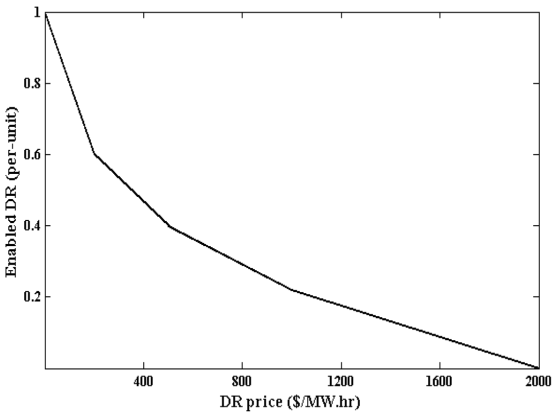

Fig. 6. The amount of enabled DR with respect to DR prices

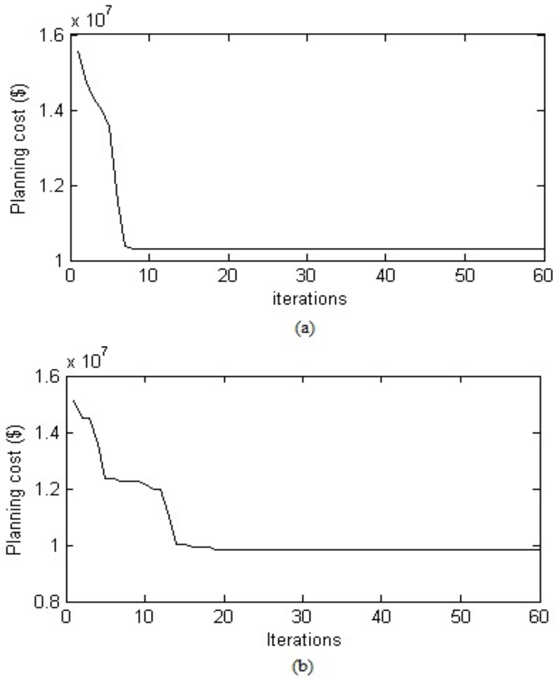

Fig. 7. PSO Optimization processes for 7-node test system: a) DEP problem, b) SDEP problem

Table 6. Optimization results for Buses' voltage

Load points	Time periods				
	Peak (p.u)	Shoulder (p.u)		Off-peak (p.u)	
	Segment 1	Segment 2	Segment 3	Segment 4	Segment 5
Case 1	*Distribution system expansion planning*				
1	1.040	1.040	1.040	1.040	1.040
2	1.016	1.022	1.022	1.026	1.026
3	1.005	1.014	1.014	1.019	1.019
4	1.004	1.013	1.013	1.018	1.018
5	0.997	1.008	1.008	1.014	1.014
6	0.997	1.007	1.007	1.014	1.014
7	0.998	1.008	1.008	1.014	1.014
Case 2	*Smart distribution system expansion planning*				
1	1.04	1.040	1.040	1.040	1.040
2	1.026805	1.028	1.029	1.030	1.031
3	1.015132	1.020	1.020	1.024	1.024
4	1.012603	1.015	1.016	1.019	1.020
5	1.00705	1.014	1.014	1.019	1.019
6	1.005508	1.009	1.010	1.013	1.016
7	1.009212	1.015	1.015	1.019	1.02

Table 7. Comparison results for the 7-node test system

Planning features	Dimension	DEP	SDEP
Planning costs	(M$)	10.3	9.8
Energy losses during 1 year	(MW.hr)	571.4	472.8
Enabled DR during 1 year	(MW.hr)	-	153.3

4.2. The 18-node network

The 18-node test system specifications are shown in Table 8. Fig. 8 demonstrates the optimal solutions of the optimization problem which indicates to the best configurations of the 18-node test system. Figure 8-a depicts the optimal topology of the system in the absence of DRRs; while Fig. 8-b illustrates the best structure of distribution network when the capacity of DR programs is considered. Network structure and the amounts of line currents are described in Table 9, for the two assumed cases. Case 1 corresponds to the solution of DEP program in which the capacity of DR is not considered. Case 2, takes into account the DR penetration level in the network and consequently indicates the optimal solution of the SDEP problem.

Table 8. 18-node test system specifications

Load points	Active load (kW)	Reactive load (kVAr)	Load points	Active load (kW)	Reactive load (kVAr)
2	750	200	11	850	190
3	900	200	12	700	210
4	900	200	13	850	190
5	850	150	14	775	170
6	850	150	15	425	135
7	525	110	16	650	170
8	700	170	17	650	170
9	700	170	18	425	135
10	775	170			

It can be concluded from Fig. 8 and Table 9, beside the changes in the types of lines, there are some differences in the system design before and after enabling DR. The cost of test system planning is evaluated equal to 39.7 (M$) and 35.6 (M$) in case 1 and 2, respectively that shows 10.3 percent (4.1 M$) cost reduction. As it is demonstrated in Fig. 8, introducing the concept of smart distribution system planning to include the extended concept of DR programs as distributed generators, will provide great changes in system design while decreasing the planning costs. Total energy losses is equal to 1314.22 (*MW.hr*) in case 1 and decreased to 1073.2 (*MW.hr*) in case 2 by implementing DR as a virtual resources in the distribution system planning. In comparison to the lines resistances, the amounts of lines currents are dominant factors and system power losses will be decreased after enabling DR. In addition, the lines' resistances in SDEP topology are lower than DEP in some corridors such as "1-2", "2-7" and etc. Beside the reduction in the system power losses, the situations of voltage drops are improved after the implementation of DR in peak hours. The amount of enabled DR is presented in Table 10. Moreover, the comparison results are listed in Table 11 to show the advantages of the proposed problem. The optimization process of the PSO method is shown in Fig. 9 with respect to the number of iterations. Figure 9-a, represents the total planning cost in the absence of DR. Also, Fig. 9-b indicates the total optimization cost in the presence of DR.

Consequently, all the simulation results and analysis confirm the performance and validity of the proposed problem.

5. CONCLUSION

This paper addressed the concept of demand response programs as distributed generation resources to be dealt with the long term horizon time. Furthermore, the problem of smart distribution system expansion planning is proposed in this paper that incorporates DRRs into the DEP problem. Mathematical model of the problem takes into account the system fault cost, cost of power losses and cost of enabling DR as well as the installation and maintenance costs of the various feeders. The proposed model of the SDEP is introduced as a minimization problem and solved using the PSO algorithm. The efficiency and performance of the proposed framework have been assessed and demonstrated using numerical studies done on two

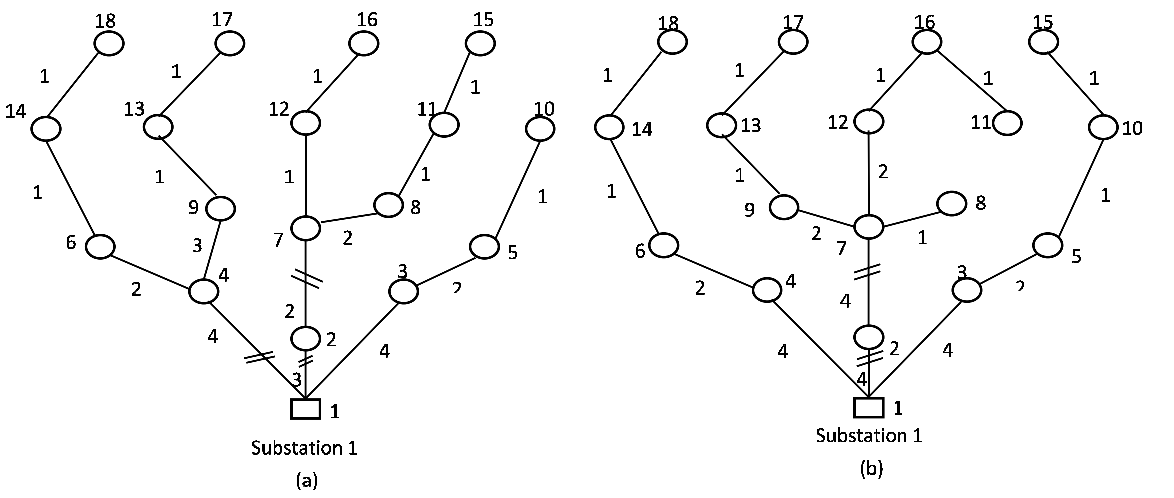

Fig. 8. 18-node test system design: a) in the absence of DRRs b) in the presence of DRRs

typical distribution networks. Furthermore, suitable comparisons have been made between traditional system expansion model and the proposed smart distribution expansion model. Comparison results illustrate that the incorporation of DRRs as a virtual and flexible generation resources with the DEP problem can effectively reduce the planning costs.

Table 9. Optimization results for network configuration and line currents of 18-Node test system

Selected lines	Type and number of lines	Line current (A)				
		Peak			Shoulder	Off-peak
		Segment 1	Segment 2	Segment 3	Segment 4	Segment 5
Case 1	*Distribution system expansion planning*					
1-2	3 (× 2)	351.6	259.4	259.4	205.5	205.5
1-3	4 (× 1)	183.6	136.9	136.9	109.2	109.2
1-4	4 (× 2)	386.1	285.9	285.9	227.1	227.1
2-7	2 (× 2)	299.3	219.8	219.8	173.7	173.7
3-5	2 (× 1)	119.2	88.7	88.7	70.6	70.6
4-6	2 (× 1)	155.7	114.9	114.9	91.0	91.0
4-9	3 (× 1)	168.1	124.0	124.0	98.2	98.2
7-8	2 (× 1)	155.3	113.9	113.9	89.9	89.9
7-12	1 (× 1)	107.3	78.6	78.6	62.0	62.0
5-10	1 (× 1)	57.7	42.8	42.8	34.0	34.0
6-14	1 (× 1)	93.0	68.4	68.4	54.1	54.1
9-13	1 (× 1)	115.8	85.2	85.2	67.4	67.4
8-11	1 (× 1)	101.0	74.0	74.0	58.3	58.3
12-16	1 (× 1)	51.6	37.8	37.8	29.8	29.8
14-18	1 (× 1)	33.7	24.8	24.8	19.6	19.6
13-17	1 (× 1)	50.6	37.3	37.3	29.5	29.5
11-15	1 (× 1)	34.3	25.1	25.1	19.8	19.8
Case 2	*Smart distribution system expansion planning*					
1-2	4 (× 2)	419.9	371.9	358.9	316.3	284.4
1-3	4 (× 1)	209.9	163.1	161.6	132.3	128.7
1-4	4 (× 1)	209.9	163.1	161.6	132.3	128.7
2-7	4 (× 2)	367.6	332.8	319.7	284.9	252.8
3-5	2 (× 1)	145.7	114.9	113.5	93.7	90.2
4-6	2 (× 1)	145.7	114.9	113.5	93.7	90.2
7-8	1 (× 1)	45.3	41.3	39.7	35.5	31.4
7-9	2 (× 1)	144.3	131.5	126.1	112.7	99.6
7-12	2 (× 1)	145.8	132.8	127.3	113.7	100.4
5-10	1 (× 1)	84.1	69.1	67.6	57.2	53.6
6-14	1 (× 1)	84.1	69.1	67.6	57.2	53.6
9-13	1 (× 1)	99.0	90.2	86.5	77.3	68.2
12-16	1 (× 1)	99.6	90.7	87.0	77.7	68.5
10-15	1 (× 1)	28.1	25.5	24.5	21.9	19.4
14-18	1 (× 1)	28.1	25.5	24.5	21.9	19.4
13-17	1 (× 1)	43.2	39.4	37.8	33.8	29.8
16-11	1 (× 1)	56.4	51.3	49.2	44.0	38.8

Table 10. Optimization results for enabled DR in 18-Node test system

Load points	Time periods	
	Peak (kW)	Other periods (kW)
2	0	-
3	0	-
4	0	-
5	0	-
6	0	-
7	51.2	-
8	105	-
9	105	-
10	29.1	-
11	127.5	-
12	105	-
13	127.5	-
14	29.1	-
15	63.8	-
16	97.5	-
17	97.5	-
18	63.8	-

Table 11. Comparison results for the 18-node test system

Planning features	Dimension	DEP	SDEP
Planning costs	(M$)	39.7	35.6
Energy losses	(MW.hr)	1314.22	1073.2
Enabled DR	(MW.hr)	-	360.7

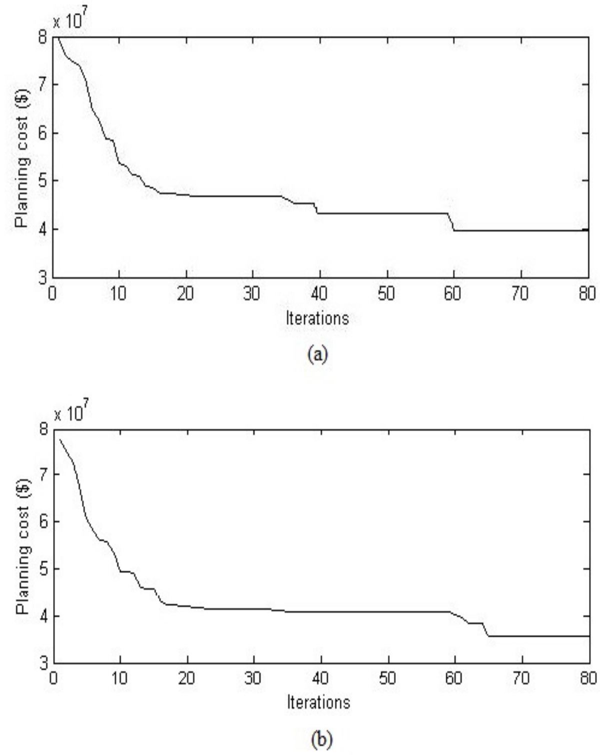

Fig. 9. PSO Optimization stages for 18-node test system: a) DEP problem, b) SDEP problem

NOMENCLATURE

***Sets*:**

Π : the set of network feeders;

Γ: the set of various line types;

Δ: the set of load points;

Υ: the set of time periods;

Ψ: the set of buses;

***Indicators*:**

n_f: indicator for the network feeders;

LT: indicator for the candidate line types;

lp: indicator for the number of load points;

per: indicator for time periods;

n: indicator for the number of buses;

***Variables*:**

$p_{lp}^{DR}(per)$: the amount of enable *DR* at load point "*lp*" and time period "*per*" [*kW*];

$T^{DR}(per)$: duration of DR enabling time [*hr*];

$p_{n_f}^{l}(per)$: the active power losses of line "n_f" in each time period [*kW*];

$pf_{n_f}(per)$: power flow of feeder "n_f" in time period "*per*" [*kW*];

$U_n(per)$: voltage level of bus "*n*" in time period "*per*" [*kV*];

$P_{sub}(per)$: the amount of injected active power from the distribution substation at time period "*per*" [*kW*];

$Q_{sub}(per)$: the amount of injected reactive power from the distribution substation at time period "*per*" [*kVAR*];

$q_{n_f}^{l}(per)$: the reactive power losses of line "n_f" in each time period [*kVAR*];

***Binary variable*:**

$\upsilon_{n_f}^{LT}$: binary variable that is equal to 1 if line "n_f" of type "*LT*" has been installed; Otherwise it is equal to 0.

***Parameters*:**

l_{n_f} : length of line "n_f" [km];

IC^{LT} : installation cost per kilometer of line "*LT*" [*$/km*];

PC^{LT}: preventive cost per kilometer of line "*LT*" [*$/km*];

CC^{LT}: corrective cost per kilometer of line "*LT*" [*$/km*];

$C_{lp}^{DR}(per)$: cost of DR per *kW* at load point "*lp*" and time period "*per*" [*$/kW.hr*];

$LC(per)$: cost of power losses in time period "*per*" [*$/kW.hr*];

$t(per)$: duration of each time period [*hr*];

λ^{LT} : failure rate of line type "*LT*" [*fail/km.year*];

$CCLF$: cost of curtailed load per fault [*$/kW.fail*];

T^{P}: Total planning horizon time [*year*];

rp^{LT} : average duration of fault on the line type "*LT*" [*hr/fail*];

HEC: energy cost per hour of fault [*$/kW.hr*];

U^{min}, U^{max} : minimum and maximum permissible voltage level [*kV*];

$pf^{LT,max}$: the maximum permissible power flow of line type "*LT*" [*kW*];

$p_{lp}(per)$: the amount of active load at load point "*lp*" [*kW*];

$q_{lp}(per)$: the amount of reactive load at load point "*lp*" [*kVAR*];

$p_{lp}^{DR,max}(per)$: maximum DR capacity at load point "*lp*" and time period "*per*" [*kW*].

APPENDIX - POWER FLOW ALGORITHM

The backward/forward sweep method is utilized in this paper for power flow calculation. The algorithm of this method is shown in Table A.1.

Fig. A.1 shows a typical radial distribution system with *N* load points. Index "*per*" is omitted in Fig. A.1 for the sake of simplicity. Z_m indicates the impedance of each main feeder. $I_{M,m}(per)$ and $I_{L,m}(per)$ are the currents of the main and lateral feeders, respectively. The substation voltage level is denoted by U_0. $P_n(per)$ and $Q_n(per)$ are the active and reactive load levels of each load points.

The procedure of the introduced method can mathematically be formulated with (A.1)-(A.7). Index υ denotes the iteration number of the backward/forward sweep algorithm ($\upsilon=\{1,\ 2,\ ...\}$).

Table A.1. Backward/forward sweep algorithm

Step	Description
1: Initializing	Initializing the voltage levels of all buses
2: Backward process	Evaluate power and current flows
3: Forward process	Evaluate voltage drops

Initializing step:

$$\upsilon=1\,,\ U_n^{(\upsilon-1)}(per)=U_0,\ \ \forall\ \ n=1:N,\ \ per\in\Upsilon \qquad \text{(A.1)}$$

Backward process:

Table A.2 shows the formulation of backward process. $P_n^{DR}(per)$ and $Q_n^{DR}(per)$ in Table A.2 are enabled active and reactive powers with DRPs at bus "*n*" and time interval "*per*". $P_n^b(per)$ and $Q_n^b(per)$ are the active and reactive powers that are shifted from other periods to "*per*th" period as a result of DR. Furthermore, $U_n^{*,(\upsilon-1)}(per)$ is the conjugate of $U_n^{(\upsilon-1)}(per)$.

Forward process:

The forward process can be formulated as (A.7) to compute the voltage of each bus in iteration "υ".

$$U_n^{(\upsilon)}(per)=U_{n-1}^{(\upsilon)}(per)-Z_n\times I_{M,n}^{(\upsilon)}(per)\ ,\quad \forall\ \ n=1:N,\ \ per\in\Upsilon \qquad \text{(A.7)}$$

The process should be repeated by substituting $\upsilon=\upsilon+1$ until the satisfaction of the convergence criteria.

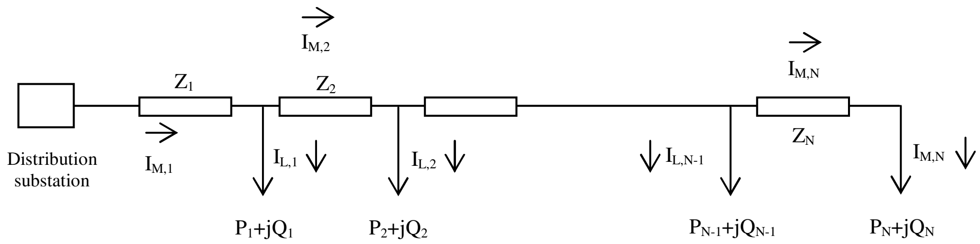

Fig. A.1. A typical radial distribution system

Table A.2. The backward-sweep formulation

Equation numbers	The absence of DR	The presence of DR
(A.2)	$I_{L,n}^{(\upsilon)}(per)=\bar{S}_n^*(per)\times\bar{U}_n^{*,(\upsilon-1)}(per)$ $\forall\ \ n=1:N,\ \ per\in\Upsilon$	$I_{L,n}^{(\upsilon)}(per)=\bar{H}_n^*(per)\times\bar{U}_n^{*,(\upsilon-1)}(per)$ $\forall\ \ n=1:N,\ \ per\in\Upsilon$
(A.3)	$I_{M,n}^{(\upsilon)}(per)=\sum_{h=n}^{N}I_{L,h}^{(\upsilon)}(per),\qquad \forall\ \ n=1:N,\ \ per\in\Upsilon$	
Components of (A.2)		
(A.4)	$\bar{S}_n^*(per)=P_n(per)-jQ_n(per),\qquad \forall\ \ n=1:N,\ \ per\in\Upsilon$	
(A.5)	$\bar{H}_n^*(per)=\left(P_n(per)-P_n^{DR}(per)+P_n^b(per)\right)-j\left(Q_n(per)-Q_n^{DR}(per)+Q_n^b(per)\right)$ $\forall\ \ n=1:N,\ \ per\in\Upsilon$	
(A.6)	$\bar{U}_n^{*,(\upsilon-1)}(per)=\dfrac{1}{U_n^{*,(\upsilon-1)}(per)},\qquad \forall\ \ n=1:N,\ \ per\in\Upsilon$	

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