Economic Operation and Planning of Distribution System Sources

by

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Author’s Declaration

I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

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Abstract

This thesis presents the findings of some research carried out pertaining to economic operation and planning distribution systems. An optimal capacitor switching algorithm is developed for distribution system based on backward-forward sweep algorithm, which can assist in real-time applications. Thereafter, an optimal reconfiguration algorithm is proposed for distribution networks that seek to minimize losses by reducing the number of spanning trees in the network. The proposed algorithm provides a faster solution method and is useful for practical applications. Finally, the issues of short-term operating and long term planning of distribution networks in the presence of distributed generators is examined. An optimization framework is developed to determine the optimal locations of these distributed generator units.

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List of Abbreviations

DG	Distribution Generator
SLIP	Successive Linear Integer Programming
ELM	Equivalent Load Model
ELDM	Equivalent Load Density Model
DELDM	Discrete Equivalent Load Density Model
LT	Local Tree
KCL	Kirchhoff Current Laws
KVL	Kirchhoff Voltage Laws
DFAM	Double-Fed Asynchronous Machine
Pg	Power generator
Ps	Power source

List of Symbols

C_{fi}	Hourly DG investment cost (\$/MVA-hr).
C_{Uei}	Cost of unserved power (\$/MVA-hr).
C_{ri}	Hourly DG operating cost (\$/MVA-hr).
P_{DGi}^{CAP}	DG capacity limit (MVA).
P_{DGi}	Power generated from DG (MVA).
P_{SSi}	Power purchased by the distribution utility (MVA).
P_{Uei}	Unserved power (MVA).
V_i	Bus voltage (Volt) at bus-i.
V_j	Bus voltage (Volt) at bus-j.
Z_{ij}	Feeder segment impedance from bus *i* to *j* (ohms)
ρ	Electricity market price (\$/MWh).
J	Objective function

Chapter 1 Introduction

1.1 General Background

Distributed generators (DGs) have the advantages of having low environmental emissions, being more flexible in installation and with shorter gestation periods. Some of the DG technologies compete with conventional centralized generation technologies in operational aspects and cost. More and more DGs are currently being integrated into the distribution networks which have affected the operation and planning of distribution networks. For example, the intermittent nature of wind speed and solar radiation has a close effect on wind and solar generation variables.

Distribution network reconfiguration is an important operational issue in these networks which can help reduce distribution losses significantly, balance the loads and enhance the reliability of the network. Capacitor switching, similarly, improves the reactive power support in the network, balance the voltage profile and reduce the losses. It is obvious that network reconfiguration and capacitor switching can significantly improve the reliability and reduce the losses of the distribution network in the short-term. In the long-term, reconfiguration and capacitor switching can lower the peak load and bring about significant economic benefits.

For efficient planning of distribution systems, high reliability at low cost is one of the desired features to arrive at optimal plans. The cost and reliability issues in distribution systems are now receiving attention because of the significant penetration of DG sources in the network, and the emergence of the notion of smart grids. Optimal distribution network planning with DGs can lower network losses and optimize the investments in supporting ancillaries such as capacitor banks, or transformer switchgear upgrades, in the medium- and long-term.

1.2 Operational Aspects of Electrical Distribution Systems

Distribution systems include a number of line sections containing normally closed sectionalizing switches in each line and normally open tie switches, which are used to connect two feeders. For radial distribution systems, a radial configuration has to be maintained between the set of open feeders and the set of closed feeders. The distribution systems have traditionally been operated with a minimum loss objective, mainly with local and manual control of capacitors, sectionalizing switches without adequate computational support from the system operators.

With developments in distribution automation, the network reconfiguration problem has been studied extensively [1-6]. An optimal flow pattern algorithm is proposed by Shirmohammadi [1] which uses a heuristic approach to determine the optimal flow pattern of meshed networks. The method can be summarized as follows:

1) Solve for AC power flow of meshed network to determine the nodal current injections.

2) Convert meshed network into a purely resistive network by deleting reactive component of the impedance of each branch.

3) Calculate branch current flows of the purely resistive network for nodal current injections, calculated in (1).

The switch exchange method is proposed by Civanlar [2,3] which alters the topological structures of distribution feeders by changing the open/closed states of sectionalizing and tie switches to reduce the real loss. This method is simple and alleviates the need of conducting numerous load flows, thereby significantly reducing the computational burden. Nowadays, artificial intelligence methods are used to solve the network reconfiguration problems [4,5]. Although these methods can usually obtain the optimal solution, the computing times are rather large. Therefore, these methods cannot be used in real-time operation. As a basic rule of applying network reconfiguration, the network must be a radial network. In [6], a reconfiguration method is proposed that optimally determines the spanning trees and hence a rule is formulated for closing the switches while not affecting the optimal solution. Then, the number of spanning trees is notably reduced by applying the Minty algorithm [28]. The short computation time of this algorithm justifies its real-time application.

The capacitor sizing problem in distribution networks is to determine the optimal size of capacitors placed on the nodes of a radial distribution system so that real power losses are minimized for a given load profile. In [7], a solution algorithm is proposed based on a Phase-I–Phase-II feasible directions approach, to determine optimal capacitor sizing in distribution networks. In [8], a Successive Linear Integer Programming (SLIP) method is proposed for capacitor switching in distribution systems. The capacitor switching problem is formulated as a series of linear integer programming sub-problems. Dual relaxation method is then used to solve each relevant linear programming sub-problem. Computation is carried out in each sub-problem to deal with integer constrains and finally to find an optimal integer solution. Reference [9] develops a new concept of optimal matching of injected flow based on the loop-analysis and the superimposition theorem. Based on the optimal matching of injected flow, a polynomial algorithm for optimal capacitor sizing is proposed. The method requires only a few power flow calculations and optimal matching of injected flow, it is very efficient and can be used in real-time operation. The problem of reactive power optimization in distribution systems with wind generators has been examined in [10]. An index based on scenario analysis is presented.

1.3 Planning Aspects of Electrical Distribution Systems with DG

The goal of modern power distribution system planning is to satisfy the growing and changing system demand over the plan period economically, reliably and safely. The issues to be considered in arriving at the optimal plan are voltage level of the distribution network, locations, sizes, service areas, long-term expansion of substations and routes, and other important issues such as reliability. Optimal planning of distribution systems has been an area of important research effort. Reviews of the historical developments in this area have been reported in the literature. These works present the evolution of the distribution planning methods. In [24], a comprehensive review of mathematical models created reported prior to 1986, which addressed the traditional distribution planning problem, is presented. This review compared the mathematical formulation of models and their treatment of element costs and characteristics. Blanchard et al., in [25], modelled the traditional distribution system planning problem using non-linear cost terms (but kept the linear transshipment power flows) as a mixed integer non-linear program (MINLP). In [11], an equivalent distribution system model is formulated to minimize the lifetime cost of system expansion considering line technology, voltage level, construction, conductor type and size. In [12], three novel models to simplify the distribution network analysis are presented, the Equivalent Load Model, Equivalent Load Density Model and Discrete Equivalent Load Density Model. Weighting values for the six load distribution patterns are calculated and consequently, voltage drop and line losses can be acquired without needing the data from each distribution transformer on the feeder line.

1.4 Objectives of the Thesis

This thesis presents a study of two different aspects of distribution networks, operation and planning. It presents a new method of network reconfiguration of distribution networks both without DGs and in the presence of DG units. The proposed method develops an algorithm to reduce the number of spanning trees and thus reduce the computation time significantly, so as to make it suitable for real-time application.

Furthermore, a new method is proposed for optimal capacitor switching in distribution networks considering both without DGs and in the presence of DGs. This is based on the idea of backward-forward sweep algorithm and is also very suitable for practical implementation.

Both the network reconfiguration problem and the capacitor switching problems are adopted to consider and include wind turbine DG units. Their intermittent nature of the wind speed is simulated via the Monte-Carlo simulation process.

Furthermore, a study in distribution system planning is presented which examines network expansion aspects with DGs. An innovative but simple framework for determining DG investments in distribution systems is presented. A heuristic cost-benefit analysis approach is developed which, combined with an optimization model, is implemented successfully to estimate the most cost-effective DG size and site that serves system peak demands optimally. This framework demonstrates the application of a simple algorithm for DG sizing and siting considering electricity market price fluctuations, and a utility budget constraint.

1.5 Thesis Organization

Chapter-2 presents the details of the proposed network reconfiguration method via the Minty algorithm and backward-forward sweep. Chapter-3 presents the capacitor switching method using the backward-forward sweep algorithm. Both these chapters use the 33-bus and the 69-bus radial distribution test systems, to demonstrate the effectiveness of the proposed methods. Chapter-4 presents a novel optimization model for distribution system planning considering distributed generation units. Chapter-5 presents the conclusions of the thesis and the scope for future work in this area.

Chapter 2

Distribution Network Reconfiguration by Reduction of Spanning Trees

2.1 Introduction

The reconfiguration of the electrical power distribution system network is one of the important ways to optimize the distribution network. Reconfiguration can be carried out through operation of switches on each branch of the distribution network so as to obtain an optimized radial network structure while satisfying the load and voltage constraints.

One of the important characteristics of power distribution networks is its radial structure. The goal of network reconfiguration is usually to find out one optimized spanning tree out of all the possible spanning trees in the network. The computations involved in network reconfiguration are normally very high because of large number of possible trees. This chapter develops a new method which can significantly reduce the computational burden involved in reconfiguration of the distribution network. The proposed method calculates the optimized network structure using the Minty algorithm and assumes the characteristics of an ideal network.

First, the given distribution network is formed and then a simplified network is developed. Then, considering an ideal network, the optimal flow model is obtained which is used to arrive at a feasible reference network configuration. Thereafter, the switching rules for switch operation are deduced while not affecting the optimal solution. Then, the number of spanning trees is reduced using the Minty algorithm, thereby enhancing the computation efficiency significantly.

This chapter is structured as follows. Section 2.2 presents the simplification of distribution networks, which is the base for the further study. Section 2.3 presents a method that uses the concept of spanning trees for an optimal reconfiguration result. Based on the optimal flow model algorithm, a feasible reference network configuration is determined. The ideal network analysis and the optimization method for it are given. Based on the analysis and the method, an optimization rule, for which switches in the distribution network must be closed, is deduced while not affecting the optimal solution. Section 2.4 gives case studies for 33-bus and 69-bus distribution systems with the proposed method. Section 2.5 tests the proposed network reconfiguration method with wind turbines via the Monte-Carlo simulation.

2.2 Formation and Simplification of Distribution Network Graph

A distribution network typically comprises bus-bars, switches, feeders, distribution transformers, loads and therefore appears as a fairly complex network structure. The main objective of distribution network reconfiguration is the appropriate configuration of switch operation. Before reconfiguration of network, a simplified network, which is suitable for reconfiguration, needs to be worked out. The method for the simplification of a given distribution network is described below.

In the context of graph theory, a graph normally consists of branches and nodes. For a distribution network, the transmission sub-station can be considered as a unique root node while the feeder, transformer and the load between switches can be considered as one single node. The switch is considered as the branch. A typical distribution network is shown in Figure 2.1, referred to as diagram G.

As shown in Figure 2.1, the distribution network has three feeders, M1 and M2 are the distribution station buses, CB1, CB2 and CB3 are the three switches for the three feeders. The switches CB4, CB5 and CB6 are distribution sectionalizing switches while CB7, CB8 and CB9 are tie switches. The equivalent simplified diagram corresponding to Figure 2.1 is shown in Figure 2.2. In this diagram, M1 and M2 are simplified as node-1. The feeders and loads between CB1, CB6 and CB8 are simplified as node-2. Feeders and loads between CB2, CB4 and CB5 are simplified as node-3. The load at CB6 is simplified as node-4. Feeders and loads between CB4, CB8, CB8 and CB9 are simplified as node-5. Feeders and loads between CB3 and CB7 are simplified as node-6. Feeders and loads between CB5 and CB9 are simplified as node-7. Lateral 1 is CB1. Lateral 2 is CB6. Lateral 3 is CB8. Lateral 4 is CB2. Lateral 5 is CB4. Lateral 6 is CB5. Lateral 7 is CB9. Lateral 8 is CB3. Lateral 9 is CB7.

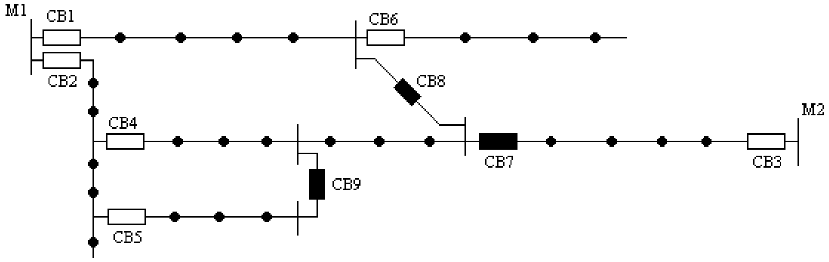

Figure 2.1: A typical distribution network diagram

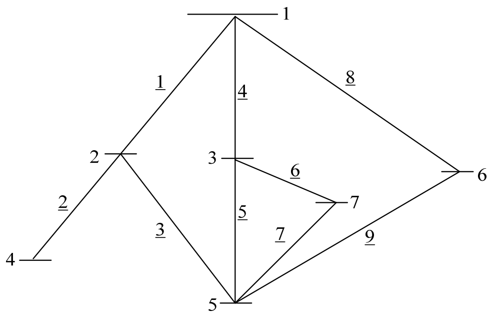

Figure 2.2: The corresponding simplified network diagram from Figure 2.1

During the study of spanning trees, the branches and nodes, which are connected to only one node, (*i.e.* branch 2 and node 4) can be ignored and merged into the connected node (node 2). The reason is that, these ignored branches and nodes (branch 2 and node 4, in this case) must be included in the final spanning trees. Figure 2.3 shows the further simplified version of the network from that represented in Figure 2.2. The purpose of the simplification of the network is to reduce the level of complication in the study of spanning trees.

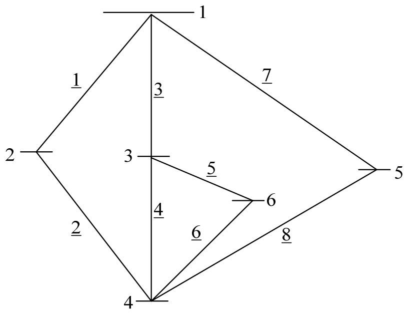

Figure 2.3: Further simplified diagram from Figure 2.2

2.3 Network Reconfiguration Based on Minty Algorithm

The tree is a simple but important structure in a graph and is critical for studies on network reconfiguration. The tree has been widely used in the area of computer science and power network analysis. The steps used in the proposed network reconfiguration procedure are outlined as follows:

- Create the spanning tree based on the Minty algorithm
- Formulate the ideal network using optimal flow model algorithm
- Using the ideal network and the spanning trees, the optimal network structure is obtained using the proposed method. In this method, there is no need to calculate all the possible trees generated from the Minty algorithm and therefore the computation is faster and simpler.

The Minty Algorithm, which can be used to generate all the possible spanning trees, is described next.

Let e_1 be a branch of Diagram G (refer to Fig.2.4, e_1 is the highlighted branch). Then, G can be divided into two sub-graphs, one with e_1 (denoted by G_1) and the other without e_1 (denoted by G_2). Thereafter in G_1, branch e_2 is selected and now G_1 can now be divided into two sub-graphs, one with e_2 and the other without e_2. The graphs without e_1 and e_2 are stacked in the program step.

Based on this method, all sub-graphs (*i.e.* spanning trees) for the network can be determined. When the computation reaches the point where either one graph has all the highlighted branches in a closed path or the graph is not a connected tree, the graphs are ignored. When a graph includes all highlighted branches in a tree structure, it can be inferred that the analysis of this graph is complete. One of the stacked graphs should be taken out for further analysis with the same above method until the stack in null.

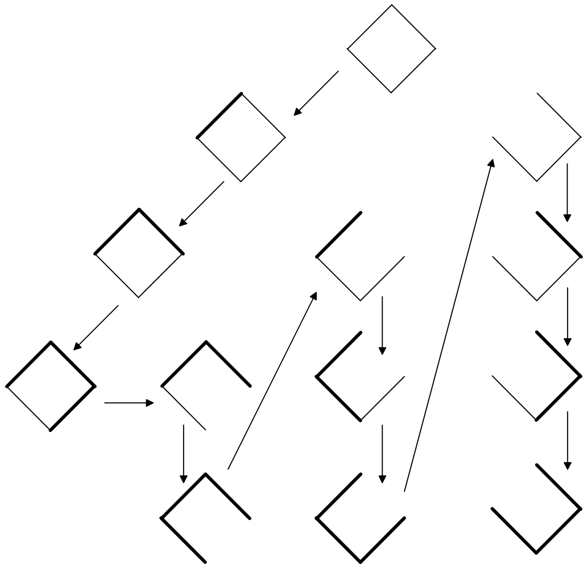

Figure 2.4: The process of numbering all spanning trees by Minty algorithm

With Minty algorithm, all possible spanning trees in diagram G can be determined and analyzed one by one. Such a method is the direct method for reconfiguration of distribution networks. However, for a typical 33-bus distribution system the number of spanning trees can be in the order of 50,000. Therefore, the direct method for network reconfiguration is not very practical.

In view of this, an optimal method is developed that enhances the efficiency of the whole computation. As discussed earlier, in each step of the Minty Algorithm, the diagram G is divided into 2 sub-graphs by selecting a branch *e*, where one sub-graph G1 includes the branch *e*, while the other sub-graph G2 does not include *e*. If it is not necessary to calculate one of the sub-graphs G2, then all spanning trees out of G2 can be ignored. This can significantly reduce the number of spanning trees, and hence the efficiency of computation can be improved significantly. The proposed method makes use of this idea to develop a fast algorithm for network reconfiguration.

2.3.1 Basic Concepts

We define a set T_i of all spanning trees in a graph as follows,

$$T_i = \{ t_{ij} \ , \ j = 1,2 \cdots m \}$$

Where, t_{ij} is the j^{th} element of sub-graph G_i, which is a radial network structure and m is the total number of radial network structures of sub-graph G_i. The set P_i is defined which contains power losses corresponding to each element of set T_i , and is defined as follows:

$$P_i = \{ p_{ij} \ , \ j = 1,2 \cdots m \}$$

Where, p_{ij} is the power loss in the network element t_{ij} in T_i .

With the optimal flow model algorithm, an initial radial configuration which is used as a reference can be worked out. The detailed procedure for the calculation is as follows:

1. Closes all switches to form a closed path
2. Ignores reactance in all branches of the network, calculate the branch currents using Kirchhoff's Current and Voltage Laws (KCL and KVL).
3. Open the switches from the low current branch to the high current branch. If the network is not connected after opening a switch, then open the next switch until the network becomes radial. The total power loss of this radial network is defined as P_{loss} .

Step 3, mentioned above, is the simplified Optimal Flow Model algorithm. So, P_{loss} usually is larger than the loss obtained from the full-scale optimal flow model algorithm. But since this method is faster and the simplification has little bearing on the results, this is used in our studies.

If each closed path in the diagram G is assumed to have an ideal source, a model can be found in which the current on each path is inversely proportional to the path resistance, and the closed path is an ideal network. The relations for such an ideal network are given as:

$$\begin{aligned} \mathbf{A}\dot{\mathbf{I}}_{opt} &= \dot{\mathbf{J}}_{opt} \\ \mathbf{BR}\dot{\mathbf{I}}_{opt} &= \mathbf{0} \end{aligned} \tag{2.1}$$

In (2.1), $\dot{\mathbf{J}}$ is the current vector at the node, $\dot{\mathbf{I}}$ is the branch current vector, $\mathbf{A}$ is the incidence matrix of nodes and branches, $\mathbf{B}$ is an independent matrix and $\mathbf{R}$ is the matrix of lateral resistance.

If P_i of sub-graph G_i is larger than P_{loss}, then G_i is not the optimal network reconfiguration structure. The calculation of each P_i is very involving. However, based on the concept of ideal network of sub-graph G_i, if $P_i \geq P_{optGi}$,and $P_{optGi} > P_{loss}$, then it is obvious that G_i does not contain the optimal reconfiguration structure.

2.3.2 Proposed Rule

For a sub-graph G_i, which has at least one closed path, the reactance of the closed path branches are replaced by resistances while other branch reactance remain unchanged, if P_{optGi} of sub-graph G_i satisfies the following,

$$P_{optGi} > P_{loss} \tag{2.2}$$

Then all spanning trees of this sub-graph G_i can be ignored.

Proof:

For any switch k in a network, when k is opened, the voltage difference between the two open points of k is $\dot{V}_k$. When k is closed, it can be considered that a voltage source $-\dot{V}_k$ is added across the connection points of k. In other words, when k is closed, a $+\dot{V}_k$ and $-\dot{V}_k$ source are connected in series. When k is open, it means a $-\dot{V}_k$ voltage source is eliminated from the circuit. As shown in Figure 2.5, to open k means that sub-graph (d) is short-cut from sub-graph and it becomes as a circuit shown in sub-graph (c).

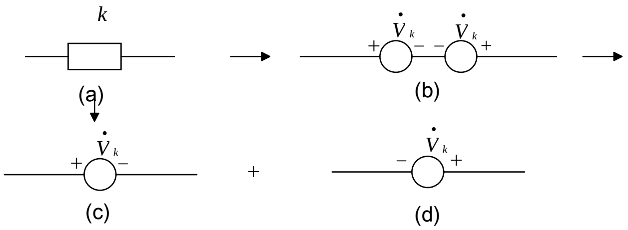

Figure 2.5: Supra-position theory

The branch current $\dot{\mathbf{I}}$ in sub-graph G should satisfy the following formulas.

$$\begin{aligned} \mathbf{A}\dot{\mathbf{I}} &= \dot{\mathbf{J}} \\ \mathbf{BZ}\dot{\mathbf{I}} &= \mathbf{0} \end{aligned} \qquad (2.3)$$

Where , Z is the reactance matrix.

During the process from sub-graph G_i to T_i, open k means eliminating a power source -$\dot{V}_k$. Under the condition of being a closed path network structure, each element of T_i can be found while the branch current $\dot{\mathbf{I}}$ does not follow (2.3). Because $\dot{V}_k$ cannot be adjusted, the best result of branch current $\dot{\mathbf{I}}$ of each element t_{ij} of T_i should follow (2.1), which is in inverse proportion to the resistance of each branch even it is normally not possible. The current $\dot{\mathbf{J}}$ in (2.3) is larger than $\dot{\mathbf{J}}_{opt}$ in (2.1). This proves p_{ij} of P_i is no less than P_{optGi}.

A branch of sub-graph G is considered as a switch in the actual network. The diagram without *e* is considered as an open switch. When P_{optGi} of sub-graph G_i is calculated, if it satisfies the above comparison rule of ideal network, then sub-graph G_i can be ignored.

Based on the above rules, the sooner the sub-graph G_i is formed, the lower is the value of *m*, which means the number of spanning trees will be less and less. The switch is numbered sequentially from the root of the network. When a numbered switch, as close as possible to the root, is switched off, P_{optGi} is larger, and it is likely to be greater than P_{loss}. The possibility of ignoring sub-graph G_i is higher. Then, sub-graph G_i, which is generated from the small numbered switch, need not be calculated. Therefore, the number of spanning tress is reduced significantly.

After large number of computations, it is seen that the number of spanning trees is related to P_{loss} of the ideal network and has little influence from the network size. The reference is nearly the optimal solution. The number of spanning trees is minimized. The calculation with this method for reconfiguring the network is faster. The method is suitable for real-time large-scale distribution network. Based on the above discussions, the flow chart of the proposed algorithm is shown in Fig.2.6.

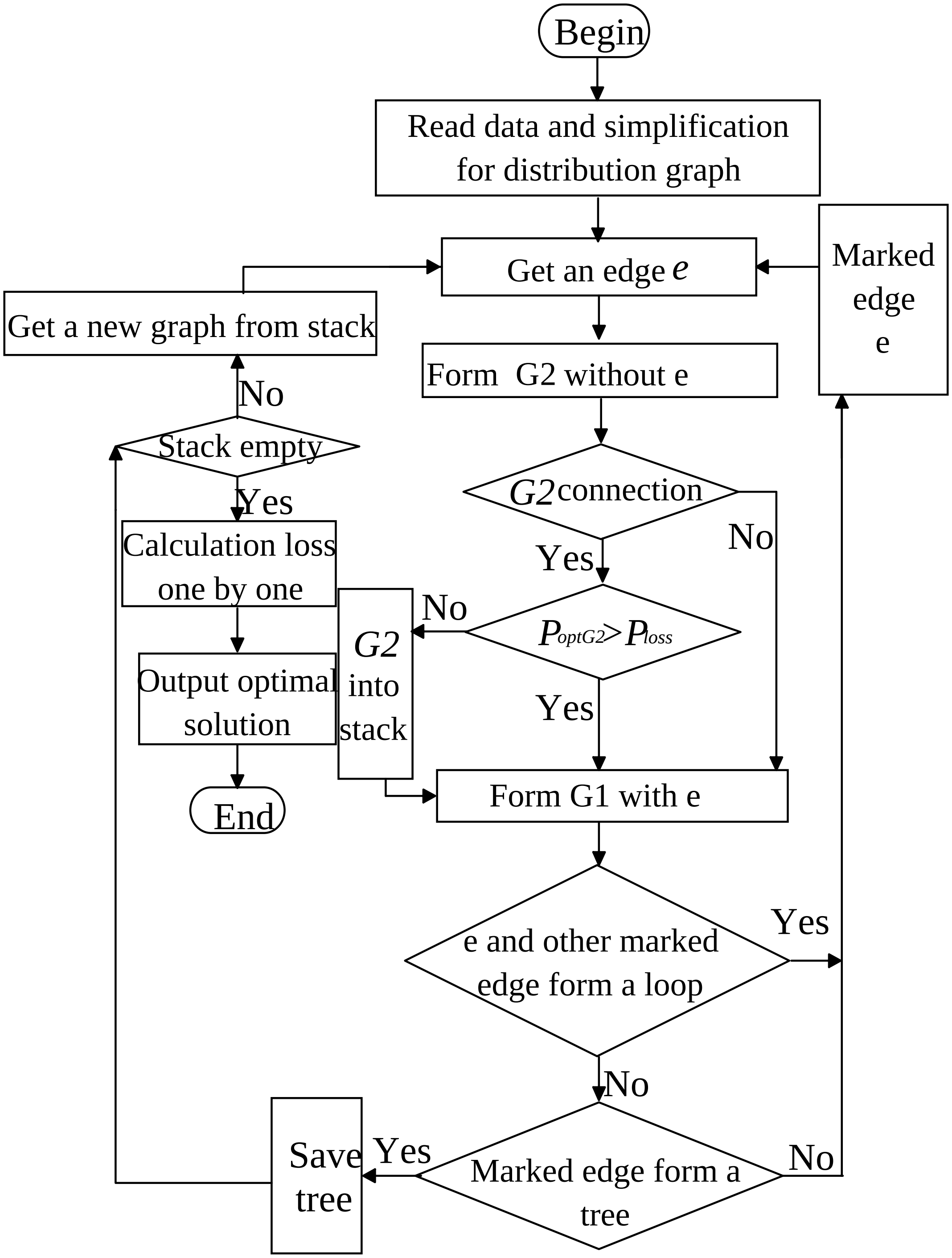

Figure 2.6: The flow chart of the proposed algorithm

2.4 Case Studies

2.4.1 The 33-Bus Distribution System

The 33-bus distribution system network has been considered to demonstrate the proposed network reconfiguration algorithm (Figure 2.7). The details of the system data are available in [26].

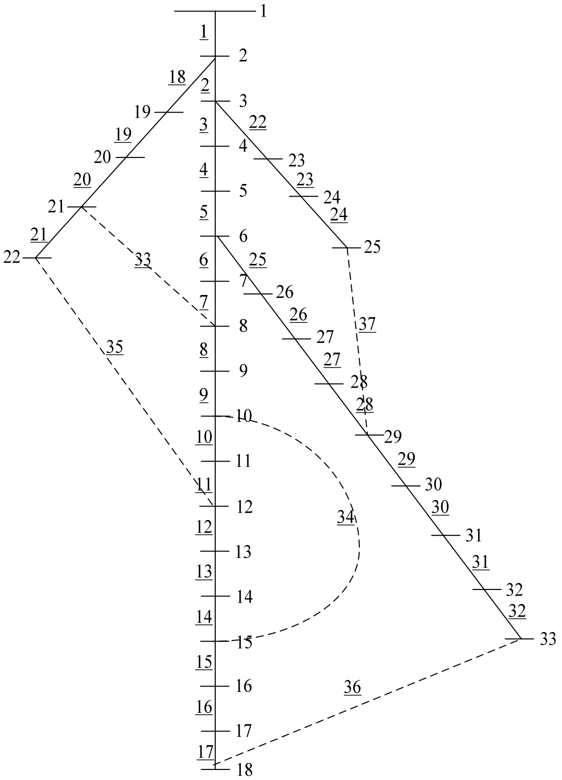

Figure 2.7: The 33-Bus Distribution System

In the above system, every branch is considered to have a switch. The number of branches is equal to the number of switches. It is clearly seen that branch-1 (denoted by 1) is in the final radial network structure which would be obtained by simplifying the structure using the above proposed method. Using the proposed method, the number of spanning trees actually handled, is reduced to only 162, from a possible maximum of 50,751 spanning trees. The result of the reconfiguration procedure is shown in Table 2.1.

Table 2.1: 33-Bus Network Reconfiguration Results

Total network loss before reconfiguration (kW)	Total network loss after reconfiguration (kW)	Switches to be opened	Lowest node voltage (kV)	Computation Time (s)
166.8	112.265	S9, s14, s28, s32, s33	11.970	1.36

As shown in Table 2.1, the best solution can be achieved by the proposed method.

2.4.2 The 69-Bus Distribution System

The second test system considered for the studies is the 69-bus distribution network (Figure 2.8). All relevant data pertaining to the system is given in [26].

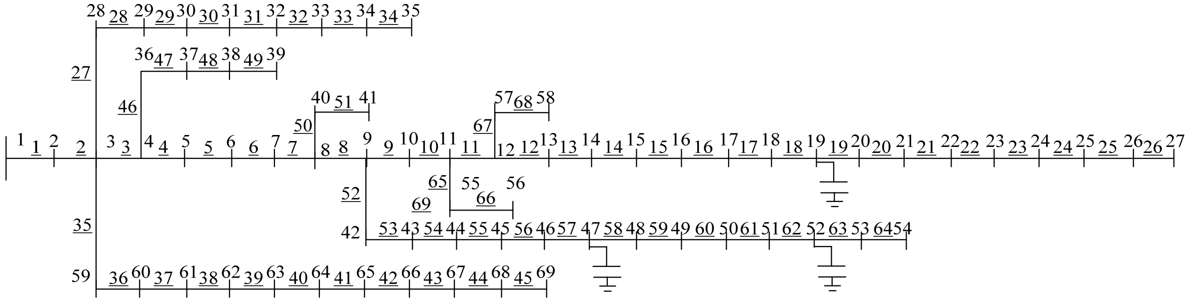

Figure 2.8: The 69-Bus Distribution System

In this system also, every branch is considered to have a switch and the number of branches is equal to the number of switches. It can again be observed that branch 1, 2, 27~34, 50, 51 and 65~68 comprise the final radial network structure which is obtained by application of the above method. The number of spanning trees considered here is only 293, as against the possible maximum of 269,539 spanning trees required to be handled by the normal method. The result of the reconfiguration is shown in Table 2.2.

Table 2.2: 69-Bus Distribution System Reconfiguration Results

Total network loss before reconfiguration (kW)	Total network loss after reconfiguration (kW)	Switches to be opened	Lowest node voltage (kV)	Computation Time (s)
233.2	104.604	s14, s58, s61, s69, s70	11.918	2.54

2.5 Network Reconfiguration Considering Wind Generation

It is assumed that a wind turbine generating unit is now connected to node 50 in the 69-bus system (Figure 2.8). The wind speed is computed considering a normal distribution $N(10,4)$. Using a 1000-run Monte-Carlo simulation, a series of wind speeds are worked out and the slip and generated power is calculated using the wind turbine characteristic curve and speed-power curve for every wind speed. Using the reconfiguration method proposed in Section 2.3, the optimal network reconfiguration for each wind speed scenario is obtained. The results are shown in Table 2.3.

Table 2.3: Optimal Network Reconfiguration After Monte-Carlo Simulation

Solution	Switches to be opened	Number of Wind-Speed Scenarios
1	s12 s58 s64 s69 s70	705
2	s69 s13 s70 s58 s45	240
3	s69 s70 s14 s58 s63	50
4	s69 s13 s70 s56 s63	4
5	s12 s58 s64 s69 s72	1

From Table 2.3 it is seen that solution-1 selects an optimal set of switches (s12, s58, s64, s69, s70) that are to be opened. And there are 705 wind speed scenarios which arrive at solution-1. In the same way, there are 240 scenarios of wind speeds that arrive at solution-2 set of optimal switching. From this study, we can conclude that solution-1 is therefore the best network reconfiguration structure for the 69-bus system.

2.6 Concluding Remarks

This chapter proposes a new method of radial distribution network reconfiguration by the method of the spanning tree. Based on the optimal flow pattern obtained using an ideal network assumption, a feasible reference network loss value is determined. The method of determining the ideal network is also presented. A comparison rule is established to simplify the computation of spanning trees using the Minty Algorithm. Case studies are presented for two different distribution systems- the 33-bus and the 69-bus system. It is seen that the proposed optimal reconfiguration scheme helps arrive at a switching scheme with low computational effort, which can be very suitable for real-time applications, and also significantly reduces the network losses.

The network reconfiguration algorithm is also tested for its suitability in distribution systems with wind generation sources via Monte-Carlo simulation.

Chapter 3

Optimal Capacitor Switching Using Backward-Forward Sweep Algorithm

3.1 Introduction

Capacitor banks are important components in power distribution systems and play a critical role in providing for reactive power compensation in the system. In real-time operation, capacitor switching can reduce network losses significantly by determining the best capacitor switching procedure. In this chapter, the well known backward-forward sweep algorithm, a practical method for optimizing capacitor switching in radial distribution networks is applied on a local tree of the network to arrive at an optimal capacitor switching strategy.

The concept of the local tree is first introduced in this chapter. Thereafter, the distribution network is divided into several local trees and then a method based on backward-forward sweep algorithm for capacitor switching solution is proposed. This is then applied to determine the optimal capacitor switching. Thereafter the algorithm is tested on a distribution system with wind generation source.

This chapter is organized as follows. Section 3.2 presents an optimal capacitor switching algorithm based on the backward-forward sweep algorithm. The procedure to divide the radial distribution network into the local trees is discussed. The concept of local trees can significantly reduce the computational burden. The proposed method also takes into account the mutual influence of the local trees. Section 3.3 presents a capacitor switching algorithm with wind turbines via the Monte-Carlo simulation.

3.2 Basic Concepts

The radial distribution network is presented as a tree T. The local trees of the tree T are its sub-graphs. All connection points for capacitor banks are in the local trees. In order to divide a tree T into several local trees, the root of each local tree has to be found first. The procedure for seeking the local trees is as follows.

1. Find all possible connection nodes which are in the path of the capacitor node to the root node and form a new tree T_c.
2. Calculate the degree of each node for tree T_c.
3. When the degree of a node is more than 2, then it is the root node of a local tree. In Figure 3.1, nodes 1, 2 and 4 are the roots of the three local trees present.

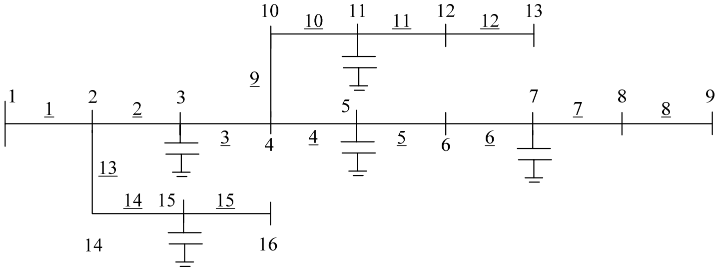

Figure 3.1: A simple distribution network

After the root of each local tree is defined, the local tree itself can be obtained. In the program, the logic of defining a local tree is as follows- if the first node of a lateral is the root node of a local tree, then this lateral is considered as a new local tree. After Tree T is divided into several local trees, the capacitor switching can be done for each local tree. With the local tree concept, the capacitor switching problem for large networks can be simplified into many sub-problems and hence become more efficient. If there is only one path between the capacitor node and the root, then the local tree has only one path.

Referring to Figure 3.1, the above is explained. The program starts searching from branch 15 (denoted by <u>15</u>). When it reaches branch 13 (i.e., <u>13</u>), it can be found that the first node is the root node of a local tree. The first local tree is set with node 2 as its root node, including branches 13, 14 and 15. The program continues its search from branch 12. When it reaches branch 9, it is seen that node-4 is the root node of a local tree. The second local tree is set with node-4 as its root node, including branches 9, 10, 11 and 12. The program further continues its search from branch 8. When it reaches branch 4, the first node of branch 4 is the root node of a local tree. The third local tree is set with node-4 as its root node, including branches 4, 5, 6, 7 and 8. Continuing the search from branch 3, when it reaches branch 2, the first node of branch 2 is the root node of a local tree. The fourth local tree is set with node-2 as its root node, including branches 2 and 3. Continuing the search from branch 1, the first node of branch 1 is the root node of the whole tree. The fifth local tree is set with node-1 as its root node, including branch 1. Figure 3.2 shows the local trees identified for the typical distribution system considered in Figure 3.1.

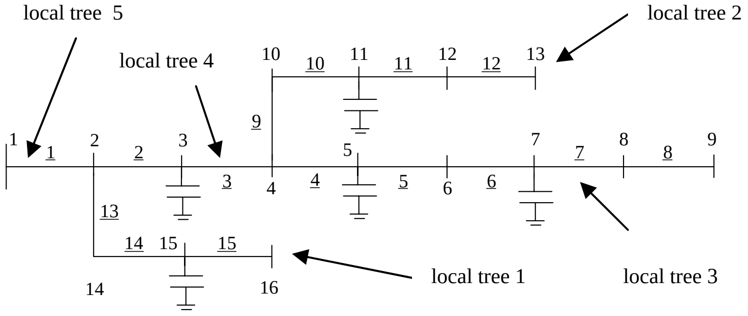

Figure 3.2:Local trees in the distribution network

3.3 Capacitor Switching Algorithm with Backward-Forward Sweep

Based on the definition of local trees introduced earlier, the Backward-forward sweep algorithm for capacitor switching is as follows.

1. Divides Tree T into several local trees
2. Calculate all possible combination of capacitor banks for the local tree $i\ (i = 1,2\ldots T_{num})$ using backward sweep, and hence calculate the power loss of the local tree i for each case. That capacitor switching combination, with the lowest power loss, is the optimal capacitor switching decision for local tree i.
3. Calculate the voltage drop of tree T using backward sweep while increasing the node voltage after obtaining all solutions of capacitor switching for each local tree. If the calculated voltage of root node is same as the given value, then calculation ends. Otherwise, set the voltage of root node to the given value, and carry out forward sweep, to calculate the voltage drop from the root node and go to step-2.

The above exhaustive search algorithm can be used to determine capacitor switching decisions in each local tree when the capacitor nodes and number of capacitor banks in each local tree are not too large.

3.4 Improvement of Algorithm

The purpose of capacitor switching in distribution networks is to compensate the reactive load and improve the node power-factor. In general, reactive power compensation by capacitors is a local issue and needs to be addressed locally. The capacitors connected to different local trees do not normally influence each other. However, when the compensation capacity of the capacitors is large, compared to the reactive power load connected at the node, there is a large-scale reactive power injection to the network tree. Under this situation, the capacitors connected to other local trees, but with the same root node, can influence each other.

In this section, at first a definition of the local tree group is presented. Then, a rule for analysis of the interaction between capacitors of local trees in the same group is presented. Finally, the solution for optimal capacitor switching for local trees group is presented.

The maximum capacity of capacitor that can be connected to the system, at a given node, is limited by system design and other parameters. The capacitors in local trees do not always influence each other. Therefore, the first step is to identify which local trees have mutual influences. The second step is to identify those trees, which have mutual influences on each other, as one local tree group.

Following is the definition of the local tree group. As shown in Figure 3.3, if local tree-1 and local tree $n_t - 1$ have the same root and this node is the last node of local tree n_t, then the local tree 1, 2,…, n_t can be defined as one local tree group of Tree T.

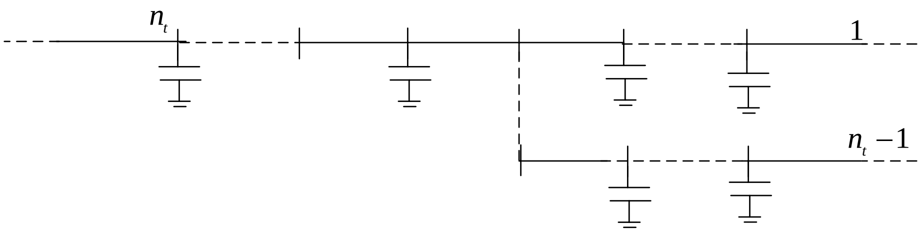

Figure 3.3: Diagram of local tree group

After presenting the definition of local tree group, it is easy to divide Tree T into several local tree groups. As shown in Figure 3.4, the first local tree group contains two, three and four local trees. The second local tree group contains 1, 4 and 5 local trees. The third local tree group contains 5 local trees.

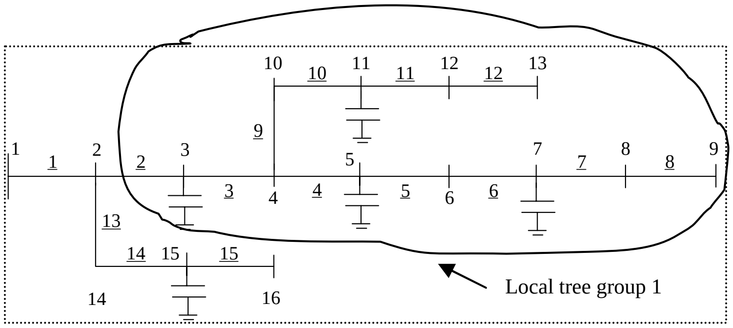

Figure 3.4: Local tree groups in the distribution network

In the procedure of backward-forward sweep algorithm, discussed in step-2 of Section-3.3, for capacitor switching, if the switching is carried out for each local tree $1, 2, \ldots, n_t - 1$ in any local tree groups, the mutual influence between each local tree must be considered. The following analysis presents the effect on losses due to increase or decrease in capacitor compensation in a local tree of a local tree group. Referring to Figure-3.3, when a capacitor connected to local tree i, is reduced, the compensation will be balanced by either:

- Adding more capacitors at local tree n_t and thus increasing the reactive power in the path between node n_t, at which capacitors are connected, and the root node of local tree i, which leads to increased losses in this local tree group.
- Adding capacitors in any of the local trees from 1 to $n_t - 1$, which means that the capacitors on the corresponding local tree (and hence the earlier optimal solution) are changed, thus leading to higher losses in that local tree. Meanwhile, the capacitors connected to local tree i also change and hence losses are increased.

Therefore, it can be concluded from the above that reducing the capacitors on local tree i leads to higher losses of the whole distribution network.

Furthermore, if the compensation is achieved by adding more capacitors to node n_t, then the reactive compensation has to be balanced by changing the capacitors connected to other trees. When a capacitor connected to local tree i, is increased, the compensation will be balanced by either:

- Reducing capacitors in local tree n_t which reduces the reactive power in the path between node n_t, at which capacitors are connected, and root node of local tree i, thereby leading to lower losses in this lateral. The capacitors connected to the local tree i also change, leading to higher losses in the path between the node, which is connected to the increased capacitors, and the root node of local tree i. When the reduction in losses is higher than the increase, the overall losses in the network is reduced.

- Reducing capacitors connected to any of the local trees 1 to $n_t - 1$, thereby the total capacitors on each local tree are changed, which leads to higher overall losses in the local trees.

Therefore, the losses in the network can only be reduced when more capacitors are added to the local tree i. As it has been clearly explained above, reducing the capacitors on local tree i will lead to higher losses.

Based on the above analysis, it can be concluded that the losses are reduced in the down-stream section of the network from local tree n_t only when capacitors are added in the local tree $i, i \in [1, n_t - 1]$ and capacitor switching at the remote node of local tree n_t is reduced. This conclusion can be extended to all local trees after n_t or in other words, the losses in the down-stream section of a network from local tree n_c is reduced only when capacitors are added in n_C and capacitors at the last node of n_c is reduced.

Based on the above conclusion, the computation procedure for determining the mutual influences between local trees within the same local tree group for capacitor switching is as follows.

1. Add a bank of capacitor to all down-stream section from local tree n_t. For example, add capacitor bank of size ΔQ_{cj} to node j.

2. Calculate the reduced losses (ΔP_{c_j}) between the node, which is connected to j capacitor banks, and node n_c node of local tree n_t. If there are no capacitors connected to local tree n_t, then ΔP_{c_j} is the actual reduced loss between the nodes.

3. Calculate the loss sensitivity to capacitor compensation, $\Delta P_{c_j} / \Delta Q_{c_j}$
4. Switch that capacitor bank which has the highest loss sensitivity.
5. Repeat the above steps until ΔP_{c_j} is negative (*i.e., losses start increasing*).

The above calculation is only carried out for minimizing the losses between node j and node n_c of local tree n_t. Because of the radial structure of the network the other laterals will not be influenced by these computations. Furthermore, considering local trees $1,2,\ldots,n_t - 1$ certain switching strategies are already worked out for specific capacitor banks, and thus the entire tree can be optimized just by adding capacitors into the local tree nodes. This leads to a much lower number of iterations compared to the standard backward-forward sweep algorithm. In other words, computation efficiency is improved significantly through the application of the proposed method.

The detailed flow chart for the computation of the proposed capacitor switching process using the backward-forward sweep algorithm is shown in Figure 3.5.

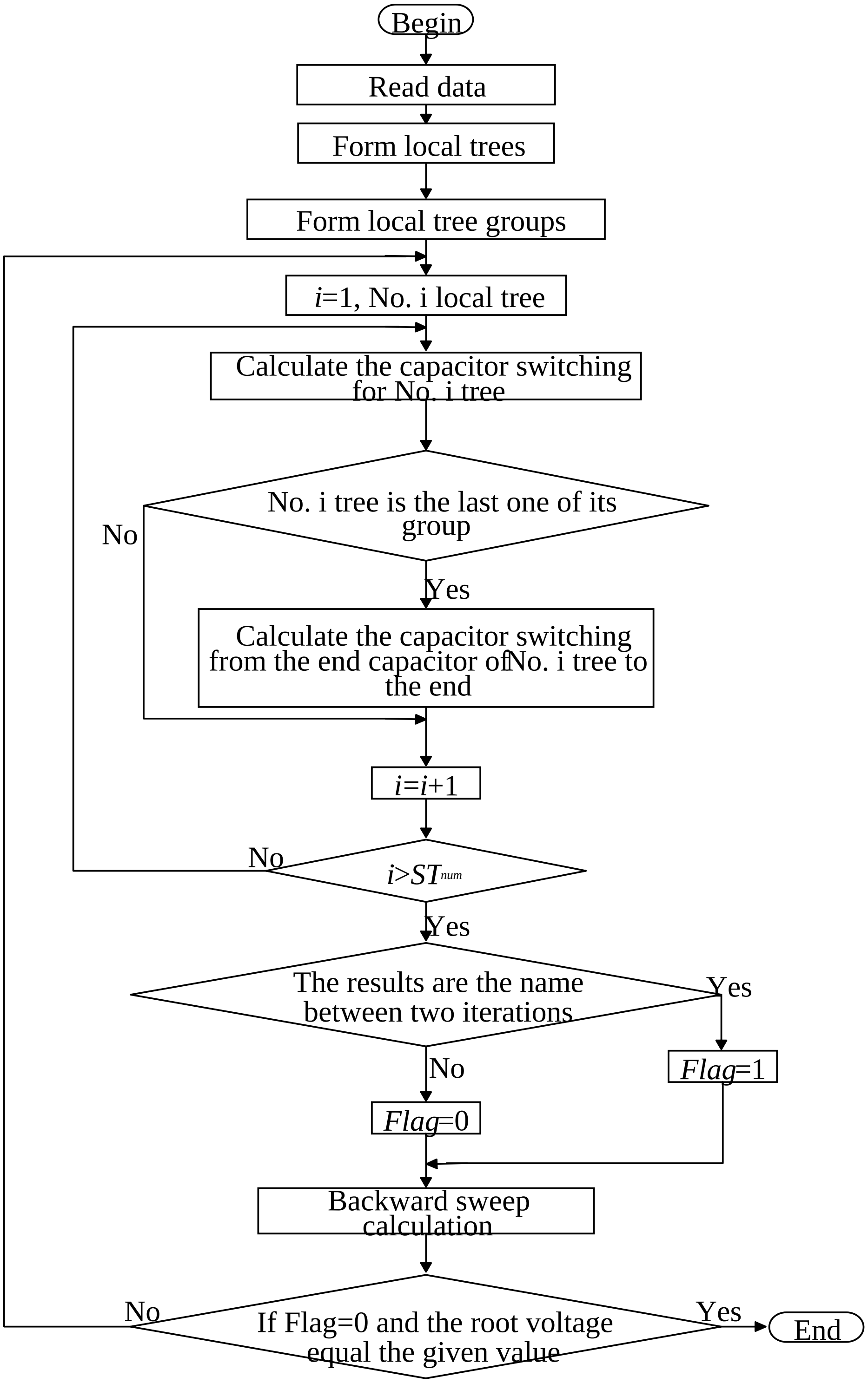

Figure 3.5: Flow chart of the proposed capacitor switching process

3.5 Case Studies

3.5.1 Case 1: 33-Bus Distribution System

The 33-bus distribution system network [26] is considered for the case study (Figure 3.6). The system has 37 branches and 5 tie switches. The system base voltage is 12.66 kV. The capacitors banks are connected at nodes 9, 14 and 28. The parameters of these capacitors are given in Table 3.1.

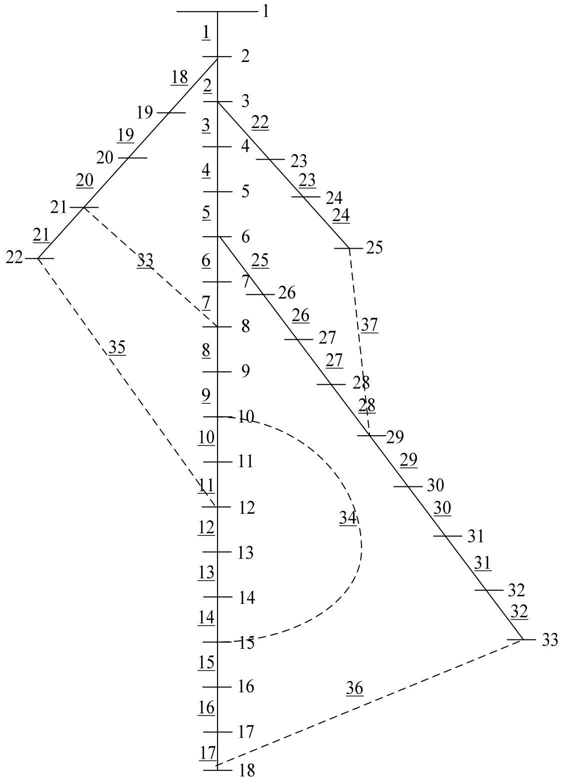

Figure 3.6: 33-Bus Distribution System

Table 3.1: Capacitor Parameters

Capacitor Type No.1	Connected to the node No.	Unit Capacity (kvar)	Maximum Capacity (kvar)
1	9	50	300
2	14	30	1000
3	28	50	2500

Using the method proposed earlier in this chapter, the network is divided into 3 local trees. The first local tree comprises the nodes, branches and loads from node-6 to node-33 and node-6 is its root node. The second local tree comprises the nodes, branches and loads from node-6 to node-18, with node-6 being its root node again. Other nodes and branches of the network comprise the third local tree. The power supply node (node-1) is the root node of the third local tree. Without considering the mutual influences between the local trees, 37 capacitor banks are connected to node-28 in the first local trees, 2 capacitor banks are connected to node-9 of the second local tree and 15 capacitor banks are connected to node-14. With the consideration of mutual influence between local trees, the results of the iterative process of capacitor switching is shown in Table 3.2.

Table 3.2: Capacitor Switching Considering Mutual Influences

Iteration	Number of capacitors connected Type-1 (node-9)	Number of capacitors connected Type-2 (node-14)	Number of capacitors connected Type-3 (node-28)
1	5	15	41
2	5	16	42

3.5.2 Case 2: 69-Bus Distribution System

The 69-bus distribution system [26] network, shown in Figure-3.7, is now considered. The system base voltage is 12.66 kV. The capacitor banks are installed on buses 19, 47 and 52. The data for the capacitors are given in Table 3.3.

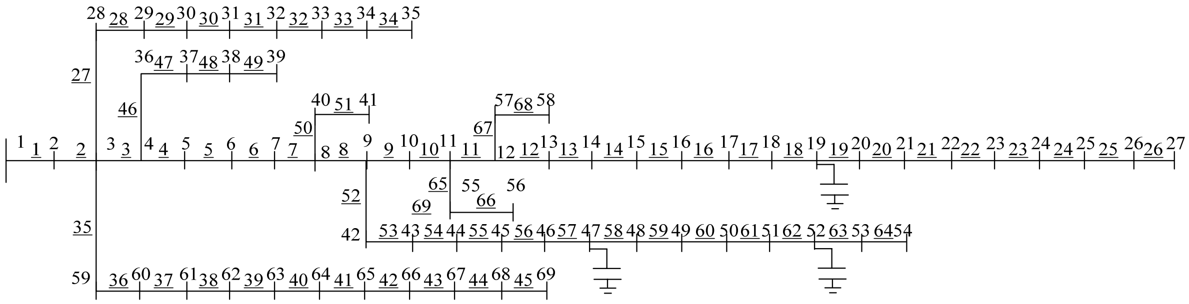

Figure 3.7: 69-Bus Distribution System

Table 3.3: Capacitor Parameters

Capacitor Type No.1	Connected to the node No.	Unit Capacity (kvar)	Maximum Capacity (kvar)
1	19	50	300
2	47	30	1000
3	52	30	1000

Using the proposed capacitor switching method, the distribution network is divided into 3 local trees. The first local tree comprises the nodes, branches and loads from node-9 to node-54 with node-9 being its root node. The second local tree comprises the nodes, branches and loads from node-9 to node-27 with node-9 being its root node. Other nodes and branches of the network comprise the third local tree. The power supply node (node-1) is the root node of the third local tree. Without considering the mutual influence between local trees, 33 capacitor banks are connected to node 52 and 12 capacitor banks are connected to node-47, both within the first local tree, and 5 capacitor banks are connected to node-19 of the second local tree. With the consideration of mutual influences between the local trees, the iteration results of capacitor switching is shown in Table 3.4.

Table 3.4: Capacitor Switching Considering Mutual Influences

Iteration	Number of capacitors connected Type-1 (node-19)	Number of capacitors connected Type-2 (node-47)	Number of capacitors connected Type-3 (node-52)
1	6	17	33
2	6	18	33

3.6 Capacitor Switching Considering Wind Generation

When a wind turbine is connected to the distribution network, the uncertainty factor is very high because the output power of wind turbine is a function of wind speed. The optimal solution, which is worked out considering deterministic generation sources, may not be suitable for the network with wind generation sources and even could be a negative impact to the network. How to obtain the optimal solution of the network with the changeable wind speed is the key objective of this section. Traditional methods usually consider a load variation curve for analysis, considering given generation patterns. The intermittent nature of wind speed variations makes the analysis more complex when wind generation presents in the distribution system.

It is assumed that wind speed variations allow a normal distribution, $N(\mu, \delta^2)$., where μ is the average value of the random wind speeds, which follows the normal distribution, and δ is the variance of the random variables of wind speeds. The wind speed variations can also be modeled considering other probability distributions [17]. When the wind speed is assumed to be a normal distribution, a series of wind speed data can be generated by using Monte-Carlo simulation [18]. Since the solution will only change when the wind speed change exceeds a certain range, one calculated solution can actually be suitable for many wind speed scenarios.

3.6.1 Case study

A Double-Fed Asynchronous Machine based wind generation unit is connected to node 50 in the 69-bus distribution network as shown in Figure 2.5. P = 1500 kW, Syn. Rpm = 1000 rpm, $r_s = 0.001692\Omega$, $r_r = 0.002423\Omega$, $x_s = 0.03692\Omega$, $x_r = 0.03759\Omega$, $x_m = 1.4568\Omega$, The wind flow/speed is calculated in accordance with normal distribution $N(10,4)$. After it runs 1000 scenarios of Monte-Carlo simulation, a series of wind speed data is worked out. The slip and generated power can be calculated using wind turbine characteristic curve and speed-power curve for every wind speed. In [19], the P and Q of the Double-Fed Asynchronous Machine (DFAM) can be calculated. With the method presented earlier in Section-2.1, the optimal capacitor switching solution for each scenario can be worked out. The result is shown in table 3.5.

Table 3.5: Capacitor switching after Monte-Carlo simulation

Solution	Total Capacitor banks connected to node	Total Scenarios suitable for the solution
1	6、8、21	6
2	6、8、20	28
3	6、8、19	50
4	6、8、18	132
5	6、7、17	174
6	6、8、16	243
7	6、7、15	291
8	6、7、14	52
9	6、6、14	19
10	6、6、13	4
11	6、6、12	1

In table 3.5, there are 291 scenarios which are suitable for the solution set-7. It is the solution which has the most scenarios. Therefore, solution set-7 is the final selected solution for the Capacitor Switching for the distribution network.

As seen from table 3.5, there are 291 wind speed scenarios that recommend solution set-7, which switch capacitors at bus-6, 7 and 15. Similarly, there are 243 wind speed scenarios that recommend capacitors switching at bus-6, 8 and 16(solution set-6). Since the most suitable solution set is set-7, we consider this to be the optimal section of capacitor switching.

3.7 Concluding Remarks

This chapter presents an optimal capacitor switching algorithm based on the idea of Backward-forward sweep algorithm. The radial distribution network is divided into several local trees, and each local tree is optimized separately. A concept of local tree group is proposed to study the mutual influence between trees which have capacitor banks. The overall optimal solution is worked out with the proposed rule based on the earlier optimal capacitor solution of each individual local tree. The computation burden is significantly released. The proposed algorithm helps to simplify large-scale calculation of capacitor switching decision for distribution networks. It not only obtains the numbers of switched capacitors to the bus, but also judge if the existing capacitor of a local tree meets the reactive power requirement of the distribution network, which leads to a further optimization of the distribution network and lowering the loss of the network. In general, with the integration of optimizing local tree to Backward-forward sweep algorithm, the algorithm becomes more efficient.

Chapter 4

Operation and Planning of Distribution Systems with DG

4.1 Introduction

When viewed from a total system point of view, a power system typically exhibits a smooth, continuous growth trend in annual peak load. Some variations are caused by weather and other factors that vary from year to year. Local area load growth usually occurs only over a few years, from a near zero to a value close to the final 'saturated' peak load.

This chapter examines the effectiveness of various factors in short-term operation and long-term planning of distribution systems. The analyses are carried out considering various load growth and associated supply-mix conditions. The optimal operation and planning of distribution systems under such conditions is explored.

This chapter is organized as follows. Section 4.2 presents the issues in DG operation, siting and sizing. Section 4.3 presents the scenarios considered for study in short-term operation with DG and a simple mathematical model is presented. Through the study of scenarios, effectiveness of the method and impact of market prices on the operation are examined. Section 4.4 presents a simple mathematical model for distribution planning and scenarios for long-term planning with DG. The results of the planning case study are discussed. Section 4.5 provides the concluding remarks of this chapter.

4.2 Operational and Planning Issues with DGs

Distributed Generators (DG) are succinctly defined as “electric power sources connected directly to the distribution network or on the customer side of the meter” [27]. This definition generally accommodates a variety of technologies and implementation across different utility structures, while avoiding the pitfalls of using more stringent criteria based on rules such as power ratings and power delivery area. Distribution planning involves the study of future power delivery needs and options, with a goal of developing an orderly arrangement of additions to the system needed to achieve satisfactory levels of service at a minimum overall cost.

Implementing DGs in the distribution network has many benefits, but at the same time it faces many restrictions and limitations. DG units, being scalable, can be built to meet immediate needs and later be scaled upwards in capacity to meet future demand growth. Scalability allows DG units to reduce their capital and operations costs and thus large capital is not tied up in investments or in their support infrastructure. Savings can also be achieved since infrastructure upgrades (such as feeder capacity expansions) can be deferred or altogether eliminated. From a customer point of view, savings may be accrued from the additional choice and flexibility that DGs allow with regard to energy purchases. However, on the other hand, installing DG in the distribution system can also increase the complexity of system planning. DG has to be adequately installed and coordinated with the existing protective devices and schemes. Higher penetration levels of DG may cause traditional power flows to change (reverse direction), since with generation from DG units, power may be injected at any point on the feeder. New planning techniques must ensure that feeders can accommodate changes in load configuration. These limitations and problems must be solved before choosing DG as a planning option. Some of the associated issues in distribution systems with penetration of DG units are as discussed next.

4.2.1 DG Operation

There are many factors affecting DG operation such as DG technologies, types, operational modes, and others. DGs installed in the distribution network can be owned, operated and controlled by either an electric utility or a customer. If DG is utility-owned, then its operating cycle is well known as is controlled by the utility. The shape of the DG operating cycle depends on the purpose of its use in the distribution network. For example:

a) Limited operating time units for peak load shaving (Internal combustion engines, small fuel cell units).

b) Limited operating time units to share the load with different operating cycles (Micro-turbines and fuel cells).

c) Base load power supply (Micro-turbines and large fuel cells).

d) Renewable energy units affected by environmental conditions such as wind speed and sunlight respectively (Wind generators and solar cells)

On the other hand, customer-owned DG operating cycles are not known to the operators unless there is a unit commitment agreement between the electric utility and the customer, which is not very likely. Thus, small customer owned DG operating cycles are considered to be unpredictable processes from the point of view of the electric utility. The utility has no control on their operation. This randomness changes the planning and operation problem from a deterministic problem to a non-deterministic one.

4.2.2 DG Siting

There are no clear restrictions on location of DG units in the distribution network, as there are no geographical limitations as in the case of substations. Hence, the only limitations arise from electrical requirements. If the DG is customer-owned then the utility has no control on its location because it is placed at the customer's site. If the DG is utility-owned then the choice of its location is based on several electrical factors such as:

- Providing the required additional load demand
- Reducing system losses
- Improving system voltage profile and augmenting substations capacities

Also, DG units have to be placed on feeders that do not impact the existing protective device co-ordinations and ratings.

4.2.3 DG Sizing

There are no clear guidelines on selecting the size and number of DG units to be installed in the network. However, some factors can be guiding the selection of DG unit size selection:

a) To improve the system voltage profile and reduce power losses, it is sufficient to use DG units of total capacity in the range of 10-20% of the total feeder demand [21]. While more DG capacity can be used to reduce the substation loading [22].

b) For reliability purposes in case of islanding, the DG size must be greater than double the required island load. The DG unit size can affect system protection coordination schemes and devices as it affects the value of the short circuit current during fault.

Therefore, as the DG size increases, the protection devices, fuses, re-closers and relays settings have to be readjusted and/or upgraded [21].

4.3 Short-term Operation with DG

4.3.1 Mathematical Model of Distribution Systems for DG Operation

The mathematical formulation for DG operation is presented in this section. At first, the distribution substation is considered to be the sole source of electricity supply to its customers. The disco has the choice to buy the power from any other supplier in the system through bilateral contracts and also has the possibility to buy power directly from a day-ahead electricity spot market.

The proposed objective function J, (4.1) aims to minimize the investment and operating costs of candidate DGs, payments toward purchased power by the distribution company, payments toward loss compensation services, as well as cost of un-served power.

$$J = \sum_{i=1}^{M}\left(C_{fi} \times P_{DGi}^{CAP} + C_{ri} \times P_{DGi}\right) + \sum_{i=1}^{ss} \rho \times P_{SSi} + \sum_{i=1}^{M} C_{Uei} \times P_{Uei} + \sum_{i=1}^{N}\sum_{j=1}^{M}\left\{\frac{\left(|V_i| - |V_j|\right)^2}{|Z_{ij}|}\right\} \times pf \times \rho \qquad (4.1)$$

The distribution company is required to meet its customers' load. The associated constraints are:

1. Demand-supply balance constraints: The algebraic sum of all incoming and outgoing power over the disco feeders (taking into account feeder losses) and the power generated from DG should be equal to the total demand at the bus net of un-served power (4.2).

$$\sum_{i=1}^{N}\left\{P_{ij}-\frac{\left(|V_i|-|V_j|\right)^2}{|Z_{ij}|}\right\}-\sum_{i=1}^{M}Pji+P_{DGj}=D_j-P_{Uej} \tag{4.2}$$

In (4.2), $P_{ij}=|V_i|\times\left\{\frac{\left(|V_i|-|V_j|\right)}{|Z_{ij}|}\right\}$ is the power flow on feeder *i-j*.

2. Voltage Drop Constraints: The voltage drop constraints depend on the voltage regulation limits provided by the disco.

$$P_{ij}=|V_i|\times\left\{\frac{\left(|V_i|-|V_j|\right)}{|Z_{ij}|}\right\} \tag{4.3}$$

3. Substation capacity constraint: The total power delivered by the substation over the outgoing distribution feeders must be within the substation capacity limit.

$$\sum_{j=1}^{M}P_{SSij}\le P_{SSi}^{Max} \tag{4.4}$$

4.4 Analysis of Short-term Operation with DG

A base price of 70 $/MWh is assumed to be the market price for purchasing power during the peak demand hours from the main grid. Choosing DG sites has some environmental restrictions [23]. Therefore, the proposed model considers natural gas DG generator sets since this technology is known to be environmentally friendly and produces the least pollution compared to other fossil fuel DGs. The candidate DG has sizes in multiples of 1 MVA with an operations & maintenance cost of 50 $/MWh. [23] The candidate unit total DG capacity for the system under study are chosen based on the assumed maximum limit for investing in DG capacities at each bus for the radial system.

4.4.1 Load Growth Scenario

The proposed approach is carried out to obtain the optimal DG sizing that meets the growth of system load. A preliminary set of candidate DGs are selected at first. DG capacity requirement varies across buses because of the load distribution pattern, differences in total primary distribution feeder parameters and hence losses in each feeder being different. It is also assumed that no DG is allowed in other locations in the 33-bus distribution network. The scenario is to obtain the DG power requirement at these selected locations, and also the power requirement from the station source while and load demand increases. Therefore, in the 33-bus distribution network, it is assumed that

- DG units are connected to buses- 9, 15, 25 and 31
- Peak load demand increases by 5% every year over a period of 10 years

It is seen from Figure 4.1 that the required power from each DG increases as the load increases. At bus-15 and bus-31, the power requirement from the two DG units increases linearly with demand. However, with a 20% increase in peak load demand, the DG power at bus-25 reaches a fairly high value and then starts to decrease with further increase in loading. It can be seen from Figure 4.2 that, at this loading point, the distribution network starts drawing power from the substation transformer. With load increase, the power drawn from the substation increases significantly and thus the optimal mix of DG supply and station power drawn for each year while the load increases is determined from this analysis.

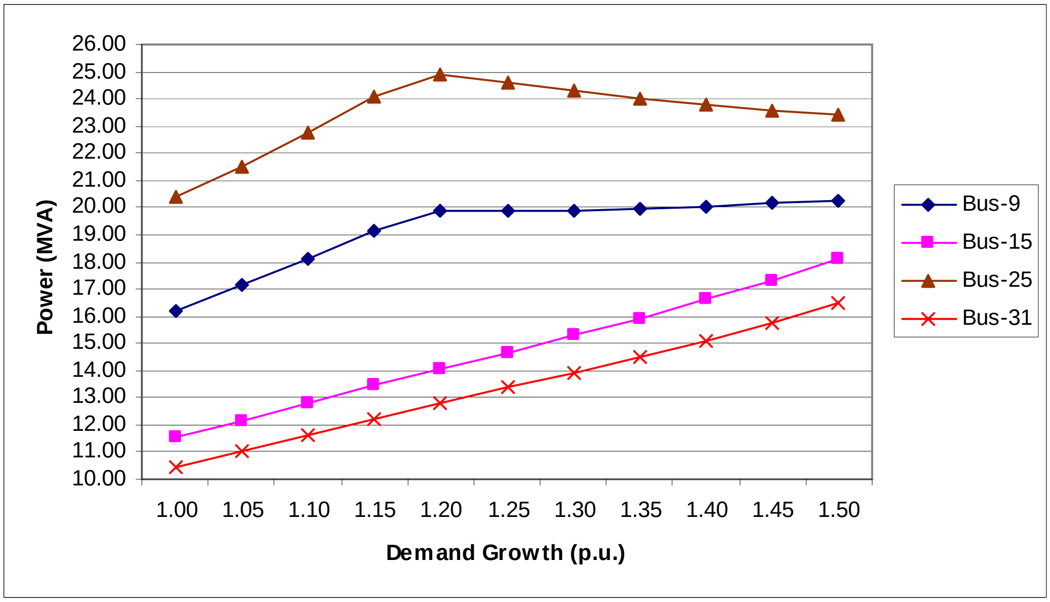

Figure 4.1: Optimal DG Generation at selected buses

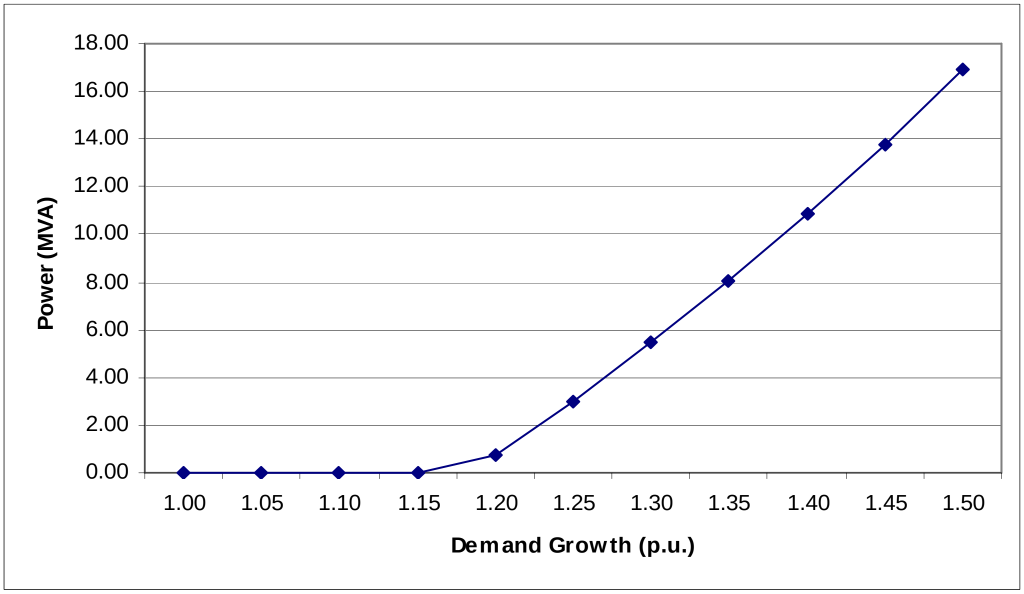

Figure 4.2: Sub-station Power Usage

4.4.2 Load Growth with Different DG Siting

In this case the pre-selection of DG siting are changed to buses- 19, 20, 5 and 36. The aim of this case-study is to examine the sensitivity of DG locations to load growth. The objective remains the same- that of minimizing the total cost of distribution operation while meeting the system load. The load demand increases by 5% every year.

It is seen that in this scenario, no optimal solution was obtained. The voltage drop constraints on the feeder voltage were binding constraints, and hence the distribution system operation with the above configuration of DG units and the considered load growth scenario results in an infeasible case. The distribution system operator will have to seek other options such as load curtailment, additional locations for DG units, additional reactive power support, etc., for this case, in order to arrive at a feasible solution.

4.4.3 Rapid Load Growth Scenario

The following study presents an approach to obtain the optimal DG sizing that meets a rapid growth of system load. A preliminary set of candidate DGs are selected. DG capacity requirement varies across buses because of the load distribution pattern, differences in total primary distribution feeder parameters and hence losses in each feeder being different. It is also assumed that no DG is allowed in other locations in the 33-bus distribution network. The scenario is to obtain the DG power requirement at these selected buses, and also the power requirement from the station source while and load demand increases. Therefore, in the 33-bus distribution network, it is assumed that

- DG is connected to the bus 10, 16, 24 and 26 of the proposed network,

- Peak load demand increases by 8% every year over a period of 10 years

Studies show (Figure 4.3) that the required power from DG units increase at each bus in a linear manner. In Figure 4.4, it is shown that although the load demand increases rapidly each year, the DG units are able to meet the demand requirements until year-7, when the demand is 85% higher than the base year demand, and the distribution system only starts to draw power from the substation at year-8. Thereafter, the power drawn from the substation increases significantly.

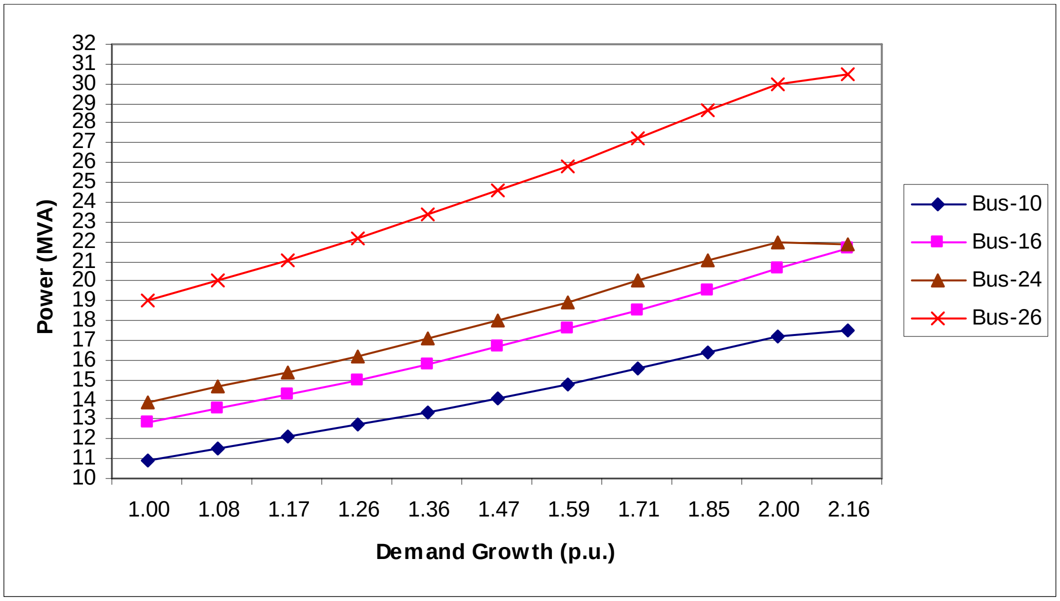

Figure 4.3: Optimal DG Generation at selected buses

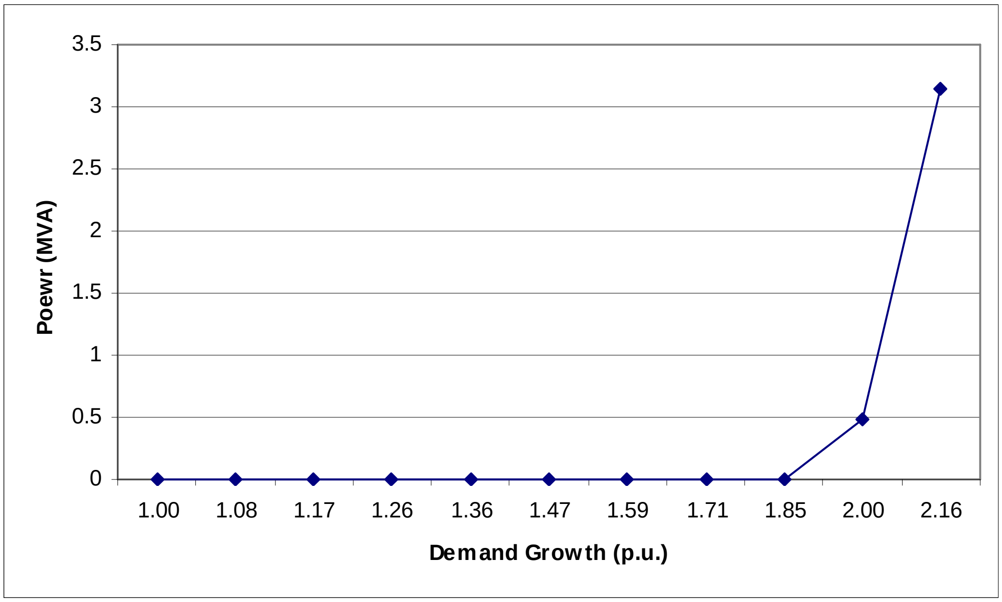

Figure 4.4: Sub-station Power Usage

4.4.4 Market Price Growth Scenario

This scenario presents the influence on the operation of the distribution network while the market price increases. As assumed in Section-4.3.1, DGs are connected at buses- 9, 15, 25 and 31. The objective is to obtain the optimal DG sizing and optimal drawal of power from the substation.

In Figure 4.5, it is shown that at bus-25 and bus-31, the power from DG is nearly unchanged even with increase in market prices. But, at bus-9 and bus-15, the power supplied from DG units increases. In general, the usage of substation supply is reduced because of the high prices. When the market price is 95 $/MWh or more, no power is drawn from the substation and all the power is supplied by the four DG units. In Figure 4.6, it is seen that there is no power delivered by the substation when the difference between the DG power cost and the market price is more than 24 $/MWh. On the other hand, when the market price is lower than the DG generation costs, the DG units back down and supply a total of 35 MW while the substation provides a major portion of the demand. It can also be observed that as the supply mix changes between DG power and substation power, the total power required by the system is not constant- this is because of the variations in distribution losses due to the difference in supply mix.

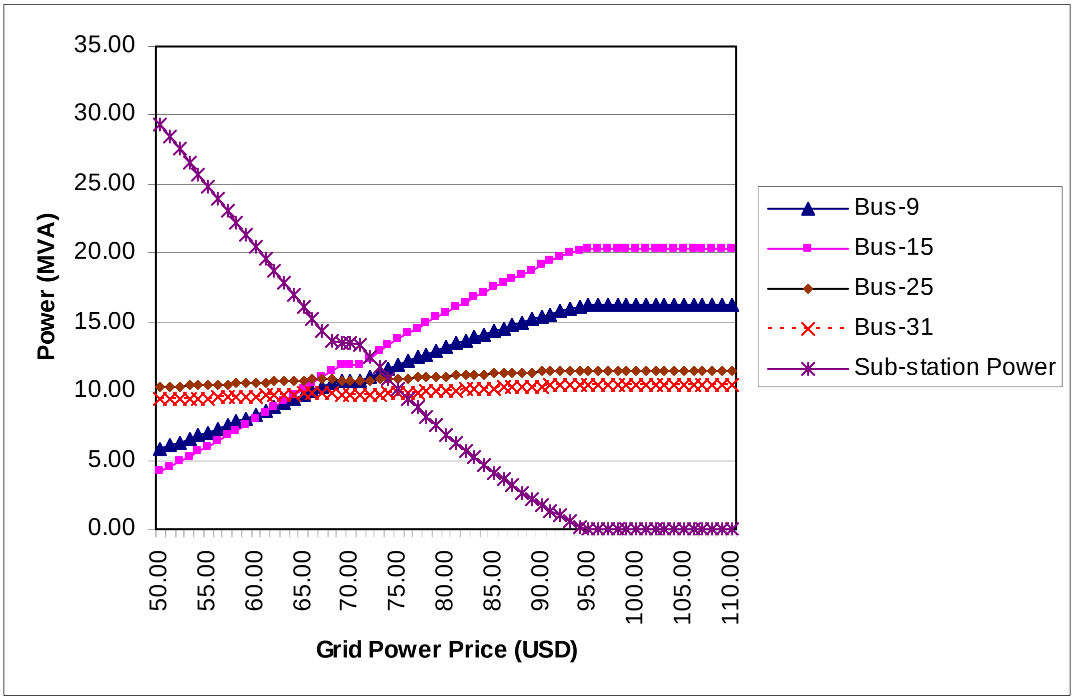

Figure 4.5: DG requirement at each bus

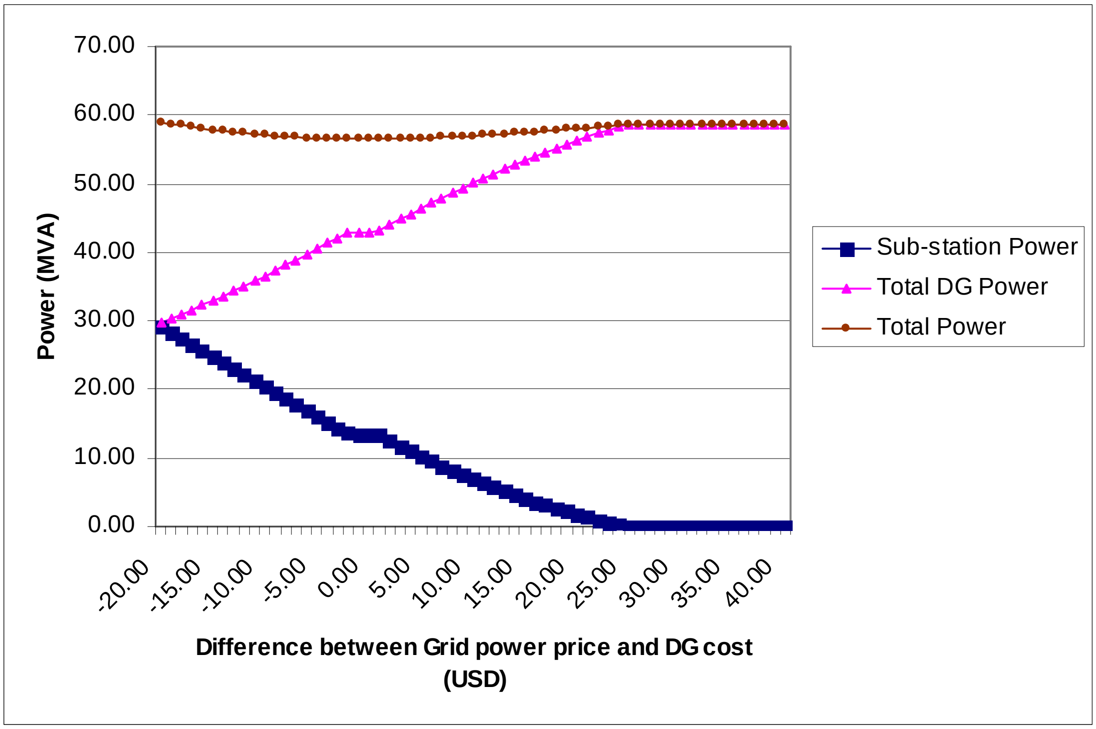

Figure 4.6: Station power usage vs DG power usage

4.4.5 Market Price Growth Scenario with Different DG Siting

In this case the pre-selection of DG siting are changed to bueses-10, 16, 24 and 26. The aim of this case-study is to examine the sensitivity of DG locations to price growth. The objective remains the same- that of obtaining the optimal DG sizing and optimal station power usage that meets the growth of grid price.

In Figure 4.7, it shows that the power from DG at all buses are changed. In general, the power supplied from DG units increases while the usage of substation supply drops significantly because of the high prices. When the market price is 78$/MWh or more, no power is drawn from the substation and all the power is supplied by the four DG units. In 4.8, it is seen that there is no power delivered by station when the difference between the DG power cost and market price is more than 9$/MWh. On the other hand, when the market price is lower than the DG generation costs, the DG units back down and supply a total of 35MW while the substation provides a major portion of the demand. Comparing to the earlier study in section-4.4.4, it is seen that the DG siting can influence each DG and substation usage while the market price growth remains unchanged. It is also observed that the total power required by the system is not constant and even higher than the power required in section-4.4.4- this is because of the higher losses due to different DG siting.

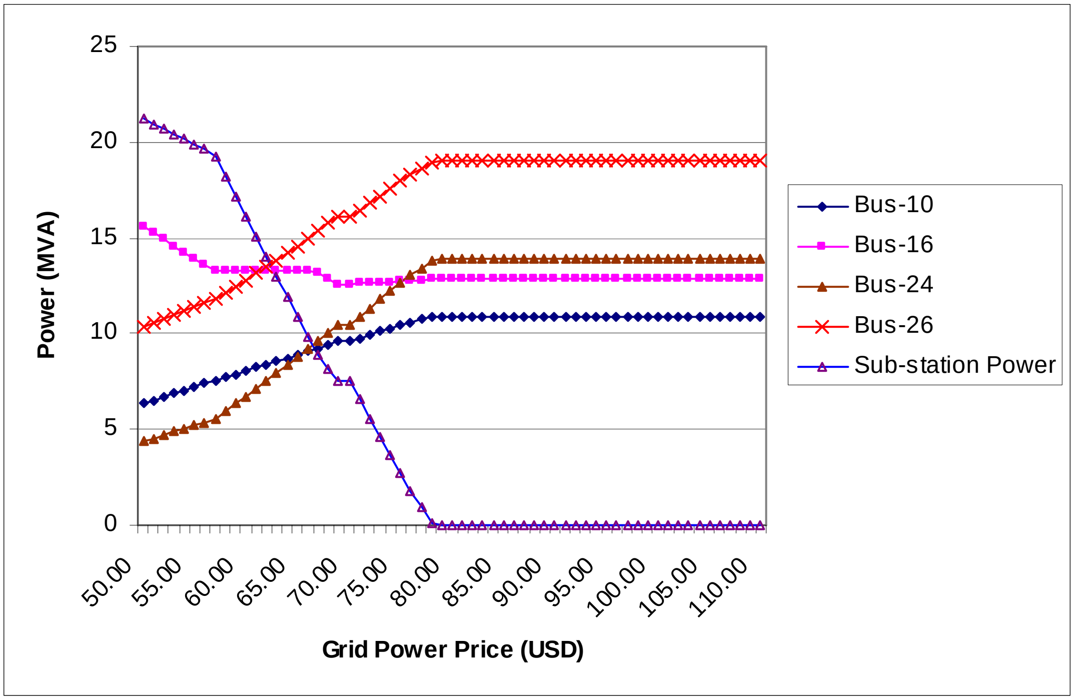

Figure 4.7: DG requirement at each bus

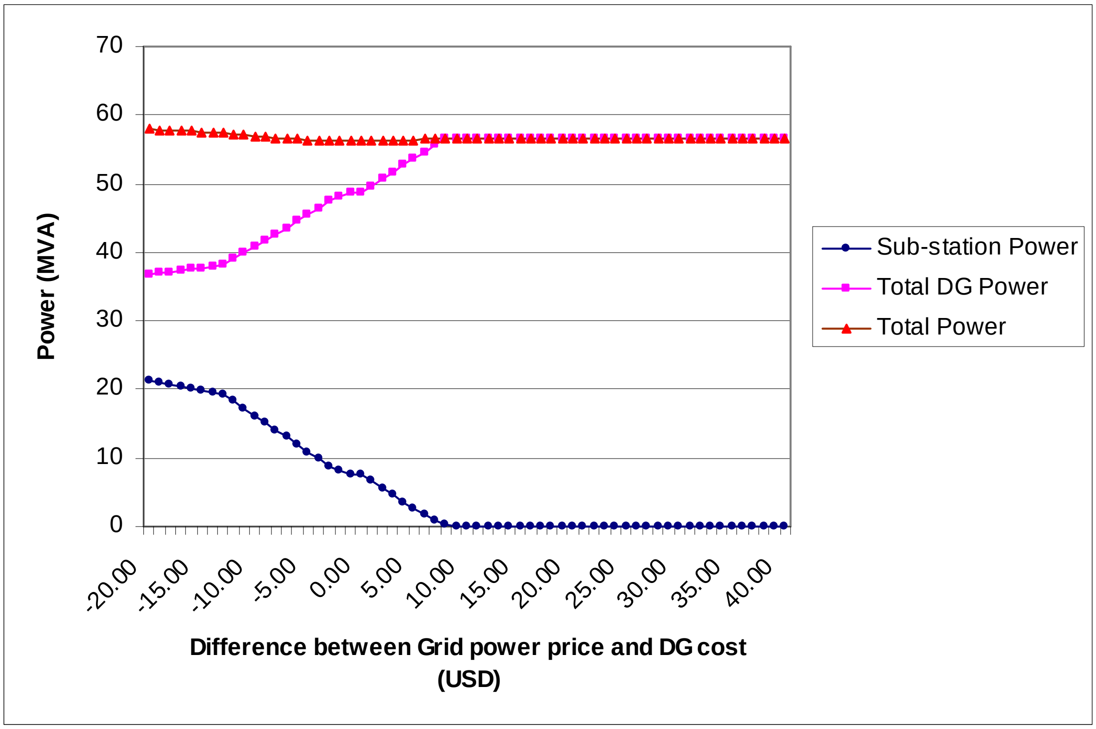

Figure 4.8: Station power usage vs DG power usage

4.5 Long-term Planning Model with DG

Long term planning involves developing a strategy to meet the utility's long term power delivery needs, usually minimizing cost by achieving an optimal balance between capital additions and operational cost. It particularly requires that the distribution planner review every alternative, including load forecasts, revenue constraints, reliability and a lot of other factors. However, the long term planning has to meet the basic constraints or requirements for the distribution network. In this thesis, the proposed method addresses a solution for long term optimal planning while meeting the proposed constraints of the network.

4.5.1 Mathematical Model of Disco for DG Planning

The proposed objective function (4.5), with consideration of the yearly factor ‘*kk*’, aims to minimize the investment and operating costs of candidate DGs, payments toward purchased power by the disco, payments toward loss compensation services, as well as cost of un-served power.

$$\min J = \sum_{kk=1}^{KK} F(kk) \times \left(\sum_{i=1}^{M} \left(C_{fi} \times P_{DGi}^{CAP} + C_{ri} \times P_{DGi} \right) + \sum_{i=1}^{ss} \rho \times P_{SSi}^{kk} + \sum_{i=1}^{M} C_{Uei} \times P_{Uei}^{kk} + \sum_{i=1}^{N} \sum_{j=1}^{M} \left\{ \frac{\left(|V_i|^{kk} - |V_j|^{kk} \right)^2}{|Z_{ij}|} \right\} \times pf \times \rho \right) \tag{4.5}$$

With consideration of the yearly factor ‘*kk*’, total Power-Conservation Constraints is modified as in 4.6: The algebraic sum of all incoming and outgoing power over the disco feeders (taking into account feeder losses) and the power generated from DG should be equal to the total demand at the bus net of un-served power.

$$\sum_{i=1}^{N} \left\{ P_{ij}^{kk} - \frac{\left(|V_i|^{kk} - |V_j|^{kk} \right)^2}{|Z_{ij}|} \right\} - \sum_{i=1}^{M} P_{ji}^{kk} + P_{DGj}^{kk} = D_j - P_{Uei}^{kk} \tag{4.6}$$

Voltage Drop Constraints: The voltage drop constraints depend on the voltage regulation limits provided by the disco on each year (yearly factor ‘*kk*’).

$$P_{ij}^{kk} = |V_i|^{kk} \times \left\{ \frac{\left(|V_i|^{kk} - |V_j|^{kk} \right)}{|Z_{ij}|} \right\} \tag{4.7}$$

Line Transmission Constraints: The maximum power transmission between bus-i and bus-j is $P_{ij}^{\max}$ every year. (yearly factor ‘*kk*’).

$$P_{ij}^{kk} \le P_{ij}^{\max} \tag{4.8}$$

Distribution Substation Capacity Constraint: Every year, the total power delivered by the substation over the outgoing distribution feeders from that bus must be within the substation capacity limit. (yearly factor '*kk*').

$$\sum_{j=1}^{M} P_{SSij}^{kk} \leq P_{SSi}^{Max} \tag{4.9}$$

4.5.2 Long-term Planning with 5 MVA DG Sets

The following study presents an approach to obtain the optimal DG sizing and siting to meet the overall load growth in 5 years. It is assumed that DG can be installed in any bus of the 33-bus distribution network. In this study, it is assumed that

- The total allowed power delivered by DG is less than 35 MVA
- The maximum capacity of installed DG is set to be 5 MVA.

As shown in the Table 4.1, the required DG siting and sizing to achieve optimal planning are different from year to year. 7 DG are required for year 1, 2 and 4. 8 DGs are required for year-3 and year-5. The result shows that in the long-term planning, it is difficult to fix DG to certain locations. It varies from year to year at siting and sizing.

Table 4.6: DG siting and sizing in 5-year-planning No.1

Bus No.	**DG at Year No.1**	**DG at Year No.2**	**DG at Year No.3**	**DG at Year No.4**	**DG at Year No.5**
10	0	0	0	0	**2.1495**
11	0	0	0	**4.4591**	0
13	**4.7944**	0	**5**	**5**	**5**
14	0	**5**	0	0	**5**
15	**5**	0	0	0	0
16	0	**5**	**4.8705**	**5**	0
17	0	0	0	0	**5**
18	0	**3.0648**	**5**	**5**	**5**
20	0	**1.9352**	0	0	0
21	0	**5**	0	0	0
22	0	0	**5**	0	0
25	**5**	0	0	**5**	0
26	0	**5**	**5**	0	0
27	0	**5**	**5**	**5**	**3.6643**
28	**5**	0	0	0	**4.2281**
29	**5**	0	0	0	0
30	**5**	0	0	0	0
31	**5**	**5**	0	0	0
32	0	0	**4.6623**	0	0
33	0	0	0	**5**	**4.8914**
Total	**34.7944**	**35**	**34.5328**	**34.4591**	**34.9333**

4.5.3 Long-term Planning with maximum 10MVA DG sets

In this scenario, the maximum capacity of each DG is set to be 10MVA. The purpose of this change is to study the sensitive of DG capacity to the network planning. It is also assumed that DG can be installed in any bus of the 33-bus distribution network. In this study, DG sources are assumed as follows.

- The total allowed power delivered by DG is less than 35 MVA
- The maximum capacity of installed DG is set to be 10 MVA.

As shown in the Table-4.2, the required DG siting are also not much changed from the result in table-4.1 while the number of bus, which require DG, is reduced. It is seen that the total power required from DG is slightly increased comparing to the result in table-4.1 because of the higher transmission losses of the distribution network.

Table 4.7: DG siting and sizing in 5-year-planning No.2

Bus No.	**DG at Year No.1**	**DG at Year No.2**	**DG at Year No.3**	**DG at Year No.4**	**DG at Year No.5**
13	0	0	**10**	**10**	**10**
14	**10**	0	0	0	0
16	0	**5.9784**	0	0	0
17	0	0	**6.9483**	0	0
18	0	**8.8634**	**7.9785**	**8.9467**	**10**
21	0	0		0	**6.413**
23	**10**	0	0	0	0
25	0	0	**10**	0	0
26	0	**10**	0	0	0
27	0	**10**	0	**5.9674**	0
28	**10**	0	0		0
30	**4.9447**	0	0	0	0
32	0	0	0	**10**	0
33	0	0	0	0	**8.5698**
Total	**34.9447**	**34.8418**	**34.9268**	**34.9141**	**34.9828**

4.6 Concluding Remarks

This chapter presents detailed analysis of short-term operation and long-term planning effects of DG units on distribution systems. It is observed from the analysis that the selection of DG unit location is sensitive to the operation of the distribution network. Furthermore, it is noted that changes in DG locations can influence DG sizing and substation power usage significantly. It is also seen that market prices can have a significant impact on the optimal

DG supply and substation power drawn, and the operator needs to arrive at an optimal mix considering the overall economics into consideration. The proposed method presents simple analysis of DG sizing and siting in distribution systems. It is also observed that in a 5-year planning context, the gross capacity limits have to be considered and not individually for each year. It is also observed that when the DG unit capacity limit is changed, the optimal plan changes to some extent although the total investment is the same, at the end of the plan period.

Chapter 5 Conclusions

5.1 Main Contributions

Efficient operation of electrical distribution systems is a challenging task considering the complexity as well as number of different problems involved. Since most of the electrical distribution systems have radial configuration due to operational convenience, this thesis focuses on development of new methods for addressing issues in distribution system operation and planning.

In particular, the thesis examined the critical problems in network reconfiguration and capacitor switching to develop new algorithms for loss minimization. It also examined the operations and planning problems in distribution systems considering DG unit penetration.

This thesis presents a new algorithm for distribution network optimal reconfiguration by reducing the number of spanning trees. In the process of creating all spanning trees by using Minty algorithm, based on the idea of ideal network, a comparison rule is presented under the condition of not losing the best solution for reconfiguration. With this new method, unnecessary spanning trees are not taken into consideration during computation. Therefore, the number of spanning trees is considerably reduced. Hence, the efficiency of computation is improved, which makes it suitable for real-time operation of the network. The proposed method is an improvement in computation over existing methods for reconfiguration of the distribution network. The proposed algorithm is tested on systems with wind generators and is found to perform satisfactorily.

The thesis presents a new optimal capacitor switching algorithm based on the idea of backward-forward sweep algorithm. The method first divides a radial distribution network into several local trees. Then, it optimizes each tree separately, which splits the large-scale optimization problem into multiple small-scale problems, thus improving the computation efficiency. The optimization process for local trees is based on the backward-forward sweep algorithm. Furthermore, a concept of local tree group is proposed. The mutual influence between each local tree is analyzed. A new method based on backward-forward sweep algorithm is finally presented for capacitor switching, which reduces the computation burden significantly. It is also tested with wind generators as DG units in the distribution network with good performance.

A short-term operation and long-term planning model for distribution systems, is presented and examined in the thesis. Several scenarios are considered for analysis and important observations are made. It is noted that the selection of DG location is dependent on the network structure and changes to selected DG locations can influence the power requirement of DG units and from the substation.

5.2 Scope for Future Work

Some of the issues that need to be examined as future work, in the context of the work reported in this thesis, are discussed below.

- In the distribution network reconfiguration algorithm, the constraint of feeder and switch breakdown is not considered. Therefore, the future work for distribution network reconfiguration is to obtain an optimal solution with consideration of safety factor.

- In the short-term operation of distribution network, the future work can be the computation actual load forecast algorithm.
- In the long-term planning of distribution network, the future capital costs and DG re-installation cost are assumed to be deterministic, however, in future research, these factors can be considered in the optimal planning of the distribution network.

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