New Paradigms in Medium-Term Operations and Planning of Power Systems in Deregulation

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

The operation of a large and complex electric power system requires meticulous and rigorous study and incessant planning. All the players involved, must plan ahead to account for the uncertainties that can affect the hour-to-hour, day-to-day, medium-term and long-term supply of electricity. Medium-term operations and planning provides the players with guidelines and strategies for short-term operating decisions vis-à-vis the market. Adequate planning helps the players to mitigate or be prepared for unforeseen circumstances encountered during scheduling of electricity generation at any stage. This thesis focuses on some aspects of the *least explored* medium-term operations and planning issues in power systems in the deregulated electricity market environment. The issues addressed in the thesis are diverse but inter-linked as medium-term problems, which have surfaced due to deregulation or are outcomes of unique thought-processes emerging from the restructuring phenomenon.

The thesis presents a novel approach to security coordinated maintenance scheduling in deregulation wherein the ISO does not generate a maintenance schedule by itself, but assesses the maintenance schedules from individual gencos by incorporating them in a medium-term security constrained production scheduling model, and verifying whether they result in unserved energy at one or more buses. Based on the information on bus-wise unserved energy, the ISO generates corrective signals for the genco(s), and directs them to alter their maintenance schedules in specific periods and re-submit. The proposed scheme exploits the concept of *commons* and *domains* to derive a novel factor to allocate the unserved energy at a bus to a set of generators responsible. The coordination scheme is based on individual genco's accountability to unserved energy at a bus.

Another important question addressed in the thesis is whether there is a need to consider customer's locations in the power system when the utility provides service to them. In other words, whether the reliability of the load service provided by the utility varies across the system, from bus to bus, and if so, how are the Locational Marginal Prices (LMPs), which are determined from market auctions, affected by such variations. The thesis also answers the important question of how the LMPs can be differentiated by the Load Service Probability (LSP) at a particular location, so that it is fair to all customers. A new approach to determining the bus-wise LSP indices in power systems is proposed in the thesis. These LSP indices are arrived at by defining and computing bus-wise Loss of Load Probability (LOLP) indices. The discrepancy in LMPs with respect to the bus-wise LSP is then

investigated and the bus-wise LSP indices are thereafter utilized to formulate a novel proposition for LSP-differentiated LMPs for electricity markets.

The thesis furthermore addresses the medium-term Transmission Reinforcement Planning (TRP) problem and proposes a practical approach to TRP by making use of standard design practices, engineering judgement, experience and thumb-rules to construct a Feasibility Set. The Feasibility Set helps in limiting the type and number of reinforcement options available to the transmission planner in selected existing corridors. Mathematical optimization procedure is then applied considering the Feasibility Set, to attain an optimal set of reinforcement decisions that are economical and meets the system demand in the medium-term, without overloading the transmission system. Two different solution approaches- the Decomposition Approach and the Unified Approach are proposed to solve the TRP optimization problem.

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I wish my mother to be present when I defend my thesis and I know, as always, that she is with me and will shower her blessings to motivate and encourage me. My father also has suffered a lot in his life without letting me know, and has always encouraged me. I would like to express my sincere gratitude towards my mother for all scarifies she made, at the cost of her life, to see me prosper. I will never ever forget that it has cost a lot to reach where I am today. It is my parents' years of love and affection that I am submitting my PhD thesis on this day.

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Dedicated to my Mother

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Nomenclature and Acronyms

Sets and Indices:

i, j	Index for system buses
b	Index for sub-periods of a period (*Base, Intermediate, Peak*)
h	Index for hydro generating units in a genco
H	Index for the set of all hydro units in the system
k	Index for generating units within a genco
K	Set of generating units connected to the same bus *i*
kL	Set of generator buses ($kL \in K$) supplying load bus, *L*
KU	Set of all generating units in the system
l	Index for line voltage class (110 kV, 220 kV, 500 kV)
L	Load buses in the system ($L \in i$)
m	Index for a specific period in t, when unserved energy is maximum
N1	Set of buses that have unserved power in period, *m*
o	Index for reinforcement option
p	Set of commons
t	Index for period (in this work, a period represents a month, *t = 1,.., 12*)
U	Set of generating companies (gencos)
u	Set of gencos receiving corrective signal from ISO, $u \in U$

Constants:

Aux	Auxiliary consumption of a generating unit, %
B	Susceptance, P.U.
Cg	Generator operating cost, \$/MWh
Cg^A	Fixed component of generator cost characteristics, \$/h
Cg^B	Linear component of generator cost characteristics, \$/MWh
Cg^C	Quadratic component of generator cost characteristics, \$/MW^2/h
Cg^q	Reactive power generation cost, \$/MVAr^2
Cm	Maintenance cost of a generating unit, \$/MW
Cc	No-load generation cost of a generating unit, \$/h
Cs	Start-up cost of a generating unit, \$
Cn	Cost of unserved energy, \$/MWh

E	Hydro energy availability factor for a hydro unit, %
G	Conductance, p.u
I^{Max}	Line thermal capacity, p.u
LF	Transmission line loss factor, %
LSF	Load Scaling Factor
N	Total number of system buses
N_l	Total number of load buses
N_g	Total number of generator buses
N_o	Total number of reinforcement options
NM	Number of units on simultaneous maintenance
P^{Max}	Power transfer capacity of a line, MW or p.u
PD	Total power demand in the system, MW or p.u
Pg^{Max}	Maximum capacity of a generating unit, MW or p.u
Pg^{Min}	Minimum capacity of a generating unit, MW or p.u
RSV	System reserve requirement, MW
T	Duration of sub-period *b*, h
T1	Duration of maintenance for a unit, over a year
ρ	Medium-term forecast of electricity price, \$/MWh
Qc^{Max}	Maximum reactive capacity of a support unit in MVAr or p.u
Qc^{Min}	Minimum reactive capacity of a support unit in MVAr or p.u
QD	Reactive power demand in MVAr or p.u
Qg^{Max}	Maximum reactive capacity of a generating unit in MVAr or p.u
Qg^{Min}	Minimum reactive capacity of a generating unit in MVAr or p.u
V^{Max}	Maximum permissible voltage at a bus, p.u
V^{Min}	Minimum permissible voltage at a bus, p.u
Ych	Line charging admittance, p.u

Parameters

AC	Absolute contribution of generator, p.u
C	Relative contribution of generator *g*
CPROB	Cumulative probability of Outage
$MCAP_u$	Capacity of *u* on maintenance in *m*, MW

Pn^{Max}_{m}	Maximum unserved power in *m*, MW
$Pn_{i,m}$	Bus-wise unserved power in *m*, MW
$Pn_{m,u}$	Unserved power in *m* attributed to *u*, MW
$Pn_{i,m,u}$	Unserved power at *i*, in *m*, attributed to *u*, MW
Pg^{SRC}	Synthetically reduced capacity, p.u
$TCAP_u$	Total capacity of *u*, MW
α_u	Proportion for sharing unserved power between gencos
β_u	Fractional capacity on maintenance in *u*
γ_u	Corrective signals to *u* indicating maximum allowable capacity on maintenance, MW
$\Delta PCap$	Line MW capacity Increment, p.u
$\Delta ICap$	Line Thermal capacity Increment, p.u

Variables:

Cost	Total annual system cost, $
e	Real component of the voltage phasor, p.u.
En	Unserved energy, MWh
f	Imaginary component of voltage phasor, p.u.
I	Current through line *i-j*, p.u
I	Inflow to a common, p.u, in Chapter 5
Loss	Total system loss, p.u.
P	Power flow on a line, MW or p.u
Pg	Real power generation, MW or p.u
Pn	Unserved power, MW or p.u
Qg	Reactive power generation per unit MVAr p.u
Qc	Reactive support per unit MVAr or p.u
S	Startup status of a generating unit at the beginning of a sub-period (1 = startup, 0 = otherwise)
V	Bus voltage magnitude, p.u
W	Commitment status of a generating unit (1 = unit committed, 0 = otherwise)
X	Maintenance status of a generating unit (1 = unit on maintenance, 0 = otherwise)
Z	Reinforcement option selection variable (1 = option selected, 0 = otherwise)
Ω	Profit of a genco, $

V	Voltage magnitude at bus *i*, p.u

Acronyms

DISCO	Distribution Company
DL	Domain List
FACTS	Flexible Alternating Current Transmission System
FCM	Fractional Capacity on Maintenance
FOR	Force Outage Rate
FTR	Financial Transmission Rights
GENCO	Generating Company
HOEP	Hourly Ontario Energy Price
IESO	Independent Electricity System Operator (ISO of Ontario)
IPSP	Integrated Power System Plan
ISO	Independent System Operator
LDC	Load Duration Curve
LMP	Locational Marginal Price
LOLP	Loss of Load Probability
LSF	Load Scale Factor
LSP	Load Service Probability
MILP	Mixed-Integer Linear Programming
MINLP	Mixed-Integer Non-Linear Programming
MS	Maintenance scheduling
OPA	Ontario Power Authority
OPF	Optimal Power Flow
RPP	Reactive Power Planning
SRC	Synthetically Reduced Capacity
TBDL	To Be Domain List
TEP	Transmission Expansion Planning
TRP	Transmission Reinforcement Planning

Chapter 1
Introduction to Medium-Term Operation and Planning in Power Systems

1.1 Introduction

The electric power sector has come a long way since the early years of small power generating stations to the present day giant power stations of large capacities and interconnected extra high voltage transmission networks. Finding out suitable strategies for efficient power system operation and planning on a utility-wide scale through the formation of interconnected grids, gathers paramount importance in view of the complexities in securing funds to undertake large power projects for capacity addition [1-3].

Power system operations and planning activities can be classified into various categories depending on the time-horizon of the activity and the decision variables involved [4]. Table-1.1 provides an overview of the various activities of the power system operator and the system planner from real-time operation to 10-years in advance, in the context of vertically integrated power industry structure. In the context of deregulation, many of these activities have undergone a paradigm shift. For example, the aspect of long-term planning has been affected significantly after the onset of deregulation.

Table 1.1 Power System Operations and Planning in Time-Domain

Time-frame	Activity	Referred to as-
> 10 years ahead	Planning to expand the generation & transmission system to meet the demand	Long-term planning
1 – 5 years ahead	Planning for fuel supply contracts, capacitor citing and sizing (reactive power planning), transmission reinforcement planning	Medium-term planning
1 – 2 years ahead	Generating unit maintenance schedules, production scheduling	Medium-term operations
1 – 7 days ahead	Schedule hydro reservoir drawdown, unit commitment	Short-term operations
5 – 30 minutes ahead	Economic load dispatch, load flow, capacitor switching, load curtailment, frequency regulation, *etc.*	Real-time operations
1 – 300 seconds	Tackle faults, disturbances, short-circuits, oscillations	Transient and dynamic state operations

As may be noted from Table-1.1, the utility's activities in the time-frame of 1-2 years ahead, referred to as medium-term, are quite extensive and involving. Both *operations* and *planning* activities are present in this time horizon.

The *medium-term operation* activities include generating unit maintenance scheduling- to decide which generators would be scheduled for maintenance and when. This is usually combined with medium-term production scheduling, where gross production schedules are drawn up one or two years in advance taking into consideration aggregated load duration curves (LDC) and hydro energy allocation schedules for reservoir-based hydro units. In some cases, fuel production, transportation and allocation schedules are also combined with medium-term operation activities of the utilities [5].

The *medium-term planning* activities include studies that are needed to be undertaken in time-frames of 1 to 5 years, and may include reactive power planning- capacitor citing and sizing, transmission reinforcement planning, *etc*.

In the literature, the term *operations* and *planning* have often been used together or interchangeably since these cover a wide range of overlapping functions. To clearly distinguish between operations and planning activities in the context of this thesis; operations activities are those where production schedules are drawn up, while planning activities are those where new investment decisions are the outcomes.

Fig.1.1 shows the basic linkages of information flow, coordination and hierarchical functions of utility operations and planning across different entities / players, both in the context of deregulation (*on the left*) and in a vertically integrated environment (*on the right*). In the erstwhile vertically integrated utility structure, the Central Load Dispatch Centre (CLDC) interacted with the "power generation division" (denoted by G, responsible for all generation in the utility, operation and maintenance of the units, *etc.*), the "transmission division" (denoted by T, responsible for all transmission) and the "distribution division" (denoted by D, responsible for all low voltage networks).

The short-term operation schedules were drawn up based on the coordination between these entities while the medium-term operation schedules were further coordinated with the short-term operation. The central planner received inputs from each of these three divisions (G, T and D) and the CLDC, and using its own forecast of demand growth, developed the medium- and long-term plans for the system as a whole. Thus, all activities of planning, procurement, erection and commissioning, operations and maintenance, medium-term operations and planning, and short-term operations, associated finance management and commercial operation were centralized and coordinated through information linkages between each and every division or sector, with the knowledge sharing of the system.

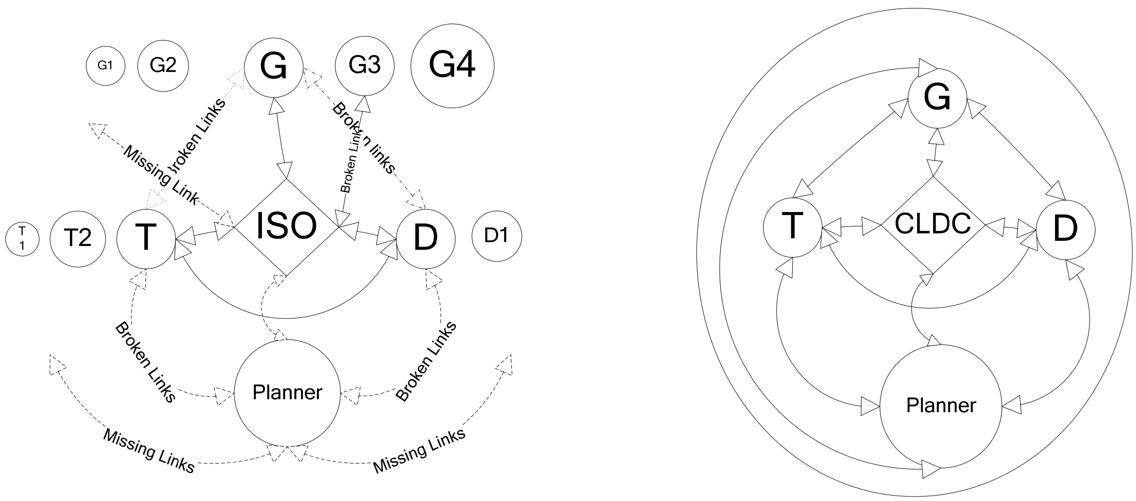

Figure 1.1 Comparative Linkage Diagram of Utility Operations and Planning- in Deregulation (*left*) and in Vertically Integrated Environment (*right*)

The deregulated power industry structure (Fig.1.1, *figure on the left*) led to deletion of the outer circle, split up of the G division to introduce multiple gencos in the system, independent of each other, and similarly existence of multiple transcos and discos. The changes observed in the new power industry structure as compared to the vertically integrated system can be summarized as follows:

1. Increased linkages because of horizontal expansion of number of participants in a category.
2. Missing / broken links between players because of allowed flexibilities in electricity market.
3. Planning is no longer a centralized activity of the system, but usually undertaken individually or by an external entity.
4. Policies, procedure and systematic organizational behavior pattern at all levels does not exist.

One important question that arises in these discussions is- who is responsible to carry out the planning activities? In the vertically integrated structure, the utility had the overall responsibility of system operations and planning while in the context of deregulation, each category of players have diverse responsibilities and interests. This makes the problems more challenging and involved.

1.1.1 Medium-Term Operations

In the context of the classical, vertically integrated power system, a large number of methods were proposed to handle different technical issues in the medium-term operational time-frame. The operations coordination mainly involved determining the optimal set of solutions that minimized a system-wide cost function subject to a set of constraints. Depending on the type of the system (hydro-thermal mix, *etc.*), size of the system, availability of information and solution tools, the medium-term operations planning problem can be addressed adequately [1, 5-7].

In the competitive market environment, medium-term operations have undergone a paradigm shift because of the diversification of functions and responsibilities amongst different entities in the deregulated industry structure. For example, maintenance scheduling functions are now decentralized and gencos formulate their own maintenance schedules. However, these self-generated schedules need to be coordinated with other gencos and subsequently with the independent system operator's (ISO) reliability requirements, and its other system related constraints. The problem thus becomes far more complex in the deregulated environment compared to that in the erstwhile vertically integrated systems.

1.1.2 Medium-Term Planning

The medium-term planning functions have also undergone changes in the way the objectives are formulated and issues are addressed. For example, in vertically integrated systems, reactive power planning typically involved a centralized optimal power flow (OPF) analysis for minimizing the system losses and hence determined the optimal capacitor placements in the system. In the context of deregulation, when the ISO does not have jurisdiction over the whole network, such loss minimizing OPFs and centralized capacitor placement plans does not hold. The local distribution companies (discos) are entrusted with the responsibilities of meeting the reactive power demand within their system while regional networks have their own areas of responsibilities. In such a context, the overall planning for reactive power and voltage support has taken an entirely new meaning, and the problem now is a multi-level, multi-objective, hierarchical optimization and coordination problem.

1.2 The Ontario Power System and Its Electricity Market

In 1995, the Ontario government initiated the process of restructuring of the province's power sector in line with the Alberta electricity market in Canada and some US states. In 2002 the electricity market in Ontario became operational. The proposed and planned shut-down of coal-fired plants in the province by the year 2020, because of environmental factors and the ongoing reduction in nuclear capacity due to nearing their life expectancy, has posed serious challenges for the electricity sector in Ontario [8].

Ontario has 22 power generating companies having a gross generating capacity of 31,840 MW from a total of 97 plants. Of these, Ontario Power Generation (OPG) owns 41 generating stations contributing 22,724 MW of capacity. Other major contributors are Bruce Power with a total capacity of 4,720 MW, Brookfield Power with 1,170 MW, Brighton Beach with 580 MW and Transalta Energy Corporation with 510 MWs. Clearly OPG is the major player in the Ontario electricity market.

Majority of the transmission network is owned by Hydro One Inc. except for a few sub-systems operated and maintained by other companies like Brookfield Power. Ontario has approximately 300 transmission sub-stations (up to 115 kV) and 30,000 km of transmission lines. Bulk transmission lines are classified into 500 kV, 220 kV and 115 kV lines, on the basis of their respective operating voltage levels. There are few facilities operating at 345 kV in Ontario.

Currently, for operational matters the Ontario power system is divided into 10 different zones while as per the Integrated Power System Plan (IPSP) [8], the zones are re-defined as given in Table-1.2.

Table 1.2 Zones of Ontario Power System

Currently Defined Zones	OPA's Planned Zones
North-West, North-East, ESSA, Bruce, West, South-West, Niagara, Ottawa, East, Greater Toronto Area.	North-West, Algoma-Sudbury, North-East of Sudbury, Sudbury-Barrie, Barrie-GTA, South-West /Bruce-GTA, Eastern Ontario-GTA, Within GTA.

Ontario is interconnected with the power systems of Manitoba, Minnesota, Quebec, Michigan and New York. It has a total of 27 inter-connecting tie-lines.

The Ontario's electricity market is a real-time physical energy, operating reserves and Financial Transmission Rights (FTR) market. The market participants can also participate in physical bilateral contracts whose financial settlements can be done either through the Independent Electricity System Operator (IESO) or on their own. The IESO also procures ancillary services to ascertain the system security and reliability through a physical market for operating reserves and through contracts with licensed reactive support providers.

The pricing of electricity and operating reserves in the Ontario electricity market is based on uniform price auction [9]. The Hourly Ontario Energy Price (HOEP) is the wholesale market price that varies throughout the day, based on prevalent supply and demand of electrical energy. The market clearing price in Ontario is determined at every 5 minute interval. The twelve interval prices thus obtained over an hour are averaged to obtain the HOEP. The HOEP is charged to non-dispatchable loads and paid to self-scheduling, intermittent and transitional scheduling generators.

1.3 Research Motivation and Objectives

The power sector in Ontario as well as in other parts of the world, including those in the developing countries such as in India and China, have undergone or are currently undergoing a phase of restructuring and with that several associate issues have emerged because of governmental energy policies with regard to emissions reduction, oil price volatilities, importance of renewable energy resources, finance and risk issues in new projects, *etc.*

Medium-term operations studies in the electricity sector therefore have a major role to play in order that the whole system is operated in a secure and reliable manner in spite of various participating entities (gencos, transcos, discos, ISO, retailers, *etc.*) operating their individual businesses with conflicting objectives. There is also a need for undertaking medium-term planning studies that look at the system investment requirements from a closer time-perspective than the traditional long-range planning. This is particularly important because of the present day market price volatilities, and with increased reluctance of investors to venture into risky capacity addition projects.

Some of the specific issues that are of importance and relevance in the context of this thesis, are briefly discussed below:

Medium-Term Production Scheduling and Operations

With deregulation, the concept of short-term "centralized" dispatch (in the day-ahead / hour-ahead stage) has been transformed to market-auction based dispatch organized by the ISO / market operator, as the case may be. Medium-term production scheduling still has an important role and gencos need to carry out such scheduling which needs to be coordinated with other gencos by the ISO so as to ensure secure and reliable operation of the whole system.

Such medium-term operations may take into consideration fuel supply linkages and constraints, reservoir draw-down scheduling in the medium-term and demand-side management options. The complexity arises in the coordination process because of the conflicting interests of the gencos and the ISO. While the gencos typically seek to maximize their profit and accordingly carry out their production scheduling, these schedules may result in an overall insecure state of operation of the system and hence are not acceptable to the ISO.

Coordinated Maintenance Scheduling

Maintenance scheduling is closely inter-linked to medium-term production scheduling and operations. This important task used to be undertaken in a centralized manner in the pre-deregulation era, but needs a re-look in the new environment. In the current deregulated environment, each genco seeks to maximize its profit and in order to do so, can often compromise the system security and reliability aspects by not developing appropriate maintenance schedules. Even if they do develop such maintenance schedules, these will be in their interests and may not be in the best interest of the system as a whole.

The ISO has thus, the challenging task of coordinating all independent maintenance schedules from gencos, and formulating a system-wide maintenance plan in the medium-term that results in a secure and reliable state of operation for the system. The resulting medium-term production schedules need to adhere to existing transmission and other system constraints.

In restructured power systems, ill-planned maintenance schedules can lead to unexpected rise in prices and may also impinge on the market operation, while introducing market inefficiencies. Therefore a proper maintenance schedule developed by coordinating with all the market participants and considering the economic and technical aspects, both at the individual genco level and at the systems level, is of paramount importance.

Locational Reliability Analysis and its Need

It has often been argued that power sector deregulation has adversely affected the reliability and security margins in power systems [10]. However, it is also true that deregulation has brought about increased interest of power engineers to reliability issues because it provides a larger choice to the customers. It can be expected that as in other commodity markets, the electricity customers would, in the future, be in a position to influence the price and reliability of the electricity service they receive, leading to a trade-off between reliability and prices.

In most of the electricity markets in North America, the electricity prices are in terms of the locational marginal price (LMP) which reflects the cost of supplying the next MWh of electricity at a bus, considering transmission constraints [11]. These locational prices provide important signals pertaining to the need of investing in new generation, upgrading transmission, or reducing electricity consumption- and therefore, are essential elements in a well-functioning market to alleviate constraints, increase competition and improve the systems' ability to meet the power demand.

In the same way as the LMP provides vital information on system conditions to the ISO, it would also be pertinent if the ISO is equipped with a Load Service Probability (LSP) index that provides critical information on the probability of supplying load to the customers at a bus. This is justified because each electricity customer in the power system attaches a different "worth" to its electricity usage and supply continuity. It is therefore necessary to determine the level of LSP received by a customer.

Such information on LSP will be very valuable to the ISO in order to improve its readiness for tackling system emergencies and other operational aspects. Furthermore, such a locational index can be integrated with the LMPs to arrive at a LSP differentiated nodal price for the power system and to charge the customers accordingly. For example, in order to ensure fair pricing, a premium on high LSP loads or a discount on low LSP loads can be introduced within the locational pricing framework.

Reinforcement of Transmission System

In most electric utilities around the world, the increase in power transfer capacity of the transmission system has been lagging the increase in generation system capacity. In other words, transmission system expansion has not received the attention that it requires and has not kept track with generation system expansion. The annual load growth in North America is approximately 2% per year and generation capacity has seen a rise of about 30% in last three decades, whereas the increase in transmission capacity has been around 15% only [12].

This issue that has not been adequately addressed post-deregulation, and needs to be examined because of the pressing requirements of system demand growth, uncontrolled and unplanned power flow patterns, penetration of distributed generation sources in the system, *etc.* There can be additional system specific issues that require strengthening of specific transmission corridors. For example, recently some coal-fired units in Ontario have been shut down and some others (at Thunder Bay and Atikokan, in Ontario) are to be phased out (*about 300 MW of capacity*) within the next few years, as per the IPSP, while feasible alternatives are being worked out. The reduction in supply capacity can be met by importing power from other zones within Ontario but the transmission line capacities need to be reinforced.

The traditional transmission expansion planning problems involve developing new transmission corridors for power transfer. However, in real life, propositions for such new corridors are extremely difficult to implement because of the reluctance of governmental agencies to approve them. Such reluctance is due to possibility of environmental degradation from forest clearances for right-of-way, land contamination, ill-effects of electromagnetic induction on general public health, *etc.* To address these issues in the medium-term, *transmission reinforcement* is the most practical approach to cope effectively with demand-supply balance and transmission overloading issues, arising as a result of lack of adequate transmission capacity.

1.3.1 Main Objectives of this Research

1. To develop a medium-term production-cum-maintenance scheduling framework applicable to participants in the deregulated electricity market environment. The comprehensive framework will consider the individual gencos' objective of profit maximization as well as the ISO's objective of cost minimization.
2. To develop a novel scheme for the coordination of the production-cum-maintenance schedules of individual gencos with the system-wide security requirement of the ISO. This scheme will be based on the contribution of gencos to unserved energy.

   The coordinated framework does not require the ISO to develop maintenance schedules by itself, but instead only requires it to verify the suitability of the individual genco's maintenance plans from the perspective of overall system demand-supply balance, system reliability and security. This is a fairly complex problem and requires the formulation of the problem as a two-tier model and the synthesis of an update signal that modifies Gencos' optimization constraint after the first-tier model (those of gencos) are executed.
3. To propose the concept of locational reliability, develop a methodology to determine novel locational reliability indices in power systems and further propose the application of this conceptual locational reliability to electricity pricing in deregulation.
4. To develop transmission reinforcement planning (TRP) model that incorporates the engineering judgment and experience to determine a Feasibility Set, which is then optimized to select one of the reinforcement options for each lines identified to be reinforced. Propose two different solution approaches and demonstrate the results on CIGRE 32 bus test system.

1.4 Outline of the Thesis

The thesis is structured as follows- Chapter 2 presents a review of the theoretical background and the state-of-art in research on operations and planning activities in the medium-term framework. The detailed mathematical modeling framework of the proposed security coordinated maintenance scheduling problem is described in Chapter-3. Chapter-4, presents the Ontario based example and detailed results of the coordinated maintenance scheduling problem. Chapter-5 discusses the novel location reliability indices, the reliability-differentiated pricing concept, and presents the detailed results on a 5 bus-test system and the representative Ontario test system. In Chapter-6 the TRP problem is presented in detail and two approaches to its solution are suggested – the Decomposition Approach and the Unified Approach. The last chapter, Chapter-7, summarizes the contributions of the thesis and discusses the scope for future research.

Chapter 2
Background and Literature Review

2.1 The Production Scheduling Problem in Medium-Term Operations

Production scheduling of a power utility in the erstwhile vertically integrated environment, involved many activities such as generation scheduling, power flow computations, coordination of inter-utility transfers, devising appropriate tariff for such transfers, fuel production and transportation scheduling, and several others. All these activities being inter-dependent, required coordination in order to achieve optimal operations since their isolated planning could lead to sub-optimal outcomes. Therefore, it was essential to take up these inter-dependent activities simultaneously while carrying out operational planning exercise for a utility.

In the recent years after deregulation of the industry, the power sector is faced with problems of demand growth far exceeding the capacity additions, uncertain and volatile market prices, and narrow operating margins. Moreover, the concept of centralized production scheduling no longer holds true because of the individual operating strategies adopted by gencos. Consequently, the ISO needs to get involved in the coordination task so that the production schedules obtained by individual gencos are realistic and feasible from the systems perspective.

One of the early approaches in medium-term power system operations studies consider a multi-period linear programming model to evaluate benefits from inter-utility transfers and trading between some US and Canadian states [13]. Rau [14] has developed a Monte-Carlo simulation model for an interconnected power system that considers random outage of plants, transmission loadings and wheeling penalties.

Parikh and Chattopadhyay [5] discuss medium-term operational issues pertaining to the Indian power system. A multi-area linear programming model is developed to quantify the merits of the integrated national grid operation in terms of cost savings, and highlights the need for optimal sharing of central sector generation. The work also proposes a pricing scheme for inter-utility transfers, and identifies four inter-utility transmission reinforcement projects.

Li and Singh [15] present a multi-area production scheduling model with a new approach to marginal cost calculation using the concept of probability of need of a unit *i*. Assuming that unit *i-1* have been processed, if unit *i* is added, then due to transmission limitation, not all the loss state would be affected. So LOLP is not an accurate indicator of the time for which unit *i* will reduce loss of load.

So a new index of probability of need of a unit is proposed to improve the segmented global simultaneous decomposition approach for calculating production cost.

Electricity sale transactions are integrated with the medium-term scheduling problem using a mixed integer programming (MIP) model in [16]. The sale transactions between two utilities is a complex decision as it is coupled with the system demand and reserve, and the decisions have to be made in conjunction with commitment and dispatch of units.

The 1992-IEEE System Operations Sub-committee [17] report some major issues in operations planning, which are of significance in the context of deregulation. The report identifies emission constraints, transmission constraints, impact of uncertainties, and a post-analysis (as a feedback loop) as the major issues in operations planning.

In a recent work [18], the issue of coordination between medium-term generation planning and short-term planning activities has been examined. Traditionally such coordination is developed by the ISO trying to minimize the total cost of the system. Coordination between different decision levels is important in order to guarantee that certain aspects of operation that arise in the medium-term are explicitly taken into consideration, for example the issue of optimal utilization of *limited energy resources*. In the same context [4] discusses the need of coordination between different decisions in a same time-frame. The importance of integrated models for analyzing fuel-supply decisions at the generator level, network decisions such as capacitor placements while incorporating the maintenance decision impact are discussed.

Another recent work [19] addresses the optimal management of hydro resources in the medium-term. The work maximizes the expected revenue of a genco from its energy generation and forward contracts in the market. Results are obtained for a Norwegian power producer participating in NordPool, the Nordic power exchange.

2.2 The Maintenance Scheduling Problem in Medium-Term Operations

Maintenance scheduling of generating units is an important medium-term operations activity that reduces the risk of capacity outages, improves unit availability and hence system reliability. Therefore, having an appropriate maintenance schedule is very important but frequent and unnecessary maintenances can drastically increase operating costs and reduce supply continuity and unit availability. An integrated maintenance schedule for the bulk power system is usually developed and such coordinated plans can improve system operational efficiencies significantly. Various factors can affect the system maintenance schedules, for example load demand profile and seasonal variation of the system demand need to be considered when devising the schedules. Similarly, the amount of maintenance required on a specific unit, the unit sizes, the elapsed time from last maintenance, hydro energy availability and the extent of hydro-thermal mix in the system, maintenance intervals and durations, and such other factors are critical.

Planned outages of power plants have a cyclical pattern. A major maintenance may be conducted every 5-6 years and take 5-10 weeks for a complete overhaul. The next year's maintenance would be simple, requiring say, 2-weeks, while year after still more, and so on till the next cycle.

Some researchers have also argued in favor of monitoring the condition of generating units and hence decide the maintenance requirement upon verifying the results [20-23]. This can be modeled by a variable elapsed time instead of having a fixed elapsed time. Condition based maintenance scheduling can save on cost of maintenance as well as increase unit availability and revenue collection without affecting the reliability. The maintenance decisions for a unit can also be deferred by a year or so. However, this aspect has not been examined or addressed in this thesis.

In the context of vertically integrated operation, lot of research has been reported on the development of efficient solutions to the maintenance scheduling problem or to address new issues within the scope of this problem [1, 21]. Some of the well known objective functions for maintenance scheduling problems used by researchers, can be listed as follows-

1) Levelizing the reserve [1]
2) Levelizing the risk or the Loss of Load Probability (LOLP) [24]
3) Minimizing the annual LOLP [25]
4) Minimizing the total maintenance cost [26]

In competitive electricity markets, ensuring system reliability is the primary responsibility of the ISO while the gencos' primary objective in its production-cum-maintenance scheduling tasks is to maximize its profits. As reported in [20, 27-29], the ISO usually does formulate a maintenance schedule annually for all generators in the system by maximizing the social welfare, but cannot impose it on the participating gencos because these gencos seek to maximize their profits by scheduling units on maintenance such that their respective loss of revenue due to maintenance outages is the least. The optimization problems therefore, for the ISO and the gencos are quite different, in principle. Strategically, the ISO would like to schedule the maintenance during low demand periods while the gencos would choose to schedule their units on maintenance during low price periods. In spite of such different objectives of the involved players, the ISO can negotiate an appropriate maintenance schedule with the gencos in order to guarantee an adequate level of security of the system. In most systems, the regulatory agreements require the gencos to schedule their mandatory maintenance by negotiation with the ISO.

Among various methods proposed to address the maintenance scheduling problem, the well-known *levelized reserve method* [1] seeks to equalize the reserve for each month of a year. Though this method is widely used because of its simplicity, it does not incorporate random outages of generating units. The *levelized risk method* [24] attempts to achieve a uniform LOLP for all months in a year. A traditional technique is to schedule the maintenance to levelize the load plus capacity on outage over a year.

A two-level hierarchical method for levelize incremental risk is proposed in [25], resulting in a minimum annual LOLP maintenance schedule. The method is extended in [30] to include network constraints. In [31], the maintenance scheduling of a power plant using the reliability criteria of maximizing 'minimum reserve' was proposed. The paper discusses the effects of cost, reliability and constraints on each other when addressing a maintenance scheduling problem. An integrated approach to least-cost maintenance scheduling of generating units for interconnected power systems is presented in [26], wherein a MIP model is developed taking into account fuel supply and transportation decisions, production and maintenance scheduling decisions, and inter-utility transfer schedules.

In a subsequent work, Chattopadhyay [32] proposed a practical method for maintenance scheduling using linear programming. It considerably improves the convergence and reduces the computational burden over integer programming methods. Inter-area transfers and stochastic reliability constraints are included in [33] for maintenance scheduling and the problem is solved using Bender's decomposition method, while transmission constraints are incorporated using a dc-OPF formulation in [34].

In [21], the problem of maintenance scheduling in restructured power systems is described and the use of decomposition techniques to coordinate the optimization of various objectives among the independently operated entities is discussed. Decomposition techniques are of significance because of their ability of solving very large-scale problems. In the context of deregulation, Shahidehpour *et al.* [21, 35-37] propose the use of decomposition techniques to coordinate the optimization of various objectives among the self-optimizing entities of the market. A composite system maintenance coordination problem in deregulated environment is presented in [29] wherein the method of coordination between gencos, the transco and the ISO is based on the practices adopted by ISO.

Conejo et al. [28] presents a coordinated maintenance scheduling approach in restructured power systems that uses an iterative procedure of coordinating the schedules between the ISO and the gencos such that an appropriate degree of reliability is attained over the year, in a manner acceptable to all. An incentive is proposed for generators willing to alter their maintenance schedules for the sake of reliability while penalizing those not altering. A two-stage scheme is developed where the gencos submit their maintenance schedules, obtained with the objective of maximizing profit to ISO, which is compared with an ISO-generated schedule that is obtained by maximizing a reliability index. If the submitted plan fails to meet the reliability criteria of the ISO, incentive and disincentives are determined and modified schedules for generators are determined until a feasible solution is achieved.

In [37] an integrated generation and transmission maintenance scheduling is presented which uses Benders decomposition approach to solve the optimization problem. Transmission constraints are incorporated using a linear flow model. In [34] the network constraints are refined by using a dc load flow representation while determining the maintenance schedules.

Shahidehpour and Marwali [36] presented a long-term transmission and generation maintenance scheduling problem in the context of deregulation. The long-term scheduling of transmission is useful in determining the available transfer capacity in the system.

2.3 Locational Reliability and Reliability Differentiated Pricing

One of the commonly used reliability indices, the LOLP [1], [38] takes into account the forced (and planned) outage rates of generating units and provides a quantitative measure of the expected duration, that the system is not able to serve the load, in a given period. For example, a day's LOLP of 0.0015 implies that the system load will remain unserved for the duration of 2.16 minutes (*i.e.*, *24 hours x 60 minutes x 0.0015*) over a given day. It is to be noted that the LOLP, however, does not specify the bus where the unserved load is expected. On the other hand, it can be appreciated that the ISOs, customers and all involved parties would indeed welcome such information if made available in advance.

The LOLP index furthermore, does not provide enough information when transmission congestion is present. Transmission congestion can force the system to operate at a sub-optimal dispatch point resulting in a low value of LSP. Location specific information on LSP can assist the ISOs to improve their readiness for an event. This is very important in the context of power system operation in deregulated environment when systems are operating at close to their security, stability and reliability limits.

Reliability evaluation of a composite system involves the simulation and load flow analysis of each state of the system over a desired period [39]. A common-mode or cause model is applied in composite system reliability evaluation. A distinct set of *measurable* reliability indices are defined in

[40] with reference to load buses in a practical system. These are, *Interruption Frequency*, *Interruption Duration*, *Average Duration per Interruption*, *Load Interrupted*, *Unsupplied Energy* and *Interruption Severity*. Guidelines for measuring the load bus reliability is presented in [41] via a useful set of terms and procedures for consistent reporting of bulk power system reliability.

In [42], a technique for reliability evaluation is proposed wherein a complex radial distribution system is reduced to a series of general feeders using reliability network equivalents. Basic equations are used to calculate the individual load-point indices. The concept of delivery point reliability index probability distributions has been recently proposed in [43] which are obtained using a sequential Monte Carlo simulation approach. It is demonstrated that these indices have unique characteristics because of differences in system topology and operating conditions.

Researchers have examined and proposed reliability indices at a bus in a composite power system, considering generation and transmission. A conditional probability approach is used in [44] to determine the reliability at any point in the composite system. The work argues that if the load can be considered a random variable and described by a probability distribution, then failure at any load bus due to component failure is conditional upon the load exceeding the defined carrying capability of the remaining facilities. The *failure* at a load bus is defined as a loss of load or a resultant voltage limit violation at the bus [38].

A reliability differentiated pricing of electricity considering outage cost and priority pricing (for customers who desire supply continuity) is proposed in the context of vertically integrated power systems in [45]. At times of shortage of supply or outages, instead of having one market clearing price for all customer classes, differentiated prices for the various customer classes is proposed based on their respective outage costs. Wang *et. al.* presented in [46], a new technique to determine nodal prices and nodal reliability indices based on probabilistic evaluation approach considering customer outage costs.

2.4 Transmission Reinforcement in Medium-Term Planning

The objective of transmission expansion planning is to determine the installation plans of new facilities so as to enable the resulting bulk power system to meet the future demand at least cost, while satisfactorily meeting the prescribed technical, environmental, legal, political and financial constraints [47]. The aim of transmission planning is therefore, to establish where and when to build new transmission lines with associated equipment required for economic and reliable supply of forecasted load. The requirements are contradictory as higher reliability means higher investment cost and hence the planner has to make a compromise such that adequate reliability is achieved at an affordable cost.

Transmission expansion planning has received considerable attention amongst researchers over the years, with research spanning over diverse issues and solution techniques. Optimal planning of an electric transmission network requires the determination of the most economical expansion plan over a specified period. The system expansion should take into account load growth, new generating sites (as per generation expansion plans), voltage levels, right-of-way availability, system interconnections *etc*., over and above the cost escalation factors. The investment decisions depend on the configuration of transmission lines required and the voltage level at which additions are needed.

A typical cost function includes both fixed and variable costs of all new line additions. This has been further generalized to include cost of power losses, non-linear network performance indices, cost of unserved energy, reliability and social cost. With regard to methods of solving the problem, integer programming methods, considering a cost minimization objective subject to a set of linear constraints, have been used since the sixties. Alternate heuristic approaches have been proposed to address the problems of realistic systems, ignoring the time-dependence of planning proposals. Recently artificial intelligence (AI) and hybrid-AI based methods have been used to address transmission expansion problems. Transmission expansion planning problems, driven by their size, have largely being studied either as a single stage, one stage synthesis, or as a static transmission expansion problem. Expansion studies have tried to transform the multi-year, long term planning problem into a yearly optimization problem.

To address these issues in the medium-term, *transmission reinforcement* is the most practical approach to cope effectively with demand-supply balance and transmission overloading issues, arising as a result of lack of adequate transmission capacity. The system overload is alleviated by increasing the power handling capacity of existing bottlenecked transmission lines without altering the right-of ways. Various line capacity reinforcement options can be exercised on an overloaded line, to increase its power handling capacity. Depending on the type and the amount of transmission line overloading [48, 49, 50], some of the reinforcement options such as, series compensation, reconductoring, duplexing, adding new circuits or even voltage upgrading of lines, can be opted for.

The problem of transmission expansion planning can be categorized either as a long-term planning problem in which the decision making exercise spans over a horizon of 20-25 years or even more, and the transmission reinforcement planning (TRP) problem which typically span up to 5 years. In this thesis, the TRP problem has been considered in order to align it in the same time-frame as with the other issues that have been addressed in the different chapters of this thesis.

Kaltenbach *et. al.,* [51] suggested a long-term transmission planning procedure, which combines the otherwise separate computations of load flow, reliability analysis and economic evaluation. A linear model is developed that determines the line capacity additions required to meet the power injections. These are then checked for compliance with system reliability constraints, prior to evaluating the economic investment decisions.

Garver [47] identifies new circuit additions to relieve capacity shortages, using linear programming. The network estimation procedure is carried out in two stages of linear flow estimation and new circuit selection. The linear flow estimation method replaces the electrical network problem with linear programming problem, by making use of guide numbers and overloads. Minimization of losses results in a flow estimate that indicates the links on which a circuit should be constructed so as to minimize the new circuit mileage. Load flow estimation is subsequently carried out to ascertain the network capabilities for handling the power flows.

Lee [52] uses a branch-and-bound integer programming technique to solve a single-stage transmission expansion planning problem. The method reduces the computational burden by using a dc-load flow model. Serna [53] treats the transmission system as a transportation network and proposes a method comprising a simulation process for the calculation of the loss of load and a heuristic optimization process to select the reinforcement to the network. Thus the model provides an orderly means of examining the effect of addition of new lines to transmission network and selecting lines that makes greater contribution to system's economy. Villasana *et. al.,*[54] addresses long-term issues such as new load growth, siting of new generation and new voltage levels, *etc.,* by combining linear power flow and the transportation model.

Romero and Monticelli [55] propose a hierarchical decomposition approach for optimal transmission network expansion planning. The hierarchical approach solves the planning problem in three stages. Initially, it solves a relaxed problem; the relaxed constraints are then reintroduced as the final solution is approached.

Arriaga and Bayona [56] formulates the long-term expansion planning problem as a static optimization problem of minimizing the global annual cost of electricity production, which is obtained as a sum of the annualized network investment cost, the operation cost and the reliability cost. The solution arrives at an optimal plan, by taking advantage of natural decomposition between the investment and operation sub-modules.

In the context of deregulation, Shrestha and Fonseka [57] use system congestion as a driving force for transmission planning. Based on the level of system congestion, the need for network expansion is determined and a compromise between congestion cost and expansion cost is used to determine the optimal scheme for expansion.

In the medium-term context, the transmission expansion planning problem is typically transformed to the TRP problem where the existing system configuration is considered and the most suitable options for strengthening the bulk transmission system are examined. The reactive power planning problem can also be seen as a part of the TRP problem in the medium-term. Transmission reinforcement problems have been addressed in the context of vertically integrated systems in combination with medium-term operations scheduling in [5, 58]. The reinforcement of new lines are decided based on the duals of the transmission line constraints in [5] while the addition of new circuits is decided by implementing a mixed-integer optimization problem in [58].

Very recently, Gajbhiye *et. al.,* [48] propose an expert system approach to short-term transmission expansion planning. A rule-based network augmentation is carried out to reduce investment cost and alleviate the network congestion. The reactive power management issues are also addressed for voltage control. Three sets of rules are defined viz. MW control, Ampacity and, Reactive Power Management rules, to develop an expert system approach for multi-year transmission expansion planning.

Baldick and O'Neil [49] estimates the costs of strengthening system load supply capability through transmission reinforcement technologies without altering the right-of-ways. They compare the cost of transmission reinforcements, considering both thermal and MW capacity increments, with the cost of new corridor additions.

In the context of Ontario, the Ontario Power Authority (OPA) has presented the Integrated Power System Plan (IPSP) [8] in consultation with participating members of the Ontario electricity market (genco, discos, transco, *etc.*) and the IESO. This plan document describes the areas for investment needs and available options for possible reinforcement and expansion of the transmission system. The IPSP outlines that the transmission system needs to be strengthened in order to-

1) achieve the long-term supply mix targets
2) facilitate development of renewable energy sources [59]
3) facilitate phasing out of coal-based power plants (once system adequacy and reliability issues are taken care of) to address environmental concerns

4) increase the system operating efficiency, reduce transmission congestion and facilitate the integration of new generation in a cost effective way, maintaining system reliability

2.5 Concluding Remarks

This chapter discusses the pertinent medium-term operations issues of production and maintenance scheduling in power systems and brings out the changed paradigms of operation and the need for coordination of these functions by the ISO in the context of deregulation. Subsequently, the need for a locational reliability index is brought out, which can provide the ISO with critical information pertaining to the probability of serving the customer loads.

Thereafter, the medium-term planning issues are discussed with particular emphasis on transmission reinforcement which has not received adequate attention so far. A modest attempt is made in this chapter to review the literature on production-cum-maintenance scheduling, locational reliability and the TRP problems in order to develop an understanding of the issues and the state-of-art in the research in these pertinent subjects of medium-term operations and planning in power systems.

Chapter 3

Security Coordinated Maintenance Scheduling in Deregulation Based on Genco Contribution to Unserved Energy: Mathematical Model[1]

3.1 Introduction

This chapter presents a new approach to coordinated maintenance scheduling in the deregulated electricity market environment. The maintenance scheduling approach described here can ideally be termed as a *levelized reserve with network constraints* type of approach. In this method the gencos submit their respective maintenance schedules to the ISO. It can be realistically assumed that since the genco are operating in deregulated electricity markets, they would seek to maximize their medium-term profit from an optimal production-cum-maintenance scheduling program. These maintenance schedules are submitted to the ISO, which is responsible to ensure that the system security is maintained while taking into account the scheduled outages of generators provided by individual gencos' maintenance schedules. The ISO also takes into account the system demand balance over the medium-term, transmission line capacities, hydro energy availabilities and other related constraints, in its analysis of the system operation incorporating maintenance schedules.

It is to be noted that in this proposed framework, the ISO does not generate a maintenance schedule by itself, but instead it generates corrective signals for each individual genco, using information on bus-wise unserved energy, and hence directing them to alter their maintenance schedules in specific periods and re-submit. The proposed framework uses the concept of *domains* and *commons* [60, 61] to allocate the unserved energy at a bus. This unserved energy arises when gencos' maintenance schedules are considered, and these are allocated to a set of generators (and hence gencos) responsible for such unserved energy at various buses during a particular period over a year. The iterations

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[1] Some parts of this chapter has been published in-

H. Barot and K. Bhattacharya, S*ecurity coordinated maintenance scheduling in deregulation based on genco contribution to unserved energy,* IEEE Transactions of Power Systems, Vol. 23, No. 4, Nov. 2008, pp. 1871-1882. See Appendix D for the IEEE Copyright Form.

between the gencos and the ISO takes place until the coordination program has converged, and there is no unserved energy at any bus, or for any period, in the system.

In the present work, a new approach to security coordinated maintenance scheduling in deregulation is proposed. The basic functioning of the proposed procedure is as follows:

- First, the gencos submit their respective maintenance schedules to the ISO. It can be realistically assumed that the gencos, operating in deregulated electricity markets, seek to maximize their medium-term profit from a production-cum-maintenance scheduling program (*called the GMS Program*, Section-3.3.1).
- The ISO is responsible for ensuring system security and reliability while taking into account individual gencos' maintenance schedules. It considers the system demand-supply balance, transmission line capacities, hydro energy availabilities and other related constraints, in its medium-term operations coordination program (*called the OCP*, Section-3.3.2) for verification of individual genco maintenance schedules. At this stage, some unserved energy may arise, at certain buses and periods when considering the genco's maintenance schedules.
- The OCP calls an UPDATE algorithm (Section-3.4.2) which synthesizes corrective signals for specific defaulting gencos, using information on bus-wise unserved energy, and directing them to alter their maintenance schedules in specific periods.
- The UPDATE algorithm uses the concept of *domains* and *commons* [60] to determine the generating units (and hence gencos) accountable for the unserved energy at a bus. A novel contribution factor is then introduced to allocate the unserved energy, to the gencos accountable for it.
- The iterations between the gencos and the ISO takes place until the coordination program has converged, and there is no unserved energy at any bus, or for any period, in the system.

3.2 Overview of the Proposed Coordination Scheme

Fig.3.1 presents an overview of the proposed coordinated maintenance scheduling problem. The individual gencos will execute their respective GMS programs (*discussed in* Section-3.3.1) and the maintenance schedules are submitted to the ISO. The ISO executes the OCP program (*discussed in* Section-3.3.2) to ensure that the submitted schedules from all gencos, when put together, yield a feasible medium-term security constrained production and operations schedule for the system as a whole.

If the gencos' submitted maintenance schedules result in violation of system constraints, then, corrective signals are synthesized by the ISO and sent to those gencos which are accountable for the resultant unserved energy at various buses, because of their maintenance schedule, during a given period. The accountability of a genco to serve a specific load is computed using the novel generation contribution factor method and this information is used to trace back the source of the unserved energy at a bus and generate update signals for the defaulting gencos.

The gencos are directed to modify their maintenance schedules based on the corrective signals and re-submit to ISO. This iterative scheme is continued until a feasible medium-term production schedule is achieved by the ISO.

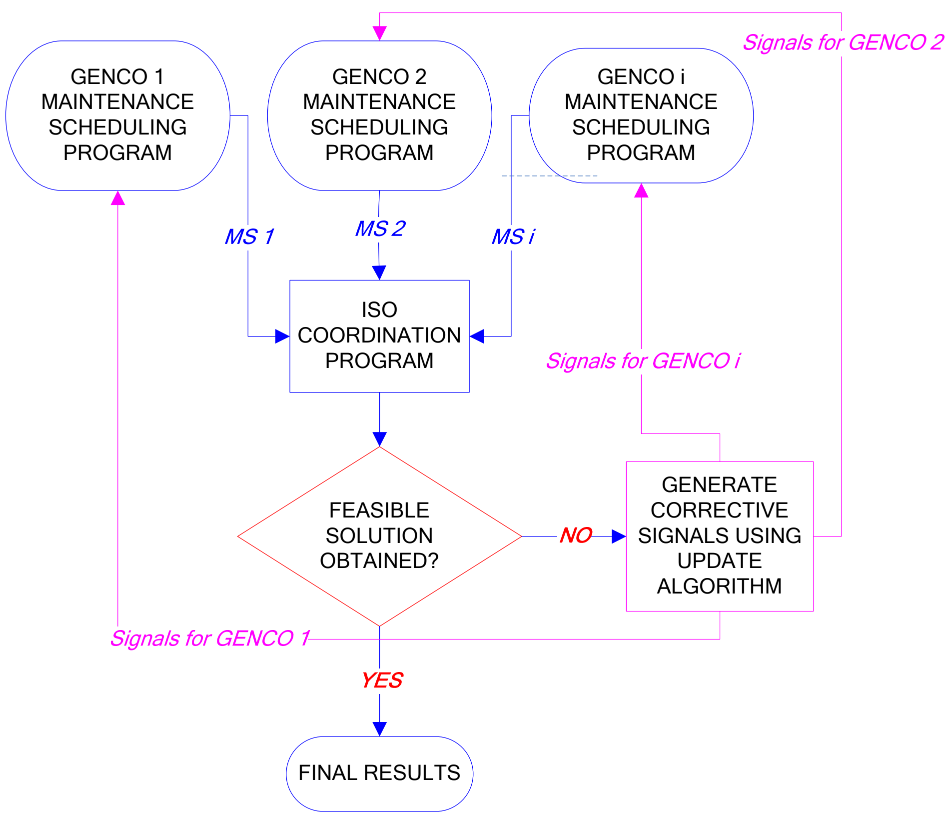

Figure 3.1 Flowchart Showing the Proposed Coordinated Maintenance Scheduling Approach

3.3 Mathematical Model Formulation

3.3.1 Genco Maintenance Scheduling (GMS) Program

The GMS Program is a mixed-integer linear programming model. In the first iteration, the model is solved without any intervention from the ISO. In subsequent iterations the GMS Program is solved taking into consideration the ISO's corrective signals, imposing hard constraints on unit maintenance schedules, if necessary.

3.3.1.1 Objective Function

A generic objective from the perspective of a specific genco *U*, is the maximization of its medium-term operating profit (3.1).

$$\begin{aligned}\Omega_U &= \sum_k \sum_t \sum_b \rho_{t,b} Pg_{k,t,b} T_{t,b} \\ &- \sum_k \sum_t \sum_b \left[(Cc_k W_{k,t,b} + Cg_k Pg_{k,t,b}) T_{t,b} + Cs_k S_{k,t,b} \right] \\ &- \sum_k \sum_t Cm_k Pg_k^{Max} X_{k,t}\end{aligned} \quad (3.1)$$

The first term of (3.1) denotes the gross revenue earnings of the genco in the medium-term assuming that it sells all its energy to the market. The medium-term market price is modeled using Price Duration Curves. Three price intervals, namely, peak, intermediate and base prices are assumed for each period (month) of the year. The second term denotes the genco's medium-term production costs comprising generators' no-load, variable and start-up costs. The third term represents the genco's gross maintenance costs over the year.

3.3.1.2 Constraints

3.3.1.3 Start-up Logic Constraints

These constraints, (3.2) and (3.3), enforce the start-up logic for generating units. Constraint (3.2) considers the change of status between the last sub-period of a period and the first sub-period of the following period while (3.3) takes care of the status change over two consecutive sub-periods of the same period.

$$W_{k,t,"Base"} - W_{k,t-1,"Peak"} \le S_{k,t,"Base"} \quad (3.2)$$

$$\forall t = 2,...12$$

$$W_{k,t,b} - W_{k,t,b-1} \leq S_{k,t,b} \tag{3.3}$$

$$\forall t = 1,..12 \qquad \forall b = \text{"Inter","P eak"}$$

3.3.1.4 Maintenance and Connection Status Constraint

This constraint ensures that a generating unit cannot be online when it is on maintenance.

$$X_{k,t} + W_{k,t,b} \leq 1 \tag{3.4}$$

3.3.1.5 Maximum and Minimum Generation Constraints

These constraints ensure that the generation is within their respective rated minimum and maximum capacities.

$$Pg_{k,t,b} \geq W_{k,t,b} Pg_k^{Min} \tag{3.5}$$

$$Pg_{k,t,b} \leq W_{k,t,b} Pg_k^{Max} \tag{3.6}$$

3.3.1.6 Maximum Outage Duration Constraint

This constraint ensures that each generating unit is on maintenance outage for a pre-specified period over the year.

$$\sum_t X_{k,t} = T1_k \tag{3.7}$$

3.3.1.7 Continuous Maintenance Check

Once a generating unit is offline for maintenance, it should return online only after the completion of its maintenance.

$$X_{k,t} - X_{k,t-1} \leq X_{k,t+(T1_k - 1)} \tag{3.8}$$

$$\text{such that} \quad X_{k,t} = 0 \quad \forall t \leq 0 \quad \text{and } \forall t > 12 \tag{3.9}$$

3.3.1.8 Maximum Number of Units on Simultaneous Maintenance within a Genco

This constraint ensures that only a specified numbers of generators are on simultaneous maintenance (because of crew availability) within a genco over a given period of time.

$$\sum_{k} X_{k,t} \leq NM_{t} \tag{3.10}$$

3.3.1.9 Hydro Energy Constraints

These constraints limit the energy scheduling from hydro generators depending on water availability in the reservoir over a given period of time. It is a simpler representation that captures the energy allocation to hydro units at a specific period, avoiding detailed reservoir balance constraints [4]-[5], [26], [32], [62]-[63].

$$\sum_{b} Pg_{h,t,b} T_{t,b} \leq \sum_{b} T_{t,b} Pg_{h}^{Max} E_{h,t} \tag{3.11}$$

The parameter $E_{h,\,t}$ representing hydro energy availability of unit h at period t can be assumed to be known to the ISO in the medium-term framework.

3.3.1.10 Maximum Allowable Capacity on Maintenance (Corrective Constraint)

This is a conditional security constraint externally imposed by the ISO in the second and subsequent GMS Program iterations of some specific gencos u ($u \in U$), if they have to receive a corrective signal from the ISO. The constraint ensures that genco u modifies its maintenance schedule by limiting its total capacity on maintenance during the ISO-specified period m to a certain maximum value. In (3.12) γ is the corrective signal (in MW) to genco u (specifying the allowable maximum capacity on maintenance in a particular period). The details of synthesis and handling of this corrective signal is discussed in Sections-3.4.2 and 3.4.3.

$$\sum_{k} X_{k,t} \times Pg_{k}^{Max} \leq \gamma_{u} \qquad \forall \quad t \in m \tag{3.12}$$

It should be pointed out that the GMS Program described by (3.1)–(3.12) is fairly similar to the genco-level maintenance scheduling model in [7] except for the conditional constraint (3.12). These maintenance scheduling models are fairly well established and accepted widely. They are linear mixed integer type optimization problems and can be solved using various available solvers, such as CPLEX. Therefore, the main emphasis of this work is to develop the coordination mechanism between the gencos and the ISO after the individual maintenance schedules are obtained.

3.3.2 Operations Coordination Program (OCP) of the ISO

The OCP executed by the ISO is very similar to the production scheduling models discussed in [4] and [5].

3.3.2.1 Objective Function

The ISO's objective function in the OCP is minimization of total system cost which includes total cost of generation (first term in 3.13) and the cost of unserved energy (second term in 3.13). It is assumed that the ISO would mandate that gencos submit their medium-term operating costs (Cg) along with their initial maintenance schedules.

$$\begin{aligned} Cost &= \sum_{t}\sum_{b}\sum_{i}\sum_{K} Pg_{K,i,t,b}\, Cg_{K,i}\, T_{t,b} \\ &\quad + \sum_{t}\sum_{b}\sum_{i} En_{i,t,b} \times Cn_{t,b} \end{aligned} \tag{3.13}$$

3.3.2.2 Constraints

3.3.2.3 Supply-Demand Balance Constraint

Constraint (3.14) ensures that the energy demand at a bus for given sub-periods (*peak, intermediate or base*) is met by generation at the bus and power imported (net of exports). This is a linear (transportation model) representation of power flows, with line losses modeled using a loss factor that is a function of line voltage class [4], [5], [26], [56], [63]-[64].

$$\begin{aligned} &\left[\sum_{K} Pg_{K,i,t,b}\left(1-Aux_{K}\right)\right] T_{t,b} + \left[\sum_{l}\sum_{j}(1-LF^{l}_{i,j}) \times P^{l}_{j,i,t,b}\right] T_{t,b} \\ &- \left[\sum_{l}\sum_{j} P^{l}_{i,j,t,b}\right] T_{t,b} + En_{i,t,b} = PD_{i,t,b} T_{t,b} \end{aligned} \tag{3.14}$$

3.3.2.4 System Reserve Requirement

This constraint ensures that the overall system has enough generating capacity in service at all times and some amount of reserve (as a fixed percent of demand) is available.

$$\sum_{i}\sum_{K}\left(1-X_{K,t}\right) Pg^{Max}_{K,i} \geq \sum_{i} PD_{i,t,b} + RSV_{t,b} \tag{3.15}$$

3.3.2.5 Generation Capacity Constraints

$$Pg_{K,i,t,b} \le \left(1 - X_{K,t}\right) Pg_{K,i}^{Max} \tag{3.16}$$

$$Pg_{K,i,t,b} \ge \left(1 - X_{K,t}\right) Pg_{K,i}^{Min} \tag{3.17}$$

3.3.2.6 Hydro Energy Constraint

This constraint ensures that energy generated from a hydro unit H, is limited by hydro energy availability over a period *t*.

$$\sum_{b} Pg_{H,i,t,b} \cdot T_{t,b} \le \sum_{b} Pg_{H}^{Max} \cdot T_{t,b} \cdot E_{H,t} \tag{3.18}$$

3.3.2.7 Line Capacity Constraints

The power flows on transmission lines are constrained by line capacities which depend on the transmission line voltage.

$$P_{i,j,t,b}^{l} \le TL_{i,j}^{l} \times P_{l}^{Max} \tag{3.19}$$

$$P_{i,j,t,b}^{l} = 0 \qquad \forall\ TL_{i,j}^{l} = 0 \tag{3.20}$$

3.4 Coordination Scheme Based on Gencos' Contribution to Loads

The coordination scheme for the ISO is based on determining a gencos' accountability to the unserved energy at a bus. These accountabilities are derived using the concept of *commons* and *domains*. Subsequently corrective signals are derived for these gencos to modify their maintenance schedules. The complete iterative procedure of coordinated maintenance scheduling can essentially be divided into three modules and is described in the following sub-sections.

3.4.1 Verification Process

After the gencos submit their maintenance schedules to the ISO, the ISO executes the OCP, given by (3.13)-(3.20), by incorporating these decisions as inputs and verifies whether the medium-term operations schedule for the whole system is feasible, that system security (line limits) is not violated and the system meets the demand at all times (*no unserved energy at any bus*). The master program of the complete iterative scheme is given in Fig. 3.2 while the UPDATE algorithm for synthesizing the corrective signals is given in Fig. 3.3.

When the ISO executes the OCP, the system may not be able to cater to the load in certain periods (or sub-periods) when large capacity generators are on maintenance simultaneously. The consequent bus-wise unserved energy is determined for every sub-period *b* of period *t*. From this, the maximum unserved power (Pn^{Max}_{m}) and the corresponding period *m* ($m \in t$) are noted. We can also determine the set of buses *N1* that contributes to Pn^{Max}_{m} in period *m*, and the bus-wise distribution of Pn^{Max}_{m}, denoted by $Pn_{i,\, m}$. It is obvious that the unserved power at a bus is either due to network constraints or shortage of generation capacity. Under some circumstances, network congestion can also be attributed to the unserved power at a bus.

According to the concept of domains and commons [60], if a group of generators (G) is responsible to serve a particular load at a bus *i*, then the same group G is responsible for not supplying the load at bus *i*. Further elaborating, if G experiences a percentage capacity outage, there will be a proportionate unserved power at bus *i*. Therefore, when an unserved power is observed at the bus *i*, it can be proportionately allocated to the responsible generators in G and hence the responsible gencos.

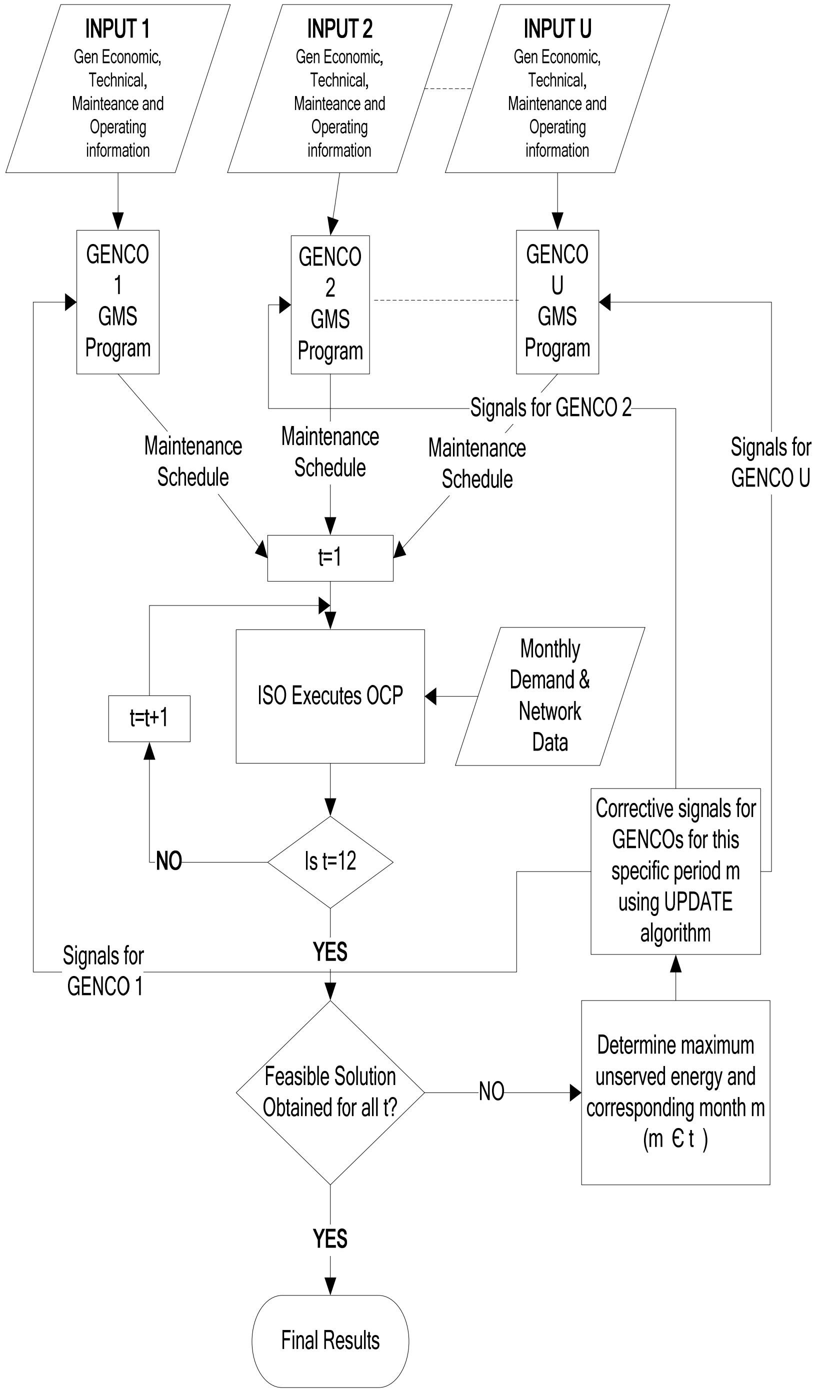

Figure 3.2 Flowchart of the Coordinated Maintenance Scheduling– Master Program

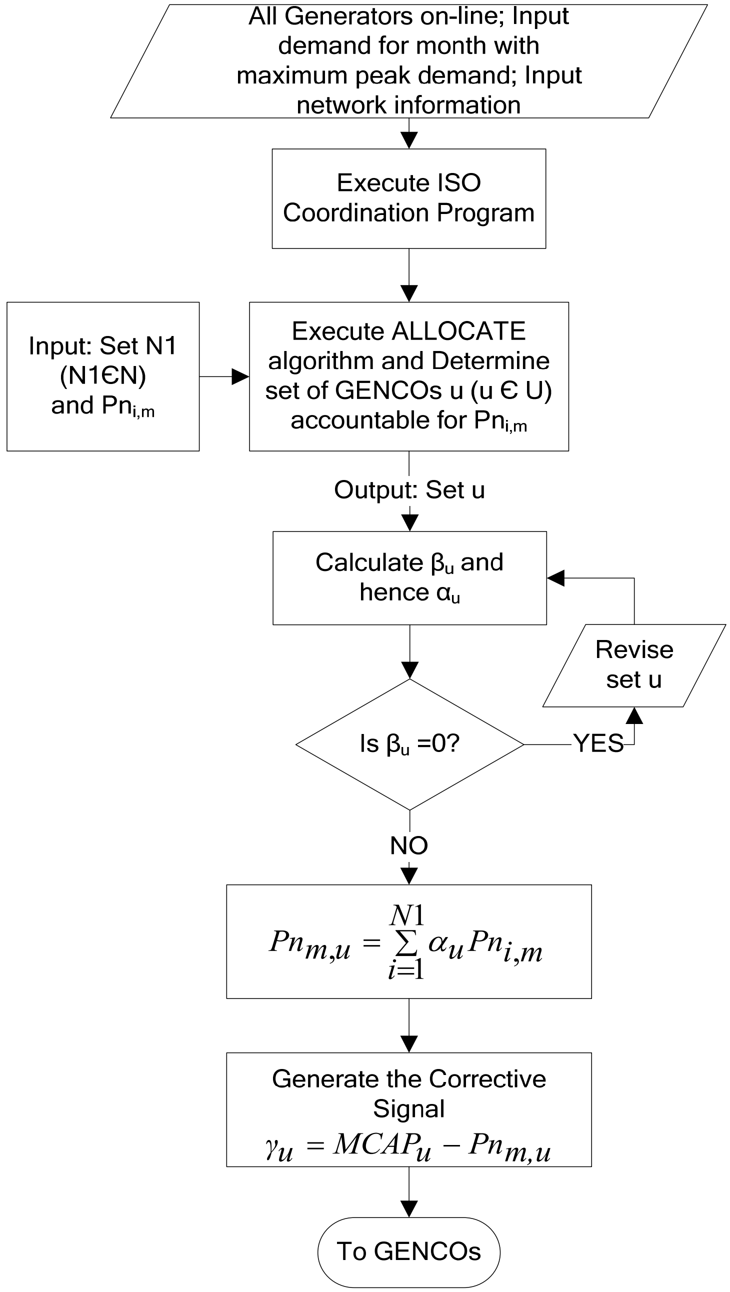

Figure 3.3 Flowchart of the UPDATE Algorithm

3.4.2 Synthesis of Corrective Signal- UPDATE Algorithm

The generating units (and hence the gencos) responsible for the unserved power at various buses are determined using the UPDATE algorithm (Fig. 3.3), and the ISO synthesizes appropriate signals for them to update their maintenance schedules. The following steps are used:

a. Call ALLOCATE algorithm (*Section-3.4.2.1*)

   Inputs: Set of buses N1 ($N1 \in N$) which have unserved power at period m; the unserved power $Pn_{i,m}$, ($i \in N1$); other outputs of OCP such as line power flows and production schedules.

   Outputs: Set of gencos u ($u \in U$) corresponding to each bus $N1$ responsible for $Pn_{i,m}$.

b. Define Fractional Capacity on Maintenance (β_u) for the set of gencos u, as follows:

$$\beta_u = \frac{MCAP_u}{TCAP_u} \tag{3.21}$$

   β_u represents the fractional capacity of a genco u on maintenance during period m.

c. Determine the proportionality constant α_u (3.22) to allocate bus-wise unserved power to each genco u in proportion to its Fractional Capacity on Maintenance.

$$\alpha_u = \frac{\beta_u}{\sum_u \beta_u} \tag{3.22}$$

d. Use α_u to allocate the bus-wise unserved power to genco u as follows:

$$Pn_{i,m,u} = \alpha_u \cdot Pn_{i,m} \tag{3.23}$$

e. Accumulate contributions of each genco u in total unserved power for the period m.

$$Pn_{m,u} = \sum_{i=1}^{N1} Pn_{i,m,u} \tag{3.24}$$

f. Calculate the maximum allowable capacity on maintenance (γ_u) for a genco during period m. This is the update signal synthesized by the ISO which will be sent to the set of gencos u ($u \in U$).

$$\gamma_u = MCAP_u - Pn_{m,u} \tag{3.25}$$

3.4.2.1 ALLOCATE Algorithm- Generators Accountable for Unserved Energy

The concept of *domains* and *commons* was proposed in [60] to determine the set of generators that supply a load at a particular bus. The ALLOCATE algorithm is developed based on the same concept, but to determine the set of generators that are accountable for unserved power at a bus.

A generator *k* connected to the system and injecting power in the network contributes simultaneously to loads at several buses. A *domain* can be defined as that set of buses in the system which can be reached by *k*, and this set is known as the *domain list* of *k* denoted by DL_k. Since the power demand at a bus may be catered by more than one generator, it can be expected that the domain list of one generator may contain buses that exist in the domain list of another.

To obtain a unique set of buses without overlap, the notion of *common* is formulated using the domain lists of all *k*. A common can be defined as the set of buses that are supplied by the same group of generators. The common is designated by $C_{p,kL}$ where *p* is the index of the common and *kL* represents a unique group of generators that supply member buses of common *p*. Fig. 3.4 and 3.5, presents the complete procedure for determining the domains of all generators in the system and then determining the commons. The steps followed to construct the domain list are:

a. From the set of generator buses *NG,* the first available generator bus, corresponding to generators *K*, is placed in the 'To Be Domain List' of *K* ($TBDL_K$).
b. Transfer the first bus in $TBDL_K$ to the domain list (DL_K).
c. Examine branches connected to this bus *i* and the power flow directions in each branch. These power flows are obtained from the OCP, for the period with maximum peak load, and all generators online.
d. If the power is flowing out of a branch at bus *i*, then the opposite end bus is added to $TBDL_K$.
e. If any bus exists in $TBDL_K$ and is not part of DL_K, then repeat from Step-b. If no buses are left in $TBDL_K$, then the domain list DL_K is complete.
f. If all *NG* are not considered, repeat from Step-a to determine DL_K for all K.

After the domain list DL_K is obtained, for all *K* ($\forall$ U), the steps to formulate the commons are as follows

a. With DL_K ($\forall K$) known, group the set of generators *kL* contributing to load at a bus *i*. Do this for all *i* ($i \in N$).

b. For all N, take a bus i and if this bus is not a part of any common $C_{p,\, kL}$, then create a new common corresponding to kL supplying the load at i.

c. Determine branches connecting to i and for every branch if the opposite-end bus is supplied by kL, then put the opposite-end bus in $C_{p,kL}$.

d. Repeat from Step-b, until all buses are considered.

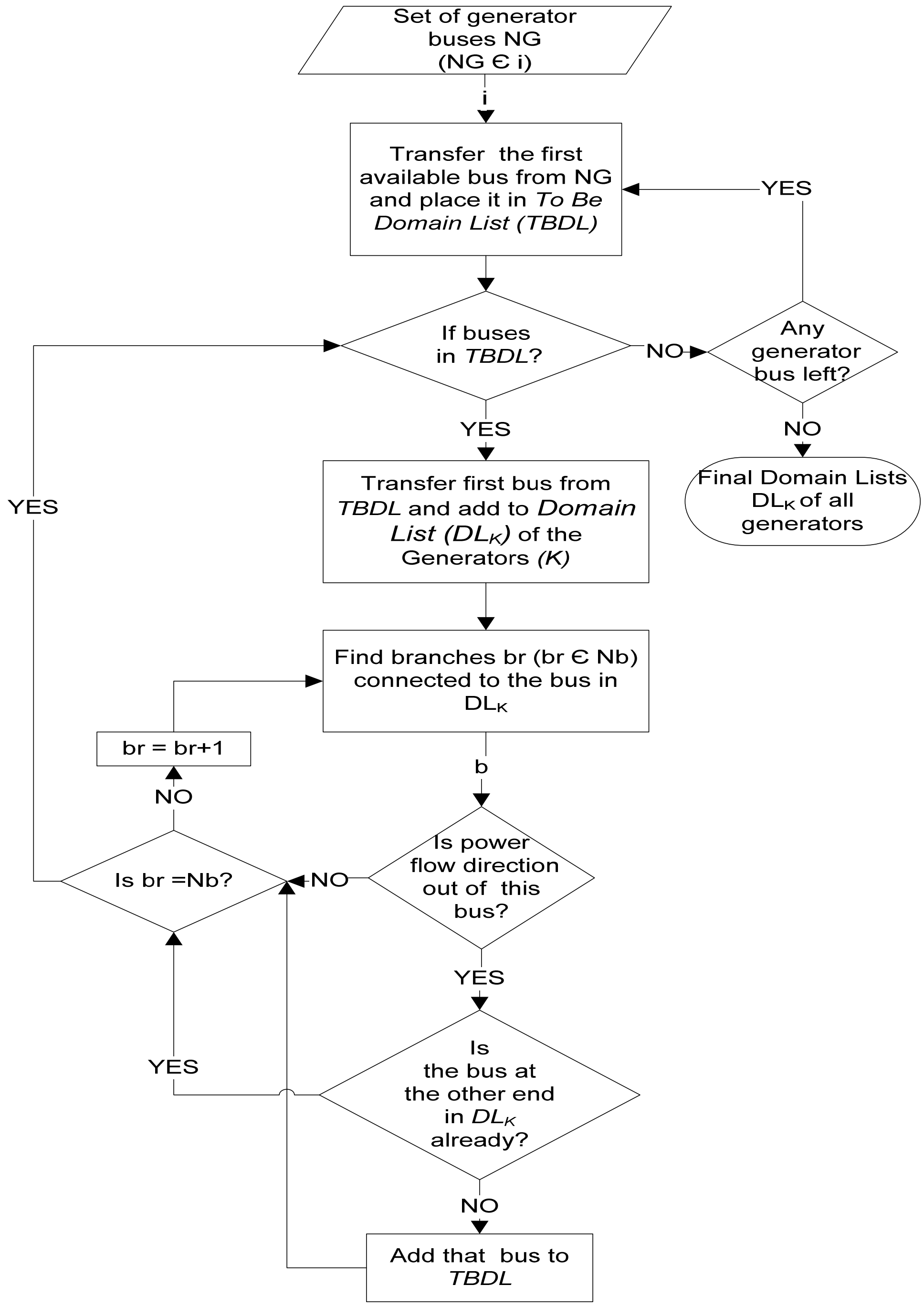

Figure 3.4 Flowchart of the ALLOCATE Algorithm (*first section*)

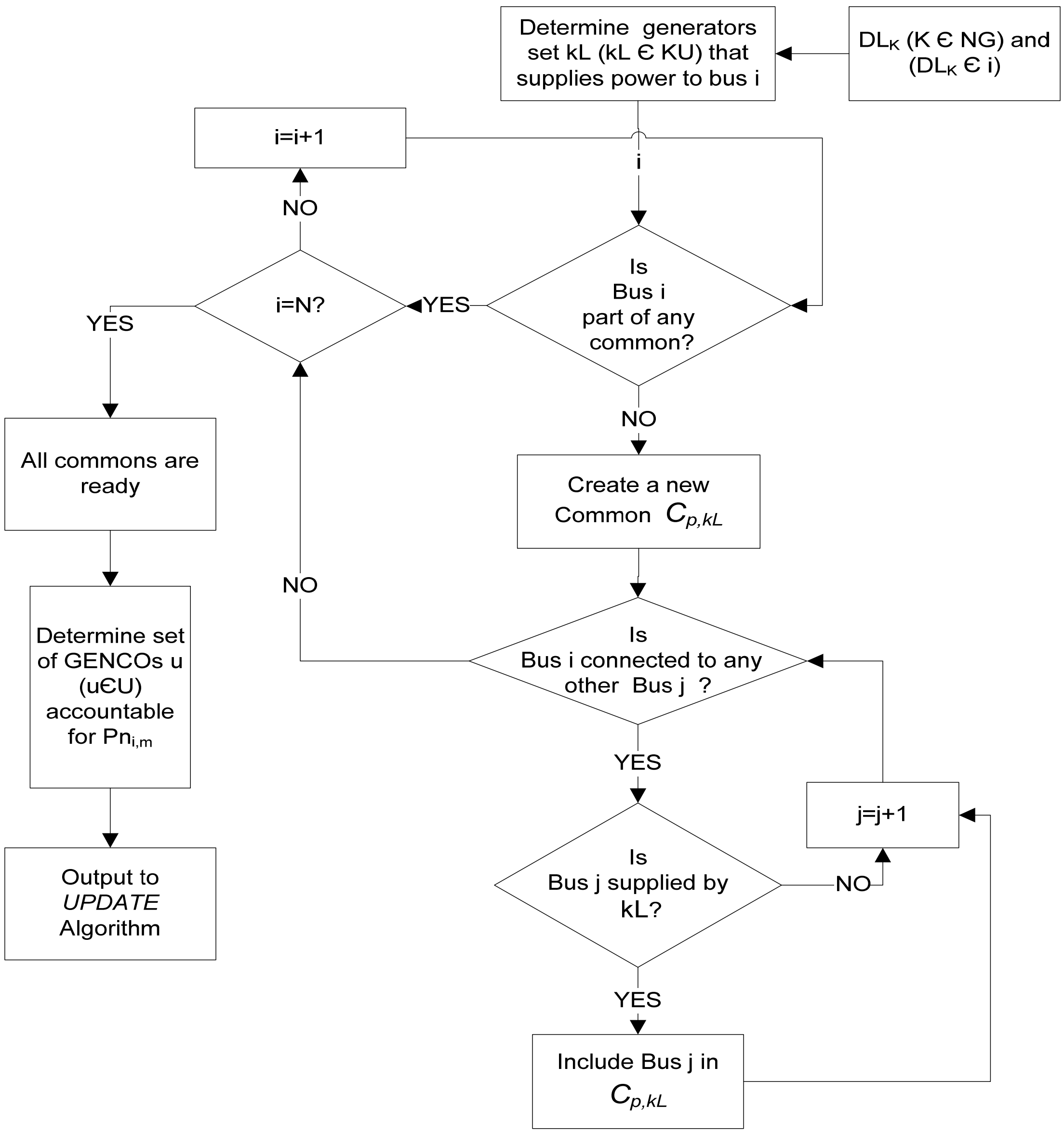

Figure 3.5 Flowchart of the ALLOCATE Algorithm (*second section*)

3.4.3 Handling of Corrective Signals by a Genco

On receiving a corrective signal γ_u (*a specified maximum allowable capacity on maintenance*) from the ISO, the particular genco-*u* incorporates it as a *corrective constraint* for period *m* (3.12). The constraint (3.12) is applied to period *m* as a *hard constraint* for subsequent iterations. This ensures that period *m* does not default again, as the period with maximum unserved energy. The process of modifying schedules, re-submitting, verification and synthesis of corrective signals is repeated until a feasible solution is obtained. The feasible solution is one when there is no unserved energy at any bus, at any period. On convergence, the final results are processed that contains a medium-term production schedule for all gencos and their generators, an approved final maintenance schedule for all gencos and other information on line power flows, bus marginal costs, *etc.*

3.4.4 Accelerating the Convergence Process

The proposed security coordinated maintenance scheduling scheme is an iterative process and fast convergence to a feasible solution is critical. To accelerate the convergence process, corrective signals are synthesized and corrective constraints can be applied to the top two defaulting periods (*m* and *m'*) simultaneously if the unserved powers at these periods are close in magnitude in a given iteration. A simple algorithm is used, as shown in Fig.3.6 that decides whether to constrain one or two periods simultaneously.

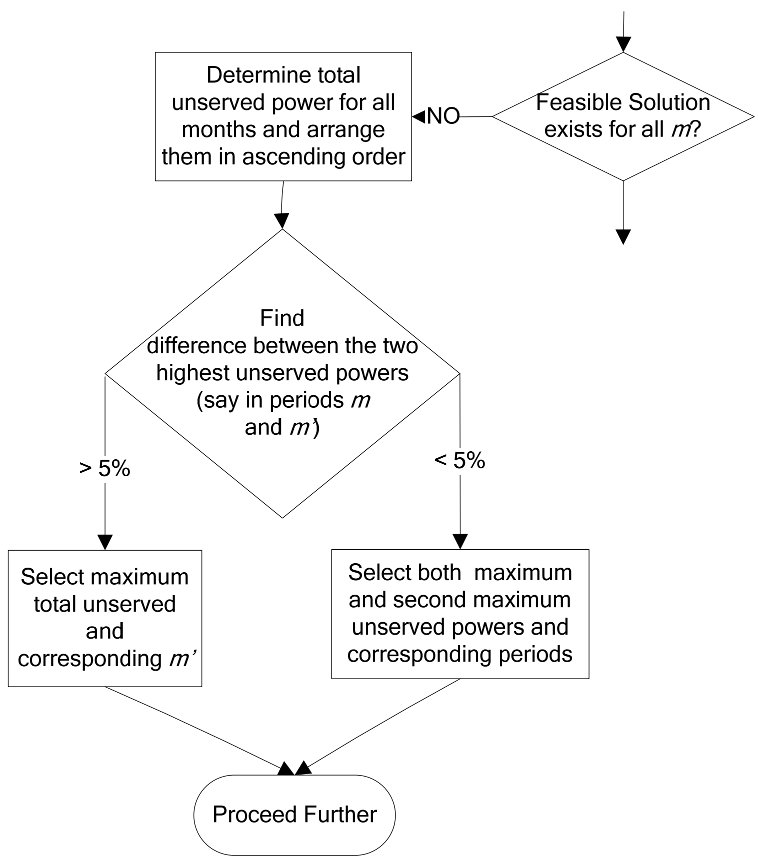

Figure 3.6 Flowchart for Acceleration of the Convergence

3.5 Concluding Remarks

This chapter presents a new scheme for security coordinated maintenance-cum-production scheduling for multiple gencos operating in the deregulated market environment. The coordination is carried out by the ISO after individual gencos submit their preliminary maintenance schedules. Based on the calculation of gencos' accountability to system unserved energy, the ISO computes and synthesizes corrective signals to defaulting gencos and these are incorporated by these gencos as hard constraints in their revised maintenance schedules. The final solution so obtained, is the set of genco schedules that maximize their respective profits while meeting system security constraints implemented via line flow limits for different voltage classes, along with other system constraints. The medium-term production schedules that are also obtained from the same scheme can be used by the gencos as guidelines for their medium-term operations.

In the next chapter, a detailed case study has been presented by considering a representative Ontario power system data set to bring out the important aspects of the proposed scheme and to examine the performance of this coordination mechanism.

Chapter 4

Security Coordinated Maintenance Scheduling in Deregulation Based on Genco Contribution to Unserved Energy: Ontario Based Example[1]

4.1 Ontario Based Example: Data Acquisition and Processing

A 57-Bus Ontario power grid system considering 500 kV, 220 kV and 115 kV voltage levels is used for the coordinated production and maintenance scheduling studies discussed in Chapter-3. The transmission specific data is obtained from the IESO, Hydro One and OPA web-sites [65]-[67]. The individual genco specific data has been constructed by the author, for the purpose of these studies, because of the difficulties associated in obtaining private cost information of generators from individual gencos. However, these are fairly generic in nature and can be easily replaced by actual data, if available.

4.1.1 Gencos' Profiles

For the sake of the analysis, genco profiles are constructed that approximately match the total installed capacity in Ontario of 25,620 MW. A total of 37 generators are considered, spread over 13 generating buses. These generating units are considered to be owned by three different gencos for the purpose of the coordinated maintenance scheduling problem. Genco-1 and genco-2 are assumed to own 9 generating units each, with total generating capacities of 4270 MW and 5950 MW respectively. Genco-1 has a fully thermal-based portfolio while genco-2 is a wholly hydro-based utility. Genco-3 is considered to own 19 generating units with a total capacity of 15,400 MW with a diverse supply mix of coal-fired thermal (580 MW), gas-fired (1530 MW), hydro (1690 MW) and nuclear (11,600 MW) units.

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[1] Some parts of this chapter has been published in-

H. Barot and K. Bhattacharya, S*ecurity coordinated maintenance scheduling in deregulation based on genco contribution to unserved energy,* IEEE Transactions of Power Systems, Vol. 23, No. 4, Nov. 2008, pp. 1871-1882. See Appendix D for the IEEE Copyright Form.

The data pertaining to their maintenance duration and number of units to be on simultaneous maintenance are designed based on the practices adopted in IEEE Reliability Test System Data [68, 69].

4.1.2 Network Data of Ontario

The transmission network of the Ontario system covering the 500 kV, 220 kV and 115 kV lines is used. A brief summary of the transmission system data is given below:

Total number of buses = 57

- Buses with generators connected = 13
- 500 kV buses = 13
- 220 kV buses = 28
- 115 kV buses = 16

Total number of transmission lines = 159

- 500 kV lines = 16
- 220 kV lines = 78
- 115 kV lines = 65

4.1.3 Assumptions

For the proposed coordinated maintenance scheduling scheme, the following assumptions are made

1. The ISO has information on average production costs of all generators (supplied by gencos).
2. Gencos are mandated to abide by ISO's instructions when system reliability and security are the issues (when there is unserved energy in the system).

4.1.4 Time Period of Medium-Term Operations Problem

The time-horizon for the medium-term operations and maintenance scheduling scheme under consideration is one year. This horizon is divided into 12 periods, each spanning one month. The month again is sub-divided into *Base*, *Intermediate* and *Peak* load sub-periods based on the electricity demand in the system

4.1.5 Price Information from Ontario Market

The weighted monthly average of the peak Ontario Hourly Energy Price (HOEP) for the year 2004 is taken [65] as the base-price to define the price of energy (ρ) in the security coordinated maintenance scheduling model. These prices are used to derive the appropriate medium-term price duration curve for peak, intermediate and base load conditions. Fig. 4.1 shows the average monthly peak HOEP variation in the year 2004.

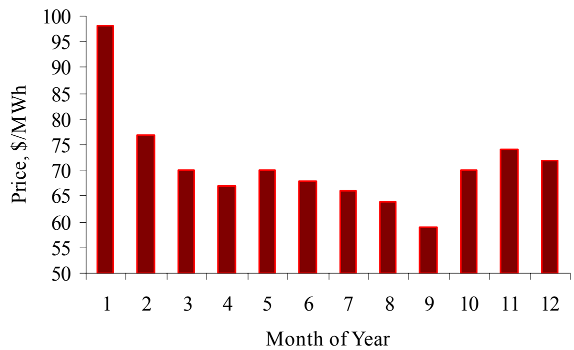

Figure 4.1 Average Peak Monthly HOEP in 2004

4.1.6 The Cost of Unserved Energy (Cn)

The cost of unserved energy (Cn) typically represents the cost of substitute energy, which could be from expensive generation sources (such as diesel generators) or the payment that the ISO makes for interrupted power. In this work we have considered *Cn* to be varying between \$1,500/MWh to \$2,500/MWh over the 12 monthly periods for base-load, between \$2,250/MWh to \$3,750/MWh during intermediate-load and between \$3,750/MWh to \$6,250/MWh during peak load sub-periods.

4.1.7 Ontario System Demand

The actual month-wise total energy demand of Ontario for 2004 is shown in Fig.4.2 from which monthly Load Scaling Factors are derived and applied to a bus-wise annual peak demand-data obtained from [65]. This gives the bus-wise monthly peak demand data for the whole system. Thereafter, a second scaling factor was applied to derive the month-wise intermediate and base demand data for every bus.

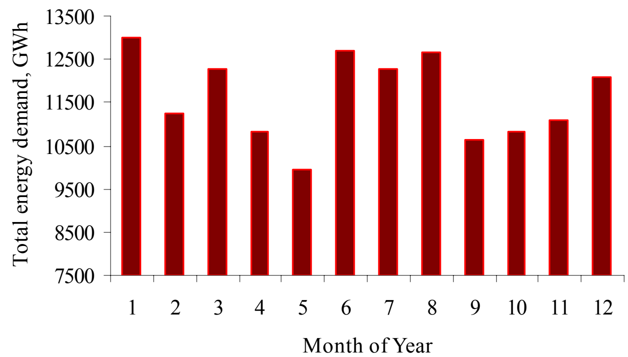

Figure 4.2 Actual Month-wise Total Energy Demand in Ontario in 2004

4.1.8 Hydro Energy Availability

It is also interesting to understand the hydro energy availability of the gencos, particularly for genco-2 which is a fully hydro-based utility. Fig.4.3 shows the hydro energy availability considered for genco-2 for 2004. It is seen that the utility has its maximum hydro availability during the months 6 to 9 (typically June to September).

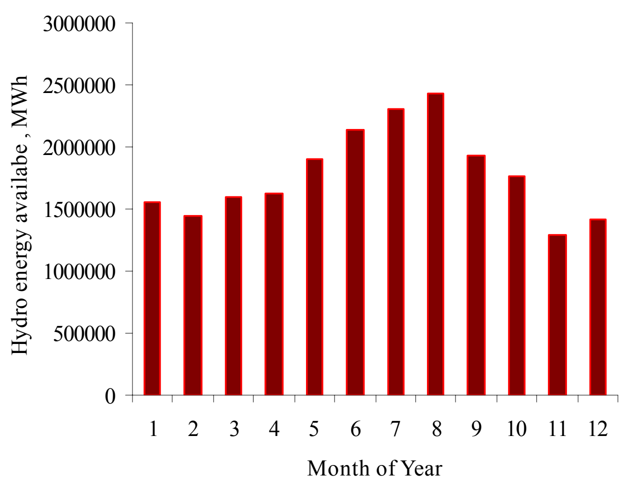

Figure 4.3 Actual Month-wise Hydro Energy Available in Ontario in 2004

4.2 Results and Discussions

Based on the mathematical formulation of the security coordinated maintenance scheduling scheme discussed in Chapter 3, and using the case-study data presented in Section-4.1, detailed simulation studies are carried out and the results are discussed in this section.

4.2.1 Calculation of Commons

Table-4.1 shows the *commons* calculated using the ALLOCATE algorithm described in Chapter 3, Section-3.4.2.1 for the Ontario system data used for the studies. In Table-4.1, p denotes the index of the common in the first column. The second column represents the set of generator buses kL ($kL \in KU$) corresponding to a common $C_{p,kL}$. This set (kL) is found by first determining the domain list for all generator buses and then grouping the set of generator buses contributing to all load buses.

For example, consider the common pertaining to $p=9$. There are four generator buses (*buses-4000, 6400, 6401, 7105*) which form the set kL corresponding to p=9. These generators in set kL, belong to gencos- U2 and U3 (as given in column-3). Column-4 corresponding to p=9 indicates the set of load buses which are supplied uniquely by set kL. This set of load buses form the *common* $C_{p,kL}$. Hence, we can write:

$$C_{9,\{4000,6400,6401,7105\}} = \{7300,7100,7108\}$$

In simple words, we can state that load buses 7300, 7100 and 7108 are uniquely supplied by generators connected at buses in set Kl. Using the same argument, the set of generating units accountable for the bus-wise and total unserved power for period m is determined, which is further used to synthesize the corrective signals as described in Section-3.4.2.

4.2.2 Initial and Final Maintenance Schedules

The initial maintenance schedules for each genco are obtained by individually executing the GMS program, maximizing their respective profits. The final security coordinated solution is obtained after five iterations and it provides the maintenance schedules of each genco, verified by the ISO, as well as their corresponding medium-term production schedules.

4.2.2.1 Genco-1 Maintenance Schedule

In Table-4.2 the initial maintenance schedule as obtained by genco-1 from its GMS program is given and then the final coordinated maintenance schedule is provided, which was obtained after the coordination scheme converged after five iterations.

Table 4.1 List of Commons

P	Set of generator buses (kL)	Genco owning generator bus kL	Common $C_{p, kL}$ (set of load buses supplied by generators buses kL)
1	1106	U1	1106
2	2007	U1	2007
3	2106	U1	2106
4	6400	U3	6400
5	7105	U2	7102, 7105, 7302, 7365
6	1106, 2007	U1	10, 103, 344, 1001
7	4000, 6400	U3	4000
8	4000, 6400, 6401	U2, U3	7000, 6401
9	4000, 6400, 6401, 7105	U2, U3	7300, 7100, 7108
10	4000, 5102, 6400, 6401	U2, U3	5102
11	4000, 5105, 6400, 6401	U2, U3	5105
12	4000, 4105, 6400, 6401, 7105	U2, U3	6402
13	4000, 5102, 5105, 6400, 6401, 7105	U2, U3	5404, 5103, 6500
14	4000, 4105, 5102, 5105, 6400, 6401	U2, U3	3107, 3108, 4100, 4105
15	4000, 5102, 5105, 6400, 6401	U2, U3	5003, 5135, 5403, 5690
16	2007, 4000, 4105, 5102, 5105, 6400, 6401	U1, U2, U3	2002
17	4000, 4105, 5102, 5105, 6400, 6401, 7105	U2, U3	6603, 6501
18	1106, 2007, 2106, 4000, 4105, 5102, 5105, 6400, 6401	U1, U2, U3	100, 1104, 1301, 2100, 3300, 3301
19	101, 1104, 2007, 2106, 4000, 4105, 5102, 5105, 6400, 6401	U1, U2, U3	101, 359
20	101, 1104, 2007, 2106, 4000, 4105, 5102, 5105, 6400, 6401, 7105, 8110	U1, U2, U3	8000, 8001, 8002, 8103, 8104, 8109, 8110, 8112, 8114, 8258
21	101, 1104, 2007, 2106, 4000, 4105, 5102, 5105, 6400, 6401, 7105, 8110, 9103	U1, U2, U3	9103, 9112, 9302, 9311

It is seen that for some generators, the initial and final schedules remain unchanged, *e.g.* unit-6 which is on maintenance during periods-7 and 8 in both cases.

It is further observed that in the initial maintenance schedule a total of 3,100 MW is on maintenance in month-7 and 2,400 MW in month-8, which can be attributed to the low market prices during these months. However, the final schedule has 1,900 MW and 1,170 MW capacities on maintenance in months 7 and 8 respectively. These are also high but are in line with genco-1's preference for maintenance during months 7 and 8. Hence the coordinated solution is not too drastically different from the initial maintenance preference of genco-1.

The notion of Fractional Capacity on Maintenance for a genco u (β_u) was introduced in Chapter 3, and was defined as:

$$\beta_u = \frac{MCAP_u}{TCAP_u} \tag{4.1}$$

Fig.4.4 shows β_u (*for u = genco-1*) for both the initial and final maintenance schedules. It is observed that the final coordinated schedule produces a flatter profile of β as compared to the initial maintenance schedule which yields high β-values during specific periods.

Table 4.2 Initial and Final Maintenance Status of Generators in Genco-1

Period	Initial Maintenance Schedule		Coordinated Maintenance Schedule	
	MCAP, MW	Units on Maintenance	MCAP, MW	Units on Maintenance
1	0	-	0	-
2	0	-	0	-
3	0	-	0	-
4	400	4,5	1700	8,9
5	0	-	1700	8,9
6	870	1,9	700	7
7	3100	6,7,8,9	1900	3,5,6,7
8	2400	6,7,8	1170	1,2,6
9	0	-	0	-
10	0	-	0	-
11	0	-	0	-
12	600	2,3	200	4

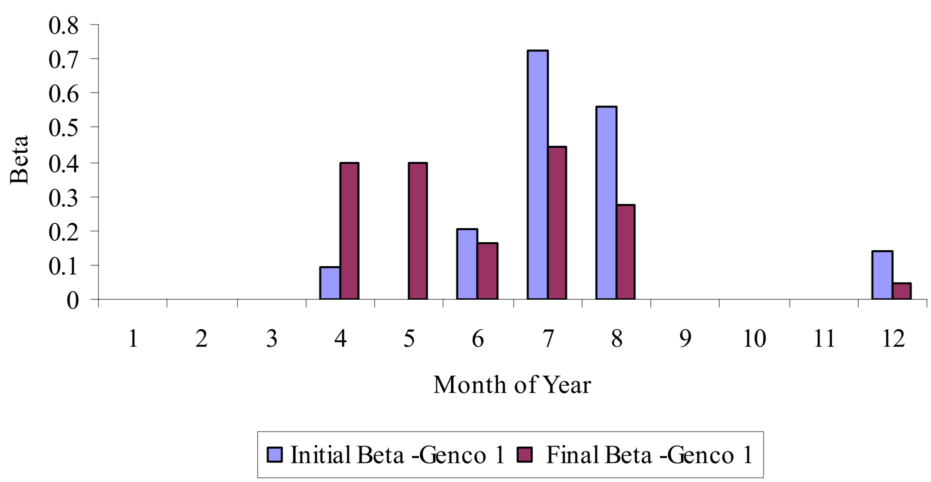

Figure 4.4 Fractional Capacity on Maintenance for Genco-1

4.2.2.2 Genco-2 Maintenance Schedule

The initial maintenance schedule of genco-2 (Table-4.3) shows that no generator is on maintenance during periods 6–9 because of the high availability of hydro energy during these months (*see Fig.4.3*) and understandably the genco seeks to maximize the utilization of its hydro generation. From its final coordinated maintenance schedule (Table-4.3), it is seen that 2,000 MW of capacity is now on maintenance in period-9 although periods 6-8 still do not have any unit on maintenance. The ISO coordinated schedule, can therefore be inferred, emphasizes more on maintenance during low demand months (4-5 and 9-11) when market prices are also low. Fig. 4.5 shows β_u (*for u = genco-2*) for both the initial and final maintenance schedules.

Table 4.3 Initial and Final Maintenance Status of Generators in Genco-2

Period	Initial Maintenance Schedule		Coordinated Maintenance Schedule	
	MCAP, MW	Units on Maintenance	MCAP, MW	Units on Maintenance
1	0	-	0	-
2	800	9	800	9
3	1800	6,9	800	9
4	2000	6,7	1450	3,6
5	1000	7	1000	6
6	0	-	0	-
7	0	-	0	-
8	0	-	0	-
9	0	-	2000	1,2,4,5
10	1500	1,2,8	1000	7
11	1150	3,8	1700	7, 8
12	1200	4,5	700	8

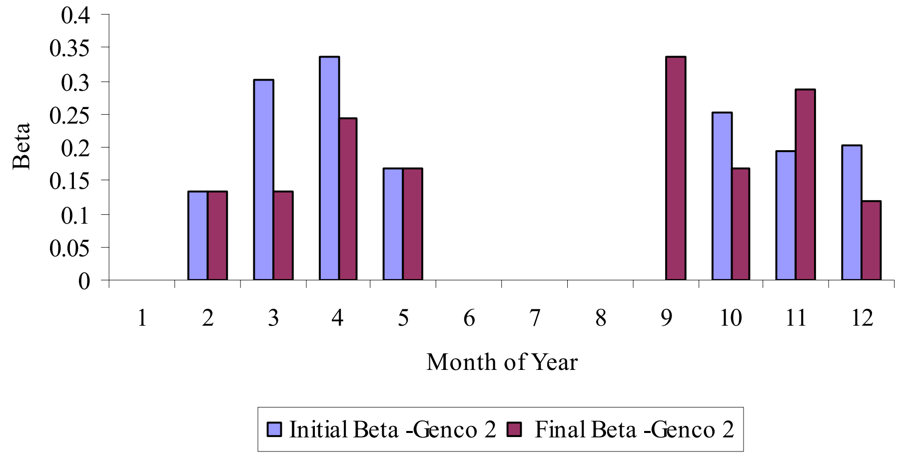

Figure 4.5 Fractional Capacity on Maintenance for Genco-2

4.2.2.3 Genco-3 Maintenance Schedule

In case of genco-3, it can be noted from a comparison of the initial and final schedules (Table-4.4) that the maintenance of nuclear units, particularly, underwent a significant shift of periods.

Note that nuclear generation capacity in genco-3 is 11,600 MW, which is made up of 7 units (units-12 to 18) each of 1,200 MW capacity and other 4 units (units-8 to 11) each of 800 MW capacity. It is seen that the large nuclear units-14, 16, 17 and 18 are on maintenance during the months 6-9. Such a clustering of the maintenance of large units during specific periods, as in the initial schedule, is not desirable because that results in shortage of power in those periods. Note that, as per the initial schedule, two nuclear units are always on maintenance between months 4 and 9, and in month-12, four nuclear units are on maintenance.

Table 4.4 Initial and Final Maintenance Status of Generators in Genco-3

Period	Initial Maintenance Schedule		Coordinated Maintenance Schedule	
	MCAP, MW	Units on Maintenance	MCAP, MW	Units on Maintenance
1	0	-	0	-
2	0	-	2400	14,15
3	1345	1,3,5,19	3200	8,14,15
4	2400	13,15	2400	12,17
5	2965	4,13,15	3245	6,12,17
6	2400	14,16	1410	4,6
7	2400	14,16	1765	3,18
8	2400	17,18	2000	10,18
9	3200	8,17,18	1750	2,16,19
10	1690	6,7	2045	7,16
11	3090	2,6,7,12	2275	5,7,13
12	3600	9,10,11,12	3000	1,9,11,13

Fig.4.6 shows β_u (*for u = genco-3*) for both the initial and final maintenance schedules along with their respective linear trend-lines. It is clear that the final schedule yields a flatter β-profile as compared to the initial schedule and hence implies that the maintenance schedule is more evenly distributed.

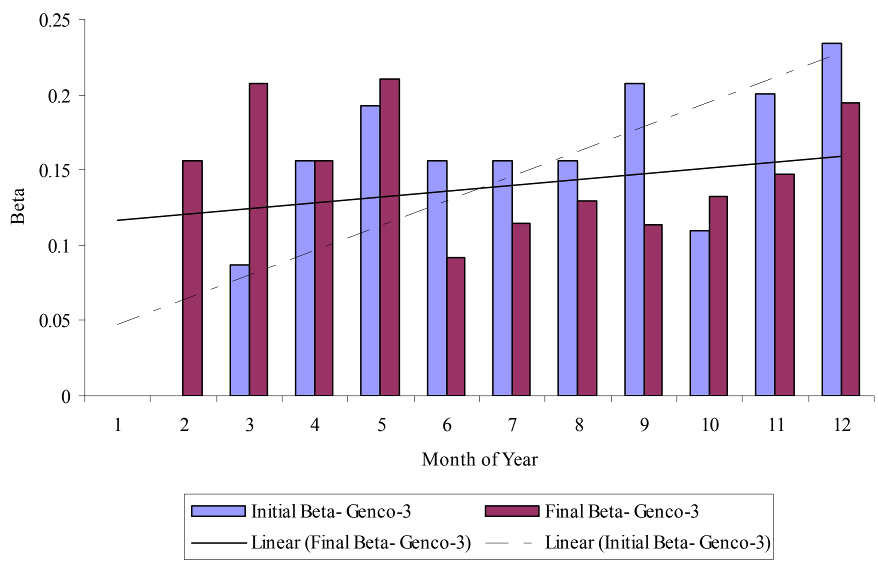

Figure 4.6 Fractional Capacity on Maintenance for Genco-3 with Trend-lines

4.2.2.4 Other Observations

An interesting observation is that the energy price in January (*period-1*) being very high (~$100/MWh), the gencos are reluctant to schedule (through GMS program) any unit on maintenance in January, since they seek to maximize their profit. The security coordinated maintenance schedule also retains the same trend and no generator is on maintenance in January. This is because, high energy prices are usually driven by high energy demand in the system and hence from the ISO's perspective as well, no generator is scheduled for maintenance in January.

Because of this correlation between market price and system demand, the OCP also seeks to schedule it maintenance at low demand (and hence low price) periods. Thus the OCP acts in the same direction as the individual genco's GMS programs. Therefore, although the gencos and the ISO have different objectives, they do not conflict or contradict each other.

4.2.2.5 Capacity Available and Peak Load

Figure 4.7 shows a month-wise comparison of peak demand and system capacity after the initial and coordinated solutions while Fig .4.8 shows the resulting system reserves in the two cases. It is seen from the figures that after the initial solution, peak demand for months 7, 8 and 12 is higher than system capacity available, implying a negative reserve condition in the system. Also, month-6 has a very low reserve available. This is attributed to over maintenance commitments by gencos during these months.

On the other hand, the security coordinated maintenance schedule results in adequate generation capacity and a fairly levelized profile of reserves at all months. This flattening of the system reserves profile, translates to the flattening of β, discussed earlier, and is a desirable feature achieved through the coordination scheme.

The coordination approach therefore provides very satisfactory results and is simple, logical and fair to all gencos. If the initial maintenance schedules of gencos are implemented without coordination with the ISO, there will be peak deficit in the system in some periods.

This suggests that the coordination process in maintenance scheduling is very critical in deregulated electricity markets from system operational security viewpoint.

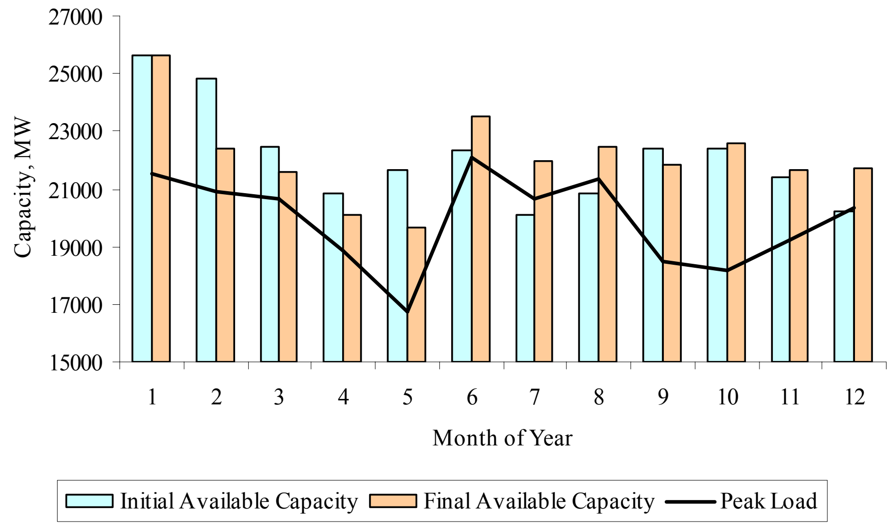

Figure 4.7 System Demand and Total Capacity Available from Initial and Coordinated Maintenance Schedule

4.2.2.6 Costs and Profits

We also examine the total system cost and the net profit of each genco as the OCP iterative process progresses. The first OCP run, based on initial submission of maintenance schedules from gencos, is termed as the *Base* iteration. Thereafter it took five iterations for the process to converge to a feasible solution. A feasible solution refers to the case where there is no unserved energy at any bus.

The system cost and the genco profits are given in Table-4.5. It is seen that the profit of the individual gencos are reduced marginally from the Base solution to the final security coordinated solution. The highest reduction in profit is for genco-3 by 0.623%, whereas the system cost is significantly reduced to the order of 77.5%. The significant reduction in total system cost is attributed to the reduction, and finally, elimination of unserved energy from the system as the coordination process progresses towards convergence. It is also understandable that the gencos' profits will decrease with OCP iterations. The Base iteration was the case when each genco maximized its profit, without any system constraints, and hence the profits were at their maximum. The profits thereafter decrease because the gencos have to modify their maintenance schedules as additional constraints are imposed by the ISO.

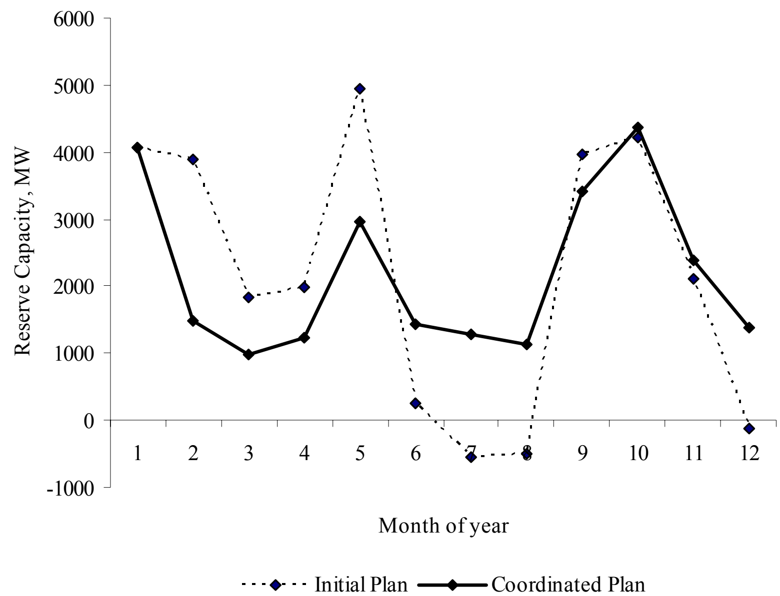

Figure 4.8 System Reserves after Initial and Coordinated Maintenance Schedules

Table-4.6 shows the iteration-wise corrective signals sent to different gencos and the period at which the signal is applied. This corrective signal- the maximum allowable capacity on maintenance, acts as a hard constraint, incorporated in the next iteration by the respective gencos.

In order to accelerate the convergence process, corrective signals are synthesized and corrective constraints are applied to top two defaulting periods (*m* and *m'*) simultaneously if the unserved power at these periods are close in magnitude in a given iteration. For example, from Table 4.6 it is seen that after Base iteration, genco-1 receives two corrective signals for periods 7 and 8 prescribing the maximum allowable capacity on maintenance to be 2,335 MW and 1,680 MW respectively.

Table 4.5 System Cost and Genco's Profit Variation with Iterations

Iteration	Profit of GENCO 1 (billion \$)	Profit of GENCO 2 (billion \$)	Profit of GENCO 3 (billion \$)	System Cost (billion \$)
Base	1.207	1.0793	5.5043	4.4
1	1.203	1.0799	5.501	5.01
2	1.2025	1.0766	5.483	1.92
3	1.202	1.0732	5.488	1.35
4	1.2019	1.076	5.481	2.3
5 (Final Coordinated Solution)	1.2018	1.075	5.47	0.99
% Change from Base	**-0.43**	**-0.4**	**-0.623**	**-77.5**

4.2.3 Production Schedules

An outcome of the GMS Program for a genco is its medium-term production schedule (PS) along with its maintenance schedule but since the gencos seek to maximize the net profit without considering the system demand, these PS are not practicable. On the other hand, the OCP outputs a set of PS from the overall system energy-supply balance perspective, for the gencos, in every iteration, seeking to minimize the total system cost subject to security and other system consraints. Hence after the convergence of the OCP, the PS generated thereby is practical, feasible, security coordinated and implementable by gencos.

Table 4.6 Corrective Signals for Gencos

Derived after Iteration	Period in which corrective signal is applied	Corrective signal (maximum allowable capacity on maintenance), γ, MW		
		Genco 1	Genco 2	Genco 3
Base	7	2335	-	2280
	8	1680	-	2260
1	12	200	880	3500
2	6	900	-	2200
3	2	-	1650	2900
4	3	-	1100	3400
5	None	-	-	-

Figs. 4.9-4.11 shows a comparison of three PS cases for each genco as discussed below:

a) Initial Genco PS- that obtained from GMS program by individual gencos based on profit maximizing maintenance scheduling without considering any ISO intervention or coordination.

b) Final Genco PS- that obtained from the GMS program by individual gencos which leads to the convergence of the coordination scheme.

c) Coordinated PS- that obtained from the OCP by the ISO after the coordination scheme has converged.

In the case of genco-1 (Fig. 4.9), it is seen that the Initial Genco PS and the Final Genco PS are somewhat different from the Coordinated PS essentially because the later takes into account the balance between the system demand and supply, whereas the first two are obtained from the genco's perspective of profit maximization without due consideration of the demand. Note that in the Coordinated PS, units are less utilized during the base sub-period as compared to intermediate and peak. This is because genco-1 has the highest operating costs amongst the three utilities and hence is not utilized as much for the base load.

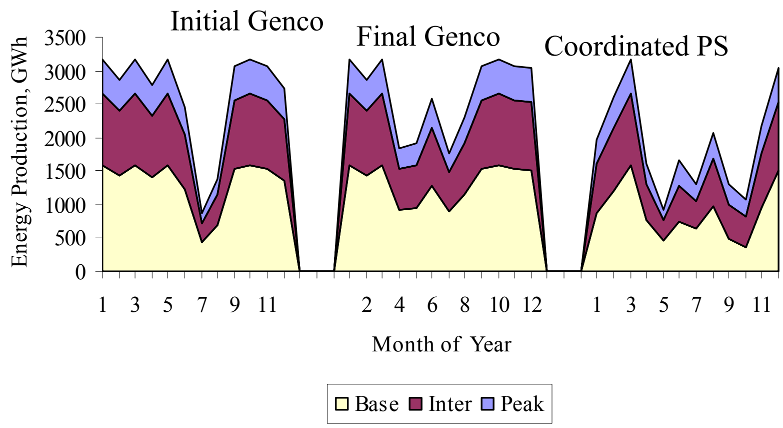

Figure 4.9 Comparison of Various Production Schedules of Genco-1 (Total Capacity = 4,270 MW)

In Fig. 4.10, a similar analysis is presented for genco-2, which is a hydro-based utility with gross capacity of 5950 MW, and its PS is generally constrained by water availability over the year. It is not advisable for such a utility to schedule its units for maintenance during high hydro availability months. This is also true from ISO's viewpoint, because hydro generation is cheaper than any other source. The PS shows that utilization of hydro resources is fairly consistent throughout the year for all the cases. This genco also operates as an intermediate and peak-load utility with very little base-load generation. Interestingly, the base-load generation is somewhat increased in the Coordinated PS as compared to the PS determined by the genco itself (Initial PS and Final PS). The increase in base load generation in the Coordinated PS is to balance the reduction in base-load generation of genco-1, observed in Fig. 4.9. Note that the total production from genco-2 attains a peak during months-6, 7 and 8 because of the high hydro energy availability during these periods.

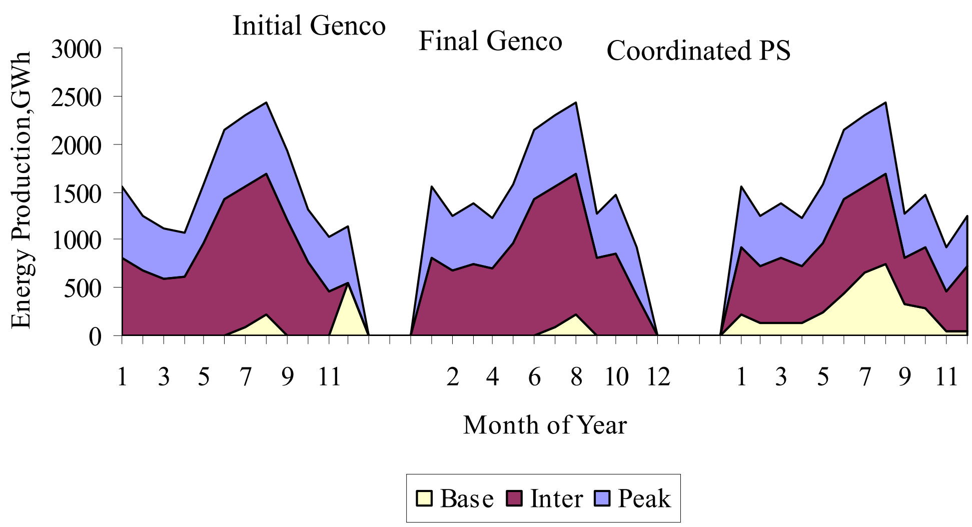

Figure 4.10 Comparison of Various Production Schedules of Genco-2 (Total Capacity = 5,950 MW)

Fig.4.11 shows a comparison of three PS cases for genco-3 which are fairly similar. Genco-3 being a large utility with pre-dominantly nuclear generation (about 48%), it is utilized to its full capacity and supplies most of the base-load demand of the system.

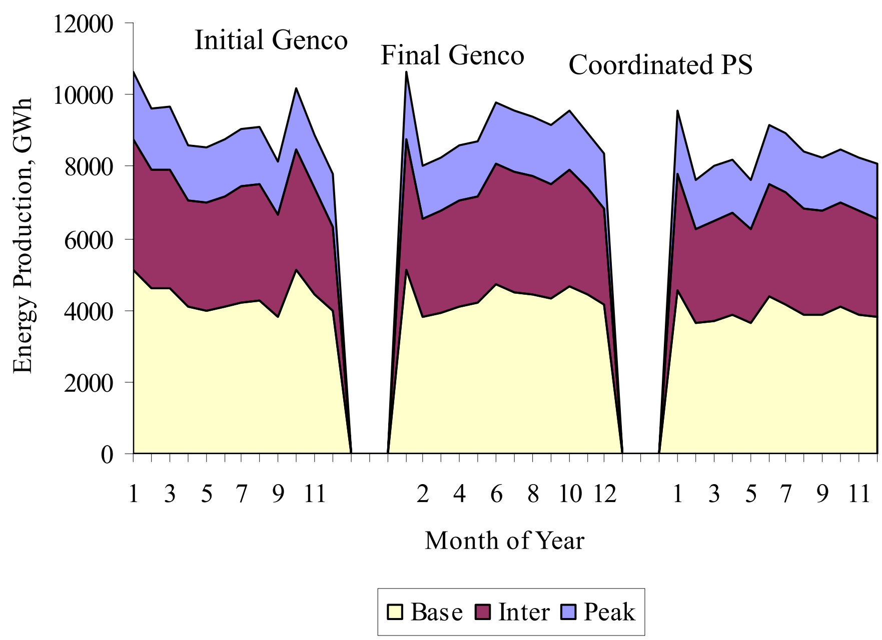

Figure 4.11 Comparison of Various Production Schedules of Genco-3 (Total Capacity = 15,400 MW)

A careful study reveals that the small changes between the initial and final PS, for a few of the periods, can be attributed to alteration of maintenance schedules. For example, month-12 which had a low initial scheduled generation has a higher schedule in the Coordinated PS.

4.3 Computational Details

In this sub-section, the details of the computational burden involved in the coordinated maintenance scheduling scheme is discussed.

The GMS programs are linear mixed-integer optimization models and are solved using the CPLEX solver in GAMS [70] environment. All the GMS programs pertaining to individual gencos have 10 equation-blocks representing the various constraints.

The OCP is a fairly large-scale linear programming model with a large number of constraints, arising because of the transmission limits at multiple voltage levels and other constraints. This model is also solved very efficiently using the CPLEX solver in GAMS environment.

The CPLEX solver is very efficient to handle such optimization models. Table-4.7 provides the details of the size of the mathematical models. The whole scheme is solved on a standard Intel Xeon processor with 3 GB RAM.

Table 4.7 Computational Details of Optimization Problems

Event	Genco-1 GMS	Genco-2 GMS	Genco-3 GMS	OCP
Equation Blocks	10	10	11	9
Variable Blocks	5	5	5	4
Single equations	1,750	1,858	3,699	1,389,601
Single variables	1,081	1,081	2,281	442,657
Non zero elements	5,286	5,538	11,170	2,338,885
Discrete variables	756	756	1596	-
Model Generation time(sec)	0.031	0.015	0.047	17.19
Model Execution time (sec)	0.031	0.031	0.047	17.21

4.4 Concluding Remarks

In this chapter, a detailed case study is presented to demonstrate the application of the security coordinated approach to generator maintenance scheduling problem in deregulation. The detailed mathematical formulation and the coordination scheme are proposed in Chapter 3. The case study approximates the Ontario power system, as a simplified 57-bus representation. Three gencos are considered which are assumed to be players operating in the competitive electricity market environment and operating with profit maximization objective. The ISO coordinates the maintenance schedules and also arrives at an optimal medium-term production schedule that takes into account system security and other relevant system constraints.

The proposed scheme is very efficient and converges within five iterations. The scheme has the advantage of being fair, logical, understandable and simple. It also takes into consideration the gencos' individual maintenance schedules, and tries to retain these schedules as far as possible, unless it is absolutely important from system security considerations, to request for their modifications.

Chapter 5

Load Service Probability Differentiated Nodal Pricing in Power Systems[1]

5.1 Introduction

In Chapters-3 and 4, one of the important medium-term operational issues of production-cum-maintenance scheduling and its coordination amongst several gencos, by the ISO was presented. In this chapter another important question is addressed – that of – whether there is a need to consider the issue of customer's locations in the power system when the utility provides service to them. In other words, whether the reliability of the load service provided by the utility varies across the system - from bus to bus- and if so, how the LMPs, which are determined from market auctions, affected by such variations. It also answer the important question of how the LMPs be differentiated by the load service probability so that it is fair to all customers.

In this Chapter, a new approach to determine bus-wise Load Service Probability (LSP) indices in power systems is presented. For example, using this index, one can precisely state that the LSP at bus-15 is 23.5 hours on a given day, while it is 23.2 hours at another bus-17, on the same day. Such bus-wise LSP information can be very valuable to customers, gencos and ISO. These LSP indices are arrived at by defining and computing, bus-wise *LOLP* ($LOLP_i$) indices, as explained in Section-5.3.3. The bus-wise LSP indices are thereafter utilized to formulate a novel proposition for LSP-differentiated LMPs for electricity markets.

Furthermore, the LMP variations across a set of power system buses are compared with the proposed bus-wise LSP indices. The LMPs would vary across the system buses because of the system load pattern, bus-wise load distribution, congestion on certain transmission lines or transmission losses. The proposed bus-wise LSP indices vary across the system buses because of differences in contribution of individual generators to serving the load at a given bus. Now, for a given bus *i*, LMP_i can be very high while LSP_i can be low which would indicate more chances of outage at bus *i*. In such a case, the LMP_i should be appropriately scaled to factor in the LSP so that the customers

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[1] Some parts of this chapter has been submitted for publication in-

- H. Barot and K. Bhattacharya, *Load service probability differentiated nodal pricing in power systems*, *IET Proceedings on Generation, Transmission and Distribution,* in revision.

located at bus-*i* are fairly priced. On the other hand, customers at a bus *j,* having a significantly low LMP_j but enjoying a high value of LSP_j should be charged a higher price.

The rest of the chapter is organized as follows: in Section-5.2 an overview of the proposed scheme is presented. Section-5.3 discusses the concept of locational LSP while Section-5.4 presents a case study and discusses the results so obtained. Section-5.5 provides the concluding remarks of the chapter.

5.2 The Proposed Load Service Probability Index

In order to determine the bus-wise LSP indices, first, a set of bus-wise LOLP indices are computed, denoted by $LOLP_i$, using the scheme shown in Fig.5.1. It is assumed that individual gencos would provide the ISO with information on their respective generating unit availability status, as appropriate.

Using this information, the ISO executes an OPF program to compute the power flows and transmission line loadings for a given load condition. Such detailed OPF computations can be very involving, particularly, for large systems. Moreover, for the sake of LMP calculations, only active power flows are sufficient. Therefore, simpler, linear power flow models can as well, be used by the ISO. In this thesis, the OCP presented in Chapter 3 has been used, which is a linear programming model of the system and determines the power flows for a given load condition while ignoring the reactive power flows and voltage constraints.

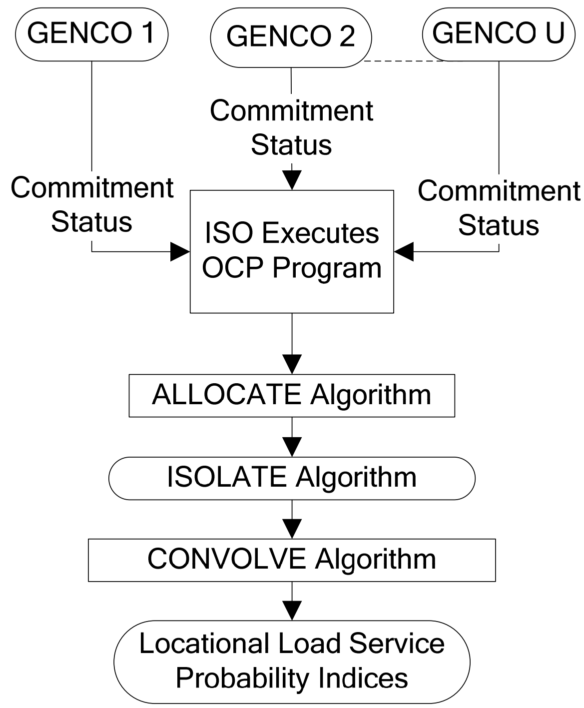

Figure 5.1 Schematic Overview of Computation of Bus-wise LSP

Using the transmission line power flows determined from the OCP, the ALLOCATE algorithm presented in Section-3.4.2.1 is executed to obtain the *domains* and *commons* for the system. (*The explanation for domains and commons is given in Section-3.4.2.1*). Using the domains and commons, the set GR_i is determined, which represents the *group of generators responsible for supplying the load at a bus i*.

The set GR_i and the power flow information obtained from OCP are used to calculate the contribution of generators to loads [60]**.** The ISOLATE algorithm determines the contribution factors of generators (*discussed in Sectio-5.3.2*) and hence arrives at an isolated bus representation of the system, assuming the load to remain constant for the period.

The last step in the proposed scheme is the CONVOLVE algorithm which is applied to each isolated load bus to calculate the cumulative outage probability of generators supplying a load at bus *i* and hence to determine $LOLP_i$. The bus-wise LSPs, *i.e.*, LSP_i are easily computed once $LOLP_i$ are determined, as explained in the next section.

5.3 The Concept of Locational Load Service Probability

5.3.1 Domains, Commons and the ALLOCATE Algorithm

The concept of domains and commons was proposed in [60] and explained in detail in Chapter 3, to determine the share of generators to the load being served. The ALLOCATE algorithm, presented in detail earlier, is used to determine the domains and commons. The commons also help in finding the contribution of a generator to a particular load making use of proportionality assumptions. The following terminologies and definitions are explained below, which were first introduced in [60]:

- *Rank* of common- denotes the number of generators supplying a specific common *i.e.* if two generators supplies a common then rank of the common is 2.
- The transmission lines can be classified as either being *internal* to a common or *external* to a common.
- *Link*- the set of external transmission lines connecting same commons.
  - Power flow directions in all transmission lines constituting a link, are always same.
  - The power always flows from a common of lower rank to a common of a higher rank in a link.
- The total power injection in a common is called the *inflow* of the common while the total power extraction (loads and power flows to other commons of higher ranks) is termed as *outflows* from a common.

It can be argued that if a set of generators Gr_i is responsible to serve the load at bus i, then Gr_i is also responsible for any load that remains unserved at bus i. Therefore, if any generator belonging to Gr_i experiences a capacity outage, there will be some unserved energy at bus i proportional to the capacity on outage, from within the set Gr_i.

5.3.2 Isolated Bus Representation of System

In an integrated power system, generators connected to generator buses supply various load buses through a mesh of transmission lines. The power delivered by each generator reaches a specific set of load buses, depending on the electrical properties of the available paths for power transmission.

Let us consider a generator G connected to generator bus g and having a capacity of P MW. From the principles of Kirchhoff's Laws and applying the concept of domains it can be determined that G supplies some load at specific buses, say, buses-1, 4, 5 and 6, for a given system condition. Therefore, it can be stated that the power P generated by G was shared by the loads at buses 1, 4, 5, and 6 in a certain proportion. If the load at bus-6 receives a% of P, we can assume that a generator of capacity (a*P/100) MW is instead connected at bus-6 and not at bus *g*. Extending the same principle, assume that the load at bus-6 is supplied by three generators of capacities P_1, P_2 and P_3 (connected at some generator buses in the system), in proportions of a_1%, a_2% and a_3% respectively. Then bus-6 can be considered to exist in isolation with three generators connected to it, with respective reduced capacities of (a_1*P_1/100), (a_2*P_2/100) and (a_3*P_3/100) MW (Fig. 5.2).

The integrated power system can therefore be viewed as a system of isolated load buses, each having a group of generators of proportionally reduced capacities, supplying the load locally.

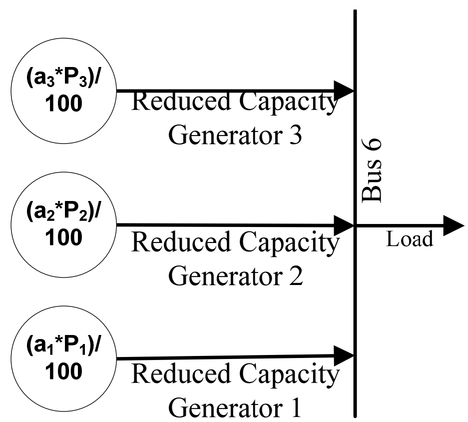

Figure 5.2 Isolated Bus Representation

5.3.2.1 ISOLATE Algorithm

When the domains and commons are determined for a given state of the power system, the electrical power system can be represented by a state diagram [60]. In the state diagram, the commons are represented as nodes and links are represented as branches with power flows that are in the direction from a common of lower rank to a common of higher rank. Therefore the state graph is always a directed graph that is acyclic in nature (*no closed path of flows*).

Using the state graph and the power flow information available from OCP, the contribution of generators to total outflows from a common is determined. The total outflows is the total load on the member buses of the common plus the power flowing out of a common to other commons of higher rank. Using the above calculated contribution of generators to total outflows, the contribution of generators relative to their own generation levels can be computed. This is used to allocate the reserve capacity of a generator to different commons and then to different load buses within the common to finally arrive at the isolated load bus representation. The complete algorithm is described below, and is depicted in Fig.5.3.

Let I_j be the inflow to the common j, which is the sum of power flowing out to other commons of higher rank and the total load of the common j.

$$I_j = \sum_p P_{j,p} + \sum_{\substack{i \\ i \in j}} PD_i \tag{5.1}$$

Where,

$P_{j,p}$ = Power flow over links from common j to common p

PD_i = Power demand at load bus i in common j

Then, the relative contribution of generator g to the inflow or total outflow of common j is given by,

$$C_{g,j} = \frac{AC_{g,j}}{I_j} \quad \forall \quad g \in Gr_i \tag{5.2}$$

$AC_{g,j}$ is the absolute contribution of generator g to inflow of common j. Let $P_{g,j,p}$ be the power flow over link between common j to common p (from j to p), due to generator g. Then,

$$P_{g,j,p} = C_{g,j} * P_{j,p} \quad \forall \quad g \in Gr_i \tag{5.3}$$

The contribution of generator g to the inflow or the total outflow of common p is denoted as $C_{g,p}$ and given by:

$$C_{g,p} = \frac{\sum_j P_{g,j,p}}{I_p} \quad \forall \quad g \in Gr_i \tag{5.4}$$

In (5.4) I_p is the inflow to common p. Let P_g be the power generated by generator g and P_g^{Max} be its generating capacity. Then, the absolute contribution of generator g to common p is given by:

$$AC_{g,p} = \left(\sum_m P_{p,m} + \sum_{\substack{i \\ i \in p}} PD_i \right) \cdot C_{g,p} \cdot R_g \quad \forall \quad g \in Gr_i \tag{5.5}$$

$$where, \; R_g = P_g^{Max} \big/ P_g$$

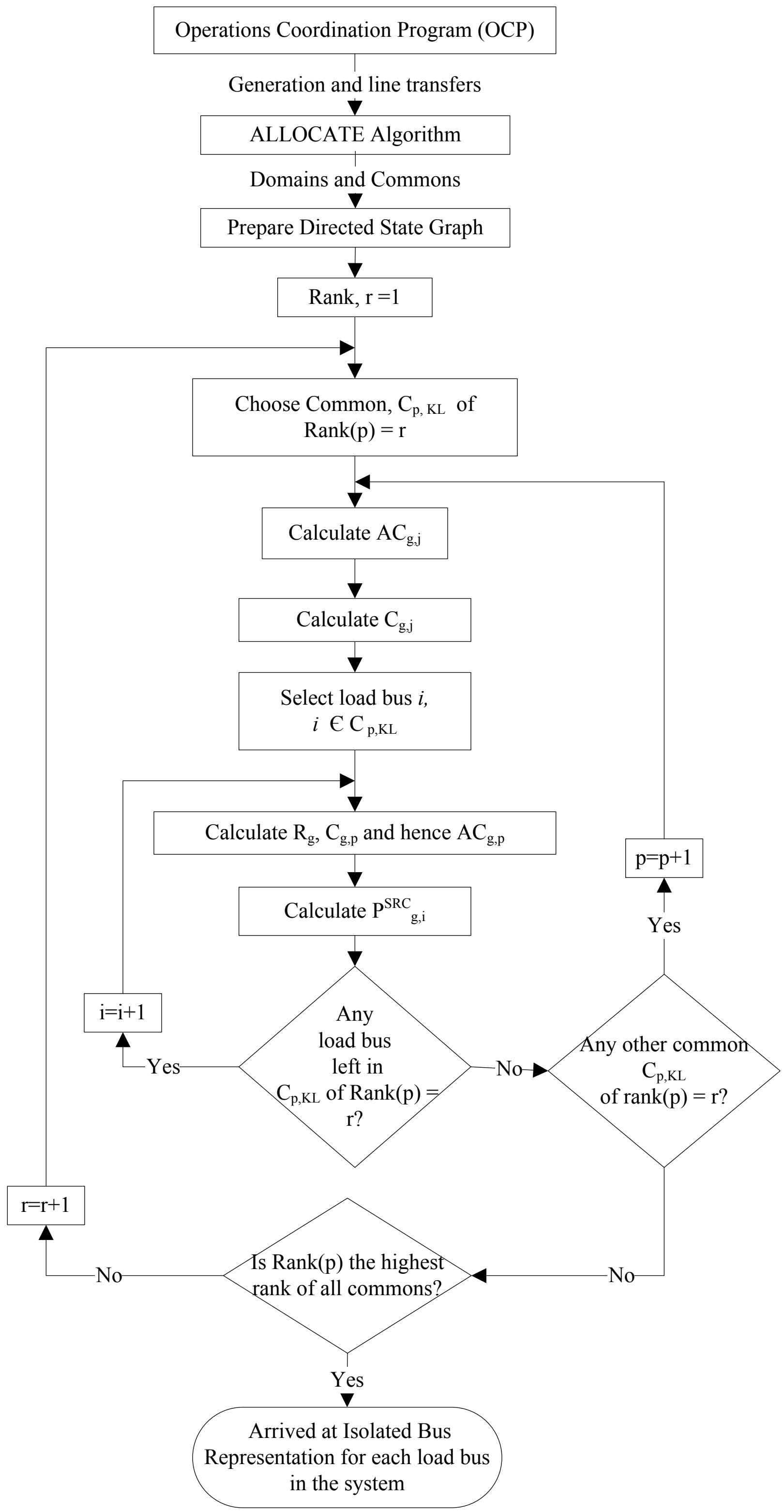

Figure 5.3 Schematic for Determining Isolated Bus Representation

Equation (5.5) proportionately allocates reserves available from a generator *g* to a common *p*. It is assumed here that the bus load remains unchanged during the period under consideration. For example, if the LMPs are calculated hourly, then the bus load is assumed to remain unchanged during the hour. On the other hand, if the LMPs are determined 5-minutes ahead, as in Ontario, the bus-loads are assumed to remain unchanged for the 5-minute interval under consideration.

Now from the proportionality assumption, if X_{gj} is the contribution of generator *g* to common *j*, it is also the contribution of generator *g* to every load bus in common *j* and henceforth generation capacity at each load bus can be obtained by reducing (5.5) to:

$$P_{g,i}^{SRC} = PD_i \cdot C_{g,p} \cdot R_g \qquad i \in p, \quad g \in Gr_i \tag{5.6}$$

In (5.6), $P_{g,i}^{SRC}$ is the *synthetically reduced capacity* (SRC) of generator *g* ($g \in Gr_i$) at load bus *i* in common *p.*

5.3.3 Locational Load Service Probability Indices

As per the procedures described so far, the entire power system can now be represented by a set of isolated load buses. The load at each isolated load bus is met locally by a corresponding set of SRC generators, Gr_i, depending on their individual contributions to the load. The $LOLP_i$ indices can thereafter be determined taking into account the Forced Outage Rates (FORs) of these SRC generators supplying each bus.

Consider a power system where generators are available as per their commitment status known *a priori*. Considering a security constrained system (*i.e.,* line limits are enforced), all the generators will generate power at their respective "scheduled generation levels". This generation level may be equal to or less than a generator's maximum generation capacity. If, from the isolated set of generators Gr_i responsible for supplying the load at the bus *i*, there is some capacity outage, the following events may take place:

1) The set Gr_i has some reserve capacity available and it can supply the load at bus-*i* by increasing its contribution, if line limits are not violated.
2) The set Gr_i does not have any reserve capacity available or the capacity outage is more than the reserve capacity available, the load at bus *i* will not be served.

Using this rational, the $LOLP_i$ indices can be formulated for a bus *i*. These indices are determined using the cumulative outage probability table of SRC generators, Gr_i, supplying load at bus *i.*

5.3.3.1 LOLP Convolution Algorithm and Calculating $LOLP_i$

The computation of $LOLP_i$ is carried out using the well known generating unit convolution algorithm [38] to develop the cumulative outage probability table. However, it should be noted that the main difference in the construction of the outage table is the use of Gr_i *(the set of SRC generators, pertaining to the load bus i)* instead of the total set of generating units with their full capacities. The convolution equations are given as follows:

$$\begin{aligned} &CPROB_i^{New}(X) = CPROB_i^{Old}(X) * (1 - FOR_n) + CPROB_i^{Old}(X-C) * FOR_n \\ &CPROB_i^{Old}(X-C) = 1 \quad \forall \ (X - C) \le 0 \end{aligned} \tag{5.7}$$

In (5.7), C_P is the cumulative outage probability of X MW or more of generating capacity on outage, C is the capacity of the next generating unit n being convolved, and FOR_n represents the forced outage rate of unit n.

From the cumulative outage probability table, $LOLP_i$ can be determined, assuming the load at bus i to remain constant for the period of study. The $LOLP_i$ is calculated for a value of X_0 that is the difference between the sum of capacities of SRC generating units in Gr_i and the load at the bus i.

$$LOLP_i = CPROB_i^{New}(X_0) \tag{5.8}$$

Where,

$$X_0 = \sum_g P_{g,i}^{SRC} - PD_i \quad g \in Gr_i \tag{5.9}$$

5.3.3.2 Locational Load Service Probability (LSP_i)

The bus-wise LSP, LSP_i, can be computed from $LOLP_i$ using the formula:

$$LSP_i = 1 - LOLP_i \tag{5.10}$$

As mentioned earlier, the LSP provides information to the ISO, customers and other market players as to what is the probability that the load at a bus i will be served, during the given period of market settlement. This information can be effectively integrated with the LMPs determined from energy market clearing to arrive at locational LSP differentiated nodal prices for the power system

5.3.4 Differential Locational Load Service Probability

Let us now refer to the classical system-level LOLP, referred to as $LOLP_{System}$ in this chapter to distinguish it from $LOLP_i$. The $LOLP_{System}$ can be determined using the CONVOLVE algorithm for the total system demand, assuming all generators are available. Once $LOLP_{System}$ is computed by the ISO, taking that as a reference, we define:

$$\Delta LOLP_i = LOLP_i - LOLP_{System} \tag{5.11}$$

The differential $LOLP_i$, defined by $\Delta LOLP_i$ in (5.11), indicates the probability of not serving the load at a bus as compared to the probability of not serving the total system load. Consequently, we can define the differential LSP_i as, ΔLSP_i, as follows:

$$\begin{aligned} \Delta LSP_i &= (1 - LSP_i) - (1 - LSP_{System}) \\ &= LSP_{System} - LSP_i \end{aligned} \tag{5.12}$$

5.3.5 LSP Differentiated Nodal Prices

From Section-5.3.4 the ΔLSP_i values are obtained for every bus in the system. The ΔLSP_i in (5.12) denotes the probability of serving the load at a bus as compared to the probability of serving the total system load. A positive value of ΔLSP_i at a bus indicates a deteriorated probability of serving the load at a bus as compared to the system LSP. Therefore, the LMP at a bus needs to be suitably adjusted-downwards. Similarly, when ΔLSP_i is negative, it indicates an enhanced load serving probability at the bus, compared to system LSP, and therefore the LMP at that bus needs to be suitably adjusted upwards.

It is proposed that the LMP at a bus be appropriately adjusted by using the ΔLSP_i values. A reverse scaling approach of the LMPs with respect to ΔLSP_i is proposed. The LSP differentiated LMP, denoted by $L\hat{M}P_i$ is given by (5.13) below.

$$L\hat{M}P_i = \frac{LMP_i}{\left(1 + \Delta LSP_i\right)} \tag{5.13}$$

From (5.13) it is observed that customers at buses with higher probability of load being served ($\Delta LSP_i < 0$) are charged a higher price than the LMP_i determined from market clearing. On the other hand, at those buses where the probability of load being served is lower ($\Delta LSP_i > 0$), the customers are charged lower than the market determined LMP_i.

It should be noted that in this chapter a simple method is used to demonstrate how the bus-wise LSP_i can be synthesized with the LMPs, and hence arrive at LSP differentiated LMPs. There can be other applications and usefulness of LSP_i, such as in power system planning where such locational indices can act as a signal for investments. There is a need for further research in this area to investigate how ideally the LMPs are scaled taking into account the LSPs.

5.4 Case Study

5.4.1 5-Bus Simple Power System Case Study

The proposed concept of LSP indices and hence the LSP-differentiated LMPs are now calculated for a simple 5-bus test power system to understand the steps and the methodology in a clear manner. The configuration of the 5-bus test system and the associated data are provided in the Appendix. The three generators connected at bus-1, bus-2 and bus-4 have forced outage rates as follows: $FOR_1 = 0.08$, $FOR_2 = 0.1$, $FOR_4 = 0.08$.

An OPF is executed to obtain the power flow information for the system and then the ALLOCATE algorithm is applied to determine the commons for the 5-bus test system, as given in Table-5.1. As an example, let us consider common $p=3$. The unique set {kL} of generator buses {1, 2, 4} supplies the member load buses {3, 4, 5} of common $C_{3,\,kL}$. From the system configuration, it can be seen that at these generator buses three generators are connected: {U1, U2, U4}. Hence these three generators are responsible for supplying the load at buses-3, 4 and 5. However, until this point, no information is available as to how much these generators contribute to the loads. The directed acyclic state graph was now developed for the commons obtained in Table-5.1, as shown in Fig.5.4. The state graph has 3 nodes, each representing a common and has generation sources, as denoted by the bold incoming arrows.

The nodes in the state-graph are arranged in various horizontal levels, each level representing commons of same rank. The levels are ordered in ascending order of their ranks. For example, node-1 is a common of rank = 1, node-2 of rank = 2, and node-3 of rank = 3. Node-1 is the root node for the power flow. It can be observed that the power flow directions are from nodes (commons) of lower ranks to nodes of higher ranks. Hence the state-graph is termed as a directed and acyclic graph. Note that in 5-bus system we have 3 commons with different ranks and no two commons have same rank.

Table 5.1 List of Commons in the 5-Bus system

p	Set of generator buses (kL)	Rank	Common $C_{p, kL}$
1	1	1	1
2	1,2	2	2
3	1,2,4	3	3,4,5

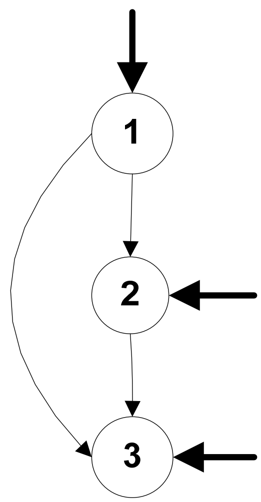

Figure 5.4 State Graph of 5-Bus System Showing Commons, Power Generation and Links Connecting to other Commons

5.4.1.1 Isolated Bus Representation

Using the state-graph, the contribution of each generator to the loads and outflows of a common is determined. From these contributions, a relative share of generation capacity is computed in order to arrive at the Isolated Bus Representation for each load bus. We have presented one sample load bus, bus-4, to demonstrate the results (Fig 5.5).

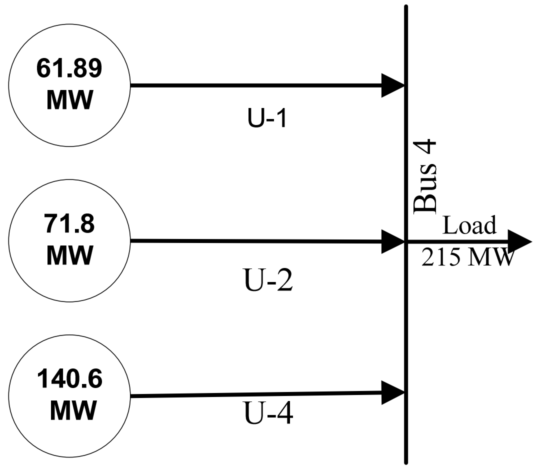

Figure 5.5 Isolated Bus Representation for Bus-4 in the 5-Bus Test System

5.4.1.2 Determining Locational LSP Indices and LSP-Differentiated LMPs

The CONVOLVE algorithm was applied to determine the cumulative outage probability of the three SRC generators supplying the specified load at bus-4. Fig.5.6 shows the variation of cumulative outage probability for different MW blocks or more of generation capacity on outage at bus-4. At bus-4, the total SRC of the set Gr_4 is 274.34 MW and the load is 215 MW. Therefore, from (5.9), an outage of X_0 = 274.34 – 215 MW = 59.34 MW or more will result in load not being served at bus-4. Therefore, $LOLP_4(59.34)$ corresponds to the cumulative probability of 59.34 MW or more on outage, at bus-4, which is 0.23824, as seen in Fig.5.6.

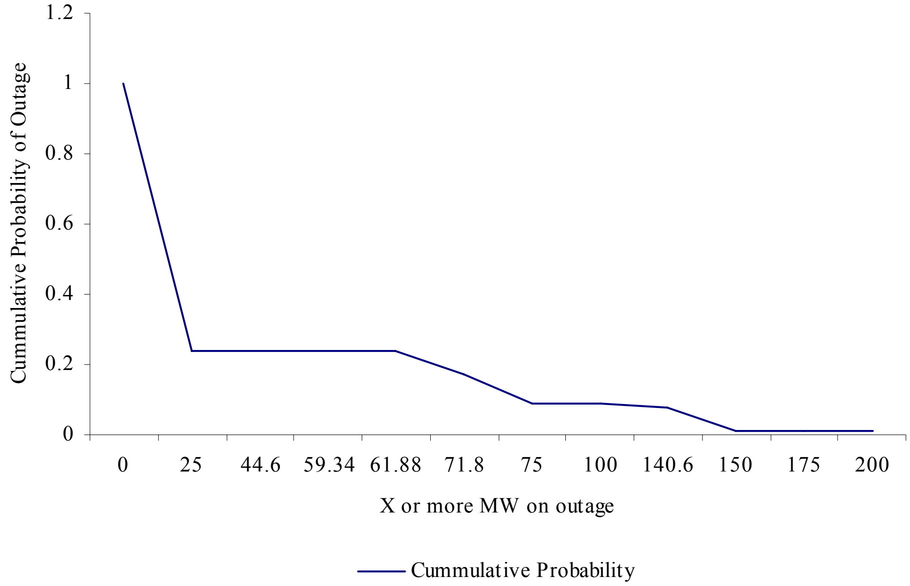

Figure 5.6 Cumulative Outage Probability at Bus-4 of the 5-Bus Test System having 3 SRC Generators Accountable for Supplying its Specified Load

Now, the $LOLP_{System}$ is determined for the 5-bus test system considering the total available system generating capacity of 1,100 MW supplying a total load of 810 MW. The cumulative probability of outage of X_0 = 1,100 – 810 MW, *i.e.*, of 290 MW or more, is the $LOLP_{System}$, which is found to be 0.23824. The $LOLP_i(X_0)$ for all load buses in the 5-bus system and $LOLP_{System}$ are plotted in Fig.5.7. Fig. 5.8 shows the locational LSP indices for all the buses in the system along with the system LSP for the sake of comparison. It is seen from Fig.5.7 and Fig.5.8 that the $LOLP_{System}$ and the system-LSP coincides with the bus-wise LOLPs and LSPs respectively, for three of the system buses, namely bus-3, 4 and 5. On the other hand, bus-1 and bus-2 have significantly lower LOLPs or higher LSPs compared to that of the overall system.

The consequent effect of the bus-wise variation in LSPs is seen in the computation of LSP-differentiated LMPs. It can be seen in Fig.5.9 that the LMPs at bus-1 and bus-2 are increased from their base-case values, because the LSP at these buses are higher than the system-LSP. For rest of the buses, there is no change in the LMPs from their base-case values because the LSP at these buses is exactly the same as the system-LSP.

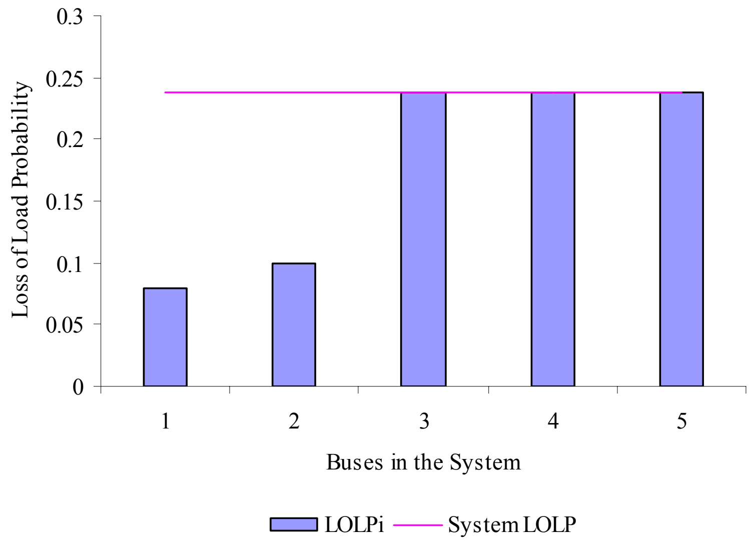

Figure 5.7 Locational LOLP at all Buses in 5-Bus Test System

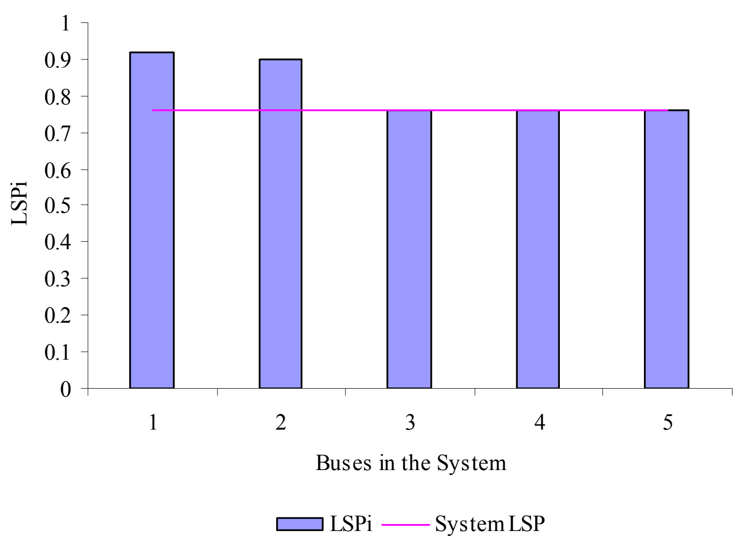

Figure 5.8 Locational LSPs at all Buses in 5-Bus Test System

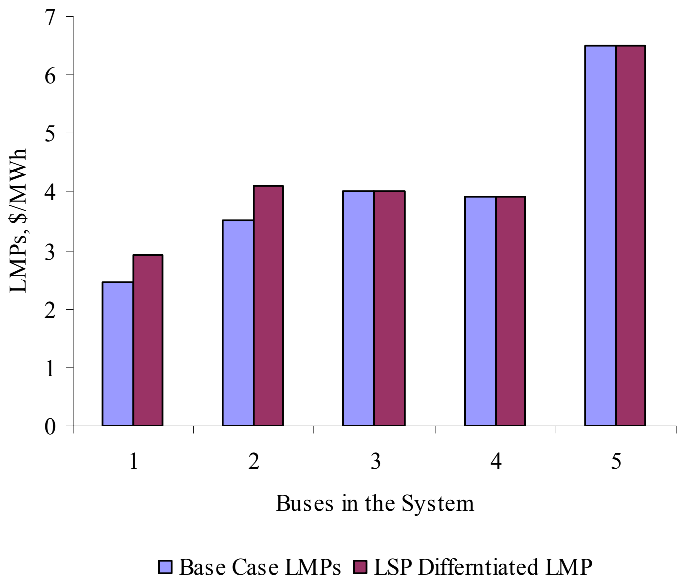

Figure 5.9 Comparison of Base Case LMPs with LSP-Differentiated LMPs

5.4.2 57-Bus Ontario Based Example

The 57-Bus representative Ontario power system which was considered in Chapter-4 is considered for this study. The analysis reported here is carried out considering a specific load condition on the system that remains constant for the duration of one hour.

The total capacity in the system is 25,620 MW and it approximately matches the current total installed capacity in Ontario. A total of 37 generators spread over 13 generating buses are considered. The data pertaining to their outages *i.e.* their FOR data were designed based on the practices adopted in IEEE Reliability Test System Data [68]. The transmission network of the representative Ontario power system was used.

5.4.2.1 System State Graph and Generator Contributions

On executing the OCP and applying the ALLOCATE algorithm, the commons for the representative Ontario power system are obtained as given in Table-5.2. As an example, let us consider common *p=15*. The unique set {kL} of generator buses {4000, 4105, 5102, 5105, 6400, 6401} supplies the member load buses {3107, 3108, 4105} of common $C_{15,\ kL}$. From the system data, it can be determined that at these generator buses the following eighteen generators are connected: {U26, U27, U34, U35, U36, U37, U38, U39, U310, U311, U312, U313, U314, U315, U316, U317, U318, U319}. Hence these 18 generators are responsible for supplying the load at buses-3107, 3108 and 4105.

However, until this point, no information is available as to how much these generators contribute to the loads.

Similarly, for *p=19* it can be observed that bus-101 is being supplied by a group of generators that are connected to 9 generator buses {101, 1106, 2007, 4000, 4105, 5102, 5105, 6400, 6401}. From system data, we know that there are 27 generating units actually connected at these 9 generator buses. Similarly, for *p=1*, it is observed that bus-2007 is being uniquely supplied by the generator located at bus-2007.

The directed acyclic state graph was therefore developed for the commons obtained in Table-5.2. The graph is shown in Fig.5.10. The state graph has 19 nodes each representing a common. Out of these 19 commons, 13 of them have generation sources, as denoted by the bold incoming arrows.

The nodes in the state-graph are arranged in various horizontal levels, each level representing commons of same rank. The levels are ordered in ascending order of their ranks. For example, nodes 1, 2, 3, 4 and 5 are commons with rank 1. They are the root nodes for the power flows. Similarly, nodes 6 and 7 have a rank of 2 while nodes 8, 9, and 10 have a rank 3 as shown in Table-5.2 and in Fig.5.10. Lastly node 19 has the highest rank of 9 in the state graph. It can be observed that the power flow directions are from nodes (commons) of lower ranks to nodes of higher ranks. Hence the state-graph is termed as a directed and acyclic graph.

5.4.2.2 Isolated Bus Representation

Using the state-graph, the contribution of each generator to the loads and outflows of a common is determined. From these contributions, a relative share of generation capacity is computed in order to arrive at the Isolated Bus Representation for each load bus.

Table 5.2 List of Commons in the 57-Bus Ontario Based Power System

p	**Set of generator buses (kL)**	**Rank**	**Common $C_{p, kL}$**
1	2007	1	2007
2	6400	1	6400, 6500
3	7105	1	7102, 7105, 7302, 7365
4	8110	1	8001, 8002, 8103, 8109, 8110, 8258
5	9103	1	9103, 9302, 9311
6	4000, 6400	2	4000, 4100, 6402
7	6400, 6401	2	6401, 7000
8	4000, 5105, 6400	3	5105
9	4000, 6400, 8110	3	8000, 8104, 8112, 8114
10	6400, 6401, 7105	3	7108
11	4000, 5105, 6400, 6401	4	5003, 5135, 5690
12	4000, 6400, 8110, 9103	4	9112
13	4000, 5102, 5105, 6400, 6401	5	5102, 5403
14	4000, 5105, 6400, 6401, 7105	5	359, 5103, 5404, 6501, 6603, 7100, 7300
15	4000, 4105, 5102, 5105, 6400, 6401	6	3107, 3108, 4105
16	2007, 4000, 4105, 5102, 5105, 6400, 6401	7	2002, 2100, 3300, 3301
17	1106, 2007, 4000, 4105, 5102, 5105, 6400, 6401	8	10, 100, 103, 344, 1001, 1104, 1106, 1301
18	2007, 2106, 4000, 4105, 5102, 5105, 6400, 6401	8	2106
19	101, 1106, 2007, 4000, 4105, 5102, 5105, 6400, 6401	9	101

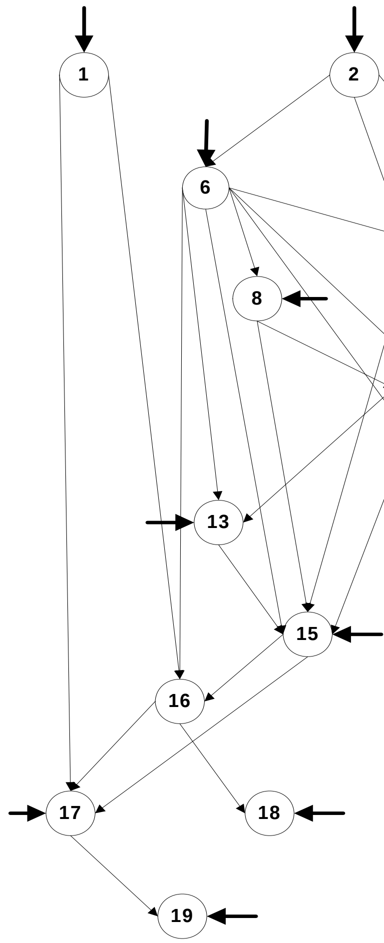

Figure 5.10 State Graph of the 57-Bus Ontario Based Power System Showing Commons, Power Generation and Links Connecting to Other Commons

In this chapter we have presented two sample load buses, bus-3107 and bus-2007, chosen arbitrarily, to demonstrate the results. It was seen that the isolated bus representation for bus-3107 involved 18 SRC generating units while that for bus-2007 involved 3 SRC generating units, as shown in Fig. 5.11. The associated capacities of the SRC generators connected to the isolated buses are also labeled alongside. The 'ring' structure of the isolated bus-3107 has been used for the purpose of accommodating and depicting the 18 SRC generating unit connections at the bus.

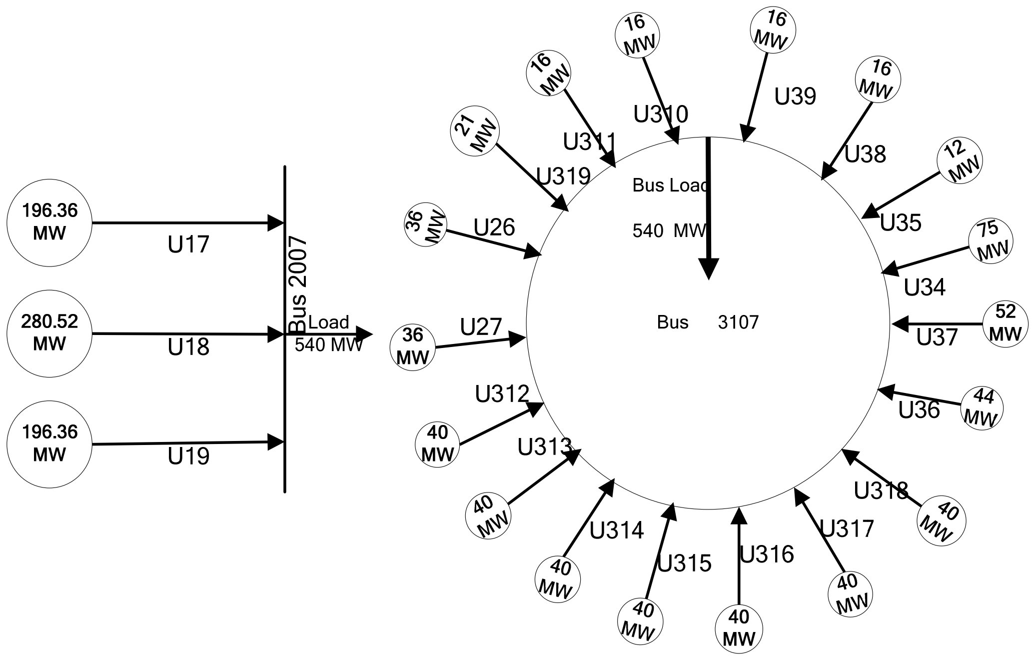

Figure 5.11 Isolated Bus Representation for Bus-2007 and Bus-3107 of the Ontario Based Power System

5.4.2.3 Determining Location LSP Indices

The CONVOLVE algorithm was applied to determine the cumulative outage probability of the 18 SRC generators supplying the specified load at bus-3107, and the 3 SRC generators supplying the specified load at bus-2007.

Table-5.3 and Fig.5.12 shows the variation of cumulative outage probability for different MW blocks or more of generation capacity on outage at bus-3107. At bus-3107, the total SRC of the set Gr_{3107} is 619.88 MW and the load is 540 MW. Therefore, from (9), an outage of X_0 = 619.88 – 540 MW = 79.9 MW or more will result in load not being served at bus-3107. Therefore, $LOLP_{3107}$ *(79.9)* corresponds to the cumulative probability of 79.9 MW or more on outage, at bus-3107, which is 0.111622 (from Table-5.3).

Similarly, for bus-2007, the total SRC of the set Gr_{2007} is 673.24 MW and the bus load is 540 MW. Hence, an outage of X_0 = 673.24 – 540 = 133.24 MW or more will result in load not being served at bus-2007. Therefore, $LOLP_{2007}$ *(133.24)* = 0.24652 (Table-5.4). The corresponding $LOLP_i$ for both buses 3107 and 2007 are shown by the rows in bold, in Tables-5.3 and 5.4 respectively.

For bus-359, the total SRC of the set Gr_{359} is 273.44 MW and the bus load is 270 MW. Hence, an outage of X_0 = 273.44 – 270 = 3.44 MW or more will result in load not being served at bus-359. Therefore, $LOLP_{359}(3.44)$ = 0.5652 (Fig 5.13).

Table 5.3 Cumulative Outage Probability Table for bus-3107

MW or More on Outage	Generators Convolved Sequentially										
	U26	**U27**	**U34**	**U35**	Remaining Units Convolved… *(not shown)*	**U314**	**U315**	**U316**	**U317**	**U318**	**U319**
0	1.00	1.00	1.00	1.00		1.00	1.00	1.00	1.0000	1.0000	1.0000
10	0.05	0.13	0.20	0.25		0.53	0.56	0.59	0.6170	0.6285	0.6470
20	0.05	0.13	0.20	0.20		0.42	0.46	0.49	0.5243	0.5386	0.5616
30	0.05	0.13	0.20	0.20		0.42	0.45	0.48	0.5195	0.5339	0.5386
40		0.00	0.08	0.09		0.26	0.27	0.29	0.3109	0.3201	0.3310
50		0.00	0.08	0.08		0.21	0.23	0.25	0.2707	0.2802	0.2929
60		0.00	0.08	0.08		0.15	0.17	0.18	0.2062	0.2158	0.2210
70		0.00	0.08	0.08		0.14	0.16	0.17	0.1953	0.2049	0.2087
75			0.08	0.08		0.12	0.13	0.14	0.1474	0.1523	0.1557
79.7			0.01	0.02		0.07	0.09	0.10	0.1103	0.1164	0.1213
79.8			0.01	0.02		0.07	0.08	0.09	0.1006	0.1061	0.1116
79.9			**0.01**	**0.02**		**0.07**	**0.08**	**0.09**	**0.1006**	**0.1061**	**0.1116**
80			0.01	0.02		0.07	0.08	0.09	0.1006	0.1061	0.1116
85			0.01	0.01		0.07	0.08	0.09	0.0967	0.1019	0.1073
90			0.01	0.01		0.05	0.06	0.06	0.0722	0.0763	0.0827
100			0.01	0.01		0.04	0.05	0.05	0.0613	0.0655	0.0682
120			0.00	0.00		0.02	0.02	0.02	0.0275	0.0296	0.0314
160						0.00	0.00	0.00	0.0050	0.0054	0.0059
190						0.00	0.00	0.00	0.0009	0.0011	0.0012
195						0.00	0.00	0.00	0.0008	0.0010	0.0010
200						0.00	0.00	0.00	0.0005	0.0005	0.0006
205						0.00	0.00	0.00	0.0003	0.0004	0.0004
210						0.00	0.00	0.00	0.0003	0.0003	0.0004
215						0.00	0.00	0.00	0.0002	0.0003	0.0003
220						0.00	0.00	0.00	0.0002	0.0002	0.0002

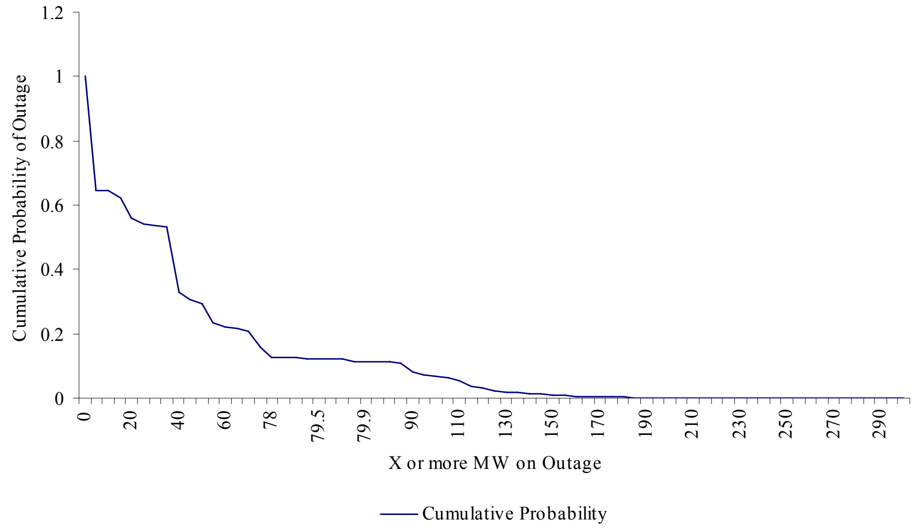

Figure 5.12 Cumulative Outage Probability at Bus-3107 of the Ontario Based Power System having 18 SRC Generators Accountable for Supplying its Specified Load

Table 5.4 Cumulative Outage Probability Table for bus-2007

MW or More on Outage	Generators Convolved Sequentially		
	U17	**U19**	**U18**
0	1	1	1
100	0.08	0.172	0.24652
133.2	**0.08**	**0.172**	**0.24652**
180	0.08	0.172	0.24652
196.36	0.08	0.172	0.24652
280.52		0.1	0.10648
300		0.008	0.02276
400		0.008	0.01628
500			0.00072

For the purpose of comparison, $LOLP_{System}$ is determined considering the total available system generating capacity of 25,620 MW supplying a total load of 22,086 MW. The cumulative probability of outage of X_0 = 25,620 – 22,086 MW, *i.e.*, of 3,534 MW or more, is the $\mathrm{LOLP}_{\mathrm{System}}$, which is found to be 0.04466. The $LOLP_i(X_0)$ for all load buses in the representative Ontario power system under study and $LOLP_{System}$ are plotted in Fig.5.14 and the corresponding expected outage durations at each bus are plotted in Fig.5.15. Fig.5.16 shows the locational LSP indices for all the buses in the system along with the system LSP for the sake of comparison.

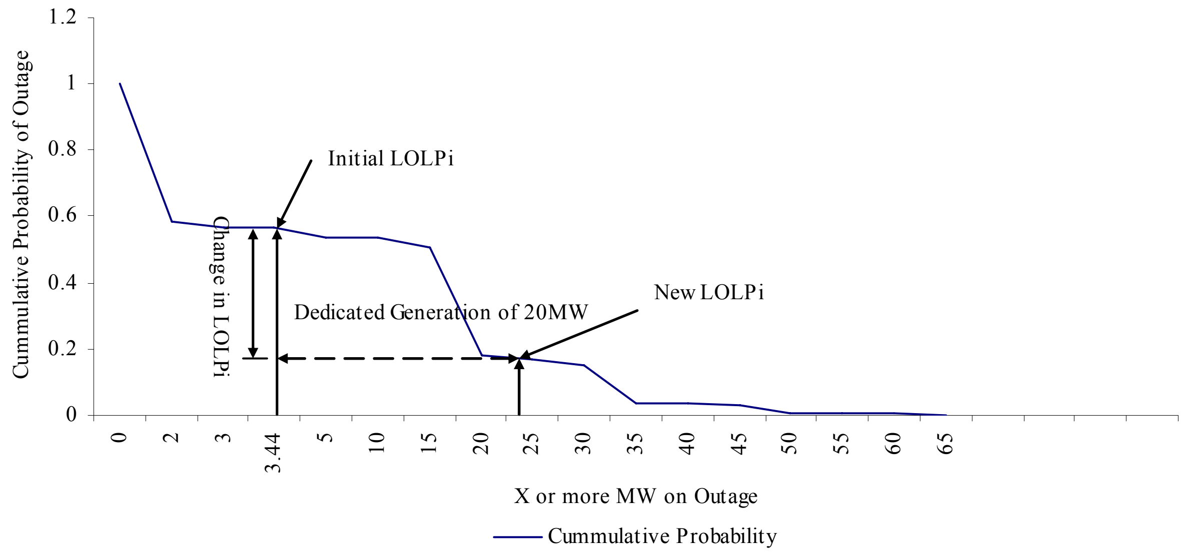

Figure 5.13 Cumulative Outage Probability at Bus-359 of the Ontario Based Power System having 19 SRC Generators Accountable for Supplying its Specified Load

The following observations are made from Figs.5.13-5.16.

- $LOLP_{System}$ is considerably low as compared to $LOLP_i$ for several load buses. This explains that the system reserve of 3,534 MW is not uniformly accessible to all the load buses in the system. Therefore, although there is adequate reserve in the system as a whole, some buses do not have access to that reserve, and hence face a low reliability condition.
  - Fig. 5.13 shows the cumulative outage probability curve for bus-359. It can be seen that due to the low reserve margin availability at this bus, of 3.44 MW, $LOLP_{359}$ = 0.5652, which is fairly high. However, when a dedicated capacity of 20 MW is available at bus-359, $LOLP_{359}$ reduces significantly (to less than 0.2). Therefore, the locational LOLP indices can be used as a basis for siting of generation capacity, in particular, distributed generation capacities.
- LSP_i indices have significant variations from bus to bus. At some buses the LSP_i is considerably low compared to other buses while at a few buses LSP_i is higher than the LSP_{System}.
  - There are 14 load buses that receive a higher or almost the same level of LSP as that of the system as a whole.

o There are about 10 load buses at which LSP is significantly worse, because of non-accessibility of the reserves.

Examining this from another perspective, it is seen that in general the low voltage buses and buses electrically farther away from generators have a low LSP, while high voltage buses have comparatively higher LSP. This is on expected lines.

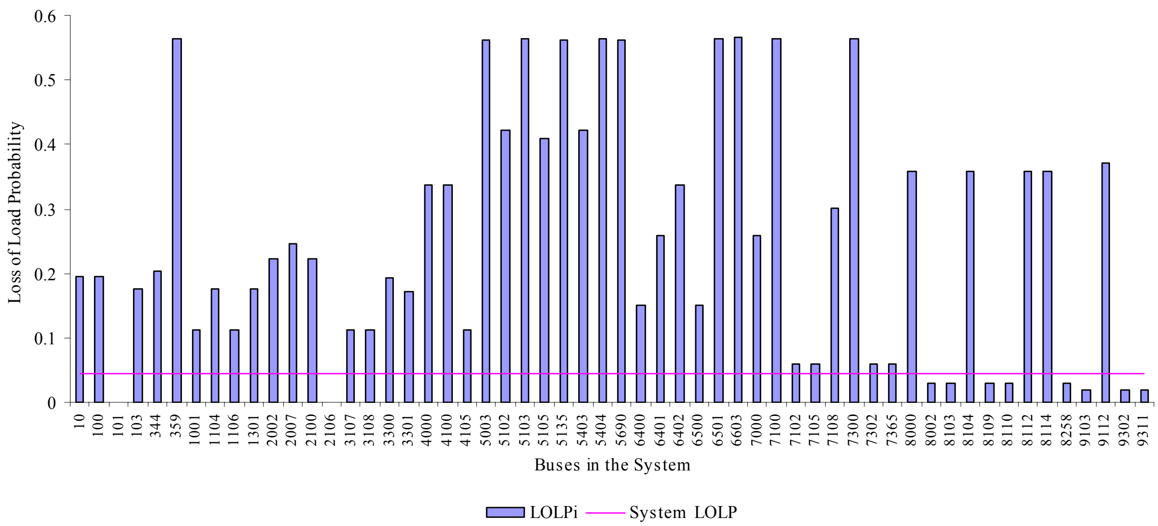

Figure 5.14 Locational LOLP at all Load Buses in Ontario Based Power System

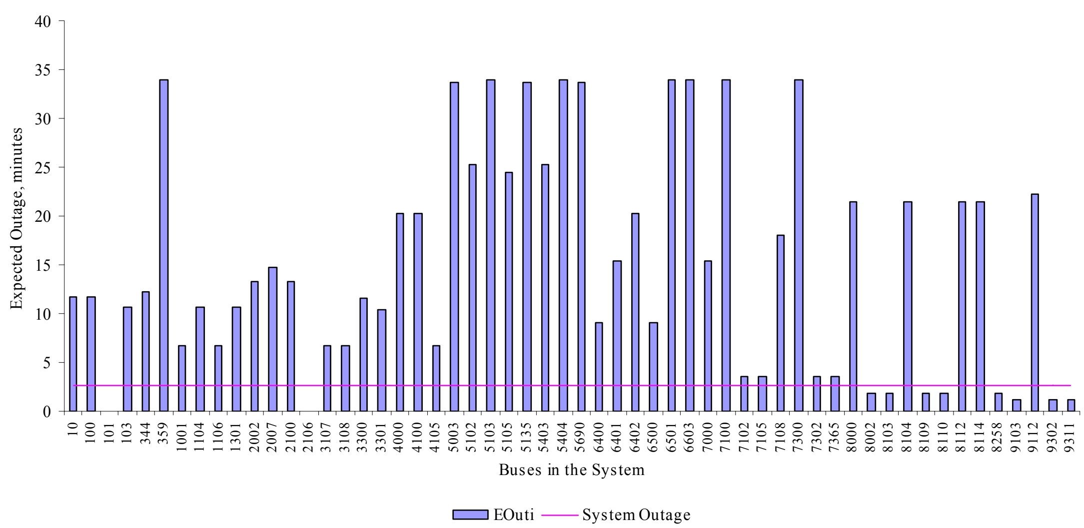

Figure 5.15 Locational LOLP in terms of Expected Outage Duration, at all Load Buses in Ontario Based Power System

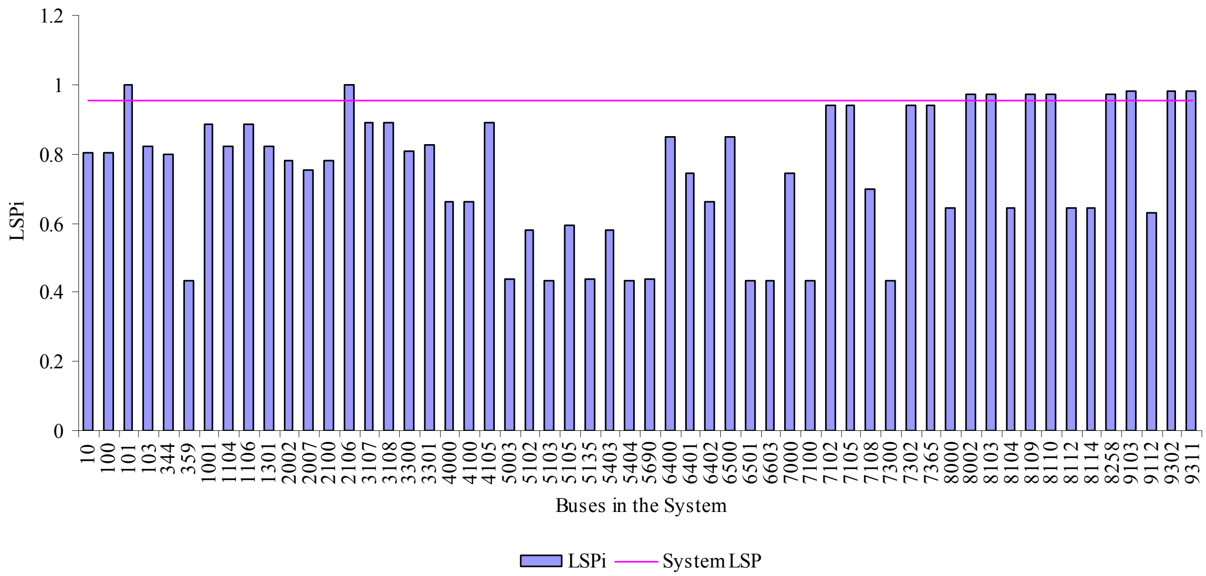

Figure 5.16 Locational LSP at all Load Buses in Ontario Based Power System

5.4.2.4 LSP Differentiated LMPs

From the simulation of the OCP for the Ontario system, we obtain the LMPs through the duals of the demand-supply balance constraint. A plot of bus-wise LMPs for the load condition considered is shown in Fig.5.17. It can be observed from Fig.5.17 that the LMPs are almost equal at all the buses. This is because the loss model used in the OCP is approximate. Nevertheless, this does not affect the main premise of the investigation. Also, there is no congestion in the system for the load condition considered.

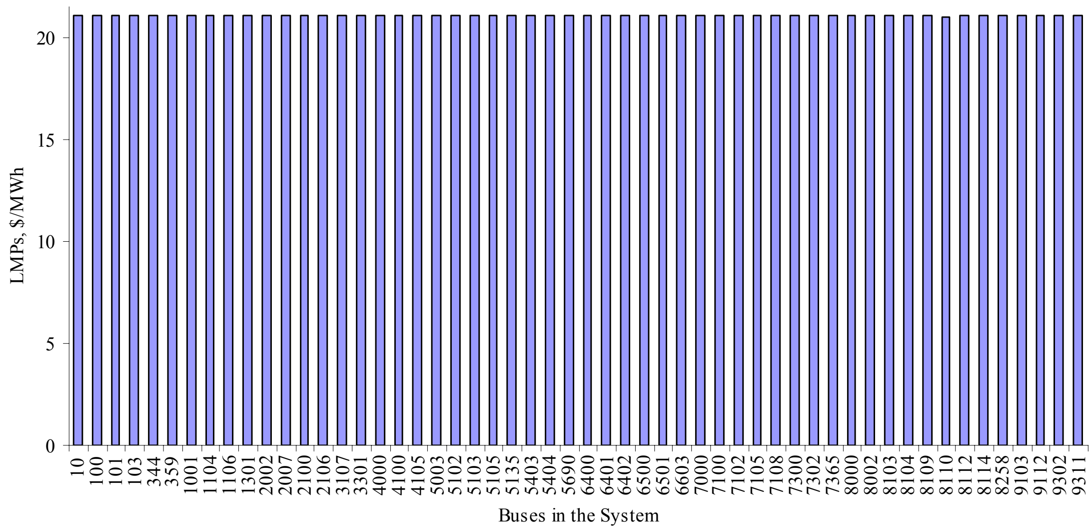

Figure 5.17 LMPs at Different Buses

The distribution of LSP_i in Fig.5.16 shows that some load buses receive low levels of service probabilities, although they pay the usual LMP rates while, customers at some buses are provided with a higher probability of service for the same LMPs. This critical observation stimulates the thought of LSP-differentiated LMPs for the sake of fairness in electricity charges. One of the simplest methods to incorporate LSP in LMPs is to reverse scale the LMPs, and obtain $L\hat{M}P_i$, as in (5.13).

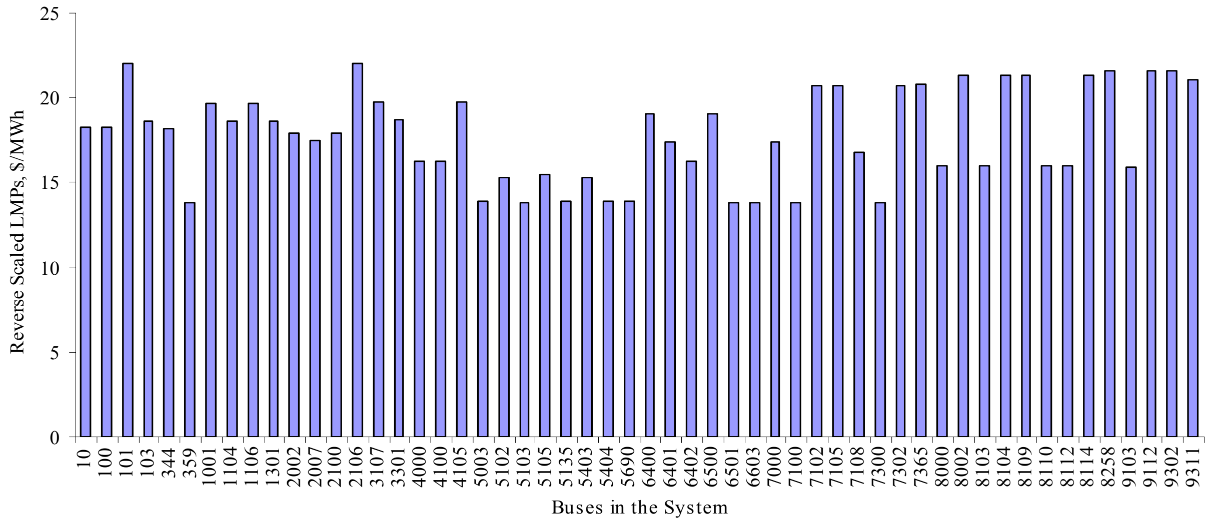

Figure 5.18 LSP Differentiated Nodal Prices at Different Buses

When the LMPs are reverse-scaled using $\Delta LSP_{i,}$ the LSP differentiated LMPs are obtained, as shown in Fig.5.18. It can be observed that the customers at buses with higher LSP pays a proportionately higher LMP rate while customers at the buses that are offered lower LSP level, pays proportionately scaled lower LMPs or nodal prices.

5.5 Concluding Remarks

This chapter proposes a novel set of locational LSP indices and demonstrates how it can be used to modify the LMP to take into consideration the probability of supply received by the customers at a bus. The concept of domains and commons and generators' contributions to the loads is used to formulate an isolated bus configuration for each individual load bus and the LOLP index, is re-defined based on location, from which the locational LSP indices are determined. Two case studies are presented viz. 5-Bus test power system and the 57-Bus Ontario based example, to elaborate the proposed approach and help develop a clear understanding of the proposed concepts. From the analysis of the Ontario based power system it is seen that while the LMPs at all system buses are nearly the same, in the order of \$21/MWh, at several buses, the customers are faced with a low LSP, *e.g.*, buses- 5003, 5004, 5135 and others. Therefore, it is rational to take into account the LSP at a bus and appropriately incorporate that into the locational prices.

Indeed, customers at a bus with a lower LSP level are entitled to a lower price as compared to customers located at a high LSP bus. This chapter investigates the discrepancy in LMPs with respect to the bus-wise LSP. It shows that reverse scaling the LMPs with respect to the differential locational LSP indices opens a scope for effective pricing of electricity. In the system studies undertaken, it has been shown that LSP differentiated prices can range from approximately $13/MWh at low LSP buses, to $22/MWh at high-LSP buses, contrary to the more or less uniform LMPs of $21/MWh at all buses, without LSP consideration.

This work also opens up the prospect for research on reliability as a tradable feature in deregulation. Furthermore, the knowledge of locational LSPs can be used by the system operators to be prepared for contingency conditions and take preventive measures, specific to locations, in readiness. Such measures can include reserves, load curtailment, and capacitor switching provisions.

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Chapter 6

A Practical Approach to Transmission Reinforcement Planning[1]

6.1 Introduction

In the previous chapters, medium-term operational and planning functions pertaining to the ISO were presented. A security coordinated medium-term maintenance-cum-production scheduling scheme was developed and presented in Chapters-3 and 4. Thereafter, a new locational reliability index was proposed in Chapter-5 that can aid both in medium-term operational and planning functions in deregulated power systems.

This chapter proposes a practical approach to medium-term Transmission Reinforcement Planning (TRP) by making use of standard design practices, engineering judgement, experience and thumb-rules to construct a Feasibility Set. The Feasibility Set limits the type and number of reinforcement options available to the planner in selected existing corridors. Mathematical optimization is then applied considering the Feasibility Set, to attain an optimal set of reinforcement decisions that are economical and meets the system demand in the medium-term, without overloading the transmission system.

6.2 The Transmission Reinforcement Problem

The TRP exercise does not consider altering the right-of-way of existing corridors and hence is the fastest and most practically viable medium-term solution to alleviating the transmission system overload problem. There are various reinforcement options available that can be opted for, and implemented in a modular fashion so as to meet the budget constraints. Some of the obvious advantages of transmission reinforcement, which makes it an attractive alternative, are:

1. Smaller system investment cost
2. Shorter gestation lag
3. Effective technical solution
4. Defer new corridor addition decisions

[1] Based on the findings of this chapter, a paper is in preparation to be submitted to the IEEE Transactions on Power Systems.

To exercise the reinforcement options, a dedicated feasibility analysis is required in order to prove their effectiveness. The technical requirements needed to be outlined and the transmission system design parameters that would be affected by exercising specific options are identified.

The transmission system is characterised by the voltage level, current carrying capacity and its power handling capacity. There are obvious limitations on a line's power handling capacity arising from the voltage level and current carrying capacity of the transmission line. When the transmission system as a whole is considered, then the operational limits become active and are governed by power system stability issues.

The traditional transmission expansion planning problems involve developing new transmission corridors for power transfer. In real life, propositions for such new right-of-ways are extremely difficult to implement because of the reluctance of governmental agencies to approve them. Such reluctance is because of the possibility of environmental degradation from forest clearances, land contamination, ill-effects of electromagnetic induction on general public health, *etc.*

To address these issues in the medium-term planning horizon (of about 5 years), transmission reinforcement is the most practical approach to cope effectively with future demand-supply balance and persistent transmission overloading issues, arising as a result of lack of adequate transmission capacity.

The power transfer capacity of transmission lines can be affected by several factors such as changing the connections of lines at substations, installing phase angle regulators, installing series capacitors and /or FACTS devices, by small inertia generators and dispersed generation sources, online dynamic security assessments and automatic voltage regulator and governor control systems [1,71]**.**

In this work, the following TRP options are selected in order to increase the power transfer capability of existing lines in the medium-term framework of up to five years:

a. Series compensation- Series compensation of transmission lines is known to increase the MW loading capacity of a line by up to 45%, depending on the amount or degree of series compensation [48, 49, 71, 72-74].
b. Reconductoring- Reconductoring of transmission lines increases both the MW and thermal loading capacity of the line [49, 75]. Reconductoring can further be sub-categorized as i) changing the size of the conductor only, which can increase the overall MW and thermal capacity by 40% and ii) duplicating or duplexing the line conductors [75].

c. New lines or circuits- This option enhances both the thermal and MW capacity.

d. Voltage level upgrades- This option enhances the thermal and MW handling capacity of lines.

6.2.1 Line Characteristics and Line Design Aspects

Transmission lines are built to transmit bulk power over a long distance, satisfying the electrical and mechanical constraints. They are designed and constructed to meet the specified power handling capacity while adhering to the safety and reliability requirements and operating within the statutory and/or acceptable range of performance parameters [71]. The transmission line efficiency and voltage regulation are its electrical performance parameters. The mechanical performance parameters are its temperature rise limits and mechanical loading limits considering weather factors such air pressure and ice loading. The mechanical design has to be safe and capable of withstanding all weather effects along with electrical safety, phase-to-ground and line-line electrical clearances.

The electrical design of a line has to take into consideration the electrical performance and its effects on other parameters. To be more specific, the line losses in conjunction with ambient conditions may result in thermal overheating of conductors to cause annealing of the conductor material. This reduces the mechanical strength of the line and increases the sag, which may lead to reduction in line-to-ground clearances. Also in case of EHV and HV transmission line design, the corona effect is one of the crucial factors that is given due consideration because of the increased losses and the radio interference, resulting from it [76-78].

A brief discussion of transmission line design from the power transfer capability view point is presented next, to provide a background to transmission reinforcement problems. The electrical design of transmission lines considers following aspects:

- Choice of voltage level
- Choice of conductor
- Choice of insulation system - between conductors, and between conductor-ground

6.2.1.1 Choice of Voltage Level

The power transfer over a transmission line is directly proportional to the square of the voltage level of the line. Increasing the voltage level reduces the line current proportionately and this in turn results in a reduction of line loss. Appropriate choice of the voltage level can therefore reduce line losses but would increase the line costs and the occurrence of corona effects.

Therefore, voltage level of the transmission line has to be judiciously selected, after considering the economics and taking into account the cost of lines, cost of equipment such as transformers and associated switchgear. This cost rises rapidly with the voltage level. In selecting the voltage level of a line, the existing voltage levels of lines in its vicinity and future plans are also to be considered. The amount of power to be transferred and the distance over which the bulk power is to be transmitted, provides a preliminary guideline for the selection of the voltage level. This is the MW-Mile or kW-km principle of choice of voltage level [71].

6.2.1.2 Choice of Conductor

The choice of conductor involves selecting the type and the size of conductors. Copper conductors (hard drawn or stranded), ACSR conductors (Aluminium Conductor Steel Reinforced) and AAA conductors (All Alloy Aluminium) are the most commonly used transmission line conductors. For high voltage lines the weight of the conductor becomes an important factor due to increased span of support towers. In such cases, ACSR conductors are preferred because of their light weight. In many countries copper is scarce and expensive, and therefore it is not common to use copper conductors [1, 71, 79].

The conductor size depends on the power to be transferred over the line, the distance over which it is to be transmitted and the voltage level of the line selected. The selection of conductor size thus depends on the losses occurring in the conductor over a year. Special conductors such as trapezoidal conductors, composite reinforced conductors, *etc.*, are also utilized in special conditions for thermal upgrading of lines.

The conductor configuration is the way in which conductors per phase are arranged and depends on the power handling capacity and the voltage level of the transmission line. Selection of a proper conductor configuration becomes critical with higher voltage levels.

6.2.1.3 Choice of Insulation System

In overhead transmission systems, the insulation system generally comprises the air-gap between conductors, and that between lines to ground. The physical separation between conductors depends on the voltage level of the system and the span, *i.e.,* the distance between the towers, which in turn depend on the size and weight of the conductor. At the support structures, the conductors are isolated from the ground using the insulator strings, made of porcelain, glass or composite material.

6.2.2 Factors Affecting Power Transfer Capacity of a Line

The power transfer capacity of a transmission line is a function of three main parameters. -1) Line thermal limit, 2) Line voltage limit and 3) Line operating limit [80, 81].

1) Line thermal limit: The allowable temperature rise limit of a transmission line is crucial because it determines the thermal expansion of the transmission line conductor. This depends on the current carrying capacity of the conductor and the ambient conditions. Exceeding the thermal limit may result in increase in sag, unsafe clearances and a shortening of life expectancy in the long-term.
2) Line voltage limit: Transmission systems have a specific voltage rating. The voltages should remain within the statutory limits of this specified voltage rating. Voltages beyond the limit are unacceptable. Over-voltages in the transmission system can cause transformer saturation or mal-function of any equipment or may even result in a fault condition. Under-voltages are not advisable since these may lead to voltage collapse conditions. Furthermore, the limit on the voltage magnitude directly affects the power transfer capability of the transmission line.
3) Line operating limit: The power transfer between two buses can be restricted by operating constraints such as the steady-state, transient and small-signal stability limits. Sometimes parallel flows, margins to be kept for contingency allowances and other system conditions also restrict the full utilization of a line's thermal and MW loading capacity [80, 81, 82].

6.2.3 Classification of Transmission Reinforcement Alternatives

In this subsection, the four transmission reinforcement options mentioned earlier are elaborated to provide greater insight. It is assumed that in exercising these options, there is no need of considering addition of new right-of-ways.

1) Series Compensation: Connecting a capacitor in series with the transmission line results in reduction of net transfer-reactance of the transmission line, which in-turn increases the maximum steady-state power-transfer limit. The amount of series compensation can be varied depending on the system requirement. With 30% series compensation, the line MW loading limit can be increased by approximately 45% [48, 49, 72]. The series compensation options considered in the present TRP problem are:
    a. 10% series compensation
    b. 20% series compensation
    c. 30% series compensation

2) Reconductoring: This option is meant for increasing the line power transfer capacity by line conductor reconfiguration [48, 49, 75, 83]. There are two possibilities of reconductoring:
    a. Replacing the existing conductor by a larger size conductor – generally 40% over sizing is permitted, which increases the line power transfer by 40% [48, 75, 83].
    b. Duplexing is the second alternative where another conductor is added to the existing conductors [75]. It is assumed that if one conductor is added to a single conductor configuration, the power handling capacity approximately gets doubled.
3) Addition of new circuits: If a single circuit line is made double circuit, the power transfer of the transmission line is approximately doubled. If an existing double-circuit line is converted to a three-circuit line, the power handling capacity increases by 50 percent of existing capacity.
4) Voltage level upgrade: There is a practical limit on the extent a reinforcement alternative can be exploited. The last measure is the voltage level upgrade of the existing transmission line. As it is assumed that the right-of-way remains unaltered, this option is not considered for a 400 kV transmission line. The power handling capacity is proportional to the square of the voltage level for a given distance and accordingly the increase in power handling capacity is considered in the optimization problem.

A feasibility analysis needs to be carried out after selecting the transmission reinforcement option in order to verify whether an option will be feasible technically and economically. Further, shunt compensation option is not considered as one of the alternatives for the transmission reinforcement because we have assumed that reactive power injection is already available at the load buses.

6.3 Proposed Approach to TRP

6.3.1 Construction of TRP Feasibility Set

Transmission expansion planning problems are often modelled as mixed-integer non-linear programming (MINLP) problems, which are difficult to solve for large systems. The mathematical model of TRP will also be a MINLP problem because of the presence of non-linear load flow equations and integer variables for selection of alternatives. The difficulties in solving such MINLP problems can be eliminated or regulated by controlling the size of the problem *i.e.,* by controlling the number of selection variables.

The notion of 'Feasibility Set' limits the number of selection variables in the TRP problem by pre-identifying the lines to be reinforced and the possible set of options that may be exercised on that line. This is done using a rule-based identification of reinforcement options for each and every line pre-identified for augmentation. It is important to mention that by knowing the type of line and the amount of overload, a smaller set of feasible options can be arrived at, using standard design procedures and engineering judgement. Optimal selection of the options from within the Feasibility Set renders the proposed approach to TRP to be practical, and easy to implement.

6.3.1.1 Identifying Overloaded Lines

Two types of line loadings are considered *viz.* thermal and MW loading. The line MW loading limits are realistically determined from the line voltage rating and the line length. A simple load flow run, considering full-load condition, can be used to determine the actual MW and thermal loading of the lines. These two can then be compared to arrive at the practical MW loading limits for all lines. In the same way, the ampacity or thermal loading limit based on conductor selection; depending on voltage level and the power handling capacities, as discussed in Section 6.2.1, are compared with the thermal loading obtained from the load flow run, to determine practical line current carrying limits.

These limits are used to determine the line overloads (both thermal and MW) for specified load conditions.

6.3.1.2 Proposed Set of Rules to Alleviate Persistent Transmission Overload

Persistent transmission line overloads can be eliminated by increasing the line capacity. The transmission capacity reinforcement rules, considered in this work, are as listed below.

1) If the line thermal and MW overload is less than 90%, the line does not need capacity reinforcement
2) If the line MW loading is 90-150% of nominal and thermal loading is less than 90%, various degrees of series compensation are used to increase line MW loading limits
3) If line MW loading is less than 90% and thermal loading is between 90-150%, either reconductoring or the option of adding new lines is considered.
4) For both line thermal and MW loading in the range of 90-150%, either reconductoring or addition of new lines options is considered.
5) For 150% and more thermal and MW loading of a line, the option to add new circuits or a voltage upgrade is considered.

The above proposed set of rules is shown in Table 6.1.

Table 6.1 Allotting Reinforcement Options Based on the Type and Amount of Line Overload

% MW Loading → % Thermal Loading ↓	≤ 90%	90-150%	≥ 150%
≤ 90%	No Reinforcement	Series Compensation	New line addition Voltage Upgrade
90-150%	Reconductoring	Reconductoring New Line Addition Voltage Upgrade	Duplexing only New Line Additions Voltage upgrade
≥ 150	Duplexing only New Line Additions Voltage upgrade	Duplexing only New Line Additions Voltage upgrade	Duplexing only New Line Additions Voltage upgrade

6.3.2 Overview of the Proposed TRP Approach

The TRP problem is a MINLP problem and therefore it might not be possible to arrive at a feasible optimal solution for larger systems, because of the nature of the problem itself. Two solution approaches are proposed in this work, to determine the feasible selection of reinforcement options.

6.3.2.1 Decomposition Approach to TRP

The first approach, presented in this sub-section is a decomposition-based approach in which the TRP problem is split into two sub-problems and solved sequentially and iteratively, to arrive at a solution (Fig. 6.1). In the proposed approach, first a Base-OPF is executed to identify the lines that have a thermal or MW overload. Thereafter, the reinforcement options are identified and the Feasibility Set for the overloaded lines is developed using Table 6.1. Once the lines are identified and the Feasibility Set is available, the Transmission Reinforcement Selection (TRS) model, which is a mixed-integer linear program (MILP) discussed later, is executed to select the reinforcement options that best reinforce the thermal and/or MW loading capacities of the overloaded lines identified, while minimizing the investment cost objective.

The optimal selection of reinforcement options are incorporated in the power system configuration with new upgrades and the revised system is executed for Base-OPF run, to identify any further existing transmission overloads. This scheme is iterative in nature, but is expected to converge fast. Once the Base-OPF yields a solution with no transmission overloads, the optimal solution of reinforcement options is obtained.

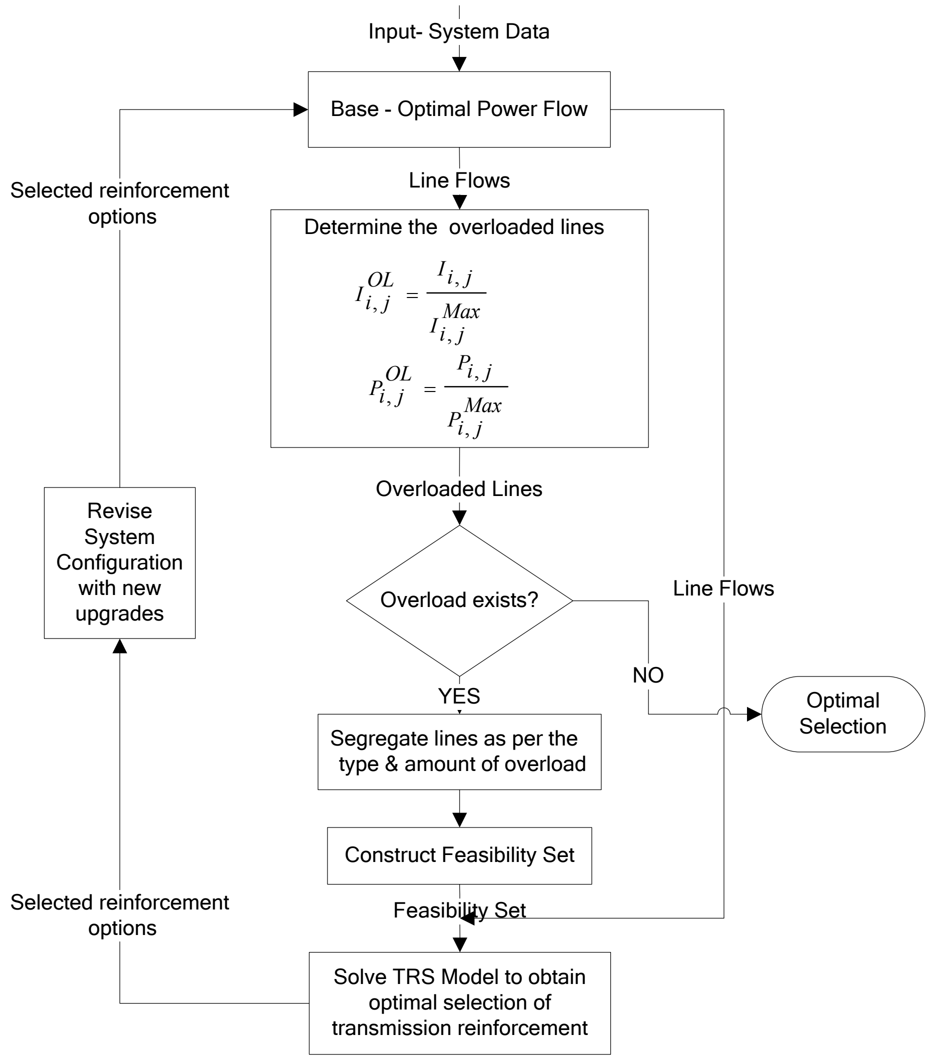

Figure 6.1 Decomposition Approach to TRP

6.3.2.2 Unified Approach

In this approach, the comprehensive TRP problem, which is a MINLP problem, is considered where the imposition of line constraints and the reinforcement option selections are simultaneously implemented so as to arrive at a cost effective solution that best meets the system requirements. Once the overloaded lines are identified and the Feasibility Set is constructed, the Security-Constrained Composite Transmission Reinforcement Selection (SCC-TRS) model (discussed later), which is MINLP in nature, is executed to select the reinforcement options that best reinforce the thermal and/or MW loading capacities of the overloaded lines identified, while minimizing the investment cost objective, subject to the line security constraints.

Although this is a unified approach dealing with a MINLP problem, because of the presence of the Feasibility Set, the size of the problem is strictly limited and can be easily solved using available MINLP solvers. The overall TRP solution method using the unified approach is described in the Fig. 6.2.

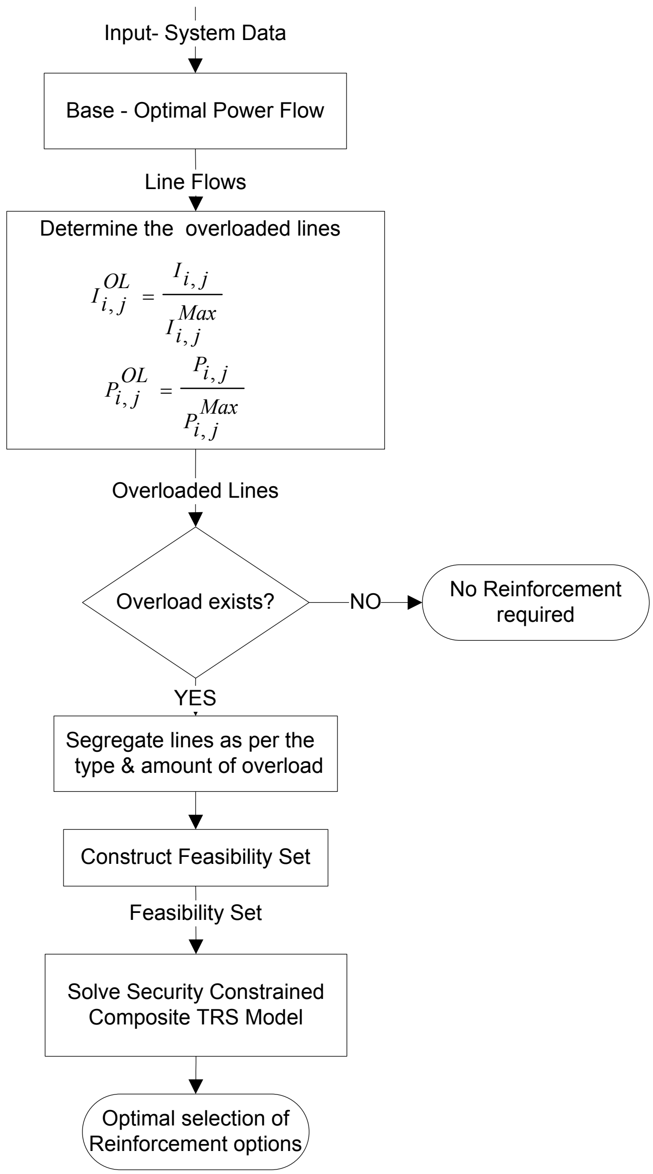

Figure 6.2 Unified Approach to TRP

6.4 Mathematical Modeling of the TRP Problem

6.4.1 Base Optimal Power Flow (OPF) Model

6.4.1.1 Objective Function

The classical OPF model with cost minimization objective is used to determine the Feasibility Set. The cost objective function comprises the cost of real and reactive power generation, as given in (6.1):

$$Cost = \sum_{i}^{N} Pg_i^2 \times Cg_i^C + Pg_i \times Cg_i^B + Cg_i^A + \sum_{i}^{N} Qg_i^2 \times Cg_i^q \tag{6.1}$$

6.4.1.2 Constraints

6.4.1.3 Load Flow Constraints

The active and reactive power load flow equations in rectangular coordinates, are given by (6.2) and (6.3), respectively. A load scaling factor (LSF) is used to increase the system loading uniformly at all buses, and hence determine the overloaded lines.

$$Pg_i - (1 + LSF)PD_i = \sum_{j=1}^{N} \left\{ e_i \left(G_{i,j} e_j - B_{i,j} f_j \right) + f_i \left(G_{i,j} f_j + B_{i,j} e_j \right) \right\} \tag{6.2}$$

$$Qg_i - (1 + LSF)QD_i + Qc_i = \sum_{j=1}^{N} \left\{ f_i \left(G_{i,j} e_j - B_{i,j} f_j \right) - e_i \left(G_{i,j} f_j + B_{i,j} e_j \right) \right\} \tag{6.3}$$

6.4.1.4 Line Current and Power Flow Equations

The real and imaginary components of the line currents are given by (6.4) and (6.5) respectively. The magnitude of the line current is given by (6.6). Subsequently, by using (6.4) and (6.5), we can represent the line active and reactive power flows, by (6.7) and (6.8) respectively.

$$I_{i,j}^{\mathrm{Re}} = \left\{ \left(e_i - e_j \right) g_{i,j} - \left(f_i - f_j \right) b_{i,j} \right\} - f_i Ych_{i,j} \tag{6.4}$$

$$I_{i,j}^{\mathrm{Im}} = \left\{ \left(f_i - f_j \right) g_{i,j} + \left(e_i - e_j \right) b_{i,j} \right\} + e_i Ych_{i,j} \tag{6.5}$$

$$I_{i,j} = \sqrt{\left(I_{i,j}^{\mathrm{Re}} \right)^2 + \left(I_{i,j}^{\mathrm{Im}} \right)^2} \tag{6.6}$$

$$P_{i,j} = e_i\{(e_i - e_j)g_{i,j} - (f_i - f_j)b_{i,j}\} + f_i\{(f_i - f_j)g_{i,j} + (e_i - e_j)b_{i,j}\} \tag{6.7}$$

$$\begin{aligned} Q_{i,j} = {} & f_i\{(e_i - e_j)g_{i,j} - (f_i - f_j)b_{i,j}\} - e_i\{(f_i - f_j)g_{i,j} + (e_i - e_j)b_{i,j}\} \\ & + (e_i^2 + f_i^2)Ych_{i,j} \end{aligned} \tag{6.8}$$

6.4.1.5 Generation Capacity Constraints

The real and reactive power generations are constrained by their respective maximum and minimum generation limits, as follows:

$$Pg_i^{Min} \le Pg_i \le Pg_i^{Max} \qquad \forall \quad i \in N_g \tag{6.9}$$

$$Qg_i^{Min} \le Qg_i \le Qg_i^{Max} \qquad \forall \quad i \in N_g \tag{6.10}$$

6.4.1.6 Bus Voltage Magnitude Constraints

The bus voltage magnitudes are constrained to be within their statutory limits, as follows:

$$V_i^{Min} \le |V_i| \le V_i^{Max} \quad \forall\ i \in N \tag{6.11}$$

Where,

$$|V_i| = \sqrt{e_i^2 + f_i^2} \tag{6.12}$$

6.4.1.7 Bus Reactive Power Injection Limits

The reactive power injection by load bus capacitor or reactor is constrained as follows:

$$Qc_i^{Min} \le Qc_i \le Qc_i^{Max} \quad \forall\ i \in N_l \tag{6.13}$$

6.4.2 The Transmission Reinforcement Selection (TRS) Model

6.4.2.1 Objective Function

The generic investment cost, representing the cost of new investments in transmission reinforcement, described in (6.14), is the objective function for the TRS Model. The variable Z represents the binary selection variable of reinforcement options and $OC_{i,j,o}$ is the annualised cost of reinforcement option o for line i-j.

$$Inv = \sum_{i}^{N}\sum_{j}^{N}\sum_{o}^{N_o} OC_{i,j,o} \times Z_{i,j,o} \tag{6.14}$$

6.4.2.2 Line MW and Thermal Capacity Deficit Constraints

The MW and/or the thermal capacity deficit, if any, are to be compensated by total equivalent capacity reinforcement, given by (6.15) and (6.16) respectively. $\Delta PCap_{i,j,o}$ and $\Delta ICap_{i,j,o}$ are the incremental MW and thermal capacity addition on the line i-j by the reinforcement option o.

$$\sum_{O}^{N_o} \Delta PCap_{i,j,o} \times Z_{i,j,o} \geq P_{i,j} - P_{i,j}^{Max} \tag{6.15}$$

$$\sum_{O}^{N_o} \Delta ICap_{i,j,o} \times Z_{i,j,o} \geq I_{i,j} - I_{i,j}^{Max} \tag{6.16}$$

6.4.2.3 Feasibility Constraints

For a line that requires capacity addition, only one reinforcement option has to be selected, which is imposed by equation (6.17). Equation (6.18) restricts the range of the binary selection variable Z to the lines within Feasibility Set, and when there is no MW or thermal overload, Z is set to zero.

$$\sum_{o}^{N_o} Z_{i,j,o} \leq 1 \tag{6.17}$$

$$Z_{i,j,o} = 0 \quad \forall \;\; \Delta PCap_{i,j,o} = 0 \; and \; \Delta ICap_{i,j,o} = 0 \tag{6.18}$$

6.4.3 Security Constrained Composite TRS (SCC-TRS) Model

6.4.3.1 Objective Function

The objective function of the SCC-TRS model is the minimization of the total cost of transmission reinforcement investments, given by:

$$Inv = \sum_{i}^{N} \sum_{j}^{N} \sum_{o}^{N_o} OC_{i,j,o} \times Z_{i,j,o} \tag{6.19}$$

6.4.3.2 Load Flow Constraints

The active and reactive power load flow equations in rectangular coordinates, presented earlier, are included, and are given below again, for the sake of continuity in reading.

$$Pg_i - (1 + LSF)PD_i = \sum_{j=1}^{N} \left\{ e_i \left(G_{i,j} e_j - B_{i,j} f_j \right) + f_i \left(G_{i,j} f_j + B_{i,j} e_j \right) \right\} \tag{6.20}$$

$$Qg_i - (1 + LSF)QD_i + Qc_i = \sum_{j=1}^{N} \left\{ f_i \left(G_{i,j} e_j - B_{i,j} f_j \right) - e_i \left(G_{i,j} f_j + B_{i,j} e_j \right) \right\} \tag{6.21}$$

The other constraints considered in the SSC-TRS model are, the real and reactive power generation limits, voltage magnitude and reactive power injection by capacitor / reactors, as described in the Base-OPF model.

6.4.3.3 Line MW and Thermal Capacity Constraints

The security constraints are described by (6.22) and (6.23), and represent the line MW and the line thermal limits respectively. Both (6.22) and (6.23), incorporates the binary selection variable Z to increment the respective capacity corresponding to the suitable reinforcement option from within the Feasibility Set.

$$P_{i,j} \le \sum_{o}^{N_o} \left(\Delta PCap_{i,j,o} \times Z_{i,j,o} \right) + P_{i,j}^{Max} \tag{6.22}$$

$$I_{i,j} \le \sum_{o}^{N_o} \left(\Delta ICap_{i,j,o} \times Z_{i,j,o} \right) + I_{i,j}^{Max} \tag{6.23}$$

6.4.3.4 Feasibility Constraints

For a line that requires capacity addition, only one reinforcement option has to be selected. The equation (6.24) limits the option selection for a line to 1. Equation (6.25) restricts the range of the binary selection variable to the lines within the Feasibility Set.

$$\sum_{o}^{N_o} Z_{i,j,o} \le 1 \tag{6.24}$$

$$Z_{i,j,o} = 0 \quad \forall \quad \Delta PCap_{i,j,o} = 0 \; and \; \Delta ICap_{i,j,o} = 0 \tag{6.25}$$

6.5 Case Study – CIGRE 32 Bus Test System

6.5.1 System Data

The proposed approach to TRP is carried out considering the CIGRE 32 bus test system (Fig. 6.3) [84] to examine and compare the performance of the Decomposition Approach with the Unified Approach, The detailed data for this test system is provided in the Appendices. The transmission line reinforcement options considered for the present studies are as follows:

a. Series compensation
b. Reconductoring
c. New line addition
d. Voltage level upgrade

The line thermal and MW power handling capacities considered in these work, are selected as shown in Table 6.2 [1, 48, 49, 71-82]:

Table 6.2 Line MW and Thermal Capacities

Line Voltage Level, kV	MW Capacity, MW	Thermal Capacity, A
132	300	450
230	500	700
400	1200	1400

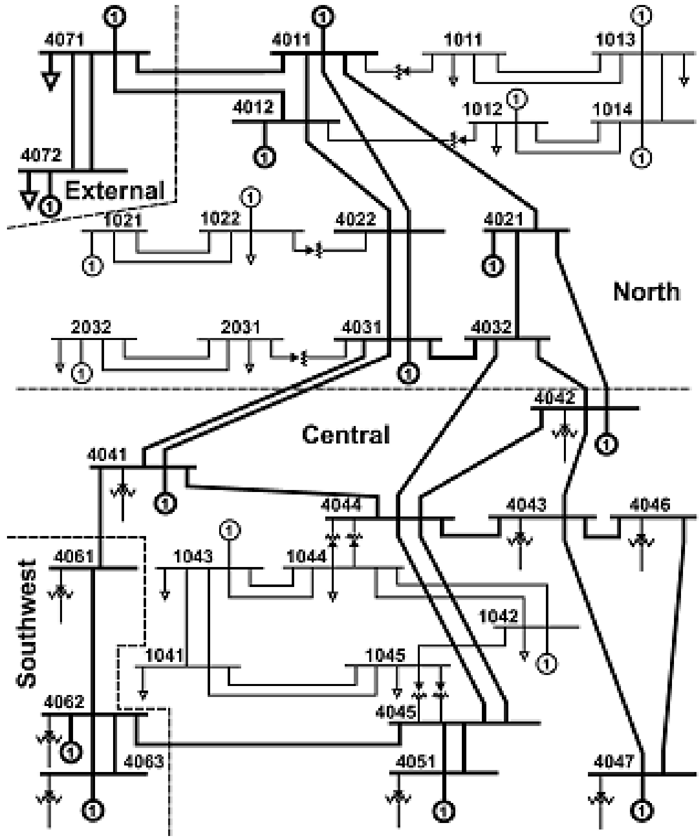

Figure 6.3 CIGRE 32-Bus Test System [84]

6.5.2 Cost Data

6.5.2.1 Assumptions for Cost and Reinforcement Option Considerations

1) Transmission lines are assumed to be 200 miles long for the purpose of estimating existing line costs. This assumption is made because of lack of such information on the CIGRE 32-Bus Test System. However, the proposed approaches are generic enough to consider specific line lengths.
2) No right-of-way addition or modification is required to implement the reinforcement options.
3) MW loading and thermal loading of a line are considered separately.

4) Thermal loading of a line is approximated as ampacity limit of the conductor. For all transmission lines, the conductor configuration is assumed to remain constant for a specific voltage level.

5) The four reinforcement options are further sub-categorized as shown in the Table 6.3, to define the amount of reinforcement and the alternatives available within each option. The Table 6.3 also shows the respective option codes which are later used to discuss the results. This provides an opportunity to the planner to optimize within the limited standard design options available, for overload mitigation and also allows to either choose a modular reinforcement option or to help schedule the selected alternatives over a specified time-frame.

Table 6.3 Reinforcement Option Sub-categories and Respective Codes

Options	**Sub-categories**	**Option Codes**
Series Compensation	10% Compensation	S_1_V
	20% Compensation	S_2_V
	30% Compensation	S_3_V
Reconductoring	Resizing	R_S_V
	Duplexing	R_D_V
New Line Addition	Single Circuit Addition	N_1_V
	Double Circuit Addition	N_2_V
Voltage Level Upgrade (Not considered for 400 kV lines)	One Level Upgrade Only	V_V_{NEW}_V
Note: V in Option Code stands for voltage level of a line, V=1 for 132 kV line, V=2 for 230 kV line and V=4 for 400 kV line. V_{NEW} = 2 for 132 kV line and V_{NEW}= 4 for 230 kV line. Therefore, for example, S_1_1 denotes 10% series compensation in a 132kV line and R_S_2 denotes a conductor resizing in a 230 kV line.		

6.5.2.2 Cost Parameters of a Transmission Line and Reinforcement Alternatives

In order to determine the cost parameters of all the transmission reinforcement alternatives, the costs of existing transmission are estimated and then appropriate percentage of various transmission line costs are allotted to specific reinforcement options for a line type. The transmission line costs vary significantly, due to factors other than the line capacity, such as land acquisition costs, labour cost, other regulations, and lead time impacts on projected cost, *etc.*, [1, 49]. For the work presented in this chapter the costs for 138kV, 230kV and 400 kV lines are estimated considering the assumptions stated in Section-6.5.2.1. The transmission line capacities are also considered as specified in Table 6.2 [1, 48, 49, 71-82].

- The cost of the series compensation depends on the degree of compensation and the voltage rating of the transmission line to be compensated. Generally 30% series compensation results in 45-50% rise in the MW power handling capacity [48, 49] of the line. For 10% and 20% series compensation, the incremental MW power handling capacity reduces proportionately. Capacitor costs are estimated to be in the range of 10-15% of the cost of new lines [49, 50]. The other major cost for series compensation is the cost associated with the terminal station, and the outage cost of the transmission line during commissioning.
- The cost of resizing option is approximated to be 40% of the new line cost. The cost of duplexing option is approximated to be 70% of the cost of a new line. Re-sizing increases line power handling capacity by 40%, while the capacity increase achieved from the duplexing option is 80% of line capacity [75].
- New line or circuit addition and voltage upgrade costs are derived from the estimated costs of existing transmission lines for various voltage levels and their differentials in case of voltage upgrade.

All the estimated costs corresponding to the reinforcement options are annualized considering a period of 25 years and a discount rate of 10%.

6.5.3 Result and Discussions

6.5.3.1 Determination of Feasibility Set

The Base OPF simulations are used to compute the line thermal and MW overloads assuming 15% system load increase over a five year span, which implies a 3% annual load growth. The overloaded lines identified are segregated on the basis of the amount of thermal overload or MW overload or both thermal and MW overload, as shown in Table 6.4.

The applicability of various reinforcement options to alleviate any type of overload in each "identified" line was determined. Finally, the identified lines and suitable reinforcement options are together used to construct the Feasibility Set for the TRP problem. For example, lines with thermal loading less than 90% and the MW loading in the range of 90-150% requires the series compensation option in order to increase the MW loading capacity of these lines. Lines with lower MW loading and high thermal overloading require thermal up-rating of the transmission lines.

Table 6.4 Overload Paths for a 15% System Load Growth

MW loading / Thermal loading	≤ 90%	90% – 150%	≥ 150%
≤ 90%	None	4011-4021 4031-4032 4062-62 1043-1041 4044-1044 4045-1045 1045-1041	None
90% – 150%	1022-4022	4031-4041 1013-1011 1044-1043	4042-42 4022-4031
≥ 150%	None	None	None

Table 6.5 presents the capacity increments and Table 6.6 presents the corresponding annualized costs of different reinforcement options. These two tables along with another table (not shown here) representing thermal capacity increment for various reinforcement options will comprise the Feasibility Set for the TRP problem under consideration.

For example, line 4011-4021 has only MW overloading, and it does not require thermal upgrade. Therefore, series compensation can provide the increase in line MW loading capability. The degree of series compensation can be varied by, say, 10%, 20% or 30% of compensation, with proportionate increase in MW loading (Table 6.5). Table 6.6 displays the corresponding reinforcement costs by series compensation for line 4011-4021 in rows S_1_4, S_2_4 and S_3_4 respectively.

Table 6.5 Power Transfer (MW) Capacity Increment in Various Reinforcement Options (PU)

Lines / Option Code	4011-4021	4031-4032	4044-1044	4045-1045	4062-62	1043-1041	1045-1041	1022-4022	4031-4041	1013-1011	1044-1043	4042-42	4022-4031
S_1_1					0.3	0.3	0.3						
S_2_1					0.75	0.75	0.75						
S_3_1					1.35	1.35	1.35						
S_1_4	1.2	1.2	1.2	1.2									
S_2_4	3	3	3	3									
S_3_4	5.4	5.4	5.4	5.4									
R_S_1								1.2		1.2	1.2		
R_S_4									4.8				
R_D_4									9.6				
N_1_1										3	3	3	
N_2_1										6	6	6	
N_1_4									12				12
V_2_1												2	

Table 6.6 Annualized Cost of Reinforcement Options (in M$)

Lines / Option Code	4011-4021	4031-4032	4044-1044	4045-1045	4062-62	1043-1041	1045-1041	1022-4022	4031-4041	1013-1011	1044-1043	4042-42	4022-4031
S_1_1					0.56	0.56	0.56						
S_2_1					0.84	0.84	0.84						
S_3_1					1.40	1.40	1.40						
S_1_4	1.75	1.75	1.75	1.75									
S_2_4	2.63	2.63	2.63	2.63									
S_3_4	4.38	4.38	4.38	4.38									
R_S_1								1.87		1.87	1.87		
R_S_4									5.84				
R_D_4									10.22				
N_1_1										4.66	4.66	4.66	
N_2_1										9.33	9.33	9.33	
N_1_4									14.59				14.59
V_2_1												2.06	

6.5.3.2 TRP Solution Using Decomposition Approach

The transmission reinforcement options selected using the Decomposition Approach is presented in Table 6.7. It is observed from Table 6.7 that three lines (4062-62, 1043-1041 and 1045-1041, all 132 kV) are provided with 20% series compensation, one line (4031-4041, 400kV) is allotted the reinforcement option of conductor re-sizing while one 400 kV line (4022-4031) is advised the option of adding one more circuit to alleviate thermal and MW overloading. Figure 6.4 shows the 32 bus CIGRE system with the options suggested as an outcome of the Decomposition Approach to TRP problem.

Table 6.7 TRP Solution using Decomposition Approach

	S_2_1	R_S_4	N_1_4
4031.4041		1	
4062.62	1		
1043.1041	1		
4022.4031			1
1045.1041	1		

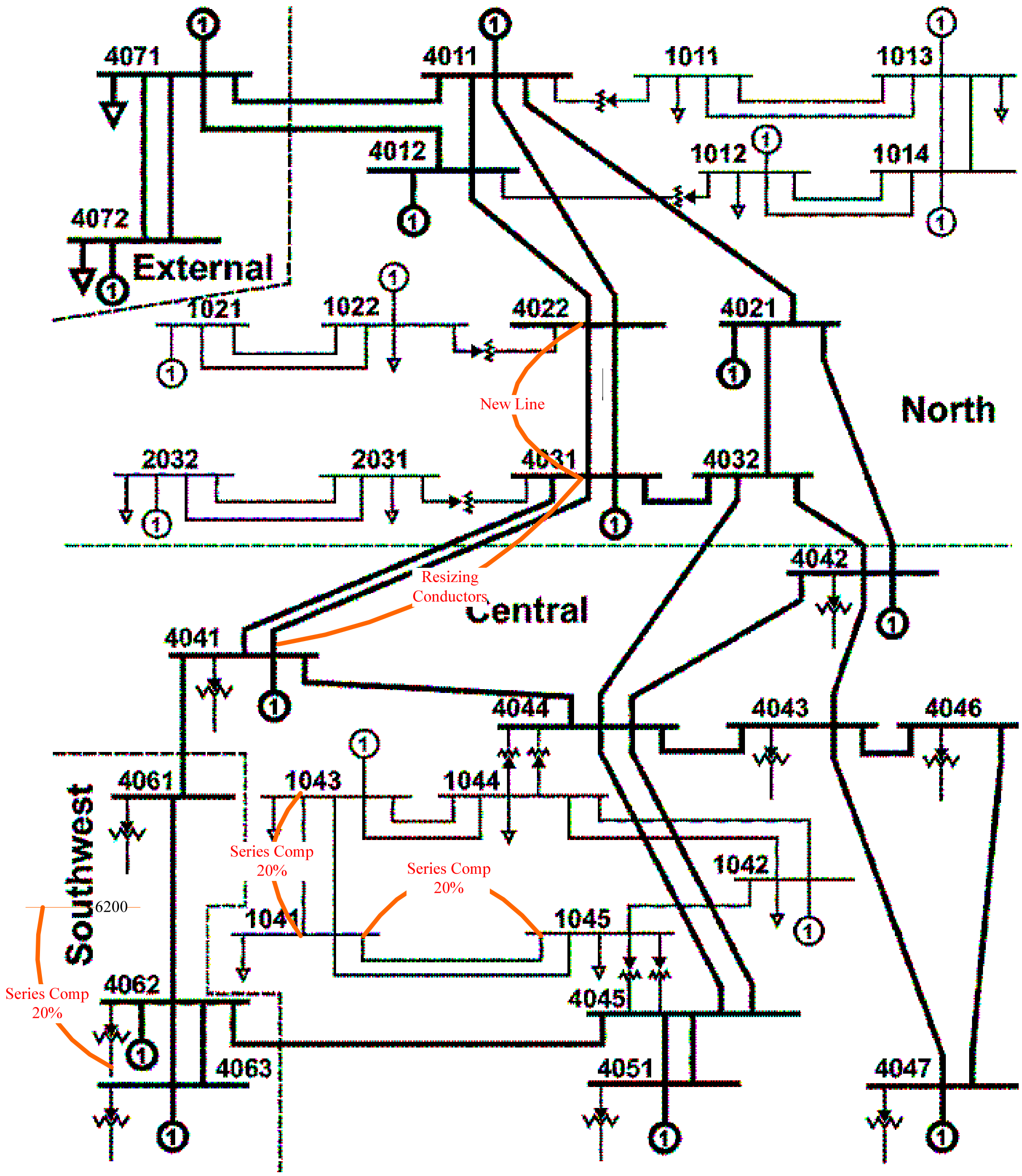

Figure 6.4 Reinforcement Options Selected in the Decomposition Approach

6.5.3.3 TRP Solution Using the Unified Approach

The optimal selection of transmission reinforcement options obtained using the Unified Approach is presented in Table 6.8.

Table 6.8 TRP Solution using Unified Approach

	S_1_1	S_2_1	S_3_1	S_1_4	N_1_4
4011-4021				1	
4062-62		1			
1043-1041			1		
4022-4031					1
1045-1041	1				

It is observed from Table 6.8 that four lines (4011-4021, 4062-62, 1043-1041 and 1045-1041) are provided with different degrees of series compensation options and one line (4022-4031, 400kV) is advised the option of adding one more circuit for alleviating thermal and MW overloading.

Figure 6.5 shows the 32-bus CIGRE system with the options suggested as an outcome of the Unified Approach to TRP problem.

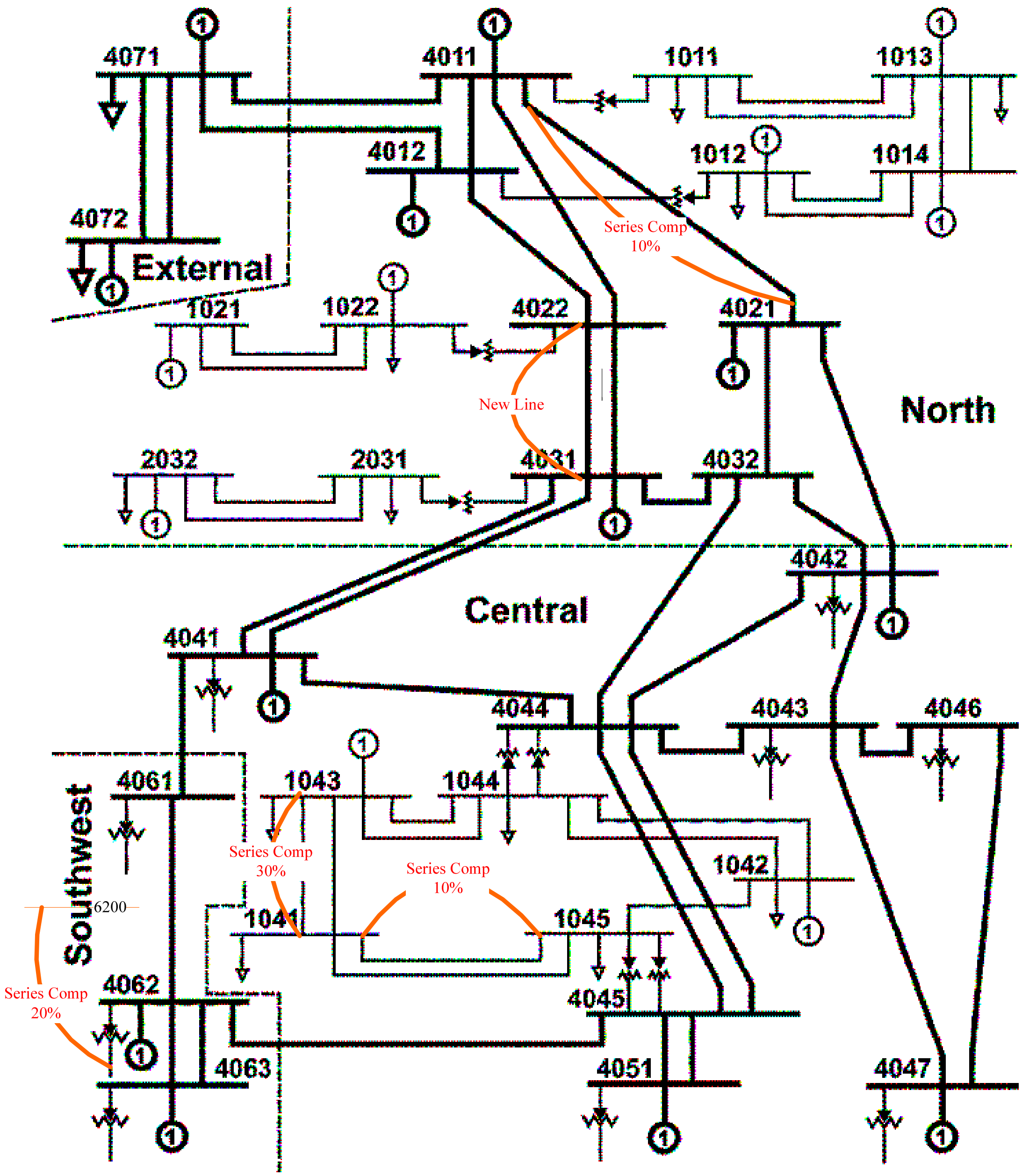

Figure 6.5 Reinforcement Options Selected in the Unified Approach

The investment costs obtained from both approaches are presented in Table 6.9. It is observed that the total investment cost resulting from the Decomposition Approach is 22.95 M$, which is higher by 16.12%, than the investment cost of 19.25 M$ accrued in the Unified Approach. This is because of the inherent inability of the Decomposition Approach to capture the interactive overloads.

Table 6.9 Investment Costs in M$ Obtained from both TRP Solution Methods

Decomposed Approach	22.95
Unified Approach	19.1400

The computational burden of the Unified Approach is higher than the Decomposition Approach due to the obvious differences in the nature of these problems. However, the Unified Approach is easily solved by the commercially available MINLP solvers. In this work, the CPLEX solver in GAMS [70] is used to solve the TRP problem using Decomposition Approach, while SBB solver on NEOS [85] is used to solve the TRP problem using Unified Approach. Table-4.7 provides the details of the size of the mathematical models. The decomposition approach is solved on a standard Intel Xeon processor with 3 GB RAM.

Table 6.10 Computational Details of Optimization Problems

Event	Decomposition Approach		Unified Approach
	Base OPF	TRS	SCC-TRS
Equation Blocks	10	3	17
Variable Blocks	8	2	14
Single equations	3,650	1,687	13,737
Single variables	3,568	35,302	43,954
Non zero elements	5,184	35,385	53,174
Discrete variables	-	70	70
Model Generation time(sec)	0.141	0.187	0.219
Model Execution time (sec)	0.157	0.234	0.241

6.6 Concluding Remarks

This chapter presents a new approach to address the medium-term TRP problem by using practical judgment and engineering experience to simplify the computational aspects via the notion of Feasibility Set. The Feasibility Set helps reduce the problem size and hence optimal solution is easily obtained even when the TRP problem is modeled as a MINLP problem. Two approaches to solution of the MINLP problem are examined, the Decomposition Approach and the Unified Approach. It is seen that although the Decomposition Approach simplifies the computation, the total investment cost is higher. On other hand the Unified Approach is able to solve the comprehensive TRP problem directly using the MINLP solvers, easily, because of the reduced problem size achieved with the help of the Feasibility Set and also achieves a lower total investment cost.

Chapter 7
Conclusions

7.1 Summary and Conclusions

This thesis explores different aspects of medium-term operations and planning of power systems in deregulated electricity market environment. The research work focuses on diverse but interlinked issues in medium-term power system operations and planning. These issues are either discovered or have surfaced due to electricity sector deregulation or generated as a result of a unique thought-process emerged because of the restructuring phenomenon.

Chapter 1 of the thesis introduces to the issues in medium-term operations and planning in restructured electricity market environment. It briefs the present state of Ontario's electricity sector and outlines the challenges faced by Ontario electricity market. Thereafter the Chapter provides insight in to the motivation that inspired this research work. The chapter finally discusses the objectives set for this thesis.

Chapter 2 discusses the pertinent medium-term operations issues of production and maintenance scheduling in power systems and brings out the changed paradigm of operation and need for coordination of these functions by the ISO in the context of deregulation. It further charts the need for a locational reliability index, which can provide critical information regarding the load serving probability, to ISO.

The chapter discusses the medium-term planning issues with specific focus on the "insufficiently attended" transmission reinforcement activity. A modest attempt is made in this chapter to review the literature on production-cum-maintenance scheduling, locational reliability and the TRP problems in order to develop an understanding of the issues and the state-of-art in the research in these significant subjects of medium-term operations and planning in power systems.

Maintenance scheduling of generating units is an important medium-term operations planning activity that reduces the risk of capacity outages. Chapter 3 presents the mathematical formulation and details, of a new approach to security coordinated maintenance scheduling in deregulation. In this novel framework, the ISO does not generate a maintenance schedule by itself, but calls for maintenance schedules from individual gencos. The maintenance schedules plans, when incorporated in a medium-term security constrained production scheduling model can result in unserved energy at one or more buses. Based on the information on bus-wise unserved energy, the ISO generates corrective signals for the genco(s), and directs them to alter their maintenance schedules in specific periods and re-submit. The proposed scheme exploits the concept of commons and domains to derive a novel factor to allocate the unserved energy at a bus to a set of generators responsible. Iterations between the gencos and ISO continue until the coordination program has converged, and there is no unserved energy at any period in the system.

The coordination scheme is based on individual genco's accountability to unserved energy at a bus. Chapter 4 presents a comprehensive case study for a large 3-utility, 37-generator system that approximately represent the Ontario power system. Detailed model simulation results are presented in this Chapter to demonstrate the application of the proposed scheme with insight on the coordination process. The proposed scheme is computationally simple, efficient and can be applied to practical power systems. The scheme is very efficient and converges within five iterations and has the advantage of being fair, logical, understandable and simple. It also takes into consideration the gencos' individual maintenance schedules, and tries to retain these schedules as far as possible, unless it is absolutely important from system security considerations, to modify them.

Chapter 5 focuses on locational reliability indices and introduces the concept of reliability differentiated pricing in the context of competitive electricity markets. A new LSP index based on locational LOLP indices are proposed and the mathematical approach to compute these locational reliability indices is presented. The methodology is applied to a 5-bus test system and the reduced representative Ontario test system, to make the approach easy to understand and verify its applicability to a practical sized system.

Chapter 5 investigates the discrepancy in LMPs with respect to the bus-wise LSP, determined from locational LOLP indices. It shows that reverse scaling the LMPs with respect to the differential locational LSP indices opens a scope for effective pricing of electricity. This work also opens up the prospect for research on reliability as a tradable feature in deregulation. Furthermore, the knowledge of locational LSPs can be used by the system operators to be prepared for contingency conditions and take preventive measures, specific to locations. Such measures can include reserves, load curtailment, and capacitor switching provisions.

Chapter 6 presents a new approach to medium-term TRP which takes into account engineering judgment and experience to develop a Feasibility Set of transmission reinforcement options.

The proposed approach is easier to implement and reduces the size of the problem and seeks to attain optimal solution within the feasibility range. Two modelling approaches to solve the TRP problem are presented. The Decomposition Approach focuses on the cost minimization of identified reinforcement options for the congested lines. Its solution is a feasible solution, but as the interactive overloads are not taken into considerations, an iterative solution strategy has to be formulated considering the verification after each step of selection of reinforcement options for congested lines. The Unified Approach does take interactive overloads into account, and provides better solution as compared to the Decomposition Approach.

7.2 Main Contributions of the Thesis

1. A novel security coordination scheme is proposed in the thesis for the medium-term maintenance scheduling problem in deregulation that iterates between the multiple GMS Programs and the OCP using gencos' contribution to unserved energy, as critical signals.
2. A novel factor is introduced to allocate the unserved energy to the gencos who are accountable for not serving the energy, based on their contribution to a load at a bus and the capacity of genco on maintenance.
3. The coordinated maintenance scheduling scheme arrives at an optimal medium-term production-cum-maintenance schedule that takes into account all relevant system constraints. The proposed scheme is very efficient and converges in five iterations. The scheme is fair, logical, understandable and simple. It takes into consideration the gencos' individual schedules, and tries to maintain these schedules as far as possible, unless it is absolutely critical from system security considerations to request for their modifications.
4. The computational burden on ISO is also reduced tremendously as the proposed coordination scheme does not require the ISO to compute the maintenance schedules for all gencos.
5. A novel concept of locational reliability indices is put forward in this thesis and the locational LOLP, and locational LSP indices are proposed.
6. An innovative concept of Isolated Bus Representation is developed, proposed and utilized to derive a methodology of computing the locational LOLP indices and hence, to arrive at, the locational LSP indices.
7. The concept of reliability differentiated pricing is proposed in this thesis and a simple reverse scaling approach based on locational LSP indices, to obtain reliability differentiated LMPs, is proposed.
8. A new approach is presented in the thesis to address the medium-term TRP problem by using practical judgment and engineering experience to simplify the computational aspects via the notion of Feasibility Set. The proposed Feasibility Set helps reduce the problem size and

hence optimal solution is easily obtained even when TRP problem is modeled as a MINLP problem.

9. Two different solution approaches to solve the MINLP TRP problem are proposed. The Decomposition Approach and the Unified Approach. The Decomposition Approach is a sequential approach that solves a MILP problem to select the feasible solution while trying to overcome the thermal and/or MW capacity deficit observed from Base OPF. Whereas the Unified Approach is able to solve the comprehensive TRP problem directly using the MINLP solvers, easily, because of the reduced problem size with the help of Feasibility Set and also achieves a lower total investment cost. System security constraints are incorporated in terms of line MW and thermal overload limits, which are realistically determined.

7.3 Scope for Future Work

On the basis of the research work reported in this thesis, the following directions may be pursued for future research work.

1. Apply a stochastic programming approach to address the uncertainties associated with price, fuel costs, load demand and other parameters that are subject to variations, in the medium-term security coordinated maintenance scheduling problem, and hence obtain the expected medium-term solution.
2. Apply a sensitivity based approach using information provided by Langrangian multipliers to identify the contributions of gencos to the loads and solve the medium-term security coordinated maintenance scheduling problem. This method will provide a comparison of performance of the method of commons and domains presented in this thesis.
3. The Isolated Bus Representation concept can be further developed to a matured state and there is scope for exploring newer methods of computing locational reliability indices. Furthermore, specialized reliability differentiated pricing mechanism can be developed considering social welfare and other electricity market economic aspects.
4. The proposed Decomposition Approach to TRP can be made more robust to take into consideration the interactive overloads without losing its simplicity and the MILP nature of the model. A prioritizing approach can be exploited to develop a comprehensive iterative algorithm, so that the optimal solution on the convergence of algorithm is guaranteed.
5. The proposed Unified Approach to TRP may also be modified and other contingency and transient analysis, in the verification stage, may be incorporated to make it more effective and

robust. Further, risk management, and uncertainties may be considered to attain a sophisticated, practically applicable TRP solution Approach.

Appendices

Appendix A
5-Bus Test System

A sample 5-bus test system (Fig.A.1) is used in Chapter 5 of this thesis to determine the locational reliability indices and the reliability differentiated pricing.

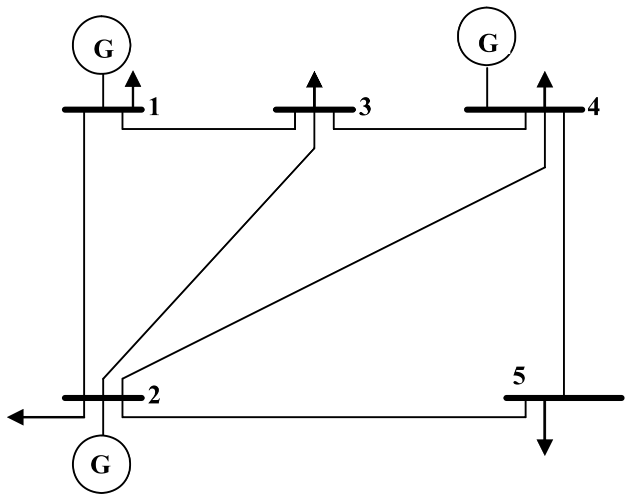

Figure A.1 5-Bus Test System Configuration

Table A.1: Load Flow Data

Line Data (all data are in pu)			Bus Data (use a 100 MW Base)		
Line i-j	Impedance, Z_{ij}	Line Charging y_{ij}	Bus	Real Power Demand, MW	Reactive Power Demand, MVAr
1-2	0.02 + j 0.06	j0.03	1	125	45
1-3	0.08 + j0.24	j0.025	2	150	50
2-3	0.06 + j0.18	j0.02	3	175	65
2-4	0.06 + j0.18	j0.02	4	215	60
2-5	0.04 + j0.12	j0.015	5	145	55
3-4	0.01 + j0.03	j0.10			
4-5	0.08 + j0.24	j0.025			

Table A.2: Generation Data

Unit	P Limits, MW		Q Limits, MVAr	
	Max	Min	Max	Min
1	400	50	100	-50
2	350	50	100	-50
4	350	50	100	-50

Appendix B

CIGRE 32-Bus Test System

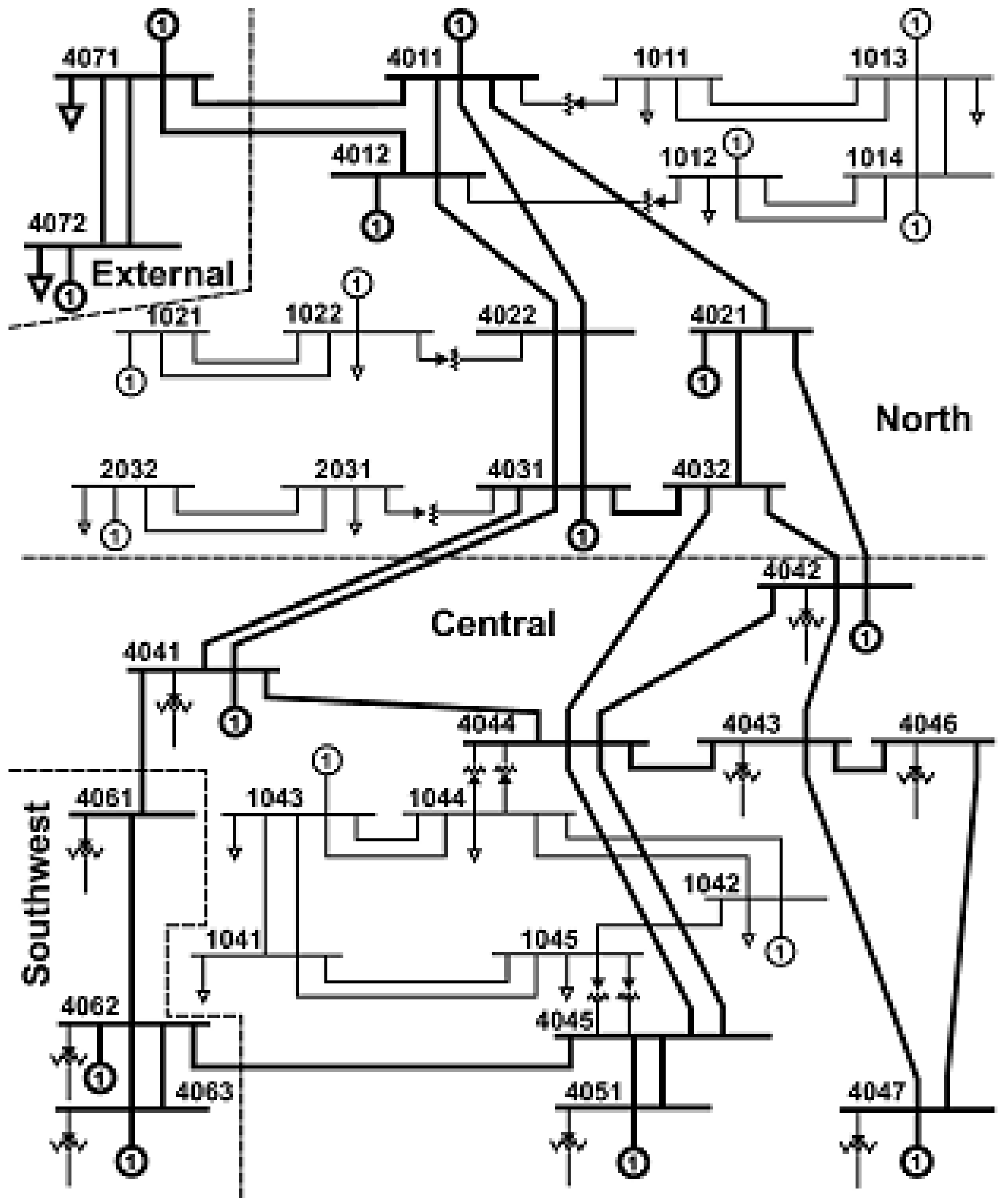

Figure B.1 CIGRE 32-Bus Test System [84]

The CIGRE 32-bus test system (Fig. B.1) has been used in Chapter 6 of this thesis to implement and test both the proposed TRP solution approaches. The system has a total demand of 10,940 MW and has 20 generators, 9 shunt capacitors, and 2 reactors. Bus 4011 is selected as the slack bus. The data for generator buses is provided in Table B.1 that includes the generation limits, the demand and the voltage level at all the 20 generator buses. The real and reactive power demand at load buses, together with the installed shunt capacitors and voltage levels, are given in Table B.2. The data for the transmission lines in CIGRE system is given in Table B.3.

Table B.1 Generator Buses

Bus	P^{Max} (MW)	P^{Min} (MW)	Q^{Min} (MVAr)	PD (MW)	QD (MVAr)	Q_{sh} (MVAr)	V_{Level} (kV)	Xs (P.U.)
4072	4500	0	-300	2000	500	0	400	1.5
4071	500	0	-50	300	100	-400	400	0.8
4011	1000	0	-100	0	0	0	400	1.2
4012	800	0	-160	0	0	-100	400	1.1
4021	300	0	-30	0	0	0	400	0.7
4031	350	0	-40	0	0	0	400	0.7
4042	700	0	0	0	0	0	400	1
4041	300	0	-200	0	0	200	400	0.7
4062	600	0	0	0	0	0	400	0.9
4063	1200	0	0	0	0	0	400	1.2
4051	700	0	0	0	0	100	400	1
4047	1200	0	0	0	0	0	400	1.2
2032	850	0	-80	200	50	0	220	1.1
1013	600	0	-50	100	40	0	130	0.9
1012	800	0	-80	300	100	0	130	1.1
1014	700	0	-100	0	0	0	130	1
1022	250	0	-25	280	95	50	130	0.7
1021	600	0	-160	0	0	0	130	0.9
1043	200	0	-20	230	100	150	130	0.6
1042	400	0	-40	300	80	0	130	0.8

Table B.2 Load Buses

Bus	PD (MW)	QD (MVAr)	Q_{sh} (MVAr)	V_{Level} (kV)
4022	0	0	0	400
4032	0	0	0	400
4043	0	0	200	400
4044	0	0	0	400
4045	0	0	0	400
4046	0	0	100	400
4061	0	0	0	400
2031	100	30	0	220
1011	200	80	0	130
1041	600	200	200	130
1044	800	300	200	130
1045	700	250	200	130
42	400	125.67	0	130
41	540	128.8	0	130
62	300	80.02	0	130
63	590	256.19	0	130
51	800	253.22	0	130
47	100	45.19	0	130
43	900	238.83	0	130
46	700	193.72	0	130
61	500	112.31	0	130

Table B.3 Transmission Lines

Line	Resistance (Ω)	Reactance (Ω)	Line Charging (P.U)
4011.4012	1.6	12.8	0.4
4011.4021	9.6	96	3.58
4011.4022	6.4	64	2.39
4011.4071	8	72	2.79
4012.4022	6.4	56	2.09
4012.4071	8	80	2.98
4021.4032	6.4	64	2.39
4021.4042	16	96	5.97
4031.4022	3.2	32	1.2
4031.4032	1.6	16	0.6
4031.4041	4.8	32	2.39
4042.4032	16	64	3.98
4032.4044	9.6	80	4.77
4041.4044	4.8	48	1.79
4041.4061	9.6	72	2.59
4042.4043	3.2	24	0.99
4042.4044	3.2	32	1.19
4043.4044	1.6	16	0.6
4043.4046	1.6	16	0.6
4043.4047	3.2	32	1.19
4044.4045	1.6	16	0.6
4045.4051	3.2	32	1.2
4045.4062	17.6	128	4.77
4046.4047	1.6	24	0.99
4061.4062	2.4	24	0.9
4062.4063	2.4	24	0.9
4071.4072	2.4	24	3
2031.2032	2.9	21.78	0.05
1011.1013	0.85	5.9	0.13
1012.1014	1.2	7.6	0.17
1013.1014	0.59	4.23	0.1
1021.1022	2.54	16.9	0.29
1041.1043	0.85	5.07	0.12
1041.1045	1.27	10.14	0.24
1042.1044	3.21	23.66	0.57
1042.1045	8.45	50.7	1.13
1043.1044	0.85	6.76	0.15

Appendix C
57-Bus Ontario (Representative) Test System

The 57-Bus Ontario test system has been used in Chapter 4 of this thesis to implement the proposed Security Coordinated Maintenance Scheduling scheme, and in Chapter 5 to determine the locational reliability indices and the reliability differentiated pricing. The Bus data is provided in Table C.1 showing the peak demand and bus voltage level. Table C.2 provides the line data.

Table C.1 Bus Data

Bus	PD (MW)	V_{Level} (kV)
10	500	500
100	500	220
101	600	220
103	200	220
344	300	115
359	300	115
1001	400	500
1104	200	220
1106	400	220
1301	200	115
2002	700	500
2007	600	500
2100	700	220
2106	600	220
3107	600	220
3108	600	220
3300	600	115
3301	200	115
4000	700	500
4100	500	220
4105	600	220
5003	700	500
5102	700	220
5103	700	220
5105	700	220
5135	700	220
5403	600	115
5404	600	115
5690	600	115
6400	700	500
6401	700	500

Continued Table C.1

Bus	PD (MW)	V_{Level} (kV)
6402	600	500
6500	500	220
6501	700	220
6603	200	115
7000	500	500
7100	500	220
7102	500	220
7105	400	220
7108	400	220
7300	300	115
7302	300	115
7365	40	115
8000	400	500
8001	0	500
8002	500	500
8103	40	220
8104	40	220
8109	300	220
8110	500	220
8112	40	220
8114	40	115
8258	40	115
9103	300	220
9112	200	220
9302	300	115
9311	200	115

Table C.2 Line Data

Line	Resistance (Ω)	Reactance (Ω)
10.103	0.00006	0.00638
10.1001	0.00104	0.01174
100.103	0.00423	0.0523
100.344	0.32725	1.55716
100.1104	0.0391	0.22753
100.1106	0.87305	4.54493
100.2002	0.05263	0.67838
100.2100	0.03966	0.25471
100.3301	0.16706	1.55841
100.4105	0.22606	1.11239
101.359	0.21292	0.56306
101.1104	0.03975	0.20408

Continued Table C.2

Line	Resistance (Ω)	Reactance (Ω)
103.344	0.03327	0.17064
103.1106	0.01209	0.11434
103.1301	0.71669	3.0509
103.2002	0.05037	0.76884
103.2100	0.10397	0.90844
103.3301	0.16798	1.76686
103.4105	0.24085	1.26263
344.1106	0.22019	0.75781
344.1301	0.60033	1.51777
359.4100	0.02545	0.42854
359.6501	0.02117	0.32188
359.8103	0.12695	1.37184
359.8104	0.04877	0.60641
359.8258	1.41062	7.03381
1001.1106	0.00009	0.00979
1001.2007	0.00049	0.0056
1104.1301	0.00059	0.0219
1104.2100	0.01319	0.08366
1106.1301	0.13092	0.6152
110.2002	0.02302	0.78521
1106.2100	0.025	0.25447
1106.3301	0.1061	1.80639
1106.4105	0.19891	1.29532
2002.2007	0.0001	0.00143
2002.2100	0.00011	0.00796
2002.3301	-0.00063	0.05221
2002.4000	0.00013	0.00143
2002.4105	0.00308	0.03769
2100.2106	0.00017	0.00354
2100.3301	0.00082	0.01858
2100.4105	0.00126	0.01293
3107.4105	0.00027	0.00288
3108.3300	0.00319	0.0265
3108.4105	0.00031	0.00323
3300.3301	0.00073	0.00308
3301.4105	0.00965	0.08657
4000.4100	0.00006	0.00475
4000.4105	0.00222	0.03499
4000.5003	0.00117	0.01139
4000.5102	0.00105	0.02875
4000.5103	0.00711	0.47442
4000.5105	0.00325	0.18381

Continued Table C.2

Line	Resistance (Ω)	Reactance (Ω)
4000.5135	0.05033	0.59174
4000.5403	0.31533	3.86628
4000.5690	-0.0653	8.60719
4000.6400	0.00225	0.02622
4000.6401	0.00291	0.03182
4000.6402	0.00047	0.00457
4000.7100	0.01091	0.49128
4100.4105	0.00014	0.00182
4100.6501	0.02878	0.18356
4100.8103	0.53027	2.62092
4100.8104	0.22023	1.16008
4105.5003	0.02024	0.27047
4105.5102	0.00188	0.01381
4105.5105	-0.03146	4.89749
4105.6401	0.02191	0.36319
5003.5102	0.0022	0.03951
5003.5103	0.00274	0.19792
5003.5105	0.00011	0.00926
5003.5135	0.01978	0.24199
5003.5403	0.10053	1.24658
5003.5690	-0.00432	3.32838
5003.6401	0.02493	0.24429
5003.7000	0.00179	0.02009
5003.7100	0.00459	0.21008
5102.5103	0.00869	0.07999
5102.5105	0.00335	0.03073
5102.5135	0.00431	0.03197
5102.5403	0.00032	0.00899
5102.5690	0.03247	0.37919
5102.6401	0.01079	0.35288
5102.7100	0.01077	0.08978
5103.5105	0.00863	0.13339
5103.5135	0.05894	0.4408
5103.5403	0.41868	2.91595
5103.5404	0.00037	0.01349
5103.5690	0.36475	7.05442
5103.6500	0.00679	0.06239
5103.6501	0.01171	0.0769
5103.6603	2.71214	9.55219
5103.7100	0.00364	0.03589
5105.5135	0.02212	0.16522
5105.5403	0.1131	0.85375

Continued Table C.2

Line	Resistance (Ω)	Reactance (Ω)
5105.5690	0.11898	2.32369
5105.6401	0.09137	4.43319
5105.7100	0.01058	0.14406
5135.5403	0.09274	0.4631
5135.5690	0.00085	0.0256
5135.7100	0.06663	0.46654
5403.5690	0.20758	0.81607
5403.7100	0.46837	3.24967
5404.6500	0.09801	0.35063
5404.6501	0.76308	2.78377
5404.6603	4.56593	7.73344
5690.7100	0.33487	6.84244
6400.6401	0.00003	0.00056
6400.6500	0.00007	0.00609
6400.7000	0.00202	0.02366
6401.7000	0.00207	0.02377
6402.6501	0.00011	0.00949
6402.8000	0.00174	0.0184
6500.6501	0.01867	0.14755
6500.6603	0.07989	0.46269
6501.6603	0.00065	0.0376
6501.8103	0.41099	1.96679
6501.8104	0.17103	0.87062
7000.7108	0.00004	0.00422
7100.7102	0.06111	0.4279
7100.7105	0.005	0.04764
7100.7108	0.00146	0.01446
7100.7300	0.00031	0.0139
7100.7302	0.05393	0.5619
7100.7365	0.82758	2.39551
7102.7105	0.01831	0.12925
7102.7108	0.03234	0.27991
7102.7302	0.00492	0.05162
7105.7108	0.00321	0.02977
7105.7300	0.09326	0.53407
7105.7302	0.01609	0.16971
7105.7365	0.1015	0.32608
7108.7302	0.02531	0.3671
7300.7365	2.13473	4.05301
7302.7365	0.05819	0.26047
8000.8002	0.0023	0.0276
8000.8104	0.00008	0.00663

Continued Table C.2

Line	Resistance (Ω)	Reactance (Ω)
8001.8002	0.00172	0.02078
8001.8109	0.00009	0.01044
8002.8109	0.42794	1.02072
8002.8110	0.00042	0.02341
8002.8258	0.98651	1.55475
8103.8104	0.0549	0.24891
8103.8258	0.00101	0.04635
8104.8112	0.02244	0.18282
8104.8114	0.19171	0.5857
8104.8258	0.40592	0.72847
8109.8110	0.55893	1.65142
8109.8258	4.43407	5.19554
8110.8258	0.2246	0.72789
8112.8114	0.00165	0.04398
8112.9112	0.01376	0.08455
9103.9112	0.05132	0.38089
9103.9302	0.0011	0.04398
9103.9311	0.03081	0.21427
9112.9302	0.38839	1.58607
9112.9311	0.18859	1.35689
9302.9311	0.10566	0.37829

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