Distribution System Planning with Distributed Generation: Optimal versus Heuristic Approach

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.

I understand that my thesis may be made electronically available to the public.

Abstract

Distribution system design and planning is facing a major change in paradigm because of deregulation of the power industry and with rapid penetration of distributed generation (DG) sources. Distribution system design and planning are key features for determining the best expansion strategies to provide reliable and economic services to the customer. In classical planning, the load growth is typically met by adding a new substation or upgrading the existing substation capacity along with their feeders. Today, rapid advances in DG technology and their numerous benefits have made them an attractive option to the distribution companies, power system planners and operators, energy policy makers and regulators, as well as developers.

This thesis first presents a comprehensive planning framework for the distribution system from the distribution company perspective. It incorporates DG units as an option for local distribution companies (LDCs) and determines the sizing, placement and upgrade plans for feeders and substations. Thereafter, a new heuristic approach to multi-year distribution system planning is proposed which is based on a back-propagation algorithm starting from the terminal year and arriving at the first year. It is based on cost-benefit analysis, which incorporates various energy supply options for LDCs such as DG, substations and feeders and determines the size, placement and upgrade plan. The proposed heuristic approach combines a bi-level procedure in which Level-1 selects the optimal size and location of distribution system component upgrades and Level-2 determines the optimal period of commissioning for the selected upgrades in Level-1. The proposed heuristic is applied to a 32-bus radial distribution system. The first level of the distribution system planning framework is formulated as a mixed integer linear programming (MILP) problem while the second level is a linear programming (LP) model. The results demonstrate that the proposed approach can achieve better performance than a full optimization for the same distribution system.

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NOMENCLATURE

Sets and Indices

i, j	Index for buses
N	Set of buses in distribution system
SS	Subset of buses with substation
t, t'	Year
T	Overall planning horizon ($t \in T$)

Parameters

BL	Budget limit ($)
C_t^{Ex}	Price received for exported energy ($/MWh)
$C_t^{DG.f}$	Capital cost of DG unit ($/MW)
$C_t^{Fdr.f}$	The engineering, procurement, and construction (EPC) cost of feeder ($)
$C_t^{SS.f}$	EPC cost of substation ($)
$C_t^{DG.r}$	Operating cost of DG ($/MW)
C^{Un}	Cost of unserved power ($/MW)
$C_t^{Fdr.v}$	Variable component of capital cost of feeder ($/MW)
$C_t^{SS.v}$	Variable component of capital cost of substation ($/MW)
Ge	Geograghic cost factor of feeder between i and j
Le	Length between i and j (km)
Lf	Estimated loss factor on feeder between i and j
Ny	Number of years in a planning horizon
M	Big number (for MIP model)
Pd_t	Active power demand (MW)
$P_{i,t}^{DGCap}$	DG capacity limit (MW)
$P_i^{DG.ini}$	Initial DG unit size (MW)

P^{DG_MAX}	Maximum DG unit size (MW)
$P_{(i,j),t}^{Fdr_{Cap}}$	Existing feeder capacity (MW)
$P_{i,t}^{SS_{Cap}}$	Existing substation capacity (MW)
R	LDC's discount rate (%)
Rs	Reserve margin (% of demand)
ρ	Electricity market price ($/MWh)

Variables

$P_{i,t}^{DG}$	Power generated from DG (MW)
$P_{i,t}^{Ex}$	Power export to grid (MW)
$P_{(i,j),t}^{Fdr.C.A}$	Capacity added to feeder (MW)
$P_{(i,j),t}^{Fdr}$	Power flow on feeder between i and j
$P_{i,t}^{Im}$	Power imported by the distribution utility (MW)
P_{t}^{SS}	Capacity added to substation (MW)
P_{i}^{Un}	Unserved power (MW)
$z_{(i,j),t}^{Fdr}$	Decision on feeder upgrade (0/1)
$z_{i,t}^{SS}$	Decision on substation upgrade (0/1)

Chapter 1

Introduction

1.1 Motivation

A number of factors are motivating distribution system planners to determine optimal expansion strategies to serve the load growth and provide their customers with reliable and economical services. Deregulation of the power sector has incentivized the planners to examine the economical and technical feasibility of new energy supply alternatives such as distributed generation (DG). Furthermore, advancements in DG technologies have made them feasible and an attractive option for the planners. In addition, the use of renewable and clean DG technologies have numerous benefits to the environment.

Among the various possible benefits of DG, some of the significant ones are environmental sustainability, reduced need of constructing new transmission lines and large power plants, improvement in power quality and reliability, reduced line losses and network congestion. DGs also have the potential to increase competition in generation, which can lead to better service and low energy price.

In recent years, penetration of DG into distribution systems has been increasing around the world. For instance, in the United States, demand growth combined with plant retirements is projected to require as much as 1.7 million GWh of additional electrical energy by 2020, almost twice the growth of the last twenty years. Over the next decade, the United States DG market, in terms of installed capacity to meet the demand, is estimated to be 5 to 6 GWh per year. Worldwide forecasts show electricity consumption increasing from 12 million GWh in 1996 to 22 million GWh in 2020, largely due to demand growth in developing countries. The projected embedded and renewable DG capacity increase associated with the global market is conservatively estimated at 20 GW per year over the next decade [1]. Table **1.1** summarizes the drivers and the policy regulations of DG in different countries, including a summary of regional renewable DG developments [1].

In Canada, widespread integration of DG and wind energy is still in the initial stage. However, changes in provincial and federal policies, together with new technological developments suggest that wind and DG will likely play an increasingly important roles in the future. For instance, in the province of Quebec alone, over 3000 MW of wind capacity will be integrated by 2013 [2]. In Ontario, demand growth and generation retirement will create a gap of 24,000 MW by 2025. This is equivalent to almost 80% of the current system capacity [3].

The Integrated Power System Plan (IPSP) for Ontario [90], developed by the Ontario Power Authority (OPA) every three years, is designed to assist, through the effective management of electricity supply, transmission, capacity and demand, the achievement of the government of Ontario's goals. The current IPSP, covering the next 20 years, emphasizes the development of clean and renewable energy sources and the phasing out of several major polluting coal-fired power plants [4]. The OPA submitted its supply mix recommendation to the Ministry of Energy highlighting the best way to meet electricity needs over the long term. According to this advice, the capacity of renewable resources would be increased to 37% of the total installed capacity in 2025. This capacity is expected to provide Ontarians with 47% of their electricity needs. Wind power is expected to be a significant part of Ontario's supply mix, representing 15% of the total installed capacity by 2025 [3]. A comparison between the 2005 and the proposed 2025 supply mix is presented in Figure **1.1** [5].

Table 1.1: DG drivers and development in various countries [1].

	Criteria	Geographies and countries									
		Australia	North America		South America	Europe		Asia			
			USA	Canada	Brazil	Germany	Spain	Japan	India	China	Korea
Drivers of DG	Low level of investment	•	•	•	•	•	•	•	•	•	•
	Flexible location sitting in underserved or hard to reach areas	•	•	•	•				•	•	•
	Bill saving at the time of high pricing	•	•	•	•	•	•	•		•	•
	Load balancing and peak reduction	•	•	•	•	•	•	•	•	•	•
	Surplus electricity production at customer site	•	•	•	•	•	•	•	•	•	•
	Generation capacity reduction due to deregulation			•	•			•	•	•	•
	Energy security and decreased dependency on fossil fuels	•	•	•	•	•	•	•	•	•	•
	Green alternatives	•	•	•	•	•	•	•	•	•	•
	Economic growth	•	•	•	•	•	•	•	•	•	•
	Resource availability at large to commercialize renewable DG technologies				•		•	•	•	•	•
	Renewable DG business and new market development opportunity ownership	•	•	•		•	•				
Geography Specific Details		Australia has been a world leader in the implementation of remote area power supply systems; they currently represent best practice in the existing deployment of DG technologies.	The United States and Canada are the countries with high energy consumption per capita. The US becomes the global leader in 2008, with 24 billion invested in DG renewable, or some 20% of the global total.		South America ranks third in predicted growth rate (2.8%) of energy consumption for the period of 2003-2030. Brazil constitutes the largest part of this demand at 38%.	DG and renewable energy sources have attracted special attention in Europe to increase the security of energy supplies and reduce the emission of greenhouse gases, with high planned investment in DG resources.		The highest annual growth of energy consumption between 2003 and 2030 is predicted for Asia (3.7%). Japan has plans to increase its total energy ratio to 1.6% by 2014 with the use of DG applications. In India, renewable energy solutions for DG and stand-alone systems are envisaged for supplementing rural, urban, industrial and commercial energy requirements. China plans to develop 120,000 MWs of renewable energy by 2020. Korea supplied 2.4% of total energy consumption with new and renewable energy (NRE) in 2009 and will increase the ratio of NRE generation out of the entire energy generation from current 2.4% to 11% by 2030.			

To achieve the former, two offer programs , developed by the Ontario Energy Board (OEB) and OPA, was introduced. The first program is feed-in tariff or FIT Program which is North America's first comprehensive guaranteed pricing structure for renewable electricity production. The FIT Program was enabled by the Green Energy and Green Economy Act, 2009 which was passed into law on May 14, 2009. It offers stable prices under long-term contracts for energy generated from renewable sources [6]. The second program is the microFIT program which is a stream of the OPA Feed-in Tariff (FIT) program for renewable energy in Ontario. It is intended to encourage the development of micro scale renewable energy across the province [7].

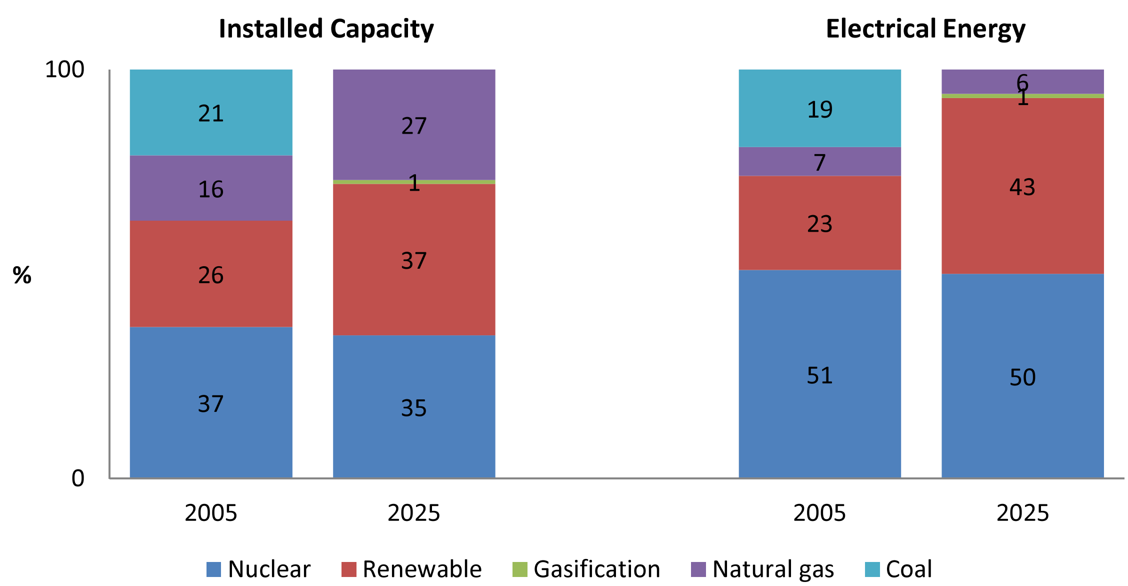

Figure 1.1: Ontario supply mix [5].

Finding a precise and cost-effective method for distribution system design and planning is one of the objectives of this thesis. The planning process has to be applicable for distribution systems. It should consider DG units as well as conventional and other nonconventional options providing the size, placement and upgrade plan.

The motivation of this thesis is to investigate the sizing, placement and upgrade plan for various energy supply options for LDCs such as DG, substations and feeders in radial distribution systems.

1.2 Background

1.3 Distribution Systems

The bulk electric power systems can be divided into generation, transmission, sub-transmission and distribution. Traditionally, generation is to supply the power to the transmission system which can be defined as the carrier of power from the generating stations to the sub-transmission system, at voltage levels of 230 kV or higher. The sub-transmission system then transfers the power at voltage levels between 69 kV – 138 kV to the distribution systems. Finally, the distribution system, at voltages typically under 34.5 kV, delivers electricity to the consumer [8]. Figure **1.2** illustrates a typical bulk electric power system.

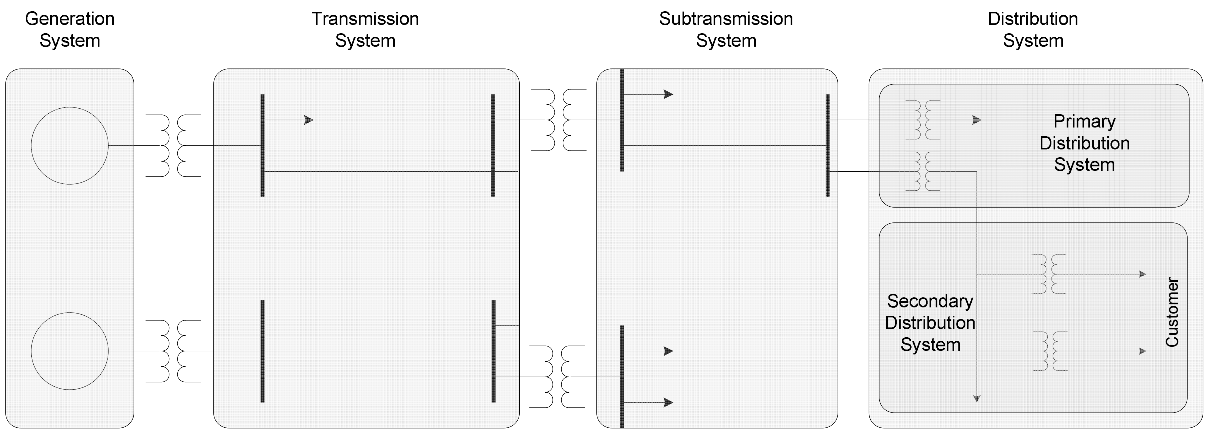

Figure 1.2: Basic power system structure.

The distribution system can be divided into primary and secondary systems. The primary distribution system consists of distribution substations and feeders. The distribution substations step down power from the sub-transmission system to between 34.5 kV and 4.16 kV. The primary distribution main feeders branch out from the substation and then lateral feeders to serve local areas. From the lateral, distribution transformers step the voltage down again to the secondary level at which most customers are served, generally at 120/240 V and 480 V.

1.3.1 Configuration

An important characteristic of distribution systems is their configuration, or how their lines are connected. There are three common configurations of distribution systems: radial, loop and network [9].

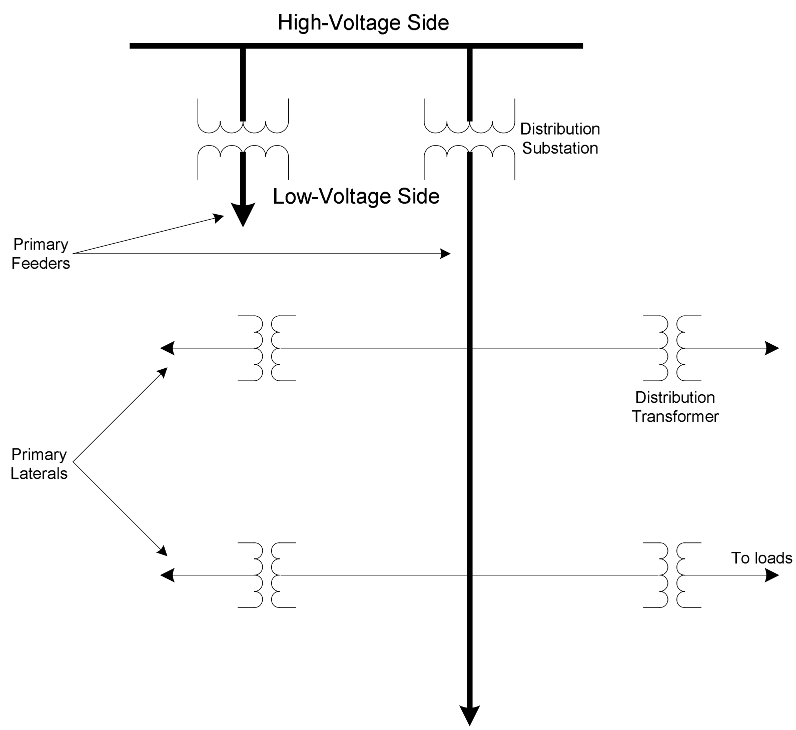

Figure 1.3: Radial Distribution System [9]

In radial configurations lines branch out sequentially and power flows in one direction, as shown in Figure **1.3**. It has the lowest capital cost; however, it also has the lowest reliability, since any faults in the feeders will cause service interruptions at all points downstream. In a network configuration, it is more interconnected meaning that any two points are usually connected by more than one path and some lines form loops within the system. A networked system is generally more reliable because there exists more than one path for the power to flow, if a line fails. Economically, the cost of a network system is the highest because of its numerous feeders with associated protection and control systems. Figure **1.4** shows a network configuration of a distribution system. Loop configured distribution systems fall in between the two in terms of cost and reliability. As shown in Figure **1.5**, loop configuration can be described as two radial systems separated by a normally open switch, a failure of one of the two substation transformers the switch can be closed and one section of the distribution system energized through the other.

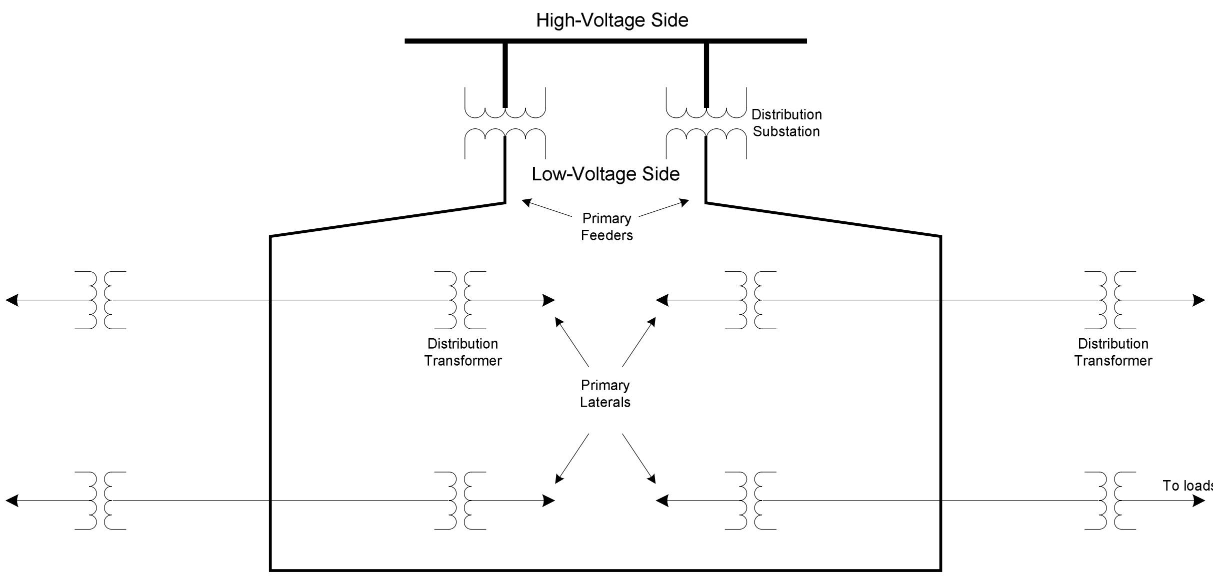

Figure 1.4: Distribution System - Network configuration [9]

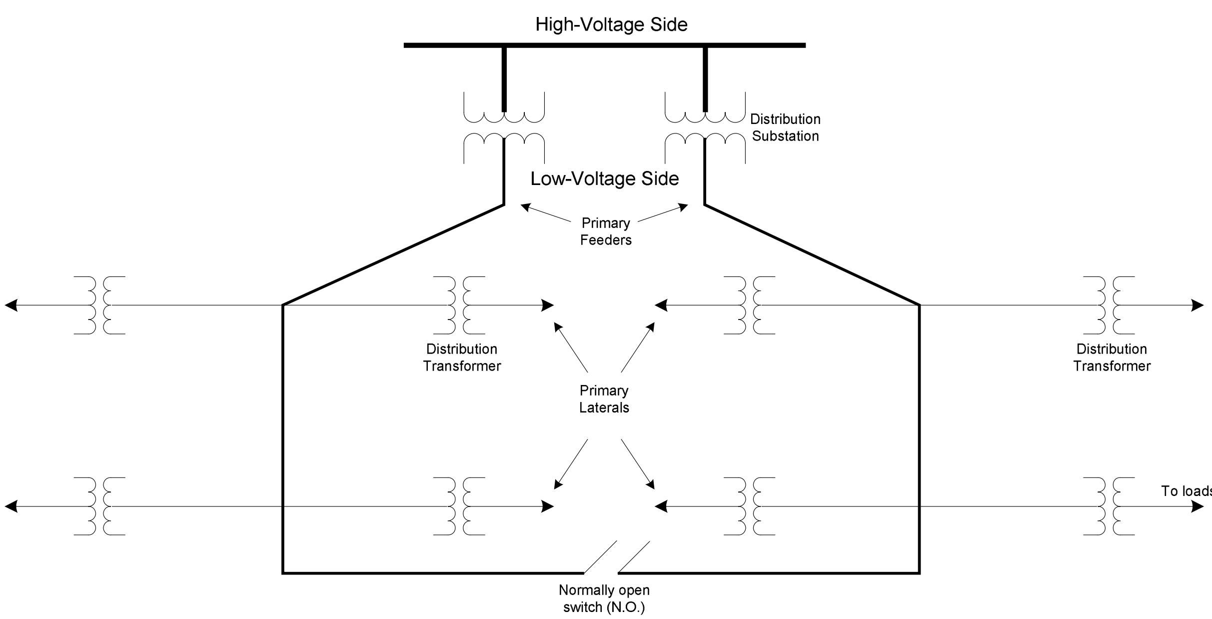

Figure 1.5: Distribution System - Loop Configuration [9]

Distribution system design and planning is facing a major change in paradigm due to deregulation of the power industry, policy changes and advancements in DG technologies. A proper distribution system design and planning is the key to determining the best expansion strategies to provide reliable and economic services to the customer. In classical planning, the load growth typically is met by adding a new substation or upgrading the existing substation capacity along with their feeders. Today, the rapid advances in DG technology and their numerous benefits have made them an attractive alternative to the distribution companies in their planning tasks [10].

1.4 Distributed Generation

DG can be defined as "electric power generation within distribution networks or on the customer side of the network" [11]. From an environmental prospective, use of renewable energy reduces emissions as well as help in avoidance of construction of new transmission lines and large power plants. DG units can also have a beneficial impact on power quality and reliability such as improved voltage profile, reduced line losses and network congestion [12]. DGs also have the potential to increase competition in generation which will lead to better service and low energy price. Another incentive for the penetration of renewable energy based DG sources is Feed-in-Tariffs (FIT) paid by regulators to achieve their goals of meeting electricity demand with clean or renewable energy resources [12].

Two main classifications of DGs are proposed in [11]. The first classification is based on unit capacity which ranges from 1 kW photo voltaic cells, 1 MW engine generators to 1000 MW offshore wind farms [12]:

- Micro DG: 1 W - 5 kW
- Small DG: 5 kW - 5 MW
- Medium DG: 5 MW - 50 MW
- Large DG: 50 MW - 300 MW

The second classification is based upon unit technologies which are renewable, modular or combined heat and power (CHP). DG units based on renewable energy resources can be readily replenished and are viewed as ‘environmentally friendly’. Modular DG refers to units that can be built and placed within a short time span and can be operated together (as distinct units) to meet larger output requirements. All DG units are regarded as modular in this thesis. Combined heat and power (CHP) units generate usable process heat as well as electric power.

1.5 Objectives of the Thesis

The main objectives of the thesis are outlined as follows:

- To examine the local distribution companies (LDC’s) long term planning task taking into account DG unit options, and to propose a comprehensive planning framework that will assist in understanding the role of DG and the impact it has on the distribution system.
    - The planning framework incorporates traditional planning elements, including the optimal sizing, placement, and upgrading of feeders and substations.
    - DG units are included as possible options to address the complex issues arising from the deregulated environment.
- To propose a new heuristic optimization approach for multi-year distribution system planning based on back-propagation of the planning process starting from the terminal year. Hence compare the plan with the optimization based solution.
- Compare and examine the impact of external factors, such as market prices, and demand on the LDC’s plan.
- To examine and compare the computational burden of the optimal planning model vis-à-vis the heuristic approach.

1.6 Thesis Outline

A review of literature on research pertaining to the topics of this thesis is presented in Chapter 2, covering two main topics as follows. The first topic covers distribution system including distribution system configurations, characteristics, planning and some of the recent developments in distribution system planning in deregulation. The second topic covers DGs including DG types, benefits and optimal DG placement and sizing methods.

Chapter 3 presents a comprehensive planning framework for the distribution system from the distribution company perspective with DG units. The mathematical model is described in details. Then, it is applied to the 32-bus radial distribution system and the detailed plan results have been successfully demonstrated. Finally, the sensitivity of the results to changes in energy prices and the demand are investigated.

Chapter 4 presents a new heuristic approach for multi-year distribution system planning. The proposed approach is based on a back-propagation algorithm starting from the terminal year and arriving at the first year incorporating various energy supply options for LDCs such as DG, substations and feeders and hence determines the size, placement and upgrade plan. The proposed approach is based on cost-benefit analysis to identify the most beneficial upgrade plan for DG units, substation and feeders. The proposed heuristic combines a two-level procedure. The sensitivity of the results to changes in energy prices is investigated. The results demonstrate that the proposed approach can achieve better performance than a full optimization for the same distribution system.

Finally, Chapter 5 concludes with a summary of the research in this thesis, contributions, and directions for future research.

Chapter 2

Modern Distribution System Planning: A Review

2.1 Modern Distribution System Planning

Distribution system design and planning problems have been studied and researched since the very beginning. However, these problems have faced a major change in paradigm over the past decade due to deregulation of the power industry, policy changes and advancements in DG technologies. In the beginning, the research focused on traditional planning problems such as the placement of substations and routing of feeders to minimize costs and losses to the LDC. Since then, the research has advanced keeping in step with the changes in the tools available to researchers, changes to distribution systems, advancement in technology and changes in policy. This section discusses various proposals for optimal distribution planning in the deregulated environment.

Nahman et al., in [13], presents an optimization method for radial distribution network planning based on a combination of the steepest descent and the simulated annealing approaches. The optimization procedure starts by applying the steepest descent approach continued by applying the method of simulated annealing. The method takes into account the capital recovery, energy loss and undelivered energy costs.

In [14], a long-term optimization approach to distribution systems planning for existing system configurations is presented. It allows substation, feeder, and DG upgrades while accounting for line limits, technology limitations, varying energy prices, environmental (emissions) limits, and zoning restrictions.

In [15], a probabilistic reliability model is used to determine the optimal DG locations and sizes. The paper concludes that while DG addition is the most expensive alternative, it could become a cost-effective solution, with the right generator size and distribution capital deferral credit.

In [16], a multi-objective model for placing DG under load uncertainty is proposed where minimization of economic cost (including investment, operation cost of DG units and cost of losses), technical risks (including risks of voltage and loading constraints violation) and economic risks (due to the uncertainty in the electricity price) are considered. The output of the algorithm is a set of Pareto-optimal multi-objective DG placement solutions and the planners select the most satisfactory Pareto-optimal solution on the basis of their experience.

Singh et al. [17], considers a multi-objective performance index-based size and location determination of distributed generation in distribution systems. While most of the studies assumed a constant power (real and reactive) load model, Singh et al. examined the use of different load models, finding that the choice of models has a significant impact on the optimal planning of DG. The proposed technique is based on genetic algorithm (GA).

In [18], a multi-objective problem is solved to determine the placement and sizing of DG resources into existing distribution networks. The procedure, based on the application of GA, allows the planner to decide the best compromise solution toward his particular requirements. The cost of network expansion, cost of power losses, cost of served and unserved energy are included in the objective function.

Two methods for the planning of DG units are proposed by El-Khattam et al [19, 20]. The first method [19] presents a heuristic approach to DG investment planning from the perspective of a LDC. The notion of benefit-to-cost ratio is used to select the set of DG units with a net benefit. The mathematical objective function includes investment and operating costs, energy import costs, unserved power costs, and losses. However, this model only incorporates DG units and does not include other distribution system components nor incorporates planning over time. The second model [20] uses the same concepts but with the use of binary variables. However, This model allows the planners to upgrade substations and feeder capacity and does not incorporate the planning over time.

While the previous models have been proposed, with particular emphasis on DG placement and sizing, Wong et al. in [21, 22], proposed a planning model to examine the policies related to deregulation. In [21], a distribution system planning model that is suitable for examining the impact of regulatory policies on DG unit investments is presented. By examining these investments, it is possible to determine the effects of the policies on long-run energy dispatch and purchases and thus predict the role the policies play on distribution system economics and environmental emissions. In [22], a method for coordinating the approval process of DG proposals submitted by multiple, competing, private investors to achieve maximum investor participation while complying with the technical operational limits of the local distribution company. The proposed model utilizes a feedback mechanism between the LDC and Private investors to maximize their participation and the penetration of DG-units into the distribution system.

2.2 Distributed Generation

Several benefits can be obtained when DG unit is correctly integrated. As identified by Lopes et al. in [12], the main drivers behind the rapid growth of DG units, are:

- Environmental sustainability drivers

  One of the main drivers behind the growth of DG units is the use of renwable energy and CHP in order to limit green house gas (GHG) emissions by the use of renewable energy. Another important driver for DG from the environmental perspective is the avoidance of construction of new transmission lines and large power plants.

- Commercial drivers

  In competitive market environment and the uncertainty associated with it, small capacity generations are preferred. Another commercial driver is that DG units can have a beneficial impact on power quality and reliability such as improve voltage profile, reduce line losses and reduce network congestion since it is distributed around the network close to customers.

- Regulatory drivers

  From the policy makers prospective, diversifying the energy sources will enhance energy security. For example, the failure of a small generation has limited impact compared to failure of one large power plant or bulk electricity transmission facility. Moreover, it will support the competition policy which will lead to low energy prices and better service.

2.2.1 DG Planning

DG planning is the process of optimizing DG type, size and/or location in order to achieve a set of objectives and subject to a set of constraints. This problem has nonlinear equality constraints which are the power flow equations. It also includes some nonlinear optimization objectives, such as line loss minimization. This optimization problem can be dealt with using two approaches. The first is to apply some assumptions in order to simplify the formulation of the problem. In this way, the optimization problem can be tackled using traditional mathematical programming methods, for which powerful programming methods are available (e.g. Linear Programming). The second approach is based on the use of heuristic optimization techniques, such as Evolutionary Algorithms (EA). Such techniques enable more detailed modeling of the time-variability of DG [23].

Recently, diverse methods for optimizing the location, size and/or type of DG have been proposed, with particular emphasis on DG placement and sizing. Such optimization methods can be summarized into two categories. The first group of DG planning methods focuses on the optimization of a single objective. One of the most common objectives found in literature is the minimization of line losses (e.g. [24]). Other single-objective DG planning approaches focus on the minimization of total cost [25]. Cost can be aggregated from different points-of-view. Hence, these techniques formulate the problem either from the perspective of a DG developer or from the perspective of a distribution system operator [23]. These methods are based on the use of traditional mathematical optimization techniques and genetic algorithms.

The second group of the proposed DG planning optimization techniques is a multi-objective DG planning methods (e.g. [16-18]). Hence, planning objectives can be formulated from different perspectives such as the DG developer, the LDC, or the regulator. The solution methods of multi-objective problems to are divided into two main types [26]. The first type makes use of single-objective techniques and the solution set is identified by changing the master objective iteratively. The weighted-sum method is one of the most common methods of this type [26]. The second type of multi-objective optimization methods is based on Evolutionary Algorithms e.g. [18] and [26].

To the best of our knowledge, there has been a few works on planning distribution network, bridging the gap between traditional distribution planning frameworks and methods for siting DG within the distribution system.

2.3 Concluding Remarks

In this chapter an attempt has been made to discuss and review some of the published literature on distribution system planning. In the first section a brief background of electric power system and distribution system including distribution system configurations and their characteristics is presented. In the second section a brief background of conventional distribution system planning is presented, followed by a review and summary of some of the published recent developments in distribution system planning in deregulation. Thereafter, a brief background of DG types, benefits and optimal DG placement and sizing methods are presented. The last section discusses the few recent publications that are related to the presented work.

Chapter 3

Multi-Year Distribution System Planning with Distributed Generation

3.1 Introduction

As described in Chapters 1 and 2 distribution systems design and planning is facing a major change in paradigm due to the deregulation of the power industry and with the rapid penetration of DG sources. A proper distribution system design and planning is the key to determining the best expansion strategies to provide reliable and economic services to the customer.

In this chapter, a comprehensive planning framework for the distribution system from the distribution company perspective is presented. It incorporates DG units as an option for LDCs and determines the sizing, placement and upgrade plans for feeders and substations.

In Section 3.2, the mathematical modeling of the optimization framework is described. This is followed by the description of 32-bus radial distribution system and the computational details in Sections 3.3 and 3.4 respectively. The detailed plan studies and results considering a 32-bus radial distribution system are presented in Section 3.5 including utility investment plan, operation and production plan, voltage profile and the sensitivity analysis. Finally, a summary of this chapter will be presented in Section 3.6**Error! Reference source not found.**.

3.2 Mathematical Formulation

In this section the mathematical model for distribution system planning is presented. This model is solved to obtain the optimal plan.

3.2.1 Objective Function

The proposed objective function (3.1) aims to minimize the present value of the total investment and operating cost of the LDC. The second line of (3.1) is the capital and operating cost of the candidate DG units. The third line includes the engineering, procurement, and construction (EPC) cost and the variable component of the capital cost to upgrade the substation, payment toward purchased power by the LDC and the revenue earned by the LDC for power export to the grid via substation, net of the imports. The fourth line is the EPC cost and the variable component of the capital cost to upgrade the feeders. The mathematical formulation is described in (3.1) as follows:

$$J = \min \sum_{t=1}^{T} \Big(\frac{1}{\left(1 + R\ \right)^{t}} \Big($$

$$\sum_{i \epsilon N} \left(C_t^{DG.f} .\ P_{i,t}^{DG_{Cap}} + C_t^{DG.r} . P_{i,t}^{DG} \right)$$

$$+ \sum_{i \epsilon SS} \left(C_t^{SS.f} . z_{i,t}^{SS} + C_t^{SS.v} . P_t^{SS} + \rho . P_{i,t}^{Im} - C_t^{Ex} . P_{i,t}^{Ex} \right)$$

$$+ \sum_{i,j \epsilon N : \exists (i,j)} \big(C_t^{Fdr.f} .\ Ge .\ Le .\ z_{(i,j),t}^{Fdr} + P_{(i,j),t}^{Fdr.C.A} .\ C_t^{Fdr.v} \big)\big)\big) \quad \textbf{3.1}$$

The associated operational and planning constraints are discussed next.

3.2.2 Nodal power balance

The algebraic sum of all incoming and outgoing power over the LDC feeders and the power generated from DG units should be equal to the total demand including reserve margin at the bus, net of unserved power. Feeder losses are approximated by a loss factor and are accounted for, in the incoming power flow direction at the bus.

$$\sum_{i,j\epsilon N:\exists(i,j)} (1-Lf).P^{Fdr}_{(j,i),t} - P^{Fdr}_{(i,j),t} + P^{Im}_{i,t} - P^{DG}_{i,t} + P^{Ex}_{i,t} = (1+Rs).Pd_t \qquad \forall i \,\boldsymbol{\epsilon}\, N, t \,\boldsymbol{\epsilon}\, T$$

3.2

3.2.3 Feeder capacity limits

Power flow on any distribution feeder must comply with the thermal capacity limit of the feeder. This limit also takes into consideration the new investments in feeder upgrade.

$$P^{Fdr}_{(i,j),\boldsymbol{t}} \leq \sum_{t'=1}^{t} (P^{Fdr_{Cap}}_{(i,j),t'} + P^{Fdr.C.A}_{(i,j),t'} + P^{Fdr.C.A}_{(j,i),t'}) \qquad \forall (i,j)\epsilon N: \exists (i,j), t \,\epsilon\, T$$

3.3

$$P^{Fdr.C.A}_{(i,j),t} \leq M \,.\, z^{Fdr}_{(i,j),t} \qquad \forall (i,j)\epsilon N: \exists (i,j), t \,\epsilon\, T$$

3.4

3.2.4 Substation capacity limits

Substation capacity constraints (3.5), (3.6) and (3.7) ensure that the total power delivered by the substation over the outgoing distribution feeders and the total exported power by the substation must be within the substation capacity limit. These limits take into consideration the new investments in substation upgrade.

$$P^{Im}_{i,t} \leq \sum_{t'=1}^{t} (P^{SS_{Cap}}_{i,t'} + P^{SS}_{i,t'}) \qquad \forall i \,\epsilon N, t \,\epsilon\, T$$

3.5

$$P^{Ex}_{i,t} \leq \sum_{t'=1}^{t} (P^{SS_{CAP}}_{i,t'} + P^{SS}_{i,t'}) \qquad \forall i \,\epsilon N, t \,\epsilon\, T$$

3.6

$$P_{i,t'}^{SS} \leq M\ .\ z_{i,t}^{SS} \qquad \forall i\ \epsilon N, t\ \epsilon\ T$$

3.7

3.2.5 DG capacity limits

The power generated by a DG unit must be less than its initial capacity and any upgrade, in (3.8). Eq. 3.9 limits maximum size of DG.

$$P_{i,t}^{DG} \leq P_i^{DG.ini} + \sum_{t'=1}^{t} P_{i,t'}^{DG\_Cap} \qquad \forall i\ \epsilon N, t\ \epsilon\ T$$

3.8

$$\sum_{t}^{T} P_i^{DG.ini} + P_{i,t}^{DG\_CAP} \leq\ P^{DG\_MAX}$$

3.9

3.2.6 Budget limits

This constraint imposes a limit on how much capacity the LDC can invest in over the plan period. The first term is the capital cost of DG units. The second term is the EPC cost and the variable component of the capital cost to upgrade the substation. The third term is the EPC cost and the variable component of the capital cost to upgrade the feeders. The total capital expenditure of the distribution company is constrained to be within the budget limit.

$$\frac{1}{(1+R)^t}($$

$$\sum_{i\epsilon N} C_t^{DG.f} . P^{DG_{CAP}}$$

$$+ \quad \sum_{i\epsilon SS} \left(C_t^{SS.f}\ . z_{i,t}^{SS} + C_t^{SS.v} . P^{SS}\right)$$

$$+ \sum_{i,j \epsilon N:\exists(i,j)} (C_t^{FDR.f}.Ge.Le.z_{(i,j),t}^{fdr} + P^{FDR}.C_t^{FDR.v})) \leq BL_t \qquad \forall t \epsilon T$$

3.10

3.3 Description of Radial Distribution Test System

The proposed model presented in Section 3.2 is applied to the 32-bus radial distribution system shown in Figure **3.1**[14]. The system comprises 32 buses, split among four branches with a grid-connected substation at bus-1. The total system peak demand is 37 MW in year-0 and assumed to grow 3% annually. Each feeder segment is 1 km long, has geographic cost factor (Ge) of 0.4, and a loss factor of 2% [27]. Table 3.1 provides the assigned investment costs of the resources available to the LDC. The cost of generation from gas turbine DG units, market price, and export price through substation are given in Table 3.2. A budgetary limit on annual capital expenditures by the LDC of $10M is imposed.

Table 3.1: Investment Cost of Utility Resources [27]

Element	EPC Cost		Capital cost	
	Symbol	Cost	Symbo	Cost
Feeder	C_f^{FDR}	$150,000/km	C_v^{FDR}	$1,000/MW
Substation	C_f^{SS}	$200,000	C_v^{SS}	$50,000/MW
Gas Turbine DG	-	-	C_f^{DG}	$825,000/MW

Table 3.2: Price of Electricity From and To Utility Resources

Resource	Price/Cost
Market, ρ	$110/MWh
For Export, C_e^x	$108/MWh
Gas Turbine DG, C_r^{DG}	$75/MWh

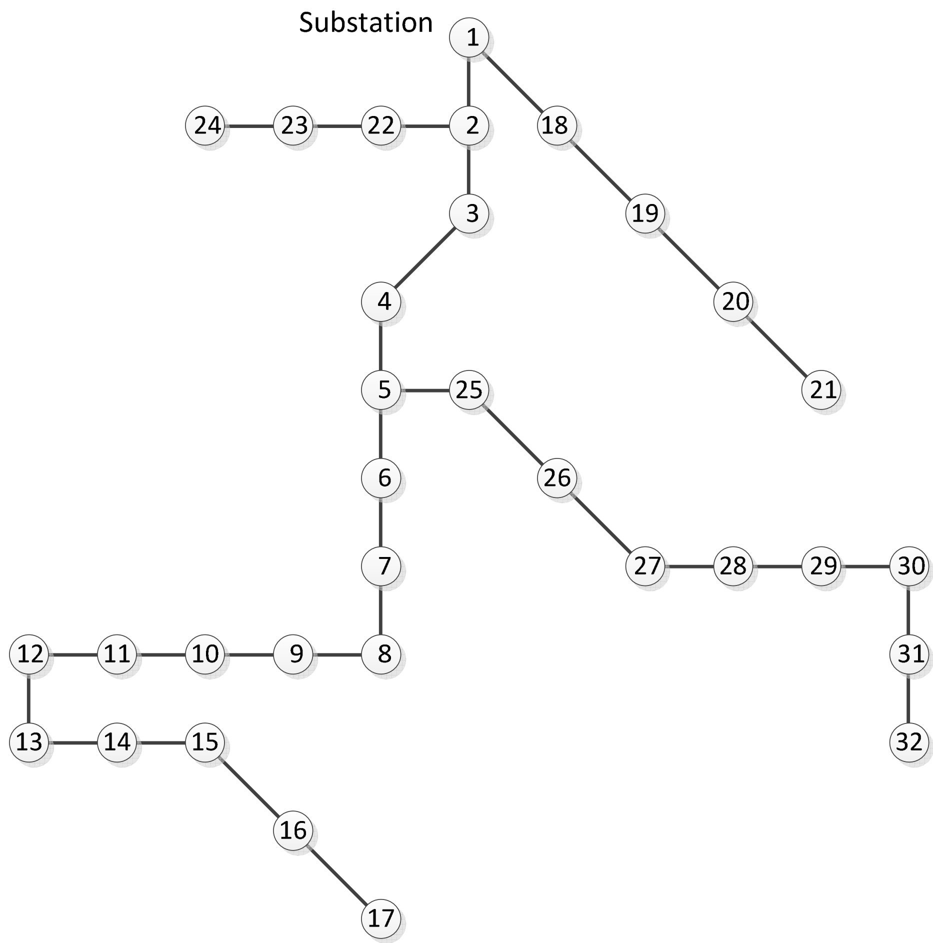

Figure 3.1: 32-Bus Radial Distribution System Configuration [14]

3.4 Computational Details

The considered test system was programmed and executed in the GAMS environment [28]. In order to determine the optimal set of recommendations for a 10-year investment plan, the proposed model is formulated as a mixed integer linear programming (MILP) problem. The model is solved using CPLEX, a powerful Mixed-Integer Programming (MIP) solver. The MIP algorithm is an implementation of a branch-and-bound search with modern algorithmic features such as cuts and heuristics. The MIP optimizer solves large and numerically difficult MIP models[28]. The model and solver statistics are given in Table **3.3**.

Table 3.3: Model Statistics

	FOM
Complexity	MIP
Solver	CPLEX
BLOCKS OF EQUATIONS	24
BLOCKS OF VARIABLES	14
SINGLE EQUATIONS	33,347
SINGLE VARIABLES	32,962
NON ZERO ELEMENTS	171,073
DISCRETE VARIABLES	21,431
MODEL GENERATION TIME (Sec)	0.610

3.5 Test Results

To demonstrate the suitability of the proposed methodology, the 32-bus radial distribution system is considered for the studies (Figure **3.1**). The outcome from this model provides the optimal size, location and period of commissioning of distribution system component upgrades along with DG units.

To examine the suitability of the proposed planning framework, two different cases are considered. The first case is the base case which applies the framework as a distribution system planner, so as to make recommendations on a 10 year investment plan and production schedule. The second case is to examine the sensitivity of the distribution plan to change in the market price and the demand.

3.5.1 Base Case Plan

3.5.1.1 Capacity Investment Plan

Figure 3.2 shows the consolidated optimal investment plan for the distribution system. Feeder segments that are to be upgraded are denoted by the dotted lines. The corresponding distribution system investment plan is given in Table 3.4. It is observed that the 10 year plan emphasizes gas turbine DG investments in year-1 with one feeder upgrade. In later years, substation upgrade is recommended followed by 4 feeder upgrades in order to feed the imported power to the distribution buses by the substation. Note that all the recommended DG investments are placed near the end of feeder branches where they have the most impact on reducing feeder losses.

Table 3.4: Utility Investment Plan

	Investment Size (MW) and Site(Bus)		
Year	Substation	Feeder	DG
1	-	0.5 (16-17)	3.7 (13), 3.3 (17), 2.9 (31), 2 (32)
4	4 (1)	-	-
6	-	2 (2-22)	-
9	-	0.5 (1-18)	-
10	-	1.5 (1-2), 0.5 (22-23)	-

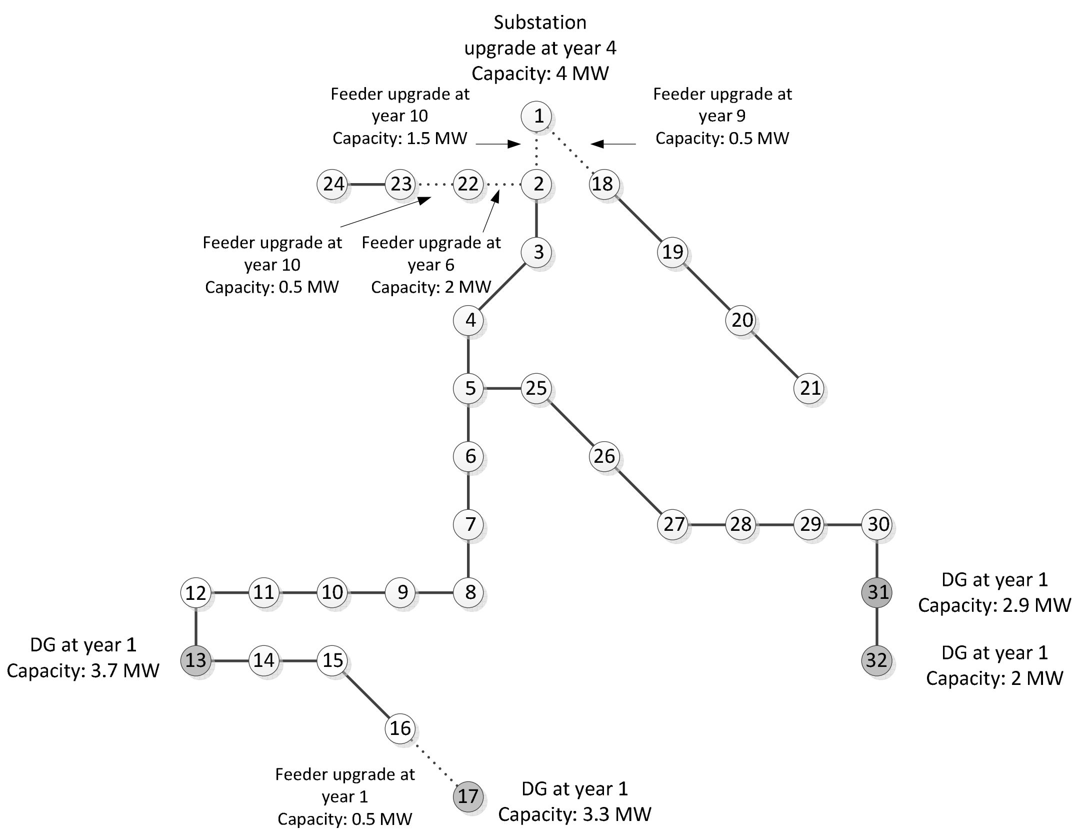

Figure 3.2: Distribution system plan. Dashed lines indicated upgraded feeder segments.

3.5.1.2 Production Plan

Table **3.5** presents the LDC's energy export and import schedules. The schedules are consistent with the resource assets available to it. The DG units are used to their maximum capacity while the substation always has excess capacity available in order to serve the system's energy adequacy requirement.

Table 3.5: Production Schedule of the LDC

Supply Element	Bus	Year/Supply (MW)										
		0	1	2	3	4	5	6	7	8	9	10
Substation (Import)	1	42.31	28.14	29.44	30.79	32.18	33.61	35.08	36.59	38.16	39.76	41.42
Generation from DG units	13	3.7	→	→	→	→	→	→	→	→	→	3.7
	17	3.3	→	→	→	→	→	→	→	→	→	3.3
	31	2.9	→	→	→	→	→	→	→	→	→	2.9
	32	2	→	→	→	→	→	→	→	→	→	2

Figure **3.3** presents the LDC's demand and the imported energy via substation. It can be seen that the imported energy at year-0 is higher than the demand in order to satisfy the demand plus the distribution network losses. In year-1, the imported energy is reduced and become less than the demand. The reduction in the imported energy is due to addition of four DG units which have lower operational cost.

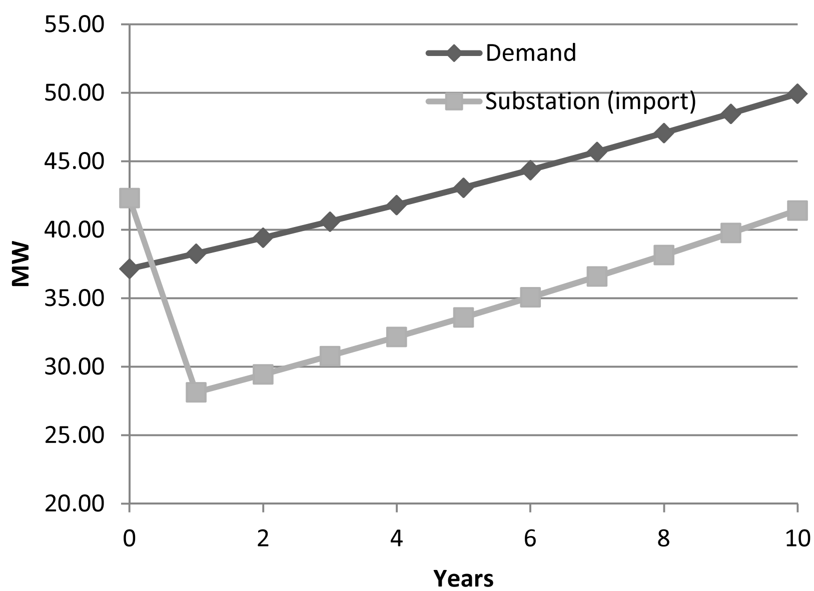

Figure 3.3: LDC's demand and imported energy via substation

3.5.1.3 **Voltage Profile and Losses**

Figure **3.4** shows the voltage profile of the system busses over the planning period. As seen from the figure, bus numbers 18-21 have a better voltage profile in year-0 which means voltage magnitude between 0.99 - 1 (p.u). The reason is that these busses are close to the distribution substation. On the other hand, buses 17 and 32 have the lowest voltage magnitude in year-0 because these are located at the end of the feeders. In year-1, four DG units at busses 32, 31, 17 and 13 are planned to be built which help improve the voltage profile of the distribution system. Similar conclusion may be drawn from Figure **3.5** with respect to system losses. It is to be noted that the system loss is the highest in year-0 before the DG units are installed. The system losses are minimum in year-1 and then increase gradually as system demand increase.

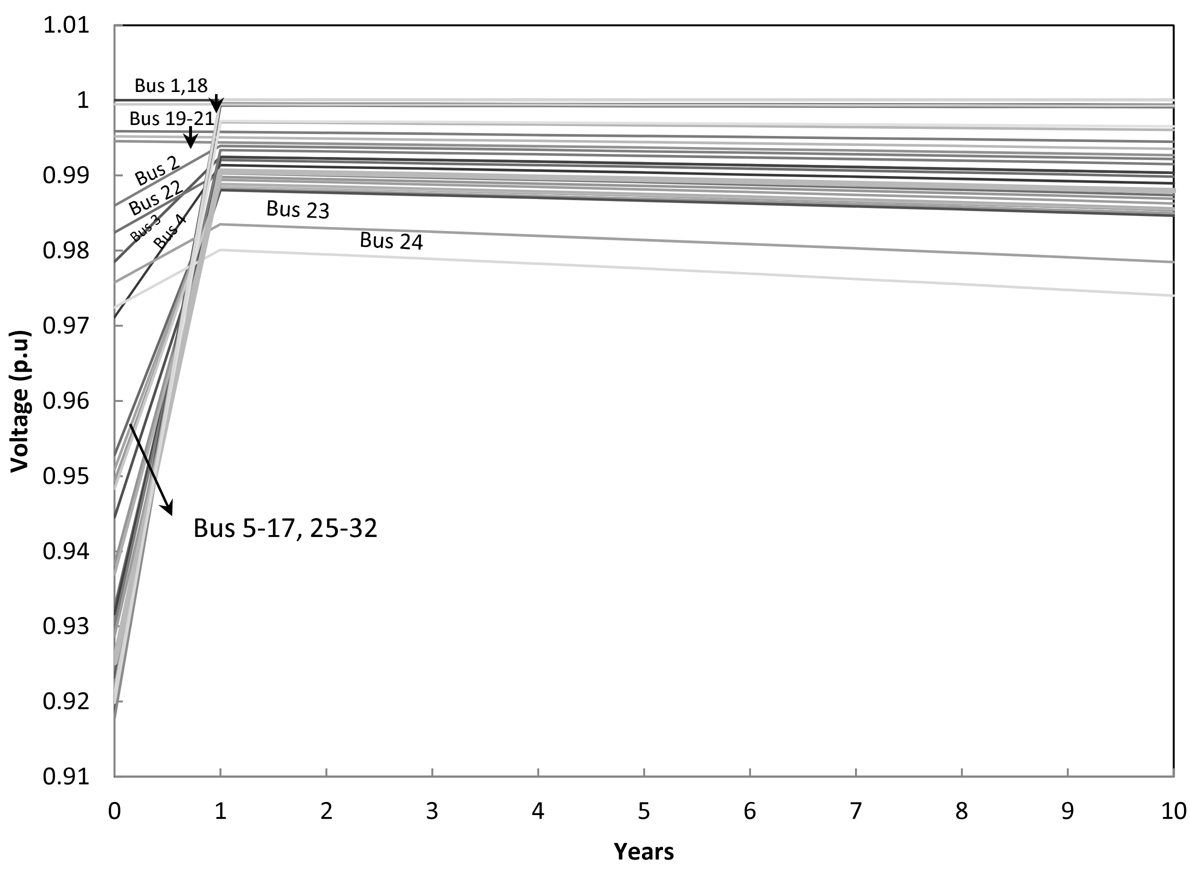

Figure 3.4: Bus voltage profiles over the plan period

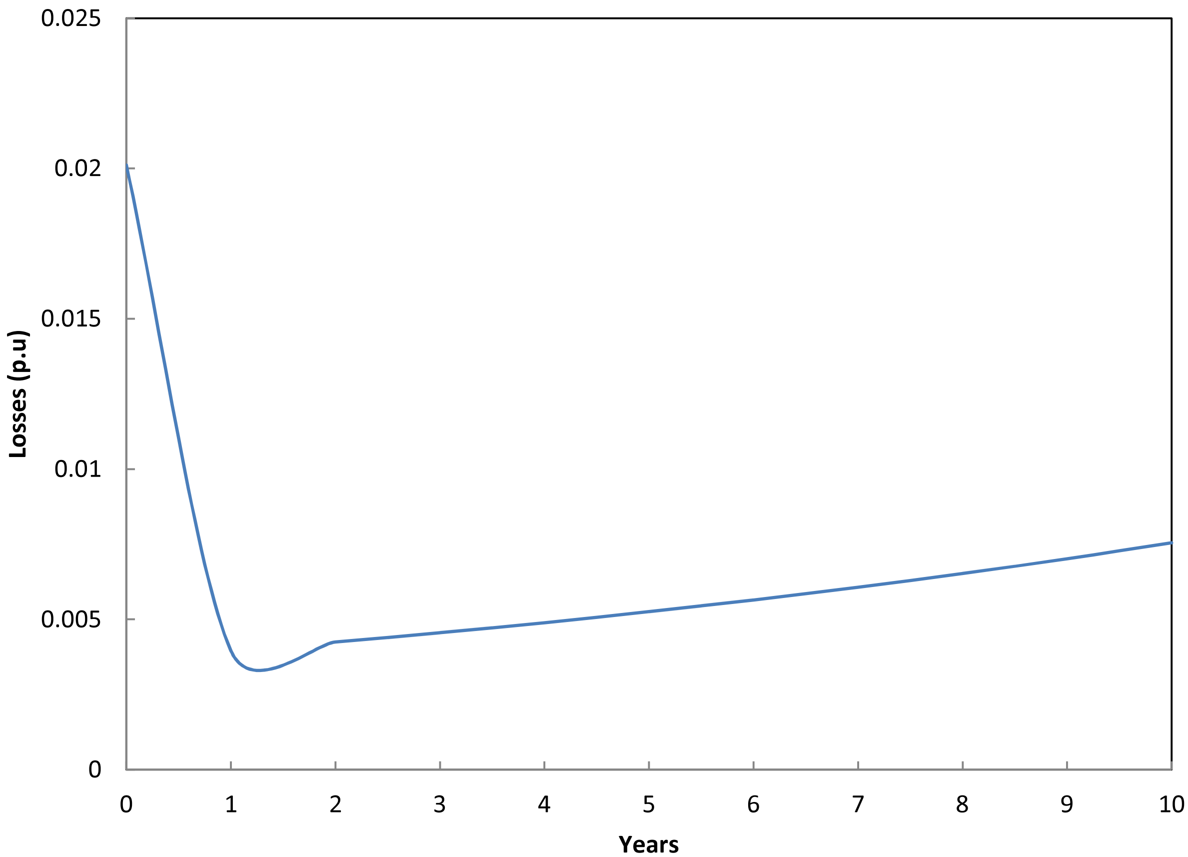

Figure 3.5: Variation of total system losses over the plan period

3.5.2 Sensitivity Analysis

The deregulation of the power industry has introduced high levels of uncertainty in the price of electricity. Therefore, it is important to examine the sensitivity of the plan results to the change in the market price and the demand. Therefore, three different cases are investigated in this section to evaluate the investment and upgrade plan for the distribution system. These cases are discussed as follow:

3.5.2.1 30% Decrease in Electricity Market Base Price

In this case, the electricity market price is reduced by 30% of the base market price. The proposed planning model is executed to obtain the optimal plan decisions that meet the system peak load. At this price, the LDC's net present value of the total cost decreases commensurate with decreasing energy and capital costs. The results of this case are demonstrated in Table **3.6**. The proposed plan outcomes identifies one substation upgrade in the first year followed by twelve feeder upgrades in subsequent years in order to feed the imported power to the distribution buses. It is observed that the plan emphasizes substation upgrade in the first year, which is justifiable given the low market price for electricity. In this case, investment in DG units is not justifiable because of decreased market price compared to operating costs of DG units and hence substation upgrade is recommended. However, it is noted that substation upgrade at this price point is an attractive alternative.

Table 3.6: Optimal plan for 30% reduction in base market price

	Investment Size (MW) and Site(Bus)		
Year	Substation	Feeder	DG
1	15 (1)	12.5 (1-2)	-
2	-	8.6 (2-3)	-
3	-	6.2 (3-4)	-
5	-	4.6 (4-5)	-
6	-	1.7 (2-22)	-
7	-	1.9 (5-6)	-
8	-	0.7 (7-8), 0.2 (15-16)	
9	-	0.3 (1-18)	-
10	-	0.2 (22-23), 0.1 (26-27), 0.1 (29-30)	-

3.5.2.2 20% increase in Electricity Market Base Price

In this case, we assume that the electricity price in the market is increased by 20% of the base market price. Under such a price condition, five DG units and four feeder upgrades are selected by the proposed algorithm (Table **3.7**). At this price, the LDC's net present value of the cost increases, commensurate with increasing energy and capital costs. However, the increased energy costs are mitigated by increased investments in utility DG capacity. The increased DG investments lead to a technically improved system (in terms of losses and voltage profile).

Table 3.7: Optimal plan for 20% increase in base market price

Year	Investment Size (MW) and Site(Bus)		
	Substation	Feeder	DG
1	-	0.5 (16-17)	4.5 (7), 5 (13), 3.5 (17), 5.6 (29), 5.3 (31)
3	-	1.7 (2-22), 0.3 (22-23)	-
6	-	-	-
9	-	0.4 (1-18)	-
10	-	-	-

3.5.2.3 10% Increase in Demand

In this scenario, the demand is expected to increase by 10% of the base case demand. By implementing the proposed approach, four DG units in year-1 and two substation upgrades in years 2 and 8, followed by seven feeder upgrades are selected in order to feed the DG units generation and the imported power to the loads (Table **3.8**). However, it is observed that the increased demand is mitigated by increased investment in DG and substation capacity.

Table 3.8: Optimal plan for 10% increase in base demand

Year	Investment Size (MW) and Site(Bus)		
	Substation	Feeder	DG
1	-	0.5 (16-17)	4.5 (13), 3.6 (17), 2.2 (30), 4 (31)
2	2	-	-
3	-	0.6 (2-22)	-
5	-	1 (1-18), 1.2 (2-22)	-
7	-	1.4 (22-23), 0.3 (23-24)	-
8	4	1.3 (2-22), 0.4 (19-18)	-
9	-	3.3 (1-2), 0.4 (23-24)	-
10	-	-	-

3.6 Concluding Remark

In this chapter, we present a comprehensive planning framework for the distribution system from the distribution company perspective with DG units. The mathematical model is described in detail and it is applied to a 32-bus radial distribution system. The detailed plan results obtained have been successfully demonstrated. The sensitivity of the results to the change in the market price and the system demand are investigated. Three different cases are investigated in order to evaluate the investment and upgrade plan for the distribution system.

Whereas this chapter uses a comprehensive optimization model to find the optimal planning decisions, the next chapter introduces a new back-propagation heuristic approach based on cost-benefit analysis combined with an optimization model to determine the optimal component upgrades for a distribution system.

Chapter 4

A Heuristic Back-Propagation Approach to Multi-Year Distribution System Planning with Distributed Generation[1]

4.1 Introduction

This chapter presents a new heuristic approach for multi-year distribution system planning. The proposed approach is based on a back-propagation algorithm starting from the terminal year and arriving at the first year while incorporating various energy supply options for distribution companies such as DG, substations and feeders and determines the size, placement and upgrade plan. It is based on cost-benefit analysis to identify the most beneficial upgrade plan for DG units, substation and feeders. This chapter is structured as follows:

a) A comprehensive, two stage framework for the long term planning of distribution systems is proposed, bridging the gap between traditional distribution planning frameworks and methods for siting DG within the distribution system. The framework determines parameters for planning considering multiple distribution system elements.

b) A cost-benefit analysis is used to identify the most beneficial upgrade plan for DG units, substation and feeders.

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[1] The work presented in this chapter has been accepted for publication and presented as:
A. Bin Humayd, and K. Bhattacharya, "A Heuristic Back-Propagation Approach To Multi-Year Distribution System Planning With Distributed Generation," in *2010 CIGRÉ Canada Conference on Power Systems: Power System Solutions for a Cleaner, Greener World,* Vancouver, 2010.

c) A novel method for determining the year of commissioning is presented in this chapter. This method, OPTPERIOD, is based on a back-propagation algorithm starting from the terminal year and arriving at the first year.

d) In order to investigate the uncertainty of the energy price, the sensitivity of the results to changes in energy prices and demand is analyzed and presented.

e) To show the effectiveness of the proposed methodology, the results are compared with the results obtained from a a full optimization model for the same distribution system.

In Section 4.2, the mathematical modeling of the optimization model is described. This is followed by the description of the heuristic approach in Section 4.3. The computational details are presented in Section 4.4. In Section 4.5, the proposed methodology is implemented in a 32-bus system and the results are presented including utility investment plan, operation and production plan and the sensitivity analysis. In Section 4.6, the results are compared with the full optimization method presented in Chapter-3 to demonstrate the effectiveness of the proposed methodology. Finally, conclusions are drawn in Section 4.7.

4.2 Mathematical Model

In this section the generic mathematical model for distribution system planning is presented, referred to as DSPLAN. This model is solved within each of the levels of the proposed heuristic in order to obtain the optimal plan.

4.2.1 Objective Function

The proposed objective function (4.1) aims to minimize the investment and operating cost of the LDC. The first line is the capital and operating cost of the candidate DG units. The second line includes the EPC cost and the variable component of the capital cost to upgrade the substation, payment toward purchased power by the LDC and the revenue earned by the LDC for power export to the grid via substation. The third line is the EPC cost and the variable component of the capital cost to upgrade the feeders and the last line is the cost of the unserved power. The mathematical formulation is described in (4.1) as follows:

$$J = \sum_{i \epsilon N} \left(C^{DG.f}.P_i^{DG_{Cap}} + C^{DG.r}.P_i^{DG} \right)$$

$$+ \sum_{i \epsilon SS} \left(C^{SS.f}.z_i^{SS} + C^{SS.v}.P^{SS} + \rho.P_i^{Im} - C^{Ex}.P_i^{Ex} \right)$$

$$+ \sum_{i,j \epsilon N:\exists(i,j)} \left(C^{Fdr.f}.\ Ge.\ Le.\ z_{(i,j)}^{Fdr} + P_{(i,j)}^{Fdr.C.A}.C^{Fdr.v} \right)$$

$$+ \sum_{i \epsilon N} C^{Un}.P_i^{Un}$$

4.1

The associated operational and planning constraints are discussed next.

4.2.2 Nodal power balance

The algebraic sum of all incoming and outgoing power over the LDC feeders and the power generated from DG should be equal to the total demand including reserve margin at the bus, net of unserved power. Feeder losses are approximated by a loss factor and are accounted for in the incoming power flow direction at the bus.

$$\sum_{\boldsymbol{i,j \epsilon N}:\exists(\boldsymbol{i,j})} (\mathbf{1} - \boldsymbol{Lf}).\boldsymbol{P}_{(\boldsymbol{j,i})}^{\boldsymbol{Fdr}} - \boldsymbol{P}_{(\boldsymbol{i,j})}^{\boldsymbol{Fdr}} + \boldsymbol{P}_{\boldsymbol{i}}^{\boldsymbol{Ex}} - \boldsymbol{P}_{\boldsymbol{i}}^{\boldsymbol{ss}} - \boldsymbol{P}_{\boldsymbol{i}}^{\boldsymbol{Un}} - \boldsymbol{P}_{\boldsymbol{i}}^{\boldsymbol{DG}} = (\mathbf{1} + \boldsymbol{Rs}).\boldsymbol{Pd} \qquad \forall \boldsymbol{i}$$

4.2

4.2.3 Feeder capacity limits

Power flow through any distribution feeder must comply with the thermal capacity limit of the feeder. This limit also takes into consideration the new investments in feeder upgrade.

$$P_{(i,j)}^{Fdr} \leq P_{(i,j)}^{Fdr_{Cap}} + P_{(i,j)}^{Fdr.C.A} \qquad \forall (i,j) \epsilon N: \exists (i,j)$$

4.3

$$P_{(i,j)}^{Fdr.C.A} \leq M \, . \, z_{(i,j)}^{fdr} \qquad \forall i \qquad \textbf{4.4}$$

4.2.4 Substation capacity limits

Substation capacity constraints (4.5), (4.6) and (4.7) ensure that the total power delivered by the substation over the outgoing distribution feeders and the total exported power by the substation must be within the substation capacity limit. These limits take into consideration the new investments in substation upgrade.

$$P^{Im} \leq P^{SS_{CAP}} + P^{SS} \qquad \forall i \qquad \textbf{4.5}$$

$$P^{Ex} \leq P^{SS_{CAP}} + P^{SS} \qquad \forall i \qquad \textbf{4.6}$$

$$P^{SS} \leq BM \, . \, z^{SS} \qquad \forall i \qquad \textbf{4.7}$$

4.2.5 DG capacity limits

The power generated by a DG unit must be less than the DG capacity.

$$P_i^{DG} \leq P_i^{DG_{Cap}} \qquad \forall i \qquad \textbf{4.8}$$

4.2.6 Budget limits

This constraint imposes a limit on how much capacity the LDC can invest in a given year. The first term is the capital cost of DG units. The second term is the EPC cost and the variable component of the capital cost to upgrade the substation. The third term is the EPC cost and the variable component of the capital cost to upgrade the feeders. All these costs together, must be within the budget limit.

$$\sum_{i \epsilon N} C_f^{DG} . P_i^{DG_{Cap}}$$

$$+ \quad \sum_{i \epsilon SS} \left(C_f^{SS} . z_i^{SS} + C_v^{SS} . P^{SS} \right)$$

$$+ \sum_{i,j \epsilon N : \exists (i,j)} (C_f^{FDR} . Ge . Le \ . z_{(i,j)}^{FDR} \ + P^{FDR} . C_v^{FDR}) \leq BL$$

4.9

4.3 Proposed Back-Propagation Heuristic Approach

The proposed heuristic approach is based on back-propagation of the planning process starting from the terminal year. The proposed heuristic combines a bi-level procedure as follows:

Level-1: Select the optimal size and location of DS component upgrades (OPTSELECT) which will be installed in the system by the terminal year.

Level-2: Determine the optimal period of commissioning for the selected upgrades obtained in Level-1 (OPTPERIOD).

4.3.1 Level-1: OPTSELECT PROCEDURE

The mathematical model described in Section 4.2 is executed for the peak load condition pertaining to the plan terminal year to support optimal planning decisions. The plan so obtained, provides continuous decisions on investments, which is not a practical solution. The proposed heuristic approach standardizes the selected capacities and uses a cost-benefit analysis to identify the most beneficial upgrade plan for DG units, substation and feeders for the terminal year. The flowchart of OPTSELECT is shown in Figure 4.1 and the step-by-step procedure is discussed as follows.

1) Set all distribution system components as candidates for upgrade that include substation

upgrade, feeder upgrade and DG installation, set {L}. Pre-select the capacities for substation, feeders and DG units.

2) Obtain the optimal solution, set {H}, by minimizing (4.1) for the peak load of the plan terminal year while satisfying the constraints (4.2)–(4.9). It is to be noted that only at the beginning of the simulation, $P_i^{DG_{Cap}}$ is an unknown, which needs to be determined. Hence, we use P_i^{DG} as a variable for both the fixed and variable cost components.

3) Using the pre-selected values, standardize the upgrade capacities of {H}. By using the standardized capacities for the selected upgrades, re-calculate the exact value of J from (4.1).

4) Uninstall an upgrade, one at a time, from set {H}, and repeat Step-2 to calculate the marginal benefit of each upgrade. The marginal benefit for an upgrade is obtained from the difference in the objective function before and after removing it.

5) Calculate the *benefit-cost-ratio* (BCR) for this upgrade by dividing the marginal benefit by the total cost of the upgrade. Calculate this for all upgrades.

6) Modify set {H} by selecting all upgrades with BCR>1, set {H1}, also construct a set {R} with rejected buses having BCR<1.

7) Perform Step-2 with modified set {H1} and check if the above selected upgrades satisfy the system constraints.

8) Check if the Step-7 results meet all constraints, optimal solution obtained.

9) If the output from Step-7 is not feasible, go to Step-1 after modifying set {L} with all buses except those in set {R}.

10) After all upgrades are tested for BCR>1 and final upgrade selections set is still not satisfying system constraints, choose upgrades with the highest BCR from the rejected set {R}.

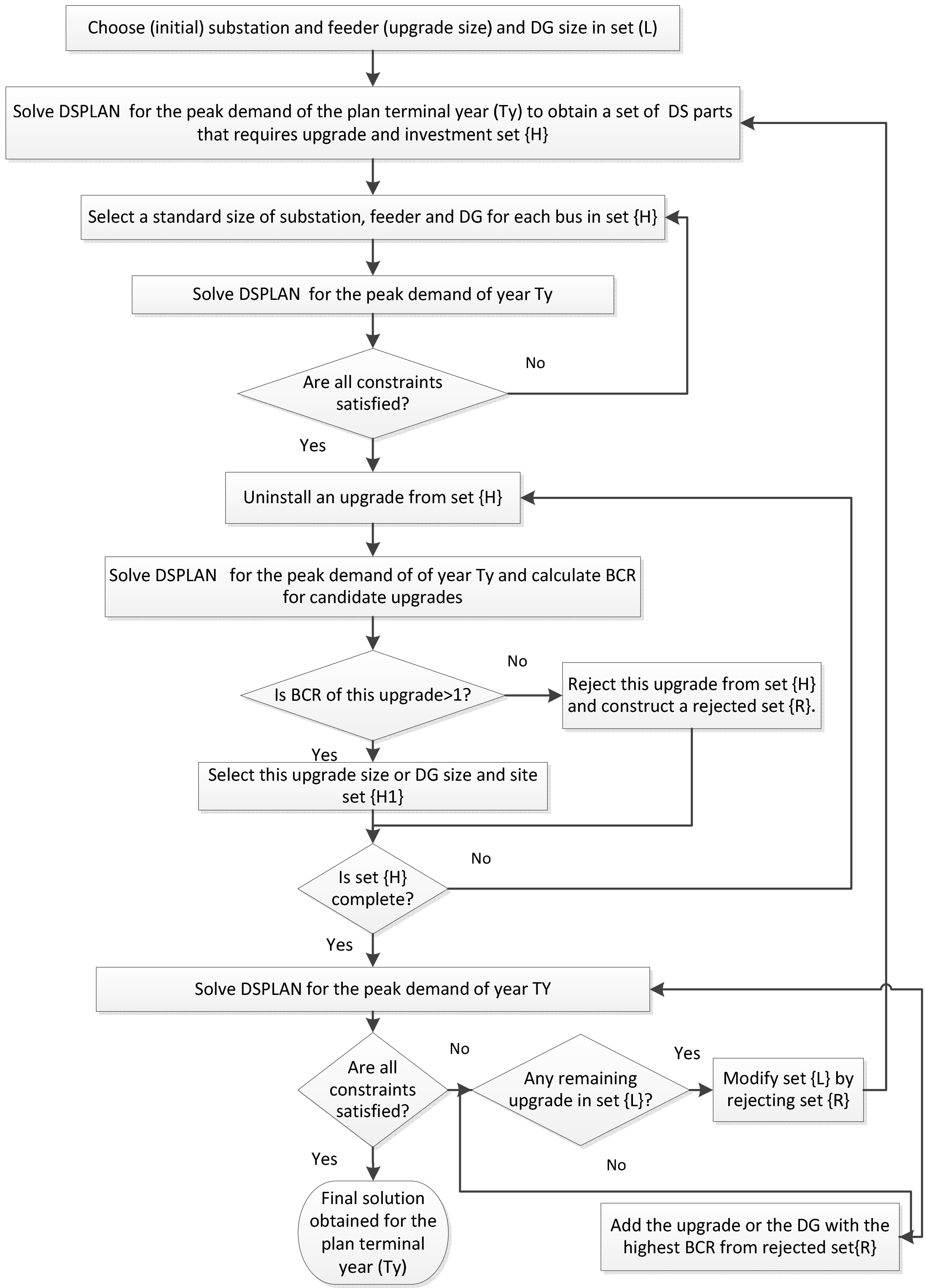

Figure 4.1: Level-1: Schematic for OPTSELECT algorithm

4.3.2 Level-2: OPTPERIOD PROCEDURE

In this Level, back-propagation heuristic approach is used along with the output from OPTSELECT, set {H1}, which is the final upgrade selection to be in place at the end of the planning horizon. The objective of OPTPERIOD is to determine the specific period of commissioning of the selected upgrade investments. The DSPLAN model is now modified to consider the selected set {H1} as fixed decisions, and thus transforming it to a linear programming (LP) model, DSPLAN1. The flowchart of this approach is shown in Figure 4.2 and the step-by-step procedure is discussed as follows.

1) Set initial value T= Ny-1.
2) Solve DSPLAN1 for the peak demand in year T and calculate BCR for all upgrades.
3) Reject the upgrades with BCR<1 from set {H1} and form the rejected set {R2}. It is to be noted that the rejected upgrades that are rejected, only for year T and earlier, implying that these upgrades are made in year T+1.
4) Check if the selected upgrades satisfy the system constraints. If yes, go to Step-6.
5) If not feasible, reselect the upgrade with the highest BCR from {R2} and go to Step-4.
6) Modify set {H1} with all upgrades that are selected for year T.
7) T=T-1. If T≠0, go to Step-2.
8) The final plan is obtained.

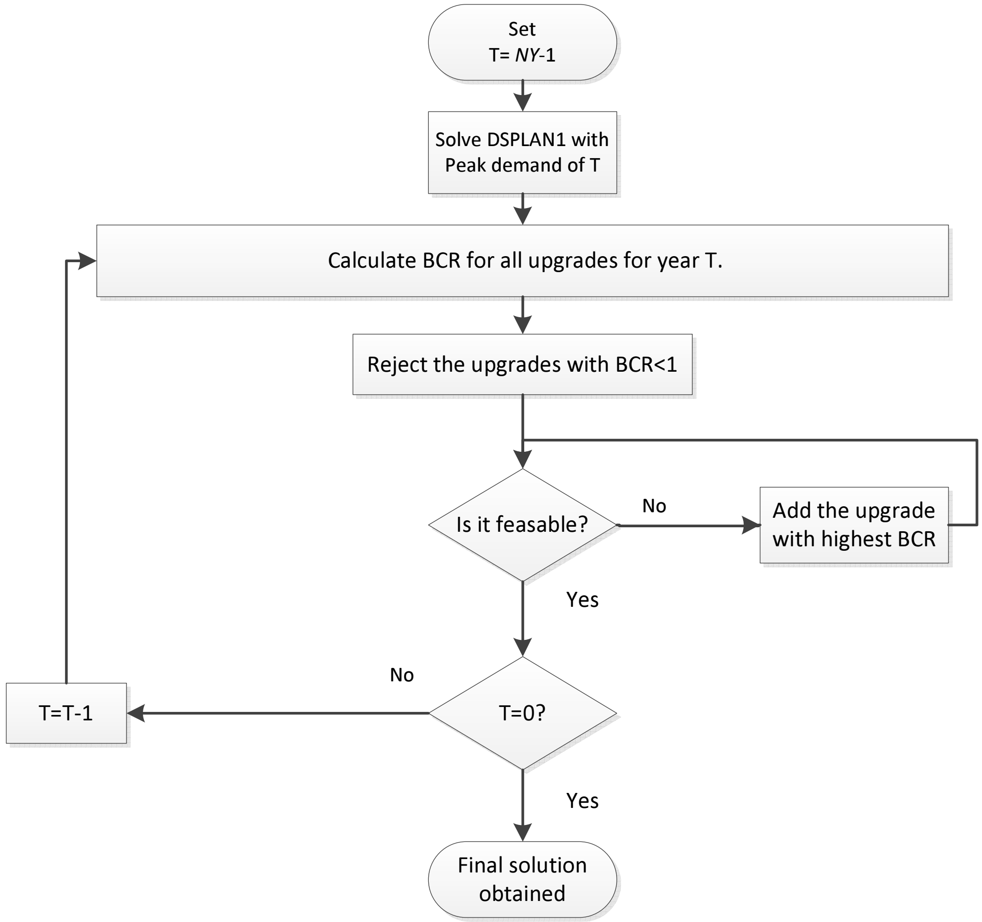

Figure 4.2: Level-2: Back-Propagation Approach algorithm

4.4 Computational Details

The considered test system was programmed and executed in the GAMS environment [28]. In order to determine the optimal set of recommendations for a 10-year investment plan, the first level of the distribution system planning framework is formulated as a MILP problem while the second level, is a LP model. The first level is solved using the BARON (Branch-And-Reduce Optimization Navigator) solver, while the second level is solved using BDMLP which is suitable for linear programming problems [28]. The model and solver statistics are given in Table **4.1**. It can be observed that the proposed approach is significantly simpler in terms of the number of equations, and variable (both continuous and discrete) as compared to the comprehensive optimization approach reported in Table **3.3**. The proposed approach also has a shorter computational time as compared to the optimal planning model.

Table 4.1: Model Statistics

	Proposed Approach (Per Iteration)	
	level 1	level 2
COMPLEXITY	MIP	LP
SOLVER	BARON	BDMLP
BLOCKS OF EQUATIONS	9	7
BLOCKS OF VARIABLES	9	8
SINGLE EQUATIONS	131	99
SINGLE VARIABLES	130	130
NON ZERO ELEMENTS	453	296
DISCRETE VARIABLES	32	-
GENERATION TIME (Sec)	0.031	0.031

4.5 Test, Results, and Discussions

The proposed heuristic approach presented in Section 3 is applied to the 32-bus radial distribution system shown in Figure **3.1** [14]. Table 3.1 provides the investment costs of the resources available to the LDC. The cost of generation from gas turbine DG units, market price, and export price through substation are given in Table 3.2. A budgetary limit on terminal year capital expenditures by the LDC of $100M is imposed.

4.5.1 Base Case Plan

4.5.1.1 Level-1: OPTSELECT

In this level, the proposed heuristic approach is carried out to select the optimal size and location of component upgrades that meet the system peak load in year-10. Table 4.2 demonstrates the step-by-step outcome of the OPTSELECT process.

Table 4.2: Step-by-step outcomes of OPTSELECT

Iteration	Preliminary selection	Generation (MW)	Capacity (MW)	BCR	BCR>1 Selected set {H}	Rejected Set{R}
1	DG at #16	3.816	4	2.33	{16,17,21,24}	{32}
	DG at #17	5	5	2.94		
	DG at #21	0.271	1	1.11		
	DG at #24	1.537	2	3.71		
	DG at #32	0.081	1	0.24		
2	DG at #16	3.816	4	2.36	{16,17,21,24}	{31,32}
	DG at #17	5	5	2.96		
	DG at #21	0.271	1	1.11		
	DG at #24	1.537	2	3.71		
	DG at #31	0.083	1	0.23		
3	DG at #16	3.816	4	2.38	{16,17,21,24}	{30, 31,32}
	DG at #17	5	5	2.98		
	DG at #21	0.271	1	1.11		
	DG at #24	1.537	2	3.71		
	DG at #30	0.085	1	0.21		
4	DG at #17	4.566	5	3.64	{17,24,SS,Fdr1-2,Fdr1-18,Fdr2-3,Fdr29-30}	{29, 30, 31,32}
	DG at #24	1.537	2	3.71		
	DG at #29	0.037	1	-0.05		
	SS upgrade	6.121	7	11.6		
	Fdr upgrade 1-2	4.429	5	15.4		
	Fdr upgrade 1-18	0.294	1	13.4		
	Fdr upgrade2-3	2.283	3	6.67		
	Fdr upgrade 29-30	0.086	1	3.65		
5	DG at #16	3.816	4	2.42	{16,17,21,24,Fdr29, 30}	{28, 29, 30, 31,32}
	DG at #17	5	5	3.01		
	DG at #21	0.271	1	1.11		
	DG at #24	1.537	2	3.71		
	DG at #28	0.037	1	-0.06		
	Fdr upgrade 29-30	0.086	1	3.65		
6	DG at #16	1.277	2	1.01	{16,17,24,SS,Fdr1-2,Fdr1-18,Fdr29-30}	{27, 28, 29, 30, 31,32}
	DG at #17	5	5	3.4		
	DG at #24	1.537	2	3.71		
	DG at #27	0.038	1	-0.08		
	SS upgrade	3.791	4	6.07		
	Fdr upgrade 1-2	2.1	3	-0.14		
	Fdr upgrade 1-18	0.294	1	13.4		
	Fdr upgrade 29-30	0.086	1	3.65		
7	DG at #16	3.893	4	3.49	{16,17,21,24,Fdr26-27,Fdr29-30}	{27, 28, 29, 30, 31,32}
	DG at #17	5	5	3.87		
	DG at #21	0.271	1	1.11		
	DG at #24	1.537	2	3.71		
	Fdr upgrade 26-27	0.039	1	1.31		
	Fdr upgrade 29-30	0.086	1	3.65		

In the first iteration, the preliminary set of candidate DG units are selected and standardized which are DG units at buses #16, #17, #21, #24 and #32. Then, BCR for each selected DG unit is calculated. DG units at buses #16, #17, #21 and #24 are found to have a BCR greater than unity whereas DG #32 has BCR less than unity and hence it is rejected. Therefore, another iteration is needed. In the fourth iteration, DG units at buses #17, #24 and #29, feeder upgrades between buses 1-2, 1-18, 2-3 and 29-30 and substation upgrade are preliminarily selected and standardized. After calculating BCR for each selected upgrade, it is found that DG unit at bus #29 and feeder upgrades between buses 1-18, 2-3 and 29-30 have BCR less than unity and hence these selections are rejected. In the final iteration, four DG units and two feeder upgrades are selected and found to have a BCR greater than unity and hence the optimal investment plan for the terminal year is obtained.

It is to be noted that the upgrade capacity, location and BCR vary across buses because of the load distribution pattern, differences in total primary distribution feeder length and hence losses in each feeder being different.

4.5.1.2 Level-2: OPTPERIOD

The period of commissioning of the selected upgrades is determined in this level using back-propagation heuristic approach. In this level, the BCR of the final selected upgrades from OPTSELECT, set {H1}, is calculated at each year starting from the terminal year. Table 4.3 demonstrates OPTPERIOD process. In year-9, the BCR is calculated and it is found that feeder upgrade 26-27 and 29-30 have BCR less than unity and the system is feasible without these upgrades. Therefore, they are rejected from year-9 and backward, and are installed in year-10 (Table 4.3). In year-8, DG units #16 and #21 have BCR less than unity but the system is not feasible without these upgrades. Therefore, the DG with lower BCR is rejected, which is DG unit 21, is rejected from this year. Table 4.4 shows the LDC investment plan for the plan period.

Figure 4.3 and Table 4.4 show the consolidated optimal investment plan for the distribution system determined from the OPTSELECT and OPTPERIOD procedure as per the heuristic approach proposed.

Table 4.3: Step-by-step outcomes of OPTPERIOD

Year	Selected Upgrades {H1}	Capacity (MW)	BCR	
10	DG at #16	4	3.489	
	DG at #17	5	3.868	
	DG at #21	1	1.115	
	DG at #24	2	3.705	
	Fdr upgrade 26-27	1	1.311	
	Fdr upgrade 29-30	1	3.654	
9	DG at #16	4	1.926	
	DG at #17	5	2.618	
	DG at #21	1	0.375	
	DG at #24	2	2.733	
	Fdr upgrade 26-27	1	-0.4	Needed in year10
	Fdr upgrade 29-30	1	-0.4	Needed in year10
8	DG at #16	4	0.41	
	DG at #17	5	1.404	
	DG at #21	1	-0.3	Needed in year9
	DG at #24	2	1.788	
7	DG at #16	4	-0.08	
	DG at #17	5	1.013	
	DG at #24	2	0.871	
6	DG at #16	4	-0.12	Needed in year7
	DG at #17	5	-0.1	
	DG at #24	2	-0.02	
5	DG at #17	5	2.689	
	DG at #24	2	-0.3	Needed in year6
4	DG at #17	5	3.184	
3	DG at #17	5	2.137	
2	DG at #17	5	1.121	
1	DG at #17	5	0.134	
0	DG at #17	5	-0.1	Needed in year1

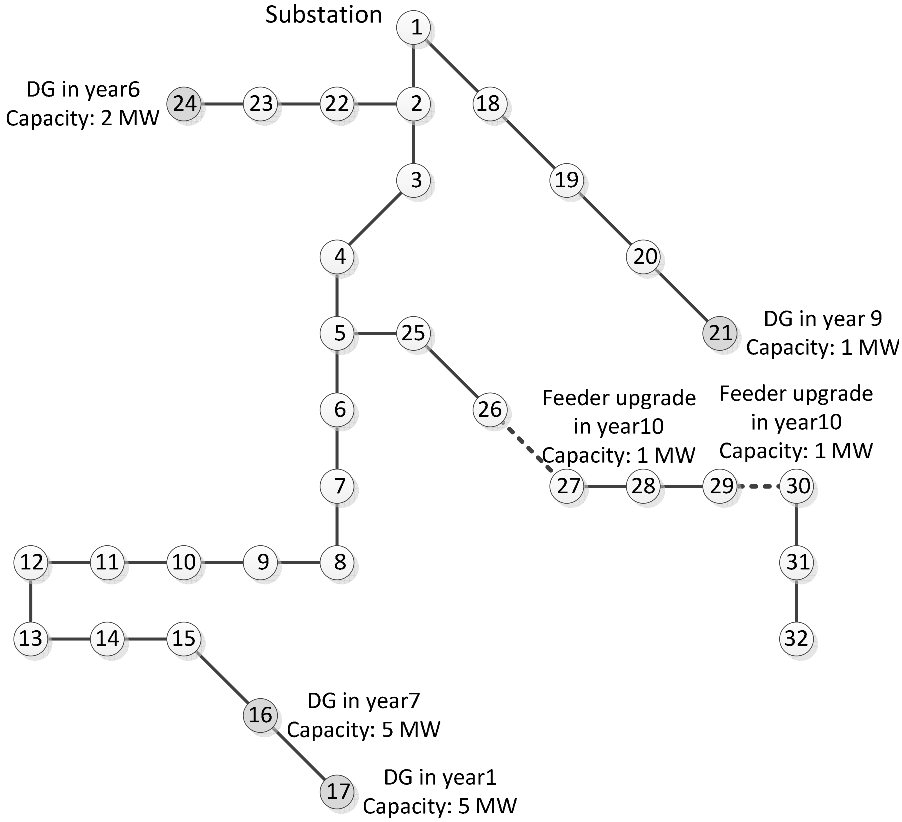

Figure 4.3: Optimal Distribution System Plan Based on Heuristic Approach

Table 4.4: Optimal Distribution System Plan

Year	Investment Size (MW) and Site(Bus)		
	Substation	Feeder	DG
1	-	-	5 (17)
6	-	-	2 (24)
7	-	-	4 (16)
9	-	-	1 (21)
10	-	1 (26-27) and 1 (29-30)	-

4.5.1.3 Production Plan

Table **4.5** presents the LDC's energy production schedules. The schedules are consistent with the resource assets available to it. The DG units are used to their maximum capacity while the substation always has excess capacity available in order to serve the system's energy adequacy requirement.

Figure **4.4** presents the LDC's demand and the imported energy via substation. It can be seen that the imported energy at year-0 is higher than the demand in order to satisfy the demand plus the distribution network losses. In later years, the imported energy is reduced and become less than the demand. The reduction in the imported energy is due to addition of four DG units which have lower operational cost.

Table 4.5: Production Schedule

Supply Element	Bus	Year/Supply (MW)										
		0	1	2	3	4	5	6	7	8	9	10
Substation	1	42.31	36.67	37.98	39.33	40.72	42.14	41.45	37.55	39.11	39.63	41.29
Generation from DG units	16	-	-	-	-	-	-	-	4	→	→	4
	17	-	5	→	→	→	→	→	→	→	→	5
	21	-	-	-	-	-	-	-	-	-	1	1
	24	-	-	-	-	-	-	2	→	→	→	2

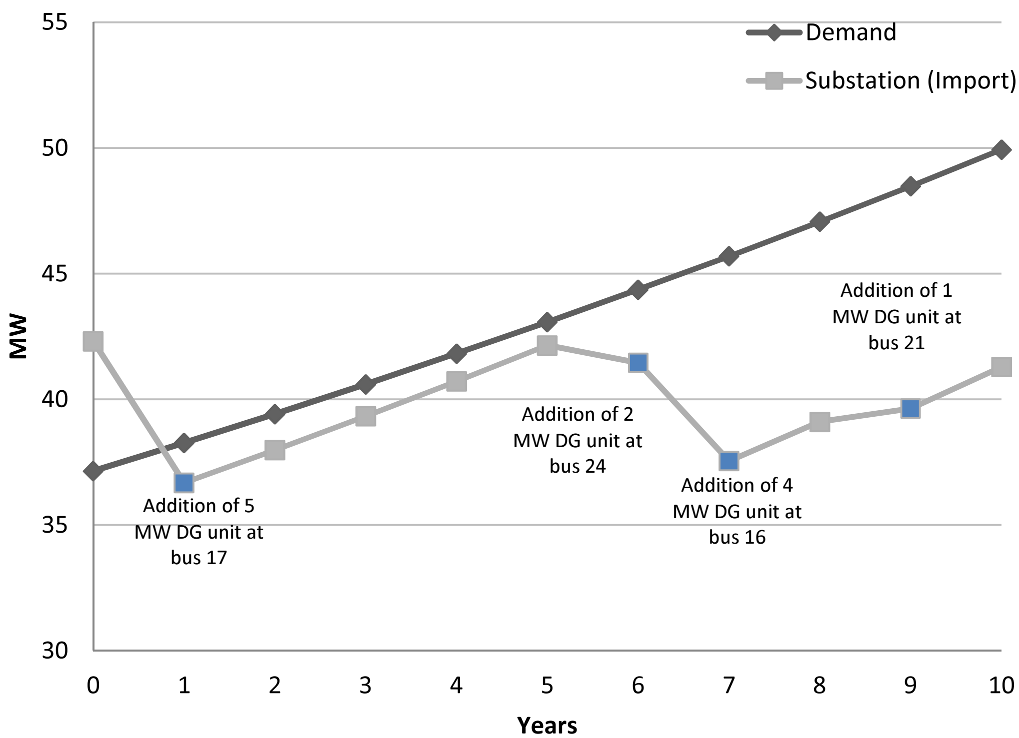

Figure 4.4: LDC's demand and imported energy via substation

4.5.2 Sensitivity Analysis

Three different cases are investigated in this section similar to these in Chapter-3 to evaluate the investment and upgrade plan for the distribution system. These cases are discussed as follow:

4.5.2.1 30% Decrease in Electricity Market Base Price

In this case, the Electricity Market price is reduced by 30% of the base market price. The proposed heuristic approach is carried out to obtain the optimal planning decisions that meet the system peak load. In Table **4.6** the step-by-step outcome of the OPTSELECT process is demonstrated. The proposed algorithm identifies two DG units, substation upgrade, and six feeder upgrades to arrive at a BCR grater than unity in the eighth iteration (Table **4.6**) and hence is the optimal solution for year-10 which is the plan terminal year. However, in this scenario, it is noted that the LDC reduces its DG investments and increases the substation upgrade. In order to feed the additional power from the substation upgrade, six feeder upgrades are also selected.

Table 4.6: OPTSELECT outcomes for 30% reduction in base market price

Iteration	Preliminary selection	Generation (MW)	Capacity (MW)	BCR	BCR>1 Selected set {H}	Rejected Set {R}
1	DG at bus #17	1.43	2	3.41	{17,SS,Fdr 1-2,Fdr 2-3,Fdr 3-4,Fdr 4-5,Fdr 1-18,Fdr 2-22}	{24,32}
	DG at bus #24	0.10	1	0.03		
	DG at bus #32	0.08	1	0.01		
	SS upgrade	11.95	12	16.76		
	Fdr upgrade 1-2	10.26	11	24.95		
	Fdr upgrade 2-3	6.47	7	24.83		
	Fdr upgrade 3-4	4.10	5	17.28		
	Fdr upgrade 4-5	2.62	3	10.22		
	Fdr upgrade 1-18	0.29	1	14.00		
	Fdr upgrade 2-22	1.53	2	14.07		
2	DG at bus #17	1.43	2	3.41	{17,SS,Fdr 1-2,Fdr 2-3,Fdr 3-4,Fdr 4-5,Fdr 2-22,Fdr 22-23,Fdr 26-27,Fdr 29-30}	{24,32,21}
	DG at bus #21	0.27	1	0.96		
	SS upgrade	11.87	12	19.17		
	Fdr upgrade 1-2	10.47	11	32.99		
	Fdr upgrade 2-3	6.57	7	31.66		
	Fdr upgrade 3-4	4.20	5	26.85		
	Fdr upgrade 4-5	2.72	3	26.16		
	Fdr upgrade 2-22	1.63	2	40.65		
	Fdr upgrade 22-23	0.10	1	4.82		
	Fdr upgrade 26-27	0.04	1	1.40		
	Fdr upgrade 29-30	0.09	1	3.85		
3	DG at bus #17	0.51	1	2.32	{17,SS,Fdr 1-2,Fdr 2-3,Fdr 3-	{24,32,21,23,31}
	DG at bus #23	0.10	1	0.02		
	DG at bus #31	0.08	1	0.00		
	SS upgrade	13.22	14	16.65		

Iteration	Preliminary selection	Generation (MW)	Capacity (MW)	BCR	BCR>1 Selected set {H}	Rejected Set {R}
	Fdr upgrade 1-2	11.53	12	27.34	4,Fdr 4-5,Fdr 1-18,Fdr 2-22}	
	Fdr upgrade 2-3	7.72	8	28.33		
	Fdr upgrade 3-4	5.32	6	23.20		
	Fdr upgrade 4-5	3.82	4	20.87		
	Fdr upgrade 5-6	1.18	2	11.01		
	Fdr upgrade 1-18	0.29	1	14.00		
	Fdr upgrade 2-22	1.53	2	14.60		
4	DG at bus #17	1.43	2	3.41	{17,SS,Fdr 1-2,Fdr 2-3,Fdr 3-4,Fdr 4-5,Fdr 2-22,Fdr 22-23}	{24,32,21,23,31,20,30}
	DG at bus #20	0.28	1	0.95		
	DG at bus #30	0.09	1	-0.01		
	SS upgrade	11.76	12	16.90		
	Fdr upgrade 1-2	10.37	11	28.82		
	Fdr upgrade 2-3	6.47	7	25.10		
	Fdr upgrade 3-4	4.10	5	17.66		
	Fdr upgrade 4-5	2.62	3	10.85		
	Fdr upgrade 2-22	1.63	2	40.65		
	Fdr upgrade 22-23	0.10	1	4.82		
5	DG at bus #17	1.43	2	3.41	{17,SS,Fdr 1-2,Fdr 2-3,Fdr 3-4,Fdr 4-5,Fdr 2-22,Fdr 22-23,Fdr 29-30}	{24,32,21,23,31,20,30,19,29}
	DG at bus #19	0.28	1	0.94		
	DG at bus #29	0.04	1	-0.27		
	SS upgrade	11.82	12	16.99		
	Fdr upgrade 1-2	10.43	11	28.90		
	Fdr upgrade 2-3	6.53	7	25.23		
	Fdr upgrade 3-4	4.16	5	17.85		
	Fdr upgrade 4-5	2.68	3	11.16		
	Fdr upgrade 2-22	1.63	2	40.65		
	Fdr upgrade 22-23	0.10	1	4.82		
	Fdr upgrade 29-30	0.09	1	3.85		
6	DG at bus #17	1.43	2	3.41	{17,SS,Fdr 1-2,Fdr 2-3,Fdr 3-4,Fdr 4-5,Fdr 2-22,Fdr 22-23,Fdr 29-30}	{24,32,21,23,31,20,30,19,29,18,28}
	DG at bus #18	0.29	1	0.93		
	DG at bus #28	0.04	1	-0.28		
	SS upgrade	11.82	12	17.07		
	Fdr upgrade 1-2	10.43	11	28.98		
	Fdr upgrade 2-3	6.53	7	25.36		
	Fdr upgrade 3-4	4.16	5	18.03		
	Fdr upgrade 4-5	2.68	3	11.46		
	Fdr upgrade 2-22	1.63	2	40.65		
	Fdr upgrade 22-23	0.10	1	4.82		
	Fdr upgrade 29-30	0.09	1	3.85		
7	DG at bus #17	1.43	2	3.41	{17,SS,Fdr 1-2,Fdr 2-3,Fdr 3-4,Fdr 4-5,Fdr 1-18,Fdr 2-22,Fdr 22-23,Fdr 29-30}	{24,32,21,23,31,20,30,19,29,18,28,27}
	DG at bus #27	0.04	1	-0.29		
	SS upgrade	12.12	13	17.56		
	Fdr upgrade 1-2	10.43	11	29.06		
	Fdr upgrade 2-3	6.53	7	25.49		
	Fdr upgrade 3-4	4.16	5	18.20		
	Fdr upgrade 4-5	2.68	3	11.75		
	Fdr upgrade 1-18	0.29	1	14.00		
	Fdr upgrade 2-22	1.63	2	40.65		
	Fdr upgrade 22-23	0.10	1	4.82		
	Fdr upgrade 29-30	0.09	1	3.85		

Iteration	Preliminary selection	Generation (MW)	Capacity (MW)	BCR	BCR>1 Selected set {H}	Rejected Set {R}
8	DG at bus #16	1.31	2	3.01	{16,17,SS,Fdr 1-2,Fdr 1-18,Fdr 1-18,Fdr 2-22,Fdr 22-23,Fdr 26-27,Fdr 29-30}	{24,32,21,23,31,20,30,19,29,18,28,27}
	DG at bus #17	5.00	5	4.20		
	SS upgrade	5.46	6	16.75		
	Fdr upgrade 1-2	3.77	4	26.46		
	Fdr upgrade 1-18	0.29	1	14.00		
	Fdr upgrade 2-22	1.63	2	40.65		
	Fdr upgrade 22-23	0.10	1	4.82		
	Fdr upgrade 26-27	0.04	1	1.40		
	Fdr upgrade 29-30	0.09	1	3.85		

OPTPERIOD process and the optimal plan for 30% reduction in base market price are demonstrated in Table **4.7**. In year-9, the BCR is calculated and it is found that DG unit at bus-16 and feeder upgrades 22-23, 26-27, and 29-30 have BCR less than unity. Feeder upgrades 22-23, 26-27, and 29-30 are rejected from year-9 and backward because the system is feasible without these upgrades but the system is not without DG unit at bus-16. Therefore, it is not rejected. In year-8, DG units #16 and feeder upgrade 1-18 have BCR less than unity and the system is feasible without these upgrades. Therefore, they are rejected from year-8 and backward (Table **4.7**). Table 4.8 shows the LDC investment plan for the plan period.

Table 4.7: OPTPERIOD output for 30% reduction of the base market price

Year	Selected upgrade{H1}	Capacity (MW)	BCR	
9	DG at # 16	2	0.93	
	DG at # 17	5	3.37	
	SS upgrade	6	10.24	
	Fdr upgrade 1-2	4	12.13	
	Fdr upgrade 1-18	1	6.43	
	Fdr upgrade 2-22	2	30.72	
	Fdr upgrade 22-23	1	-0.40	Needed in year 10
	Fdr upgrade 26-27	1	-0.40	Needed in year 10
	Fdr upgrade 29-30	1	-0.40	Needed in year 10
8	DG at # 16	2	-0.38	Needed in year 9
	DG at # 17	5	2.56	
	SS upgrade	6	3.93	
	Fdr upgrade 1-2	4	-0.11	
	Fdr upgrade 1-18	1	-0.40	Needed in year 9
	Fdr upgrade 2-22	2	21.07	
7	DG at # 17	5	3.85	
	SS upgrade	6	8.02	
	Fdr upgrade 1-2	4	10.11	
	Fdr upgrade 2-22	2	11.71	

Year	Selected upgrade{H1}	Capacity (MW)	BCR	
6	DG at # 17	5	3.09	
	SS upgrade	6	2.07	
	Fdr upgrade 1-2	4	-0.11	Needed in year 7
	Fdr upgrade 2-22	2	2.61	
5	DG at # 17	5	3.64	
	SS upgrade	6	-0.33	Needed in year 6
	Fdr upgrade 2-22	2	-0.21	Needed in year 6
4	DG at # 17	5	3.09	
3	DG at # 17	5	1.99	
2	DG at # 17	5	0.92	
1	DG at # 17	5	-0.12	
0	DG at # 17	5	-0.37	Needed in year 1

Table 4.8: Optimal DS plan for 30% reduction of the base market price

	Investment size (MW) and site (Bus)		
Year	Substation	Feeder	DG
1	-	-	5 (17)
6	6 (1)	2 (2-22)	-
7	-	4 (1-2)	-
9	-	1 (1-18)	2 (16)
10	-	1 (22-23), 1 (26-27), and 1 (29-30)	-

4.5.2.2 20% Increase in Electricity Market Base Price

In this case, we assume that the energy price in the market is increased by 20% of the base market price. Under such a price condition, the proposed algorithm identifies four DG units, and three feeders upgrade to arrive at a BCR grater than unity in the seventh iteration (Table **4.9**) and hence is the optimal solution. At this price point, the LDC's net present value of the cost increases commensurate with increasing capital costs. However, the increased energy costs are mitigated by increased investments in utility DG. The increased DG investments lead to a technically improved system (in terms of losses and voltage profile).

Table 4.9: OPTSELECT outcomes for 20% increase of the base market price

Iteration	Preliminary selection	Generation (MW)	Capacity (MW)	BCR	BCR>1 Selected set {H}	Rejected Set {R}
1	DG at #14	5.00	5	0.01	{24,Fdr 1-18}	{14,15,16,17,32}
	DG at #15	5.00	5	0.04		
	DG at #16	5.00	5	0.06		
	DG at #17	5.00	5	0.08		
	DG at #24	1.54	2	3.74		
	DG at #32	0.08	1	0.39		
	Fdr upgrade 1-18	0.29	1	13.06		
2	DG at #12	4.57	5	2.26	{12,13,21,24,Fdr 15-16}	{14,15,16,17,32, 31}
	DG at #13	5.00	5	2.37		
	DG at #21	0.27	1	1.22		
	DG at #24	1.54	2	3.74		
	DG at #31	0.08	1	0.37		
	Fdr upgrade 15-16	0.17	1	7.13		
3	DG at #12	5.00	5	3.04	{12,13,21,Fdr 2-22,Fdr 15-16}	{14,15,16,17,32, 31,24,30}
	DG at #13	5.00	5	3.14		
	DG at #21	0.27	1	1.22		
	DG at #24	0.10	1	0.34		
	DG at #30	0.92	1	0.35		
	Fdr upgrade 2-22	1.53	2	13.14		
	Fdr upgrade 15-16	0.17	1	7.13		
4	DG at #12	4.62	5	2.32	{12,13,21,23,Fdr 29-30,Fdr 15-16}	{14,15,16,17,32, 31,24,30,29}
	DG at #13	5.00	5	2.43		
	DG at #21	0.27	1	1.22		
	DG at #23	1.57	2	3.72		
	DG at #29	0.04	1	0.10		
	Fdr upgrade 29-30	0.09	1	3.51		
	Fdr upgrade 15-16	0.17	1	7.13		
5	DG at #12	4.615	5	2.32	{12,13,21,23,Fdr 29-30,Fdr 15-16}	{14,15,16,17,32, 31,24,30,29, 28}
	DG at #13	5	5	2.43		
	DG at #21	0.271	1	1.22		
	DG at #23	1.568	2	3.72		
	DG at #28	0.037	1	0.10		
	Fdr upgrade 29-30	0.086	1	3.51		
	Fdr upgrade 15-16	0.165	1	7.13		
6	DG at #12	4.62	5	2.32	{12,13,21,23,Fdr 29-30,Fdr 15-16}	{14,15,16,17,32, 31,24,30,29, 28,27}
	DG at #13	5.00	5	2.43		
	DG at #21	0.27	1	1.22		
	DG at #23	1.57	2	3.72		
	DG at #28	0.04	1	0.10		
	Fdr upgrade 29-30	0.09	1	3.51		
	Fdr upgrade 15-16	0.17	1	7.13		
7	DG at #12	4.65	5	3.16	{12,13,21,23,Fdr 15-16,Fdr 26-27,Fdr 29-30}	{14,15,16,17,32, 31,24,30,29, 28,27}
	DG at #13	5.00	5	3.27		
	DG at #21	0.27	1	1.22		
	DG at #23	1.57	2	3.72		
	Fdr upgrade 15-16	0.17	1	7.13		
	Fdr upgrade 26-27	0.04	1	1.26		
	Fdr upgrade 29-30	0.09	1	3.52		

OPTPERIOD process and the optimal DS plan for +20% of the base market price are demonstrated in Table **4.10**. In year-9, the BCR is calculated and it is found that DG unit at bus-21 and feeder upgrades 26-27and 29-30 have BCR less than unity. Feeder upgrades 22-23, 26-27, and 29-30 are rejected from year-9 and backward because the system is feasible without these upgrades but the system is not without DG unit at bus-21. Therefore, it is not rejected. In year-8, three DG units at buses 12, 13, and 21 have BCR less than unity but the system is infeasible without these DG units. Therefore, the DG unit with the lowest BCR is rejected which is DG at bus-21 (Table **4.10**. Table **4.11** shows the LDC investment plan for the plan period.

Table 4.10: OPTPERIOD output for 20% increase in base market price

Year	Selected Upgrade {H1}	Capacity (MW)	BCR	
10	DG at #12	5	3.16	
	DG at #13	5	3.27	
	DG at #21	1	1.22	
	DG at #23	2	3.72	
	Fdr upgrade 15-16	1	7.13	
	Fdr upgrade 26-27	1	1.26	
	Fdr upgrade 29-30	1	3.52	
9	DG at #12	5	1.96	
	DG at #13	5	2.07	
	DG at #21	1	0.50	
	DG at #23	2	2.77	
	Fdr upgrade 15-16	1	4.26	
	Fdr upgrade 26-27	1	-0.40	Needed in year 10
	Fdr upgrade 29-30	1	-0.40	Needed in year 10
8	DG at #12	5	0.79	
	DG at #13	5	0.90	
	DG at #21	1	-0.15	Needed in year 9
	DG at #23	2	1.86	
	Fdr upgrade 15-16	1	1.47	
7	DG at #12	5	0.41	
	DG at #13	5	0.52	
	DG at #23	2	0.96	
	Fdr upgrade 15-16	1	-0.40	Needed in year 8
6	DG at #12	5	-0.03	Needed in year 7
	DG at #13	5	-0.01	
	DG at #23	2	0.10	
5	DG at #13	5	2.71	
	DG at #23	2	-0.17	Needed in year 6
4	DG at #13	5	3.16	
3	DG at #13	5	2.15	
2	DG at #13	5	1.17	
1	DG at #13	5	0.22	
0	DG at #13	5	-0.01	Needed in year 1

Table 4.11: Optimal plan for 20% increase in base market price

Year	Investment Size (MW) and Site(Bus)		
	Substation	Feeder	DG
1	-	-	5 (13)
6	-	-	2 (23)
7	-	-	5 (12)
8	-	1 (15-16)	
9	-	-	1 (21)
10	-	1 (26-27) and 1 (29-30)	-

4.5.2.3 10% Increase in demand

In this scenario, the demand is considered to increase by 10% of the base case demand. Under such a demand condition, the proposed algorithm identifies five DG units to have a BCR greater than unity and one DG unit with a BCR less than unity in the first iteration (Table **4.12**). The second iteration is similar to the first. In the third iteration, five DG units are selected that are eventually found to have a BCR greater than unity and hence is the optimal solution.

Table 4.12: OPTSELECT outcomes for +10% of the base case demand

Iteration	Preliminary selection	Generation (MW)	Capacity (MW)	BCR	BCR>1 Selected set {H}	Rejected Set {R}
1	DG at #15	0.82	1	-0.14	{16,17,21,24,32}	{15}
	DG at #16	5.00	5	3.46		
	DG at #17	5.00	5	3.58		
	DG at #21	0.80	1	3.66		
	DG at #24	2.83	3	4.60		
	DG at #32	1.10	2	2.63		
2	DG at #14	0.84	1	-0.15	{16,17,21,24,32}	{15,14}
	DG at #16	5.00	5	3.48		
	DG at #17	5.00	5	3.60		
	DG at #21	0.80	1	3.66		
	DG at #24	2.83	3	4.60		
	DG at #32	1.10	2	2.63		
3	DG at #16	5.00	5	4.42	{16,17,21,24,32}	{15,14}
	DG at #17	5.00	5	4.54		
	DG at #21	0.80	1	3.66		
	DG at #24	2.82	3	4.60		
	DG at #32	1.96	2	3.78		

OPTPERIOD process and the optimal DS plan for 10% increase of the base case demand are demonstrated in Table **4.13** and Table **4.14** respectively.

Table 4.13: OPTPERIOD output for +10% base case demand

Year	Selected upgrade{H1}	Capacity (MW)	BCR	
9	DG at #16	5	3.05	
	DG at #17	5	3.17	
	DG at #21	1	2.84	
	DG at #24	3	3.89	
	DG at #32	2	1.76	
8	DG at #16	5	1.71	
	DG at #17	5	1.83	
	DG at #21	1	2.05	
	DG at #24	3	3.19	
	DG at #32	2	0.91	
7	DG at #16	5	0.42	
	DG at #17	5	0.53	
	DG at #21	1	1.28	
	DG at #24	3	2.52	
	DG at #32	2	0.13	
6	DG at #16	5	-0.12	
	DG at #17	5	-0.10	
	DG at #21	1	0.54	
	DG at #24	3	1.87	
	DG at #32	2	-0.17	Needed in year 7
5	DG at #16	5	-0.12	Needed in year 6
	DG at #17	5	-0.10	
	DG at #21	1	-0.18	
	DG at #24	3	1.23	
4	DG at #17	5	4.07	
	DG at #21	1	-0.30	Needed in year 5
	DG at #24	3	1.73	
3	DG at #17	5	3.34	
	DG at #24	3	0.97	
2	DG at #17	5	2.64	
	DG at #24	3	-0.30	Needed in year 3
1	DG at #17	5	3.42	
0	DG at #17	5	2.37	Needed in year 0

Table 4.14: Optimal plan for 10% increase in base case demand

	Investment size (MW) and site (Bus)		
Year	**Substation**	**Feeder**	**DG**
0	-	-	5 (17)
3	-	-	3 (24)
5	-	-	1 (21)
6	-	-	5 (16)
7	-	-	2 (32)

4.6 Comparison of Distribution System Plan

In this section the distribution system plan from the proposed heuristic approach is compared with that obtained using the full optimization model of Chapter 3 for the same distribution system. The investment plan, the total investment cost, and the system losses for these methods are presented in Table **4.15**. It is noted that the proposed heuristic approach results in a distribution system expansion plan of higher cost (56.8) as compared to the optimal approach(54.6). Moreover, it is observed that the terminal year loss in the proposed heuristic approach is lower than that obtained in full optimization method. The reason is that the proposed heuristic approach uses a back-propagation that results in a compatible set of upgrades and investments at the end of the planning horizon.

Table 4.15: Investment plan comparison

Year	Investment Size (MW) and Site(Bus)	
	Proposed Approach	Full Optimization
1	DG: 5 (17)	DGs: 3.7 (13), 3.3 (17), 2.9 (31), 2 (32) Feeder: 0.5 (16-17)
4	-	Substation: 4 (1)
6	DG: 2 (24)	Feeder: 2 (2-22)
7	DG: 4 (16)	-
9	DG: 1 (21)	Feeders: 0.5 (1-18)
10	Feeders: 1 (26-27) and 1 (29-30)	Feeders: 1.5 (1-2), 0.5 (22-23)
Total cost (M$)	56.8	54.6
Terminal year losses (MW)	3.361	3.393
The losses of the plan period (MW)	35.202	25.509

4.7 Concluding Remarks

This chapter introduces a comprehensive framework for distribution system planning in the presence of DG units. A new back-propagation heuristic approach based on cost-benefit analysis combined with an optimization model is implemented successfully to determine the optimal distribution system component upgrades to serve the peak demand. A sequential two-level scheme comprising the OPTSELECT and the OPTPERIOD algorithms is proposed to obtain the optimal planning decisions i.e. size, location and period of commissioning of distribution system component upgrades. The proposed optimization model aims to minimize the total system cost; DG investment and operating costs, substation investment cost, feeder investment cost, cost of purchasing power by distribution utility, the revenue earned by the LDC for power export to the grid, and the unserved power cost. To demonstrate the effectiveness of the proposed methodology, the results are compared with the previously presented plan results using full optimization, for the same distribution system. The comparison shows that the model is simpler and has a shorter computational time, and the losses in the terminal year are lower, which indicate a compatible set of upgrade and investment.

Chapter 5

Conclusions and Future Research

5.1 Summary

Distribution system design and planning is facing a major change in paradigm due to deregulation of the power industry, policy changes and advancements in DG technologies. This thesis examines distribution system planning in the context of these changes. In chapter 1, the motivation behind this work is presented. This is followed by a brief background on distribution system planning, DG penetration, and deregulation. Finally, the objectives of this work are presented.

In chapter 2, a review of literature addressing distribution system planning is presented. The literature review has examined the significant contributions pertaining to distribution system planning in deregulation, DG types, benefits, and optimal DG placement and sizing methods. It is observed that traditional planning methods are typically focused on placement of substations and routing of feeders to minimize costs and losses to the LDC. However, the research has advanced due to the changes in the tools available to researchers, changes to distribution systems, advancement in technology and changes in policy. Deregulation has resulted in energy costs being considered alongside infrastructure costs, and additional DG supply alternatives added to substation options.

A comprehensive long-term framework for the planning of distribution systems is proposed in Chapter-3. It incorporates DG units as an option for LDCs and determines the sizing, placement, year of commissioning and upgrade plans for feeders and substations. The model is applied to the

32-bus radial distribution system and the detailed plan results have been successfully demonstrated. Finally, the sensitivity of the results to changes in energy prices and the demand are investigated.

Chapter 4 presents a new heuristic approach for multi-year distribution system planning. The proposed approach is based on a back-propagation algorithm starting from the terminal year and arriving at the first year which incorporates various energy supply options for LDCs such as DG, substations and feeders and determines the size, placement and upgrade plan. It is based on cost-benefit analysis to identify the most beneficial upgrade plan for DG units, substation and feeders. The proposed heuristic combines a two levels procedure. The sensitivity of the results to changes in energy prices and the demand are investigated. The results demonstrate that the proposed approach can achieve better performance than a full optimization for the same distribution system.

5.2 Main Contributions of Thesis

The main contributions of the research presented in this thesis are as follows:

a) A comprehensive optimization framework for long-term planning of distribution systems is proposed, bridging the gap between traditional distribution planning frameworks and methods for siting DG within the distribution system. The framework determines parameters for planning considering multiple distribution system elements.

b) A comprehensive, two-stage heuristic framework for long-term planning of distribution systems is proposed. A cost-benefit analysis is used to identify the most beneficial upgrade plan for DG units, substation and feeders. A novel method for determining the year of commissioning is presented in this thesis. This method, OPTPERIOD, is based on a back-propagation algorithm starting from the terminal year and arriving at the first year.

c) In order to investigate the uncertainty of the energy price, the sensitivity of the results to changes in energy prices and demand is analyzed and presented for both the approaches.

d) To show the effectiveness of the proposed methodology, the results are compared to a full optimization for the same DS. The comparison shows that the heuristic model is simpler and has a shorter computational time, and the losses of the terminal year are lower, which indicate a compatible set of upgrade and investment.

5.3 Future Work

Further research can be conducted based on the work presented in this thesis. Some ideas are presented below:

a) In this thesis, parameters, such as market prices and future capital costs, etc. are assumed to be deterministic; however, in future research these may be considered as uncertain. Consequently, stochastic optimization, or robust programming techniques, can be applied to the proposed framework to mitigate the effects of this uncertainty.

b) Intertie and new areas planning are not considered in the proposed framework and may be considered in future research.

c) Gas turbine DG is considered in the proposed framework; however, different DG technology may be considered in future research.

d) It may be useful to examine the role that DG units have providing ancillary services such as reactive power and consider them in determining optimal placement.

e) The issue of smart grid has not been examined in this thesis. This can have a big influence in the planning process in the future.

Appendix A

32-Bus Radial Distribution System Data

Table A. 1: Active and Reactive Loads [27]

Bus	P (p.u.)	Q (p.u.)
1	1	0.6
2	0.9	0.4
3	1.2	0.8
4	0.6	0.3
5	0.6	0.2
6	2	1
7	2	1
8	0.6	0.2
9	0.6	0.2
10	0.45	0.3
11	0.6	0.35
12	0.6	0.35
13	1.2	0.8
14	0.6	0.1
15	0.6	0.2
16	0.6	0.2
17	0.9	0.4
18	0.9	0.4
19	0.9	0.4
20	0.9	0.4
21	0.9	0.4
22	0.9	0.5
23	4.2	2
24	4.2	2
25	0.6	0.25
26	0.6	0.25
27	0.6	0.2
28	1.2	0.7
29	2	6
30	1.5	0.7
31	2.1	1
32	0.6	0.4

Table A. 2: Feeder Parameters [27]

Bus-A	Bus-B	R (1 × 10−4, p.u.)	X (1 × 10−4, p.u.)
1	2	3.076	1.567
2	3	2.284	1.163
3	4	2.378	1.211
4	5	5.11	4.411
5	6	1.168	3.861
6	7	4.439	1.467
7	8	6.258	4.617
8	9	6.514	4.617
9	10	1.227	0.406
10	11	2.336	0.81
11	12	9.159	7.206
12	13	3.379	4.448
13	14	3.687	3.282
14	15	4.656	3.4
15	16	8.042	10.74
16	17	4.567	3.581
1	18	1.023	0.976
18	19	9.385	8.457
19	20	2.555	2.985
20	21	4.423	5.848
2	22	2.815	1.924
22	23	5.603	4.424
23	24	5.59	4.374
5	25	1.267	0.645
25	26	1.773	0.903
26	27	6.607	5.826
27	28	5.018	4.371
28	29	3.166	1.613
29	30	6.08	6.008
30	31	1.937	2.258
31	32	2.128	3.308

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