Operational and Planning Aspects of Distribution Systems in Deregulated Electricity Markets

by

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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

In the current era of deregulated electricity markets, the power distribution systems have attained a very important and crucial role in the industry. A distribution company (referred to as a *disco*) plays an active and effective role in electricity markets, and can positively impact the market efficiency and make it more reliable, secure and beneficial to customers. Therefore, operation and planning issues of discos in such electricity market environment requires extensive analysis and research in order to improve their operational strategies both in the short-term and long-term.

A generic operations framework for a disco operating in a competitive electricity market environment is presented in the thesis. The operations framework is a two-stage hierarchical model in which the first stage deals with disco's activities in the day-ahead stage, the Day Ahead Operations Model (DAOM). The second stage deals with disco's activities in real-time and is termed Real-Time Operations Model (RTOM). The DAOM determines the disco's operational decisions on grid purchase, scheduling of distributed generation (DG) units owned by it, and contracting for interruptible load. These decisions are imposed as boundary constraints in the RTOM and the disco seeks to minimize its short-term costs keeping in mind its day-ahead decisions. A case-study is presented considering the well-known 33-bus distribution system and three different scenarios are constructed to analyze the disco's actions and decision-making in this context.

The thesis presents a new paradigm for distribution system operation taking into account the presence of DG sources and their *goodness factors.* The proposed concept of *goodness factor* of DG units is based on the computation of the incremental contribution of a DG unit to distribution system losses. The incremental contributions of a DG unit to active and reactive power losses in the distribution system are termed as the active / reactive Incremental Loss Indices (ILI). The goodness factors are integrated directly into the distribution system operations model. This model seeks to minimize the disco's

energy costs in the short-term taking into account the contribution (goodness factor) of each DG unit. The analysis was carried out considering an 18-bus distribution network, considering two different ownership structures of DG units, and a 69-bus distribution system considering specific characteristics of wind-DG units.

The concept of goodness factors is further extended to determine a new set of goodness factors pertaining to a DG's impact on feeder unloading by virtue of its power injection. A novel long-term planning model has been developed for the disco that considers investments in DG capacity, distribution system feeder addition / expansion and substation transformers capacity addition. The model includes the new set of goodness factors pertaining to both loss reduction and feeder unloading and arrives at an optimal set of new expansion plan, with specified locations, and year of commissioning. The work clearly demonstrates the effectiveness and contribution of DG units in distribution systems both in the short-term and long-term framework.

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NOMENCLATURE

i, j	Index for all buses in the disco system
k	Index for feeder segment
t,l	Index for operating hours
g	Set of buses with DG units, $i \in g$
s	Set of disco substation buses, $i \in s$
T	Horizon year of planning
y	Index for a period of the planning problem, year
J^{DA},J^{RT}	Day-ahead and real-time objective functions of the disco, $/h
J_1	Objective function of the disco with utility-owned DG, $/h
J_2	Objective function of the disco with investor-owned DG, $/h
J_P	DCPM objective function of the disco, $
J_V	DPVM objective function of the disco, $
r	Discount rate for annualization of long-term costs, %
MDN	Minimum down-time of a DG unit, h
MUP	Minimum up-time of a DG unit, h
N	Total number of disco system buses
NDG	Total number of the DG units in the system
NF	Total number of disco feeders
NL	Total number of disco system load buses
NS	Total number of substation buses
DA	Day ahead values (*appearing as superscript*)
RT	Real-time values (*appearing as superscript*)
A, B, C	Operating cost parameters of a DG unit
C_C	Cost of reactive power from capacitors, $/Mvar
C_{ILi}	Cost of IL at a bus, $/MW

$C_{IL,t}^{DA}$	Expected interruptible load (IL) bid price in day-ahead stage, \$/MW
$C_{IL,i}^{RT}$	Real-time bid price for IL at a bus, \$/MW
C_P^{Feeder}	Active power component of feeder capacity cost, \$/MW
C_Q^{Feeder}	Reactive power component of feeder capacity cost, in \$/Mvar
CDG	DG investment cost, \$/MVA
CD	Shut-down cost of a DG unit, \$
C_Q	Cost of reactive power imported through disco transformer, \$/Mvar
C_{QG}	Cost of reactive power from DG units, \$/Mvar
DGCap	Updated capacity investment in DG over plan period, p.u.
FC_k	Feeder investment cost, \$/MVA
$FCap_k$	Feeder capacity investment at any year of the planning period, p.u.
$Im\{I_{ij,y}\}$	Imaginary component of feeder current, p.u.
LF	Feeder loss factors
CS	Start-up cost of a DG unit, \$
G_{ij}, B_{ij}	Conductance, susceptance of feeder branch, p.u.
M_t^{DA}	Binary variable for contract of day-ahead IL (m=1 contract, m=0 No contract)
M_i^{RT}	Binary variable for selection of real-time IL (m=1 contract, m=0 No contract)
P^*	Optimal active power dispatch from DG units without goodness factors, p.u.
PD	Active power demand at bus, p.u.
P_{inj}	Active power injected at a bus, p.u.
P_{Loss}	System active power loss, p.u.
P_s, P_g, P	Active power supplied through substation, by DG, or either, respectively, p.u.
P_k	Active power flow on a feeder branch, p.u.
P_S^{DA}, P_S^{RT}	Power purchased from external grid at market price in day-ahead and real-time respectively, p.u.
P^{DA}, P^{RT}	Power generated by DG units in day-ahead and real-time operation, respectively, p.u.
PD^{DA}	Day-ahead active power demand of the disco, p.u.
PD^{RT}	Real-time active power demand of the disco, p.u.
PD_0	Nominal load demand, p.u.

PF	Load power factor
Pf	Power factor of DG power generation
Pf1	Power factor of grid power import via substation buses
P_{ILi}	Total IL called, p.u.
$P_{ILC,t}^{DA}$	Contracted amount of IL in day-ahead stage, p.u.
$P_{IL,t}^{DA}$	Scheduled amount of IL in day-ahead stage, p.u.
P_{IL}^{RT}	Amount of power curtailed in real-time, p.u.
P_{ILC}^{DA*}	Optimal IL contact from day-ahead operation, p.u.
$P_{ILCAP,t}^{DA}$	Disco's expectation of total amount of IL bids in day-ahead stage, p.u.
P_{ILCAP}^{RT}	Bid amount of IL at a bus in real-time operation stage, p.u.
P_S^{DA*}	Total grid purchase decision from day-ahead operation, p.u.
P_S^{Max}	Disco substation transformer active power capacity limit, p.u.
P^{Max}	Maximum DG capacity limit for active power, p.u.
P^{Min}	Minimum DG capacity limit for active power, p.u.
Q^*	Optimal reactive power dispatch from DG units without goodness factors, p.u
QC	Reactive power supplied by load-bus capacitors, p.u.
Q_{IL}^{RT}	Corresponding amount of reactive power curtailed in real-time, p.u.
Q^{RT}	Reactive power from DG units in real-time, p.u.
Q_s, Q_g, Q	Reactive power supplied through substation, by DG, or either, respectively, p.u.
Q_S^{RT}	Grid reactive power via substation transformer in real-time, p.u.
QD	Reactive power demand at bus, p.u.
QD^{RT}	Disco reactive power demand in real-time, p.u.
Q_{inj}	Reactive power injected at a bus, p.u.
Q_k	Reactive power flow on feeder branch, p.u.
Q_{Loss}	System reactive power loss, p.u.
Q^{Max}	Maximum DG capacity limit for reactive power, p.u.
Q^{Min}	Minimum DG capacity limit for reactive power, p.u.
Q_S^{Max}	Disco substation transformer reactive power capacity limit, p.u.
R_{DN}	Ramp-down limit for DG unit, p.u.

R_{UP}	Ramp-up limit for DG unit, p.u.
$Re\{I_{ij,y}\}$	Real component of feeder current, p.u.
RESV	Adequacy reserve maintained by the disco, p.u.
S^{Dem}	Complex power demand at a bus, p.u.
S_k, S_k^F	Complex power flow in feeder *k*, p.u.
S_k^{Max}	Feeder capacity limit on complex power flow, p.u.
S^{DG}	Complex power provided from DG units, p.u.
S_s^{Max}	Disco substation capacity limit, p.u.
S^T	Complex power imported via substation bus, p.u.
SDG	Investment in DG capacity at a bus, p.u.
SDG^{CAP}	Maximum limit of installed DG capacity at a bus, p.u.
SF^*	Existing feeder capacity limit, p.u.
SF_k	Feeder capacity added in a year, p.u.
ST	Investment in transformer capacity at a bus, p.u.
ST^{CAP}	Maximum limit of installed transformer capacity at a bus, p.u.
TC	Transformer investment cost, $/MVA
TCap	Transformer capacity updated over plan period, p.u.
V	Bus voltage, p.u.
V^{Min}, V^{Max}	Minimum and maximum limit on bus voltages, p.u.
W	Binary variables denoting DG unit commitment status, (W=1 ON, W = 0 OFF)
W^*	Optimal decisions on DG unit commitment status at an hour, obtained from day-ahead stage (W = 1 unit ON, W = 0 unit OFF)
X	Binary variables denoting DG start-up decisions, (X=1 Start-up, X = 0 No start-up)
Y_{ij}	Magnitude of admittance matrix element, p.u.
Z	Binary variables denoting DG shut-down decisions, (Z=1 Shut-down, Z = 0 No shut-down)
α, β	Model estimation parameters for disco demand
α^{Loss}	Goodness factor of active power injection pertaining to feeder losses

β^{Loss}	Goodness factor of reactive power injection pertaining to feeder losses
α^{Feeder}	Goodness factor of active power injection pertaining to feeder unloading
β^{Feeder}	Goodness factor of reactive power injection pertaining to feeder unloading
ρ^{DA}	Day-ahead electricity market price, \$/MWh
ρ^{RT}	Real-time electricity market price, \$/MWh
ρ_{IL}^{RT}	Uniform price for selected IL in real-time, \$/MWh
ρ^{P}	Energy market price, \$/MWh
ρ^{Q}	Payment for reactive power supply from external grid, \$/Mvarh
τ	Energy contract price from investor-owned DG, \$/MWh
λ^{P}_{i}, λ^{Q}_{i}	Self active and reactive power Incremental Loss Indices (ILI)
σ^{P}_{i}, σ^{Q}_{i}	Mutual active and reactive power ILI
$\mu^{P}_{k,i}$, $\mu^{Q}_{k,i}$	Self active and reactive power Incremental Feeder Loading Indices (IFLI)
$\psi^{P}_{k,i}$, $\psi^{Q}_{k,i}$	Mutual active and reactive power IFLI
θ_{ij}	Angles of complex Y-bus matrix elements, rad
δ	Voltage angle at a bus, rad

Chapter

1

Introduction

1.1 Overview

In general, the electrical energy sector over the past two decades or so, has been affected by two important factors. The first factor is the advancement in generation technologies which has been evolving on a continuous basis, and newer and different energy transformation resources have been introduced to achieve high standards of energy provision. The second factor is the trend to liberate the energy sector from a monopolistic operating regime to a deregulated one, and to establish competitive markets for electricity.

The deregulation of the power industry and setting up of open markets for electricity in many countries, from the erstwhile vertically integrated systems has led to a clear separation between generation, transmission and distribution activities. All of these activities have undergone significant transformation processes in the restructured environment in order to find the operational range which is more secure, reliable and economic [1]-[5].

1.2 A Brief Introduction to Electricity Markets

The operation of the electric power industry world-wide has been changing from a vertically integrated mode to competitive market models. In the traditional system, the generation, transmission and distribution activities were managed and operated by a single, centralized, utility operator who ensured energy flow to the customers in the whole service territory. The electricity tariff was set by a regulatory process, rather than by market forces, whereby rates were established to recover the cost of producing and delivering the power to consumers as well as to recover the capital costs [3].

The term *deregulation* in the context of the electric power industry refers to a new industry structure of companies producing unbundled electrical services. It also means a clear separation between generation, transmission and distribution activities, and creating a competition structure amongst generation companies either through auction markets or through bilateral/multi-lateral mechanisms. The transmission sector is still considered a monopoly that must be regulated so as to ensure open and non-discriminatory access for all market participants.

The combination of full market opening, unbundling of transmission activities, regulated access to the network and liberalization of electricity trade is known as “retail competition”. Under retail competition, transaction among generators, end users and a number of possible intermediaries, such as retailers, power exchanges and brokers take place freely (within the “physical” constraints imposed by the network). Thus, on the demand side, end users are free to choose their supplier and to negotiate their contracts; on the supply side, generator can sell their electricity to any other market players.

1.2.1 Electricity Market Participants

The development of electricity markets have progressed in different directions across the countries / regions around the world. Therefore, some of entities that may be present in one market may not necessarily exist by the same name or function in another market. Moreover, one entity can also play more than one role in the market. In the following, the most common entities participating in electricity markets are briefly described [4],[5].

- *Generation companies (gencos)*

  Generation companies participate in the electricity market by producing and selling electrical energy either to the pool or directly to the customers through bilateral contracts. Their main aim is to maximize their own profit while participating in the market.

- *Transmission companies (transco)*

  Transmission companies are entities that own and operate the high voltage transmission networks. Transco assets are usually under the control of the Independent System Operator (ISO) and they operate in close cooperation with each other with the objective to provide non-discriminatory connections to all market participants.

- *Distribution companies (discos)*

  Distribution companies are entities that own and operate the distribution networks. Their main function is to operate, maintain and develop the network from a technical viewpoint. In a fully deregulated environment, the sale of energy to retail consumers is decoupled from the disco's operational responsibilities and is a separate business where different *retailers* can compete in. The disco may or may not be a retailer.

- *Independent System Operator (ISO)*

  The ISO is truly an *independent* entity in the deregulated electricity market environment having no interest in the commercial aspects of energy transactions, but is involved in maintaining the instantaneous demand-supply balance of the system and ensures that the energy delivery process is secure. Providing a non-discriminatory open access to all bulk system users is one of its functions. In other words, its main responsibility is to operate the system at high levels of security and reliability.

- *Market Operator (MO)*

  The market operator is an entity that receives sell offers and buy bids from market participants for electrical energy and sometimes for other products such as spinning reserves, *etc.* It carries out a market settlement process to determine the market clearing prices using a certain criterion such as maximizing social welfare. In most electricity markets in North America, the market operator and the ISO is one and the same entity.

- *Retailers*

  Retailers are entities that buy energy from the wholesale electricity market and sell it to customers. However, they need not necessarily own any generation or network asset. A retailer can simultaneously serve customers that are connected to different discos using their respective network facilities.

- *Customers*

  Wholesale customers are entities that purchase electrical energy either from the gencos through bilateral contracts or from the market by participating in the market clearing process. On the other hand, end-use customers are entities (*usually connected at distribution voltage levels*) that purchase their electrical energy from the disco/retailer and usually do not participate in the market.

1.2.2 Wholesale Electricity Market

In the restructured electricity market environment, the wholesale market is an organized process based on the principle of competition. All generators compete amongst each other to sell power to the market, or directly to customers and retailers if retail competition is allowed. The wholesale electricity market operation is coordinated by two entities, the market operator and the ISO. As mentioned earlier, in most systems in North America, the market operator is also the ISO. Functions of the wholesale market operator include electric energy auctions and settlement of energy transactions in different operational time frames- such as forward, day-ahead, real-time, *etc.* In contrast, the ISO oversees that the system is secure in real-time, and therefore it is responsible for procuring and managing the ancillary services to enhance the system reliability. In the literature, the organization and structure of the wholesale electricity market has been discussed with the help of two basic models, the pool model and the bilateral contract model, which are briefly discussed below.

a) Pool Model

In this model, participation in the pool is usually mandatory for all participants and the market operator functions as the central coordinator. The gencos submit their offers to the pool in order to supply energy to the grid and not directed to specific customers. These offers are arranged in increasing order of their prices to form an aggregate supply curve. The buyers, on the other hand, can also submit their bids to the pool where they are ranked and arranged as a demand function (inverse slope, in decreasing order of prices). The pool matches the sale offers and purchase bids and clears the market for sellers and buyers. Two main approaches have been reported for market clearing in a pool- the first is the *uniform price auction* and the second is the *locational marginal price* (LMP) auction, both of which seeks to maximize the social welfare.

b) Bilateral Contract Model

Bilateral contract based market models are negotiated agreements for delivery and receipt of power between two parties. These contracts set the terms and conditions of agreements independent of the ISO or the market operator. In this model the ISO and the transco are only involved after the settlement process to verify that sufficient transmission capacity exists to complete the transactions between the parties and to ensure system security. The bilateral contract model is very flexible because the trading parties involved in the contracts specify their own desired contract terms. In practice, most of the bilateral markets function as hybrid ones where a pool / power exchange exists along side but participation in the pool is not obligatory and customers can negotiate bilateral agreements directly with suppliers or choose to buy/sell power at the pool.

1.2.3 Retail Electricity Market

The provision of retail electricity markets allow all customers, particularly those at the low-voltage levels and who have not participated in the wholesale market, to be able to choose their electricity providers [2]. In such markets, the distribution network operations are two-fold. The first task is to ensure provision for distribution network facilities to the customers, and the second task is to ensure the provision for retail energy to customers by any retailer, including those without network facilities.

As explained in [4], electricity retailers are in business to bridge the gap between the wholesale market and small consumers. The challenge for them is that, they have to buy energy at variable price in the wholesale market and sell it at a fixed price at the retail level. In order to reduce their exposure to the risk associated with the unpredictability of spot market prices, the retailer therefore tries to forecast as accurately as possible the demand of its customers. It then purchases energy on the spot market to match this forecast. A retailer therefore, has a strong incentive to understand the consumption patterns of its customers.

In many instances the retailer also plays the dual role of being the distribution company (disco), with the responsibility of network operational aspects. With technical developments in distributed generation (DG) and their penetration in the distribution network, the disco's role has therefore, further evolved.

The tariff of electrical energy charged from the end-use customers usually comprises two cost components- that of the retail energy and the network access. In Spain, for instance, the retail access tariffs for end-use customers are calculated from the retail tariffs charged to regulated customers minus the market price of energy [2]. The implementation of retail markets world-wide, especially in countries or states that have decided to introduce a total competition for end-use customers, have taken different approaches with respect to regulations and operations.

1.3 Operational Aspects of Distribution Systems

1.3.1 Distribution Systems in General

Distribution systems can be defined as electrical interconnections joining the bulk electric power system to end-use customers requiring energy services at voltage levels below that of transmission and sub-transmission systems. At the generating station, the voltage level of the generated power is boosted up by a step-up transformer to match the voltage level of the transmission system. After a long distance transmission of this power, and near to the customer end, step-down transformers transform the bulk power to lower voltage levels. The power is transferred further over the sub-transmission system network to reach the local sub-stations close to the demand centre. At the distribution sub-station, the power is transformed to a lower voltage level for distribution on a primary distribution feeder [6]-[9]. Figure 1.1 shows the typical configuration of a power system with different voltage levels.

The primary distribution feeder can be configured as radial, loop or as primary network systems. The radial distribution system is the most frequently and widely used configuration since it is the simplest and the least expensive system to build. In this configuration, there is only one path for the power flow from the substation to the end-user. So the operation and expansion of such distribution systems are simple [9]. However, radial feeder configurations suffer from low reliability because any fault occurring immediately after the substation will cause a power interruption on the downstream feeder. The service reliability can be improved on this feeder by installing automatic reclosing devices at the substation or at various locations on the feeder. These devices work to reduce the duration of interruptions by re-energizing the feeder if the fault is temporary. Sectionalizing fuses are also installed on branches of radial feeders to isolate the affected portions of a feeder and allow the unaffected ones to remain in service.

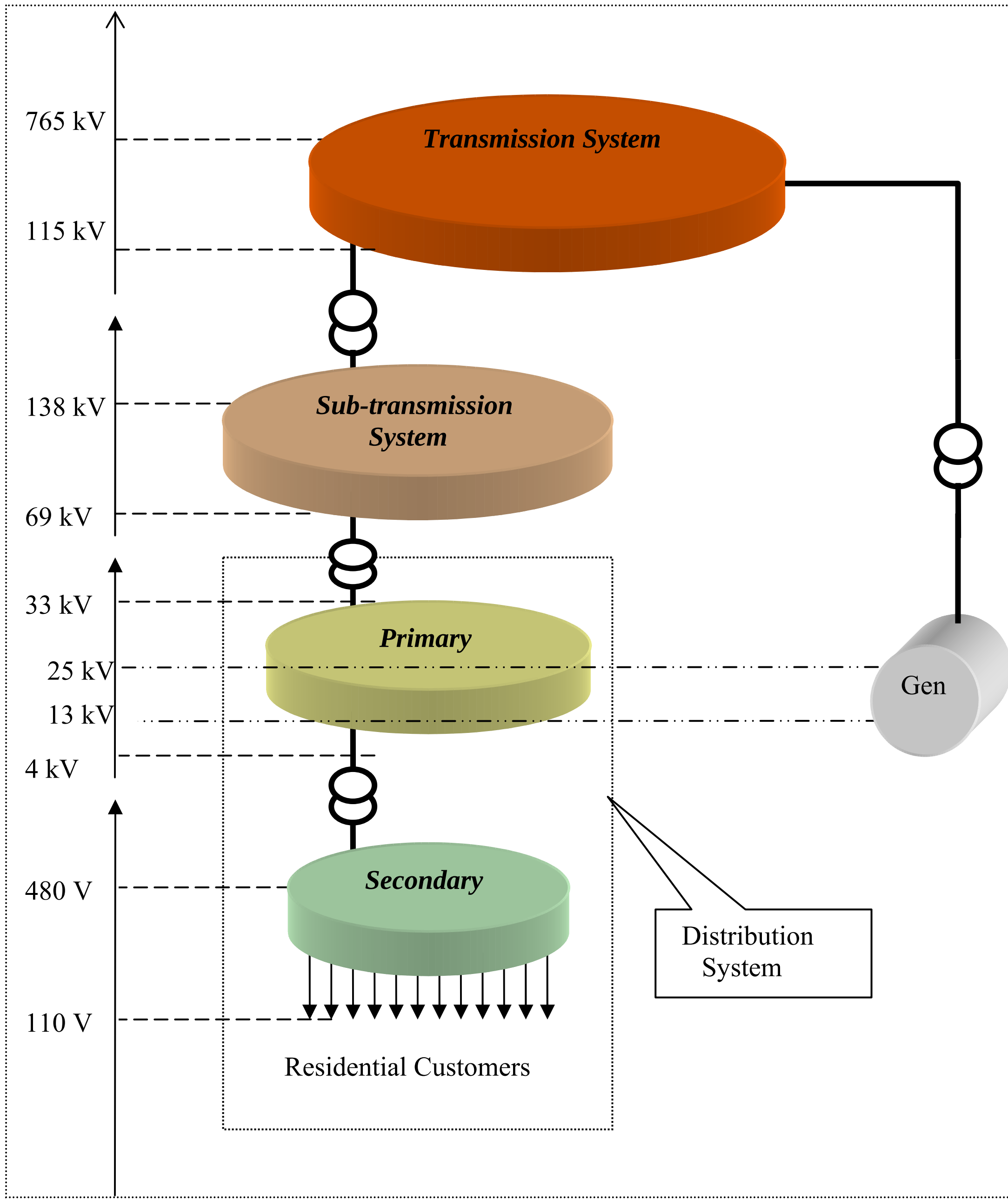

Figure 1.1: Typical power system transmission and distribution structure with different voltage levels

1.3.2 Traditional Operational Issues in Distribution Systems

In the past, the distribution systems used to operate with minimum monitoring systems, mainly with local and manual control of capacitors, sectionalizing switches and voltage regulators and without adequate computational support from the operators. However in modern times, Supervisory Control and Data Acquisition Systems (SCADA) have been implemented widely in order to operate the distribution systems more efficiently. SCADA is a convenient tool for the enhancement of distribution system performance as it enables reconfiguration of the network. Distribution networks 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. Network reconfiguration can alleviate, to some extent, some of the important and frequently encountered problems such as higher power loss, overloading, voltage instability and voltage collapse [10].

The flow of electric current through different equipment on the distribution system produces thermal loss which is dependent on the inherent characteristics of electric power systems. An earlier study stated that up to 13% of the total power generation was lost as feeder losses in distribution networks [11]. Power loss is calculated as I^2R where I is the current flowing in the conductor and R is the resistance of that conductor. The cost of such losses in distribution systems is estimated to be in the order of millions of dollars per feeder, annually [12]. Optimal reconfiguration, for example, of a radial distribution system will control the power flow resulting in minimization of the branch currents of the system thereby decreasing the I^2R losses.

Voltage instability is one of the other basic problems in distribution systems. It is initiated due to insufficient local reactive power support combined with heavy loading of some parts of the distribution network. Voltage collapse can result in losing a significant part of the electric power system. It is usually very difficult to predict the area that will be affected or electrically isolated because of the collapse. The distribution utilities can utilize reactive power compensation devices to maintain the bus voltage levels within acceptable limits. Load shedding is also an operational option available with the disco to relieve heavy feeder loadings in addition to avoiding cascaded voltage collapse problems [13].

1.3.3 Operational Issues in Distribution systems in Deregulation

The operation of electric power systems in the competitive market environment has taken new trends. The traditional operational problems in distribution systems (*as discussed in Section-1.3.2*) pertaining to the vertically integrated power system structure continue to be important issues in the context of deregulation, as well. However, further new issues have arisen because of the emergence of new entities within the distribution system domain such as generation sources and interties, which make it a very complex arrangement both from the technical and the economic perspectives.

The current trend in penetration of generating sources located within the distribution system (*termed as Distributed Generators or DG*) is a very promising option in the context of deregulation. The DG units have a significant impact on the operation of distribution systems. For example, radial distribution feeders are normally regulated using on-load tap changing transformers at substations or switched capacitors on feeders. With the installation of DG units there will be an impact on the system voltage profile. This impact can be positive such as voltage support in some cases, but can also be negative such as over-voltage or an under-voltage, depending on relative DG size and their location, distribution line and load characteristics, and method of voltage regulation.

The DG sources can also alter the power flow patterns on distribution feeders. Instead of the unidirectional flows, that distributions systems have typically experienced, there would be reverse flows, particularly during low load conditions in the network. Such reverse flows would also consequently impact the reactive power drawn from load bus capacitor banks, the active and reactive power transferred over substation transformers, *etc.* There are also issues regarding impact of the reverse power flows on the protection devices.

Clearly there is a need to examine the very important role that DG will play in the disco operations- in the coming years. And finally, with the emergence of retail electricity markets there are important issues concerning efficient and reliable metering, control, protection and automation systems to operate the distribution systems in an efficient manner.

1.4 Research Motivation and Objectives

As discussed earlier, the latest sub-sector to be affected by deregulation has been the distribution system- with introduction of retail competition and penetration of DG sources. Various issues have arisen from this, such as the role of the DG in short-term system operations with regard to reduction of feeder losses, reactive power support provisions and reserve services, *etc.* There are also issues regarding the role the discos can play in the long-term and their impact on the distribution system's growth and investment requirements. These issues need to be examined in greater detail so as to utilize and plan for the DG capacities optimally. Furthermore, there is a growing need for participation of customers in system operations aspects to help the system in several ways. Several regulatory authorities and governments have established Conservation and Demand Management (CDM) programs that involve the participation of customers in load relief and supporting the system reliability and security.

The role of the disco has therefore evolved into a very important and critical one for a sound and efficient operation of the whole power system taking into consideration the presence of new DG units and the new mechanisms of flexibility in customer load behaviour.

The issues of operations and planning of discos therefore need to be studied and examined in detail. The main objectives of this research are two-fold, first to examine the short-term operations aspects of electrical distribution systems in deregulated electricity markets in the presence of various new issues and constraints. The second is to examine the long-term policies of distribution system expansions and how they are affected in the new environment. The main objectives of the thesis are outlined as follows:

1. In order to analyze the gamut of issues involved, there is a need to develop a comprehensive modeling framework pertaining to discos that incorporate the complete distribution system power flow conditions. The modeling framework should take into account the disco's optimization objectives and operating constraints arising from both the distribution system and the retail electricity market. Thereafter, there is a need to examine and validate such a

model for fairly large and ill-conditioned distribution systems for their solvability and to examine their computational aspects.

2. To examine the optimal operation of a disco in a competitive market environment to determine its short-term decisions such as scheduling of its DG production, calls for interruptible loads, and grid purchases. The short-term operations framework of the disco should be in synchronism with the electricity market operations framework. In this thesis, a two-settlement market structure comprising a Day-ahead Market and a Real-time Market is assumed.
3. It is also important to note that an individual disco is only a part of a large integrated power system. The wholesale market price in the system will have an effect on the system demand, and consequently, on the individual disco's demand. Therefore, such inter-relationship between the external electricity market price and the local disco demand is an issue of importance, and the disco's operations can be affected by such interactions. There is a need to examine this issue within the short-term operations framework developed.
4. In addition to the above, it is also important to examine the impact of reactive power flows in distribution feeders, the effect of capacitor compensation on disco losses, and the contribution of DGs and customer load curtailment and their appropriate pricing mechanisms.
5. In order to systematically compare and weigh the various options available to the disco, it needs to examine how a resource contributes to its operations. A novel set of indices that examine the impact of various resources located at different buses, on the disco's losses, termed as the *Incremental Loss Indices* (ILIs), can provide such critical information. The ILIs are essentially power flow sensitivity indices denoting the impact on disco feeder power flows due to changes in bus injections, to be obtained from multiple distribution load flow calculations.
6. At this stage the disco operator will be well equipped with the operations planning model incorporating all aspects of technical constraints and

markets, and also with the information on ILIs. It is important that the disco operator uses these tools effectively to operate the system in the best possible manner, helpful to the customers, and maintains a high level of supply quality and reliability. Analysis will be carried out to examine the effectiveness of the modified operations planning model when applied to test case systems.

7. It has been mentioned earlier that DG resources also have long-term impact on the disco with regard to capacity deferrals. However, no systematic studies have been reported in the literature to examine this aspect so far. Similar to ILIs, but on a long-term framework, another novel set of indices are developed that denote the impact of DG resources at a given bus, on the disco's feeder unloading, termed the *Incremental Feeder Loading Index (IFLIs)*. Planning studies will be carried out to examine the importance of the DGs in overall disco planning framework and their role in capacity deferrals and how important the IFLI indices are in such studies.

1.5 Outline of the Thesis

This thesis is structured as seven chapters. Following this introductory chapter a literature review is presented in **Chapter-2** where research publications pertaining to operational and planning aspects of distribution systems are discussed to develop a clear picture of the state-of- art.

Chapter-3 first presents an overview of distribution power flow analysis in the traditional load flow framework. Thereafter a simplified version, and a full-scale distribution system optimal power flow model is developed that can address the new issues arising from the introduction of retail competition and penetration of DG sources. A simple 9-Bus test-case distribution system and three well known large-scale, ill-conditioned, radial distribution systems (the 28-Bus, the 33-Bus and the 69-Bus systems) are considered for analysis in order to verify the feasibility of the proposed optimal power flow model for distribution systems.

In **Chapter-4**, a generic operations planning model is presented for a disco owning and operating the 33-Bus distribution system in a retail electricity market environment. The operations framework is a two-stage hierarchical model in which the first stage deals with disco's activities in the day-ahead stage, the Day Ahead Operations Model (DAOM). The second stage deals with disco's activities in real-time and is termed Real-Time Operations Model (RTOM). The DAOM determines the disco's operational decisions on grid purchase, scheduling of distributed generation (DG) units owned by it, and contracting for interruptible load. These decisions are imposed as boundary constraints in the RTOM and the disco seeks to minimize its short-term costs keeping in mind its day-ahead decisions. Three different scenarios are constructed to analyze the disco's actions and decision-making in its operational activities.

Chapter-5 introduces a set of indices that can assist the disco in its operational decision making functions. These indices denote the sensitivity of system loss to an incremental change in active and/or reactive power injection at a node. In order to integrate the effects of these indices in an optimal energy provisions framework for the disco, the novel concept of goodness factor is introduced to the system buses. The disco's operations model is appropriately modified to include the goodness factors.

In **Chapter-6** the concept of goodness factors is further extended to determine a new set of goodness factors pertaining to a DG's impact on feeder unloading by virtue of its power injection. A novel long-term planning model is presented for the disco that considers investments in DG capacity, distribution system feeder addition / expansion and substation transformers capacity addition. The model includes the set of goodness factors pertaining to both loss reduction and feeder unloading and arrives at an optimal set of new expansion plan, with specified locations, and year of commissioning.

Chapter-7 draws the conclusions from the research work carried out in the thesis, summarizes the main conclusions, and outlines some scope for future work in this area.

Chapter

2

Review of Literature

Electric power distribution system operation and planning are not new problems. These have been handled by utilities since the very beginning. However, as we have discussed in Chapter-1, these problems have undergone a paradigm shift with the emergence of deregulation of the power industry. With the possibility of retail competition and of power being supplied by DG sources and injected into the low-voltage distribution network, several complex issues have arisen.

In this chapter a modest attempt is made to review some of the previous research that has addressed one or more of the issues pertinent to this thesis. The review is grouped into the following categories.

- Distribution systems and their operational aspects
- Disco operations in deregulation, DG operations
- Disco planning in deregulation
- Interruptible loads and their integration in system analysis models
- Retail electricity markets.

2.1 Distribution System Operations and Planning

Traditional distribution system operational aspects have been researched extensively over the years. Some of the important publications are discussed here.

The general formulation and solution methods for distribution load flow are proposed in [10] for loss reduction and load balancing based on radial network reconfiguration. Two approximate power flow methods are developed in order to determine the best radial configuration. A load flow technique for solving radial distribution networks by using a unique lateral, node and branch numbering scheme is presented in [14]. The method solved a recursive relation of voltage magnitude without any trigonometric functions while loads are represented as constant power.

In [15], the load flow equations are written in terms of new variables instead of the conventional state variables (complex bus voltages). This leads to a set of 3N equations, of which 2N equations relate to power injections and are linear, while the remaining N equations relate to bus voltages and are quadratic. Then, the Newton-Raphson method is used to solve these equations.

The formulation of the radial distribution load flow problem as a conic program is presented in [16]. The main advantages of the conic programming formulation are that ill-conditioned systems are easily handled and distribution power flow equations are included in radial system optimization problems.

In [17] the reactive power optimization problem with time-varying loads in a distribution system is investigated. The objective is to determine the hourly settings of capacitor banks and transformer taps for the next day. A combination of heuristic and algorithmic approach is proposed that simplifies the mathematical model of the daily setting values of reactive power/voltage control devices, solves the temporal optimization of each control devices by heuristic rules, and then converts the optimization model with time-varying load into one as conventional optimization model with constant load.

A fuzzy-logic based algorithm to determine the optimal capacitor allocation in radial distribution feeders is developed in [18]. The effect of varying some parameters in the membership functions to obtain better results is discussed. Also, the effect of selection of parameters that should be used in the fuzzy modeling is investigated.

A two-stage, heuristic method, for determining a minimum loss configuration, based on real power loss sensitivities with respect to the impedances of the candidate branches is presented in [19]. In the first stage, the method uses this sensitivity information while the second stage uses branch exchange procedure to improve the solution.

In [20] the authors propose an Ant Colony Optimization (ACO) method for solving distribution reconfiguration problem for loss minimization. The ACO algorithm is implemented in a novel hypercube framework on a 33-bus test system and the results obtained show that the ACO algorithm provided the most optimum solution found thus far by any other method proposed in the literature for the 33-bus test system considered.

In [21], a joint optimization algorithm of combining network reconfiguration and capacitor control is proposed for loss reduction in distribution systems. To achieve high performance and high efficiency an improved adaptive genetic algorithm optimizes the capacitor switching, and a simplified branch exchange algorithm determines the optimal network structure for each iteration of capacitor optimization algorithm.

A method to optimally locate resources in a meshed network for maximizing the potential benefits is outlined in [22]. The algorithm computes the required amount of resources at selected nodes to achieve the desired optimization objectives such as the minimization of losses, or loading on selected lines.

A method for selection of optimal set of conductors is presented in [23]. Several financial and engineering factors are considered in the proposed procedure. The intent is to arrive at a least-cost solution, considering both capital and operating costs

A framework for solving the capacitor placement problem on a radial distribution system using a Genetic Algorithm has been presented in [24]. The objective is to minimize the peak power losses and the energy losses in the distribution system considering the capacitor cost. A sensitivity analysis based method is used to select the candidate locations for the capacitors.

2.2 Disco Operations in Deregulation, DG Operations

A method for distribution access via uniform pricing for remuneration of distribution networks is presented in [25]. Hourly uniform marginal prices are derived, *i.e.*, tariffs for use of network, from maximization of a social welfare. These prices are efficient indicators (signals) to the disco and consumers regarding optimal operation of the grid and use of energy at peak and valley hours, respectively. A linear optimal power flow (OPF) model is used to determine the prices.

A nodal pricing scheme applicable to short-term disco operations is proposed in [26] that seek to reward DGs for reducing feeder losses. Significant nodal price differences between distribution network buses are found to exist because of high losses. The nodal pricing mechanism is a good incentive to DG resources providing a noticeable reduction in feeder losses and loading.

A new circuit-based loss allocation technique, based on the decomposition of the branch currents, specifically developed for radial distribution systems with DGs is presented in [27]. The technique is simple and effective and is only based on the information provided by the network data and by the power flow solution.

In [28] a method for allocation of fixed costs at the medium-voltage distribution level is presented. It is derived from the widely used MW-mile method for transmission networks that bases fixed cost allocations on the “extent of use”, derived from load flows. The “extent of use” in this case, is calculated by multiplying the total consumption or generation at a bus-bar by the marginal current variations, or power to current distribution factors that an increment of active and reactive power consumed, or generated in the case of DG, at each bus-bar, produces in each feeder. These factors are analogous to power transfer distribution factors (PTDFs).

A distributed slack bus model has been developed in [29] using the concept of participation factors, applicable to unbalanced systems. The participation factors were incorporated in three-phase power flow equations which were solved using a Newton-Raphson algorithm. Such a model can be used for DG placement studies, network reconfiguration, economic analysis for fair pricing and aggregate substations loading.

A day-ahead energy acquisition model for a disco in a pool market in the presence of financial bilateral contracts is presented in [30]. Both investor and utility-owned DG units are considered in the model and include interruptible load (IL) options. An OPF model is used to arrive at the optimal set of energy schedules and decisions

A multi-objective model to evaluate the impact of energy storage specific costs on net present value of energy storage installations in distribution substations is presented in

[31]. Specific cost effects on economic performance of energy storage technologies are evaluated for an HV/MV substation. For each technology, sets of optimal economic operation strategies and capacities of the storage devices are determined.

Tracing of real and imaginary components of the feeder current is used in [32] to allocate the losses in distribution networks with DG. First losses are calculated considering no DGs in the distribution network, and allocated to the consumers. Thereafter, the variations in losses because of DG are allocated to them. The allocation is made to each user of the network based on its impact on a branch basis.

The performance of distribution systems including DG is analyzed in [33] by considering the deterministic and stochastic natures of power systems. Monte Carlo simulation is employed taking into consideration the system operation constraints. The uncertainties in their siting , expected penetration level and states (on/off) of the DG units constitute the random parameters. The algorithm incorporates these parameters within traditional power flow equations.

There are other associated issues in disco operations such as the issue of operational limit to be imposed on particularly, wind-based DGs because of steady-state voltage rise problems. Various techniques can be applied to limit steady-state voltage rise such as network reinforcement or power factor control as proposed in [34].

An approach to analyzing the technical impact and assessing the voltage rise that would be caused by high DG penetration was presented in [35]. It was concluded that considerable penetration of DGs may be accommodated without modification of network voltage control systems.

A multi-period energy acquisition model for a disco with DG and IL options has been presented in [36]. A bi-level optimization formulation is developed wherein the upper sub-problem maximizes the disco's revenue, while the lower sub-problem addresses the ISO's market clearing by minimizing generation costs and compensation costs for IL. The model takes into consideration inter-temporal effects such as ramping.

In [37] a quantification of benefits from customer-owned back-up generators to discos is carried out. An integration scheme for DGs in a pool-based market structure is proposed in [38] that encompasses both energy and capacity payment procedures. The problem of dispatch and control of DGs is formulated in [39] as a multi-agent system-based scheme, specifically for the purpose of voltage support.

In [40] it has been brought out that DG owners create significant benefits to the utility by loss reduction and capacity deferral. However, they are still charged a connection tariff instead of being financially compensated for the benefit they provide. In [40], mathematical models, somewhat approximation, have been developed to quantify these benefits.

A control approach is proposed in [41] to mitigate the voltage rise in distribution networks with DGs. In this approach the injection regulation mechanisms for DG is provided where the voltage level at the bus is not perturbed.

In [42], the effect of implementing intentional islanding on electricity market prices is examined. It has been clearly identified that disco prices are affected during such a system condition.

2.3 Disco Planning in Deregulation

The change in power flow patterns in distribution systems because of the presence of DG units, calls for detailed analysis and development of tools that can compute their contributions on increase/reduction of feeder losses and feeder loadability. To this effect an approach to quantification of the distribution network capacity deferral value of DGs is presented in [43]. It is reported that the most important benefits from deferral are obtained when DGs are installed at the end of long feeders and near load pockets.

Optimal location of DGs in distribution networks is an important issue in order to derive maximum benefits from them. In [44], analytical methods are proposed to determine the optimal location of DGs in radial and networked distribution systems to minimize the power losses.

In [45], a comprehensive optimization model is developed that also incorporates the planner’s experience to achieve optimal sizing and siting of DG. Binary decision variables are employed in the model to determine exact planning decisions. A present worth analysis of different scenarios is carried out to estimate the feasibility of introducing DG as a key element in solving the planning problem. In the same context, a heuristic cost-benefit analysis based approach was proposed in [46] to obtain the optimal DG sizing and sitting that meets peak demand forecast. The model aims to minimize the disco's investment and operating costs as well as payments toward loss compensation.

In [47] a method for optimal planning of radial distribution networks is presented based on a combination of steepest descent and simulated annealing approaches. The optimal network of available routes is determined that results in the minimal total annual cost. The minimum capital cost solution obtained from the steepest descent approach is used as the initial solution for the optimization procedure that is further improved by simulated annealing to obtain the minimum total cost solution. The method takes into account the capital recovery, energy loss and undelivered energy costs.

A DG investment planning model is presented in[48] using various reliability indices in order to determine the optimal DG locations and sizes. It was concluded that although the DG addition may be the most expensive alternative, using the reliability techniques and the capital deferral credit obtained from disco, the DG option could become a cost-effective solution.

A Benders decomposition solution is used in [49] to determine optimal DG sitings on network buses. The model considers stochastic nature of generator outputs, with power flows represented using linear models. A locational marginal pricing approach for the siting and sizing of DG units is proposed in [50].

2.4 Load Management, Interruptible Load and Its Implications

Direct load control and demand side management (DSM) programs are not new, and have been discussed by researchers and policy makers since the eighties decade. DSM programs and load control measures have also been implemented in several electric utilities. These programs can provide enhanced system security and also result in several benefits to the participants. In [51] a comprehensive review of the existing load control programs has been made.

A systematic review on recent research trends related to interruptible load management (ILM) and its operational role in deregulated electricity markets was provided in [52]. In an ILM the customer signs a contract with the local utility (*e.g.* disco) or the ISO, as the case may be, to reduce its demand as and when requested. The disco/utility benefits by way of reduction in its peak load and thereby saving costly generation reserves, restoring quality of service and ensuring reliability. The customer benefits from reduction in its energy costs and particularly from monetary incentives provided by the disco/ISO. Provisions also exist in certain markets for the customer to bid, in the auction, their ability to modify their demand- referred to as *demand side bidding*. For example, a form of interruptible load (IL) used in UK prior to 2001, involved large industrial customers bidding into the pool directly on their ability to reduce load [53]. Depending on the structure of the electricity market and the perception of the customer, appropriate ILM contracts can be designed to attract customer's participation in IL schemes so as to maximize the overall economic efficiency.

An optimal power flow (OPF) framework is developed in [54] to address issues of advance notification for load curtailment as well as short and long term price discounts on demand charges. In [55] optimal incentive rates are determined for a real-time interruptible tariff mechanism. An OPF framework, modified to include the incentive rate as a variable, is used. Interaction between the utility and customers contracting IL is incorporated in the analytical framework by formulating customer response function to the interruptible tariff. The effect of spot pricing on IL services and how the utility can procure the demand offers in real-time to maintain the security of the system is an important issue. A competitive framework for optimal procurement of IL services within secondary reserve ancillary service markets is introduced in [56].

In [57], optimal IL contracts are formulated by using mechanism design in order to encourage customers, through sufficient incentives, to voluntarily sign up for the contract that best suits their needs and reveal their true value of electricity.

The price induced consumer/supplier dynamics and their elasticity effects on a short-run demand forecasting model has been examined in [58] by the introduction of the concept of a cross-time price elasticity matrix. This method allowed the consideration of how demand for electricity may redistribute itself over a time period such as a day or a week. In the same context a theoretical model was introduced in [59] for incorporating behavioral aspects of consumers in response to real-time pricing and the concept of demand elasticity with time was introduced. In [60], the load at each bus was no longer considered to be a fixed quantity but becomes a decision variable in the ISO's optimization problem. The actions of price responsive loads were represented in terms of the customers' willingness-to-pay. The impact of different levels of elasticity on the market and on congestion relief was assessed in terms of prices and main economic metrics. From each customer's demand curve, the elasticity of the load at different prices was known and benefit function was derived.

Reference [61] explores how short-term elasticity of demand, using a matrix of self and cross elasticity, could be considered when scheduling generation and setting the price of electricity in a pool-based electricity market.

A most recent Norwegian survey on consumer valuation of interruptions and voltage problems is presented in [62]. The raw data were normalized by *energy not supplied* and interrupted power, providing cost estimates that are incorporated in the quality of supply regulation.

2.5 Retail Competition in Electricity Markets

The transmission and distribution networks are natural monopolies that are expected to provide open access to all market participants without discrimination and are fully transparent in their operations. Some countries or states world-wide have already initiated a full retail competition market structure where their customers can be directly involved in electricity market alternatives and can choose their energy provider.

A procedure was introduced in [63] to evaluate electricity supply contracts for retail consumers who have a choice of retail supply offers under deregulated environment. A long-term contract at a fixed price can be attractive to some consumers because the electricity market spot-price may be very volatile. An index was introduced to reflect the consumers' preference for a low price with some margins. Uncertain market prices were estimated by an extended regression model that considered the possible ranges of prices.

A stochastic linear programming model was proposed for constructing piecewise-linear bidding curves for retailers in the Nord Pool market [64]. The objective was to minimize the expected cost of purchasing power from the day-ahead energy market and the short-term balancing market.

In Canada the deregulation of the power industry has varied across the provinces, as each province assesses its own unique regional circumstances. Only two provincial governments- Alberta and Ontario- have established markets characterized by wholesale and retail unbundling, although their specific market designs differ. In Ontario and Alberta, an ISO sets and administers polices for grid interconnection, transmission planning and spot market operations. Ontario implemented full retail access on 1 May 2002. Alberta restructured its electricity market over a five-year period culminating in full retail access on 1 January 2001.

2.5.1 Retail Competition in Ontario

The *Energy Competition Act* was proclaimed in October 1998 that recommended Ontario Hydro be split into two main commercial companies: Hydro one and Ontario Power generation, which would operate in a reform and more effective regulatory framework. A new regulatory body, was created- the Independent Electricity System Operator (IESO). Now Hydro One owns and operates the province-wide electricity transmission grid and some local distribution systems across Ontario. Hydro One and the other 94 local distribution companies (LDCs) in Ontario are “natural monopolies” which are subjected to independent regulation by the Ontario Energy Board (OEB) and the ISO (IESO). The OEB must regulate and approve transmission and distribution rates.

Consumers now have an opportunity to choose to purchase their electricity from a retail seller. The OEB also licenses retail sellers of electricity and regulates to prevent abuse and fraud. Competitors can also provide other benefits, such as offering customers the choice of “green” source of power, like wind or solar generation.

The diagram below provides a simple illustration of how transactions occur in the competitive retail market. Customer-A is on standard supply service while Customer-B is a consumer with a competitive supply contract with an alternative retailer.

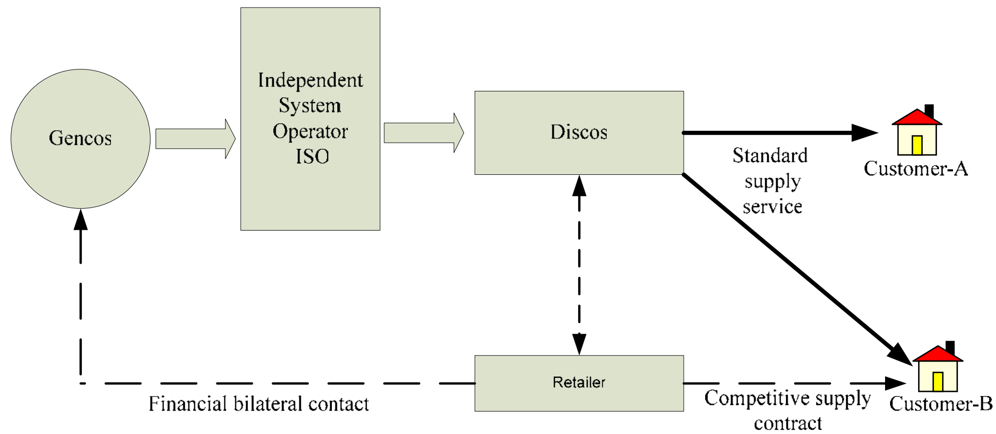

Figure 2.1: Schematic representation for retail electricity markets structure in Ontario

In Ontario retail market, the IESO dispatches the load and delivers power through the grid to every distributor/disco. Each distributor/ disco accepts/receives the electrical energy at their meter and delivers it to the end-use customers who are connected to the distributor's distribution system/network (Figure 2.1).

The IESO charges each distributor /disco for its load based on the hourly usage at the distributor's meter and the Hourly Ontario Electricity Price (HOEP). The distributor in turn, calculates the energy for each of its customers based on HOEP and a weighting mechanism, either a load profile for customers who have Kilowatt-hour meters, or the actual hourly consumption for those customers who have interval meters. Where a consumer has chosen to buy electricity from an alternative retailer (*e.g.* Customer-B), the distributor still calculates the consumer's electricity bill, but may direct it to the retailer for payment on behalf of the consumer. The alternative retailer may be an independent retailer or the distributor's retail affiliate.

Regardless of who supplies electricity to a customer, the distributor must have the capability of calculating the wholesale spot market value of the electrical energy portion of that customer's bill.

A retailer who receives the customer's electricity bill from the distributor would be required to pay the distributor for the amount of electricity the customer has used, priced by the distributor according to the weighted average of the HOEP. However, the customer pays its retailer in accordance with the competitive supply contract which has been mutually agreed to by the two parties. A retailer also may have a contract with a generator to support the arrangement the retailer has with its customer. In this retail market design, a distributor does not need to know anything about the contracts that a retailer has with its customers or with generators. The distributor is required to calculate the wholesale spot market value of the electrical energy that a customer uses, regardless of whether it is served by an alternative retailer or the distributor itself, and despite whatever other arrangement a retailer may have.

2.6 Concluding Remarks

In this chapter an attempt has been made to discuss and review some of the published literature pertaining to various aspects of distribution system operation and planning in deregulation. The publications have been categorized in five areas. The first category pertains to classical distribution system operation and power flow analysis. Distributed generation pricing and economic operations issues are discussed next. Thereafter, literatures pertaining to planning issues in the context of deregulation are discussed. Load management and interruptible load options in deregulated electricity markets are reviewed in the fourth section, and the last section discusses the few recent publications on retail electricity markets and some practical developments in Ontario electricity market.

Chapter

3

Distribution Power Flow Models for Retail Electricity Markets[1]

3.1 Introduction

Electric power distribution networks are generally characterized by their radial configuration and high R/X ratios in feeder parameters. These factors impose limitations on their solution methods and the traditional power flow methods such as those based on Newton-Raphson or Gauss-Seidel's algorithms often fail to converge. Distribution networks and hence their load flow problems are therefore, termed as ill-conditioned problems [10], [65]. In this chapter, it is first demonstrated that the well developed non-linear programming (NLP) based optimization framework can be used to solve the distribution system load flow, and satisfactory results can be obtained. A distribution load flow (DLF) framework is proposed for the same.

Further, in recent years, OPF models have found extensive use in power system analysis. These OPF models are usually NLP formulations, with the objective to minimize cost, loss, *etc.* In this chapter, the traditional OPF model is extended to distribution system power flow analysis. For example, when DG sources are present in the distribution system models the number of variables increase significantly and there is a need for optimal decisions pertaining to their operations and scheduling. The same

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[1] Some parts of this chapter have been published in:

- A. Algarni and K. Bhattacharya, *Novel sensitivity indices based siting of distributed generation resources*, Proc. IEEE PES Annual General Meeting 2008, Pittsburg, USA applies to capacitor placement problems in distribution systems, and a distribution OPF (DOPF) can be very useful in determining their optimal placements, switching, *etc.* Moreover, using the DLF and DOPF models, both active and reactive power flows in the distribution system can be handled easily and simultaneously.

3.2 Distribution Power Flow Analysis

The solution of the traditional load flow problem provides the voltage magnitudes, angles, and line power flows through the network for a set of loads at different buses. These loads are usually represented as constant power loads instead of their impedances, and similarly, the generation sources are also considered as power sources, not voltage or current sources. Therefore, the load flow problem is formulated as a set of nonlinear equations solved by using the well known methods such as the Newton-Raphson or Gauss-Seidel [66].

3.2.1 Traditional Distribution Load Flow

The three-phase radial distribution system is assumed to be balanced and can be represented by an equivalent single-line diagram as shown in Figure 3.1. The line shunt capacitance at the distribution voltage level is small and, hence, can be neglected.

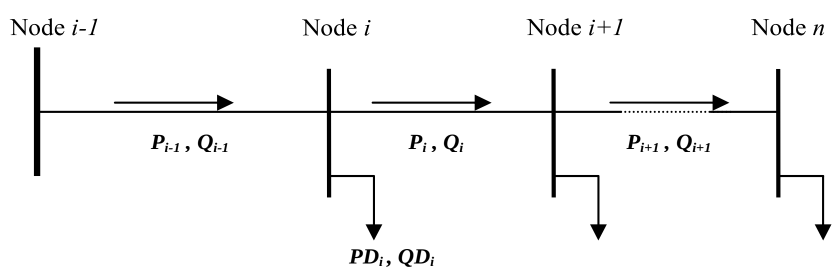

Figure 3.1: Single-line diagram of a radial distribution network

In the radial distribution system, as shown in Figure 3.1, a main feeder is connected to a single source that represents the distribution substation. As per Figure 3.1, the node *i-1* is accordingly the distribution substation bus in this case. The branch impedances are denoted by $z= r + jx$ and loads at a bus are considered constant power sinks, denoted by $PD_i + jQD_i$.

A set of recursive equations, known as the distribution branch flow equations (3.1)-(3.3), can be obtained using basic circuit theory [10] which is usually solved to arrive at the solution of the distribution system power flow. P_i and Q_i are the active and reactive power injections respectively, on a feeder at the sending end, i. The feeder bus voltage is denoted by V.

$$P_{i+1} = P_i - r_i \frac{P_i^2 + Q_i^2}{V_i^2} - PD_{i+1} \tag{3.1}$$

$$Q_{i+1} = Q_i - x_i \frac{P_i^2 + Q_i^2}{V_i^2} - QD_{i+1} \tag{3.2}$$

$$V_{i+1}^2 = V_i^2 - 2\left(r_i P_i + x_i Q_i\right) + \left(r_i^2 + x_i^2\right)\frac{P_i^2 + Q_i^2}{V_i^2} \tag{3.3}$$

3.2.2 Distribution Load Flow Formulation (DLF)

The classical power system load flow equations are given by:

$$\varphi_1\left(V_i, \delta_i\right) = P_{inj,i} - \sum_j V_i V_j Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) = 0 \qquad \forall \quad i \neq slack \tag{3.4}$$

$$\varphi_2\left(V_i, \delta_i\right) = Q_{inj,i} + \sum_j V_i V_j Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) = 0 \qquad \forall \quad i \neq NPV, slack \tag{3.5}$$

In (3.4) and (3.5), Y_{ij} and θ_{ij} are the magnitudes and corresponding angles of the Y-bus matrix elements respectively; and δ is the associated voltage angle at a bus. $P_{inj,i}$ is the active power injected at bus i, which is determined from the bus generation and load. Similarly, $Q_{inj,i}$ is the reactive power injection at bus i. NPV is the set of voltage control buses in the system.

When a distribution system is modeled in the above framework, the substation bus will be analogous to the transmission slack bus, providing for all the distribution system feeder losses, and will be the only PV bus in the system, having a constant voltage. For example, in an N-bus distribution system, if bus-1 is the sub-station bus (or slack bus), the remaining N-1 buses will be the load buses (*P-Q buses*). Accordingly, (3.4) and (3.5) can be re-written as follows:

$$\begin{aligned} \varphi_1(V_i,\delta_i) &= -PD_i - \sum_j V_i V_j Y_{i,j} \cos(\theta_{i,j} + \delta_j - \delta_i) = 0 \quad \forall \quad i \in NL \\ \varphi_2(V_i,\delta_i) &= -QD_i + \sum_j V_i V_j Y_{i,j} \sin(\theta_{i,j} + \delta_j - \delta_i) = 0 \quad \forall \quad i \in NL \end{aligned} \tag{3.6}$$

In (3.6), NL is the set of load buses, and PD_i, QD_i are the active and reactive power demand at bus i, respectively. Note that (3.6) will require the calculation of distribution system Y-bus matrix in the usual way. If, in the above formulation, an objective function J is included, the set of simultaneous non-linear equations is converted to a NLP problem, and powerful methods of NLP solution can be used.

To this effect, a *dummy* objective function, where J is a constant, is used and the problem can be stated as follows:

$$\begin{aligned} &Minimize \quad J \\ &Subject \quad to, \\ &\qquad \varphi_1(V_i,\delta_i) = 0 \\ &\qquad \varphi_2(V_i,\delta_i) = 0 \end{aligned} \tag{3.7}$$

The above NLP model can be solved iteratively using MINOS5.1 in the GAMS environment by solving sub-problems with linearized constraints and an augmented Lagrangian objective function. This iterative scheme implies that only the final optimal solution is feasible for nonlinear models, in contrast to the feasible path method used by other large scale NLP solvers.

The substation power, which is the power injected at the slack bus, denoted by P_{Slack} and Q_{Slack} respectively, from the external grid, is calculated post optimization, as follows:

$$P_{Slack} = \sum_{j} P_{slack,j};$$
$$Q_{Slack} = \sum_{j} Q_{slack,j} \qquad \forall\ j \in NL \tag{3.8}$$

3.2.3 Simplified Distribution Optimal Power Flow (SDOPF)

In this model the power supplied from the distribution substation is assumed to be of a constant power factor and therefore the nodal reactive power balance constraint can be eliminated. However, this model is consequently unable to examine issues related to capacitor placement, voltage support, *etc*. This model has been used in [46] to examine DG planning problems. Complex power representation is used to model the nodal power balance (Eqn. 3.9). The optimization framework of this model is presented below with a loss minimization objective function, which however can be replaced by any other objective function as appropriate.

Minimize

$$Loss = \sum_{i=1}^{N} \sum_{j=1}^{M} \left(\frac{V_i^2 - 2V_i V_j + V_j^2}{Z_{ij}}\right).\ pf \tag{3.9}$$

Subject to

$$\sum_{j=1}^{NL} \{S_{ji} - \frac{(|V_j| - |V_i|)^2}{|Z_{ij}|}\} + S_i^{SS} = PD_i \qquad \forall i \in N \tag{3.10}$$

$$S_{ji} \le S_{ji}^{Max} \qquad \forall\ i \in N,\ j \in NL \tag{3.11}$$

$$0 \le |V_i - V_{i+1}| \le \Delta V \qquad i \in NL \tag{3.12}$$

In Eqn.(3.9), pf is the system power factor which can also be denoted by $pf = R_{ij}/Z_{ij}$ $\forall\ i, j$. Eqn.(3.10) denotes the distribution system nodal power balance, where S_{ij} is the complex power flow over a feeder connecting buses *i-j* and S_{ij}^{Max} in (3.11) is the feeder capacity limit on complex power flow. In Eqn.(3.12), the permissible feeder voltage drop between two consecutive distribution system buses is limited by a small value.

3.2.4 Distribution Optimal Power Flow Formulation (DOPF)

The DOPF formulation is developed considering the total distribution system loss as the objective function, given by Eqn.(3.13), although this can be replaced by any other objective as well. It should be noted that the loss representation in Eqn.(3.13) is detailed, as compared to that used in Eqn.(3.9).

Minimize

$$Loss = \frac{1}{2}\sum_{i=1}^{N}\sum_{j=1}^{N} G_{i,j} \times \left[V_i^2 + V_j^2 - 2V_iV_j \cos(\delta_j - \delta_i) \right] \tag{3.13}$$

Subject to,

$$\varphi_1(V_i, \delta_i) = 0 \tag{3.14}$$

$$\varphi_2(V_i, \delta_i) = 0 \tag{3.15}$$

$$V_i^{Min} \le V_i \le V_i^{Max} \qquad i \in NL$$

$$V_i = 1.0\, p.u; \quad \delta_i = 0 \qquad i = slack$$

$$\sqrt{P_i^2 + Q_i^2} \le SS^{Cap} \qquad i = slack$$

In (3.13), G_{ij} denotes the conductance of feeder branch *i-j*, N is the total number of buses in the system, and SS^{Cap} is the substation capacity. The voltage magnitude at each load bus is constrained within a certain range as in Eqn.(3.16). The power magnitude, imported via the substation bus should not exceed the transformer thermal capacity, as given in Eqn.(3.18). The above formulation can also consider feeder power transfer capability limits, but in such cases there is a need to have more decision variables- such as DG options or load curtailment options in order to arrive at a feasible solution set. In the same context, imposition of voltage limits at each load bus introduces a constraint that may, during certain conditions, require capacitor support decision variables and the model can be used for capacitor planning and switching problem in distribution systems. If reactive power support is not available, the bus voltage limits need to be selected properly in order to obtain a feasible solution.

3.3 Results and Discussions

Four different distribution system test-cases published in the literature [14], [67]; with their detailed network parameters and load data, are used for analysis in this chapter. These systems are classified into two categories based on their size (number of buses), type of data which has been provided of the system, and the applied distribution power flow analysis model.

3.3.1 Small Distribution System with SDOPF Model Simulations

The first system is a 9-bus distribution system (Figure 3.2) where the load magnitude at each load bus is given in terms of MVA. The SDOPF model is applied to this system to analyze the power flows for this system.

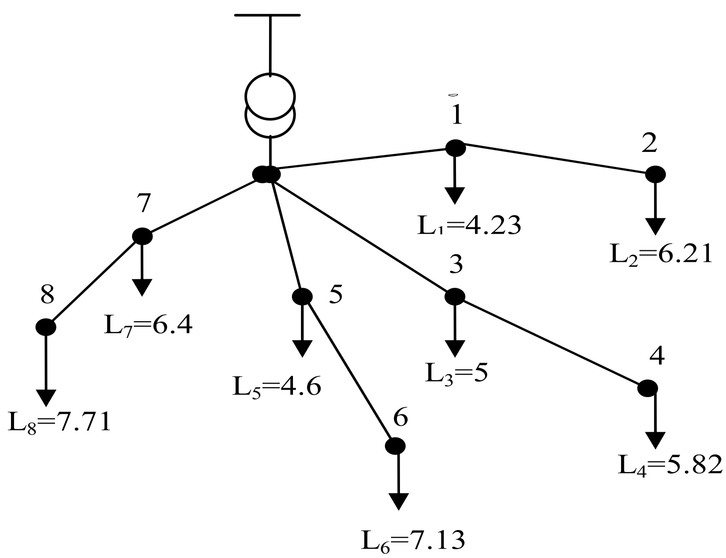

Figure 3.2: 9-Bus distribution system layout [68]

The bus voltage magnitudes and MVA power flows on the distribution feeders are given in Table 3.1.

It can be observed that the 9-Bus distribution system is a fairly well-behaved system and all buses maintain a very high voltage profile. This is also attributed to the fact that reactive power flows are not represented in the SDOPF model, and hence the voltage profile is expected to be good.

TABLE 3.1: VOLTAGE MAGNITUDES AND POWER FLOWS FOR THE 9-BUS TEST SYSTEM

Bus#	Voltage (kV)	|V|, p.u.	Sending Bus	Receiving Bus	Power Flow (MVA)
1	33.9919	0.9998	1	2	6.2118
2	33.9823	0.9995	3	4	5.8215
3	33.9874	0.9996	5	6	7.1320
4	33.9783	0.9994	7	8	7.7121
5	33.9851	0.9996	9	1	10.4443
6	33.9754	0.9993	9	3	10.8256
7	33.9862	0.9996	9	5	11.7372
8	33.9772	0.9993	9	7	14.1178
9	34.000	1			

Substation bus is denoted as bus 9 in this system

3.3.2 Large Distribution System Analysis with DLF and DOPF Models

The remaining part of the analysis reported in this chapter is carried out considering three large-scale and ill-conditioned radial distribution systems- the 28-bus, the 33-bus and the 69-bus systems. The detailed data pertaining to active and reactive components of the load at each receiving end bus as well as the resistance and reactance parameters of the feeders are provided in the Appendix. The analysis aims to study the applicability of both DLF and DOPF models on these systems and to carry out a comparison between these models and with the reported distribution network solutions.

Case-1: 28-Bus rural distribution system with laterals:

The 28-bus system configuration is shown in Figure 3.3. The bus voltage magnitudes are given in Table 3.2 when the DLF and DOPF models are executed. Also, the calculated active and reactive power flows on each feeder segment are stated in Table 3.3.

Furthermore, the total active and reactive power supplied from the substation is 830.0 kW and 822.06 kvar, respectively.

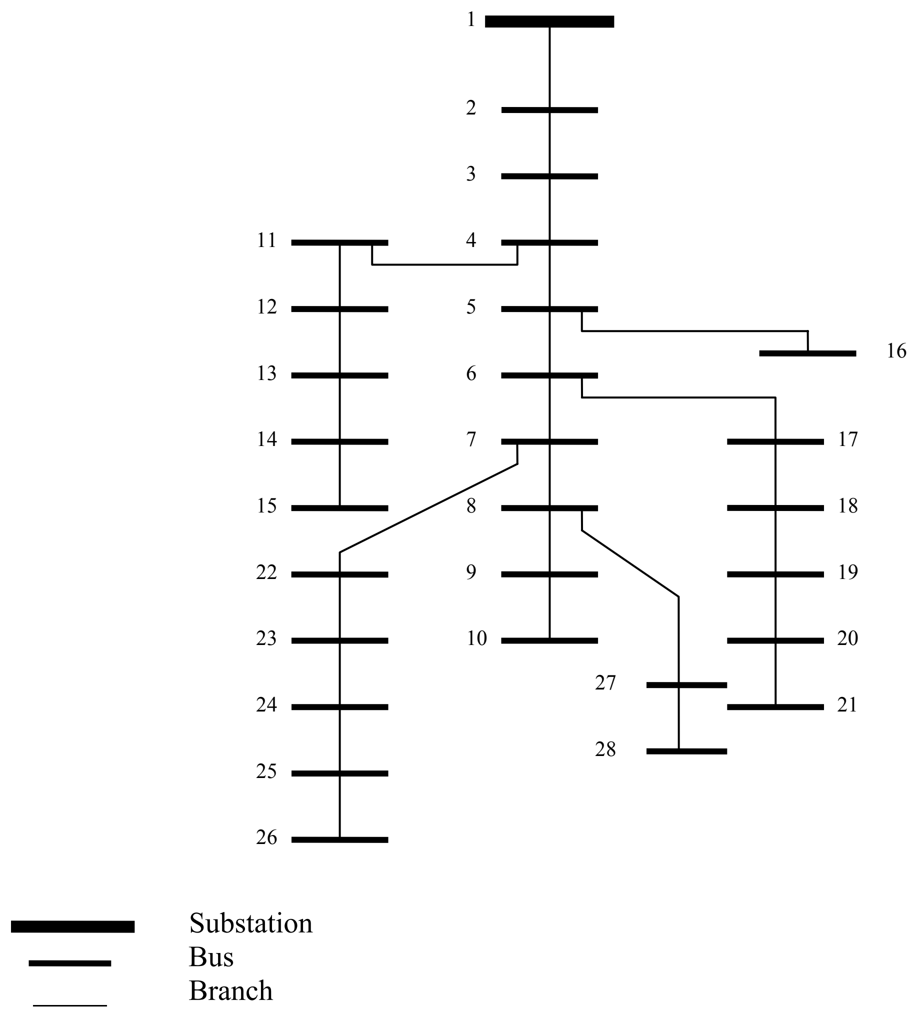

Figure 3.3: Layout of 28-Bus rural distribution system with laterals

TABLE 3.2: VOLTAGE MAGNITUDES OBTAINED SOLVING DLF AND DOPF FOR 28-BUS SYSTEM

Bus	|V|, p.u.	Bus	|V|, p.u.	Bus	|V|, p.u.	Bus	|V|, p.u.
1	1.0000	8	0.91603	15	0.94282	22	0.91561
2	0.98622	9	0.91575	16	0.93706	23	0.91407
3	0.96645	10	0.91551	17	0.92588	24	0.9129
4	0.95236	11	0.94617	18	0.9249	25	0.91264
5	0.93819	12	0.94440	19	0.9232	26	0.91247
6	0.92766	13	0.94334	20	0.92237	27	0.91554
7	0.91849	14	0.94306	21	0.92174	28	0.91542

TABLE 3.3: ACTIVE AND REACTIVE POWER FLOWS IN 28-BUS SYSTEM

Branch No.	Sending end	Receiving end	Active Power Flow (p.u)	Reactive Power Flow (p.u.)
1	1	2	0.0830	0.0822
2	2	3	0.0781	0.0777
3	3	4	0.0749	0.0750
4	4	5	0.0522	0.0525
5	4	11	0.0178	0.0180
6	5	6	0.0464	0.0468
7	5	16	0.0035	0.0036
8	6	7	0.0319	0.0323
9	6	17	0.0103	0.0105
10	7	8	0.0134	0.0137
11	7	22	0.0146	0.0148
12	8	9	0.0028	0.0029
13	8	27	0.0071	0.0072
14	9	10	0.0014	0.0014
15	11	12	0.0120	0.0122
16	12	13	0.0085	0.0086
17	13	14	0.0049	0.0050
18	14	15	0.0035	0.0036
19	17	18	0.0094	0.0096
20	18	19	0.0085	0.0086
21	19	20	0.0049	0.0050
22	20	21	0.0014	0.0014
23	22	23	0.0110	0.0112
24	23	24	0.0100	0.0102
25	24	25	0.0044	0.0045
26	25	26	0.0035	0.0036
27	27	28	0.0035	0.0036

It can be observed from Table-3.2 that the voltage drop across the main feeder section is quite significant, in this case. For example, voltage at bus-10 is 0.92 p.u. and at bus-26 is 0.91 p.u., which are significant drops from the substation voltage level and would ideally require a voltage support.

It is also observed from Table-3.3 that the feeder branch reactive power flow is almost of the same magnitude as the active power flow. This is because of the nature of the loads in this system, having a fairly low power factor in the range of 0.7.

And finally, it is also observed that with the loss minimizing DOPF the power flow solution is exactly same as that of the DLF solution. This implies that the DLF solution yields a power flow pattern that seeks the least loss path to meet the loads.

Case-2: 33-Bus distribution system with laterals:

The 33-Bus radial system is shown in Figure 3.4. The voltage magnitude at each bus obtained solving the DLF model is given in Table-3.4. Also, the calculated active and reactive power flows on the feeder segments are given in Table-3.5. The total active and reactive power supplied from the distribution substation is 3,918.0 kW and 2,435.0 kvar, respectively. The tie-lines are not included in the Y-bus matrix formulation since system reconfiguration has not been considered in this research. In this case too, the DLF and DOPF model simulations yield exactly same solutions, when loss minimization is the objective function in DOPF.

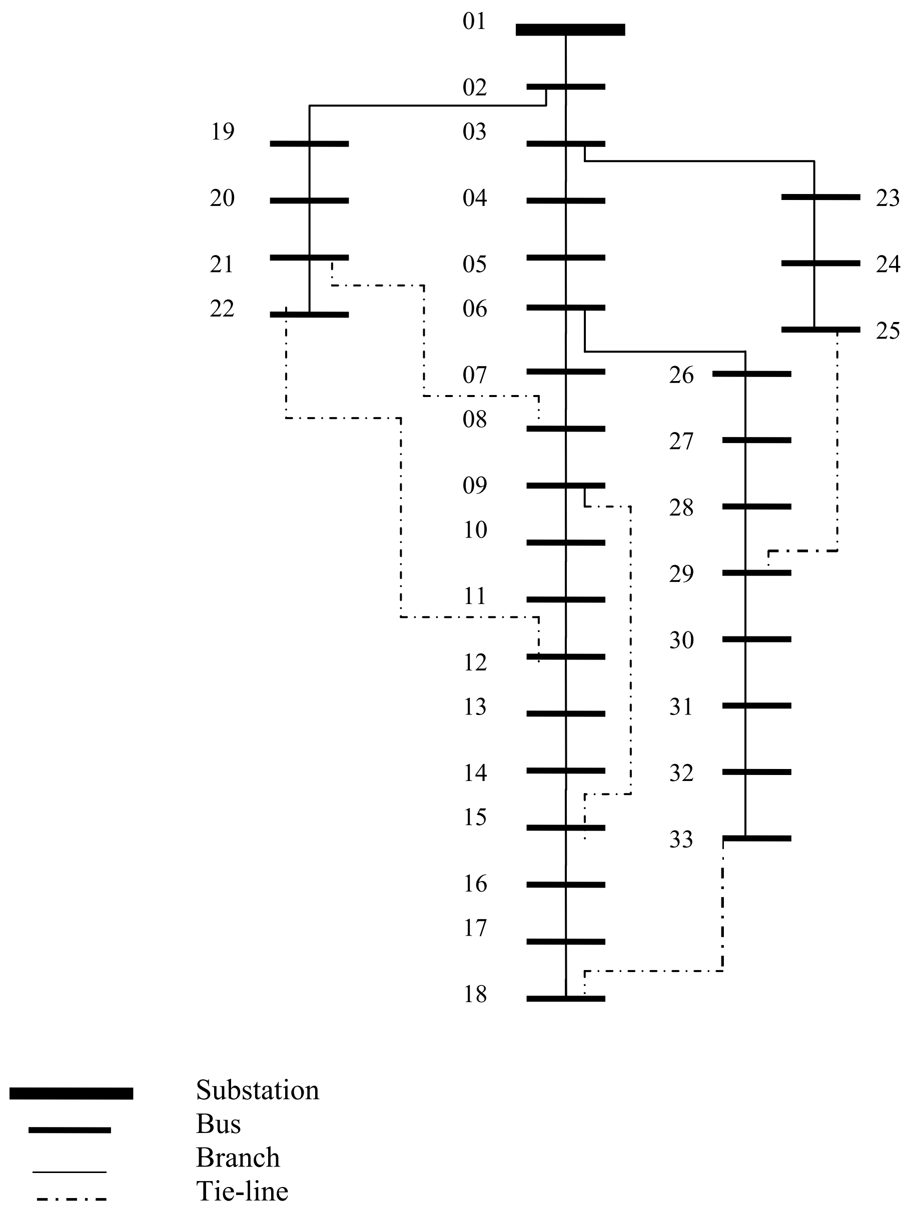

Figure 3.4: Layout of 33-Bus radial distribution system.

TABLE 3.4: VOLTAGE MAGNITUDES OBTAINED SOLVING DLF AND DOPF FOR 33-BUS SYSTEM

Bus	|V|, p.u.	Bus	|V|, p.u.	Bus	|V|, p.u.
1	1.000	12	0.927	23	0.979
2	0.997	13	0.921	24	0.973
3	0.983	14	0.919	25	0.969
4	0.975	15	0.917	26	0.948
5	0.968	16	0.916	27	0.945
6	0.950	17	0.914	28	0.934
7	0.946	18	0.913	29	0.925
8	0.941	19	0.996	30	0.922
9	0.935	20	0.993	31	0.918
10	0.929	21	0.992	32	0.917
11	0.928	22	0.992	33	0.917

TABLE 3.5: ACTIVE AND REACTIVE POWER FLOWS IN 33-BUS SYSTEM

Branch No.	Sending end	Receiving end	Active Power flow (p.u)	Reactive Power flow (p.u)
1	1	2	0.3918	0.2435
2	2	3	0.3444	0.2208
3	2	19	0.0361	0.0161
4	3	4	0.2363	0.1684
5	3	23	0.0940	0.0457
6	4	5	0.2223	0.1594
7	5	6	0.2144	0.1555
8	6	7	0.1095	0.0528
9	6	26	0.0951	0.0974
10	7	8	0.0893	0.0422
11	8	9	0.0689	0.0320
12	9	10	0.0624	0.0297
13	10	11	0.0561	0.0274
14	11	12	0.0515	0.0244
15	12	13	0.0454	0.0209
16	13	14	0.0392	0.0172
17	14	15	0.0271	0.0091
18	15	16	0.0211	0.0081
19	16	17	0.0150	0.0060
20	17	18	0.0090	0.0040
21	19	20	0.0271	0.0121
22	20	21	0.0180	0.0080
23	21	22	0.0090	0.0040
24	23	24	0.0846	0.0405
25	24	25	0.0421	0.0201
26	26	27	0.0888	0.0947
27	27	28	0.0825	0.0921
28	28	29	0.0754	0.0891
29	29	30	0.0626	0.0814
30	30	31	0.0422	0.0212
31	31	32	0.0270	0.0140
32	32	33	0.0060	0.0040

From Tables-3.4 and 3.5, we note the following:

1. Voltage drop across the main feeder branch is significant, as well as for other branches. The remote bus voltages are close to their lower allowable limits of 0.9 p.u.
2. Because of the presence of loads with higher power factors in this system, the feeder active power flow is not identical, any more, to the reactive power flows.

Case-3: 69-Bus distribution system with laterals:

The 69-bus radial network is shown in Figure 3.5. The voltage magnitude at each bus is given in Table-3.6 when the DLF and DOPF models are executed. Also, the calculated active and reactive power flows on the feeders are stated in Table-3.7. The total active and reactive power supplied from the substation is 4,030.0 kW and 2,800.0 kvar respectively. As in previous examples, DLF and DOPF solutions are exactly same here.

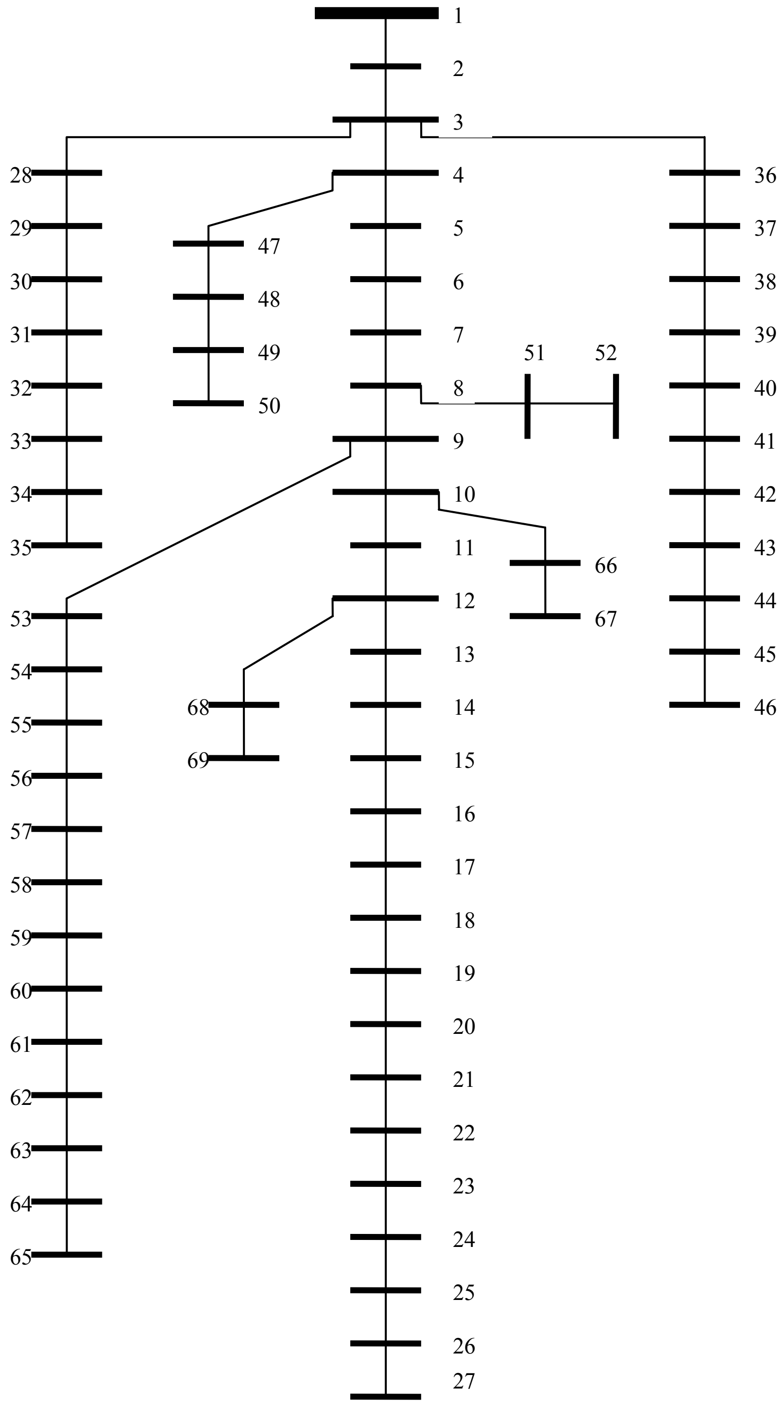

Figure 3.5: Layout of 69-Bus radial distribution system.

TABLE 3.6: VOLTAGE MAGNITUDES OBTAINED SOLVING DLF AND DOPF FOR 69-BUS SYSTEM

Bus	|V|, p.u.	Bus	|V|, p.u.
1	1	35	0.99895
2	0.99997	36	0.99992
3	0.99993	37	0.99975
4	0.99984	38	0.99959
5	0.99902	39	0.99954
6	0.99008	40	0.99954
7	0.98079	41	0.99884
8	0.97858	42	0.99855
9	0.97744	43	0.99851
10	0.97244	44	0.99850
11	0.97132	45	0.99841
12	0.96815	46	0.99840
13	0.96523	47	0.99979
14	0.96233	48	0.99854
15	0.95946	49	0.99470
16	0.95893	50	0.99416
17	0.95805	51	0.97854
18	0.95804	52	0.97853
19	0.95757	53	0.97466
20	0.95727	54	0.97141
21	0.95679	55	0.96694
22	0.95678	56	0.96257
23	0.95671	57	0.94010
24	0.95656	58	0.92904
25	0.95638	59	0.92476
26	0.95631	60	0.91973
27	0.95629	61	0.91234
28	0.99993	62	0.91205
29	0.99985	63	0.91166
30	0.99973	64	0.90976
31	0.99971	65	0.90919
32	0.99961	66	0.97126
33	0.99935	67	0.97126
34	0.99901	68	0.96782
		69	0.96782

TABLE 3.7: ACTIVE AND REACTIVE POWER FLOWS IN 69-BUS SYSTEM

Branch No.	Sending end	Receiving end	Active Power flow (p.u)	Reactive Power flow (p.u)
1	1	2	0.0403	0.0280
2	2	3	0.0403	0.0280
3	3	4	0.0375	0.0260
4	3	28	0.0009	0.0007
5	3	36	0.0019	0.0013
6	4	5	0.0290	0.0199
7	4	47	0.0085	0.0061
8	5	6	0.0290	0.0199
9	6	7	0.0287	0.0197
10	7	8	0.0280	0.0193
11	8	9	0.0267	0.0184
12	8	51	0.0004	0.0003
13	9	10	0.0078	0.0053
14	9	53	0.0186	0.0128
15	10	11	0.0075	0.0051
16	11	12	0.0057	0.0038
17	11	66	0.0004	0.0003
18	12	13	0.0036	0.0024
19	12	68	0.0006	0.0004
20	13	14	0.0035	0.0023
21	14	15	0.0034	0.0023
22	15	16	0.0034	0.0023
23	16	17	0.0030	0.0020
24	17	18	0.0024	0.0016
25	18	19	0.0018	0.0013
26	19	20	0.0018	0.0013
27	20	21	0.0018	0.0012
28	21	22	0.0006	0.0004
29	22	23	0.0006	0.0004
30	23	24	0.0006	0.0002
31	24	25	0.0003	0.0002
32	25	26	0.0003	0.0004
33	26	27	0.0001	0.0001
34	28	29	0.0007	0.0005
35	29	30	0.0004	0.0001
36	30	31	0.0004	0.0005
37	31	32	0.0004	0.0003
38	32	33	0.0004	0.0003

Branch No.	Sending end	Receiving end	Active Power flow (p.u)	Reactive Power flow (p.u)
39	33	34	0.0004	0.0003
40	34	35	0.0003	0.0003
41	36	37	0.0001	0.0002
42	37	38	0.0016	0.0001
43	38	39	0.0013	0.0011
44	39	40	0.0011	0.0009
45	40	41	0.0009	0.0007
46	41	42	0.0008	0.0006
47	42	43	0.0008	0.0006
48	43	44	0.0008	0.0006
49	44	45	0.0008	0.0005
50	45	46	0.0004	0.0003
51	47	48	0.0085	0.0061
52	48	49	0.0077	0.0055
53	49	50	0.0038	0.0027
54	51	52	0.0021	0.0010
55	53	54	0.0185	0.0127
56	54	55	0.0181	0.0125
57	55	56	0.0178	0.0123
58	56	57	0.0177	0.0123
59	57	58	0.0172	0.0121
60	58	59	0.0170	0.0120
61	59	60	0.0159	0.0113
62	60	61	0.0158	0.0112
63	61	62	0.0032	0.0023
64	62	63	0.0029	0.0020
65	63	64	0.0029	0.0020
66	64	65	0.0006	0.0004
67	66	67	0.0002	0.0001
68	68	69	0.0003	0.0002

From Table-3.6 and 3.7 we can observe the following:

a) The voltage profile of the main feeder branch of the 69-bus system is fairly good, as compared to previous test-systems analyzed. For example remote buses # 27 and # 46 have voltages in the order of 0.96 p.u. and 0.998 p.u. This can again be attributed to high load power factors on their branches.
b) The remote bus-65, on the other hand, has a voltage of 0.91 p.u., which is because of the low power factor loads on this feeder branch.

It is observed that the DLF solutions for bus voltages and feeder flows obtained using the formulation presented in Section-3.2.2 match closely with the reported distribution power flow solutions [14], [67]. This justifies that instead of using the traditional iterative equations for power flow, a straight-forward classical power flow in a NLP optimization framework can be adequate for distribution systems.

An interesting observation was that the DLF solutions also match very closely with the DOPF solutions, when the DOPF objective function is minimization of losses. This implies that the DLF solution basically arrives at a power flow pattern that seeks the *least loss path* in the feeders while the loads are being met. The distribution system power flow analysis models used so far (SDOPF, DLF and DOPF) are examined and the model statistics for each system is summarized in Table-3.8. These models are formulated and executed in GAMS [69] environment and solved using the MINOS 5.1 solver on a standard Pentium PC. The active and reactive power supplied by the substation (P_{SS} and Q_{SS}), and the total active and reactive power losses (P_{Loss} and Q_{Loss}) are also reported.

It is also noted that, the execution time for the DLF program is lesser compared to the DOPF because of the reduction in the number of variables and because of fewer constraints, and memory required is reduced significantly. The DLF program helps the disco operator to obtain a fast diagnostic for its system conditions. On the other hand, the DOPF program is a comprehensive optimization framework which is suitable to handle many variables as well as meshed network flows, DG penetration and other issues arising there from.

TABLE 3.8: SUMMARY AND COMPARISON OF MODEL STATISTICS

		No. of Equations	No. of Variables	Generation time, s	Execution time, s	P_{Loss}, Q_{Loss}	P_{SS}, Q_{SS}
9-Bus	SDOPF	172	181	0.013	.013	S_{Loss}= 0.025 MVA	S_{SS} = 47.125 MVA
28-Bus	DLF	55	57	0.020	0.02	69.0 kW 46 kvar	830.0 kW 823 kvar
	DOPF	818	4846	0.211	0.22	69.0 kW 46 kvar	830.0 kW 823 kvar
33-Bus	DLF	65	67	0.016	0.016	203.0 kW 135 kvar	3918.0 kW 2435 kvar
	DOPF	668	6701	0.25	0.26	203.0 kW 135 kvar	3918.0 kW 2435 kvar
69-Bus	DLF	137	139	0.07	0.07	230.0 kW 102 kvar	4030.0 kW 2800 kvar
	DOPF	28844	28913	1.0	1.02	230.0 kW 102 kvar	4030.0 kW 2800 kvar

Note: For the 9-bus system, instead of *P* and *Q*, we have complex power loss and substation complex power import (in MVA).

3.4 Concluding Remarks

The main objective of this chapter was to develop distribution system load flow models that could be solved in the same manner as traditional optimal power flow programs using an optimization structure. The load flows are re-constructed as optimal power flows using dummy objective function and exactly similar power flow solutions can be obtained by making use of the strengths of non-linear programming solvers. The Distribution Load Flow (DLF) and Distribution Optimal Power Flow (DOPF) models can assist the disco operator in its DG scheduling, capacitor switching, load management and other operations very effectively. In addition, the DOPF model, with suitable modifications, can also address various issues in the context of the emergence of retail competition in electricity markets. These aspects will be discussed in the following chapters by appropriate usage of the DLF and DOPF models.

Chapter

4

A Generic Operations Framework for Discos in Retail Electricity Markets[2]

4.1 Introduction

The earlier chapters have discussed the operational issues of discos in the context of retail electricity markets. In Chapter-3, the basic DOPF model was developed to address the decision making problems of discos in the presence of DG units.

The overall operational aspects of such a disco (and a retailer) responding to the dynamics of the electricity market needs to be investigated. The short-term contribution of DGs and ILs in reducing feeder losses, providing reactive power compensation effects, *etc.* needs to be examined.

In this chapter, a generic operations framework has been presented that addresses the short-term operations of discos in retail electricity markets. Mathematical models have been developed to represent the operations aspects of a retailer and its interaction with the spot electricity market. This environment, where a retailer is the main player and the external electricity market has a considerable influence on its decision making, is considered as the 'retail electricity market'. However, this thesis does not address all

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[2] Some parts of this chapter have been published in:

- A. Algarni and K. Bhattacharya, *A generic operations framework for discos in retail electricity markets*, IEEE Transactions on Power Systems, vol. 24, no. 1, pp. 356-367, Feb. 2009
  Initial versions of the work appeared in:
  - A. Algarni, K. Bhattacharya and R. El-Shatshat, *Optimal operation of a disco in competitive electricity markets with elasticity effects*, Proc. IEEE PES Annual General Meeting, 2007, Tampa, USA
  - A. Algarni and K. Bhattacharya, *A comprehensive short-term operations framework for a disco in competitive electricity markets*, Proc. Electric Power Conference 2007, Montreal, Canada, October 2007

aspects of retail electricity markets; for example, the competition amongst retailers is beyond the scope of this thesis. On the other hand, this thesis considers that the retailer is also the disco and is hence responsible for network operations aspects.

As mentioned before, such a retailer-disco (*henceforth referred to, as disco only*) has the possibility to own DG units and contract ILs and hence schedule their decisions such that its operations aspects can be optimized.

The generalized operations framework takes into account the disco's day-ahead preparations for energy provision options available within its territory, while considering effects of electricity market prices. On one hand, the disco has to monitor the dynamics of the wholesale energy market price and on the other hand, the optimal operation decisions have to be computed.

Furthermore, real-time operations of the disco are affected by network configuration and demand response. In the presence of DGs and with possibility of contracts for ILs with its customers, the feeder power flows will be significantly different from the traditional distribution systems. As a result, disco feeder losses, voltage profiles and feeder capacity margins will be affected.

In order to examine these issues, a two-stage operations framework and associated mathematical models have been developed in this chapter. The first stage pertains to the day-ahead operations of the disco and the corresponding mathematical model is termed *Day-Ahead Operations Model* (DAOM) while, the second stage pertains to the disco's real-time operations and is termed *Real-Time Operations Model* (RTOM). The two stages of operations are in hierarchical order with the DAOM feeding into the RTOM with information on day-ahead decisions which the disco needs to incorporate in its real-time operations.

The rest of the chapter is organized as follows: Section 4.2 presents the comprehensive short-term operations framework of the disco, and the detailed mathematical models of DAOM and RTOM. Section 4.3 first presents the development of the disco demand as a function of the wholesale market price and thereafter incorporates it in a detailed case-study considering the 33-bus radial distribution system to provide insight into disco operations in day-ahead and real-time. The chapter conclusions are discussed in Section 4.4.

4.2 Proposed Disco Operations framework

In this section, the comprehensive disco operations framework and the DAOM and RTOM pertaining to discos in competitive electricity markets are presented. Figure 4.1 presents an overview of the proposed framework wherein the first stage is the DAOM which has a time-horizon of 24-hours ahead of real-time. The inputs to the DAOM are the DG characteristics (costs and capacity), substation limits, and an initial range of estimate of the IL bid prices. In addition, a forecast of the day-ahead market price (ρ^{DA}) is assumed to be available to the disco, based on which the disco estimates its hourly demand for the next day. Detail of this estimation procedure has been elaborated in Section-4.3.1. Based on this information, the disco executes the DAOM and arrives at an optimal set of decisions with regard to DG unit commitment, grid purchases, and contracts for IL while seeking to maximize/minimize its day-ahead operations objectives.

All these decisions are passed on to the RTOM for the real-time operations decisions. Additionally, the RTOM uses detailed representation of distribution feeder parameters, actual hourly IL bids from customers which are specified by location, and disco bus voltage limits. It also has a near-term (*one-hour ahead*) forecast of the electricity market price (ρ^{RT}). Using the real-time price forecast, the disco updates its demand estimates, and now, more specifically incorporates the bus-wise distribution of the loads as well (discussed in Section-4.3.1). Equipped with these information, the disco executes the RTOM on an hourly basis to determine its optimal operating strategies on grid purchase, DG dispatch and actual IL invocation, while seeking to maximize/minimize its real-time operational objective.

4.2.1 Day-Ahead Operations Model (DAOM)

With the availability of day-ahead prices being posted in most markets, the 24-hour ahead operations decision-making is a meaningful activity for the disco and can save significant costs as well as reduce its risks arising from operating in a volatile real-time market. The

DG unit commitment and IL contracting decisions are included as variables at this stage. The distribution substation transformer represents the main point of connection of the disco with the bulk power system/market.

It should be mentioned that in this chapter, we only consider utility-owned or disco-owned DG units, which are dispatchable, both in the day-ahead and real-time operations.

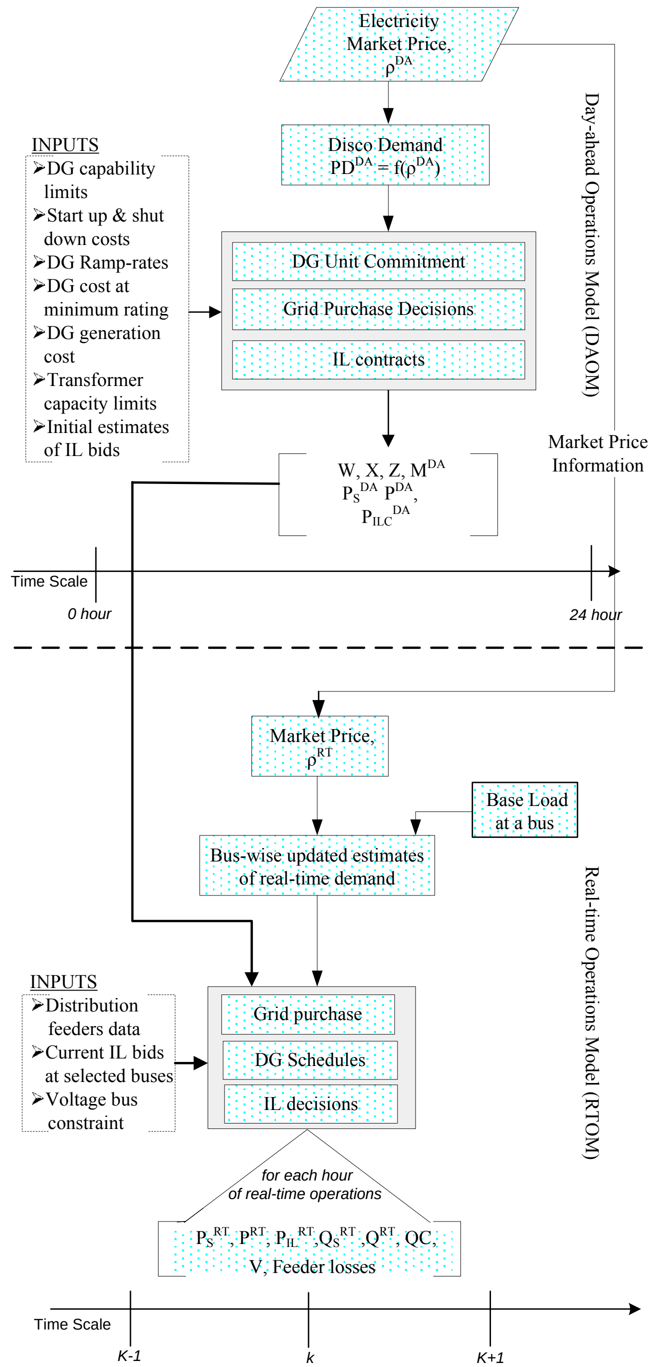

Figure 4.1: Proposed two-stage generic operations framework of disco

The mathematical models however are general enough and therefore, investor-owned DG units can easily be included by slight modifications of the models.

The total day-ahead cost of operations of the disco system is considered as the objective function for minimization (4.1).

4.2.1.1 Objective Function

$$\begin{aligned} J^{DA} = \sum_{t=1}^{24} (& \rho_t^{DA} \, . \, P_{S,t}^{DA} \\ & + \sum_{i=1}^{NDG} \left\{ \left(C_i W_{i,t} + B_i P_{i,t}^{DA} \right) + X_{i,t} CS_i + Z_{i,t} CD_i \right\} \\ & + C_{IL,t}^{DA} \cdot P_{ILC,t}^{DA}) \end{aligned} \tag{4.1}$$

The first component of J^{DA} in (4.1) is the total payment to be made by the disco for power purchased from the market and imported via the sub-station transformer, at the day-ahead market price. The second component is the gross 24-hour cost of generation from DG units having different operational, start-up and shut-down costs. These are dispatchable units and their active power production is managed through the day-ahead unit commitment program.

The third component is the disco's cost of contracting IL in the day-ahead stage, in preparation for next day's operation. A bid-based mechanism for IL is proposed wherein the customers submit their offers for load curtailment on an hourly basis in real-time, as in [56]. However, the disco requires determining in the day-ahead stage, how much IL it may require at an hour the next day, to get a fairly clear picture of how much load to be interrupted in real-time and how much will it cost, since the IL prices can be highly volatile and disco demand will also be affected consequently.

In order to do so in the day-ahead stage, it uses an estimate of the range of IL bid prices based on its past experience. This estimate need not be very accurate because the actual bids are accounted for in the real-time stage.

4.2.1.2 Constraints

Demand-Supply Balance Constraint

This constraint ensures that the generation from DG units and power purchased from the grid is able to meet the next day's hourly forecasted demand of the disco. If the supply from these two resources is not sufficient, the disco can also schedule some IL by contracting IL capacity at the day-ahead stage.

$$\sum_{i=1}^{NDG} P_i^{Min} W_{i,t} + P_{i,t}^{DA} + P_{S,t}^{DA} + P_{IL,t}^{DA} = PD_t^{DA}\left(\rho^{DA}\right) \tag{4.2}$$

System Adequacy Constraint

In the day-ahead stage the disco seeks to ensure that there is enough committed DG units, contracted grid purchase power, as well as contracted IL capacity so as to meet the hourly demand forecast while also ensuring a reserve margin.

$$\sum_{i=1}^{NDG} P_i^{Max} \cdot W_{i,t} + P_S^{Max} + P_{ILC,t}^{DA} \geq RESV_t + PD_t^{DA}\left(\rho^{DA}\right) \tag{4.3}$$

Generation Limits on DG Units

These constraints ensure that the power generated from DG units is constrained by the capacity limits of the DG unit.

$$W_{i,t} \cdot P_i^{Min} \leq P_{i,t}^{DA} \leq P_i^{Max} \cdot W_{i,t} \qquad \forall\, i \in g \tag{4.4}$$

Ramp-up and Ramp-Down constraints

The generation from DG units should also respect the ramp-up and ramp-down constraints at every hour, as given below.

$$\begin{aligned} & P_{i,t+1}^{DA} - P_{i,t}^{DA} \leq R_{UP_i} \\ & P_{i,t}^{DA} - P_{i,t+1}^{DA} \leq R_{DN_i} \qquad \forall\, i \in g, \quad t = 0,1,\ldots,(t-1) \\ & P_{i,t}^{DA}\Big|_{t=0} = 0 \end{aligned} \tag{4.5}$$

Minimum Up- and Down-Time Constraints

The DG unit commitment should adhere to the minimum-up and down time constraints, as follows.

$$\sum_{l=1}^{MUP} W_{i,t+l-1} \geq MUP \qquad \forall\, X_{i,t} = 1, i \in g \tag{4.6}$$

$$\sum_{l=1}^{MDN} (1 - W_{i,t+l-1}) \geq MDN \qquad \forall Z_{i,t} = 1, i \in g \tag{4.7}$$

It should be noted that the computer programming of the above constraints are fairly complex in GAMS environment. A special technique using the Big-M approach is adopted in this thesis. The detailed GAMS program of the DAOM is supplied for the benefit of future researchers, in the Appendices.

It should also be pointed out that the minimum up and down-time constraints may not always be necessary in disco systems with DG units because of their flexibility of operating and having short up- and down-time requirements. Therefore these constraints may also be ignored in order to keep the computation simple, without affecting the solution in any significant way.

Coordination Constraints

This set of constraints ensure that the inter-relationships of the three binary decision variables, W, X and Z are in sequential logical order and there are no conflicting situations.

$$\begin{aligned} &W_{i,t} - W_{i,t-1} \leq X_{i,t} \\ &W_{i,t-1} - W_{i,t} \leq Z_{i,t} \\ &W_{i,t} - W_{i,t-1} = X_{i,t} - Z_{i,t} \qquad \forall i \in g, t > 1 \end{aligned} \tag{4.8}$$

Grid Purchase Constraints

These constraints limit the day-ahead, hour-wise, grid purchase decisions of the disco from the market. The limiting value depends on the disco's substation transformer capacity which is the gateway to the external market.

$$P_{S,t}^{DA} \leq P_S^{Max} \qquad \forall\, t \tag{4.9}$$

Limit on IL Contract

The limit on IL contract is imposed assuming that only a certain fraction of the total load will participate in this initiative. The disco has to use its experience to determine the total MW expected from IL bids in the day-ahead stage for optimal contracting of ILs. In (4.10), M^{DA} is a binary variable denoting the selection or not, of IL contract at a given hour.

$$P_{ILC,t}^{DA} \leq P_{ILCAP,t}^{DA} \cdot M_t^{DA} \tag{4.10}$$

Limit on IL Schedule

This constraint ensures that the amount of IL actually scheduled in the day-ahead stage is limited by the amount of IL contracted for.

$$P_{IL,t}^{DA} \leq P_{ILC,t}^{DA} \tag{4.11}$$

The DAOM, described by (4.1)-(4.11), is a mixed-integer linear programming (MILP) model solved in the GAMS [69] environment for energy provisions of the disco in the day-ahead stage and does not consider detailed distribution network configuration.

The decisions obtained from this model include, the power contracted for purchase by disco from the market, the DG commitment and production schedule and optimal contracts for IL that will be available for call by the disco during the next day's real-time operation.

The optimal decision on power purchase from the grid, P_S^{DA*}, obtained from DAOM, is part of the day-ahead energy market settlement and is in agreement with the market operator. Any deviation from this, in real-time stage, will be liable to a penalty or receiving a payment credit, depending on the deviation being positive or negative respectively, and will be imposed on the disco by market operator.

It is to be noted that the DAOM is generally similar to a price-based unit commitment (PBUC) model [70]. However, there are certain differences in the proposed DAOM with the generation-side PBUC model, which are outlined as follows:

- Unlike the PBUC, the objective function of the DAOM is not Profit Maximization. The DAOM seeks to minimize the day-ahead operation cost of the disco, while meeting its day-ahead forecasted demand. The PBUC, on the other hand, does not seek to match a demand forecast but to maximize its total profit by an optimal mix of supply scheduling.

- The DAOM takes into consideration grid power transfer, via distribution substation and associated transformer capacity limits.
- Day-ahead interruptible load contracts are treated as decision variables within the DAOM model and associated constraints are included, as well as IL costs appear in the disco's objective function.

4.2.2 Real-Time Operations Model (RTOM)

The second-stage of the generalized operations framework is to determine the disco's optimal decisions at close to real-time. An OPF-based model is introduced to distribution networks wherein both active and reactive power balance equations and a set of new operations constraints are now included. The decision variables on grid purchase, IL contracts, and DG unit commitment obtained from DAOM are passed on to the RTOM, as fixed parameters, as shown by the link between the two stages in Figure 4.1. Treating these decisions as "known" and "fixed", from the day-ahead stage, reduces the risks faced by the disco from real-time electricity market price volatility.

4.2.2.1 Objective Function

The objective function of the RTOM, J^{RT}, (4.12) seeks to minimize the actual disco payments in real-time operation on an hour-by-hour basis.

$$\begin{aligned} J^{RT} = {} & \rho^{RT}(P_S^{RT} - P_S^{DA*}) + \sum_{i=1}^{NDG}\left[A_i \cdot \left(P_i^{RT}\right)^2 + B_i P_i^{RT} + C_i\right] \\ & + \sum_{i=1}^{NL}\rho_{IL}^{RT} \cdot P_{IL,i}^{RT} + \sum_{i=1}^{NDG} C_{QG_i} \cdot Q_i^{RT} + \sum_{i=1}^{NL} C_C \cdot QC_i + C_Q \cdot Q_S^{RT} \end{aligned} \tag{4.12}$$

The first component of (4.12) represents the penalty that the disco has to pay for deviations of its real-time grid purchase decisions from the optimal day-ahead decisions P_S^{DA*} . Since this is an additional burden on the disco, it seeks to keep the real-time grid purchase as close as possible to the P_S^{DA*} decisions.

In some operational situations the penalty imposed on the deviation from day-ahead scheduled amount can be interpreted economically as an encouragement or a payment credit. The use of payment credits between Day Ahead Markets (DAM) and Real-Time Markets (RTM) is a fairly well established mechanism in two-settlement markets. When a *Load Serving Entity* (in this case, the disco) deviates downwards, *i.e.*, purchases lesser amount of power in RTM than its scheduled purchase of DAM, it receives a *Payment Credit*, as formulated in (4.12). Similarly, a credit is also applicable to gencos when they generate more in RTM than their scheduled dispatch of DAM. These *Payment Credits* are applied in most two-settlement markets in USA, such as PJM, New England, *etc.* [71], [72].

The second term in (4.12) represents a more detailed, quadratic, operations cost function for each DG unit dispatched in real-time.

The third component in (4.12) represents the actual payments made by the disco for usage of IL in real-time. This payment is made based on the basis of an hourly uniform price for IL to all selected customers offering this service.

The last three components in (4.12) represent the costs incurred by the disco for reactive power support provision from DG units, capacitor banks and imports over the substation transformer, respectively.

4.2.2.2 Constraints

Network Equations

The active and reactive power flow equations are modified to include grid purchase, DG production and IL. The reactive power equation also includes an additional reactive power support component from capacitor banks at load buses.

$$P_s^{RT} + P_g^{RT} - PD_i^{RT}\left(\rho^{RT}\right) + P_{IL,i}^{RT} = \sum_j |V_i||V_j||Y_{ij}|\cos(\theta_{ij} + \delta_j - \delta_i) \tag{4.13}$$

$$Q_s^{RT} + Q_g^{RT} - QD_i^{RT}\left(\rho^{RT}\right) + Q_{IL,i}^{RT} + QC_i = -\sum_j |V_i||V_j||Y_{ij}|\sin(\theta_{ij} + \delta_j - \delta_i) \tag{4.14}$$

$$Q_{IL,i}^{RT} = \tan(\cos^{-1}(PF_i)) \cdot P_{IL,i}^{RT} \tag{4.15}$$

Grid Purchase Constraints

These constraints ensure that the active and reactive power purchased by the disco from the external grid/market is within the transfer limits imposed by substation transformer capacity.

$$P_s^{RT} \le P_s^{Max} \tag{4.16}$$

$$Q_s^{RT} \le Q_s^{Max} \tag{4.17}$$

Bus Voltage Limits

These limits ensure acceptable voltages at all buses and that the bus voltages do not drop below certain specified values, which is particularly possible because of the generally radial nature of disco systems. The substation bus voltage is held at a constant value, similar to the slack bus in classical load flow programs.

$$\begin{aligned} &|V_s| = \text{Constant} \\ &V_i^{Min} \le |V_i| \le V_i^{Max} \qquad i \in NL \end{aligned} \tag{4.18}$$

Generation Limit on DG Units

These constraints ensure that the real-time dispatch from a DG unit is within its maximum and minimum limits of generation. It is to be noted that the unit commitment decisions obtained from DAOM are used as fixed parameters in these constraints.

$$P_i^{Min} \cdot W_i^* \le P_i^{RT} \le P_i^{Max} \cdot W_i^* \quad \forall i \in g \tag{4.19}$$

$$Q_i^{Min} \cdot W_i^* \le Q_i^{RT} \le Q_i^{Max} \cdot W_i^* \quad \forall i \in g \tag{4.20}$$

Hourly Ramp-Rate Check

As we discussed earlier, the DAOM yields decisions on DG generation in the day-ahead stage where ramping constraints are taken into consideration within the model itself. In the RTOM, the generation from DG units is also being optimized and the solution may violate the ramp-rate constraints.

In order to handle this issue, an hourly rule-base check is introduced in RTOM which alleviates the need for dynamic ramping constraints. The hourly dispatches from the DG units must abide by their ramp-up or ramp-down limits. These would depend on previous hour's dispatch status and the unit's ramp-rate characteristic. If the generating limits are exceeded, the generation level is set at the limits.

Since hour-1 in DAOM represents a normal operation condition (*i.e.,* no price spike or IL) the DG generations at that hour is kept as a maximum limit for the control variable of current DG generations. Based on this, the ramp-rate limits will be checked and re-adjusted as follows.

$$\begin{aligned} &P_{i,t+1}^{RT} \le P_{i,t}^{RT} + R_{UP,i} \\ &P_{i,t+1}^{RT} \ge P_{i,t}^{RT} - R_{DN,i} \quad \forall i \in g \end{aligned} \tag{4.21}$$

Limit on Real-time Call for IL

The amount of IL that can be invoked in real-time by the disco is bounded by the optimal IL contract for hour t determined in DAOM, $P_{ILC,t}^{DA*}$.

$$\sum_{i=1}^{NL} P_{IL,i}^{RT} \le P_{ILC,t}^{DA*} \qquad \forall \quad t \tag{4.22}$$

Uniform Price for IL in Real-time

The constraints (4.23)-(4.24) ensure that the highest priced bid for IL is selected as the uniform price for IL in real-time, ρ_{IL}^{RT}, and all the selected IL participants are paid at this rate as in (4.12). In (4.23) and (4.24), M_i^{RT} is a binary variable associated with selection or not, of IL at a bus.

$$M_i^{RT} \cdot C_{IL,i}^{RT} \le \rho_{IL}^{RT} \tag{4.23}$$

$$P_{IL,i}^{RT} = \begin{cases} P_{ILCAP,i}^{RT} \cdot M_i^{RT} & \forall M_i^{RT} = 1 \\ 0 & \forall M_i^{RT} = 0 \end{cases} \quad \forall t \tag{4.24}$$

The RTOM, described by (4.12)-(4.24), is a mixed-integer non-linear programming (MINLP) model solved in the GAMS [69] using the DICOPT solver.

The optimal decisions from this model include, the actual power imported over the disco substation, DG generation schedules, IL invoked at a bus, reactive power import over the substation transformer, reactive power dispatch from DG units, reactive power support from capacitor banks at load buses and uniform price paid to IL customers for their participation in the real-time IL service provision.

Additionally, the disco operator has detailed information on its feeder loadings, network losses, voltage profile and other network performance related measures.

4.3 Analytical Studies

4.3.1 Disco Demand Function

The disco is considered to be the main player in the wholesale market on behalf of its customers in its territory. It also functions as a retailer responsible for supplying electricity to individual end-users and also ensures that the network is secure. In competitive electricity markets, the discos/retailers are required to closely understand the consumption patterns of their customers, in order to reduce the risks associated with unpredictability of spot market prices. The discos can utilize the day-ahead electricity prices posted by market operators and come up with a good estimate for its demand and the consumption pattern over 24 hours of operation. This will be mainly driven by the dynamics of electricity prices, and can provide the disco a fairly clear picture of its short-term operation activities. Consider that disco-A is a *price-taking* participant in the electricity market, alongside several other discos participating in the market, at the same time. That means, disco-A does not hold any market power, and its price bids can not influence the market price. The demand of disco-A is only a small fraction of the total system demand. Based on historical trends, one can derive a relationship between the total system demand and the market price. For example, a high price in the market is generally linked to a high system demand condition while a low market price to a low system demand condition, under normal circumstances.

Such price-demand relationships observed in the wholesale market, can be scaled down to the level of each individual disco, also because, the individual disco demands, when all added up, make up for the total system demand. Therefore, disco-A's demand, for example, can be modeled as a dependent variable that follows the electricity market price fluctuations– a high price relates to a high demand condition, *etc.* and therefore can be scaled down by an appropriate factor based on market price trends.

The problem of fashioning a relationship between these two variables, demand and price, that best fits a set of data was carried out using the method of Ordinary Least Squares. Hourly Ontario Energy Price (HOEP) data for multiple days in 2005 and corresponding hourly system load data was used for this exercise. Since the data was not scattered and because of a fairly strong correlation between these two variables, the estimated linear model so obtained, is given by (4.25).

$$PD_t^{DA} = \alpha \cdot \rho_t^{DA} + \beta \tag{4.25}$$

In (4.25), PD^{DA} is the total disco demand at hour t, estimated day-ahead, from market price information, ρ^{DA}. In order to arrive at an estimate of real-time disco demand, the same relation of (4.25) can be used, but with an updated price forecast for the real-time, as in (4.26):

$$PD_t^{RT} = \alpha \cdot \rho_t^{RT} + \beta \tag{4.26}$$

It should be mentioned here that the estimated linear load model developed in (4.26) is not a demand-forecast model. This work does not attempt to forecast the disco demand, rather it attempts to capture the price dependence relationship in a simple model, so as to make the disco's operational framework more realistic and sensitive to market prices.

In (4.26) the α and β parameters are known from the day-ahead relationship of (4.25). Once the gross real-time demand of the disco has been estimated, its bus-wise share can be determined from the base case load distribution in the network, and assuming that the bus load shares remain unchanged (4.27):

$$PD_{i,t}^{RT} = \frac{PD_{0,i}}{\sum_{i=1}^{NL} PD_{0,i}} \cdot PD_t^{RT} \tag{4.27}$$

In (4.27), $PD_{0,i}$ is the nominal demand at a bus, independent of the electricity market price, which the disco operator is expected to have a fairly good idea of. Correspondingly, the bus-wise reactive power demand will be given by,

$$QD_{i,t}^{RT} = \tan(\cos^{-1}(PF_i)) \cdot PD_{i,t}^{RT} \tag{4.28}$$

4.3.2 System under Consideration

The 33-bus radial distribution system [10], shown in Figure 4.2, is modified and used in this study. Four DG units owned by the disco are assumed to be connected at the remote-end distribution buses. Two of them, at buses-18 and 33 are of 5 MW capacities each (or 0.5 p.u., with MVA_{Base} = 10 MVA), while the remaining two, at Bus-22 and 25 respectively, are of 4 MW capacities each (*i.e.*, 0.4 p.u.). The dotted lines in the 33-Bus radial distribution system configuration are from the original dataset of [10]. They represent tie-line reconfiguration sets and depict accurately the system. These tie-lines, however, are not in use in the present work. We have depicted them with dotted lines, so as to retain the original system configuration, and thus have the possibility to include them in any future research, using this system.

It is important to point out that the choice of locations for four DG units, considered here, is entirely arbitrary. Typically DG units would be located at remote ends of the feeders, and the choice of locations was thus made.

The main emphasis of this work is to demonstrate how, the proposed framework and the operational objective can influence the disco's dispatch decisions in the short-term. It is well recognized that if the initial choice of DG locations is different, the operational decisions will be different. The issue of optimal sizing and siting of DG units has been addressed in a comprehensive manner in Chapter-6.

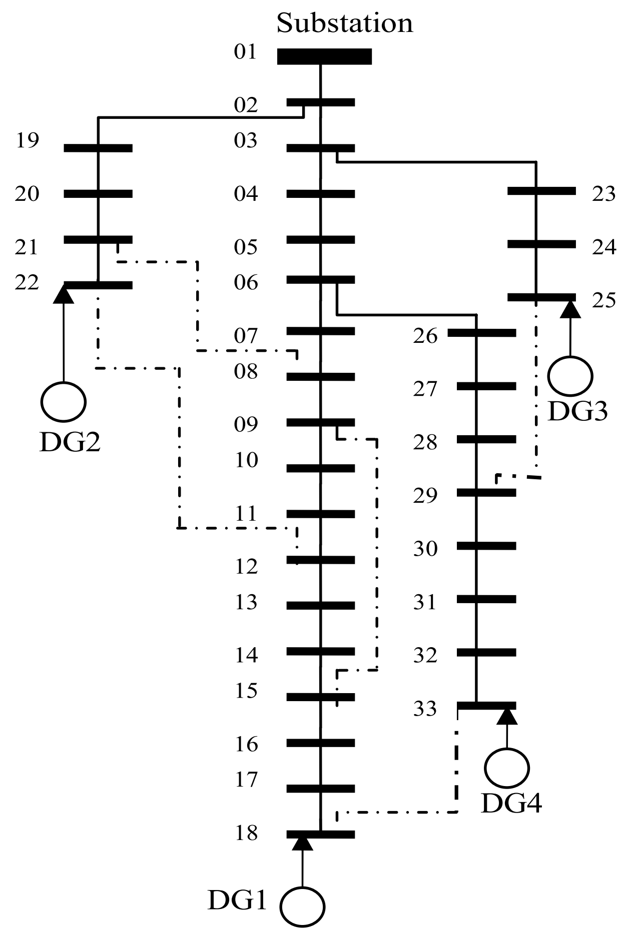

Figure 4.2: Layout of 33-Bus radial distribution system [10]

4.3.3 Scenario Studies

In order to examine the operational issues as mentioned before, three realistic scenarios are constructed as explained below:

- *Scenario-A: Normal Operation:* This scenario represents a normal condition in the distribution network. The day-ahead hour-wise disco demand is derived using

(4.25), considering that day-ahead price forecast is available to the disco. The real-time demand is derived using (4.26)-(4.28) assuming that an updated real-time price forecast is available with the disco.

- *Scenario-B: Demand Spike in Real-time:* This scenario considers a 10% excursion in disco demand arising during hours 11-14, the disco being aware of it only one-hour in advance, from short-term demand forecast and observation of system conditions. The real-time price remains in normal state.
- *Scenario-C: Price Spike Associated with Demand Spike in Real-time:* This scenario considers the fact that a demand excursion in the disco territory is associated with real-time market price spikes. Accordingly, a 23% price spike is considered between hours 11-14, and a corresponding demand spike (in both active and reactive) in real-time takes place between these hours, as per (4.26)-(4.28).

Figure 4.3 shows the prices in the three scenarios as discussed above, along with the day-ahead price. Figure 4.4 shows the real-time disco demand in the three scenarios, alongside its day-ahead demand.

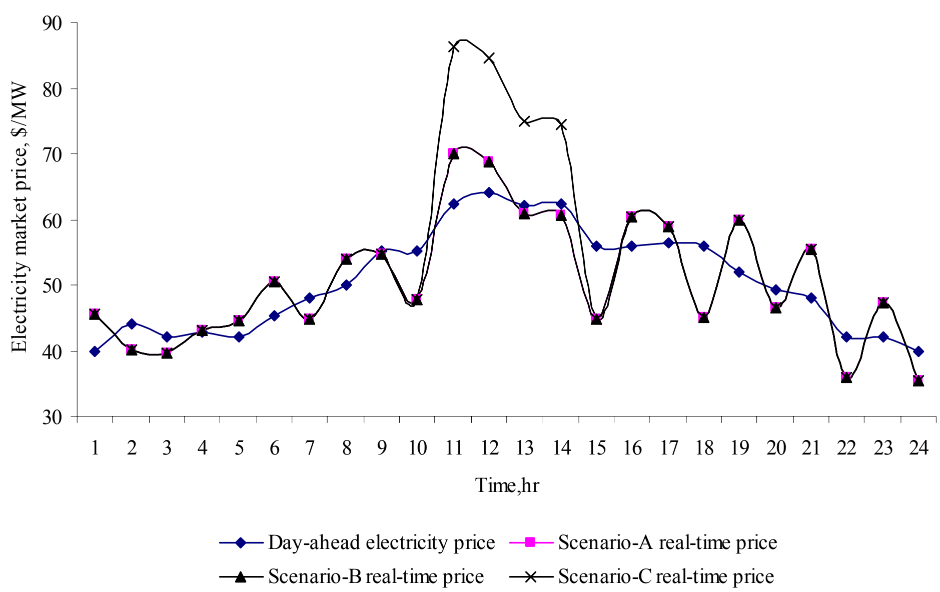

Figure 4.3: Electricity market prices as per the three scenarios

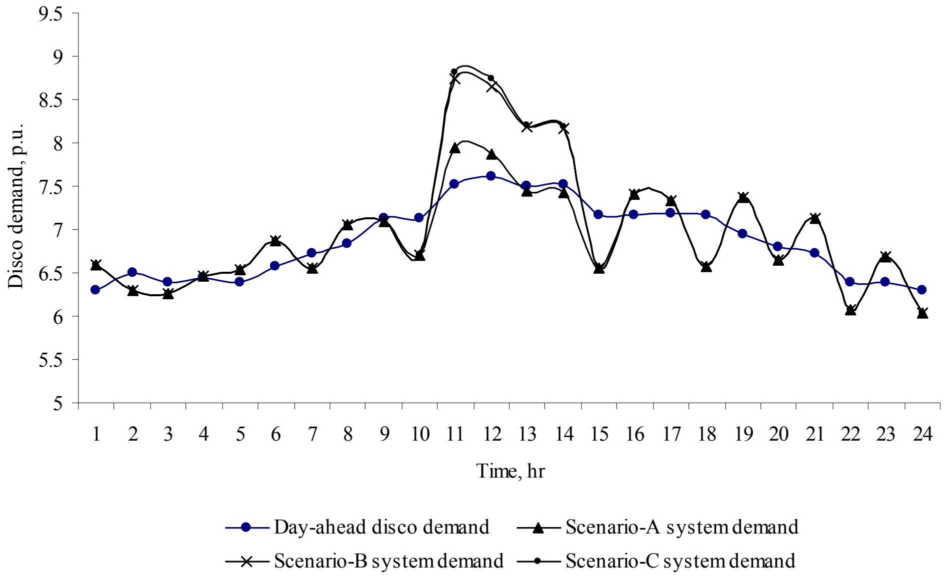

Figure 4.4: Day-ahead disco demand and real-time demand as per the scenarios

4.3.3.1 Scenario-A: Normal Operation

This scenario considers the normal operation of the distribution system and no untoward incident takes place. The electricity market prices in DAOM and RTOM are shown in Figure 4.3, and these act as the input to both models.

It is to be noted that the full substation capacity of 7 p.u. can meet the disco's demand in most of the hours by importing all the power from the external grid, and can also cover for a reasonable amount of reserve. However, since the disco seeks to minimize its day-ahead as well as real-time payments, the optimal decisions include a combination of all choices.

Figure 4.5 shows the deviations in disco's real-time decisions on active power purchase from external grid/market, as compared to its day-ahead commitment for purchase. Although the objective function (4.12) penalizes the disco for not fulfilling its day-ahead purchase contract, the RTOM nevertheless ends up with significantly increased purchases from the grid. The maximum deviation was 0.7238 pu (*i.e.*, 7.238 MW) at hour-11 when the real-time demand of the disco was very high. At four specific hours (15, 18, 22, 24) the disco buys lesser power from the market compared to its day-ahead contract. This is because of the somewhat lower demand levels of the disco in real-time, at these hours. For these hours the disco receives a payment credit from the market.

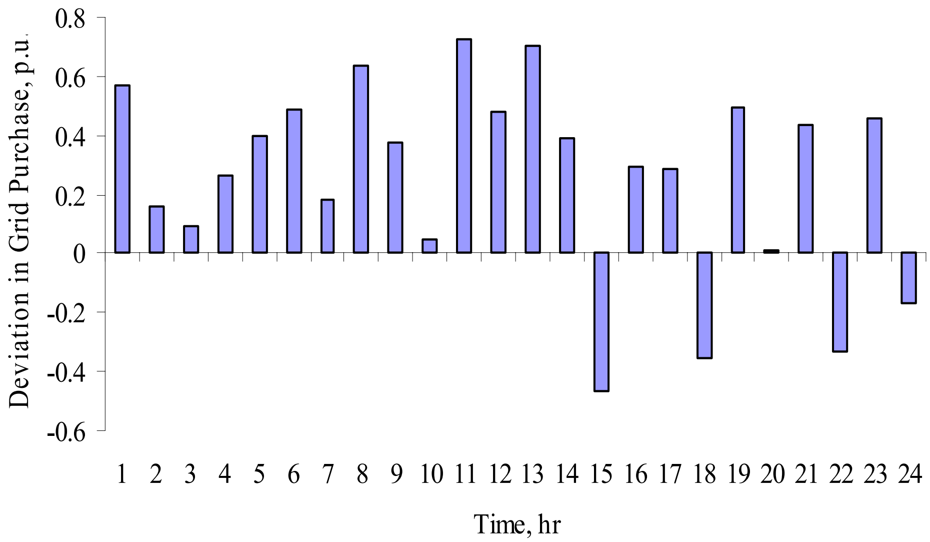

Figure 4.5: Deviation in RTOM grid purchase from DAOM decisions (*positive axis denotes increased grid purchase in RTOM, negative axis denotes reduced purchase in RTOM*)

DG generation schedules for both day-ahead and real-time markets are shown in Figure 4.6. In the DAOM, the total generation attains a maximum level of 1.5 p.u., during hours 9-18, while in RTOM the total generation reaches the maximum available DG capacity (*i.e.* 1.8 pu) at hours 13, 14 and 16.

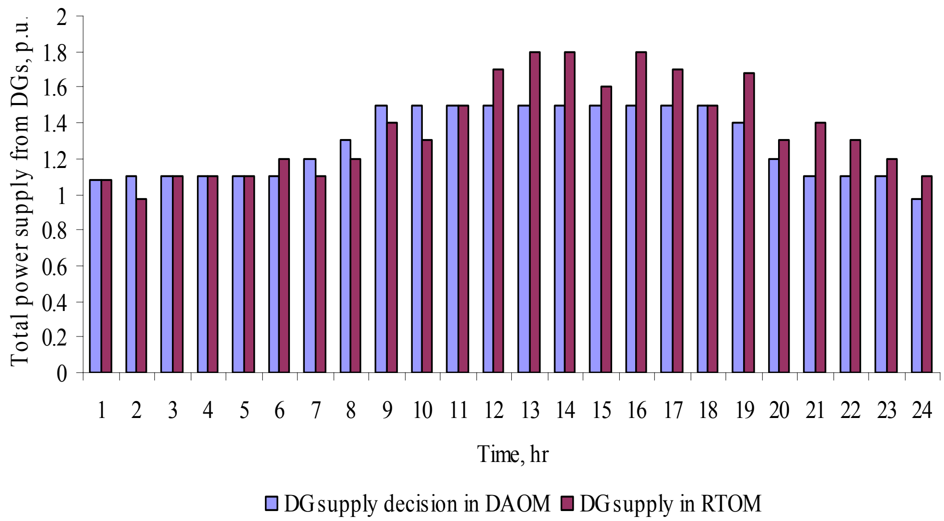

Figure 4.6: DG schedules as per DAOM and RTOM.

The RTOM provides a degree of freedom to each DG unit to re-adjust its generation based on short-term operating conditions. Figure 4.7 shows the hourly differences between the RTOM and DAOM generation schedule for each DG unit. We observe that since DG at bus-18 is a cheap unit, it is always scheduled at full capacity (0.5 pu) in the DAOM as well as in the RTOM and hence does not appear in Figure 4.7.

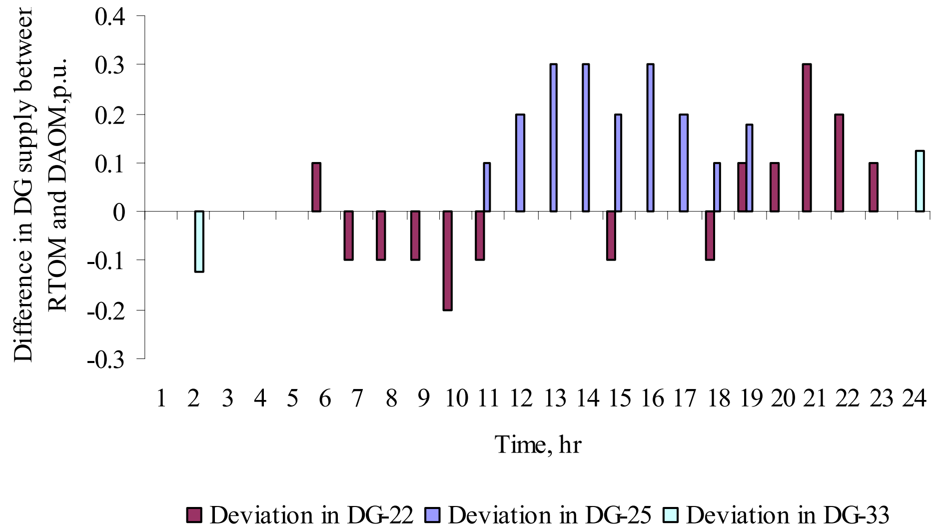

Figure 4.7: Unit-wise difference in DG schedules between RTOM and DAOM (*positive y-axis denotes RTOM schedule > DAOM schedule, and vice versa*)

Also since DG at bus-18 is at a remote end of the feeder, more generation from this unit reduces the feeder power losses and consequently the amount of power purchased from the grid. The disco system active power loss and the “worst bus voltage” are depicted in Figure 4.8. It is seen that the “worst” or the lowest voltage at a bus is 0.91 p.u. Note that at hours-13, 14, 16, 17 and 19 the worst bus voltage in the distribution system is close to 0.91 p.u. and the corresponding feeder losses are at the peaks. It can be concluded that when feeder losses are kept at a minimum, a significant improvement in bus voltage magnitudes is achieved.

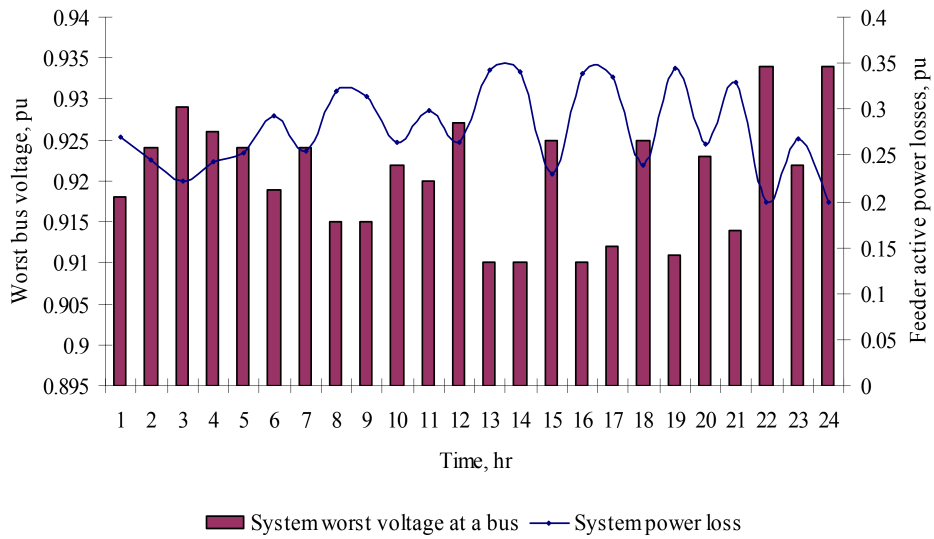

Figure 4.8: Worst bus voltage and feeder active power losses.

Furthermore, the DAOM determines an optimal amount of demand for IL contract while the actual quantity of IL invoked in real-time is obtained from the RTOM and is limited by this contracted IL. For example, the DAOM advises the disco to contract 0.8566 p.u. of IL in the day-ahead stage, for hour-12 next day (Figure 4.9) while it is seen that the actual IL at hour-12 was 0.71 p.u.

In the DAOM, the disco operator uses an expected IL bid-price, C_{IL}^{DA} which represents the disco's expectation of the IL bid price range for the real-time operation. For example, an expected IL bid-price range of 85 to 110 \$/MWh was used for the day-ahead IL contract decisions in DAOM. Uniform random numbers are generated in this range to represent a bid-price for a given hour.

In RTOM the actual bid prices are submitted for IL decisions. The highest IL price bid at hour-12 was 99.31 \$/MWh. This IL price is the highest accepted IL bid price at hour-12 and each individual IL participant will be compensated based on that price.

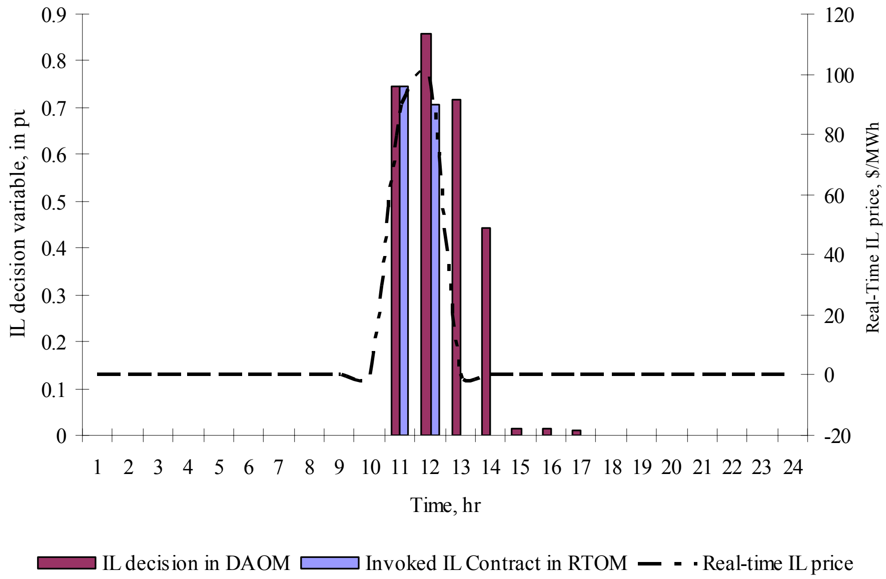

Figure 4.9: Comparison of IL decisions in Case-A and the real-time IL price

4.3.3.2 Scenario-B: Demand Spike in Real-time

The DAOM decisions remain unchanged while the RTOM seeks to arrive at an optimal set of decisions, under the given circumstances, in real-time.

It is of importance to examine how the decisions in this scenario differ from that of the normal scenario and the ability of the proposed operations framework to handle such a case. The grid purchase decision in RTOM is limited by the maximum transformer capacity available at the substation bus. This decision variable (grid purchase) now moves closer to that limit in order to meet the demand spike taking into account other control decisions, in an optimal manner (Figure 4.10).

For instance, in hour-11 (see Figure 4.10), when the demand is very high, the grid purchase decision attains a value of 6.882 p.u. and cannot be increased further, because of the minimum bus voltage constraints of 0.9 p.u. at all load buses in the presence of capacitor banks. Moreover, the disco seeks to minimize its total payments which include cost of reactive power support. Therefore, the disco has to invoke IL decisions from its IL contracts. Similar decisions are observed at the other demand-spike hours as well.

An interesting observation is that, when reactive power compensation at load buses is increased, or DG units inject more reactive power, there is a noticeable increase in grid purchase and consequent reduction in total system cost. This is because the feeder losses are reduced and the substation transformer is utilized more efficiently to import cheaper grid active power rather than expensive grid reactive power. The possibility to inject more reactive power locally and acquiring more active power through the substation bus opens the way for more choices to the disco in a competitive environment.

It is also observed from Case-B that the power generation from DG units do not change from those in Case-A. This is because the DG units at buses-18 and 33 are already at their maximum capacity of generation while the ramp rate checks for DG units at buses-22 and 25 are binding constraints and do not allow variations.

It is observed in Figure 4.11 that the calls for IL in real-time are significantly increased compared to the normal case (Figure 4.9). The real-time IL prices are determined for each hour when an IL decision is invoked. For example, in hour-11 the DAOM contracted an aggregated 0.745 p.u. of demand as IL, and the RTOM utilizes the whole contracted IL for curtailment. Furthermore, the highest IL price during these four hours of interruption was 99 $/MWh.

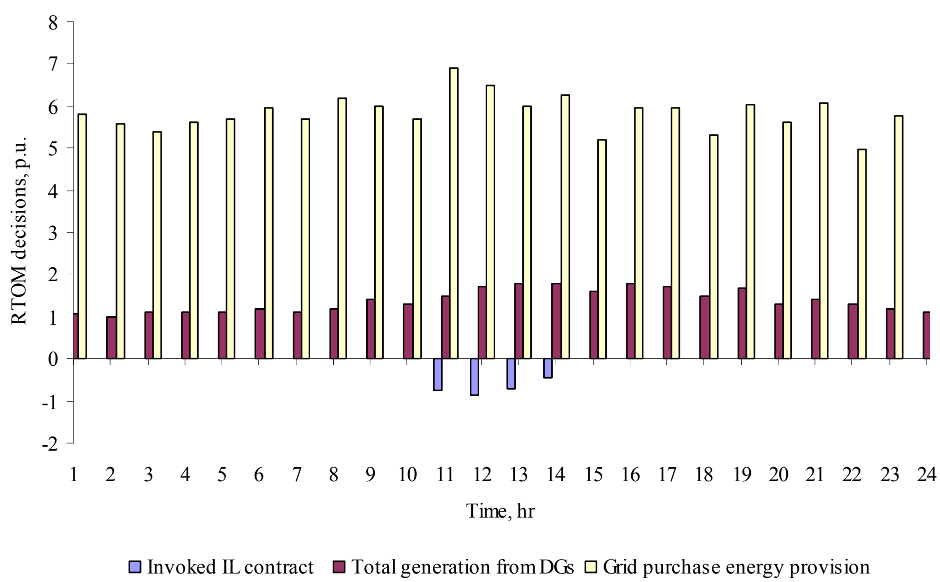

Figure 4.10: RTOM optimal decisions in Case-B

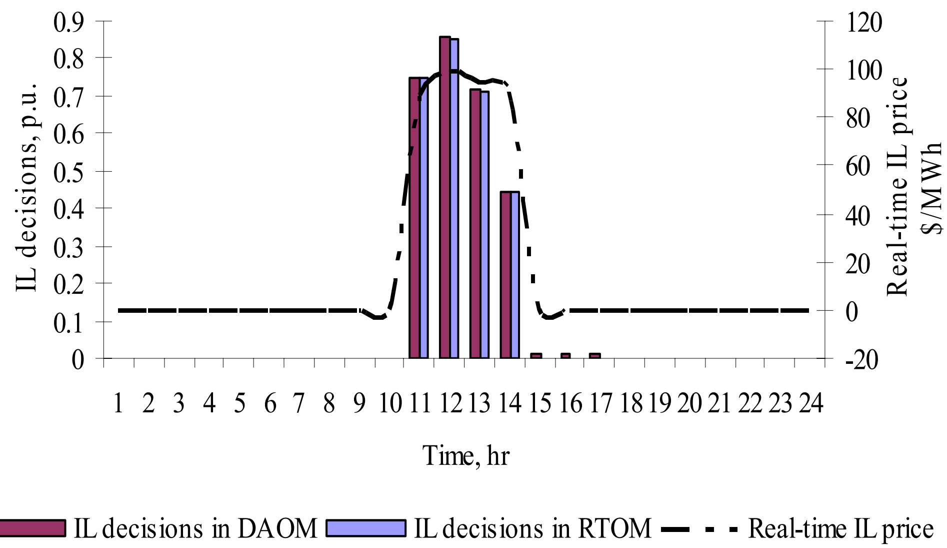

Figure 4.11: Comparison of IL decisions in Case-B and the real-time IL price

4.3.3.3 Scenario-C: Price Spike Associated with Demand Spike in Real-time

The main difference between this case and Case-B is in the market price excursion taking place simultaneously during the peak demand hours; while Case-B had no price excursion. Consequently, there are variations in hourly grid purchase and IL call decisions in the real-time stage although the day-ahead decisions remain unchanged.

Since the system has, in general, a poor power factor, a high disco demand (both active and reactive) coinciding with market price excursion, will affect the disco's reactive power management. It will need to import more reactive power from the external grid while also using more reactive power from load bus capacitors. Accordingly, the disco's gross payments will also increase.

Figure 4.12 shows that the system bus voltage profiles at hour-11, for the normal case as compared to Case-C are significantly different. Examining the 33-bus radial distribution system layout (Figure 4.2) we observe that two of the feeder branches had a significant voltage difference in the two cases in spite of the presence of DG units. Because of the large demand spike in hour-11 there are significant voltage drops taking place in feeder branch-2 (*second branch from left*) and the largest voltage difference appearing in the middle of the branch while in branch-3 (*third branch from left*) the largest differences are at the end of the feeder section. This is due to the combined effects of total feeder length in each branch, the reactive loading of the feeders and the effect of reactive power contribution from DGs at the end of the branch segments in each case.

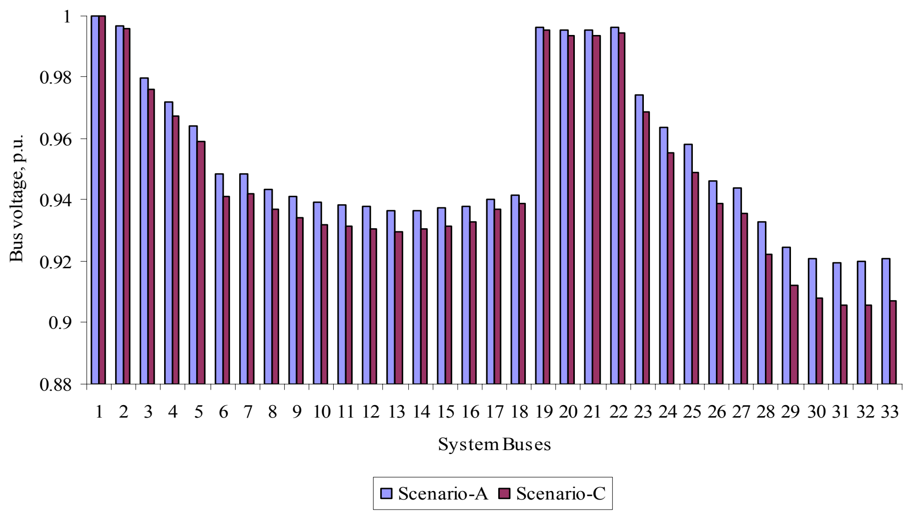

Figure 4.12: Comparison of hour-11 system voltage profile for Cases-A and C

On the other hand it can be observed that the IL invocations in Scenario-3 (Figure 4.13) will be somewhat reduced compared with that scenario-B.

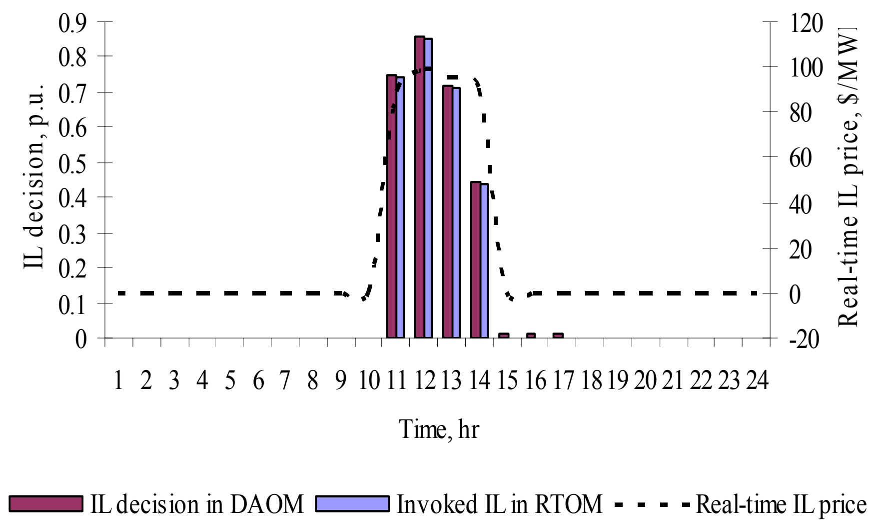

Figure 4.13: Comparison of IL decisions in Case-C and the real-time IL price

4.3.3.4 Summary of Scenarios

Table 4.1 summarizes the complete operations scenarios for the disco with regard to both its day-ahead and real-time decisions. It is seen that the day-ahead decisions remain unchanged in all the three scenarios, with the maximum share of energy supply to be met by power purchased from the external market and transferred via the disco substation transformer. The disco also contracts a small amount of IL in the day-ahead stage and also commits its DG units to supply the remaining demand.

In the real-time stage we note the following:

- There is an increase in real-time grid purchase across all the three scenarios compared to day-ahead. The maximum increase occurs in Scenario-C because of the steep demand increase at some hours.
- Scenarios-B and C, both require almost full utilization of their day-ahead contracted IL for call during real-time operation.
- DG unit schedules are slightly modified in the real-time stage as compared to the production schedules determined at the day-ahead stage. However, the schedules do not differ across the scenarios because they are constrained by ramp rates and unit limits.

- It is noted that the load-bus capacitors provide the main reactive support at the buses, while the DG units also contribute to some extent. Very little reactive power is transferred over the substation transformer, which is desirable.

TABLE 4.1: SUMMARY OF DAOM AND RTOM OPERATION DECISIONS

	Scenario-A	**Scenario-B**	**Scenario-C**
Day-Ahead Operations and Contract Decisions, after DAOM			
Total energy purchase schedule from grid, MWh	1310.25	1310.25	1310.25
Total IL Contract, MWh	28.008	28.008	28.008
Total energy generation scheduled from DG, MWh	309.5	309.5	309.5
Actual Operation Decisions Aggregated over 24-hours, after RTOM			
Energy purchased from grid, MWh	1371.806	1391.308	1393.614
IL called, MWh	14.487	27.5	27.459
Energy generated by DG units, MWh	329.267	329.267	329.267
Reactive power purchased from grid, MVArh	0.636	3.742	5.232
Reactive power provided by load bus capacitors, MVArh	926.973	931.816	932.098
Reactive power provided by DG units, MVArh	125.81	125.95	125.78
Active energy loss in feeders, MWh	66.7	68.562	68.642
Reactive energy loss in feeders, MVAr	44.098	45.321	45.371
Worst bus voltage	0.91 p.u. at hours 13, 14, 16	0.907 p.u. at hour-11	0.906 p.u. at hour-11

Table 4.2 provides a summary of the disco's costs and payments in day-ahead and real-time operations for the three scenarios. Examining Table 4.2, the following inferences can be made:

- The disco incurs most of the day-ahead cost in its grid purchase and DG unit schedules. A small component is also spent on IL contracts.
- The grid purchase payments are increased in real-time because of deviations from day-ahead purchase decisions, thus incurring a penalty. The maximum penalty and hence the largest payment for grid purchase occurs in Scenario-C because of the largest deviation in grid purchase in this case.
- The IL payments in real-time are calculated by determining the uniform IL price at each hour in which the IL is called for, as the highest accepted customer bid.
- DG dispatch cost is increased in real-time because of increased generation from DG units compared to the day-ahead schedule (see Table 4.1) and because of the more detailed DG cost function considered in RTOM.
- Examining Scenario-C for real-time operations, we note that although the disco purchased very little reactive power from the external grid, the payment is significantly high, compared to what it has to pay the DG units for their high level of reactive support provisions. It would therefore be important for the disco to examine this aspect further and increase its reactive power support at the load buses through additional capacitor banks.

TABLE 4.2: DISCO TOTAL PAYMENTS IN DAOM AND RTOM
(ALL UNITS ARE IN DOLLARS)

	Scenario-A	**Scenario-B**	**Scenario-C**
Day-Ahead Values			
Grid purchase cost	66,323.96	66,323.96	66,323.96
IL Contract Cost	2,452.72	2,452.72	2,452.72
DG Scheduling Cost	10,985	10,985	10,985
Real-time Values			
Grid Purchase Payment (including deviation penalty)	69,926.32	71,254.34	72,095.64
IL payment	1,347.09	2,584.68	2,584.50
DG Dispatch Cost	16,594.98	16,594.98	16,594.98
Payment for reactive power from grid	38.65	258.09	441.77
Reactive power cost from load bus capacitors	4,634.88	4,659.09	4,660.50
Reactive power cost from DG	629.12	629.82	628.95

4.4 Concluding Remarks

This chapter proposes a two-stage inter-related operations framework, pertaining to disco activities, in retail competitive markets. The mathematical models address the energy systems within disco territory and their optimal management such that the disco's economic costs are minimized. The first stage of the hierarchical framework is the day-ahead model which determines the disco's operational decisions and feeds them into the real-time model which is the second-stage of the proposed scheme.

Distributed generation (DG) schedules are determined based on day-ahead electricity prices posted by the market operator. Ramp rates, minimum up and minimum down limits for DG units are treated carefully to account for the technical constraints or financial risks that may arise in real-time operations. In addition, the operations framework considers the disco's participation in day-ahead energy market settlement and purchase power from the grid while keeping its energy payments as low as possible. Furthermore, the interruptible load (IL) decisions are managed by disco and an hourly unified IL price is paid to customers participating in this mechanism during stressed operational conditions. Different operation scenarios have been discussed and the generic nature of the proposed operations framework has been demonstrated.

The main contributions of this chapter are:

- Development of a comprehensive operational tool that a disco can readily use when functioning in an open electricity market environment.
- Proposes a two-stage mathematical model considering disco's operational needs, objectives and constraints both in its day-ahead and real-time operations.
- Addresses the optimal utilization of disco's available resources, for both active and reactive power through the dispatch of DG units and capacitor banks while taking into consideration the external electricity market effects.
- Includes optimal IL contracting (in day-ahead) and their optimal invocation (in real-time) in conjunction with other decision variables, and formulates their incentive pricing.
- Develops a mathematical model for a disco's day-ahead and real-time demand in terms of the external market price variations, based on historical dependence of the price and demand.

Chapter

5

Disco Operation Considering DG Units and Their Goodness Factors[3]

5.1 Introduction

In the previous chapters, it has been discussed that the presence of DG resources within a disco territory, can significantly affect the short-term operations and long-term planning tasks in electric power distribution systems. For instance, instead of the traditional unidirectional power flows emanating from the distribution substations towards the end-use demand sinks, it is now possible to have power flows in many arbitrary directions.

It has also been brought out in Chapter-2 that several researchers, over the past decade, have examined the penetration effects of DG resources on the distribution network system [43], [29], [32] and [41].

In this chapter, first, a novel set of sensitivity indices that quantifies the contribution of a DG resource at a specific bus are developed. The contribution of the DG unit is computed in terms of the incremental reduction in system loss for any incremental injection of active or reactive power from the DG unit. Furthermore, in order to provide a proper economic insight to these sensitivity indices, the set of incremental loss indices (ILIs), so obtained, corresponding to active and reactive power injections, are judiciously

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[3] Some parts of this chapter have been reported in:

- A. Algarni and K. Bhattacharya, *Disco operation considering DG units and their goodness factors*, IEEE Transactions on Power Systems, in revision.

Earlier versions of this work has been published in:

- A. Algarni and K. Bhattacharya, *Novel sensitivity indices based siting of distributed generation resources*, Proc. IEEE PES Annual General Meeting 2008, Pittsburg, USA
- A. Algarni and K. Bhattacharya, *Utility-owned DG units' impacts on distribution system operation*, IEEE PES Power Systems Conference & Exposition, 2009, Seattle, USA (accepted)

combined so as to arrive at a set of *goodness factors*. The goodness factors provide a clear signal to the disco operator as to the ‘worth” of a DG unit’s active and reactive power injection into the distribution network, in actual dollar terms. The distribution network can thereafter be clustered into different sections based on these indices.

The next part of the chapter presents an application of the goodness factors to short-term disco operations. The classical operations model objective is suitably modified to incorporate these goodness factors. Consequently, it is demonstrated that the disco can achieve superior operating decisions by way of lower system costs, reduced losses and an overall economic efficiency when these goodness factors are included in its operational decision making. Finally, it has been demonstrated that the payoffs to the DG units can be made on a rational basis from the above modified operations model that takes into account the goodness factor of each DG unit.

The rest of this chapter is organized as follows: Section-5.2 presents the mathematical formulation of the ILIs in a disco and the corresponding goodness factors. Section-5.3 presents the modified operations model of the disco and the analytical studies considering two different test systems are presented in Section-5.4. Section-5.5 discusses the main conclusions of the chapter.

5.2 Incremental Loss Indices and Goodness Factors

5.2.1 Incremental Loss Indices (ILI)

5.2.1.1 Self Indices

The active power self-ILI (5.1) denotes the incremental change in system active power loss due to an incremental active power injection at a bus, and the reactive power self-ILI (5.2) denotes the incremental change in system reactive power loss due to an incremental reactive power injection at a bus.

$$\lambda_i^P = \frac{\partial P_{Loss}}{\partial P_{inj,i}} \tag{5.1}$$

$$\lambda_i^Q = \frac{\partial Q_{Loss}}{\partial Q_{inj,i}} \tag{5.2}$$

The active and reactive power self-ILIs can be obtained from the Lagrange multipliers of an active / reactive power loss minimizing OPF model. The corresponding active and reactive power loss functions, P_{Loss} and Q_{Loss} respectively, are given below:

$$P_{Loss} = \frac{1}{2}\sum_{i=1}^{N}\sum_{j=1}^{N} G_{i,j}\left[V_i^2 + V_j^2 - 2V_iV_j\cos\left(\delta_j - \delta_i\right)\right] \tag{5.3}$$

$$Q_{Loss} = \frac{1}{2}\sum_{i=1}^{N}\sum_{j=1}^{N} B_{i,j}\left[V_i^2 + V_j^2 - 2V_iV_j\cos\left(\delta_j - \delta_i\right)\right] \tag{5.4}$$

The "reactive power loss" on a feeder is the reactive power demanded by the feeder reactance to transfer the load to the receiving end. It is used as a companion term to active power loss associated with resistive elements and hence the notation Q_{Loss} is used, for the sake of uniformity. This is discussed in detail in Kundur [73], p.254.

5.2.1.2 Mutual Indices

The active power mutual-ILI (5.5) denotes the incremental change in system active power loss due to an incremental reactive power injection at a bus, and the reactive power mutual-ILI (5.6) denotes the incremental change in system reactive power loss due to an incremental active power injection at a bus.

$$\sigma_i^P = \frac{\partial P_{Loss}}{\partial Q_{inj,i}} \tag{5.5}$$

$$\sigma_i^Q = \frac{\partial Q_{Loss}}{\partial P_{inj,i}} \tag{5.6}$$

In any distribution system configuration (radial or networked) power injection at different buses would result in differing effects on the system losses. It is important to note that in a radial system, a feeder section with multiple possible candidate buses for

DG injections will have correlated ILIs because of the inherent effects of power injection at a bus on the other buses in the feeder section. On the other hand, in a networked configuration the DG injections will result in arbitrary counter-flows in the distribution system and hence the ILIs will not be correlated.

5.2.2 Goodness Factors

The contribution of active and / or reactive power injection by a DG unit to overall system loss reduction can be better understood if the ILIs are represented in corresponding economic terms. A money value is attached to these indices to arrive at a *goodness factor* for a DG at a given bus. The goodness factors therefore indicate the relative importance and contribution of 1 unit of DG power (active or reactive) at a bus, as compared to a DG located at another bus in the distribution system. The goodness factors can also be interpreted as the savings in operational costs because of reduction in system loss, from DG power injection at a bus.

The proposed goodness factors are given below in (5.7) and (5.8).

$$\alpha_i^{Loss} = \rho^P \lambda_i^P + \rho^Q \sigma_i^Q \tag{5.7}$$

$$\beta_i^{Loss} = \rho^Q \lambda_i^Q + \rho^P \sigma_i^P \tag{5.8}$$

In (5.7), α_i^{Loss} is the goodness factor denoting the impact on system losses, in dollar terms, because of active power injection from a DG at bus *i.* Similarly, in (5.8), β_i^{Loss} is the goodness factor denoting the impact on system losses, in dollar terms, because of reactive power injection from a DG at bus *i.* The parameter ρ^P is the market price of energy while ρ^Q is the payment made by the disco for reactive power supply from external grid.

5.3 Disco Operations Considering Loss Indices

The short-term operations model of a disco in the presence of DG resources is appropriately modified to include the goodness factors of the DG units, as described in Section-5.2.2. The optimal mix of generation from DG resources and other energy supply provisions is determined by considering these effects and then compared to the case when goodness factors are not included.

5.3.1 Disco Optimal Energy Provisions Considering DG Goodness Factors

The disco's objective in the short-term operations framework (one-hour ahead) is to minimize its energy costs for the hour. Equation (5.9) provides the mathematical formulation of a disco owning all DG resources while (5.10) provides the objective function of the disco where DG units are investor-owned.

Objective Function

$$\begin{aligned} J_1 = &\sum_{i=1}^{NS} \rho^P \cdot P_i + \sum_{i=1}^{NS} \rho^Q \cdot Q_i \\ &+ \sum_{i=1}^{NDG} \left[(A_i \cdot P_i^2 + B_i \cdot P_i + C_i) \right] + \sum_{i=1}^{NDG} Q_i \cdot C_{QGi} \\ &- \sum_{i=1}^{NDG} \alpha_i^{Loss} \cdot \Delta P_i - \sum_{i=1}^{NDG} \beta_i^{Loss} \cdot \Delta Q_i \end{aligned} \tag{5.9}$$

The first component of (5.9) is the cost of power purchased from the external grid or energy market and depends on the electricity market price, ρ^P. It can be safely assumed that the disco operator will have a fairly accurate forecast of next hour's price from publicly available market information provided by the market operator.

The second component denotes the payment for reactive power from the external grid, transferred over substation transformers at a pre-determined price, ρ^Q. The issue of determining the price of this reactive power is beyond the scope of this chapter and thesis and is assumed to be known *a priori*. The third and fourth components in (5.9) represent the operational cost of DG units for the active and reactive power supplied, respectively.

The last two terms of (5.9) are included in the objective function to attach additional importance to DG units based on their contribution to the disco loss. These two terms encourage the DGs with high goodness factors to generate more power, compared to their original dispatch point. This is done with the view to induce more cheaper DG generation with disco grid while reducing purchases from external market and also reduce the losses. And we have,

$$\Delta P_i = P_i - P_i^* \qquad i \in g$$
$$\Delta Q_i = Q_i - Q_i^* \qquad i \in g$$

The goodness factors α^{Loss} and β^{Loss} are used in conjunction with active and reactive power generated by the DG units, respectively, to compute the cost savings to the disco.

The disco's objective will be slightly modified when the DG units are investor-owned instead of utility-owned. In such a case, the DG units will inject a pre-determined amount of power into the disco system, and will not be included in the disco's dispatch program. Eqn.(5.10) represents the disco's objective function when the DG units are investor owned.

$$\begin{aligned} J_2 = & \sum_{i=1}^{NS} \rho^P \cdot P_i + \sum_{i=1}^{NS} \rho^Q \cdot Q_i + \sum_{i=1}^{NDG} \tau_i \cdot P_i \\ & + \sum_{i=1}^{NDG} Q_i \cdot C_{QGi} \\ & - \sum_{i=1}^{NDG} \alpha_i^{Loss} \cdot \Delta P_i - \sum_{i=1}^{NDG} \beta_i^{Loss} \cdot \Delta Q_i \end{aligned} \tag{5.10}$$

In (5.10), the third term is a constant term, and will not affect the optimization solution if removed. It represents the price paid by the disco for energy purchased from the investor-owned DG units, τ (in \$/MWh), and the corresponding DG power purchased, which is known *a priori*.

Network Equations

The active and reactive power flow equations are modified to include grid purchased active and reactive power through disco transformers as well as DG generated active and reactive power.

$$P_s + P_g - PD_i = \sum_j |V_i||V_j||Y_{ij}| \cos(\theta_{ij} + \delta_j - \delta_i) \tag{5.11}$$

$$Q_s + Q_g - QD_i = -\sum_j |V_i||V_j||Y_{ij}| \sin(\theta_{ij} + \delta_j - \delta_i) \tag{5.12}$$

Grid Purchase Constraints

These constraints ensure that the active and reactive power purchased by the disco from the external grid / market is within the transfer limits imposed by disco transformer capacity.

$$P_s \le P_s^{Max} \tag{5.13}$$

$$Q_s \le Q_s^{Max} \tag{5.14}$$

The transformer capacity is further represented by its total p.u. MVA capacity as follows.

$$\sqrt{P_s^2 + Q_s^2} \le S_s^{Max} \tag{5.15}$$

Bus voltage limits

These limits ensure acceptable voltages at all disco buses and that the bus voltages do not drop below certain specified values, which is particularly an issue in distribution systems. The substation bus voltage is held at a constant value, similar to the slack bus in classical load flow programs.

$$\begin{aligned} |V_i| &= \text{Constant} && \forall\, i \in s \\ V_i^{Min} \le |V_i| &\le V_i^{Max} && i \in NL \end{aligned} \tag{5.16}$$

Generation limit on DG units

This constraint ensures that the power dispatched from a DG unit is within its maximum and minimum limits of generation.

$$P_i^{Min} \leq P_i \leq P_i^{Max} \qquad \forall i \in g \tag{5.17}$$

$$Q_i^{Min} \leq Q_i \leq Q_i^{Max} \qquad \forall i \in g \tag{5.18}$$

However, it should be noted that constraint (5.17) is not required when the DG units are investor-owned, because such units are pre-dispatched at the contracted output level (P^{Max}, in this work). Only (5.18) will be applicable to investor-owned DG units because of the provision of reactive power from them.

Feeder Limits

The power carrying capability of distribution feeders are limited by the feeder current limits, which are consequently represented by their MVA limits.

$$\sqrt{P_k^2 + Q_k^2} \leq S_k^{Max} \qquad \forall\ k \tag{5.19}$$

The disco operations model presented above is a nonlinear programming problem, which is solved using the GAMS/MINOS solver [69].

5.4 Systems Analysis and Case Studies

5.4.1 Systems under Study

Two distribution systems with different configurations are considered in this analysis. The first is a network configuration system with 18-buses (Figure 5.1) wherein three substation transformers connect it with the external grid / market at buses-1, 11 and 16. This system has been extracted from the well-known IEEE-30 bus system by considering only the 33 kV network. The second distribution system is a 69-bus radial configuration system with a single substation at bus-1 (see Figure 3.5). The network parameters and the load data are given in the Appendices.

5.4.2 Determination of ILIs and Goodness Factors

The ILIs for the systems under study are first determined using the definitions developed in Section-5.2, and using a loss minimizing OPF with objective functions (5.3) and (5.4) respectively. In the following subsections the calculated ILIs and goodness factors for each considered system will be illustrated in details.

5.4.2.1 Network Configuration: 18-bus system

The ILIs for the 18-bus system under study are determined using the definitions developed in Section-5.2, and reported in Table 5.1. It can be observed that corresponding to buses-1, 11 and 16, which are the substation transformers, the ILIs are zero. This is because the substation transformers are not fully loaded and can supply the extra MW or Mvar demand at these buses locally, without affecting the system losses. It should also be noted that the ILIs in Table-5.1 appear with a negative sign. This denotes the direction of change of the disco loss (reduced loss) for DG power injection (increased injection). However, this negative sign need not be considered for computation of goodness factors in (5.7) and (5.8) since this is only a sign convention associated with the Lagrange multipliers.

Using (5.7) and (5.8), the goodness factors $\alpha^{Loss}{}_{i}$ and $\beta^{Loss}{}_{i}$ for active and reactive power injections from a DG at a bus are calculated and presented in Table 5.2. For example, one unit of DG active power injected at bus-18, will accrue a cost saving of 12.8 \$/h because of the avoided losses. On the other hand, one unit of DG reactive power injected at bus-15, for instance, will accrue a cost saving of 5.67 \$/h to the disco from reduction in the system power losses.

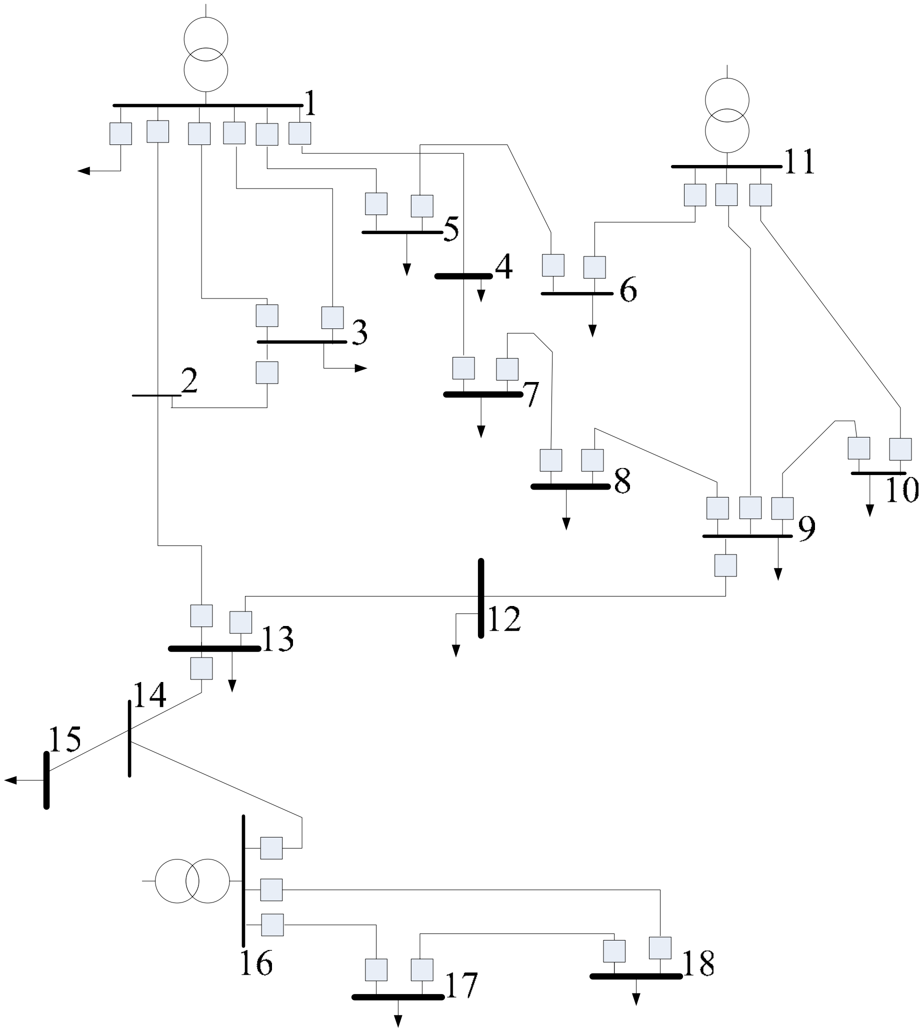

Figure 5.1: Schematic diagram of the 18-bus distribution system

TABLE 5.1: 18-BUS SYSTEM INCREMENTAL LOSS INDICES

Bus-i	Impact on Active Power Loss		Impact on Reactive Power Loss	
	Active power injected by DG	Reactive power injected by DG	Active power injected by DG	Reactive power injected by DG
	λ_i^P	σ_i^P	σ_i^Q	λ_i^Q
1	0	0	0	0
2	-0.010331	-0.006260	-0.022827	-0.014662
3	-0.010612	-0.006524	-0.023300	-0.014996
4	-0.020761	-0.007283	-0.045314	-0.016860
5	-0.005604	-0.003594	-0.013972	-0.008865
6	-0.005970	-0.000686	-0.016748	-0.008006
7	-0.027111	-0.009668	-0.057459	-0.021274
8	-0.026774	-0.009641	-0.055670	-0.020613
9	-0.019116	-0.007457	-0.038208	-0.015263
10	-0.016757	-0.006864	-0.033753	-0.012356
11	0	0	0	0
12	-0.025392	-0.013521	-0.048905	-0.025537
13	-0.024814	-0.017143	-0.045051	-0.030154
14	-0.014099	-0.010260	-0.026251	-0.018208
15	-0.033250	-0.023053	-0.055033	-0.037434
16	0	0	0	0
17	-0.028056	-0.007895	-0.052914	-0.014892
18	-0.047511	-0.011133	-0.089568	-0.020989

TABLE 5.2: GOODNESS FACTORS OF VARIOUS BUSES IN THE 18-BUS SYSTEM

Bus, i	α^{Loss}_{i}	β^{Loss}_{i}
1	0	0
2	3.08753	1.94558
3	3.15820	2.00204
4	6.15436	2.2457
5	1.81788	1.15725
6	2.10432	0.78914
7	7.88241	2.88146
8	7.68770	2.81927
9	5.35032	2.11937
10	4.71347	1.79844
11	0	0
12	6.94065	3.65043
13	6.53599	4.42816
14	3.77249	2.66472
15	8.27797	5.67436
16	0	0
17	7.56786	2.12978
18	12.81222	3.00231

5.4.2.2 Radial Configuration:69-bus system

The ILIs for the radial 69-bus distribution system are determined using the previous definitions and reported in Table 5.3. The transformer at the substation bus-1 is not fully loaded and the possibility to supply locally the extra MW or Mvar demand if any, without affecting the system losses, yields the ILIs to be zero at bus-1.

Using (5.7) and (5.8), the goodness factors ${\alpha^{Loss}}_i$ and ${\beta^{Loss}}_i$ for active and reactive power injections from a DG at a bus are calculated and presented in Table 5.4. It is to be noted that the remote end buses in this system have the higher values of goodness factors compared to the other buses in the system. The concept of ILIs and goodness factors verify mathematically the importance of locating DG units at remote buses, which was also stated in [43]. In this radial configuration, for instance, one unit of DG active power injected at bus-65, will accrue a cost saving of 23.55 \$/h because of the avoided losses. Also, at the same bus, one unit of DG reactive power injected will accrue a cost saving of 16.19 \$/h to the disco from reduction in the system power losses.

TABLE 5.3: 69-BUS SYSTEM INCREMENTAL LOSS INDICES

Bus i	Impact on Active Power Loss		Impact on Reactive Power Loss	
	Active power injected by DG	Reactive power injected by DG	Active power injected by DG	Reactive power injected by DG
	λ_i^P	σ_i^P	σ_i^Q	λ_i^Q
1	0.0	0.0	0.0	0.0
2	-0.000027	-0.000021	-0.000061	-0.000044
3	-0.000054	-0.000043	-0.000122	-0.000087
4	-0.000129	-0.000104	-0.000293	-0.000210
5	-0.001121	-0.000825	-0.001394	-0.000982
6	-0.015714	-0.010651	-0.008737	-0.005944
7	-0.031152	-0.021099	-0.016506	-0.011220
8	-0.034877	-0.023625	-0.018382	-0.012497
9	-0.036795	-0.024924	-0.019346	-0.013152
10	-0.045701	-0.030977	-0.022365	-0.015204
11	-0.047677	-0.032326	-0.023107	-0.015710
12	-0.053394	-0.036173	-0.025045	-0.017014
13	-0.058770	-0.039682	-0.026865	-0.018202
14	-0.064126	-0.043185	-0.028681	-0.019390
15	-0.069458	-0.046681	-0.030488	-0.020575
16	-0.070452	-0.047334	-0.030825	-0.020796
17	-0.072095	-0.048414	-0.031382	-0.021163
18	-0.072111	-0.048425	-0.031388	-0.021167
19	-0.072969	-0.049033	-0.031679	-0.021373
20	-0.073521	-0.049424	-0.031865	-0.021504
21	-0.074411	-0.050056	-0.032167	-0.021718
22	-0.074424	-0.050065	-0.032171	-0.021722
23	-0.074557	-0.050160	-0.032216	-0.021754
24	-0.074845	-0.050366	-0.032314	-0.021824

Bus i	Impact on Active Power Loss		Impact on Reactive Power Loss	
	Active power injected by DG	Reactive power injected by DG	Active power injected by DG	Reactive power injected by DG
	λ_i^P	σ_i^P	σ_i^Q	λ_i^Q
25	-0.075158	-0.050589	-0.032430	-0.021907
26	-0.075287	-0.050681	-0.032474	-0.021938
27	-0.075323	-0.050707	-0.032486	-0.021947
28	-0.000059	-0.000046	-0.000134	-0.000096
29	-0.000111	-0.000084	-0.000263	-0.000187
30	-0.000308	-0.000223	-0.000328	-0.000233
31	-0.000342	-0.000248	-0.000339	-0.000241
32	-0.000516	-0.000370	-0.000396	-0.000282
33	-0.000930	-0.000664	-0.000536	-0.000381
34	-0.001476	-0.001049	-0.000716	-0.000508
35	-0.001587	-0.001123	-0.000751	-0.000532
36	-0.000064	-0.000050	-0.000147	-0.000105
37	-0.000192	-0.000139	-0.000460	-0.000321
38	-0.000368	-0.000260	-0.000666	-0.000462
39	-0.000419	-0.000295	-0.000725	-0.000503
40	-0.000421	-0.000296	-0.000728	-0.000505
41	-0.001204	-0.000825	-0.001642	-0.001123
42	-0.001532	-0.001046	-0.002027	-0.001381
43	-0.001576	-0.001075	-0.002077	-0.001416
44	-0.001585	-0.001081	-0.002089	-0.001423
45	-0.001692	-0.001153	-0.002224	-0.001514
46	-0.001693	-0.001153	-0.002225	-0.001514
47	-0.000165	-0.000130	-0.000382	-0.000274
48	-0.001073	-0.000786	-0.002604	-0.001879
49	-0.003897	-0.002815	-0.009515	-0.006845

Bus i	Impact on Active Power Loss		Impact on Reactive Power Loss	
	Active power injected by DG	Reactive power injected by DG	Active power injected by DG	Reactive power injected by DG
	λ_i^P	σ_i^P	σ_i^Q	λ_i^Q
50	-0.004300	-0.003103	-0.010501	-0.007550
51	-0.034933	-0.023664	-0.018410	-0.012517
52	-0.034949	-0.023677	-0.018416	-0.012521
53	-0.041618	-0.028186	-0.021762	-0.014793
54	-0.047265	-0.032010	-0.024591	-0.016717
55	-0.055123	-0.037338	-0.028525	-0.019397
56	-0.062867	-0.042601	-0.032404	-0.022045
57	-0.107380	-0.072831	-0.047973	-0.032601
58	-0.129948	-0.088506	-0.055866	-0.038073
59	-0.138820	-0.094732	-0.058932	-0.040221
60	-0.149483	-0.102251	-0.062372	-0.042639
61	-0.163909	-0.112519	-0.069498	-0.047711
62	-0.164480	-0.112926	-0.069779	-0.047912
63	-0.165245	-0.113471	-0.070157	-0.048181
64	-0.169002	-0.116148	-0.072012	-0.049503
65	-0.170141	-0.116960	-0.072575	-0.049904
66	-0.047778	-0.032399	-0.023138	-0.015733
67	-0.047779	-0.032400	-0.023139	-0.015733
68	-0.053982	-0.036593	-0.025244	-0.017157
69	-0.053984	-0.036594	-0.025245	-0.017157

TABLE 5.4: GOODNESS FACTORS OF VARIOUS BUSES IN THE 69-BUS SYSTEM

Bus-i	α^{Loss}_{i}	β^{Loss}_{i}
1	0.0	0.0
2	0.008190	0.006060
3	0.016380	0.012130
4	0.039270	0.029300
5	0.237560	0.170880
6	2.357730	1.600060
7	4.600740	3.119700
8	5.142080	3.487230
9	5.420640	3.676080
10	6.582950	4.466060
11	6.847330	4.646500
12	7.593450	5.148560
13	8.294850	5.606380
14	8.993890	6.063600
15	9.689720	6.519850
16	9.819450	6.605040
17	10.033880	6.746070
18	10.036020	6.747530
19	10.148010	6.826870
20	10.219950	6.877760
21	10.336130	6.960220
22	10.337790	6.961480
23	10.355140	6.973860
24	10.392760	7.000760
25	10.434500	7.030530
26	10.451360	7.042520

Bus-i	α^{Loss}_{i}	β^{Loss}_{i}
27	10.456040	7.045930
28	0.017960	0.013240
29	0.034770	0.025230
30	0.060320	0.043270
31	0.064710	0.046490
32	0.087240	0.062380
33	0.141240	0.100690
34	0.212040	0.150620
35	0.226290	0.160180
36	0.019630	0.014450
37	0.060600	0.042790
38	0.096740	0.067580
39	0.107150	0.074770
40	0.107620	0.075050
41	0.268180	0.183570
42	0.335630	0.228890
43	0.344530	0.234940
44	0.346510	0.236170
45	0.369360	0.251560
46	0.369550	0.251560
47	0.050880	0.037660
48	0.341660	0.247710
49	1.246050	0.897550
50	1.375090	0.989800
51	5.150200	3.492930
52	5.152340	3.494590
53	6.120380	4.149970

Bus-i	α^{Loss}_{i}	β^{Loss}_{i}
54	6.939690	4.705530
55	8.079550	5.479530
56	9.203060	6.244150
57	15.055570	10.217190
58	18.022740	12.277170
59	19.185880	13.093090
60	20.561780	14.062610
61	22.645720	15.545890
62	22.728110	15.604680
63	22.838630	15.683390
64	23.381280	16.070070
65	23.545850	16.187360
66	6.860220	4.655870
67	6.860410	4.655970
68	7.670160	5.203430
69	7.670450	5.203530

5.4.3 Operational Scenarios

In this section, four DG units are introduced to analyze the operational impact of injections from DGs on both the 18-bus networked and 69-radial configuration systems. The DG unit characteristics and cost data are provided in the Appendices.

Based on the values of α^{Loss} and β^{Loss} given in Table 5.2 and Table 5.4, these DG units are connected at different buses within each system under study. The selection of DG buses is made where the values of α^{Loss} and β^{Loss} are fairly high. In the 18-bus system, buses-7, 8, 15 and 18 are considered as candidate buses for the DG units installation. In the case of 69-bus system, buses-27, 52, 65 and 69 are the candidate buses for DG units installation. A proper optimal planning model could also be used for determining the optimal DG locations. But the main emphasis of this chapter is to demonstrate the new operations model and hence this simplistic and straight-forward selection is made. A more comprehensive planning cum operations model will be presented in Chapter-6 by extending the concept of goodness factors even further.

The dispatch of these DG units, as affected by α_i^{Loss} and β_i^{Loss}, is determined from the optimal operation model. Two scenarios of DG ownership are considered for our analysis as described next.

5.4.3.1 Utility-owned DG Units

In this scenario, the DG units are considered to be owned by the disco, and the disco seeks to optimize their operation. Two operational cases are considered: a) Case-I: optimal operation of disco when ILIs and bus goodness factors are not considered and (b) Case-II: optimal operations of the disco considering the effect of the proposed ILIs and goodness factors. This operational scenario and its two cases are first analyzed for the networked 18-bus system and the related results are discussed. Then the radial 69-bus system is analyzed where the two cases of operation are also considered for the sake of comparison. Furthermore, the effect of renewable energy resources, for instance wind turbine and its operation characteristics on disco operation and its total costs is investigated in more detail.

5.4.3.1.1 Network Configuration:18-Bus System:

As mentioned earlier, the 18-bus system is a 33 kV network. The nominal demand is appropriately modified to consider the DG supply into the system. The system demand is 62.82 MW and 30.48 Mvar, and the goodness factors are computed for this load condition.

Case-I: Without ILIs and Goodness Factors

The analysis in this case is carried out by setting $\alpha_i^{Loss} = \beta_i^{Loss} = 0$ ($\forall$ i) in (5.9). Consequently, the objective function will be the minimization for a disco cost function comprising different components of energy provisions. The energy market price has been assumed to be 100 \$/MWh (*which is close to a typical peak price in the Ontario market*). A forecast of this price, close to the real-time, will usually be made available to all market participants by the market operator. The price for reactive power transfers over the substation transformers have been assumed to be 90 \$/Mvarh.

The optimal amount of power purchased from the grid through the three substation buses and the DG dispatch decisions are reported in Table 5.5. It can be noted that the DG at bus-18, for instance, is not dispatched for either active or reactive power although the goodness factor, particularly α^{Loss} , is the highest at bus-18 amongst all DG buses as seen in Table 5.2. This is because the disco operator seeks to minimize the costs without taking into consideration the system effects of DG generation. This DG being somewhat more costly to operate, is not dispatched at all, which is not an appropriate decision, as will be seen in the next sub-section.

TABLE 5.5: CASE-I OPTIMAL DECISIONS WITHOUT GOODNESS FACTORS-18 BUS SYSTEM

Bus-i	P_S	Q_S	P_g	Q_g
1	0.311	0.203	-	-
7	-	-	0.06	0.01
8	-	-	0.03	0.01
11	0.158	0.075	-	-
15	-	-	0.013	-
16	0.06	0.015	-	-
18	-	-	-	-

Case-II: With ILI and Goodness Factors

This case takes into consideration the previously computed ILIs and bus goodness factors within the disco objective function (5.9). It can be observed (in Table 5.6) that the optimal disco operation was altered from the dispatches of Case-I (Table 5.5). The power fed to the system over transformer at bus-16 is significantly reduced as compared to the operational decisions in Case-I. On the other hand, two DG unit dispatches are considerably affected, the DG at buses-15 is dispatched at its maximum limit for its active power provision and the DG at bus-18 is dispatched at 64% of its active power capacity.

TABLE 5.6: CASE-II OPTIMAL DECISIONS WITH GOODNESS FACTORS-18 BUS SYSTEM

Bus-i	P_S	Q_S	P_g	Q_g
1	0.287	0.214	-	-
7	-	-	0.06	0.01
8	-	-	0.03	0.01
11	0.155	0.075	-	-
15	-	-	0.03	-
16	0.024	0.001	-	-
18	-	-	0.045	-

It is obvious that the ILIs and the goodness factors significantly affect and alter the operating decisions and a more desirable optimal solution was obtained in Case-II.

Table-5.7 provides a comparison between the operations decisions of the two cases.

TABLE 5.7: 18-BUS SYSTEM SUMMARY COMPARISONS

	Cost of grid purchased active and reactive power, $/hr	**Cost of gross generation from DG units, $/hr**	**Total cost, $/hr**	**P_{Loss}, pu**	**Q_{Loss}, pu**
Case-I	7926.89	134.70	8061.59	0.004076	0.00790
Case-II	7275.18	215.37	7490.55	0.002894	0.005688
Benefit / Loss to Disco	651.71 Saving in grid costs	80.67 Increased DG cost	571.04 disco saving	Reduced P_{Loss} of 0.001182	Reduced Q_{Loss} of 0.002212

The disco operator can clearly perceive the advantage of Case-II over Case-I operation from the obvious difference in the two costs, *i.e.*, its payment burden. It is seen that in Case-II, the disco spends $651.71/h lesser in grid-purchased power, but has an increase in its DG operations cost by $80.67/h. The total operating cost of the disco in Case-II is $7490.55/h, which is significantly lesser compared to Case-I. The disco has gained $571.04/h in its total operational savings by modifying its dispatch decisions as given in Case-II.

The active power scheduled for each DG unit along with the goodness factors α_i^{Loss} are shown in Figure 5.2. It is seen that there is a strong correlation between the active power dispatch and the goodness factor α^{Loss}; when α^{Loss} is high at a bus, the Case-II solution selects a high dispatch level for the DG.

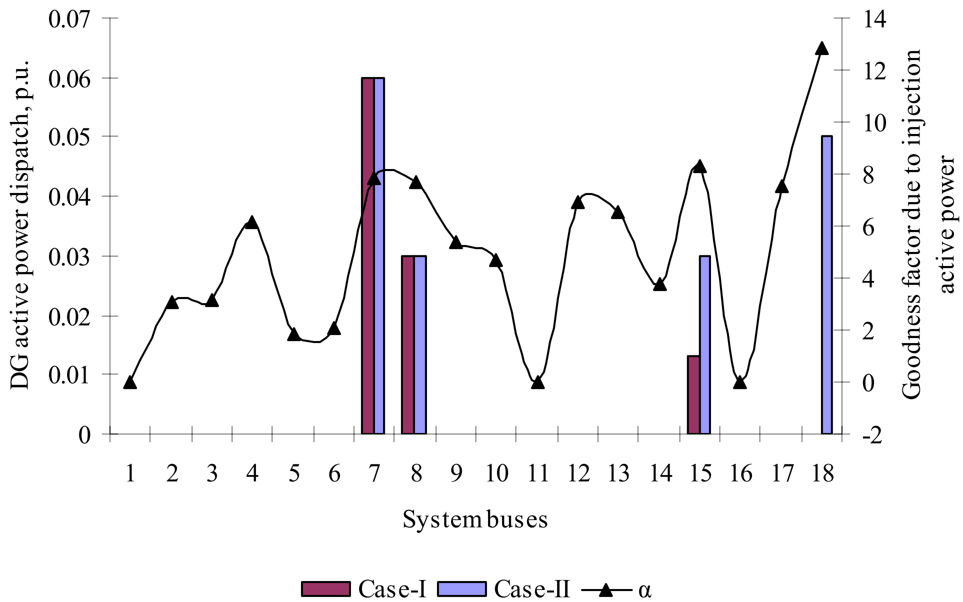

Figure 5.2: Active power dispatch from DG units and goodness factor α

The correlation between the reactive power dispatch and goodness factor β^{Loss} also exits but since the Case-I solution already makes use of all reactive power capacity from dispatched DG, there is not much room for reactive power dispatch changes between the two cases.

A comparison of the system voltage profile between the two cases (Figure 5.3) depicts that Case-II solutions yield a superior profile, particularly at remote end buses. Since there is no more power to be efficiently scheduled from the DG units in Case-I, there was a need to import more power from the external grid, thereby, increasing the losses in the system, which thereby affected the system bus voltages.

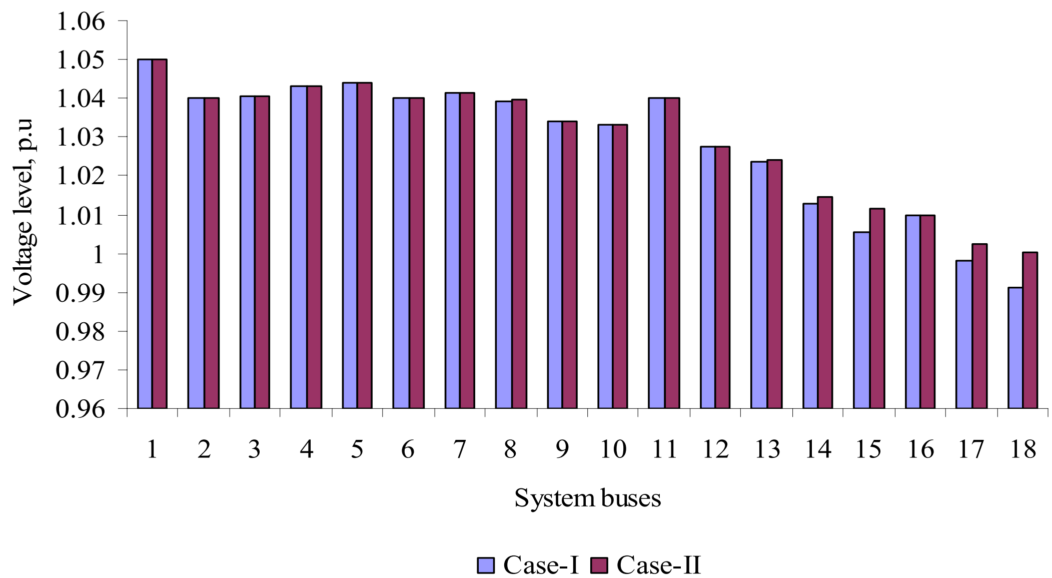

Figure 5.3: Comparison of system voltage profile, without and with goodness factors

The shadow prices are analyzed in the presence of DG units and these provide information to the disco operator on the marginal cost of supplying power at a bus. The shadow prices for Case-I and Case-II are shown in Figure 5.4 and Figure 5.5 respectively. It can be seen that in Case-I, the marginal cost of supplying power at most of the disco buses are fairly uniform and are in the range of 100 $/MWh which is the assumed market price of energy. However, in Case-II, the bus marginal costs vary significantly at the remote buses, bus numbers-13 to 18. At buses-15, 16, 17 and 18 the marginal cost of supplying power is negative which implies that at these buses, one unit of demand increase will result in a reduction in total costs for the disco by way of reduced losses and generation redispatch. The customers at these buses will thus receive a payment credit, because of their contribution to the system by reducing losses, by virtue of their location.

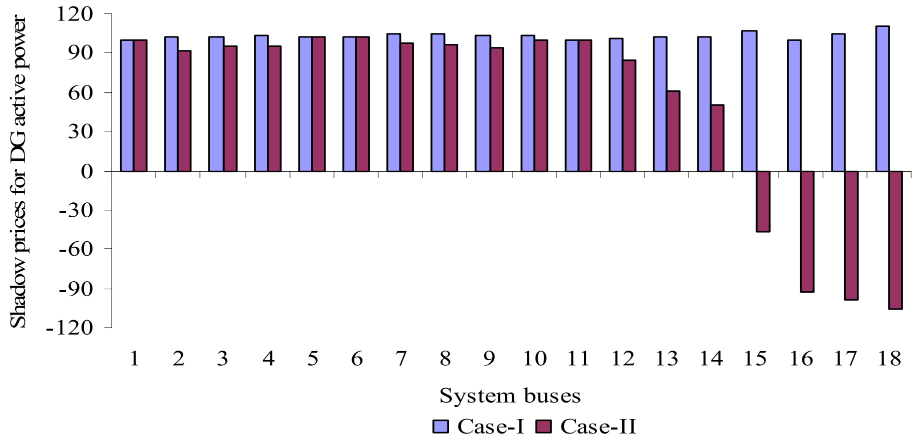

Figure 5.4: Comparison of active power shadow prices, without/ with goodness factors

The above aspect is captured only by the modified disco model presented as Case-II and the traditional Case-I is not able to bring out this aspect of marginal cost impact. The same characteristic is observed in case of reactive power bus marginal costs (Figure 5.5). The customers located at buses-15-18 will receive a credit from the disco for their reactive power consumption because of their loss reduction impact.

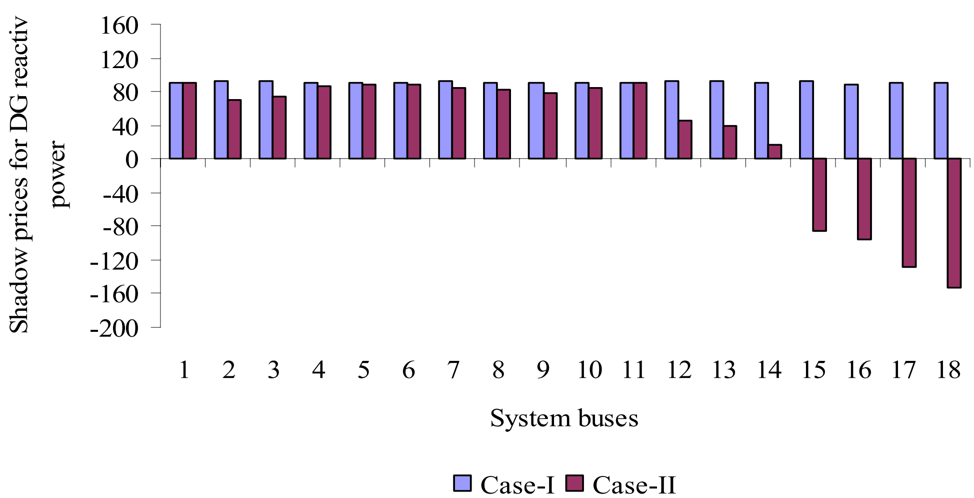

Figure 5.5: Comparison of reactive power shadow prices, without / with goodness factors

5.4.3.1.2 Radial Configuration: 69-Bus System:

In this section we consider the 69-bus system discussed earlier to study the effect of DG participation in disco operation, particularly in the context of a fairly large system. We also consider the presence of two wind DG units at specific buses having no operational costs, but with non-dispatchable power generation and injection into the grid, as determined by wind speed variations.

The analysis examines the impact of DG goodness factors and how operation are impacted and cost savings are achieved.

A) All DG Units are Dispatchable

We consider all the DG units, in addition to being utility-owned, are also of such technologies and resources, that they can be dispatched by the disco. For example, gas-turbine DG units would be typical examples.

Case-I: Without ILIs and Goodness Factors

The analysis is carried out by setting $\alpha_i^{Loss} = \beta_i^{Loss} = 0$ ($\forall$ *i*) in (5.9) as discussed before. Consequently, the objective function will be the minimization of a disco cost function comprising different components of energy provisions.

The optimal amount of power purchased from the grid through the substation transformer located at bus-1 and the DG dispatch decisions are reported in Table 5.8. The DG at bus-65, for instance, is not dispatched for active power although it has the highest goodness factor among the DG buses (see Table 5.4). This is because the disco operator seeks to minimize the costs without taking into consideration the system effects of DG generation. This DG being somewhat more costly to operate, is not dispatched at all for active power provision, which is not an appropriate decision, as will be seen in the next sub-section.

TABLE 5.8: CASE-I OPTIMAL DECISIONS WITHOUT GOODNESS FACTORS-69BUS SYSTEM

Bus-i	P_S	Q_S	P_g	Q_g
1	0.0225	0.0175	-	-
27	-	-	-	0.001588
52	-	-	0.016853	-
65	-	-	-	0.007874
69	-	-	-	0.000572

Case-II: With ILI and Goodness Factors

This case takes into consideration the previously computed ILIs and bus goodness factors within the disco objective function (5.9). It can be observed (in Table 5.9) that the optimal disco operation was altered from the dispatches of Case-I in Table 5.8. The power fed to the system over substation transformer is reduced slightly while the DG at bus-65 is dispatched to provide active power.

TABLE 5.9: CASE-II OPTIMAL DECISIONS WITH GOODNESS FACTORS-69 BUS SYSTEM

Bus-i	P_S	Q_S	P_g	Q_g
1	0.02	0.015	-	-
27	-	-	-	0.001588
52	-	-	0.016853	-
65	-	-	0.002216	0.010261
69	-	-	-	0.000572

The disco operational costs and its system losses in each case are summarized in Table-5.10.

TABLE 5.10: 69-BUS SYSTEM SUMMARY COMPARISONS

	Cost of grid purchased active and reactive power, $/hr	**Cost of gross generation from DG units, $/hr**	**Total cost, $/hr**	**P_{Loss}, pu**	**Q_{Loss}, pu**
Case-I	382.500	19.58	402.08	0.001338	0.00059
Case-II	335.00	32.95	367.95	0.001054	0.000475
Benefit / Loss to Disco	47.5 Saving in grid costs	13.37 Increased DG cost	34.13 disco saving	Reduced P_{Loss} of 0.000284	Reduced Q_{Loss} of 0.000115

The disco operator can clearly perceive the advantage of Case-II over Case-I operation from the obvious difference in the two costs, *i.e.*, its payment burden. It is seen that in Case-II, the disco spends $47.50/h lesser in grid-purchased power, but has an increase in its DG operations cost by $13.37/h. The total operating cost of the disco in Case-II is $367.95/h, which is lesser compared to Case-I. The disco has gained $34.13/h in its total operational savings from its dispatch decisions of Case-II.

B) Disco Owns both Dispatchable and Non-Dispatchable Units

Now, it is assumed that two dispatchable DG units are installed at bus-52 and 65, and two wind turbine generation units are connected at bus 27 and 69. In order to represent the wind DG provisions as a function of wind speed, a 24-hour operation is introduced in this case, and the load scaling factor (LSF) is also used with each load bus in the system over one day of operation.

The wind speed is an independent variable that determines the units' generation in wind DG units. A normal distribution function is used to model the hourly wind speeds (Ws) at the two buses.

$$Ws_i(t) = N(\mu_i, \sigma_i^2) \qquad \forall i \in g \tag{5.20}$$

Where μ_i is the mean wind speed at a bus while σ_i^2 is the variance of the wind speed.

Figure 5.6 depicts the wind speed simulation for the wind turbines installed at bus-27 and 69.

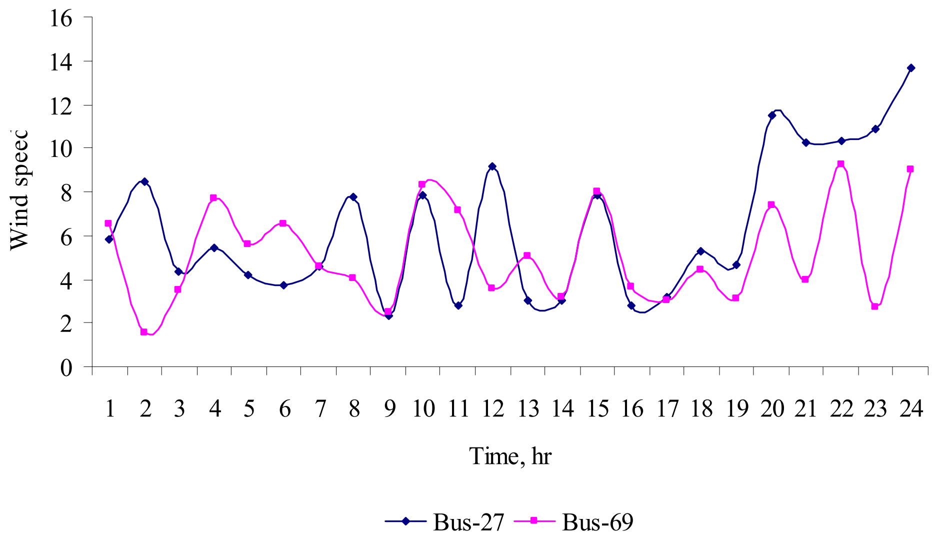

Figure 5.6: Wind speed simulation of wind turbines at bus-27 and 69

For any wind turbine generator there are three distinct wind speeds of importance- the cut-in, the nominal and the cut-out speeds [74]. The power output from each wind generator is accordingly modeled as follows.

$$P_i = \begin{cases} 0 & , Ws_i(t) < Ws_i^{cut-in} \\ (\alpha_i \cdot Ws_i(t) - \beta_i) \cdot P_i^{Max} & , Ws_i^{cut-in} \le Ws_i(t) \le Ws_i^{cut-out} \\ P_i^{Max} & , Ws_i(t) > Ws_i^{cut-out} \end{cases} \qquad \forall i \in g \tag{5.21}$$

The above model takes into account the fact that because of technical limits, the wind turbine generators cannot generate power when the wind speed is lower than the cut-in speed or higher than the cut-out speed. The short-term operation costs for such renewable units are very low and in this work are considered to be zero [75]. These units are assumed to inject active power only. Figure 5.7 shows the generated power from each wind turbine generator over 24-hour.

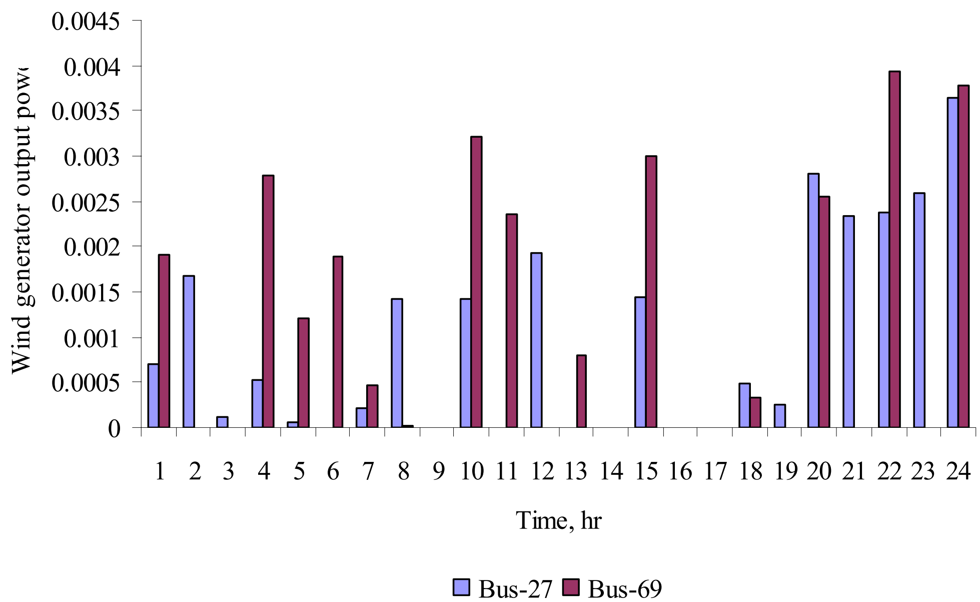

Figure 5.7: Generator output power from wind turbines at bus-27 and 69

It is of interest to examine the operational decisions and the disco costs while the operation model is optimized. At hour-22, for example, the wind speeds at site-27 and site-69 are 10.32 m/s, and 9.24 m/s respectively, which are in the nominal speed ranges. The operation decisions of active and reactive power supply without and with the system goodness factors are shown in Figure 5.8 and Figure 5.9, respectively.

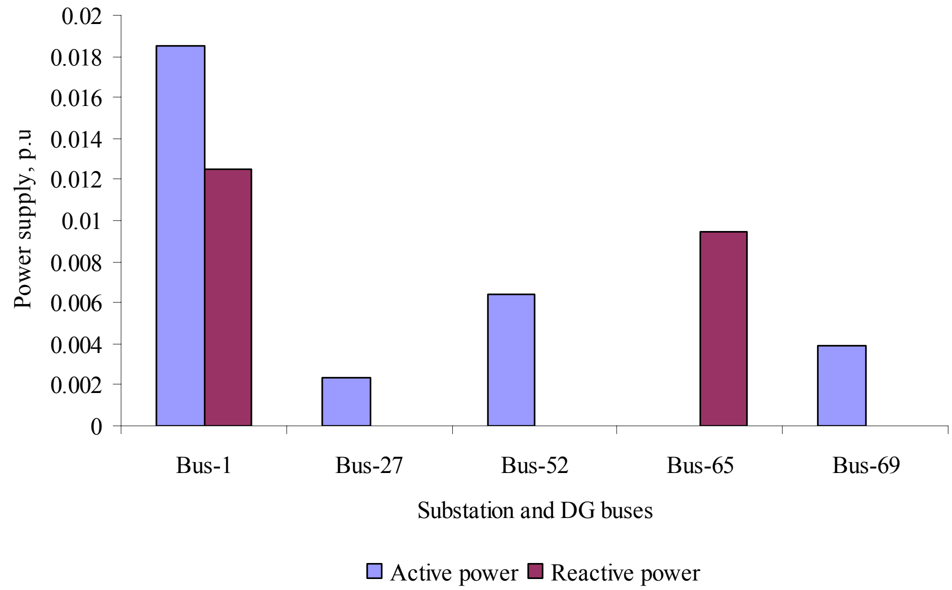

Figure 5.8: Active and reactive power supply without goodness factors, at hour-22

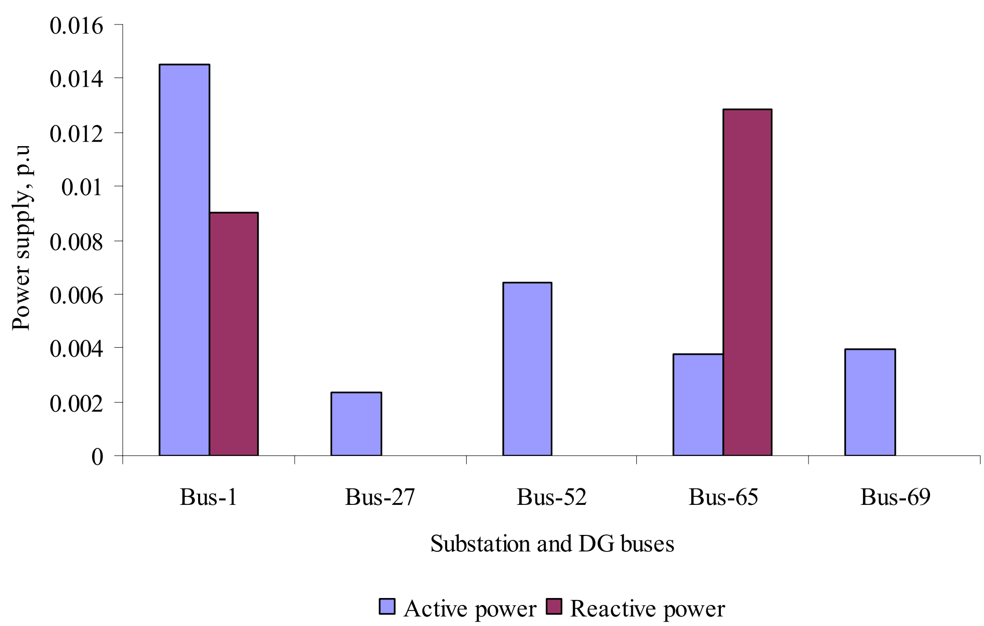

Figure 5.9: Active and reactive power supply with goodness factors, at hour-22

It is observed that with goodness factors, the DG at bus-65 comes to the picture and provides active power. This DG has the highest goodness factor among the other DG buses. It is to be noted that the active and reactive power imported via the substation bus (bus-1) are now reduced. The total operation cost of power provisions during this hour without goodness factors is $311.88. The disco, however, saves an amount of $56.13 when the goodness factors are incorporated in its operational decision.

The total generation costs of active and reactive power without and with goodness factors over 24-hour of operation are shown in Figure 5.10. It is seen that significant savings are achieved through the 24-hour operation when the goodness factors are included.

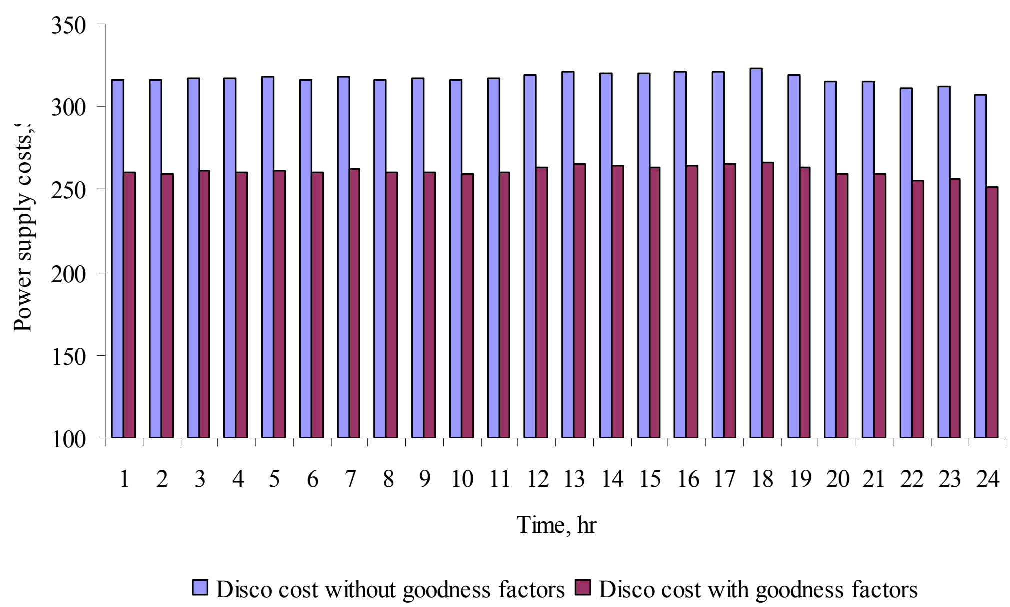

Figure 5.10: Disco total cost without and with goodness factors

Figure 5.11 shows that the system losses are also significantly reduced in the presence of goodness factors, hence the overall system voltage profile is improved.

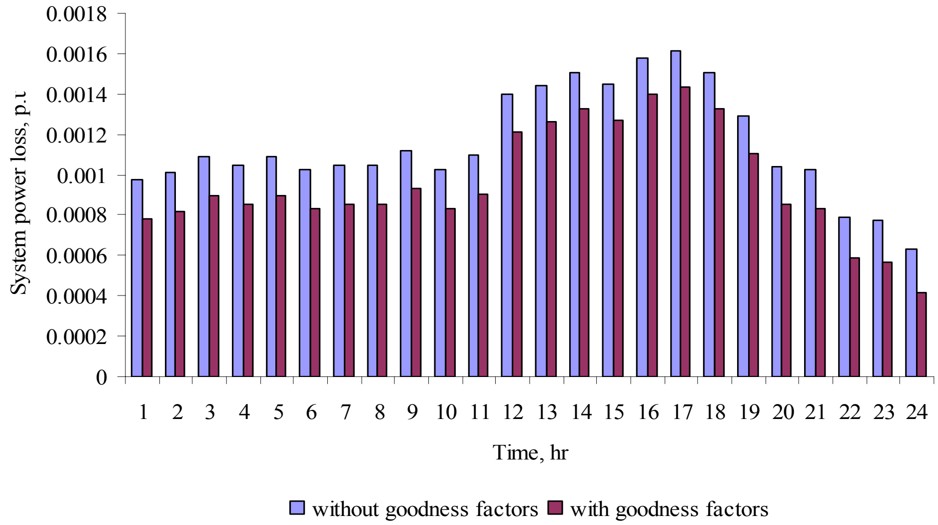

Figure 5.11: System active power loss without and with goodness factors

5.4.3.2 Investor-owned DG Units

In this scenario, it is assumed that all the DG units are investor-owned and they inject a fixed (pre-determined, bilaterally contracted on long-term) amount of power into the disco network at a given hour. The disco is not responsible for the dispatch or scheduling of these DG units but is required to absorb their active power injections which involves providing for network services such as reactive power support and loss compensation. To this effect, the disco continues to purchase reactive power from these investor-owned DG units as before, in the dispatch stage.

In this analysis, we considered that the DG units were contracted to operate at their respective maximum generation levels, P^{Max}. Two cases were considered, as before, the first where goodness factors are not taken into account, while in the second, the operational model includes the effects of ILIs and goodness factors.

It was noted from the analysis that there were no significant differences in cost savings between the two cases. This is very much expected, and can be explained by referring to (5.10). It can be seen from (5.10) that the fifth terms yield a value of zero, since the DG dispatch output with goodness factors are the same as those without goodness factors, and is equal to P^{Max}. Therefore, if the investor owned DG units operate at their respective maximum capacities, there is no scope for active power re-dispatch (upwards), and hence no contribution to system savings from reduced losses. There may be a small reduction in system losses because of reactive power re-dispatch, but that will depend on system conditions. However, if investor-owned DG units are operating at less than their maximum capacities, and the disco has the provision to increase their dispatch levels, then significant savings will be accrued, but in such a case the problem becomes similar to the utility-owned DG operations problem.

5.5 Concluding Remarks

This chapter introduces a set of indices that assist the disco in its operational decision making functions. These indices utilize the distribution power flow framework and the sensitivity of the system losses to an incremental change in active and/or reactive power injection at a node. In order to integrate the effects of these indices in an optimal energy provisions framework for the disco, the notion of a goodness factor is introduced to the system buses.

The disco real-time operations model is appropriately modified to include these goodness factors in the disco objective function. Case studies have been carried out considering two different DG ownership structures, utility-owned and investor-owned. It has been demonstrated through the case studies that when the goodness factors are included in the operations model of the disco, significant benefits in terms of reduced losses and cost savings are achieved. The main contributions of this chapter are:

- Development of a novel concept of bus goodness factors that serve as an indicator of the contribution of DG power injection at a bus, to system losses, in dollar terms.
- Modification of the short-term operations model of the disco to incorporate the DG goodness factors in its decision making framework.
- Examining the benefits accrued from inclusion of the goodness factors in the discos operations, both for utility-owned and investor-owned DG units.

Chapter

6

A Novel Approach to Disco Planning in Electricity markets[4]

6.1 Introduction

From the investigations carried out in the previous chapters, it was seen that the presence of DG sources in the disco system significantly affects its operational decisions. It was also brought out that if the contributions of these DG units are appropriately included in the operations model then increased benefits are accrued to the disco.

In the same way, as pointed out in the literature review in Chapter-2, the presence of DG resource in the disco system could significantly alter its long-term planning decisions. For example, the injected power from DG sources at a bus has the ability to reduce the net power flow on some feeders while increasing the power flow in others. Therefore, the long-term plans for feeder capacity addition are now not only driven by the forecasted demand growth over the planning horizon, but also on the location and capacity of DG units that may be commissioned over this period. This can play a vital role in precisely determining feeder capacity addition decisions. The benefits of installing DG units towards deferment of distribution system upgrades therefore need to be examined in detail.

In this chapter a comprehensive optimization model aiming to assist the disco planner in solving the DG siting and sizing problem is proposed. The model also includes

[4] Some parts of this chapter have been accepted for presentation and publication in the following paper:

- A. Algarni and K. Bhattacharya, *A novel approach to disco planning in electricity markets*, IEEE PES Power Systems Conference & Exposition, 2009, Seattle, Washington USA investment decisions for feeders and substation transformers over the planning horizon. The main features and assumptions used in the planning model are as follows:

- Specific details of DG technologies are not considered. Only a data set that represents a range of average cost data of DG generation, is used. When technology choices are incorporated, specifying whether the DG is wind-turbine or a solar DG, *etc.*, their operational characteristics and location specific aspects (such as the local wind speed levels, local solar radiation levels, *etc.*) need to be considered in the model. This thesis does not consider the detailed features of DG units, but considers them to be simply injecting active and reactive power to the grid.
- Since technology choices are not considered, only one type of DG unit is assumed for the planning and the work is focused on determining the most effective location of such a DG unit in term of its impact on system loss reduction and deferral of disco infrastructure investments.
- An ac-power flow model is employed and hence both active and reactive power flows are considered. This provides an in depth perspective on system planning in the presence of new DG capacity.
- The planning model discussed in this chapter considers dynamic addition of substation transformers and /or expansion decisions on feeder capacity as well as new DG capacity year by year, incorporated in the objective function. Furthermore, operational cost of both active and reactive power supplied from the DG or purchased from the grid are also included in the model.

This chapter is organized as follows: Section-6.2 presents a discussion of the ILIs and introduces a new set of indices, the Incremental Feeder Loading Indices (IFLI). This is followed by the development of an expanded set of goodness factors. Section-6.3 presents the disco planning framework which is decomposed into two stages- a capacity planning stage and a verification stage. System studies considering the 18-bus distribution network are presented in Section-6.4 and the main contributions of this chapter is summarized in Section 6.5.

6.2 Incremental Loss Indices, Incremental Feeder Loading Indices and Their Goodness Factors

6.2.1 Incremental Loss Indices (ILI)

The concept of ILIs was introduced in Chapter-5 Section 5.2, and detailed mathematical formulations for the self and mutual active /reactive power ILIs were presented. The same indices will be used again in this chapter in conjunction with another new set of indices, as will be discussed next. In view of this, the details of ILIs are not repeated in this chapter, and the reader is referred to Section 5.2.

6.2.2 Incremental Feeder Loading Indices (IFLI)

The active/reactive power self-IFLIs (6.1) denoted by μ^P and μ^Q are defined as the incremental change in feeder k active/reactive power flow due to active/reactive power injection at a bus i.

$$\mu_{k,i}^P = \frac{\partial P_k}{\partial P_{inj,i}} \quad \mu_{k,i}^Q = \frac{\partial Q_k}{\partial Q_{inj,i}} \tag{6.1}$$

The incremental active/reactive power injections can be represented as small changes in active/reactive power demand at a bus, generation remaining constant. The active/reactive mutual-IFLIs (6.2) denoted by ψ^P and ψ^Q can similarly be defined as the incremental change in feeder k active/reactive power flow due to reactive/active power injection at a bus i.

$$\psi_{k,i}^P = \frac{\partial P_k}{\partial Q_{inj,i}} \quad \psi_{k,i}^Q = \frac{\partial Q_k}{\partial P_{inj,i}} \tag{6.2}$$

It should be noted that if for a positive injection of active / reactive power the indices μ and ψ are positive then the feeder k is loaded, while if they are negative, feeder k is unloaded.

6.2.3 Goodness Factors

In Chapter-5, the goodness factors corresponding to ILIs were introduced. In this chapter, the same concept is extended to include the IFLIs as well. A monetary value is attached to ILIs and IFLIs to arrive at the *goodness factors* for a DG at a given bus. The goodness factors indicate the relative importance and contribution of 1 unit of DG power (active or reactive) at a bus, as compared to a DG located at another bus in the distribution system. These can also be interpreted as the savings in operational costs (from ILIs) because of reduction in system loss and savings in investment costs (from IFLIs) because of deferral of feeder and transformer capacity investment costs, due to DG power injection at a bus. The proposed expanded set of goodness factors are given below in (6.3)-(6.6).

$$\alpha_i^{Loss} = \rho^P \lambda_i^P + \rho^Q \sigma_i^Q \tag{6.3}$$

$$\beta_i^{Loss} = \rho^Q \lambda_i^Q + \rho^P \sigma_i^P \tag{6.4}$$

$$\alpha_i^{Feeder} = C_P^{Feeder} \sum_{k=1}^{NF} \mu_{k,i}^P + C_Q^{Feeder} \sum_{k=1}^{NF} \psi_{k,i}^Q \tag{6.5}$$

$$\beta_i^{Feeder} = C_P^{Feeder} \sum_{k=1}^{NF} \psi_{k,i}^P + C_Q^{Feeder} \sum_{k=1}^{NF} \mu_{k,i}^Q \tag{6.6}$$

It can be observed that (6.3)-(6.4) are the goodness factors corresponding to ILIs, and were introduced in Chapter-5. The new goodness factors corresponding to the IFLIs are represented in (6.5)-(6.6). In (6.5), α_i^{Feeder} is the goodness factor denoting the dollar value equivalent of the net feeder unloading because of active power injection by a DG at bus *i.* Similarly, in (6.6), β_i^{Feeder} is the goodness factor denoting the dollar value equivalent of net feeder power unloading because of reactive power injection by a DG at bus *i.* The parameters C_P^{Feeder} (in \$/MW) and C_Q^{Feeder} (in \$/Mvar) are the active and reactive components respectively of the feeder capacity cost (in \$/MVA) that is deferred or added because of the DG.

6.3 Disco Optimal Planning Framework

The long-term planning framework of the disco should ideally include decision making variables that are binary in nature, take into consideration dynamic constraints (*i.e., variables linked across time-periods*) and non-linear power flow equations. Such a model would be a mixed-integer non-linear programming (MINLP) problem with dynamically inter-linked constraints.

Obtaining the optimal solution to such problems, even for small test systems can be a challenging task. One of the class of well known methods to handle such problems are known as the Decomposition methods, and they have found applications in several power system problems [76]. In this work as well, the composite problem of disco planning has been decomposed into two stages. The first stage is a linear programming (LP) model that seeks the optimal capacity plan for the disco, and is termed as the Distribution Capacity Planning Model (DCPM). The dynamically inter-linked constraints pertaining to capacity addition variables are included in this stage and the DCPM yields a long-term capacity addition plan for the disco.

The second stage is the year-wise verification procedure of the capacity plan evolved in stage-1. This model, termed as Distribution Plan Verification Model (DPVM), is essentially a non-linear programming (NLP) model considering detailed power flow equations and associated constraints. The output of DPVM yields the optimal dispatches for both active and reactive power and other operational decisions. Figure 6.1 presents a schematic overview of the proposed decomposed planning-cum-operations framework for the disco.

A novel feature of the decomposed planning framework is the inclusion of the goodness factors that were developed in the previous section. The goodness factors α_i^{Feeder} and β_i^{Feeder} (corresponding to the IFLIs) are included in the DCPM while those corresponding to the ILIs, *i.e,* α_i^{Loss} and β_i^{Loss} are included in the DPVM. It has been demonstrated that inclusion of these goodness factors significantly affect the disco's overall capacity addition plan and associated operational decisions.

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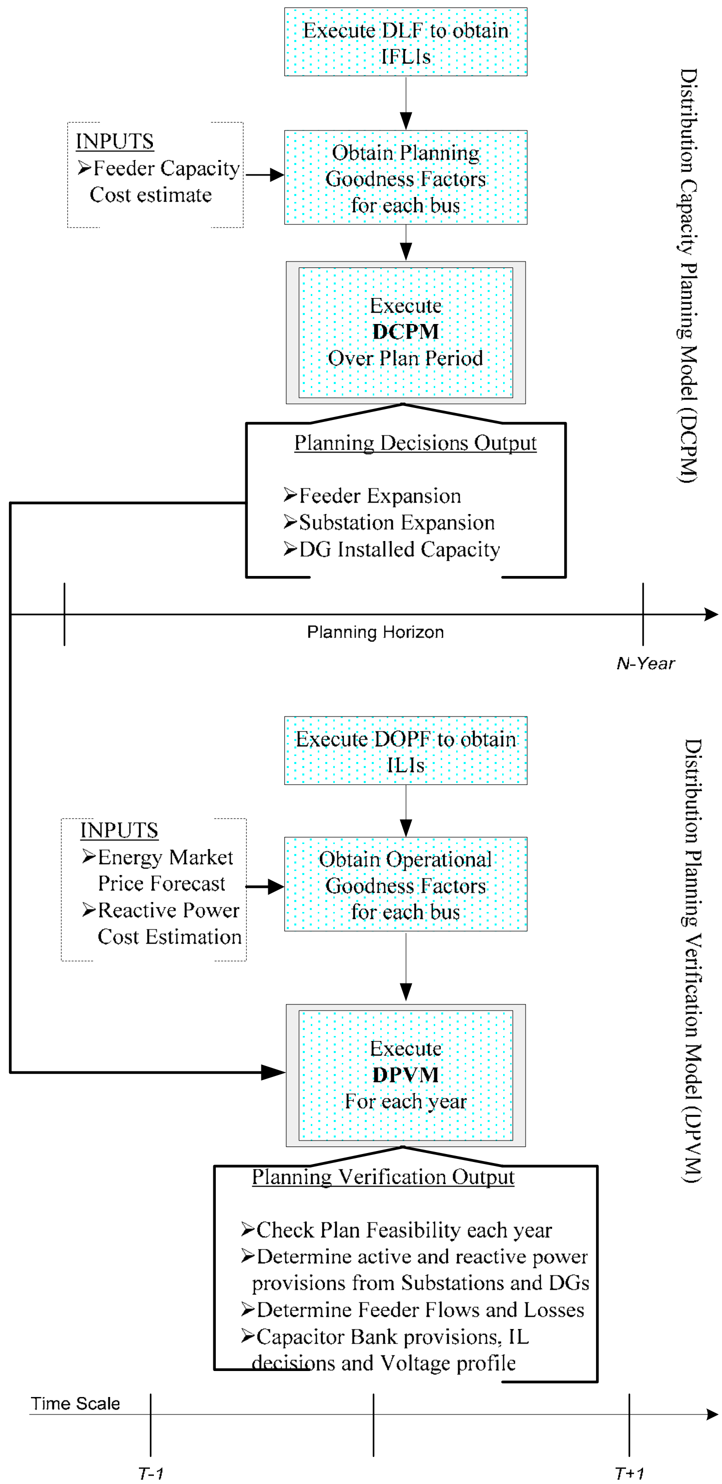

Figure 6.1: Schematic representation of proposed disco planning framework

6.3.1 Stage-1: Distribution Capacity Planning Model (DCPM)

The DCPM objective function given in (6.7) represents the long-term discounted cost of investments in new DG capacity, new feeder capacity and new sub-station transformers. The DCPM is executed over the planning horizon to arrive at optimal decisions on required capacity to be added taking into account the growing demand for power within the disco system. A novel feature of this objective function is the inclusion of the last two terms in (6.7) in DCPM that accounts for a cost credit to the disco (*denoted by the negative sign*). This cost credit, which is also discounted over the planning horizon, represents equivalent monetary savings accrued from feeder unloading because of DG power (both active and reactive) injected at a bus.

Objective Function

$$
\begin{aligned}
J_P = &\sum_{y=1}^{T} \frac{1}{(1+r)^y} \Big(\sum_{k}^{NF} FC_k \cdot SF_{k,y} \\
&+ \sum_{i=1}^{NS} TC_i \cdot ST_{i,y} + \sum_{i=1}^{NDG} CDG_i \cdot SDG_{i,y} \\
&- \sum_{i=1}^{NDG} \alpha_i^{Feeder} \cdot \Delta P_{i,y} - \sum_{i=1}^{NDG} \beta_i^{Feeder} \cdot \Delta Q_{i,y}
\end{aligned}
\qquad (6.7)
$$

And we have,
$$
\begin{aligned}
\Delta P_{i,y} &= P_{i,y} - P_{i,y}^{*} \qquad i \in g \\
\Delta Q_{i,y} &= Q_{i,y} - Q_{i,y}^{*} \qquad i \in g
\end{aligned}
$$

The disco's objective function will need to be modified when DG units are investor-owned. Such DG units will inject power into the grid as per external conditions, such as wind speed, radiation levels, etc, and the disco will need to absorb this power and adjust its own DG units dispatch accordingly.

Network Equations

The SDOPF model presented in Chapter-3 is utilized in the DCPM. The power flow equation is modified to include power generated by DG units, in addition to the power provided from the available substations. It is to be noted that the DCPM simultaneously determines the optimal capacity decisions for all years of the planning horizon.

$$\sum_j S^F_{j,i,y} \cdot (1 - LF) - \sum_j S^F_{i,j,y} + S^T_{i,y} + S^{DG}_{i,y} = S^{Dem}_{i,y} \qquad (6.8)$$

Substation Transformer Constraints and Dynamic Capacity Updates

These constraints ensure that the power provided by the disco substation is within the transformer capacity, year to year, taking into account the existing capacity in year *y-1* and the new capacity added in year *y*.

$$TCap_{i,y} = TCap_{i,y-1} + ST_{i,y} \qquad \forall\, y > 1, i \in s \qquad (6.9)$$

$$TCap_{i,y} = ST_i^{CAP} \qquad \forall\, y = 1,\ i \in s \qquad (6.10)$$

$$ST_{i,y} \le ST_i^{CAP} \qquad \forall\, y, s \qquad (6.11)$$

$$S^T_{i,y} \le TCap_{i,y} \qquad \forall\, y, s \qquad (6.12)$$

Generation Limit on DG Units, Dynamic Capacity Updates

The constraints (6.13) and (6.14) ensures that the DG capacity at a bus is aggregated over the planning periods considering the existing capacity at year *y-1* and the new capacity added in a year *y*. It is to be noted that SDG^* is an assumed initial value for the installed DG capacity at year 1. This value is set to zero initially.

There is an upper limit on total DG capacity that can be installed in a year, at a given bus, denoted by SDG^{CAP} (6.15). Equation (6.16)-(6.18) define the complex power generation constraint, and corresponding active and reactive power relations.

$$DGCap_{i,y} = DGCap_{i,y-1} + SDG_{i,y} \qquad \forall\, y > 1, i \in g \qquad (6.13)$$

$$DGCap_{i,y} = SDG^*_{i,y} \qquad \forall\, y = 1, i \in g \qquad (6.14)$$

$$SDG_{i,y} \le SDG_i^{CAP} \qquad \forall\, i \in g, y \tag{6.15}$$

$$S_{i,y}^{DG} \le DGCap_{i,y} \qquad \forall\, i \in g, y \tag{6.16}$$

$$P_{i,y} \le S_{i,y}^{DG} \cdot pf \qquad \forall\, i \in g, y \tag{6.17}$$

$$Q_{i,y} \le S_{i,y}^{DG} \cdot \sqrt{1 - pf^{2}} \qquad \forall\, i \in g, y \tag{6.18}$$

Feeder Limits and Dynamic Capacity Updates

The power carrying capability of distribution feeders is limited by the feeder current limits, which are consequently represented by their MVA limits. These limits are determined by the total feeder capacity in a given year, which is dynamically related to the previous year's feeder capacity and the new feeder capacity added in the current year (6.19)-(6.20).

$$FCap_{k,y} = FCap_{k,y-1} + SF_{k,y} \qquad \forall\, y > 1, k \tag{6.19}$$

$$FCap_{k,y} = SF_k^{*} \qquad \forall\, y = 1, k \tag{6.20}$$

$$SF_{k,y} \le SF_k^{*} \qquad \forall\, y, k \tag{6.21}$$

$$S_{k,y}^{F} \le FCap_{k,y} \qquad \forall\, y, k \tag{6.22}$$

The DCPM, described by (6.7)-(6.22), is a LP model solved in the GAMS platform [69] and its outputs include decisions on new capacity to be added for feeder, substation transformers and DGs. It is to be noted that all load buses within this model are considered available as candidate buses for DG installation. These capacity planning decisions are passed on to the stage-2 model (DPVM), where a verification procedure is carried out for every year as explained later, in order to check the plan feasibility and arrive at optimal operational strategies.

6.3.2 Stage-2: Distribution Plan Verification Model (DPVM)

The Stage-2 objective function given in (6.23) represents the operational costs that will be accrued in each year. They include the cost of operation of DG units, purchase cost of power from grid, and cost associated with reactive power generation from DG units and that purchased from the grid. The IL decision is included in this phase where a very high cost is attached with it. One novel feature of the current objective function is the inclusion of the last two terms in (6.28) that accounts for a cost credit to the disco (*denoted by the negative sign*). This cost represents the monetary savings to the dicso accrued from reduced feeder losses because of DG injected power. This approach is similar to the one used in Chapter-5. However, the whole planning framework will be affected by these factors and the IL and capacitor compensation as new variables will also be optimized.

Objective Function

$$
\begin{aligned}
J_V = & \sum_{i=1}^{NS} \rho^P \cdot P_i + \sum_{i=1}^{NS} \rho^Q \cdot Q_i \\
& + \sum_{i=1}^{NDG} \left[(A_i \cdot P_i^2 + B_i \cdot P_i + C_i) \right] \\
& + \sum_{i=1}^{NDG} Q_i \cdot C_{QGi} + \sum_{i=1}^{NL} C_{IL} \cdot P_{IL,i} + \sum_{i=1}^{NL} C_C \cdot QC_i \\
& - \sum_{i=1}^{NDG} \alpha_i^{Loss} \cdot \Delta P_i - \sum_{i=1}^{NDG} \beta_i^{Loss} \cdot \Delta Q_i
\end{aligned}
\tag{6.23}
$$

$$\Delta P_i = P_i - P_i^* \qquad i \in g$$

$$\Delta Q_i = Q_i - Q_i^* \qquad i \in g$$

Network Equations

The active and reactive power flow equations are modified to include grid purchased active and reactive power through disco transformers, DG generated active and reactive power, the amount of power to be curtailed as well as reactive power compensation from capacitor banks at load buses. It should be noted that the DPVM is executed on a year-by-year basis, where PD_i and QD_i are the bus peak demand conditions in the disco system in the given year.

$$P_s + P_g - PD_i + P_{IL,i} = \sum_j |V_i||V_j||Y_{ij}| \cos(\theta_{ij} + \delta_j - \delta_i) \tag{6.24}$$

$$Q_s + Q_g - QD_i + Q_{IL,i} + QC_i = -\sum_j |V_i||V_j||Y_{ij}| \sin(\theta_{ij} + \delta_j - \delta_i) \tag{6.25}$$

Grid Purchase Constraints

These constraints ensure that the active and reactive power purchased by the disco from the external grid / market is within the transfer limits imposed by disco transformer capacity.

$$P_i \le TCap_i \cdot pf1 \qquad \forall\, i \in s \tag{6.26}$$

$$Q_i \le TCap_i \cdot \sqrt{1 - pf1^2} \qquad \forall\, i \in s \tag{6.27}$$

$$Q_i \ge -TCap_i \cdot \sqrt{1 - pf1^2} \qquad \forall\, i \in s \tag{6.28}$$

Bus voltage limits

These limits ensure acceptable voltages at all buses and that the bus voltages do not drop below certain specified values. The substation bus voltage is held at a constant value, similar to the slack bus in classical load flow programs.

$$\begin{aligned} &|V_i| = \text{Constant} && \forall\, i \in s \\ &V_i^{Min} \le |V_i| \le V_i^{Max} && i \in NL \end{aligned} \tag{6.29}$$

Generation Schedule Limit on DG Units

These constraints ensure that the power dispatched from a DG unit is within the maximum and minimum limits of generation installed and available in a specific year (6.30)-(6.31).

$$P_i \le P_i^{Max} \qquad \forall\, i \in g \tag{6.30}$$

$$Q_i^{Min} \le Q_i \le Q_i^{Max} \qquad \forall\, i \in g \tag{6.31}$$

Feeder power flow Limits

The power carrying capability of distribution feeders are limited by the feeder current limits, which are consequently represented by their MVA limits. The complex power on the feeders can be determined from the power flow equations and the final relations are given as under:

$$\mathrm{Re}\{I_k\} = f(V_i, \delta_i) \tag{6.32}$$

$$\mathrm{Im}\{I_k\} = f(V_i, \delta_i) \tag{6.33}$$

$$S_{ij} = f\left(\mathrm{Re}\{I_k\}, \mathrm{Im}\{I_k\}\right) \tag{6.34}$$

$$S_{ij} \le FCap_k \tag{6.35}$$

The DPVM, described by (6.23)-(6.35), is a nonlinear programming problem, which is solved using the GAMS/MINOS solver [69] for every year individually.

6.4 System Details

6.4.1 System under study

The 18-bus distribution system, considered in Chapter-5, has been used here for the studies. The system configuration is presented in Figure 6.2 for ready reference. The system data is provided in the Appendix.

6.4.2 Assumptions in the Study

Some assumptions have been made in this planning framework, both in terms of economical and technical aspects, summarized as follows:

- The disco system load is assumed to grow at a constant rate of 3% per year with respect to the base year, over the 6-year plan horizon. Accordingly, year-1 is the base year with nominal load in the system and there are five plan periods and the total system forecasted load increasing to be 115% of year-1 load. It is also assumed that the bus-wise loads are also increasing in the same proportion.
- The capacity planning model is formulated based on MVA unit capacity. The nominal demand of the 18-bus system is modified and scaled-up. However, the

DPVM considers both active /reactive supply-demand balance constraints to account for the real system operation.

- Actual distances for the feeder segments are not known and are therefore not considered. Instead of that, feeder impedances are used and the Y-bus matrix is accordingly formulated. In the case where feeder upgrade decisions are taken in a year, the Y-bus matrix is accordingly upgraded. The effects of this on system losses, thermal capacity and system voltage profile is included in the DPVM.
- A simplistic representation of new capacity costs for feeders, transformers and DG units is used, by a single fixed cost parameter. The investment cost for DG units is assumed to be 0.45 M$/MVA. The investment costs for substation transformer and distribution feeder are assumed to be 0.3 and 0.4 M$/MVA, respectively. A quadratic cost function is used to represent DG operational costs.
- The maximum DG capacity that can be installed at a bus is set to be 0.07 p.u. The possibility for install more than one DG unit at a bus is also available. This choice is not limited by a specific number of units in order to assist the model to choose the most effective location within the system.
- The decision variables pertaining to the optimal sizing of new capacity are continuous variables and the optimal sizing so obtained, might need to be rounded to the available market sizes, based on the planner's experience. Such a continuous variable helps avoid the complexities of inclusion of binary variables in the model.

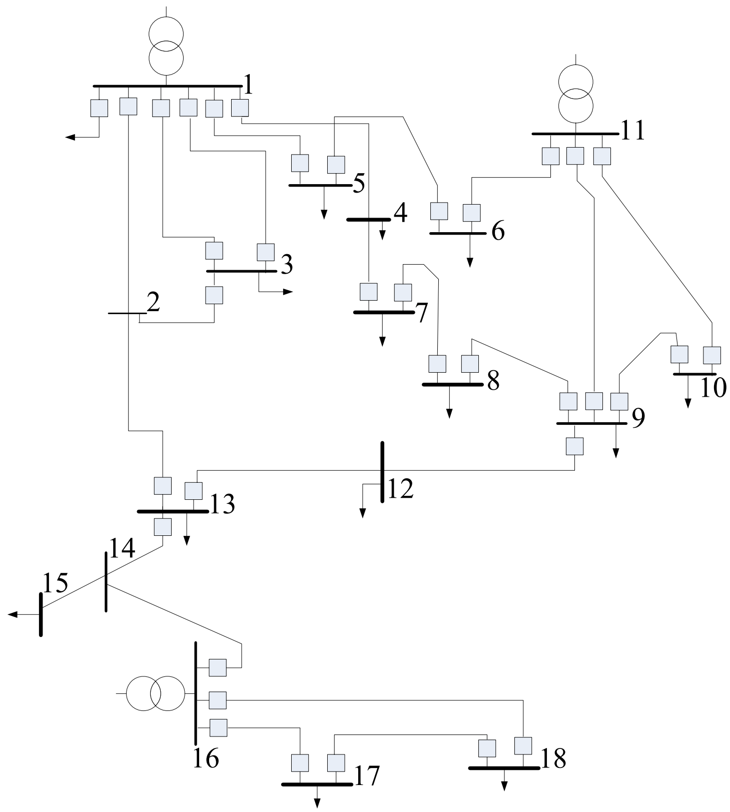

Figure 6.2: Schematic diagram of the 18-bus distribution system

6.5 Results and Analysis

In this section different scenarios will be presented in order to examine the performance of the proposed planning approach and determine the optimal decisions that would help in distribution system planning process.

6.5.1 DCPM Decisions and Comparison across Scenarios

The DCPM determines the optimal investment decisions in each year over the planning period, with regard to capacity additions of substations and feeders. The model clearly points out new feeder connections, specifying the buses, and the required capacity of the feeder to be added. It also clearly determines the new transformer capacities required at the substations, and at what year. In those cases where DG investment options are included, the DCPM also determines the optimal DG siting, sizing and year of investment decisions.

6.5.1.1 Scenario-A: Classical Distribution System without DG

In this scenario the three substation transformers are assumed to have enough capacity in the base-year (year-1) to feed electricity from the external market/grid to supply the disco demand and no DG investment options are considered. The aim of this scenario is to examine the capability of the existing substations and the system feeders to meet the load growth over the planning horizon. It is also of interest to study how the optimal expansion decisions would be managed without taking into account new resources but only the traditional components of investment, *i.e.* substations and feeders.

Table 6.1 shows the optimal decisions obtained from this model in this scenario. It is seen that the transformer bus-1 is identified by the model for capacity addition, starting from year-2. The total capacity available at this bus at the terminal year of the plan period (year-6) is 1.49 p.u. (*i.e.*, 149 MVA). It can be observed from Figure 6.2 that there are five feeder segments connected to bus-1, compared to only three feeders connected to the other two substation buses, bus-11 and bus-16. This can be attributed to be the reason for the choice of substation bus-1 for the multiple capacity addition decisions, over the planning horizon- because there is enough feeder capacity to evacuate the power from this substation.

Furthermore, because of the demand growth taking place over the plan period, the model also determines the need to add few new feeder segments as well, spread over the planning horizon. The total investment cost for the disco is 17.2 million dollars.

Table-6.1: Investment Plan Decisions from DCPM, Scenario-A

	Capacity added in each year, p.u.							
Substation Transformer	***Year-1***	***Year-2***	***Year-3***	***Year-4***	***Year-5***	***Year-6***	**Capacity in Base Year (year-1), p.u.**	**Total Cost of New Capacity (M$)**
1	-	0.12	0.08	0.17	0.17	0.15	0.8	**17.2**
11	-	-	-	-	-	-	0.5	
16	-	-	-	-	-	-	0.25	
Feeder i-j								
2-13	-	-	-	-	-	0.01	0.1	
9-11	-	0.004	.06	-	-	-	0.1	
15-14	-	0.03	-	-	-	-	0.1	

6.5.1.2 Scenario-B: Distribution System with DG Units

In this scenario, DG units are considered for investment decisions and each load bus in the disco system is a candidate bus for a single DG installation or multiple DGs in different years. It should also be mentioned again, that in this chapter, only utility-owned DG units are considered for the studies without any loss of generality. Table-6.2 presents the optimal plan decisions obtained from the DCPM for this scenario. It is observed that the resultant plan is cheaper by 4.1 million dollars simply because the plan allows for installation of DG units. It is seen that the optimal plan yields three DG installations at buses-2 and 6 in year-5, and at bus-15 in year-6. It can be observed through a comparison of Table-6.2 with Table-6.1 that these DG installation decisions in Scenario-B are able to defer two feeder capacity investment decisions of Scenario-A, in feeder segments 9-11 (of 6.4 MVA total capacity) and 15-14 (of 3 MVA total capacity). It can furthermore be observed, that there is a significant displacement of substation capacity addition requirements when compared to Scenario-A.

Table-6.2: Investment Plan Decisions from DCPM, Scenario-B

	Capacity added in each year, p.u. MVA							
Substation Transformer	***Year-1***	***Year-2***	***Year-3***	***Year-4***	***Year-5***	***Year-6***	**Existing Capacity**	**Capacity Cost (M$)**
1	-	-	0.17	0.17	-	-	0.8	**13.1**
11	-	-	-	-	-	0.072	0.5	
16	-	-	-	-	-	-	0.25	
Feeder i-j								
2-13	-	-	-	-	0.006	-	0.1	
DG *I*								
2	-	-	-	-	0.04	-	0	
6	-	-	-	-	0.07	-	0	
15	-	-	-	-	-	0.06	0	

6.5.1.3 Scenario-C: Distribution System with DG Units and their Goodness Factors

In this scenario, the goodness factors of the DG units, determined in Section-6.2, are incorporated in the DCPM. Table-6.3 summarizes the consolidated disco plan over the planning horizon. It can be observed that by simply including the goodness factors in the mathematical model, the plan is significantly different from Scenario-B, and therefore from Scenario-A, as well. There is a further reduction of 4.35 million dollars in total investment costs from Scenario-B cost, and an aggregated savings of 8.45 million dollars compared to Scenario-A which represents classical distribution planning.

It can be noted from Table-6.3 that the new plan only involves DG investments, and is able to defer all feeder capacity investment decisions as well as all substation capacity addition decisions over the plan period of six years.

Table-6.3: Investment Plan Decisions from DCPM, Scenario-C

Substation Transformer	Capacity added in each year, p.u. MVA						Existing Capacity	Capacity Cost (M$)
	Year-1	*Year-2*	*Year-3*	*Year-4*	*Year-5*	*Year-6*		
1	-	-	-	-	-	-	0.8	**8.75**
11	-	-	-	-	-	-	0.5	
16	-	-	-	-	-	-	0.25	
Feeder i-j								
2-13	-	-	-	-	-	-	0.1	
DG *I*								
7	-	0.07	0.07	0.07	0.07	0.07	0	
12	-	0.04	0.04	0.04	0.04	0.04	0	

6.5.2 Plan Verification Studies Using DPVM

In the verification stage, the DPVM carries out tests to examine the feasibility of the planned investments in the yearly operations time-frame. The three scenarios that were discussed in the context of the DCPM decisions are again considered here and their effect on the operational decisions are now examined. The optimal plan decisions determined from the DCPM are used as exogenous parameters in the DPVM.

The DPVM carries out year-wise operational analysis using (6.23) –(6.35), assuming an energy market price at peak demand to be \$100/MWh (*which is close to a typical peak price in the Ontario market*). The reactive power imported from the external grid/market is priced at 90\$/Mvarh. The IL decisions are introduced with very high price penalties in order to discourage the use of IL in a planning model. Reactive power support options from load bus capacitors are also included, at a very low price.

It is observed in Figure 6.3 that the active power imported via substation transformers in Scenario-A will increase yearly, in order to meet the growing demand of the disco system. In Scenario-B the import requirements increase somewhat but there is a reduction in imports at year-5 when new DG units are commissioned. On the other hand, because of significant DG additions in Scenario-C, there is a gradual decline in the import requirements from year-3 onwards.

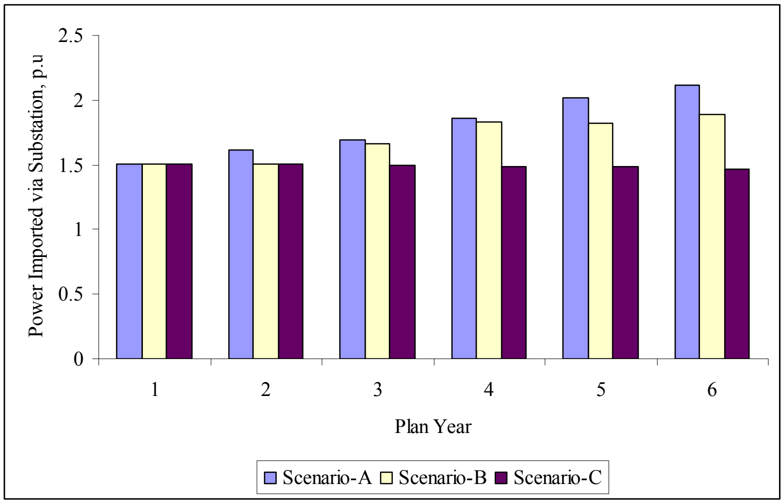

Figure 6.3: Comparison of active power imported via substation transformers for yearly peak demand conditions in DPVM

Figure 6.4 shows a comparison of DG generation across the three scenarios. As expected, the generation from DG units is the most preferred option in Scenario-C and is driven by the optimal investment decisions from DCPM.

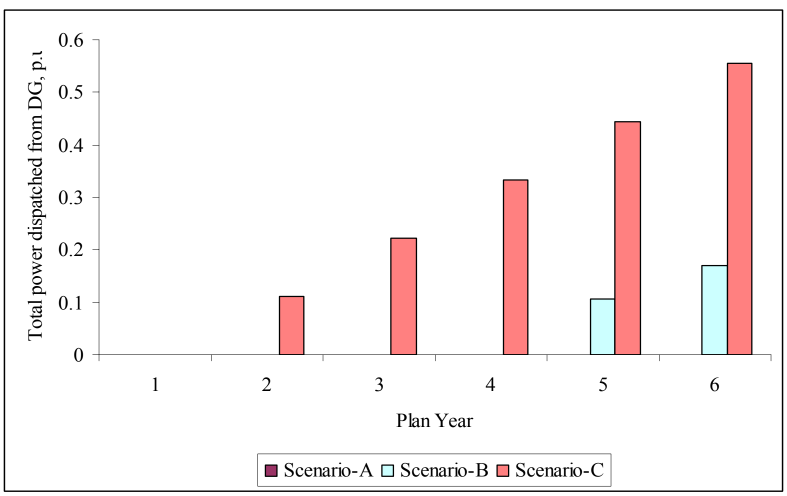

Figure 6.4: Comparison of active power generated by DG units for yearly peak demand conditions in DPVM

In Figure 6.5, it is shown that in Scenario-A, the reactive power required to be transferred over the disco substation transformers increases over the plan period. However, in the case of Scenarios-B and C, the transfer required is much lower because the injection of active power from the remote ends by the DG helps reduce the system losses significantly. However, it was observed that if reactive power support through capacitor banks is increased at the load buses, then the reactive power import requirements decrease significantly.

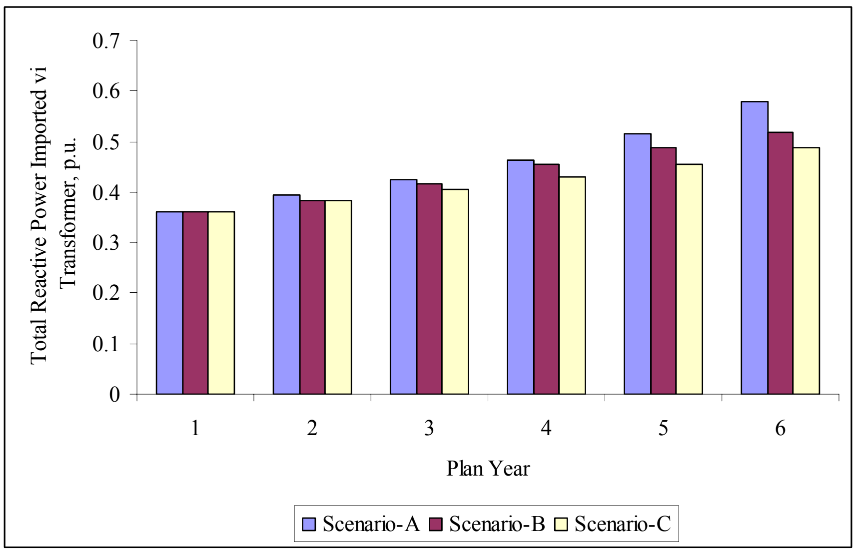

Figure 6.5: Comparison of reactive power imported via substation transformers for yearly peak demand conditions in DPVM

6.5 Concluding Remarks

This chapter presents a detailed mathematical model of a novel planning framework for discos operating in competitive electricity markets. The planning framework includes investment in DG capacity, distribution system feeder addition and substation transformer capacity addition. The effects of power injected from DG units on the distribution system network, both on loss reduction and on feeder capacity deferment, are represented in the model by using goodness factors. A monetary value is attached to these factors so that they can be used appropriately in the planning objective function. A decomposition approach is used to solve the model. The first stage model is the planning model which provides the optimal plan additions over the horizon, while the second stage is the plan verification model wherein operations decisions are verified and the plan feasibility is ensured. This chapter clearly demonstrates the effectiveness and contribution of DG units in the distribution network both in the short-term and long-term framework. The main contributions of this chapter are:

- Introduction of a new set of indices (IFLIs) that represent the DG units' impact on feeder unload, both in terms of active and reactive power injection
- The proposed set of indices are defined in terms of a novel set of goodness factors denoting the long-term effect of DG units in feeder capacity deferral.
- A disco planning model has been presented that incorporates the novel concept of goodness factors to arrive at the optimal plan as well as the planned dispatch decisions over the horizon.
- It has been clearly demonstrated that inclusion of goodness factors in the disco planning framework can yield substantially improved plan decisions in terms of lower investment costs, reduced losses and an overall better operated system.

Chapter

7

Conclusion

7.1 Summary and Conclusions

This thesis presents the operational and planning problems pertaining to electric power distribution systems in the deregulated environment. Several issues have been discussed and examined in the thesis involving the presence of DG resources in the distribution network and their impact on system performance, both in the short-term operations stage and in the long-term planning stage.

The thesis provides a comprehensive review of the published literature pertaining to various aspects of distribution system operation and planning, in deregulation. The literature review has examined the significant contributions pertaining to classical distribution system operation and power flow analysis, DG planning and its pricing and economic operations, load management and IL options in electricity markets, and retail electricity markets.

The thesis demonstrates that traditional load flow models can be used in case of ill-conditioned radial distribution networks and exactly similar power flow solutions can be obtained by making use of the strengths of NLP solvers and an optimization structure. The DLF and DOPF models have been developed to assist the disco operator in optimal DG scheduling, capacitor switching, load management and other operations.

The thesis proposes a two-stage inter-related operations framework, pertaining to disco activities, in retail competitive markets. The mathematical models address the energy systems within a disco territory and their optimal management such that the disco's economic costs are minimized. The first stage of the hierarchical framework is the day-ahead model, Day-Ahead Operations Model (DAOM), which determines the disco's operational decisions and feeds them into the real-time model, Real-Time Operations Model (RTOM), which is the second-stage of the proposed scheme. Different operation scenarios have been discussed and the generic nature of the proposed operations framework has been demonstrated.

The thesis introduces for the first time, a set of indices that can assist the disco in its operational decision making functions. These indices utilize the distribution power flow framework and sensitivity of the system losses to an incremental change in active and/or reactive power injection at a node. In order to integrate the effects of these indices in an optimal energy provisions framework for the disco, the novel concept of goodness factor is introduced to the system buses. The disco's operations model is appropriately modified to include the goodness factors. It has been demonstrated through the case studies that when the goodness factors are included in the operations model of the disco, significant benefits in terms of reduced losses and cost savings are achieved.

The concept of goodness factors is further extended to determine a new set of goodness factors pertaining to a DG's impact on feeder unloading by virtue of its power injection. A novel long-term planning model has been developed for the disco that considers investments in DG capacity, distribution system feeder addition / expansion and substation transformers capacity addition. The model includes the new set of goodness factors pertaining to both loss reduction and feeder unloading and arrives at an optimal set of new expansion plan, with specified locations, and year of commissioning. The work clearly demonstrates the effectiveness and contribution of DG units in distribution systems both in the short-term and long-term framework.

7.2 Main Contributions of the Thesis

The main contributions of the thesis can be outlined as follows:

- A comprehensive operational tool has been developed that can be used by a disco readily, when functioning in an open electricity market environment.

- A novel two-stage mathematical model has been developed considering disco's operational needs, objectives and constraints both in its day-ahead and real-time operations.
- The thesis addresses optimal utilization of disco's available resources, for both active and reactive power through the dispatch of DG units and capacitor banks while taking into consideration the external electricity market effects.
- The operations framework includes optimal IL contracting (in day-ahead) and their optimal invocation (in real-time) in conjunction with other decision variables, and formulates their incentive pricing.
- The thesis has presented a mathematical model for a disco's day-ahead and real-time demand function in terms of the external market price variations, based on historical dependence of the price and demand.
- A novel concept of bus goodness factors has been presented that serve as an indicator of the contribution of DG power injection at a bus, to system losses, in dollar terms. The thesis demonstrates that the operations model can be suitably modified to incorporate the DG goodness factors in its decision making framework and hence achieve significant benefits.
- The novel concept of goodness factors has been further expanded to include the DG's impact on feeder unloading, or capacity deferral, in dollar terms. A novel planning model has been presented that includes the expanded set of goodness factors to arrive at the disco's optimal plans.

7.3 Scope for Future Work

The work presented in this thesis can be further extended to examine various other relevant and associated problems of distribution systems operations and planning in the deregulated environment. Some of them are listed below.

- The impact of disco operations on electricity market prices; in particular, the impact of multiple discos' competition aspects need to be investigated

- The operations and planning decisions of discos are often affected by governmental incentive rates and special pricing structures. It would be important to examine such specific cases and their impact on disco operations and planning.
- This work has not taken into consideration the different characteristics of technologies of DGs. Detailed studies need to be carried out for disco operations considering the presence of solar, wind, micro-hydro, and such specific generation technologies, along with their specific operational characteristics.
- The issue of reactive power from DG units has not been examined in detail in this thesis. This can be a very important issue in the future, and appropriate pricing and contracting mechanisms for DG reactive power need to be investigated.
- The goodness factors proposed in this thesis need to be examined further to explore possibilities of designing incentive rates for DG units.
- The presence of investor-owned DG units and their impact on a disco's operations and planning strategies need to be investigated.

APPENDICES

APPENDIX –A: Distribution System Data

Data for 9-Bus system: Feeder Parameters

Line i-j	R p.u.	X p.u.
1.2	0.0278	0.0451
3.4	0.0278	0.0451
5.6	0.02433	0.03946
7.8	0.02085	0.03383
9.1	0.0139	0.02255
9.3	0.02085	0.03383
9.5	0.02259	0.03664
9.7	0.01738	0.02819

Data for 28-Bus system: Feeder Parameters

Bus i-j	R ohms	X ohms
Main Branch		
1.2	1.197	0.820
2.3	1.796	1.231
3.4	1.306	0.895
4.5	1.851	1.268
5.6	1.524	1.044
6.7	1.905	1.305
7.8	1.197	0.820
8.9	0.653	0.447
9.10	1.143	0.783
Left Branch-1		
4.11	2.823	1.172
11.12	1.184	0.491
12.13	1.002	0.416
13.14	0.455	0.189
14.15	0.546	0.227
Left Branch-2		
7.22	1.548	0.642
22.23	1.092	0.453
23.24	0.910	0.378
24.25	0.455	0.189
25.26	0.364	0.151
Right Branch-1		
5.16	2.550	1.058
Right Branch-2		
6.17	1.366	0.567
17.18	0.819	0.340
18.19	1.548	0.642
19.20	1.366	0.567
20.21	3.552	1.474
Right Branch-3		
8.27	0.546	0.226
27.28	0.273	0.113

Data for 28-Bus system: Load

Bus i	P kW	Q kvar
2	35.28	35.99
3	14	14.28
4	35.28	35.99
5	14	14.28
6	35.28	35.99
7	35.28	35.99
8	35.28	35.99
9	14	14.28
10	14	14.28
11	56	57.13
12	35.28	35.99
13	35.28	35.99
14	14	14.28
15	35.28	35.99
16	35.28	35.99
17	8.96	9.141
18	8.96	9.141
19	35.28	35.99
20	35.28	35.99
21	14	14.28
22	35.28	35.99
23	8.96	9.141
24	56	57.13
25	8.96	9.141
26	35.28	35.99
27	35.28	35.99
28	35.28	35.99

Data for 33-Bus system: Feeder Parameters

Line i-j	**R** ohms	**X** ohms	**charging** p.u.
Main Branch			
1.2	0.0922	0.0477	0.0052
2.3	0.4930	0.2511	0.0277
3.4	0.3660	0.1864	0.0206
4.5	0.3811	0.1941	0.0214
5.6	0.8190	0.7070	0.0460
6.7	0.1872	0.6188	0.0105
7.8	0.7114	0.2351	0.0961
8.9	1.0300	0.7400	0.0578
9.10	1.0440	0.7400	0.0586
10.11	0.1966	0.0650	0.0110
11.12	0.3744	0.1238	0.0210
12.13	1.4680	1.1550	0.0824
13.14	0.5416	0.7129	0.0304
14.15	0.5910	0.5260	0.0332
15.16	0.7463	0.5450	0.0419
16.17	1.2890	1.7210	0.0724
17.18	0.7320	0.5740	0.0411
Left Branch			
2.19	0.1640	0.1565	0.0092
19.20	1.5042	1.3554	0.0845
20.21	0.4095	0.4784	0.0230
21.22	0.7089	0.9373	0.0398
Right Branch			
3.23	0.4512	0.3083	0.0253
23.24	0.8980	0.7091	0.0504
24.25	0.8960	0.7011	0.0503
6.26	0.2030	0.1034	0.0114
26.27	0.2842	0.1447	0.0160
27.28	1.0590	0.9337	0.0595
28.29	0.8042	0.7006	0.0452
29.30	0.5075	0.2585	0.0285
30.31	0.9744	0.9630	0.0547
31.32	0.3105	0.3619	0.0174
32.33	0.3410	0.5302	0.0191

Data for 33-Bus system: Load

Bus i	P kW	Q kvar
2	100	60
3	90	40
4	120	80
5	60	30
6	60	20
7	200	100
8	200	100
9	60	20
10	60	20
11	45	30
12	60	35
13	60	35
14	120	80
15	60	10
16	60	20
17	60	20
18	90	40
19	90	40
20	90	40
21	90	40
22	90	40
23	90	50
24	420	200
25	420	200
26	60	25
27	60	25
28	60	20
29	120	70
30	200	600
31	150	70
32	210	100
33	60	40

Data for 69-Bus system: Feeder Parameters

Line i-j	R ohms	X ohms
	Main Branch	
1.2	0.0005	0.0012
2.3	0.0005	0.0012
3.4	0.0015	0.0036
4.5	0.0251	0.0294
5.6	0.3660	0.1864
6.7	0.3811	0.1941
7.8	0.0922	0.0470
8.9	0.0493	0.0251
9.10	0.8190	0.2707
10.11	0.1872	0.0691
11.12	0.7114	0.2351
12.13	1.0300	0.3400
13.14	1.0440	0.3450
14.15	1.0580	0.3496
15.16	0.1966	0.0650
16.17	0.3744	0.1238
17.18	0.0047	0.0016
18.19	0.3276	0.1083
19.20	0.2106	0.0690
20.21	0.3416	0.1129
21.22	0.0140	0.0046
22.23	0.1591	0.0526
23.24	0.3463	0.1145
24.25	0.7488	0.2745
25.26	0.3089	0.1021
26.27	0.1732	0.0572
Left-1 Branch		
3.28	0.0044	0.0108
28.29	0.0640	0.1565
29.30	0.3978	0.1315
30.31	0.0702	0.0232
31.32	0.3510	0.1160
32.33	0.8390	0.2816
33.34	1.7080	0.5646
34.35	1.4740	0.4673
Right-1 Branch		
3.36	0.0044	0.0108

36.37	0.0640	0.1565
37.38	0.1053	0.1230
Line i-j	R ohms	X ohms
38.39	0.0304	0.0355
39.40	0.0018	0.0021
40.41	0.7283	0.8509
41.42	0.3100	0.3623
42.43	0.0410	0.0478
43.44	0.0092	0.0116
44.45	0.1089	0.1373
45.46	0.0009	0.0012
Right-2 Branch		
4.47	0.0034	0.0084
47.48	0.0851	0.2083
48.49	0.2898	0.7091
49.50	0.0822	0.2011
Right-3 Branch		
8.51	0.0928	0.0473
51.52	0.3319	0.1114
Left-2 Branch		
9.53	0.1740	0.0886
53.54	0.2030	0.1034
54.55	0.2842	0.1447
55.56	0.2813	0.1433
56.57	1.5900	0.5337
57.58	0.7837	0.2630
58.59	0.3042	0.1006
59.60	0.3861	0.1172
60.61	0.5075	0.2585
61.62	0.0974	0.0496
62.63	0.1450	0.0738
63.64	0.7105	0.3619
64.65	1.0410	0.5302
Right-4 Branch		
11.66	0.2012	0.0611
66.67	0.0047	0.0014
Left-3 Branch		
12.68	0.7394	0.2444
68.69	0.0047	0.0016

Data for 69-Bus system: Load

Bus	P, KW	Q, kvar	Bus	P, kW	Q, kvar
2	0.0	0.0	36	26.0	18.55
3	0.0	0.0	37	26.0	18.55
4	0.0	0.0	38	0.0	0.0
5	0.0	0.0	39	24.0	17.0
6	2.6	2.2	40	24.0	17.0
7	40.4	30.0	41	1.2	1.0
8	75.00	54.0	42	0.0	0.0
9	30.0	22.0	43	6.0	4.3
10	28.0	19.0	44	0.0	0.0
11	145.0	104.0	45	39.22	26.3
12	145.0	104.0	46	39.22	26.3
13	8.00	5.5	47	0.0	0.0
14	8.00	5.5	48	79.0	56.4
15	0.0	0.0	49	384.7	274.5
16	45.5	30.0	50	384.0	274.5
17	60.00	35.0	51	40.5	28.3
18	60.0	35.0	52	3.6	2.7
19	0.0	0.0	53	4.35	3.50
20	1.00	0.60	54	26.4	19.0
21	114.0	81.0	55	24.0	17.20
22	5.3	3.50	56	0.0	0.0
23	0.0	0.0	57	0.0	0.0
24	28.0	20.0	58	0.0	0.0
25	0.0	0.0	59	100.0	72.0
26	14.0	10.0	60	0.0	0.0
27	14.0	10.0	61	1244.0	888.0
28	26.0	18.6	62	32.0	23.0
29	26.0	18.6	63	0.0	0.0
30	0.0	0.0	64	227.0	162.0
31	0.0	0.0	65	59.0	42.0
32	0.0	0.0	66	18.0	13.0
33	14.0	10.0	67	18.0	13.0
34	19.5	14.0	68	28.0	20.0
35	6.0	4.0	69	28.0	20.0

Data for 18-Bus system: Feeder Parameters

Line i-j	R pu	X pu
11.10	0.1231	0.2559
11.9	0.0662	0.1304
11.6	0.0945	0.1987
10.9	0.2210	0.1997
6.5	0.0524	0.1932
9.8	0.1070	0.2185
8.7	0.0639	0.1292
7.4	0.0340	0.0680
1.4	0.0936	0.2090
1.5	0.0324	0.0845
1.3	0.0348	0.0749
1.2	0.0727	0.1499
3.2	0.0116	0.0236
9.12	0.1000	0.2020
2.13	0.1150	0.1790
12.13	0.1320	0.2700
13.14	0.1885	0.3292
14.15	0.2544	0.3800
14.16	0.1093	0.2087
16.17	0.2198	0.4153
16.18	0.3202	0.6027
17.18	0.2399	0.4533

Data for 18-Bus system: Load

Bus *i*	P p.u.	Q p.u.
1	0.058	0.02
2	0	0
3	0.175	0.112
4	0.022	0.007
5	0.09	0.058
6	0.035	0.018
7	0.095	0.034
8	0.032	0.009
9	0.082	0.025
10	0.062	0.016
11	0.112	0.075
12	0.032	0.016
13	0.087	0.067
14	0	0
15	0.035	0.023
16	0	0
17	0.024	0.009
18	0.106	0.019

APPENDIX –B: GAMS Program for DAOM of Chapter-4

```
Option decimals = 4 ;
OPTION LIMROW = 30 ;
OPTION LIMCOL = 30 ;
Option ITERLIM = 50000 ;
Option Solprint = Off;
Option Sysout = Off ;
Option Reslim = 5000000 ;
OPTION OPTCA  = 5.35 ;
OPTION OPTCR  = 5.35 ;

set i buses/1*33/ ;
set k hours per day /1*24/;
alias (i,j) ;
Set Gen(i)   generator buses PV bus /1/
    Gen1(i)  generating units at these buses /1/
    Load1(i) load buses /2*33/
    Load(i)  load buses /2*33/
    DG(i)    DG units at remot buses /18, 22, 25, 33/
    NDG(i)   Non-DG buses /1*17,19,20,21,23,24,26*32/
    Cap(i)   Capacitor buses/2*17,19,20,21,23,24,26*32/;

Set Head Generator Data heads /Pmin, Pmax, Qmin, Qmax, A, B, C, GCst,
StCst, SdCst, Cmin/;
Set Head1/resis, react, charging/;
Set Head2 /Pmin, Pmax, Qmin, Qmax, A, B, C/;

Scalar  phi/3.141592654/;
Scalar  SBase     System base in MVA / 10 /;
Scalar  VBase     System base voltage in kV /12.66/;
Scalar  PriceCap  /55/;
Scalar  IntLim /0.2/;
TABLE Generat(i, Head2)  generator data
*-----Substation data here--------------
TABLE DistGen(i, Head)  generator data
*-----DG units data here--------------
Table LineData(i,j,head1)
*-----Line data here--------------
LineData(j,i,head1) = LineData(i,j,head1) ;
Parameter R(i,j,head1);
R(i,j,"resis")    = Linedata(i,j,"resis")*SBase/(VBase*VBase) ;
R(i,j,"react")    = Linedata(i,j,"react")*SBase/(VBase*VBase) ;
R(j,i,"resis")$(R(i,j,"resis") gt 0) = R(i,j,"resis") ;
R(j,i,"react")$(R(i,j,"react") gt 0) = R(i,j,"react") ;
R(j,i,"charging")$(R(i,j,"charging") gt 0) = R(i,j,"charging") ;
Parameter Z(i,j), GG(i,j), BB(i,j);
Z(i,j) = (r(i,j,"resis"))**2 + (r(i,j,"react"))**2 ;
```

```
GG(i,j)$(z(i,j) ne 0.00) = r(i,j,"resis")/z(i,j) ;
bb(i,j)$(z(i,j) ne 0.00) = -r(i,j,"react")/z(i,j);
bb(j,i)$(z(i,j) ne 0.00) = -r(i,j,"react")/z(i,j);
Parameter YCL(i);
YCL(i) = sum(j, r(i,j,"charging"));
Parameter g(i,j) , b(i,j) ;
b(i,i) = sum(j,bb(i,j)) + ycl(i);
g(i,i) = sum(j,gg(i,j));
g(i,j)$(ord(i) ne ord(j)) = -gg(i,j);
b(i,j)$(ord(i) ne ord(j)) = -bb(i,j);

Parameter Y(i,j);
   Y(i,j) = sqrt(g(i,j)*g(i,j) + b(i,j)*b(i,j));
Parameter zi(i,j);
 zi(i,j)$(g(i,j) ne 0.00)  = abs(b(i,j))/abs(g(i,j)) ;
Parameter theta(i,j);
theta(i,j) = arctan(zi(i,j));
theta(i,j)$((b(i,j) eq 0) and (g(i,j) gt 0)) = 0.0 ;
theta(i,j)$((b(i,j) eq 0) and (g(i,j) lt 0))   = -0.5*phi ;
theta(i,j)$((b(i,j) gt 0) and (g(i,j) gt 0))   = theta(i,j) ;
theta(i,j)$((b(i,j) lt 0) and (g(i,j) gt 0))   = 2*phi - theta(i,j) ;
theta(i,j)$((b(i,j) gt 0) and (g(i,j) lt 0))   = phi - theta(i,j);
theta(i,j)$((b(i,j) lt 0) and (g(i,j) lt 0))   = phi + theta(i,j);
theta(i,j)$((b(i,j) gt 0) and (g(i,j) eq 0))   = 0.5*phi;
theta(i,j)$((b(i,j) lt 0) and (g(i,j) eq 0))   = -0.5*phi;
theta(i,j)$((b(i,j) eq 0) and (g(i,j) eq 0))   = 0.0 ;

Parameter Pdem0(i)
*-----Active power demand data here--------------;
Parameter Qdem0(i)
*-----Reactive power demand data here------------;

Parameter Pdem1(i), QDem1(i);
Pdem1(i)= Pdem0(i)/(1000*SBase);
Qdem1(i)= Qdem0(i)/(1000*SBase);
parameter TPdem, LW(i), pri(k), GPcap, Dem(k), LoadAngle(load),
tanthe(i), TotalDem,Resv,PSF(k), CILa;
Pri(k) = PSF(k);
Dem(k)= 0.0548*Pri(k) + 4.095;
TPdem = sum(i, Pdem1(i));
LW(i)= Pdem1(i)/TPdem;
LoadAngle(load)= (1)*(arctan(Qdem0(load)/Pdem0(load)));
tanthe(load) = Qdem0(load)/Pdem0(load);

Variables
PG(dg,k)
GridP(k)
U1(dg,k)
V1(dg,k)
W(dg,k)
U2(k)
Payment1
ILCont(k)
ILsch(k)
;
Binary variable U1, V1, U2, W;
```

```
W.Fx(dg,"1")    = 1;

Equations
obj1
Eq1a(dg,k)
Eq2a(dg,k)
Eq3a(k)
Eq3b(k)
Eq3c(k)
Eq4a(dg,k)
Eq5a(k)
Eq6a(k)
Eq6b(k)
Eq7a(dg,k)
Eq8a(dg,k)
Eq9a(dg,k)
Eq10a(dg,k)
Eq11a(dg,k)
;

Obj1.. Payment1 =e= Sum(k, Pri(k)*GridP(k)+ CILa*ILCont(k)
                  + (Sum(dg, DistGen(dg,"StCst")*U1(dg,k)
                  + DistGen(dg,"SdCst")*V1(dg,k)
                  + DistGen(dg,"CMin")*W(dg,k)
                            + DistGen(dg,"GCst")*PG(dg,k)))) ;

Eq1a(dg,k)$(ord(k) gt 1)..PG(dg,k) =l= PG(dg,k-1)+
0.25*DistGen(dg,"Pmax");
Eq2a(dg,k)$(ord(k) gt 1).. PG(dg,k) =g= PG(dg,k-1) -
0.25*DistGen(dg,"Pmax");

Eq3a(k)..    Sum(dg, PG(dg,k) + DistGen(dg,"Pmin")*W(dg,k)) + GridP(k) +
ILsch(k) =e= Dem(k);
Eq3b(k)..    Sum(dg, DistGen(dg,"Pmax")*W(dg,k)) + Generat("1","PMax") +
ILCont(k) =g= Resv*Dem(k);
Eq3c(k)..    ILCont(k) =l= IntLim*Dem(k)* U2(k);
Eq4a(dg,k).. PG(dg,k) =l= (DistGen(dg,"PMax") -
DistGen(dg,"Pmin"))*W(dg,k);
Eq5a(k)..    GridP(k) =l= Generat("1","PMax");
Eq6a(k)..    GridP(k) =g= 0;
Eq6b(k)..    ILsch(k) =l= ILCont(k);
Eq7a(dg,k)$(ord(k) le 22).. W(dg,k) + W(dg,k+1) + W(dg,k+2) =g= 3 -
1000*(1 - U1(dg,k));
Eq8a(dg,k)$(ord(k) le 22)..  [1 - W(dg,k)] + [1 - W(dg,k+1)]+ [1 -
W(dg,k+2)] =g= 3 - 1000*(1 - V1(dg,k));
Eq9a(dg,k)$(ord(k) gt 1)..  W(dg,k) - W(dg,k-1) =l= U1(dg,k);
Eq10a(dg,k)$(ord(k) gt 1).. W(dg,k-1) - W(dg,k) =l= V1(dg,k);
Eq11a(dg,k)$(ord(k) gt 1).. U1(dg,k) - V1(dg,k) =e= W(dg,k) - W(dg,k-1);

Model DAOM
/
all
/ ;

Solve DAOM using MIP Minimizing Payment1;
```

APPENDIX –C: Cost Data and Generation Characteristics

33-Bus system used in Chapter-4

Bus with DG	**A** $/MW^2	**B** $/MW	**C** $	**CS**	**CD**	P^{min} pu	P^{max} pu	Q^{min} pu	Q^{max} pu
18	0.005	35	15	50	10	0.1	0.5	0	0.35
22	0.003	50	20	25	10	0.1	0.4	0	0.2
25	0.004	65	50	25	10	0.1	0.4	0	0.25
33	0.002	40	25	50	10	0.1	0.5	0	0.5

18-Bus system used in Chapter-5

DG-bus	P^{min} pu	P^{max} pu	Q^{min} pu	Q^{max} pu	**A** $/puMW^2	**B** $/puMW	**C** $	C_{QG} $/puMvar
15	0.0	0.03	0.0	0.00	0.0075	787.5	6.3000	0.063
18	0.0	0.07	0.0	0.02	0.0075	1260.0	10.575	1.00
8	0.0	0.03	0.0	0.01	0.0045	900.0	6.7700	0.068
7	0.0	0.06	0.0	0.01	0.0075	1260.0	8.7750	0.088

69-Bus system used in Chapter-5

DG-bus	P^{min} pu	P^{max} pu	Q^{min} pu	Q^{max} pu	**A** $/puMW^2	**B** $/puMW	**C** $	C_{QG} $/puMvar
52	0.0	0.03	0.0	0.00	0.0075	787.5	6.3000	0.063
65	0.0	0.07	0.0	0.02	0.0075	1260.0	10.575	1.00
27	0.0	0.03	0.0	0.01	0.0045	900.0	6.7700	0.068
69	0.0	0.06	0.0	0.01	0.0075	1260.0	8.7750	0.088

Note that when wind DG is considered at buses 27 and 69, the above cost functions for DGs at these buses are no longer used [Ref. Ch.5].

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