Planning of Distribution Networks for Medium Voltage and Low Voltage

Iman Ziari

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School of Engineering Systems

Faculty of Built Environment and Engineering

Queensland University of Technology

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Abstract

Determination of the placement and rating of transformers and feeders are the main objective of the basic distribution network planning. The bus voltage and the feeder current are two constraints which should be maintained within their standard range. The distribution network planning is hardened when the planning area is located far from the sources of power generation and the infrastructure. This is mainly as a consequence of the voltage drop, line loss and system reliability. Long distance to supply loads causes a significant amount of voltage drop across the distribution lines. Capacitors and Voltage Regulators (VRs) can be installed to decrease the voltage drop. This long distance also increases the probability of occurrence of a failure. This high probability leads the network reliability to be low. Cross-Connections (CC) and Distributed Generators (DGs) are devices which can be employed for improving system reliability. Another main factor which should be considered in planning of distribution networks (in both rural and urban areas) is load growth. For supporting this factor, transformers and feeders are conventionally upgraded which applies a large cost. Installation of DGs and capacitors in a distribution network can alleviate this issue while the other benefits are gained.

In this research, a comprehensive planning is presented for the distribution networks. Since the distribution network is composed of low and medium voltage networks, both are included in this procedure. However, the main focus of this research is on the medium voltage network planning. The main objective is to minimize the investment cost, the line loss, and the reliability indices for a study timeframe and to support load growth. The investment cost is related to the distribution network elements such as the

transformers, feeders, capacitors, VRs, CCs, and DGs. The voltage drop and the feeder current as the constraints are maintained within their standard range.

In addition to minimizing the reliability and line loss costs, the planned network should support a continual growth of loads, which is an essential concern in planning distribution networks. In this thesis, a novel segmentation-based strategy is proposed for including this factor. Using this strategy, the computation time is significantly reduced compared with the exhaustive search method as the accuracy is still acceptable. In addition to being applicable for considering the load growth, this strategy is appropriate for inclusion of practical load characteristic (dynamic), as demonstrated in this thesis.

The allocation and sizing problem has a discrete nature with several local minima. This highlights the importance of selecting a proper optimization method. Modified discrete particle swarm optimization as a heuristic method is introduced in this research to solve this complex planning problem. Discrete nonlinear programming and genetic algorithm as an analytical and a heuristic method respectively are also applied to this problem to evaluate the proposed optimization method.

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List of Principle Symbols and Acronyms

C_{CAP}	Total capital cost
C_{ES}	Energy saving
c_i	Acceleration coefficient
C_I	Interruption (Reliability) cost
C_L	Line loss cost
$C_{O\&M}$	Operation and maintenance cost
C_{PL}	Peak load loss cost
DNS_{ll}^{y}	Customer energy lost in load level *ll* in planning interval *y*
DP	Penalty factor
$gbest^k$	Best position among all particles at iteration *k*
$HNLB$	Number of load blocks in horizontal axis in an LV zone
$HNTB$	Number of LV zones in horizontal axis in an MV zone
I_{f_i}	Feeder actual current
I_f^{rated}	Feeder rated current
$Iter$	Current iteration number
$Iter_{max}$	Maximum iteration number
k_L	Cost per MWh ($/MWh)
k_{NS}	Customer energy loss penalty factor ($/MWh)
k_{PL}	Saving per MW reduction in the peak power
LL	Number of load levels
LLB	Length of a load block

lsf	Loss load factor
LWB	Width of a load block
NS	Number of streets
OF	Objective function
$pbest_j^k$	Best position of particle *j* at iteration *k*
P_{LOSS}	Line loss power
Q_C	Size of a switched capacitor bank
r	Discount rate
RSD	Relative standard deviation
TLB	Length of an LV zone
T_{ll}	Duration of load level *ll*
TWB	Width of an LV zone
V_{bus}	Bus voltage
V_j^k	Velocity of particle *j* at iteration *k*
$VNLB$	Number of load blocks in vertical axis in an LV zone
$VNTB$	Number of LV zones in vertical axis in an MV zone
WS	Width of a street
X_j^k	Position of particle *j* at iteration *k*
Y	Number of years in the study timeframe
ω	Inertia weight factor
ω_{max}	Final inertia weight factor
ω_{min}	Initial inertia weight factor

Statement of Original Authorship

The work contained in this thesis has not been previously submitted to meet requirements for an award at this or any other higher education institution. To the best of my knowledge and belief, the thesis contains no material previously published or written by another person except where due reference is made.

Signature

Date

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Iman Ziari

CHAPTER 1:

Introduction

1.1. Motivation and Overview

Distribution system planning is an important issue in power engineering. The term distribution system consists of Low Voltage (LV) and Medium Voltage (MV) networks. Planning of LV network is to find the placement and rating of distribution transformers and LV feeders. This is implemented to minimize the investment cost of these devices along with the line loss. Planning of MV network is to identify the location and size of distribution substations and MV feeders. The objective of MV network planning is to minimize the investment cost along with the line loss and reliability indices such as SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). There are several limitations which should be satisfied during the planning procedure. The bus voltage as a constraint should be maintained within a standard range. The actual feeder current should be less than the rated current of the feeder.

Improving the voltage profile, line loss and system reliability is a main concern in planning of distribution networks particularly for semi-urban and rural areas. Supporting the load growth and peak load level is another factor which should be considered in the planning procedure.

The voltage drop and line loss are two factors which should be considered in the planning procedure. Various approaches can be performed to keep the bus voltage within a standard range and minimize the line loss. Finding the optimal voltage level is a choice for alleviating the voltage drop; however, it is commonly determined using the voltage level of the distribution networks located close to the planning area. Installing capacitors is another way which highly increases the voltage level and reduces the line loss. The Voltage Regulators (VRs) are also common elements for covering these problems.

Reliability is another issue in planning of distribution networks. Long length of distribution lines increases the probability of occurrence of a failure in distribution lines which leads to a low system reliability. Installation of Cross-Connections (CC) is a useful way to lighten this difficulty. Injecting the active and reactive powers, Distributed Generators (DG) decrease the reliability indices and improve the voltage profile. However, their high investment cost prevents the power engineers from wide use of these devices.

In practical distribution networks, the loads are growing gradually. Additionally, the load level is changing during a period. Conventionally, transformers and feeders need to be upgraded to support the load growth and peak load level. However, upgrading the transformer and feeder rating for peak load level, which is 1-2% of a year, may not be cost benefit. That is why other supporters such as capacitors and DGs can be installed to avoid extra upgrades of transformers and feeders.

Regarding the discrete and nonlinear nature of the allocation and sizing problem, the resulting objective function has a number of local minima. This underlines the importance of selecting a proper optimization method. Optimization methods are categorized into two main groups: Analytical-based methods and heuristic-based methods. The analytical methods have low computation time, but they do not deal appropriately with the local minima. For solving the local minima issue, the heuristic methods are extensively applied in the literature. In this research, both analytical and heuristic methods will be implemented in Matlab, Discrete Nonlinear Programming (DNLP) as an analytical approach and Discrete Particle Swarm Optimization (DPSO) as a heuristic approach. Additionally, some other heuristic methods, such as Genetic Algorithm (GA), are programmed and applied to the planning problem to evaluate these optimization methods. DSPO is also modified by GA operators to increase the diversity of the variables. It will be shown that the proposed Modified DPSO (MDPSO) enjoys higher robustness and accuracy in dealing with this complex problem compared with conventional DPSO and GA.

1.2. Key Features in this Research

Above mentioned problems highlight the need for a comprehensive planning of distribution networks. This planning method should minimize the line loss, maximize the system reliability, improve the voltage profile, and support the load growth. Therefore, the following key features are satisfied during this study:

F1. Reliability is an essential factor in distribution networks particularly in rural areas which is low and should be maximized. This factor is rarely included in the planning papers while it influences the result significantly.

F2. The line loss is another feature which should be minimized. Almost all of the available papers in the distribution system planning field are based on minimization of the line loss. It demonstrates the necessity of considering this factor in the computations.

F3. Supporting the load growth and peak load level is an important issue for planning a distribution network.

F4. The investment cost along with the reliability and line loss cost are the objective function elements. The main objective of distribution network planning is to minimize these costs while the load growth is supported and the voltage and current constraints are met.

F5. Since the problem is highly discrete and nonlinear, a proper optimization method is required to deal appropriately with the local minima issue.

F6. As the main contribution of this research, a comprehensive planning is implemented for distribution networks so that the total cost is minimized and the constraints are satisfied. As mentioned, this total cost is composed of the investment cost, the line loss cost, and the reliability cost. It should be noted that these costs can be decreased by installing some devices such as capacitors, VRs, DGs, and CCs. The constraints are the bus voltage and the feeder current which should be maintained within their standard range.

1.3. Aims of the Study

As mentioned in sub-section 1.2, the main contribution of this research is an integrated planning of the distribution networks. The primary definition of the planning problem is to find the placement and rating of transformers and feeders. As mentioned in sub-section 1.2, the objective is to minimize the investment cost, the reliability cost and the line loss cost while the load growth is supported and the constraints are satisfied. To decrease the reliability and the line loss costs, some devices such as capacitors, VRs, DGs, and CCs can be installed. Capacitors and VRs are employed to decrease the line loss cost and to improve the voltage profile. CCs and DGs are mainly installed to improve system reliability. For supporting the load growth, the distribution transformers and feeders can be upgraded. Furthermore, DGs and capacitors can help transformers for this goal to avoid extra upgrades. Given the above points, a framework has been designed. Following shows a 7-step framework for achieving the main innovation of this research which is the integrated planning of MV and LV networks:

Step1. Planning of an area with only transformers and feeders and with no other devices such as capacitors, VRs, CCs, and DGs.

Step2. Designing an optimization method which deals properly with this nonlinear and discrete problem.

Step3. Studying the planning of capacitors and VRs, as the voltage profile improvers and line loss reducers, and including them in the distribution network planning.

Step4. Investigation of DGs and CCs as the devices which improve the reliability and considering them in the distribution network planning.

Step5. Improvement of reliability, line loss, and voltage profile altogether by integration of DGs and capacitors.

Step6. Integrated planning of distribution networks in which distribution transformers, feeders, DGs and capacitors are all included to improve the line loss, system reliability, and voltage profile and to support load growth.

Step7. One more step toward improving system reliability using CCs to decrease the investment cost in DGs. It should be noted that CCs are primarily used for planning distribution systems in urban areas.

1.4. Key Innovations in this Research

The main contribution of this research is a comprehensive planning of MV and LV distribution networks. During the planning, the investment cost, the line loss cost, and the reliability cost are minimized. Moreover, the bus voltage and the feeder current as constraints are satisfied and the load growth is supported. In order to decrease the line loss cost and to improve the voltage profile, capacitors and VRs are optimally planned. DGs and CCs are also optimized to minimize the reliability cost with minimum cost. For supporting the load growth, planning of DGs along with upgrading of the distribution transformers and feeders is implemented. Therefore, planning of distribution networks in presence of capacitors, VRs, DGs, and CCs is performed as the main innovation of this research. To attain this key innovation, the following achievements will be accomplished:

1. A new configuration for planning LV and MV networks sequentially is a contribution of this research. In this procedure, the placement and size of transformers and feeders for both MV and LV networks are optimally determined. The discrete cost model of transformers and feeders, a realistic configuration, and including all line loss and reliability costs in addition to the investment cost in the objective function are the factors which make this work as unique.

2. Introduction of a proper optimization method is another innovation of this research. The proposed optimization method is constructed by developing DPSO. This method is more robust and accurate compared with DNLP, GA, SA, and DPSO for solving discrete problems such as the capacitor planning.

3. A new segmentation-based strategy is contributed to find the location and rating of fixed and switched capacitors with reasonable accuracy and computation time for different load levels.

4. For the first time, VRs and Load Tap Changer (LTCs) are optimized altogether with capacitors to minimize the line loss and to improve the voltage profile.

5. An integrated planning of distribution networks is introduced in which DGs and capacitors along with the distribution transformers and feeders are planned simultaneously to improve the voltage profile, line loss, and system reliability.

6. A new arrangement is innovated to minimize the reliability cost along with other costs. This arrangement is composed of the allocation and sizing of DGs along with the allocation of CCs while the distribution transformers and feeders are planned under load growth.

7. Proposing a segmentation-based strategy to plan the distribution systems under load growth.

8. A comprehensive planning is contributed to minimize the line loss cost, the reliability cost, and the investment cost simultaneously and to improve the voltage profile as the load growth is supported. In this planning, all electrical elements are optimally planned.

1.5. Structure of the thesis

This thesis is organized in nine chapters. An overview of the research along with the features and aims are outlined in **Chapter 1**. The key contributions are also named in this chapter. A literature review is carried out in **Chapter 2**. In this chapter, the justification for doing this research is expressed. It is illustrated that a comprehensive planning technique is required to cover almost all aspects of planning. As a conventional planning, the transformers and feeders are planned in **Chapter 3**. A practical technique is proposed in this chapter which can be a reliable guidance for conventional planning. VRs are commonly installed in distribution networks to improve the voltage profile. Capacitors are considered to decrease the line loss as the voltage and current constraints are maintained in the standard level. Since improvement of the line loss and voltage profile is one of the main objectives in the distribution network planning, VRs and capacitors need to be included. Power system elements have practically discrete size. Additionally, reliability indices and line loss values have a nonlinear relation with the size and location of these elements. That is why planning these elements results in a highly discrete and nonlinear objective function. Since the objective function is normally nonlinear and discrete, the optimization problem has a number of local minima. To alleviate this problem, a new optimization method is proposed in **Chapter 4**. This optimization method is employed for planning both VRs and capacitors simultaneously in **Chapter 5**. As capacitors influence the voltage profile and line loss significantly, they are joined to transformers and distribution line upgrading altogether with DGs to design a distribution network in **Chapter 6**. As system reliability is improved by using DGs, this factor is also included in this chapter.

Load growth as a major factor in planning of distribution networks is taken into account in **Chapter 7**. In this chapter, capacitors as a less expensive devices help DGs for supporting the load growth to avoid extra upgrading of transformers. In this chapter, DGs and capacitors are planned along with the transformer and distribution line upgrading to minimize the total investment cost while the line loss and reliability costs are minimized, the bus voltage and feeder current are kept within their standard level, and the load growth is supported.

Given that the DGs are very expensive, CCs are employed to decrease the total investment cost in DGs required for minimizing the reliability cost. This case is studied in **Chapter 8**.

Conclusions drawn from this research as well as recommendations for future works are given in **Chapter 9**. The list of references and a list of publications resulted from this thesis are presented after this chapter.

CHAPTER 2

Literature Review

2.1. Introduction

Distribution networks are conventionally designed by planning transformers and distribution lines for minimizing the line loss, maximizing the system reliability, and improving the voltage profile. Capacitors, VRs and the load tap changer of the transformers are three elements which can help the conventional planning to improve the line loss and voltage profile more. However, these devices cannot influence the system reliability. On the other hand, DGs, switches, and CCs significantly improve the system reliability. DGs can decrease the line loss, but they are so expensive that are not justified to be installed only for minimizing the line loss. The above points highlight the need for a combination of capacitors and DGs to decrease the total cost.

Improving system reliability can be achieved by using DGs. However, since they are expensive devices, CCs are acceptable alternatives for helping these costly elements particularly in urban areas.

Load growth, as an important factor in planning, is conventionally supported by upgrading transformers and distribution lines. However, this applies a large number of upgrades so a large investment cost. For alleviating this issue, DGs are found as reliable alternatives which can decrease the total cost significantly compared with the conventional planning.

2.2. Allocation and Sizing of Distribution Transformers and Feeders

Distribution network planning is primarily identified by the allocation and sizing of distribution transformers. The location of transformers directly specifies the length and route of MV and LV feeders. Therefore, location and rating of transformers should be determined along with the length and size of MV and LV feeders. For this purpose, an optimization procedure is required to minimize the investment cost of transformers and feeders; while, the loss cost is minimized and the system reliability is maximized. The voltage drop and the feeder current as constraints need to be maintained within their standard range.

Although the LV network cost is, to some extent, comparable with the MV network cost, the majority of the published papers in planning of distribution networks are dedicated to the planning of MV networks [1-37] rather than LV networks [38-46] and there are only a few papers developing both MV and LV networks simultaneously [47-49]. The planning of either of these networks separately will not lead to an accurate result. Since, MV feeders cost is a common element in both networks which should be determined based on the LV and MV side data. This illustrates that both MV and LV networks should be optimized simultaneously.

The classical branch and bound techniques [1-10] are considered as a natural application for solving this problem. Although these procedures can lead the objective function to a minimum value, they suffer severely from very excessive computation time owing to their combinatorial complexity. To improve this difficulty, some other approaches have been presented. Among these techniques, the heuristic methods are well accepted in the literature [11-19,38-41] and among the heuristic methods, PSO is also becoming more popular than others [50,51].

Another point is that almost all of the mentioned papers use a continuous cost function to model the cost of the distribution network components, LV conductors, distribution transformers, MV feeders and substations. Only a few authors have used the discrete function cost [13,38,41]. This is of concern since this approximation strictly decreases the accuracy of solution.

2.3. Allocation and Sizing of Capacitors and VRs

Capacitors are commonly used in distribution systems to minimize the reactive component of the line current. This compensation reduces the distribution line loss and improves the feeder voltage profile. Similar to capacitors, LTC and VRs keep the bus voltages within the standard level and can reduce the line loss. Particularly in the peak load, reduction of the line loss by these elements can prevent additional investment for using high rating equipment. However, the investment cost is an issue which limits the wide use of these devices and highlights the importance of finding their location and rating.

There are only a few papers which deal with the VRs. Among these, in [52], a two-stage method is proposed to find the placement of VRs in a distribution system to minimize the line loss and to improve the voltage profile for a specific load level. In the first stage, the VRs placement and tap setting are found as an initial solution. The number of initial VRs is reduced in the second stage using a recursive procedure. Similar to this paper, the VRs allocation problem is solved using a Micro GA in [53].

In spite of a limited number of VR-associated papers, many papers have been presented for finding the location and size of capacitors. Chang in [54] employs a heuristic method, called ant colony search algorithm, for reconfiguration and finding the placement of capacitors to reduce the line loss. GA, as another heuristic method, is used in [55] for finding the placement, replacement and sizing of capacitors with consideration of nonlinear loads. These authors used the combination of GA and Fuzzy Logic [56] four years later in 2008 and improved the results obtained by GA. Wu et al in [57] employ the maximum sensitivities selection method for allocation of fixed and switched capacitors in a distorted substation voltage.

In general, due to the discrete nature of this problem, the associated papers are mostly based on the heuristic optimization methods e.g. GA [58,59]. However, there are a few papers solving the problem using the analytical methods [60,61]. In spite of [54], the papers [55-61] solve the problem with assumption of the multi-level loads. It should be noted that calculation of the distribution line loss based on the average load level is not acceptable since the loss is proportional to the square of rms current. Therefore, the average loss value is not equal to the loss associated with the average load level. Also, it is not feasible to solve the problem at every load level, since a number of load levels will be chosen. To avoid this problem, the loads should be modeled using an approximation of the load duration curve in multiple steps. Increasing the number of steps leads to higher accuracy and consequently higher computation time.

LTCs along with capacitors are scheduled in [62-64]. In [62], an analytical method, called nonlinear interior-point method, is proposed for dispatching the main transformer under a LTC and capacitors for minimizing the line loss. The same problem is solved in

[63] by a dynamic programming method. Ulinuha et al in [64] include the nonlinear loads and minimize the line loss and improve the voltage profile by scheduling of LTCs and capacitors using evolutionary-based algorithms.

As observed, the main focus of all the above methods is on minimizing the line loss and improving the voltage profile and no effort was made on maximizing system reliability while this is a dominant factor in planning of distribution networks.

2.4. Allocation and Sizing of Distributed Generators

The generation of electrical energy and avoiding greenhouse gas emissions issue are currently challenging issues. As a result of this, the renewable energy sources are presently known as a reasonable solution [65]. The interest in using the renewable energy sources is increasing due to the decrease of the production cost, environmental impact and line loss as well as the improvement of reliability indices. Based on the benefits mentioned in [66], it is predicted that the future energy demand will be mostly provided by renewable energies (about 30%-50%) by 2050 [67]. However, the large investment cost required for installing DGs is an issue which limits their wide use so that many papers study the economic aspects of renewable resources [68-71]. These illustrate the importance of allocation and sizing of DGs.

A variety of solution techniques have been employed to find the location and size of DGs, analytical methods e.g. NLP [72,73] and heuristic methods e.g. GA [74-79]. The discrete nature of this problem leads the objective function to have several local minima. As random based methods, the heuristic methods deal properly with the local minima. Therefore, they are employed more than the analytical methods for planning of DGs.

Reference [74] uses GA to find the placement of one DG to minimize the line loss. This problem is solved in [72] for multiple DGs using an analytical-based optimization method. One year later in 2005, GA was employed in two papers [75,76] for allocating and sizing of DGs. Similar to [75], Popovic et al presented a paper [73] based on an analytical method for planning of DGs to improve the reliability. In [77], the location and rating of one DG is determined to improve the reliability, losses and voltage profile using GA. In [78], another GA-based approach is introduced to improve the reliability indices using allocation and sizing of DGs. As another heuristic method, ant colony system is employed in [79] for planning DGs to increase system reliability.

Although these methods optimize the location and rating of DGs for different load levels, they do not include the load growth in their computation while supporting the load growth is one of the main benefits of using DGs.

2.5. Allocation of Switches

Since almost 80% of faults occur in the distribution networks, they are considered as one of the most critical parts in an electrical system. This highlights the need for protection devices such as fuses, breakers, sectionalizers, CCs and reclosers. Among these devices, sectionalizers and CCs have attracted more attention. Using these devices is studied in two aspects, investment cost and system reliability. In order to increase system reliability, more investment is required and vice versa. To satisfy these two aspects simultaneously, an optimization procedure is needed to lump them into one objective function. This shows the importance of the allocation of switches problem.

The CCs are devices connecting feeders so that the loads located in one feeder can be supplied by another feeder when a fault occurs in the corresponding feeder. Although CCs influence the reliability indices significantly, only a few papers have included CCs [80,81] and most authors have taken into account only the placement of sectionalizers [82-90]. In [80], some specific points are assumed as the candidate location of CCs and in [81], only final end points of feeders are selected for installation of CCs.

Billinton et al [81] use the Simulated Annealing (SA) to find the location of switches. In 1994 and 1995, Levitin et al presented two publications [82,83] based on GA. A procedure based on Bellmann's Optimality Principle is also presented in [84] to minimize the capital cost of sectionalizers and another strategic formulation was proposed by Teng et al in [85] in 2002. One year later, Teng introduced a method based on the ant colony [86] and showed that the results are superior over GA. Falaghi et al in [90] also used the ant colony optimization in 2009. In [87], Mao et al formulated the switch placement problem using Graph-based algorithms. References [88] and [89] are based on Immune Algorithm and PSO, respectively.

Since both DGs and switches influence system reliability, integration of both these elements in the optimization method decreases the total cost. This can be the next step in the above papers for completing their proposed planning approach.

2.6. Planning of Distribution Networks under Load Growth

The economical planning of a reliable distribution network that satisfies the annual load growth for the planning period is a significant issue for distribution network companies striving to survive in the competitive electricity market [91]. For this purpose, installation of new substations or upgrading the substation capacity is required. DG is an alternative approach to such upgrades that has attracted engineers' attention in recent years. In addition to supporting the annual load growth, DGs can decrease the line loss by reducing the line's power flow and can improve the reliability by supplying isolated loads after an outage.

A DG-based planning method is presented in [91] to minimize the line loss in a planning area. In this paper, two scenarios are discussed to evaluate the feasibility of implementing DG investment versus other traditional planning choices. Dynamic ant colony search algorithm is employed in [92] to minimize the line loss for a planning period. Similarly, the DG installation is studied in this paper instead of traditional options to meet the load growth. In [93,94], an optimization software, based on the branch and bound method, is used to solve the planning problem. In these two papers, a multistage model is proposed to consider the traditional planning options as well as the use of DGs.

In addition to DGs, capacitors can postpone the need to upgrade the HV/MV transformer required due to the load growth [95]. The capacitors are used commonly for minimizing the line loss and improving the voltage profile by reducing the reactive component of the feeder current [54]. In [63], a dynamic programming method is used for solving the reactive power and voltage control. The capacitors and the main transformer tap changer are dispatched in this paper to minimize the line loss and to improve the voltage profile. A similar procedure is implemented in [96,97] using the GA. A mechanism for optimal voltage support is proposed in [98], which introduces a procedure to optimize VRs in addition to capacitors and the main transformer tap. It is observed that including VRs can decrease the total cost by 3.6%. In the presence of nonlinear loads, papers [55-57] introduce a capacitor planning to minimize the line loss.

Similar to the capacitor size, the line characteristics, DG size and location, and adjusting the distribution transformer tap setting can assist to keep the bus voltage within the standard level and to reduce the line loss [91,92,99-101,76]. Such reductions of the line loss at peak load level can reduce the need for investment in equipment of a greater power rating.

In addition to reducing the line loss and improving the voltage profile, increasing reliability is another benefit that DGs can provide for electric utilities. An economical DG planning method is implemented in [76] to improve reliability as well as the line loss. In [102], the impact of DG location on reliability is studied, and the placement of DGs for maximizing the reliability improvement and minimizing the line loss is obtained. An ant colony system algorithm is employed in [79] to optimize the location of DG and reclosers to enhance the system reliability.

Improving the voltage profile, minimizing the line loss and reliability costs, and supporting the load growth are the main objective in planning of a distribution network. Since capacitors improve the voltage profile and line loss and DGs increase system reliability and that both these elements can help the HV/MV transformers for supporting the load growth, capacitors and DGs should be planned simultaneously to have a low cost planning. This highlights a need for a method to consider this integrated planning method as implemented in this research.

2.7. Reliability Based Planning of Distribution Networks under Load Growth

A main aim of distribution network companies is to plan a reliable distribution network economically. This target is achieved by planning the reliability improver elements such as DGs and CCs. CC is a line, equipped with a tie-switch, to connect a feeder to another one when a fault occurs in the feeder and to disconnect for normal state. Totally, these devices are reliable alternatives for supplying isolated loads after an outage [87].

Allocation and sizing of DGs is solved in [103] using an analytical based method to minimize the line loss. The same problem is solved using an ordinal optimization method in [100]. In addition to the line loss, the system reliability is included in the DG planning problem as a constraint in [77] for improving the system reliability, line loss, and voltage profile. In [77], GA is employed as the required optimization method.

To further improve the system reliability, switches such as reclosers and CCs are incorporated in the DG-based planning problem. An ant colony system algorithm is employed in [79] for finding the placement of reclosers and DGs. This method minimizes an objective function composed of two reliability indices, SAIDI and SAIFI. A two-step design is presented in this paper. First, the placement of reclosers is identified while the DG locations are fixed. Then, DGs are planned for the reclosers obtained in the previous step. Similar problem with the same objective function is solved using GA in [104,73]. In [105], an ant colony algorithm based reconfiguration methodology is proposed for solving the switching operation of distribution networks in the presence of DGs.

The number of loads which can be supplied by a DG or a CC, located at the end point of a line, is limited if a low rating conductor is selected. On the other hand, using a high rating conductor imposes higher investment cost. Therefore, the rating of distribution lines influences the number of supplied loads so the system reliability. That is why the line ratings should be included in the variables. A reconfiguration based method is presented in [99] to minimize the line loss. In this method, DGs and lines are optimized as the variables. The same problem is solved in [91] in which different scenarios for system planning are compared. The results demonstrate that DG-based planning approach can improve the voltage profile and minimize the line loss more than other methods. The tabu search is employed in [101] for solving the reconfiguration problem in which DGs, capacitors, and lines are optimally planned. Similar problem is optimized using the dynamic ant colony search algorithm in [92]. In [93,94], a multistage model is proposed for distribution network expansion. This expansion includes the upgrading of substations and feeders and planning of DGs.

The above papers highlight the need for an approach which include both DGs and CCs in the optimization procedure as the voltage profile is improved, the line loss and reliability cost are minimized and the load growth is supported.

2.8. Optimization Methods for Power System Problems

A variety of optimization methods exists in the literature for solving power system problems, such as capacitor planning, DG planning, and switches planning. These optimization methods can be divided into two main groups: analytical-based methods and heuristic-based methods.

The simplest analytical method is linear programming which is employed when the objective function and constraints are linear. This method has been applied to various problems such as, power system planning and operation [106], optimal power flow [107], and economic dispatch [108]. Since some or all variables are discrete, the integer and mixed-integer programming techniques were introduced into power system analysis. These techniques have been used for hydro scheduling [109], TCSC planning [110], and planning and expansion of distribution and transmission networks [47,111]. The objective function associated with most of the power system problems contains nonlinearity. This resulted in the use of NLP for optimizing a variety of issues, such as stability analysis [112], optimal power flow [113], and DG planning [114]. The analytical techniques are highly sensitive to initial values and frequently get trapped in local minima particularly for the complex problems which have nonlinearity and discreteness. In addition to the convergence problem, algorithm complexity is another disadvantage associated with the NLP methods [115]. This has led to the need for developing another class of optimization methods, called heuristic methods. GA is a search technique for finding the approximate solutions to the optimization problems. This technique is inspired by evolutionary biology, such as mutation and crossover. PSO is another evolutionary computation technique which is inspired by the social behavior of bird flocking and fish schooling. This method is not highly sensitive to the size and nonlinearity of the problem and can converge to reasonable solution where analytical methods fail [51]. That is why a number of papers have been published in the past few years based on this optimization method, such as in allocation of switches in distribution networks [89], planning of capacitors [116], planning of harmonic filters [117], economic dispatch [118], optimal power flow [119], and loss minimization [120]. Comparing with other similar optimization techniques like GA, PSO has some advantages [50,51]:

1. In PSO, each member remembers its previous best value and the next value for each member is calculated using this memory.

2. There are fewer parameters to be set in PSO compared with other methods.

3. Implementation of PSO is easier than some other methods.

4. The diversity of variables is maintained in PSO, while in some other methods like GA, the worse solutions are discarded.

The main aim of distribution networks planning is to minimize an objective function composed of the line loss cost, reliability cost, and the investment cost. Since the line loss and system reliability values have a nonlinear relation with the element sizes and that the size of elements is discrete, the planning problem is highly nonlinear and discrete. Additionally, a large number of variables should be optimized during the planning procedure. All these characteristics ensure that the planning problem is a complex problem.

Given that PSO is a reliable optimization method in the literature, this optimization method is employed in this research for solving the distribution system planning problem. Figure 2.1 shows the flowchart of PSO method. The parameters and variables in this figure will be described in Chapter 4 of this report. In Chapter 4, a modification is applied to PSO method to increase the diversity of the optimizing variables. The results demonstrate that the MDPSO has higher robustness and accuracy compared with some other heuristic methods, such as GA and conventional PSO.

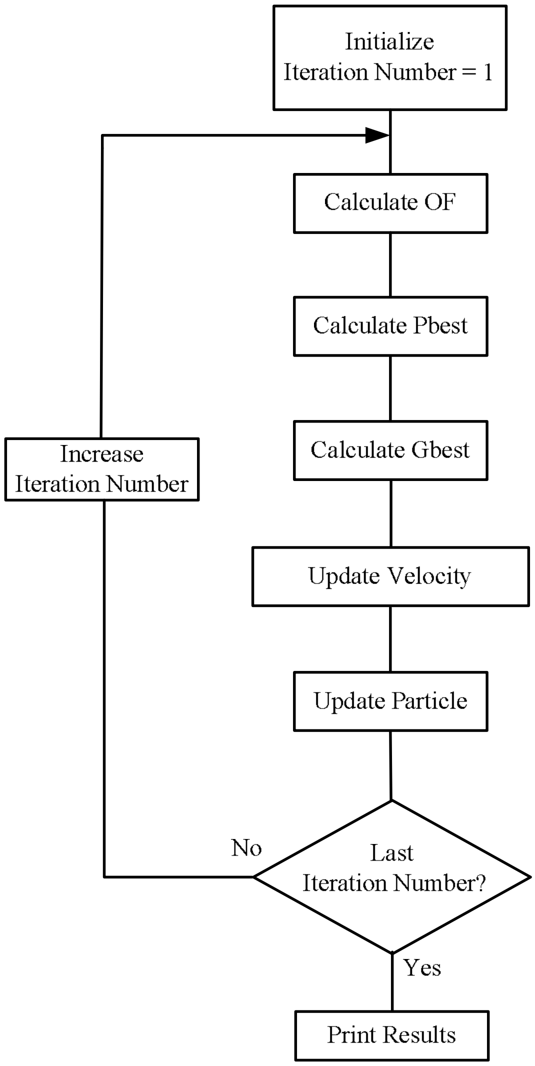

Figure 2.1. Algorithm of PSO method

Considering the literature review done in this report, it is clear that a comprehensive algorithm is required to develop the planning of distribution networks. In this algorithm, the location and size of the transformers and feeders, the location and size capacitors and DGs in different load levels, the location and operation of VRs in different load levels, and the location of CCs should be optimized while the voltage drop and feeder current constraints are satisfied and the load growth is supported.

2.9. Summary

In this chapter, a brief review is presented based on the previous published research works on the planning issues. Some papers propose methods for basic planning. In these papers, the effort is on determination of the location and rating of transformers as well as the route and type of feeders. Almost all papers focus mainly on MV or LV network. However, consideration of both these networks simultaneously is required since the MV feeder is a common element is both these networks which can influence the final outcome.

For planning a distribution network, some characteristics should be considered such as minimizing the line loss, improving the voltage profile, maximizing the system reliability, and including the load growth. Supporting each of these aspects needs to install some other electrical devices rather than only transformers and feeders.

Electrical devices have normally discrete size. Additionally, the line loss, system reliability, bus voltage and feeder current values have a nonlinear relation with these electrical devices' size and location. This makes the engineers to employ the optimization methods, which can deal appropriately with discrete and nonlinear objective function. Therefore, different optimization methods are employed for this objective. A reliable optimization method should have some main characteristics such as high accuracy and robustness. These highlight the need for an optimization method which has these key factors.

The basic planning methods are improved mainly by inclusion of capacitors and partly by inclusion of VRs. Capacitors decrease the line loss and improve the voltage profile significantly and VRs mainly maintain the bus voltage into the standard range as presented in many papers. However, integration of these two elements needs to be studied for improving both line loss and voltage profile to decrease the total investment cost.

Capacitors improve line loss and voltage profile but they cannot influence the system reliability. On the other hand, DGs increase system reliability significantly. However, improving system reliability as well as the line loss and voltage profile all should be included in a reliable planning. Since DGs are expensive, using these devices is not justified for minimizing the line loss and voltage profile. Hence, capacitors, as less expensive devices, are integrated in DG-based planning to minimize the total cost.

Since the loads in a distribution network are growing rapidly, this factor should be considered in the planning procedure. For supporting this factor, the transformers and feeders are conventionally upgraded which applies a large investment cost. For alleviating this issue, DGs are employed along with the capacitors to avoid extra upgrades of the transformers and feeders as the system reliability, line loss and voltage profile are improved.

Although DGs significantly reduce the reliability cost, their investment cost is an issue. On the other hand, CCs are less expensive than DGs but they cannot support the load growth. Therefore, using these elements for decreasing reliability cost under load growth can significantly reduce the required investment cost.

Selection of an appropriate optimization method for solving the planning problem is another issue. Since the planning problem is composed of nonlinear elements such as system reliability and line loss and discrete elements such as investment cost, a number of local minima exist in the resulting problem. The use of analytical methods such as nonlinear programming results in trapping in local minima. Therefore, heuristic methods like GA and PSO are mainly employed in the literature for solving these problems. The MDPSO is employed in this research. For this purpose, PSO is modified using two operators of GA to increase the diversity of variables. The results illustrate that the MDPSO is more accurate and robust compared with conventional PSO and GA.

CHAPTER 3

Guidance for Planning of Distribution Networks

3.1. Introduction

The proposed methodology covers planning both LV and MV networks. For planning distribution systems around a city, typically the electrical load density decreases from downtown towards the rural areas. Given this, the proposed procedure starts by dividing the planning area into the regions with fairly uniform load density: urban, semi-urban, sub-urban, etc. Within each region, the optimization considers LV zones, each of which is supplied by an MV/LV transformer whose rating is determined by the power of loads, located in the corresponding LV zone. As variables, the dimensions of LV zones along with the placement and rating of MV/LV transformers and the route and type of LV feeders are determined using the loads' powers and configuration. In the next step, another type of zone, called MV zone, is constituted to supply MV/LV transformers, located in LV zones, using a HV/MV transformer. The dimensions of MV zones along with the placement and rating of HV/MV transformers and the route and type of MV feeders are identified in this step.

3.2. Problem Formulation

The main objective of the Planning of Distribution Systems (PDS) is to minimize the cost of substations, transformers, MV feeders and LV conductors while the bus voltage and feeder current are maintained within acceptable ranges. To accommodate these, the objective function (OF) as the net present value of total cost is defined as:

$$OF = C_{CAP} + \sum_{y=1}^{Y} \frac{C_{O\&M} + C_I + C_L}{(1+r)^y} + DP \tag{3.1}$$

where C_{CAP} is the total capital cost, $C_{O\&M}$ is the total operation and maintenance cost, C_I is the interruption cost, C_L is the loss cost, r is the discount rate, Y is the number of years in the study timeframe, and DP is the penalty factor.

The interruption cost is calculated using two components – the cost related to the duration of interruptions and that related to the number of interruptions. The summation of these two costs is taken as the interruption cost. The duration based interruption cost is the multiplication of the cost for the average interruption duration in a year (in terms of minutes) and the average interruption duration. The average interruption duration can be found using the multiplication of SAIDI, as a reliability index, and the number of customers. Similarly, the number based interruption cost is found by the multiplication of SAIFI, the cost of average interruption number per customer, and the number of customers. The cost of average interruption duration and number per customer is provided by the local electrical company. Based on the above description, the total cost of interruption is calculated using (3.2).

$$C_I = W_{SAIDI} \times SAIDI + W_{SAIFI} \times SAIFI \tag{3.2}$$

$$W_{SAIDI} = NC \times C_{ID} \tag{3.3}$$

$$W_{SAIFI} = NC \times C_{IN} \tag{3.4}$$

where W_{SAIDI} and W_{SAIFI} are the reliability weight factors, C_{ID} and C_{IN} are the cost of average interruption number per customer (\$/interruption) and the cost of average interruption duration per customer ($/minute), respectively. NC is the number of customers served.

The loss cost is expressed in (3.5). In this, the loss cost has two parts – the energy loss cost which is proportional to the cost per MWh and the peak power cost which is proportional to the cost saving per MW reduction in the peak power.

$$C_L = P_{LOSS}\times(k_{PL}+ k_L\times 8760\times lsf) \tag{3.5}$$

where P_{LOSS} is the loss power, k_{PL} is the saving per MW reduction in the peak power, k_L is the cost per MWh, and lsf is the loss load factor. The constraints include bus voltages and feeder currents. The bus voltage (V_{bus}) should be maintained within the standard level.

$$V_{min} \leq V_{bus} \leq V_{max} \tag{3.6}$$

The feeder current (I_{f_i}) should be less than the feeder rated current ($I_{f_i}^{rated}$) in the ith feeder.

$$I_{f_i} \leq I_{f_i}^{rated} \tag{3.7}$$

The Death Penalty method is a simple and popular method to handle constrained optimization problems for including constraints. In this method, the constraints are incorporated in the objective function with a penalty factor, called DP. If all constraints are satisfied, DP will be zero. Otherwise, DP is set as a large number and is added to the objective function to exclude the relevant solution from the search space [121].

3.3. Methodology

The proposed methodology is to plan both LV and MV networks sequentially. For this purpose, the planning procedure starts by dividing the planning area into the regions where the loads density is relatively uniform. Each region is composed of several MV zones and LV zones. An LV zone contains an MV/LV transformer along with a number of LV loads supplied by this transformer. The MV zone includes an HV/MV transformer together with several LV zones supplied by this transformer. In this research it is assumed that both of zones, MV and LV, and regions are rectangular.

As variables, the dimensions of LV zones along with the placement and rating of MV/LV transformers and the route and type of LV feeders are optimized using the loads' powers and configuration in the LV zone planning. The dimensions of MV zones along with the placement and rating of HV/MV transformers and the route and type of MV feeders are optimized in the MV zone planning. These zones are defined in the following sub-sections.

3.3.1. LV Network

In this methodology, each customer is assumed to occupy a rectangular block, called load block, with a specific power demand. The dimensions of these blocks and their power consumption are related to the average load density of the region. Subsequently, a rectangular service area, composed of these load blocks that are supplied by a distribution transformer, is formed. This service area, called the LV zone, is shaped in an arrangement as shown in Figure 3.1. In this figure, a distribution transformer "T" supplies several customers. The white blocks are the customers and the grey parts are the streets. The length and the width of each load block are denoted by *LLB* and *LWB*, respectively and *WS* indicates the width of streets. It should be noted that the three-phase distribution line is located in all streets.

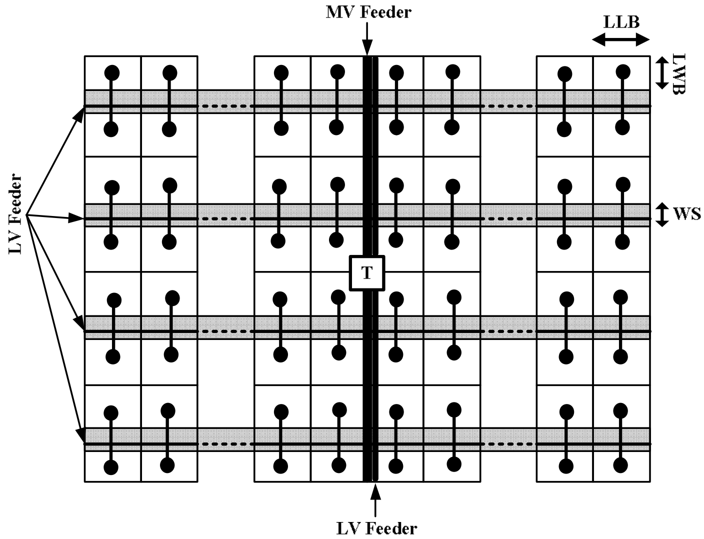

Figure 3.1. Typical distribution transformer service area (LV Zone)

The aim is to find the length and width of the LV zones along with the LV feeders' types and routes and the transformer size and location as the variables to minimize the total cost per load block (or per unit area). The objective function for LV planning problem is the cumulative cost of the transformer, LV and MV feeders, and line loss. Note that the length and thus the cost of the MV feeders are partly determined by the dimensions of the LV zone. The reliability cost is not incorporated into the LV zone planning since the cost benefit obtained from reducing outages for some loads in an LV zone is usually much lower than the cost of required switches.

3.3.2. MV Network

After finding the dimensions of the LV zones and corresponding transformer size, a rectangular zone is allocated to a distribution substation for optimization of the MV system. This rectangular zone, called MV zone, is composed of LV zones. Figure 3.2

shows an MV zone when all LV zones belong to a single load density region. In this figure, *TLB* and *TWB* are the length and the width of each LV zone. Transformers and substations are shown by “T” and “SS”, respectively.

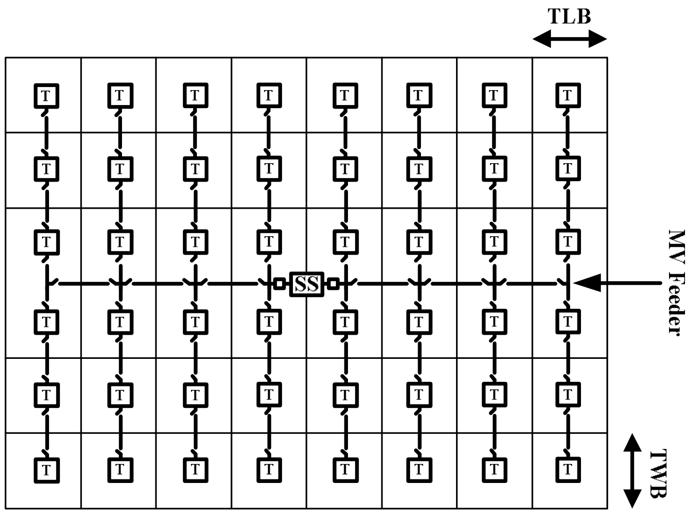

Figure 3.2. Typical distribution substation service area (MV Zone)

The values of *TLB* and *TWB* are known since they are the output of the LV zone planning program.

$$TLB = LLB \times HNLB \tag{3.8}$$

$$TWB = (LWB + 0.5 \times WS) \times VNLB \tag{3.9}$$

where *HNLB* and *VNLB* are the number of load blocks supplied by each distribution transformer in the horizontal and vertical axes which have been optimized in the LV zone planning section, respectively.

The location and size of substations and MV feeders’ types and routes in addition to the length and width of the MV zones are as the variables in the MV zone planning procedure. The objective function is composed of the loss cost, the reliability cost as well as the capital cost for HV/MV transformers and MV feeders per unit area. Here only the SAIDI and SAIFI contribution from the feeder faults is considered. The bus voltage level and the feeder current constraints should be satisfied in both LV and MV zones.

3.4. Implementation of DPSO for PDS Problem

3.4.1. Overview of PSO

PSO is a population-based and self adaptive technique introduced originally by Kennedy and Eberhart in 1995 [122]. This algorithm handles a population of individuals in parallel to search capable areas of a multi-dimensional space where the solution is searched. The individuals are called particles and the population is called a swarm. Particles as the variables are updated during the optimization procedure [51]. In DPSO, as the discrete version of PSO, the solution can be reached by rounding off the actual particle value to the nearest integer during the iterations. In [51], it is mentioned that the performance of the DPSO is not influenced by this rounding of process. Note that the continuous methods perform the rounding after the convergence of the algorithm, while in DPSO, it is applied to all particles in each iteration.

3.4.2. Methodology for Optimization of the PDS Problem

In the PDS problem, the particles are composed of the variables associated with the LV zones and MV zones. Dimensions of LV zones, distribution transformer sizes and locations, and the LV feeders' types and routes are the particles associated with the LV zone planning. The dimensions of MV zones, distribution substation sizes and locations, and the MV feeders' types and routes are those associated with the MV zone planning (Figure 3.3). Figure 3.4 shows the flowchart of the proposed planning method. In this figure, 'Si' in the blocks refers to the Step *i* in the description. The description and comments of the steps are presented as follows:

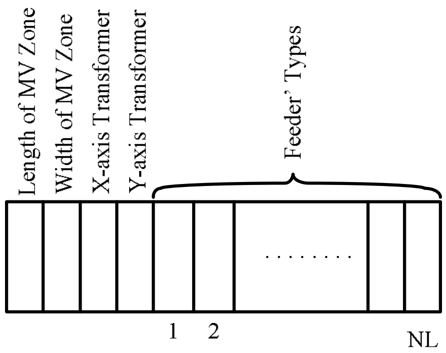

Figure 3.3. The structure of a particle

Step 1: (Input System Data and Initialization)

The inputs are the data of the planning area, the available transformers, LV conductors and MV feeders. The maximum allowed voltage drop and the rated current of available feeders are also specified. The particles and their velocities are randomly initialized. The number of population members and iterations are set respectively to 10 and 20.

Step 2: (Divide Planning Area into Regions)

In this step, the planning area is divided into the regions in which the load density is almost uniform such as urban, semi-urban, sub-urban, etc. For this purpose, first, the load density value associated with each load is identified (load size divided by its area). Then, the first rectangular region starts being formed. In order to find the size of this region, sets of loads are entered in this rectangular region in order. By adding each set of loads, the ‘Relative Standard Deviation’ index (%RSD) of the load density value of loads is calculated. This index is defined as the Standard Deviation divided by the Average. If this value is less than a separation rate, the next set of loads is added. Otherwise, this new set of loads are entered the second region. This collection continues till all the loads located in the planning area are lumped in regions. The separation rate depends on many factors such as the size of the planning area. For example it may be true that separated private houses have a %RSD between 2 and 3 but that high rise apartments have a %RSD of 10. This would thus give a clear separation of categories.

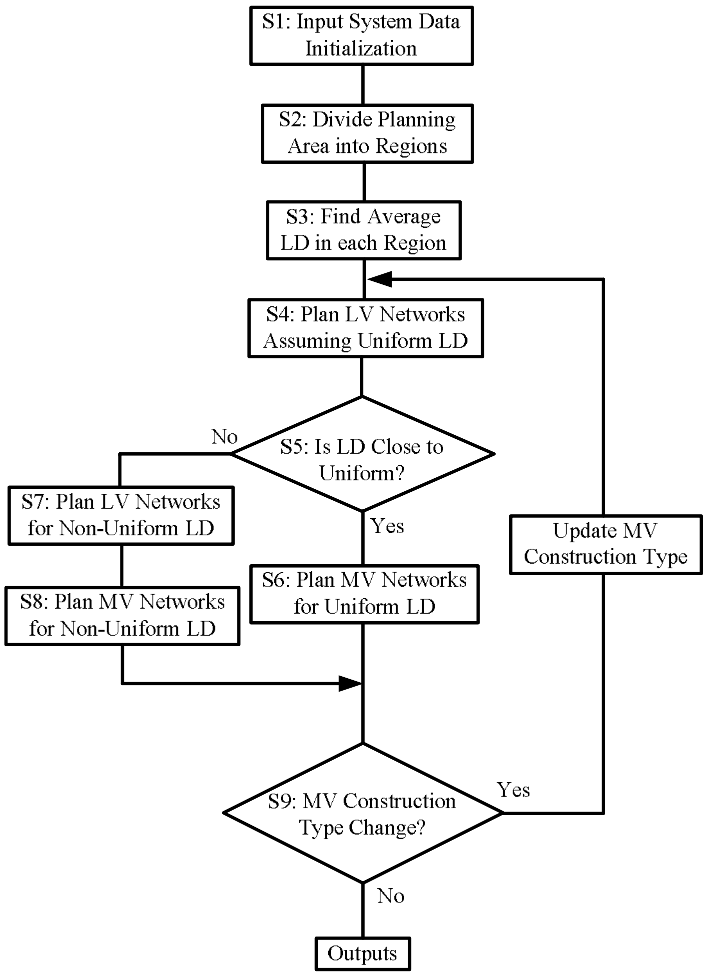

Figure 3.4. Overall iteration process linking LV-MV optimization

Step 3: (Find Average Load Density in each Region)

Regarding the loads located in each region, the average load density corresponding with each region is calculated. Using the average load density and average size of the load blocks in each region, the LV zone dimensions (the number of streets and the number of blocks in each street) will be calculated optimally as shown in Step 4.

Step 4: (Plan LV Networks Assuming Uniform Load Density)

Assuming uniform load density, it is clear that the minimum voltage in an LV zone is found for the farthest customer load. This voltage depends on the distance between the transformer and the farthest load. To reduce the voltage drop, this distance should be reduced. Therefore, the transformer should be located in the centre of the LV zone as shown in Figure 3.1.

DPSO is employed for optimizing the dimensions of LV zones in this step. The objective function is the cumulative cost of the MV/LV transformer, LV and MV feeders, and line loss cost. It should be noted that the length and thus the cost of the MV feeders are partly determined by the dimensions of the LV zone. For each region, the dimensions of LV zones as variables are specified as particle $N1^R$ in the optimization process.

$$N1^R = [\, HNLB^R , VNLB^R \,]$$

where $HNLB^R$ and $VNLB^R$ are the number of load blocks in the horizontal and vertical axes in region R, respectively. Since $HNLB^R$ and $VNLB^R$ are discrete, they are rounded to the nearest integers.

Since the planning area and the loads in a region are assumed to be completely uniform in this step, the size and location of distribution transformer and the conductors' types and routes can be found from the dimensions of the LV zone. Given the number of load blocks in the horizontal and vertical axes, a rectangular zone is created and the distribution supply is implemented as shown in Figure 3.1.

The area of LV zone can be simply calculated as:

$$ALV = (HNLB \times LLB) \times (VNLB \times (LWB + 0.5 \times WS)) \quad (3.10)$$

where ALV is the area of the LV zone in km^2. The transformer size and the LV conductor length are determined as given in (3.11) and (3.12).

$$S_{Trans} = (HNLB \times VNLB) \times P_{Load} \quad (3.11)$$

$$LLV = ((HNLB - 1) \times LLB) \times NS \quad (3.12)$$

where S_{Trans} and P_{Load} are the rating of transformer and the load demand per area. LLV is the total length of LV conductors required for supplying the load blocks. *NS* is the number of streets supplied by a transformer. The length of required MV feeder to supply the distribution transformer is also calculated by multiplying *VNLB* and *LWB*. It should be noted that the type of MV feeder is already known from previous steps.

To calculate the line losses and evaluate the optimization constraints, the bus voltages need to be calculated. For this purpose, an admittance matrix is formed using the current number of the load blocks as well as the transformer and LV conductor impedances. It should be noted that the impedance model is used for the loads. To calculate the bus voltage, the following equation can be used only if the I_{bus} is known.

$$V_{bus} = Y_{bus}^{-1} \,.\, I_{bus} \Rightarrow V_{bus} = Z_{bus} \,.\, I_{bus} \quad (3.13)$$

where the dimensions of *V*, *I* and *Y* depend on the number of load blocks. It should be noted that the dimensions of the Y_{bus} matrix change during the optimization procedure since different dimensions of LV zones are generated by each particle. Since there is no current injection (sources) in any of the buses except bus 1, the bus voltages can be calculated as:

$$V_{bus}(i) = Z_{bus}(1,i) \,.\, I_{bus}(1) \tag{3.14}$$

In this expression, $V_{bus}(i)$ is the voltage of bus i and $I_{bus}(1)$ is the injecting current to bus 1. $I_{bus}(1)$ is calculated using the network power and the voltage of the MV side of the distribution transformer which is assumed to be set by the transformer tap as 1.03 pu. Calculating the non-zero element of I_{bus}, $I_{bus}(1)$, the voltage at all the buses are found using (3.14). The line current can be calculated when the bus voltages and feeder impedances are known. An iterative-based procedure is employed to determine the lowest cost LV conductor types which maintain the bus voltage within the standard level.

Step 5: (Is Load Density Close to Uniform?)

If the load density in the planning area is close to uniform, the program continues to the next step to plan the MV networks for uniform load density. Otherwise, the program goes to step 7 for applying the non-uniform density condition to the LV zones resulting from Step 4. It should be noted that the criteria for uniform load density is that the %RSD of the load density value of the loads in the planning area is less than the separation rate.

Step 6: (Plan MV Networks for Uniform Load Density)

In this step, there are two variables: the length and width of the MV zone. Similar to the transformer placement in the LV zone planning for uniform load density, a distribution substation is situated in the centre of the MV zone to supply the distribution transformers, and thus their related load blocks, as shown in Figure 3.2. DPSO is employed for optimizing the length and width of the MV zones. The objective function is composed of the capital cost, loss cost and reliability cost per unit area. The bus voltage level and the feeder current are included in the objective function as constraints. The particle *N1*, composed of the number of LV zones in the horizontal and vertical axes, is used in DPSO as follows:

$N1=[HNTB, VNTB]$

where *HNTB* and *VNTB* are the number of LV zones located on the horizontal and vertical axes respectively. Since these are discrete values, they are rounded to the nearest integers. The total number of blocks is calculated by multiplying *HNTB* and *VNTB*. Since the MV zone is rectangular, the MV zone area is

$$AMV = (HNTB \times VNTB) \times OALV \quad (3.15)$$

where *AMV* is the area of MV zone in (km^2). OALV is the LV zone area, resulting from Step 4.

To calculate the cost of substation and MV feeder as parts of the objective function in the MV zone planning, the rating of substation and length of MV feeder need to be calculated.

$$S_{Subs} = (HNTB \times VNTB) \times OS_{Trans} \quad (3.16)$$

$$LMV = (TLB \times HNTB) - TWB \quad (3.17)$$

where S_{Subs} and OS_{Trans} are the rating of substation and the transformer rating calculated from the LV zone planning (Step 4) respectively and *LMV* is the length of the MV feeder. Similar to the LV zone planning, an iterative procedure is used to determine the MV feeder types as the optimization constraints are met.

It should be noted that the configuration of both MV and LV zones are like the letter "H" as observed in Figures 3.1 and 3.2. As a result, they are called the H-type configuration. Another configuration, called Branch-type, is considered in section 3.5.1. The minimum bus voltage is calculated using (3.13) and (3.14) following the same procedure as used in the LV zone planning (Step 4). Note that the substation voltage is set as 1.03 pu. After finalizing this step, the program goes to Step 9.

Step 7: (Plan LV Networks for Non-Uniform Load Density)

In this step, the non-uniform condition is applied to the LV zones resulting from Step 4. For this purpose, the uniform load blocks, located in an LV zone, are replaced with realistic loads (realistic placement and size), while the LV zone dimensions are kept the same as identified in Step 4. After that, the placement and size of distribution transformers and LV conductors' types in the LV zone are considered as the variables, particle $N2^R$ in DPSO, and are optimized to minimize the objective function.

$$N2^R = [\ XDTL^R\ , YDTL^R\ , LC1^R\ , LC2^R\ , \ldots,\ LCNC^R\ ]$$

$XDTL^R$ and $YDTL^R$ are the location of distribution transformer on horizontal and vertical axes in region R, respectively. LCi^R is the type of LV conductor i in region R. NC is the number of required different LV conductors in an LV zone.

For LV network, when some portions of the planning area cannot be approximated by a complete rectangle such as having an obstacle like a lake, a complete rectangle is formed as if no obstacle exists (the size of the rectangle is determined from step 4). After that, a zero power is assigned to the load blocks located in the part of this rectangle in which the obstacle is situated.

To allocate a distribution transformer, the following points should be noted:

1. If the location of transformer is within one of the load blocks, it should be changed to the nearest street (Figure 3.1).

2. If the location of transformer is in the middle of a street, it should be moved to one side of the street.

3. If the location of transformer is on an obstacle, it should be moved to the nearest feasible point.

In this step, the bus voltages are determined using (3.13) and (3.14) similar to Step 4.

Step 8: (Plan MV Networks for Non-Uniform Load Density)

In this step, in addition to the length and width of the MV zone, the HV/MV substation size and location, and the MV feeders' types and routes are included as the variables. Similar to Step 6, the objective function is composed of the capital cost, loss cost and reliability cost per unit area and the constraints are the bus voltage level and the feeder current (calculated using (3.13) and (3.14)). The particle *N2*, used in the employed DPSO, is composed of the number of LV zones in the horizontal and the vertical axes, the rating and location of substation, and the type of MV feeders in the corresponding MV zone (see Figure 3.3).

$$N2 = [\, XDSL, YDSL, MF1, MF2, \ldots, MFNF \,]$$

where *XDSL* and *YDSL* are the location of distribution substation on horizontal and vertical axes, respectively. *MFi* is the type of MV feeder *i*. *NF* is the number of required different MV feeders in an MV zone.

Step 9: (MV Construction Type Change?)

Since the MV feeder cost is the common element in the total cost associated with LV and MV zones, the optimized MV feeder types, obtained in Step 6 or 8, are compared with those used in the planning of the LV zone (Step 4 or 7). If they are the same, the program is terminated and the final results are printed. Otherwise, the program continues from Step 4 in the next iteration and the LV zone planning is implemented based on the MV feeders' types resulted from the current MV zone planning (Step 6 or 8).

3.5. Results

Two different cases are evaluated in this section. In the first case, it is assumed that both MV and LV zones are planned in a uniform load density region. In the second case, the non-uniform load density conditions applied in order to make the solution more realistic.

3.5.1. Uniform Load Density Based Case

The planning approach is tested on an area, the characteristics of which are listed in Table 3.1. Two configurations are investigated in this case: the H-type and the Branch-type configurations (Figures 3.2 and 3.5). The main benefit of the H-type configuration over the Branch type is its low total capital cost. However, it suffers from higher reliability cost. Selection between these two configurations depends on the reliability weight factors.

To compare the performance of DPSO, both GA and NLP are also applied to the PDS problem. The population size and the generation number for GA are selected 10 and 20 respectively similar to those used for DPSO. Other parameters in GA are selected similar to those defined as default in 'GAtool' in Matlab. In the studies performed, the NLP converges to local minima for some starting points. It should be noted that the DPSO results are also compared with those obtained with an exhaustive search method and they are found to be identical. In computer science, exhaustive search or brute-force search, also known as generate and test, is a technique which consists of systematically enumerating all possible candidates for the solution. Performance comparisons of DPSO with GA are given in Tables 3.2 to 3.4. Tables 3.5 and 3.6 give the list of available transformers and LV and MV feeders along with their characteristics.

Table 3.1. Characteristics of the test system

Parameter	Value
Load Power	2.5 (kW)
Length of Load Block	20 m
Width of Load Block	20 m
Width of Street	10 m
Base LV Voltage	415 (V)
Base MV Voltage	33 (kV)
Power Factor	0.8
Failure Rate	0.1864 (fault/km.yr)
Load Impedance	44 + j 33 (Ω)
k_{PL}	168000 $/MW
k_L	4 ¢/kWh
lsf	0.3
r	0.07
T	20 years
C_{ID}	0.02 ($/min)
C_{IN}	6 ($/interruption)
Switching Time	30 minutes
Repair Time	90 minutes

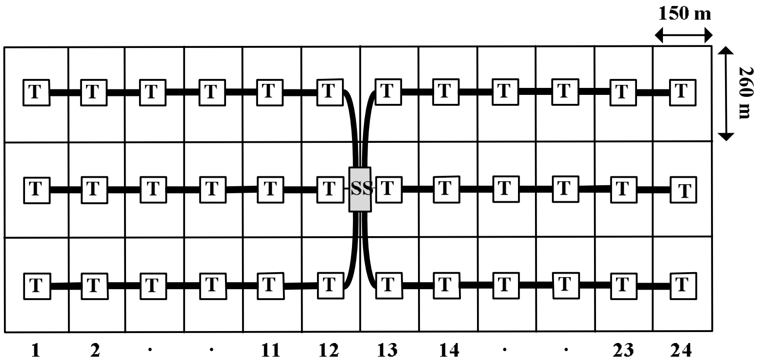

Figure 3.5. The optimized MV zone in Branch-type configuration

The reliability parameters are selected based on [48,49]. The planning is performed for peak load power (2.5 kW per block) and the upper voltage limit of 1.03 pu is chosen such that the low load voltage does not rise above 1.05 pu due to the Ferranti effect. The acceptable voltage drops in the MV and LV sides are assumed to be 97% and 95%, respectively [14,41]. Based on a sample load duration curve used in [14], the loss factor is assumed to be 0.35. The coding is written in Matlab 7.6 programming language and is executed in a desktop computer with the features as Core 2 Due CPU, 2.66 GHz, and 2 GB of RAM.

Based on the dimensions of load blocks and their power demand, the average load density is found to be 5 MW/km^2. Solving the LV zone planning, the solution is that each transformer should supply 3 streets (i.e., 78 blocks). The transformer size, calculated by (3.11), is 195 kVA. Using the available transformers listed in Table 3.5, the transformer rating is selected as 200 kVA. Using (3.10), the rectangular LV zone area is obtained as 0.039 km^2. Table 3.2 gives a summary of the LV zone planning outputs. It should be noted that the costs mentioned in Table 3.2 and all other tables are the cost per block.

Table 3.2. The output of LV Zone planning

Parameter	Value	
	DPSO	**GA**
LV Zone Size (blocks × blocks)	13 × 6	8 × 10
LV Zone Dimensions (km × km)	0.26 × 0.15	0.16 × 0.25
LV Zone Area (km^2)	0.039	0.04
Transformer Rating (kVA)	200	200
Transformer Cost ($)	800	780
LV Conductor Cost ($)	2233	2323
MV Construction Cost ($)	216	352
Loss Cost ($)	664	652
LV Conductor Types	1,7	1,6
Minimum Bus Voltage (PU)	0.9531	0.9535
Total Cost per Load Block ($)	3914	4107
Total Cost per km^2 (k$)	7828	8214

As observed from this table, the highest cost ($2233) is related to the LV conductors, which is 57% of the total cost ($3914). The LV conductor cost is obtained using the length of LV conductor from (3.12) and the cost per km (Table 3.6). The transformer cost also highly influences the results. However, the loss cost is small (17%). LV conductor types 1 and 7, given in Table 3.6, are selected for the horizontal and the vertical directions, respectively. Based on these, the minimum bus voltage is found to be 0.9531.

Compared with GA, DPSO converges to a lower total cost per square kilometer ($7.828M for DPSO and $8.214M for GA) which shows a cost benefit about $386000.

Furthermore, the exhaustive search method shows identical results with the proposed algorithm at the expense of longer computation time. In this case, the proposed DPSO converges quickly within 10 iterations.

After receiving the outputs of LV zone planning, the transformer characteristics and the dimensions of LV zone are considered as the inputs of MV zone planning. Then, a similar procedure is applied for the MV zone planning as in the case of H-type configuration. Table 3.3 illustrates the results of MV zone planning.

Table 3.3. The output of MV Zone planning for H-type configuration

Parameter	Value	
	DPSO	GA
MV Zone Size (blocks × blocks)	5 × 15	9 × 8
MV Zone Dimensions (km × km)	1.3 × 2.25	2.34 × 1.2
MV Zone Area (km^2)	2.925	2.808
Substation Rating (MVA)	15	15
Substation Cost (k$)	43.89	45.72
MV Construction Cost (k$)	8.66	9.01
MV Construction Type	1	1
Reliability Cost (k$)	11.35	11.45
SAIDI (min)	41.45	48.25
SAIFI	2.15	2.15
Loss Cost (k$)	2.71	3.75
Minimum Bus Voltage (PU)	0.9776	0.9795
Total Cost per Block (k$)	66.61	69.94
Total Cost per km^2 (k$)	1708	1793

The MV zone planning results in 5 blocks in the horizontal axis and 15 blocks in the vertical axis. With these, the area of MV zone is calculated using (3.15) as 2.925 km^2. Given the number of LV zones located in the MV zone, the substation rating is calculated using (3.16) as 15 MVA. As shown in Table 3.3, the rating 15 MVA is selected as the HV/MV transformer size. Compared with the LV zone planning in which the LV conductor cost is the main cost, the substation cost is the major cost of k$43.89 in the MV zone planning, which is 66% of the total cost. Similar to the LV zone, the loss cost is small compared with the other costs.

The SAIDI and SAIFI are found to be 41.45 minutes and 2.15, respectively. This calculation is based on the assumption that the sectionalizing switches are located on both ends of each primary branch and a circuit breaker is at the beginning of each main lateral (Figure 3.2). Similar to the LV zone planning, the minimum bus voltage is found near the boundary value of 0.97 using the lowest cost MV feeders to satisfy the constraints.

It should be noted that after applying the exhaustive search, similar results were obtained and this illustrates the accuracy of the employed DPSO, albeit faster convergence time. Compared with GA, total cost per LV block obtained by DPSO is about $3300 (≈$85000 per square kilometer) less than GA as seen in Table 3.3. All these results are based on the H-type configuration zones.

In order to improve the reliability index, another structure called Branch-type configuration is applied to the proposed planning. In this type of configuration, each substation is connected directly to the nearest distribution transformer as shown in Figure 3.5. Table 3.4 illustrates the outputs of MV zone planning for the Branch-type configuration. The trend of MV zone dimensions from first iteration to the last iteration is shown in Figure 3.6. Table 3.4 gives costs obtained by DPSO and GA. An exhaustive search method is also employed for this problem that gives identical results with the DPSO method.

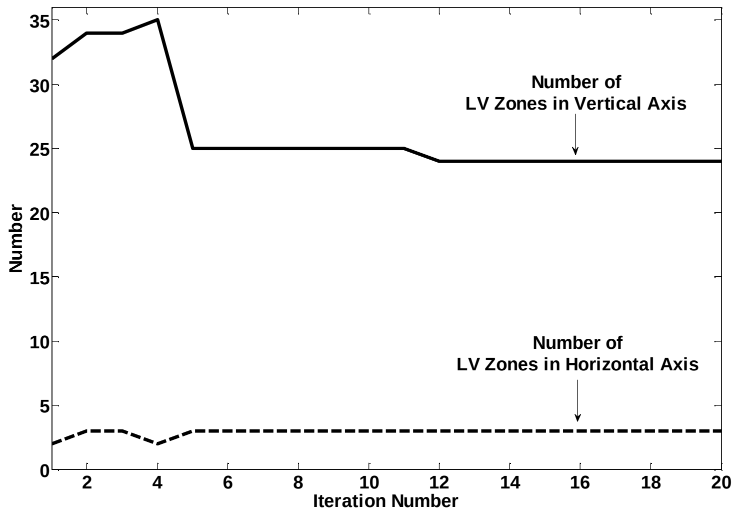

Figure 3.6. Number of blocks in horizontal and vertical axes in Branch-type configuration

The proposed iterative method for optimizing both LV and MV zones (Figure 3.4) in the Branch type configuration is assessed. For this purpose, the exhaustive search method is applied to both LV and MV zones. To apply the exhaustive search method, the objective function for all combinations of LV zone dimensions and MV zone dimensions should be calculated. For example, assume that an LV zone side cannot include more than 19 load blocks (because of the voltage drop constraint) and an MV zone side cannot include more than 35 LV zones. The number of states will be $19 \times 19 \times 35 \times 35 = 442225$. The running time for calculating the objective function is about 4 seconds. Therefore, the total required time for the exhaustive search method will be at least 20 days. This computation time is reduced to 15 minutes using the proposed iterative method while the final results are identical.

Table 3.4. The output of MV Zone planning for Branch-type configuration

Parameter	**Value**	
	DPSO	**GA**
MV Zone Size (blocks × blocks)	3 × 24	3 × 34
MV Zone Dimensions (km × km)	0.78 × 3.6	0.78 × 5.1
MV Zone Area (km^2)	3.808	3.978
Substation Rating (MVA)	15	25
Substation Cost (k$)	45.72	37.42
MV Construction Cost (k$)	9.29	18.20
MV Construction Type	1	9
Reliability Cost (k$)	10.65	14.95
SAIDI (min)	21.90	30.29
SAIFI	2.07	2.91
Loss Cost (k$)	2.23	0.34
Minimum Bus Voltage (PU)	0.9808	0.9522
Total Cost per Block (k$)	67.88	70.91
Total Cost per km^2 (k$)	1740	1818

One key characteristic of Branch-type system is that the voltage drop is not a main issue unlike the H-type. This helps the program to find a narrower zone (lower MV construction cost) with higher number of LV zones in each branch (see the MV construction cost in Tables 3.3 and 3.4). The number of LV zones located at each branch is limited because of the reliability and voltage drop. As shown in Table 3.4, the planned zone is composed of 72 (3× 24) LV zones. The length of this Branch-type based MV zone is 3 times of the length of the LV zone and its width is 24 times of the width of the LV zone. Based on these dimensions, the rating of substation is found as 14.4 MVA. Using Table 3.5, 15 MVA is selected as the substation rating. Figure 3.7 illustrates a comparison between the convergence characteristic of the proposed DPSO and GA when they are used for planning the MV network (Step 6 in the proposed iterative method).

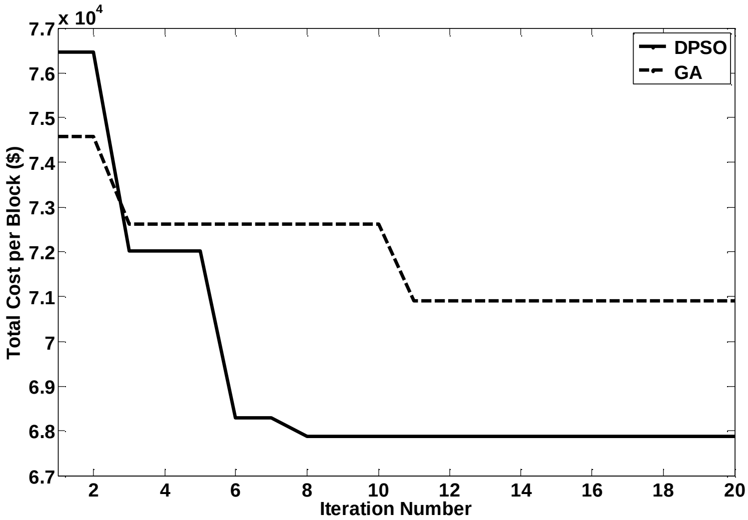

Figure 3.7. Total cost per block based on MV zone planning in Branch-type configuration

As seen in this figure and Table 3.4, DPSO converges in lower objective function value compared with GA ($67880 by DPSO and $70909 by GA). This demonstrates that the total cost per square kilometer obtained by DPSO is $78000 less than GA.

Compared with the H-type configuration, SAIDI decreases to about half in the Branch-type configuration, from 41.45 to 21.9 minutes as expected. On the other hand, the MV construction cost per block in the Branch-type is about 7% more than the H-type configuration ($9290 in the Branch-type and $8660 in the H-type). This is because the length of MV feeder in the Branch-type is more than the H-type (11.87 km in the Branch-type and 11.54 km in the H-type). Overall, the objective function value for the H-type and the Branch-type configurations are $66610 and $67880, respectively. This demonstrates that the H-type has a cost benefit over the Branch-type with the assumed reliability weight factors (reliability cost is about 16% of total cost). It is clear that if the reliability weight factors are decreased, the benefit margin of the Branch-type decreases and for the reliability penalties higher than these, the Branch-type configuration is preferred.

Applying the proposed technique for planning the LV and MV networks with the assumption of uniform load density provides a helpful and simply applicable guidance to evaluate the design solutions. In the next sub-section, non-uniform load density assumption is applied.

3.5.2. Non-Uniform Load Density Based Case

As a more realistic case, the non-uniform assumption is taken into account in this case study. To evaluate the proposed technique, it is assumed that the planning area is composed of three different load densities regions. The average load block dimensions are assumed to be 10m×10m, 20m×15m, and 30m×20m in regions 1 to 3, respectively. The average street width is assumed to be 5m, 10m, and 15m in regions 1 to 3. The average peak power in all load blocks is assumed to be 5 kW. After applying the uniform LV zone planning, the length and width of LV zones in these regions are found as 150m×50m, 315m×180m, and 750m×95m in regions 1 to 3, respectively. The corresponding transformer sizes are calculated as 300 kVA, 300 kVA, and 150 kVA, respectively.

After finding the dimensions of LV zones in regions 1 to 3, assuming a uniform load density, the transformer size and location as well as the LV feeder's routes and types are re-optimized based on the real non-uniform load sizes and locations in each LV zone. For this purpose, assume that the loads are realistically located in an LV zone resulted in region 1 as in Figure 3.8. As mentioned, the dimensions of this LV zone is 150m×50m which shows a rectangular zone in which there are 15 load blocks in the horizontal direction and 2 load blocks in the vertical direction. In order to make the analysis more understandable, this LV zone is assumed to have three parts in which the peak power per load block is 7 kW, 5 kW, and 3 kW, respectively (Figure 3.8).

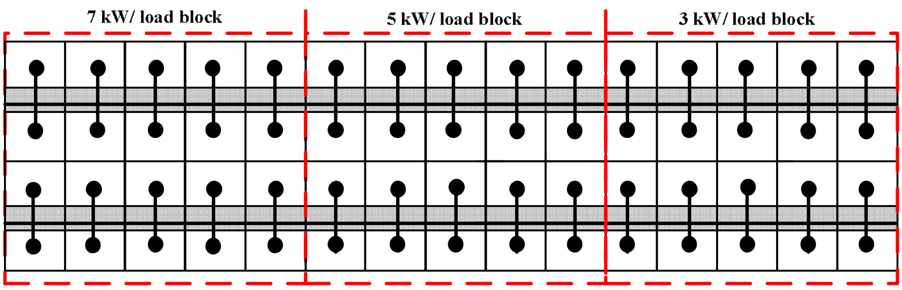

Figure 3.8. The optimized LV zone for non-uniform load density (region 1)

Optimizing this LV zone, the x-axis placement of transformer changes to 53 m (close to the last of the 7 kW loads) compared with the uniform load density case in which the transformer is at the centre of the zone (75 m). As expected, since the load density on the 7 kW part is more than other parts, the transformer is found closer to this part. The type of LV conductors changes to 7 (backbone) and 5 (laterals) from types 8 and 4 for the uniform case. It should be noted that because of practical reasons, no more than 2 types of conductors are allowed to be used in a zone.

For MV zone planning, it is assumed that the length of region 1 is 900 m, the length of region 2 is 1260 m, and the length of region 3 is unlimited. The width of regions is also assumed to be unlimited. After applying the MV zone planning, a substation with the rating of 15 MVA is found to be located at 1451 m and 150 m in x and y axes (Figure 3.9). The length and width of MV zone is determined to be 5160 m and 300 m.

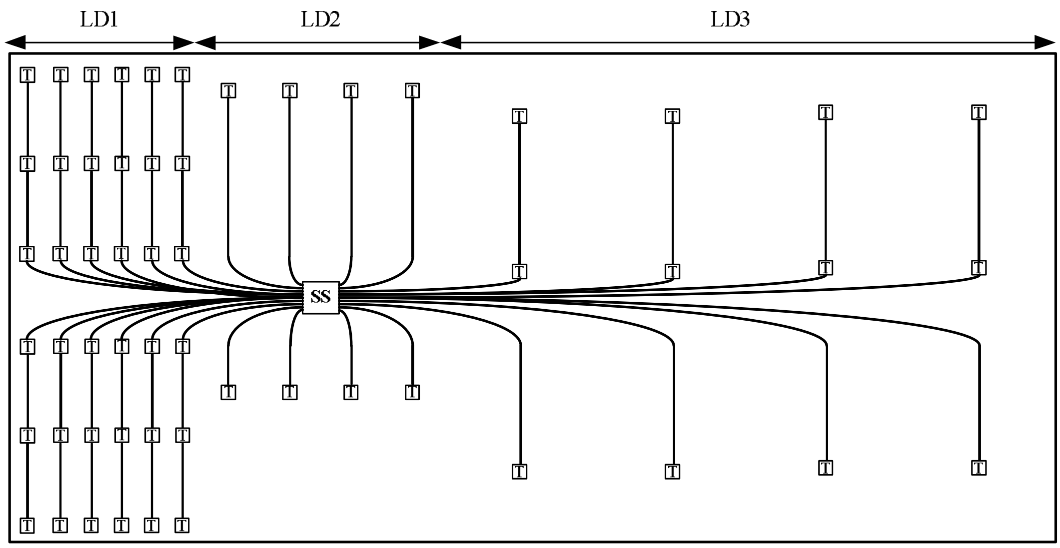

Figure 3.9. The optimized MV zone for non-uniform load density (not to scale)

As observed, the substation location is not in the centre of the MV zone since the load density is not uniform in the resulted MV zone and as expected the location of substation is found closer to the region with higher load density. The type of feeders for all load densities is found to be type 1. Figure 3.9 shows the configuration of MV zone after planning based on the non-uniform load density assumption.

A comparison between the convergence characteristic of the proposed DPSO and GA for MV zone planning (Step 8 in the iterative method) in this non-uniform load density based case is illustrated in Figure 3.10. As observed, DPSO converges in lower total cost per square kilometer rather than GA ($1.035M by DPSO and $1.092M by GA).

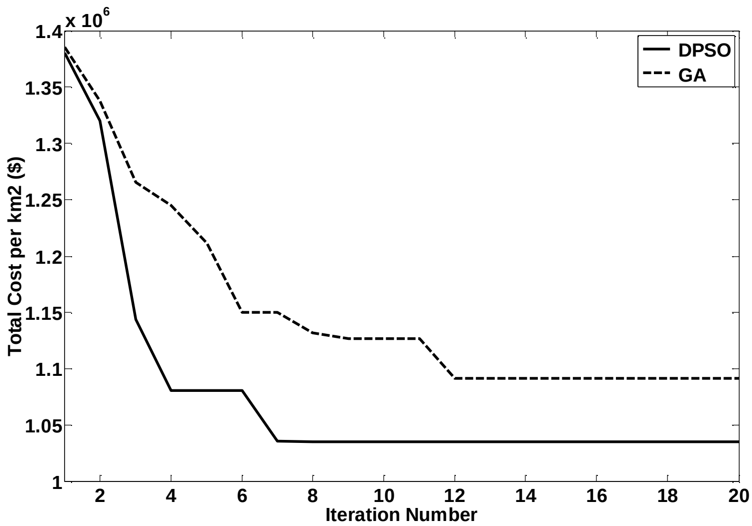

Figure 3.10. Total cost per square kilometer based on MV zone planning in case 2

Tables 3.5 show the characteristics of available MV/LV and HV/MV transformers such as the impedance, the capital cost, and the operation and maintenance cost. These characteristics along with the rated current associated with the available LV and MV feeders are given in Table 3.6.

3.6. Summary

A new methodology is introduced in this chapter for integrated planning of MV and LV segments of a distribution system optimally considering feeder types and routes, as well as, transformer ratings and placements. The objective function associated with the LV segment planning is composed of the loss cost as well as the total capital cost for MV/LV transformers, LV conductors, and the part of the MV feeders located in an LV zone. The objective function associated with the MV segment planning consists of the reliability cost, the line loss cost and the total capital cost for HV/MV transformers and MV feeders. The voltage drop and the feeder current are considered as constraints in planning both LV and MV segments.

DPSO is employed iteratively to solve the integrated distribution planning problem. The results are compared with those obtained by NLP, GA and the exhaustive search method. NLP as an analytical method could not improve the initial values due to the high discreteness of the problem. The proposed algorithm illustrates higher accuracy in all cases compared with GA for similar expected computational effort. Also the results of the DPSO have been compared with the exhaustive search method and are found to be identical. However, the exhaustive search is more time consuming.

A low computational effort iterative based technique is proposed for planning both LV and MV networks altogether. The results are found to be identical with those obtained by the exhaustive search. This illustrates the high accuracy of the proposed technique. It is shown that the proposed technique can be employed for planning of both uniform and non-uniform load densities. The proposed method can provide guidance for planning of practical MV and LV distribution systems.

Table 3.5. The characteristics of available transformers

Elements	Impedance	Capital Cost	O&M Cost
Transformers (kVA)	**Ω (PU)**	**k$**	**$/year**
25	0.006+0.017 i	10	300
30	0.006+0.018 i	12.3	311
50	0.005+0.018 i	16.8	325
63	0.005+0.019 i	18.5	348
100	0.005+0.021 i	22	376
150	0.005+0.022 i	24.8	408
200	0.003+0.022 i	26.3	455
250	0.005+0.023 i	37	503
300	0.004+0.024 i	40.2	564
350	0.004+0.022 i	45.7	607
Substation (MVA)	**Ω (PU)**	**M$**	**$/year**
3	0.040 i	1.6	16000
8	0.045 i	2.47	16800
15	0.045 i	3.1	18100
25	0.055 i	3.6	20500
30	0.060 i	3.8	23700
50	0.065 i	4.1	28000

Table 3.6. The characteristics of available feeders

Elements	**Impedance**	**Current Rating**	**Capital Cost**	**O&M Cost**
MV Feeders	**(Ω)**	**(A)**	**k$/km**	**$/year/km**
No. 1	1.75 + j 0.100	198	52	405
No. 2	1.40 + j 0.100	212	53	553
No. 3	1.00 + j 0.100	232	54.5	695
No. 4	0.90 + j 0.080	275	56.7	821
No. 5	0.75 + j 0.050	332	60	940
No. 6	0.63 + j 0.090	300	68.5	1042
No. 7	0.47+ j 0.087	386	76	1122
No. 8	0.30 + j 0.080	486	86	1197
No. 9	0.15 + j 0.076	601	100	1258
LV Conductor	**(Ω)**	**(A)**	**k$/km**	**$/year/km**
No. 1	2.50 + j 0.200	84	40	255
No. 2	2.20 + j 0.100	96	41.5	364
No. 3	1.90 + j 0.100	110	43	364
No. 4	1.60 + j 0.080	145	45	546
No. 5	1.30 + j 0.050	197	48.5	632
No. 6	0.74 + j 0.080	244	51.5	698
No. 7	0.44 + j 0.070	312	56	749
No. 8	0.25 + j 0.068	387	63	780
No. 9	0.10 + j 0.067	443	75	807

CHAPTER 4

A New Optimization Method for Planning Problems

4.1. Introduction

Since the size of electrical elements is a discrete value and that the objective elements have a nonlinear relation with the size of elements, the resulting objective function in planning problems is nonlinear and discrete. This discreteness and nonlinearity make the function to have a number of local minima. Therefore, selecting an appropriate optimization method is a main concern in planning of a distribution network. A reliable optimization method should have high accuracy and robustness.

In this chapter, a Modified Discrete Particle Swarm Optimization (MDPSO) is proposed. This method is studied by finding the placement and size of capacitors in a distribution system. The objective function is composed of the line loss and the capacitors investment cost. The bus voltage and the feeder current as constraints are included in the objective function by a constraint penalty factor.

To validate the proposed method, the 18-bus IEEE distribution system and the semi-urban distribution system which is connected to bus 2 of the Roy Billinton Test System (RBTS) are used. The proposed method is applied to the problem and its robustness and accuracy are studied. The results are compared with conventional DPSO, GA, and NLP. It is illustrated on two examples that the MDPSO is more accurate and particularly more robust than others for the planning of capacitors.

4.2. Problem Formulation

The loads and capacitors are modeled as impedance, a series RL for loads and a capacitive reactance for capacitors. The objective function and the constraints are also expressed in this section. Minimizing the total cost of capacitors as well as the distribution line loss is the main objective of the Allocation and Sizing of Capacitors (ASC) problem. The bus voltage and the feeder current as constraints are included in the objective function with a penalty factor. As all of the objective function elements are simply converted into the composite equivalent cost, this problem is solved using a single-objective optimization method. The objective function is defined as (3.1) in which C_I is zero. In this equation, C_{CAP} and $C_{O\&M}$ are the capital cost and the operation and maintenance cost of capacitors. The line loss is converted into an equivalent cost by a simplified equation of (4.1) as:

$$C_L = P_{Loss} \times k_L \times 8760 \tag{4.1}$$

The bus voltage and the feeder current should be maintained within standard levels as given in (3.6) and (3.7).

4.3. Applying Modified DPSO to ASC Problem

The first step in an optimization procedure is identifying the variables. The variables, particles, in the ASC problem are the size and the placement of capacitors. Figure 4.1 shows the structure of particles in the employed DPSO.

As observed, the particle is composed of NB cells with the value of C_i. Each candidate bus for installing a capacitor is assigned by a cell and the rating of the capacitor at the relative candidate bus is the value of the corresponding cell.

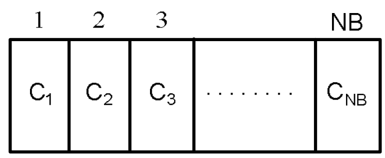

Figure 4.1. Structure of a particle

For example, C_i is the rating of the capacitor installed at bus i. If all buses are candidates for installing capacitors, NB will be the number of buses. Therefore, the number of variables is at most equal to the number of buses. If the value of a cell, the capacitor size, is more than a specific threshold, it indicates that a capacitor is installed at that bus. Otherwise, no capacitor is placed at the relative bus. This specific threshold is the minimum size of the available capacitors.

It will be observed that the results obtained by conventional DPSO are improved when the crossover and mutation operators are included in DPSO procedure. Furthermore, the robustness of optimization method is improved by this modification. This is mainly because these operators increase the diversity of variables. Figure 4.2 shows the flowchart of the proposed method. The description and comments of the steps are presented as follows.

Step 1: (Input System Data and Initialization)

In this step, the distribution network configuration and data and the available capacitors are input. The maximum allowed voltage drop, the characteristics of feeders, impedance and rated current, are also specified. The DPSO parameters, number of population members and iterations as well as the PSO weight factors, are also identified. The random-based initial population of particles X_j (size of capacitors) and the particles velocity V_j in the search space are also initialized.

Step 2: (Calculate the Objective Function)

Given the capacitors size determined in the previous step, the admittance matrix is reconstructed. Using the new admittance matrix, a load flow program is run and the bus voltages as well as the feeder currents are calculated. These are used to calculate the distribution line loss. After that, the objective function is constituted and the constraints are also computed in this step and included in the objective function with a penalty factor, (3.1). It means that if a constraint is not satisfied, a large number as a penalty factor is added to the objective function to exclude the relevant solution from the search space.

Step 3: (Calculate pbest)

The component of the objective function value associated with the position of each the particles is compared with the corresponding value in previous iteration and the position with lower objective function is recorded as *pbest* for the current iteration.

$$pbest_j^{k+1} = \begin{cases} pbest_j^k & \text{if } OF_j^{k+1} \geq OF_j^k \\ x_j^{k+1} & \text{if } OF_j^{k+1} \prec OF_j^k \end{cases} \tag{4.2}$$

where, k is the number of iterations, and OF_j is the objective function component evaluated for particle j.

Step 4: (Calculate gbest)

In this step, the lowest objective function among the pbests associated with all particles in the current iteration is compared with it in the previous iteration and the lower one is labeled as gbest.

$$gbest^{k+1} = \begin{cases} gbest^k & \text{if } OF^{k+1} \geq OF^k \\ pbest_j^{k+1} & \text{if } OF^{k+1} \prec OF^k \end{cases} \tag{4.3}$$

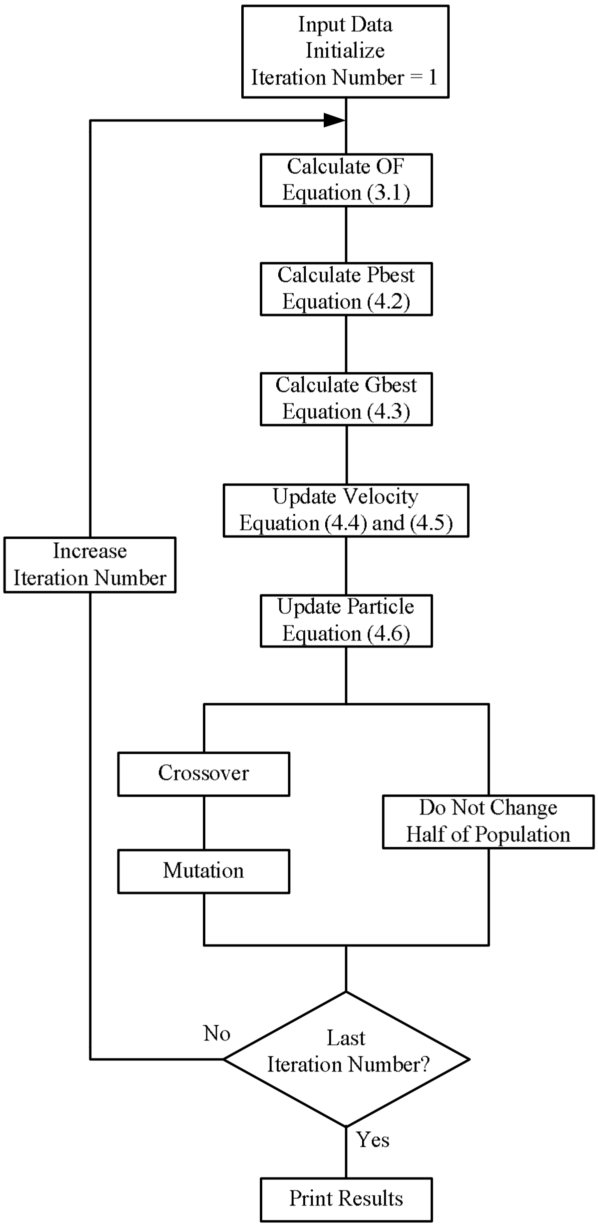

Figure 4.2. Algorithm of proposed PSO-based approach

Step 5: (Update position)

The position of particles for the next iteration can be calculated using the current pbest and gbest as follows:

$$V_j^{k+1} = \omega V_j^k + c_1\, rand\,(\,pbest_j^k - X_j^k\,) + c_2\, rand\,(\,gbest_j^k - X_j^k\,) \tag{4.4}$$

where V_j^k is the velocity of particle j at iteration k, ω is the inertia weight factor, c_i is the acceleration coefficients, X_j^k is the position of particle j at iteration k, $pbest_j^k$ is the best position of particle j at iteration k, and $gbest^k$ is the best position among all particles at iteration k.

As mentioned before, using the available data, ω as inertia weight factor, and c_1 and c_2 as acceleration coefficients, the velocity of particles is updated. It should be noted that the acceleration coefficients, c_1 and c_2, are different random values in the interval [0,1] and the inertia weight ω is defined as follows:

$$\omega = \omega_{max} - \frac{\omega_{max} - \omega_{min}}{Iter_{max}} \times Iter \tag{4.5}$$

where ω_{max} is the final inertia weight factor, ω_{min} is the initial inertia weight factor, $Iter$ is the current iteration number, and $Iter_{max}$ is the maximum iteration number.

As observed in (4.5), ω is to adjust the effect of the velocity in the previous iteration on the new velocity for each particle. Regarding the obtained velocity of each particle by (4.5), the position of particles can be updated for the next iteration using (4.6).

$$X_j^{k+1} = X_j^k + V_j^{k+1} \tag{4.6}$$

The inertia weight factor is set as 0.9 and both the acceleration coefficients as 0.5.

After this step, half of the population members continue DPSO procedure and other half goes through the crossover and mutation operators. The first half continues their route at Step 7 and the second half goes through step 6.

Step 6: (Apply Crossover and Mutation Operators)

In this step, the crossover and mutation operators are applied to the half of the population members. This is done to increase the diversity of the variables to improve the local minimum problem. Figures 4.3 and 4.4 show the operation of crossover and mutation operators.

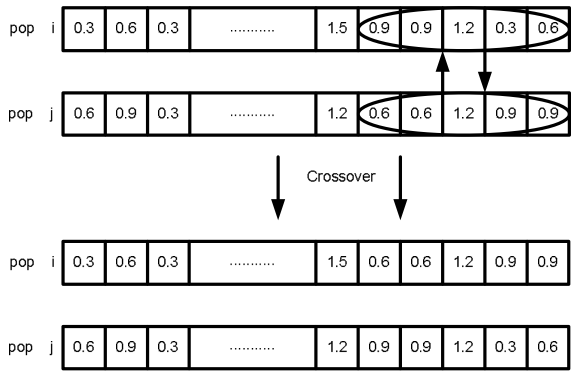

Figure 4.3. A sample crossover operation

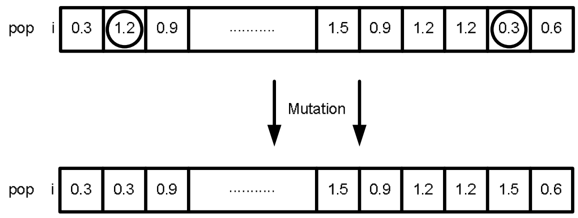

Figure 4.4. A sample mutation operation

Step 7: (Check convergence criterion)

If $Iter = Iter_{max}$ or if the output does not change for a specific number of iterations, the program is terminated and the results are printed, else the program goes to step 2.

4.4. Results

To validate the proposed method, two test systems are studied: the 12.5 kV 18-bus IEEE distribution system as case 1 and the 11 kV 37-bus distribution system connected to bus 2 of the RBTS as case 2. It is assumed that the energy cost is 6 ¢/kWh. The installation cost of capacitors is assumed to be 4$/kvar and the annual incremental cost is selected 8.75% of the installation cost. The available capacitors are considered as multiple sets of 300 kvar banks. The number of years in the study timeframe is assumed to be 20 years.

To evaluate the proposed method, it is compared with four methods for capacitor planning, DPSO, GA [17,38,39], SA [48], and DNLP [20]. DPSO is programmed as a m-file in Matlab. In order to simulate the rest of these optimization methods, the optimization tool in Matlab, called Optimtool, is used. This tool includes GA and SA, but for simulating DNLP, 'fminunc' [8] and 'fminsearch' [9], as NLP solvers in Optimtool, are modified by quantizing the variables (capacitor rating) in each step.

4.4.1. Case 1

The 12.5 kV 18-bus IEEE distribution system [19,100,123] is modified and used in this case (Figure 4.5).

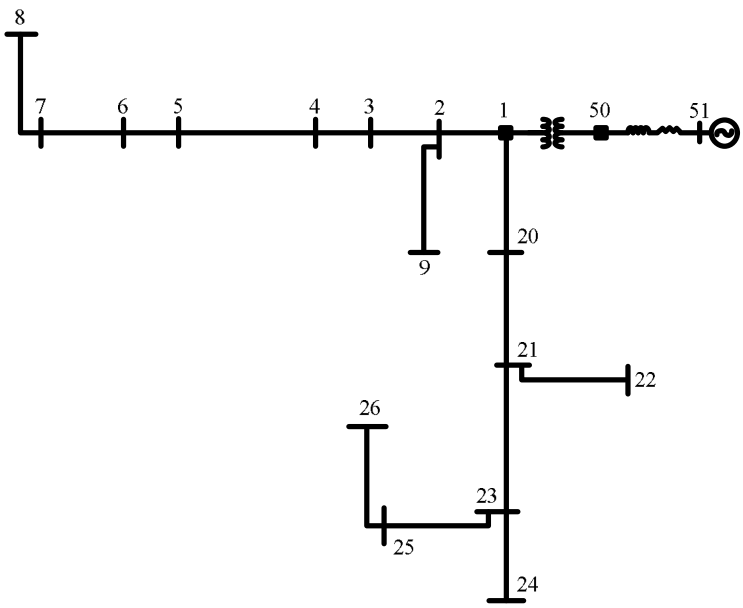

Figure 4.5. Single-line diagram of the 18-bus IEEE distribution system

In this system, 16 buses are candidate for installing the capacitors. Therefore, the number of variables is 16. The population number is assumed to be about 15 times the number of variables. Hence, the number of population is selected as 250.

The robustness of MDPSO, with respect to changes of the PSO parameters, is studied and compared with DPSO. Figure 4.6 shows the trend of the objective function versus an acceleration coefficient, c_1 in (4.4). During the computations, the rest of parameters are kept constant. Moreover, the initial values in both of the DPSO and MDPSO are assumed to be identical.

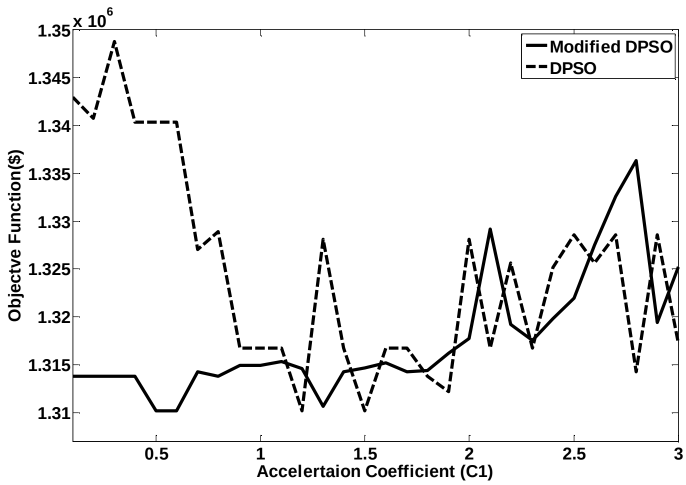

Figure 4.6. OF versus acceleration coefficient c_1

As shown in Figure 4.6, the changes of the objective function versus c_1 for MDPSO are lower than DPSO. The %RSD is used to evaluate the robustness of methods. The lower this index is, the more robust a method will be. The %RSD of the objective function points (see Figure 4.6) for MDPSO is %0.48 being lower than the %0.8 for DPSO.

In order to decrease these values more, a range of (0.1-2) for MDPSO and (0.7-3) for DPSO are assigned for this acceleration coefficient. These ranges reduce the %RSD to

%0.3 and %0.6 for MDPSO and conventional DPSO, respectively. The 'Average' index is used to evaluate the accuracy of methods. The higher this index is, the more accurate a method will be. Given the average of the objective function points, $1317621 for MDPSO and $1324609 for DPSO, the higher accuracy of the proposed method over DPSO is illustrated. Similar to c_1, the trend of the objective function versus c_2 is studied for MDPSO and conventional DPSO (Figure 4.7). It is observed that DPSO for c_2=1.4 does not satisfy the constraints. The higher accuracy of MDPSO over DPSO is seen in this figure. The %RSD of the MDPSO based the objective function points is %0.97 and %0.6 for the c_1 ranges of (0.1-3) and (0.1-2), respectively.

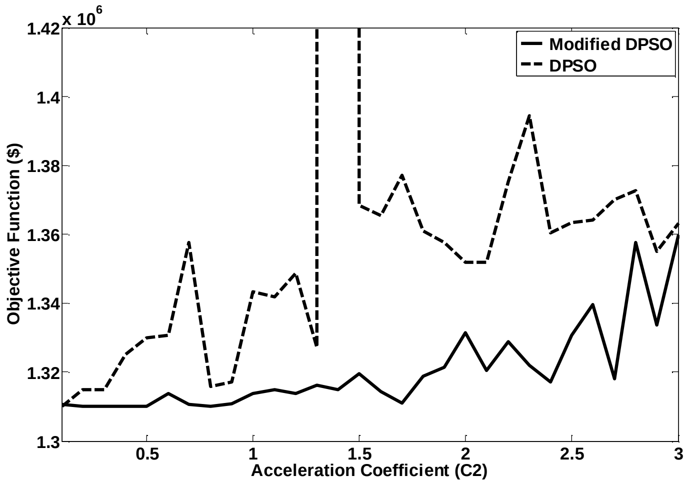

Figure 4.7. OF versus acceleration coefficient c_2

Figure 4.8 depicts the trend of the objective function versus the initial weight factor, ω_{min}. The %RSD of the objective function points is %0.13 and %0.40 for MDPSO and DPSO, respectively. This highlights the insensitivity of these optimization methods to this parameter. The average of the objective function points is $1311178 for MDPSO and $1334127 for DPSO which demonstrates the higher accuracy of the proposed technique. A range of (0.1-1) is appropriate for both of the methods because in which, the objective function variation is negligible.

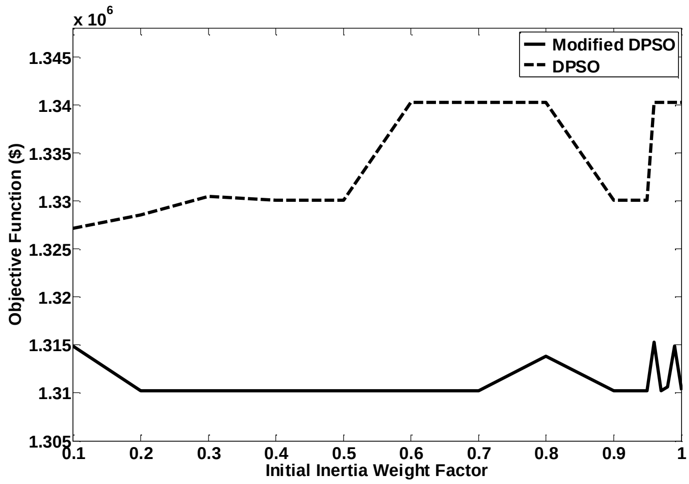

Figure 4.8. OF versus initial weight factor ω_{min}

Similar to this procedure is performed for the final weight factor, ω_{max}, and ranges of (0.4-1) and (0.6-1) are selected as the robustness range of this parameter for MDPSO and DPSO, respectively. In these ranges, %RSD for MDPSO is %0.65 and in conventional DPSO is %0.85. Furthermore, the average objective function for MDPSO and conventional DPSO is $1312175 and 1331140, respectively. This shows $18965 cost benefit by employing the proposed method.

As comprehended, both of the MDPSO and DPSO methods are insensitive to a wide range of their parameters. This robustness verifies the selection of these PSO-based algorithms as good options for solving the ASC problem. Particularly compared with DPSO, MDPSO is more robust and accurate.

After studying the robustness, with respect to changes of the PSO parameters, the robustness with respect to changes of the initial values is investigated. For this purpose, the MDPSO, DPSO, GA, and SA are run 25 times and the outputs are sorted by optimized Objective function value in Figure 4.9.

As observed in Figure 4.9, the robustness of MDPSO is more than others (%RSD by MDPSO is %0.138 being lower than %0.766 by DPSO, %0.953 by GA, and %4.01 by SA). Higher robustness and accuracy features highlight the priority of MDPSO over the other methods for capacitor planning.

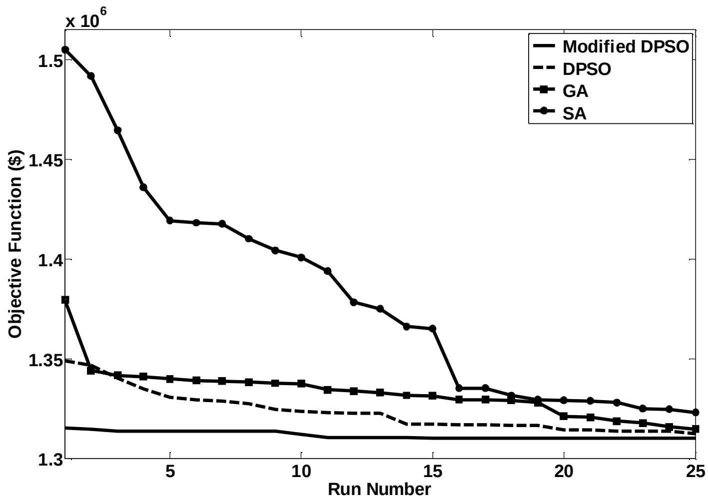

Figure 4.9. A comparison of objective functions

Table 4.1 shows a summary of the results. As observed in Table 4.1, MDPSO is the most accurate method compared with DPSO, GA and SA for capacitor planning in this case study (the error of average from the best point which is 1.3102×106 by MDPSO is $1500 by DPSO is $13300, by GA is $22900, and by SA is $57600). This means $11800, $21400, and $56100 cost benefits are gained by employing MDPSO instead of DPSO, GA and SA, respectively. A comparison among the MDPSO, DPSO, GA, and SA along with the total cost with no installed capacitor is given in Table 4.2. In these heuristic methods, the median solution among the 25 runs is selected as the average value and is given in Table 4.2.

Table 4.1. Comparison of optimization methods

	Worst ($)	**Best ($)**	**Average Error ($)**	**%RSD**
SA	1.5049×106	1.33231×106	57600	4.010
GA	1.3795×106	1.3147×106	22900	0.953
DPSO	1.3488×106	1.3122×106	13300	0.766
MDPSO	1.3153×106	1.3102×106	1500	0.138

Table 4.2. Comparison of MDPSO, DPSO, GA, SA, and 'No Capacitor' state

	Capacitors Size (kvar)	**Capacitor Cost ($)**	**Loss (kW)**	**Loss Cost ($)**	**Total Cost $**
No Capacitor	0	0	332.1	1.849×106	1.849×106
SA	8100	6.243×104	234.4	1.3054×106	1.3678×106
GA	7800	6.012×104	229.4	1.2774×106	1.3375×106
DPSO	7800	6.012×104	227.3	1.2658×106	1.3259×106
MDPSO	7500	5.781×104	225.2	1.2540×106	1.3118×106

Table 4.2 illustrates that the total cost decreases from $1849000 to $1311800 by installing the capacitors ($537200 cost benefit). This underlines the importance of allocation and sizing of capacitors in a distribution system for minimizing the line loss. DNLP was also applied for capacitor planning, but it could not move from the initial values for many random initial values. This shows the objective function has several local minima. Compared with other heuristic methods, MDPSO is demonstrated to be

more accurate and robust for this case. The trend of the objective function is depicted in Figure 4.10 for the iteration number after 8. It should be noted that the objective function includes high penalty factors due to constraint violation in the first 8 iterations. Figure 4.11 shows a comparison between the voltage profile before and after the installation of capacitors.

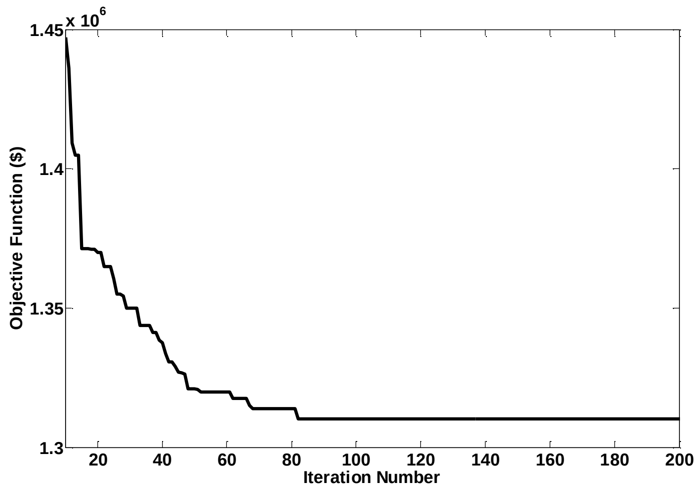

Figure 4.10. Trend of OF versus iteration number

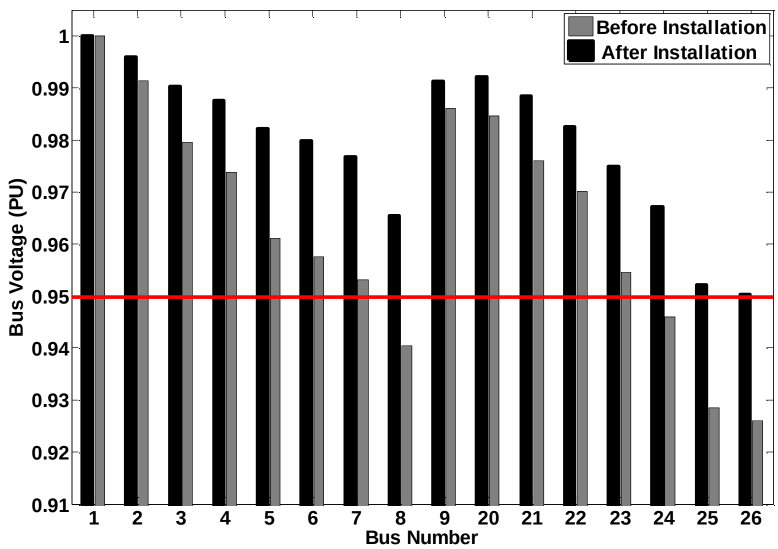

Figure 4.11. Voltage profile before and after installation of capacitors

As observed in Figure 4.10, the objective function value at the 9th iteration is $1620558. This value decreases to $1310202 at the 82th iteration.

Above shown in Figure 4.11, before installation of capacitors, the bus voltage in 4 buses, 8, 24, 25, and 26 is lower than 0.95 pu which is unacceptable. The voltage profile has been increased in all buses to the standard range by installing the capacitors.

4.4.2. Case 2

The RBTS is studied in this case as the second test system. This test system is shown in Figure 4.12 and its characteristics are given in Table 4.3. As shown, 22 loads are located in the test system. These are composed of 9 residential loads and 6 government loads at feeders F1, F3 and F4, 5 commercial loads at feeders F1 and F4, and 2 industrial loads at feeder F2.

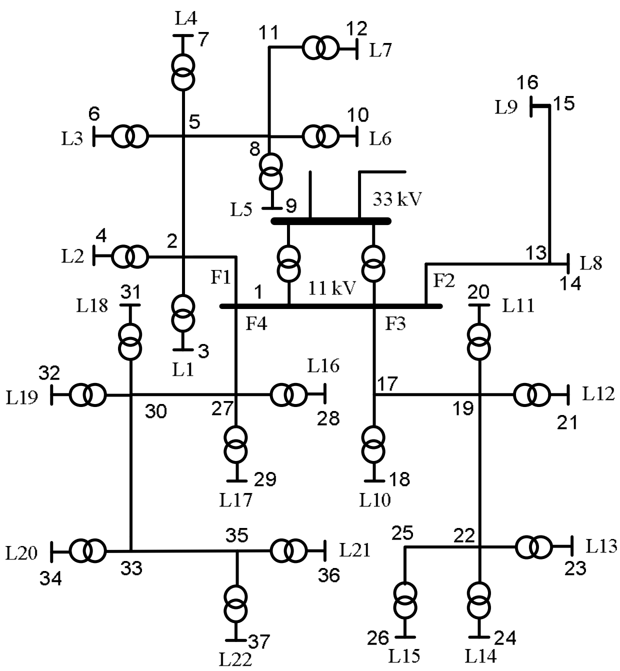

Figure 4.12. Test distribution system in case 2

Table 4.3. Characteristics of the test system

Customer Type	Load Points	Load Level MW
Residential	1-3,10-12,17-19	0.50
Commercial	6-7,15-16,22	0.45
Government	4-5,13-14,20-21	0.57
Industrial	8-9	1.10

The program is run 10 times using each of the optimization methods, MDPSO, DPSO, GA and SA. The results here are based on the median solution among these 10 runs. Before installation of capacitors, the voltage at buses 36 and 37 is lower than 0.95 pu and the line loss is 363 kW. The voltage profile before and after installation of capacitors is shown in Figure 4.13. The line loss decreases to 242.7 kW by installing capacitors (by MDPSO).

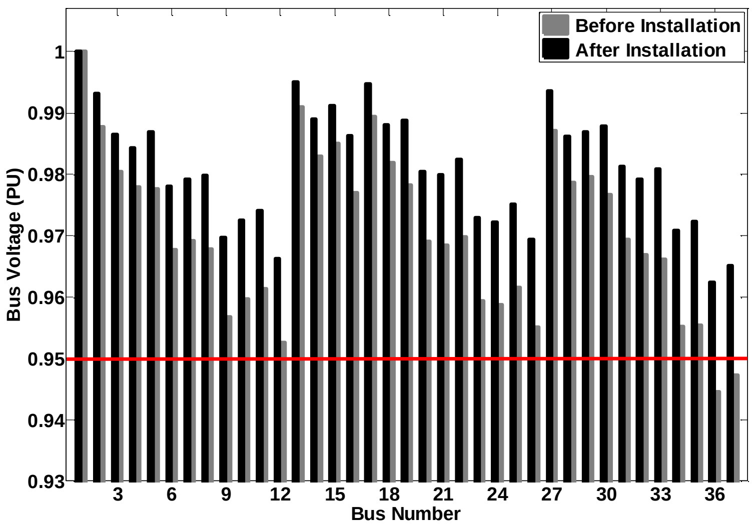

Figure 4.13. Voltage profile before and after installation of capacitors

As shown in Figure 4.13, the bus voltage at all buses has been increased to more than 0.95 pu by installing the capacitors. In order to evaluate the proposed method, the results are compared with DPSO, GA, SA, and 'No Capacitor' state (Table 4.4).

Table 4.4. Comparison of MDPSO, DPSO, GA, SA, and 'No Capacitor' state

	Capacitors Size (kvar)	**Capacitor Cost ($)**	**Loss kW**	**Loss Cost ($)**	**Total Cost ($)**
No Capacitor	0	0	363	2.0212×106	2.0212×106
SA	7500	5.781×104	267.7	1.4906×106	1.5484×106
GA	8400	6.475×104	247.6	1.3785×106	1.4432×106
DPSO	7500	5.781×104	277.5	1.5451×106	1.6029×106
MDPSO	8100	6.243×104	242.7	1.3514×106	1.4138×106

As shown in Table 4.4, the MDPSO demonstrates higher accuracy rather than DPSO, GA, and SA, the average total cost by MDPSO is $1413800, by DPSO is $1602900, by GA is $1443200, and by SA is $1548400. As mentioned, the analytical methods (e. g. DNLP) do not deal appropriately with the problem with several local minima. This is revealed in this case similar to case 1, the DNLP cannot move from its initial values for many random initial values.

Similar to case 1, the importance of allocation and sizing of capacitors for minimizing the line loss is approved in this case so that the total cost decrease from $2021200 to $1413800 by installing the capacitors. The reasonable accuracy and robustness of the proposed MDPSO lead this method as a good choice for the capacitors planning problem.

If the required reactive power of all buses is provided by a capacitor located at the corresponding bus, the line loss is decreased to 239 kW. This reveals that the loss cannot be decreased to lower than 239 kW only by using capacitors; since, the rest of line loss is related to the active power.

4.5. Summary

In this chapter, the MDPSO method is presented to optimize the location and size of capacitors in a distribution system to minimize the line loss. The objective function is composed of the capacitors investment cost and the line loss which is converted into the genuine dollar. The bus voltage and the feeder current as constraints are maintained within the standard level.

Given the discrete nature of the capacitors planning problem, selection of a proper optimization method is important. The heuristic based methods deal appropriately with the local minima. Among these methods, DPSO is employed in this chapter. To increase the diversity of the variables, DPSO is developed by the crossover and mutation operators.

The proposed method is evaluated by two test systems, the 18-bus IEEE test system and the modified semi-urban distribution system connected to bus 2 of the RBTS. The robustness and accuracy of the method is studied with respect to changes of the parameters and changes of the initial values. The results are compared with 'No Capacitor' state, DNLP as an analytical method, and three heuristic methods, DPSO, GA and SA. It is revealed that a high cost benefit is found by installing the capacitors. DNLP could not move from its initial values for many random choices of initial values.

Compared with DPSO, GA and SA, MDPSO presents lower %RSD and average objective function which illustrates its higher robustness and accuracy for planning the capacitors.

CHAPTER 5

Distribution System Planning for Minimizing Line Loss and Improving Voltage Profile

5.1. Introduction

As mentioned before, the line loss and voltage profile are two main concerns in planning distribution networks. These two can be improved by employing capacitors and VRs and by adjusting the operation of LTCs and VRs.

In this chapter, the operation of VRs, capacitors, HV/MV transformer tap changers along with the location of VRs and capacitors are determined for minimizing the line loss and improving the voltage profile when the load level is time varying. For this purpose, the MDPSO proposed in the previous chapter is employed. It should be noted that direct optimization of the tap position is not appropriate since in general the HV side voltage is not known. Therefore, the tap setting can be determined given the Voltage on Customer side of Transformer (VCT) once the HV side voltage is known. The objective function for the optimization is composed of the distribution line loss cost, the peak power loss cost and capacitors' and VRs' capital, operation and maintenance costs. The constraints on the optimization program are composed of the bus voltage and feeder current along with VR taps. The bus voltage should be maintained within the standard level and the feeder current should not exceed the feeder rated current. The taps are to adjust the output voltage of VRs between 90% and 110% of their input voltages.

For validation of the proposed method, the 18-bus IEEE system is used. The results are compared with prior publications to illustrate the benefit of the employed technique. The results also show that the lowest cost planning for voltage profile will be achieved if a combination of capacitors, VRs and VCTs is considered.

5.2. Problem Formulation

The main objective of the Planning of Capacitors and VRs and the optimization of VCT (PCVV) problem is to minimize the cost of capacitors and VRs as well as the distribution line loss and peak power which will require higher investment of using high rating equipment. This is achieved by reducing the power loss at the peak load. The bus voltage and the feeder current are also limited as constraints and added to the objective function with a penalty factor. The bus voltage is maintained within the standard range. The feeder current should be kept lower than the rated current of the relative feeder. The tap setting of VRs is adjusted during the optimization procedure to minimize the line loss and improve the voltage profile. The taps are practically limited to ±10%.

Given that all of the objective function elements are simply converted into the composite equivalent cost, this problem can be solved using a single-objective optimization method. This objective is defined as (3.1) in which C_I is zero. The capital cost is composed of the cost for installing and purchasing the capacitors and VRs. The operation and maintenance costs are self explanatory. The loss cost is expressed in (5.1). As observed, the loss cost has two parts, the energy loss cost which is proportional to the cost per MWh and the peak power cost which is proportional to the cost saving per MW reduction in the peak power.

$$C_L = k_{PL} \times P_{Loss_{LL}} + k_L \times \sum_{ll=1}^{LL} T_{ll} \,.\, P_{Loss_{ll}} \tag{5.1}$$

where LL is the number of load levels and T_{ll} is the duration of load level ll. The constraints include the bus voltage and the feeder current. The bus voltage should be maintained within the standard level as (3.6) and (3.7). Additionally, tap setting as a constraint should be limited to ±10%. At any load level, when a switched capacitor bank is connected or disconnected, the bus voltage increases or decreases, respectively. To minimize the effect on customers, this voltage change is limited to a value in the range of 2% to 3%. A good approximation to the voltage change is given in [124].

$$\Delta V = \left(\frac{Q_C}{MVA_{SC}} \right) \times 100\% \tag{5.2}$$

Here ΔV is the voltage change (assumed 3% in this chapter), Q_C is the size of a switched capacitor bank, and MVA_{SC} is the available three-phase short-circuit MVA at the bus, where the capacitor bank is located. Given this equation, the maximum permitted size of a switched capacitor bank can be determined.

5.3. Methodology

The methods presented for scheduling of VRs either find only VRs location and tap setting [52,53], or treat VRs separately from capacitors [125-127]. Using these approaches, solving the problem for a specific load level will not lead to accurate results when the load level is time varying.

The papers that deal with capacitor either focus on the scheduling of capacitors and LTCs [62-64], or concentrate on the allocation and sizing of only capacitors [54-61]. These papers are generally follow one of the following strategies:

1. The capacitors are allocated and sized for the lowest load level as the fixed capacitors. Subsequently, the problem is solved for higher load levels and the additional capacitors are presumed as the switched capacitors [55-57] (Building Strategy).

2. The capacitors are obtained in all load levels; then, the minimum capacitor in each bus is assumed as the fixed capacitor and the rest as the switched capacitors [59-61] (Separating Strategy).

3. All of the load levels are optimized simultaneously. The optimization method should solve a problem with (number of buses × number of load level) optimization variables [128].

In the first strategy, the capacitors obtained for higher load levels are not used for lower load levels while they can be used for loss minimization and voltage profile improvement with applying no extra cost. In addition to the shortcoming mentioned for the first strategy, the second strategy suffers from having a large number of buses for installation of capacitors, which implies a high installation cost because there is no guarantee that the placement for a capacitor in a load level is determined the same in next load level. Eventually, in the techniques associated with the third strategy, the number of variables severely increases the computation time and decreases the accuracy. The aforementioned limitations highlight the necessity of an appropriate technique to incorporate the influence of LTCs, VRs and capacitors simultaneously and to include the multi-load level assumption. There is also a need to have a compromise between the accuracy and computation time.

As mentioned, increasing the number of variables leads to a more complex optimization problem and so lower accuracy. For alleviating this problem, using a segmentation-based algorithm is required. Building and Separating strategies are two types of segmentation algorithm. In this section, a segmentation-based algorithm is proposed to solve the PCVV problem for all load levels. This algorithm classifies variables into different segments. Each of segments contains the variables associated with a load level. Since the objective function value associated with a load level is mainly dependent on the capacitors and voltage regulators location and setting for the corresponding load level, each segment can contains the variables related to the rating and setting of capacitors and voltage regulators in the corresponding load level. These segments are optimized sequentially till optimized value of the variables in all segments become equal to their value in the previous iteration.

Figure 5.1 shows the flowchart of the proposed algorithm. As illustrated in this flowchart, the program starts from the average load level since the majority part of the load duration curve is for this load level (100%). In the next step, the proposed Modified optimization method is applied and using the objective function, the VRs and capacitors are allocated and set. The VCT is also adjusted to find the corresponding transformer tap. After deriving results of this load level, the next load level is optimized. This procedure is implemented till the peak load level is optimized. This part of the flowchart is called initialization.

After the initialization, the load levels are optimized from the lowest one to the peak load level by an iterative based strategy as shown in Figure 5.1. In the proposed strategy, the objective function for a load level is penalized if the capacitor rating in a bus is more than it in the previous load levels as given in (5.3)-(5.5):

$$OF = C'_{CAP} + \sum_{y=1}^{Y} \frac{C'_{O\&M} + C_L}{(1+r)^y} + DP \tag{5.3}$$

$$C'_{CAP\,j} = \begin{cases} C^{ll}_{CAP_j} - C^{ll-1}_{CAP_j} & \text{if a capacitor is at bus } j \\ C^{ll}_{CAP_j} & \text{if no capacitor is at bus } j \end{cases} \tag{5.4}$$

$$C'_{O\&M\,j} = \begin{cases} 0 & \text{if } 0 < C^{ll}_{O\&M} \le C^{ll-1}_{O\&M} \\ C^{ll}_{O\&M\,j} - C^{ll-1}_{O\&M\,j} & \text{if } C^{ll}_{O\&M} > C^{ll-1}_{O\&M} \\ C^{ll}_{O\&M\,j} & \text{if } C^{ll-1}_{O\&M} = 0 \end{cases} \tag{5.5}$$

where $C^{ll}_{CAP_j}$ and $C^{ll}_{O\&M\,j}$ are the capital cost and the operation and maintenance cost of a device at bus j for load level ll, respectively.

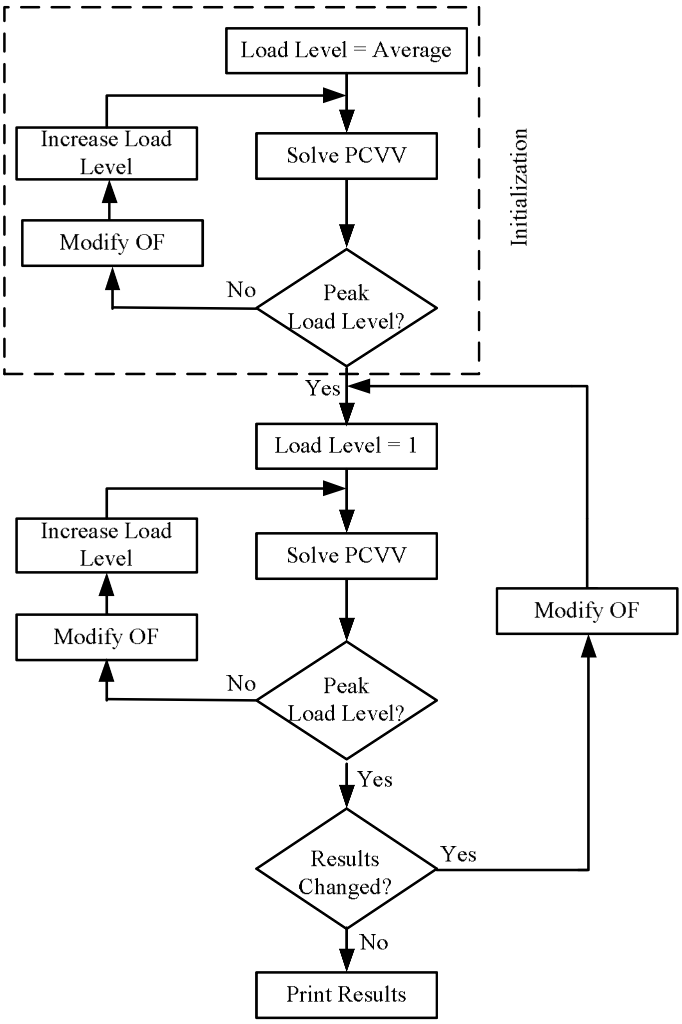

Figure 5.1. Flowchart of the proposed algorithm

Adding a capacitor at a bus where another capacitor has been already installed causes a back-to-back switching problem [124]. One of the solutions of this problem is to add a current limiting reactor [124]. Therefore, two different types of switched capacitors are used in this method, switched capacitors with reactor and without reactor. The installation cost of a switched capacitor with reactor is more than the cost of one without reactor. During the optimization procedure, if a single capacitor bank is installed at a bus, it does not need a reactor. Any further switched capacitor at that bus will need to include the cost of a reactor.

The proposed procedure increases the probability of selecting the optimized locations in the previous load level as the locations in the current load level. While, it does not force the program to select the devices found for the previous load level as the fixed devices for the current load level. This leads the program to results with lower investment cost and line loss.

After the completion of an iteration from the lowest to the highest load level, the minimum capacitor size in a bus in the iteration is considered as the fixed capacitor and the rest as the switched capacitor installed. The tap setting of VRs and the VCTs in each load level are also optimized during this procedure.

5.4. Applying Modified DPSO to PCVV

This problem is solved using the proposed MDPSO, which was described in the previous chapter (Figure 4.2). The PSO parameters selected for the algorithm are as follows: population size = 400, iteration number = 1000, acceleration coefficients $c_1 = c_2 = 0.5$ and inertia weight factor $\omega = 0.9$. The GA parameters, mutation and crossover rates, are selected as 0.2 and 0.5. The acceleration coefficients, inertia weight factors, and the mutation and crossover rates are kept fixed for all uses of MDPSO in the next chapters.

The first stage in the optimizing procedure is to determine the variables, which are the discrete capacitors size as well as the VR and the VCT. It is assumed that all buses are candidate for installation of VRs and capacitors. Given these points, the particle is constituted as shown in Figure 5.2.

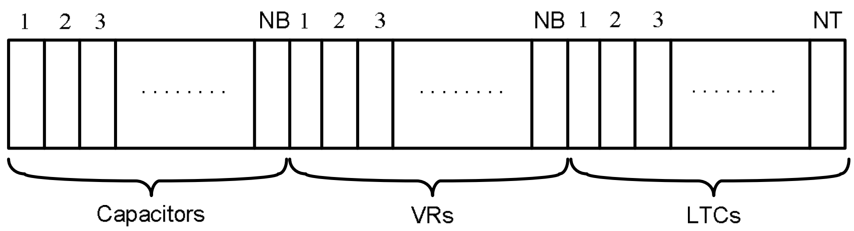

Figure 5.2. The structure of a particle

In Figure 5.2, NB and NT are the number of buses and VCTs in the optimizing distribution system. Each member of this particle is assigned as a placement of a device. The value of the corresponding member is the size of capacitors, the tap setting of VRs, and VCTs. For the capacitors, if the value of this member is more than a specific threshold, it indicates a capacitor with the corresponding size installed at the corresponding bus. Otherwise, no capacitor is placed at that bus. This specific threshold is the minimum size of the available set of capacitors. For the VRs, the member value is the tap setting. If the tap setting is equal to 1, no VR is installed at the corresponding bus. Otherwise, a VR with the corresponding tap setting is installed at the corresponding bus. The same procedure as VRs is implemented for optimizing the tap setting of transformers.

5.5. Results

To validate the proposed method, the 12.5 kV 18-bus IEEE distribution system [19,100,123] is used (Figure 4.5) with parameters given in Table 5.1 to provide practical current limits and realistic conductor impedances.

Table 5.1. Test system line data and conductors data

Lines	**Conductor Type**	**R (Ω)**	**X (Ω)**	**Current Rating (A)**
1-2	1	0.0816	0.207	724
2-3,3-4,4-5	2	0.0995	0.212	648
1-20,20-21	3	0.167	0.228	441
5-6,6-7,21-23	4	0.367	0.256	259
7-8,2-9,21-22, 23-24,23-25,25-26	5	1.31	0.296	108

The load duration curve of this test system is shown in Figure 5.3. The most complex but accurate way is to study the network and solve the PCVV problem for every point in this curve. However, this procedure is excessively time consuming. On the other hand, the easiest and fastest but least accurate way is to approximate the load duration curve with 2-3 levels (as implemented in most papers) and solve the PCVV problem based on small number load levels.

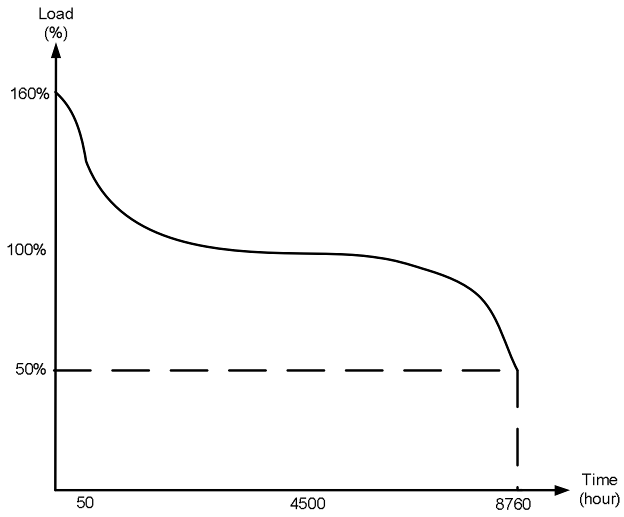

Figure 5.3. Load duration curve used in the testing distribution system

In this chapter, to implement a compromise between accuracy and computation time, this curve is approximated with 5 load levels. It is assumed that the load peaks for 2% of the time and is at its lowest for 3% of the time. The average load is drawn from the network for 40% of the time. For 30% and 25% of the time, the load level is 120% and 80% of the average load, respectively. However, using sensitivity analysis to find the load level number can be included in the future.

It is assumed that the cost per kWh is different for different load levels, 3 ¢ for 50% and 80% of the average load, 6 ¢ for 100%, 8 ¢ for 120% and 10 ¢ for peak load level. These prices are in the same range of [129-131] and show a similar trend to the generating electricity cost from different types of technology in the UK [132]. The saving per MW reduction in the peak power loss is presumed to be $168000. The installation cost of switched capacitors with reactor and without reactor is assumed to be $(3000+45/kvar) and $(3000+25/kvar), respectively. The annual incremental cost is supposed to be 1$/kvar. Application of constraint (5.2) for this test system results in a capacitor bank step of 150kvar. For the VRs, the installation cost is presumed \$10000 and the annual incremental cost is selected as \$300. The VRs are characterized by 32 taps which can change the output voltage between 0.9 and 1.1 times of the input voltage. Therefore, each step can change the input voltage as 0.00625 pu. The coding is written in Matlab 7.6 programming language and is executed in a desktop computer with the features as Core 2 Due CPU, 2.66 GHz, and 2 GB of RAM.

Adding current limiting reactors or pre-insertion resistors increases the cost of capacitors. This penalty decreases the number and size of capacitors significantly. This decrease in size will alleviate the problem of nuisance tripping and voltage magnification of modern load sensitive to electromagnetic transients. For particular sensitive busses, solutions such as point-on-wave switching [133] will give rise to an additional cost for capacitor banks in the optimization.

When no capacitor is installed, the minimum and maximum line losses related to the lowest and highest load levels are 87.3 kW and 801.6 kW respectively. The standard range of the bus voltage is assumed to be between 0.95 pu and 1.05 pu. Given this, the bus voltage constraint for the lowest load level is satisfied, but for the peak load, the bus voltage at 8 buses violates the voltage constraint. In order to decrease the line losses and to improve the voltage profile, VRs and capacitors are allocated and the capacitors size as well as the VR and the LTC taps are adjusted.

To clarify the importance of consideration of both capacitors and VRs in the line loss minimization and bus voltage improvement, three cases are studied. In the first case, the objective function is only composed of the capacitors. Only VRs are included in the objective function in the second case. Finally, both of VRs and capacitors are involved in the objective function in the third case. In all of these cases, the VCT is optimized for all load levels.

5.5.1. Case 1

In this case only capacitors are used for minimizing the line loss and improving the voltage profile. The capacitor locations and ratings as well as the optimization of VCT for different load levels are shown in Table 5.2. As observed in this table, 3 fixed capacitors are required to minimize the line loss in the test system. The scheduling of the switched capacitors is given in Table 5.3.

Table 5.2. Capacitors location and rating (Mvar) and VCT

		Bus Number				VCT
		8	**24**	**25**	**26**	
Load Level	**50%**	0.60	0.30	0.60	----	0.9775
	80%	0.60	0.45	0.75	0.15	0.9949
	100%	0.60	0.45	0.75	0.45	1.0057
	120%	0.60	0.45	0.75	0.60	1.0188
	160%	0.60	0.45	0.75	0.60	1.0497
Fixed Capacitor		**0.6**	**0.30**	**0.60**	**----**	

Table 5.3 illustrates that the switched capacitors should be allocated at 3 buses, 24, 25, and 26. When the load level is average, 1 bank at bus 24, 1 bank at bus 25, and 3 banks at bus 26 should be switched on along with the fixed capacitors to result minimum line loss in this load level.

Table 5.3. Scheduling of switched capacitors

		Bus Number			
		8	**24**	**25**	**26**
Load Level	**50%**	----	----	----	----
	80%	----	0.15	0.15	0.15
	100%	----	0.15	0.15	0.45
	120%	----	0.15	0.15	0.60
	160%	----	0.15	0.15	0.60
Switched Capacitor		**----**	**0.15**	**0.15**	**0.60**

Figures 5.4 and 5.5 show the line loss and the voltage profile after and before installation of the capacitors. A remarkable reduction is observed in the line loss for all load levels. Furthermore, the bus voltage constraint in the peak load level is satisfied when the capacitors are allocated optimally. It should be noted that the line loss before the installation of capacitors is based on the assumption that the VCT is equal to 1 pu. It should also be noted that the line losses before installation of capacitors for the 100%, 120% and peak load level cases are invalid because the voltage constraint is not satisfied. However, these are shown in Figure 5.4 only to illustrate the effect of capacitors. The calculations show that increasing the VCT (or LTC tap setting) results in more line loss when no capacitor is installed. For example, when the load level is 120%, the line loss is 469 kW. As observed in Table 5.2, the VCT is adjusted to 1.0188 pu for this load level to have an acceptable bus voltage. In this condition, the line loss increases to 481 kW. Therefore, the capacitors are partly used for improving the voltage profile, partly for compensating the line loss increase due to the increment of the VCT (LTC tap setting) and also partly for minimizing the loss.

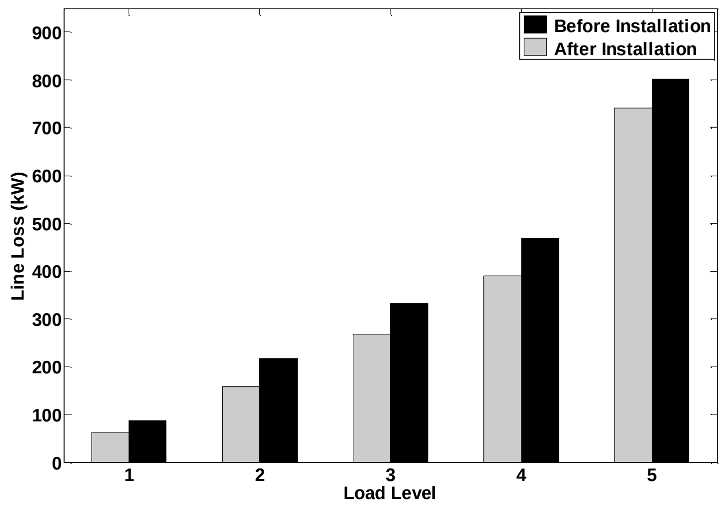

Figure 5.4. Line loss before and after installation of capacitors

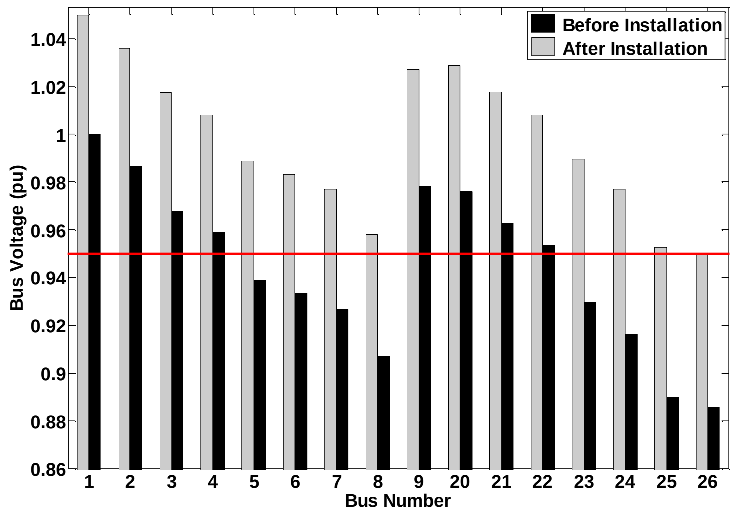

Figure 5.5. Voltage profile before and after installation of capacitors in peak load (Case 1 (CAP))

To validate the proposed strategy, the results are compared with the strategies mentioned in section 5.3, (Building and Separating Strategies). Table 5.4 shows the results obtained using these strategies.

Table 5.4. Scheduling of switched capacitors

		Bus Number				
		8	**23**	**24**	**25**	**26**
Building Strategy	**Fixed Capacitor**	----	----	----	----	----
	Switched Capacitor	0.75	----	0.45	0.75	0.60
Separating Strategy	**Fixed Capacitor**	----	----	----	----	----
	Switched Capacitor	0.75	0.15	0.15	1.05	1.20

These strategies start from the lowest load level. Therefore, when no capacitor is found for this load level in the test system, no fixed capacitor is found by these strategies. The corresponding results are evaluated in sub-section 5.5.3.

The allocation and sizing of capacitors along with scheduling of switched capacitors and optimization of VCT was studied in case 1. In addition to the capacitors and the VCT, the VRs are other devices which influence the line loss and the voltage profile.

5.5.2. Case 2

Case 2 investigates VRs and their placement and scheduling for minimizing the line loss and improving the voltage profile. The scheduling of VRs and VCT (LTC) is shown in Table 5.5.

Figure 5.6 shows the voltage profile before and after installation of VRs. Improvement of the voltage profile is observed after installation of VRs. The main difference between capacitors and VRs is that capacitors inject the reactive power to the distribution network and reduce the reactive-element of the line loss. But, VRs do not have this influential characteristic.

Table 5.5. VRs location and tap setting and VCT

		Bus Number			VCT
		4	7	13	
Load Level	50%	-8	+1	-6	1.0247
	80%	-8	+2	-4	1.0352
	100%	-8	+3	-3	1.0440
	120%	-8	+4	-1	1.0499
	160%	-5	+5	+4	1.0495

After finding the placement and scheduling of VRs, the line loss for the lowest load level to the peak load level is calculated as 81.1, 210.2, 331.7, 483.7, 887.7 kW. As observed, the line loss decreases significantly for the 50% and 80% load level cases and slightly for the 100% to peak load levels. However, these decreases are not as much as the capacitors. This is mainly because VRs do not inject the reactive or active power. These devices improve the voltage profile appropriately but they cannot decrease the line loss as well as the capacitors do.

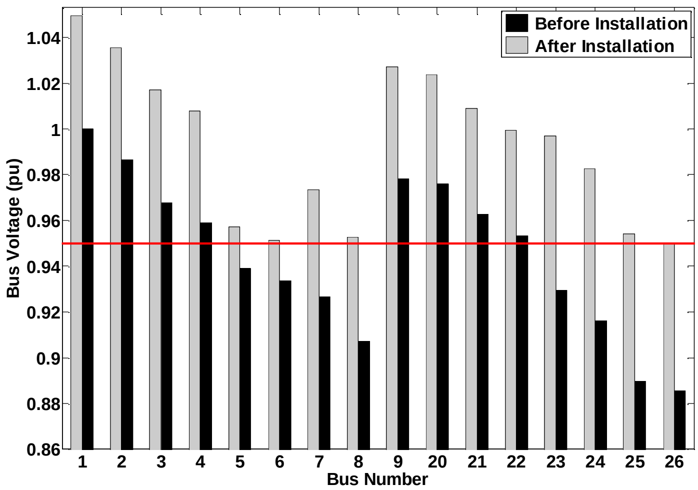

Figure 5.6. Voltage profile before and after installation of capacitors in peak load (Case 2 (VR))

Given the main characteristic of the capacitor, which is the reduction the reactive-element of the line loss and the main characteristic of the VRs, which is the improvement of the voltage profile, a combination of these devices is expected to be more effective when the objective is to improve the voltage profile along with minimizing the line loss. This is studied in case 3.

5.5.3. Case 3

In this case, a comprehensive voltage support mechanism is planned in which all technologies, capacitors, VRs, and VCT (LTC), are optimized to minimize the line loss. The results are shown in Tables 5.6 to 5.8.

Table 5.6. Capacitors location and rating (Mvar)

		Bus Number			
		8	**24**	**25**	**26**
Load Level	**50%**	0.75	0.30	0.60	----
	80%	1.05	0.30	0.75	0.15
	100%	1.05	0.30	0.75	0.30
	120%	1.05	0.30	0.75	0.30
	160%	1.05	0.30	0.75	0.30
Fixed Capacitor		**0.75**	**0.30**	**0.60**	**----**

As observed in Tables 5.6 and 5.7, the optimization yields three fixed and three switched capacitors. This table shows that 1.65 Mvar fixed capacitors along with 0.75 Mvar switched capacitors are required. Similar to case 1, the solution results in more fixed capacitors and less switched capacitors because of the higher cost of switched capacitors (mainly switched capacitors with reactor) compared with fixed capacitors.

Table 5.7. Scheduling of switched capacitors

		Bus Number			
		8	**24**	**25**	**26**
Load Level	**50%**	----	----	----	----
	80%	0.30	----	0.15	0.15
	100%	0.30	----	0.15	0.30
	120%	0.30	----	0.15	0.30
	160%	0.30	----	0.15	0.30
Switched Capacitor		**0.30**	**----**	**0.15**	**0.30**

The VRs location and their scheduling along with the VCT are shown in Table 5.8. This table shows that two VRs are required at buses 4 and 23. As observed, simultaneous optimizing capacitors, VRs, and VCT results in lower capacitors and VRs costs. This combination also leads to lower line loss (total line loss cost by optimizing only capacitors, only VRs, and all technologies is found \$1808254, \$2212891, and \$1719887, respectively).

Consider the case when there is no loss term in the objective function. If only capacitors are used, then at 160% load level, the optimization result allocates 2 capacitors with sizes 1.05 and 0.6 Mvar at buses 25 and 26. If only VRs are used, the result is to install one VR at bus 23. If both capacitors and VRs are used in the optimization without the loss term, the voltage requirement is satisfied by locating one VR at bus 23.

Table 5.8. VRs location and tap setting and VCT

		Bus Number		VCT
		4	**23**	
Load Level	**50%**	-8	-7	1.0224
	80%	-8	-7	1.0398
	100%	-8	-7	1.0499
	120%	-6	-4	1.0491
	160%	-2	+1	1.0495

The dominance of loss control by capacitors is supported by the results in Table 5.9 where the capacitors only (case 1) results in much lower line loss compared with VRs (case 2). These points illustrate that for the cost levels in this method, the main role of VRs is for voltage control while capacitors are mainly used to reduce the line loss. That is why the placement of capacitors and VRs do not necessarily change when they are combined in case 3.

Associated with the load level changes from 100%, 120% to 160%, the corresponding load durations are from 40%, 25% to 3%. There is a substantial increase in the loss at 160% but because the duration is low, there is insufficient justification for a change in capacitor size. Tables 5.6 and 5.7 show no change of capacitor size was obtained when the VRs are available. In case 1, the capacitors have two roles, voltage control and loss minimization. Because the voltage control is a compulsory requirement then an increase of capacitors with loading levels is seen.

If VRs type is the Automatic Voltage Regulators (AVRs), the output voltage set point can be found using the voltage obtained when the tap setting, given in Table 5.8, is applied to the VRs in each load level. For example, when the network is supplying the peak load level, the VRs tap is set to -2 and +1, respectively. This setting leads their output voltage to be 0.9975 and 0.9916 pu for the VRs located at buses 4, and 23, respectively. Therefore, to minimize the line loss along with improving the voltage profile, these values can be selected as their voltage set point when their type is AVR and their tap cannot be set manually.

Figure 5.7 reveals the voltage profile for the peak load obtained after the allocation and sizing of capacitors along with the allocation and scheduling of VRs and optimization the VCT. The line loss in this case is decreased to 60.82, 157.76, 252, 376.44, and 727.44 kW for the load levels respectively.

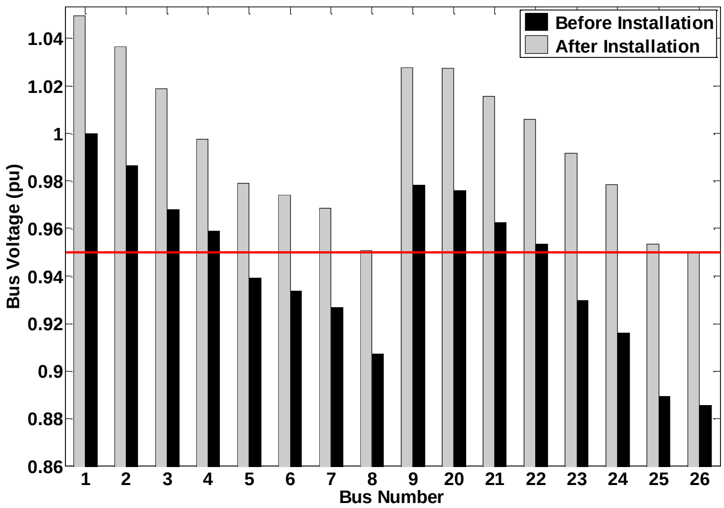

Figure 5.7. Voltage profile before and after installation of capacitors in peak load (Case 3 (CAP&VR))

A comparison among the above cases is given in Table 5.9. In Table 5.9, the line losses for the 100%, 120%, and peak load levels related to the ‘No Installation’ are in brackets to show that the voltage constraint is not satisfied in these load levels so the results are invalid. As observed in this table, compared with ‘No Installation’ case, the proposed strategy enjoys $326327 less total cost. The total cost calculated by the proposed strategy is $68012 less than it when only the capacitors are allocated and sized. This remarkable difference shows the importance of the consideration of VRs and LTC tap setting along with the capacitors in loss minimization and voltage profile improvement. Furthermore, compared with the Building and Separating strategies, the proposed strategy is at least 6.5% ($121928) more cost beneficial.

Table 5.9. A comparison among the cases ($)

	Loss Cost for Load Levels					**Capacitor Cost**	**VR Cost**	**Total Cost**
	50%	**80%**	**100%**	**120%**	**160%**			
No Installation	4861	181082	(739585)	(870128)	(357839)	0	0	(2153495)
Case 1 (CAP)	3544	140330	599010	735011	330359	86926	0	1895180
Case 2 (VR)	4516	175600	738758	897740	396277	0	39535	2252426
Case 3 (CAP&VR)	3386	131764	561296	698704	324737	80925	26356	1827168
Building Strategy	4742	177684	619097	734476	327344	153765	0	2017108
Separating Strategy	4742	177684	619097	744224	352999	177460	0	2076206

5.6. Summary

A comprehensive study is performed for minimizing the line loss and improving the voltage profile in this chapter. In this study, almost all distribution system devices which influence the voltage profile, e.g. capacitors, VRs, and LTC, are incorporated. Optimization of the LTC tap setting is not meaningful since the HV side voltage is not known. Therefore, the VCT is optimized in this chapter. The LTC tap setting can be determined given the VCT once the HV side voltage is known.

Planning for all load levels in practical networks results in dealing with a large number of variables. To handle this problem, a segmentation-based strategy is proposed in this chapter. This technique classifies the variables associated with a load level in a segment and solves them in their own segment. Finally, an algorithm is used to solve these segments sequentially for finding variables associated with whole system. Given the discrete nature of the problem and the devices rating, the local minima are the main issue of this optimization procedure. Therefore, a PSO-based optimization method is developed by the GA operators to increase the diversity of the variables (MDPSO).

The 18-bus IEEE test system is modified and used for evaluating the proposed strategy. The results are found in three different categories: the capacitors and VCT, the VRs and VCT, and the capacitors, VRs and VCT. The results prove the necessity of consideration of all these devices simultaneously. The results obtained by optimizing only the capacitors are also compared with some of the available strategies. The results demonstrate that the proposed strategy has reasonable cost benefit. The results also illustrate that the lowest cost planning is achieved by combining all the currently available technologies.

CHAPTER 6

Distribution System Planning for Improving Line Loss, Voltage Profile, and Reliability

6.1. Introduction

In the previous chapter, capacitors and VRs along with the VCTs were included in the system optimization for minimizing the distribution line loss and for improving the voltage profile. Although these elements improve line loss and voltage profile significantly, they do not influence system reliability cost which will be shown to be the dominant factor in the total cost, particularly for distribution networks located in semi-urban and rural areas.

To increase system reliability, DGs are allocated and sized in this chapter as part of the integrated optimization. Since these elements are quite expensive, the capacitors are also simultaneously planned. Since the cost benefit due to using VRs is not remarkable (3.6% in Chapter 5), these devices are not included in this chapter.

In this chapter, a comprehensive planning methodology is proposed that can minimize the line loss, maximize the reliability and improve the voltage profile in a distribution network. The injected active and reactive power of DGs and the installed capacitor sizes at different buses and for different load levels are optimally controlled. The tap setting of HV/MV transformer along with the line and transformer upgrading is also included in the objective function. The MDPSO introduced in Chapter 4 is employed to solve this nonlinear and discrete optimization problem.

The objective function is composed of the investment cost of DGs, capacitors, distribution lines and HV/MV transformer, the line loss, and the reliability. All of these elements are converted into genuine dollars. Given this, a single-objective optimization method is sufficient. The bus voltage and the line current as constraints are satisfied during the optimization procedure.

The IEEE 18-bus test system is modified and employed to evaluate the proposed algorithm. The results illustrate the unavoidable need for control on the DG active and reactive power and capacitors in distribution networks.

6.2. Problem Formulation

The objective is to minimize the investment cost of DGs, capacitors and distribution lines, the line loss cost and the reliability cost. The bus voltage and the line current as constraints are included in the objective function using a constraint penalty factor. The objective function which is the net present value of the total cost is formulated as follows:

$$OF = C_{CAP} + \sum_{y=0}^{Y} \frac{1}{(1+r)^y} (C_{O\&M}^y + C_L^y + C_{PL}^y + C_I^y) + DP \qquad (6.1)$$

where $C_{O\&M}^y$ is the total operation and maintenance cost, C_L^y is the loss cost, C_{PL}^y is the peak loss cost, and C_I^y is the reliability cost, all associated with planning interval y. The discount rate (r) is assumed to be 0.07 in this chapter. The installation cost of DGs and capacitors are assumed to be proportional to their rating. The operation and maintenance cost of capacitors depends on their rating and the study timeframe. The operation and maintenance cost of DGs depends on the fuel cost and their working time durations. The interruption cost (C_I) is calculated using (6.2).

$$C_I = \sum_{ll=1}^{LL} \begin{cases} \sum_{l=1}^{NL} k_{NS} \times P_{L,l}^{ll} \times (RT - DGT) & S_{DG,ll} \geq P_{L,l}^{ll} \\ \sum_{l=1}^{NL} k_{NS} \times \begin{bmatrix} (P_{L,l}^{ll} - S_{DG,l}) \times RT + \\ S_{DG,l} \times (RT - DGT) \end{bmatrix} & S_{DG,ll} < P_{L,l}^{ll} \end{cases} \tag{6.2}$$

where NL is the number of distribution lines, k_{NS} is the customer energy loss penalty factor (\$/MWh), $P_{L,l}^{ll}$ is the total power of under outage loads at load level ll when a fault occurs at line l, $S_{DG,l}$ is the total rating of DGs available to supply the loads under outage due to a fault at line l, RT is the average time for repairing a line after a fault, and DGT is the average time for running a DG. The loss cost and the peak loss cost are calculated using as detailed in equations (6.3) and (6.4).

$$C_L = \sum_{ll=1}^{LL} k_L \times T_{ll} \times P_{Loss,ll} \tag{6.3}$$

$$C_{PL} = k_{PL} \times P_{Loss,LL} \tag{6.4}$$

where $P_{Loss,ll}$ is the total loss at load level ll and k_{PL} is the cost per MW for supporting the distribution system at the peak load level.

The constraints are formulated as shown in (3.6) and (3.7) which are referred to the bus voltage (V_{bus}) which should be maintained within the standard level and the line current (I_f) which should be less than the line rated current (I_f^{rated}).

In an ideal diesel generator, the fuel consumption is proportional with the load. But in practice, this relation is not like this and reduced nonlinearly with reducing load so that even at no load condition, the fuel consumption is roughly between 20% and 40% of the rated power. Moreover, if the generator operates below a specific rate of the rated power for a long period, serious maintenance problems such as chemical corrosion and glazing may occur [134, 135].

$$S_{DG}^{ll} \leq k_{DG} \, . S_{DG} \tag{6.5}$$

where S_{DG}^{ll} is the output power of a DG at load level *ll*, S_{DG} is the rated power of a DG, and k_{DG} is to show minimum percentage of the rated power that a DG is allowed to generate.

6.3. Applying Modified DPSO

The optimization method introduced in Chapter 4 is employed for solving this planning problem. The population size and iteration number are selected 400 and 1000 respectively. As mentioned before, identifying the variables is the first step in an optimizing procedure. Figure 6.1 shows the structure of variables in this problem.

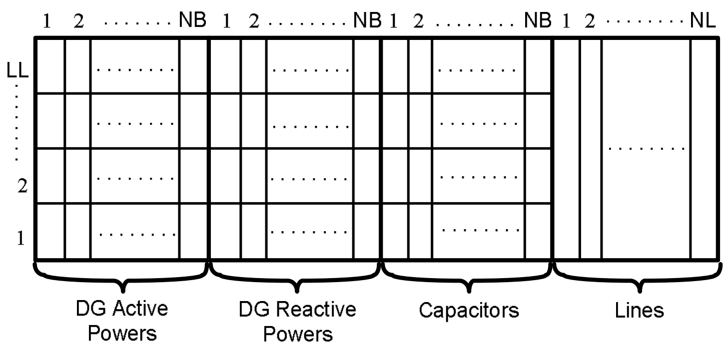

Figure 6.1. The structure of a particle

As shown in this figure, the variables are composed of the injected active and reactive power of DGs at different buses for different load levels, the size of installed capacitors at different buses for different load levels, the type of distribution lines, and the tap setting of transformers for different load levels. The HV/MV transformer tap is also set.

6.4. Results

To validate the proposed technique, the IEEE 18-bus distribution system [19,100,123] is used (Figure 4.5). The ideal distribution line in this system is replaced with practical lines in order to access their rated current. The load duration curve is approximated by three load levels (160%, 100%, and 50% of the average load) to decrease the computation time. However, a sensitivity analysis will be performed in the future work to find the load level number. It is assumed that the duration of these three load levels is 15%, 55% and 30% of a year. The size of DGs and capacitors are assumed to be discrete in multiple sets of 300 kVA and 150 kvar, respectively

To highlight the necessity of planning in presence of all technologies, five different scenarios are studied. Upgrading of distribution lines is studied in the first scenario. The capacitors are planned in the second scenario. To improve these two scenarios, an integrated planning in which both of the capacitors and lines are upgraded is investigated in the third scenario. As a new technology, DGs are optimally allocated and sized in the fourth scenario. These are combined with the use of capacitors and line upgrades in the fifth scenario. During these procedures, the transformer tap for different load levels is optimized.

6.4.1. First Scenario

As a conventional planning, the line loss and the voltage profile are improved by upgrading the distribution lines. The line number is in this order, the line between buses, 1-2, 2-3, 3-4, 4-5, 5-6, 6-7, 7-8, 2-9, 1-20, 20-21, 21-22, 21-23, 23-24, 23-25, and 25-26. It should be noted that the distribution lines are primarily in types (6-5-5-4-1-1-1-1-3-2-

1-2-1-1-1). The characteristics of the available conductors and transformers are given in Tables 6.1 and 6.2, respectively.

Table 6.1. The characteristics of available conductors

Conductor Type	**R (Ω)**	**X (Ω)**	**Current Rating (A)**
1	1.05	0.295	187
2	0.465	0.270	307
3	0.291	0.255	409
4	0.198	0.240	517
5	0.139	0.227	642
6	0.108	0.220	747
7	0.0897	0.213	837
8	0.0730	0.206	949
9	0.0634	0.201	1034
10	0.0584	0.197	1284
11	0.0505	0.193	1494
12	0.0464	0.190	1674
13	0.0414	0.188	1898

After applying the proposed MDPSO, the solution shows an upgrade in the lines to (9-9-9-7-3-1-1-1-6-5-1-2-1-1-1). This means the first five distribution lines should be upgraded from types 6, 5, 5, 4, and 1 to 9, 9, 9, 7, and 3, respectively. Furthermore, the ninth and tenth lines should be upgraded from types 3 and 2 to 6 and 5. This upgrading applies more than 1 million dollars investment cost.

Table 6.2. The characteristics of available transformers

Transformers (kVA)	Impedance Ω (PU)	Capital Cost (k$)	Operation and Maintenance Cost ($/year)
25000	0.055 i	3600	20500
35000	0.060 i	3900	25700
50000	0.070 i	4100	28000
75000	0.070 i	4300	31000
110000	0.070 i	4500	33000

The HV/MV transformer tap is set on 0.981, 0.993, and 1.03 for the lowest to peak load level. Additionally, an HV/MV transformer upgrade (from 25 kVA to 35 kVA) needs to be performed to support the loads.

6.4.2. Second Scenario

The placement and size of capacitors for different load levels are determined in this scenario. It is observed that 7 capacitors with the rating of 2400, 1950, 900, 900, 900, 1350, and 1650 are to be installed at buses 3, 4, 5, 7, 10, 15, 16, respectively. The capacitors and the transformer tap setting for different load levels are given in Table 6.3. As observed in this table, 4 fixed capacitors and 7 switched capacitors are found as the solution. No transformer upgrading is required in this scenario.

6.4.3. Third Scenario

In this scenario, the techniques mentioned in the first and second scenarios are integrated. The placement and size of capacitors along with upgrading of the distribution lines are included in this scenario. It is resulted that the lines should be upgraded to (9-9-5-4-3-1-1-1-6-6-1-2-1-1-1). This means that the line upgrading cost is significantly reduced from $1.1134M to $0.8283M compared with the first scenario. Table 6.4 demonstrates the capacitor at different buses and the transformer tap setting for different load levels.

Table 6.3. The capacitors for different load levels (kvar)

Load Level	**Bus Number**							**Tap**
	3	**4**	**5**	**7**	**20**	**25**	**26**	
1	0	150	750	600	0	900	0	0.994
2	0	750	900	600	900	1050	0	1.00
3	2400	1950	900	900	900	1350	1650	1.026
Fixed	0	150	750	600	0	900	0	
Switched	2400	1800	150	300	900	450	1650	

Table 6.4. The capacitors for different load levels (kvar)

Load Level	**Bus Number**							**Tap**
	4	**5**	**6**	**7**	**20**	**25**	**26**	
1	300	0	1350	150	0	0	600	0.984
2	300	150	1350	600	0	0	600	0.984
3	300	150	1350	900	750	1050	750	1.013
Fixed	300	0	1350	150	0	0	600	
Switched	0	150	0	750	750	1050	150	

The solution is to install 4 fixed capacitors and 5 switched capacitors in the distribution network. The fixed capacitors are located at buses 4, 6, 7, and 26 with sizes 300, 1350, 150, and 750 kvar, respectively. The switched capacitors are located at buses 5, 7, 20, 25, and 26 with sizes 150, 750, 750, 1050, and 150 kvar, respectively. As observed from Table 6.4, the total required capacitor sizes are reduced from 10050 to 5250 kvar compared with scenario 2. Similar to the second scenario, no transformer upgrading is required.

6.4.4. Fourth Scenario

DG planning is implemented in this scenario to study the influence of this technology in distribution system planning. The resulting location and output power of DGs along with the tap setting of the HV/MV transformer for different load levels are illustrated in Table 6.5.

Table 6.5. The DG outputs for different load levels (kVA)

Load Level	**Bus Number**		**Tap**
	8	**25**	
1	0	0	1.030
2	0	0	1.030
3	3000	3000	1.030

It can be seen that 2 DGs should be located at buses 8 and 25. The injected power of these DGs for the load levels less than the peak load is zero because the output power of a generator has been assumed not to be less than 30% of its rated power in order to maximize the efficiency of that generator. In this case, the 25 kVA transformer does not need to be upgraded like scenarios 2 and 3.

6.4.5. Fifth Scenario

All technologies are included in this scenario for planning a distribution system in order to increase the reliability and voltage profile and decrease the line loss. The solution shows that the lines should be upgraded to (9-9-9-4-1-1-1-1-5-2-1-2-1-1-1) which applies \$0.5913M investment cost for line upgrading (compared with \$1.1134M and \$0.8283M in scenarios 1 and 3). The location and output power of DGs and capacitor sizes for different load levels are given in Tables 6.6 and 6.7.

Table 6.6. The capacitors for different load levels (kvar)

Load Level	Bus Number									
	2	4	5	6	7	9	20	22	25	26
1	0	0	0	750	0	0	0	600	0	900
2	900	1050	1050	1500	450	750	900	600	450	900
3	900	1050	1050	1650	450	1050	900	600	450	900
Fixed	0	0	0	750	0	0	0	600	0	900
Switched	900	1050	1050	900	450	1050	900	0	450	0

Table 6.7. The DG outputs for different load levels (kVA)

Load Level	Bus Number	Tap
	26	
1	0	0.989
2	0	0.997
3	1712	1.015

Three fixed and eight switched capacitors should be installed at the distribution system in this final solution for capacitors. The solution for DGs is to allocate one DG at bus

26. The output power of this DG is 1.712 MVA which means that its practical rating should be 1.8 MVA. A significant decrease is observed in the DG investment cost in this case ($1.0936M) compared with the previous case ($4.8735M).

Similar to scenario 4, the output power of the installed DG is zero for all load levels rather than the peak level. This is because of the DG output power constraint which is not allowed to be less than 30% of its rated power. Similar to scenarios 2 to 4, no upgrading is required for the HV/MV transformer.

6.4.6. Comparison of Scenarios

In this section, the above five scenarios are compared together and with the case in which no installation and upgrading is performed (Table 6.8). This comparison is based on the constituting parts of the objective function, the investment cost of lines, DGs, capacitors, and transformer, the line loss cost and the reliability cost.

Table 6.8. Comparison of total cost during 20 years (M$)

	No Installation	**Scenario Number**				
		1	**2**	**3**	**4**	**5**
Line Cost	0	1.1134	0	0.8283	0	0.5913
Capacitor Cost	0	0	0.4241	0.2405	0	0.4213
DG Cost	0	0	0	0	4.8735	1.0936
Transformer Cost	2.2589	2.2589	0	0	0	0
Loss Cost	3.1749	1.7684	2.6390	1.7818	2.7659	2.1684
Reliability Cost	14.942	14.942	14.942	14.942	10.054	13.183
Total Cost	20.376	20.083	18.005	17.792	17.693	17.457

The total cost is a good factor to compare all configurations. The total cost associated with the 'no installation' case is not feasible because the bus voltage constraint is not satisfied. As observed in Table 6.8, the lowest cost planning and the highest cost planning belong to the proposed technique and the first scenario, respectively.

As a conventional planning, first scenario applies 15% ($2.919M) higher cost compared with the proposed technique. The next low cost planning technique is when DGs, as a new technology, are employed. As observed, using DGs significantly reduces the reliability cost ($10.054M in scenario 4 compared with $14.942M in scenarios 1 to 3). This highlights the main benefit of DGs which is improving the reliability of a distribution system. On the other hand, DG planning is not as appropriate as the line upgrading for minimizing the line loss so that the loss cost in scenarios 1 and 3 is about $1.0M lower than the fourth scenario. Capacitors have a remarkable influence on both line loss and voltage profile. Moreover, they are efficient to avoid upgrading the HV/MV transformer. These points reveal that the lowest cost planning is implemented when all of these technologies are included to deal with the planning problem.

6.5. Summary

An integrated planning is proposed to control the injected power of DGs and capacitors in this chapter. The distribution line and HV/MV transformer upgrades are included during the planning procedure. The HV/MV transformer tap is controlled based on the load level.

MDPSO is employed in this chapter to solve the planning problem. This technique is a modified version of DPSO in which two GA operators, mutation and crossover, are applied to half of the population members. This is performed to increase the diversity of the variable in order to reduce the risk of trapping in local minima, which is often the main drawback in the optimization methods. The objective function in this method is composed of the investment cost of DGs, capacitors, and distribution lines, the line cost and the reliability cost. The cost of HV/MV transformer upgrading is also included in this function. The bus voltage and the line current as constraints are added to the objective function using a penalty factor.

The IEEE 18-bus distribution system is used to evaluate the proposed configuration. A comparison is performed among different planning techniques. The results reveal the necessity of planning. Furthermore, it is demonstrated that the lowest cost planning is obtained when the proposed integrated planning technique is employed and all available technologies are included for solving the planning problem.

CHAPTER 7

A Comprehensive Distribution System Planning under Load Growth

7.1. Introduction

The prior chapters treat the power system as being in steady state and determining the lowest cost network to serve the loads. In practice, there is a continual growth of loads in the network as the dynamics of the growth influence the investment plan. If it is pretended that the network is in steady state in each planning period, there would likely be a change in all investment classes in each of the planning periods. The explicit planning for load growth over an extended planning horizon is a normal part of distribution planning. This chapter now implements a novel form of comprehensive planning for DGs and capacitors in addition to upgrading the lines and transformers over a number of planning periods.

In this chapter, a new comprehensive planning methodology is proposed for implementing distribution network reinforcement. The annual load growth, voltage profile, distribution line loss, and reliability are considered in this procedure. Options considered range from supporting the load growth using the traditional approach of upgrading the HV/MV transformer and distribution lines in the distribution network, through to the use of DGs and capacitors. In addition to these, adjusting the VCT is another option for maintaining the voltage profile within required bounds and decreasing line losses. The objective function is composed of the construction cost, loss cost and reliability cost. As constraints, the bus voltages and the feeder currents should be maintained within the standard level. The DG output power should not be less than 30% of its rated power because of efficiency. A Modified optimization method, called MDPSO, is employed to solve this nonlinear and discrete optimization problem. Five different scenarios are studied in this chapter. In the first scenario, the conventional planning method is employed in which line and transformer upgrading is performed. In the second scenario, this conventional planning approach is complemented by including capacitors. In the third scenario, the use of DG is planned to avoid the line and transformer upgrading in a distribution network. In the fourth scenario, capacitors are added to the network with DG operating, finally, all these devices are included in the fifth scenario, planning the deployment of distributed generation, capacitors, lines and transformers.

7.2. Problem Formulation

The mathematical formulation of the proposed planning problem is presented in this section. The main objective of the Distribution Network Reinforcement (DNR) problem is to minimize the line loss and reliability costs and to improve the voltage profile with minimum investment in DGs, capacitors, and line and transformer upgrading. As constraints, the bus voltage should be kept within the standard range, the feeder current should be maintained lower than the rated current, and the DG output power should be more than 30% of the DG rated power, equation (6.5).

Given that all of the objective function elements are simply converted into the composite equivalent cost, this problem can be solved using a single-objective optimization method. This objective is defined as follows:

$$OF=\sum_{y=0}^{Y}\frac{1}{(1+r)^{y}}(C_{CAP}^{y}+C_{O\&M}^{y}+C_{L}^{y}+C_{I}^{y}+C_{ES}^{y})+DP \tag{7.1}$$

where OF is the net present value of the total cost, C_{CAP}^{y} is the total capital cost, and C_{ES}^{y} is the energy saving resulted by installing DGs, all associated with planning interval y. r is the discount rate (0.07 in this chapter) and superscript y refers to the corresponding cost in planning interval y.

The capital cost is composed of the cost for installing and purchasing the DGs and capacitors and for upgrading lines and HV/MV transformers. The operation and maintenance costs are self explanatory. The loss cost is proportional to the energy lost on the distribution lines. The reliability cost is calculated based on the customer energy loss. The following equation is used to convert the line loss into the composite equivalent cost:

$$C_{L}^{y}=k_{L}\times\sum_{ll=0}^{LL}T_{ll}\times P_{Loss,ll}^{y} \tag{7.2}$$

where C_{L}^{y} is the loss cost in planning interval y and $P_{Loss,ll}^{y}$ is the total powers lost on lines for load level ll in planning interval y. The reliability cost is calculated in (7.3). This cost is based on the total customer energy lost after an outage:

$$C_{I}^{y}=k_{NS}\times\sum_{ll=0}^{LL}T_{ll}\times DNS_{ll}^{y} \tag{7.3}$$

where C_{I}^{y} is the reliability cost in the planning interval y, and DNS_{ll}^{y} is the customer energy lost in load level ll in planning interval y (MWh).

The energy saving (C_{ES}) is calculated similar to the line loss cost, (7.2), where now $P^{y}_{Loss,ll}$ is replaced by the DG output active power for load level *ll* in planning interval *y*.

The constraints are the bus voltage, the feeder current, and the DG output power. The bus voltage (V_{bus}) should be kept within the standard level and the feeder current (I_f) should be less than the rated current (I_f^{rated}). The final constraint is the DG output power, which is required to be more than 30% of the rated power as stated in (6.5) in Chapter 6.

7.3. Methodology

A novel sequential technique is proposed in this chapter to solve the DNR problem for a planning time framework as the load demand is growing. This technique is based on the segmentation-based algorithm. In this algorithm, variables are classified into different segments. Since the objective function associated with a planning year mainly depends on the variables in the corresponding planning year, each segment is assumed to contain the variables associated with a period in which the load growing. The proposed algorithm is shown in Figure 7.1. As observed, the algorithm is composed of two parts. In the first part, an initialization is performed. The second part is the main body of the procedure.

Initialization starts from the first planning interval (y=0). For this planning interval, the location and rating of DGs and capacitors and VCT for different load levels along with the upgraded line types and transformer rating are obtained by the employed optimization method, MDPSO.

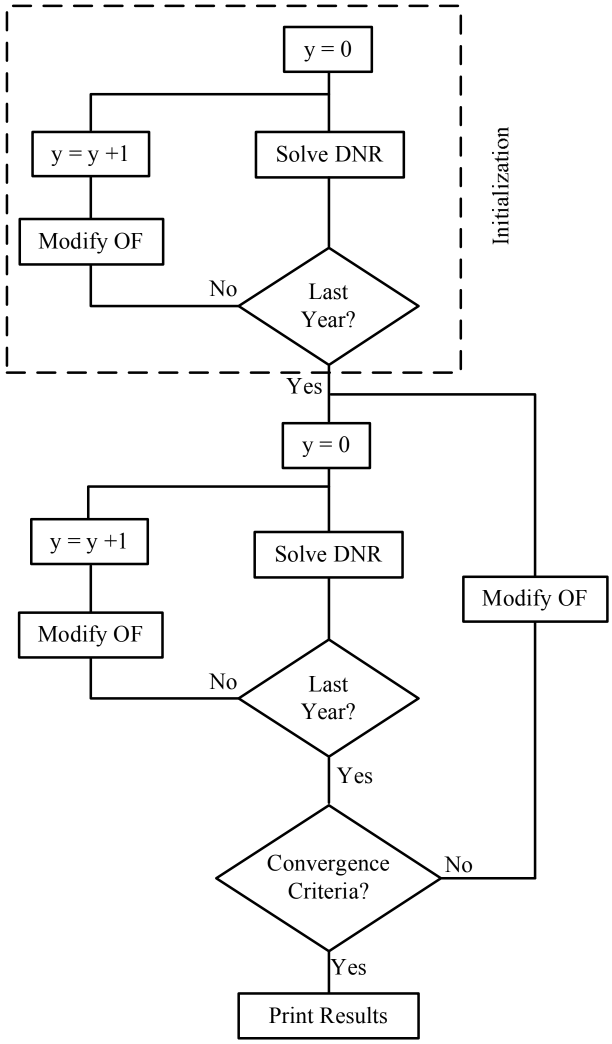

Figure 7.1. Flowchart of the proposed technique

In this procedure, the load growth during the planning period (from y=0 to the last planning interval, y=Y) is assumed to be zero. A similar procedure is implemented for the second planning interval (y=1) in which the planning period is from the beginning of the second planning interval (y=1) to the last planning interval (y=Y) with consideration of a load growth. Similarly, for planning interval i, the planning period is from the beginning of planning interval i to planning interval Y with consideration of a load growth with the power of *i*. The initialization is terminated by running the procedure for the last planning interval (y=Y).

It should be noted that the objective function for a planning interval is modified based on the capital cost in the previous planning intervals. The equations (7.4) to (7.7) are used to modify the objective function in the initialization part of the proposed segmentation-based algorithm.

$$OF^{i} = \sum_{y=i}^{Y} \frac{1}{(1+r)^{y}} (C'^{y}_{CAP} + C^{y}_{O\&M} + C^{y}_{L} + C^{y}_{I}) + DP \tag{7.4}$$

$$C'^{y}_{CAP} = \sum_{k=1}^{k=NE} C'^{y}_{CAP}(S^{y}_{k}) \tag{7.5}$$

$$C'^{y}_{CAP}(S^{y}_{k}) = \begin{cases} 0 & \text{if } S^{y}_{k} \le MS^{y}_{k} \\ C^{y}_{CAP}(S^{y}_{k}) - C^{y}_{CAP}(MS^{y}_{k}) & \text{if } S^{y}_{k} > MS^{y}_{k} \end{cases} \tag{7.6}$$

$$MS^{y}_{k} = \max(S^{1}_{k}, S^{2}_{k}, \dots, S^{y-2}_{k}, S^{y-1}_{k}) \tag{7.7}$$

where NE is the number of elements, such as DGs, capacitors, and distribution lines. $C^{y}_{CAP}(S^{y}_{k})$ is the capital cost of element k with the rating of S^{y}_{k} in planning interval y. After the initialization, the initial value of all the variables for different load levels and different planning intervals are recorded. Subsequently, the second part of the proposed technique (see Figure 7.1) begins to run.

The second part of the proposed technique starts by solving the DNR problem from y=0 to y=Y by the sequential strategy shown in Figure 7.1. In this part, each planning interval is solved based on its corresponding load growth. It should be noted that the DNR problem for each interval is optimized using the employed MDPSO. Planning for each planning interval is based on the calculation of the objective function (7.1) by assuming that the variables related to this planning interval are unknown and the rest of variables, related to other planning intervals, are substituted by their last calculated values. Since the line loss and reliability costs and the energy saving in the planning interval *i* depend on only the variables and the load demand in their own planning interval, the required procedure for calculating line loss and reliability costs for other planning intervals do not need to be included in this planning interval's computations. Therefore, the objective function given in (7.1) can be shortened in (7.8) to be used in the second part of the algorithm.

$$OF^{i} = \frac{C_{L}^{i} + C_{I}^{i}}{(1+r)^{y(i)}} + \sum_{y=0}^{Y} \frac{1}{(1+r)^{y}} (C_{CAP}^{y} + C_{O\&M}^{y}) + DP \tag{7.8}$$

In this equation, *y(i)* is the beginning of planning interval *i*. Since the capital cost in each planning interval depends on the rating and location of elements in all planning intervals, this cost is modified using (7.5) to (7.7) and included in (7.8). After solving DNR problem for y=0 to y=Y, two termination criteria can be checked: 1. the difference between the current values of variables and those obtained in the previous iteration, 2. the difference between the current value of objective function (7.1) and its value in the previous iteration. If this difference is less than a specific tolerance, the program can be terminated.

7.4. Applying Modified DPSO to DNR Problem

To further mitigate the local minimum problem, the MDPSO is employed in which the diversity of the variables is increased by employing GA mutation and crossover operators (Figure 4.2). The population size and iteration number are selected 200 an 2000, respectively. In Chapter 4, it is indicated that this optimization method is more robust and accurate compared with some other optimization methods, such as conventional DPSO, GA, SA, and DNLP.

Identification of the variables is the first stage in an optimization process. In this methodology, these variables comprise the DG locations, active and reactive power of DGs, capacitor locations and ratings, and VCT for different load levels. Furthermore, the type of lines in each optimization planning interval is included. The particle which is composed of the variables is shown in Figure 7.2. Given the rating of DGs and loads in a planning interval, the apparent power which is required to be supplied by the HV/MV transformer is calculated. This shows whether the transformer needs to be upgraded in this planning interval.

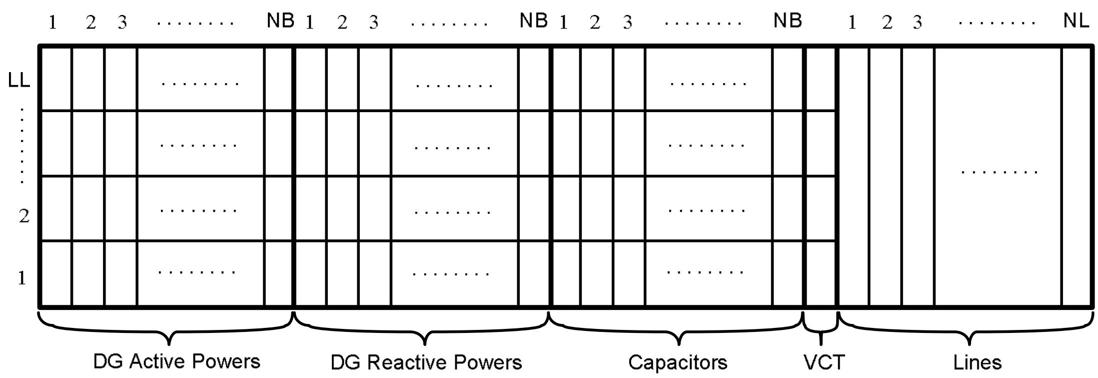

Figure 7.2. The structure of a particle

7.5. Results

The 18-bus IEEE distribution system [19,100,123] is used (Figure 4.5) to validate the proposed method. A five load level characteristic is used to approximate the load duration curve in this chapter, helping to decrease the computation time. However, using sensitivity analysis to find the load level number can be included as future research. It is assumed that the load is at the peak level for 0.05% of the total time. The load level is 81.25% of the peak level for 4.95% of the total time, 62.5% for 35% of the total time, 50% for 35% of the total time, and 37.5% for 25% of the total time. The characteristics of the test system are listed in Table 7.1. As observed in this table, the size of DGs and capacitors are assumed to be discrete in multiple sets of 300 kVA and 300 kvar, respectively.

Table 7.1. Characteristics of the test system

Parameter	**Value**
DG Installation Cost	\$50000+\$550/kVA
DG O&M Cost	¢11.4/kWh
DG Base Unit	300 kVA
Capacitor Installation cost	\$3000+\$35/kvar
Capacitor O&M Cost	\$1/kvar
Capacitor Base Unit	300 kvar
Line Upgrading Cost	(120000+30000×ΔLT)/km
Line O&M Cost	\$2000/km
Failure Rate	0.01 (fault/km.yr)
DG Time	30 minutes
Switching Time	30 minutes
Repair Time	180 minutes

k_L (from (7.2)) is assumed to be 3.5¢, 3.8¢, 4.6¢, 5¢, and 180¢ for load levels 37.5%, 50%, 62.5%, 81.25%, and 100% of the peak level, respectively. In this table, ΔLT is the difference between the type of new and old distribution lines. The transformer upgrading cost is calculated based on the constant cost (e. g. labor cost) which is assumed to be $100000 and another cost which is based on the installation cost of the new and old HV/MV transformers and related facilities. It is assumed that the old transformer and associated facilities can be sold at half price.

Five different scenarios are studied in this section. In the first scenario, the conventional planning method is applied. This scenario is improved by using capacitors in the second scenario. DGs as a new technology are employed to plan the distribution system instead of the conventional method in the third scenario. This technique is developed by using capacitors in the fourth scenario. Finally, a comprehensive planning methodology incorporating all technologies is studied in the fifth scenario.

It is assumed that the loads, located in the distribution network, are growing every five years during the planning period (40% for the peak load level and 13% for other load levels). Therefore, the planning interval is 5 years. As a result of this, four periods are defined: Period 1 starts from first year and ends on fifth year, period 2 starts from sixth year and ends on tenth year, period 3 starts from eleventh year and ends on fifteenth year, and period 4 starts from sixteenth year and ends on twentieth year. The line numbers are in this order, the line between buses, 1-2, 2-3, 3-4, 4-5, 5-6, 6-7, 7-8, 2-9, 1-20, 20-21, 21-22, 21-23, 23-24, 23-25, and 25-26. Type of lines is as 6, 5, 5, 4, 1, 1, 1, 1, 3, 2, 1, 2, 1, 1, and 1 for line 1 to line 16 in order (Table 6.1). The load pattern and growth is based on Queensland electricity network data [136].

7.5.1. Scenario 1 (Conventional Planning)

A conventional planning approach is studied in this scenario. Distribution networks are commonly planned by upgrading the HV/MV transformer rating and line types. This is mainly implemented for supporting the load growth. Additionally, it improves the line loss and voltage profile. All these aspects are included in this scenario. For this purpose, the objective function is composed of four parts, the line and transformer upgrading costs, the line loss cost and the reliability cost. The bus voltages and feeder currents as constraints should be limited into the standard level. Table 7.2 shows the results for different periods in this scenario. In this table, the underlined numbers illustrate the lines and transformer which are required to be upgraded due to the load growth in a period.

As shown in this table, 7 lines should be upgraded in period 2 to improve the voltage profile and the line loss. This number is reduced to 6 in third period. The largest number of lines requiring upgrading belongs to period 4 since the peak load level has the highest value. The number of lines requiring upgrading can be reduced if another device can assist the distribution lines by reducing the distribution lines flow.

Table 7.2. The line replacement in different periods (scenario 1)

Period	**Line Number**															**Transformer Rating (kVA)**
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	
1	6	5	5	4	1	1	1	1	3	2	1	2	1	1	1	25000
2	$\underline{8}$	$\underline{8}$	$\underline{7}$	$\underline{6}$	$\underline{2}$	1	1	1	$\underline{5}$	$\underline{4}$	1	2	1	1	1	$\underline{35000}$
3	$\underline{10}$	$\underline{10}$	$\underline{9}$	$\underline{7}$	2	1	1	1	5	$\underline{5}$	1	$\underline{5}$	1	1	1	$\underline{50000}$
4	$\underline{13}$	$\underline{13}$	$\underline{11}$	$\underline{10}$	$\underline{4}$	$\underline{2}$	$\underline{2}$	1	$\underline{9}$	5	1	5	1	$\underline{2}$	1	$\underline{75000}$

To support the load growth, the HV/MV transformer needs to be upgraded in all periods as no other devices are available to cooperate with the transformer. The main drawback of the conventional planning is the excessive number of upgrading the line types and transformer rating. To alleviate this, capacitors are employed in the next scenario to decrease the line flows and to help the transformer by supporting a part of the load growth.

7.5.2. Scenario 2 (Improved Conventional Planning)

The conventional planning method is improved in this scenario by installing capacitors. Therefore, the objective function and constraints are similar to scenario one and the only difference is that the capacitor investment cost is also included in the objective function. The line types, transformer rating and capacitors for different periods are given in Figure 7.3 and Table 7.3.

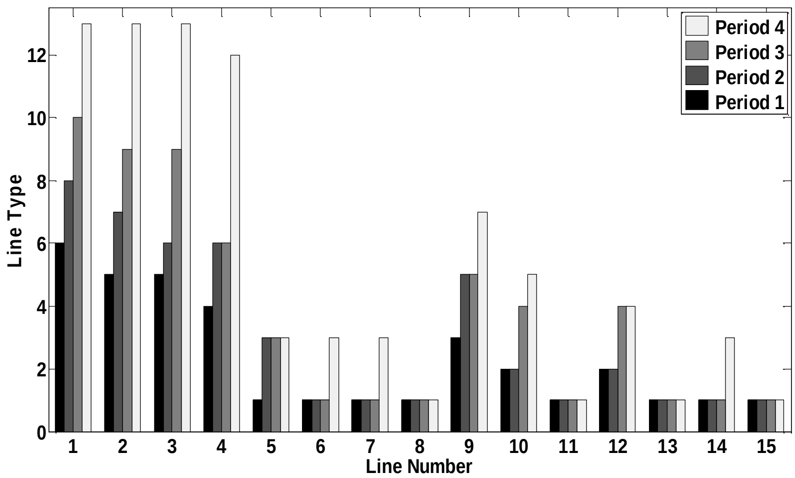

Figure 7.3. The line types in different periods (scenario 2)

Similar to the previous table, the upgraded devices are shown by the underlined numbers in this table. As observed in Figure 7.3, the number of lines requiring upgrading has been reduced in this scenario. As an illustration, the number of line upgrading in period

2 is 6 which is lower than previous scenario, 7. Similarly, this number has been decreased from 6 to 5 in period 3 in this scenario compared with scenario 1.

Table 7.3. The capacitor replacement in different periods (scenario 2)

Period	**Bus Number**								**Transformer Rating (kVA)**
	4	**6**	**7**	**9**	**20**	**21**	**23**	**25**	
1	0	0	600	0	0	0	0	600	25000
2	0	0	600	0	0	0	<u>900</u>	600	<u>35000</u>
3	0	<u>2400</u>	600	0	0	<u>1200</u>	<u>1200</u>	<u>900</u>	<u>50000</u>
4	<u>3900</u>	2400	<u>2400</u>	<u>2100</u>	<u>900</u>	<u>1800</u>	<u>3000</u>	<u>3300</u>	50000

Another benefit of this scenario compared with the previous one is that the HV/MV transformer does not need to be upgraded every period. As shown in Table 7.3, this transformer does not need to be upgraded in period 4. This is mainly because the capacitors generate a part of the reactive power required for loads. The total apparent power that the HV/MV transformer needs to supply is 58652 kVA when no capacitor is available in the distribution network. As a result of this, a 75 kVA transformer was required for period 4 in scenario 1 as the next available transformer after 50 kVA is 75 kVA. In the presence of capacitors, this power is reduced to 49969 kVA which makes the 50 kVA transformer installed in the third period sufficient for the fourth period.

Table 7.3 demonstrates that two capacitors at buses 7 and 25 should be installed in the first year. Another capacitor at bus 23 is then required to be employed in year 6. Two more buses, 6 and 21, will have capacitors in year 11. Finally, buses 4, 9, and 20 will be provided with a capacitor in year 16.

7.5.3. Scenario 3 (DG Planning)

As a new technology, DGs are novel assets considered in this scenario to support the load growth, minimize the line loss, increase the reliability, and satisfy the bus voltages and feeder currents. Thus, DG technology can act as a substitute for the line and transformer upgrading. Because of the DG, the transformer rating (25000 kVA) and line types are found to remain constant for different periods in this scenario. The objective function consists of the DG investment cost, energy saving benefit, the line loss cost and the reliability cost. The results are demonstrated in Table 7.4.

Table 7.4. The DG replacement in different periods (Scenario 3)

Period	**Bus Number**							
	4	**5**	**6**	**7**	**8**	**24**	**25**	**26**
1	0	0	0	0	4200	1200	2700	0
2	0	0	0	0	4200	3300	2700	0
3	0	4500	5700	0	4800	3300	6000	1500
4	8100	4800	5700	3600	4800	3900	8700	1500

As observed in Table 7.4, three DGs need to be installed at buses 8, 24, and 25 for period 1. It should be noted that the major part of the output power of these DGs is their active power so that their injected active powers are 4051, 1118, and 2524 kW while their injected reactive powers are 92, 155, and 0 kvar. After optimizing the next period, the solution is that the DG located at bus 24 is upgraded from 1200 kVA to 3300 kVA. Three more buses, 5, 6, and 26, are provided with a DG for period 3. Furthermore, DGs located at buses 8 and 25 are upgraded to 4800 and 6000 kVA, respectively. Finally, two more buses will have DGs in the last period. Moreover, the DGs located at buses 5, 24, and 25 are upgraded. It is worth noting that the DG located at bus 26 does not need to inject power in the fourth period. Therefore, it can be sold on sixteenth year.

The DGs, optimized in periods 1 to 3, operate only at peak load times, helping the transformer by supporting the load growth. These generators do not operate at other load levels since the benefit gained by minimizing the line loss in these load levels is not sufficient compared with the fuel cost of DGs. Therefore, these DGs are switched on in the non-peak load levels only to supply the loads when an outage occurs. For improving the voltage profile in these load levels, the HV/MV transformer tap is set optimally. For example, the VCT is optimized to be 0.99, 1.01, 1.01, 1.02, and 1.05 pu for different load levels in period 2 or is set on 1.05 pu for all load levels in period 3.

As mentioned, the fuel cost of DGs is high which leads the solution not to use DGs in non-peak load levels for reducing the line loss. In these low load times, capacitors, as less expensive devices, can cooperate with DGs to decrease the line loss in non-peak load times and to support a part of the load growth in the peak load times, thus decreasing the required size of DGs, as more expensive devices, for this function. This is considered in the following scenario.

7.5.4. Scenario 4 (Improved DG Planning)

The capacitors help DGs in this scenario to support the load growth and to minimize the line loss. However, they do not have a considerable influence on the reliability as a part of the objective function. Table 7.5 and Figure 7.4 show the capacitor and DG sizes and locations in different periods, respectively. As observed, the total required DG is decreased from 41100 kVA to 33900 kVA by using capacitors. This is a significant benefit when the investment cost of DGs is much higher than capacitors.

The line and transformer upgrading is not included in scenarios 3 and 4. In order to find a low cost planning, a compromise among installing DGs and capacitors, upgrading line types and the HV/MV transformer needs to be done. This is implemented in the fifth scenario.

Table 7.5. The capacitor replacement in different periods (Scenario 4)

Period	**Bus Number**								
	2	**3**	**4**	**5**	**9**	**20**	**22**	**23**	**25**
1	1200	0	1200	1800	600	0	0	1500	0
2	900	1800	1200	1800	0	1800	0	0	0
3	2400	2100	600	0	2400	0	600	0	1200
4	900	300	2100	2700	0	0	0	0	2700

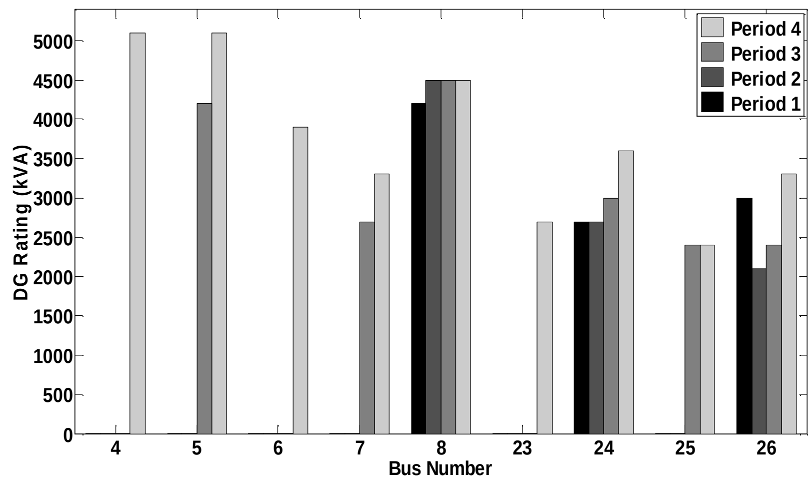

Figure 7.4. The DG rating in different periods (scenario 4)

7.5.5. Scenario 5 (Proposed Technique)

A comprehensive study considering all options is performed in this scenario. During the optimization procedure, the variables are composed of the output active and reactive power of DGs, rating of capacitors, and the VCT for different load levels and periods, and the line types and transformer rating for different periods. The location of capacitors and DGs are also obtained. The objective function is composed of the investment cost of DGs, capacitors, lines, and transformer, the energy saving benefit, the line loss cost and the network reliability cost. The results corresponding to this scenario for line and transformer upgrades are given in Table 7.6.

Table 7.6. The line and transformer upgrades in different periods (Scenario 5)

Period	**Line Number**															**Transformer Rating (kVA)**
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	
1	6	5	5	4	1	1	1	1	3	2	1	2	1	1	1	25000
2	6	5	5	4	1	1	1	1	3	2	1	2	1	1	1	25000
3	11	9	9	6	3	1	1	1	5	5	1	2	1	1	1	50000
4	11	11	10	10	5	1	1	1	5	5	1	2	1	1	1	50000

As observed in Table 7.6, only one transformer upgrade is required at period 3. No line upgrades are needed for the first two periods. However, seven lines are upgraded in the third period which incurs much less cost compared with periods 1 and 2 as the net present value of the cost is decreased after 11 years. Finally, lines 2, 3, 4, and 5 will be upgraded in period 4 as the solution.

The capacitors are shown in Table 7.7. The final solution for DGs is that a DG with the rating of 2700 kVA and a DG with the rating of 4500 kVA should be installed at buses 8 and 16 respectively in the first period. No more DG is justified to be employed in next periods.

Table 7.7. The capacitor replacement in different periods (Scenario 5)

Period	**Bus Number**							
	4	**5**	**6**	**7**	**9**	**21**	**23**	**25**
1	1200	0	900	0	0	0	900	0
2	1500	0	1500	0	600	0	1200	900
3	1500	1500	1500	0	0	0	1200	900
4	2100	2100	2400	2100	300	600	1500	1200

Table 7.7 reveals that three capacitors with the rating of 1200, 900, and 900 kvar are installed at buses 4, 6, and 23 in the first year, respectively. All these capacitors are upgraded in the next period and two more capacitors are installed at buses 9 and 25. In period 3, only 1 capacitor is employed at bus 5. Plus, the capacitors located at bus 9 will not be switched on in this period. Finally, all these capacitors are upgraded in the last period except bus 9. Two more capacitors are also employed at buses 7 and 21 in this period.

Figure 7.5 shows the test system configuration after planning in the last period. The black dashed elements in this figure illustrate the location of capacitors and DGs and the required line upgrades in the last period of planning.

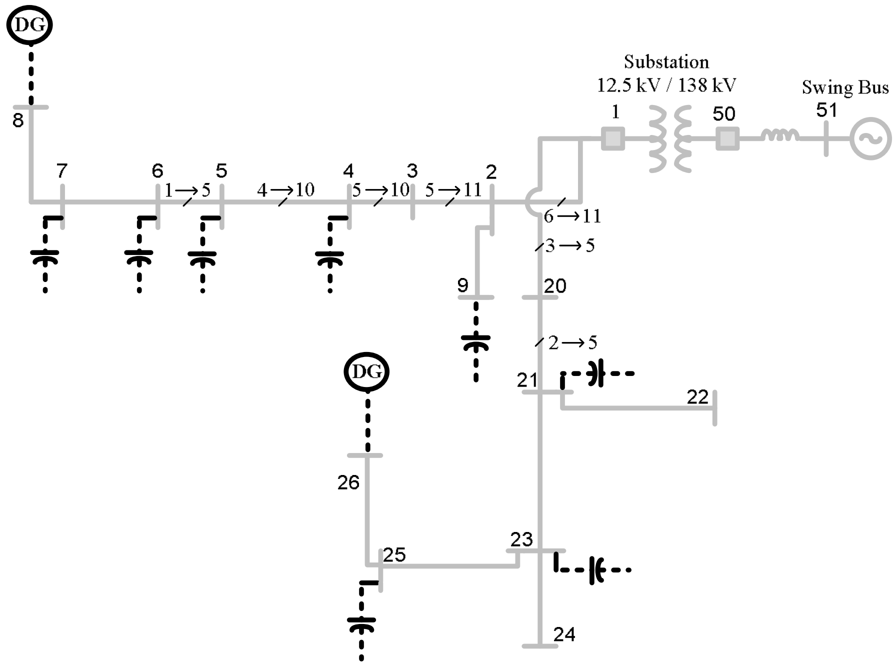

Figure 7.5. The test system configuration after planning in the last time interval

Importantly, by considering all elements in this scenario, the total rating of DGs is significantly decreased to 7200 kVA. These DGs are switched on only for peak load levels in all periods as other devices support the distribution network at other load levels. It should be noted that the output apparent power of the DGs located at buses 8 and 16 are (2700 kVA,4391 kVA) in period 1, (2700 kVA,4500 kVA) in period 2, (2478 kVA,4206 kVA) in period 3, and (2576 kVA,4384 kVA) in period 4. Similar to all scenarios, the transformer tap is also optimized for different load levels in all periods. For example, the VCT is found to be 0.98, 0.99, 0.99, 1.02, and 1.02 for the lowest load levels to peak load levels in period 1.

In order to find out which scenario results in the lowest cost planning, a comparison among all these scenarios is done in the next sub-section.

7.5.6. Comparison of Different Scenarios

A variety of techniques for distribution network planning was implemented in scenarios 1 to 5. A conventional planning was studied in the first scenario. This technique was improved by considering the capacitors in the second scenario. As a new coming technology, DGs were planned to avoid upgrading the line and transformer upgrading in scenario 3. This scenario was got better by including capacitors in the fourth scenario. A comprehensive planning technique was finally presented in the fifth scenario in which all technologies are incorporated. A comparison of the results for different scenarios is shown in Table 7.8. All costs in this table are based on their net present value. The economical results corresponding to scenario 5, as the proposed technique, for all periods are given in Figure 7.6.

Table 7.8. Comparison of Total Cost during 20 years

Cost Elements	**Scenario Number**				
	1	**2**	**3**	**4**	**5**
Line (M$)	1.66	1.524	0	0	0.728
Transformer (M$)	3.59	2.734	0	0	1.237
Capacitor (M$)	0	0.358	0	0.509	0.316
DG (M$)	0	0	13.588	11.731	4.096
Loss (M$)	0.813	0.761	1.202	1.094	0.874
Reliability (M$)	15.766	15.766	6.477	6.700	10.539
Energy Saving (M$)	0	0	-1.483	-1.359	-0.563
Total Cost (M$)	**21.829**	**21.143**	**19.784**	**18.675**	**17.227**

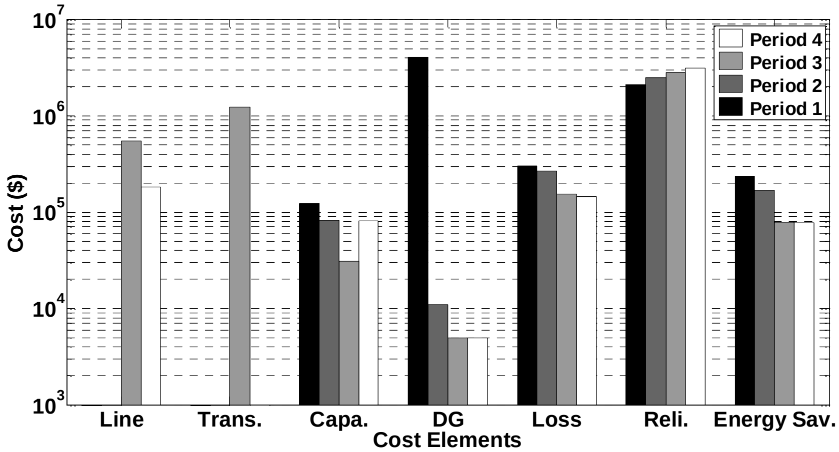

Figure 7.6. A summary of results for scenario 5

Table 7.8 reveals the main role of each element. As an illustration, the capacitors employed in scenarios 2 reduce the loss cost and upgrading cost of transformer so that these costs are \$0.813M and \$3.59M in scenario 1 which are reduced to \$0.761M and \$2.734M by installing capacitors in scenario 2. Similarly, the line loss cost is decreased from \$1.202M to \$1.094M in scenario 4 compared with scenario 3. The total cost corresponding to the conventional planning is decreased \$686000 by installing capacitors. The total cost is also decreased from \$19.784M to \$18.675M in scenario 3 by installing the capacitors (scenario 4).

The main effect of DGs on the reliability is observed in scenarios 3 and 4 compared with scenarios 1 and 2. The reliability cost in scenario 1 and 2 is \$15.766M which is reduced to about \$6.5M in scenarios 3 and 4. On the other hand, this is observed that these devices are not as appropriate as capacitors in minimizing the line loss so that this cost is \$0.813M in scenario 1 and is increased to \$1.202M by installing DGs.

As revealed in Table 7.8, the highest total cost is related to the conventional planning in which no capacitor and DG is included. After that, the second scenario suffers from high total cost. This illustrates the significant role of DGs in planning distribution networks, ultimately, planning techniques in which DGs are not included have higher total cost. Using DGs can reduce the total cost by approximately 10% ($19.784M in scenario 3 compared with $21.829M in scenario 1 and $18.675M in scenario 4 compared with $21.143M in scenario 2). Furthermore, using capacitors also decreases the total cost by approximately 4% ($21.143M in scenario 2 compared with $21.829M in scenario 1 and $18.675M in scenario 4 compared with $19.784M in scenario 3). The lowest cost plan is associated with the technique proposed in this chapter, in which all technologies are included, with a total cost of $17.277M. This demonstrates that the total cost related to the conventional planning technique can be reduced 21% using the proposed technique.

As a conclusion, the total cost can be reduced $4.602M, $3.916M, $2.557M, and $1.447M by using the proposed technique instead of the conventional planning (scenario 1), improved conventional planning (scenario 2), DG planning (scenario 3), and improved DG planning (scenario 4), respectively.

7.6. Summary

In this chapter, a new methodology is proposed to perform the distribution network reinforcement planning. This technique optimizes the following issues: 1) the line type, 2) transformer rating, 3) DG output active and reactive powers for all load levels, 4) capacitor rating for all load levels, and 5) voltage on the customer side of HV/MV transformer for all load levels. This optimization process results in supporting the annual load growth, minimizing the line loss, maximizing the system reliability and improving the voltage profile, all while minimizing construction costs. The bus voltage, line current, and DG output power are constraints that should be within 5% of the rated voltage, less than the rated current, and more than 30% of the rated power of DG, respectively. This methodology is a segmentation-based approach for solving the problems, which have a large number of variables. Given that the reliability cost and the line loss cost associated with a planning year in the objective function only depend on the variables in the corresponding planning year, the variables related to each planning year is solved in a separate segment. Finally, the segments are solved sequentially to solve the whole system. As a discrete problem, distribution network reinforcement is approached using a MDPSO which is a modified version of DPSO. In this method, the diversity of variables is increased which reduces the risk of trapping in the local minima. Having considered a variety of scenarios, from traditional planning approaches to the planning of a variety of assets, a number of conclusions can be made. The results illustrate the importance of using capacitors in minimizing the line loss and preventing the need for transformer upgrades, as a part of the loads are supported by capacitors. Eventually, for the lowest cost, DGs must be included, where the main benefit of DGs is to reduce the reliability cost and assist the transformer in meeting the load growth. It is observed that the DGs are mainly required at the peak load level since the cost benefit gained due to the line loss reduction by using DGs is less than the required fuel cost. Ultimately, these outcomes demonstrate that the lowest cost planning results if the proposed technique is used.

CHAPTER 8

A Comprehensive Reliability-Based Planning under Load Growth

8.1. Introduction

A comprehensive planning approach was studied in previous chapter in which DGs were employed chiefly for improving system reliability and supporting the load growth. Although DGs improve system reliability significantly, their investment cost is an issue. For alleviating this problem, less expensive elements, called cross-connections, are employed in this chapter to help DGs for this goal. It should be noted that CCs are primarily used in distribution networks located in urban and suburban areas where there is short distance between buses which implies a reasonable cost for CCs. Here both DGs and CCs are included in the optimization so the process can smoothly make transition between urban and rural planning.

In this chapter, an integrated methodology is proposed for planning distribution networks in which the operation of DGs and CCs is optimally planned. Distribution lines and HV/MV transformers are also optimally upgraded. These are to improve system reliability and to minimize line losses under load growth.

An objective function is constituted which is composed of the investment cost, loss cost, and system reliability cost. The energy saving resulted by installing DGs is also included in this function. The bus voltage and line current are maintained within their standard bounds as constraints. As another constraint, the DG output power should not be less than 30% of its rated power; otherwise, it is not switched on.

The MDPSO method, which was already described in chapter sub-section 4.3, is employed in this chapter for optimizing this planning problem. To evaluate the proposed approach, the distribution system connected to bus 4 of the RBTS is used. Four different scenarios are assessed. In the first scenario, a basic planning approach is studied. In the second scenario, the use of DG is planned to avoid the line and transformer upgrading. In the third scenario, CC-based planning is studied when no DG exists. Finally, the proposed technique, in which all technologies are included, is investigated in the fourth scenario. The outcomes demonstrate that the lowest cost planning is resulted when all technologies are incorporated.

8.2. Problem Formulation

In this section, the mathematical formulation of the proposed planning problem is presented. The objective function is composed of system reliability, line losses, energy saving and the investment cost as given in (7.1). As constraints, the bus voltage and the feeder current should be maintained within the standard bounds and the DG output power in a load level should be more than 30% of its rated power [134,135]. Converting all of the objective function elements into the composite equivalent cost, this problem can be solved using a single-objective optimization method. The objective function which should be minimized is similar to (7.1).

The capital cost is composed of the cost for installing and purchasing DGs and CCs and for upgrading lines and HV/MV transformers. It is mentioned that the CC investment cost is calculated based on the length and conductor type of the corresponding CC and the employed tie-switch cost. The operation and maintenance costs are self explanatory. The distribution line loss cost is proportional to the energy lost on distribution lines. The reliability cost is calculated based on the cost of energy not supplied.

The distribution line loss is converted into the composite equivalent cost using (7.2) and the reliability cost is calculated using the total unsupplied demand after an outage as given in (7.3). The energy saving (C_{ES}) is determined similar to the line loss cost, (7.2), in which $P^{y}_{Loss,ll}$ is replaced by the DG output active power for load level *ll* in the planning interval *y*. The bus voltage and the feeder current, as constraints, should be kept within the standard level as given in (3.6) and (3.7). The final constraint is the DG output power, (6.5), which is required to be more than 30% of the rated power in all times.

8.3. Methodology

To solve the planning problem considering that the load demand is growing, a sequential algorithm is proposed as shown in Figure 7.1. This algorithm was described in sub-section 7.3.

8.4. Applying Modified DPSO to Problem

The MDPSO, described in Chapter 4, is employed in this chapter for solving the planning problem. The population size and iteration number are selected 300 an 2000, respectively. Figure 8.1 shows the structure of variables associated with a planning interval.

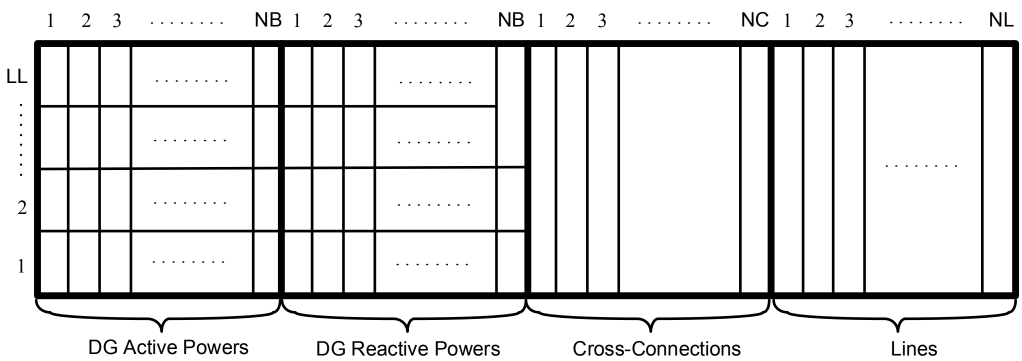

Figure 8.1. The structure of a particle

In this figure, *NB* is the number of buses, *NC* is the number of CCs, and *NL* is the number of distribution lines (almost similar to sub-section 7.4).

8.5. Results

To evaluate the proposed method, the distribution system connected to bus 4 of the RBTS [89,137,138] is used. This network is composed of 3 HV/MV transformers with the rating of 25, 15, 15 MVA which are supplying the loads using 7 main feeders. In this chapter, the load duration curve is approximated in a four load level characteristic helping to decrease the computation time. However, using sensitivity analysis to find the number of load levels can be included in the future. The load is at the peak level for 0.05% of the total time. The load level is 81.25% of the peak level for 4.95% of the total time, 62.5% for 65% of the total time, and 37.5% for 30% of the total time.

The characteristics of the test system are similar to listed in Table 7.1 except the CC costs which are available in Table 8.1. In this table, ΔLT is the difference between the type of new and old conductor and *LT* is the conductor type (Table 6.1). k_L is assumed to be 3.5¢, 4.6¢, 5¢, and 180¢ for load levels 37.5%, 62.5%, 81.25%, and 100% of the peak level, respectively. The transformer upgrading cost is calculated based on a constant cost (e. g. labor cost) which is assumed to be $100000 and another cost which is based on the installation cost of the new and old HV/MV transformers and related facilities (Table 6.2). It is assumed that the net cost of removal and sale of the old transformer and associated facilities are half of the value quoted as the installation cost in Table 6.2.

Similar to Chapter 6, the loads are assumed to grow every five years during the planning period. This means that the planning interval is five years. Therefore, four periods are required to be studied – one for each 5-year period.

Table 8.1. Characteristics of CCs

Parameter	Value
CC Upgrading Cost	(120000+30000×ΔLT)/km
CC O&M Cost	$2000/km
CC Installation Cost	(180000+30000×LT)/km

It is assumed that all buses can be selected as a candidate for installing DGs and all lines and transformers are capable of being upgraded. For CCs, a limited number of candidate paths are selected based on the geographical and economical condition of the planning area.

Four different scenarios are studied in this section. In the first scenario, a basic planning is presented in which both distribution lines and HV/MV transformers are optimally upgraded for supporting the load growth, decreasing the line loss, and improving the voltage profile. In the second scenario, DGs as new technology are planned in the test distribution system to improve the system reliability, line loss, and voltage profile and to help the HV/MV transformers and distribution lines for supporting the load growth. CCs, as reliability improver tools, along with the distribution lines are optimized in the third scenario. Finally, an integrated planning methodology incorporating both DGs and CCs is presented in the fourth scenario.

8.5.1. Scenario 1 (Basic Planning)

Distribution networks are basically planned by upgrading the HV/MV transformer ratings and line types. This is mainly to support the load growth. Additionally, it improves the line losses and voltage profile as the line impedance changes. Figure 8.2 shows the upgrading trend of HV/MV transformers.

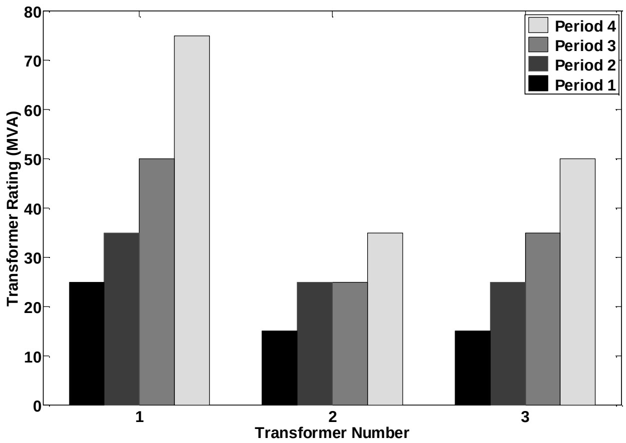

Figure 8.2. The transformer ratings in different periods (scenario 1)

As observed in the above figure, the HV/MV transformers need to be upgraded in all periods since no element such as DG is available in this planning for supporting the load growth. In addition to upgrading of transformers, the distribution lines need to be upgraded excessively so that 13, 12, and 30 lines are re-rated in the second, third and fourth periods, respectively. This extreme number of upgrades applies about $9.43M and $3.46M as the net present value of the investment cost in transformers and lines. DGs can be employed as alternatives for alleviating this issue as well as increasing the system reliability as will be explained in the following sub-section.

8.5.2. Scenario 2 (DG Planning)

The future planning of distribution companies in many countries like Australia is to increase the use of DGs in distribution networks. This is due to the large number of benefits DGs have such as supporting the load growth and the peak load times, improving the system reliability, mitigating the climate change, etc. In this chapter, DGs are employed to help the transformers and lines for supporting the load growth and escalating system reliability. Figure 8.3 shows the location and injection active, reactive, and apparent power of DGs for the peak level in the last planning period.

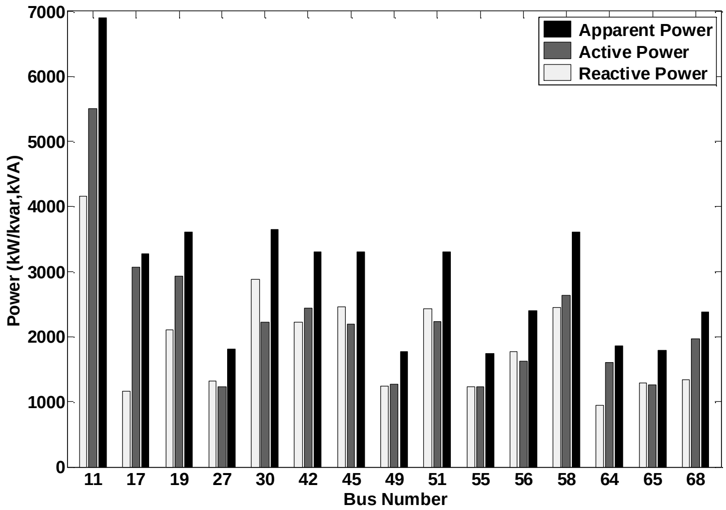

Figure 8.3. The output power of DGs for the peak level in last period

As the final solution, fifteen DGs with the rating of 6900, 3300, 3600, 1800, 3900, 3600, 3300, 1800, 3300, 1800, 2400, 3600, 2100, 1800, and 2400 kVA are required to be installed at buses 11, 17, 19, 27, 30, 42, 45, 49, 51, 55, 56, 58, 64, 65, and 68, respectively.

It should be noted that the DG output powers in all load levels other than peak load level are zero. This highlights the main benefit of DGs which is avoiding the upgrading of transformers. It is observed that no line and transformer upgrade is required for the first and second periods. For the third period, 4 lines are re-rated and still no transformer upgrade is needed. The main re-rates are for the last period when 28 lines are upgraded and the HV/MV transformers are upgraded to 35, 25, and 25 MVA, respectively. Consequently, the investment cost in transformers and lines are reduced to \$2.37M and \$2.24M by utilizing DGs. Furthermore, the reliability cost is decreased significantly from \$45.04M in the basic planning to \$11.15M by including DGs in the planning procedure. Although remarkable benefits are gained by using DGs, their large investment cost is an issue so that the DG investment cost in this planning is calculated to be \$22.05M. Since major part of DGs are employed for improving the system reliability, planning less expensive alternatives such as CCs is described in the subsequent sub-section.

8.5.3. Scenario 3 (CC Planning)

In this scenario, CCs as less expensive devices compared with DGs, are employed to be included in the basic planning. The required CCs in different periods are given in Table 8.2. The underlined values show that a CC needs to be upgraded.

Table 8.2 illustrates that seven CCs are required to be installed in the first year and one more in the sixth year. It should be noted that the CCs specified in Table 8.2 (CC1 to CC8) are located between buses (6 and 63), (11 and 18), (11 and 68), (15 and 22), (16 and 30), (29 and 43), (38 and 49), and (50 and 57), respectively. As observed, the type of conductor required for CC1 is 2, for CC2 is 1, CC3 is 1, for CC4 is 2, for CC6 is 1, and for CC8 is 2 in all planning periods. CC5 is not installed in the first period. This CC is established at the sixth year with a conductor type 1. This conductor is upgraded to type 2 in the sixteenth year. CC7 has the conductor type 2 for 15 years and it is upgraded to type 3 in the beginning of last period.

Table 8.2. CC conductor types in different periods

Period	**CC Number**							
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
1	2	1	1	2	0	1	2	2
2	2	1	1	2	1	1	2	2
3	2	1	1	2	1	1	2	2
4	2	1	1	2	2	1	3	2

Although the reliability cost is about $2.67M higher than the second scenario, the CC investment cost is $20.33M lower than the DG investment cost in DG-based planning scenario. This demonstrates a significant benefit in reducing the reliability cost by using CCs as alternatives for DGs. The CC-based planning cannot avoid upgrading the HV/MV transformers. That is why the transformer upgrading in this scenario is like the basic planning. Additionally, the line investment cost is increased (from \$3.46M to \$4.56 compared with the basic planning) since the rating of lines need to be enlarged to help CCs in supplying more loads in a fault condition.

In order to support the load growth and reliability simultaneously, a comprehensive planning is required as proposed in this chapter. The following sub-section presents the results obtained by the proposed technique in which broad set of technologies are included.

8.5.4. Scenario 4 (Proposed Integrated Planning)

In this section, an integrated planning is expressed which incorporates DGs and CCs along with the lines and transformers upgrades. The main goal is to find the location as well as the injection active and reactive power of DGs for different load levels, the location and conductor type of CCs, and the upgrading of lines and HV/MV transformers for different planning intervals under load growth. The objective function is composed of the investment cost in these elements together with the line loss and reliability costs and the energy saving due to using DGs. The test system configuration after planning in the last period is shown in Figure 8.4. In this figure, the black dashed elements are to illustrate the location of DGs and the required CCs in the last period of planning.

The CC conductor types for different periods are given in Table 8.3. As observed in this table, the placement and conductor type of the CCs installed in the first year is similar to those obtained by the third scenario. In the second period, no CC is required to be installed between buses 16 and 30 as it was in the CC-based planning scenario. CCs in the third period are the same as those in the second one. Finally, one CC with the conductor type 1 is installed between buses 16 and 30 in the sixteenth year. The conductor type of CC7 is also upgraded to 3 in the beginning of last period.

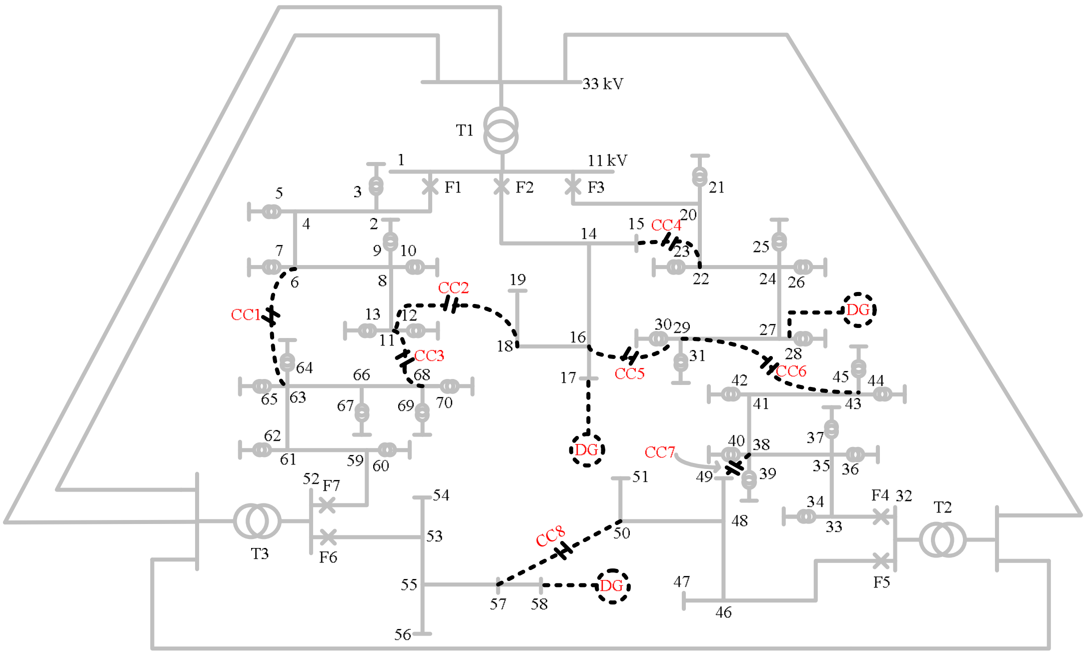

Figure 8.4. The test system configuration after planning in the last time interval

Table 8.3. CC conductor types in different periods

Period	**CC Number**							
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
1	2	1	1	2	0	1	2	2
2	2	1	1	2	0	1	2	2
3	2	1	1	2	0	1	2	2
4	2	1	1	2	1	1	3	2

The CC investment cost is reduced from $1.72M to $1.62M if the proposed technique is employed compared with the CC-based planning technique. Table 8.4 gives the transformer ratings resulted by the proposed technique. This is observed that the number of transformer upgrades decreases from 7 times to 5 times by combining both technologies compared with the first and third scenarios. Furthermore, the transformer ratings in different periods are lower than those obtained by non-DG based planning scenarios (see Figure 8.2).

Table 8.4. The transformer ratings (MVA) in different periods (scenario 4)

Period	**Transformer Number**		
	1	**2**	**3**
1	25	15	15
2	25	<u>25</u>	<u>25</u>
3	<u>50</u>	25	25
4	50	<u>35</u>	<u>35</u>

The rating of first transformer in the sixth year is 25 MVA in this scenario while it needs to be upgraded to 35 MVA in the first and third scenarios. The same is for the third transformer in the eleventh year. The rating of first and third transformers in the last period is 75 and 50 MVA in the proposed technique while they are 50 and 35 MVA in the non-DG based planning techniques. Totally, the transformer investment cost is reduced from $9.43M to $5.93M compared with the non-DG based planning methods.

Similar to the second scenario, no DG is switched on for minimizing the line loss in load levels other than the peak load level apart from running during faults for reliability purposes. That these DGs are switched on for only the peak load times is to avoid upgrading the HV/MV transformers.

The injection active, reactive, and apparent power of DGs at the peak load level along with the DG ratings for different periods are given in Table 8.5.

Table 8.5. DG active, reactive, and apparent powers at peak load level (MVA) and DG ratings (MVA)

Period	DG (bus =17)			DG (bus =28)			DG (bus =58)		
	P	**Q**	**S**	**P**	**Q**	**S**	**P**	**Q**	**S**
1	893	0	893	0	0	0	0	0	0
2	884	0	884	876	206	900	0	0	0
3	974	197	993	866	242	899	442	180	477
4	536	1124	1245	1427	386	1478	642	642	908
Rating (MVA)	1500			1500			1200		

As observed in Table 8.5, despite the second scenario in which 15 DGs are required to be installed, the number of DGs in the fourth scenario is 3 so that the DG investment cost is decreased extensively from \$22.05M to \$1.52M (about 93% cost reduction). The results illustrate that three DGs with ratings 1500, 1500, and 1200 MVA are optimally located at buses 17, 28, and 58, respectively. It should be noted that if the planning area is rural with long distribution lines, the share of DGs will increase much more in the provision of reliability since the CC investment cost will be large.

A summary of the economical results corresponding to scenario 4, as the proposed technique, for all periods are given in Figure 8.5. It is mentioned that all costs in this figure and all tables are based on the net present value. As observed in this figure, the major part of the total cost is associated with the reliability cost and the transformer investment cost. These costs are reduced considerably by using CCs and DGs simultaneously compared with other scenarios.

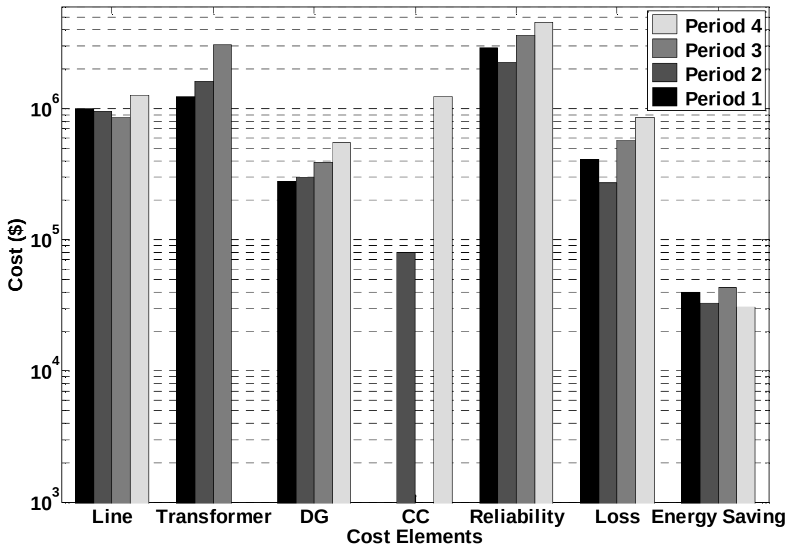

Figure 8.5. A summary of results for the proposed planning

Table 8.6 shows a comparison among the results derived from different scenarios. As observed in this table, planning based on DGs reduces the investment cost in distribution lines so that the line cost in the second scenario is \$2.24M which is about 65% of it in the basic planning.

Comparing the line cost in the second, third and fourth scenarios illustrates that despite DGs, using CCs lead to an increase in the line cost as the rating of lines need to be raised to assist the CCs in supplying more loads in a fault condition as expected. The outcomes illustrate that the reliability cost is significantly lessened by employing DGs and CCs (from \$45.04M by the basic planning method to \$13.42M by the proposed technique). Particularly, CCs are more applicable than DGs for the reliability purposes as their investment cost is much lower.

Table 8.6. Comparison of Total Cost during 20 years

Cost Elements	**Scenario Number**			
	1 basic	**2 DG**	**3 CC**	**4 all**
Line (M$)	3.46	2.24	4.56	4.09
Transformer (M$)	9.43	2.37	9.43	5.93
DG (M$)	0	22.05	0	1.52
CC (M$)	0	0	1.72	1.62
Reliability (M$)	45.04	11.15	13.82	13.42
Loss (M$)	2.32	2.87	2.09	2.11
Energy Saving (M$)	0	-2.56	0	-0.15
Total Cost (M$)	**60.25**	**38.12**	**31.62**	**28.54**

The total cost is significantly reduced by installing CCs and DGs. A cost benefit about $22.13M, $28.63M, and $31.71M is gained if CCs, DGs, and both CCs and DGs are included in the basic planning. The minimum total cost is associated with the proposed technique (scenario 4) in which all technologies are planned simultaneously. This is observed that cost benefits about 9.58 and $3.08M are gained if the DG-based and CC-based planning techniques are replaced with the proposed integrated based methodology.

The results illustrate that the main benefits of DGs are to decrease the transformer, the line upgrading and the system reliability cost. However, the large investment in DG is an issue (See scenarios 2 and 4). CCs lessen the reliability cost significantly in a similar way to DGs but with much lower cost. However, they increase the line investment cost and cannot help the transformers to support the load growth (See scenario 3). These aspects clarify why the integrated planning is required for a reliability-based planning with minimum cost.

That DGs should be switched off for all load levels other than the peak load level demonstrates that DGs are not justified for minimizing the line loss since the operation and maintenance cost of DGs is more than the benefit gained from reducing the line loss. That is why the line loss cost does not change remarkably by installing DGs as observed in Table 8.6.

8.6. Summary

In this chapter, an integrated planning technique is proposed in which broad set of technologies such as DGs and CCs are included to improve system reliability under load growth. This planning determines the location and injection active and reactive power of DGs for different load levels, the rating of lines and HV/MV transformers, and the location and rating of CCs for different planning intervals.

To evaluate the proposed technique, the distribution system connected to bus 4 of the RBTS is used. Four different scenarios are studied from basic planning approach to the planning of a variety of assets.

The results illustrate that the main benefit of DGs is to avoid upgrading the HV/MV transformers and distribution lines. The system reliability is also significantly improved by installing DGs (75% cost reduction). Similarly, the transformer and line investment costs are decreased about 75% and 35%, respectively. It is observed that DGs are switched on only at the peak load level apart from running during faults for reliability purposes since the benefit gained due to the line loss reduction is less than the required fuel cost. On the other hand, CCs improves the system reliability almost as much as DGs but with much lower investment cost particularly for urban networks. However, they increase the line investment cost and cannot avoid upgrades of the transformers. The outcomes demonstrate that inclusion of both technologies, DGs and CCs, reduces the total cost significantly so that the lowest cost planning results if the proposed integrated based technique is used.

CHAPTER 9

Conclusions and Recommendations

The conclusions of the thesis and recommendations for future work are presented in this chapter.

9.1. Conclusions

A comprehensive approach to plan MV and LV distribution networks is the key contribution presented in this thesis. First of all, a new configuration is proposed for optimal allocation and sizing of distribution networks. A segmentation-based method is proposed to decrease the size of the planning problem in which the optimal rating and placement of distribution transformers and feeders for both MV and LV networks are obtained sequentially. During this procedure, the line loss and reliability costs along with the investment cost are minimized. This is demonstrated that the proposed methodology is applicable to both uniform and non-uniform load densities. The employed optimization method, DPSO, illustrates higher accuracy compared with GA and identical results with the exhaustive search method. However, the exhaustive search method is much more time consuming.

Since the objective function in planning problems is typically discrete and nonlinear, using an appropriate optimization method is essential. Conventional optimization approaches such as NLP ad DNLP usually work with continuous variables. However, the real problems are discrete as the size of capacitor banks, DGs and transformers is discrete. It has been found that these methods had a moderate probability of getting stuck in local minima because of this discrete nature. The heuristic methods are reliable alternatives for solving this type of discrete problems. In this thesis, a PSO-based technique was developed through including some of the concepts in GA to provide sufficient variability to avoid local minima. It has been found that this method, applied to several distribution problems, is more robust and accurate compared with DNLP, GA, SA, and DPSO for solving discrete and nonlinear problems such as the capacitor planning.

As the voltage drop and line loss are two main concerns in distribution systems, almost all distribution system devices which influence the voltage profile and the line loss, VRs, LTCs, and capacitors, are incorporated for the first time in this research as the next step of planning. A new segmentation-based strategy is contributed to find the location and rating of these elements with reasonable accuracy and computation time where the loads are practically assumed to have dynamic characteristics. It is illustrated that the lowest cost planning is achieved by combining all the currently available technologies.

In addition to the line loss and voltage profile, the system reliability is another main concern for distribution networks. For improving this index, DGs are involved in the next step. An integrated planning is introduced for this purpose. During this procedure, DGs and capacitors along with the distribution transformers and feeders are planned simultaneously to improve the voltage profile, line loss, and system reliability. The results highlight that the proposed integrated planning method results in the lowest planning cost.

Another important factor which should be considered in planning problems is an index, called load growth. For improving the system reliability along with line loss and voltage profile as the load growth is supported, a new arrangement is contributed for allocation and sizing of DGs along with capacitors while the distribution transformers and feeders are planned under load growth. For inclusion of the load growth factor, a segmentation-based strategy is innovated. This segmentation-based strategy is then employed in a new integrated method for performing a comprehensive planning to minimize the line loss cost, the reliability cost, and the investment cost simultaneously and to improve the voltage profile under load growth. In order to avoid using extra DGs, as extremely expensive elements, CCs are employed for increasing the system reliability. The outcomes demonstrate that inclusion of both technologies, DGs and CCs, reduces the total cost significantly so that the lowest cost planning results if the proposed integrated based technique is used.

The results illustrate that the main benefit of DGs is to avoid upgrading the HV/MV transformers and distribution lines. It is also observed that DGs are required to be switched on only at the peak load level apart from running during faults for reliability purposes since the benefit gained due to the line loss reduction is less than the required fuel cost. On the other hand, capacitors are lower-expensive alternatives for minimizing the line loss, improving the voltage profile, and preventing the need for transformer upgrades, as a part of the loads are supported by capacitors. From system reliability viewpoint, CCs improve reliability indices almost as much as DGs but with much lower investment cost particularly for urban networks. However, they increase the line investment cost and cannot avoid upgrades of the distribution transformers. This demonstrates that, for the lowest cost planning, DGs must be included, to reduce the reliability cost and chiefly to assist the transformer in meeting the load growth.

Ultimately, compared with the traditional planning approaches, the outcomes demonstrate that the lowest cost planning results if the proposed technique is used and all available technologies are included.

Given that the reliability and line loss cost in a planning year only depend on the rating and placement of elements in the corresponding planning year, variables associated with a planning year are more sensitive to each other rather than to variables in the other planning years. Therefore, a segmentation-based algorithm was proposed to categorize the variables into different segments (each segment is associated with a planning year). Then the segments are solved sequentially to find a solution for whole system in a lower time compared with exhaustive search. The above mentioned planning strategies are reasonably applicable for a medium-scale network. However, if the planning network has a large-scale, applying a reliable segmentation-based algorithm is required which is pointed out in the future work.

9.2. Recommendations for Future Research

The following future works are recommended:

9.2.1. Integration of Different Types of DGs

In this research, the type of DGs is also optimized based on the geographical characteristic of the planning area. For this purpose, each candidate location is identified using a variety of geographical coefficients for different types of DGs and the optimization program optimize the desired DG.

9.2.2. Inclusion of the Stability Index in the Wind turbine Planning

This research focuses on optimizing the injecting power of wind turbine generators based on the load duration curve and wind characteristics while the network stability when the wind turbine is suddenly disconnected is maintained.

9.2.3. Consideration of Power Quality in the DG Planning

Another benefit of using DGs is to improve the power quality. This index can be satisfied as the DG is improving the line loss, voltage profile, system reliability, and the load growth support.

9.2.4. Using Large-Scale Optimization Method for Distribution Network Planning

Since the practical distribution networks are quite large, the number of candidate buses so the number of variables is remarkable. Optimizing a large system may result in significant decrease of the accuracy and increase of the computation time. For solving this issue, segmentation procedure can be applicable. For this purpose, a sensitivity analysis can be applied to find the dependant variables. It is obvious that a correct segmentation can decrease the computation time while the accuracy decreases negligibly. Among the segmentation-based methods, Benders Decomposition method has presented acceptable results [139]. This method is employed extensively in the power system literature, such as in unit commitment [140], electricity market [141], hydrothermal scheduling [142], and distribution systems reconfiguration [143]. Benders Decomposition method is originally applied when integer variables (particularly binary variable) and continuous variables exist in the optimization problem. In this method, the continuous and discrete variables are manipulated separately in two different stages. The first stage, called master, deals with the discrete variables and the second stage, called slave, is to solve the continuous variables.

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Publications Arising from the Thesis

Accepted Conference Papers:

1) **I. Ziari**, G. Ledwich, A. Ghosh, G. Platt, "Optimal Control of Distributed Generators and Capacitors by Hybrid DPSO", AUPEC 2011, Australia.
2) **I. Ziari,** G. Ledwich, A. Ghosh, G. Platt, "Planning of Distribution Networks in Presence of Distributed Generators and Cross-Connections", IECON 2011, Australia.
3) M. Wishart, **I. Ziari**, M. Dewadasa, G. Ledwich, A. Ghosh, "Intelligent Distribution Planning and Control Incorporating Micro-grids", PES General Meeting 2011, USA.
4) **I. Ziari**, G. Ledwich, A. Ghosh, G. Platt, "A New Method for Improving Reliability and Line Loss in Distribution Networks", AUPEC 2010, December 2010, New Zealand.
5) **I. Ziari**, G. Ledwich, A. Ghosh, D. Cornforth, M. Wishart, "Optimal Allocation and Sizing of DGs in Distribution Networks", PES General Meeting 2010, USA.
6) **I. Ziari**, G. Ledwich, M. Wishart, A. Ghosh, D. Cornforth, "Optimal Allocation and Sizing of Capacitors to Minimize the Transmission Line Loss and to Improve the Voltage Profile", PCO 2010, February 2010, Australia.
7) **I. Ziari**, G. Ledwich, M. Wishart, A. Ghosh, M. Dewadasa, "Optimal Allocation of a Cross-Connection and Sectionalizers in Distribution Systems", TENCON 2009, November 2009, Singapore.

8) **I. Ziari**, G. Ledwich, M. Wishart, A. Ghosh, "Optimal Allocation and Sizing of DGs in a Distribution System Using PSO", QUT Smart Systems Postgraduate Student Conference 2009, October 2009, Australia.
9) **I. Ziari**, G. Ledwich, M. Wishart, A. Ghosh, "Initial Steps in Optimal Planning of a Distribution System", AUPEC 2009, September 2009, Australia.

Accepted Journal Papers:

1) **I. Ziari**, G. Ledwich, A. Ghosh, "Optimal Integrated Planning of MV-LV Distribution Systems Using DPSO", Electric Power Systems Research, Vol. 81, Issue 10, October 2011, PP. 1905-1914.
2) **I. Ziari**, G. Ledwich, A. Ghosh, "Optimal Voltage Support Mechanism in Distribution Networks", IET Generation, Transmission & Distribution, Vol. 5, Issue 1, 2011, PP. 127-135.
3) **I. Ziari**, G. Ledwich, A. Ghosh, D. Cornforth, M. Wishart, "Optimal Allocation and Sizing of Capacitors to Minimize the Transmission Line Loss and to Improve the Voltage Profile", Computers & Mathematics with Applications, Vol. 60, Issue 4, August 2010, PP. 1003-1013.

Submitted Journal Papers:

1) **I. Ziari**, G. Ledwich, A. Ghosh, G. Platt, "Integrated Distribution Systems Planning to Improve Reliability under Load Growth", Submitted to IEEE Transactions on Power Delivery, March 2010.

2) **I. Ziari**, G. Ledwich, A. Ghosh, G. Platt, “Optimal Distribution Network Reinforcement Considering Load Growth, Line Loss and Reliability”, Submitted to IEEE Transactions on Power Systems on February 2010.

3) **I. Ziari**, G. Ledwich, A. Ghosh, “Optimal Allocation and Sizing of Capacitors and Setting of LTC”, Submitted to International Journal of Electrical Power & Energy Systems on November 2010.