Market-Based Transmission Congestion Management Using Extended Optimal Power Flow Techniques

A thesis submitted for the degree of

Doctor of Philosophy

By

Xing Wang, MPhil

Department of Electronic and Computer Engineering

Brunel University, West London, UK

June 2001

Market-Based Transmission Congestion Management Using Extended Optimal Power Flow Techniques

Xing Wang

Abstract

This thesis describes research into the problem of transmission congestion management. The causes, remedies, pricing methods, and other issues of transmission congestion are briefly reviewed. This research is to develop market-based approaches to cope with transmission congestion in real-time, short-run and long-run efficiently, economically and fairly. Extended OPF techniques have been playing key roles in many aspects of electricity markets. The Primal-Dual Interior Point Linear Programming and Quadratic Programming are applied to solve various optimization problems of congestion management proposed in the thesis.

A coordinated real-time optimal dispatch method for unbundled electricity markets is proposed for system balancing and congestion management. With this method, almost all the possible resources in different electricity markets, including operating reserves and bilateral transactions, can be used to eliminate the real-time congestion according to their bids into the balancing market. Spot pricing theory is applied to real-time congestion pricing.

Under the same framework, a Lagrangian Relaxation based region decomposition OPF algorithm is presented to deal with the problems of real-time active power congestion management across multiple regions. The inter/intra-regional congestion can be relieved without exchanging any information between regional ISOs but the Lagrangian Multipliers.

In day-ahead spot market, a new optimal dispatch method is proposed for congestion and price risk management, particularly for bilateral transaction curtailment. Individual revenue adequacy constraints, which include payments from financial instruments, are involved in the original dispatch problem. An iterative procedure is applied to solve this special optimization problem with both primal and dual variables involved in its constraints.

An optimal Financial Transmission Rights (FTR) auction model is presented as an approach to the long-term congestion management. Two types of series FACTS devices are incorporated into this auction problem using the Power Injection Model to maximize the auction revenue. Some new treatment has been done on TCSC's operating limits to keep the auction problem linear.

DECLARATION

The work described in this thesis has not been previously submitted for a degree in this or any other university and unless otherwise referenced it is the author's own work.

Statement of Copyright

The copyright of this thesis rests with the author.

No quotation from it should be published without his prior written consent,

and information derived from it should be acknowledged.

Acknowledgments

Principal Symbols and Abbreviations

Symbols

Superscript and subscript:

i,j,l,m,n	index of network buses,
ij	bilateral contract or branch flow from bus i to bus j,
A, B	index of regions,
k	index of iteration,
l	index of branches,
s	slack bus,
†	transpose,
+	incremental adjustment on generators or loads in the balancing market,
−	decremental adjustment on generators or loads in the balancing market,
max	upper limit,
min	lower limit,
0	current value or scheduled value,
Res	operating reserves,
Rep	replacing procurement for used operating reserves,
En	energy,
Cap	capacity,
−	average value.

Sets:

D	the set of consumers,
G	the set of generators,
L	the set of branches,
N_D	the set of demand buses,
N_G	the set of generation buses,
Ω	set of buses in the whole system,
Ω^A	set of buses in region A,
Ξ^A	set of buses which have direct connection with buses in region A,
Θ_i	set of buses which have branches connected with bus i and flows on the branches are flowing to bus i.

Variables:

V	bus voltage magnitude,
θ	bus voltage angle,
t	transformer turning ratio,
P	active power,
Q	reactive power,
λ, μ	Lagrangian multiplier,
ρ	Locational marginal price or nodal spot price,
CfD	MW amount of a Contract for Differences,
FTR	MW amount of a Financial Transmission Right,
R	profit of individual market participant,

P_F power injection of FACTS devices,

x_c reactance of series compensator,

ψ phase shifter angle.

Prefix:

Δ change of variables based on scheduled points,

∂ partial derivative.

Functions:

$C(\bullet)$ active power cost or bidding functions,

$B(\bullet)$ active power bid functions of consumers in the spot market,

$h(\bullet)$ equality constraints,

$g(\bullet)$ inequality constraints,

$LF(\bullet)$ piece-wise linear loss functions of branches.

Parameters:

x_{ij} reactance of branch ij,

B linearized active power Jacobian matrix,

H matrix of branch power flow constraint coefficient,

M mapping matrix of FTRs in the auction,

M_B mapping matrix of FTRs in the base case,

M_F connection matrix of FACTS devices,

P_B matrix of FTR injection in the base case,

b, w, r bidding prices.

Abbreviations

AGC	Automatic Generation Control
ATC	Available Transmission Capability
BCM	Bilateral Contract Market
CBM	Capacity Benefit Margin
CfD	Contracts for Differences
DTS	Dispatch Training Simulator
ED	Economic Dispatch
EMS	Energy Management System
FACTS	Flexible AC Transmission System
FERC	Federal Energy Regulatory Commission
FGR	Flowgate Transmission Rights
FTR	Financial Transmission Rights
ISO	Independent System Operator
IT	Information Technology
LTR	Link-based Transmission Rights
LMP	Locational Marginal Price
LOLP	Loss of Load Probability
VOLL	Value of Lost Load
LR	Lagrangian Relaxation
NETA	New Energy Trading Arrangement

NGC	National Grid Company
OASIS	Open Access Same-Time Information System
OPF	Optimal Power Flow
PIM	Power Injection Model
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PAAM	Pool Day-ahead Ancillary Services Auction Market
PBC	Physical Bilateral Contract
PEAM	Pool Day-ahead Energy Auction Market
PPP	Pool Purchase Price
PSP	Pool Selling Price
PTDF	Power Transfer Distribution Factor
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
PX	Power Exchange
RBM	Real-time Balancing Market
RTO	Regional Transmission Organisation
SCADA	Supervisory Control and Data Acquisition
SMP	System Marginal Price
SRMC	Short Run Marginal Pricing
TCC	Transmission Congestion Contracts
TCPS	Thyristor Controlled Phase Shifters
TCSC	Thyristor Controlled Series Compensators

TRM	Transmission Reliability Margin
TTC	Total Transfer Capability
VSM	Voltage Source Model
UC	Unit Commitment

CONTENTS

Figures

Tables

Chapter 1. Introduction

1.1 Aims of the Thesis

1.1.1 Background to the Research

There has been a worldwide trend towards restructuring and deregulation of the power industry over the last decade. The competition in the wholesale generation market and the retail market together with the open access to the transmission network can bring many benefits to the end consumers, such as lower electricity prices and better services. However, this competition also brings many new technical problems and challenges to the operation of power system, which was regarded as "natural monopoly" due to the special characteristics of electricity as a commodity. On the other hand, this means real opportunities and challenges to power engineers and researchers [1-2, 6-8].

An important driving force behind this significant reform is the recent development of technology. At the end of the 20th century, many technological innovations are emerging. In all sectors of the electric power industry, these innovations lead to changes or even revolutions. Some of the most prominent developments are [11]:

- Generation technology. New power generation technologies with higher efficiencies and lower emissions are being developed. Coal gasification and small gas turbine (from 1 MW down to 1KW) technologies are progressing steadily. Mass production and market penetration of such installations may turn the current network design philosophy completely upside down. The concept of distributed generation can easily incorporate power generation from renewable sources [2].

- Transmission technology. New technologies in transmission and distribution may have a tremendous impact on the power industry. High-efficiency transformers, ultra-high-voltage transmission lines (1,500KV or even higher) and eventually the application of superconducting materials will reduce power losses between power plants and consumers [6].

- Control technology. Advanced network control technologies enhance the optimal allocation of transmission lines, improve the stability of power systems, and may eventually open the transmission sector to competition. The most promising development is the replacement of the present low-speed control electronics by a new branch of control devices, the Flexible AC Transmission System (FACTS). With FACTS devices it is possible to control power flow through transmission lines, to regulate voltage, phase angle and line impedance [4].

- Metering technology. The development of new metering systems is indispensable for the implementation of an electricity market. Due to the price of electricity varying with time in the market, metering must be time-dependent in order to bill the consumers the correct prices. Advanced techniques for automatic meter reading are being developed, either by reading the meter data from a distance radiographically, or by meter communicating with the supply company through the telecommunication or the power grid.

- Information technology (IT). Advances in IT, driven by the doubling of the microprocessor power every 18 months, the exponential growth of information storage capacity and the fast growth of the Internet, have a tremendous impact on the many aspects of electricity markets, such as bidding systems, billing systems, market information publishing systems, etc.

Transmission plays a key role in making the competitive market work while the transmission operator is a vital entity to maintain grid reliability. More and more free bilateral trades of electricity are making the existing transmission system become a scarce resource and transmission congestion occurs more frequently. Congestion management is a crucial function of any system operator and is the process that ensures the security and reliability of market operation [12, 14]. Traditional mandatory dispatching actions (adjust fast-responded generators, curtail loads, etc.) are easy to implement and maybe still necessary in the worst situation, but they are not encouraged in a competitive electricity market as they are not transparent and may prevent the market from further development. With all the new technologies mentioned above, market-based approaches are needed urgently to cope with transmission congestion efficiently, economically, fairly, and transparently.

1.1.2 Aims of the Research

The primary aim of the research presented in this thesis is to develop market-based approaches to transmission congestion management with extended Optimal Power Flow

(OPF) techniques. The congestion problems should be managed in different time scales ranging from real-time dispatching through short-term scheduling up to long-term planning.

First, an efficient approach to congestion management through real-time balancing market is proposed. This approach deals with the real-time imbalance and congestion problems caused by unexpected contingencies and unpredictable load fluctuation. The aim of this part of work is to use all the possible resources in unbundled electricity markets according to the various bids from market participants to eliminate the real-time congestion and then to find an accurate pricing method for it.

Since a modern power system is usually a large interconnected system with multiple control regions and system operators, the real-time operation and congestion management needs the coordination between these system operators, particularly when congestion occurs on the tie lines between regions. The second part of this research is to find a feasible and fast way to implement this coordinated operation without exchanging a huge amount of data between regions.

In the short term spot market, the Locational Marginal Price (LMP) [13] has been used for congestion management and pricing. To hedge against high price risk caused by congestion, some pure financial instruments have been introduced into electricity markets. The purpose of market participants to trade electricity is to make a profit, thus those participants suffering from high prices will be willing to reduce their transactions to protect their individual revenue adequacy. The third part of this research in this thesis is to eliminate congestion by considering the individual revenue adequacy constraints of market participants.

To avoid the appearance of transmission congestion, the limited transmission capacity should be allocated to the users who value it best in the long run. Financial transmission rights (FTR) have been proven as an efficient and flexible approach to transmission capacity reservation. The last part of this research work of this thesis is to implement an optimal auction for FTR to maximize the revenue from the use of transmission system by controlling FACTS devices in the grid.

1.2 The Restructuring of Electricity Industry

Before restructuring, the electricity industry in the world was either a private-owned monopoly like the United States (US) or a state-owned monopoly like the United Kingdom

(UK). Although their background and the detailed restructuring processes are different, the common goal is to introduce competition into the electricity industry and to provide customers with their choices of power supplier. In the following section, the evolution of the UK electricity industry [24,178] and the US electricity industry [6,15] will be introduced respectively.

1.2.1 The Evolution of the UK Electricity Industry

Public electricity supply in the UK dates from 1881 when Siemens began operation of a small hydro-electric generating plant in Godalming, Surrey. Firstly promoted by Joseph Chamberlain in 1881, the Electric Lighting Act of 1882 allowed local authorities to break up streets for the laying of cables or to give their consent to private companies to do so.

As the technology of the industry progressed, some consolidation of the industry into large connected units was required. The Central Electricity Board (CEB) was established in 1926 with responsibility for constructing a high-voltage national electricity grid. This was the first attempt to create a national executive body capable of integrating disparate local supply networks. The CEB developed a grid control system and encouraged construction of large capacity and more thermally efficient generating plant.

Originally nationalized in 1947 as a response to a shortage of capacity left after World War II, the UK electricity system remained government controlled until privatization and restructuring began in April 1, 1990. A White paper called *Privatizing Electricity*, which was unveiled in early 1988, became the core of the Electricity Act of 1989. The first stage of instituting a new regulatory authority (to replace the Central Electricity Generating Board (CEGB) created in 1957) came shortly after the Electricity Act in the form of the Office of Electricity Regulation (OFFER), now the Office of Gas and Electricity Markets (OFGEM). The Electricity Act of 1989 has provided the basic framework for competition among generators. The major provisions of the act include the privatization of area boards, converting them into regional electricity companies (RECs), with a separation of infrastructure (wires) and power sales and purchases. The CEGB was ordered to separate into three parts: National Power, PowerGen, and a monopolized transmission company, the National Grid Company (NGC). A power pool was created to set wholesale prices, accepting bids from power generators. Retail competition was planned to phase in over time, reaching the goal of full retail competition by 1998.

The Competitive Act of 1998, which took full effect in March 2000, includes two guiding principles: the prohibition of agreements that prevent, restrict, distort competition; and the prohibition of the abuse of a dominant business position. The Electricity Act of 1989 was significantly amended in 2000 by the Royal assent of the Utilities Act, which removes the distinction between private and public electric supplier franchise areas.

The New Electricity Trading Arrangement (NETA) began in 1997, when a review of the arrangements in force since 1989, the Pool, found that the system was flawed, uncompetitive and susceptible to manipulation. NETA "went live" on March 27, 2001. The aim of NETA is to bring about a more competitive wholesale market, bringing downward pressure on the price of bulk electricity and ultimately prices to all consumers. The primary tenets of NETA are:

- Forward and futures markets,

- Balancing mechanism administered by NGC,

- Settlement process for recouping system operator costs.

Essentially, NETA opens the way for a variety of bilateral contracts between entities buying, selling, producing, or consuming electricity. NGC will still act as System Operator and Transmission Owner, but not market operator any longer. Optimistically, OFGEM states: "Under NETA there will be less opportunity to manipulate the market."

1.2.2 The Evolution of the US Electricity Industry

The US modern electricity industry could date back to the early 1880s with the opening of Thomas Edison's Pearl Street station in Manhattan in the United States, which initially supplied 59 customers with direct-current (DC) electricity. Because of the inefficiency of DC transmission, George Westinghouse proposed a better idea of alternating current (AC). With AC systems, electricity can be transmitted at high voltages much more efficiently. By 1896, AC lines delivered electricity from generators at Niagara Falls to Buffalo, about 20 miles away. The AC transmission grid was born. From then, the power industry in the US went through an incredible expansion and formed large interconnected power systems generally.

Electric power was a natural monopoly. Centralized systems with large generators that reduced costs and attracted business customers were clearly more efficient than specialized generators and masses of wires. After the Public Utility Holding Company Act (PUHCA) of 1935 passed by Congress, electric utilities were established as vertically integrated natural

monopolies serving captive markets. Utilities and regulators determined the allowable expenses, which were used to set rates consumers had to pay. Until the early 1970s the vertical monopoly structure provided a stable basis for building an extensive and reliable system. Electric rates were steadily decreasing while electricity demand increased significantly at rates of seven to eight percent each year. Generally speaking, power systems comprise four main components: generation, transmission, distribution and consumption. The integrated utility built the generators that supplied electricity, built the wires that transported the electricity to each community and to each individual consumer, and directly billed the consumer for this bundled service.

However, change came suddenly to this fully regulated system, starting from the dramatic increase of fossil-fuel prices during and after the 1973-1974 oil embargo, along with high inflation and some other events. As a result, the electric rates stopped decreasing but started to increase regularly. Meanwhile, Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA) to respond to political concerns, including US independence on foreign oil and interest in alternative generation technologies such as solar, wind, waste, or geothermal. PURPA mandated that each investor-owned utility had to purchase power at its avoided cost from a new class of generation, known as qualifying facilities (QF), located in its service territory. PURPA therefore introduced competition into the generation section of the industry. QFs became a threat to the generation side of this monopoly. However, the utility still maintained its monopoly as it was in control of the method of distributing the product to the consumer: the transmission and distribution systems.

If the industry were to move towards a truly competitive marketplace, the access to the transmission grid has to be opened. The first step toward this was another legislative act, the 1992 Energy Policy Act. This was followed in 1996 by orders from the Federal Energy Regulatory Commission (FERC): FERC Order 888 (Promoting wholesale competition through open access non-discriminatory transmission services by public utilities) and 889 (Open Access Same-Time Information System, OASIS).

Since then open access transmission and the opening of wholesale competition in the electric industry have brought many changes in the past several years, which include divestiture by many integrated utilities of some or all of their generating assets; increases in the number of new participants in the industry in the form of both independent and affiliated power marketers and generators as well as independent power exchanges; increases in the volume of

trade in the industry, particularly sales by marketers; state efforts to introduce retail competition; and new and different uses of the transmission grid.

So far, electricity industries are still in the midst of this revolutionary restructuring with more and more emerging challenges and opportunities. The general restructuring process is shown in Figure 1.1. An ideal fully deregulated power industry should have competitive generation and retail markets along with the regulated transmission and distribution networks.

```
                    ┌─────────────────────┐
                    │     Generation      │
                    ├─────────────────────┤
                    │   System Operation  │
                    ├─────────────────────┤
                    │    Transmission     │
                    ├─────────────────────┤
                    │    Distribution     │
                    ├─────────────────────┤
                    │      Merchant       │
                    └─────────────────────┘
                              │
                              ▼
                    ┌─────────────────────┐
                    │      Consumer       │
                    └─────────────────────┘
```

Vertically Bundled Power Industry

- -

Fully Unbundled Power Industry

```
┌───────────┐      ┌───────────┐      ┌───────────┐
│ Generator │      │ Generator │      │ Generator │
└───────────┘      └───────────┘      └───────────┘
                                          Competitive

        ┌──────────────────────────────────┐
        │   Independent System Operator    │
        └──────────────────────────────────┘
                        │
                        ▼
              ┌────────────────────┐
              │    Transmission    │
              └────────────────────┘
                        │
                        ▼
              ┌────────────────────┐
              │    Distribution    │
              └────────────────────┘
                                        Regulated

                                        Competitive
     ┌──────────────┐        ┌──────────────┐
     │   Retailer   │        │   Retailer   │
     └──────────────┘        └──────────────┘

┌──────────┐ ┌──────────┐ ┌──────────┐ ┌──────────┐
│ Consumer │ │ Consumer │ │ Consumer │ │ Consumer │
└──────────┘ └──────────┘ └──────────┘ └──────────┘
```
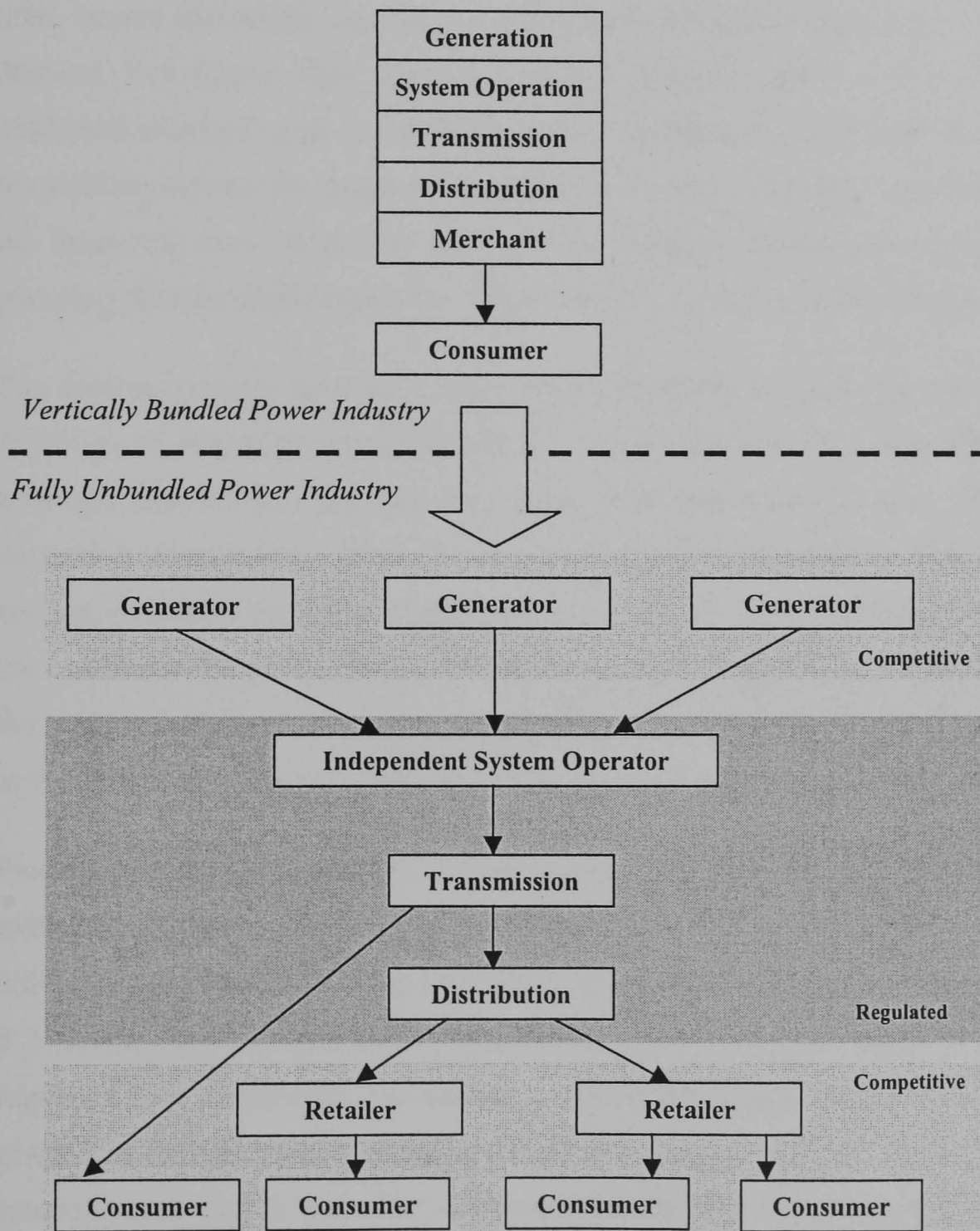
Figure 1.1 Restructuring electricity industry

1.2.3 Effects of Industry Restructuring on System Reliability

Maintaining reliability involves two sets of operations: normal operations and emergency operations. Markets can do much to maintain reliability and prevent outages (by preparing

resources for use in emergencies) during normal operations. Markets alone may be much less effective during actual emergencies [9].

Response time is the key factor that will determine whether the independent actions of participants in competitive markets can perform some reliability functions or whether technical standards and direct control will be required. Roughly speaking, competition is likely to work well for actions that occur half an hour or more in the future. Given this lead time, buyers and sellers can find the price level for each service that will balance supply and demand. For shorter time periods, however, system control is still likely to be required. Technical standards may be needed to specify the amount of each service that is required and to establish metrics for judging the adequacy of service delivery; markets can then determine the least-cost ways to deliver the required services. Disturbance response and generation planning provide useful examples of the two ends of the temporal spectrum.

The system operator must have the ultimate authority to compel actions needed to maintain reliability in real time and to restore the system quickly and safely after an outage occurs, although after-the-fact disputes may occur over who pays for what. If the system operator deemed it necessary to reduce flows on a particular transmission line, to take a line out of service, to reduce output at a particular generator, or to increase output at another generator, the operators of those pieces of equipment would be required to comply with the orders from the system operator. Such real-time operating authority is necessary to ensure system security in the future, as in the past, although these services may be obtained in a market-based means.

Providing for system adequacy, however, may be different in the future than in the past. For example, generation planning will be entirely different from its past practice. Historically, utilities planned for and built power plants to meet a predetermined reserve criterion, typically a 1-day-in-10-years loss-of-load probability or a minimum installed reserve margin. The regulator then determined the extent to which the utility would recover the costs of these generators through rates charged to the utility's retail customers. In addition, these costs were generally reflected in embedded-cost rates that did not vary from hour to hour. In the future, in a market-based model for providing adequate generation resources, decisions on retirement or repowering of existing generators and the construction of new units are likely to be made by investors with much less regulatory involvement. Of course, governments will still oversee the siting and environmental consequences of these decisions. But with retail choice of generation suppliers, markets (investors and consumers), rather than economic regulators, will decide which supplies are needed and economical.

These decisions will be made on the basis of trends in market prices and projected revenues from the sale of electricity relative to the construction and operating costs of the unit in question. Generators will be built when projected market prices of electricity are high enough to yield a profit. Prices in the future are likely to vary from hour to hour throughout the year, based on the units in operation each hour and the balance between unconstrained demand and supply online. When demand begins to exhaust the available supply, prices will rise, sometimes sharply, which in turn will suppress demand and induce investment in new supply. Spot prices will stop rising only when constrained demand is brought down, supply is increased, or both. Although these spot prices are likely to be quite low for most hours, they may be very high for a few hours each year. It is the level, frequency, and duration of these high prices that will signal markets to build more generating capacity, rather than the decisions of planners in vertically integrated utilities. This price volatility will also signal customers on the benefits of managing their loads in real time.

In electricity markets, customer response to real-time pricing signals could also help to improve reliability. High prices will encourage the construction of new generating units and the prompt restoration to service of existing units that are off-line. Similarly, with real-time price information, consumers can decide whether they want to conserve or reduce their usage at times of high prices. Together, these supply and demand responses to price will reduce the need to maintain expensive generating capacity that is only rarely used. Thus, economics can substitute for engineering to maintain real-time reliability when demand would otherwise exceed supply. The challenge of restructuring the electricity industry is to find an appropriate mix of economic incentives and performance standards that maintain reliability at the lowest reasonable cost.

1.3 The Deregulated Electricity Markets

1.3.1 Market Models

From the point of view of competition, in the product market, there are only four fundamental models of structuring the industry, although there are many possible variations on each. The four models correspond to varying degrees of monopoly, competition, and choice in the industry.

- Model 1: monopoly at all levels. Generation is not subject to competition and no one has any choice of supplier. A single company has the monopoly of producing electricity and

delivering it over the transmission and distribution networks to final consumers. This is the model for traditional power industry.

- Model 2: purchasing agency. A single buyer, which is the purchasing agency, chooses from a number of different generators to encourage competition in generation sector. Access to transmission grid is not permitted for sales to final consumers. The purchasing agency has a monopoly on transmission networks and on sales to final consumers.

- Model 3: wholesale competition. Distribution or retail companies buy electricity directly from a producer and deliver it over transmission networks. But the distribution/retail companies still have a monopoly over final consumers. There is open access to transmission grid.

- Model 4: retail competition. All consumers can choose their suppliers. There is open access to transmission and distribution networks. The distribution is separate from the retail activity which is fully competitive. Most likely, this model is the world of the future of power industry. Retail competition makes the most competitive forces by bringing all final consumers into the market. However, it also greatly increases transaction costs due to requiring more complex trade arrangements and metering.

The four models will lead to very different types of trading arrangements. A brief comparison between them is given in Table 1.1

Table 1.1 Comparison between Four Fundamental Market Models

Model of Electricity Market	Model 1	Model 2	Model 3	Model 4
	Monopoly	Purchasing Agency	Wholesale Competition	Retail Competition
Competition in Generation Sector	✗	✓	✓	✓
Choice for Retailers	✗	✗	✓	✓
Choice for final Consumers	✗	✗	✗	✓

1.3.2 Bilateral Markets versus Pool Markets

In a wholesale competitive market, there are two basic ways to arrange trades between buyers and sellers. They can make bilateral trades directly between one buyer and one seller, or they can trade through an intermediary. Both bilateral and mediated markets can have several variations, which are shown in Figure 1.2.

Less organized

More centralized
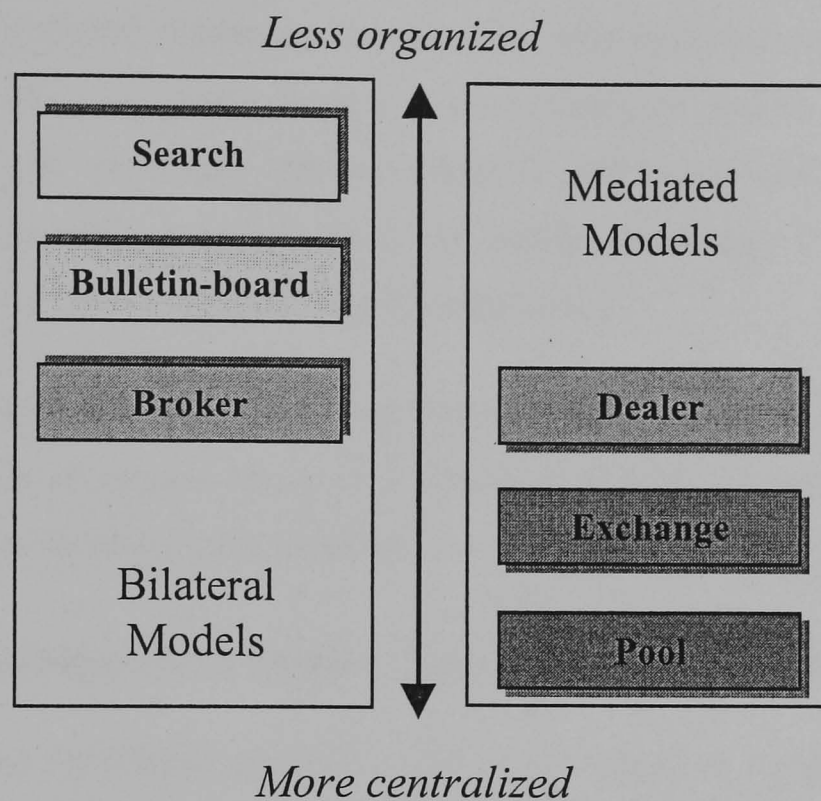
Figure 1.2 Variations of bilateral and mediated market models

Markets often use a mixture of all these models. For example, the used car market is a mixture of direct search, bulletin board, and dealer markets. The New York Stock Exchange is normally an exchange using an auction, but it becomes a dealer market when the market is thin. Here the term "pool" has a special meaning with regards to electricity markets. Before deregulation, some utilities have organized their production into "tight" power pools which used centralized dispatch. In a deregulated electricity market, a pool is an exchange in which the supply bids are complex and the ISO carries out a complex calculation to select winning bids. Auction is an important form of exchange and a simple method to implement competition.

Exchanges and pools are more centralized while bilateral markets are less organized. An exchange can have a number of advantages over a bilateral market. It can reduce trading costs, increase competition, produce a publicly observable price and facilitate the detection of market power. Under some circumstances it may facilitate market collusion. On the other hand, a bilateral market can provide more flexibility than an exchange and it needs little

designing. Power marketers often favor bilateral markets because without an exchange there is more room for them to earn commission fees as brokers.

Very often electricity markets can utilize both approaches. In real-time, organization is crucial and something like a pool is needed. Far in advance of real-time, there is no need for such coordination, and less organized markets can play a useful role. Of course, there will also be a place for centralized futures exchanges. The only real controversy is if the day-ahead market should be a pool, a bilateral market, or a set of private deal markets and exchanges. UK, PJM, and many other electricity markets adopted pool-based model as day-ahead markets while California adopted a combination of public exchange (Power Exchange) and private exchanges and dealers (Scheduling Coordinators).

Different market models will have different market rules and behaviors. But due to the special characteristics of electric power as a commodity, at least a centralized dispatching function is necessary for the real-time operation.

1.3.3 The Independent System Operator (ISO) and Its Functions

Regardless of the market structures that may emerge in various parts of the world, one fact seems to be always true is that transmission and generation services will be unbundled from one another. The generation market will become fully competitive with many market participants who will be able to sell their energy services (or demand side management). On the other hand, the operation of transmission system is expected to remain a regulated monopoly whose function is to allow open, non-discriminatory and comparable access to all suppliers and consumers of electrical energy. This function can be implemented by an entity called the Independent System Operator (ISO) [10, 14].

Although electricity markets may have many different ISO designs and approaches all over the world, there are nonetheless elements that are necessary to all types of ISOs in order to meet their common basic requirements. Basically, the ISO has responsibility for the reliability functions in its region of operation and for assuring that all the participants have open and nondiscriminatory access to transmission services through its planning and operation of the power transmission system. The ISO should conduct all of its functions in an impartial manner so that all participants are treated equitably. The main functions of the ISO can be categorized into reliability-related functions and market-related functions.

1.3.3.1 Reliability-Related Functions of the ISO

The reliability-related functions include two aspects:

- System operation and coordination. The ISO should perform system security monitoring functions and redispatch generation as necessary to eliminate real-time transmission congestion and to maintain system reliability, including taking all necessary emergency actions to maintain the security of the system in both normal and abnormal operating conditions.

- Transmission planning and construction. The ISO should carry out reliability studies and planning activities in coordination with the transmission owners and other market participants to assure the adequacy of the transmission system. The ISO should publish data, studies and plans relating to the adequacy of the transmission system. Data might include locational congestion prices and planning studies that identify options for actions that might be taken to remedy reliability problems on the grid and cost data for some of these actions.

1.3.3.2 Market-Related Functions of an ISO

First of all, an ISO must be a market enabler with no commercial interest in the competitive generation market. The market-related functions of an ISO must be carried out according to transparent, understandable rules and protocols. The following operational functions are necessary to enable a competitive generation market:

- Determine Available Transmission Capability (ATC) for all paths of interest within the ISO region.

- Receive and process all requests for transmission service within and through the ISO region from all participants, including transmission owners.

- Schedule all transactions it has approved.

- Operate or participate in an Open Access Same Time Information system (OASIS) for information publishing.

- Establish a clear ranking of transmission rights of all the participants on the ISO transmission system. Facilitate trading of transmission rights on its grid among participants.

- Manage transmission congestion in accordance with established rules and procedures for generation redispatch and its cost allocation.

- Assure the provision of ancillary services required to support all scheduled delivery transactions.

- Market settlement and billing functions.

The minimum functions of the ISO should include the operation and coordination of power system to ensure the security. In this case, a separate market operator (for example, the Power Exchange in California) is needed to perform the market-related functions. On the other hand, the maximum functions of the ISO will include all the reliability-related and market-related functions mentioned above and in addition the ISO is the transmission owner (for example, the National Grid Company of UK). The functions of the ISO at various sizes and time scales are shown in Figure 1.3.
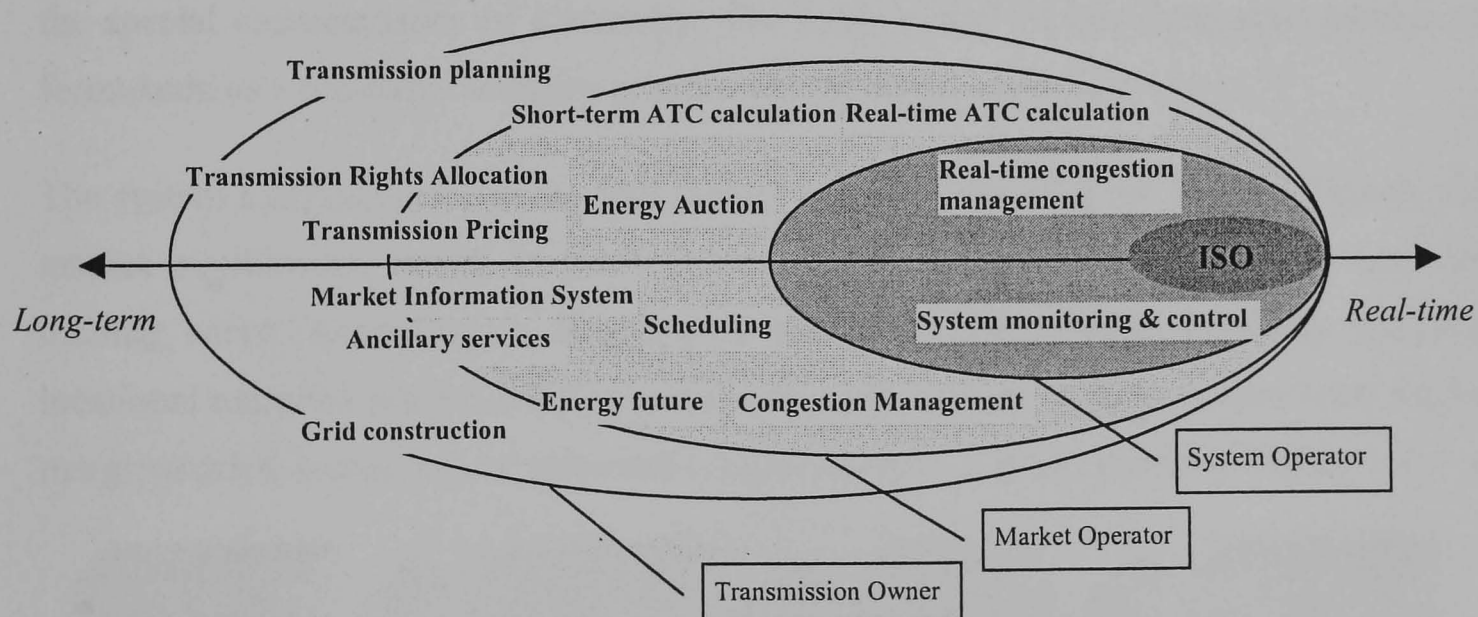
Figure 1.3 Functions of the ISO at various sizes and time scales

1.3.4 Electricity Spot Market and Pricing

The wholesale electricity market, like any well-functioning commodity market, will include diverse commercial and financial arrangements, including contracts of various types and duration, vertical integration where allowed, short-term trading and so on. The core of these commercial arrangements will be a spot market in which physical electricity is priced and traded. A spot market will be developed for any commodity. However, the special characteristics of electricity increase the importance of the spot market in designing a

framework to support competition. According to Hogan [13], A spot market in electricity has two principal functions:

- **Maintain efficient short-term operation.** A spot market coordinates short-term operations of separately owned entities to assure that demand is met economically and reliably given the production facilities actually available on the day, largely independent of longer-term contract arrangements.

- **Facilitate long-term contracts.** A spot market reduces the risks of long-term contracts by allowing participants to buy and sell adjustments to meet their obligations at least cost or highest profits.

An electricity spot market can work much like any other wholesale markets in which buyers and sellers make bids and offers, determine the prices at which supply equals demand and trade the product at those prices. Some special market arrangements are needed to deal with the special characteristics of electricity. The basic model of electricity spot market can be formulated as a bid-based security-constrained economic dispatch problem.

The system marginal price in the spot market can be obtained at the market clearing point or market equilibrium, which is the intersect of the generation bidding curve and demand bidding curve. According to Schweppe's theory of spot pricing, generally speaking the locational marginal price (LMP) or nodal spot price consists of three components: the system marginal price, losses-related price and congestion-related price, shown in Figure 1.4.
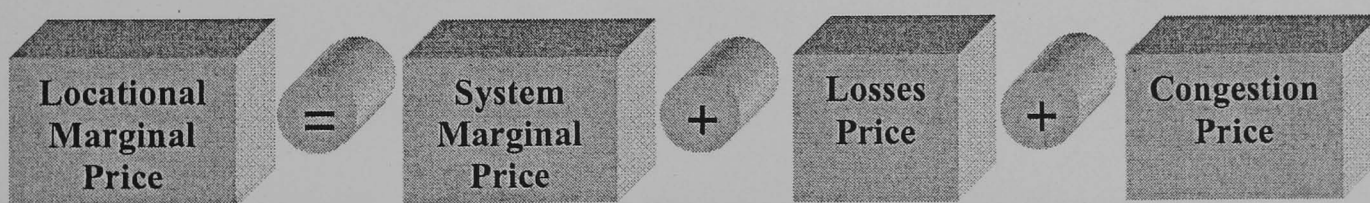
Figure 1.4 Three components of locational marginal price in the spot market

1.3.5 Market Power

The economic definition of market power is "the ability to alter profitably prices away from competitive levels". The competitive price level is implicitly assumed to be the price level if both the supply and demand side of the market behaved competitively. When exercised on the supply side, market power is called monopoly power, while on the demand side, it is called monopsony power. The economic definition covers both. To know if the market price has been raised it is necessary to have a standard for the normal price, which is the competitive

equilibrium price. This is consistent because this equilibrium is defined in terms of "price taking" firms, who take the market price as unalterable and so do not try to affect it. A simple example of market power caused generation withholding is given in Figure 1.5. The market power leads to the market price ρ_m higher than the competitive price ρ_c which equals the marginal cost.

The primary inefficiency caused by market power is not productive inefficiency but inefficiency of consumption. Consumers could buy less because market power raises price above marginal cost, so consequently they under consume. Of course the primary concern with market power is not inefficiency but simply the transfer of income from consumers to producers caused by the higher price.

Insufficient transmission can cause bottlenecks and local market power while additional transmission can expand the size of the market and reduce market power. On the other hand, well-designed transmission congestion management can limit the market power.
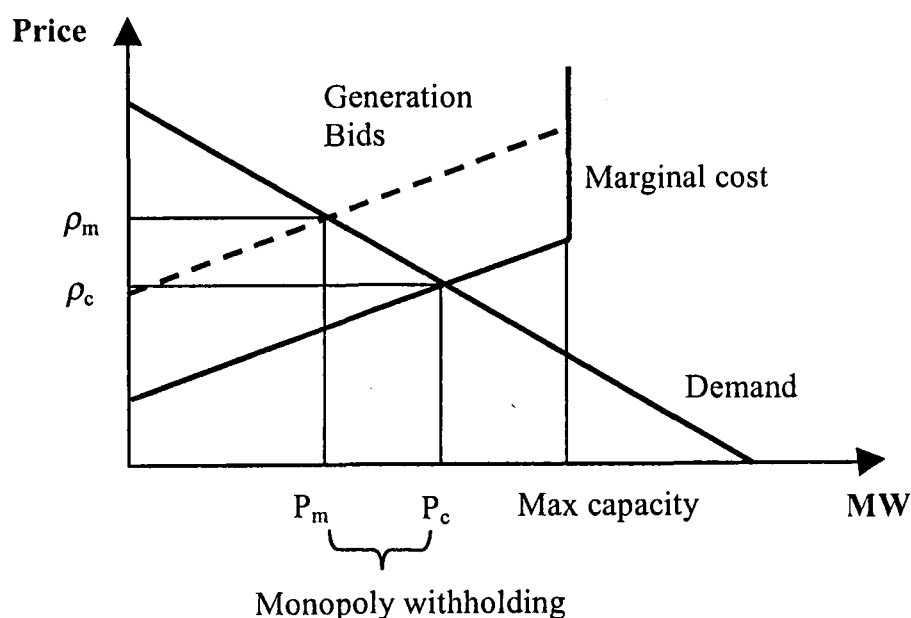
Figure 1.5 Example of market power caused by monopoly generation withholding

1.3.4 New Requirement on Software Systems in Electricity Markets

New software systems are needed for generators, retailers, the ISO and other market participants to meet the operating, scheduling, planning, and financial requirements in the emerging competitive market environment. For example, generation companies may need new bidding systems to decide their bidding strategies and to communicate their bidding information with the market operator; the retailers and distribution companies may need new billing systems and new load management system to meet the time varying spot prices.

The most complex requirement on software systems will come from the ISO, who is in charge of the secure operation of the power system and may even run a few markets for energy auction, ancillary services procurement, and transmission rights auction, etc. Historically, the main software system in the control center of power system is the well-known Energy Management System (EMS), which consists of four major elements [16]:

- Supervisory Control and Data Acquisition (SCADA), including data acquisition, control, alarm processing, online topology processor, etc.

- Generation scheduling and control applications, including Automatic Generation Control (AGC), Economic Dispatch (ED), Unit Commitment (UC), hydrothermal coordination, short term load forecast, interchange scheduling, etc.

- Network analysis application, including topology processor, state estimator, power flow, contingency analysis, Optimal Power Flow (OPF), security enhancement, voltage and reactive power optimization, stability analysis, etc.

- Dispatch Training Simulator (DTS), including all the three above components but in a separate off-line environment.

The EMS is still needed by the ISO in the electricity market, but some of its functions will change to meet the new requirement [17]. For example, some generation scheduling applications might be removed or redesigned to be something like energy market trading applications while some other network analysis application, like OPF, should be extended to be able to perform new functions. DTS is also facing significant changes. It must include all the market applications and power system applications.

Besides EMS, some new software systems will be needed in the ISO [18]. These new systems may include:

- Market long-term planning subsystem, including applications like a plan for future transmission expansion, long-term ATC determination, maintenance of transmission facilities, etc. This subsystem needs coordination between the ISO and transmission owners;

- Market trading subsystem, including all the possible functions associated with market administration roles of the ISO or a separate market operator. These functions could be a day-ahead energy auction to match supply offers and demand bids (a spot market),

electricity futures trading, ancillary services procurement, transmission rights auction, etc.;
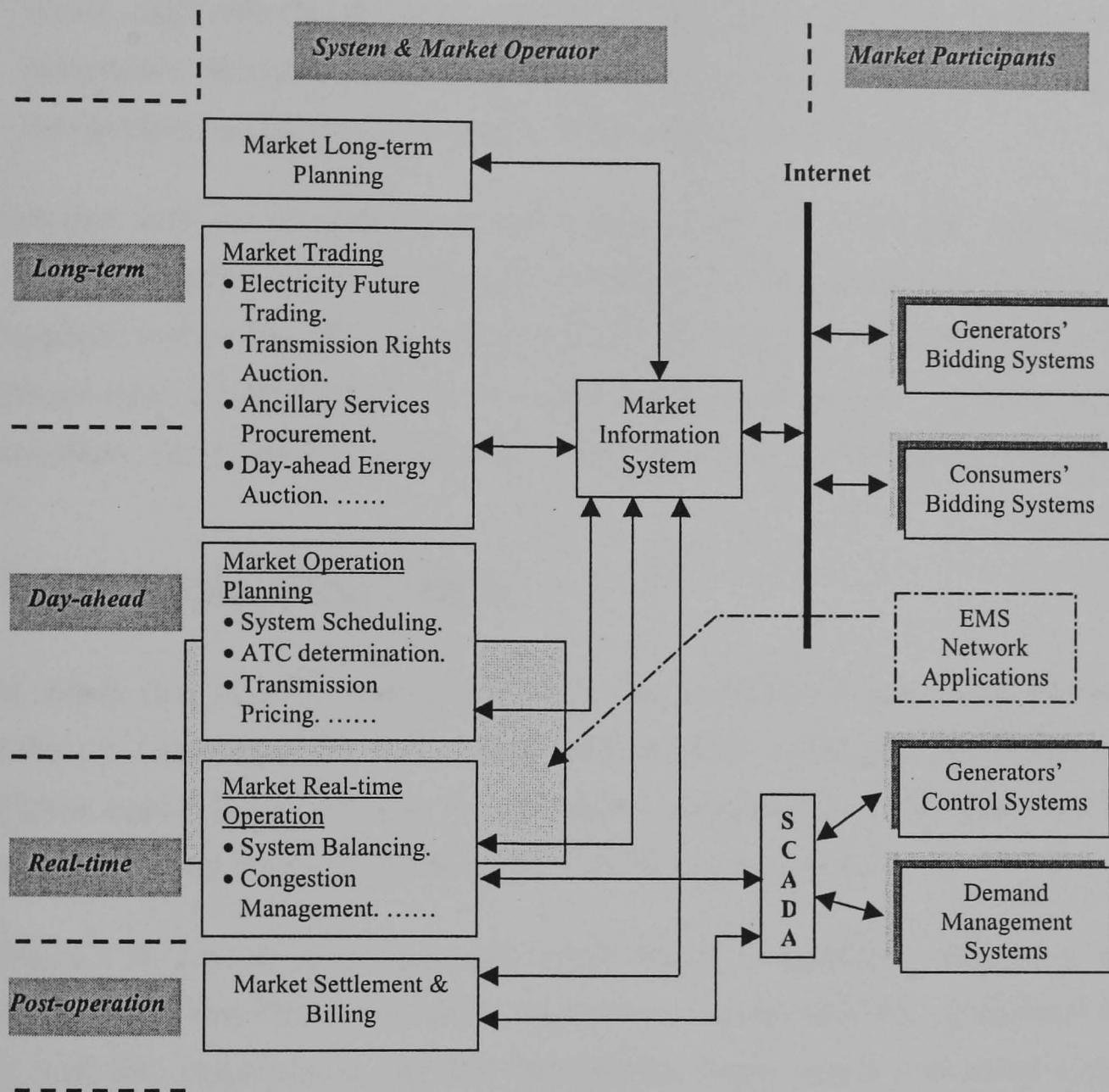
Figure 1.6 Overview of software systems in the competitive electricity market

- Market operation planning subsystem, including power system scheduling function, short-term ATC determination, short-run transmission related services pricing, congestion management, etc.;

- Market real-time dispatching subsystem, including power system dispatch function, system balancing, real-time ATC determination, real-time congestion management, etc.;

- Market settlement and billing subsystem, determining deviations from the schedules and bilateral contracts, determining payments to suppliers and ancillary services providers, determining payments to financial instrument holders;

18

- Market information subsystem. All ISOs are expected to provide a system of open communication for information related to power system operations. In the US, some of this information will be published on the FERC mandated OASIS. The Information that would assist with the efficiency and security of system operation should include: system information on transmission congestion, locational market clearing prices, need and bid for ancillary services and their prices, and all applicable ATCs, etc.

These new software subsystems are linked tightly with each other and must coordinate with the existing systems in the control room to support the implementation of electricity market. Therefore, besides the development of new applications, there are still enormous works on software system integration to be done. An overview of possible software systems in the competitive market environment and the relationship between them are given in Figure 1.6.

1.3.5 Contents of the Thesis

The thesis first reviews existing approaches to transmission congestion management and existing methodologies for OPF. Using extended OPF techniques, the thesis is to develop efficient market-based methods for congestion management in different time scales. The contents of the thesis are described in more detail in this section.

Chapter 2 focuses on the transmission sector and its congestion management in electricity markets. Some important issues about the transmission sector in the deregulated environment are analyzed, including the physical transmission limits which may cause congestion, the impact of transmission congestion, the role of the ISO in congestion relief, and a brief review of transmission pricing methods. Three fundamental methodologies for congestion management are discussed in detail and then an overall congestion management approach is suggested. To price transmission congestion correctly, the Locational Marginal Price (LMP) is recommended while other alternatives are also introduced. To hedge the price risks brought about by congestion the Financial Transmission Rights (FTR) are introduced. At the end of this chapter, a comparison of market models and congestion management approaches between five typical electricity markets in the world is presented.

In Chapter 3, a general formulation of OPF problem is introduced with various objective functions, constraints and control variables. The existing methodologies for OPF solution are reviewed briefly. They are classified into five categories: gradient method, quadratic programming method, Newton-based method, linear programming method, and interior point

method. Then the conventional applications of OPF and OPF's potential roles in deregulated electricity markets are discussed respectively. Since interior point linear programming and quadratic programming are used in this thesis to solve extended OPF problems, the general procedure of successive linear programming method for OPF is presented and a brief description of the second order primal-dual predictor-corrector method for interior point linear and quadratic programming is given.

Chapter 4 proposes a framework for real-time coordinated optimal dispatch in electricity markets, which includes two main tasks: system balancing and congestion management. The real-time balancing market is the core of the framework. Various contracts, such as bilateral contracts, pool energy contracts, and ancillary services contracts, can submit their adjustment bids to the balancing market for real-time dispatching. A modified P-Q decoupled OPF is appled to solve this problem. Real-time pricing for system balancing and congestion management is also analyzed. The comparison between Primal-Dual Interior Point Linear Programming (PDIPLP) and Revised Simplex Linear Programming (RSLP) shows that the PDIPLP is much more efficient to deal with large systems with huge number of control variables.

Chapter 5 particularly deals with the real-time congestion management problem across multiple interconnected regions. Since each regional ISO cannot obtain the full network operating data of other regions, one of the main difficulties is how to implement the congestion management coordinatedly without a huge amount of information exchange between regions. A new approach is proposed to decompose an OPF problem by applying Augmented Lagrangian Relaxation (LR) in order to implement the multi-regional active power congestion management under the framework presented in Chapter 4. Using this approach, it can be implemented as an iterative procedure. The ISO of each region does not need to know any information of other regions but the corresponding Lagrangian multipliers, thus the dispatching independence of the ISO is preserved. Optimal transaction prices on all the interconnecting lines are the by-product of the multi-regional congestion management.

In Chapter 6, short-term congestion management during the scheduling of the spot market is discussed. Some new individual revenue adequacy constraints are introduced into the typical spot market dispatch model to produce a more reasonable result for bilateral contract delivery under a transmission congestion situation. First, the basic model of optimal dispatch in the spot market and the fundamental of Locational Marginal Pricing theory are presented. In particular, the impact of limits of bus generation and load on nodal prices are emphasised

from the analysis of different forms of nodal price. The concepts of two pure financial instruments, Contracts for Differences (CfDs) and Financial Transmission Rights (FTRs) and how they work together to hedge against price risks are analyzed. A new dispatch model with individual revenue adequacy constraints is proposed to mitigate congestion using the natural incentive of market participants. This complex problem with dual variables in constraints of the primal problem can be solved by an iterative procedure.

Chapter 7 describes the optimal FTR auction model as a long-term congestion management approach. A new method is proposed to incorporate some FACTS devices into the FTR optimal auction model to enlarge the transfer capability of the existing network by eliminating the parallel flow and loop flow problems. The objective of this auction model is to maximize the revenues from transmission grid use. Two types of series FACTS devices, which are Thyristor Controlled Series Compensators (TCSC) and Thyristor Controlled Phase Shifters (TCPS) are modeled into the proposed FTR auction with Power Injection Model. Interior Point Linear Programming is applied to solve this optimization problem. The solution of this FTR optimal auction consists of the feasible sold FTRs and their prices and the optimal control parameters of FACTS devices.

In Chapter 8 the main conclusions of the thesis are presented, and proposals for the future work are made.

Chapter 2. Transmission Congestion Management in Electricity Markets

2.1 Introduction

Transmission network plays a key role in making the competitive electricity market work. The first important step of power industry restructuring is the transmission open access. Transmission services have been unbundled as separate businesses from generation. However regarded as a natural monopoly, the transmission sector remains more or less regulated to permit a competitive environment for generation and retail services. The operating and planning of transmission network and the pricing of the transmission services are still retained as challenges on both theoretical and practical aspects in the development of electricity markets.

Transmission Congestion is defined as the condition where there is insufficient transmission capability to simultaneously implement all preferred transactions in electricity markets. Unlike many other commodities, electricity can not be stored easily, and the delivery of electricity is constrained by some physical transmission limits which have to be satisfied all the time to keep the operating security of the power system. Without transmission limits, the deregulation of the power industry would be much easier. Therefore, congestion management is a major function of any type of ISOs in any type of electricity markets. It is so important that if not implemented properly it can impose a big barrier to trading electricity.

The purpose of this chapter is to present an overall review and a discussion about the transmission congestion management in electricity markets. First, some important issues about transmission sector in the deregulated environment are analyzed, including the physical transmission limits which may cause congestion, the impact of transmission congestion, the role of the ISO in congestion relief, and a brief review of transmission pricing methods. Then, three fundamental methodologies for congestion management are discussed in detail and an overall congestion management approach is suggested. To price transmission congestion correctly, the Locational Marginal Price (LMP) is recommended while other alternatives are also introduced. To hedge the price risks brought about by congestion the Financial Transmission Rights (FTR) are introduced. Then, a comparison of market models and

congestion management approaches between several typical electricity markets in the world is presented. Finally, a brief literature survey on congestion management is presented.

2.2 Transmission in Electricity Markets

2.2.1 Transmission System

Historically, vertically integrated electric utilities designed and operated integrated transmission and generation systems. The primary historical transmission function was to connect the utility's generators to the utility's customers and to operate the system reliably. Utilities interconnected their transmission systems with other utilities' systems to increase reliability and share reserves, as well as take advantage of economic exchanges. When transmission congestion required generation to be redispatched to support reliability or economic transactions, the utility was able to evaluate generation and transmission implications (and even occasionally load-reduction options) in both a real-time basis and for long-term planning purposes, if needed. A solution for new transmission facilities, based on current conditions as well as expectations for load growth and future electricity prices and availability, could be developed and presented to the regulator for approval, subject to a number of constraints relating to siting and cost issues. The selected strategy could then be implemented and the costs passed on to customers. Investment decisions were made by utilities and regulators with prudent investment and operational costs borne by customers.

As competition is introduced through power industry reforms around the world, transmission assumes new strategic importance in supporting market trading between individual buyers and sellers. However, despite the widespread experience of restructuring during the past decade, important issues remain open about the best way to operate transmission to support reliability management and market trading. With the development of a competitive power market, there are more and more bilateral transactions which could stress the existing transmission network heavily. It makes the transmission congestion management one of the toughest problems in electricity market design and operation.

2.2.2 Physical Transmission Limits

To design an efficient congestion management approach, the possible causes for transmission congestion should be investigated first. Transmission limits are complex but there are at least

the following physical transmission limits that should be of concern in congestion management.

- Thermal limits — Power flow causes a loss of electrical power which heats power lines and causes the line sag. Beyond a certain temperature the overloaded line will be permanently damaged. It is caused not only by real power flow but also by reactive power flow.

- Voltage magnitude limits — Voltage constraints define operating bounds which can limit the amount of power flowing on transmission lines. Voltage constraints inevitably require attention to both the real and reactive power loads and transfers in the AC transmission system. Consumption of reactive power tends to make the voltage sag. Often this must be corrected by injecting reactive power locally because reactive power is not easily transmitted over long distances.

- Stability limits on power lines — Power flows through AC power lines because the voltage at the generator end reaches its maximum slightly ahead of the voltage at the load end. The amount by which the generation voltage is ahead is called the "phase angle." Beyond 90 degrees, power flow decreases and becomes completely unstable. This is the line's physical stability limit. Angle stability can be classified into two categories: small-signal stability, which is the ability of the system to maintain synchronism under a small disturbance; transient stability, which is the ability to maintain synchronism when subjected to a severe transient disturbance [180].

- Voltage stability limits — Voltage stability is the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal conditions or after being subjected to a disturbance [180]. The main factor causing voltage instability is the inability of the power system to meet the demand for reactive power. The heart of the problem is usually the voltage drop that occurs when active power and reactive power flow through inductive reactance associated with the transmission grid.

Besides the four physical limits listed above, contingency constraints should also be considered for transmission congestion. Contingency constraints are a fundamental element of economy-security control. Contingency analysis identifies potential emergencies through extensive "what if?" simulations on the power system network. A more conservative estimation of transmission capability will be obtained after considering the post-contingency constraints [50].

In the research of this thesis, only the first two types of limits are considered in the congestion management.

The above physical transmission limits decide the Total Transfer Capability (TTC) and the Available Transfer Capability (ATC), which is very important system information to be published in any electricity market. According to the definitions in [19], TTC determines the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner based on the following conditions. For the existing or planning system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings must be within normal ratings and all voltages must be within normal limits. The electric systems must be capable of absorbing the dynamic over swings, and remain stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit. With this very general definition, the TTC is a function of system thermal, voltage, and stability limits and is given by

TTC = min {thermal limits, voltage limits, angle stability limits, voltage stability limits}.

Transmission Reliability Margin (TRM) is the amount of transfer capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of system conditions. This measure reflects the effect of various sources of uncertainty in the system and in system operating conditions. Capacity Benefit Margin (CBM) is the amount of transfer capability reserved by load-serving entities to ensure access to generation from interconnected neighboring systems to meet generation reliability requirements.

ATC is then defined to be a measure of transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses:

ATC = TTC – TRM – CBM – existing transmission commitments.

The ATC information should be calculated and posted for the next hour, month, and for the following 12 months.

2.2.3 Transmission Congestion

In the absence of congestion and operational reliability problems, there is no need to invest in transmission expansion; the existing system is adequate to handle all desired transactions on a reliable basis. In theory, such a system can allow for a minimum-cost dispatch of generation and load curtailment. Congestion results when there is a desire, for either reliability or

commercial reasons, to move more power through a transmission line (or an interface) than the transmission line (or interface) can accommodate. A consequence of a congested interface is that it creates a bottleneck which prohibits delivery of economic energy supplies to consumers on the high-cost side of the bottleneck. This means that these consumers pay more for their power than they would if there was sufficient transmission capacity to carry all economic transactions. In other words, energy costs are genuinely location dependent, given transmission constraints.

Presuming that congestion results in economic inefficiencies, the option to relieve congestion through transmission enhancements is desirable where cost-effective. In any particular circumstance, there are usually several alternatives to relieve congestion and the goal should be to devise systems of incentives that produce cost-effective means to reduce such congestion where it is economical to do so. From the respect of planning side, effective relief methods can include installation and/or operation of large or small scale generation in the congested area for energy production, for voltage support, to enhance stability, or to reduce flows on specific lines. Transmission-based solutions can include construction of new lines or facilities, upgrading of lines or facilities, installation of voltage support (capacitors, inductors, voltage regulating transformers, static condensers, or static VAr compensators), or installation of flow-control devices (phase angle regulators or FACTS devices), and power system stabilizers at generating stations. The technologies allow more power to be delivered over a line or to operate the system more reliably. Load management approaches (including bidding interruptible load in response to different market clearing prices) can also provide congestion relief under certain circumstances. The incentives (and moreover, disincentives) for a particular type of relief depend on various economic, technical, informational, and regulatory elements.

2.2.4 ISO and Congestion Relief

As discussed in Chapter 1, ISO has been proposed as a way to facilitate competitive generation markets in an environment where some power-system facilities and functions remain inherently monopolistic. Where ISOs have been established as the means to assure non-discriminatory access to transmission for all generators in a region's wholesale (and retail) power markets, functions that require allocation of existing scarce monopoly resources, such as existing transmission capacity, among competing parties in an agreed manner should be under the control of the ISO. With market rules in place an ISO can then determine how best to operate the transmission system to reliably accommodate as many users as possible on

a non-discriminatory basis, and allow competitive markets to function. Congestion management can be designed that solicit and select among generation redispatch, demand-side solutions, or transaction curtailment as ways of dealing with specific congestion, both on a long-term planning basis and in real-time operational markets.

Two fundamental problems arise, however, when trying to decide whether it is desirable to make capital investments of one sort or another to alleviate congestion. The first problem is that there is no agreement on the appropriate way to price "use-of-transmission" from the point of view of creating efficient price signals for investment (generation) or use (demand). The second problem is that competing options for relieving congestion operate in different markets with different structures: generation and demand-side solutions operate primarily in competitive markets, while transmission remains largely a regulated monopoly service. When a generator is selling into both a competitive and a regulated market, it is difficult to unambiguously determine the appropriate allocation of costs between those markets and to establish appropriate incentives for efficient investments (or product substitution) in those markets. Uncertainty may lead to under investment.

The ISO should conduct planning and implementation for transmission enhancement, much as vertically integrated utilities do today and provide congestion-based signals so that markets might resolve congestion-related problems through market forces.

An ISO would identify constraints where congestion was likely to impact reliability. It could then take a variety of actions. It might ask the local transmission company to build transmission, or it might request proposals to construct and/or own the needed facility. It might share pricing and other planning information with other market participants. The ISO might request proposals for solutions. Proposals could be generation, transmission or load based. The ISO could select the least-cost solution for the overall system and would support approval from the appropriate regulatory authority for investments made by others (e.g., generation developers or transmission owners), the requestor of firm transmission service that caused the need for new transmission enhancements, or the ISO itself. The solution could be implemented and the costs could be included in overall transmission rates.

An ISO would also provide congestion-related pricing signals to transmission users when allocating access across constrained interfaces and through settlements on contracts following implementation of measures to relieve reliability constraints. Transmission capacity constraints would be based upon reliability criteria and transmission loading. Market

participants themselves could decide whether and when to propose transmission investments. In the absence of investment, any resource which is fully interconnected with firm transmission rights would enjoy priority service during periods of congestion.

2.2.5 Transmission Pricing

Transmission pricing can be complex since electricity does not travel along predetermined paths that respect the terms of a supply contract. Power flows along the path of least resistance. In an integrated network, this means that power may flow through many parallel paths according to network status which can change from one moment to another and which is influenced by all users of the network. This phenomenon is commonly referred to as parallel flows. Parallel flows can cause increased losses and congestion.

In order to reflect transmission costs and network externalities correctly, transmission costs can be separated into three distinct components: sunk transmission costs, variable transmission costs (losses and congestion), and new investment recovery costs [1]. There are two main categories of charging structures — historical cost charging and marginal cost charging [3]. Historical cost mechanisms base prices on costs that have already occurred and include postage stamp pricing, contract path pricing, and megawatt-kilometer pricing [22]. Postage stamp pricing is the simplest approach and is based on the simple division of total network cost by total connected load. This yields a price that is based on the premise that the network provides similar service to all users. Congestion and loss costs would be charged to all users on a load-ratio share basis. Contract path pricing is similar to postage stamp but only uses the total cost of assets along the path between producer and consumer. The contract path approach does not take into account loop flows resulting in inefficiency problems. The megawatt-kilometer pricing method is based on the assumption that the length of the transmission route and the amount of power transmitted provide a reasonable proxy for transmission cost including losses and congestion.

There are two marginal cost approaches in use — incremental cost related pricing [22] and Locational Marginal Pricing [20, 23]. The incremental cost related pricing approach calculates transmission costs by comparing total system costs before and after the transaction. The calculated costs could include or exclude investment costs associated with the transaction.

LMP, also known as Nodal Spot Pricing, was first proposed by Schweppe *et al* [1] and further developed by Hogan [13][14]. The LMP approach is used in the United States, New Zealand and Australia. LMP is based on the theory of optimal electricity pricing: the efficient spot

price for energy delivered at a given electrical node should be the sum of (a) marginal energy cost at the swing bus, (b) marginal line loss, and (c) marginal congestion cost of transmission. As (a) is identical at all nodes, the efficient transmission rate should capture (b) and (c). If there is no transmission congestion, all nodes would pay the same energy cost plus marginal line losses. When congestion occurs, higher cost generation may have to be substituted for lower cost generation that would otherwise be used. Under the LMP approach, energy pricing would differ from place to place whenever congestion occurs, reflecting the real-time marginal cost of supplying energy at each point on the network. The energy price difference between two nodes can be considered to be the marginal congestion cost of transmission.

It is widely recognized that marginal cost pricing will not recover the total revenue requirement of the transmission owners [21, 23]. Therefore, a common approach is to use a postage stamp charge in addition to marginal cost pricing.

2.3 General Methodologies for Congestion Management

Different market structures and market rules lead to different methods for congestion management [33, 34]. Basically, a proper approach for resolving transmission congestion in competitive electricity markets should at least have the following features:

- Fair and non-discriminatory. For the same service, different users should pay the same price and should be treated equally.

- Economically efficient. Individual behaviors of generation, demand and transmission operators should lead to the system optimum through relevant incentives, which could involve cost-reflective charges.

- Transparent and non-ambiguous. The whole congestion management process should be clear to every market participant and should have enough consideration to prevent market gaming. Moreover, simplicity is also essential for all the players to understand the rules.

- Feasible. Congestion management process must always have a feasible solution to maintain the system reliability.

- Compatible with various types of contracts. The contracts will include contracts in spot market, real-time balancing market, ancillary services market and contracts in short-term/long-term bilateral markets.

There are at least two main purposes for the transmission congestion management:

- Adjust the preferred transactions to keep the power system operating within its security limits;

- Collect congestion charge from market participants and pay it to transmission grid owners to compensate their investment on the grid.

In this section, three fundamental methods for congestion management will be discussed in detail. They are transaction curtailment, transmission capacity reservation, and system redispatch.

2.3.1 Transaction Curtailment

The operation of an electricity market requires sufficient information about generation and loads within each control area as well as between them in both day-ahead and real-time periods. Without this information the ISO can not inform market participants of the possible transmission constraints and can not apply curative actions. The published TTC and ATC is the minimum information which is required for market actors to evaluate the risks of seeing their transaction curtailed. ATC summarizes complex information and in many cases it may be ambiguous information, although ATC is based on a clear definition. Therefore, an over-simplified use of this concept could lead to misunderstanding of market participants. Furthermore, to help market agents manage the risk of transaction curtailment, ATC publication could include statistical uncertainty of published values and some other dependent information.

This method needs a set of priority rules to curtail transactions when the ATC values are reached. The three common rules are as follows:

- *Pro rata rationing*. In this rule no real priority is defined. All transactions are carried out but the ISO curtails them in case of congestion according to the ratio: existing capacity/requested capacity. This rule is transparent but brings the participants to an economically inefficient use of the system.

- *Contribution based on physical flow*. The ISO calculates the contribution of each transaction to the congestion to define its priority. The relative contribution to a transaction is the ratio between the flow induced by the transaction on the congested line and the volume of the transaction. The transactions will be curtailed in accordance with

this rank till congestion disappears. This rule is also transparent, but it is not a market-based method. Its long term efficiency is not ensured, because this physical contribution factor varies with topology, generation and load patterns.

- *Willing-to-pay.* Transactions submit a price signal to the ISO to show how much they are willing to pay to ameliorate transmission curtailment imposed by the ISO during congestion period [35]. The ISO picks out some transactions to curtail starting from the one with the lowest will-to-pay bid price. It is a market-based rule for transaction curtailment, because it complies with the principle of "allocating the transmission capacity to the users who value it most highly". However, this method may not be efficient for curtailment against published ATC. More likely, it will be combined with some other congestion management approaches.

With published ATC values and submitted demands for transmission services, the ISO can reject transactions that would cause overloads with a priority rule. One advantage of this curtailment method is that no additional costs are incurred, and therefore there is no cost allocation mechanism. The main drawback is that transaction curtailment based on ATC publication does not convey any economic incentive to the ISO, generators, retailers, or final consumers, and therefore does not promote efficient trade.

2.3.2 Transmission Capacity Reservation

When transmission becomes a scarce resource in the electricity markets, a natural approach to deal with transmission congestion is to allocate the limited transmission capacity in advance to the users who value it best [37]. Auction could be the basic market mechanism for transmission capacity reservation. In a transmission rights auction market, each transmission user submits a price for use of transmission. The bids are selected from the highest one to the lowest one until the capacity is completely used up. The clearing price of transmission market is calculated and all the participants pay at this price. In some circumstances, the counter-flowing transactions should get paid since they make a contribution to relieve the congestion.

The auction is efficient regarding competition. The bids reflect exactly the real market value as perceived by participants while the highest priority for access is granted to the one who is ready to pay the highest price. This method allows integrating long-term contracts with bilateral markets or even spot markets. On the other hand, auction implies supplementary complexity when a transaction is involved in more than one congestion or when parallel flows

are important. In these cases, transmission users will have to make bids for each bilateral transaction.

The other alternative for transmission capacity reservation is the "first come, first served" method. The first reservation made for a given period of time has priority over the following reservations. This method encourages participants to make longer forecasts. Thus, it allows better and sooner security assessment for the ISO who knows accurately the volume of exchanges in advance. However, this method may not leave enough room for short-term trading, which is a requirement to ensure the success of market dynamics. This method is well suited for bilateral trades, but fails to provide an efficient priority mechanism for day-ahead or real-time pool transactions.

2.3.3 System Redispatch

System redispatch occurs when a central operator directs generation adjustments (incremental or decremental) to relieve congestion and avoid undesired transaction interruptions [35,36]. The cost of these adjustments may be allocated to the responsible participants with established tariff or shared equally among all the participants. This allows the transmission users to "buy through" the congestion without the need to enter into contracts with other parties for the redispatch. Financial instruments may be developed to provide transmission users with the opportunity to hedge against the possible high cost of congestion management.

System redispatch is a real-time centralized method for congestion management. It is necessary because the bulk power transmission grid is highly dynamic and predicting constraints well ahead of time is therefore difficult. The main advantage of this method is that due to the centralized nature of the dispatch, no delay occurs between the identification of a constraint and the implementation of redispatch to control the constraint. However, employing a bid-based auction makes it a market-based system, the congestion management is therefore accomplished based on market participants' offers and their indicated willing to buy through congestion to protect their transactions.

Almost all the market participants can have their contribution in system redispatch.

- Generators. Generators submit incremental/decremental adjustment bids to the ISO. The generators selected by the ISO to relieve transmission congestion will get paid for their contributions.

- Consumers. Some adjustable loads can also provide redispatch service and make profit from it. Demand elasticity against spot price signals is an efficient way to alleviate congestion.

- Transmission companies. Many transmission devices, like transformers, FACTS devices, and reactors/capacitors, can be controlled by the ISO to eliminate congestion. Conventionally, these actions are regarded as free resources for system security. However, in a competitive market environment, they need to be priced properly to encourage transmission companies to improve the power grid.

- Power marketers. Power markets can adjust their transactions according to the ISO's redispatch commands.

2.3.4 Overall Congestion Management Process

In the real world in order to efficiently manage transmission congestion, market participants must have freedom to engage in various mechanisms to protect their business. The best solution might always be a combination of several of the basic methods for different time scales. In general, the overall transmission congestion management process, which is shown in Figure 2.1, could consist of three major steps:

(1) Long-term transmission capacity reservation. The reservation of transmission capacity can be made yearly, monthly, weekly, or even daily. The latest stop time for transmission capacity auction should be no later than the morning of day-ahead. Users can obtain the transmission rights from the ISO through a centralized auction or exchange them through a secondary bilateral market. The transmission rights could be either physical or financial. After obtaining transmission rights, market participants can create new or revise existing bilateral transactions.

(2) Short-term scheduling in day-ahead spot market. The day-ahead schedules are made with consideration of transmission constraints. The input data will include all the signed bilateral contracts and all the generation offers and demand bids in the spot market. Some bilateral contracts might be curtailed if congestion occurs.

(3) Real-time redispatch in real-time balancing market. Because of unpredictable events and fluctuating loads, even after the two previous steps, transmission congestion may still occur during the real-time operation of the market. A centralized balancing mechanism is

needed to relieve the real-time congestion problems. Although the real-time redispatch is also a market-based method, the ISO can take any mandatory actions to maintain the system security in emergent cases.
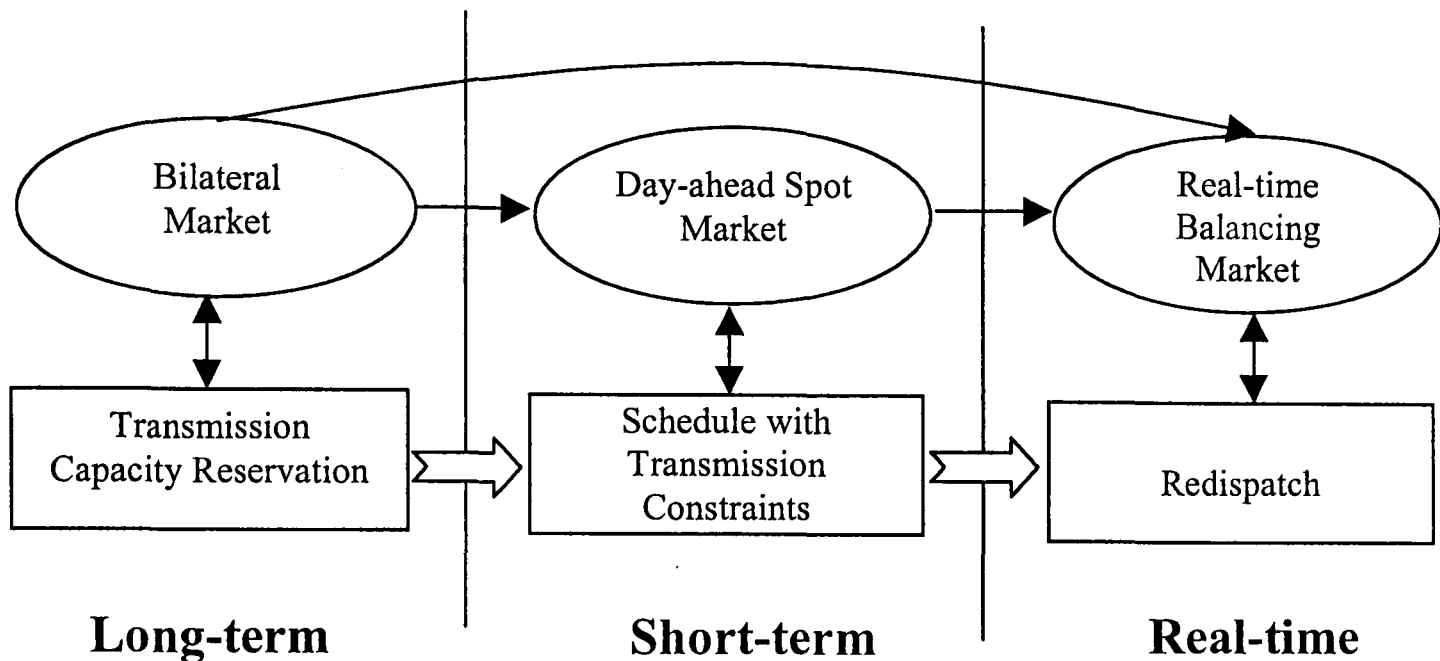
Figure 2.1 Overall congestion management process

2.4 Congestion Pricing

Efficient congestion management needs a transparent commodity market, which must include an appropriate pricing approach. Although the costs imposed by congestion in an efficiently run system are quite low, badly designed congestion pricing can make the system unmanageable. This was proven by Pennsylvania-New Jersey-Maryland Interconnection (PJM) just before the official opening of its market when it instituted a form of average-cost congestion pricing that resulted in massive gaming of the pricing rules. According to FERC's Order2000 [27], a congestion pricing approach should seek to ensure that

(1) the generators that are dispatched in the presence of transmission constraints are those who serve system load at least cost, and

(2) limited transmission capacity is used by market participants that value the use most highly.

Congestion pricing is an important part of transmission pricing. Some transmission pricing methods can be used to price congestion. In electricity markets, congestion pricing will be competitive pricing. The Locational Marginal Pricing approach is advocated by a number of

researchers and has been put into practice in PJM power market. The locational marginal prices are typically calculated as dual variables or Lagrangian Multipliers from Optimal Power Flow (OPF) or security-constrained economic dispatch. With LMP, the security-constrained economic dispatch can produce prices for energy at each location of the system, incorporating the combined effect of generation, losses and congestion. The corresponding transmission price between location where power is supplied and where it is consumed can be determined as the difference between the energy prices at the two locations. Therefore the same framework is easily extended to include bilateral transactions. On the other hand, with LMP, the ISO coordinates the dispatch and provides price information for settlements through a bid-based economic dispatch.

Under LMP, transmission users are assessed congestion charges consistent with their actual use of the system and actual redispatch amount that their transactions cause. This also provides an economic option to non-firm transmission users to self-curtail their use of the transmission system or pay congestion charges determined by the market.

The accurate LMP signals for investment to reduce congestion may become even more important as distributed generation presents opportunities for small-scale, fine-tuned (with respect to both size and location) generation investments to eliminate the transmission congestion, in place of large-scale transmission or generation investments.

In addition, LMP can facilitate the creation of financial transmission rights, which enable users to pay known transmission rates and to hedge against potential high congestion charges. This will be discussed in detail in the following section.

Although there is only one set of efficient congestion prices which are set by the LMP approach, there are some other approaches that would in theory give these same prices, or a good approximation of them. Wu and Varaiya proposed the most extreme alternative to LMP [32]. In their "multi-lateral" approach, the system operator would have no knowledge of the congestion prices. It would simply assign certain parties the right to use lines in a "reasonable but arbitrary way" that would prevent overuse of the lines. These parties would then either exercise their rights by using the lines or they would sell their rights to those who valued the lines more. If it worked efficiently as a competitive market, the market would then produce the exact same prices for the use of congested lines as the system operator would compute under LMP.

Congestion prices make money. The ISO charges users of transmission for a scarce resource, and this always has a positive value. The revenues collected are called the congestion rent. Because congestion prices are the same under any efficient system, so is the congestion rent. Under LMP, the system operator collects the congestion rent. Under the multi-lateral approach, some private party will collect these rents. This is at the heart of the controversy.

2.5 Transmission Rights: Financial versus Physical

Transmission rights are fundamental to an efficient design of competitive electricity markets [37-39]. However, the specification of transmission rights is complicated by externalities due to parallel flows. Since the actual power flows in an electrical network observe the physical laws known as Kirchhoff's Laws, the power flow paths generally diverge from the intended delivery paths, known as contract paths. These parallel flows, or loop flows, can cause the apparent costs of running generators to diverge from the real costs and make it difficult to determine the available transfer capabilities of the transmission system. This leads to misalignment between the private cost and the social cost in electricity transactions and causes a potentially costly dislocation of resources in the power market.

In essence, a transmission right is a property right that allows its holder to access a portion of the transmission capacity. Generally, a property right consists of three possible components: (1) the right to receive financial benefits derived from use of the capacity, (2) the right to use the capacity, and (3) the right to exclude others from accessing the capacity. Since the transmission schedule is centrally controlled, transmission rights can be defined as any combination of these three components. Basically, there are two types of transmission rights:

- Physical rights, which include the last two out of all three components, confer right or priority to physical delivery.

- Financial rights, which provide market traders an instrument for price risk hedges as part of long-term energy contracts, only entitle owner payments without any requirement to actual power delivery.

These two types of transmission rights reflect two different philosophies of forward trading.

2.5.1 Physical Transmission Rights

Physical transmission rights may confer a scheduling priority, but unlike financial rights, they do not provide payments. They are only useful to those who are actually trading power. This approach seems straightforward, but it is difficult to implement it in a real system. Physical rights holders could exercise market power by withholding transmission capacity. In addition, if a system operator is excluded from accessing the withheld capacity, this approach may reduce system reliability and security. However, the system operator must take complete control of all transmission capacity in real-time, therefore withholding capacity must be forbidden. So the pure physical transmission rights may face difficulties in electricity markets.

2.5.2 Financial Transmission Rights

The concept of Financial Transmission Rights (FTR) is based on the LMP model. Assume that there is a spot market to provide balancing services. The combination of schedules and bids, which are submitted by market participants, forms an economic redispatch problem. The solution produces a set of inputs and outputs at every location with the different LMPs. Market participants who have chosen to buy and sell through the spot market settle these transactions at the corresponding LMP. Those who have scheduled deliveries between locations pay the opportunity cost of transmission defined as the difference in the locational prices at injection and withdraw locations.

The FTR provides a disbursement of the congestion rents by defining a point-to-point contract to collect the difference between the locational prices. These rights could be options (one-sided) or obligations (two-sided) as forward contracts.

The FTRs provide long-term transmission rights that can be different from the actual dispatch of the system. Although it is impossible to maintain a perfect match of long-term rights and the actual dispatch, it is possible to guarantee the financial payments to the FTR holders as long as the outstanding FTRs continue to pass the test of simultaneous feasibility.

The concept of FTRs is by now well supported by practical experiences. It has been adopted by the Pennsylvania-New Jersey-Maryland Interconnection (PJM) and New York, and embraced as a reform in New England.

2.5.3 Flowgate Rights

The essential market ingredients of FTR model outlined above include a coordinated spot market integrated with system operations to provide balancing services and congestion management. In principle, an alternative to central coordination would be a system of decentralized congestion management that used the same basic information as does the system operator but which could be handled directly by the market participants.

The most prominent recent example of such a decentralized congestion management model is the so-called "flowgate" approach [38]. It is the procedure embraced by NERC as a principal market alternative to its disruptive administrative Transmission Loading Relief (TLR) procedures [175]. The basic idea of Flowgate Transmission Rights (FGR) is simple. It begins with the recognition that the contract path is flawed. Power does not flow over a single path from source to sink, and it is this fact that causes the problems that lead to the need for TLR in the first place. If a single contract path is not good enough, perhaps many paths would be better. Since power flows along many parallel paths, there is a natural inclination to develop a new approach to transmission services that would identify the key links or "flowgates" over which the power may actually flow, and to define transmission rights according to the capacities at these flowgates. This is a tempting idea with analogies in markets for other commodities and echoes in the electricity industry MW-mile proposals or rated-path methodologies.

Essentially, a system of FGRs builds on the simple principle that it is desirable to match the scheduled transactions and actual power flows as closely as possible. The system adopts a trading rule that embodies the power transfer distribution factor (PTDF) to translate the physical effects of each energy transaction into requirements of transmission rights and transmission loss coverage.

W. Hogan pointed out some wrongs of the FGR model [174]. J. Chandley proposed a hybrid market design seeking to combine the use of locational marginal pricing (LMP) in the real-time market with the allocation and use of FGRs in the forward markets [176]. However, the debate on FTR and FGR is still going on.

2.6 International Comparison of Congestion Management Approaches

Different market structures and rules lead to different approaches to transmission congestion management and congestion pricing. Before any further research can be done, it is very important to see what has been happening in the real world by having an analysis on the existing congestion management approaches in some major electricity markets all over the world. This section will compare the congestion management methodologies between 5 typical electricity markets, which are the UK, PJM (US), California (US), Norway and Sweden, and New Zealand, and point out their similarities and differences. A brief comparison between these 5 electricity markets is shown in Table 2.1 (p49).

2.6.1 The UK Market

The UK (England & Wales) market [24] had been a pool-based market since 1990 until the New Energy Trading Arrangement (NETA) [25] went live on March 27, 2001. The congestion management and some related issues will be discussed in the previous trading arrangement and NETA, respectively.

2.6.1.1 Congestion Management in Previous Energy Trading Arrangement

In the previous energy trading arrangement (PETA), almost all electricity supplied in England and Wales was traded through the Pool [40]. The Pool mechanism set the wholesale price and established the generation merit order to meet the forecast demand (plus a reserve margin) at the day-ahead stage. The National Grid Company (NGC) was responsible for the scheduling and dispatch of generation on the day to meet actual demand. The actual dispatch of plant might not match that anticipated at the day-ahead stage due to: transmission constraints, changes in plant availability and differences between actual and forecast demand.

Pool prices were set on the basis of a competitive bidding process for generation. NGC produced a forecast of demand for each half-hour of the following day and then scheduled the generators' bids to meet this demand. This schedule was called Unconstrained Schedule. Generally, the price of the most expensive unit scheduled to meet forecast demand in each half-hour set the price for energy, called as the System Marginal Price (SMP). To the SMP was added a component called the Capacity Payment, which was provided to give an incentive to generators to maintain an adequate margin of generation over the level of demand for electricity in order to cover for unexpected demand and generator failures on the system.

This payment is the product of two factors: the Loss of Load Probability (LOLP) and the Value of Lost Load (VOLL). Together, SMP and the Capacity Payment constituted the Pool Purchase Price (PPP). PPP values are calculated the day-ahead, i.e. *ex-ante*. Unscheduled Availability Payments (USAV) were made to plant which were available but which were not included in the Unconstrained Schedule. Although not generating, these plants contribute to the security of the system since they can be called upon to generate if required.

Constraints on the transmission system can cause the actual half-hourly generation produced by a unit to differ from that anticipated in the Unconstrained Schedule. Units which were scheduled before taking constraints into account might have their output reduced or withdrawn (called as "constrained-off"). Other units might have their output increased or be dispatched without being included in the Unconstrained Schedule (called as "constrained-on"). The cost of transmission constraints was embedded in the Uplift costs, which was added to the PPP to work out the Pool Selling Price (PSP).

The rights of access to the transmission system of participants were not well defined in the PETA. The access of generators is limited in their Supplemental Agreements to the Master Connection and Use of System Agreement (MCUSA) to their notified Maximum Export Capacities or Registered Capacities. Suppliers do not have specific access limits although the access of distribution network operators is limited to their notified Connection Site Demand Capabilities and this provides an upper bound on the aggregate access limits of all the suppliers within a distribution network. However, these limits can be reduced if NGC is prevented from transporting electricity due to transmission constraints that could not have been avoided. Thus, NGC's connection agreements ie. the Supplemental Agreements, do not confer firm access rights. Another issue related to access to the transmission system is the treatment of transmission losses. Suppliers pay for all losses on the transmission system on a uniform basis. Thus, neither generators nor suppliers are exposed to the short-term costs imposed by their choice of location.

2.6.1.2 Congestion Management in NETA

The NETA replaces the Pool with voluntary forwards markets for energy trading, a voluntary Balancing Mechanism for resolving energy and system imbalances close to real-time, and mandatory imbalance cash-out. Under NETA, there will be no unconstrained schedule but instead generators will be able to self-dispatch. Generators and suppliers will contract bilaterally until the Balancing Mechanism for a half-hour trading period opens and

notifications of contract volumes for the period have to be made. At this point, known as "Gate Closure", market participants will have to inform NGC, as System Operator, of their intended generation or consumption profiles for the relevant half-hour. The real-time transmission congestion will be mainly managed through the new balancing mechanism [25], which provides a basis whereby NGC can accept offers of electricity (generation increases and demand reductions) and bids for electricity (generation reductions and demand increases) at very short notice. Accepted offers will be paid for at the prices offered (and accepted bids will pay the prices bid).

In addition, NGC will continue to be able to sign contracts with participants for the provision of specific services to aid in balancing the system. Generators and suppliers whose contract position does not match their metered volumes will be subject to energy imbalance payments based on the costs of the actions accepted by NGC in the Balancing Mechanism and relevant balancing services costs.

In the latest document of Ofgem [177], it is preferred that transmission losses are charged by adjusting participants' metered volumes using estimated zonal loss factors. Ofgem considers that the introduction of a market in firm access rights is likely to be the most effective way of meeting the objective for reform. A regime of firm access rights means that participants must purchase sufficient access rights to match the amount of electricity they wish to transmit across the transmission grid. To allocate these rights in a non-discriminatory way, which allows the value that participants place upon them to be revealed in an efficient manner, auctioning the transmission rights is believed to be an efficient means.

Transmission constraints on the NGC system, including thermal constraints, voltage constraints, and stability constraints, are studied over time-frames from several years to the control room phase. Traditionally, these constraints have been analyzed in off-line studies using DC and AC loadflows and transient stability programs. NGC's on-line dispatch program (known as DISPATCH) runs every 5 minutes, and optimizes the generation dispatch over the next 2 hours by studying 6 linked time-steps, whilst respecting the transmission constraints. A project called CODA (Combined Dispatch Advisor) aims to achieve the on-line constraint management [186]. CODA takes data from the EMS and elsewhere and calculates the values of network constraints for actual and forthcoming conditions up to 2 hours ahead. The intention of this is to reduce transmission service cost by providing control engineers with up-to-the-minute constraint values and recommendations for control actions. The constraint limits calculated by CODA will eventually be passed to the DISPATCH.

2.6.2 The PJM Market in the US [42]

PJM started as a Security Coordinator and Control Area Operator in 1927. It was initially a wholesale power exchange in 1997, and finally assumed the formal obligations of an ISO in January 1998. Though still evolving, it has been an example to represent one of the most stable electricity markets in the US. PJM retains the unit commitment model of daily price clearing and incorporates transmission constraints to the bid and scheduling basis.

PJM includes a spot market coordinated by the ISO, who accepts both bilateral schedules and voluntary bids of the market participants. Using these schedules and bids, the ISO finds an economic, security-constrained dispatch for power flows and the associated LPMs. When the transmission system is constrained, the spot prices can differ substantially across locations. Sales through the spot market are settled at the LMPs. The transmission usage charge for bilateral transactions is the difference in the LMPs between origin and destination. An accompanying system of Fixed Transmission Rights provides financial hedges between locations. These Fixed Transmission Rights are the equivalent of perfectly tradable firm transmission rights.

The PJM LMP system was embraced after an experiment during 1997 with an alternative zonal pricing approach that proved to be fundamentally inconsistent with a competitive market and user flexibility. According to PJM's experience, the earlier zonal pricing system allowed market participants the flexibility to choose between bilateral transactions and spot purchases, but did not simultaneously present them with the costs of their choices. The circumstances created a false and artificial impression that savings of $10 per MWh or more could be achieved simply by converting a spot transaction into a bilateral schedule. By contrast, the locational pricing system avoids this perverse incentive. By construction, the LMPs equal system marginal costs. Every generator would be producing at its short-run profit maximizing output, given the prices. The market equilibrium would support the necessary dispatch in the presence of the transmission constraints. Spot market transactions and bilateral schedules would be compatible. Flexibility would be allowed and reliability maintained consistent with the choices of the market participants.

In PJM the system experienced transmission constraints, large differences in locational prices, and the opportunity cost of transmission was quite large. The lowest locational prices were sometimes negative, reflecting the value of counterflow in the system where it would be cheaper to pay participants to take power at some locations and so relieve transmission constraints. The highest locational prices were larger than the marginal cost of the most

expensive plant running, reflecting the need to simultaneously increase output from expensive plants and decrease output from cheap plants, just to meet an increment of load at a constrained location. Over all hours in April 1998, for example, the low price was -$45 at 1500 hours on April 18 at "JACK PS," and the highest price was $232 at 1100 hours on April 16 at "SADDLEBR," both locations being in the Public Service Gas & Electric territory.

PJM adopts a two-settlement system to enhance the robust and competition market and to provide increased price certainty to market participants. It consists of 2 markets, with separate accounting for each market:

- Day-ahead market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day based on generation offers, demand bids and bilateral schedules. The day-ahead schedule is developed using a least-cost security-constrained unit commitment and a security-constrained economic dispatch. Day-ahead congestion charges for bilateral transactions are based on the differences of LMPs between the source and sink.

- Real-time market is an energy market in which hourly clearing prices are determined by security-constrained economic dispatch with actual system operating conditions described by state estimation. Transmission customers pay congestion charges for bilateral transaction quantity deviations from day-ahead schedules.

2.6.3 The California Market in the US [26, 41]

On December 20, 1995, the California Public Utility Commission (CPUC) ruled to restructure the electric utility industry in California, to allow for competition in the wholesale and retail electricity markets, in an effort to lower electric rates. The decision requires that utilities form an Independent System Operator (ISO) to begin operation on January 1, 1998 to conduct system dispatch and transmission operations functions, and create a Power Exchange (PX), and file plans to voluntarily divest 50% of their fossil generation to mitigate the current utility market power. The new market structure mandates separating the wholesale PX from the ISO. The ISO manages three key markets – competitively procured ancillary services, a real-time energy balancing market and a congestion management market. The PX operates three energy markets, a daily auction for each hour of the next day, an on-the-day market and a Block Forwards market.

In California, market participants can take part in the process of congestion management through submission of "adjustment bids" to the ISO. ISO's congestion management process is accomplished in two time scales: day-ahead and hour-ahead. In both time periods, the ISO reschedules to eliminate potential congestion and minimizes rescheduling to allow market participants to voluntarily seek their lowest cost of delivered energy. Overall, the congestion management recognizes and separates each Schedule Coordinator (SC)'s portfolio of generation and load from other SCs while finding the lowest rescheduling cost to maintain system reliability.

To simplify the congestion pricing, California uses zones or geographical locations to define electrical characteristics of the power grid and determine a financial value for the ability to serve its energy needs. Zones are defined as areas where congestion is infrequent and can be easily priced on an average cost basis. The California congestion pricing method uses the term "Interzonal" to describe congestion and pricing between zones and the term "Intrazonal" to describe congestion and pricing within a zone. Zones can be merged or added to if interzonal congestion becomes infrequent and inefficiently priced at marginal cost or intrazonal congestion becomes frequent and inefficiently priced at average cost.

To mitigate the shortcoming of traditional transmission allocation methods, a mix of physical and financial rights was selected for implementation of the Firm Transmission Rights process in California starting February 1, 2000. In this model, Firm Transmission Rights provide scheduling priority as well as financial rights. Firm Transmission Rights that are not sold in the day-ahead market are released in the hour-ahead market, but the original owner will retain the financial rights.

However, in 2000 California's electricity market has collapsed due to many reasons [29]. Besides the abnormal climate, high gas prices, and strict environmental rules, some fatal flaws in market design, which caused market power and gaming, have also been severely criticized and the Federal Energy Regulatory Commission (FERC) has proposed remedies for these problems. According to [30], one of the serious flaws is the poorly structured separation of the ISO from the PX. This separation allowed generators to "game" the market by bidding only a portion of their capacity ahead of time into the PX, and then reaping exceptionally high prices when the ISO was forced to buy power in real-time to balance supply and demand. In addition, the frozen retail prices in California meant that rising wholesale prices could in no way be moderated by being passed on to consumers so as to reduce their demand.

2.6.4 The Norway and Sweden Market (Nord Pool) [31, 41]

Deregulation in Norway was created by the Energy Act of June 1990. Market started in May 1992. The principal restructuring was the removal of transmission ownership from Statkraft, the national utility, and the founding of the nationally owned company Statnett to be the transmission owner, market operator and ISO. Sweden passed deregulation legislation in October 1995 and joined the Norwegian market in January 1996. Transmission operation was removed from the national utility Vattenfall, which continues to operate generation while Svenksa Kraftnät, the national grid owner and ISO, was formed. Meanwhile, the Nord Pool, a market operator owned equally by Statnett and Svenksa Kraftnät, was founded and took over the operation of spot and future markets in both countries.

Norway and Sweden have different philosophies of congestion management. Norway is using the spot market settlement process to prevent congestion efficiently. When transmission congestion is predicted, the ISO declares that the system is split into price zones as predicted by congestion bottlenecks. Bidders in spot market must submit separate bids for each price zone where they have generation or load. If no congestion occurs, the market will be settled at one price. If congestion does happen, price zones are settled at different prices caused by binding transmission constraints. Zones with excess generation will have lower prices while zones with excess load will have higher prices. Revenue from this price difference is paid to the ISO, who uses it to reduce the capacity fee. Bilateral contracts that span price zones must pay for its load at the price in the zone of its load, in order to account for its contribution to congestion and to expose the contract to financial consequences of congestion.

In contrast to Norway, Sweden is always only one price zone, because Sweden does not want the transmission system to affect the market solution. However, Sweden varies the capacity charge portion of its point tariff based on geography. Since power flow in Sweden is always from north to south, generation is charged more and load less, in the northern part of this country. This affects generation costs and thus the bids submitted to the market, deferring some congestion.

Congestion in real-time is eliminated by purchase of the adjustment of generation and load from the ISO regulatory markets, which is known as "buyback". Congestion has been infrequent in the Nord Pool market. Despite using different approaches to congestion management, the Norwegian ISO and the Swedish ISO coexist successfully within one market. Because Svenksa Kraftnät does not use price zone congestion management, the Swedish transmission system is always regarded as one price zone. Revenue to market due to

congestion between Norway and Sweden is split equally by Statnett and Svenksa Kraftnät. No special fee is charged for energy transfers across national boundaries, and the two ISOs do not charge each other transmission tariffs at their connection points.

2.6.5 The New Zealand Market [41, 43]

On October 1, 1996, a wholesale electricity market in New Zealand commenced operation under the name Electricity Market Company (EMCO). This market is an *ex post* market and is not mandatory. There is separation between the power exchange, which is EMCO, and the system operator, which is Trans Power. The interconnecting transmission constraint from South Island to North Island has a significant impact upon the operation of the system. Transmission losses are also relatively high in New Zealand.

New Zealand's wholesale electricity market is characterized by its adoption of full nodal pricing. Participating generators and purchasers submit offers and bids for each half-hour at the day-ahead stage. Bilateral contract volumes are notified to the system operator, and any deviations are settled at the prices emerging from the spot market. The marginal costs of transmission losses and constraints are reflected in the half-hourly *ex post* market prices calculated for each of the connection points on the network using actual flows. Constrained-on payments are paid to scheduled generators whose offer prices turn out to be higher than the nodal *ex post* price. There are no constrained-off payments to generators who did not run despite bidding below the *ex post* nodal price. The marginal pricing of losses and constraints within the spot market results in a surplus of funds being collected, which is passed on to Trans Power. Bilateral market participants trading outside the spot market pay Trans Power directly for losses and constraints via a charge based upon the volume of power traded and the price differential between the generation and supply nodes. Trans Power uses these funds to lower its use of system charges.

2.7 Congestion Management Literature Survey

Since transmission congestion management in electricity markets is a new problem emerging after the deregulation of power system, almost all the published papers about this topic are found later than 1990. Basically, these researches can be classified as two categories: methodological studies based on general market models and industrial experiences and researches based on some specified market models.

Major publications of general methodological studies on congestion management are listed as follows. In [33], Singh, Hao and Papalexopoulos studied the approaches to transmission congestion management in the markets with pool model (nodal pricing framework) and bilateral model (cost allocation procedures) respectively. In [32], Wu and Varaiya proposed a decentralized optimal dispatch method with the objective of maximizing social welfare under the coordinated multilateral trade model. In [34-35, 156], David and Fang proposed mathematical models for pool dispatch, bilateral dispatch and multilateral dispatch. They also provided some useful curtailment strategies based on the purpose of minimizing deviations from transaction requests made by market participants in a structure dominated by bilateral and multilateral contracts. In [182], Glavitsch and Alvarado discussed four main concepts on congestion management: congestion pricing can lead to the same solution as an OPF, pricing needs not have cost information available, good estimates of nonlinear cost coefficients are necessary, and pricing for congestion management is separable from pricing for the purpose of transmission revenue reconciliation. A tutorial review of how to calculate optimal bus prices and congestion costs using DC power flow approximation was given by Gedra in [181].

Some researches have been done on congestion management taking contingency-constrained limits, voltage stability limits, and transient stability limits into consideration. Alomoush and Shahidepour presented a procedure for minimizing the number of adjustments of preferred schedules to alleviate congestion with contingency-constrained limits in [157]. Singh and David investigated the impact of incorporating dynamic security consideration in congestion management in [183]. Transient stability and voltage stability constraints were incorporated into the market dispatch/pricing model by Chattopadhyay and Gan in [184].

Cadwalader, Harvey, Hogan, and Pope proposed a LR-based approach [148] to decompose the global congestion management problem into sub-problems corresponding to different regions. But full information of the whole system is still needed for every regional sub-problems. Moreover, some other drawbacks of this method have been pointed out by Oren and Ross in [149], such as convexity problem.

Hogan proposed a market model including well-defined point-to-point FTRs supported by a spot market [13]. Application of LMP and FTR to multi-zonal congestion management was illustrated by Alomoush and Shahidepour in [153]. The FTR auction model was presented by Hogan in [159] and was elaborated by Alomoush and Shahidepour in [160].

Congestion management is one of the most important tasks of the ISO in an electricity market. Many electricity markets in the world have presented their experiences on this issue. Gribik *et al* presented California's zone-based congestion management protocol in [185], which includes inter/intra zonal congestion management. In [103] and [104], optimal scheduling methods were proposed for the power markets in New Zealand and New England of the USA, where the procurement of necessary operating reserves is coordinated with the procurement of the energy while the network constraints are taken into account.

2.8 Summary

In this chapter, the causes, remedies, and pricing methods of transmission congestion are discussed. Planning, constructing, maintaining, and operating of transmission grid are completely different in the competitive electricity market compared with the situation in the integrated power industry. Physical limits of transmission include steady limits, stability limits and contingency limits. All these limits decide the TTC and ATC of a system, which are crucial information for long-term and short-term congestion management. The ISO is playing a vital role in congestion relief, ranging from long-term planning down to real-time operating.

There are many various approaches to congestion management. It depends on the market model, the policy, the technical development, and many other factors. Generally speaking, they can be classified into three fundamental categories: transaction curtailment, transmission capacity reservation, and system redispatch. However, the best solution might always be a combination of several of the basic methods for different time scales.

Two main congestion pricing methods are analyzed. The LMP approach seems to be better, not only because it produces correct competitive prices for congestion but also because it can facilitate the creation of financial transmission rights, which enable users to pay known transmission rates and to hedge against potential high congestion charges.

To find out what is going on in the real world, the congestion management approaches of 5 typical electricity markets in the world are investigated. Every approach has its own advantages and disadvantages. However, none of them is the final version. Continuous reforms are still taking place everywhere. Congestion management is widely open to power system researchers for further development. Finally, a brief literature survey on congestion management is presented.

Table 2.1 Comparison of market models and congestion management approaches between major power markets

Electricity Market	UK		PJM	California	Nord Pool		New Zealand
	E&W Pool	NETA			Norway	Sweden	
System Operator & Market Operator	Combined (NGC is the owner of grid)	Separate	Combined	Separate	Separate		Separate
Energy Pricing	*Ex ante*	No pool pricing	*Ex ante*	*Ex ante*	*Ex ante*		*Ex post*
Balancing Mechanism	Uplift	Balancing market	Balancing market	Balancing market	Balancing market		No
TRANSMISSION — Losses	Borne by all suppliers on a uniform basis.	Average zonal loss factors	Moving towards loss factor at each node	Zonal pricing-application of loss factors at each node	Zonal fee calculated from spot price and marginal loss factors	Recovered through grid charges uniformly	Nodel pricing
TRANSMISSION — Congestion	Additional generation costs recoverd through uplift to pool price	Imbalance settlement	Nodal pricing	Zonal pricing	Zonal pricing	Recovered through grid charges uniformly	Nodal pricing
TRANSMISSION — Cost Recovery	Zonal charges calculated using long run incremental costs	Zonal charges calculated using long run incremental costs	Mixture of postage stamp charges to recover fixed costs and location specific charges	Locational specific transport and access charges	Uniform capacity charges	Locational capacity charges	Locational specific transport and access charges
TRANSMISSION — Investment	Planning by NGC. Published plan allows participants to assess capability available	Planning by NGC. Published plan allows participants to assess capability available	Planning by system operator. Published plan allows participants to assess capability available	Coordinated planning by system operator, integrating utilities' plans into one region-wide plan	Planning by the transmission owner and ISO: Statnett	Planning by the transmission owner and ISO: Svenska Kraftnat	Participants or system operator identifies and funded by coalitions of beneficiaries
TRANSMISSION — Transmission Rights	No	Moving to Firm Transmission Rights	Financial Transmission Rights	Flow-based transmission Rights	No		Moving to Financial Transmission Rights
Bilateral Contract	Only CfD, no physical bilateral contract	Encourage physical bilateral contract	Allow physical bilateral contract	Allow physical bilateral contract	Allow physical bilateral contract		Allow physical bilateral contract

Chapter 3. Optimal Power Flow (OPF) and Its Roles in Electricity Markets

3.1 Introduction

In 1962, Carpentier introduced a generalized nonlinear programming formulation of the economic dispatch (ED) problem including voltage and other operating constraints [44]. The problem was later named as the Optimal Power Flow (OPF) by Dommel and Tinney [45]. Since then, OPF has been playing a very important role in power system operation and planning. Today OPF has been extended to any problem that involves the determination of the instantaneous optimal steady state of power system.

Historically, the solution of the ED by the equal incremental cost method was a precursor of the OPF. The appearance of the OPF ended the era of the "classical period of economic dispatch", which had developed for nearly 30 years [46]. Both ED and OPF are optimization problems, even with the same minimum cost objective. However, ED only considers real power generations and represents the power system by a single equality constraint (the system power balance equation) while OPF is an optimization problem with both active and reactive power variables and a full network model.

Rapid development of the OPF in the last four decades with the evolving power systems has produced many different applications of it and thus many new forms of OPF problems with various objectives, constraints, and variables. Online implementations pose the most onerous requirements on the OPF technology. These requirements include response time, robustness with respect of starting point, infeasibility detection and handling, discrete modeling, contingency constraints modeling, and so on. Some efforts have been made and are still being made to meet these requirements so that the OPF, as an online application of the Energy Management system (EMS), can be useful to operators [49].

The emerging competitive electricity markets bring more requirements and challenges to OPF [52]. As the only application with both economic concerns and full power network modeling in current EMSs, OPF becomes an ideal candidate tool for spot market clearing, energy and transmission pricing, transmission congestion management, optimal ancillary services

procurement, ATC evaluation and enhancement, and optimal allocation of transmission rights, etc.

In this chapter, the general formulation of OPF problem is introduced with various objective functions, constraints and control variables. The existing methodologies for OPF solution are reviewed briefly. Then the conventional applications of OPF and OPF's potential roles in deregulated electricity markets are discussed respectively. Since linear programming and quadratic programming are used in this thesis to solve extended OPF problems, the general procedure of successive linear programming method for OPF is presented and finally a brief description about interior point linear and quadratic programming is given.

3.2 The General Formulation of OPF Problem

The OPF problem requires the solution of non-linear equations, which describe optimal and secure operation of a power system. The general nonlinear OPF problem can be formulated as (3-1). A full formulation of AC OPF problem can be found in Appendix A.

$$\text{Minimize} \quad F(x,u) \tag{3-1}$$

$$\text{subject to:} \quad g(x,u) = 0$$

$$h(x,u) \leq 0$$

where $g(x,u)$ is a set of nonlinear equality constraints, and $h(x,u)$ is a set of nonlinear inequality constraints. The vector x consists of dependent variables and fixed parameters while the vector u consists of control variables.

The dependent variables include bus voltage magnitudes and phase angles, as well as MVAr output of generators performing bus voltage control. The fixed parameters are items like the reference bus angle, non-controlled generator MW and MVAr outputs, non-controlled MW and MVAr loads, fixed bus voltages, network branch parameters, and so on.

The control variables might be:

- real and reactive power generations,

- real and reactive power loads (load shedding),

- control voltage settings

- LTC transformer tap positions,

- MW interchange,

- DC transmission line flows,

- phase shifter angles,

- shunt capacitors and reactors,

- static VAR compensators.

The equality and inequality constraints include:

- balance of generation and load,

- power flow equations,

- limits on all the control variables,

- branch flow limits (MW, MVAr, MVA),

- bus voltage limits,

- transmission interface (corridor) limits,

- system reserve limits.

The objective of OPF problems has many different forms with different applications of OPF. The four most popular objectives of OPF are:

- active power generation cost minimization,

- active power losses minimization,

- minimization of control-shift,

- minimization of number of rescheduled controls.

3.3 Existing Methodologies for OPF

The OPF development in the last 40 years has been following closely the progress in numerical optimization techniques and computer technology. Many different approaches have been proposed to solve the OPF problems [47-48]. These techniques can be classified into 6 categories:

- Gradient methods,

- Quadratic Programming (QP),

- Newton-based methods,

- Linear Programming (LP),

- Interior Point methods,

- Heuristic optimization methods.

In addition, there are two other important fields of OPF research which need to be mentioned here:

- P-Q decoupled OPF,

- Area decomposition OPF.

3.3.1 Gradient Methods

Historically speaking, this is the earliest efficient solution of OPF since Carpentier proposed a generalized reduced gradient method, which solves the OPF by the primal method [54]. In 1968, Dommel and Tinney developed a nonlinear programming method to minimize fuel cost and active power losses [45]. This approach solves the Kuhn-Tucker equations using a combination of the gradient method for a fixed set of independent variables and penalty functions for violated dependent constraints. This work is regarded as the guiding pioneer for commercial OPF tools.

Alsac and Stott proposed a reduced gradient method utilizing the Lagrange multiplier and penalty function techniques in 1974 [53]. Wu et al. solved the OPF in two stages, both by the gradient method [55]. This program has the capability of handling very large problems, but

often infeasible values remain upon completion. Since then some other works have been done on the development of the gradient method [56].

In a gradient method, the gradient will give the direction of maximum increase in the cost function as a function of the adjustment of each variable. However, the gradient method does not give any indication about how far we should move along the negative gradient direction. Therefore, the main problem with the gradient method lies in the fact that the direction of gradient must be changed very often and this may lead to a very slow convergence.

3.3.2 Quadratic Programming

Quadratic programming is a special form of nonlinear programming with quadratic objective function and linear constraints. Its applications for dispatching first appeared in 1973-1974 [57-61]. In 1973, Reid and Hasdorf [60] presented a quadratic programming method to solve OPF problems. This method employs Wolfe's algorithm specialized to solve the ED problem which does not require penalty factors or the determination of the gradient step size. This method was developed purely for research purposes, so the model used is limited and employs the classic ED with voltage, real, reactive power as constraints. Another significant contribution in 1974 was presented by Wollenberg and Stadlin [61], in which two optimization processes for solving ED, Dantzig-Wolfe algorithm and Quadratic Programming, were compared. Using optimally ordered sparsity programmed matrix solution techniques, the proposed method is reliable and produces acceptable results and achieves a real-time solution. The method solves contingency constrained ED problems and serves as one of the pioneering works of decomposition algorithm for ED.

More papers about applications of quadratic programming to the OPF solution appeared in 1980s, including Giras and colleagues' method which employs a Quasi-Newton Technique based on Han-Powell algorithm [62], Aoki and Satoh's method which employs a parametic quadratic programming to overcome the problem of dealing with transmission losses as a quadratic form of generator outputs [63], the method of El-Kady et al. which solves the OPF problem for voltage control using a quadratic programming algorithm [64], and the method presented by Aoki et al. which formulates constrained load flow problems as Quasi-quadratic programming problems to satisfy nonlinear constraints and the MINOS technique is used [65].

3.3.3 Newton-based Methods

Generally speaking, in Newton-based methods the necessary conditions of optimality commonly referred to as the Kuhn-Tucker conditions are obtained. The solution of these nonlinear equations need iterative methods, among which the Newton method is favored for its quadratic convergence properties. The Newton method is a version of successive quadratic programming which implements the Lagrange-Newton solver to quadratic approximations of the original OPF problem. This method can efficiently solve highly nonlinear and non-separable OPF problems such as active power losses minimization and combined full optimization. OPF solution with Newton method has also been found to be very reliable in finding solution of feasible OPF problems, and has no problem in identifying the set of active constraints.

Quasi-Newton methods were first used in conjunction with penalty methods in the late 1960's. In these methods an approximation of the Hessian matrix is built up iteratively using efficient updating formulae. The development of the Han-Powell technique revived interest in quasi-Newton methods in the late 1970's to early 1980's. These methods [66-67] are useful only for problems of limited size or using a dense formulae, because they generate dense Hessians.

Some well known commercial OPF packages have evolved along with MINOS from a gradient solver [56] to a quasi-Newton solver [68-69] to a Newton solver [70-71]. In 1984 the ESCA package [72] by Sun and colleagues implemented the Lagrange-Newton solver to sparse decoupled subproblems with penalty terms added to handle violated dependent constraints. The super-linear convergence to Kuhn-Tucker condition makes this method suitable for practical large systems. Since then the Newton method has been widely applied to implement OPF tools [73].

Handling inequality constraints is very difficult in either gradient or Newton approaches. The usual method is to form a quadratic constraint "penalty" function. Since Newton Method has the second derivative information built into it, it has good convergence features and it can handle the inequality constraints as well. The difficulty with Newton method arises in the fact that near the limit the penalty is small, so that the optimal solution will tend to allow the variable to float over its limit. When there are few limits to be concerned with, Newton method is the best method for OPF.

3.3.4 Linear Programming

The gradient and Newton methods suffer from the difficulties in handling inequality constraints. Linear Programming, however, is very good at dealing with inequality constraints, as long as the problem can be linearized without loss of accuracy. For many years linear programming has been recognized as a reliable and robust technique to solve a large subset of specialized OPF problems characterized by linear separable objective functions and linear constraints.

In 1968, Wells [74] developed a linear programming approach to determine an economic schedule that is consistent with network security requirements for loading plants in a power system. The cost function and constraints were linearized and solved by the simplex method. In 1970, Shen and Laughton [75] presented a dual linear programming technique for the solution of power system load scheduling with security constraints. The solution was obtained using the revised simplex method. In 1978, Stott and Hobson [76] efficiently solved power system security control problems by employing a linear iterative technique for network sparsity selection of binding constraints. In 1979, Stott and Marinho [77] presented a linear programming approach using a modified revised simplex technique for security dispatch and emergency control calculation on large power systems. In 1983, Irving and Sterling [78] presented a linear programming approach with an AC power flow to solve a economic dispatch of active power with constraints relaxation. Since then, the LP based OPF methods have been successfully implemented in solving active [79-82], as well as reactive power [80, 83-85] scheduling problems and the active losses minimization problem [51].

Successive linear programming has been used in quite a few OPF application to date. Khan [86] suggested the use of a linear programming subproblem in a nonlinear iterative loop, with special consideration to avoid oscillation of the iteration. Stott and Alsac present their experiences with successive linear programming in [51, 80].

3.3.5 Interior Point Methods

The current interest in interior point methods was sparked by Karmarkar's projective scaling algorithm for linear programming [87]. Shortly after Karmarkar's algorithm became well-known, Gill et al. [88] showed that under certain conditions, the projective scaling algorithm is equivalent to logarithmic barrier methods which has a long history in linear and nonlinear programming. This led to the development of Mehrotra's primal-dual predictor-corrector

method which is currently the most efficient interior point approach [89]. The main ideas behind these barrier methods are:

- Convert functional inequalities to equalities and bound constraints using slack variables;

- Replace bound constraints by adding them as additional terms in the objective function using logarithmic barriers;

- Use Lagrange multipliers to add the equalities to the objective thereby transforming the problem into an unconstrained optimization problem;

- Use Newton's method to solve the first order conditions for the stationary points of unconstrained problem.

The application of interior point methods to power system optimization problems started slightly later. In 1991, Clements et al. [90] presented probably the first interior point research on power systems, which is solving state estimation by a nonlinear programming interior point technique. In the same year, Ponnambalam et al. [91] presented a newly developed dual affaine algorithm to solve the hydro-scheduling problem. In 1992, Vargas et al. [92] presented an interior point method to solve the economic dispatch problem. In 1993, Momoh et al. [93] used an extended quadratic interior point method to solve economic dispatch and VAR planning problems.

Interior Point Methods can be applied to OPF problems in two ways. The first way is to use the successive linear programming technique and to employ an interior point method for solving the linear problems [94-97]. The other way is to directly apply interior point methods to nonlinear OPF formulation using the relation to barrier methods [98-102].

3.3.6 Heuristic Optimization Methods

The optimization methods described above are essentially based on the idea of neighbourhood search (also called local search), which involves searching through the solution space by moving to the neighbours of a known solution in a direction. The process is repeated at the new point until a local minimum is found. These methods rely on convexity to obtain the global optimum and as such are forced to simplify relationships in order to ensure convexity. However, the OPF problem is in general non-convex and as a result, many local optima may exist. Heuristic optimization methods can help to find the global optimum. The major ones include: Evolutionary Algorithm, Simulated Annealing, Tabu Search, Ant Colony, Neural

Network, and Fuzzy Programming. Essentially, these methods all approach optimization through the use of guided search techniques [5, 179]. For instance, genetic algorithms and simulated annealing solve conventional optimization problems by "randomly generating new solution and retaining better ones". These heuristic optimization methods have been applied to solve various problems in power systems, such as economic dispatch, unit commitment, generator maintenance scheduling, network planning, and so on. The major drawback of heuristic optimization methods is usually their poor computation efficiency. Due to the complexity of real world problems, hybridization of these optimization algorithms would be a way forward to develop more powerful approaches to produce some particular properties.

3.3.7 P-Q Decoupled OPF

The splitting of OPF into active and reactive subproblems has been quite common. This splitting of OPF is important to its online implementation especially. The advantages of a decoupled OPF include:

- Decoupling greatly improves computational efficiency.

- Decoupling makes it possible to use different optimization techniques to solve the active and reactive power OPF subproblems.

- Decoupling makes it possible to have a different optimization cycle for each subproblem. In general, active power controls are scheduled frequently to satisfy economic requirements, while the reactive power controls are optimized less frequently to provide a secure post contingency voltage level or a voltage/VAR dispatch which minimizes transmission losses.

Dopazo was the first to solve a P-Q decomposition problem [116]. The proposed solution process used classical economic dispatch for active power and a minimum loss objective for reactive power. Later publications used various solvers for both subproblems. Solvers included linear programming [117, 122], quadratic programming [58, 118], gradient method [119-120]. A hybrid decoupled approach was presented in [121] using linear programming to solve an active power subproblem and quadratic programming to solve a reactive power subproblem.

3.3.8 Area/period Decomposition OPF

The original motivation to decompose a very large-scale OPF problem into several smaller problems by control areas or by time periods is to improve the computation speed. Decomposition strategies can also been found in solving the N+1 subproblems (base case and N contingency cases) independently for a contingency constrained OPF. Several common decomposition approaches have been applied to split OPF problems. These approaches include Benders decomposition [124,134], Dantzig-Wolfe decomposition [125-127], Cross decomposition (a combination of Benders decomposition and Lagrangian relaxation) [123], and Lagrangian decomposition and Augmented Lagrangian decomposition [127-133, 135-136]. More discussion about an area decomposition OPF will continue in Chapter 5.

3.4 Conventional Applications of OPF

In electric utilities, the OPF can be seen as the tool to determine the possible optimal state of the network. For system operation, OPF can be used for real-time and study applications. In EMS, OPF is the most advanced on-line network analysis application. The off-line OPF-based tools are important for the planning department of an electric utility. It has been applied to long-term transmission planning and VAr planning. Some major applications of OPF in electric utilities before deregulation will be described briefly in this section.

3.4.1 OPF in EMS

As a part of an EMS, the OPF function is designed to operate in real-time mode or study mode, to schedule active or reactive power controls or both, and to optimize a defined operational objective function. The relationship between OPF and other applications in EMS is shown in Figure 3.1.

In the study mode, the OPF obtains study cases (with violated constraints) from Power Flow or Contingency Analysis and produces optimal results with various objectives and eliminating all the violated constraints. These results are presented as recommendation to the dispatcher. In addition, OPF can help an instructor to create a particular scenario in Dispatch Training Simulator (DTS). For example, if an instructor wants to build a scenario that contains a few lines overloaded, OPF can help him to find remedial control actions for it.

In real-time mode, the close loop control can be implemented via the SCADA system of the EMS. Obtaining real-time power flow data from state estimation, OPF is run to get real-time

corrective controls (for example, automatic voltage/VAr control), which are sent to SCADA directly. Another online application of OPF is the OPF-ED-AGC control hierarchy. The overall objective is to impose the security constrained MW schedules produced by OPF to Automatic Generation Control (ATC) through ED. A promising approach is to install a Security Constrained Economic Dispatch (SCED) which plays the combined role of OPF and ED. In SCED, total generation cost is minimized while branch power flow limits and unit MW limits are used as constraints.
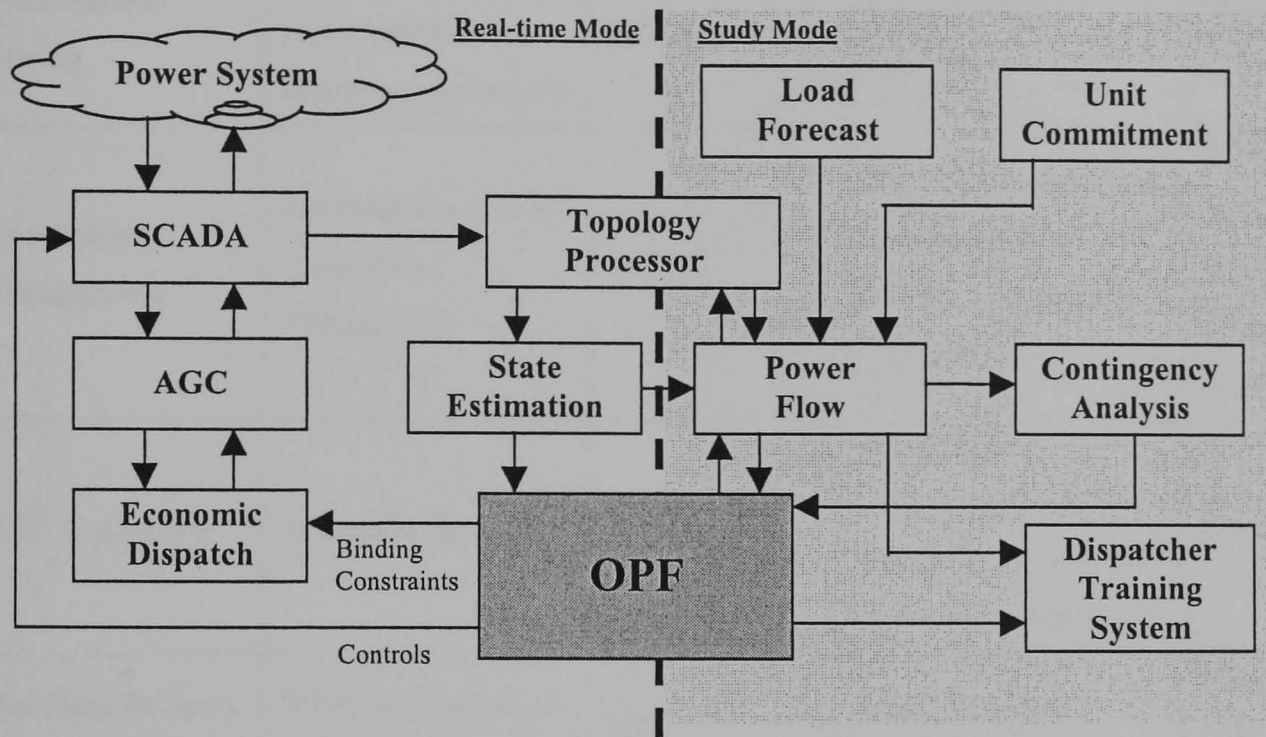
Figure 3.1 The relationship between OPF and other main EMS applications

3.4.2 OPF for System Planning

Besides its real-time and short-term applications in EMS, off-line OPF-based tools, which use forecast system data, can be applied to medium term and long-term system planning, such as generation planning and transmission planning. The objective of long-term transmission expansion planning is to determine possible alternatives which must present power transmission capacity satisfying the load forecast and generation planning. Using OPF-based tools, the problem is formulated considering both economic objectives and a power transmission electrical law. Usually, the power flow accuracy is obtained including DC power flow model in this optimization problem. Another typical application of OPF to system VAr planning is the optimal installation of capacitors. The size and location of new capacitors to ensure a certain level of stead-security for a given base-case operating condition is easily expressed and solved as a contingency constrained OPF problem.

Table 3.1 Applications of OPF in Electricity Markets

Applications in Electricity Markets	Extended OPF Problems			
	Objective Function	Network Model	Special Constraints	Special Controls
Spot Market Clearing and Pricing	maximize the social welfare	DC/AC	ramp-rate constraints and reserve-related constraints	Supply offers and demand bids (mostly piece-wise linear bidding functions)
Transmission Pricing	minimize generation cost/maximize consumer net benefit	DC/AC	Contingency constraints	Generation, load, and FACTS devices
Congestion Management	minimize the cost of congestion management	DC/AC	Operating constraints, Contingency constraints, stability constraints	Incremental and decremental adjustment, FACTS devices, curtailment on bilateral contracts
ATC Evaluation	Maximize the TTC	AC	Contingency constraints, stability constraints, stochastic operating constraints	FACTS devices
Ancillary Services Procurement	Minimize the cost of ancillary services	DC	reserve-related constraints	Reserve capacity from generation and demand
Transmission Rights Allocation	Maximize the revenue of transmission rights auction	DC	Bids-related constraints, contingency constraints	Injections and withdraws for bids of transmission rights, FACTS devices

3.5 Applications of OPF in Electricity Markets

In competitive electricity markets, some of the conventional application of OPF may still be useful, like OPF in AGC and OPF in Voltage/VAR control, etc. However, the competition and transmission open access have brought about many new potential applications and technical challenges to the OPF. Transmission system, which appears to have characteristics of a natural monopoly, is the major source of technical complication in a competitive electricity market. OPF techniques enter the scene with their explicit recognition of network characteristics within the broader context of power system optimization. The potential roles of

OPF in electricity markets is shown in Table 3.1. In this section we will briefly review some important applications of extended OPF techniques in deregulated electricity markets.

3.5.1 Spot Market Clearing and Pricing

An electricity spot market requires an OPF for comparability and transparency, which encourages usage of systematic tools and procedures. Electricity spot market clearing is also an optimization problem with network constraints. But different from conventional OPF models, its objective function is to maximize total market profit based on bidding price instead of generation cost. Market clearing prices for different locations can be calculated from the Lagrangian multipliers of constraints in the OPF solution.

New Zealand wholesale electricity market is using an extended OPF to implement a security-constrained bid-clearing system, which includes DC network constraints, ramp-rate constraints and reserve-related constraints [103]. This problem is solved by Advanced Dual Simplex and Interior Point algorithm. The Interim New England Electricity Market is also employing an extended OPF technique to perform the joint energy and reserve dispatch [104]. Various forms of OPF problems appeared in papers about pricing of real and reactive power [105-110].

3.5.2 Transmission Pricing

In deregulated electricity markets, Short Run Marginal Pricing (SRMC) has been applied to transmission pricing since it was first proposed by Schweppe *et al.* [141] Under this scheme, the transmission price or wheeling rate is the difference between locations of seller and buyer. OPF can be used to produce the SRMC, thereby to be used in transmission pricing [111-115]. Farmer and Cory [142-143] proposed another novel approach by alleviating the inherent shortcomings of SRMC based pricing while maintaining the economic efficiency of the price signals. In their method, the objective of the optimal pricing problem is to maximize the 'consumer net benefit' and contingency constraints are considered by DC approximation.

3.5.3 Congestion Management

In real-time, congestion management actually is an optimal redispatch problem. Its objective function could be minimization of the cost of adjustment or minimization of bilateral transaction curtailment. Generators and consumers can submit linear incremental and decremental bidding curves to the ISO. The constraints include all the network constraints,

plus contingency constraints and stability constraints. An extended OPF can solve this problem perfectly and produce a corresponding congestion price.

In California power market, the interzonal congestion management is modeled with a DC OPF with market separation constraints while the intrazonal congestion management is modeled with an AC OPF considering voltage constraints [26]. Other OPF-based congestion management methods can be found in [33-36]

3.5.4 ATC Evaluation

ATC is the measure of the ability of interconnected power systems to reliably move or transfer power from one area to another over all transmission lines or paths between those areas under specified system conditions. There are at least three possible approaches for the calculation of TTC and ATC. The first one is based on distribution factors or sensitivity factors calculated from DC power flow [137]. The second one is called continuation power flow algorithm, which traces the power flow solution curve, starting at a base load, leading to the steady state voltage stability limit or the maximum loading point of the system [138]. The third one is based on OPF techniques [139-140]. During this analysis, all the security constraints and reserve constraints are included. Post-contingency constraints may also be considered into the model.

ATC can be evaluated as a true optimization problem using a DC network together with linear programming. However, this level of modeling accuracy can be dubious, and since Vars and voltages often determine MW transfer limits, the results could be dangerously optimistic. An EPRI sponsored project evaluated ATC based on an AC modeled security constrained OPF (SCOPF) problem.

3.5.5 Ancillary Services Procurement

Ancillary services include spinning reserves, non-spinning reserves, AGC, replacement reserves, voltage support and black start. For the ISO, there are two approaches to procure reserves. One approach is to simultaneously procure reserves and energy in a single combined auction and compensate the units providing reserves at their opportunity costs derived from energy auction. The other approach is to set up a separate auction for procuring reserves. Both approaches can be formulated as OPF problems. In the first approach the requirement of reserves is treated as a constraint while in the second approach the cost of reserves is the objective function.

3.5.6 Optimal Transmission Rights Allocation

Transmission rights allocation or transmission capacity reservation is very important for trading electricity and congestion management. All the sold transmission rights must be simultaneously feasible. Usually, the ISO will run an auction to allocate transmission rights. Market participants can bid into the auction to buy or sell transmission rights. The Auction can be implemented by a modified OPF. Transmission Rights are modeled as pairs of power injections and withdrawals. The objective is to maximize revenues from transmission rights while keeping the system within limits when all transmission rights exist simultaneously in the system. The DC network model is often used here, because the auction of transmission rights are usually held long before the real-time operation and only active power is concerned.

3.6 Interior Point Linear/Quadratic Programming and OPF

3.6.1 Successive Linear Programming

The nonlinear OPF problem in equation (3-1) can be solved as a succession of linear approximation to this problem, i.e.:

$$\text{Minimize} \quad F(x^0 + \Delta x, u^0 + \Delta u) \tag{3-2}$$

$$\text{subject to:} \quad g'(x^0 + \Delta x, u^0 + \Delta u) = 0$$

$$h'(x^0 + \Delta x, u^0 + \Delta u) \leq 0$$

where: x^0, u^0 initial values of x and u,

        $\Delta x, \Delta u$ shifts about the initial points,

        g', h' linear approximations to the original non-linear constraints.

The basic steps required in the LP-based OPF algorithm are:

1. Solve the AC power flow problem;

2. Linearize the OPF problem (express it in terms of changes about the current exact system operating point) by:

     A. piecewise linearizing the objective function,

B. contructing and factoring the network Jacobian matrix (unless it has not changed since last time),

C. expressing the limits of monitored constraints as changes with respect to the values of these quantities, accurately calculated from power flow,

D. expressing the incremental control variables Δu as changes about the current variable values.

E. expressing the incremental limits obtained in Step 2.B above in terms of the incremental control variables Δu .

3. Solve the linearized OPF problem by a LP algorithm, computing the incremental control variables Δu ;

4. Update the control variables $u = u + \Delta u$ and solve the AC power flow problem again;

5. If changes in control variables Δu were below user-defined tolerances, the solution has been reached. If not, go to Step 2 and continue the iteration.

As shown in equation (3-2), the optimization problem that is solved at each iteration is a linear approximation to the actual optimization problem. Step 2 corresponds to forming the linear network model and expressing it in terms of changes about the initial operating points.

The linearized network model may be derived using either a Jacobian-based coupled formulation or a decoupled formulation based on the modified P-Q decoupled power flow equations. Since the latter is used in most applications of LP-based OPF, the linear decoupled network model is described here. The modified P-Q decoupled power flow equations are:

$$B'\Delta\theta = \Delta P \qquad (3-3)$$

$$B''\Delta V = \Delta Q \qquad (3-4)$$

The active power model linearization is based on a linear incremental lossless network model in which the change in active power flow in branch l for bus i to j is the same at ends i and j.

$$\Delta P_{ij} = (\Delta\theta_i - \Delta\theta_j)/x_l \qquad (3-5)$$

Here, $\Delta\theta_i$ and $\Delta\theta_j$ are the bus voltage incremental angles, and x_l is the branch reactance.

The reactive power model is derived from the simplified incremental branch flow equation:

$$\Delta Q_{ij} = -b_l(\Delta V_i - \Delta V_j - \Delta t_l) - yc_l \Delta V_i \tag{3-6}$$

where b_l is the series admittance of the branch, t_l is the transformer tap ratio, and yc_l is the total branch shunt susceptance. This model ignores changes in series reactive losses.

3.6.2 Interior Point Linear Programming

Karmarkar's algorithm is significantly different from Dantzig's simplex method in 1963, which solves a linear programming problem starting with one extreme point along the boundary of the feasible region and skips to a better neighboring extreme point along the boundary, finally stopping at an optimal extreme point. Karmarkar's interior point rarely visits too many extreme points before an optimal point is found. The IP method stays in the interior of the polytope and tries to position a current solution as the "center of the universe" in finding a better direction for the next move. By properly choosing the step lengths, an optimal solution is achieved after a number of iterations. Although this IP approach requires more computational time in finding a moving direction than the traditional simplex method, better moving direction is achieved resulting in fewer iterations.

Figure 3.2 illustrates how the two methods, IP method and simplex method, reach an optimal solution. In this small problem, the projective scaling algorithm requires about the same number of iterations as the simplex method. But for a large problem this method would only require a small fraction of the number of iterations that the simplex method requires.
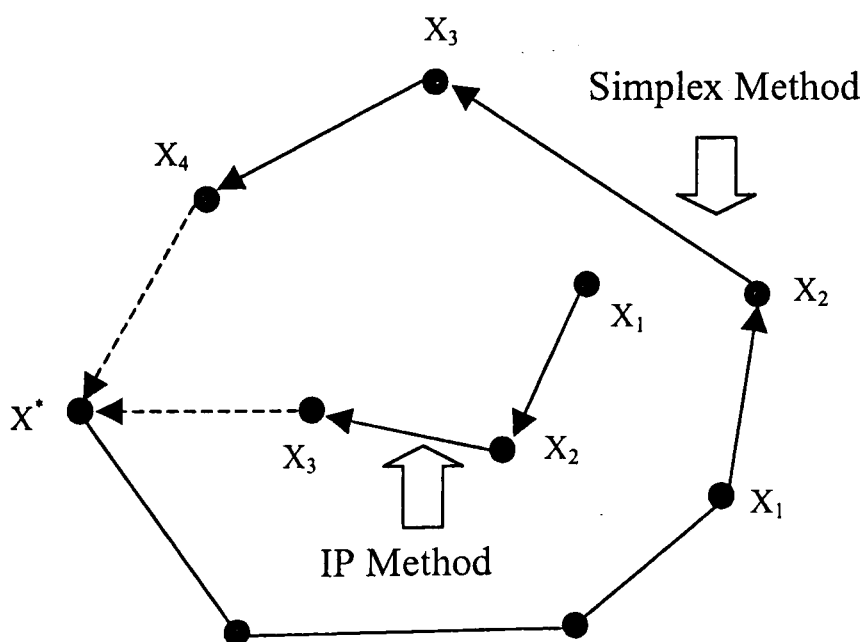
Figure 3.2 Comparison between IP and simplex methods

As mentioned above, since Karmarkar's discovery of the interior point method and its reported speed advantage over the simplex method, many variants of the IP method have evolved in an attempt to solve linear programming problems. As one of the most efficient interior point approaches, a second order primal-dual predictor-corrector method, based on Mehrotra's method [89], is introduced here briefly.

The linearized OPF problems in (3-2) can also be written as the following standard primal linear programming problem:

Minimize $\quad c^T x$

Subject to $\quad Ax = b$ $\hfill$ (3-7)

$\qquad\qquad x + s = u$

$\qquad\qquad x, s \geq 0$

where $c, x, s, u \in R^n, b \in R^m, A \in R^{m \times n}$. Its dual problem is:

Maximize $\quad b^T y - u^T w$

Subject to $\quad A^T y + z - w = c$ $\hfill$ (3-8)

$\qquad\qquad z, w \geq 0$

where $z, w \in R^n, y \in R^m$.

The logarithmic barrier function is given by adding the nonnegativity of constraints in the primal formulation into the objective function as logarithmic barrier penalty items:

$$L(x, s, \mu) = c^T x - \mu(\sum_{j=1}^{n} \ln x_j + \sum_{j=1}^{n} \ln s_j) \qquad (3\text{-}9)$$

The first-order Karush-Kuhn-Tucker (KKT) optimality conditions for (3-9) are:

$\qquad Ax = b$

$\qquad x + s = u$

$\qquad A^T y + z - w = c$ $\hfill$ (3-10)

$\qquad XZe = \mu e$

$$SWe = \mu e$$

where X, S, Z, W are diagonal matrices with the elements x_j, s_j, z_j, w_j, respectively, e is the n-vector of all ones, and μ is a barrier parameter.

So the Newton's direction can be obtained by solving:

$$
\begin{bmatrix}
A & 0 & 0 & 0 & 0 \\
I & 0 & I & 0 & 0 \\
0 & A^T & 0 & I & -I \\
Z & 0 & 0 & X & 0 \\
0 & 0 & W & 0 & S
\end{bmatrix}
\begin{bmatrix}
\Delta x \\
\Delta y \\
\Delta s \\
\Delta z \\
\Delta w
\end{bmatrix}
=
\begin{bmatrix}
b - Ax \\
u - x - s \\
c - A^T y - z + w \\
\mu e - XZe \\
\mu e - SWe
\end{bmatrix}
\tag{3-11}
$$

Once $(\Delta x, \Delta y, \Delta s, \Delta z, \Delta w)$ (denoted with Δ below) has been calculated, the maximum step sizes α_P and α_D, which maintain the nonnegativity of variables in the primal and dual spaces, are found. Next, the variables are updated by:

$$
\begin{aligned}
x^{k+1} &= x^k + \alpha_0 \alpha_P \Delta x \\
s^{k+1} &= s^k + \alpha_0 \alpha_P \Delta s \\
y^{k+1} &= y^k + \alpha_0 \alpha_D \Delta y \\
z^{k+1} &= z^k + \alpha_0 \alpha_D \Delta z \\
w^{k+1} &= w^k + \alpha_0 \alpha_D \Delta w
\end{aligned}
\tag{3-12}
$$

where α_0 is the step-reduction factor. Then, the barrier parameter μ is updated and the iteration process is repeated.

The factorizations of KKT matrix can take 60% to 90% of the total CPU time for solving a problem. So it is important to look for some way to reduce the number of iterations. Mehrotra's predictor-corrector technique [89] incorporates high-order information when approximating the central trajectory and computing the direction step. The second-order variant of this technique has been used widely and proved to be efficient.

The predictor-corrector technique regards the direction step Δ as two parts:

$$\Delta = \Delta_A + \Delta_C \tag{3-13}$$

where Δ_A is the affine-scaling component which is the predictor term and is responsible for optimization to reduce the primal and dual infeasibilities and the duality gap, Δ_C is the

68

centering component which is the corrector term and keeps the current iteration away from the boundary of feasible region (keeps it close to the central path ideally) .

Δ_A is obtained by solving (3-11) with $\mu = 0$. Δ_C is the solution of (3-11) with the right-hand side replaced by

$$(0,0,0,\mu e - XZe, \mu e - SWe)^T$$

where $\mu > 0$ is centering parameter ($\mu = \dfrac{x^T z + s^T w}{2n}$, for example). The maximum stepsizes in the primal and in the dual spaces preserving the nonnegativity of (x,s) and (z,w), respectively, are determined, and the predicted complementarity gap

$$g_a = (x + \alpha_{Pa} \Delta x)^T (z + \alpha_{Da} \Delta z) + (s + \alpha_{Pa} \Delta s)^T (w + \alpha_{Da} \Delta w)$$

is computed. It is then used to determine the barrier parameter

$$\mu = (\frac{g_a}{g})^2 \frac{g_a}{n} \tag{3-14}$$

where $g = x^T z + s^T w$ is the current complementarity gap. Next, the second-order component of the predictor-corrector is computed.

$$(X + \Delta x)(Z + \Delta z) = \mu e \Rightarrow Z\Delta x + X\Delta z = -XZ + \mu e - \Delta x \Delta z$$

When solving (3-11) the second-order term $\Delta x \Delta z$ is neglected. To obtain Δ_C, $\Delta x \Delta z$ can be estimated using the affine-scaling direction $\Delta x_A \Delta z_A$. The same process is applied to the other second-order term $\Delta s \Delta w$. So for such a μ in (3-14) the Δ_C can be calculated by solving:

$$\begin{bmatrix} A & 0 & 0 & 0 & 0 \\ I & 0 & I & 0 & 0 \\ 0 & A^T & 0 & I & -I \\ Z & 0 & 0 & X & 0 \\ 0 & 0 & W & 0 & S \end{bmatrix} \begin{bmatrix} \Delta x_C \\ \Delta y_C \\ \Delta s_C \\ \Delta z_C \\ \Delta w_C \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ 0 \\ \mu e - \Delta X_A \Delta Z_A e \\ \mu e - \Delta S_A \Delta W_A e \end{bmatrix} \tag{3-15}$$

Finally, the direction Δ in (3-13) is determined.

In the above method, a single iteration of the second-order predictor-corrector primal-dual method needs two solves of the same linear system with two different right hand sides. The

advantage of this method is that the barrier parameter μ can be estimated very well and a high-order approximation is applied to the central path.

One advantage of the primal-dual method is that it allows for separate step lengths in the primal and dual spaces as shown in (3-12). This has been proven highly efficient in practice, significantly reducing the number of iterations to converge. The step lengths (α_P, α_D) are determined in the following way that the nonnegativity conditions $x, s \geq 0$ and $z, w \geq 0$ are preserved, respectively.

$$\alpha_P = \min\left\{1, -\frac{x_j}{\Delta x_j}, -\frac{s_j}{\Delta s_j}, \Delta x_j < 0, \Delta s_j < 0\right\} \tag{3-16}$$

$$\alpha_D = \min\left\{1, -\frac{z_j}{\Delta z_j}, -\frac{w_j}{\Delta w_j}, \Delta z_j < 0, \Delta w_j < 0\right\} \tag{3-17}$$

According to the experience in [95], the step-reduction factor α_0 in (3-12) can be initially set as $\alpha = 0.95$, then be increased to $\alpha = 0.9995$ when the primal and dual infeasibility is less than a certain value (say 10^{-2}). This will be far more efficient than using a constant value.

The iteration terminates when the following feasibility and optimality conditions are all satisfied.

- Primal feasibility: $\dfrac{\|Ax - b\|}{1 + \|x\|} \leq \varepsilon_f$

- Bound feasibility: $\dfrac{\|x + s - u\|}{1 + \|x\| + \|s\|} \leq \varepsilon_f$

- Dual feasibility: $\dfrac{\|A^T y - w + z - c\|}{1 + \|y\| + \|w\| + \|z\|} \leq \varepsilon_f$

- Optimality: $\dfrac{\|c^T x - (b^T y - u^T w)\|}{1 + \|b^T y - u^T w\|} \leq \varepsilon_0$

where ε_f and ε_0 are convergence tolerance for feasibility and optimality conditions, respectively.

3.6.2 Interior Point Quadratic Programming

Quadratic Programming is similar to Linear programming but with quadratic objective function. The general convex quadratic problem with linear constraints can be written as:

Minimize $\qquad c^T x + \dfrac{1}{2} x^T Q x$

Subject to $\qquad Ax = b$ $\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad$ (3-18)

$\qquad\qquad\qquad x + s = u$

$\qquad\qquad\qquad x, s \geq 0$

where $c, x, s, u \in R^n, b \in R^m, A \in R^{m \times n}$. The matrix $Q \in R^{n \times n}$ is positive semi-definite. Its dual problem is:

Maximize $\qquad b^T y - u^T w - \dfrac{1}{2} x^T Q x$

Subject to $\qquad A^T y + z - w - Q x = c$ $\qquad\qquad\qquad\qquad\qquad$ (3-19)

$\qquad\qquad\qquad z, w \geq 0$

where $z, w \in R^n, y \in R^m$.

After adding the logarithmic barrier function into primal and dual problems, the first order optimal conditions are:

$\qquad Ax = b$

$\qquad x + s = u$

$\qquad A^T y + z - w - Q x = c$ $\qquad\qquad\qquad\qquad\qquad\qquad$ (3-20)

$\qquad XZe = \mu e$

$\qquad SWe = \mu e$

So similarly to linear programming case, the Newton's direction can be obtained by solving:

$$
\begin{bmatrix}
A & 0 & 0 & 0 & 0 \\
I & 0 & I & 0 & 0 \\
-Q & A^T & 0 & I & -I \\
Z & 0 & 0 & X & 0 \\
0 & 0 & W & 0 & S
\end{bmatrix}
\begin{bmatrix}
\Delta x \\
\Delta y \\
\Delta s \\
\Delta z \\
\Delta w
\end{bmatrix}
=
\begin{bmatrix}
b - Ax \\
u - x - s \\
c - A^T y - z + w + Qx \\
\mu e - XZe \\
\mu e - SWe
\end{bmatrix}
\tag{3-21}
$$

There are two essential differences between the primal-dual method for linear and for quadratic programming:

- Q appears in the left-hand side of system (3-21);

- Qx appears in the right-hand side of (3-21).

Except for these two differences, the rest of the process for quadratic programming is the same as the process for linear programming.

3.7 Lagrangian Relaxation Decomposition Approach

The Lagrangian Relaxation (LR) decomposition procedure, which will be used in Chapter 5 to solve multi-regional congestion management problem, is presented below.

Assume that the primal problem has the structure below:

$$
\text{minimize}_x \quad f(x)
$$

$$
\text{Subject to} \quad
\begin{aligned}
& a(x) = 0 \\
& b(x) \le 0 \\
& c(x) = 0 \\
& d(x) \le 0
\end{aligned}
\tag{3-22}
$$

where $f(x): R^n \to R$, $a(x): R^n \to R^{\bar{a}}$, $b(x): R^n \to R^{\bar{b}}$, $c(x): R^n \to R^{\bar{c}}$, $d(x): R^n \to R^{\bar{d}}$, and $\bar{a}$, $\bar{b}$, $\bar{c}$ and $\bar{d}$ are scalers.

Constraints $c(x) = 0$ and $d(x) \le 0$ are complex constraints, which should be relaxed to simplify the problem (3-22). Therefore, the Lagrangian function is defined as

$$
L(x, \lambda, \mu) = f(x) + \lambda^\dagger c(x) + \mu^\dagger d(x)
\tag{3-23}
$$

where λ and μ are Lagrange multiplier vectors. Under the local convexity assumptions ($\nabla_x^2 L(x^*, \lambda^*) > 0$) the dual function is defined as

$$\phi(\lambda,\mu) = \text{minimize}_x \quad L(\lambda,\mu,x)$$
$$\text{subject to} \quad a(x) = 0$$
$$b(x) \leq 0 \tag{3-24}$$

The dual function is concave and in general non-differentiable. This is a fundamental fact in the algorithm stated below. The dual problem is then defined as

$$\text{maximize}_{\lambda,\mu} \quad \phi(\lambda,\mu) \tag{3-25}$$

subject to $\quad \mu \geq 0$

The LR decomposition procedure will be attractive if problem (3-24) can be easily solved with fixed values of λ and μ. The problem to be solved to evaluate the dual function for the given values $\widetilde{\lambda}$ and $\widetilde{\mu}$ is the so-called relaxed primal problem, i.e.

$$\text{minimize}_x \quad L(\widetilde{\lambda},\widetilde{\mu},x)$$
$$\text{subject to} \quad a(x) = 0$$
$$b(x) \leq 0 \tag{3-26}$$

Problem (3-26) typically decomposes into the following sub-problems, which can be solved in parallel. The decomposition facilitates its solution, and normally allows physical and economical interpretations.

$$\text{minimize}_{x_i, \forall i=1,\ldots,n} \quad \sum_{i=1}^{n} L(\widetilde{\lambda},\widetilde{\mu},x)$$
$$\text{subject to} \quad a_i(x_i) = 0, \quad i=1,\ldots,n$$
$$b_i(x_i) \leq 0, \quad i=1,\ldots,n \tag{3-27}$$

Under local convexity assumptions, the local duality theorem says that

$$f(x^*) = \phi(\lambda^*,\mu^*) \tag{3-28}$$

where x^* is the optimum for the primal problem and (λ^*,μ^*) is the optimum for the dual problem. In the non-convex case, given a feasible solution for the primal problem, x, and a feasible solution for the dual problem, $(\lambda, \mu.)$, the weak duality theorem says that

$$f(x) \geq \phi(\lambda,\mu) \tag{3-29}$$

Therefore, in the convex case the solution of the dual problem provides the solution of the primal problem while in the non-convex case the objective function value at the optimal

solution of the dual problem provides a lower bound to the objective function value at the optimal solution of the primal problem. The difference between the objective function values of the primal and dual problems at their optimal solutions is called the duality gap. Once the solution of the dual problem is achieved, its associated primal problem solution could be unfeasible. So feasibility procedures are usually required.

Lagrange multiplier updating is crucial to implement the LR decomposition procedure. The existing methods include subgradient method, cutting plane method, bundle method, dynamically constrained cutting plane method, and so on. The description of these methods can be found in [5].

3.8 Summary

The background, existing algorithms, applications and new challenges in electricity market of OPF techniques are introduced and discussed in this chapter. Particularly, the LP-based OPF approach and the primal-dual predictor-corrector interior point Linear/Quadratic Programming method are presented for the purposes of further illustrations and discussions in the following chapters.

More and more economic concerns in deregulated power industry, together with system security constraints, place increasing demand on the extended OPF's modeling, algorithmic, and implementation capabilities. All the existing OPF methodologies have their own peculiar limitations in terms of flexibility, adaptability and performance, and it is always difficult to identify the method with the best combination of properties. For applications of OPF in electricity markets, the robustness and feasibility have particular importance compared with its conventional applications. In addition, the bidding curves in various markets are often piecewise linear instead of the quadratic generation cost functions in traditional EMS applications. Therefore the well-known LP-based OPF approaches are showing more attraction than before and have been adopted by many ISOs in practice.

Chapter 4. Coordinated Real-time Optimal Dispatch through Balancing Mechanism

4.1 Introduction

With the deregulation of the power industry, the main services in power systems have been unbundled into several separate markets, such as the pool auction energy market where the schedule of generation can be arranged to meet the system load, the bilateral contract market where the generators and consumers can sell or buy electricity by themselves, and the ancillary services market where the ISO can procure the necessary services like system reserves and voltage support to maintain the system security.

Same as the other commodities markets, an electricity market should also be fully open and encourage the competition among the participants. However, because electrical energy can not be stored in large amounts for a long time, the deregulated unbundled electricity markets need a centralized control, which is the ISO, to keep the power system operating in light of the criteria of security, economy, and reliability. The functions of the ISO have been presented in Chapter 1. The basic tasks of the ISO during real-time operation should include:

- meeting the real-time imbalance between the actual and scheduled load and generation,

- and mitigating any real-time network congestion due to unexpected contingencies.

One of the solutions for the real-time dispatch of electricity markets is to establish a separate real-time balancing market and to encourage all the market participants to take part in the competition in this balancing market. This real-time balancing mechanism has been adopted by California [26] and appears as a key part in the New Electricity Trading Arrangement (NETA) in England and Wales [25].

Some research has been undertaken on the dispatch problems in electricity markets. In [32], F. F. Wu and P. Varaiya proposed a decentralized optimal dispatch method with the objective of maximizing social welfare under the coordinated multilateral trade model. In [33], H. Singh, S. Hao and A. Papalexopoulos made some comparisons between the approaches of transmission congestion management in pool model and bilateral model respectively. In [34-

35], A.K. David and R.S. Fang provided some useful curtailment strategies based on the purpose of minimizing deviations from transaction requests made by market participants in a structure dominated by bilateral and multilateral contracts. H. Singh and A. Papalexopoulos introduced the basic idea of auction market for ancillary services in California in [144]. The dispatch of ancillary services and the interaction between the various markets are also discussed in this paper briefly. In [103] and [104], optimal scheduling methods were proposed for New Zealand market and New England market, where the procurement of necessary operating reserves is combined with the procurement of the energy (joint dispatch) while the network constraints are taken into account.

However, the problem still remaining for an ISO to resolve is how to use all the possible resources during the real-time execution of various electricity commodity contracts efficiently and coordinately to ensure the system security. The main difficulties occurring in this real-time coordinated dispatch problem could be:

- how to dispatch the agreed system reserves contracts together with the supplemental energy bids in the balancing market;

- with the trend that more and more bilateral contracts are used to trade electricity, how to eliminate network congestion if the resources in the balancing market are not enough;

- to maintain the system security level, how to purchase replacement operating reserves if any of the pre-arranged operating reserves are called upon to provide energy for real-time system balancing or congestion management [26].

To resolve these difficulties, a new framework for real-time dispatch of unbundled electricity markets is proposed in this chapter. Under this framework, almost all the contracts in various markets can be dispatched and coordinated by submitting their adjustment bids to the balancing market. In particular, some bilateral contracts can be adjusted if the congestion of the network is very serious [36, 145]. Demand side participants are encouraged to play an active role in the competition of the real-time balancing market. A modified P-Q decoupled OPF is applied to solve this problem. The objective of the P sub-problem is to coordinate the dispatch among the pool auction contracts, the bilateral contracts and some operating reserve contracts, in accordance with the cost which is determined by the bids submitted by these contracts to the balancing market. The spot pricing and the two possible settlement methodologies are analyzed as well. A 5-bus test system and the IEEE 30-bus test system are studied to illustrate the proposed framework and its mathematical solution.

4.2 Framework of Real-Time Coordinated Dispatch

In the proposed framework which is shown in Figure 4.1, there are four unbundled markets, which are Bilateral Contract Market (BCM), Pool Day-ahead Energy Auction Market (PEAM), Pool Ancillary Services Auction Market (PAAM) and Real-time Balancing Market (RBM), respectively.
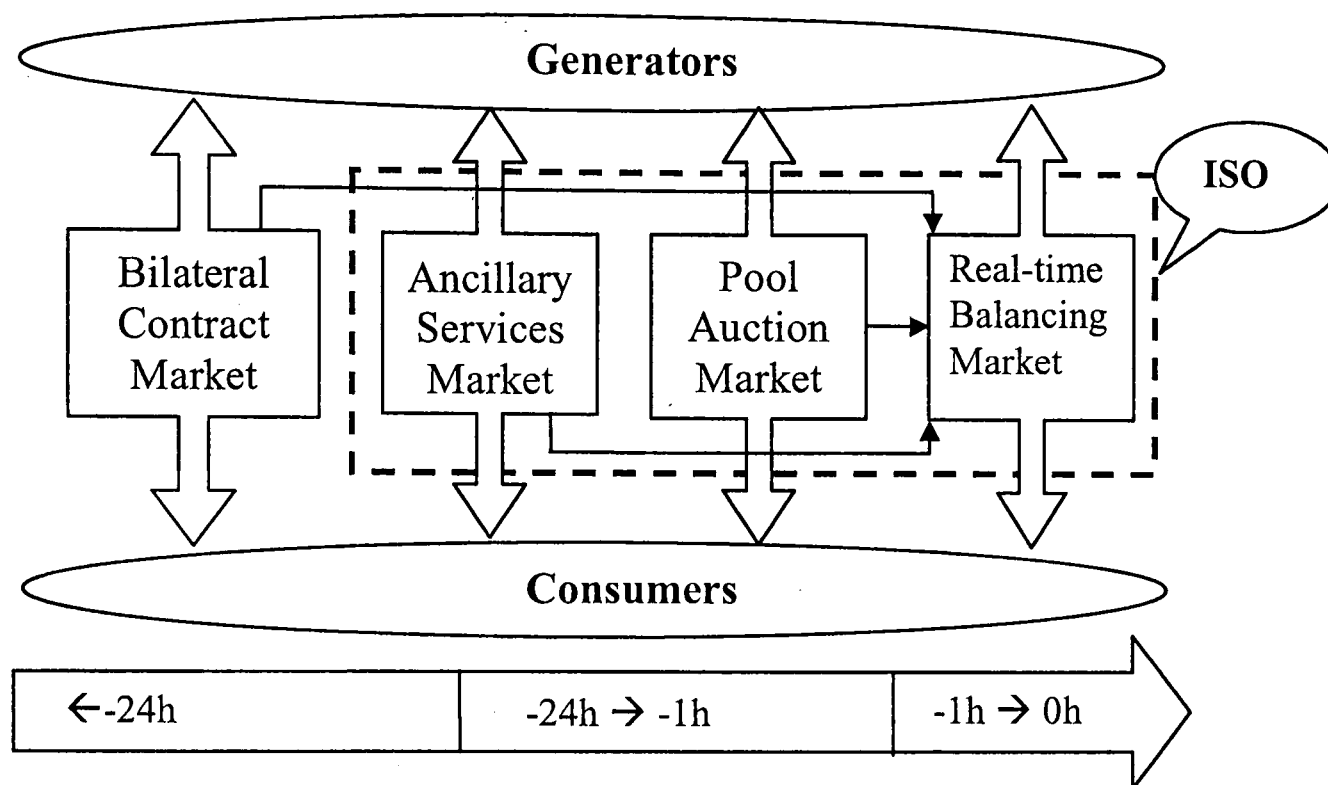
Figure 4.1 The proposed framework of real-time coordinated dispatch

4.2.1 Bilateral Contract Market (BCM)

In BCM, generators and consumers arrange physical electrical energy trades with each other based on their own financial interests. Instead of letting the ISO know the prices of their contracts, participants must report the quantities of their bilateral contracts to the ISO before the opening of the day-ahead energy auction market.

4.2.2 Pool Day-ahead Energy Auction Market (PEAM)

In PEAM all the contracts must be signed with the ISO, who receives energy bids from generators and consumers, and then selects cheapest generations to supply the demands in the whole system while all the network constraints must be satisfied. PEAM opens after BCM closes. It gives market participants another opportunity to buy or sell sufficient electricity to meet their requirement if they can not conclude all the necessary transactions in BCM.

4.2.3 Pool Ancillary Services Auction Market (PAAM)

Instead of electrical energy, the ancillary services are the commodities traded in PAAM. The ISO can determine the amount of required ancillary services by the load forecast and the preferred schedule. The ancillary services traded here include regulation reserves (AGC), spinning reserves, non-spinning reserves and replacement reserves, which are shown in Figure 4.2. The other two services, voltage support and black start can be procured in some special long-term markets. Each participant in PAAM must submit both a capacity bid and an energy bid for each service [144]. The energy bid will be used for real-time dispatch in RBM. The coordinated bid clearing strategies between PEAM and PAAM were given for New Zealand in [103] and for New England in [104]. Since the subject of this paper is real-time dispatch, only the operating reserves, which include AGC, spinning reserves and non-spinning reserves, are taken into account.
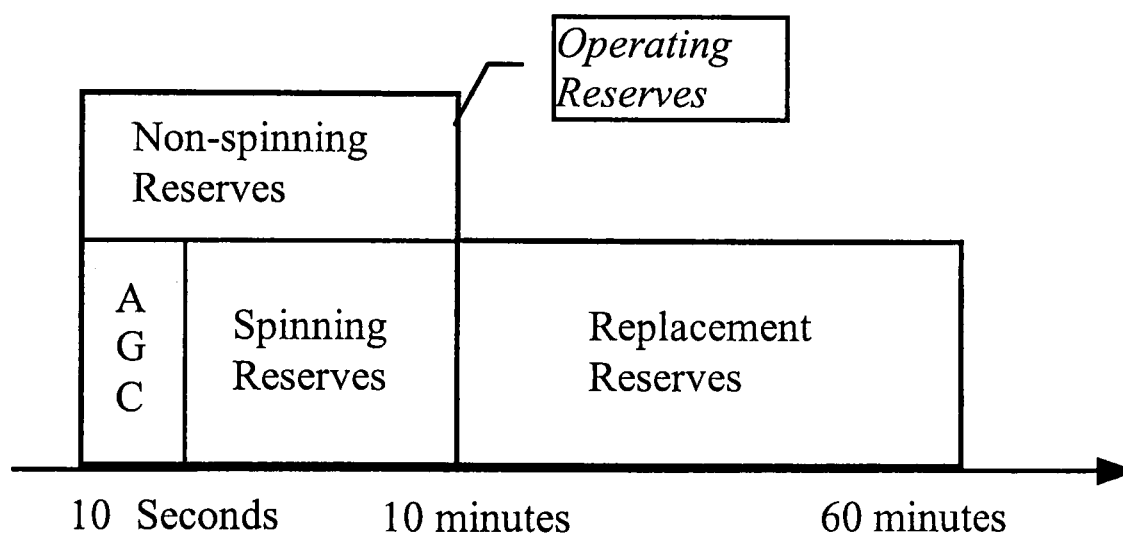
Figure 4.2. Four types of reserves traded in PAAM

4.2.4 Real-time Balancing Market and Coordinated Dispatch (RBM)

RBM plays a key role in real-time operation of electricity markets. In RBM the ISO is responsible for dispatching all the available resources to meet imbalances between actual and scheduled load and generation and alleviate network congestion. The ISO will select the least cost resources to meet these imbalances. In addition, the ISO may also need to purchase replacement ancillary services if any service arranged in advance are used to provide balancing energy [26]. The purpose of RBM is to establish a fully open market-based mechanism for all the market participants to take part in the real-time competition. In RBM, all the generators and consumers can submit to the ISO their incremental and decremental bids for providing balancing energy and their capacity bids for the replacement of operating

reserves which are used as balancing energy. In the NETA of the UK market, these incremental/decremental bids are called "pairs of offer and bid".

Because the ISO does not know the price information of bilateral contracts and the modification of a bilateral contract could involve both sides of a contract, it is very difficult to find a proper way to change them for the purpose of reducing transmission congestion. One method is that both parties submit their own supplemental bids in RBM separately, just like the other participants in the pool. The ISO does not take into account the content of the bilateral contract during settlement. However, in the event of a high percentage of bilateral contracts not producing enough voluntary supplemental bids from them or both parties of a bilateral contract are willing to be curtailed by the same amount to simplify the settlement, other methods are needed. In the proposed framework, every bilateral contract should submit a sort of compensative price that both parties of the contract are willing to accept if the curtailment needs to be imposed by the ISO during congestion periods. In accordance with such information, the ISO can reduce the scheduled bilateral contract if the other available resources in RBM are not enough to eliminate the congestion.
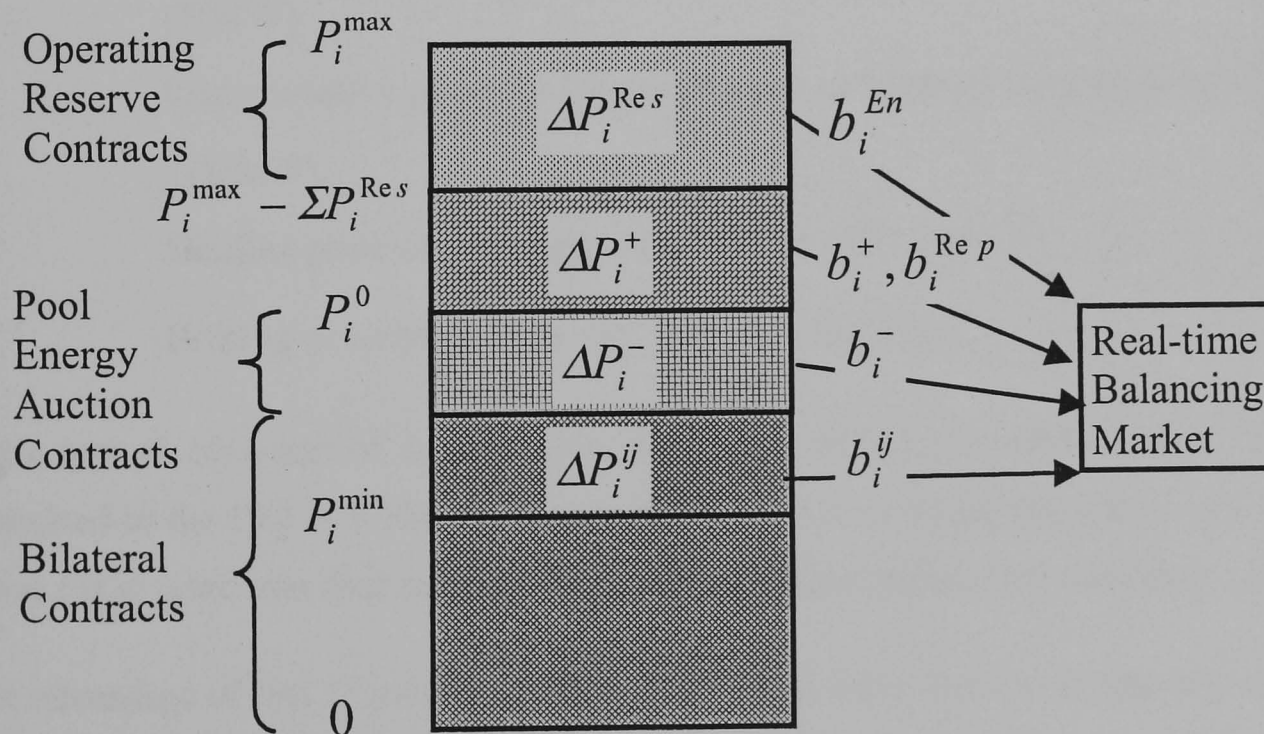
Figure 4.3 Typical contracts associated with a generator at bus i and their adjustment bids to RBM

In Figure 4.3,

i,j Index of network buses.

P_i^0 Scheduled MW generation of generator or MW load of consumer at bus i.

P_i^{ij} Total MW amount of bilateral contracts between buses i and j.

P_i^{min}, P_i^{max} Low and high limit of MW at bus i either for generator or for consumer.

P_i^{Res} Operating reserves procured by ISO from participant at bus i in ancillary services market.

$\Delta P_i^{+}, \Delta P_i^{-}$ Incremental and decremental MW changes of participant at bus i in real-time balancing market.

ΔP_i^{ij} Curtailment of bilateral contract between buses i and j.

ΔP_i^{Res} Operating reserves called upon by ISO in the real-time balancing market out of P_i^{Res}.

ΔP_i^{Rep} Reserves at bus i procured by ISO in real-time balancing market to replace the used operating reserves.

b_i^{+}, b_i^{-} Incremental and decremental bidding prices of participant at bus i in RBM ($/MW).

b_i^{ij} Compensative price for the curtailment of bilateral contract between buses i and j ($/MW).

b_i^{En} Bidding price of the energy output from P_i^{Res} ($/MW).

b_i^{Rep} Bidding price to provide ΔP_i^{Rep} at bus i ($/MW).

Some typical contracts of active power associated with a generator at bus i and their bids submitted to the ISO in RBM are shown in Figure 4.3, in which the adjustment of generation at bus i is divided into four separate parts based on three unbundled electricity contracts.

One advantage of this framework is that the ISO can have more available real-time resources to dispatch in accordance with various adjustment bids in RBM to maintain the system security. The cost of real-time dispatch can be allocated to all the other market participants in light of real-time Locational Marginal Price (LMP) or through a system uplift.

4.3 Mathematical Model of the Proposed Framework

A modified P-Q decoupled OPF is applied to implement the proposed framework. Both P- and Q sub-problems are presented, and the P sub-problem is analyzed in more detail. Before

the trade period, the schedules of unbundled markets should have been established. The principle of the balancing mechanism is to follow the schedules as close as possible and to minimize the cost of real-time dispatch. After linearization at the scheduled operating point, the model of real-time coordinated optimal dispatch can be written in following sections.

4.3.1 P Sub-problem

4.3.1.1 Objective

To make the settlement of unbundled markets clear and simple, the objective of real-time active power dispatch can be decomposed into four parts.

$$\text{Min: } C_p = C_{p1} + C_{p2} + C_{p3} + C_{p4} \tag{4-1}$$

where

$$C_{p1} = \sum_{i \in PEAM} (b_i^+ \Delta P_i^+ + b_i^- \Delta P_i^-) \tag{4-2}$$

is the total cost for the adjustment of PEAM contracts whose supplemental bids are accepted in RBM. But for accepted decremental bids, the participants can not get any payment for this part of reduced energy from the ISO in PEAM settlement;

$$C_{p2} = \sum_{i \in PAAM} b_i^{En} \Delta P_i^{Res} \tag{4-3}$$

is the cost for calling upon energy from the agreed operating reserve contracts in RBM;

$$C_{p3} = \sum_{i \in BCM} \sum_{\substack{j \in BCM \\ j < i}} (b_i^{ij} \Delta P_i^{ij}) \tag{4-4}$$

is the cost for curtailment of bilateral contracts in RBM. This curtailment should be done at the both sides of bilateral contract; and

$$C_{p4} = \sum_{i \in RBM} (b_i^{Re\,p} \Delta P_i^{Re\,p}) \tag{4-5}$$

is the cost of reserves re-procured by ISO in RBM to replace the used operating reserves. In the event of an unscheduled increase in system load, the ISO will be required to purchase additional reserves. In addition, if any of the pre-arranged operating reserves are used to meet a real-time imbalance, the ISO will be required to purchase replacement operating reserves.

The reserve market and the balancing energy market will be still settled separately. Embedding the cost of replacement of operating reserves in the objective function of real-time dispatch is to find a global optimal solution. It can be regarded as the real-time joint dispatch of energy and reserves.

Obviously, the objective is to minimize the modification on all the scheduled contracts in light of the associated dispatch cost. $\Delta P_i^+, \Delta P_i^-, \Delta P_i^{ij}, \Delta P_i^{Res}$ and ΔP_i^{Rep} are treated as independent control variables during the optimization process. But their upper/lower limits are coupled with each other. All the bidding curves could be multi-step. The incremental bidding price is higher than decremental bidding price while the curtailment price of bilateral contracts is much higher than the other two. The reason is that increasing output needs more fuel cost and the curtailment to a bilateral contract will affect the financial interests of both parties.

4.3.1.2 Equality Constraints

The equation below is the nodal active power flow balance equation of bus i:

$$(-1)^{\beta}[\Delta P_i^+ - \Delta P_i^- - \sum_{\substack{j \in BCM \\ j \neq i}}(\Delta P_i^{ij})] + \Delta P_i^{Res} + \sum_{\substack{j=1 \\ j \neq s}}^{n} B_{ij}'\Delta\theta_j - \Delta P_i^{Loss} = 0 \qquad (4\text{-}6)$$

$\beta = 0, \text{if } i \in G; \ \beta = 1, \text{if } i \in C.$

where G is the set of buses connected with generators, C is the set of buses connected with consumers, n is the total number of network buses, s is the index of the slack bus, B_{ij}' is an element of matrix B' which is the inverse reactance of branch ij. ΔP_i^{Loss} is the summed change of losses on branches that are connected to bus i and flows on the branches are flowing to bus i. Using the piece-wise linear loss model, ΔP_i^{Loss} can be written as $\Delta P_i^{Loss} = \sum_{j \in \Theta_i} LF_{ij}(\Delta P_{ij})$. Θ_i is the set of buses which have branches connected with bus i and flows on the branches are flowing to bus i.

The requirement of re-procurement to replace used operating reserves is given by

$$\sum_{i \in RBM} \Delta P_i^{Rep} = \alpha \sum_{i \in PAAM} \Delta P_i^{Res} \qquad (4\text{-}7)$$

where α is decided by the ISO according to how many new operating reserves are procured to compensate for the used reserves in real-time dispatch. $0 \leq \alpha \leq 1$.

4.3.1.3 Inequality Constraints

The changing ranges of the various control variables are given by

$$0 \leq \Delta P_i^+ + \Delta P_i^{\mathrm{Re}\,p} \leq \Delta P_i^{+,\max} = P_i^{\max} - P_i^0 - P_i^{\mathrm{Re}\,s} \tag{4-8}$$

$$0 \leq \Delta P_i^- \leq \Delta P_i^{-,\max} = P_i^0 - \max(\sum_{\substack{j=1 \\ j \neq n}}^{n} P_i^{ij}, P_i^{\min}) \tag{4-9}$$

$$0 \leq \Delta P_i^{\mathrm{Re}\,s} \leq P_i^{\mathrm{Re}\,s} \tag{4-10}$$

$$0 \leq \Delta P_i^{ij} \leq P_i^{ij}, 0 \leq \sum_{\substack{j=1 \\ j \neq i}}^{n} \Delta P_i^{ij} \leq \min(\sum_{\substack{j=1 \\ j \neq i}}^{n} P_i^{ij}, P_i^{\min}) \tag{4-11}$$

whilst

$$-P_l^{\max} - P_l^0 = \Delta P_l^{\min} \leq \Delta P_l \leq \Delta P_l^{\max} = P_l^{\max} - P_l^0 \tag{4-12}$$

is the constraint for real power flow change on branch l.

4.3.1.4 Pricing for Real-Time Active Power Dispatch

From (4-6), we can have the system active power balance equation as:

$$\sum_{i=1}^{n} \Delta P_i - \Delta P^{Loss} = 0 \tag{4-13}$$

where ΔP_i is the total change of active power at bus i and ΔP^{Loss} is the total change of active power losses. $\Delta P^{Loss} = \sum_{i=1}^{n} \Delta P_i^{Loss}$. So the Lagrangian function of the primal optimization problem is:

$$L = C_p - \lambda(\sum_{i=1}^{n} \Delta P_i - \Delta P^{Loss})$$
$$- \mu^{Re\,p}(\sum_{i\in RBM} \Delta P_i^{Re\,p} - \alpha \sum_{i\in PAAM} \Delta P_i^{Res})$$
$$+ \sum_{i\in PEAM} \mu_i^+ (\Delta P_i^+ + \Delta P_i^{Re\,p} - \Delta P_i^{+,max})$$
$$+ \sum_{i\in PEAM} \mu_i^- (\Delta P_i^- - \Delta P_i^{-,max})$$
$$+ \sum_{i\in PAAM} \mu_i^{Res} (\Delta P_i^{Res} - P_i^{Res}) + \sum_{i\in BCM} \mu_i^{ij} (\Delta P_i^{ij} - P_i^{ij})$$
$$+ \sum_{l\in B} \mu_l^{min} (\Delta P_l^{min} - \Delta P_l) + \sum_{l\in B} \mu_l^{max} (\Delta P_l - \Delta P_l^{max})$$

(4-14)

According to the KKT first order conditions, we have:

$$\frac{\partial C_p}{\partial \Delta P_i^+} - (-1)^\beta \lambda(1 - \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i^+}) + \mu_i^+ + \sum_{l\in B} (\mu_l^{max} - \mu_l^{min}) \frac{\Delta P_l}{\Delta P_i^+} = 0 \qquad (4\text{-}15)$$

$$\frac{\partial C_p}{\partial \Delta P_i^-} + (-1)^\beta \lambda(1 + \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i^-}) + \mu_i^- + \sum_{l\in B} (\mu_l^{max} - \mu_l^{min}) \frac{\Delta P_l}{\Delta P_i^-} = 0 \qquad (4\text{-}16)$$

$$\frac{\partial C_p}{\partial \Delta P_i^{ij}} + (-1)^\beta \lambda \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i^{ij}} + \mu_i^{ij} + \sum_{l\in B} (\mu_l^{max} - \mu_l^{min}) \frac{\Delta P_l}{\Delta P_i^{ij}} = 0 \qquad (4\text{-}17)$$

$$\frac{\partial C_p}{\partial \Delta P_i^{Res}} - \lambda(1 - \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i^{Res}}) + \alpha \mu^{Re\,p} + \mu_i^{Res}$$
$$+ \sum_{i\in B} (\mu_l^{max} - \mu_l^{min}) \frac{\Delta P_l}{\Delta P_i^{Res}} = 0 \qquad (4\text{-}18)$$

$$\frac{\partial C_p}{\partial \Delta P_i^{Re\,p}} - \mu^{Re\,p} + \mu_i^+ = 0 \qquad (4\text{-}19)$$

It is obvious that

$$\frac{\partial \Delta P^{Loss}}{\partial \Delta P_i} = (-1)^\beta \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i^+} = \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i^{Res}} = (-1)^{\beta+1} \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i^-} = (-1)^{\beta+1} \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i^{ij}} \qquad (4\text{-}20)$$

and

$$\frac{\partial \Delta P_l}{\partial \Delta P_i} = (-1)^\beta \frac{\partial \Delta P_l}{\partial \Delta P_i^+} = \frac{\partial \Delta P_l}{\partial \Delta P_i^{Res}} = (-1)^{\beta+1} \frac{\partial \Delta P_l}{\partial \Delta P_i^-} = (-1)^{\beta+1} \frac{\partial \Delta P_l}{\partial \Delta P_i^{ij}} \qquad (4\text{-}21)$$

Using the theory of spot pricing [1, 108], the LMP of a participant (either a generator or a consumer) at bus i is:

$$\rho_i^P = \lambda - \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i} \lambda - \sum_{l \in B} (\mu_l^{max} - \mu_l^{min}) \frac{\partial \Delta P_l}{\partial \Delta P_i} \qquad (4\text{-}22)$$

Shown in equation (4-22), the real-time spot price at bus i can be decomposed into three parts: the system lambda, the active power losses and the congestion management cost.

From equations (4-15 to 4-18), we can have different forms of ρ_i^P at bus i at which the participant has made some contribution to the real-time dispatch.

$$\rho_i^P = \begin{cases} (-1)^\beta (\dfrac{\partial C_p}{\partial \Delta P_i^+} + \mu_i^+); \text{ or} \\[2mm] (-1)^{\beta+1} (\dfrac{\partial C_p}{\partial \Delta P_i^-} + \mu_i^-); \text{ or} \\[2mm] \dfrac{\partial C_p}{\partial \Delta P_i^{Res}} + \alpha \mu^{Re\,p} + \mu_i^{Res}. \end{cases} \qquad (4\text{-}23)$$

Although the adjustment on the contracts of a participant is divided into four independent control variables (two increasing ones and two decreasing ones), at the optimal point only one of them could be active (on adjustment). From equation (4-23) we can find out the effects of the costs and the changing ranges of these control variables on λ.

From equations (4-17) and (4-23), it is noticed that the curtailment of bilateral contracts has little effect on the system λ. It is due to the item ΔP_i^{ij}, which exists in two nodal active power balance equations with different sign, but does not appear in the system balance equation (4-13). The various cases of bilateral contract curtailment and its pricing will be discussed in the following section.

4.3.1.5 Meeting Real-Time Imbalance of Market under Normal Operating Conditions

Providing there is no serious contingency, the operating reserves and the supplemental energy in RBM should be enough to follow the system load fluctuation. The curtailment of bilateral contracts and load shedding are not necessary in this case. To model this problem, the objective in (4-1) should be rewritten as:

Min: $C_p = C_{p1} + C_{p2} + C_{p4}$ \qquad (4-24)

and all the constraints of ΔP_i^{ij} should be removed.

Given the system load fluctuation ΔP^{sys}, the bus load change can be expressed as:

$$BL_i = \eta_i \Delta P^{sys} \tag{4-25}$$

where η_i is bus load allocation factors, $\sum_{i \in C} \eta_i = 1$.

To meet this system imbalance, the right hand side of equation (4-6) changes to BL_i from 0. Considering that rapid response generation units are enough to meet the normal system imbalance, to reduce the number of control variables, the nodal active power balance equations (4-6) for pure load buses can be rewritten as:

$$\sum_{\substack{j=1 \\ j \neq s}}^{n} B'_{ij} \Delta \theta_j - \Delta P_i^{Loss} = BL_i \tag{4-26}$$

and the system balance equation (4-13) can be changed to:

$$\sum_{i=1}^{n} \Delta P_i - \Delta P^{Loss} = \Delta P^{sys} \tag{4-27}$$

Without any branch limit violation, the LMP at bus i is:

$$\rho_i^P = \lambda - \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i} \lambda \tag{4-28}$$

4.3.1.6 Replacement of Operating Reserves

From equation (4-19), the marginal price of the replacement of operating reserves is:

$$\rho^{\text{Re}P} = \mu^{\text{Re}P} + \mu_i^+ \tag{4-29}$$

The cost of replacement of operating reserves affects the LMPs through the item $\alpha \mu^{\text{Re}P}$ instead of appearing in the equation (4-22) or (4-28) directly.

Calling up energy from operating reserves during real-time dispatch, the ISO must pay for not only the energy but also the procurement of the reserve replacement. Therefore, if the supplemental energy in RBM is fast and cheap enough, the reserve contracts signed in PAAM

could be left unchanged. As a result, the real-time balancing mechanism expands the concept of operating reserves and gives market participants more competitive opportunities.

4.3.1.7 Curtailment of Bilateral Contracts

According to the characteristics of bilateral contract, the curtailment should be done to both parties of the contract as has been discussed above. However, the problem in pricing is that the system λ and the LMPs can not reflect the cost of the curtailment of bilateral contracts. During the settlement of RBM, the ISO should pay the owners of a bilateral contract its bidding price while the ISO will allocate this cost to all the other participants by uplift or according to the ratios decided by equation (4-22).

But sometimes the load in a bilateral contract is too important to be curtailed or the response of the generation unit in a bilateral contract is not fast enough to decrease its output to mitigate the network congestion. In these two cases, the energy imbalance caused by single side curtailment will be taken by the other available resources in RBM. Here, the partner of a bilateral contract without curtailment will not get the compensation payment from the ISO. On the contrary, this participant must pay for the dispatch cost for this imbalance. Because one ΔP_i^{ij} has been removed from the nodal power balance equation (4-6), equation (4-17) changes to:

$$\frac{\partial C_p}{\partial \Delta P_i^{ij}} + (-1)^\beta \lambda (1 + \frac{\partial \Delta P^{Loss}}{\partial \Delta P_i^{ij}}) + \mu_i^{ij} + \sum_{l \in B}(\mu_l^{max} - \mu_l^{min})\frac{\Delta P_l}{\Delta P_i^{ij}} = 0 \qquad (4-30)$$

Then the equation (4-23) has another form as:

$$\rho_i^P = (-1)^{\beta+1}(\frac{\partial C_p}{\partial \Delta P_i^{ij}} + \mu_i^{ij}) \qquad (4-31)$$

In these two cases, the LMPs can reflect the curtailment of this bilateral contract.

4.3.2 Q Sub-problem

The Q Sub-problem of real-time coordinated optimal dispatch can be formulated as:

$$\text{Minimize: } \sum_{i=1}^{n}(w_i^+ \Delta Q_i^+ + w_i^- \Delta Q_i^-) + \sum_{k=1}^{T} r_k(\Delta t_k^+ + \Delta t_k^-) \qquad (4-32)$$

Subject to:

$$\Delta Q_i^+ - \Delta Q_i^- + \sum_{j=1}^{n} B_{ij}'' \Delta V_j + \sum_{k=1}^{T} \partial Q_i \Big/ \partial t_k (\Delta t_k^+ - \Delta t_k^-) = 0 \tag{4-33}$$

$$0 \leq \Delta Q_i^+ \leq Q_i^{max} - Q_i^0, 0 \leq \Delta Q_i^- \leq Q_i^0 - Q_i^{min} \tag{4-34}$$

$$0 \leq \Delta t_k^+ \leq t_k^{max} - t_k^0, 0 \leq \Delta t_k^- \leq t_k^0 - t_k^{min} \tag{4-35}$$

$$V_i^{min} - V_i^0 \leq \Delta V_i \leq V_i^{max} - V_i^0 \tag{4-36}$$

where w_i^+ and w_i^- are the reactive power incremental and decremental bidding prices of participant i in RBM respectively, ΔQ_i^+ and ΔQ_i^- are its increasing output and decreasing output of reactive power respectively, Q_i^0, Q_i^{min}, Q_i^{max} are its current reactive power output or load, minimum reactive power and maximum reactive power respectively. T is the number of transformers, whose tap positions are adjustable, in the system. Δt_k^+ and Δt_k^- are the increasing tap ratio and the decreasing tap ratio of transformer k. r_k is the bidding price for the adjustment of tap positions of transformer k if there are any independent transmission companies and the transmission sector is also competitive. $t_k^0, t_k^{min}, t_k^{max}$ are the current tap ratio, the minimum and maximum tap ratios of transformer k, respectively. ΔV_i is the change of the voltage magnitude at bus i, V_i^0, V_i^{min}, and V_i^{max} are its current value, lower limit and upper limit. B_{ij}'' is an element of the matrix B''.

The Q sub-problem looks similar to the P sub-problem. Because the reactive power can not be sent through a long distance, there is no bilateral contract for it. The first item in the objective represents all the controllable reactive power injections, such as generators, capacitors, reactors, STATCOM, SVC and so on. These devices may belong to generation companies, transmission companies, distribution companies or large consumers. The second item in the objective is the cost for adjusting the taps of controllable transformers which belong to the transmission or distribution companies. Equation (4-33) is the nodal reactive power balancing equation of bus i. The constraints of control variables of reactive power are given in Formulae (4-34) and (4-35). Formula (4-36) is the voltage constraint of bus i.

4.4 Imbalance Settlement Methodologies

Basically, the imbalance settlement should be a post-event of limited volumes and mandatory for most market participants. There are two possible methods to settle the dispatch cost in RBM:

- Pay as bid. The ISO pays the participants, whose bids have been accepted in RBM, for their measured adjustment according to their bidding prices. Generators, whose decremental bids have been accepted by the ISO, will get payment in RBM, but these reduced outputs should not be included in the settlement of PEAM. On the other hand, the ISO will allocate the dispatch cost to those participants whose have caused the system imbalance. The advantage of this method is its simplicity while the disadvantage is that all the participants are treated equally even though they have very different effects on network congestion or the change of system loss;

- Pay as LMPs. The ISO will use the obtained LMPs to make the payment as well as to collect the dispatch cost. The principle of this method is to settle the cost in RBM in accordance with the participants' contribution to network congestion and system loss, as analyzed in section 4.3. Because the settlement of RBM should use the *ex post* pricing, the proposed coordinated dispatch method should be run again after the ISO obtains the measurement from SCADA to provide the exact LMPs for the settlement.

4.5 Implementation

To solve the problem fast and reliably, an AC Power Flow and a Primal-dual Interior Point (IP) Linear Programming (LP) are used to implement the above OPF algorithm as described in Chapter 3.

There have been some discussions in Chapter 3 on the point at which method is more suitable for OPF, LP-based, Newton-based method, or other methods. Regarding the real-time optimal dispatch problem in electricity market, LP seems to have very good prospects due to the following reasons:

- Multi-step bidding price curves instead of second order cost curves are used to form the objective function. Linearizing the objective function, which is one of the main problems of LP-based OPF [13][14], does not exist any longer.

- LP-based OPF is more reliable than Newton-based OPF. LP-based OPF can detect an infeasible problem quickly and deal with any sort of constraints easily. These features are very important to the real-time dispatching of the electricity market.

- The new development in IP method makes the LP-based OPF much faster than before when solving large-scale problems and more suitable for the real-time application.

- The LMPs can be obtained from the shadow prices of nodal equation constraints, which are the by-products of Prime-Dual LP-based OPF.

The procedure of the decoupled OPF implemented in this chapter is as follows:

Step1: Run the AC Power Flow to get the initial state of power system;

Step2: Compute the necessary sensitivities and linearize the constraints;

Step3: Select the control variables of LP according to the bids in RBM. Decide if the bilateral contract curtailment is needed and which curtailment strategy should be used;

Step4: Run LP to solve P sub-problem;

Step5: Run LP to solve Q sub-problem;

Step6: Correct the control variables, then run AC Power Flow to get the new state of power system;

Step7: Check if all the constraints have been satisfied. If yes, continue; if no, go to step2;

Step8: Obtain the optimal coordinated dispatch strategy.

4.6 Test Results

Two test systems are studied to illustrate the proposed method. First, a 5-bus test system is analyzed to demonstrate the proposed congestion management approach through the Real-time Balancing Market, particularly the curtailment of bilateral contracts in case of very serious transmission congestion. Then, the IEEE 30-bus test system is studied to show how the real-time coordinated optimal dispatch works and the LMPs obtained from it. Finally, a computational comparison between the Simplex LP method and Interior Point LP method is performed to show the efficiency of the latter.

4.6.1 5-bus Test System

The network structure and the power flow in base case are shown in Figure 4.4. In this system there are two generators which are G1 at bus 4 and G2 at bus 5 and three consumers which are L1 at bus 1, L2 at bus 2 and L3 at bus 3. One bilateral contract, which is 300MW, is signed between G1 and L3 in BCM. All the other electricity supplies in this system are arranged by ISO in PEAM. In RBM, G1, G2 and L3 submit their incremental and decremental bids to the ISO to take part in the real-time dispatching competition. The bilateral contract P^{34} also submits a curtailment price b^{34} to ISO. From these bidding prices, it can be found easily that the prices for adjustment of loads is higher than generators, because the latter are much more flexible to adjust. The curtailment price of bilateral contract is prohibitively high because both sides of the contract do not want any curtailment at all. So the control strategy given by (4-1 to 4-12) is to curtail bilateral contract only if the network congestion is so serious that the available resources in RBM can not mitigate it efficiently.
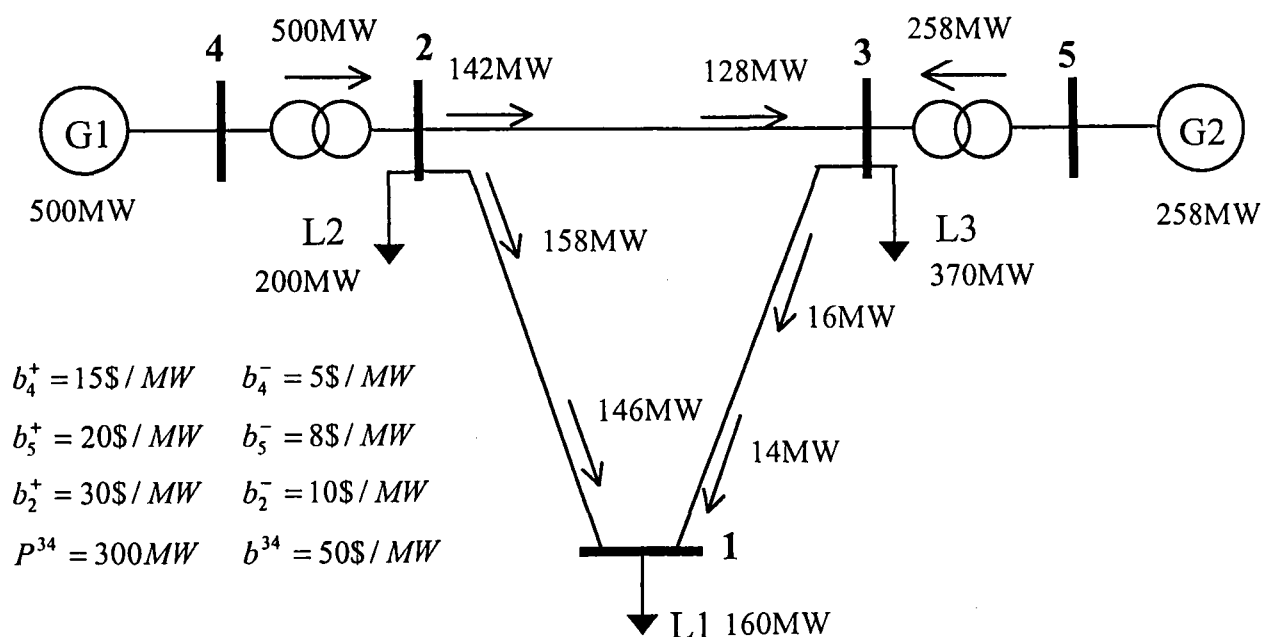
Figure 4.4 The base case power flows of the 5-bus test system

Case 1: Congestion management without changing bilateral contracts. Assume that the MW limit on line 2-3 is reduced to 100MW due to some reason. To mitigate this congestion, the cheapest solution is to decrease the output of G1 to 440.60MW and to increase the output of G2 to 308MW. As a result, the active power flow of line 2-3 at bus 2 is reduced to 99.67MW. The total cost of this re-dispatch is $1497. In this case, no balancing resources of consumers are used although L2 has highest sensitivity to active power flow of line 2-3, because the bidding prices of L2 are much higher than generators. The bilateral contract P^{34} is carried out

without curtailment because the available resources of G1 in RBM are enough to eliminate the congestion.

Case 2: Congestion management with changing bilateral contracts. Assume that the MW limit on transformer 4-2 is reduced to 250MW. Obviously, the output of G1 should be reduced to 250MW. But because 300MW of the output of G1 belong to the bilateral contract P^{34} between G1 and L3, the curtailment to P^{34} must be done in this case. The optimal controls to solve this problem are as follow:

- Reducing 200MW from the output of G1 in RBM;

- Curtailing 50MW from bilateral contract P^{34}, which means both G1 and L3 will be reduced by 50 MW;

- Increasing the output of G2 to 444MW.

The total cost of the re-dispatch in this case is $7200.

4.6.2 IEEE 30-bus system
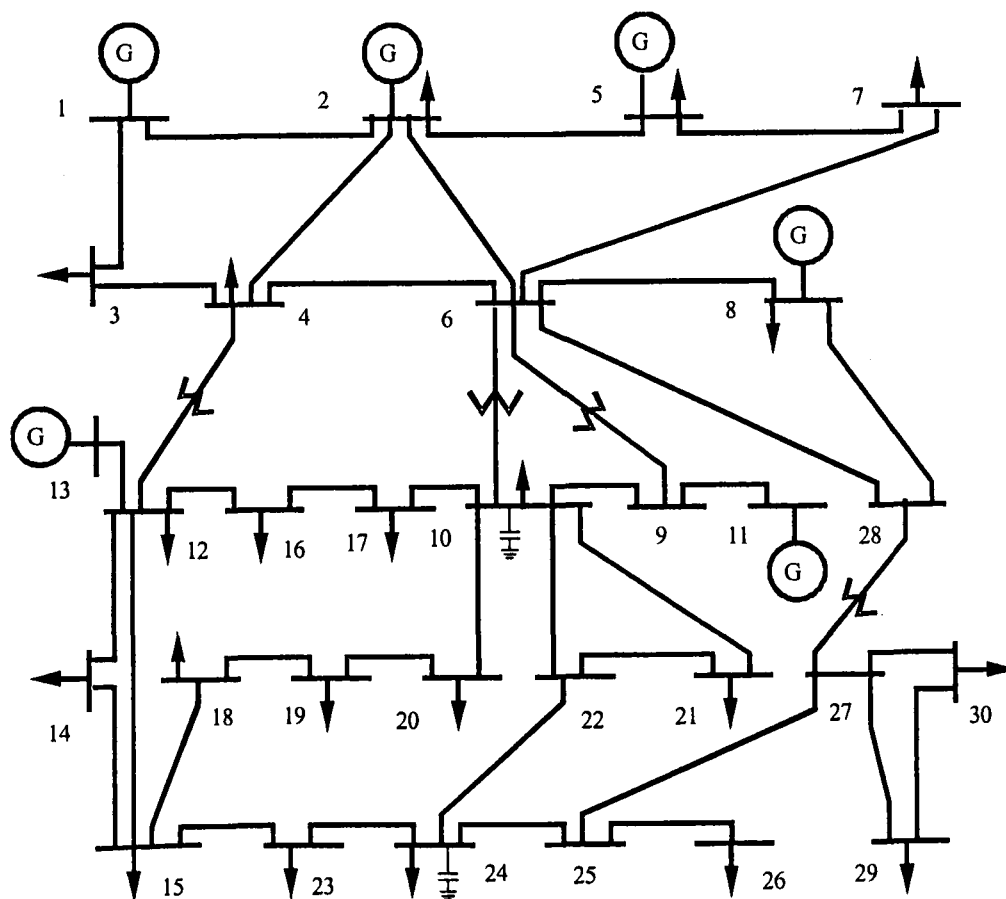
Figure 4.5 IEEE 30-bus test system

The IEEE 30-bus system, shown in Figure 4.5, is used here to illustrate the proposed coordinated dispatch method. The network parameters and injection data can be found in Table B.1 and Table B.2 in Appendix B.1.

Table 4.1 The bids of participants in RBM

Partici-pants	Supplemental bids		Operating Reserves			Base Point (MW)	MAX MW	MIN MW
	Incr. Bids ($/MWh)	Decr. Bids ($/MWh)	Cap. Bids ($MW)	En. Bids ($/MWh)	Amount (MW)			
G-1	35	15	3.5	35	/	138.53	200	50
G-2	15	8	2.5	15	/	57.56	100	20
G-5	15	8	1.5	15	/	24.56	100	10
G-8	30	12	1.5	15	30	35.00	65	10
G-11	25	10	2.5	25	/	17.93	50	10
G-13	15	5	1.5	15	/	16.91	50	5
C-24	/	40	/	/	/	8.70	15	3

Bilateral contract	From	To	Contract Amount (MW)	Curtailment Bids ($/MW)
B1	G-13	C-30	10.6	50

The various bids of participants, including generators, consumers and bilateral contracts, are given in Table 4.1, in which G-1 means generator at bus 1 and C-24 means consumer at bus 24.

4.6.2.1 Coordinated Dispatch without Network Congestion

Assume that there is a 100MW increase on system load, which has been distributed to individual buses according to their current load shares. Set $\alpha = 1$, then the obtained optimal dispatch strategy to meet this load fluctuation is shown in Table 4.2. Figure 4.6 reveals the two components of LMPs under normal operating conditions, which are system lambda and network losses.

Table 4.2 The optimal dispatch strategy to meet the load fluctuation

Partici-pants	PEAM contracts		Calling Upon PAAM contracts (MW)	Replacement of Operating Reserves (MW)
	Increase (MW)	Decrease (MW)		
G-5	75.44	0	0	0
G-8	0	0	24.72	0
G-13	0	0	0	24.72
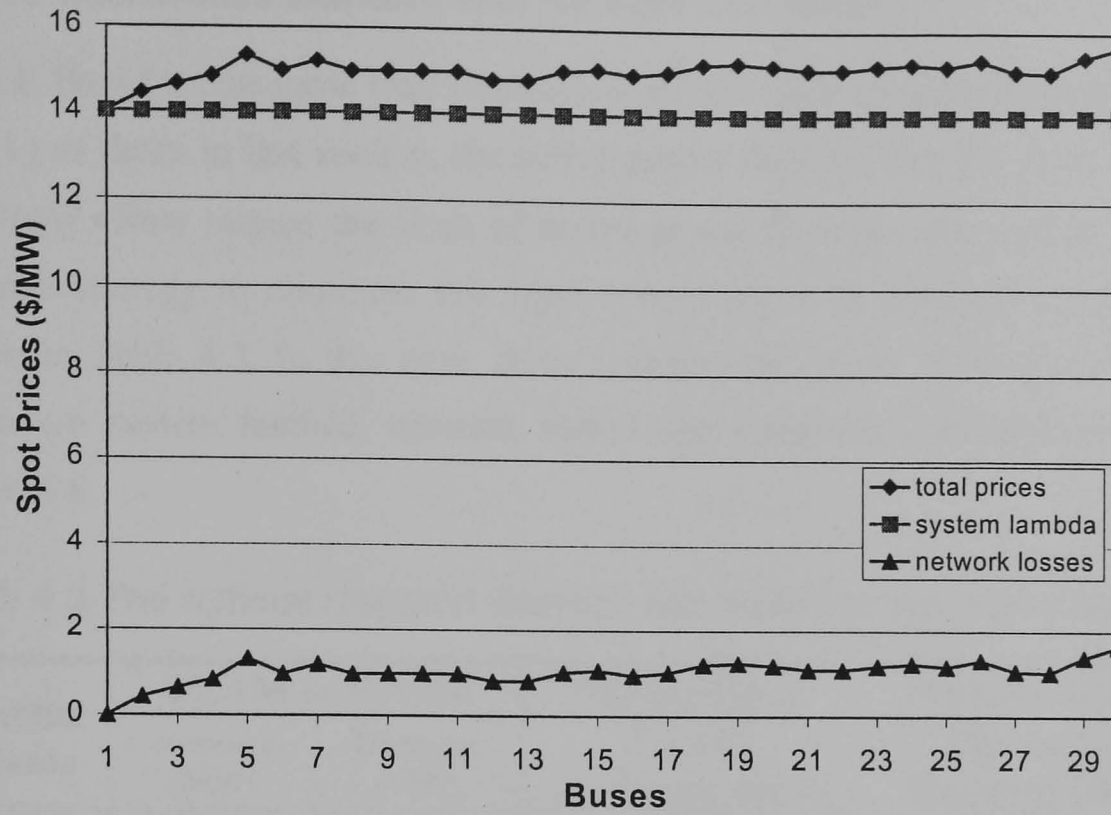
Figure 4.6 Components of spot prices under normal operating condition

The cost of replacement of used operating reserves is not a component of LMPs in Equation (4-28). However, it can affect the value of system lambda. Figure 4.7 demonstrates the change of LMPs under different replacement procurement of used operating reserves by giving $\alpha = 0$, $\alpha = 0.5$, $\alpha = 1$.
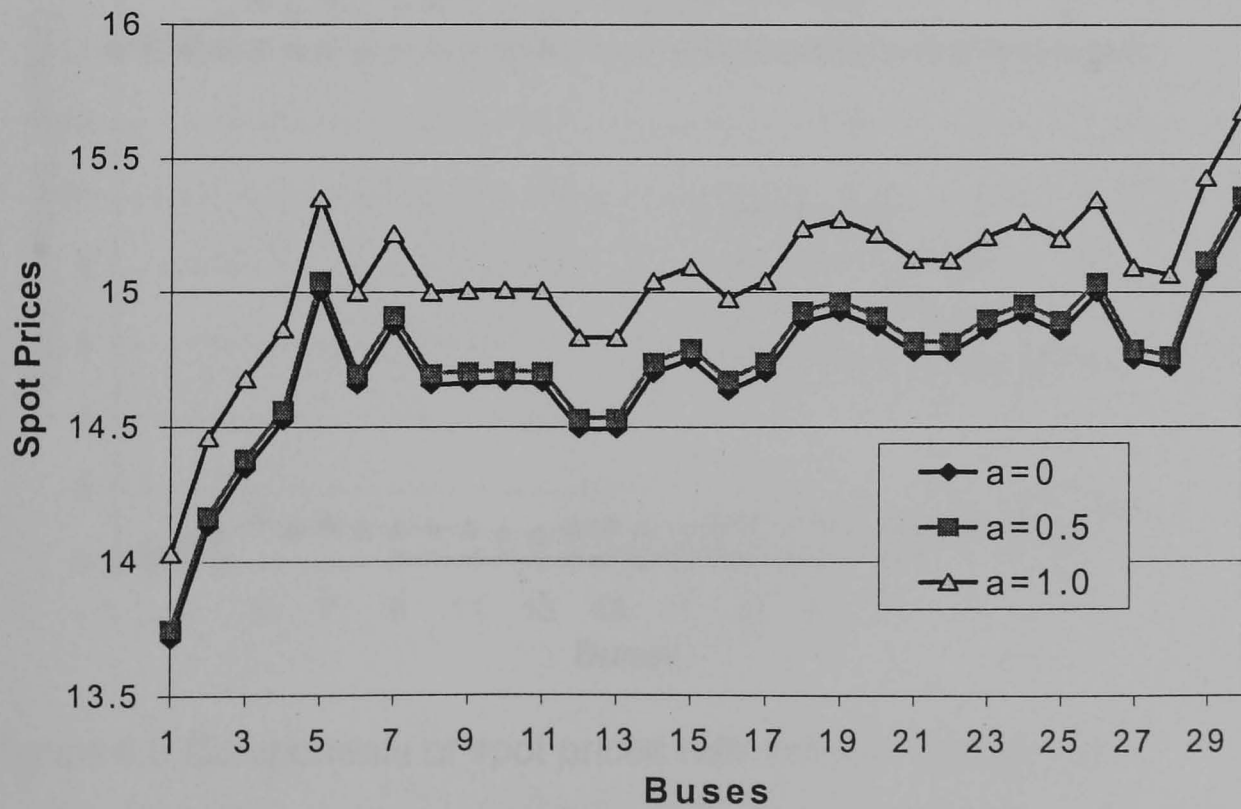
Figure 4.7 Effects of different replacement procurement of operating reserves on LMPs

4.6.2.2 Coordinated Dispatch with Network Congestion

Case 1: Based on the same load fluctuation and the same operating reserves replacement level ($\alpha = 1$) as those in last section, the active power flow on line 36 (from bus-28 to bus-27) is 24.79MW. Now reduce the limit of active power flow on this line to 24MW, the optimal dispatch strategy to eliminate this light congestion with meeting the given load change is shown in Table 4.3. In this case, three components of the LMP given in Equation (4-22), which are system lambda, network losses and congestion management, are illustrated in Figure 4.8.

Table 4.3 The optimal dispatch strategy with active power flow violation on line 36.

Partici -pants	PEAM contracts		Calling Upon PAAM contracts (MW)	Replacement of Operating Reserves (MW)
	Increase (MW)	Decrease (MW)		
G-5	75.44	0	0	0
G-8	0	0	13.22	0
G-13	11.63	0	0	13.22
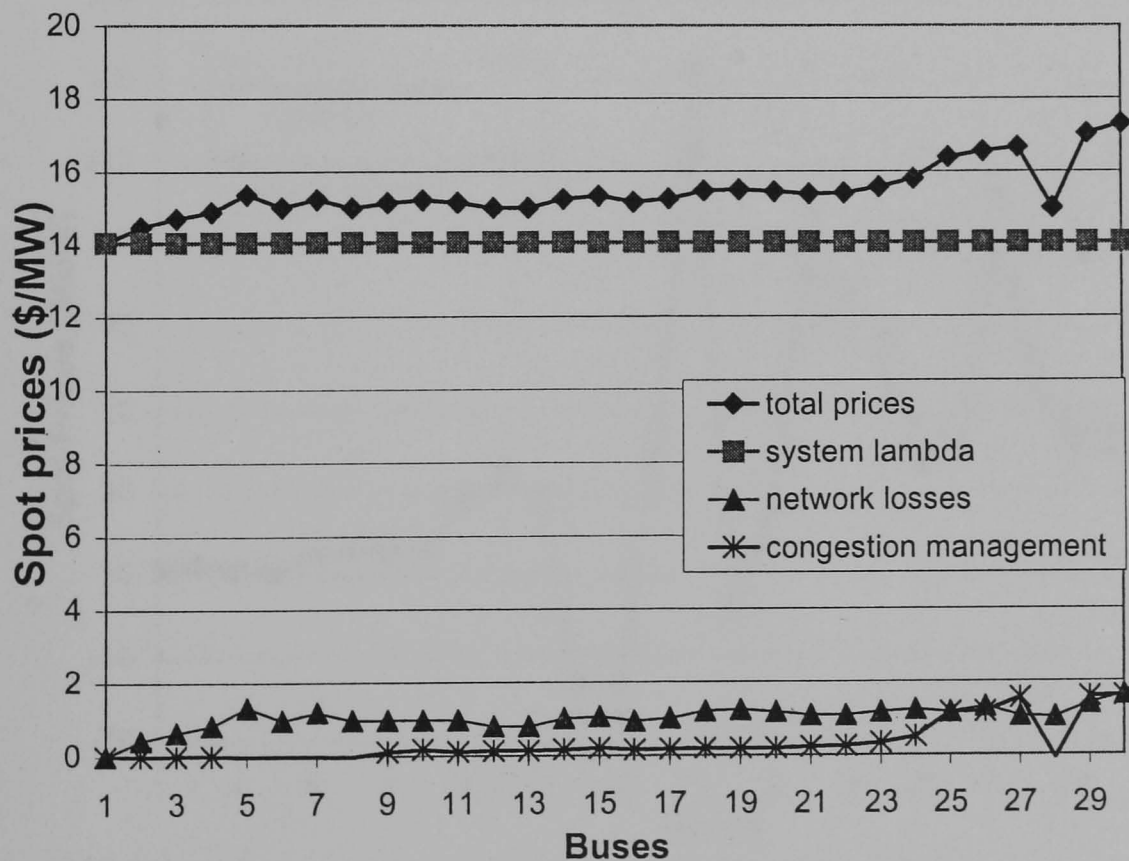
Figure 4.8 Components of spot prices with network congestion

Compared with Figure 4.6, the spot prices in Figure 4.8 have not changed a lot at most buses except buses 25-27, 29-30. That means these several buses have higher sensitivity to the congested line 36 than the other buses. In other word, the consumers at these buses should pay

most of the cost caused by network congestion. Because the congestion is very slight, the associated Lagrangian multiplier $\mu_{36}^{max} = -2.21$ is not terribly big.

Case 2: Based on the same operating condition as in case 1, but the congestion branch in this case is line 18 (from bus-12 to bus-15), whose base active power flow is 22.67MW. Now reduce the limit of active power flow on this line to 19MW because of an unexpected contingency, the optimal dispatch strategy to eliminate this congestion with meeting the given load change is shown in Table 4.4.

Table 4.4 The optimal dispatch strategy with active power flow violation on line 18.

Partici -pants	PEAM contracts		Calling Upon PAAM contracts (MW)	Curtailment of Bilateral Contracts (MW)	Replacement of Operating Reserves (MW)
	Increase (MW)	Decrease (MW)			
G-5	45.50	0	0	/	15.60
G-8	0	0	30.00	/	0
G-11	32.07	0	0	/	0
G-13	0	6.31	0	1.50	14.40
C-30	/	/	/	1.50	/
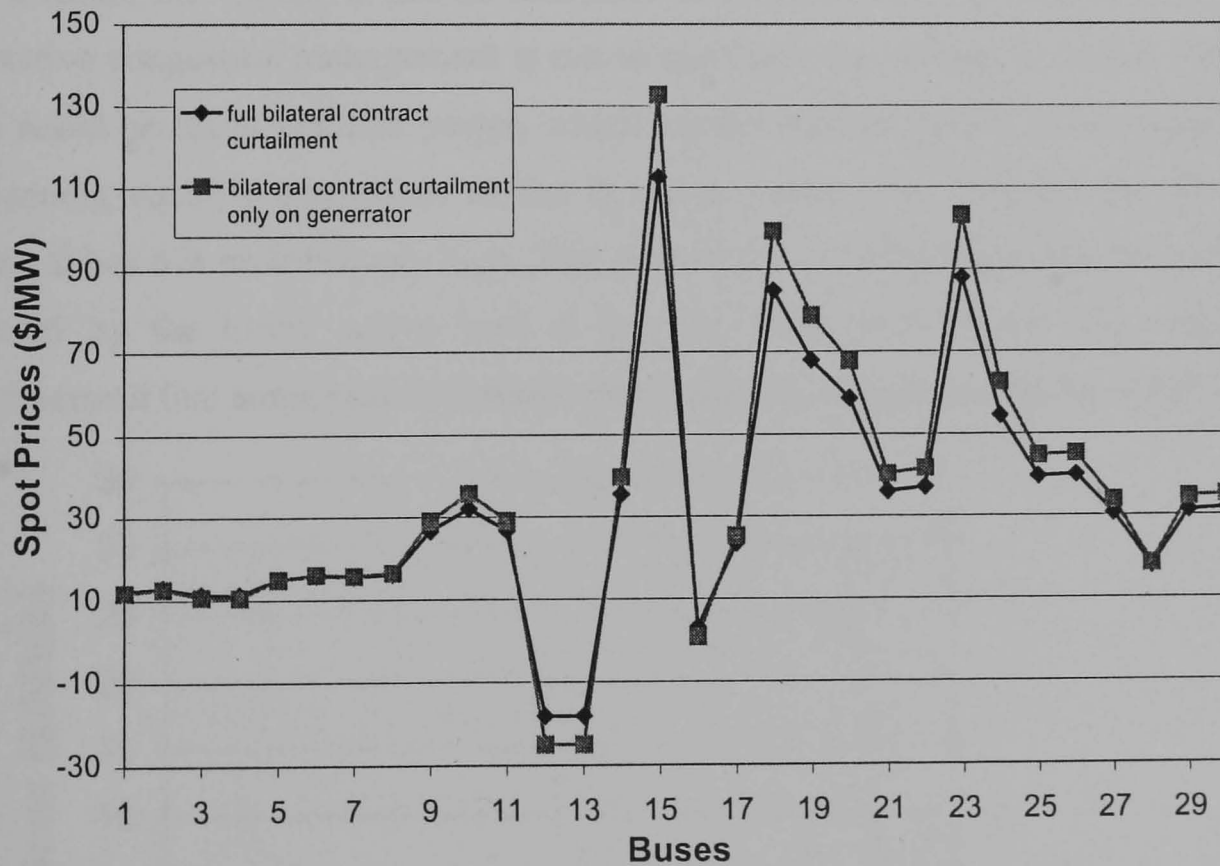
Figure 4.9 Spot prices for congestion management with bilateral contract curtailment

From Table 4.4 it can be noticed that this network congestion is so serious that the decremental bids of G-13 is still not enough to eliminate it. Some transaction in bilateral contract B1 has to be curtailed. However, according to the discussion in section 4.3.1.7, the

cost of this curtailment can not be embedded into the defined spot prices. It must be allocated to market participants separately.

To demonstrate it, we change the curtailment strategy of bilateral contract to only decreasing the generation while keeping the load supplied by other available resources in RBM. The comparison of spot prices between these two situations is given in Figure 4.9. Compared with Figure 4.8 the fluctuation of spot prices in Figure 4.9 is very large, which means the congestion in this case is very serious. The price at bus 15 is prohibitively high because the consumer at bus 15 is the main cause of this congestion. Another phenomenon that should be noticed in Figure 4.9 is that the spot prices at buses 12 and 13 are negative. Negative price at bus-13 means that decremental or bilateral curtailment bids from G-13 must have been accepted by the ISO to eliminate the network congestion. Negative price at bus-12 implies that L-12 can get payment in RBM from increasing its load since this action could be helpful to alleviate the congestion.

Case 3: Voltage limit violation. Change the active load at bus 26 from 3.5 MW to 33.5 MW. As a result, the voltage at bus 26 decreases to 0.82 p.u. and violates the lower limit 0.85 p.u. Reactive congestion management is run to eliminate the voltage violation. Figure 4.10 shows the nodal prices of reactive power, which are the shadow prices of the nodal reactive power balancing equality constraints of the Q sub-problem. It is obvious that the reactive power price at bus 6 is prohibitively high. This penalty is reasonable, because the voltage violation is caused by the heavy active load at bus 26. This price signal also implies a planning requirement that some reactive power compensation devices should be installed at or near this spot.
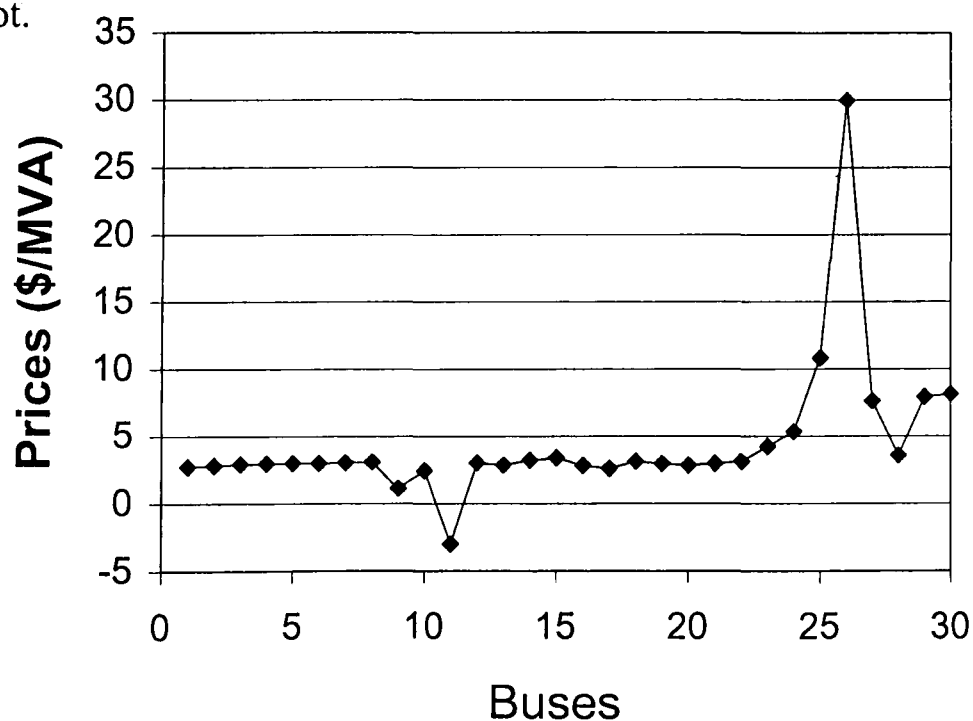
Figure 4.10 Effects of voltage violation on nodal prices

4.6.3 The Comparison Between the RSLP and PDIPLP

Figure 4.11 and Figure 4.12 exhibit the iteration number and the CPU time of linear programming to solve the real-time dispatch problem in 5-bus, IEEE 30-bus, IEEE 57-bus and IEEE-118 bus test systems using the Primal-Dual Interior Point Linear Programming (PDIPLP) and the Revised Simplex Linear Pprogramming (RSLP). Both algorithms have been coded in Visual FORTRAN 6.0 and implemented on a PII/400 PC. The advantages of PDIPLP can be seen clearly from these two figures. With increasing the size of the problem, the iteration number of RSLP increases very quickly while the iteration number of PDIPLP almost keeps unchanged. The CPU time of PDIPLP is also much less than that of RSLP. The bigger the system is, the better performance PDIPLP will show than RSLP. Therefore, applying PDIPLP to real-time dispatch of electricity market can meet its time requirement very well.
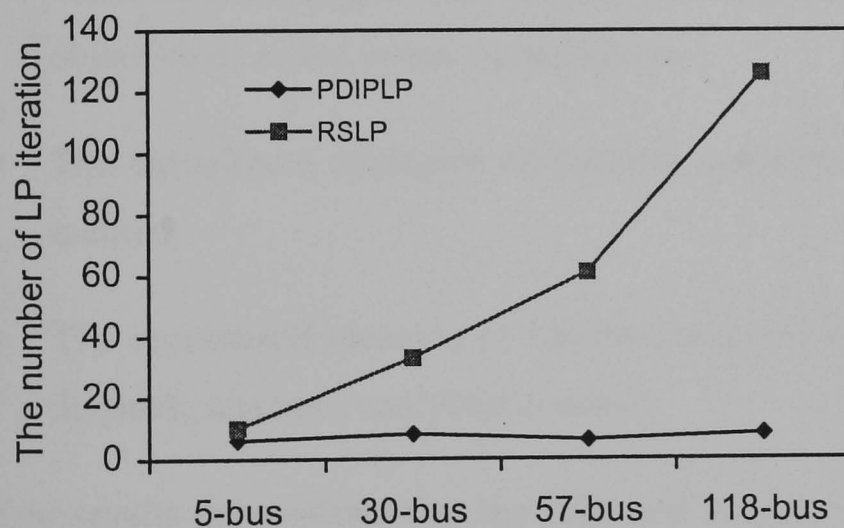
Figure 4.11 Comparison between PDIPLP and RSLP on iteration number
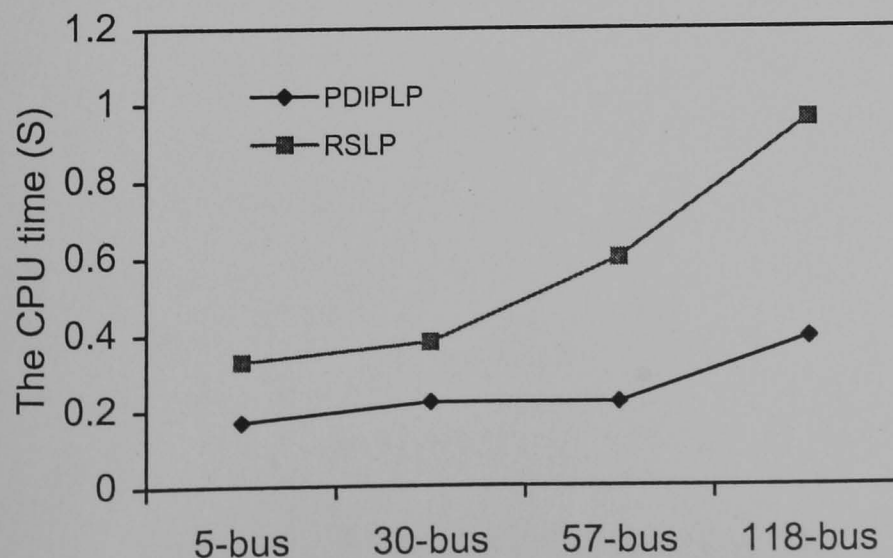
Figure 4.12 Comparison between PDIPLP and RSLP on CPU time

4.7 Conclusions

In this chapter, a coordinated real-time optimal dispatch method for unbundled electricity markets has been proposed. The main features of this method are the following:

- Three types of electricity contracts, which are bilateral energy contract, Pool energy auction contract and ancillary services contract, have been taken into account in the coordinated dispatch;

- Balancing mechanism plays the key role in the proposed framework, where the ISO can meet the system imbalance and mitigate the network congestion by using various bids;

- The adjustment of bus injection has been divided into several independent control variables according to unbundled contracts to embed all the possible bids in RBM into the objective of active power optimization;

- The curtailment strategies of bilateral contracts have been integrated into the proposed method;

- The economical meaning of Lagrangian multipliers, which decide the LMPs of real-time dispatch, has been analyzed in detail.

Test results demonstrate that the proposed coordinated dispatch method implemented with a modified OPF can deal with the system imbalance and network congestion simultaneously and successfully. The comparison between PDIPLP and RSLP shows that the PDIPLP is much more efficient to deal with large systems with a huge number of control variables.

Chapter 5. Real-time Congestion Management across Interconnected Regions

5.1 Introduction

In the emerging competitive environment, congestion management is one of the most important functions of any Independent System Operator (ISO), which is required to ensure the delivery of all the transactions without any violation on the operating limits of the transmission system. The physical redispatch and real-time balancing mechanism have been applied to some electricity markets in the world successfully to relieve the transmission congestion within a separated region.

Coordination of activities among regions is a significant element in maintaining a reliable bulk transmission system and for the development of competitive markets. FERC Order 2000 [27] has mandated the formation of Regional Transmission Organisations (RTO), which will accelerate interregional transaction and increase the burden of interregional transmission. The Association of European Transmission System Operators (ETSO), founded in July 1999, has been investigating congestion management methods for cross-border transmission between European countries [28]. However, problems are still unsolved for the coordinated congestion management across multiple interconnected regions. Since each regional ISO cannot obtain the network operating data of other regions, one of the main difficulties to meet the requirement presented in [27-28] is how to implement coordinated congestion management without a huge amount of information exchange between regions.

In this chapter a new approach has been proposed to decompose an optimal power flow (OPF) problem by applying Augmented Lagrangian Relaxation (LR) in order to implement the multi-regional active power congestion management. The LR algorithm has been applied to many aspects of power systems successfully, especially to solving problems of unit commitment, hydro-thermal coordination and OPF. Compared with existing methods for regional decomposition OPF (a brief review on regional decomposition OPF can be found in Section 3.3.7 of Chapter 3), neither fictitious buses, generators, or loads are added nor the model of transmission line is modified to decouple interconnecting lines in the proposed method. Using this approach, the multi-regional active power congestion management can be

100

implemented as an iterative procedure. The ISO of each region does not need to know any information of other regions but for the corresponding Lagrangian multipliers of the tie-lines between regions, thus the dispatching independence of the ISO is preserved. Optimal transaction prices on all the interconnecting lines are the by-product of the multi-regional congestion management. Finally, the IEEE RTS-96 with three interconnected regions and 73 buses is studied to illustrate the proposed decomposition approach to the congestion management across interconnected regions.

5.2 The Proposed Method for Regional Decomposition OPF

The original motivation to decompose a large-scale OPF problem into several smaller problems by regions is to improve the computation speed. In the last decade, some mathematical decomposition methods have been applied to regional decomposition OPF successfully. In [126], Deeb and Shahidephour applied Dantzig-Wolfe decomposition method to solve the multi-area reactive power optimization problem. Kim and Baldick presented a Lagrangian Relaxation based "auxilliary problem principle" approach to parallelizing OPF for very large inter-connected power systems in [128]. In [129], a Lagrangian Relaxation decomposition procedure was used by Conejo and Aguado to achieve a multi-area decentralized DC nonlinear OPF. Furthermore, in [130] Nogales, Prieto, and Conejo proposed a decomposition approach, which did not require the solution of sub-problems in each iteration, to solve a multi-area AC OPF problem.

Since in this chapter the main purpose of a regional decomposition OPF is to give regional ISOs the capability to dispatch the interconnected network coordinately without knowing operating data of other regions and to obtain the optimal prices of inter-region transactions, the Lagrangian Relaxation decomposition is applied.

In order to decompose a system into regions by LR decomposition, the key point is to find proper coupling constraints between regions and then to relax them into the objective function. To obtain such coupling constraints, a dummy bus is defined at the border for each interconnecting line and then duplicated into two dummy generators in [128] while one or two fictitious buses are added per interconnecting line and the model of the interconnecting line is modified in [129]. Authors of [130] mentioned that their method is based on the decomposition of the set of optimal conditions for a nonlinear programming problem without modifying the original problem, but they did not give any further physical explanation about

this and the sub-problem for each area. In the research of this thesis, a new decomposition scheme is presented to achieve the regional decomposition OPF without any modification on the original network model.

The general OPF problem, which has been described in Chapter 3, can also be formulated as

Minimize: $\sum_{i \in \Omega} C_i(P_i)$

Subject to: $\boldsymbol{h}(\boldsymbol{P}, \boldsymbol{Q}, \boldsymbol{V}, \boldsymbol{\theta}) = \boldsymbol{0}$ (5-1)

$\boldsymbol{g}(\boldsymbol{P}, \boldsymbol{Q}, \boldsymbol{V}, \boldsymbol{\theta}) \leq \boldsymbol{0}$

where $C_i(P_i)$ active power cost or bidding function of generator at bus i,

$\boldsymbol{h}(\ )$ matrix of equality constraints,

$\boldsymbol{g}(\ )$ matrix of inequality constraints,

$\boldsymbol{V}$ matrix of bus voltage magnitudes,

$\boldsymbol{\theta}$ matrix of bus voltage angles,

$\boldsymbol{P}$ matrix of active power injections,

$\boldsymbol{Q}$ matrix of reactive power injections,

Ω set of buses in the whole system.

The proposed regional decomposition scheme is shown in Figure 5.1. In the case of a system with two interconnected regions A and B, the tie-line ij and bus j in region B will be reserved in the computation of region A while the tie-line ij and bus i in region A will be reserved in the computation of region B. Therefore, the following coupling equation constraints should be added into the original problem.

$\boldsymbol{T}^A - \boldsymbol{T}^B = \boldsymbol{0}$ (5-2)

where $\boldsymbol{T}^A = \begin{bmatrix} V_i^A & \theta_i^A & P_{ij}^A & Q_{ij}^A \end{bmatrix}^\dagger$, $\boldsymbol{T}^B = \begin{bmatrix} V_i^B & \theta_i^B & P_{ij}^B & Q_{ij}^B \end{bmatrix}^\dagger$ are matrices of interconnecting variables in region A and region B, respectively. V_j, θ_j are not included in these matrices because they can be obtained by knowing V_i, θ_i and P_{ij}, Q_{ij}. The nodal power balance equations of bus j^A and bus i^B are not necessary to be included in the regional sub-problems,

where the voltages of bus j^A and bus i^B appear only in the nodal power balance equations of bus i^A and bus j^B and they are constrained by the branch power flow constraints of P_{ij} and Q_{ij}. Therefore, no dummy generators or loads are added at bus j^A in the region A sub-problem and at bus i^B in the region B sub-problem.
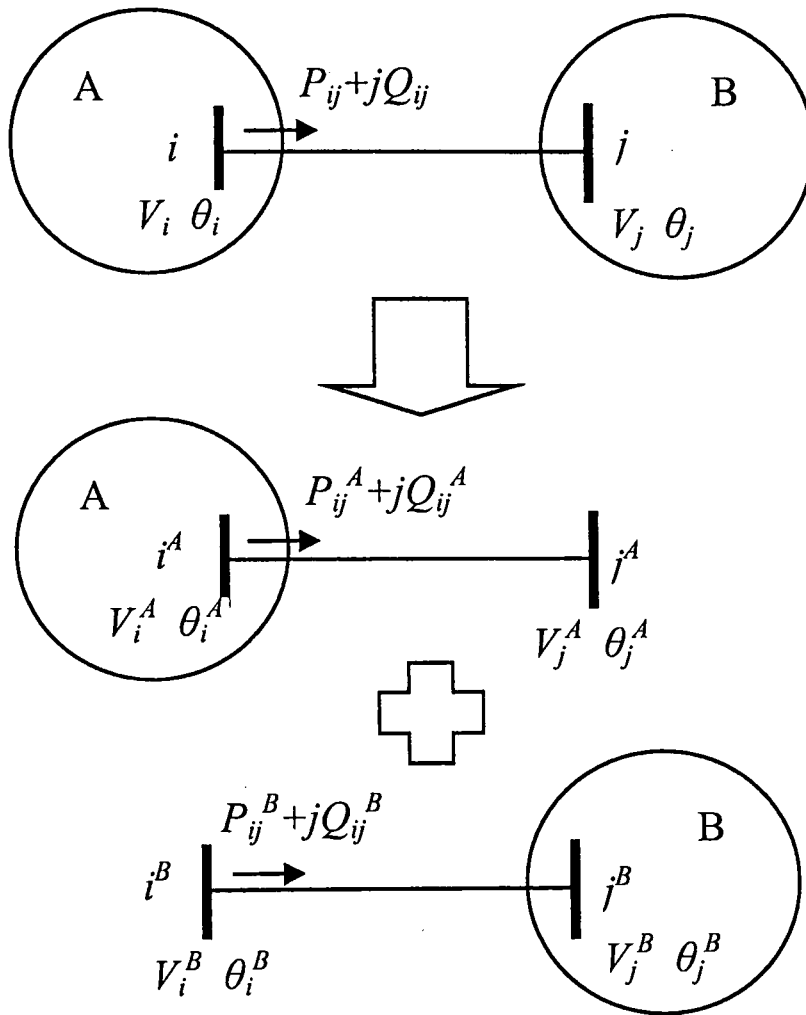
Figure 5.1 The proposed region decomposition scheme

After the regional coupling constraints have been relaxed into the objective function, the dual function is obtained as

$$\Phi(\lambda) = \text{Minimize: } \sum_{i \in \Omega} C_i(P_i) + \lambda^\dagger (T^A - T^B)$$

Subject to: $\quad h^A(P^A, Q^A, V^A, \theta^A) = 0$ \hfill (5-3.a)

$$h^B(P^B, Q^B, V^B, \theta^B) = 0$$

$$g^A(P^A, Q^A, V^A, \theta^A) \leq 0$$

$$g^B(P^B, Q^B, V^B, \theta^B) \leq 0$$

where λ is the matrix of multipliers of coupling constraints. Then the dual problem is

Maximize$_\lambda$: $\Phi(\lambda)$ (5-3.b)

The LR solution can be obtained by solving problem (3.a) at a fixed λ and then updating λ to increase the dual objective function until the dual objective function and λ do not change significantly. Therefore, the decomposed sub-problem of region A can be formulated as

Minimize: $\sum_{i\in\Omega^A} C_i(P_i) + \lambda^{\dagger} T^A$

Subject to: $h^A(P^A, Q^A, V^A, \theta^A) = 0$ (5-4)

$g^A(P^A, Q^A, V^A, \theta^A) \leq 0$

where $h^A()$ matrix of equality constraints in Region A,

$g^A()$ matrix of inequality constraints in Region A,

V^A matrix of voltage magnitudes of buses in region A and directly adjacent buses to Region A,

θ^A matrix of voltage angles of buses in region A and directly adjacent buses to Region A,

P^A matrix of active power injections,

Q^A matrix of reactive power injections,

Ω^A set of buses in region A.

In (5-3) and (5-4), it can be seen that the coupling constraints forcing the interconnecting variables to match on both regions of a tie-line are dualized and this decomposes the OPF problem into separate regional OPF problems. The Lagrangian multipliers are updated iteratively as follows by simply applying sub-gradient method until the interconnecting variables on both interconnected regions match.

$\lambda^{k+1} = \lambda^k + \alpha(T^{A,k+1} - T^{B,k+1})$ (5-5)

where k is the index of iteration. The values of Lagrangian multipliers are the costs to maintain the regional coupling equation constraints. Especially, the economic explanations of the multipliers for active and reactive power flows between two interconnected regions are the optimal prices of inter-regional transactions.

Because some of the coupling constraints (P_{ij} and Q_{ij}) are nonlinear, relaxing them to the objective function could affect its convexity. To ensure local convexity, the augmented Lagrangian decomposition should be used and the augmented Lagrangian function of problem (5-1) can be written as

$$L = \sum_{i \in \Omega} C_i(P_i) + \lambda^\dagger (T^A - T^B) + \frac{1}{2} \beta \left\| T^A - T^B \right\|^2 \tag{5-6}$$

If β is big enough the quadratic term can keep good local convexity of (5-6). However, this new quadratic term makes the relaxed primal problem non-decomposable. To make (5-6) decomposable again, the following iterative form (so-called Alternating Direction Method [147]) is adopted, in which the variables not in the analysing region are fixed to the values of the previous iteration.

$$(T^{A,k+1}, T^{B,k+1}) = \arg\min \left\{ \begin{array}{l} \sum_{i \in \Omega^A} C_i(P_i) + (\lambda^k)^\dagger T^A + \frac{1}{4} \beta \left\| T^A - T^{B,k} \right\|^2 \\ + \sum_{i \in \Omega^B} C_i(P_i) - (\lambda^k)^\dagger T^B + \frac{1}{4} \beta \left\| T^{A,k} - T^B \right\|^2 \end{array} \right\} \tag{5-7}$$

The stopping criteria for solving the decomposed regional OPFs is when the maximum mismatch between coupling variables is smaller than a preset threshold value.

$$\left\| T^{A,k} - T^{B,k} \right\| \leq \varepsilon \tag{5-8}$$

It is worth noting that the proposed method can solve all the regional sub-problems in parallel. The only information needed to exchange between regions is the LR multipliers of coupling constraints.

5.3 Application of the Proposed Method to Congestion Management across Interconnected Regions

A large electric network with multiple interconnected regions requires coordination of all the regional ISOs to have good inherent use of the grid within its secure capacity. Particularly in the deregulated environment, with the introduction of competition and greater interregional trading, a new efficient coordination mechanism should be developed to manage the transmission congestion situation across multiple interconnected regions. The general principles with which the coordinating congestion management across interconnected regions should be in line are as follows.

- System reliability is preserved based on market bids;

- Avoid any unnecessary information exchange between regional ISOs and any unnecessary network reduction;

- The whole procedure should be simple, robust and priced correctly.

Cadwalader, Harvey, Hogan, and Pope proposed a LR-based approach [148] to decompose the global congestion management problem into sub-problems corresponding to different regions. But full information of the whole system is still needed for every regional sub-problem. Moreover, some other drawbacks of this method have been pointed out by Oren and Ross in [149], such as convexity problem.

The real-time balancing mechanism has been adopted broadly for congestion management in recent years. A framework of congestion management through real-time balancing market (RBM) has been proposed in Chapter 4. To achieve the coordination between regions, the proposed regional decomposition OPF method is applied under the framework presented in Chapter 4.

5.3.1 Mathematical Model

Assume that a preferred schedule has been made through the bilateral contract market and the day-ahead auction market, all the generators and consumers are encouraged to submit their incremental and decremental bids to the ISO in the balancing market for the requirement of system balancing and congestion management. Ignoring the curtailment of bilateral contracts and operating reserves in the model of (4-1 to 4-12), the problem of active power congestion management can be simplified as:

Minimize: $\sum_{i \in \Omega^A} C_i^+ (\Delta P_i^+) + \sum_{i \in \Omega^A} C_i^- (\Delta P_i^-)$

Subject to: $\Delta P_i^+ - \Delta P_i^- - \sum_{l \in \Omega} B_{il}' \Delta \theta_l - \Delta P_{Loss,i} = 0 \quad \forall i \in \Omega^A$ (5-9)

$$\Delta P_{mn}^{\min} \le \Delta P_{mn} = B_{mn}' (\Delta \theta_m - \Delta \theta_n) \le \Delta P_{mn}^{\max} \quad \forall m, n \in \Omega; m \ne n$$

$$\Delta P_i^{\min} \le \Delta P_i = \Delta P_i^+ - \Delta P_i^- \le \Delta P_i^{\min} \quad \forall i \in \Omega$$

After applying the proposed regional decomposition OPF method, the active power congestion management in region A can be formulated as:

106

Minimize: $\sum_{i \in \Omega^A} C_i^+ (\Delta P_i^+) + \sum_{i \in \Omega^A} C_i^- (\Delta P_i^-) + \sum_{m \in \Omega^A, n \in \Xi^A} \lambda_{\Delta Pij}^k \Delta P_{mn}^A + \frac{1}{4} \beta \sum_{m \in \Omega^A, n \in \Xi^A} \left\| \Delta P_{mn}^A - \Delta P_{nn}^{B,k} \right\|^2$

Subject to: $\Delta P_i^+ - \Delta P_i^- - \sum_{l \in \Omega^A} B_{il}' \Delta \theta_l - \sum_{j \in \Xi^A} B_{ij}' \Delta \theta_j^A - \Delta P_i^{Loss} = 0 \quad \forall i \in \Omega^A \qquad (4\text{-}10)$

$$\Delta P_{mn}^{min} \leq \Delta P_{mn} = B_{mn}' (\Delta \theta_m - \Delta \theta_n) \leq \Delta P_{mn}^{max} \qquad \forall m, n \in \{\Omega^A \vee \Xi^A\}; m \neq n$$

$$\Delta P_i^{min} \leq \Delta P_i = \Delta P_i^+ - \Delta P_i^- \leq \Delta P_i^{min} \qquad \forall i \in \Omega^A$$

The objective of congestion management is to follow the schedule as closely as possible and to minimize the cost of real-time dispatch. $C_i^+ (\Delta P_i^+)$ and $C_i^- (\Delta P_i^-)$ are the cost functions of incremental and decremental adjustment at bus i, respectively. They can be either quadratic functions or linear functions. Ω^A is the set of buses in region A, and Ξ^A is the set of buses which have direct connection with buses in region A.

The adjustment of active power flows of tie lines has been relaxed into the objective function by augmented Lagrangian Relaxation method. The first set of constraints stands for the linearized nodal active power flow balance equations of all the buses in region A. As mentioned in Chapter 4, ΔP_i^{Loss} is the summed change of losses on branches that are connected to bus i and flows on the branches are flowing to bus i. The second set of constraints represents the changing ranges of active power flow on branches within region A or connected to region A. The third set of constraints is the changing ranges of nodal injections in region A.

5.3.2 Sequential Solution versus Parallel Solution

According to the analysis in section 5.2, there should be some items in the objective function of (5-10) for the relaxed coupling constraint $\Delta \theta_i^A = \Delta \theta_i^B$. Since the change of voltage angle is a relative value, this coupling constraint can be maintained by adjusting the voltage angle of slack bus in each region. Therefore items for this constraint have been removed from the objective function.

This algorithm can be implemented either sequentially or in parallel, depending whether single or multiple slack buses are used in the whole system. If the slack bus in region A is the unique slack bus in the whole system, $\Delta \theta_i^A$ which is the result of the sub-problem of region A is needed for the solution of the sub-problem of region B in order to maintain the coupling constraint $\Delta \theta_i^A = \Delta \theta_i^B$. In other words, the sub-problem of region B can not be solved until

the solution of region A is obtained. So with the unique slack bus, the presented algorithm can only be implemented sequentially.

In case each region has its own slack bus, as mentioned in [128], at each iteration the voltage angles of slack buses are chosen so that the average of the changes of border angles in region A equals the average of changes of border angles in region B. As a result, all the regional sub-problems can be solved in parallel.

5.3.3 Global Congestion Management versus Two-Level Congestion Management

Using this decomposition model, ISOs in all the regions can relieve the transmission congestion in a global way without exchanginga huge amount of information between each other. The global optimal solution can be obtained by solving sub-problem (5-10) for each region iteratively, which is the same as solving the problem of the whole system. However, all the regional ISOs must take part in the procedure, no matter whether there is any congestion in their regions or not. A regional ISO may prefer to relieve intra-regional congestion management independently rather than to always perform the calculation together with all the other regional ISOs.

To keep this independence of intra-regional dispatching, the other option, which is the two-level inter/intra-regional congestion management, is required. To eliminate inter-regional congestion, all the available adjustment bids in the Real-time Balancing Market in all regions are regarded as control variables and all the regional ISOs must act together coordinately, so model (5-10) is still used here. In the event of intra-regional congestion, the control variables only include all the submitted adjustment bids within the congested region and no additional inter-regional transactions should be made. Although a regional ISO wants to keep the independence for the intra-regional congestion management, it might still need help from the adjacent regions if the internal violation can not be relieved by local resources. To model this situation, the objective of problem (5-10) should be modified to

$$\text{Minimize } \sum_{i \in \Omega^A} C_i^+ (\Delta P_i^+) + \sum_{i \in \Omega^A} C_i^- (\Delta P_i^-) + \sum_{i \in \Omega^A, j \in \Xi^A} (\gamma_{\Delta Pij}^+ \Delta P_{ij}^{A,+} + \gamma_{\Delta Pij}^- \Delta P_{ij}^{A,-}) \qquad (5\text{-}11)$$

where $\gamma_{\Delta Pij}^+$ and $\gamma_{\Delta Pij}^-$ are the pre-negotiated coefficients for the active power interchange incremental adjustment and decremental adjustment, which should be big enough to keep the additional inter-regional transactions as the last control option to eliminate the intra-regional congestion.

5. 4 Test Results

The IEEE RTS-96 test system shown in Figure 5.2, which has 3 interconnected regions, 96 generators, 119 lines and 73 buses, has been used to demonstrate the performance of the proposed algorithm. The system power flow data and full one-line diagram of the IEEE RTS-96 test system can be found in Appendix B.2. To simplify the demonstration of multi-regional congestion management, it is assumed that all the participants in the Real-time Balancing Market of each region submit uniform incremental bidding price and uniform decremental bidding price, which are shown in Table 5.1. Obviously, region 1 has the most expensive real-time adjustable resources and Region 2 has the cheapest ones.
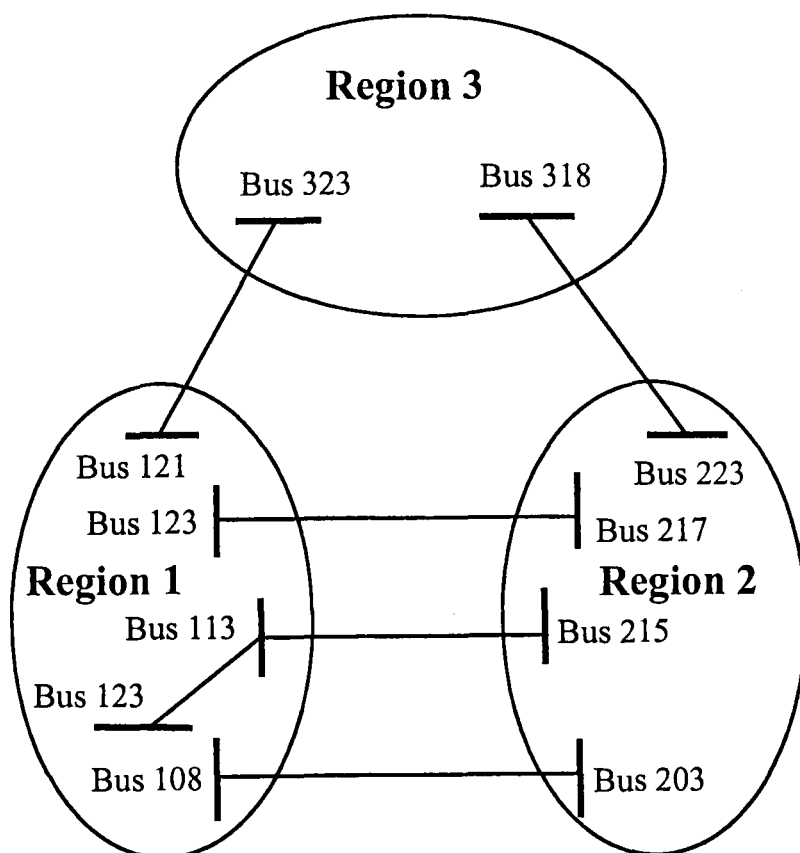
Figure 5.2 IEEE RTS-96 test system

To illustrate how to apply the proposed LR regional decomposition algorithm to relieve the inter-regional transmission congestion and intra-regional transmission congestion, two cases have been studied and their results are analyzed in the following sections.

Table 5.1 The incremental and decremental bidding prices in each region

Regions	Incre. Prices (p.u./MW)	Decre. Prices (p.u./MW)
1	1.1	0.5
2	0.5	0.3
3	0.9	0.5

5.4.1 Case 1: The Inter-regional Congestion Management

Assumed that there is an unexpected contingency, which causes the operation MW limit of tie-line 113-215 between region 1 and region 2 reducing from 400MW to 160MW. Since the base MW flow on line 113-215 is 197MW, an inter-regional transmission congestion occurs. Using the presented regional decomposition congestion management algorithm, the cheapest and the most efficient resources in the Real-time Balancing Market are called upon to eliminate this congestion. Here all the initial values of LR multipliers are set to 0, i.e. flat start. The initial points of LR multipliers will not affect convergence, however, good initial points can reduce iteration times significantly.
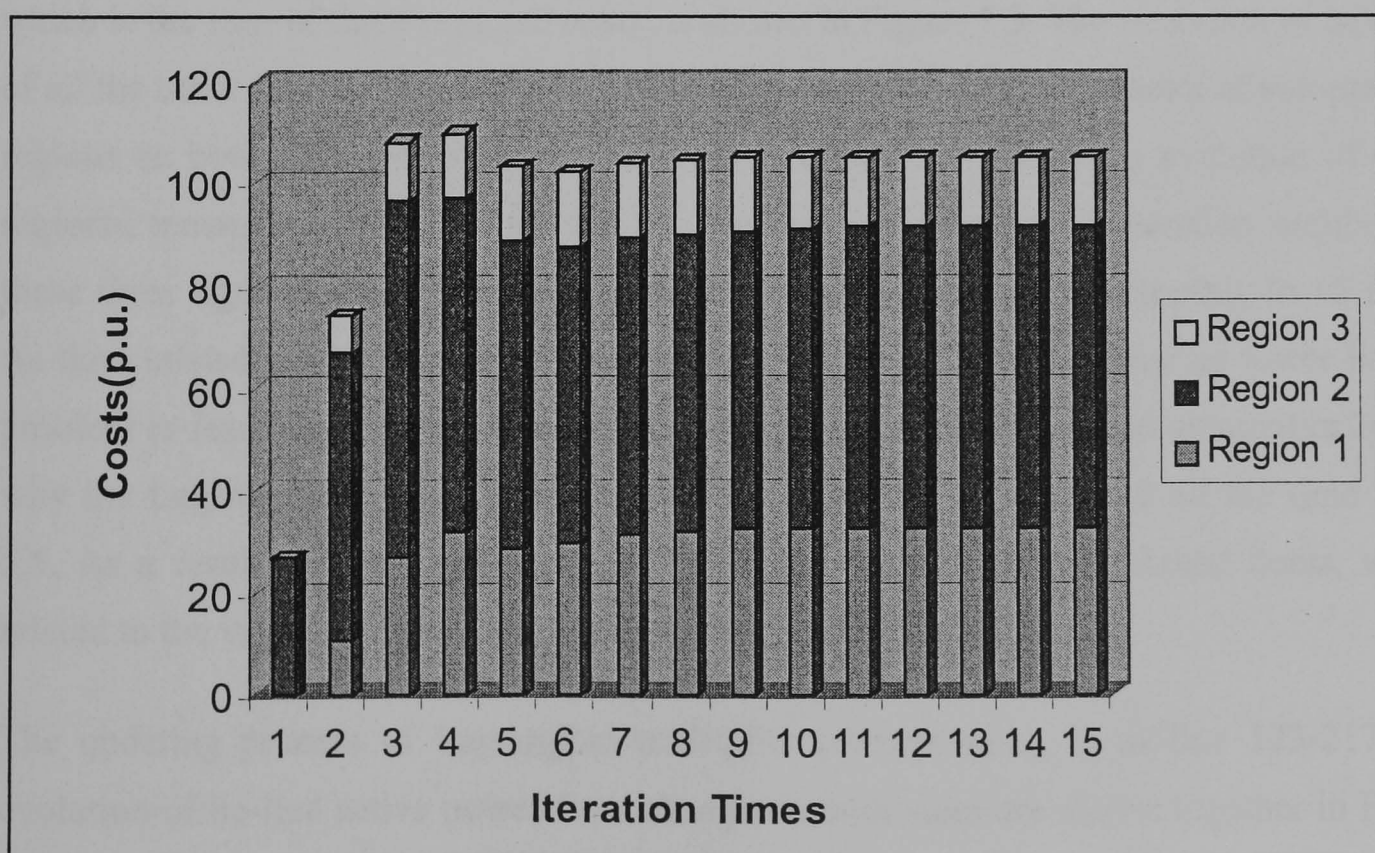
Figure 5.3 The evolution of the redispatching cost of each region in case 1
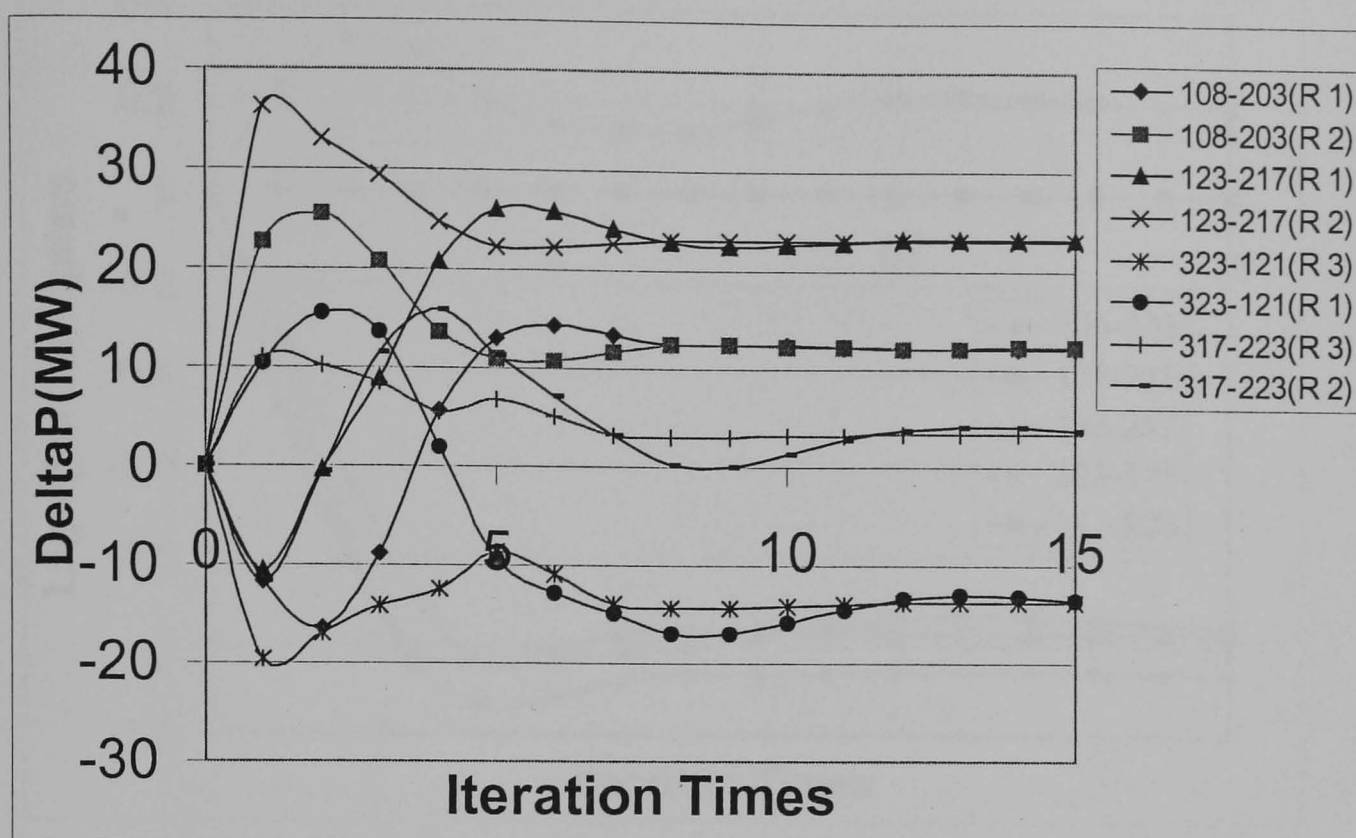
Figure 5.4 The evolution of MW changes of tie-lines obtained from the solutions of different regional sub-problems in case 1

The evolution of the total redispatching cost of the inter-regional congestion management, which is the sum of three regional costs, is shown in Figure 5.3. The evolution of MW change of all the other four tie-lines except for the congested one from the results of sub-problems of regions on both sides are shown in Figure 5.4. Figure 5.5 shows the evolution of the inter-regional transaction prices of all the five tie-lines as functions of iteration numbers. From these three figures, it can be seen that the convergence is reached smoothly in 15 iterations. As the violated tie-line power flow constraint will be fixed at its upper or lower limit if the problem is feasible, the corresponding coupling constraint is satisfied automatically. This is why the Lagrangian multiplier corresponding to tie-line 113-215 is 0 all the time in Figure 5.5. As a result, in the objective function of problem (5-10) the relaxed items, which are related to the violated interconnected constraint, can be removed.

The updating process of Lagrangian multiplier corresponding to tie-line 123-217 and the evolution of tie-line active power flow change on both sides are shown together in Figure 5.6 to demonstrate how the Lagrangian multiplier is updated in accordance with the MW mismatch of the correspondent inter-regional coupling constraint in every iteration and how the iterative process drives $\Delta P^1_{123-217}$ and $\Delta P^2_{123-217}$ together.
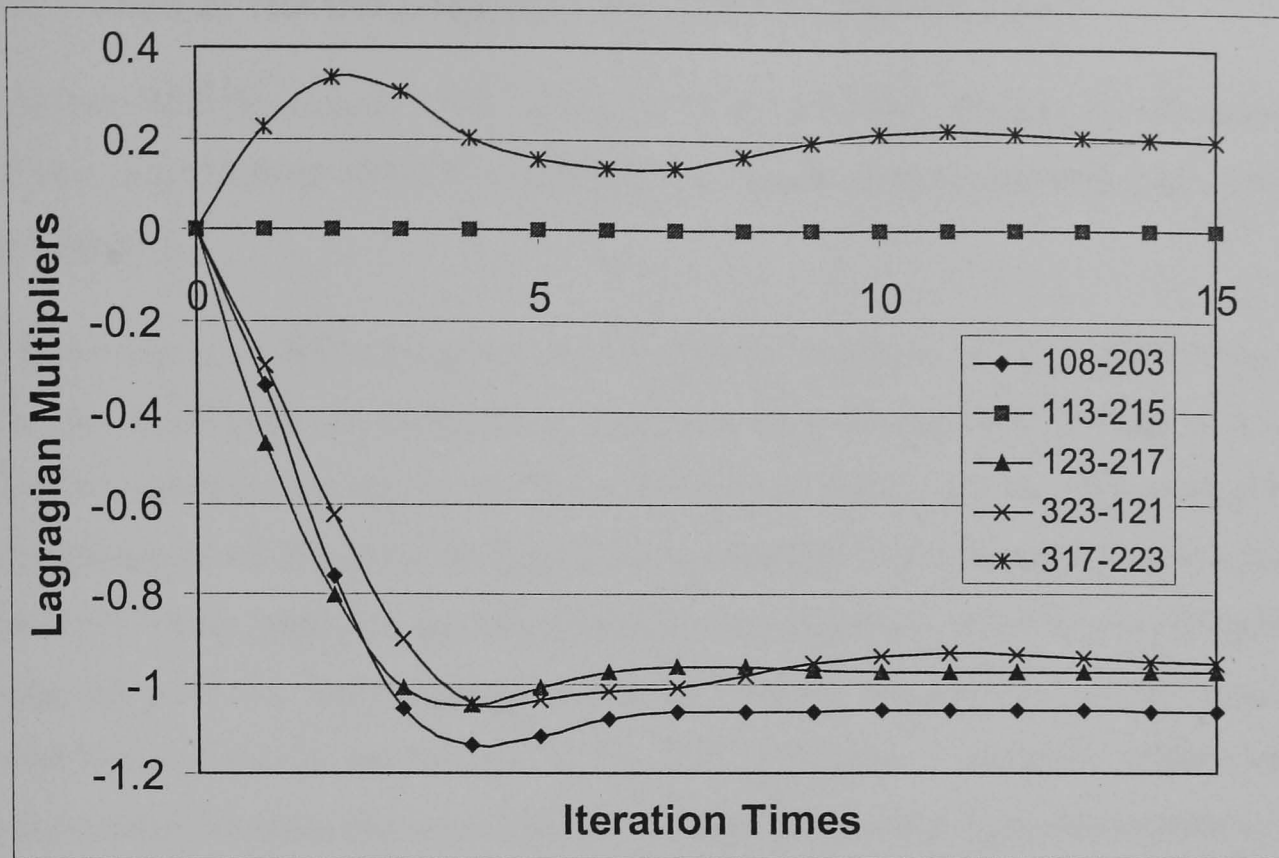
Figure 5.5 The evolution of the Lagrangian multipliers in case 1
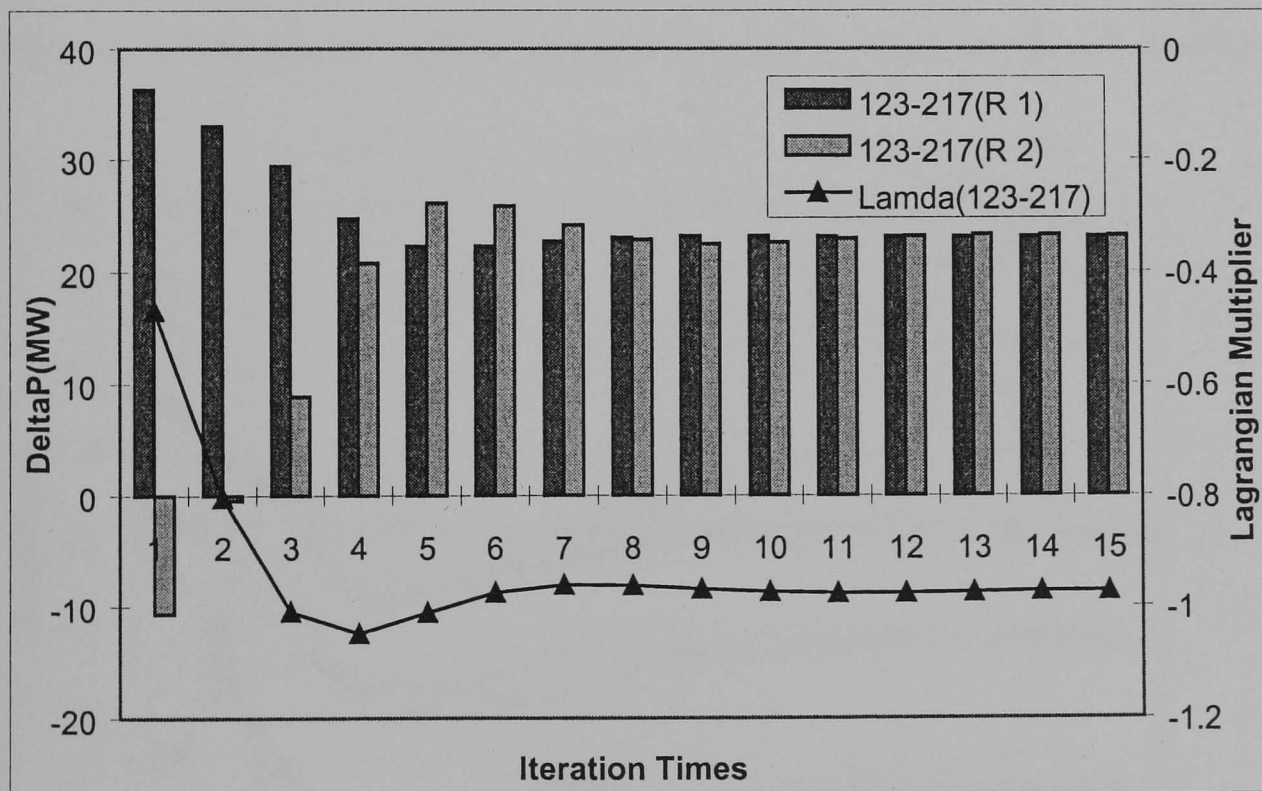
Figure 5.6 The demonstration of updating process of Lagrangian multiplier corresponding to tie-line 123-217 in accordance with the mismatch of the coupling constraint

5.4.2 Case 2: The Intra-regional Congestion Management

The base MW flow on line 113-123 is 245MW. Now the reduction of the operation MW limit of line 113-123 from 400MW to 200MW will cause an intra-regional transmission congestion in Region 1.

The evolution of MW change of tie-line 108-203, tie-line 113-215 and tie-line 123-217 from the results of both sub-problem of Region 1 and sub-problem of Region 2 as functions of iteration numbers are shown in Figure 5.7. Figure 5.8 shows the evolution of the Lagrangian multipliers of all the three tie lines between Region 1 and Region 2 as functions of iteration numbers. From these two figures, it can be seen that the iteration is just like sellers and buyers haggling over the inter-regional transaction prices. Because the initial prices of additional interchange between regions are 0, the ISO in Region 1 certainly prefers buying as many incremental/decremental resources as possible from other adjacent regions to using its own resources. On the other hand, the ISOs in other regions without any congestion do not want to accept this deal because the prices of interregional transactions are too low. With the iterative process going on, they increase or decrease the amount of interchange in light of the change of prices, and finally the optimal solution is reached, which can be accepted by both sides.
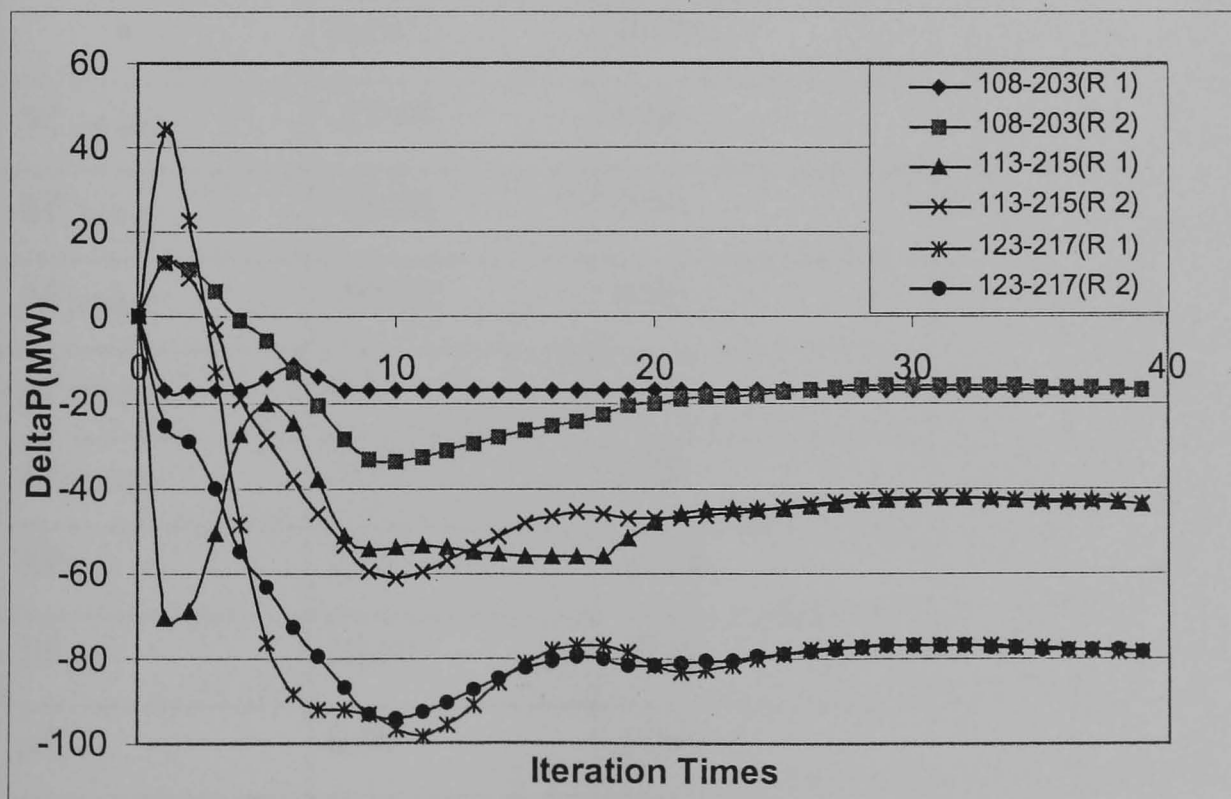
Figure 5.7 The evolution of MW changes of tie-lines between region 1 and region2 from the results of both region 1 sub-problem and region 2 sub-problem in case 2
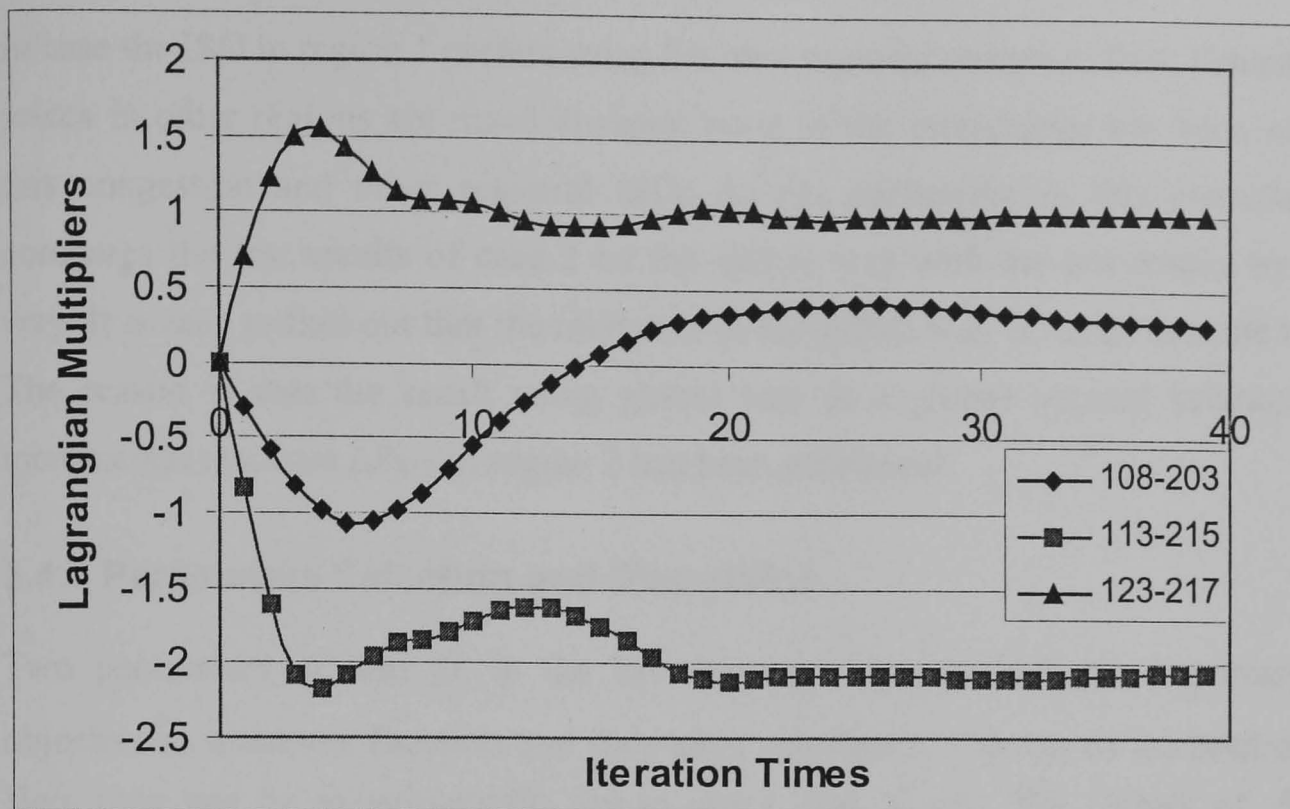
Figure 5.8 The evolution of the Lagrangian multipliers of three tie-lines between region 1 and region 2 in case 2

Table 5.2 Comparing the test results of case 2 by using the global way and the two-level way

	Global Way (MW)	Two-level Way (MW)
$\Delta P_{108\text{-}203}$	-17.40	0.00
$\Delta P_{113\text{-}215}$	-45.28	0.00
$\Delta P_{123\text{-}217}$	-80.07	0.00
$\Delta P_{317\text{-}223}$	4.43	0.00
$\Delta P_{323\text{-}121}$	-4.56	0.00
ΔP_{101}	2.16	84.94
ΔP_{102}	20.00	20.00
ΔP_{107}	0.00	17.40
ΔP_{123}	-165.81	-116.98
ΔP_{213}	148.02	0.00
Total cost	**181.29 p.u.**	**193.06 p.u.**

In case the ISO in region 1 prefers using his own regional resources first, although the bidding prices in other regions are much cheaper, none of the interchange has been made to relieve this congestion and other regional ISOs do not participate in this procedure. Table 5.2 compares the test results of case 2 by the global way with the test results by the two-level way. It is easy to find out that the total cost of the global way is lower than the two-level way. The reason is that the result using global way is a global optimal solution and cheaper incremental resource ΔP_{213} in region 2 has been purchased.

5.4.3 Parameters Selection and Discussion

Two parameters α and β in the LR decomposition method are important to keep the objective as a convex function and they have significant impacts on the total iteration times. Here they can be experimentally set to $\alpha = 1$ and $\beta = 2$. The impact of β on the total iteration number is shown in Figure 5.9. The iteration times in case 2 are more sensitive to the value of β than in case 1. Different systems might need to tune α and β to improve convergence. According to the analysis in the appendix of [128], the convergence was reliable with the choice of $\beta = 2\alpha$, which gave us a guideline to tune α and β for different systems.
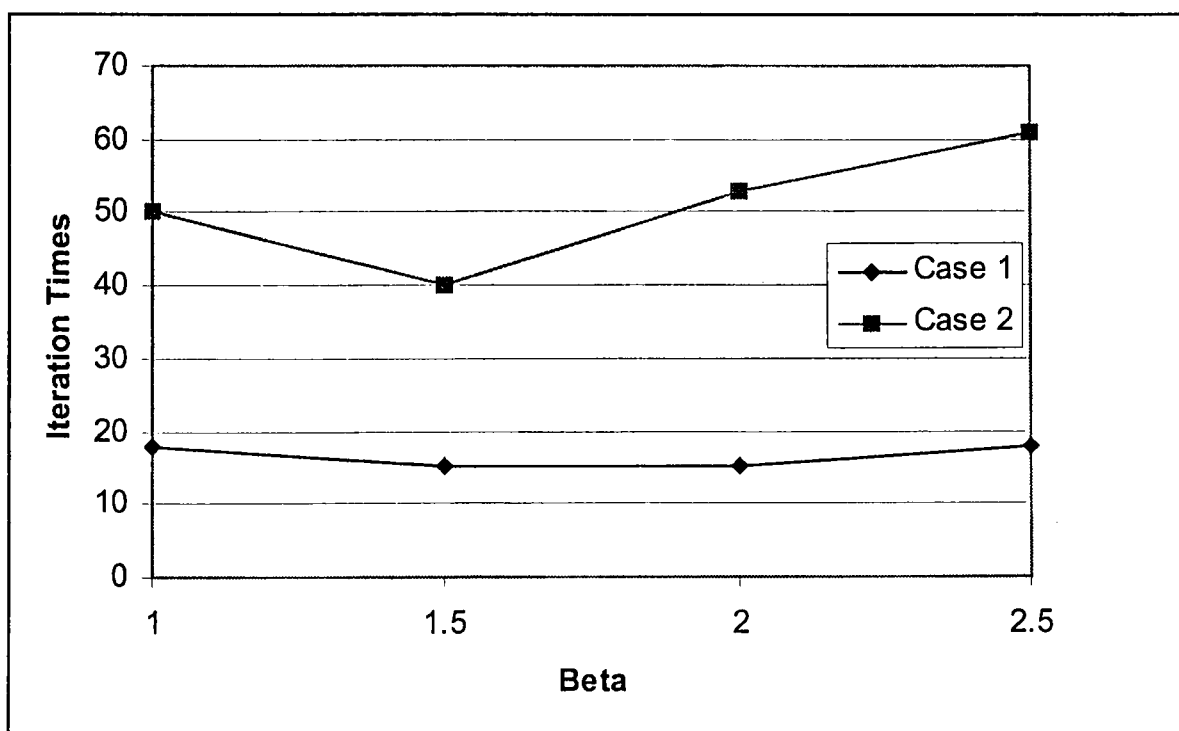
Figure 5.9 The effect of β on the total iteration times ($\alpha = 1$)

The tolerance of mismatch of tie-line power flow is set to $\varepsilon = 0.01 MW$. From the test results of case 1 and case 2, it can be noted that convergence is smoothly attained but the presented method has bad tail behaviour. The mismatch is reduced significantly in the first several iterations, but it takes many more iterations to drive the mismatch smaller than the pre-set

tolerance. Although the main purpose of the regional decomposition here is not to improve the computing speed, it is still very important to reduce the iteration times to be of use to the industry. The strategy to update LR multipliers is very important to reduce the tail behaviour. In this chapter, a simple way is used to update LR multipliers as shown in (5-5), but some more research should be done to find a more advanced method. Even an *ad hoc* approach to update LR multipliers more efficiently could be useful.

5.5 Conclusions

A new scheme for an augmented LR based region-decomposition OPF has been presented in this chapter. Comparing with some existing algorithms, neither fictitious buses, generators, loads are added nor the model of transmission line is modified to decouple interconnecting lines in the proposed algorithm. All the regional sub-problems can be solved in parallel.

Applying this region-decomposition OPF algorithm to the active power congestion management across interconnected regions through the Real-time Balancing Mechanism, an efficient redispatch way is developed to relieve the inter/intra-regional congestion without exchanging too much information between regional ISOs. The iteration process is like sellers and buyers haggling over prices and when the convergence is reached the optimal interchanges and prices can be obtained.

The proposed method is of particular interest to a multi-utility or a multi-country interconnected system, such as the USA and the Europe, where the regional dispatching independence should be retained. Case studies based on the three-region IEEE RTS-96 are presented to illustrate the proposed method.

Chapter 6. Optimal Dispatch of Spot Market with Individual Revenue Adequacy Constraints for Congestion and Risk Management

6.1 Introduction

In Chapters 4 and 5, congestion management in the real-time operation of electricity markets has been discussed. A framework has been proposed and implemented, in which the ISOs can balance their systems and relieve transmission congestion coordinated and efficiently through a real-time balancing market. This chapter is about how to avoid and manage transmission congestion during short-term (day-ahead to hour-ahead) scheduling of electricity markets.

Traditional approaches to transmission access and pricing have focused on "contract path" and cost-recovery-based transmission tariffs, which ignore the economic and physical realities of a power grid. Locational Marginal Pricing, developed by Schweppe, et al [1], provides a more economic way to transmission pricing and congestion management. Furthermore, Hogan elaborated this theory and proposed a market model including well-defined point-to-point Financial Transmission Rights (FTRs) supported by a spot market [13]. Application of LMP and FTR to multi-zonal congestion management was illustrated by Alomoush and Shahidepour in [153].

Despite of the advantages of LMP, it can also create temporal and locational price risks. However, these risks can be hedged through some pure financial instruments such as Contracts for Differences (CfDs) and FTRs. Bushnell and Stoft have explained how it works for long-run electric grid investment [154].

A fully open electricity market should encourage more bilateral contracts and give market participants more freedom to arrange their own transactions. However, due to the special characteristics of power energy commodity, a bid-based spot market is still needed to balance the system and eliminate potential transmission congestion. How to redispatch all the bilateral contracts, when required, has always been the main problem facing the ISO who runs the spot market. Some of the physical approaches to curtail bilateral contracts have been presented by Fang and David in [156].

Bilateral contracts can be modelled as physical bilateral contracts or CfDs. CfDs are more flexible than physical bilateral contracts. Bilateral contracts are encouraged to buy FTRs in order to reserve transmission capacity and maintain their revenue adequacy. Bilateral contracts without protection of FTRs may face serious congestion charges and may not be able to make enough profit. Therefore, managing bilateral contracts in light of their revenue is a very natural and straightforward way to congestion management in a spot market.

In this chapter, some new individual revenue adequacy constraints are introduced into the typical spot market dispatch model to produce a more reasonable result for bilateral contracts delivery under transmission congestion situation. In Section 6.2, the basic model of optimal dispatch in the stop market and the fundamental of Locational Marginal Pricing theory are presented. In particular, the impact of limits of bus generation and load on nodal prices are emphasized from the analysis of different forms of nodal price. Section 6.3 introduces the basic concepts of CfDs and FTRs and how they have been used to hedge against price risks. In Section 6.4, a new dispatch model with individual revenue adequacy constraints is presented to improve congestion management in a spot market with bilateral contracts. This complex problem with dual variables in constraints can be solved by an iterative procedure. Finally, a 5-bus system and the IEEE 30-bus system are analysed to illustrate the proposed approach.

6.2 Impacts of Operating Limits on Locational Marginal Prices

6.2.1 Spot Market Dispatch Model

The spot market dispatch model can be formulated as a bid-based DC Optimal Power Flow (OPF) problem, whose objective is to maximise the social welfare.

$$\underset{P_g, P_d}{Max} \quad \sum_{i \in N_D} B_i(P_{di}) - \sum_{i \in N_G} C_i(P_{gi})$$

Subject to: $\hspace{11cm}$ (6-1)

$$P_g - P_d - B'\theta = 0 \qquad : \quad \lambda$$

$$P_{l,min} \le H\theta \le P_{l,max} \qquad : \quad \mu_l$$

$$P_{g,min} \le P_g \le P_{g,max} \qquad : \quad \mu_{g,min}, \quad \mu_{g,max}$$

$$P_{d,min} \le P_d \le P_{d,max} \qquad : \quad \mu_{d,min}, \quad \mu_{d,max}$$

where $C(\ )$ is the active power offer functions of generators in the spot market,

$B(\ )$ is the active power bid functions of consumers in the spot market,

N_D is the set of the set of demand buses,

N_G is the set of generation buses,

B' is the linearized active power Jacobian matrix,

H is the matrix of branch power flow constraint coefficient,
θ is the matrix of bus voltage angles,

P_g is the matrix of generators' MW outputs,

P_d is the matrix of Consumers' MW loads,

P_l is the matrix of branch MW power flows,

λ is the matrix of shadow prices (dual variables) of nodal power balancing equality constraints,

μ is the matrix of shadow prices (dual variables) of inequality constraints.

According to the spot price theory, the LMP at bus i is

$$\rho_i = \lambda_i = \lambda_s - \sum_l^{N_l} \mu_l \frac{\partial P_l}{\partial P_i} \tag{6-2}$$

where λ_s is the system lambda (shadow price of the nodal power balancing equality constraint of the slack bus), N_l is the set of branches. From (6-2), it seems that when losses are ignored, locational marginal price is only decided by the system lambda and transmission congestion charge. This has been well known since Schweppe's spot pricing theory. In fact, there are some other important factors which can also have important effects on LMPs.

6.2.2 Operating Limits and LMPs

Baughman and Siddiqi pointed out the impacts of generation limits on nodal prices in [105]. As they stated, at a generation bus the price of active power is equal to the marginal cost of production until the generating capability limits are reached. In this chapter, both generation and demand are treated as control variables (i.e. the demand elasticity is fully taken into account by consumers' submitted bidding curves to the ISO), thus from the KKT first order conditions the LMP can have the following alternative forms for generation buses and demand buses, respectively.

$$\rho_i = -\frac{\partial B(P_{d,i})}{\partial P_{d,i}} + \mu_{di,min} - \mu_{di,max} \qquad i \in N_D \tag{6-3}$$

$$\rho_i = \frac{\partial C(P_{g,i})}{\partial P_{g,i}} - \mu_{gi,min} + \mu_{gi,max} \qquad i \in N_G \tag{6-4}$$

Here, it can be noticed that not only transmission congestion, but also upper/lower limits of market participants can have significant impacts on LMP. In fact, if we neglect the last two inequality constraints in problem (6-1) and assume all the consumers submit quadratic benefit curves to the ISO, there will never be any real risk of high spot prices caused by congestion. Without minimum load level limit, consumers can reduce their loads down to zero in accordance with their bidding curves when they suffer from high congestion charge. In other words, congestion can not do any real harm (i.e. negative profit) to consumers if they can always decrease their demand against raising prices. However, in the real world few consumers can reduce their loads down to very low level.

A bilateral contract can be modelled as one generation at the supply bus and the same amount of load at the demand bus when the losses are ignored. Bilateral contracts are traded in bilateral market instead of spot market, so injections from bilateral contracts cannot be regarded as control variables in problem (6-1). They should be treated as base load and expressed by lower limits of the offers and bids from generators and consumers in the spot market. These lower limits may bring prohibitively high nodal spot prices to consumers in case of transmission congestion.

6.3 Description of CfD and FTR

Electricity prices in a competitive power market will fluctuate temporally and locationally. This could create high price risks. Two types of pure financial instruments, Contracts for Differences (CfDs) and Financial Transmission Rights (FTRs) have been proposed for dealing with these price risks.

Two Parties conducting a bilateral contract in a spot market face two types of price uncertainty: temporal uncertainty and locational uncertainty. In spite of the fact that the two parties to a bilateral contract are forced to trade directly with the grid at fluctuating spot prices, they can completely insulate themselves from these fluctuations provided that they face the same spot price. This can be done by the use of a CfD. If spot prices are different

locationally due to transmission congestion, new price risk is created. This locational price risk can be managed by an FTR. In this section, we will present the mathematical models of these two financial contracts, and then describe how they work together to hedge against market price risks.

6.3.1 Contracts for Differences

Bilateral contracts take many forms, and in theory can include any provisions agreed to by the contracting parties. In order to have a simple standard of comparison for CfDs we define a typical bilateral contract that the parties can make direct physical trades as a Physical Bilateral Contract (PBC). Two major characteristics of such a contract are a price and a quantity. Although quantity may be specified, it is recognized that if either party does not comply there will be no way to force compliance. Consequently financial penalties are generally specified along with the target quantity. For instance it is common to require the demander to pay for electricity that is not "taken", and to penalize the supplier for electricity that is not supplied. These penalties are said to enforce "physical performance" of the contract. For simplicity, it is assumed that the contract specifies a penalty for reduced consumption, and a penalty for reduced supply. In summary, a PBC specifies requirements for both financial performance, and physical performance.

In the presence of a pool-based spot market, CfD is a form of long-term financial bilateral power supply contract to hedge against temporal price risks. In describing CfDs below, we assume a uniform locational spot price for market participants. Imagine a generator at node i and a consumer at node j who wish to trade CfD_{ij} units of power at a future time at which the unknown universal spot price will be ρ. However, the traders wish to trade a negotiated strike price ρ_{ij}^C. This can be achieved indirectly by writing a CfD, which is now defined as:

Under a CfD, the consumer will pay the generator $(\rho_{ij}^C - \rho)CfD_{ij}$, where ρ_{ij}^C is the contract price, CfD_{ij} is the contract quantity and ρ is the market spot price.

Notice that there is no specification of quantities delivered or received because quantity transactions are carried out in the spot market. Once such a contract is in place either party can assure itself of the trade that is specified by the analogous PBC, by simply trading the specified quantity.

- If the consumer buys CfD_{ij}, his net cost will be $\rho CfD_{ij} + (\rho_{ij}^C - \rho)CfD_{ij}$, independent of the generator's actions.

- If the consumer sells CfD_{ij}, his net income will be $\rho\, CfD_{ij} + (\rho_{ij}^C - \rho)CfD_{ij}$, independent of the generator's actions.

The importance of specifying only financial performance cannot be seen as long as both parties actually do perform physically in line with the contract's nominal quantity. It is only when traders fail to supply or consume the contracted quantity that the potential benefit of the CfD becomes apparent.

Table 6.1 Benefit of a CfD when its parties fail to trade the specified quantity

		$\rho <$ cost of generation	$\rho >$ value of use
Generator	CfD	Reward $= (\rho_{ij}^C - \rho)$	Trade $= CfD_{ij}$
	PBC	Possible Penalty	Trade $= CfD_{ij}$
Consumer	CfD	Trade $= CfD_{ij}$	Reward $= (\rho_{ij}^C - \rho)$
	PBC	Trade $= CfD_{ij}$	Possible Penalty

Table 6.1 shows that since their trade of CfD_{ij} is actually with the spot market, either party may decide to modify CfD_{ij}. This does not effect the payment of $(\rho_{ij}^C - \rho)CfD_{ij}$ from buyer to seller. Generally if the spot price is very low, the generator will find it more profitable to stop generating, while if the spot price is very high, the demander will find it beneficial to stop demanding. This behavior is consistent with economic rationality and the parties capture the benefits of this rational behavior. This is in spite of the fact that they always have the contract's fixed price available to them. Under a PBC, the participants' benefits from fluctuations in the spot price may be more limited. For this reason combining a CfD with the spot market produces a synthetic bilateral contract which can offer short-term advantages over PBC. The scale of these advantages will depend on the degree to which performance penalties and transactions costs limit the ability of parties holding bilateral contracts to take advantage of favorable spot market prices.

However, if the spot prices at nodes i and j differ sometimes in case of transmission congestion, the whole transaction could still be exposed to the locational price risk. In the spot market, given the locational spot prices ρ_i and ρ_j, there is a spectrum of CfDs. At one extreme the generator's LMP is used, in which case the consumer pays the congestion charge, while at the other extreme, the consumer's LMP is used and the generator pays the congestion

charge. If the two parties split the payment of congestion charge, the payments of the CfD to the generator and the consumer are $(\rho_{ij}^C - \bar{\rho}_{ij})CfD_{ij}$ and $-(\rho_{ij}^C - \bar{\rho}_{ij})CfD_{ij}$, respectively, where $\bar{\rho}_{ij} = (\rho_i + \rho_j)/2$. In any case, the transaction will suffer a marginal congestion charge which equals the difference between the nodal prices. So another financial instrument is needed to hedge the locational price risk.

6.3.2 Financial Transmission Rights

Before analyzing FTRs and their effect on congestion management, we need to define and describe the need for such an instrument. A FTR is essentially an indirect way of conferring a property right for transmission. As mentioned in Chapter 2, generally speaking there are two approaches to defining property rights to the transmission network: physical rights and financial rights. The physical right is obviously the strongest form of ownership, which can affect usage on the entire system. The function of financial rights is to allocate the economic rents that should accrue to portions of the network.

A physical transmission right means the control of its usage: to be able to transmit electricity along that transmission link whenever one wants to. However, exercising (or not exercising) control of a link can affect the ability of others to exercise the control of their links. In fact within the meshed part of a network, power transmitted between any two nodes actually flows on every link. The rigidity introduced by defining transmission property in this way will further limit the ability of dispatchers to adjust to fluctuating demand and generation conditions in an efficient manner.

Financial rights of transmission can have two varieties: Link-based Transmission Rights (LTR) and Financial Transmission Rights. LTR associates the ownership with the right to collect rent accrued by the link in the network. For example, the owner of LTR_{ij}, the right to a link connecting node i and node j, would collect the price difference between those two nodes times the actual power flow on that link. However the most telling criticism of this approach is the possibility of providing the wrong signal to grid construction. The classic example of this is the construction of a line from i to j with low capacity and high admittance relative to an existing path from i to j. Such an addition to the network can easily reduce the total capacity from i to j. Thus, rewarding an expansion with a LTR can encourage extremely harmful improvements.

FTR, also known as Transmission Congestion Contracts (TCC), was developed by W. Hogan. Like LTR, FTR pays the right holder the price difference between the two nodes specified by

that right. The two approaches differ in that the quantity, which is multiplied by this price difference, is defined by the right itself, rather than by the actual flow on a specific link. FTR can be defined as:

FTR is a financial instrument that entitles holder to receive compensation for Transmission Congestion Charges that arise when the transmission grid is congested in the spot market and differences in Locational Marginal Prices (LMPs) results from the dispatch of generators out of merit order to relieve the congestion.

In the spot market, given the LMPs ρ_i and ρ_j, under an FTR with magnitude FTR_{ij} from i to j would pay its owner $(\rho_j - \rho_i)FTR_{ij}$, which can be shared equally by both parties, no matter how much power flows between node i and j. This is exactly the marginal loss the transaction could suffer under congestion. One very important implication of this fact is that FTRs, unlike LTRs, need not be limited to existing physical links. This allows FTRs to be applied to any bilateral transaction between two nodes anywhere on the network. The evolution of definitions of transmission rights is shown in Figure 6.1.

Physical
Transmission Rights

Link-based
Transmission Rights

Financial
Transmission Rights

Contract path fiction   Too many links   Flows implicit
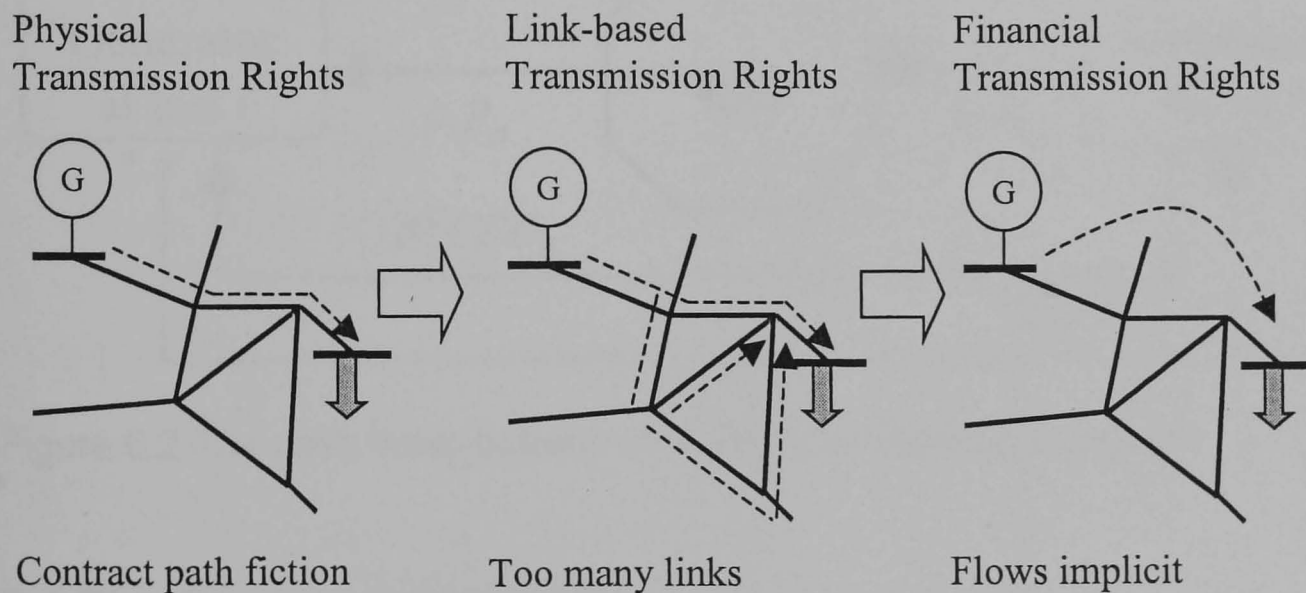
Figure 6.1 Evolution of definitions of transmission rights

Basically, FTR is defined as a point-to-point contract. However, it can have a form of network, which is from multiple points to multiple points. FTR could be option (one-sided) or obligation (two-sided). In this thesis we treat FTR as an obligation.

- Option FTR: income $= \max\{0, (\rho_j - \rho_i)FTR_{ij}\}$;

- Obligation FTR: income $= (\rho_j - \rho_i)FTR_{ij}$. When $\rho_j > \rho_i$, income > 0; when $\rho_j < \rho_i$, income < 0.

FTRs provide long-term transmission rights that can be different from the actual dispatch of the system. Although it is impossible to maintain a perfect match of long-term rights and the actual dispatch, it is possible to guarantee the financial payments to the FTR holders as long as the outstanding FTRs continue to pass the simultaneous feasibility test. FTRs can be initially obtained through an auction, which will be discussed in detail in the next chapter, and can be exchanged in a decentralized secondary market.

6.3.3 Combined Application of CfD and FTR

Through the combined application of a CfD and a matching FTR, both the consumer and the generator can hedge against temporal and locational price uncertainties. Even in the absence of CfDs, FTRs can remove spot price risk on an aggregate level when the injections of system are matched by consolidation of all FTRs. The payment relationship between the ISO, generators and consumers is given in Figure 6.2.

Figure 6.2 The cash flows between the ISO and market participants

6.4 The Proposed Approach

6.4.1 Formulation of Individual Revenue Adequacy Constraints

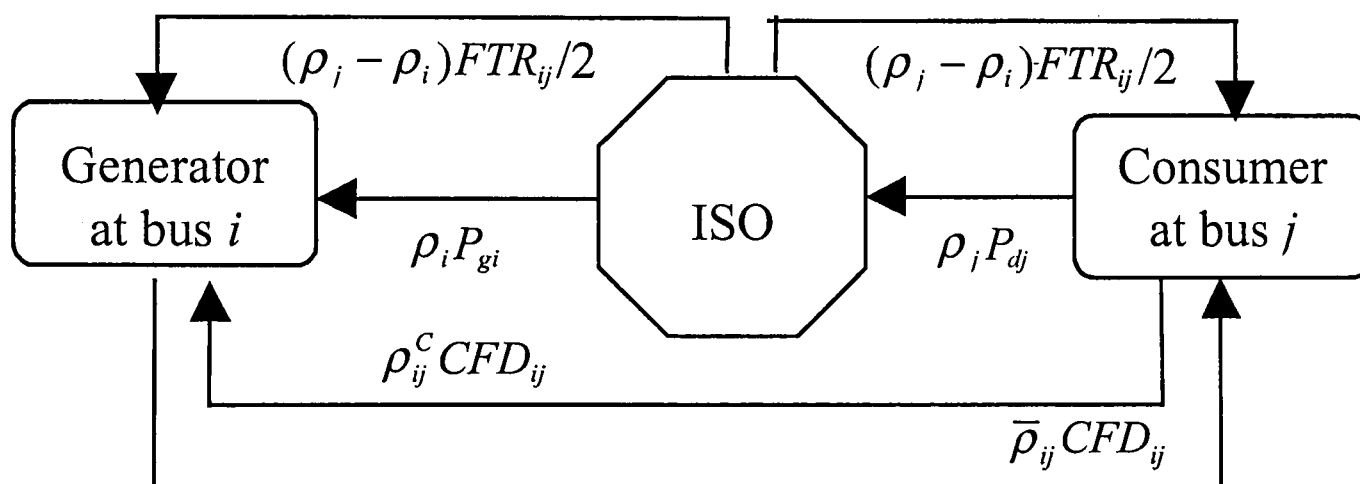With spot market and two financial instruments analyzed above, a bilateral contract could have four forms:

- physical bilateral contract without a matching FTR,

- physical bilateral contract with a matching FTR,

- CfD without a matching FTR,

- CfD with a match FTR.

As shown in Figure 4.1 of Chapter 4, before a market participant enters the day-ahead spot market, it may have signed some bilateral contracts with other participants. To take signed bilateral contracts into account, they can be treated as the fixed parts of their output/load. Therefore the bids of a participant submitted to the ISO should include two major types of data: the bidding prices and the upper/lower limits. The lower limit is not only decided by the physical operating limit, but also decided by the amount of bilateral contracts the participant has signed.

Bidding lower limit = Max {physical operating limit, Σ bilateral contracts}

As discussed in section 6.2, these bidding limits in spot market may cause high congestion price risks. And the LMPs in spot market can be changed by participants adjusting not only their bidding prices but also their bidding limits.

To calculate the revenue of a market participant, we must know its generation cost or consumption benefit. The revenue associated with the energy traded in the spot market can be directly obtained with participant's bidding curve. For a CfD, since the energy is actually traded in spot market, the bidding curve can also be used. However for a physical bilateral contract, it is difficult to obtain its revenue, because the ISO does not know its price information. Here we take the participant's bidding curve as a true reflection of its cost or benefit and use the extended bidding curve to calculate its total revenue. In some sense, another benefit of doing so is to prevent market participants from "gaming" during their bidding.

With full consideration of risk hedging financial instruments, a consumer's profit can be formulated as below:

$$R_{dj} = B_j(P_{dj}) - \rho_j P_{dj} - \sum_{i \in N}((\rho_{ij}^C - \bar{\rho}_{ij})CfD_{ij}) + \sum_{i \in N}((\rho_j - \rho_i)FTR_{ij}/2) \qquad (6\text{-}5)$$

In (5) the first item is the value of the power purchased; the second item is the cost of power; the third item is the payment from signed CfDs; the fourth item is the payment from FTRs. Similarly, a generator's profit can be formulated as below:

$$R_{gi} = \rho_i P_{gi} - C_i(P_{gi}) + \sum_{j \in N}((\rho_{ij}^C - \bar{\rho}_{ij})CfD_{ij}) + \sum_{j \in N}((\rho_j - \rho_i)FTR_{ij}/2) \qquad (6\text{-}6)$$

126

For a physical bilateral contract from bus i to bus j, the profit of this contract can be formulated as:

$$R_{Pij} = B_j(P_{ij}) - C_i(P_{ij}) - (\rho_j - \rho_i)P_{ij} + (\rho_j - \rho_i)FTR_{ij} \qquad (6\text{-}7)$$

The profit of physical bilateral contract can be equally shared by the two parties. To keep the incentive of a market participant for implementing its transactions, its profit should be bigger than a minimum profit level. This minimum revenue requirement may include some operation cost and the cost for purchase of FTRs. In this chapter it is called individual revenue adequacy constraint given by:

$$R_{dj} \left(+\sum_{i \in N} R_{Pij} / 2 \right) \geq R_{dj,\min} \qquad (6\text{-}8)$$

$$R_{gi} \left(+\sum_{j \in N} R_{Pij} / 2 \right) \geq R_{gi,\min} \qquad (6\text{-}9)$$

Obviously, without the hedge of CfDs and FTRs, a participant could be exposed directly to the risk of high LMP caused by congestion and could lose money from the delivery of its bilateral contracts. Under this circumstance, the participant should be willing to adjust its original transaction without any force from the ISO.

6.4.2 Implementation

Although the financial instruments like FTRs should be separated from the delivery of physical transactions and their owners should not have any scheduling priority, they may still be able to provide economic incentives to individual market participants for congestion management. The reason is that the original purpose to purchase FTRs is to reserve enough transmission capacity for physical delivery while the matching of financial rights with network usage can mitigate the risk of congestion charge most economically.

In order to utilize the economic incentives of individual participants to transmission congestion management, individual revenue constraints should be embedded into the spot market dispatch problem (6-1). In other words, participants will be willing to curtail some of their transactions to meet their minimum revenue requirements if they are losing money due to the high congestion prices. However, the LMPs in (6-5 to 6-9) are functions of the dual variables of the primal problem (6-1), so it is impossible to add these new constraints directly into problem (6-1). To avoid this obstacle, an iterative procedure, which is similar to the

"two-level" approach used in [105, 155], is applied to solve the problem of optimal dispatch with individual revenue adequacy constraints.
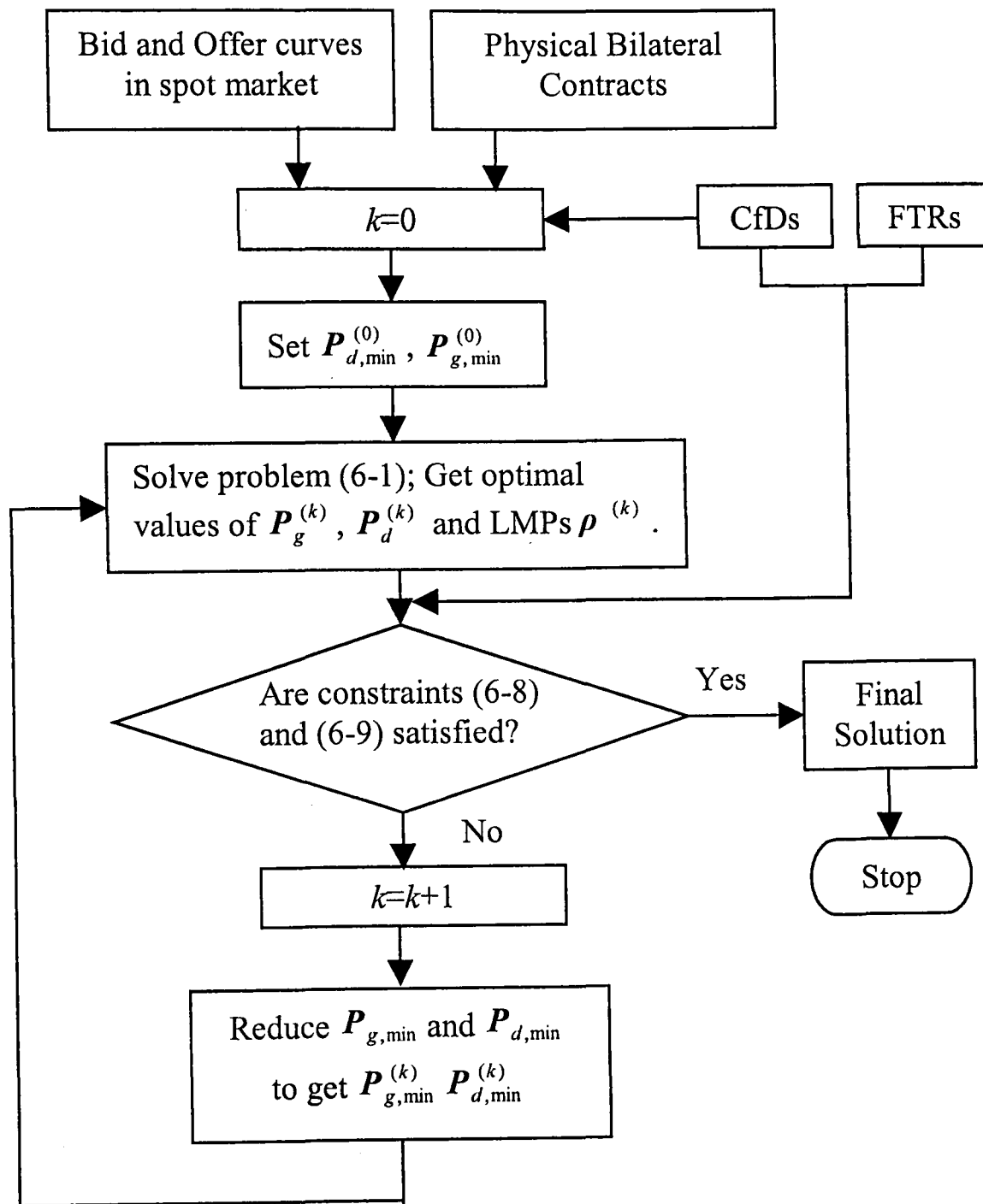
Figure 6.3 The iterative procedure to solve optimal dispatch problem with individual revenue adequacy constraints

This iterative procedure is shown in Figure 6.3. First set the lower MW limits of all the generators and consumers in light of their physical operation limits and existing bilateral transactions. Then solve the problem (6-1) by Interior Point Primal-Dual Quadratic Programming to get optimal generation, demand and nodal prices. Check individual revenue adequacy constraints of all the participants. If any of these constraints can not be satisfied, reduce associated participants' lower MW limits (i.e. curtail its bilateral contracts) and then solve the problem (6-1) again. Do this iterative procedure until all the constraints are satisfied.

There are at least two ways to update the lower MW limit of a participant. The first one is to reduce the lower MW limit by a proper step (a certain ratio of the current value) in each iteration. By this way the procedure can reach convergence smoothly but might be a bit slow. The second way is to solve (6-8) or (6-9) to obtain the minimum value of P_{di} or P_{gi} that can make (6-8) or (6-9) satisfied, then update lower MW limits with these values. By this method, the procedure can converge faster but some transactions can be over-curtailed. If the minimum profit of a participant is too high for some reasons that (6-8) or (6-9) can not be satisfied even when $P_{di}^{(k)} > P_{di,\min}^{(k)}$ or $P_{gi}^{(k)} > P_{gi,\min}^{(k)}$ (i.e. $\mu_{di,\min}^{(k)} = 0$ or $\mu_{gi,\min}^{(k)} = 0$), the revenue adequacy constraint of this participant will be removed from the iterative procedure.

Without unpredictable contingencies, the minimum feasible solution set of the optimal dispatch of spot market will equal to the set of sold FTRs, which has passed the simultaneous feasible test during the FTR auction. In this sense, the bilateral contracts which hold matching FTRs will be guaranteed to deliver.

6.5 Test Results

The proposed approach will be tested on two test systems: a 5-bus system and the modified IEEE 30-bus system. In the first system, a simple case is studied in detail to illustrate how the proposed approach works. In the second system, a more complicated case is studied to show how the LMPs are affected by an unreasonable bilateral transaction and how to eliminate this bad impact using the natural incentive of market participants.

6.5.1 System I: 5-bus System

A 5-bus test system is shown in Figure 6.4. Generators' offer curves and consumers' bid curves in the spot market are given at the left-bottom corner in Figure 6.4. Bilateral contracts traded in the bilateral market and their associated financial instruments are listed in Table 6.2. Based on these bilateral contracts, the lower MW limits for all the participants entering spot market are set at the right-bottom corner in Figure 6.4. The congested branch is Line 1-3, whose thermal limit is assumed as 80MW. Under the given conditions, the optimal solution of problem (6-1) and the nodal spot prices are also shown in Figure 6.4. In this case, the nodal price at bus 1 is very high due to the congestion of Line 1-3 while the nodal prices at bus 3 and 5 are very low since D3 must increase its load level to absorb some part of the minimum output of G2. As you can see, the ISO won't be happy with this result which may bring about serious market power.

$P_4=18.42\$/MW$ $P_2=18.42\$/MW$ $P_3=3.14\$/MW$ $P_5=3.14\$/MW$
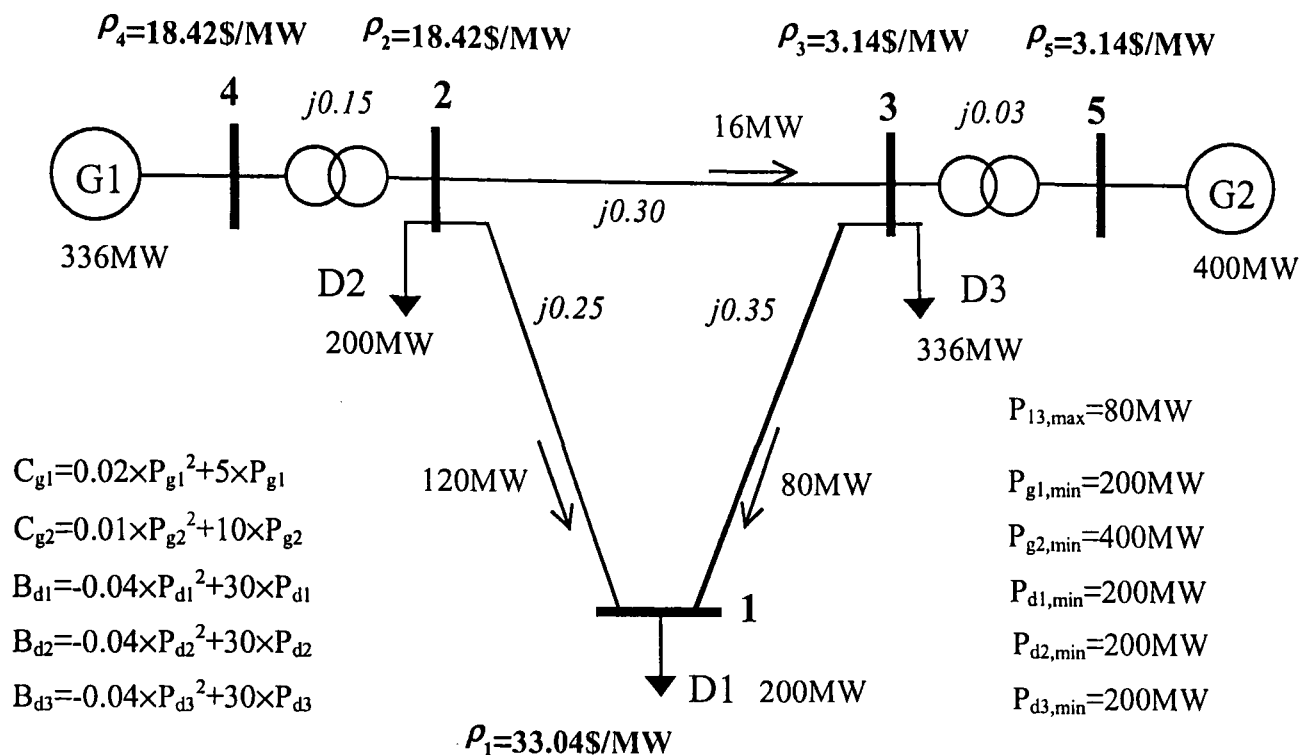
Figure 6.4 The 5-bus test system

Table 6.2. Bilateral contracts and associated financial instruments

Transaction Participants	Transaction Amount (MW)	Transaction From/To Buses	Amount of CfD (MW)	Strike Price of CfD ($/MW)	Amount of FTR (MW)
G2→D2	200	5→2	200	17	200
G2→D1	100	5→1	100	17	100
G1→D3	100	4→3	100	17	100
G1→D1	100	4→1	0	0	0
G2→D3	100	5→3	0	0	0

Given the minimum profit levels for D1 and G2 as $1,800 and $2,000 respectively, their individual revenue adequacy constraints can not be satisfied under this situation because they have transactions exposed directly to locational price risk. So they should be willing to reduce their transactions to make enough profits. Applying the iterative procedure presented in last section, we reduce the lower MW limits of D1 and G2 at a step of 10MW per iteration. In

every iteration a new set of nodal prices are produced by solving problem (6-1) with updated $P_{D1,min}$, $P_{G2,min}$, and then check if all the individual revenue adequacy constraints have been satisfied. If not, repeat this iterative procedure again.

The change of the nodal prices and total profits of D1 and G2 against the reduction of their lower MW limit is given in Figure 6.5. The impact of lower MW limits on nodal prices is very clear. When the lower MW limit of D1 is reduced to 160MW and the lower MW limit of G2 is reduced to 360 MW, the nodal price at bus 1 goes down to 20.51\$/MW and the nodal prices at bus 3,5 go up to 9.4\$/MW. Therefore, their revenue adequacy constraints can be satisfied. Meanwhile, the spot market produces much more reasonable nodal prices.
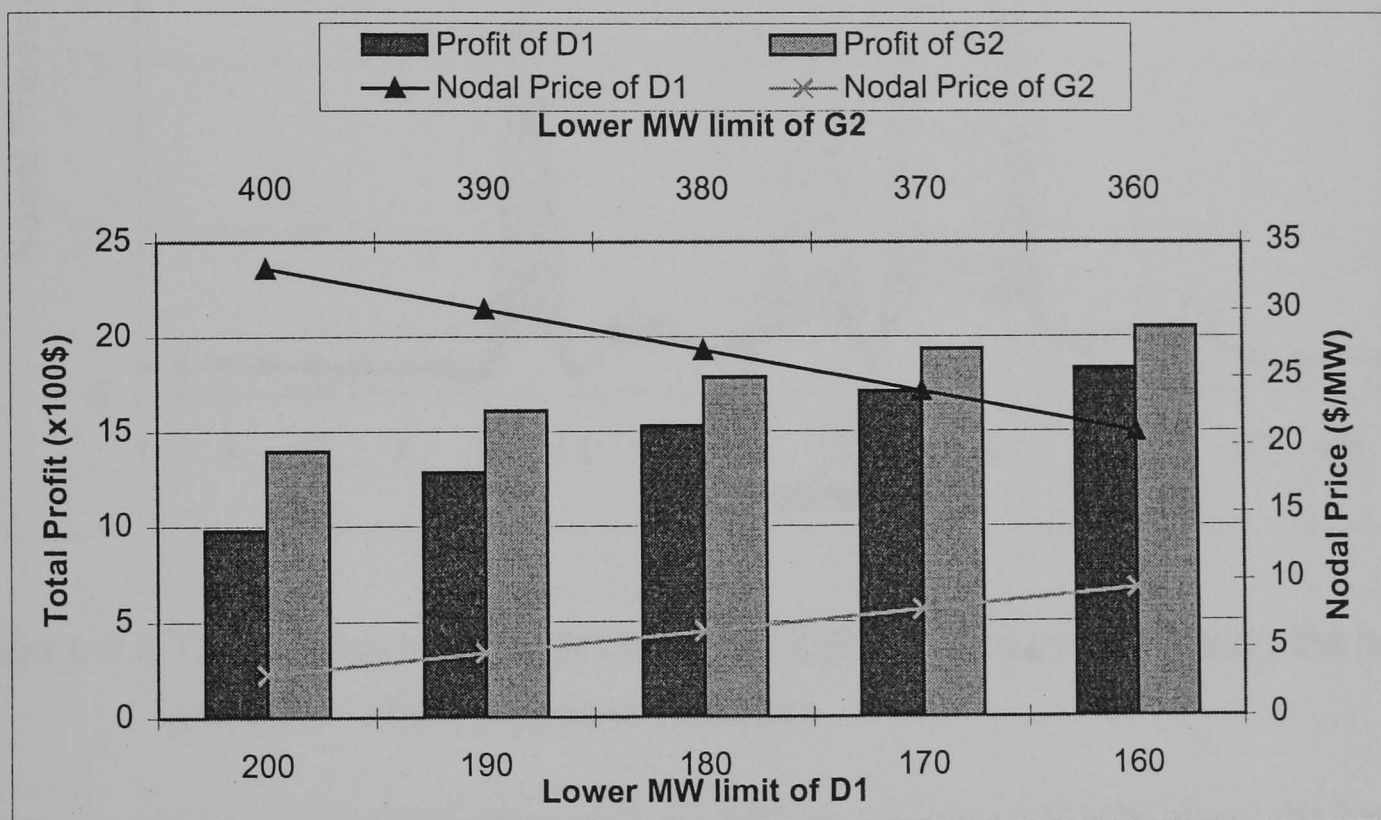
Figure 6.5 D1 and G2's feedback to nodal spot prices on their total profits and lower MW limits

6.5.2 System II: IEEE 30-bus System

The standard IEEE 30-bus test system is modified here to test the proposed method. The system data can be found in Section 7.6.2 and Appendix B.1. The network branch parameters are given in Table B.2 and their thermal limits can be found in Table 7.9. A feasible FTRs set can be found in Table 7.6 (FTRs in the base case) and Table 7.8 (FTRs in the auction result); the system one-line diagram is shown as Figure 7.9. Here, it is assumed that each defined FTR has a matched CfD. In other words all the participants have full hedge against both temporal and locational price risks. The lower MW limits of all the generators and consumers are set

according to their holding CfDs. To simplify the description of the test results, in the spot market all the generators' offer functions are set as $C(P_g) = 0.02P_g^2 + 5P_g$ and all the consumers' bid functions are set as $B(P_d) = -0.01P_d^2 + 10P_d$. As the result of optimal dispatch of the spot market, the limit binding branches include Lines 6-10, 9-10, 15-18, 18-19, 21-22 and 25-27. The nodal prices of this case are shown in Figure 6.6 as the curve of "Base Case".
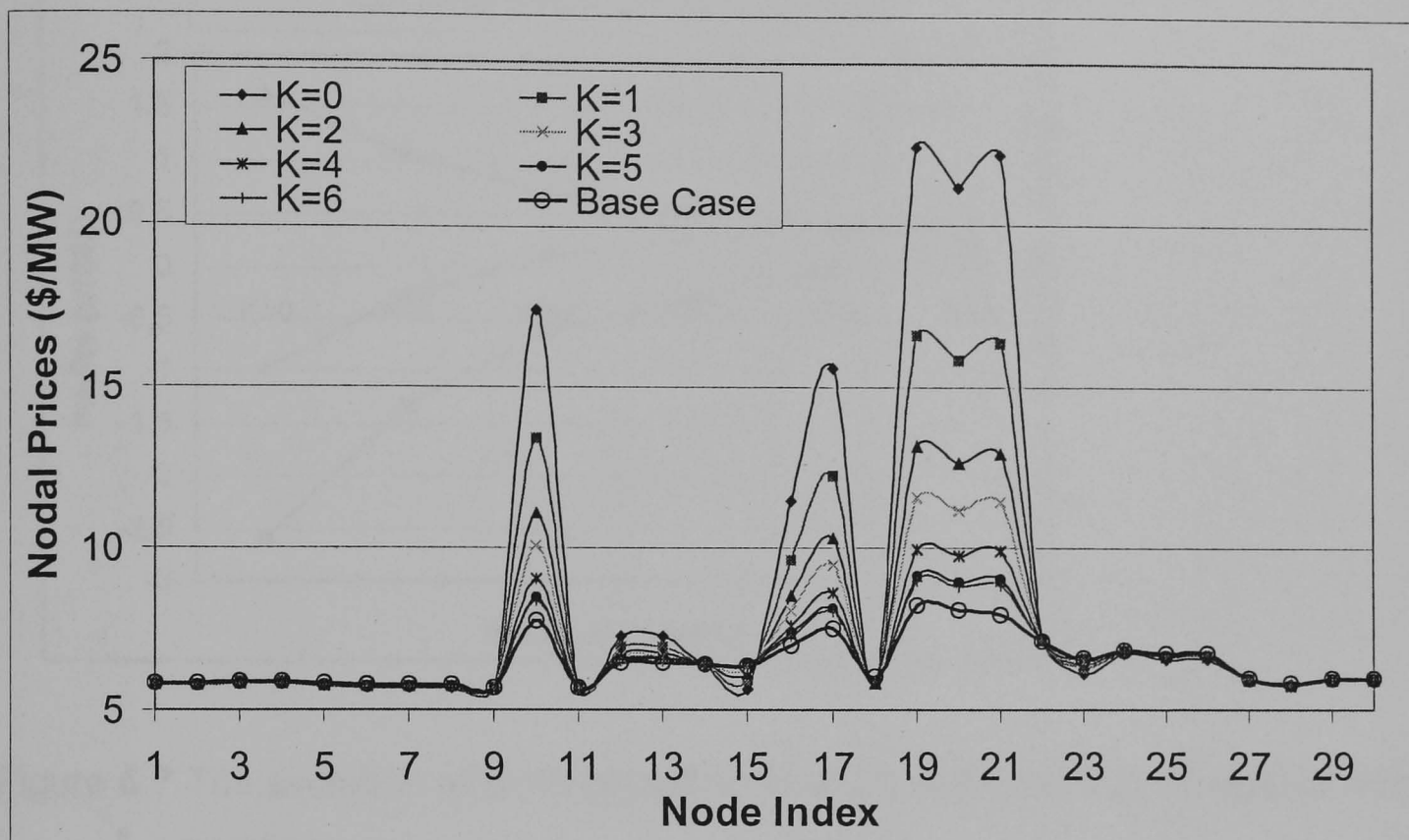
Figure 6.6 The change of nodal prices in the IEEE 30-bus system during the iterative
procedure of the proposed approach

Now we add an additional transaction T_{13-19} with an amount of 11MW above the base case. This transaction is not holding any financial instrument to hedge against price risks. The nodal prices for this case are given in Figure 6.6 as the curve of "K=0", in which the prices at bus 10, 17, 19, 20, 21 are very high due to the congestion charge. These abnormal high prices may prevent participants from trading energy in the spot market and may imply serious market power. On the other hand, the consumer at bus 19 will not be willing to continue the transaction of T_{13-19} at such a high price, because its revenue adequacy constraints can not be satisfied without the protection of the associated financial instruments. The proposed iterative procedure is applied by reducing the lower MW limit of this consumer with a step of 1MW per iteration. The decrease of nodal prices with the development of iteration is also shown in Figure 6.6. When T_{13-19} is curtailed to 5MW after 6 iterations, the nodal price at bus 19 has gone down enough to satisfy the local consumer's revenue adequacy constraint. As a result

the iterative procedure stops. Not only the consumer at bus 19 but also all the other participants including the ISO can benefit from this more sensible dispatch result.
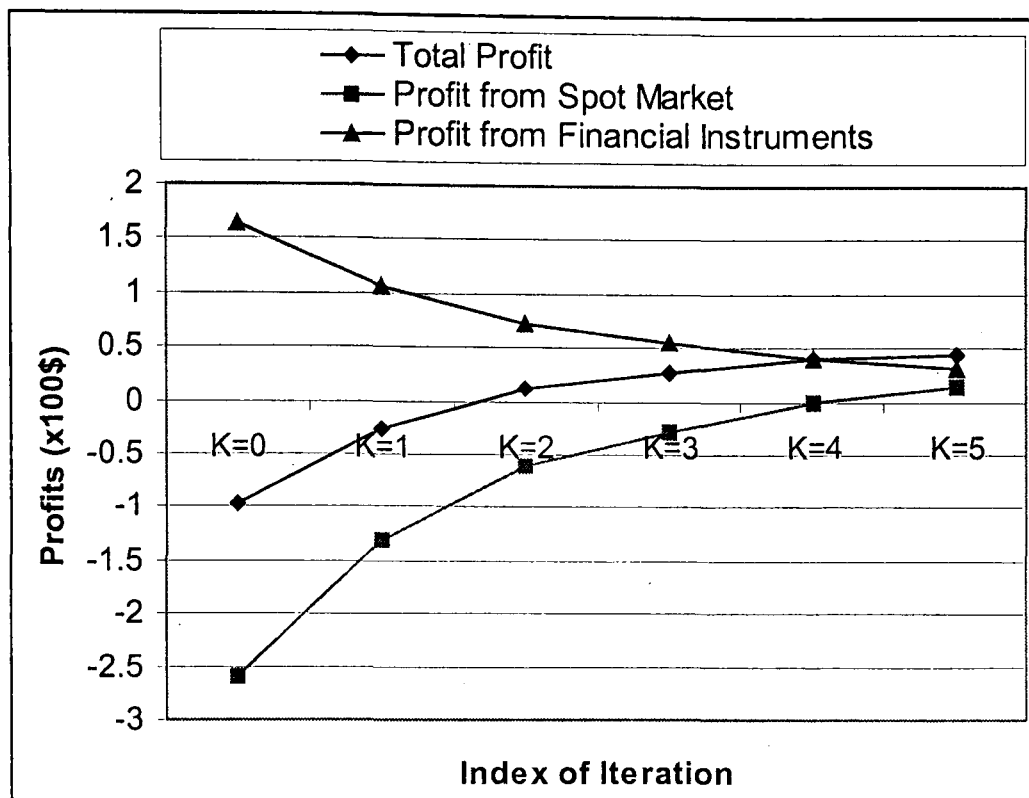
Figure 6.7 The evolution of profit components of consumer at bus 19 against iteration numbers

Figure 6.7 and Figure 6.8 illustrate the evolution of profit components of consumer at bus 19 and consumer at bus 21 against iteration numbers, respectively. As analyzed in Section 6.4.1, the total profit of a market participant, either a generator or a consumer, can be divided into two parts, which are the profit earned in spot market and the profit earned from financial instruments. From Figure 6.7 it can be seen that the total profit is negative at k=0, which means that its profit from financial instruments can not cover the huge congestion charge in spot market. With the iteration going on, the profit from financial instrument decreases while the profit in spot market increases, and eventually the total profit increases to reach the minimum profit requirement. The reason is the nodal price at bus 19 is decreasing dramatically with the curtailment of bilateral transaction $T_{13\text{-}19}$. In Figure 6.8, the total profit of the consumer at bus 21, who is also suffering from a very high nodal spot price, can keep constant, although its two components both change a lot during iteration. The explanation for this phenomenon is the consumer at bus 21 has bought enough financial instruments to fully hedge against price risks. Consequently, its income from CfDs and FTRs can always cover its loss of profit in spot market exactly no matter how much its nodal price changes.
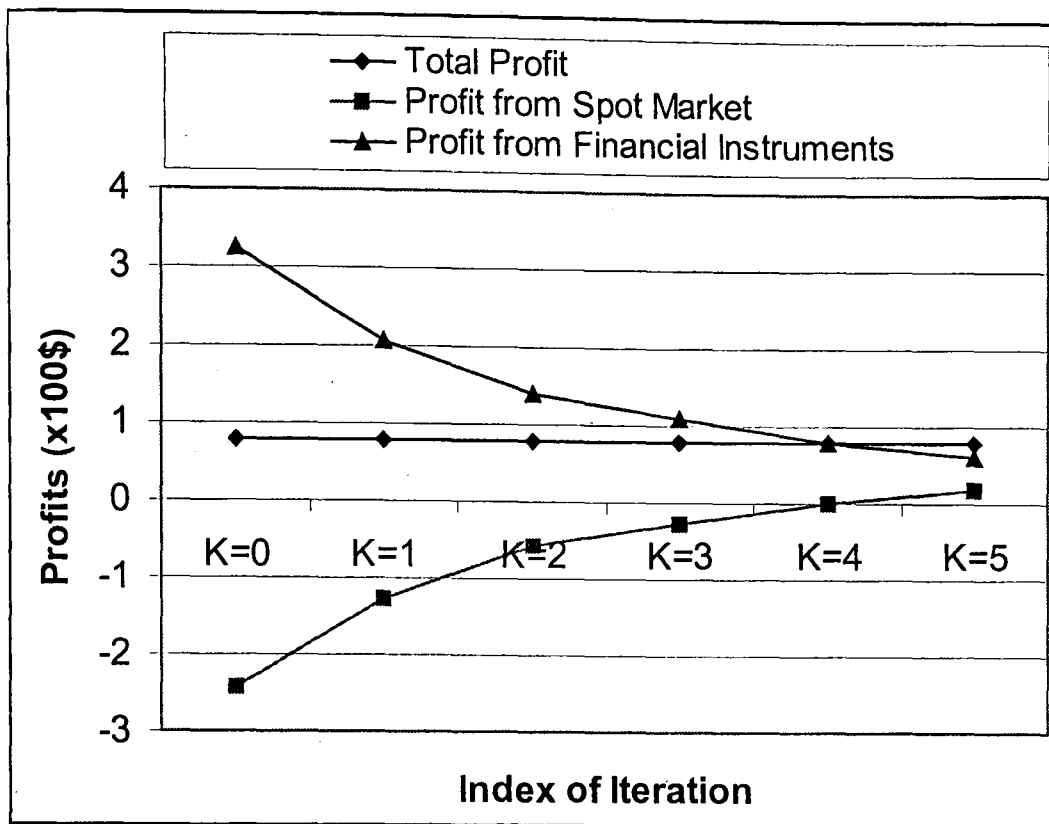
Figure 6.8 The evolution of profit components of consumer at bus 21 against iteration
numbers

In the proposed approach, the ISO needs to know the information about price and amount of CfDs and FTRs to mitigate congestion while in some previous methods bilateral contracts must submit some price signals like "willing to pay" to the ISO for curtailment in the spot market. It would be possible and harmless for the ISO knowing the price information about bilateral financial instruments like CfDs, if the ISO is a just and non-profit organization. The presented formulae can also be applied to model the problem of optimal individual bidding strategy.

6.6 Conclusions

To hedge against the temporal and locational price risks, two pure financial instruments, CfDs and FTRs, are described. The cashflows between the ISO, generators, and consumers are analyzed after CfDs and FTRs being combined together to manage the congestion and price risks. This chapter presents a new optimal dispatch method for the spot market with bilateral contracts, which takes into account the total revenue of an individual participant not only from its payment in the spot market but also the payment from its signed financial instruments. The aim of this approach is to eliminate transmission congestion and to avoid prohibitively high

nodal spot prices by utilizing the natural profitable incentive of individual market participants. To implement this approach, individual revenue adequacy constraints should be involved in the original dispatch problem. An iterative procedure is applied to solve this special optimization problem with both primal and dual variables in its constraints.

Chapter 7. Optimal Financial Transmission Rights Auction with FACTS Devices

7.1 Introduction

Financial Transmission Rights (FTR), supported by a spot market and the Locational Marginal Pricing method, has been presented in Chapter 6 as an effective approach to manage transmission congestion and high price risks. It has also been mentioned that the initial allocation of FTRs can be implemented through an auction as an approach to long-run congestion management and then they can be exchanged in the decentralized secondary market. Market participants can submit their bids for purchase and sale of FTRs in a separated auction market conducted by the ISO, whose objective is to maximise revenues from FTRs while to keep all the FTRs simultaneously feasible [159, 160]. An FTR auction has been put into practice in PJM since May 1999 [161] and has been running efficiently.

Since the concept of Flexible AC Transmission Systems (FACTS) was first proposed in 1988 [162], many various FACTS devices have been utilised to meet a growing demand of transfer capabilities due to increasing wheeling transactions in the deregulation environment. Some interesting applications of FACTS devices to Economic Dispatch (ED), AC/DC Optimal Power Flow (OPF), Optimal Power Delivery, Contract-Path based electricity trading, and Transmission Congestion Management can be found in [164-169]. Besides all the well known advantages brought by FACTS devices, they can offer new opportunities for the ISO to run a more efficient FTR auction to make the full use of the existing power grid.

A new method is proposed in this chapter to incorporate some FACTS devices into the FTR optimal auction model. A point-to-point FTR is modelled as an injection at one node and an extraction at another node. To purchase a certain FTR in the auction, a bidder should provide the maximum amount of FTR MW he is willing to pay, bid price and points of injection and extraction. The objective of this auction model is to maximise the revenues from transmission grid use. To make the sold FTRs simultaneously feasible, nodal power balance equations and inequality constraints for system operational limits are considered. Since the FTR auction is usually run monthly and only concerns active power, the DC power flow model is used here. Therefore, two types of series FACTS devices, which are thyristor controlled series

compensators (TCSC) and thyristor controlled phase shifters (TCPS) are modelled into the proposed FTR auction. Here the so-called Power Injection Model is used to model FACTS devices. This can give some participants more chances to win their bids for FTRs. Interior Point Linear Programming is applied to solve this optimisation problem. The solution of this FTR optimal auction consists of the feasible sold FTRs and their prices and the optimal control parameters of FACTS devices. An 8-bus test system and the modified IEEE 30-bus system are studied to illustrate the proposed method. The comparison between cases with FACTS devices and without FACTS devices shows that appropriate FACTS devices can improve the result of FTR auctions significantly.

7.2 Optimal FTR Auction

As described in Chapter 6, FTR is a system of transmission usage pricing and congestion risk management based on LMP approach. Based on bids and actual dispatch in the day-ahead/hour-ahead spot market, the ISO determines LMPs and charges locational differences on these prices for transmission services of power delivery from one location to another. Total congestion payments collected by the ISO (congestion charge) for the actual use of transmission system would always be at least as large as congestion payments to FTR holders (congestion credit) to make adequate system revenues [37, 159].
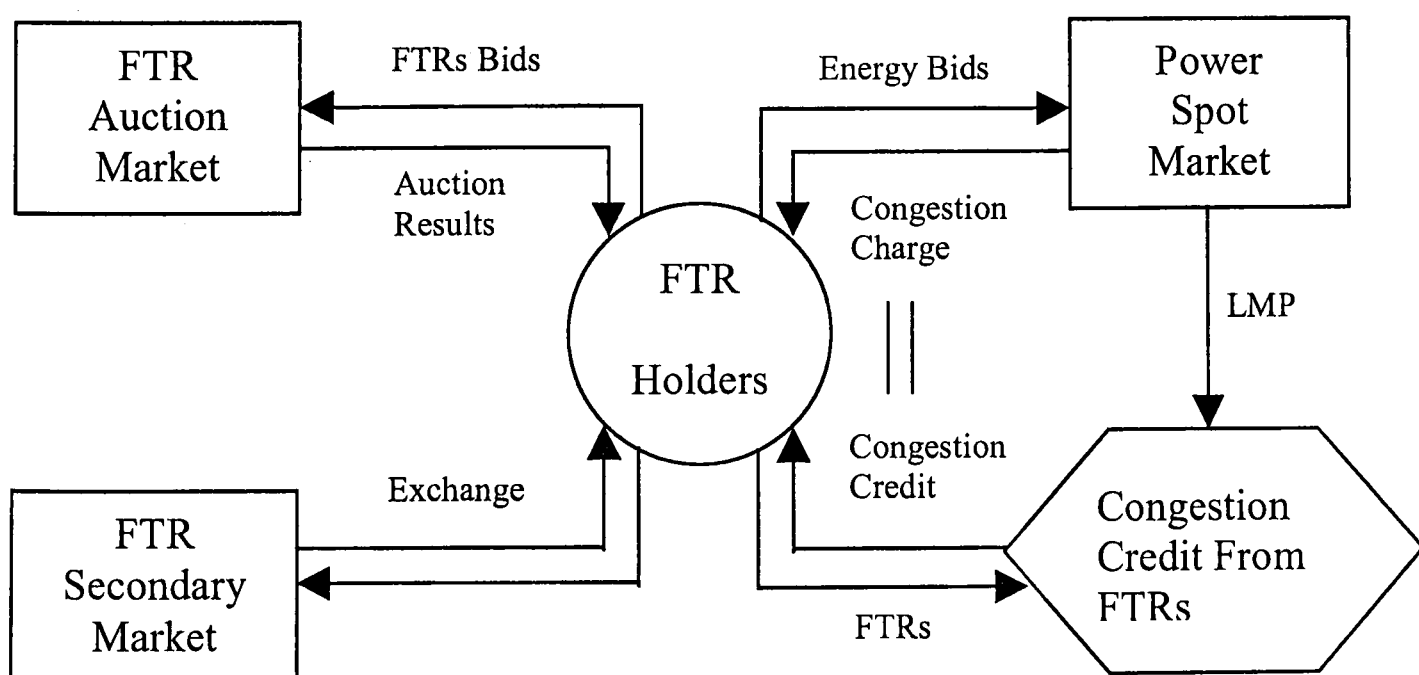

Figure 7.1 FTR's purchase and its role in congestion management

With the well-defined Financial Transmission Rights, it is natural to have an auction for allocation of part or all of the FTRs to provide open access to the grid through a market mechanism. An OPF dispatch model can be adapted to provide a formulation of an FTR auction model for selecting the long-term capacity awards based on the willing-to-pay principle. The power flow equations embedded into the FTR auction make it straightforward to identify which FTRs are available by characterizing all possible rights and selecting a set of feasible rights that would provide the highest valued use of the network. The market clearing price (MCP) for each FTR in the auction is based on the lowest winning bid for that FTR. The auction provides market participants with the opportunities to purchase FTRs which would not be able to get through bilateral transactions in a secondary market. A secondary market provides a contractual mechanism for long-term pricing of the transmission grid. A long-term (yearly or monthly) auction can be used to initially allocate FTRs to transmission users. A short-term auction (weekly or daily) can be regarded as a short-term reshaping of FTRs. FTR's purchase and its role in congestion management are given in Figure 7.1. The objective of the ISO is to maximize the profit from FTR auction while keeping all existing FTRs simultaneously feasible without violating any operation limits. Each FTR can be either from single bus to single bus or from multiple buses to multiple buses. According to the contents of [159-161], with DC model the optimal FTR auction can be formulated as the following linear programming problem.

$$Max(b^{FTR})^{\dagger} FTR$$

Subject to:

$$B'\theta - M\ FTR - M_B P_B = 0 \tag{7-1}$$

$$FTR^{min} \leq FTR \leq FTR^{max}$$

$$P_l^{min} \leq H\theta \leq P_l^{max}$$

where FTR is the matrix of winning FTR bids (MW), b^{FTR} is the matrix of bidding prices of FTR bidders, P_B is the matrix of FTR injections in the base case, B' is the linearized active power Jacobian matrix, H is the matrix of branch power flow constraint coefficients, θ is the matrix of bus voltage angles, P_l^{min} and P_l^{max} are the matrix of the lower and upper MW flow limits of branches, FTR^{min} and FTR^{max} are the matrix of minimum and maximum amount of FTR MW value the bidders are willing to pay for, M_B is the nodal injection mapping matrix of FTRs in the base case, M is the nodal injection mapping matrix of FTRs in the auction. M is a

$N \times Nbidder$ Matrix. N is the total number of buses while $Nbidder$ is total number of the bidders in the auction.

$$M = \begin{array}{c} \\ bus\ 1 \\ bus\ 2 \\ \vdots \\ bus\ N \end{array} \begin{array}{cccc} FTR^1 & FTR^2 & \cdots & FTR^{Nbidder} \\ \begin{bmatrix} m_{1,1} & m_{2,1} & \cdots & m_{Nbidder,1} \\ m_{1,2} & m_{2,2} & \cdots & m_{Nbidder,2} \\ \vdots & \vdots & \ddots & \vdots \\ m_{1,N} & m_{2,N} & \cdots & m_{Nbidder,N} \end{bmatrix} \end{array} \quad (7\text{-}2)$$

The control variables in problem (7-1) are the nodal injections associated with the MW values of FTRs submitted to the auction. A FTR can have either positive or negative depending on whether it is an FTR to be purchased or a FTR to be sold. To insure the final FTRs set is simultaneously feasible, the FTRs not entering the auction should be treated as base case loads and generations in nodal power balancing equality constraints.

To enter the auction, bidders should submit their data to the ISO. These data include the bid prices, points of injection and extraction, minimum and maximum MW values of FTRs. After running the FTR auction, the output includes an optimal set of winning bids of FTRs and the Market Clearing Prices (MCPs) of winning FTRs. The MCP of a FTR is defined by the opportunity cost of that FTR in the auction, i.e. the difference of market prices between the both sides of the FTR. A purchaser of FTR will pay MCP and a seller of FTR will be paid MCP. The revenue from the FTR auction will be allocated to the Transmission Owners (TO) to compensate for their investment on improving the power grid.

7.3 Parallel Flow and Loop Flow

In Section 2.2.2 of Chapter 2, the physical limits of transmission system are analyzed and the Available Transfer Capability (ATC) is defined to be a measure of transfer capability remaining in the physical transmission network. In fact, the capability of the transmission system cannot be described by a single number --- the transmission system does not have a fixed "capacity". At any time, a transmission system has transfer capabilities between any two nodes or any two areas. Transfer capability is the amount of power that can be transferred between the two selected points or areas and still be able to withstand various system contingencies involving the loss of generators, transmission lines or transformers.

Since with very few exceptions, the flow of power over the various lines in an AC network cannot be controlled, this leads to the result that portions of one system's power flowed through other systems' lines. The distribution of power flows over all parts of an interconnected transmission system results in two phenomena.

One is parallel path flow or parallel flow, which is shown in Figure 7.2. Parallel flow occurs when one utility delivers power to another utility. Because of the laws of physics, some of that power flows through the transmission system of the neighboring utilities which parallel the transmission systems of the utilities involved in the transaction. Parallel flows may appear on another utility's system without that utility having any knowledge of the circumstances that gave rise of it. Such parallel flows may easily interfere with the neighboring utility's operation of their own system. On the other hand, a weak parallel link will significantly reduce the transfer capability between two areas. The total transfer capability of a transmission interface does not simply equal to the sigma of the transfer capability of each parallel link in this interface.
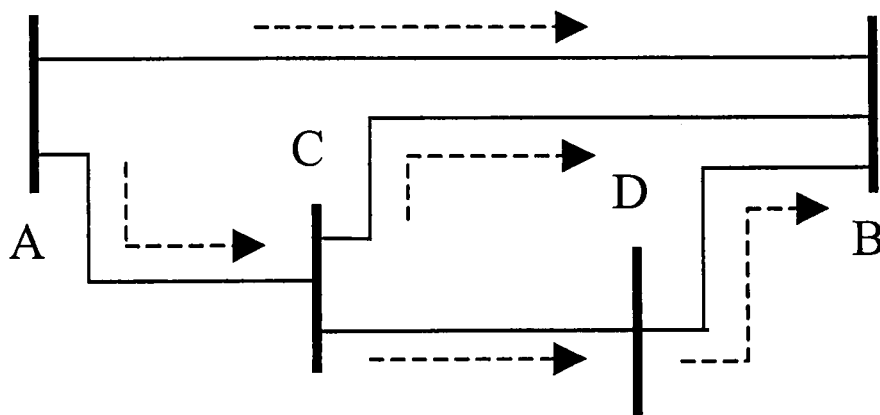

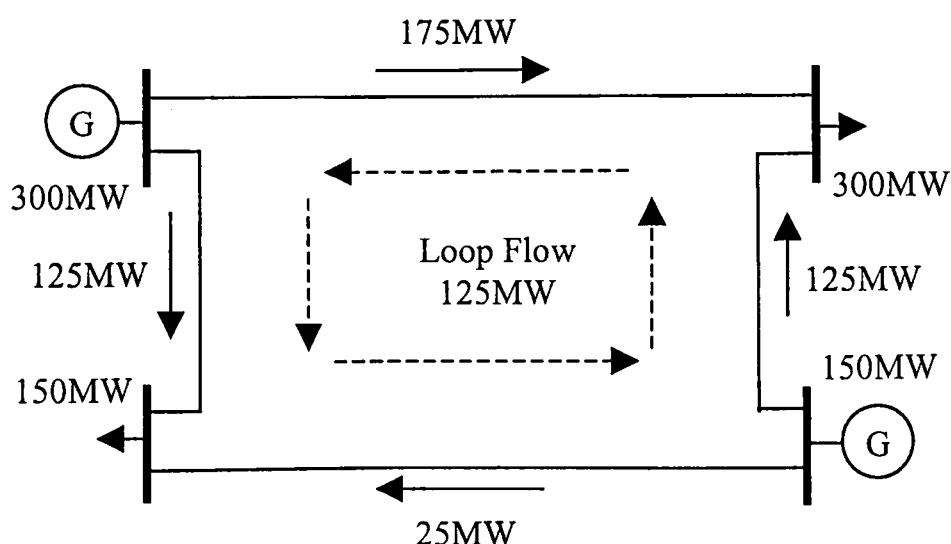Figure 7.2 Example of parallel flows

Figure 7.3 Example of loop flows

The second phenomenon is loop flow which is shown in Figure 7.3. Loop flow involves two or more utilities. Each is supplying its own loads from its own sources. But the actual flows on the system from the combined operations result in the use of transmission in other systems in such a way that there is apparent circulating power flow around a closed loop. Obviously this loop flow is unwanted and will have bad effect on the transfer capability.

Both parallel flow and loop flow make it difficult to define ATC and may even reduce the transfer capabilities of the existing transmission system. One of the most efficient remedies for the problems of parallel flow and loop flow is the application of FACTS devices to transmission system control.

7.4 FACTS Devices and Power Injection Model

7.4.1 Role of FACTS Devices in Electricity Markets

Flexible AC transmission System (FACTS) is defined by the IEEE as "Alternating current transmission systems incorporating power electronic-based and other static controllers to enhance controllability and increase power transfer capacity". The significance of the power electronics and other static controllers is that they have high-speed response and there is no limit to the number of operations. Power devices such as thyristors lead to a variety of FACTS controllers and HVDC converters. These controllers can dynamically control line impedance, line voltage, active power flow and reactive power flow. They can absorb or supply reactive power and when storage becomes economically viable they can supply and absorb active power as well.

There are three basic kinds of FACTS controllers. One kind can be characterized as injection of voltage in series with the line, the second kind as injection of current in shunt and the third kind is a combination of voltage injection in series and current injection in shunt. Then there are controllers based on conventional thyristors (without gate turn-off capability) and those based on gate turn-off thyristors. Basically there are two types of shunt controllers for injection of reactive current, the conventional thyristor based Static VAR Compensator (SVC), and turn-off thyristor based Static Compensator (STATCOM). Their primary function is dynamic voltage control. Similarly there are two types of series controllers for injection of reactive voltage in series, the Thyristor Controlled Series Capacitor (TCSC) and Static Synchronous Series Capacitor (SSSC), whose primary function is dynamic current flow control. Another series controller for phase angle is the Thyristor Controlled Phase Shifter

(TCPS). Then there is one Shunt-Series combined Controller, the Unified Power Flow Controller (UPFC), whose primary function is power flow control. There are also several other controllers which can be found in detail in [4].

The main idea of FACTS devices is to use the network parameters as control variables to direct power flows and eliminate problems caused by unwanted loop flows or parallel flows. The potential benefits brought from this new technology have been found on many aspects, such as congestion management reducing system operation cost, reducing transmission investment, increasing the Available Transmission Capabilities (ATC), and improving system stability and reliability, etc. As discussed in the previous section, the revenue from the FTR auction is limited by the existing network transfer capability. Considering the control of installed FACTS devices in the network during the FTR auction can make better use of the current grid properties, which can bring benefits not only to TOs but also to other market participants.

7.4.2 Power Injection Model of Series FACTS Devices

Generally speaking, there are two types of models of FACTS devices for static power flow control and calculation. The first model is Voltage Source Model (VSM), which is formed in light with the physical operating principles of FACTS devices [170]. VSM is straightforward but will destroy the symmetric characteristics of the network admittance matrix. The second FACTS-model is called as Power Injection Model (PIM), which results from the VSM by interpreting the power injections of the shunt and series converters as real and reactive node injections [165,167,171]. With PIM, FACTS devices can be embedded into power flow equations even without any modification of network admittance matrix and Jacobian matrix [172]. As the DC model is used in this chapter, only two types of series FACTS devices, which are TCSC and TCPS, are discussed here.

7.4.2.1 TCSC (Thyristor Controlled Series Compensator)
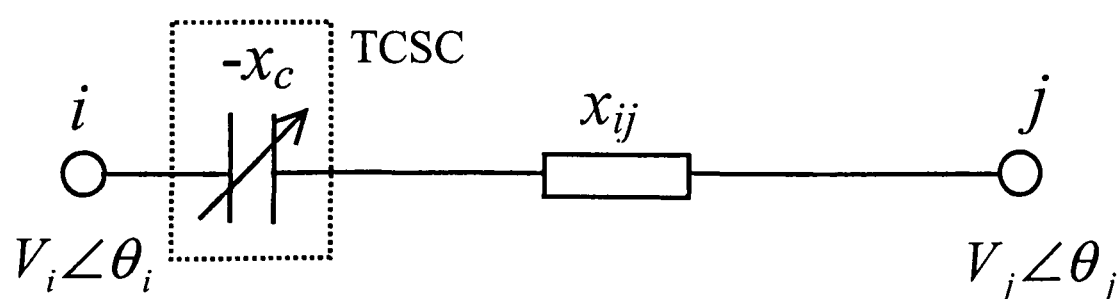
Figure 7.4 Equivalent circuit of TCSC

A transmission line compensated by a TCSC is shown in Figure 7.4, in which the reactance of the line is x_{ij} and the reactance of the TCSC is $-x_c$. The total susceptance between bus i and bus j is formulated as:

$$b_{ij} = 1 \Big/ (x_{ij} - x_c)$$

(7-3)

Based on the DC power flow model, the active power flow along the line ij with a TCSC can be formulated as:

$$P_{ij} = b_{ij}(\theta_i - \theta_j)$$

(7-4)

7.4.2.2 TCPS (Thyristor Controlled Phase Shifter)

Figure 7.5 Equivalent circuit of TCPS

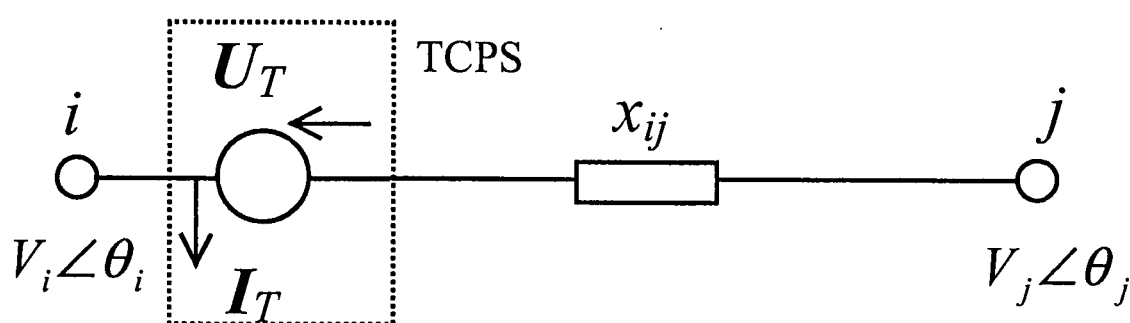The equivalent circuit of a transmission line with a TCPS is shown in Figure 7.5. Given the susceptance of the line $b_{ij} = 1 \Big/ x_{ij}$ and the voltage shift angle ψ of the TCPS, the active power flow along this line is:

$$P_{ij} = b_{ij}(\theta_i - \theta_j + \psi)$$

(7-5)

7.4.2.3 Power Injection Model
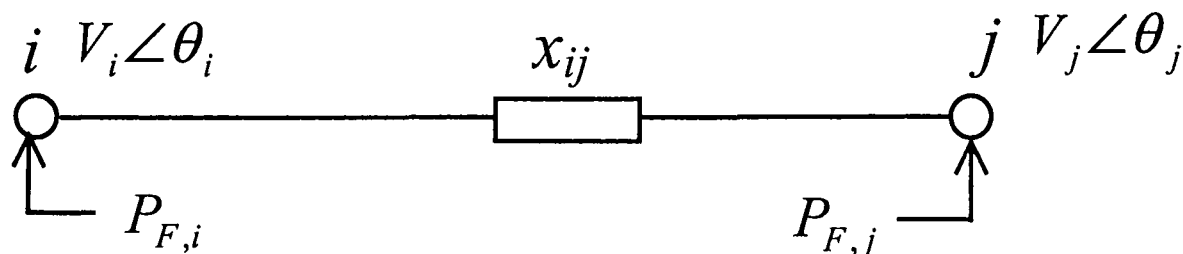
Figure 7.6 Power injection model of TCSC and TCPS

The equivalent circuit of the general PIM of the transmission line with series FACTS devices under the DC assumption is shown in Figure 7.6, in which components associated with FACTS devices have been replaced with two power injections on both sides of the transmission line. The formulae of power injections are different for different FACTS devices. For a TCSC, the power injection can be derived as:

$$P_{F,i} = -P_{F,j} = \frac{-x_c}{x_{ij}(x_{ij} - x_c)}(\theta_i - \theta_j) \tag{7-6}$$

For a TCPS, the power injection can be formulated as:

$$P_{F,i} = -P_{F,j} = -b_{ij}\psi \tag{7-7}$$

Here it should be noted that the value of power injections for a TCSC is a function of not only its reactance but also the difference of voltage angles between two ends of the transmission line. On the other hand, the power injections for TCPS have nothing to do with the state variables of the system.

7.5 The Proposed FTR Auction Model with Series FACTS Devices

The proposed FTR auction model can be seen as an extension of the general FTR auction model presented in Section 7.2, where two additional types of control variables are introduced:

- Angle of TCPS;

- Reactance of TCSC.

In [164-165] where DC power flow model was adopted too, phase shifter angle is replaced by compensation power injection at end buses while series compensation is modelled as variation in circuit reactance. The PIM of TCPS is proved to be no problem but treating circuit reactance as control variable turns the corresponding nodal power balance constraints into non-linear equations. To make the problem still solvable by Linear Programming, a decomposition approach based on Benders decomposition scheme is applied in [164] while in [165] the non-linear power flow control with FACTS devices was solved in a separate sub-problem.

In this chapter a uniform PIM is adopted to represent both TCSC and TCPS to keep the problem linear and to simplify the programming. The mathematical model of the proposed method is formulated based on problem (7-1):

$$Max (b^{FTR})^\dagger FTR$$

Subject to:

$$B\theta - M\ FTR - M_B P_B + M_F P_F = 0 \qquad (7\text{-}8)$$

$$FTR^{min} \leq FTR \leq FTR^{max}$$

$$P_l^{min} \leq H\theta \leq P_l^{max}$$

$$P_F^{min} \leq P_F \leq P_F^{max}$$

Comparing with problem (7-1), power injections associated with FACTS devices have been added into nodal power balance constraints. M_F is the connection matrix for FACTS devices, in which the elements are 1 or -1. The last inequality constraint set is the operating limits for power injections of FACTS devices. To make this model practical, constraints of FACTS internal parameters must be involved. For TCPS, the limits of power injections can be easily derived from the limits of phase shifter angle.

$$P_{F,i}^{min} = -b_{ij}\psi^{max},$$

$$P_{F,i}^{max} = -b_{ij}\psi^{min} \qquad (7\text{-}9)$$

But for TCSC, the limits of power injections are more complex as shown in (7-6). Since there are no fixed limits for power injections of TCSC (though there are fixed limits for x_c), its operating constraints can be formulated as:

$$P_{F,i} + \frac{x_c^{max}}{x_{ij}(x_{ij} - x_c^{max})}(\theta_i - \theta_j) \geq 0 \qquad (7\text{-}10)$$

and

$$P_{F,i} + \frac{x_c^{min}}{x_{ij}(x_{ij} - x_c^{min})}(\theta_i - \theta_j) \leq 0 \qquad (7\text{-}11)$$

After the optimal solution of this problem is obtained, the optimal control parameters of FACTS devices are given in (7-12) and (7-13) for TCSC and TCPS, respectively.

$$x_c^* = \frac{x_{ij}^2 P_{F,i}^*}{-(\theta_i^* - \theta_j^*) + x_{ij} P_{F,i}^*} \qquad (7\text{-}12)$$

$$\psi^* = \frac{P_{F,i}^*}{-b_{ij}} \qquad (7\text{-}13)$$

The proposed FTR optimal auction model with series FACTS devices can be actually represented by problem (7-8) plus internal operating constraints of FACTS devices (7-9 to 7-11). This is a typical linear programming problem, which can be solved easily by the Interior Point Primal-Dual Linear Programming presented in Chapter 3.

7.6 Test Results

To illustrate the proposed FTR optimal auction model, two test systems, which are an 8-bus system and the modified IEEE 30-bus system, are studied.

7.6.1 System I: 8-bus Test System

An 8-bus system, which is modification based on the first test system in [157], is studied to illustrate the proposed FTR auction model. Its network configuration and the FTRs of base case and bidding into the auction are shown in Figure 7.7. The branch parameters and limits and the bid prices of 6 bidders in the FTR auction are given in Tables 7.1 and 7.2. In addition, there are a TCPS installed on Line 6 and a TCSC installed on Line 2. From Figure 7.7 it can be seen that basically the system can be divided into Left zone including buses 1, 5 and 6 and Right zone including the rest buses. The Left zone is generation zone while the Right zone is demand zone. The tie lines between these two zones are Lines 1, 2 and 6.

To demonstrate the impacts of different series FACTS devices on the results of the optimal FTR auction. 4 cases are analysed here:

Case I: FTR auction without FACTS devices;

Case II: FTR auction with a TCSC on Line 2;

Case III: FTR auction with a TCPS on Line 6;

Case VI: FTR auction with both TCSC on Line 2 and TCPS on Line 6.
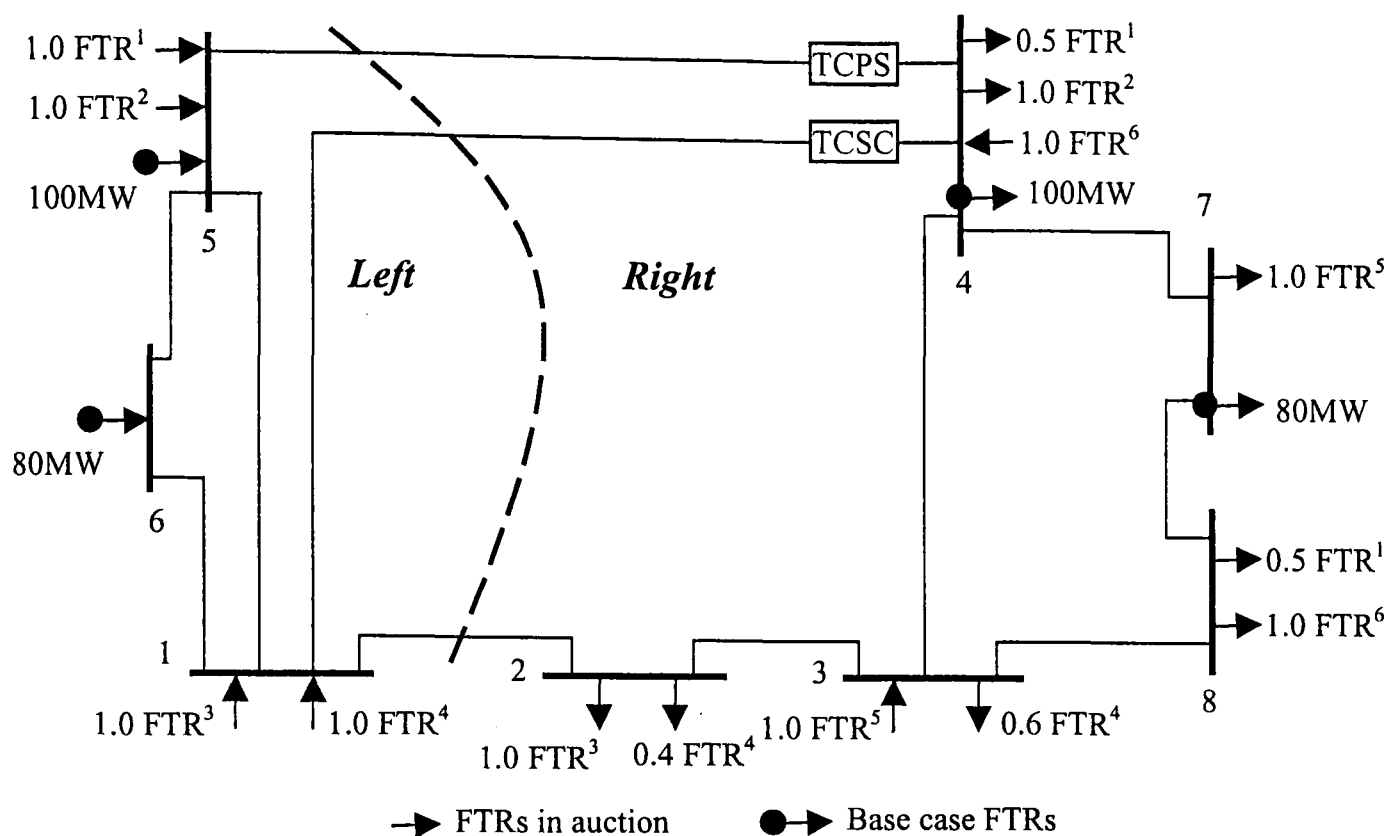
Figure 7.7. The 8-bus test system

Table 7.1 Branch data of the 8-bus system

Line	From Bus	To Bus	Reactance	Limit (MW)
1	1	2	0.0300	150
2	1	4	0.0300	340
3	1	5	0.0065	380
4	2	3	0.0100	120
5	3	4	0.0300	230
6	4	5	0.0300	150
7	5	6	0.0200	300
8	6	1	0.0250	250
9	7	4	0.0150	350
10	7	8	0.0220	340
11	8	3	0.0180	240

147

Table 7.2 Bid prices in FTR auction

Bidder	1	2	3	4	5	6
Bid Price (\$/MW)	12.0	10.0	12.0	11.0	9.0	8.0
FTR^{min} (MW)	0	0	0	0	0	0
FTR^{max} (MW)	200	300	100	175	120	200

The line flows in the results of the FTR auction in 4 cases are shown in Table 7.3. The revenues from FTR auction in 4 cases are given in Figure 7.8. The operating limits and the optimal control parameters of FACTS devices and their corresponding power injection values in Cases II, III, and VI are listed in Table 7.4. In Case I, because of the bottleneck between Left zone and Right zone, not all the FTR bids can be satisfied and the revenue from FTR auction is limited. In Table 7.3, it can be noted that MW flow constraints of Line 1 and Line 6 are bound while Line 2 still has nearly two thirds of its transfer capacity left. To improve the transmission capability between Left zone and Right zone, the TCSC on Line 2 is controllable in Case II while the TCPS on Line 6 is controllable in Case III. The results of both cases are better than Case I. However the TCSC on Line 2, which increases the power flow on Line 2 to 296.58MW from the value of 123.69MW in Case I, has better impact on the FTR auction than the TCPS on Line 6. The reason is that in case III a new binding constraint of line flow (Line 4) occurs.

In Case VI, both installed FACTS devices are controllable in the FTR auction. Obviously this is the best result out of the four cases. From Table 7.3, it can be seen that all the three tie lines have reached their thermal limits in this case. In other words, the total transmission capability between Left zone and Right zone has been fully utilised with the help from both FACTS devices. Compared with Case II, the reactance of TCSC also reaches its maximum value but its power injection value is different from Case II. The reason is that the power injection of TCSC is also a function of voltage angle difference between bus 1 and bus 4, which varies in each case. The results show that the coordination between the two installed FACTS devices works very well. It is due to directly embedding the power injection models of FACTS

devices into the linear programming problem instead of solving the control sub-problems of FACTS devices separately.

Table 7.3 Line flows in 4 cases

| Line	Line Flow in Case I (MW)	Line Flow in Case II (MW)	Line Flow in Case III (MW)	Line Flow in Case VI (MW)	Limit (MW)
1	150.00	150.00	150.00	150.00	150
2	123.69	296.58	220.63	340.00	340
3	-121.44	-236.03	-266.57	-311.98	380
4	50.85	96.64	120.00	52.60	120
5	-43.26	-82.35	30.63	-54.20	230
6	-150.00	-150.00	-150.00	-150.00	150
7	26.90	-10.35	-5.94	0.62	300
8	53.10	69.65	74.06	80.62	250
9	-258.16	-288.56	-195.94	-273.20	350
10	58.16	88.55	-4.06	73.20	340
11	-214.11	-211.44	-209.37	-226.80	240
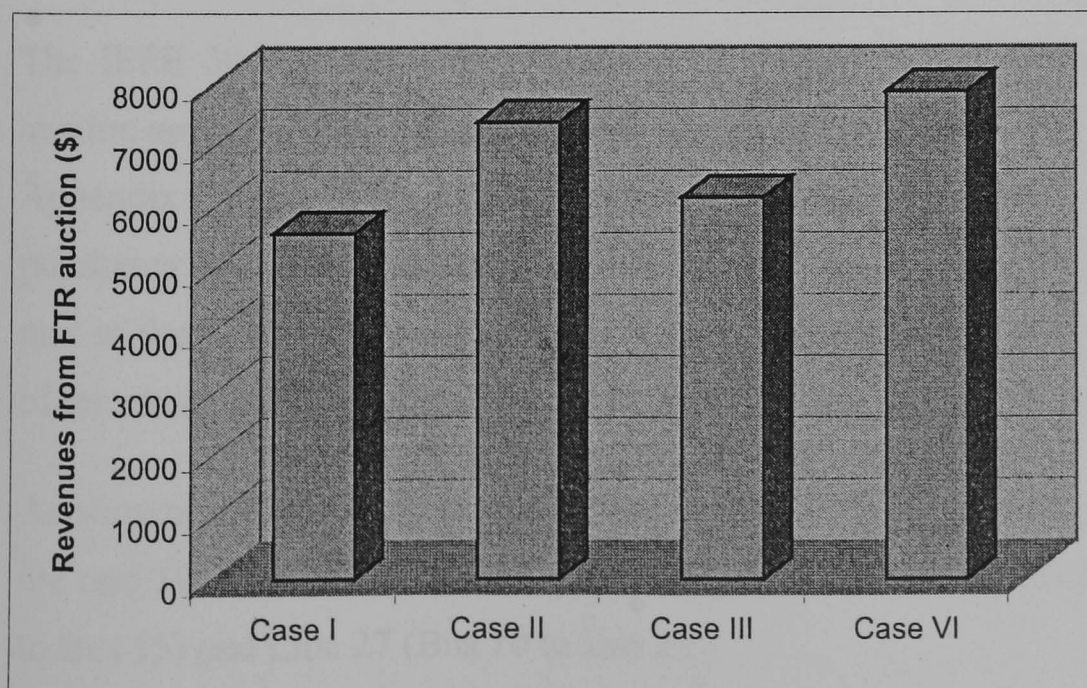
Figure 7.8 Revenue from FTR auction in 4 cases

Table 7.4 Optimal control parameters of the FACTS devices

		Optimal Value	Min Value	Max Value
Case II	x_c of the TCSC	0.02	0.00	0.02
	Power Injection at Bus 1 (MW)	-197.72	-197.72	0.00
Case III	ψ of the TCPS	0.0384	-0.10	0.10
	Power Injection at Bus 5 (MW)	-128.38	-333.33	333.33
Case VI	x_c of the TCSC	0.02	0.00	0.02
	Power Injection of the TCSC at Bus 1 (MW)	-226.67	-226.67	0.00
	ψ of the TCPS	0.0093	-0.10	0.10
	Power Injection of the TCPS at Bus 5 (MW)	-30.93	-333.33	333.33

7.6.2 System II: 30-bus Test System

The IEEE 30-bus test system is modified to give further illustration of the proposed FTR auction approach and its application to a bigger network. The bus and branch data are given in Appendix C. The layout of the system as well as injection and extraction points of FTRs for purchases and sales of different bidders are shown in Figure 7.9. The data of bidders who take part in the FTR auction are given in Table 7.5. Table 7.7 shows detailed base case FTR data of the existing FTR holders who will not participate in the FTR auction.

As shown in Figure 7.9, there are three series FACTS devices installed in the system. They are one TCSC installed on Line 5 (Bus 2 to Bus 5), two TCPSs installed on Line 18 (Bus 12 to Bus 15) and Line 27 (Bus 10 to Bus 21).
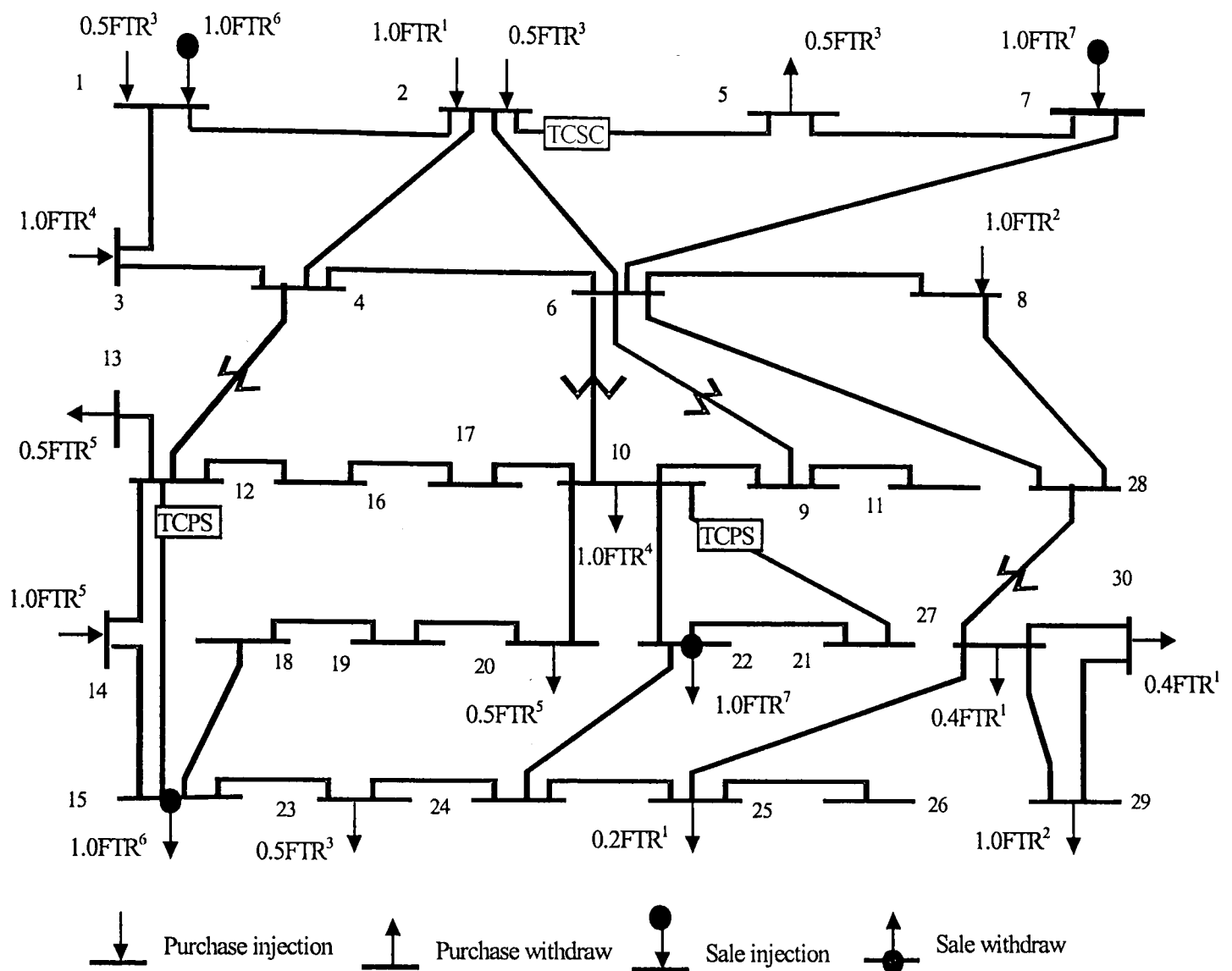
Figure 7.9 The modified IEEE 30-bus system and bidders in FTR auction

Table 7.5 Bidders data in IEEE 30-bus test system

Bidder	1	2	3	4	5	6	7
Bid Price ($/MW)	13.0	10.0	12.0	11.0	9.0	12.5	10.5
FTR^{min} (MW)	0	0	0	0	0	0	0
FTR^{max} (MW)	100	75	120	90	80	70	100

151

Table 7.6 Base case FTRs data in IEEE 30-bus system

From Bus	To Bus	FTR Value (MW)
1	3	95
1	20	5
2	14	30
2	15	30
2	18	20
13	21	20
22	12	34
22	16	6
22	19	10
23	7	30
23	10	20
27	8	5
27	10	15

To demonstrate the impacts of the FACTS devices on FTR auction, two cases will be studied here:

- Case I: FTR auction without any FACTS devices;

- Case II: FTR auction with all the FACTS devices.

The auction results in the two cases, as obtained by solving the auction optimization problems (7-1) and (7-8) respectively, are given in Table 7.7 and Table 7.8. Table 7.7 shows the distribution of FTRs in terms of bidders. Table 7.8 shows detailed FTRs in terms of pairs of injection and withdraw points. Obviously, the auction result of case II is much better than the result of case I, since more FTRs have been traded (purchased or sold) in case II with the help of the three series FACTS devices.

Table 7.7 Auction results in IEEE 30-bus system

Bidder	FTR value in Case I (MW)	FTR VALUE IN CASE II (MW)	FTR^{max} (MW)	FTR Type
1	27.0	45.6	100	purchase
2	16.1	11.9	75	purchase
3	120	120.0	120	purchase
4	0.0	85.4	90	purchase
5	0.0	0.0	80	purchase
6	58.5	56.3	70	sale
7	4.3	30	100	sale

Table 7.8 Auction results in IEEE 30-bus system in terms of injection and withdraw points

From Bus	To Bus	FTR value in Case I (MW)	FTR value in Case II (MW)	Bidder
2	25	5.4	9.12	1
2	27	10.8	18.24	1
2	30	10.8	18.24	1
8	29	16.1	11.9	2
1	5	60.0	60.0	3
2	23	60.0	60.0	3
3	10	0.0	85.4	4
14	13	0.0	0.0	5
14	20	0.0	0.0	5
1	15	58.5	56.3	6
1	22	4.3	30.0	7

Table 7.9 Branch flows of FTR auction results of IEEE 30-bus system

Branch No.	From Bus	To Bus	MW Flow in Case I	MW Flow in Case II	MW Flow Limit
1	1	2	28.15	47.89	130
2	1	3	73.32	55.83	130
3	2	4	64.13	53.75	65
4	3	4	-21.68	46.19	130
5	2	5	66.00	114.74	130
6	2	6	65.00	65.00	65
7	4	6	7.74	51.28	90
8	5	7	6.00	54.74	70
9	6	7	28.34	5.26	130
10	6	8	-5.73	0.82	32
11	9	6	-22.97	-53.39	65
12	6	10	13.14	30.54	32
13	9	11	0.00	0.00	65
14	9	10	22.97	53.39	65
15	12	4	-34.71	-48.66	65
16	12	13	-20.00	-20.00	65
17	12	14	14.62	32.00	32
18	12	15	5.24	-14.78	32
19	12	16	0.85	17.44	32
20	14	15	-15.38	2.00	16
21	16	17	-5.15	11.44	16
22	15	18	16.00	16.00	16
23	18	19	-4.00	-4.00	16
24	19	20	-14.00	-14.00	32
25	10	20	19.00	19.00	32
26	10	17	5.15	-11.44	32
27	10	21	-12.00	-12.00	32
28	10	22	-11.03	-32.00	32
29	21	22	-32.00	-32.00	32
30	15	23	2.38	-2.49	16
31	22	24	11.30	16.00	16
32	23	24	-7.62	-12.49	16
33	24	25	3.69	3.51	16

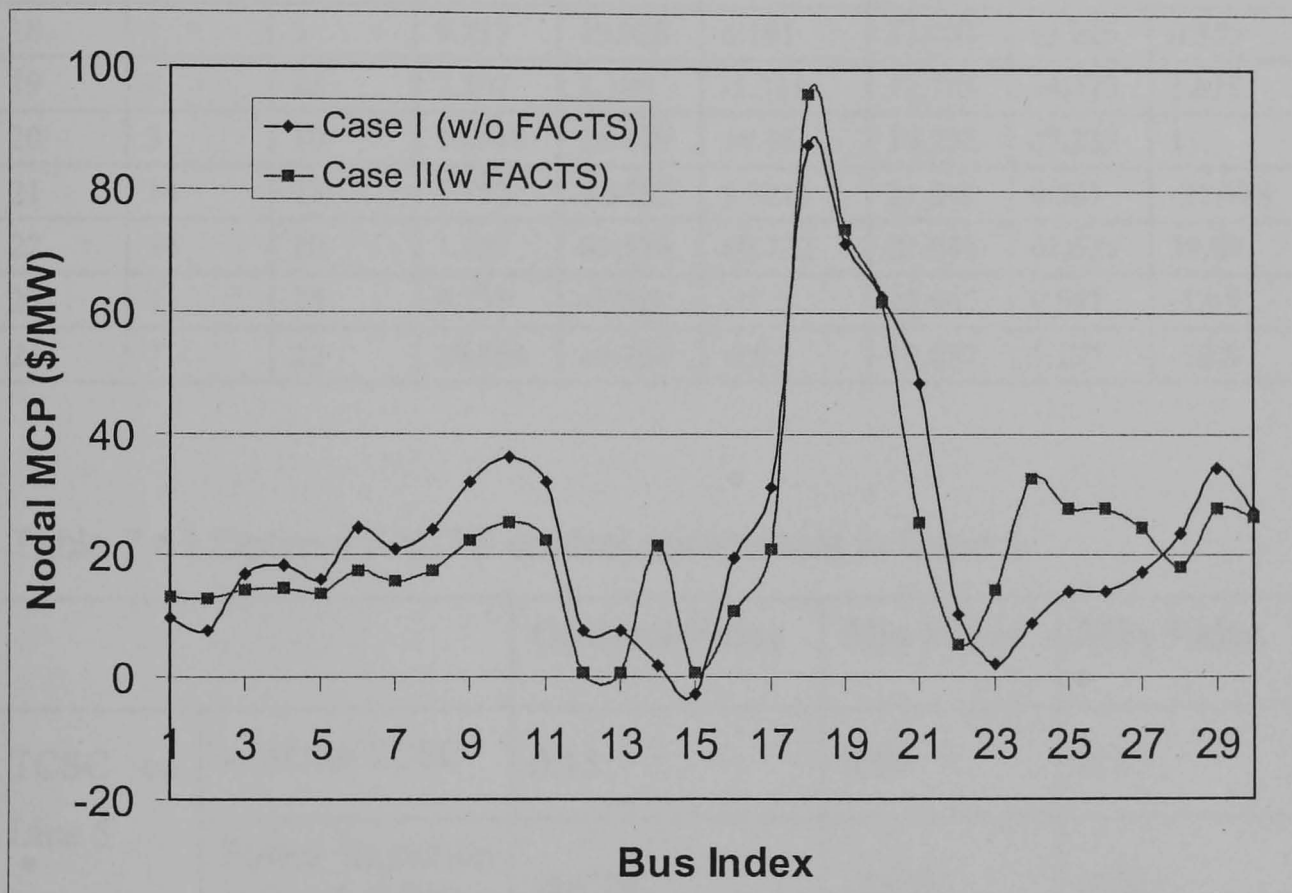| Branch No.	From Bus	To Bus	MW Flow in Case I	MW Flow in Case II	MW Flow Limit
34	25	26	0.00	0.00	16
35	25	27	-1.71	-5.61	16
36	28	27	19.42	33.97	65
37	27	29	16.00	16.00	16
38	27	30	10.92	14.12	16
39	29	30	-0.13	4.12	16
40	8	28	5.40	7.70	32
41	6	28	14.02	26.28	32

Figure 7.10 Nodal MCPs in the results of two cases

Table 7.10 MCPs of all the feasible FTRs in two cases

FTR No.	From Bus	To Bus	Case I			Case II			FTR TYPE
			MCP_i	MCP_j	MCP of FTR	MCP_i	MCP_j	MCP of FTR	
1	1	3	9.737	16.919	7.182	13.067	14.232	1.165	Basecase
2	1	2	9.737	7.507	-2.23	13.067	12.705	-0.362	Basecase
3	2	14	7.507	1.757	-5.75	12.705	21.645	8.94	Basecase
4	2	15	7.507	-2.763	-10.27	12.705	0.567	-12.138	Basecase
5	2	18	7.507	87.485	79.978	12.705	95.984	83.279	Basecase
6	13	21	7.578	48.283	40.705	0.567	25.232	24.665	Basecase
7	22	12	10.354	7.578	-2.776	5.337	0.567	-4.77	Basecase

155