Power System Energy Imbalance Settlement in Deregulated Electricity Market

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by

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Declaration of Author's Right

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GLOSSARY OF TERMS

The terms considered in this section are defined and explained in the context of this thesis and may not agree with the general understanding in other research areas.

AGC	Automatic Generation Control
AI	Artificial Intelligence
ANN	Artificial Neural Network
ARR	Auction Revenue Rights
AS	Ancillary Service
ATC	Available Transfer Capability
BM	Balancing Mechanism
CFD	Contracts for Difference
CM	Congestion Management
DG	Distributed Generator
EMS	Energy Management System
E&W	England and Wales
FERC	Federal Energy Regulatory Commission
FPN	Final Physical Notification
FTR	Financial Transmission Rights
GIS	Geographic Information System
ISO	Independent System Operator
LMP	Locational Marginal Pricing
LODF	Line Outage Distribution Factor
LOLP	Loss of Load Probability
LSEs	Load serving entities
MCP	Market Clearing Price
MSS	Multi Settlement System
NEM	The National Electricity Market In Australia

NETA	The New Electricity Trading Arrangements in the UK
NGC	National Grid Company
OPF	Optimal Power Flow
PJM	Pennsylvania-New Jersey-Maryland
PPP	Pool Purchasing Price
PSP	Pool Selling Price
PTDF	Power Transfer Distribution Factor
RMCP	Regulation Market Clearing Price
RTM	Real-Time Market
RTO	Regional Transmission Organizations
RTED	Real-Time Economic Dispatch
SBP	System Buy Price
SFT	Simultaneous Feasibility Testing
SMD	Standard Market Design
SMP	System Marginal Price
SPD	Scheduling, Pricing and Dispatch
SSP	System Sell Price
UIE	Uninstructed Imbalance Energy
VOLL	Value of the Lost Load
ZMP	Zonal Marginal Price

Contents

List of Figures

List of Tables

ABSTRACT

In regulated electricity market the difference between forecast demand and actual demand is balanced by additional generation from the cheapest available source after network security is taken into consideration. The electricity price to supply this difference in demand forecast error is already pre-fixed through the bulk supply tariff. In deregulated market many of the current market structures rely on bilateral contracts for trading. This means that the amount of electricity purchased is pre-determined with the price or pricing method specified in the contract. In the event that the forecast does not agree with the actual demand, the difference is taken from the balancing market. The price for this difference in energy is not known until after the event. The financial settlement for this imbalance energy is different from the normal contract settlement. In the ideal case the imbalance should be zero but this is almost impossible as the contracted values are usually based on demand forecasts and which contain errors. The imbalance settlement thus depends very much on the electricity prices of the real time balancing market, and also on the structure of the balancing market which could be different from one country to another and could even be different for different markets within the same country.

This thesis begins by reviewing the 5 typical electricity markets (UK, US, Australian, New Zealand and Argentina) in the world on aspects of dispatching method, trading inside the Pool and trading outside the Pool. The existing arrangement, balance & imbalance settlement method of each electricity market will be presented. The IEEE 30-bus system will be taken as the illustrate example, detailed comparison of total revenue income and load total payment has been conducted among the different settlement systems of each electricity market.

Although some of these methods are very reliable and have been used extensively, as the limitation of the fuel and development of the renewable source, the Distributed Generator (DG) access, they may not be economical given the probability of

contingencies and changes in the market environment. As a new application, a Dual use of electricity storage method is proposed to solve the imbalance settlement problem. The Dual Use Distributed Generator (DUDG) could access the real time market for balancing the errors from the demand forecast, no matter the demand increases or reduces, with a reasonable price both for generation side and the distribution side.

Chapter 1 Introduction

1.1 Research Motivation

The imbalance settlement problem is becoming more and more important as the developing of the deregulated electricity market. This thesis aims to improve the economy of the imbalance settlement in the electricity market. Many electricity industries worldwide are in a state of flux due to the global trend in privatization, unbundling and deregulation of some sectors in the industry. At the turn of the 20^{th} century, electricity generating companies were segregated and mainly supplied consumers in their immediate environment through their own distribution networks [1]. As technology evolved and the ability to transmit power over large distances was made possible, transmission elements were put in place to take advantage of cheaper electricity generated elsewhere or for interconnectivity purposes. These transmission elements were expensive and usually put in place by a central body (or government) for the social welfare and development of the state. Later on, many of the independent generators then became part of the said centralized body, which also dealt with transmission, and distribution of electricity. This arrangement worked well in the formation of the electricity network as it has brought to bear taxpayers money to enhance generation capability and reinforce the electricity networks. In the UK environment, this arrangement continued well into the 1980’s.

However, the centralized electricity body was perceived by many to exhibit inefficiencies, which affect its ability to reduce cost to consumers. Restructuring and privatization was the buzzword in the late 1980’s and its purpose was to establish mechanisms which can optimize existing resources, guarantee prudent and future investments whilst lowering costs to consumers. These were the main motivations for the privatization and deregulation of the electricity industry.

1.2 Models of the Electricity Industry

There are four basic models that can be applied to structure/restructure an electricity industry [2]. These models can also be loosely interpreted to show the evolution from the basic regulated model to a fully fledged electricity market model. The least advanced deregulated model is Model 1 and the most advanced is Model 4.

1.2.1 Model 1 - Fully Regulated Model

This model indicates the most common electricity industry structure prior to deregulation. In this model, no competition occurs and customers have no choice but to purchase electricity from their own local utility. The utility has full control and is responsible over all sectors of generation, transmission and distribution within its control area. Figure 1.1 indicates an integrated utility which fully owns generators (Genco), transmission (Transco and Gridco) and distribution (Distco) sectors.

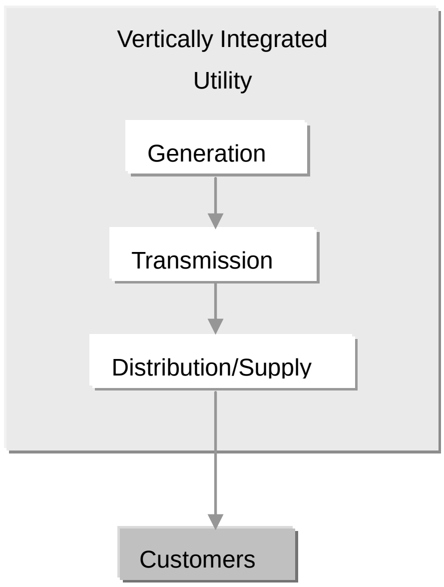

Figure 1. 1 Model 1 – Monopoly in the Electricity Industry [1, 2]

1.2.2 Model 2 – Purchasing Agency Model

In the model shown in Figure 1.2, a single buyer or the sole purchasing agency, will buy power from its own generators or the independent power producers (IPPs) and stimulate competition between the generators. IPPs will usually have a Power Purchase Agreement (PPA) with the purchasing agency. The PPA includes capacity payments to ensure that the capital costs of the generators are covered and an energy cost to cater for the variation of demand during plant operation. The purchasing agency can be the Transco itself and has no competition. It then sells the power to distribution companies which have no choice but to buy from the purchasing agency. There is no competition on the retail side either.

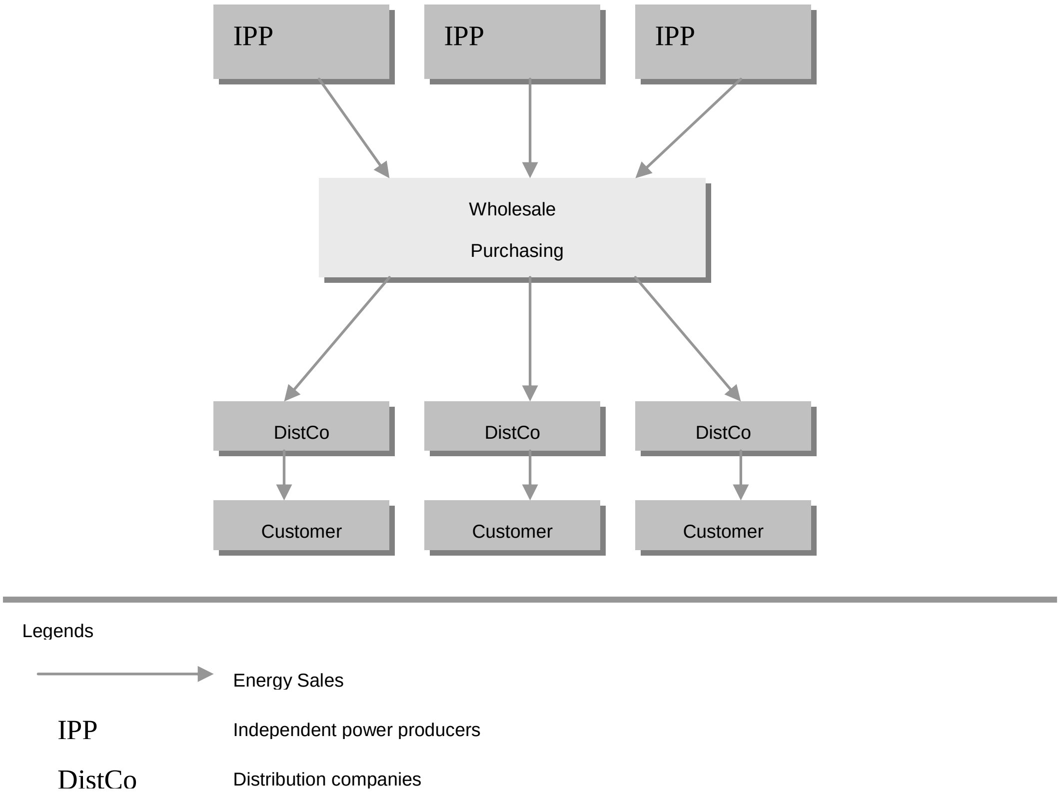

Figure 1. 2 Model 2 – Single Buyer/Purchasing Agency Model[2,3]

1.2.3 Model 3 – Wholesale Competition Model

Figure 1.3 shows the wholesale competition model. In this model, the transmission network is open to all parties. This allows generators to compete and sell their electricity directly to any distribution companies and brokers or offer it in a power exchange. The transmission company no longer deals with buying and selling electricity and is now focused on facilitating the power flow between IPPs and distribution companies. In turn, the company collects payments from the generators and distribution companies for using their transmission facilities and services. Distribution companies in this phase have the dual role of operating the distribution network and selling electricity. The latter role requires distribution companies to shop around and get the best deals from generators. This has prompted the growth of brokers and power exchanges, which can facilitate further competition. If necessary, distribution companies can also agree on long-term contracts, which can stabilise the price of their electricity purchases. Wholesale competition can further liberalise the market and bring down wholesale electricity prices.

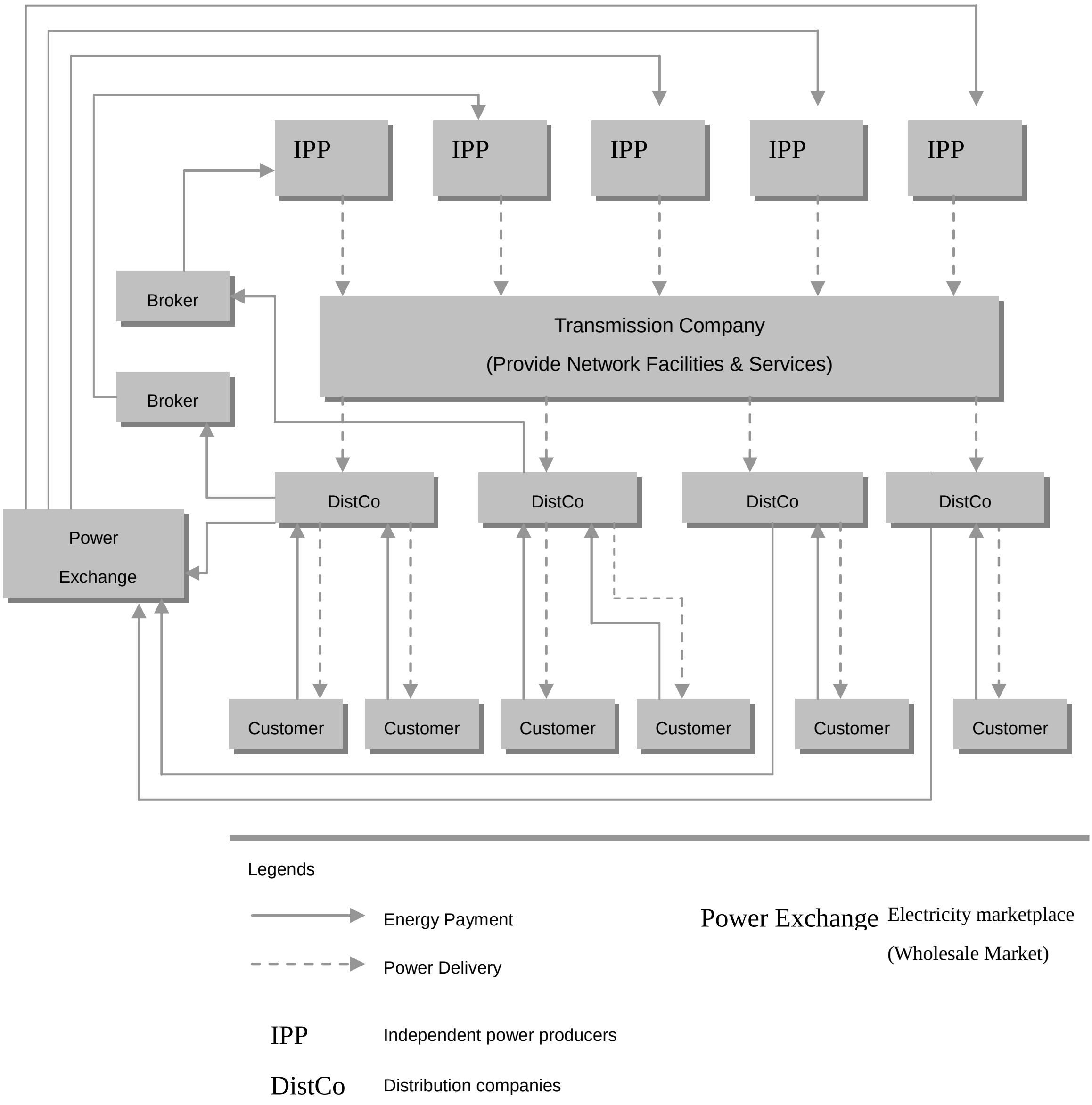

Figure 1. 3 Model 3 – Wholesale Competition [2,3]

1.2.4 Model 4 – Retail Competition Model

The model shown in Figure 1.4 is the most advanced model of electricity deregulation. This model is an extension of the wholesale competition model, but in this model, access to both transmission and distribution is open to all parties. This effectively limits distribution companies to network operation functions, and allows customers to select their own supplier, SupplyCo, rather than being constrained to their local distribution company (as was in the wholesale competition model). This results in the development of the supply sector, which only deals with buying electricity from brokers, generators, or power exchanges. The retail competition model represents the final phase of electricity deregulation and can be seen to open up the market considerably. All in all, deregulation has changed the way the electricity supply industry operates its network, the market and the way electricity companies think and strategise.

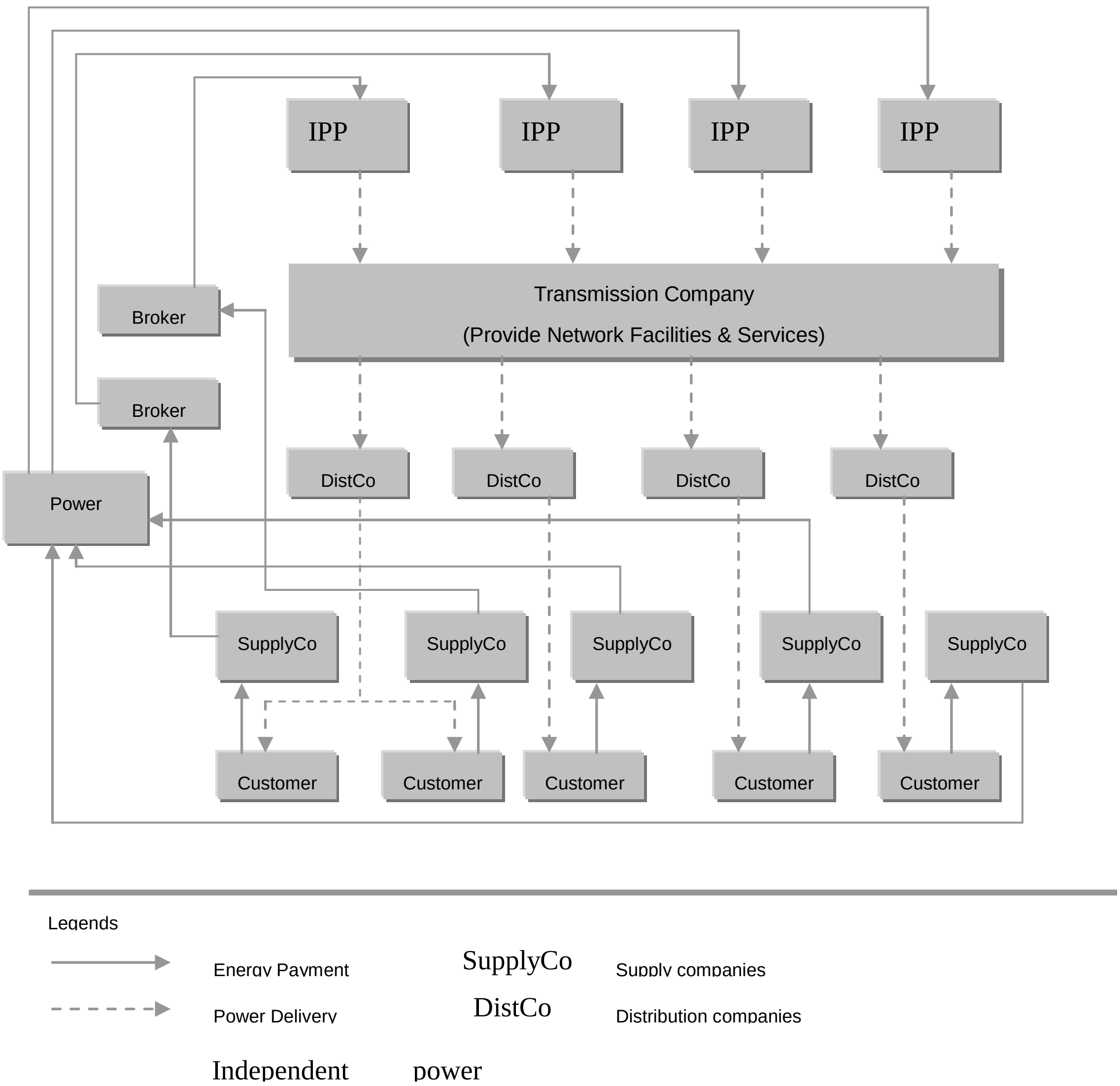

Figure 1. 4 Model 4 - retail competition [2,4]

1.3 Trading methods and imbalance settlement

There are several different types of trading methods and imbalance settlement methods in the world. This thesis takes the UK, US PJM, Australian, New Zealand

and Argentina electricity market trading method as example, will discuss the market structure, the price mechanism, and the energy imbalance settlement method.

Generally speaking, there are three main kinds of pricing mechanism and the theoretical concepts, the Uniform price, Zonal Marginal Price, Locational Marginal Price. The nodal pricing is formulated using security constrained optimal power flow dispatch while the uniform pricing is formulated without considering the effect of physical laws and line-flow limits as well as the Zonal pricing. Early electricity spot market designs are based on uniform pricing such as old UK Pool market. However, several of these markets have moved to nodal pricing or to Zonal pricing for a more efficient, fair and non-discriminatory and transparent mechanism in a competitive market environment.

1.4 Objective of the thesis

Inspired by the above incentive in the restructuring power industry, the following objectives have been chosen for the research work in this thesis:

- ♦ To review and analyze world experiences on various electricity market designs, including energy, ancillary services, and generation capacity market structures.
- ♦ To investigate and compare the imbalance settlement schemes and the associated pricing mechanisms utilized by main electricity markets in the world.
- ♦ To conclude the different imbalance settlement pricing calculation methods by the same illustrate system, and comparison the results by total revenue income and total load payment
- ♦ To model dual use of distributed generator access to power system to balance the imbalance energy, and its advantage to the system price.

1.5 Main Original Contribution

Based on the objectives above, this research has analyzed the issues on the deregulated electricity market design, pricing mechanism, imbalance settlement method, imbalance price on different load forecasting uncertainty, and power contract portfolio management. A deep investigation has been performed in the area of electricity system economics. The main original contributions of this thesis can be stated briefly as follows:

- ♦ A valuable analysis and comparison on imbalance settlement schemes, namely uniform, nodal and zonal market is reviewed. A comparison is made on various major markets in the world. This could help market designers to have better understanding and improve their energy imbalance settlement system and provide a better pricing approach.
- ♦ A detailed explanation and a study of major worldwide electricity market structure, pool and price mechanism are provided. This could provide a better understanding on how each imbalance price is calculated.
- ♦ Based on a sample system Total Genrator Income and Total Load Payment by different imbalance price has been made. It includes different types of imbalance price, different results of Total Geneator Income and Total Load Payment caused by the different imbalance pricing method.
- ♦ A new possible solution to power system energy imbalance base on dual use of generators is proposed with supporting results.

1.6 Thesis organization

This thesis is made up of eight chapters. They are organized as follows:

Chapter 1 presents the research motivation, objectives, and main contributions in this thesis.

In chapter 2, the design features of the UK electricity markets are discussed. It reviews the basic features of energy market designs, the responsibilities of the Balancing Mechanism and the bilateral contract for market power. In addition to energy markets, this chapter also introduces two types of energy imbalance settlement system the POOL system and the NETA system, case study will be included to illustrate how the imbalance settlement system work and how the imbalance price SBP and SSP come out.

Chapter 3 will introduce the US PJM energy imbalance settlement method. This Chapter discusses the concept of the locational marginal pricing used in the PJM electricity market. An example will be used to illustrate the locational marginal pricing methodology based on energy settlement system. Issues of imbalance settlement by locational marginal pricing are addressed at the end of the chapter.

Chapter 4 focuses on the imbalance settlement method of Australian's NEM. The calculation methods of zonal marginal price will be introduced. The 6-bus system will be the case study to illustrate the zonal marginal pricing methodology based on NEM imbalance settlement method.

Chapter 5 is a worldwide review, will present the New Zealand and Argentina as the typical electricity market. The structure and market design of the two countries will be described. The nodal marginal price is the settlement method of the two countries, same as the LMP， the imbalance settlement theory is the same as mentioned in Chapter 2, the PJM electricity market.

Chapter 6 calculates the imbalance energy price by three different types of price mechanism, uniform price, locational marginal price, and zonal marginal price. The total actual load is calculated by random ±2% ±5% ±8% ±10% ±20% of the forecasting load. The generator income and generator total revenue income of each scenario will be calculated; the load payment and load total payment will be calculated. The comparison will be made by the results, the effect of different imbalance settlement methods will be concluding.

Chapter 7 will introduce an application of imbalance settlement. A Dual use of electricity storage method is proposed to solve the imbalance settlement problem. The Dual Use Distributed Generator (DUDG) could access to the real time market for balancing the errors from the demand forecast, no matter the increased demand or the reduced demand, it could provide system participants with an index for trading economic benefits. The 7-Bus system will be used as the illustrate example, the system will be simulated by the POWERWORLD software.

Chapter 8 summarizes the conclusions and major contributions of this thesis, and possible future research works.

1.7 Publication

The following publications have been published or are under preparation for submission as a result of the research work reported in this thesis:

1. Mingming Zhang, K.L.LO, 'A comparison of imbalance settlement methods of electricity markets' The 44th International Universities Power Engineering Conference (UPEC) 2009, Print ISBN: 978-1-4244-6823-2.
2. Mingming Zhang, Zuhaina Zakaria, K.L.LO; ' Research On Load Profiling in Power System Operation' China International Conference on Electricity Distribution, CICED, Beijing, China, 17 - 20 Sept. 2006, TS6-11
3. Mingming Zhang, Lo, K.L.; 'Long Term Energy Scenario for China' Power and Energy Engineering Conference (APPEEC), 2010 Asia-Pacific, Digital Object Identifier: 10.1109/APPEEC.2010.5448591 Publication Year: 2010 , Page(s): 1 - 7 IEEE Conferences
4. Mingming Zhang, K.L.Lo; 'Application of Dual Use Energy Storage Generator on Imbalance Settlement Problem' under preparation
5. Mingming Zhang, K.L.LO; 'The Practice of Energy Imbalance Settlement in China Future Electricity Settlement System', under preparation

1.8 References

[1] K.L.Lo, 'Power Markets and System Economics', MSc Course Notes, University of Strathclyde, 2004

[2] Hunt, Helen and Shuttleworth, Graham, 'Competition and Choice in Electricity', John Wiley&Sons, 1997

[3] Dr. Carlos Arturo Lozano Moncada's PhD Thesis On ' Game Theory Application

to the Analysis of Wheeling Charges Allocation and Bidding Strategies', Power System Research Group, Strathclyde University
[4] Salla ANNALA and Satu VIUAINEN, 'The Impact of Retail Electricity Market Model on Competition' 20th International Conference on Electricity Distribution Prague, 8-11 June 2009 Paper 0499

Chapter 2 Imbalance Settlement in UK Deregulated Power Market

2.1 Introduction

Over the last twenty years, commencing with England & Wales and followed by Norway, major west European countries have restructured their electricity industries to introduce competition. A common feature in all west European countries is that the transmission asset owner is also the SO (System Operator). In all countries except Germany and France the transmission system operators are stand alone corporate entities completely independent of generation and retail. Some are privately owned companies and some have stock market quotations, while the others are publicly owned.

In the UK electricity market, before the electricity industry privatization in 1990, England and Wales use the vertical integration mode of operation. With the privatization of the electricity, the POOL electricity market starts to operate in England and Wales. As the design of Pool, all the electricity trading should be inside the Pool. From the year 1998, the UK government introduces the retail market. In the retail electricity market, allow the consumers to choose any electricity suppliers, so there is a great competition in the sale of electricity side. Pool is a day-ahead market, so the wholesale electricity prices were identified day-ahead. On the day of trading, the NGC (National Grid Company) as the SO is responsible for real-time dispatching, to balance the energy between generation and demand. After eight years operation of the Pool system, from the year of 1998, the UK government decided to develop a new trading arrangement based on the experiences derived from the Pool system. In the year 2001, the NETA (New Electricity Trading Arrangement) officially started to be operated. NETA system is a bilateral market with demand side participants. It has the BM (Balancing Mechanism) which could arrange the balancing settlement and reduce the energy imbalance cost.

The following sections of the chapter will discuss the market structure of the two arrangements in detail, and also their settlement methods, a case study will be given for each arrangement.

2.2 Deregulation of the Electricity Market

Many electricity industries worldwide are in a state of restructuring due to the global trend in privatization, unbundling and deregulation of some sectors in the industry. At the turn of the 20^{th} century, electricity generating companies were segregated and mainly supplied consumers in their immediate environment through their own distribution networks [1]. As technology evolved and the ability to transmit power over large distance were made possible, transmission elements were put in place to take advantage of cheaper electricity generated elsewhere or for interconnectivity purposes. These transmission elements were expensive and usually put in place by a central body (or government) for the social welfare and development of the state. Later on, many of the independent generators then became part of the called centralized body, which also dealt with transmission, and distribution of electricity. This arrangement worked well in the formation of the electricity network as it used taxpayers' money to enhance generation capability and reinforce the electricity networks. In the UK environment, this arrangement continued well into the 1980's.

Deregulation has resulted in the breakdown of the three core power industry sectors which are generation, transmission and distribution. These are now has a 4^{th} sector which concentrates on retail and is at the front end of electricity selling. In each sector, deregulation has divided generators into many smaller companies that compete to sell electricity in the wholesale market. However, the wires business is still a monopoly where the transmission and distribution network are still run and maintained by a single national entity for the transmission's case in England and Wales (E&W) and local distribution companies covering only their franchise area.

Deregulation has made companies involved in the buying and selling of power more competitively. It has also created other economic activities such as the power exchange where brokers and agents can represent generators or supply companies to acquire power. In some markets of the United States, there are also scheduling co-coordinators who buy and sell transmission rights to facilitate the sale of power. In the UK England and Wales systems, the National Grid Transco (NGT) is solely responsible for the transmission co-ordination and operation fall under the SO activity whilst the maintenance of the grid assets is the responsibility of the grid owner.

It may appear that deregulation is the way forward for all electric utilities in the world but the approach to dismantle a large organization financially and technically is a serious undertaking. Each integrated utility is unique as they have different regulatory framework due to their historical and technical differences. While some integrated utilities can be broken down, have applied certain markets rules and became successful, the same approach may fail in another power system.

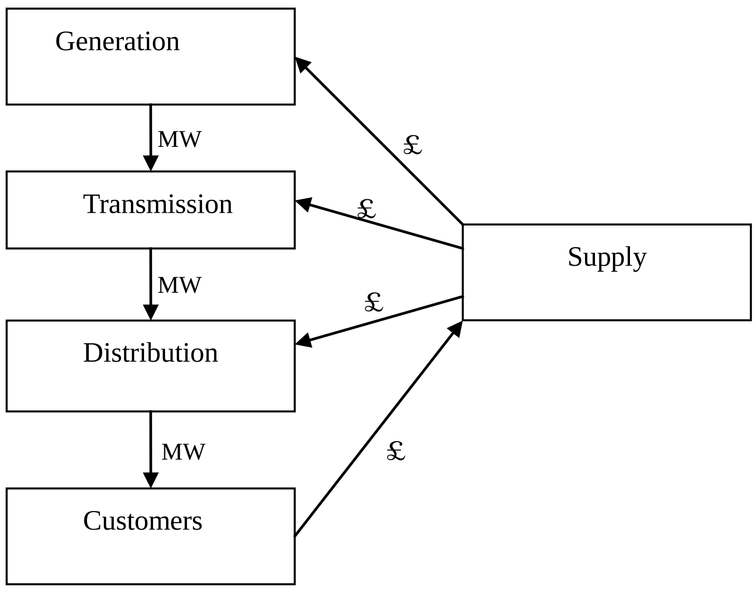

Figure 2. 1 Electricity Supply Industries

The diagram in the figure 2.1 shows a generic representation of the deregulated electricity market. Each block shows a sector in the electricity industry. MW arrows indicate physical power flow. Power flow from the generators to the customers is via the transmission and distribution sector which is known as the ‘wires businesses in the electricity supply industry. Companies in the transmission and distribution sector do not compete in the power market but collect a toll, based on a formula devised by a regulator, on the power that passes through their system. Competition for customers occurs in the generation and supply sectors.

The £ arrows show the financial flow of the deregulated electricity industry. Revenue in collecting from the customers by the supply companies, who in turn will pay for the power bought from the generator, the services rendered by the transmission and distribution entities. In certain cases, companies may own more than one sector (e.g. generation and supply) if it maintains the equitability of the market and is approved by the regulator. In other cases, the customer may be a large power consumer and can deal directly with the generator. In this case, it bypasses the supply company and will negotiate with the generators directly and to procure power.

2.3 UK Electricity Market Design

A POOL system been operated for eight years from 1990 to 1998 in UK. NETA has replaced the mandatory POOL arrangement since 27 March 2001 after 3 years of development. It was introduced to overcome some of the fundamental weaknesses of the wholesale electricity trading arrangement under the POOL. The major role of NETA programme is to develop a contract-based market and to provide a mechanism for near real-time clearing and settlement of the imbalance between contractual and physical positions.

The key function of the NETA is the bilateral contracts, which share the imbalance cost among the participants. Figure 2.11 in section 2.8.1 shows the period structure of the NETA and BETTA which is currently used in UK.

During the early years of implementation of the E&W Pool System, there were relatively few generation companies in the market and they exercised what was termed ‘market power’. This means that in the absence of sufficient credible competitors, they can manipulate the prices of electricity due to the ability of all generators to receive the PPP. Some generators bid a very low price or even ‘0’ for the selling price of their electricity to ensure dispatch inclusion by being at the bottom part of the stack and still get paid SSP. This has resulted in inefficiencies as the price that buyers pay is the marginal price rather than the actual price of the bid. On the generator side, some base load generators with lower generating cost are getting the benefit of the higher price quoted by more expensive peaking plants.

2.3.1UK Electricity Market Structure

In the long-term forward and short-term spot market, most bilateral trades of electricity for physical delivery conducted over the counter (OTC) and power exchanges respectively. The power exchange acts as a neutral and reliable power contract counter-party to market participants, and offers the spot market for market participants to “fine tune” their contract positions for each half-hour. By gate closure, generators and suppliers are required to notify the SO, the National Grid Company, of their expected outputs and demands, which is termed the Final Physical Notification (FPN). They may also submit offers and bids indicating their ability to deviate from their FPN, and the payments they would require for such changes.

At the core under NETA are the Balancing Mechanism and Imbalance Settlement processes. During the Balancing Mechanism period, the SO balances actual demand and generation by accepting appropriate bids and offers. Figure 2.2 shows the bids and offers of a simplified generator and demand of the BM unit. Offer means BM unit wished to operate at a higher level than FPN, and bid means a BM unit is willing to operate at a lower level than FPN. If the SO wish to raise the total power transmits to the system, it will accept the offer from the BM unit. If this is a generator BM unit, the BM unit should raise the power output level; and if this is a demand BM unit, the BM unit should reduce the power input level. Likewise, if the SO wishes to reduce the total power transmitting to the system, it will accept the bid from the BM unit. If this is a generator BM unit, the BM unit should reduce the power output level; and if this is a demand BM unit, the BM unit should raise the power input level. In the real operation, under a certain exchange period, a BM unit allows having several bids and offers in one time. [2]

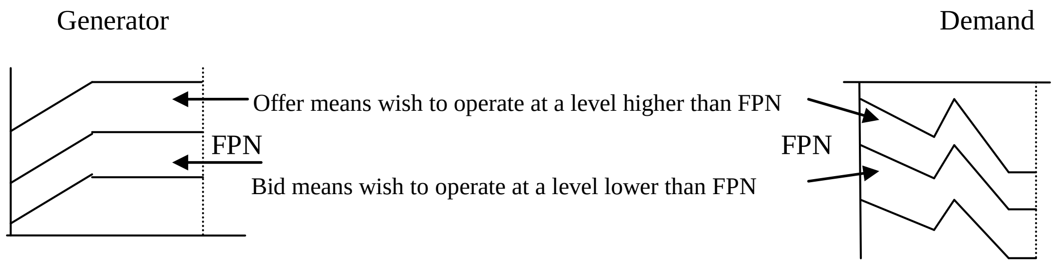

Figure 2. 2 Bids and Offers

2.4 Regulator in the UK OFGEM

Ofgem is short for the Office of Gas and Electricity Market. It was established to promote competition among companies in the electricity industry and protect the interests of gas and electricity customers. It aims to achieve that by producing sound policies which can influence companies to give choice and value to all gas and electricity customers. Ofgem is in charge of overseeing and regulating the gas and electricity industries in the UK. Its powers are provided for under the Gas Act 1986, the Electricity Act 1989 and the Utilities Act 2000 [3].

Ofgem promotes competition in all parts of the gas and electricity industries by creating the conditions which would allow companies to compete fairly and enable customers to make an informed choice between suppliers. Ofgem is empowered to grant licenses to utility companies. Further, it is responsible to regulate areas of the industry where competition is not realisable by setting price controls and standards to ensure customers get value for money and a reliable service. In the case of the electricity industry, the regulated areas are the Distribution and Transmission sectors. Ofgem also runs a public service by publishing any new proposals or discussions of how gas and electricity trading will be changed, any amendments to the rules and liases closely with Energywatch, a watchdog under the late Department of Trade and Industry (DTI) which is now known as Department of Energy and Climate Change (DECC), which compares prices between suppliers for the benefits of electricity and gas customers.

2.5 System Operator

The System Operator (SO) or Independent System Operator (ISO) controls and manages the transmission system. Its function in the regulated and deregulated area has changed due to the industry environment. Even after deregulation, its function varies between different markets or countries. In the regulated area, the SO was part of a fully integrated utility consisting of the generation, transmission and distribution network.

After deregulation, although its core function remains the reliable and efficient operation of the transmission system, the SO is now an independent entity and its interests are modified to reflect its status in the new market environment.

The SO can take the form of the MiniSO or the Max SO [4]. As a MiniSO, it is not involved in the energy market and its role in the generation scheduling is limited to purely ensuring that power transactions can be carried out between generators and loads. In the operation to match the load, system balance is linked to satisfactory levels of reactive power, operating reserves and other Ancillary Services (AS). It will also co-ordinate measures to alleviate transmission congestion and perform contingency analysis to ensure system security. On the other extreme, the MaxSo would combine the responsibilities of the MinSO and energy Trading. Its roles would include generation and AS scheduling, pricing of transmission facilities, despatching generation in cases of imbalance, and facilitating the energy and AS markets. In this thesis an example of a MinSO is NGT, the E&W SO and the California ISO. An example of the MaxSO is the Argentinean and East Australian SO.

The market requires the transmission system to give a fair and non-discriminatory access to transmission services. Thus, the SO must be independent of all the other sectors of the industry. At the same time, the SO needs to maintain the safe and reliable operation of the power system and promotes efficiency in the transmission business. The operation of the SO in the deregulated market is a huge challenge as the market environment is different in many ways such as differences in transmission charge determination and allocation, generation despatch or even acquisition of AS. Some of the benefits that can be derived from having an independent and dedicated SO include:

1) develop efficient methods for pricing transmission services
2) manage and resolve transmission congestion efficiently
3) simplify procedures for new market entrants
4) provide a clear framework for resolving disputes among utilities

Depending on the structure of the market, the SO role varies. In the previous UK Pool system, the SO operate as a MaxSO. It was responsible for market settlement including scheduling and despatch and transmission management including transmission pricing and security aspects. In the open access structure (bilateral/multilateral model), the SO has no role in scheduling, despatch or settlement and thus operates as a MinSO. Its role is constrained to system security and reliability functions. For instance, in the E&W NETA environment, the bilateral and multilateral transactions are handled by power exchanges and brokers rather that the SO itself. In other markets, the SO can be detached from the transmission asset owner and is not responsible for the maintenance of transmission elements.

2.6 UK Power Market Evolution

The deregulation of the UK electricity industry has gone through several changes. In the UK England and Wales System, the Pool System was introduced in 1989 to facilitate the trading of power and to have competition between generators and buyers of electricity. NETA replaced the Pool operation in 2001 and is a form of bilateral market arrangement. According to Ofgem, the Pool operation failed to reduce wholesale electricity price although generating costs were dropping. This was because the Pool used a single System Marginal Price (SMP) for all parties and did not encourage demand side bidding. The SMP was also said to give insufficient price signals to the market as low cost generators were benefiting from the price set by higher cost generating units.

NETA introduced ‘pay as bid’ for each participant and allows for shorter period between gate closure and time of power delivery. This was seen as a step in the right direction as generators will be paid the price close to its marginal price. Further, the reduction of the period between gate closure and the delivery time enhances the forecasting of the load and reduces imbalances between contracted power and actual power demand. Both these measures contribute to make the market more efficient. In 2004, the regulator of the UK electricity and gas industry proposed that a UK wide electricity trading arrangement would be introduced to include Scotland and Northern Ireland, call the British Electricity Trading and Transmission Arrangement (BETTA). The potential effect of BETTA is an increase in cross border transactions as a more uniform pricing structure would exist.

Further, the increase of green energy sources from the wind farms of Scotland will add to the demand for increased power transmission between Scotland to the rest of the UK. However, this brings new issues to the UK transmission network such as the non-firm supply from renewable and the limitations of the Scotland- England interconnections.

The Pool System and NETA operation will be detailed discussed in the following sections.

2.7 The Pool System

The Pool System was introduced in the UK England and Wales power system in 1989. At that time, it was a pioneer market and a cutting edge arrangement for power trading in the world. The Pool system retained the single command and control ability of the dispatch and transmission operation not dissimilar from the regulated area. As the name suggests, all power generated enter into the Pool and buyers and sellers pay or receive a uniform price for electricity. The Pool system can be described within the Figure 2.3 below.

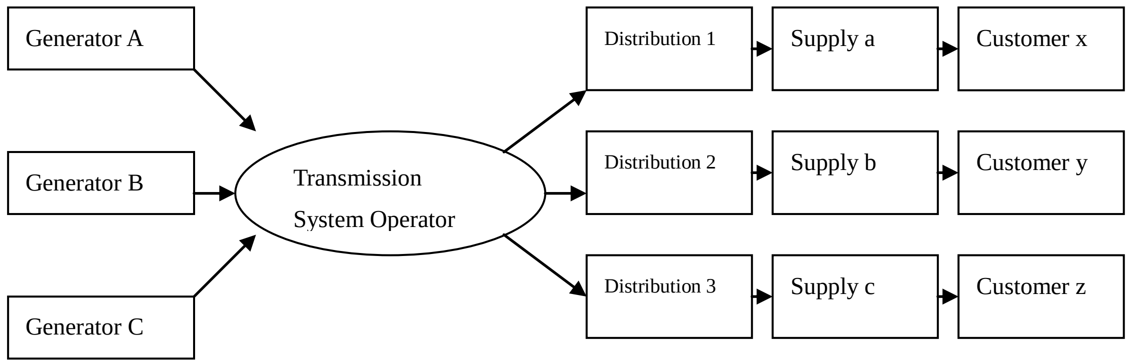

Figure 2. 3 the Pool System

The Figure 2.3 above shows that all generation was dumped into a pool which in most cases was run by the SO. The SO then despatches the generators based on the system load and system constraints. The role of the distribution elements in this model was limited to just operating the distribution network and its income was regulated. The supply companies in turn pay the SO for supplying it with the power that it contracted for its customers. In the Pool model, the supply companies and large power consumers can only buy from a single purchasing agent. However, Supply companies and large power consumers can have separate contracts with generators to hedge against price fluctuation in the Pool.

2.7.1 Pool System Operation and Price Determination

In the Pool system, generators bid for despatch one day before delivery and the bids were stacked by the SO for each half an hour. During the day of operation, the SO would despatch the generators in the sequence of its position on the stack as the load fluctuates. The generators which bid the least price will be put at the bottom of the stack and correspondingly, the most expensive generator will be put at the top of the stack. The marginal price of electricity for that period would then correspond to the generator last despatched within the stack.

This price is called the System Marginal Price (SMP) and formed the basis for calculation the price to pay generators which are despatched.

The actual price paid to the generator was called the Pool Purchase Price (PPP). This was calculated by;

$$PPP = SMP *(1-LoLP) + VoLL*(LoLP) \text{------------------ } 2.1$$

where,

LoLP is Loss of Load Probability

VoLL is Value of Loss Load

The price that the supply companies pay to obtain power from the Pool was termed Pool Selling Price (PSP) and this was determined from the SMP and transmission costs/ uplift cost. The PSP was calculated by;

$$PSP = PPP+ Uplift \qquad \text{---------------------------------- } 2.2$$

where,

Uplift = Cost of providing Ancillary Services (AS) or other network operation, AS can include costs to produce MVar, load following, maintenance services, black start capabilities.

2.7.2 Pool System Characteristics

During the early years of implementation of the E&W Pool System, there were relatively few generation companies in the market and they exercised what was termed 'market power'. This means that in the absence of sufficient credible competitors, they can manipulate the prices of electricity due to the ability of all generators to receive the PPP. Some generators bid a very low price or even '0' for the selling price of their electricity to ensure despatch inclusion by being at the bottom part of the stack and still get paid SSP. This has resulted in inefficiencies as the price that buyers pay is the marginal price rather than the actual price of the bid. On the generation side, some base load generators with lower generating cost are getting the benefit of the higher price quoted by more expensive peaking plants. The Pool system also did not allow for retail side participation. Price was controlled by the SMP and smaller customers usually do not have contract for differences (CFDs) with generators to determine a mutually agreed price. In order to counter this effect, the regulators have requested that these large generators divest their generation interests so that more competition can be introduced into the market. This has resulted in more competition and has resulted in the reduction of the wholesale electricity prices.

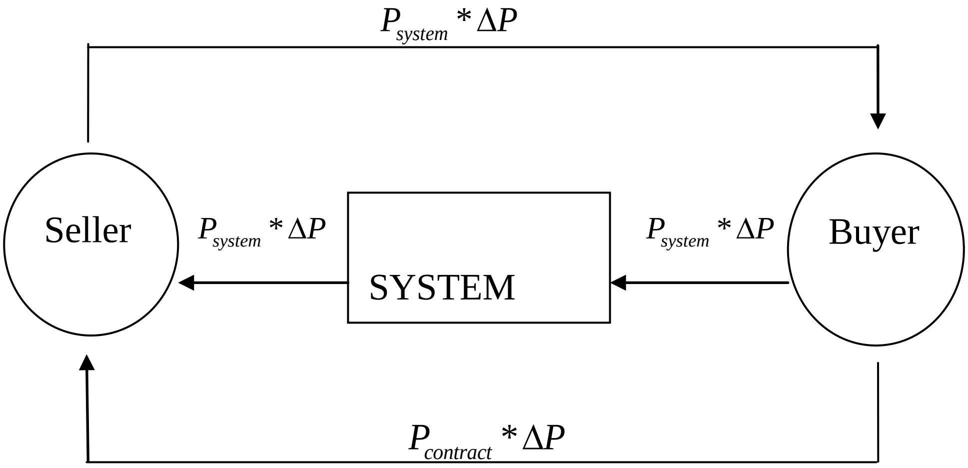

Figure 2. 4 Contracts for Differents

2.7.3 Case study of pool system operation

Case 1 of Pool Operation

3 generators indicating G1, G2 and G3 operating in the pool system with Load 1 and 2 is given in Figure 2.5 below, each generator has a maximum capacity and bid price for their power as indicated in Table 2.1.

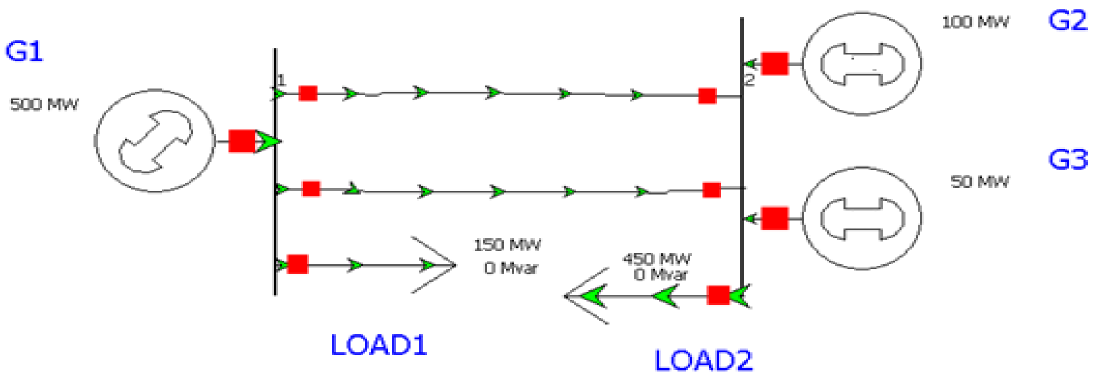

Figure 2. 5 Example of Pool Operation

Table 2. 1 Generator Capacity and Bid Price

Generator ID	Max Capacity (MW)	Bid Price(￡/MWh)
G1	500	10
G2	100	15
G3	50	20

Load 1 and 2 are required 150 MW and 450 MW respectively. LOLP is assumed to be 0 and therefore PPP = SMP. The transmission elements are assumed lossless. Each of the two lines has a transmission limit of 250 MW.

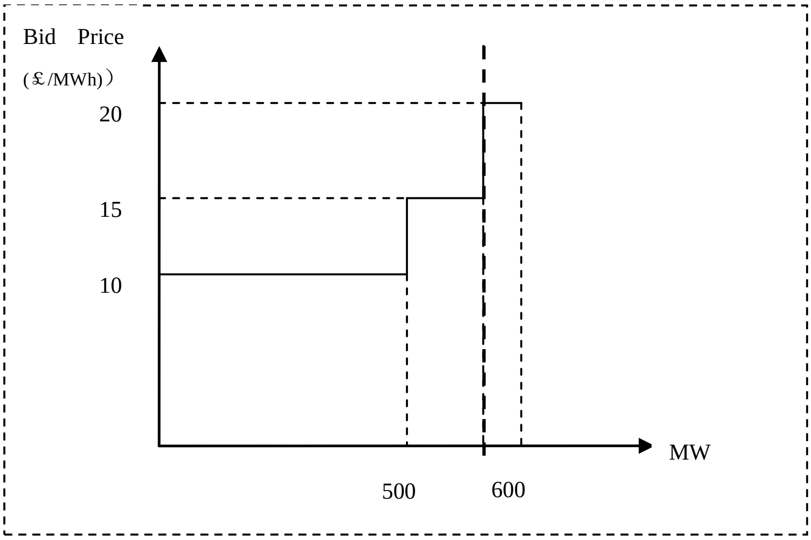

Figure 2. 6 the Pricing Curve

a）In the Unconstrained Dispatch[5]

The above Figure 2.6 shows that G1 generator up to its capacity as both load 1 and load 2 draw power from it. The export from G1 to Load 2 is 350MW. The balance of the requirement of Load 2 is only 50 MW and is supplied by G2. Thus System Marginal Price (SMP) depends on G2 and both G1 and G2 are paid based on the SMP of ￡16/MWh.

The generation cost for this unconstrained case is:

= (500 MW*￡10/MWh) + (50MW*￡15/MWh) = ￡5750 /h

The PPP and PSP can be calculated from the steps below;

Table 2. 2 Generator Output and PSP

Gen	**Output**	**PSP**
G1	500MW	￡15/MWh
G2	50MW	￡15/MWh
G3	0MW	￡15/MWh

PPP = PSP = ￡15 /MWh

PSP = PPP + Uplift

= PPP + (Security Cost/ Total Load)

= ￡15 + （￡0 /550MWh）

= ￡15/ MWh

The generator income for this case can be calculated below;

G1 = 500MW * ￡15 / MWh

= ￡7500.00/h

G2 = 50 MW * ￡ 15/ MWh

= ￡750.00/h

G3 = ￡0/h

The demand charges for the loads can be calculated below;

L1 = 150MW * ￡15/MWh + Security Cost (=0)

= ￡2250/h

L2 = 400MW * ￡15/MWh + Security Cost (=0)

= ￡6000/h

However, in the above case, the transmission limits are violated, as each line should only transmit 125MW to cater for any (n-1) contingency. The generators must be redespatched so that these line contingency limits are not exceeded. This means that G1 has to reduce its generation and G3 will have to be dispatched. The new dispatch is called the Security Constrained Dispatch and is discussed below.

b) The Security Constrained Dispatch

In the case shown in the figure above, G1 can only supply 250MW to Load 2 to obey the security based transmission limits of the lines. The rest of the power must be supplied by G2 and G3. However, the SMP is still determined by the Pricing Curve in the Figure 2.6 and stands at ￡15/MWh.

The generation cost for the security constrained case is;

= (400MW*￡10/MWh) + (100MW *￡15/MWh) + (50MW *￡20/MWh)

= ￡6500/ h

Thus cost of security by re-despatching the generators is;

= Constrained Despatch Cost – Unconstrained Despatch Cost

= ￡6500 - ￡5750 = ￡750/h

However this figure does not take into account other cost of security services such as MVAr support, Spinning Reserves, Black Start and others.

The PPP and PSP of the security constrained case are given by;

PPP = SMP

= ￡15/MWh

PSP = PPP + Uplift

= PPP +（ Security Cost/ Total Load）

= ￡15/MWh + (￡750/550)

= ￡ 16.36/MWh

Due to the redespatch of the generators, the security constrained case require Adjustment calculations to compensate G1 which cannot generate to its full capacity and G3 which is paid the PPP which is lower than its bid price. The adjustment calculations are as follows;

G1 is constrained OFF

Adjustment G1 = （Capacity – Generation）* (PPP – Bid Price)

= (500MW-400MW)*(￡15/MWh-￡10/MWh)

= ￡500/h

G2 has no constraints

Adjustment G2 = ￡0/h

G3 is constrained ON

Adjustment G3 = (Generation) * (Bid Price – PPP)

= (50MW)*(￡20/MWh-￡15/MWh)

= ￡250/h

To determine the actual individual generator income for the constrained case;

G1 = 400MW * PPP + AdjustmentG1

= ￡6500/h

G2 = 100MW * PPP + Adjustment G2

= ￡1500/h

G3 = 50 MW * PPP + Adjustment G3

= ￡1000/h

Demand Charges for L1 and L2 is given by

L 1 = (P_{L1} * PPP) + Security Cost

= (150 MW * ￡15/ MWh) + (125 MW * (￡750 per hour/ 550 MW))

= ￡2420 /h

L 2 = (P_{L2} * PPP) + Security Cost

= (400 MW * ￡15/ MWh) + (400 MW * (￡750 per hour/ 550 MW))

= ￡6544/h

The calculations above show that the generator G1 and G3 have their loads adjusts to improve system security. However, they are compensated accordingly by the adjustment costs. These extra costs are borne out of the Load 1 and 2 as a premium for a more secure operation of the system. If the demand charges of Loads 1 and Loads 2 are added together, that value should exactly match the total generator income for G1, G2 and G3 which is (￡2420+￡6544=)￡8964. It can also be observed that G1 gets ￡500/h less than the unconstrained case.

Case 2 of Pool Operation

3 generators G1, G2 and G3 operating in the pool system with Load 360MW and 140MW is given in Figure 2.7, each generator has a maximum capacity and bid price for their power is indicated in Figure 2.8 below.

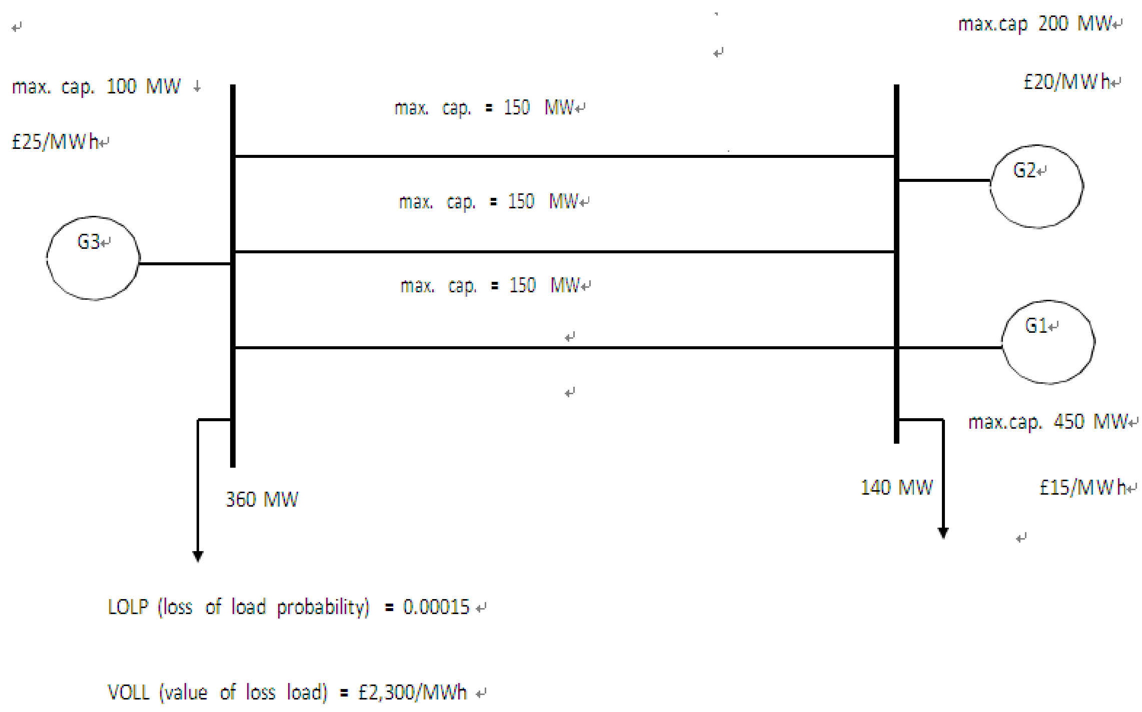

Figure 2. 7 case 2 of the pool system

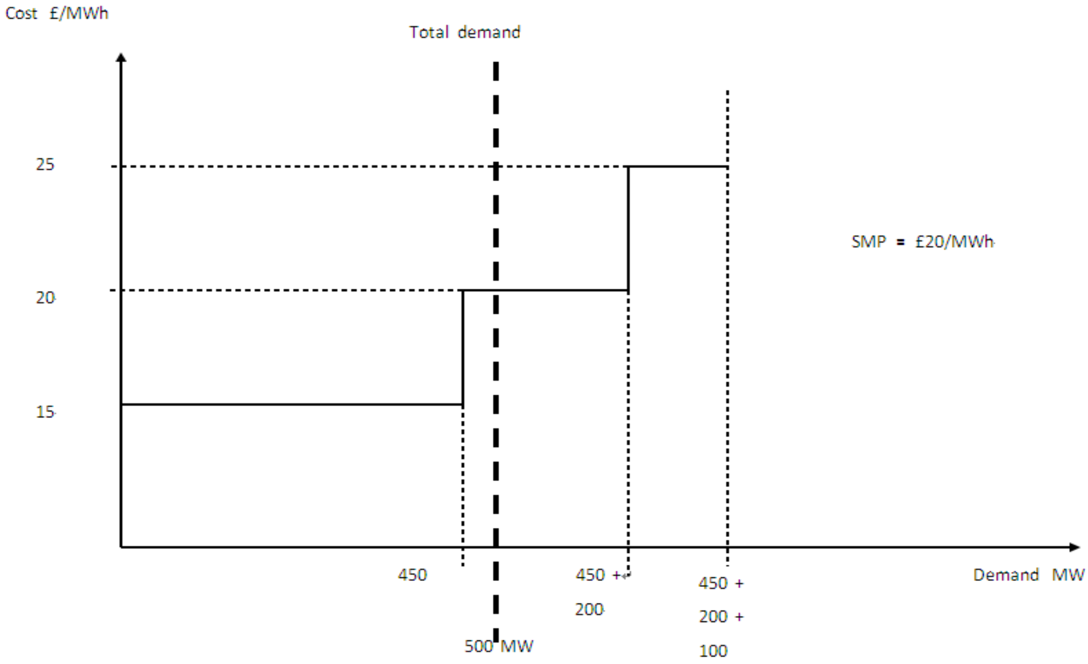

Figure 2. 8 the Pricing Curve

Unconstrained Schedule

Network insecure under (n - 1) contingency

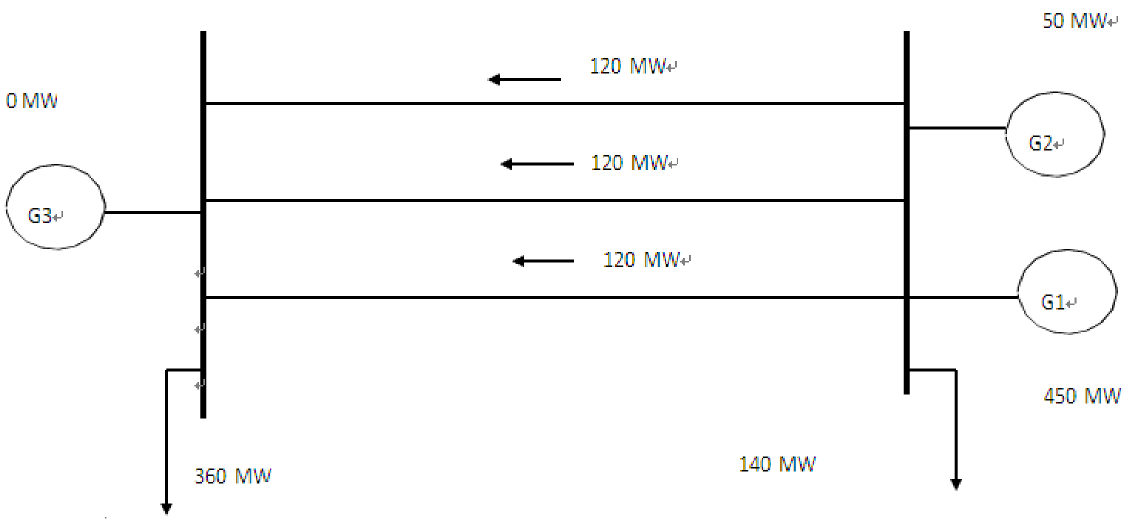

Figure 2. 9 Network insecure under (n -1) contingency

Total generation cost = £{450*15 + 50*20} = £7750

Secured Constrained Schedule

Network secure under (n - 1) contingency

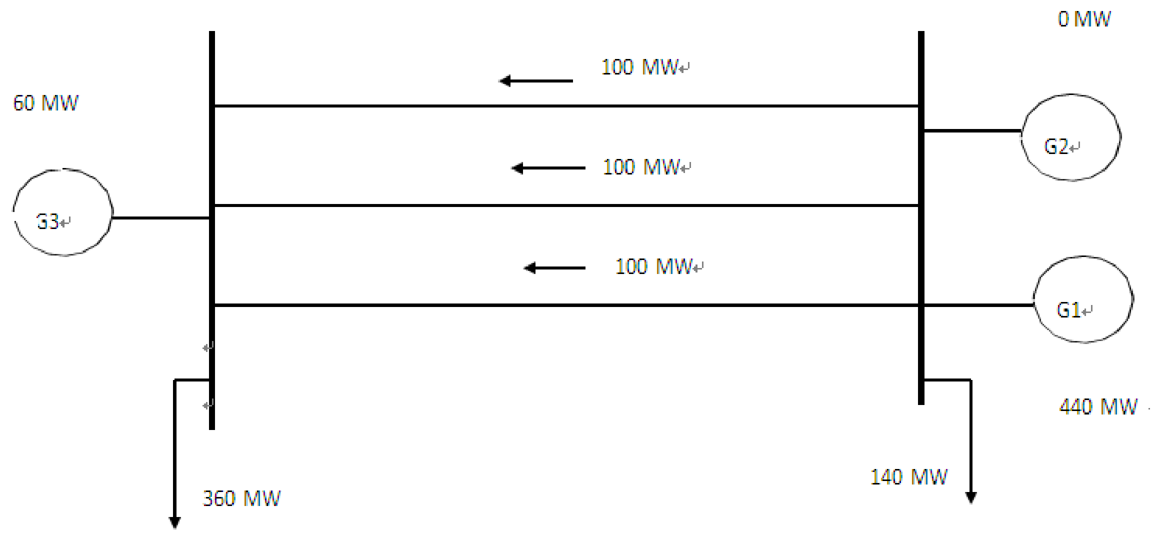

Figure 2. 10 Network secure under (n - 1) contingency

Total generation cost = £{440*15 + 0*20 + 60*25} = £8100

Additional generation cost due to security = £{8100 - 7750} = £350

2.8 NETA System

NETA stands for the New Electricity Trading Arrangement. Its philosophy is giving the market freedom to enter into negotiated/ bilateral contracts between generators, brokers and supply companies. NETA is a fully competitive market in which supply and demand determine prices. It was introduced to replace the pool system as the latter failed to satisfactorily reduce wholesale electricity prices [6].

A significant difference in NETA is that 'pay as bid' applies and System Marginal Price is no longer used to determine electricity price. The other difference is that, operationally, generators will self- dispatch based on its bilateral contract with its buyers. According to Ofgem, 95% of all transactions are done bilaterally between generators and supply companies. SO no longer controls generator dispatch as in the

Pool System and its role in NETA is limited to facilitating the contracted power flows of the industry players. However, the role of the SO cannot be understated and is very much central to the safe and economic operation of NETA. Based on the ability of all parties in the power market to buy/ sell power from/to Generators, Supply Companies and Brokers, BETTA is one of the most advanced market structure in the world now.

2.8.1 Market Structure

The contracts between generators and buyers can be made much earlier than the transaction time. These contracts can be made bilaterally between parties through bilateral negotiations or via a power exchange. At the latest, these contracts must be submitted to the SO half hour before gate closure. Gate closure is the start time when the actual power delivery takes place between generators and demand units. The contracts submitted at half hour before gate closure make up the Final Physical Notification (FPN) which is the sum of all bilateral trading between parties. BETTA also has a Balancing Mechanism (BM) to cater for any generation shortfalls and spills in the system. At half hour before gate closure, bids and offers for the BM are also submitted. The SO then has the 1/2 hour window to co-ordinate the system by analyzing the contracts and monitoring the actual demand of the system. If necessary, the SO will accept bids and offers from the BM to balance the system. Figure 2.11 below shows the significant markets in the BETTA timeline.

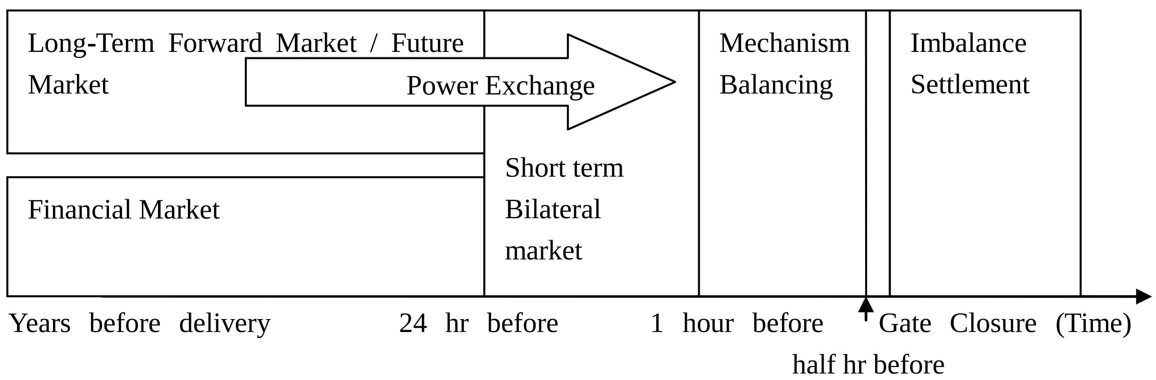

Figure 2. 11 NETA and BETTA Market Structure

2.8.2 BETTA Characteristics

BETTA has created an environment where 98% of electricity is sold like a commodity. And only 2% of electricity is traded in the balancing mechanism, which enhances competitive pressure since it provides freedom for participants to enter contractual arrangements. Under BETTA, more price information has become available, and market liquidity has increased significantly. Moreover, the most widely touted success for BETTA is the trend of falling wholesale and retail electricity prices. The BETTA has proved that an electricity market without a centralized clearing market can operate effectively and efficiently. However, it also brings some impacts on generators, suppliers, and environment.

In the BETTA Balancing Mechanism, SBP is the price participants buy electricity from the system, and SSP is the price participants sell electricity to the market, so SBP is generally higher than SSP, thus it is more economical for buyers to have power transaction higher than the predicted demand for hedging purpose. This has led to some inefficiency of generators not utilizing their full capacity as buyers often overbook their purchases to avoid being short and pay a high SBP. On the positive side, BETTA has increased demand side bidding relative to the Pool System where previously only a few large players could sign CFDs (contract for different). In BETTA, the emergence of supply companies and load aggregators has allowed smaller customers to group together and negotiate for lower prices.

2.8.3 Balancing Services and Balancing Mechanism

Ideally the normal small system load changes are of no concern to the SO of a deregulated market operating in the BETTA environment. This is because generators and loads aim to agree on a set amount of power transaction without any mismatches. However, in reality, the supply and demand cannot be met accurately and may require some other generators or loads to balance the system. The bilateral contracts are settled before the half-hour trading period. And leave the imbalance power on demand forecasting. The imbalance power lead this to happen will be the errors or mismatches.

And This mismatch of power is small and only takes up to around 2-3% of the total power transaction. However, their technical and financial implications can be significant and these mismatches are handling by the introduction of the Balancing Mechanism (BM). Apart from power mismatches, the SO must also ensure that is has purchased sufficient AS or accepted offers and bids to ensure that the contracted transactions can take place. The BM is part of the Balancing Services (which will be discussed in the next section) where any power shortage or generation 'spills can be handled. The BM is run by the Balancing Services Code Company (BSCC). The operational cost of this company is borne by the transmission network users who are also signatories of the Balancing Services Company (BSC) [7].

In the BM, generators or load elements are termed BM Units. BM Units who are 'short' of power and therefore out of balance in a particular operating period have two options. Firstly, they can do nothing before the transaction period and simply acquire any extra power needed from the offers in the BM. Secondly, they can place bids in the BM before the transaction period to buy power at a possibly lower price. On the other hand, BM units who are 'long', or have excess power, can sell their power to the Bids during the transaction period or plan ahead and place offers before the transaction period.

During the Balancing Period, the BSCC will act on behalf of any parties out of balance. BM Units which are 'short' will have the BSCC purchase their shortfall from the BM offers at System Buy Price (SBP) or acquire extra power through their own bids.

Likewise, BM Units which are 'long' will have the BSCC sell their excess power to BM units which are short or BM bids to absorb their power and get paid System Sell Price (SSP) or place offers in the BM. It is generally observed that SBP is higher than the SSP. This means that it is cheaper for transaction to go 'long' and accept SSP rather being short and pay SBP. In other word, having a contractual mismatch can mean increased costs as in the case for nearly all 'forced buying' or 'forced selling' scenarios. This is a new aspect in BETTA and requires market players to be more accurate in their load forecasts and financially adept at pricing their services.

As mentioned earlier, the BM is used to cater for energy imbalances. Prior to gate closure, all parties are required to submit the details of their transaction to the SO. The sum of generated power from individual transaction is called the Final Physical Notification (FPN). In the BETTA market, individual market players will try to forecast their loads and acquire sufficient generation accordingly and total generation FPN should match the load. However, due to forecast inaccuracies, this is the seldom case and the BM would have to cater for the energy imbalance. In this example, gate closure is at 12:00 noon and the FPN is indicated by the bold line. The actual system requirement is indicated by the dotted line and is different from the projected system

2.8.4 Imbalance Settlement in UK Electricity Market

When the pool functioned as the basis of the trading arrangements, although NGC undertook various services on behalf of the pool according to rules prescribed in the Pooling and Settlement Agreement, NGC did not operate the Pool as a market operator, it acted as an agent to the signatories to the Pooling and Settlement Agreement, and they prescribed the rules.

Physical market participants are expected to provide balanced contract schedules of injections into and take from each price zone. The imbalance arrangement in England & Wales are not intended to be markets. In England and Wales the NGC does not operate the imbalance settlement and charging arrangements. It is the role of system operator to balance the system and clearly separate from that of both the imbalance arrangements and from the administration of the settlement of imbalance which is undertaken by ELEXON. ELEXON provides the administrative support for the Panel and it procures, manages, and operates contracts and services which enable the balancing and imbalance settlement of the whole electricity market. ELEXON is a not-for-profit company, with a board consisting of a chair that is the chair of the panel, two further panel members nominated by the panel and two other independent members nominated by the panel chair. ELEXON is a wholly owned subsidiary of NGC, but NGC has no control over the board and does not have any financial link with ELEXON nor responsibility for it.

The calculation of the two settlement prices for each half-hour is undertaken by ELEXON based on first, the forward contracts for energy and reserve that NGC has bought and called, second the prices of the offers and bids which NGC has accepted in the balancing mechanism. In outline ELEXON for each half hour removes the contracts called and the offers and bids which NGC has accepted for constraint management, leaving those which it has called and accepted for energy balancing purposes, and from these it calculates the imbalance cash-out price. It also calculates the imbalance position of each market participant from their contractual position and from the metered volumes injected and taken from the system. Finally it prices the imbalance volumes at the appropriate cash-out price. The relationship between NGC's procurement and the settlement and charging for imbalances is shown in figure 2.12 [8].

Imbalances are settled by ELEXON according to the rules of the balancing and settlement code, which are determined by the balancing and settlement panel subject to authorization by Ofgem. Although in the early days of the development of NETA Ofgem proposed sponsoring a day-ahead exchange market, it made a conscious decision to withdraw from this responsibility and to let the market provide.

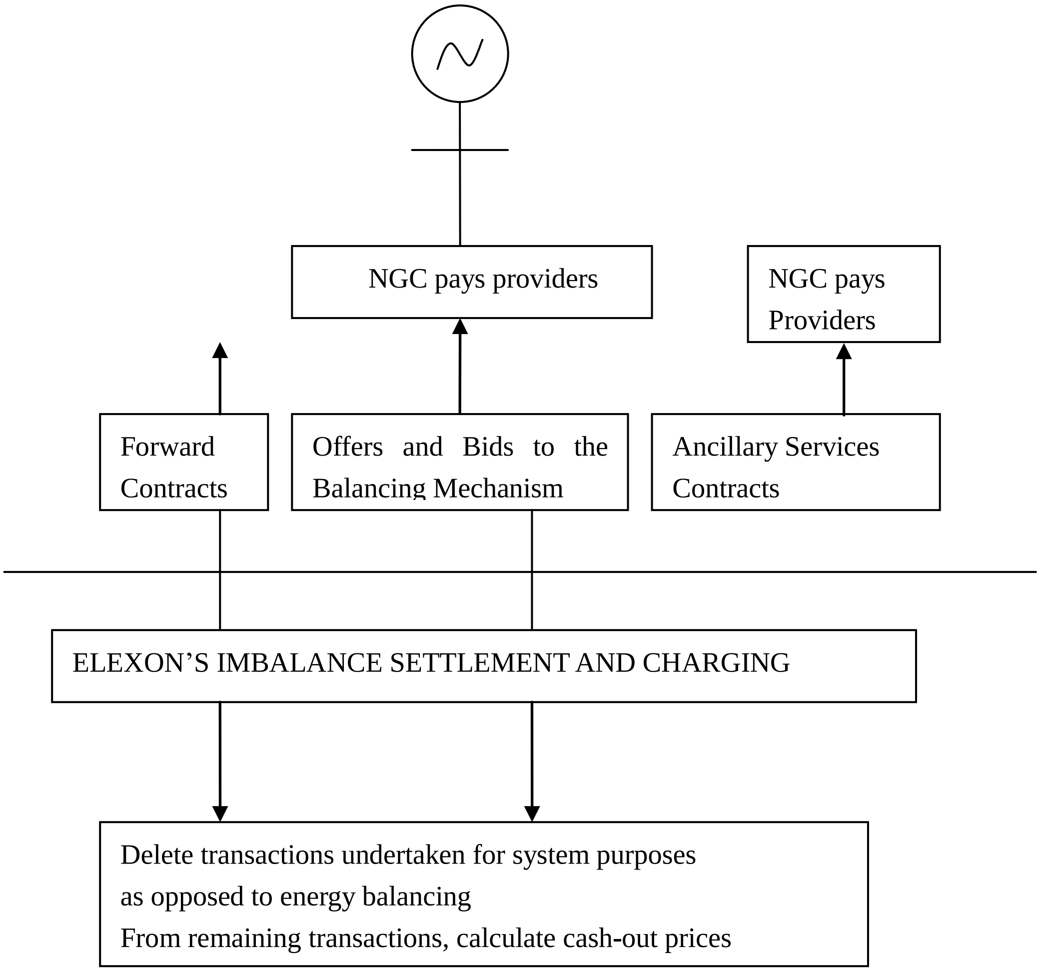

Figure 2. 12 NGC settlements and charging for imbalances [9]

2.8.5 Energy Imbalance Settlement and Imbalance Prices

The energy imbalance settlement system uses two energy imbalance prices mechanism. These two prices are from the SO which received the generalized weighted mean values with two parameters were defined of the adjust value. The generalized weighted mean values of the balance upper adjust value is the imbalance SBP, which is the price that market participants buy electricity from the system. The generalized weighted mean values of the balance lower adjust value is the imbalance SSP, which is the price that market participants sell electricity to the system. The relationship is shown as figure 2.13[9].

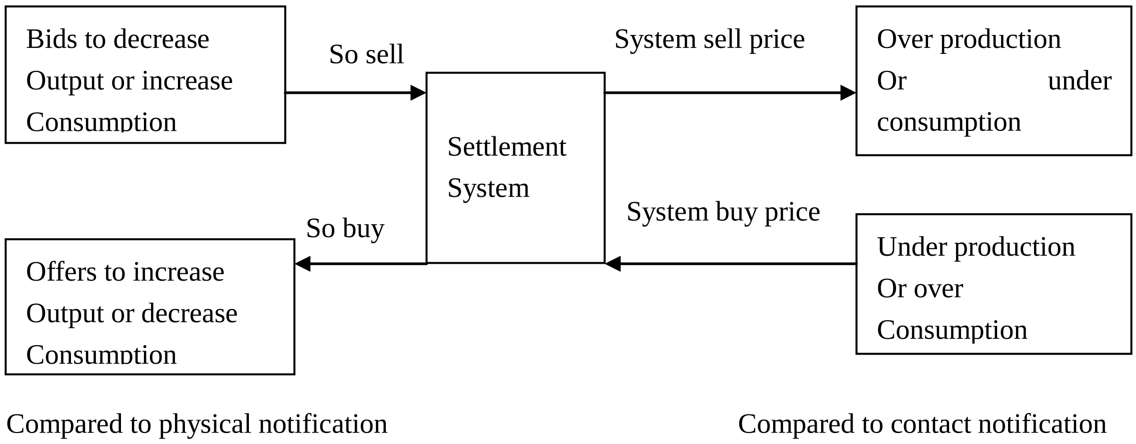

Figure 2. 13 SSP and SBP in the Electricity Market

2.8.6 SSP and SBP calculation

SSP is the price that BM Units sell their excess power to the BM. On the other hand, SBP is the price that BM Units pay to buy power from the BM. The SBP is generally higher than the SSP as BM Offers are generally higher than BM bids. Further, Balancing Services Adjustment Data (BSAD) might push prices of SBP higher to accommodate reserve cost and some AS contracts. SBP is the price at which deficits are charged, when the system is short, reflects the average price at which the system had to buy in order to make good the deficit on behalf of the party. SSP is the price at which surpluses are charged, when the system is long, reflects the average price at which the system had to sell in order to dispense with the surplus spill energy. However, some bids and offers are excluded from the averaging calculations on the basis that they are related to system balancing as opposed to energy balancing trades. In addition, an adjustment to the imbalance prices is made based on any pre-gate closure balancing services that we have used for energy balancing.

$$SSP = \frac{\sum_{1}^{i} PAB_i * VAB_i}{\sum_{1}^{i} VAB_i} \qquad \text{-----------------2.3}$$

Where; PAB = *price of accepted Bid*

VAB = *volume of accepted Bid*

i = *index for Bid accepted*

Also;

$$SBP = \frac{\sum_{1}^{i} PAO_i * VAO_i}{\sum_{1}^{i} VAO_i} \qquad \text{---------------- 2.4}$$

Where;

PAO = price of accepted offer

VAO = volume of accepted offer

i = index for Offer accepted

If the AS components above and transmission losses are factored in, the SSP and SBP values will change and the calculations can be adjusted to become;

$$SSP_j = \frac{\sum_{1}^{i} \{PAB_i * VAB_i * TLM_j\} + SCA_j}{\sum_{1}^{i} \{VAB_i * TLM_j\} + SVA_j} + SPA_j \qquad \text{--------2.5}$$

Where,

PAB = price of accepted Bid

VAB = volume of accepted Bid

TLM = transmission loss multiplier

SCA = aggregated energy contract purchases

SVA = aggregated volume of energy contract per settlement period

SPA = Sell price adjustment based on reserves costs

i = index for bid accepted

j = index of settlement period

And

$$SBP_j = \frac{\sum_{1}^{i} \{PAO_i * VAO_i * TLM_j\} + BCA_j}{\sum_{1}^{i} \{VAO_i * TLM_j\} + BVA_j} + BPA_j \qquad \text{-----------------2.6}$$

Where,

PAO = price of accepted offer

VAO = volume of accepted offer

TLM = transmission loss multiplier

BCA = aggregated energy contract sales

BVA = aggregated volume of energy contract sales per settlement period

BPA = buy price adjustment based on reserve cost

i = index for offer accepted

j = index of settlement period

The changes from Equation 2.3 to 2.5 and 2.4 to 2.6 reflect the additional uplift cost of the new BM transactions. As the offers and bids are accepted, their aggregated value makes up the SSP and SBP. These prices are used by the SO to charge the parties out of balance in order to distribute the forecast error fairly among all the market players. Apart from being used to charge parties out of balance, the values of SSP and SBP are also economic indicators of the system. They reflect the degree of shortage or excess power in real time and can help market players plan their future.

In NETA, if generators and loads can fully predict demand, then there will be no imbalance and SBP and SSP is not relevant. However, this is not the case and even the best forecast would require a certain level of energy balancing. In order to illustrate the operation of the BM during an imbalance occured, a simple example is given below.

2.8.7 Case study of SSP and SBP calculation

Three bus system with two generators G1, G2 and one load L are shown as in the Figure 2.14 below, and also the load profile data of BM Bids and Offers for the one period.

The position of the BM bids and offers in the Figure 2.15 is based on the BM bids and offers submitted by G1 and G2 in pairs. These bids and offers are submitted 30 minutes before gate closure. They are solely for imbalance purposes and are separate from energy transactions.

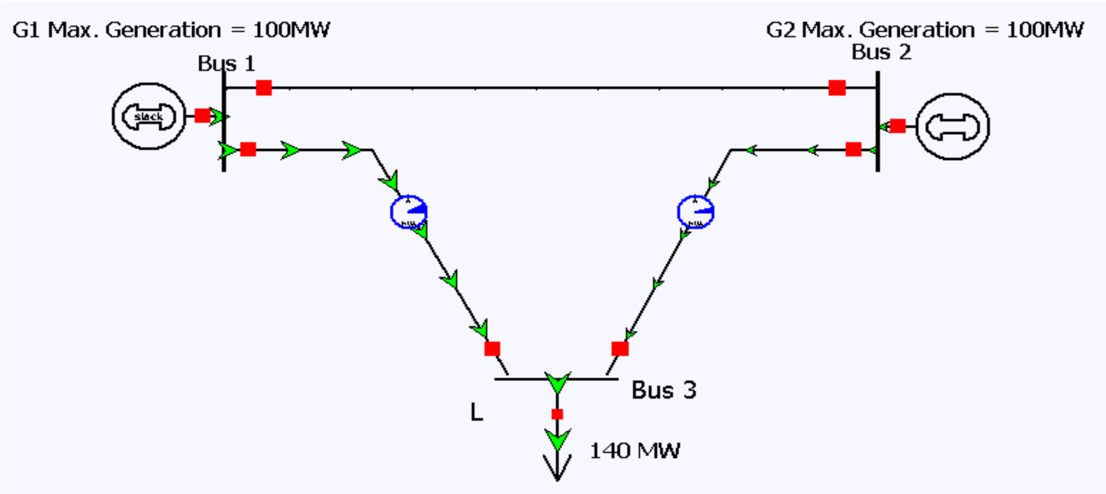

Figure 2. 14 Example of NETA Power Flow

Bids and Offers from G1	Bids and Offers from G2
Pair 1: Amount 15 MW	Pair 1: Amount 30MW
Offer Price ￡30/MWh	Offer Price ￡40/MWh
Bid Price ￡28/MWh	Bid Price ￡38/MWh
Pair 2: Amount 15MW	Pair 2: Amount 15MW
Offer Price ￡10/MWh	Offer Price ￡20/MWh
Bid Price ￡8/MWh	Bid Price ￡18/MWh

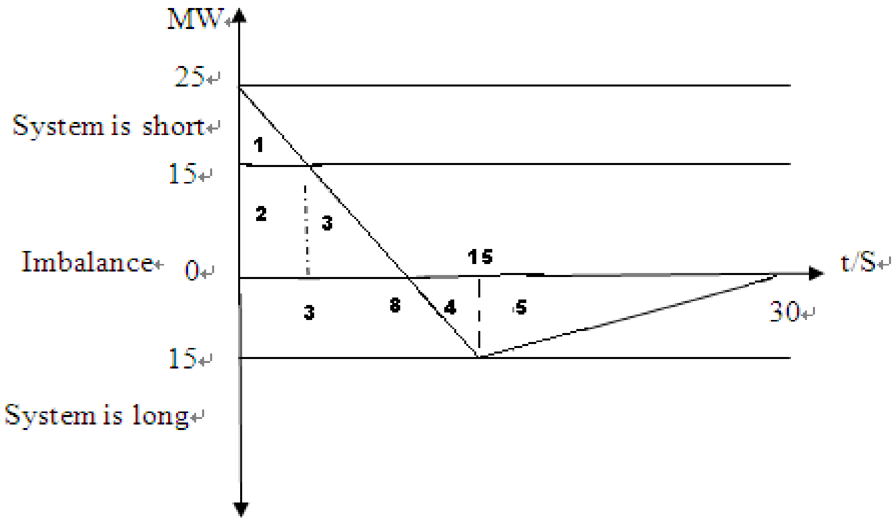

Figure 2. 15 The BM Offer and Bids by G1 and G2 for one period

This gives a forecast demand of 140MW at load (L). However, the actual demand is shown above in Figure 2.15, where the load peaks at 25 MW above the FPN at t=15 minutes. This example assumes that any imbalance will be paid by the load, though this responsibility can be negotiated between the load and the generator in a practical market. Further it is assumed to have no losses but both congested and non-congested transmission cases are discussed. In each case, the imbalance is represents by the load fluctuating by 10 MW. It is also assumed that this system does not require any reserves or AS in order simplify calculations.

In the no congestion case

Between 0 to 8 minutes, the load profile is above the FPN and the system required more power be bought from BM Units. Thus both offers from G1 and G2 will be accepted to balance the load. If there are other instances in the period when the system is short, the SBP calculation must also take into account the volume and prices at that time. However, based on the above diagram, the only time when the system is short at 0 to 8 mins and the SBP price calculated can be based on only that period. The calculations will be based on Equation 2.4 as the energy costs, reserve costs and transmission losses are assumed to be zero;

The SBP calculation for this period is:

$$SBP = \frac{\sum_{1}^{i} PAO_i * VAO_i}{\sum_{1}^{i} VAO_i}$$

$$= \frac{[(\frac{£40}{MWh} \times \frac{1}{2} \times \frac{3}{60} \times 10MWh) + (\frac{£30}{MWh} \times \frac{3}{60} \times 15MWh)(\frac{£30}{MWh} \times \frac{1}{2} \times \frac{5}{60} \times 15MWh)]}{[(\frac{1}{2} \times \frac{3}{60} \times 10MWh) + (\frac{3}{60} \times 15MWh) + (\frac{1}{2} \times \frac{5}{60} \times 15MWh)]}$$

= £31.54/MWh

Where, PAO_1 is £40/MWh, PAO_2 is £30/MWh, PAO_3 is £30/MWh

VAO_1 is $\frac{1}{2}\times\frac{3}{60}\times 10MWh$, is the volume of the upper triangle 1

VAO_2 is $\frac{3}{60}\times 15MWh$, is the volume of recangle 2

VAO_3 is $\frac{1}{2}\times\frac{5}{60}\times 15MWh$, is the volume of the lower triangle 3

The SSP calculation for this period is shown as;

$$SSP = \frac{\sum_{1}^{i} PAB_i * VAB_i}{\sum_{1}^{i} VAB_i}$$

$$= \frac{(\frac{£18}{MWh}\times\frac{1}{2}\times\frac{7}{60}\times 15MWh)+(\frac{£18}{MWh}\times\frac{1}{2}\times\frac{15}{60}\times 15MWh)}{(\frac{1}{2}\times\frac{7}{60}\times 15MWh)+(\frac{1}{2}\times\frac{15}{60}\times 15MWh)}$$

= £18.00/MWh

Where, PAB_1 is £18/MWh, PAB_2 is £18/MWh

VAB_1 is $\frac{1}{2}\times\frac{7}{60}\times 15MWh$, is the volume of the left triangle 4

VAB_2 is $\frac{1}{2}\times\frac{3}{60}\times 15MWh$, is the volume of the right triangle 5

Therefore, Load L will have to pay for extra energy to be generated between 0 to 8 minutes at SBP = £31.54/MWh and again for surplus energy to be absorbed between 8 to 30 minutes at SSP = £18.00/MWh.

Congestion case

The above example shows that G1 and G2 would provide the balancing action in the case of energy imbalance. However, in the example here, the transmission line from Bus1-Bus2 and Bus1-Bus3 are assumed to be congested. Therefore G1 would no longer be able to participate in the balancing action even if its offer is lower than G2. Thus, the SBP is solely determined by G2 at SBP = £40/MWh. For the calculation of the SSP, the congested lines Bus1-Bus2 and Bus 1-Bus 3 would not affect the selection of G2 to absorb power/reduce generation, this means that the SSP would be equal to the above example at ￡18/MWh.

Therefore, Load L will have to pay for extra energy to be generated between 0 to 8 minutes at SBP = ￡40/MWh and again for surplus energy to be absorbed between 8 to 30 minutes at SSP = ￡18/MWh.

Similar to the no congestion case, the cost of energy balancing in the non-congested or congested network, would result in load L paying for the extra charges. However, this is an idealized example where losses, reserve or energy contracts are not included. Obviously, if these are included, the SBP and SSP values would be higher.

2.9 Summary

This chapter introduced the UK electricity market and deregulated power industry. The Pool system has provided a good arrangement for power trading which has not resulted in significant burden to buyers in terms of price per unit increases. Further, the power Pool has contributed to the knowledge of deregulation with respect to metering, information management, non-real time market clearing and settlements. It may have been a good first step for newly deregulated electric industries in other countries to emulate.

The chapter has also discussed in detail two ways of operating the power system in a deregulated environment, the Pool System and the NETA System. Some details including the derivation of prices such as SMP, PPP, PSP, SSP and SBP unique to each mode of pool or NETA operation were shown. In the NETA system, it was seen that generation dispatch is no longer a responsibility of the SO and the ‘traditional’ generation optimization methods are no longer relevant. In NETA, the market forces are expected to guide the power system into optimal operation by pricing signals.

On the generation side, the change in the industry structure means that new issues such as settlement and energy imbalance must be addressed. This may change the responsibilities of the SO depending on the market structure and the SO's role whether it is a MinSO to the MaxSO. A more complicate example will be shown in Chapter 6 by using the NETA method comparing with other method.

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Chapter 3 US Electricity Market Settlement

3.1 Introduction

In the past 30 years, wholesale electricity markets have gone through fundamental changes in the United States and around the world. Electricity industry restructuring began in Latin American countries in the early 1980s, and more famously, in the United Kingdom in 1990. In the late 1990s, several US states or control areas such as California, Pennsylvania-new Jersey-Maryland (PJM) Interchange, New York, and New England established markets for electricity; and more recently, Federal Energy Regulatory Commission（FERC）Order 2000 has prompted several proposals for the establishment of regional transmission organizations (RTOs). Two key common aspects of the transition toward competitive electricity markets in the United States and around the world are a competitive generation sector and open access to the transmission system. However, there is considerable diversity among the implementation paths chosen by different states and countries. The differences are reflected in various aspects of market design and organization, such as groupings of functions, ownership structure, and the degree of decentralization in markets. The experience gained from the first wave of restructuring in places such as the United Kingdom, Scandinavia, California, and PJM, have led to several reassessment and revision proposals of various market design aspects in these jurisdictions.

In the current US electricity market, there are five parts organized electricity market, they are New England (NE) ISO, New York (NY) ISO, PJM, Texas ERCOT, and California ISO. And some other parts which do not have organized electricity power market, like Southeast, Florida, Midwest, South Central, Southwest and Northwest. All of the above are using short term bilateral power exchange system. But only the organized electricity market use real-time market. In this design, an independent system operator runs a real-time market with centralized dispatch. Bilateral trades are allowed in this system. Bilateral trades are charged locational price differences in the real-time market, and these can be hedged by some type of transmission congestion contracts, which are again financial instruments that guarantee the holder the price differential between locational specified in the contract. [1]

This chapter aims to give an introduction to the US electricity market basic structure. And will generally explain four electricity market operations, and also will take PJM electricity market as an example, deeply explain the day-ahead energy market and the real-time energy market settlement, a 3-buses power system case study will be given to shown how the settlement methods work on the system.

3.2 Introduction of the US Electricity Market

Due to the legacy of history, the design of the transmission network in many parts of the US is not as well suited to running markets as in European countries where national transmission systems were generally develops to enable national optimized dispatch. In contrast in the US, with the exceptions of the PJM area and New England and New York which have a long tradition of joint planning, the network have generally been designed to serve the native load of utilities and to connect to neighboring utilities for reliability support, not to provide the basis for wide area power flows. Thus, for example, the transmission network in California is not designed as an integrated state wide network, but is really five separate systems that are basically designed to serve the needs of integrated utilities and distributors with long term supply contracts. The systems are not generally strongly interconnected and can suffer from serious congestion when they are not operated in the manner for which they were designed.

The US has the respective states or regions independent of the electricity market, the market model and market structure is different, so the market cannot communicate, and lead to redundant construction. Especially the US, California power crisis has exposed some of the problems the original market. Therefore, in March 2002, the United States Federal Energy Regulatory Commission in a number of experts and scholars wrote of the support of two reports [2] [3]. The report concluded the US over the years, the electricity market reform based on lessons learned, and the future of electricity reform in the US Standard Market Design (SMD) bill.

The bill states the US will provide relatively standardized market rules, the guidance of the United States electricity market of construction and development, to ensure that the electricity market competitiveness and efficiency, and market conditions to maintain the stable operation of power systems and encourage investment.

The so-called “standard market design” at the regional marginal prices, market regulation, operating reserve, transmission power, intermittent power, the day after the energy market, regional transmission organizations for government participation in demand response, energy imbalance market, network access services, transmission planning, power resources, as well as the long-term adequacy of existing service contracts and the transition to the standard market were many aspects, such as a standardized design.

3.2.1 Electricity industry restructuring

By the early 1990s it was becoming apparent that electricity industry regulatory approaches were not working. IRP was successful in holding rate increases in check and simulating consumers choice, but the process was highly adversarial, time consuming, and expensive. Regardless, rates were still high and significant differences among adjacent electricity utilities and between gas and electricity utilities caused political problems.1n 1994, California completed a review of the electricity utility planning and regulatory processes in the state and concluded that reforms were needed. At that time, California had some of the highest electricity rates in the nation and it was looking for ways to bolster its economy, which was hurt by military base closures, the restructuring of the aerospace industry, a lingering recession, and a generally high cost of conducting business.

One option considered was to deregulate the electricity supply portion of the retail rate and allow consumers to have direct access to wholesale suppliers. This would remove the financial risk of power plant development from consumer rates and place the risk in the context of a competitive market. Although industry deregulation was the most radical option identified, industry quickly aligned behind it. The deregulation of the domestic electricity utility industry, means the substitution of the market prices for government regulation of the energy portion of utility rates, was launched. Deregulation in California followed several years after Great Britain and other countries. [4]

3.2.2 Real Time Instructed and Uninstructed Imbalance Energy Settlement

With the implementation of MRTU, the current radial zonal model will be replaced with Full Network Model and Locational Marginal Price (LMP) model, which will also eliminate the use of Zones for the Settlement of Energy transactions. Locational Marginal Prices will be used in principle to settle Energy transactions. Price Locations and Aggregated Price Locations are defined on collections of network nodes. A LMP will be calculated for each Price Location and each Aggregated Price Location.

The Real-Time Market (RTM) is a market for trading Energy and Ancillary Services in Real Time. The bid submission for a given Trading Hour in the RTM is allowed after the Day Ahead Market result publication for the corresponding Trading Day and up to 75 minutes before the start of that Trading Hour. The Real-Time Market processes optimize Energy and Ancillary Services Bids with an objective of satisfying Real-Time Energy needs, mitigating Congestion, allowing resources providing Regulation service to return to preferred operating point within their regulating ranges and allowing recovery of Operating Reserves utilized in Real Time operation.

The Real-Time Economic Dispatch (RTED) is responsible for dispatching Imbalance Energy and Ancillary Services at regular intervals. RTED runs automatically every 5 min, at the middle of each 5-min interval. In addition RTED can be executed manually in Manual or Contingency Dispatch modes. Instructed Imbalance Energy (IIE) resulting from RT dispatched instructions will be calculated by CAISO usually by the end of next Trading day.

The CAISO calculates and accounts for Imbalance Energy for each Dispatch Interval and settles Imbalance Energy for each Settlement Interval for each resource within the CAISO Control Area and all System Resources Dispatched or scheduled in Real-Time.

Imbalance Energy consists of following:
IIE - Real Time Instructed Imbalance Energy Settlement and HASP Energy, Congestion, Loss Pre-Dispatched Settlement
UIE - Real Time Uninstructed Imbalance Energy Settlement
UFE - Real Time Unaccounted for Energy Settlement

To the extent that the sum of the Settlement Amounts for IIE, UIE, and UFE does not equal zero, the CAISO will assess Charges or make Payments in Real Time Imbalance Energy Offset for the resulting differences to all Scheduling Coordinators based on a pro rata share of their Measured Demand for the relevant Settlement Interval.

In the Real-Time Market, the negative and positive Congestion Charges associated with a valid post-Day-Ahead TOR and ETC schedule change (including changes submitted to the Hour-Ahead Scheduling Process and changes submitted closer to Real-Time where allowed by the contract) will be reversed in RT Instructed Imbalance Energy Settlement on the Settlement Interval. Because Congestion Charges are implicitly collected by the CAISO in the Real-Time settlement and there are no holders of rights to receive Real-Time Congestion revenues under the MRTU design, all charges for Real-Time Congestion will be accumulated in a special and separate neutrality account to be distributed back to non-ETC Control Area metered Demand and exports on a per-MWh basis in Real Time Congestion Offset .

3.2.3 Uninstructed Imbalance Energy Settlement

The Real Time Uninstructed Imbalance Energy (UIE) Settlement Amount is the payment or charge due to or from a resource for its UIE. UIE Settlement Amount consists of two components:

Tier 1 UIE (UIE1) Settlement Amount, accounts for deviations' from resource IIE

Tier 2 UIE (UIE2) Settlement Amount, accounts for deviations' from resource Day Ahead schedule.

For Generating Units, MSS Operators that have elected gross Settlement, System Resources, Participating Load and Pumping Load, the Tier 1 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 1 UIE quantity and its' Resource-Specific Tier 1 UIE Settlement Interval Price. The Tier 2 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 2 UIE quantity and the simple average of the relevant Dispatch Interval LMPs.

3.2.4 Instructed Imbalance Energy Settlement

The IIE Settlement Amount per Settlement Interval for each resource shall be calculated as the sum of the Settlement Amounts for the Standard Ramping Energy, MSS Load Following Energy, Energy Dispatched through the Real-Time Market optimization, the Minimum Load Energy from units Dispatched in the Real-Time, Energy from Regulation, Ramping Energy Deviation, Rerate Energy, Real-Time Self-Schedule Energy, Residual Imbalance Energy, and the portion of Settlement Amounts for Exceptional Dispatches and emergency Energy as described below.

The Settlement Amounts for Energy dispatched through the Real-Time Market optimization, Minimum Load Energy, Energy from Regulation, Ramping Energy Deviation, Rerate Energy, MSS Load Following Energy with gross election, and Real-Time Self-Scheduled Energy and Operational Adjustment for Day-Ahead and Real-Time shall be calculated as the product of the sum of all of these types of Energy and the Resource-Specific Settlement Interval LMP. The Settlement Amount for the Standard Ramping Energy shall be zero.

When the sign convention of the Instructed Imbalance Energy of the two Dispatch Intervals have the same sign or one of the Dispatch Interval IIE is equal to zero, the Real-Time Price Pre-calculation will compute the Resource-Specific LMP as the weighted average of the two 5-minute LMPs at the resource Location, where the weights are the resource's specific Instructed Imbalance Energy MWh quantities in each of the two 5-minute Dispatch Intervals. If there is no Instructed Imbalance Energy or the sign conventions of the Instructed Imbalance Energy of the two Dispatch Interval are different, then Settlement Interval Resource-Specific Real-Time LMP shall be calculated as the simple average of the individual LMPs for the Dispatch Intervals within the given Settlement Interval for the resource.

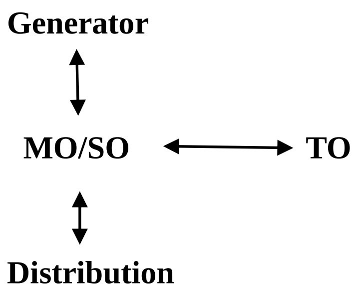
3.3 Introduction of PJM Electricity Market

PJM operates the world's largest completive wholesale electricity market and one of North America's largest power grids. PJM currently coordinates a pool generating capacity of more than 67000MW and operates a wholesale electricity market with more than 200 market buyers, sellers and traders of electricity. The PJM market covers all or parts of PA, NJ, MD, DE, OH, VA, WV, and the district of Columbia. With the April 1, 2002, additional of PJM West, for the first time nationally two separate control areas now operate under a single energy market, single security-constrained economic dispatch and a single governance structure across multiple North American Electric Reliability Councils.

There are two settlement markets in the PJM electricity market, day-ahead energy market and real-time energy market. The 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, forecast supply offers, forecast demand bids and bilateral transaction schedules submitted into the day–ahead market. The day-ahead market is based on a voluntary least-cost security constrained unit commitment and dispatch with several fundamental design features that ensure the market is robust and competitive. This market offers market participants the option to lock in energy and transportation charges at binding day-ahead prices. The balancing market is the real-time energy market in which the clearing prices are calculated every 5 min based on the actual system operations security-constrained economic dispatch. Separate accounting settlements are performed for each market, the day-ahead market settlement is based-on scheduled hourly quantities and on day-ahead hourly prices, the balancing settlement is based on hourly integrated quantity deviations from day-ahead scheduled quantities and on real-time prices integrated over the hour. The day-ahead price calculations and the balancing (real-time) price calculations are based on the concept of locational marginal price (LMP).

3.3.1 Structure of PJM Electricity Market

The structure set up characteristics of the PJM electricity market is the power generation side is fully competition. Transmission and distribution side still according to a fixed rate of return on the theory of operation and supervision of government. Transmission system could be numbers of independent transmission companies, or could be owned by one company like UK. The system operator is only responsible for system operation and market management. The PJM market and most of the US electricity markets all use the similar structure. Show as the figure below.



MO: market Operator, SO: system operator, TO: transmission owner

Figure 3. 1 PJM Electricity Market Main Structure

3.3.2 PJM Day-ahead Energy Market

The day-ahead market provides market participants with the ability to purchase and sell energy at binding day-ahead prices. It also allows transmission customers to schedule bilateral transactions at binding day-ahead congestion charges based on the differences in Locational Marginal Price between the transaction source and sink locations. Load serving entities (LSEs) may submit hourly demand schedules, including any price sensitive demand, for the amount of demand that they wish to lock-in at day-ahead prices. Any generator that has entered into an installed capacity contract must submit an offer schedule into the day-ahead market even if it is self-scheduled or unavailable due to outage. Other generation has the option to offer into the day-ahead market or into the real-time market. Transmission customers may submit fixed, dispatch able or 'up to' congestion bid bilateral transaction schedules into the day-ahead market and may specify whether they are willing to pay congestion charges or wish to be curtailed if congestion occurs in the real-time market. All spot purchases and sales in the day-ahead market are settled the day-ahead prices.

3.3.3 PJM Real-Time Market

The PJM real-time energy market is based on actual real-time operating conditions. Real-time LMPs are calculated based on the actual system operating conditions as described by the PJM state estimator using the applicable generation offer data and dispatchable external transactions. Generators that are available but not selected in the day-ahead scheduling may alter their bids for use in the real-time energy market during the generation re-bidding period from 4:00-6:00 pm, otherwise their original day-ahead market bids remain in effect for real-time energy market. LSEs will pay real-time LMPs for any demand that exceeds their day-ahead scheduled quantities and will receive revenue for demand deviations below their scheduled quantities. Generators are paid real-time LMPs for any generation that exceeds their day-ahead scheduled quantities and will pay for generation deviations below their scheduled quantities. Transmission customers pay congestion charges based on real-time LMPs for bilateral transaction quantity deviations from day-ahead schedules. All spot purchases and sales in the balancing market are settled at the real-time LMPs.

3.4 PJM AGC Market

3.4.1 Overview to Regulation market of PJM

In order to keep balance of electricity generation and load demand as well as maintain system frequency at 60 Hz, it is necessary to provide Regulation and frequency response service. Regulation and frequency response service are implemented by Automatic Generating Control (AGC), which is used to adjust the generation of on-line generators according to the swinging load.

The biggest characteristic of regulation and frequency response service of PJM is that there are no independent electric power plants for regulation. Instead, regulation duty is distributed to each load service enterprise. Load Service Entities (LSE) can fulfill the obligation of regulation through either exploiting their own generating resources or signing contracts with third parties, or even purchasing the service from PJM.

Regulation service has to be provided by PJM generators electrically within the PJM RTO. The PJM RTO requires that the Regulation range of a resource is at least twice the amount of Regulation assigned. A resource capable of automatic energy dispatch that is also providing Regulation reduces its energy dispatch range by the regulation assigned to the resource. This redefines the energy dispatch range of that resource. (The resource's assigned regulation subtracted from its regulation maximum forms the upper limit of the new dispatch range, while the resource's regulation minimum plus its assigned regulation forms the lower limit of the new dispatch range.)

Interconnection office dispatches the generating resources and supply regulation service by sending regulation orders. These generating resources must obey the regulation orders. In cases of conflict, regulation orders have higher priority than energy scheduling ones.

The PJM Regulation Market provides PJM participants with a market-based system for the purchase and sale of the regulation ancillary service. Resource owners submit specific offers to provide regulation, and PJM utilizes these offers together with energy offers and resource schedules from the eMKT System, as input data to the Synchronized Reserve and Regulation Optimizer (SPREGO). SPREGO then optimizes the RTO dispatch profile and forecasts LMPs to calculate an hourly Regulation Market Clearing Price (RMCP). This clearing price is then used to determine the credits awarded to providers and charges allocated to purchasers of the regulation service.

PJM uses resource schedules and regulation and energy offers from the eMKT System as input data to the Synchronized Reserve and Regulation Optimizer (SPREGO) to provide the lowest cost alternative for the procurement of ancillary services and energy for each hour of the operating day. The lowest cost alternative for these services is achieved through a simultaneous co-optimization of regulation, synchronized reserve, and energy. Within the co-optimization, an RTO dispatch profile is forecasted along with LMPs for the market hour and adjacent hours. Using the dispatch profile and forecasted LMPs, an opportunity cost is estimated for each resource that is eligible to provide regulation. The estimated opportunity cost for demand resources will be zero. The estimated opportunity cost is then added to the regulation offer price to create the merit order price. All available regulating resources are then ranked in ascending order of their merit order prices, and the lowest cost set of resources necessary to simultaneously meet the PJM Regulation Requirement, PJM Synchronized Reserve Requirement, and provide energy that hour is determined. The highest merit order price associated with this lowest cost set of resources awarded regulation becomes the RMCP for that hour of the operating day. Resource owners may self-schedule Regulation on any qualified resource, and the merit order price for any self-scheduled Regulation resource is set to zero.

In the after-the-fact settlement, any resources self-scheduled to provide regulation are compensated at the hourly RMCP. Any resources selected by PJM to provide Regulation are compensated at the higher of the hourly RMCP or their real-time opportunity cost plus their Regulation offer price. LSEs required to purchase

Regulation are charged the hourly RMCP plus their percentage share of opportunity cost credits.

According to PJM regulation requirement determination, certain Regulation margin must be reserved for indifference regulation. The total PJM regulation requirement for the PJM RTO is determined in whole MW for the on-peak (0500 – 2359) and off-peak (0000 – 0459) periods of day. The PJM RTO on-peak regulation requirement is equal to 1.1% of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak regulation requirement is equal to 1.1% of the forecast valley load for the PJM RTO for the day. The requirement percentage may be adjusted by the PJM Interconnection, if the adjustment is consistent with the maintenance of NERC control standards. Figure 3.2 demonstrates the previous content.

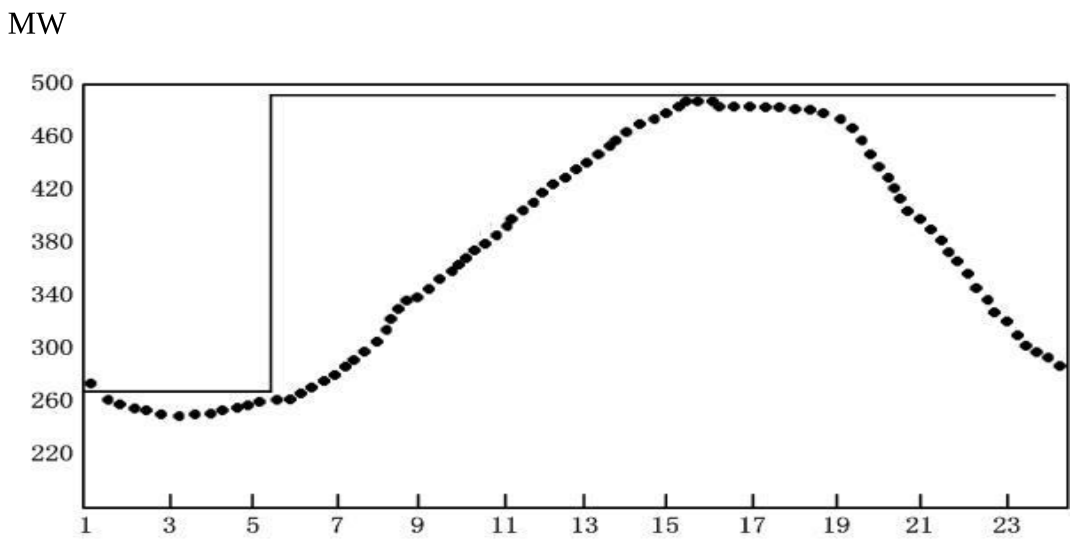


Figure 3. 2 Frequency Modulation t

3.4.2 PJM Regulation market operation

When the total Regulation requirement for the PJM RTO is obtained, according to Settlement, each LSE takes the respective Regulation obligation proportionally. In fact, the Regulation capacity is determined by the actual load percentage in PJM RTO. LSEs may fulfill their regulation obligations by:

a. Self-scheduling the entity's own resources;

b. Entering contractual arrangements with other market participants; or

c. Purchasing regulation from the regulation market.

The following are procedures of purchasing regulation ancillary service in the regulation market.

3.4.2.1. Regulation Offer Period

Resource owners wishing to sell regulation service must at least supply a cost-based regulation offer price by 6:00 p.m. the day prior to operation. The offer price cannot be more than $ 100/MW and is 24h efficacious during the operation-day.

Regulation offers may be submitted only for those resources:

a. Electrically within the PJM RTO and;

b. Meeting the following criteria:

- Generation resources must have a governor capable of AGC control.
- Resources must be able to receive an AGC signal.
- Resources must demonstrate minimum performance standards.
- Resources must exhibit satisfactory performance on dynamic evaluations.
- Resources MW output must be telemeter to the PJM control center in a manner determined to be acceptable by PJM.
- New resources must pass an initial performance test.

Besides offer prices, the following information must be supplied:

a. Resource Regulating Status (available, unavailable, self-scheduled);

b. Regulation Capability (above and below regulation midpoint, MW);

c. Regulation Maximum and Minimum values, considering any necessary offsets (MW).

The above information can be supplied or verified till 60 min before the start of the specified operating hour, when the respective regulation market closes. Should a unit‘s regulation operating parameters change after the regulation market closes for an hour, the following changes may be made through direct communication with the PJM Scheduling Coordinator.

a. Resource Regulating Status

b. Available to unavailable

c. Self-scheduled to unavailable

d. High Regulation Limit may be decreased but not increased and Low Regulation Limit may be increased but not decreased.

e. Regulating capability may be decreased but not increased.

f. Regulation Maximum capability may be decreased but not increased and Regulation Minimum capability may be increased but not decreased.

g. Any resource that is unavailable for energy when the Regulation market closes and becomes available during the operating hour may also be made available or self-scheduled for regulation. Any associated regulation offer information may be changed for such resources, since none was considered in the calculation of RMCP.

NOTE: Resources willing to provide energy and regulation service have to deduct the energy scheduling range at the energy market, shown in Fig. 3.3.

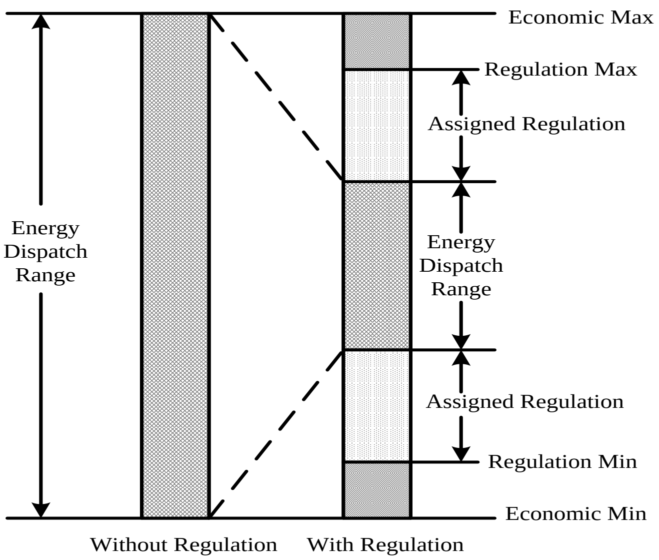


Figure 3. 3 Limit Relationship for Regulation

Bilateral transactions must be supplied by buyer via user interface of Two Settlement and confirmed by sellers before 12:00 the day when the transactions begin. Once the bilateral transaction is supplied, it is final and only can be deleted and re-supplied.

3.4.2.2 Regulation Market Clearing

PJM updates regulation information (such as regulation capacity, regulation status, etc.) each hour on the operating day, clear regulation market according to these information and offer prices supplied day-ahead, and conduct periodic checks of regulation performance.

Procedures of clearing regulation market are as follows.

Calculate the opportunity cost of regulation resources.

(1). The Synchronized Reserve and Regulation Optimizer (SPREGO) optimizes resource energy schedules and forecasts LMPs for the operating hour while respecting appropriate transmission constraints and Ancillary Service requirements.

(2). SPREGO utilizes these the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the "lost opportunity cost energy schedule"), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation.

Opportunity cost= GENOFF*ED-LMP ……….3.1

Where, ED is the price from the lost opportunity cost energy schedule associated with the setpoint the resource must maintain to provide its full amount of regulation; GENOFF is the MW deviation between economic dispatch and the regulation setpoint. Operation cost is zero if resource is self-scheduled.

Both lost opportunity cost calculations are defined simplistically for the purpose of the manual. The actual calculations are integrations that may be visualized as the area on a graph enclosed by the lost opportunity cost energy schedule, the points on that curve corresponding to the resource‘s desired economic dispatch and the setpoint necessary to provide the full amount of regulation, and the LMP.

a. Create merit order price of each regulating resource with the obtained opportunity cost and regulation offer price.
b. SPREGO ranks all available regulating resources in ascending merit order

price, and simultaneously determines the least expensive set of resources.

c. The highest merit order price becomes the Regulation Market Clearing Price (RMCP) for that hour.

d. The hourly RMCPs are posted in the User Interface public view.

Here is an example for regulation market clearing. From Table 3.1 to Table 3.5, “Available” means that regulating resource is in good status thus able to provide regulation service. “Self-scheduled” means that regulating resource is able to provide regulation basing on the supplied information at RMCP.

Table 3. 1 Status of regulating resource and results of energy day-ahead market

Regulating resource	Status	Regulation capacity	Regulation offer price ($)	Energy offer price ($)	Hourly LMP ($)
A	Available	10	2	13	22
B	Self-scheduled	5	0	20	22
C	Available	7	4	19	22
D	Available	8	5	14	22
E	Available	3	3	15	22
F	Self-scheduled	4	0	19	22
G	Available	5	3	18	22
H	Available	10	3	9	22

Table 3. 2 Opportunity costs basing on Eq.3.1

Regulating resource	Status	Regulation capacity	Regulation offer price ($)	Energy offer price ($)	Hourly LMP ($)	*LOC* ($/MW)
A	Available	10	2	13	22	9
B	Self-scheduled	5	0	20	22	0
C	Available	7	4	19	22	3
D	Available	8	5	14	22	8
E	Available	3	3	15	22	7
F	Self-scheduled	4	0	19	22	0
G	Available	5	3	18	22	4
H	Available	10	3	9	22	13

Table 3. 3 The obtained merit order prices

Regulating resource	Status	Regulation capacity	Regulation offer price ($)	Energy offer price ($)	Hourly LMP ($)	*LOC* ($/MW)	*Merit order price* ($)
A	Available	10	2	13	22	9	11
B	Self-scheduled	5	0	20	22	0	0
C	Available	7	4	19	22	3	7
D	Available	8	5	14	22	8	13
E	Available	3	3	15	22	7	10
F	Self-scheduled	4	0	19	22	0	0
G	Available	5	3	18	22	4	7
H	Available	10	3	9	22	13	16

Table 3. 4 Rank of merit order prices

Regulating resource	Status	Regulation capacity	*Merit order price* ($)
B	Self-scheduled	5	0
F	Self-scheduled	4	0
C	Available	7	7
G	Available	5	7
E	Available	3	10
A	Available	10	11
D	Available	8	13
H	Available	10	16

Table 3. 5 RMCP is zero while regulation requirement is 24

Regulating resource	Status	Regulation capacity	*Merit order price* ($)
B	Self-scheduled	5	0
F	Self-scheduled	4	0
C	Available	7	7
G	Available	5	7
E	Available	3	10
RMCP			
A	Available	10	11
D	Available	8	13
H	Available	10	16

Regulation requirement = 24 MW

SPREGO ranks all available regulating resources in ascending merit order price, and simultaneously determines the least expensive set of resources. For this example, the determined set is regulating resources {B, F, C, G, E}.

PJM clears the regulation market simultaneously with the synchronized reserve market, and posts the results no later than 30 minutes prior to the start of the operating hour.

3.4.2.3 Dispatching Regulation

The PJM Operator maintains total Regulation Zonal capabilities within a +/- 2%, but no less than +/-15MW bandwidth around the RTO regulation requirement.

PJM obtains the most cost efficient Regulation Ancillary Service available, as needed, to meet the PJM RTO‘s Regulation Requirement. PJM assigns Regulation in economic order based on the total cost of each available resource to provide Regulation, including real time opportunity cost and the resource‘s Regulation offer price. The real time opportunity cost is the result based on hour-ahead locational margin price or latest-5-min locational margin cost.

In the event of regulation excess (exceeding +/-15MW bandwidth), PJM dispatcher telephoned local control centers associated about the regulation capacity of each regulating resource. The Assigned Regulation (AR) signals are then automatically sent to the local control centers, and the local control centers assign the regulation capacity to each regulation resource. Resource Owners are responsible for maintaining unit regulating capability. Fig.3.4 shows how the Regulation is assigned to the resources.

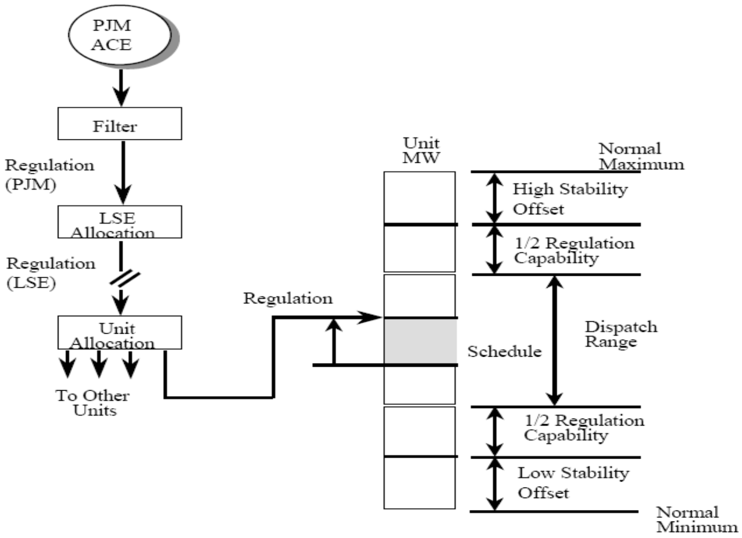


Figure 3. 4 Area Regulation Assignment

PJM dispatcher re-assigns regulating capability as necessary to meet the PJM Balancing area‘s Regulating Requirement (+/-15MW bandwidth), and informed the local control center of the last assignment via telephone.

Market Sellers must comply with Regulation dispatch signals that are transmitted by PJM. Market Sellers must operate their regulating resources as close to desired output levels.

a. Regulation Deficiency

After the initial Regulation assignments are made, and throughout the operating hour, PJM Members report changes to their resource‘s regulating capabilities either by a phone call to PJM or by virtue of the Total Regulation (TReg) signal each company sends to PJM. If a resource becomes unable to supply its assigned amount of Regulation, the PJM dispatcher must de-assign deficient resources and assign replacement Regulation to ensure that the total Regulation requirement (+/-15MW bandwidth) is met. Such assignments are made economically based on each available resource‘s total cost to provide regulation, including real time opportunity cost and the resource‘s regulation offer price. If, after assigning all available Regulation, the PJM Regulating Requirement is still not met, PJM dispatcher operates the system without the required amount of Regulation, logging such events.

b. Regulation Excess

If during the period an excess in assigned Regulation occurs and the total PJM RTO Regulation value exceeds the objectives by 15 MW or more, PJM dispatcher de-assigns Regulation economically based on each resource‘s total cost to provide regulation, including real time opportunity cost and the resource‘s regulation offer price.

c. PJM Actions

i) PJM dispatcher continuously monitors the Regulation deviation to assess Resource Owner fleet capability and reassigns Regulation as required.

ii) The PJM Operator communicates any change in resource regulating reassignments to individual Local Control Centers.

d. PJM Member Actions:

(1) When initial assignments and reassignments are made, each affected Resource Owner dispatcher then updates the entity‘s regulating capability as defined by the Resource Owner TReg value.

(2) Participants report to the PJM dispatcher changes (of at least +/-1 MW for duration greater than 15 minutes) to assigned Regulation capability.

(3) One PJM Member may sell Regulation Ancillary Service to another PJM Member. The two members must agree on the MW amount of capability being sold, schedule Regulation accordingly, and submit the two-PJM Member Regulation transaction to PJM via eMKT.

(4) All two-PJM Member transfers of regulating capability must be submitted as MW amounts via eMKT.

(5) The two members agree on the amount and duration of the Regulation transaction prior to the sale. The buying member submits the MW amount of the two-PJM Member transaction, the selling member, and the start and end time of the transaction via eMKT. The selling member confirms the transaction via eMKT by 4:00pm the day after the operating day.

3.4.3 PJM AGC Market Settlements

Regulation settlement is a zero-sum calculation based on the regulation provided to the market by generation owners and purchased from the market by LSEs.

Each PJM load serving entity, or other Regulation buyer, is charged at the hourly Regulation Market Clearing Price (RMCP) for the amount of Regulation purchased to meet their hourly obligation. Hourly Regulation obligations equal their real-time load ratio share of the total amount of Regulation assigned by PJM that hour, adjusted for any bilateral Regulation transactions. In addition, net purchasers of Regulation in an hour are also charged a proportionate share of any lost opportunity credits paid to regulating generators for unrecovered costs over and above their RMCP payments (including regulation lost opportunity costs incurred by generators operating for PJM solely for Regulation). That is,

*Charge of each LSE = Hourly RMCP * Amount of Regulation purchased + certain proportionate share of any lost opportunity credits for unrecovered costs over and above their RMCP payments.*

Energy resources that are self-scheduled to provide energy and do not supply an energy bid are not eligible to collect opportunity cost credits. These resources will receive credit equal to the RMCP times the amount of regulation self-scheduled on or assigned to them.

Resource owners of self-scheduled Regulation are credited at the hourly RMCP for each MW of Regulation supplied. Resource owners providing pool-scheduled Regulation are credited for each Regulation MWh at the higher of the hourly RMCP or their Regulation offer price (plus real-time opportunity cost, for generating resources).

3.4.4 Qualifying Regulating Resources

In order to ensure the quality of Regulation supplied to control the PJM RTO, a quality standard is developed. A resource must meet the quality standard to be permitted to regulate. In general, there are two phases to qualifying a regulating resource:

i) Certifying the resource

ii) Verifying regulating capability

An Area Regulation (AR) test is used for both certifying and verifying regulating capability for a resource.

NOTE: It must be emphasized that the Regulation test is not intended to test a resource‘s governor response to power system frequency changes.

3.4.4.1 Regulation Test

The AR test is run during a continuous 40-minute period when, in the judgment of PJM test administrator, economic or other conditions do not otherwise change the base loading of the resources that are being tested. Changes in base loading for a resource during the test period invalidate the test for that resource.

During the AR test, the AR signal is fixed for the following four ten-minute periods:

- ✧ T0-T10
- ✧ T10-T20
- ✧ T20-T30
- ✧ T30-T40

The following steps describe the implementation of the test. It is assumed that the first non-zero AR signal is positive. (NOTE that the corresponding sequence in which the first non-zero AR signal is negative is equally valid.)

Step One: T0-T10 — During this time period, the AR signal is equal to zero. This is the initiation of the AR test. This ten-minute period is provided so that the regulating resource settles at its base loading. At T10, the actual loading is sampled and the resulting value defines the base loading for that resource.

Step Two: T10-T20 — During this 10 minute period, the AR signal is set to full raise.

Step Three: T20-T30 — During this 10 minute period, the AR signal is set to zero.

Step Four: T30-T40 — During this 10 minute period, the AR signal is set to full lower.

Step Five: T40 — At this time, the AR signal is set to zero to terminate the test.

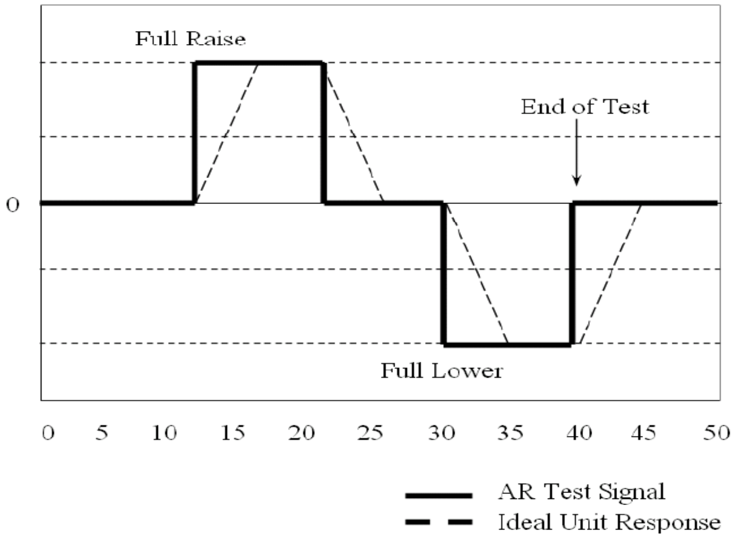


Figure 3. 5 Regulation Test Pattern

Once an AR test is announced, a Resource Owner is not permitted to change any resources Regulation assignment. Scoring the AR test is based on compliance to two calculations:

1) Rate of Response Compliance — The rate of response compliance is a measure of a resource's ability to achieve its Regulation assignment within five minutes.

2) Regulation Mismatch Compliance — The Regulation mismatch compliance is a measure of a resource's ability to maintain its actual loading at a constant desired level for five minutes.

These two compliance values are averaged to yield a test score.

The Rate of Response Compliance is an average of three compliance calculations corresponding to the end of each of the three five-minute ramping periods (T15, T25, and T35) during the test.

The Rate of Response Compliance is determined as follows:

At T15, the actual loading of the resource is sampled. This value is called AG15. Note, this is the actual loading and includes both the base generation and the AR response.

The Rate of Response Compliance at time T15 (RORC15) is:

$$RORC15 = 100 - \left[\left(\frac{ABS(Base\ Loading\ + AR\ Signal\ \ - AG15)}{Resource's\ Assigned\ AR} \right) \times 100 \right]. \qquad \ldots\ldots\ldots 3.2$$

This calculation is repeated at T25 and T35, yielding RORC25 and RORC35. The Rate of Response Compliance is:

$$Rate\ of\ \ Response\ Compliance\ = \frac{RORC15 + RORC25 + RORC35}{3}. \qquad \ldots\ldots\ldots 3.3$$

During the time period T15-T20, a number of samples, n, of actual loading, AG1, AG2, … , AGn, are taken. The mismatch for the M20 period is:

$$\mathrm{M20} = \frac{1}{n} \sum_{i=1}^{n} \left| 100 - \left(\left(\frac{ABS(Base\ Loading\ + AR\ \ - AG_i)}{Resource's\ Assigned\ AR} \right) \times 100 \right) \right|, \qquad \ldots\ldots\ldots 3.4$$

Where， AGi= AG1, AG2,…, AGn.

This calculation is repeated for T25-T30 and T35-T40, yielding M30 and M40, respectively. The Regulation Mismatch Compliance is:

$$Regulation\ Mismatch\ Compliance = \frac{M20 + M30 + M40}{3}. \qquad \ldots\ldots\ldots 3.5$$

The AR test score is determined by averaging the two compliance values.

$$Test\ \ Score = \frac{Rate\ of\ \ Response\ Compliance + Regulation\ Mismatch\ Compliance}{3}. \qquad \ldots\ldots 3.6$$

The range for a valid test score is zero to one hundred percent. Test score results that are equal to 100% indicate the perfect, idealized response. All non-ideal responses yield positive values that decrease as the responses deviate from 100%. Any negative test results default to zero. A valid test requires a continuous 40-minute period of uncorrupted test data. In the event that test data is of questionable integrity, validation is handled on a case-by-case basis. A resource may be certified only after it achieves three consecutive scores of 75% or above.

NOTE: All above is the situation of PJM EAST. For PJM WEST, there are two differences mainly.

a. PJM WEST takes 1% of the forecast of maximum load as the regulation requirement for operation day.

b. Settlement in PJM WEST is based on cost.

3.5 PJM Financial Transmission Right

Open transmission access has been standing at the center of electricity restructuring. A mechanism that allows for efficient allocation of transmission access rights has been sought in every market design. Transmission access right allocation modeling has evolved through the physical right allocation to financial transmission right methods. Currently, the FTR methods are adopted in several U.S. markets, including PJM, ISO-NE, MISO, and NY ISO.

An FTR is a financial entitlement that can hedge its owner against congestion charges incurred on a specified transmission path. It financially binds the owner to the transmission congestion activity on that path. The FTR path is defined by the transmission reservation from the point where the power is scheduled to be injected onto the grid (source) to the point where it is scheduled to be withdrawn (sink). Once determined, the FTR is in effect for the predefined period whether or not energy is actually delivered and offsets the congestion cost for the FTR's awarded MWs.

An FTR's economic value is based on the MW reservation level multiplied by the difference between the LMPs of the source and sink points. These LMP differences reflect opportunity costs of the transmission paths. FTRs in the form of obligation or forward type are financially binding and can either be a benefit or a liability to the holder. They are a benefit when the designated path is in the same direction as the congested flow. This occurs when the sink node LMP is greater than the source node LMP. FTRs are a liability when the inverse occurs. The holder of an obligation FTR must pay for holding the FTR when the sink node LMP is less than the source node LMP.

FTRs may be acquired in different ways depending on the market design. In the PJM market, transmission service customers who pay the embedded cost of the transmission system have the option of requesting auction revenue rights (ARR) through an annual allocation process. ARRs entitle its owner to share the revenue proceeds from FTR auctions. In annual FTR Auctions, ARR owners are given a self-scheduling choice to convert their ARRs into FTRs. Market participants can purchase FTRs directly from FTR auction markets, which are performed annually or monthly. They may also procure FTRs through bilateral transactions.

PJM's annual FTR auction offer complete grid capability for market participant to purchase, while monthly FTR auctions are reconfiguration auctions that allows market participants to adjust their FTR positions on a monthly basis. The annual auction consists of four rounds with each round offering 25% of the entire transmission capability. The monthly reconfiguration auctions are single round auctions. The objective of the FTR auction market is to determine the highest valued combination of FTRs, in terms of participant bids, to be awarded in the auction. The FTRs awarded must be simultaneously feasible in conjunction with the previously awarded FTRs while respecting pre- and post-contingency transmission limits. The simultaneous feasibility testing (SFT) includes power flow and n-1 contingency analysis. FTR offers and bids are cleared based on their comprehensive prices determined by both their raw bid/offer prices and their relevant impacts on all the binding constraints. This optimization is typically based on a DC transmission network model.

As mentioned earlier, the proceeds of the PJM FTR auction are allocated to ARR holders. An ARR is defined from a source point to a sink point for a specific MW amount. The economic value of the ARR is determined by the clearing prices in the annual FTR auction. The amount of the credit that the ARR holder should receive for each round is equal to the MW amount of the ARR (divided by the number of rounds) times the price difference from the ARR delivery point to the ARR source point as shown in the following formula:

$$ARR\,Credit = \left(ARR\,MW \;/\; Num\,of\;\; Rounds \right) * \left(LMP_{Sink} - LMP_{Source} \right) \qquad \ldots\ldots\ldots 3.7$$

Therefore, the ARR mechanism can provide a revenue stream to the transmission customer to offset the purchase price of FTRs on the paths for which they hold ARRs. Participation in the annual FTR auction for ARR holders is optional in the sense that an ARR holder can directly schedule an FTR purchase in the annual FTR auction on the same path and for the same MW amount as its ARR. In this case, the ARR holder would receive the FTR and be guaranteed that the ARR credit would be exactly equal to the FTR purchase price. Therefore, ARRs can act as a hedge for Network and Firm Point-to-Point transmission customers against the purchase price of an FTR in the auction.

The various FTR products that are purchased in the FTR auctions can act as hedges against congestion charges incurred in the PJM day-ahead energy market. The economic value of FTRs is determined by the hourly clearing prices in the PJM day-ahead energy market as shown in the following equation:

$$FTR\,Credit = \left(FTR\,MW \right) * \left(LMP_{Sink} - LMP_{Source} \right) \qquad \ldots\ldots\ldots.3.8$$

The transmission customer can therefore hedge energy deliveries by purchasing FTRs on the same or equivalent paths as the energy delivery is scheduled.

3.6 PJM Locational Marginal Price

The PJM market design is based on the concept of LMP. A key feature of an LMP model is that there is a fundamental consistency between the energy price and the price of delivery on the transmission system. In this model, the energy price difference between the injection point and the withdrawal point is equal to the transmission congestion cost. Therefore, a market participant who injects (sells) energy at location A and withdrawal (purchases) at location B will pay exactly the same as a market participant who pays the transmission congestion charge to deliver a bilateral contract from A to B. This consistency is a feature of both the PJM day-ahead market and the PJM real-time market.

In the additional to the LMP concept, the fundamental design objectives of the PJM day-ahead energy market are: 1) to provide a mechanism in which all participants have the opportunity to lock in day-ahead financial schedules for energy and transmission; 2) to coordinate the day-ahead financial schedules with system reliability requirement; 3) to provide incentive for resources and demand to submit day ahead schedule; 4) to provide incentive for resources to follow real-time dispatch instructions.

The first market design objective is accomplishment by providing a variety of alternatives for participation in the day-ahead market. The participation options include the ability to self-schedule resources, the ability to submit bilateral schedules and the ability to submit offers to sell or bids to buy from the day-ahead spot market. This flexibility ensures that all market participants have equal access to the day-ahead market. Therefore, any barriers to trade in the day-ahead market are minimized so that the market will be as competitive as possible. In order to further promote liquidity, the market design also includes the ability to submit purely financial positions in the form of virtual supply offers and virtual demand bids. In this way, the day-ahead market provides both the ability the hedge physical delivery and the ability to enter financial positions into the market. All positions that are cleared in the day-ahead market are financially binding and will liquidate in the balancing market if they are not covered by a real-time energy delivery.

The second market design objective is important to ensure that the day-ahead schedules are physically feasible and are consistent with reliable system operations. This feature is significant because it requires that the power flow model used to analyze the day-ahead market is consistent with the power flow model that is used in real-time system operations. It also required that the day-ahead market is cleared considering the same single contingency criteria and transmission equipment ratings that are used in real-time operations. Since the underlying powerflow model and operating constraints are consistent between the day-ahead forward market and the real-time dispatch, the LMP signals are consistent between the day-ahead and real-time markets as well. In addition to the powerflow model consistency, the day-ahead market also respects system reserve requirements and the generator physical operating limitations. This design feature ensures that the financial schedules that results from the day-ahead forward market are consistent with the physical transmission capability. Therefore the day-ahead scheduling process ensures that the transmission capability is not over-subscribed and ensures that the generation schedules are consistent with the generator's physical capabilities. The fundamental consistency between the forward market and the real-time market ensures a robust market design that promotes economic efficiency and it enables the market to avoid the gaming opportunities that have plagued other market designs.

The third market design objective involves more than just the fundamental structure of a two-settlement system. It also requires that there is consistency between the market pricing mechanisms and that price convergence occurs between the markets over time.

3.6.1 PJM LMP Model

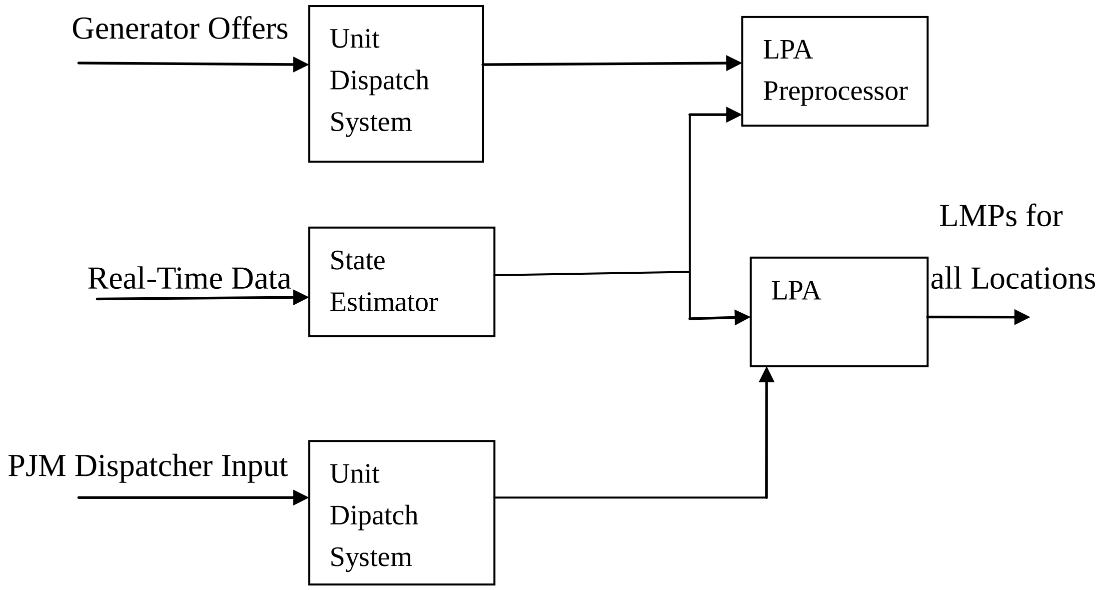


Figure 3. 6 Model of LMP

The PJM LMP calculation process consists of a variety of programming modules that are executed as part of the real-time sequence that executes every five minutes on the

PJM energy management system (EMS). A functional diagram of the PJM LMP model is shown in the Figure 3.6. As indicated in Figure3.6, the main modules of the PJM LMP model are: State estimator, LPA preprocessor, locational price algorithm (LPA), unit dispatch system (UDS).

Each of these modules is described in detail below. In addition to the main modules that are listed in the diagram, several other programs designed to ensure data integrity are executed as part of the PJM LMP calculation process. These programs include the LPA Input Data Consistency Check (ICC) program and the LPA put data consistency check (OCC) program.

The primary purpose of the ICC is to perform data verification on all input data to the LMP calculation process to ensure that the information is current, consistent and reasonable. The ICC program will monitor all input data files to ensure that each file's operating system timestamp and internal timestamps are current and consistent with the interval being processed. In addition, the ICC will check any transmission constraint data to verify that any contingencies entered and their corresponding controlling actions are all entered consistently, accurately, and in a timely manner. The ICC also monitors the status of the state estimator solution to ensure that the solution is a valid solved powerflow solution. The ICC executes at the beginning of the LMP calculation sequence and if a problem is identified the program logs the error to the LPA error log and produces an appropriate alarm to the system operator.

The primary purpose of the OCC is to verify that the LMP calculation is performed accurately and completely. The OCC will check all the output data files to ensure that each program completed successfully and produced its corresponding output file along with

LMP = Generation Marginal Cost (Energy Component)

+ ***Transmission Congestion Cost (Congestion Component)***

+ ***Cost of Marginal Losses (Loss Component)***

The energy component is the same for all locations and equals to the system balance shadow price.

Congestion components equal zero for all locations if there are no binding constraints。

The loss component is the marginal cost of additional losses caused by supplying an increment of load at the location.

LMPs will not change if we move the reference bus from one location to another. However, all three components are dependent on the selection of the reference bus (due to the dependency of the sensitivities on the location of the reference bus).

3.6.2 Optimal Power Flow (OPF) Formulation

In order to efficiently use generation resources and the transmission grid in a competitive environment optimal power flow is incorporated. OPF algorithm was formulated in 1960's [7], to minimize some objective function subject to a number of equality and inequality constraints. The objective of OPF is to determine the most cost efficient generations from all available resources to operate a power system with an objective function of minimizing operating cost subject to power flow equations and network constraint. OPF functionally combines the power flow (PF) with Economic Dispatch (ED) with the objective function of minimizing cost function (operating cost) taking into account of realistic equality and inequality constraints.

This optimization is applied in the spot pricing theory to dispatch generation and load in an economic manner where suppliers submit bid curves to the pool operator and an optimization routine is carried out to determine the dispatch results. Suppliers are then paid a price according to their bus price and consumers pay at their bus price. Several methods have been used to solve optimal power flow; these include lambda iteration method, gradient method, Newton's method, linear programming method and interior point method. In general, OPF problem for real power can be expressed as:

$$Min\sum_{k=1}^{N} C_{gen,k}(P_{gen,k})$$ Energy Bid …….(3.9)

Subject to

$$\sum_{Gen} P_{gen,k} = \sum_{Load} P_{load,k} + \sum_{transfer} P_{transfer}$$ Active Power Balance ……..(3.10)

$$P_{gen,k}^{\min} \le P_{gen,k} \le P_{gen,k}^{\max}$$ Active Power Limit …......(3.11)

$$g_{line,l} \le g_{line,l}^{\max}$$ Line limit …….(3.12)

The generator cost function model at bus k, is given as:

$$C_{gen,k}(P_{gen,k}) = (a + bP_{gen,k} + cP_{gen,k}^{2}) * FuelCost$$ ……..….(3.13)

Where a, b and c are the cost coefficient with their unit in

$$L = \sum_{k=1}^{N} C_{gen,k}(P_{gen,k}) + \sum_{k=1}^{N} \lambda_k [\sum_{Gen} P_{gen,k} - \sum_{Load} P_{load,k} - \sum_{Transfer} P_{Transfer}] +$$
$$\sum_{l=1}^{nl} \mu_l [g_{line,l-} g_{line,l}^{\max\ flow}] + \sum_{k=1}^{N} \pi_k^{\max} [P_{gen,k} - P_{gen,k}^{\max}] + \sum_{k=1}^{N} \pi_k^{\min} [P_{gen,k}^{\min} - P_{gen,k}]$$
……….(3.14)

Applying Karush-Kuhn-Tucker (KKT) theorem [8], the LMP can be expressed as follows:

$$\lambda_k = \lambda_k^{energy} + \lambda_k^{loss} + \lambda_k^{cong}$$ ………….(3.15)

Or $$\lambda_k = \lambda_o - \lambda_o \frac{\partial P_{loss}}{\partial P_k} - \sum_{l=1}^{nl} \mu_l T_{l,k}$$ ……….....(3.16)

Where λ_k is the marginal price or Locational Marginal Price at bus k,

λ_o is the marginal cost of energy component

λ_k^{los} is the marginal cost of loss component at bus k

λ_k^{con} is marginal cost of congestion component at bus k

$\frac{\partial P_{los}}{\partial P_k}$ is the real power loss sensitivity factor at bus k, denotes as L_k

μ_l is the vector of Lagrange multipliers associated to network constraints on line l,

$T_{l,k}$ is the sensitivity factor of the network at bus k due to network constraints on line l.

The bus of marginal price in Equation 3.7 can be summarized into two parts

a) λ_o Represents marginal generation cost, also called 'system lambda' or 'system marginal price' and

b) Second and third terms in Equation 3.7 are called 'lambda differential' also known as 'delivery cost' that varies within a network which are dependent to the cost of marginal losses and network constraints. Under unconstrained condition, where there is no line overloading, the third term will be equal to zero leaving the cost of lambda differential just depending on the cost of marginal losses as:

$$\lambda_k = \lambda_k^{loss} + \lambda_k^{energy} \qquad \text{…………..(3.17)}$$

The Lagrange multipliers determined from the solution of the optimum power flow provide important economic information regarding the power system. A Lagrange multiplier can be interpreted as the derivative of the objective function with respect to enforcing the respective constraint. Therefore, the Lagrange multipliers associated with enforcing the power flow Equations of the OPF can be interpreted as the marginal cost of providing energy service (£/MWh) to that bus in the power system. This marginal cost is also known as locational marginal price and sometimes is called the shadow price of the power injection at the node. The locational marginal price is then decomposed into three components which are the cost of energy, cost of marginal losses and cost of marginal congestion to reflect the effects of system marginal cost, loss compensation and congestion management as well as voltage support. These components are all important cost terms in the deregulated electricity market and can be forwarded to the generators and consumers as control signals to regulate the level of their generations and consumptions.

3.6.3 Decomposition of LMP

LMP for a location within a system can be determined by running AC OPF using Equation (3.9) to Equation (3.12). The LMP for a location in the network can then be decomposed into three components, which are the energy, loss and congestion components.

3.6.3.1 Decomposition of LMP based on Single Bus Reference

LMP decomposition based on single bus reference can be summarized as follows:

Step 1: Run the ACOPF to obtain the Lagrange multiplier associated to the real power balance constraint (i.e., LMP), real power loss sensitivity, sensitivity factor due to network constraints on line l and the Lagrange multiplier associated to the line constraint.

Step 2: The system's energy cost component is obtained by referring to the angel reference bus. The LMP at the angle reference bus is normally taken as the energy cost [8][9]

$$\lambda_k^{energy} = \lambda_0 \qquad \text{..........(3.18)}$$

Step 3: The cost of loss component at bus k is calculated by multiplying the system's energy cost component with the real power loss sensitivities of the system.

$$\lambda_k^{loss} = -\lambda_0 \frac{\partial P_{loss}}{\partial P_k} \qquad \text{...........(3.19)}$$

The negative sign on the right-hand side of Equation (3.19) is the marginal cost of transmission losses from the reference bus to bus k.

Step 4: Subtracting the LMP from the system's energy cost component and cost of loss component will give the cost of congestion component as expressed in Equation (3.20). The cost of congestion component also can be calculated using Equation (3.21) using the results obtained in Step 1.

$$\lambda_k^{cong} = \lambda_k - \lambda_k^{energy} - \lambda_k^{loss} \qquad \text{..........(3.20)}$$

$$= -\sum_{l=1}^{nl} \mu_l T_{l,k} \qquad \text{……….(3.21)}$$

The negative sign in the right-hand side of Equation (3.13) is the marginal cost of transmission congestion from reference bus to bus k. From the spot pricing based on locational marginal price, generators will get paid and loads are charged at their respective locational price. A surplus is collected for the owners of the transmission system. The surplus is directly dependent on the values of the lambda differentials which are in this case the cost of transmission losses and the cost of congestion due to the line limits.

3.6.3.2 Decomposition of LMP based on Load Weighted Average [10]

Another approach of LMP decomposition is based on load-weighted average (i.e., approximation to distributed slack bus decomposition). This approach is based on the observation that the load-weighted average loss component is close to zero when a load based distributed reference bus is used. The approximation of LMP decomposition using load-weighted average can be summarized as follow:

Step 1: Run AC Optimal Power Flow using single bus reference at bus 1 to obtain total LMP and its cost components (i.e., energy cost, λ_k^{energy}, cost of marginal loss, λ_k^{loss} and cost of marginal congestion, λ_k^{cong}). The LMP value and its cost components are obtained as described in last section.

Step 2: Recalculate system average energy component at bus k based on single reference bus 1

$$EnergyLMP_k^{new,1} = \frac{\sum_{k=1}^{N} (\lambda_k^1 * MW_{load,k})}{\sum_{k=1}^{N} MW_{load,k}} \qquad \text{……………3.22}$$

Step 3: the system average for the cost of marginal loss component at bus k based on reference bus 1 is calculated as follows:

$$LossLMP_k^{average,1} = \frac{\sum_{k=1}^{N}(\lambda_k^{loss,l} * MW_{load,k})}{\sum_{k=1}^{N} MW_{load,k}} \quad \text{..............3.23}$$

Where λ_k^l is the LMP at bus k based on single reference bus 1

(the superscript reference refer to the bus number)

$MW_{load,k}$ is the amount of load at bus k in the system

$\lambda_k^{loss,l}$ is the cost of marginal loss component at bus k based on single reference bus 1

Step 4: the marginal cost of loss component of each bus relative to the load weighted average based on reference bus 1 recalculated as:

$$LossLMP_k^{new,l} = \lambda_k^{loss,l} - LossLMP_k^{average,l} \quad \text{............3.24}$$

Step 5: Recalculate the marginal cost of congestion component of each bus based on single reference bus 1:

$$\mathrm{CongLMP}_k^{new,l} = \lambda_k^l - \mathrm{EnergyLMP}_k^{new,l} - \mathrm{LossLMP}_k^{new,l} \quad \text{...........3.25}$$

Step 6: Step 1 to Step 5 is repeated with single bus reference at bus 2 until N bus system to obtain similar decomposition for load-weighted average methodology.

3.6.3.3 Decomposition of LMP based on Distributed Slack Bus

In real network, changes in supply to match changes in load do not occur only at the slack bus and the decomposition of LMP components ends up being an arbitrary function depending on the selection of slack bus. As a result, when a single reference bus is used for LMP decomposition, the relative size of the energy, loss and congestion components and the revenues that are assigned to the bus can bring financial impact to some market participant on the selection of slack bus. An acceptable solution would be to use a common reference bus in the power-flow formulation for obtaining a similar LMP decomposition independent to the selection of reference bus.

Therefore, LMP decomposition impendent to the selection of reference bus is proposed. The load distributed-slack variable is mostly use in the real network to distribute the system slack MW among the loads in proportion to their MW load values throughout the system in order to maintain power balance. Using distributed slack based on load, the calculation for the loss and congestion components would be obtained relative to the system-wide reference and not relative to a single reference bus.

LMPs will not change if we move the reference bus from one location to another. However, all three components are dependent on the selection of the reference bus (due to the dependency of the sensitivities on the location of the reference bus).

3.6.4 Case Study of PJM 3 buses system settlement

The case study of Locational Marginal Price Calculation is given below. The impact of the reference bus selection can be illustrated through the use of the three-bus power system shown in figure3.7. The figure 3.7 values represent the system's OPF solution, with a single binding transmission constraint, the flow on the line from bus 1 to bus 2 is constrained to its 100MVA limit. While the LMP values themselves are reference bus independent, the decomposition of the LMP into its three components (Energy Component, Congestion Component and Loss Component) depends on the assumed energy reference bus. The calculation will be taken by the Equation 3.19, 3.20, and 3.21. For example, Table 3.6 shows the decomposition assuming bus 1 as the reference, while Table 3.7 shows it with bus 2 as reference. The characteristic of the reference bus is that its LMP has zero loss and congestion components.

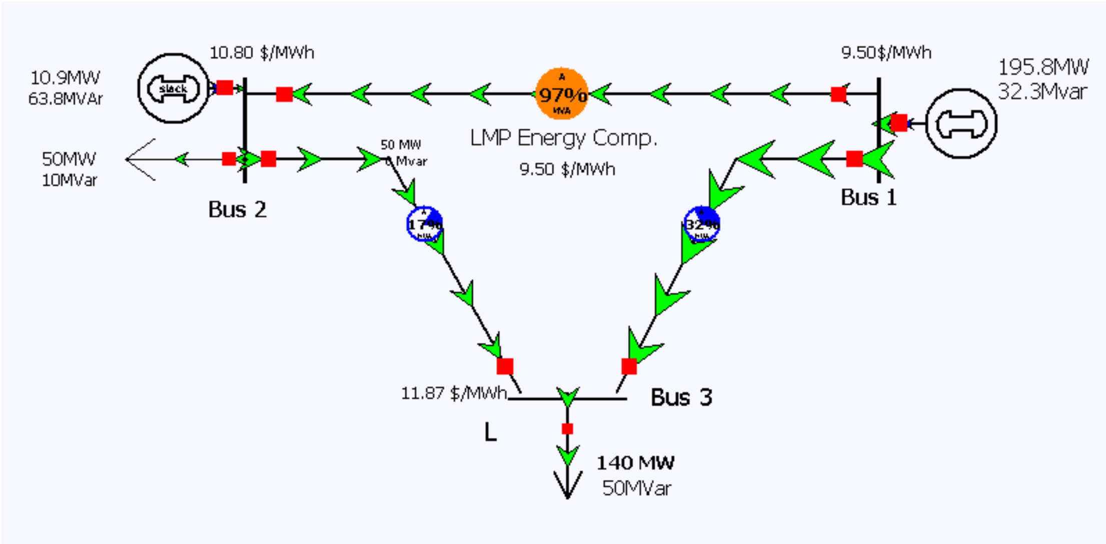


Figure 3. 7 Case Study 3-Bus System

Table 3. 6 LMP components with bus 1 as energy reference bus

($/MWh)	Bus 1	Bus 2	Bus 3
LMP	9.50	10.80	11.87
EC	9.50	9.50	9.50
LC	0.00	0.89	0.41
CC	0.00	0.41	0.25

Table 3. 7 LMP components with bus 2 as energy reference bus

($/MWh)	Bus 1	Bus 2	Bus 3
LMP	9.50	10.80	11.87
EC	10.80	10.80	10.80
LC	-0.92	0.00	1.28
CC	-0.38	0.00	-0.21

The detail analysis of the difference between the actual LMP and forecast LMP will show in the same IEEE 30 system in chapter 6.

3.7 Summary

In the US PJM electricity market, the imbalance energy between forecast demand and actual demand is reflected by the difference LMP. In an AC Optimal Power Flow, a single angle reference bus is used to maintain system balance between supply and demand. The changes in load at the slack bus will be met by changes in generation at the same bus. The marginal loss at the angle reference bus is therefore equal to zero and marginal losses at other buses are measured relative to this reference bus. The effect of LMP with distributed generation (DG) under constrained system is also studied. An important property of LMP systems is that they provide efficient price signals not only for short-term operations but also for long-run investments.

The advantages of LMPs is that, they are designed to reflect the actual cost of the system with the changes of system conditions and thereby provide an appropriate signals to resources to adapt to those changes. New generation will have an incentive to site where locational marginal prices are high. Under unconstrained condition, the corresponding congestion part of spot price is equal to zero. However, if there is constraint violation, then the spot price will jump to an unacceptable high point.

3.8 References

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Chapter 4 Australian Electricity Market Imbalance Settlement

4.1 Introduction

The Australian Electricity Market restructuring starts in 1991. The National Electricity Code Administrator Limited (NECA) was established, and the Australia Competition and Consumer Commission (ACCC) were established for guiding and monitoring the implementation of government. The national electricity market was planned and designed in 1993-1994. In the year 1994, Victoria successfully takes the lead in the reform of the electricity market in Australian, and then other states began to promote the reform. The Australian National Electricity Market (NEM) was established on 13th December 1998. It currently comprises four states, New South Wales (NSW), Victoria (VIC), Queensland (QLD), and South Australia (SA) and one non-state based snowy Mountains Hydroelectric Scheme (SNO) regional markets operating as a nationally interconnected grid.

The process of restructuring has been underway in the Australian electricity industry for approximately five years. This process involves functional separation, corporatization and, in some cases, privatization of the pre-existing state-owned supply authorities. The end point will be, for the southern and eastern states, a multi-region 'National Electricity Market' (NEM) which is regulated at the federal government level, and retail electricity markets which are implemented and regulated at the state government level. Less radical restructuring is occurring in the electricity industries of Western Australian and the Northern Territory, which for the foreseeable future will remain isolated from each other and from the NEM. Electricity restructuring in Australia is taking place in the context of a federal government system, in which coordinated actions are required at both state and federal level.

The following section discussed the settlement method of Australian Electricity Market. The main feature of the NEM is introduced in section 4.2. In section 4.3 will investigate the structure of the NEM and how it settlement, Ancillary Service is discussed in section 4.4. The calculation of Zonal marginal price and a six-bus case study are discussed in section 4.5.

4.2 Features and performance of the NEM

There are four key principles underlie the design of the NEM spot market [1]:

- ***Marginal pricing***
- ***Spot pricing***
- ***Location-dependent pricing***
- ***Decentralized decision-making, including the management of risks***

Marginal pricing is implemented via the economic dispatch algorithm, which selects the cheapest available resource (as indicated by the offers submitted by market participants) to meet incremental changes in the demand experienced by the real power system. The design of the NEM is fully symmetric so that in principle, supply and demand side participants have equal opportunity to set and respond to market prices. However to date, few demand-side resources are formally bid into the market. Thus price-elasticity effects are not well represented and prices are more volatile than they should be. Instead, demand forecasts are fed into the economic dispatch process, weakening the link between the commercial trading model and physical reality and introducing demand forecast risks that are not managed commercially.

Spot pricing is implemented by broadcasting the five minute prices to participants in ‘real time’. Moreover bids and offers can be modified until a half-hour before they apply (although participants can be asked to provide reasons for such changes). Thus supply and demand side participants are able to respond to the prices that actually apply at any given time. Moreover, demand side participants can respond to high five-minute spot prices by reducing demand without having to formally notify the market operator. There are no capacity payments in the NEM and operating decisions such as unit commitment or decommitment remain the responsibility of the participant concerned. Projections are broadcast of how the half hourly prices are expected to solve for the following day and these projections are updated on a three-hourly basis to reflect changes in bids and offers, unit availability and forecast demand.

Location-dependent pricing is implemented by the following three-level arrangements:

- The wholesale market is divided into market regions such that frequently occurring flow constraints appear on region boundaries (region boundaries are to be re-set as required to track changing patterns of network constraints). Interconnectors between regions are modeled in a simplified and abstracted fashion in the spot market.
- Intra-regional network loss factors are calculated for each transmission node within market regions in the form of averaged marginal loss factors. These are presently re-calculated on an annual basis using historical network flow data from the previous year.
- Distribution network loss factors are based on average rather than marginal losses. They are also marginal pricing is implemented via the economic dispatch algorithm, which selects the cheapest available resource (as indicated by the offers submitted by market participants) to meet incremental changes in the demand experienced by the real power system.

4.2.1Key features of the market trading rules

The NEM is being implemented in stages, NEM1 which links the Victorian and NSW markets (includes the Australian Capital Territory (ACT)), was authorized in March 1997 and commenced operation in May 1997[2].

The NEM1 code [3] does not provide complete uniformity between the Victorian and NSW electricity market rules, which must be achieved prior to full implementation of the NEM, currently anticipated in early 1998. The rules for the full NEM, has the following key features [4]:

a) All physical trading of electricity will be through a multi-region pool-style spot market, with a nominal half-hour trading interval.
b) The spot market will be a ‘smart auction’ with an embedded model of the interior losses and flow constraints between defined market regions, of which there will be at least one region per state[5].
c) The National Electricity Market Management Company (NEMMCO), owned by the participating jurisdictions, will run the spot market, manage ancillary services and undertake market projection functions including the forecasting of un-bid demand.
d) A short term forward market is to be established in financial instruments associated with regional spot prices, and an inter-regional trading and hedging function is to be conducted (at least initially) by NEMMCO.
e) A National Electricity Code Authority (NECA), owned by the participating jurisdictions, will supervise, administer and enforce the Code, administer the ongoing developments, review the arrangements for transmission and distribution pricing, publish information on market performance, and liaise with other regulatory bodies involved in electricity industry regulation
f) Network service providers are to operate within franchise regions subject to regulatory oversight by state regulatory bodies and the ACCC.
g) Committees of market participants established by NEMMCO and NECA will undertake a form of self-regulation subject to oversight by the ACCC.

In principle, the market rules were written to minimize distinctions between generation and demand side participants, and to avoid some of the more obvious problems of the UK rules. For example there is no central commitment of generators, no reliability payment, and models of the interties between regions have been incorporated in the spot market. However, full equality for demand side participants has yet to be achieved.

4.3 Australian Electricity Market Structure

NEM include contract market and spot market, the market structure is shown as Figure 4.1. According to the pre-dispatch results, system actual situation, market Participants re-bid information, conduct on-line dispatch, and market settlement.

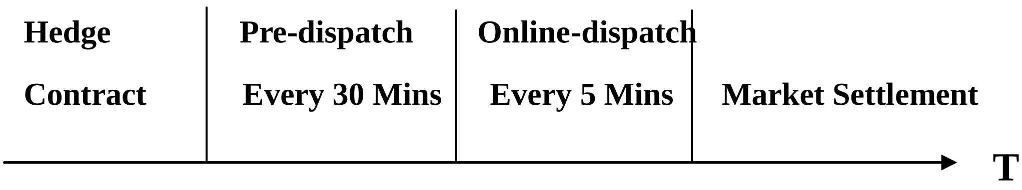

Figure 4. 1 Australian Electricity Market Structure

4.3.1 Network Losses Factor

Network Losses Work Group (NLWG) responsible for determining the entire network losses factor. The network loss factor includes dynamic factor and static factor. Static factor means the parameter not change in the year, dynamic factor means the parameter change while the load flow change.

Static factor include Intra-Regional Loss Factor (TLF) and Customer Loss Factor (DLFc). TLF means all grid access point to the according regional reference node in the network between the loss factors. It divided into Generator Intra-Regional Loss Factor (TLFg) and demand Intra-Regional Loss Factor (TLFd). DLFc refers to the grid net loss between user's access points to the geographic distribution network of affiliated retailers. Both are based on prior year actual average net loss.

Dynamic loss factor applies only to the regional reference nodes, is a practical power-flow function, the reason using dynamic numerical is the interval power flow direction may change dynamically, once every half hour calculation, calculation formulas such as:

$$IRLF_{tl} = k_1^{'} + k_2^{'} \times IFLOW_{tl} + \sum_{l=1}^{Na} k_{i+2}^{'} \times D_{t,i}$$

Where $IRLF_{tl}$ the Regional losses factor of area interconnected line l at duration t,

$IFLOW_{tl}$ the load flow of area interconnected line l at duration t,

$k_j^{'}$ area marginal losses factor coefficient, $j = 1, 2, ...Na + 2$;

$D_{t,j}$ the load forecasting value of area I at time t.

4.3.2 Pricing mechanism

According to generation bidding price, electricity consuming price, the net loss factor, and system operating parameters to optimize the maximum power market turnover target, and meeting forecast demand and ancillary services request, get the clearing price across the network. After market clearing period, each regional reference node will have market clearing price. Each node price is based on the price of electricity at regional reference node according to the conversion determined by static loss factor.

4.3.2.1 Pre-scheduling

The development of pre-scheduling is a concentrated expression of the spot market. Australian electricity market in the pre-scheduling is in 30 minutes cycle. And the optimization objective is to achieve the largest electricity market transactions. Pre-scheduling supply the main unit load level、 ancillary services backup situation、the regional price information、generation and consumption electricity balance information to all market participants. Before 16:00 on every day, NEMMCO released the next day pre-scheduling design plan and market information, including each regional reference node price of electricity and ancillary services, the sensitivity coefficient of each regional reference node to predict the load and generation capacity, the winning bid and the user unit and so on. Pre-scheduling would carry out rolling adjustment.

4.3.2.2 The real-time scheduling

As the uncertainty of power system and the special nature of electricity production and consumption, between the pre-scheduling and real-time scheduling of cases have a greater difference. Pre-scheduling is providing the price information of the main members in the spot market as a real-time market for bidding reference. While market dispatch price and market clearing price is determined by the market real-time scheduling.[6]

a）spot market real-time scheduling

Real-time scheduling time is for 5 minutes, the Spot Market Real-time Scheduler (SMRS) run once on every 5 minutes to calculate the scheduling price and ancillary service price.

b) Safety monitoring

Network security monitoring, including monitoring of area power-flow exchange, the frequency voltage, spare capacity. In addition, dispatchers also need to monitor the results of the impact of power system security submitted by the market members re-offering.

c) Ancillary services scheduling

Ancillary services are divided into market-oriented and non-market-oriented. Frequency control ancillary services market is market-oriented, and auto-completed by the real-time scheduling spot market scheduler according to the frequency control needs and market members' offer. Non-market ancillary services are run by the dispatcher based on power grid to dispatch.

d) Monitor the implementation of scheduling commands by market participants

Dispatcher is responsible for monitoring the implementation of the real-time scheduling plan in spot market by market members, including monitoring the bidding generators、loads、transmission services and market ancillary services. At the same time, computing and counting for the actual active load dispatch and scheduling plan deviation by the end of each scheduling period, automatically schedule monitoring and deviation alarming in real-time scheduling for the implementation of market participants' dispatching scheme.

4.3.3 Market Planning

Pool-style wholesale electricity markets were implemented in Victoria in December

1994, and in NSW in May1996. These markets were subsumed within the initial version of the NEM1 when it commenced operation on 4 May 1997.

Figure 4. 2 Electricity Market Trading Model

4.3.4 Two-way hedge contract

Two-way hedge contract is a financial contract signed between the electricity generators and suppliers, and the contract is indicated that if the spot market price is higher than the contract price, generator companies will subsidy the shortfall to the electricity providers. On the other hand, if the spot market price is lower than the contract price, the power generation business will compensate the amount of the electricity purchase to the electricity provider business.

The income and expenses caused by the electricity generators and electricity providers in financial markets business can be expressed as:

Electricity generators: $ContractIncome = Q_c \times (P_c - P_m)$

Electricity providers: $ContractPayment = Q_c \times (P_c - P_m)$

Taking into account the spot market revenues and expenses, the total revenue and total expenditure caused by the electricity generators and electricity providers can be expressed as:

Electricity generators: $TotalIncome = Q_g \times P_M + Q_c \times (P_c - P_m)$

Electricity providers: $TotalPayment = Q_L \times P_M + Q_c \times (P_c - P_m)$

Where,

Q_g the actual output of the generator

P_m spot market actual price

Q_L the actual capacity of the load

P_c Contract Price

Q_c Contract Capacity

Figure 4.3 shows the principle of the two-way hedge Contract

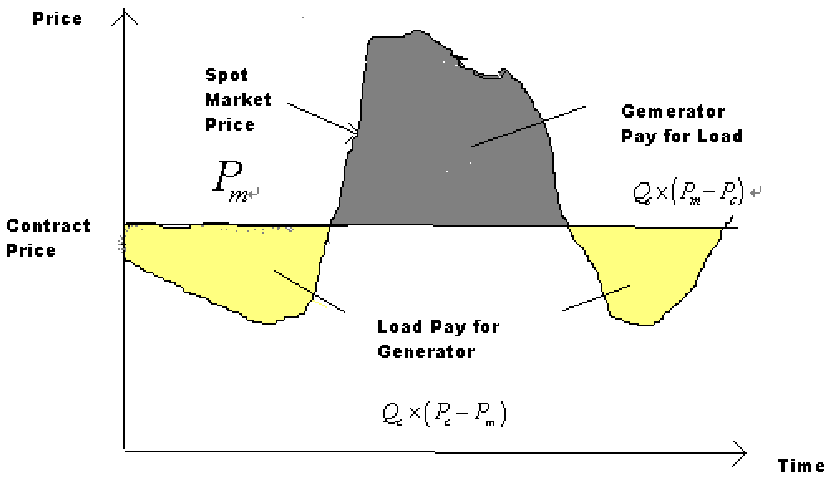

Figure 4. 3 Principle of two-way hedge Contract

A case study of the two-way hedge Contract

Q_c =40MW, P_c = ＄45/MW

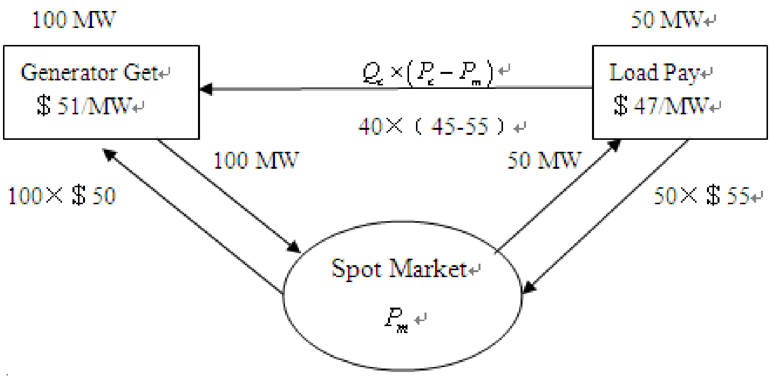

Figure 4.4 Case Study of Two-Way Hedge Contract

The Generator Total Income = (100×55) + 40 ×(45-55) = 5100
Average Price = 5100 ÷100 = ＄51.00 /MW

The Load Total Payment = (55×50) + 40 ×(45-55) = 2350
Average Price = ＄47.00 /MW

4.4 Ancillary Service Definitions

Ancillary services can be defined as a set of activities undertaken by generators, consumers and network service providers and coordinated by the system operator that have following objectives [7]:

- Implement the outcomes of commercial transactions, to the extent that these lie within acceptable operating boundaries. That is, ensure that electrical energy production and consumption by participants match the quantities specified by the outcomes of spot market.
- Maintain availability and quality of supply at levels sufficient to validate the assumption of commodity like behavior in the main commercial market. This can be achieved by keeping the physical behavior of the electricity industry within acceptable operating boundaries defined by planning studies in conjunction with operator experience.

Ancillary services can be divided into the following three categories that are described in more detail below [8]:

- Related to spot market implementation, short-term energy-balance and power system frequency. These will be labeled Frequency Control Ancillary Services (FCAS).
- Related to aspects of quality of supply other than frequency, there will be labeled Network Control Ancillary Services (NCAS)[9].
- Related to system restoration or re-start following major blackouts. There will be labeled System Restoration Ancillary Services (SRAS).

Spot-market implementation involves ensuring that participating generators and loads achieve their energy targets specified in the market solution for the current spot market interval. However market model imperfections or incompleteness (such as a lack of demand-side bidding or inadequate representation of network losses) mean that the spot market solution may not deliver an overall balance in electrical energy flows in actual operation. Also, unexpected phenomena (such as the failure of a generating unit) during a spot market interval may create a mismatch between the spot market solution and physical behavior. The overall balance in the electrical energy flows in a power system is not monitored directly because of its complexity. It depends on the operating states of all generators and loads as well as on network losses and can vary instantaneously.

However power system frequency is a useful surrogate for energy balance because it is a measure of the stored kinetic energy in the rotating masses of generating units and loads. Imbalances in electrical energy flows that persist for more than a few seconds will be reflected in a change in the stored kinetic energy and thus in power system frequency. Moreover, for time scales longer than a few seconds, frequency may be considered to be uniform across a power system. Thus ancillary services that control frequency may be used to manage short-term imbalances in overall electrical energy flows. Most generating units are fitted with active speed control devices (speed governors) and many motor-driven loads vary passively with frequency. Thus both generators and loads can contribute to managing energy-flow balance. At any particular time, the operating power level of each spot market participant will combine a power level designed to achieve its spot market energy target with that responding to frequency deviations. It is by no means straightforward to separate, monitor and account for these activities appropriately [10].

4.5 Zonal Price Calculation

The Zonal Price trading process works approximately as follows [11]:

1) The System Marginal Price (SMP) and the amount of electricity traded are obtained based on the supply and demand schedule bids given by the market participants; the market is cleared while ignore any grid limitations. This produces a system price p of energy.

2) If the resulting flows induce capacity problems, the nodes of the grid are partitioned into zones.

3) Considering the case with two zones defined, the zone with net supply is defined as the low-price area, where the net demand zone is determined the high-price area.

4) Net transmission over the zone-boundary is fixed when curtailed to meet the violated capacity limit.

5) The zonal markets are now cleared separately giving one price for each zone, Pl is defined as the low price and Ph is defined as the high price. If the flow resulting from this equilibrium still violates the capacity limit, the process is repeated from step 4). If any new limits are violated the process would be repeated from step 2), possibly generating additional zones.

6) The revenue of the grid-company, is equal to the price difference times the transmission across the zone-boundary.

An assumption made in the last steps given above is that a zone boundary should cut the link with the capacity problem. In a large network this still leaves the grid company, with a huge flexibility when defining the zone-boundaries.

According to [12] Zonal pricing is able to balance well equity concerns and efficiency goals and is less complex and therefore more transparent to market participants.

4.5.1 Case study

Generally, zonal pricing can be categorized into two stages. The first stage is identical to the market dispatch under unconstrained dispatch that is without considering transmission line constraints. Thus a unique price for the whole system is determined. The second stage will be carried out if there is violation on the transmission line limits. Each zone is treated as a node and zonal prices are calculated through a DC-OPF. The transfer capacity between the different zones is the sum of capacities of the lines that connect the zones. After re-run the DC-OPF by binding the transmission line limit the new prices are announced to the market participants [13].

Using the six-bus system, The Bid price and Generator dispatch is given in Table4.1 , the line flow data as shown in Table 4.2 .The first stage of zonal pricing gives the system marginal price for the entire network as ￡15/MWh. Based on the initial dispatch, line 1-5 is overloaded with 37.15MW. In this case the system operator defines zone A and B by separating two bottleneck nodes and re-run DC-OPF considering total transfer capacity over the lines connecting between zone A and B. Assuming two zones is defined where zone A consists of bus #1,#2 and #4 and zone B consists of bus #3,#5 and #6.

Table 4. 1 Bid price and Generator dispatch

GEN	Bid Price (＄/MWh)	Unconstrained Dispatch (MW)	Constrained Dispatch (MW)
G1	10	100.00	58.66
G2	11	100.00	100.00
G3	15	10.00	51.34
Total Operating Cost (＄/h)		2250.00	2456.70

Table 4. 2 Line flow based on unconstrained and constrained dispatch

From Bus i	To Bus j	Line flows based on unconstrained dispatch From i to j (MVA)	Line flows based on unconstrained dispatch From i to j (MVA)	Limit (MVA)
1	2	21.93	5.28	35
1	4	40.57	28.38	50
1	5	37.51	25.00	25
2	3	21.65	7.53	30
2	4	37.28	46.19	70
2	5	22.89	21.48	30
2	6	40.10	30.09	45
3	5	5.59	17.54	40
3	6	26.06	41.34	90
4	5	7.85	4.56	10
5	6	3.84	-1.42	15

The interface line flow between two zones is fixed at the capacity flow which is derived from the line constrained as explained before. Therefore, the line flow interface between zone A and B is fixed at 88.66MW. Figure 4.4, shows the equivalent two-zone system based on market splitting.

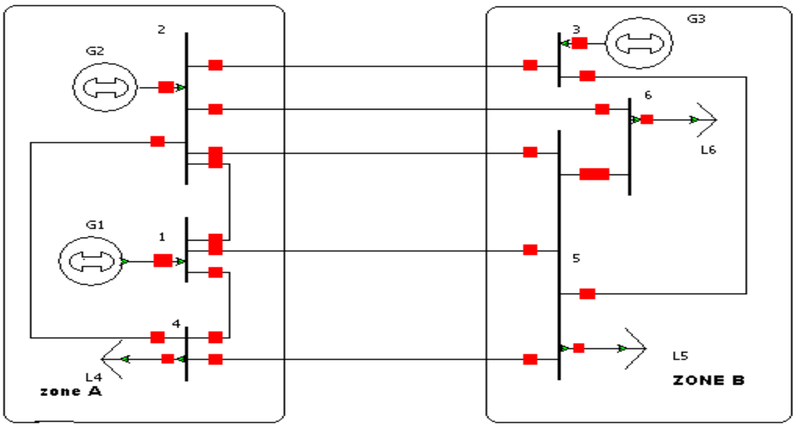

Figure 4. 4 the two zones of the case study system

Based on this market splitting approach, in the net supply area (surplus), the zonal price for this area is determined by adding an extra demand to this zone so that the quantity is equal to the total tie line capacity flow between two zones. Therefore the total equivalent load at zone A is equal to:

$$70_{Load_4} + 7.53_{Load_{2-3}} + 30.09_{Line_{2-6}} + 21.48_{Line_{2-5}} + 25.00_{Line_{1-5}} + 4.56_{Line_{4-5}} = 158.66\text{MW}$$

And the Zonal price is set as ＄11/MW as shown is Figure 4.5. Similarly, in the net demand area (deficit), the zonal price for this area is determined by adding an extra supply into this zone so that the quantity is equal to the total tie line capacity flow between two zones. In this case, the equivalent load at zone B becomes:

$$70_{Load5} + 70_{Load6} - 7.53_{Line_{2-3}} - 30.09_{Line_{2-6}} - 21.48_{Line_{2-5}} - 25.00_{Line_{1-5}} - 4.56_{Line_{4-5}} = 51.34\text{MW}$$

Which gives zonal price to this area ＄15/ MWh as shown in Figure 4.6

As the result, the generators and loads are paid and charged according to their zonal price. Due to the price differences between both zones, market participant might invest in zone B to obtain higher revenue returns.

In the above example, even though two zones are considered here, allocations nodes into two zones can be made in several ways separating two bottleneck nodes. Generally, if we consider a single congested line in an n - node network, and if we assume that the endpoints of the congested link are to be allocated to different zones, the number of allocations to two zones is equal to:

$$\sum_{r=0}^{n-2} \binom{N-2}{r} \qquad \text{…………………4.1}$$

For example, in the 6-bus system, N=6, therefore there would be total of 16 different zone allocations in this example.

$$\sum_{r=0}^{4} \binom{4}{r} = \binom{4}{0} + \binom{4}{1} + \binom{4}{2} + \binom{4}{3} + \binom{4}{4}$$

$$= \frac{4!}{0!4!} + \frac{4!}{1!3!} + \frac{4!}{2!2!} + \frac{4!}{3!1!} + \frac{4!}{4!0!}$$

$$= 1+4+6+4+1 = 16$$

However, if the endpoint of the congested line is allow to be in the same zone, the total number of different allocations to two zones for N-node network is given by: [14]

$$\sum_{r=0}^{N-2} \binom{N-1}{r} = \sum_{r=0}^{N-2} \frac{(N-1)!}{r!\left((N-1)-r\right)!} \qquad \text{………………4.2}$$

Hence, in our six-bus system, there would be a total of 31 different zone allocations of both endpoint of the congested line is group into the same zone.

$$\sum_{r=0}^{4} \binom{5}{r} = \binom{5}{0} + \binom{5}{1} + \binom{5}{2} + \binom{5}{3} + \binom{5}{4}$$

$$= \frac{5!}{0!5!} + \frac{5!}{1!4!} + \frac{5!}{2!3!} + \frac{5!}{3!2!} + \frac{5!}{4!1!}$$

$$= 1+5+10+10+5 = 31$$

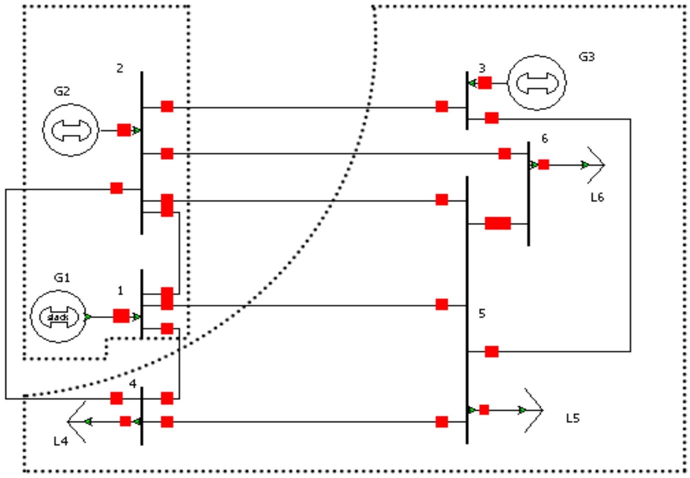

Figure 4. 5 Several Possibilities of two zones allocation (a)

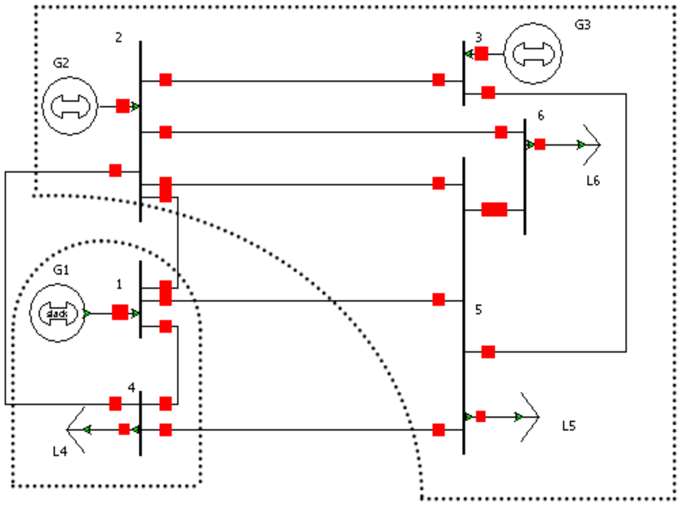

Figure 4. 6 Several Possibilities of two zones allocation (b)

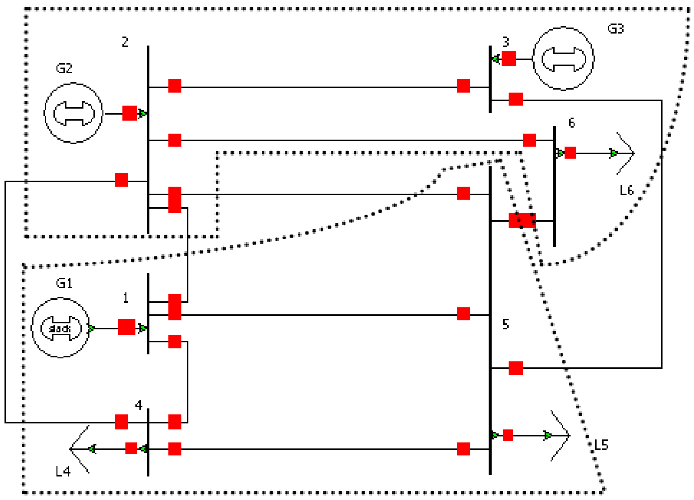

Figure 4. 7 Several Possibilities of two zones allocation (c)

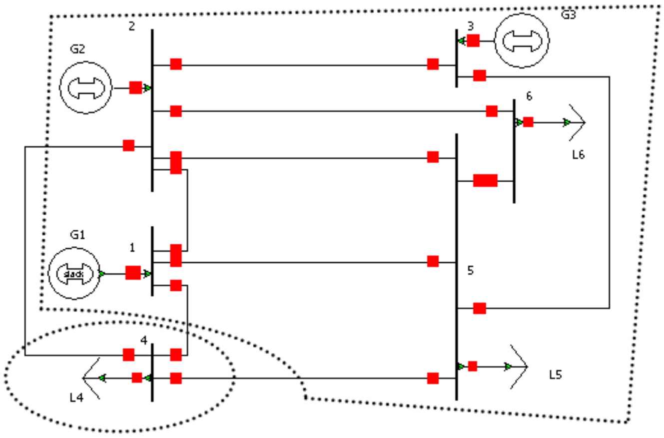

Figure 4. 8 Several Possibilities of two zones allocation (d)

From Figure 4.5 to Figure 4.8, it shows four possibilities of two zones allocation. Figure 4.5 and Figure 4.6 are two zones allocation where the endpoint of the congested line is allocated into two different zones while Figure 4.7 and Figure 4.8 are two zones allocations if the endpoint of the congested line is allowed to be in the same zone.

The Generator Revenues Income is tabulated in Table 4.3. The Load payment is tabulated in Table 4.4. The results shows that the loads are paying＄354.64/ h the different to the generators.

Table 4. 3 Generation Revenue Income on zonal pricing scheme

Gen	Redispatch Output (MW)	Zonal Price (＄/MWh)	Total Generation Revenue (＄/h)
G1	58.66	11.00	645.26
G2	100.00	11.00	1100.00
G3	51.34	15.00	770.10
Total	210.00	/	**2515.36**

Table 4. 4 Load payment on zonal pricing scheme

Load	Demand (MW)	Zonal Price (＄/MWh)	Total Load Payment (＄/h)
L4	70.00	11.00	770.00
L5	70.00	15.00	1050.00
L6	70.00	15.00	1050.00
Total	210.00	/	**2870.00**

4.6 Conclusion

The Australian National Electricity Market is an important experiment in the process of implementing electricity industry competition, it has demonstrated the feasibility of decentralized commitment of base-load generating units, and the competitive pressures that can be achieved with careful market design. The original purpose of the NEM design is to allow projected prices and real-time prices to guide participant behavior such that supply-demand balance is maintained with the minimum need for management of modeling mismatches through ancillary services.

However the NEM has a number of design weaknesses that may prove difficult to fully eliminate, despite the existence of procedures for changing market rule. Regulation will be required for the foreseeable future and challenges remain in the search for an effective combination of competition and regulation.

Similarly with the zonal marginal price method discussed in section 4.5, even though it provides a simple, transparent and easy to implement market design, it still can bring some operating issues as discussed. It is important to have further study studies whether a competitive electricity market would bring improvement in economic efficiency such as lower prices along with enhancement in technical efficiency with be discussed in chapter7.

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Chapter 5 Energy Imbalance Settlement in Several Other Countries

5.1 Introduction

Many Countries and Jurisdictions around the world are advancing down the way of electricity privatization, deregulation, and competition. As the deregulation process develops questions are often raised about design of existing markets. Studies and descriptions of market designs are common but it is more difficult to discover the success or failure of initiatives in other countries and markets. One of the key elements of market design is the settlement system.

This chapter will briefly discuss another two countries' electricity market, New Zealand and Argentina electricity market, the common feature of these two market design are full nodal pricing settlement system. The feature of New Zealand is 60% of the total installed capacity is hydro generation, and Argentina is one of the typical electricity markets in Latin America.

In the previous chapters, three types of spot markets have been discussed. The Uniform Marginal Price of the Former England& Wales Pool market (1990-2005) and the NETA market in chapter 2; Locational Marginal Price of the PJM market since 1998 in chapter 3; Zonal Marginal Pricing of the Australian market in chapter 4. The New Zealand and the Argentina which will be discussed in this chapter all use Nodal Marginal Price in Spot Market. Actually the basic theory of Nodal Marginal Price and Locational Marginal Price is the same, it is simply different names. As the Locational Marginal Price has been discussed in chapter 3, this chapter will significant introduce the market structure and the energy imbalance settlement in spot market of these two countries, and will not introduce the calculation method of nodal marginal price again.

5.2 New Zealand Electricity Market Introduction

The New Zealand electricity market system comprises two electrical and geographical island's North and the South island (NI and SI) interconnected with an HVDC link. Total installed capacity is approximately 9500MW, of which 60% is hydro generation. Annual generation is approximately 37 TWh.

The New Zealand Electricity Market (NZEM) is regulated by the Electricity Commission of New Zealand (NZ), with competition issues regulated by the Commerce Commission of NZ. The New Zealand Electricity market has operated since 1 October 1996. At the core of wholesale market operation is Nodal Marginal Pricing (Locational Marginal Price). This is based on the Scheduling, Pricing and Dispatch (SPD) software application. SPD provides a DC optimal power flow based security constrained economic dispatch [1]. In contrast to the static or aggregated network models used in most markets the relatively small New Zealand power system SPD uses a temporally and physically accurate network model. It co-optimizes load bids and offers from market participants for two reserve products and linearly modeled losses in a price based dispatch. Running every 5 minutes SPD produces an optimal energy dispatch with nodal prices for energy, and island based prices for reserves. The constraints applied by SPD are central to both a secure and reliable dispatch and to the ex post nodal 30 minute spot price. The New Zealand electricity market allows open access to transmission capacity. SPD is the sole means used to allocate transmission capacity and manage transmission congestion.

The wholesale generation sector has been significantly restructured since 1996. First a second generation company was formed from the previous single government owned Generation Company. Subsequently the remaining large company was broken into three components in 1999 with the aim of fostering generation competition.

The main transmission grid has been operated by a separate government owned company since 1992. In 1999 the government opted for a full unbundling of transmission and energy trading and retailing. This meant that each local electricity company had to commercially separate these components. The most common outcome was a sale of the retail business to one of the generation companies. Table 5.1 summarizes the size and customer base of the major energy companies in New Zealand.[2]

Table 5. 1 New Zealand Energy Companies [2]

Company	MW Capacity and %		Customer and %	
Contact Energy	2424	28%	355	21%
Genesis Power	1594	18%	158	9%
Meridian Energy	2355	27%	72	4%
Mighty River	1067	12%	271	16%
TransAlta	474	5%	518	30%
TrustPower	360	4%	208	12%
NGC			65	4%
Power				
Total	8635		1703	

The New Zealand Electricity Market (NZEM) is a voluntary market that operates without direct government legislation or regulation. Key elements of the market design are full Nodal Price.

Since beginning in late 1996, the market has undergone continuing development, assisted by the self-governing nature of a voluntary market. Proposals for rule changes are investigated by standing committees, and voted on by participants.

One of the major challenges facing the market and participants is the management of risks associated with the uncertainty of inflows and the limited amount of hydro storage. This is made more complex by the mismatch between high inflows and high demand levels. Despite variations in both inflows and storage levels since 1996, there have been no energy shortages. A careful examination of market in inflow data shows periods of high prices that can be associated with hydrological conditions.

5.3 New Zealand Electricity Market Structure

Following restructuring, New Zealand Electricity Market (NZEM) has been in wholesale operation since 1996. Electricity generators submit offers to the market, which aggregates all generator offers and determines a supply curve. Transpower [3], as system operator, then dispatches generation to meet demand every half-hour trading period. The price set by the marginal unit of generation, termed as Locational Marginal Pricing (LMP), then establishes the wholesale energy price for that half-hour. Prices are determined at each of approximately 244 nodes on the grid. Each nodal price reflects the marginal energy price and the marginal transmission losses. Operating constraints like thermal or voltage stability limits may cause price separations across parts of the grid. Although half-hourly prices are generated in the wholesale market, around 80-90% of all electricity sold is at fixed prices through bilateral contracts. These may be external contracts with end-use consumers and other generators, or an internal hedge with an integrated retail business.

5.3.1 Forward Contract Market

Market power is defined as the ability of producers to alter profitably prices away from the competitive price levels by restricting output below competitive level (withholding) for a sustained period (Financially by bidding high or physically by curtailing output). This can happen due to market concentration and transmission congestion, the effects of exercising market Power are transfer of wealth from customers to suppliers, and dead weight loss to society in terms of inefficient dispatch. Mitigation of market power in electricity markets. A number of mitigation methods are available [4].

These are Generation Divestiture, Internal re-organization, Bidding contracts, Demand side bidding, Bilateral contracts, price caps, Bid caps, Revenue caps, Revenue caps and floors, and Contract for differences.

In the NZEM the original market design sought to mitigate market power by means of:

◆ Splitting of Generation portfolio

The generation component of the vertical integrated state supply in New Zealand was split into 4 independent generating companies.

◆ Bilateral contracts

Bilateral contracts between generator and retailers can be financial and physical. Both are allowed in the NZEM. These contracts have no effect on the System Operator's secure economic dispatch of the grid.

◆ Ancillary services

Energy and reserves are co-optimized in NZEM, and these products compete for the same resource (generation), capturing the opportunity cost of producing generation and reserve. Traders are allowed to overlap for the offered quantities for energy and reserves. For example a trader with 100 MW generator can offer all 100 MW for energy as well as 100 MW or less for reserves at the same trading period. In case of shortage for energy offers the operators are allowed to adjust, for a small duration, the reserve requirement so that energy market could be supplied first. In extreme situation, SO is also allowed to supply an "only energy market" by setting the risk to zero.

◆ Congestion management

Transparent constraint management is provided by including thermal and security derived constraints in the linear optimization performed by SPD. Intervention by the SO to resolve constraint issues is priced transparently in the market.

◆ Imbalance Settlement

The NZEM settlement by the real-time Nodal Marginal Price, the imbalance price is the real-time Nodal Marginal Price minus the forecast Nodal Marginal Price, same as the Locational Marginal Price mentioned in chapter 3.

Table 5. 2 NZEM Description

Market	New Zealand Electricity Market Start 1-Oct-96, Market operator: SO, Transpower No capacity payments Wholesale trading is through compulsory pool for generators more than 30 MW, bilateral contract allowed, LMP market
Bidding	Offered daily, energy and 2 types of reserves, updated until 2 hours before real time. Regulation reserve is not bid as yet.
Market Power Monitoring Indices	Electricity Commission of NZ is the regulator and its primary role, among other updated functionalities, to oversee if any electricity governance rule has been breached. The competition issues are the responsibilities of Commerce Commission. The SO, Transpower performs re-bidding, looks after dispatch compliance and routine reports. SO also monitors the degree of transmission congestion using price ratios

5.3.2 Spot Market

Real time spot pricing of electricity has been proposed in the literature since the mid-1980s. Key proponents of real time spot pricing are the late Prof. Schweppe [5], [6], Prof. Hogan [7]–[9] and Dr. Read [9]. Others have researched specific areas of spot pricing, e.g. using optimal power-flow (OPF) software to calculate real time spot prices [10]. Thus, a vast amount of discussion of the theory, and policy and practical implications of spot pricing has occurred. As yet, however, very little practical experience with real time spot pricing in an actual power system has been obtained.

Currently, New Zealand is the only country that relies solely on a spot pricing market to totally dispatch electricity [14]. Since its commencement on 1 October, 1996, New Zealand's electricity market has revealed some unpredicted behavior of the spot prices around its system. In particular, it is recognized that real power flows from a higher priced node to a lower priced node in a constrained power system (e.g. spring washer effect [17]). However, New Zealand's spot market has demonstrated that spot prices can decrease in the direction of real power flow in an unconstrained power system; this is an apparent contradiction of economic theory. Such price behavior is known as “price inversion.”[18]

5.4 Argentina Electricity Market Introduction

Argentina has been one of the wealthiest countries in Latin America. Argentina is a country with a population of 33 million; it has two interconnected electricity systems, the main one delivering 10,000 MW and 60,000 GWh in 1994 through a 500、220 and 132 kV network. A present total installed capacity is of about 18,000 MW. 42% of the annual production is hydro, 43% thermal by natural gas and 15% nuclear. After privatization, supply has been diverted to 39 Gencos (26 thermal + 13 hydro). There are 5 Transcos (one for the high voltage network and 4 for the regional grids) and 25 Discos, of which 6 are private, the remaining 19 still owned by the Provinces (States).
An important aspect of economic reform in Argentina has been the liberalization and privatization of public utilities. Restructuring of the previously state-owned electricity utilities commenced in 1991. Following negotiations with the International Financial Institutions (IFIsde.g. the World Bank and the International Monetary Fund), after which, the three stages of electricity production (generation, transmission and distribution) were vertically disintegrated (Chisarietal., 1999). [19]

The basic concepts of the market deregulations are [20]:

- The State has a subsidiary role in relation to the energy sector. It means that the State will perform entrepreneurial activities only when such activities cannot or will not be carried out by the private sector. Its main role lies in the regulatory side of activities that are monopolistic.
- Market forces are recognized to represent a basic mechanism in the correct allocation of resources in the electric generation sector, where competition is looked for. The necessity of deconcentrating, decentralizing and privatizing the activities and property of the electricity companies are recognized as desirable for the efficiency and stability of the system.
- It is not feasible to have competition in the businesses of transmission and distribution, given economies of scale. Competition may develop in other

activities of the business.

The main features of the market deregulations are[21]:

- Vertically disintegrated Gencos. Transcos, Discos and Large Customers are defined as the market players. In Argentina, the controlling stake of a Genco. a Dism or a Large User can not control a Transco. Argentina further restricts any Genco from holding any more than 10% of the market
- Transcos and Discos require licenses to operate,
- Hydroelectric plants require a license for exploitation of natural resources; thermal plants do not require a license,
- Pricing system: both generation and transmission business have a short and long term marginal price. Spot prices along the grid represent the short term marginal cost of transportation,
- Open access: transport concessionaires must give open and non discriminatory access to their transmission systems,
- Obligation to serve: distribution concessionaires must serve all existing and future loads in their concession area,
- Penalties: both Transcos and Discos are subject to penalties in Argentina if they don't fulfill their concession contracts.

5.5 Argentina Electricity Market Structure

The restructuring of Argentina's electricity market began in 1991, the three stages of production generation, transmission and distribution were vertically disintegrated. Generation became competitive with transmission and distribution markets operating as regulated private monopolies. The Wholesale Electric Market (MEM) that supplies 93% of Argentina's demand has an installed capacity of 22831 MW, of which 46% is hydroelectric, 49% thermal and 5% nuclear. The MEM also comprises the Argentine Interconnection System (SADI), which manages 8000km of 500 KV high-tension transmission lines. Since liberalization, consumers with a peak demand equal or greater than 30 kW are permitted to purchase directly in the MEM. Transactions in the various sub-markets comprising the MEM are managed by CAMMESA, which is responsible for the coordination of the technical operations of SADI, and operates the technical and economic dispatching of the interconnected generating capacity. It is also charged with ensuring safety and quality of supply. The Department of Energy, generators, transmitters, distributors and major users jointly own CAMMESA, although the former has veto rights over decisions. [22]

The Department of Energy (which is part of the Ministry of Economy) is responsible for establishing regulations and industry policies, including rules governing technical dispatching, the calculation of MEM prices, and the settlement of appeals made against the regulatory agencies. The regulator, ENRE, is charged with ensuring private companies comply with the law, imposing appropriate sanctions, ensuring concession agreements are carried out, preventing anti-competitive behavior, and monitoring service quality.

Argentina followed most features of the basic textbook model [23]and, prior to the country's macroeconomic collapse, currency crisis, and rejection of contractual and regulatory commitments in 2002, experienced excellent performance. Argentina experienced significant improvements in the performance of the existing fleet of generating plants, significant investment in new generating capacity, and improvements in productivity and a reduction in losses (physical and due to thefts of service) on the distribution networks (Dyner, Arango and Larson 2006, Pollitt 2004a, Rudnick and Zolezzi 2001, Bacon and Besant-Jones 2001, Estache and Rodriguez-Pardina 1998)[23].

Unlike the case in England and Wales, Argentina made a serious effort at the outset to create a generation sector that was structurally competitive and there is little if any evidence of market power in the wholesale market there. These improvements in performance indicia were realized despite (or perhaps partially because of) the fact that Argentina did not have a real unregulated spot market for electricity. Following the model established in Chile, Argentina's so-called spot market was structured as a security-constrained marginal cost based (i.e. not bid-based) power pool in which the clearing price is determined mechanically by the marginal cost of the generator that clears the market in an efficient cost-based merit order dispatch. This mechanism effectively caps prices in the spot market at very low levels (about $150/MWh during the 1990s) under scarcity conditions. However, the spot market revenues are supplemented by revenues from a capacity payment mechanism to support generation investment.

5.6 Argentina Electricity Market Trading

In the Argentina electricity market, there are two types of trading between the transmission company and the distribution company, one is the bilateral contract, the other one is buy and sell from the pool. There are 50%-60% of total trading by long term contract between the generation company and the distribution company.

When the actual generated power is more than the contract value, the imbalance power will be sold by the electricity market. When the actual load is more than the forecast load, it will buy the imbalance power from the electricity market. The wholesale electricity market is not only for the generator companies, but is also for the transmission companies and distribution companies.

An electricity spot market can work in much like any other wholesale market in which buyers and sellers make offers, determine the prices at which supply equal!; demand and trade the product at those prices. However, some special market arrangements are needed to deal with the special characteristics of electricity. The most obvious special feature of electricity markets is the need for an integrated transmission grid. The more Unusual and less appreciated feature is the need for a centralized trading process. Because electrical energy cannot be economically stored, supply must equal demand virtually instantaneously everywhere on an interconnected system. Pricing energy to clear the market at all times means, strictly speaking, that a different price must be computed every minute or less and, when transmission losses or constraints are important, at different locations on the grid.

Least-cost economic dispatch is the competitive market equilibrium. The least-cost dispatch satisfies the "law of one price" and the "no arbitrage" condition of the competitive equilibrium. Convergence of a fully decentralized market to a competitive equilibrium depends on ease of trading and well defined property rights. Neither condition holds in the electricity system. Therefore, the characteristics of electricity coupled with poorly defined property rights create a natural monopoly in economic dispatch, which must be regulated to set prices with the competitive market.

In a private monopoly market such as the electricity distribution system in Buenos Aires, there is a danger that efficiency gains may not be distributed equally if regulation is poor. An ENRE executive interviewed admitted during an interview that the organization was established ‘at the same time’ as market liberalization took place, indicating that this has caused a problem for the regulators, who were not party to the negotiations or had any input into how contracts were drawn-up and awarded:

5.6.1 Contract Trading Rules

The signing of the wholesale contract is through bidding. When the bidding reaches an agreement and then signs the transmission contracts with the transmission company, the price has thus been identified. The contract tariff is released according to the Electricity Regulatory Commission tariff calculation principles and calculation methods determined by the power producers and electricity distributor or large user, consultation and the need to be approved by the Electricity Regulatory Commission. Wholesale contract price is valid for five years, but it could be adjusted annually by mutual agreement.

For the transmission and distribution, the income in order to be fully compensated for reasonable operating costs, tax and investment apportioned, it must be through economic operation. Transmission and generation must take into account the difference of the different types of electricity services at a reasonable cost, including the way in accordance with the provisions of the regulatory agencies to consider the supply, location and other characteristics, so that between the lowest reasonable cost and power users reliability for the tariff is matching. Transmission for the economic signals sent to the user, the price system is driven by decisive cost of three kinds, namely the cost of transmission power, then the costs of electricity and transmission capacity. If large users (the load is more than 100 kilowatts) purchase the electricity from the wholesale market directly, the tariff is fixed, but must include the transmission cost.

Large Users (larger than 1 MW in Argentina, 2 MW in Chile), as wholesale market members, may contract in the long term market with Gencos, or buy in the spot market (Discos can do the same in Argentina, while in Chile they only buy at nodal prices). In Argentina, users having between 100 and 1000 kW may also contract in the long term market. Each contract is being managed by its Disco who charges a fee for that service. Although the supply of contracts has an automatic back-up of the market in case of unavailability of the Genco, important incentive for consumers to enter in the long term market in Argentina is that the loads under contracts have priority of supply in case of failure of the grid. Gencos are kept from selling more capacity or energy than their company has available. Commitments must not exceed production and/or supply contracted with other Gencos.

5.6.2 Pool Trading

The Argentina electricity market regulation only allow the generators bid by the nodal marginal price, the capacity price not calculated in the spot price, calculated in the market electricity price.

In the spot market, the spot price calculation is determined by listing all the generators efficiency from high to low, the last operation generator’s running cost is the spot price. The distributed company will report the next week demand first, and the electricity market will determine the load forecast curve by the report. The settlement period is one hour, and there will be 24 prices per day.

5.6.2.1 The wholesale market and the Poolco[24]

The Argentinean wholesale electric market includes:

- A unified marketplace where producers and customers buy and sell electricity at the determined Market Clearing Spot Price
- A transport system that "carries" power and market prices, defining a spot price for each node along the grid
- A Poolco, named Compaiiia Administradora del Mercado Mayorista de Electricidad S.A. (CAMMESA), manages the dispatch, reliability and pooling functions. CAMMESA's ownership is equally shared by Gencos, Transcos. Discos, Large Users and the Government
- A Regulatory Body, ENRE, oversees regulation and arbitration in case of disputes between market players.

5.6.2.2 Pool Prices and Payments

Dispatched Gencos receive an ex-post payment based on hourly prices at every network location. They are paid by supplied energy and capacity. The capacity price is defined by the Secretariat of Energy in Argentina. The energy price includes the price of non supplied energy in weeks with risk of failure. Discos in Argentina pay a seasonal stabilized wholesale price arising from CAMMESA'S "ex-ante" review based on the average marginal price foreseen in the next season. Should these prices deviate from actual dispatch, they will be compensated in the next season.[25]

5.7 Argentina Electricity Market Settlement Rules

Wholesale contract settlement is provided for the sale of the signed contract price between power generation companies and distribution companies or large users. When the power generation unit output is short and cannot meet the contract, they could purchase electricity by the retail price from the spot market, and demand-side still base upon the contract price settlement; When the distribution companies or large users for some reason, the electricity demand is lower than the contract of provisions of electricity, power companies can sell the electricity with spot price in electricity market, distribution companies or large customers still need to pay the fixed costs of this part of the volume to the power generation.

5.8 Case Study

As the New Zealand Market and the Argentina Market all use Nodal Marginal Price settlement system, this section will simulate an illustrate 6-Bus system as an example by POWERWORLD software, which could calculate the OPF LMP directly, the calculation theory has been mentioned in chapter 3 the Locational Marginal Price Section.

Figure 5.1 shows the illustration system, the values in the programme are the forecast values. Table 5.3 shows the forecast load value of each bus, and the LMP value of each bus.

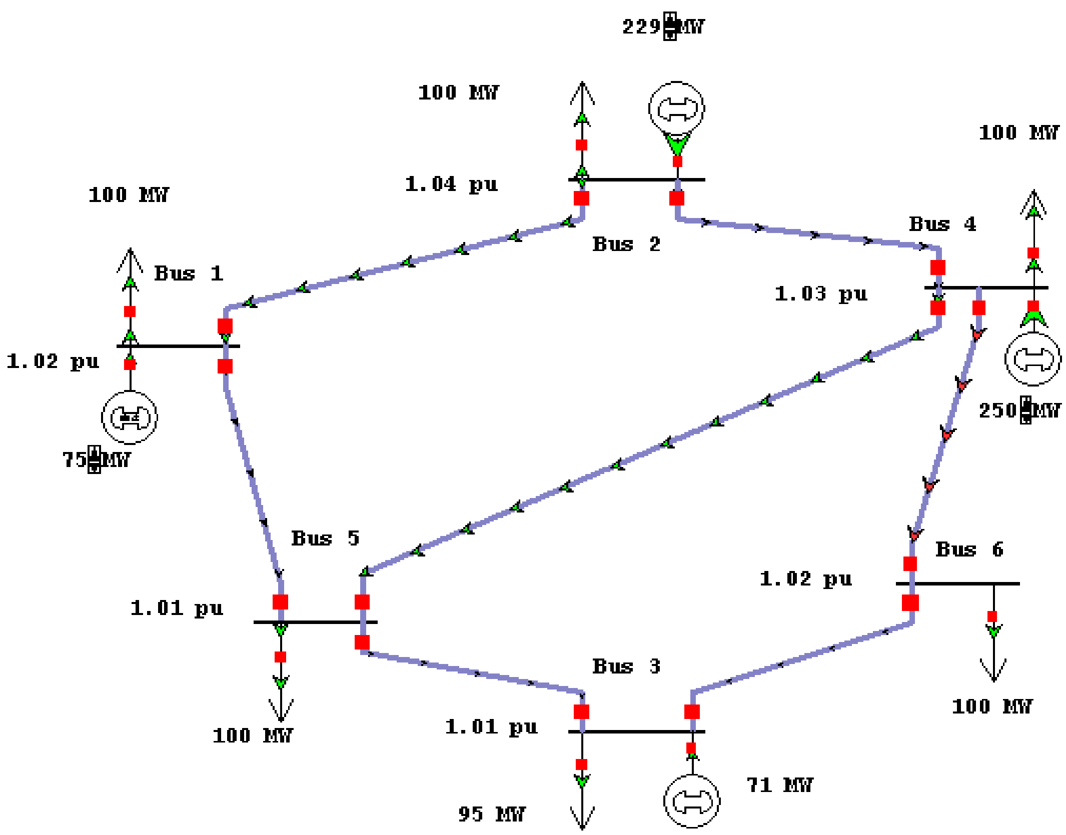

Figure 5. 1 6-Bus Illustration System Base programme

Table 5. 3 Forecasting Load and LMP Values of the System

Number	Bus ID	Load (MW)	LMP ($/MWh)
1	1	100	14.13
2	2	100	13.45
3	3	100	15.17
4	4	100	13.85
5	5	100	14.78
6	6	100	15.23

Figure 5.2 shows the actual value of the illustrate system, which is with 5% imbalance of the forecast load value. The values in the programme are the actual values. Table 5.4 shows the actual load value of each bus, and the actual LMP value of each bus.

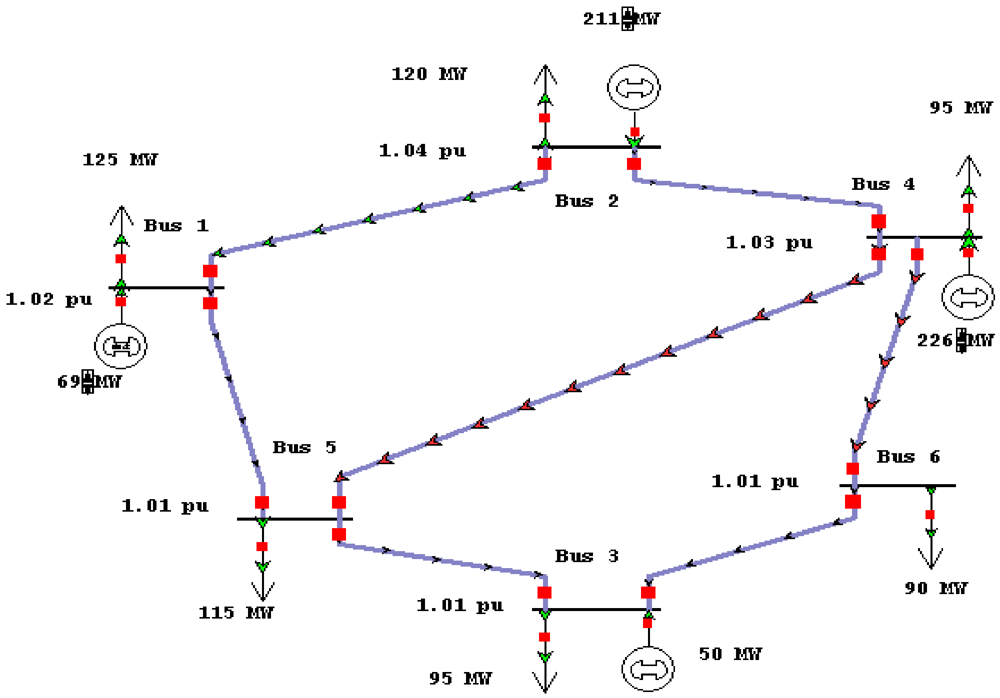

Figure 5. 2 6-Bus Illustration System Actual programme

Table 5. 4 Actual Load and LMP Values of the System

Number	Bus ID	Load (MW)	LMP($/MWh)
1	1	125	14.15
2	2	120	14.02
3	3	95	14.82
4	4	95	13.89
5	5	115	14.28
6	6	90	15.35

From the results, the different in the LMP values of each bus, is the imbalance price of each bus. When the imbalance percentage of the load changes, the LMP values will be change, this will cause the Revenue Income and Total payment change. More detail discussion will be discussed in the next chapter.

5.9 Conclusions

The experiences with the deregulated processes have been successful both in New Zealand and Argentina. Electricity prices are no longer subject to exogenous factors but follow actual availability of hydroelectric energy and fuel prices, providing correct market based economic signals orienting efficient decisions of Participants. In Argentina the change has been significant, with monthly average prices in the wholesale market.

In the New Zealand electricity market, Spot pricing, and consequently price inversion, are inherent in wholesale electricity market. However, the economic implications of price inversion need not upset the operation of such a market, provided care is taken in its design. The settlement system is similar as the PJM market which has been discussed in chapter 2. In the Argentina market electricity market, the settlement system is the same. The imbalance price shows by the difference between the forecast nodal marginal price and the actual nodal price. Further discussion on imbalance settlement price will be discussed in the next chapter.

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Chapter 6 Comparison of Different Imbalance Settlement Methods in the Demonstrate System

6.1 Introduction

The transition to a fully competitive wholesale market for electricity has altered the purchase and sale of electricity in generation as well as in transmission. For generation, long-term purchase agreement of specified generation facilities will likely to be replaced by short-term contracts based on spot market prices and quantities. There will be a risk in investing in new generating facilities as there might either be no pre-existing contracts for power or only a small percent of contracts for power output. Another change is that power from a single facility may be sold to multiple customers rather than under a single long-term contract to a purchasing utility.

Different electricity markets models have been developed and used in many countries all over the world. In the chapters before, four types of electricity market structure have been described, three methods of pricing mechanism and the theoretical concepts of uniform marginal pricing (system sell/buy pricing), zonal marginal pricing, and nodal marginal pricing (locational marginal price) are discussed. The nodal pricing is formulated using security constrained optimal power flow dispatch while the uniform pricing is formulated without considering the effect of physical laws and line-flow limits as well as the Zonal pricing. Early electricity spot market designs are based on uniform pricing such as old UK Pool market. However, several of these markets have moved to nodal pricing or to zonal pricing for a more efficient, fair and non-discriminatory and transparent mechanism in a competitive market environment.

This chapter will compare the imbalance settlement results by the three typical electricity pricing mechanism. The imbalance prices and the generators total revenue income and the loads total revenue payments of each mechanism have been calculated.

The same IEEE30 system will be given as the illustrate example. Each of the price mechanism will be used by the illustrate system, and the comparison will be made by the system total income and payment results.

6.2 Introduction of the Typical Market Structure

The main feature of decentralized electricity markets is the wholesale electricity spot market also known as pool market. The first fully competitive pool was introduced in England and Wales (E&W) in 1990. Unlike other electricity market such as bilateral market, Pool market must ensure demand and supply continuously matched to maintain network electrical equilibrium. Each generating unit is required to follow the operating instructions from system operator for coordination of generation and transmission. Competitive in electricity spot market occurs when every generator submits their price bids specifying the minimum prices at which they are willing to supply energy and the amount of capacity of each type they expect to have available.

In the E&W pool market, the pool is administrated by system operator in order to provide a practical framework for the spot pricing and trading of electricity between generators, suppliers and certain large consumers. The pool determines electricity prices for each period to reflect the changing balance between demand and supply over the day. The bidding into the pool took place by the generators only, without any bidding from the demand side supplier. The generators' price and capacity bids are used to construct a 'merit-order' of generating units. The bids received from the generating companies were stacked with the cheapest bids first and were progressively added until the volume of the electricity involved matched the demand projected by the National Grid Company. The intersection of the day-ahead supply curve with the estimated demand determines system marginal price (SMP) for each half-hour of the following day. The generators' price bids are fixed for the subsequent 48 half-hour periods and SMP for each half-hour is determined up to twelve hours in advance. SMP is determined in the England and Wales's pool by the bids price of the marginal generating unit is the unconstrained merit order.

In order to solve the uniform pricing approach, Zonal pricing was introduced. Zonal pricing mechanism is applied in Australia as mentioned in chapter 4. Generally, Zonal pricing can be categorized into two stages. The first stage is identical to the market dispatch under unconstrained dispatch to determine the LMP. Second stage will be grouping the buses in different zones.

Nodal pricing is the cost of serving the next MW of load at a given location. It is formulated using a security constrained optimal power flow dispatch so as to minimize cost of supply subject to transmission constraint based upon market participant offers and bids. Nodal pricing is also known as Locational Marginal Pricing, and also called bus marginal price or bus incremental cost, which had been detailed mention in Chapter3.

The following part of this chapter will simulate the different price mechanism by the same IEEE30 system, with the different percentage total load imbalance ±2%, ±5%, ±8%, ±10%, ±20%. The simulation software is MATLAB. The different prices will be given by the results.

6.3 Imbalance settlement in demonstrate system by the UK Electricity market settlement method

In this thesis, loss is assumed to zero and no loss will be considered for each imbalance settlement method.

The IEEE 30 system is shown as Figure 6.1 below. This section will simulate the IEEE 30 system above using MATLAB software. And use the equation of SSP/SBP in chapter 2. Results are given as the Figures below.

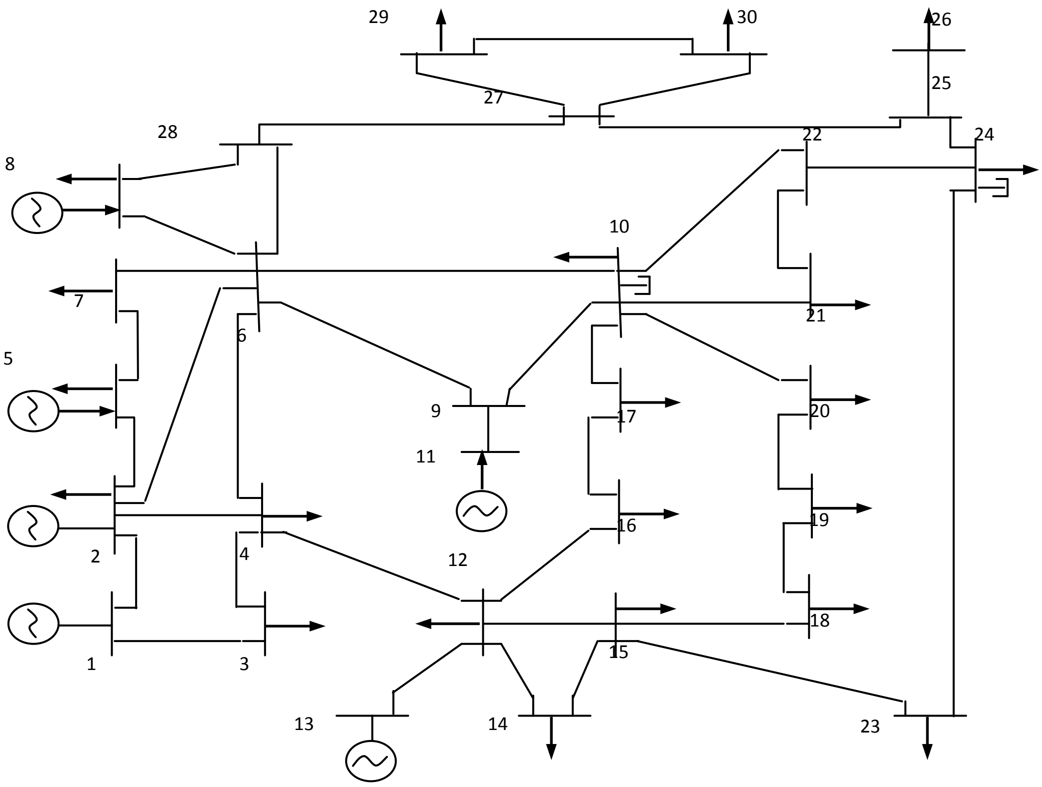

Figure 6. 1 IEEE30 Demonstrate System

Table 6. 1 Line data in demonstration system

Branch No.	**From bus**	**To bus**	**x**	**b**	**capacity(MW)**
1	1	2	0.06	0.03	130
2	1	3	0.19	0.02	130
3	2	4	0.17	0.02	65
4	3	4	0.04	0	130
5	2	5	0.2	0.02	130
6	2	6	0.18	0.02	65
7	4	6	0.04	0	90
8	5	7	0.12	0.01	70
9	6	7	0.08	0.01	130
10	6	8	0.04	0	32
11	6	9	0.21	0	65
12	6	10	0.56	0	32
13	9	11	0.21	0	65
14	9	10	0.11	0	65
15	4	12	0.26	0	65
16	12	13	0.14	0	65
17	12	14	0.26	0	32
18	12	15	0.13	0	32
19	12	16	0.2	0	32
20	14	15	0.2	0	16

21	16	17	0.19	0	16
22	15	18	0.22	0	16
23	18	19	0.13	0	16
24	19	20	0.07	0	32
25	10	20	0.21	0	32
26	10	17	0.08	0	32
27	10	21	0.07	0	32
28	10	22	0.15	0	32
29	21	22	0.02	0	32
30	15	23	0.2	0	16
31	22	24	0.18	0	16
32	23	24	0.27	0	16
33	24	25	0.33	0	16
34	25	26	0.38	0	16
35	25	27	0.21	0	16
36	28	27	0.4	0	65
37	27	29	0.42	0	16
38	27	30	0.6	0	16
39	29	30	0.45	0	16
40	8	28	0.2	0.02	32
41	6	28	0.06	0.01	32

Table 6. 2 Generator data

Bus ID	**Capacity(MW)**	**Pmax(MW)**
1	80	80
2	80	80
5	50	50
8	55	55
11	50	50
13	60	60

Table 6. 3 Load data

Bus no.	**P(MW)**	**Q(MW)**	**Assigned area**
1	0	0	1
2	21.7	12.7	1
3	2.4	1.2	1
4	7.6	1.6	1
5	0	0	1
6	0	0	1
7	22.8	10.9	1
8	30	30	1
9	0	0	1
10	5.8	2	3
11	0	0	1
12	11.2	7.5	2
13	0	0	2
14	6.2	1.6	2

15	8.2	2.5	2
16	3.5	1.8	2
17	9	5.8	2
18	3.2	0.9	2
19	9.5	3.4	2
20	2.2	0.7	2
21	17.5	11.2	3
22	0	0	3
23	3.2	1.6	2
24	8.7	6.7	3
25	0	0	3
26	3.5	2.3	3
27	0	0	3
28	0	0	1
29	2.4	0.9	3
30	10.6	1.9	3

Table 6. 4 Offer and Bid for Generators over 24 hours (48 Slots)

Time slot	Gen ID	Offer (RMB/MWh)	Bid (RMB/MWh)	Available volume(MW)
1	1	225.35	147.32	79.27
1	2	214.01	159.66	24.98
1	5	220.68	161.82	41.52
1	8	229.45	147.64	45.99
1	11	225.16	155.86	27.06
1	13	223.13	158.88	39.81
2	1	217.63	159.26	116.65
2	2	218.59	154.28	18.39
2	5	223.4	157.26	45.13
2	8	224.33	160.3	73.71
2	11	210.13	150.11	0.00
2	13	218.22	156.29	5.56
3	1	223.42	159.92	114.40
3	2	215.84	153.95	19.46
3	5	217.97	154.68	23.31
3	8	221.82	155.92	63.56
3	11	210.6	150.54	0.00
3	13	217.6	155.8	23.47
4	1	212.77	160.71	3.73
4	2	229.31	160.04	112.07
4	5	227.04	157.16	31.76
4	8	226.94	160.49	79.02
4	11	210.95	148.45	0.00
4	13	226.96	156.3	27.22

5	1	224.53	148.56	106.05
5	2	218.46	148.54	14.51
5	5	224.8	155.69	29.82
5	8	228.34	152.64	55.37
5	11	226.56	161.41	41.52
5	13	215.98	155.18	0.00
6	1	209.7	153.45	26.74
6	2	213.07	149.31	0.00
6	5	230.31	157.28	67.65
6	8	230.76	154.16	72.71
6	11	229.75	158.2	40.43
6	13	226.92	148.53	26.16
7	1	215.09	151.28	7.95
7	2	228.91	149.94	107.66
7	5	220.69	155.68	22.37
7	8	209.01	148.09	0.00
7	11	224.04	155.9	30.87
7	13	226.36	158.4	59.97
8	1	210.02	159.65	7.16
8	2	230.55	153.31	108.38
8	5	216.15	158.43	7.07
8	8	228.04	150	46.22
8	11	211.91	152.11	0.00
8	13	227.75	162.69	53.44
9	1	211.14	153.94	15.14
9	2	218.66	160.14	104.85
9	5	211.32	155.35	0.00
9	8	222.48	157.52	60.93
9	11	224.9	149.83	27.63
9	13	220.12	152.75	7.51
10	1	227.12	161.37	99.75
10	2	211.44	159.7	0.00
10	5	222.44	162.65	30.52
10	8	230.78	152.38	59.01
10	11	211.43	156.9	0.00
10	13	222.98	162.3	31.51
11	1	224.29	150.07	85.33
11	2	214.68	148.19	0.00
11	5	226.13	150.64	11.99
11	8	220.61	161.18	58.15
11	11	211.58	162.56	9.02
11	13	229.92	152.62	39.43
12	1	215.98	151.34	39.63
12	2	217.99	153.44	80.56

12	5	218.32	148.89	0.00
12	8	219.55	149.08	29.70
12	11	223.1	149.89	20.42
12	13	218.77	160.99	49.78
13	1	229.9	149.51	104.03
13	2	222.09	155.42	50.36
13	5	211	148.95	0.00
13	8	226.63	162.57	69.10
13	11	216.23	151.25	43.12
13	13	210.32	154.3	1.03
14	1	209.76	149.36	0.00
14	2	214.77	153.71	86.36
14	5	214.86	148.24	0.00
14	8	214.01	155.62	34.93
14	11	223.38	153.4	28.56
14	13	228.07	153.66	49.20
15	1	218.65	160.72	126.70
15	2	222.26	157.43	93.91
15	5	212.38	153.52	0.00
15	8	219.96	158.21	44.40
15	11	225.48	148.4	17.23
15	13	222.89	150.62	0.00
16	1	217.39	156.24	21.19
16	2	224.65	156.98	147.45
16	5	215.18	154.2	0.00
16	8	228.82	162.74	83.76
16	11	221.83	157.85	25.04
16	13	216.81	149.2	0.00
17	1	225.84	155.77	122.59
17	2	213.88	151.78	0.00
17	5	218.68	152.92	0.21
17	8	221.64	151.71	43.23
17	11	225.28	153.49	29.07
17	13	230.93	152.04	55.52
18	1	226.49	149.5	114.72
18	2	211.58	153.94	0.00
18	5	220.6	159.08	29.76
18	8	227.59	153.68	58.12
18	11	214.17	162.48	22.41
18	13	213.93	158.5	20.92
19	1	213.11	160.47	91.42
19	2	215.53	147.49	0.00
19	5	219.06	156.98	5.12
19	8	225.25	154.46	47.55

19	11	225.17	153.48	20.27
19	13	223.35	159.38	39.29
20	1	219.77	156.89	70.92
20	2	216.01	162.5	35.39
20	5	228.26	159.22	29.26
20	8	221.89	159.09	31.01
20	11	230.35	156.87	27.39
20	13	222.31	158	0.00
21	1	218.8	152.69	84.66
21	2	218.33	149.84	0.00
21	5	220.4	161.71	34.51
21	8	214.43	159.93	30.06
21	11	228.07	149.64	19.87
21	13	217.52	147.4	24.90
22	1	223.22	155.21	96.14
22	2	220.17	148.9	0.00
22	5	229.76	162.33	59.17
22	8	223.66	148.8	34.28
22	11	210.9	153.16	0.00
22	13	212.13	160.32	17.52
23	1	224.61	153.48	100.52
23	2	210.88	153.02	0.00
23	5	223.03	150.23	43.69
23	8	210.84	150.01	13.87
23	11	217.06	149.75	12.84
23	13	209.55	161.55	27.95
24	1	225.6	148.43	109.30
24	2	214.77	150.32	0.00
24	5	230.07	149.4	20.61
24	8	222.77	152.82	34.11
24	11	217.12	159	17.84
24	13	218.26	159.2	31.82
25	1	215.07	150.97	6.10
25	2	226.62	154.84	129.40
25	5	214.3	158.04	0.00
25	8	223.54	148.13	25.80
25	11	224.07	160.75	42.86
25	13	213.05	147.91	0.00
26	1	223.95	149.16	94.82
26	2	209.64	152.51	0.00
26	5	223.87	148.7	0.00
26	8	225.05	155.34	45.79
26	11	222.15	152.69	22.91
26	13	224.97	153.11	10.17

27	1	223.41	150.1	3.92
27	2	229.43	162	102.59
27	5	215.36	155.39	0.00
27	8	228.6	152.46	33.38
27	11	226.37	157.88	22.54
27	13	217.15	158.17	51.53
28	1	212.58	150.97	0.00
28	2	225.07	161.52	95.96
28	5	223.78	155.47	0.00
28	8	230.61	149.97	25.05
28	11	217.09	151.81	0.00
28	13	227.51	158.56	18.61
29	1	211.62	153.72	40.95
29	2	219.75	148.07	0.01
29	5	224.29	160.6	59.66
29	8	225.92	150.49	50.49
29	11	213.53	155.47	0.00
29	13	225.15	150.73	13.68
30	1	219.96	148.02	0.00
30	2	221.73	158.69	96.60
30	5	210.5	154.77	0.00
30	8	221.79	161.28	32.61
30	11	210.91	160.15	0.00
30	13	221.56	151.42	15.65
31	1	230.11	161.24	84.62
31	2	214.22	151.42	23.98
31	5	214.61	153.35	0.00
31	8	229.42	157.72	21.16
31	11	225.98	156.51	2.72
31	13	212.89	157.68	0.00
32	1	281.76	200.28	84.49
32	2	279.93	201.22	8.36
32	5	281.82	200.59	0.00
32	8	281.51	198.42	15.23
32	11	279.09	198.24	2.41
32	13	281.73	200.14	0.00
33	1	282.27	199.88	87.41
33	2	279.64	200.31	0.14
33	5	282.7	200.72	0.00
33	8	278.14	198.57	9.25
33	11	278.85	199.26	13.27
33	13	281.39	201.54	0.00
34	1	277.91	198.05	51.77
34	2	279.7	198.73	17.87

34	5	281.29	200.54	0.00
34	8	282.03	198.67	17.65
34	11	281.38	201.09	9.98
34	13	277.87	201.6	27.19
35	1	282.31	199.35	76.37
35	2	278.92	198.96	0.00
35	5	279.13	201.78	0.00
35	8	282.74	200.48	17.27
35	11	277.26	200.79	42.13
35	13	280.14	200.5	0.00
36	1	280.74	198.65	47.96
36	2	280.05	201.55	16.47
36	5	280.47	198.84	0.00
36	8	280.08	200.29	9.82
36	11	277.47	198.5	0.00
36	13	279.02	198.55	0.00
37	1	277.75	201.18	59.46
37	2	280.06	198.11	11.80
37	5	277.8	200.84	0.00
37	8	282.15	198.21	11.13
37	11	280.94	198.52	1.60
37	13	280.26	198.87	0.00
38	1	278.76	199.24	40.83
38	2	281.78	199.96	20.49
38	5	282.28	198.94	5.96
38	8	280.49	201.72	11.61
38	11	280.58	198.37	43.26
38	13	279.43	198.73	0.00
39	1	280.26	200.11	62.26
39	2	281.65	198.67	0.00
39	5	282.13	198.48	19.33
39	8	278.07	200.91	4.05
39	11	280.15	198.03	0.00
39	13	279.52	198.17	0.00
40	1	282.56	198.66	60.45
40	2	280.81	201.91	0.22
40	5	281.78	200.43	34.30
40	8	278.32	200.95	0.80
40	11	281.29	199.69	0.00
40	13	278.21	198.43	0.00
41	1	282.6	200.41	59.35
41	2	279.32	200.85	33.19
41	5	278.66	199.8	0.00
41	8	279.48	198.25	43.63

41	11	281.16	200.62	0.00
41	13	278.63	200.47	0.00
42	1	278.08	199.05	30.57
42	2	281.74	200	16.99
42	5	280.53	199.83	0.00
42	8	281.39	201.44	9.17
42	11	281.58	200.89	0.01
42	13	277.32	201.76	0.00
43	1	282.64	200.62	48.78
43	2	280.18	199.88	35.44
43	5	277.33	200.65	0.00
43	8	281.82	201.74	5.35
43	11	278.81	200.12	0.00
43	13	282.37	199.42	0.00
44	1	282.56	200.76	80.17
44	2	279.16	198.24	0.00
44	5	279.58	201.08	0.00
44	8	281.62	201.94	10.98
44	11	281.08	198.44	0.00
44	13	280.86	199.64	12.61
45	1	279.92	200.99	59.11
45	2	282.46	200.73	19.27
45	5	278.95	199.4	0.00
45	8	278.98	201.44	30.64
45	11	280.32	200.53	0.50
45	13	282.42	201.94	0.00
46	1	281.68	199.8	69.50
46	2	282.11	198.17	0.79
46	5	278.1	200.65	0.00
46	8	280.19	201.14	13.33
46	11	279.42	198.51	0.53
46	13	278.12	201.78	0.00
47	1	216.49	161.89	60.82
47	2	219.09	153.8	34.22
47	5	213.93	157.66	0.00
47	8	221.76	154.51	10.42
47	11	213.52	152.45	0.00
47	13	230.06	154.65	8.66
48	1	221.88	154.86	17.91
48	2	230.19	155.74	56.36
48	5	223.69	158.74	2.74
48	8	209.37	161.39	24.63
48	11	217.54	151.89	12.34
48	13	214.84	156.92	0.00

6.3.1 SSP and SBP calculation

In this section, the SSP and SBP will be calculated following with five cases of total load unbalance ±2%、 ±5%、 ±8%、 ±10%、 ±20%.

6.3.1.1 Scenario1: with ±2% total load imbalance

Figure 6.2 shows the output of the six generators of 48 slots (over 24 hours) when the system with ±2% total load imbalance.

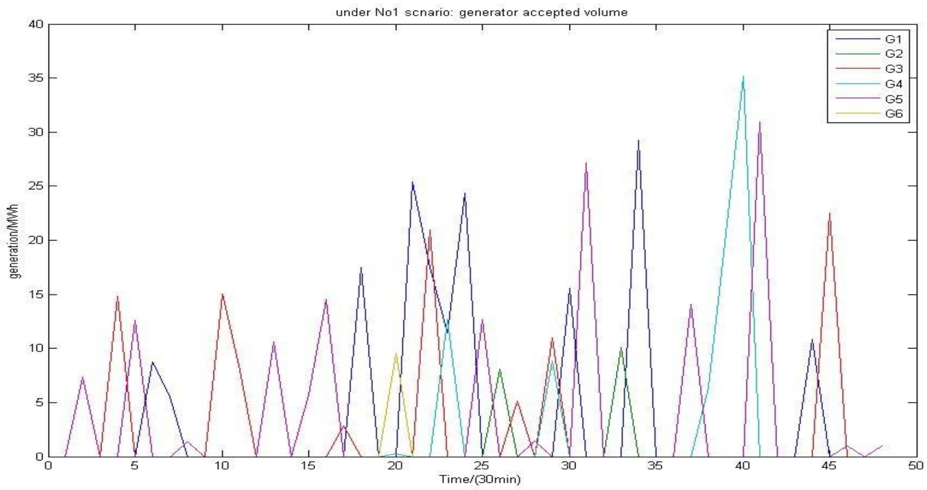

Figure 6. 2 the generation curve with ±2% total load imbalance

Figure 6.3 is the Total Load Curve of 48 periods (24 hours), the blue line is the forecast value, the red line is the actual value, and the green line is the difference between the two values.

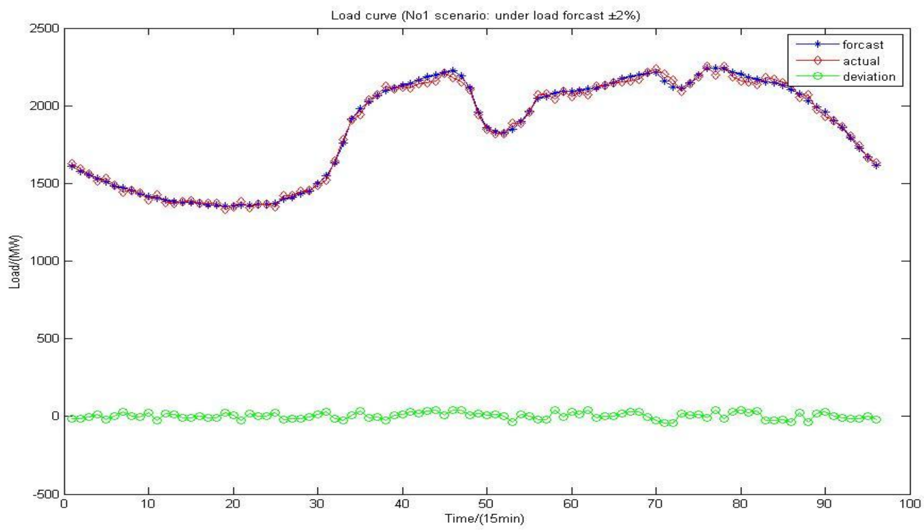

Figure 6. 3 the load curve with ±2% total load imbalance

In the Figure 6.4, the blue line is the SBP, and the green line is the SSP. The reason causing the difference between SBP and SSP is the imbalance energy between the forecast and the actual demand. The same calculation for the different percentage of imbalance energy would be taken below.

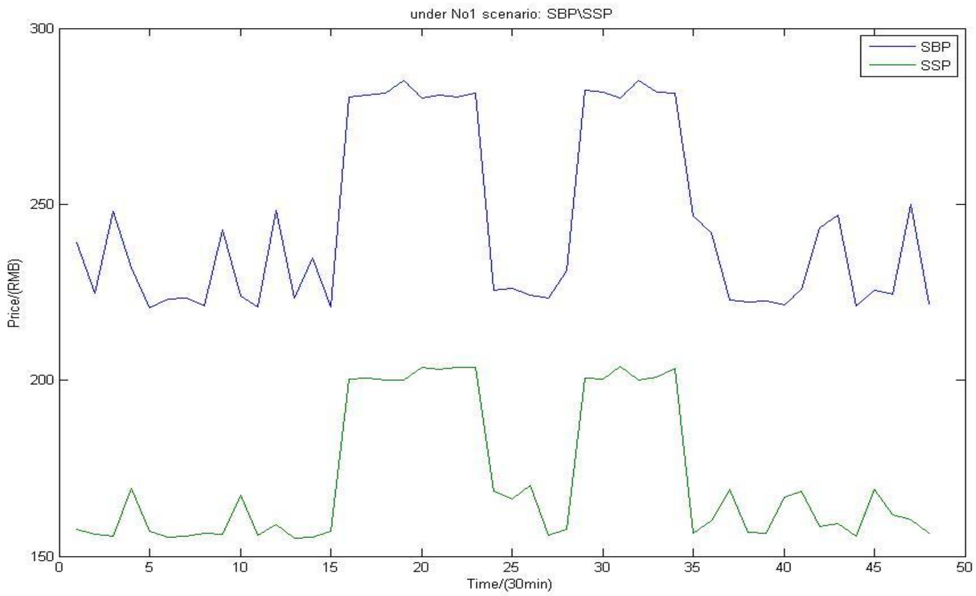

Figure 6. 4 the SSP/SBP with ±2% total load imbalance

6.3.1.2 with ±5% total load imbalance

Figure 6.5 shows the output of the six generators over 24 hours when the system with ±5% total load imbalance.

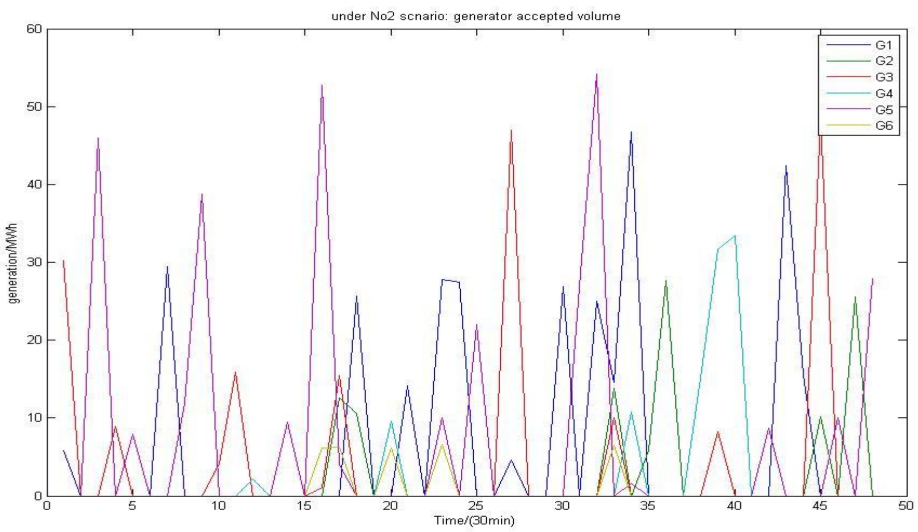

Figure 6. 5 the generation curve with ±5% total load imbalance

Figure 6.6 is the Total Load Curve of 48 periods (24 hours), the blue line is the forecast value, the red line is the actual value, and the green line is the difference between the two values.

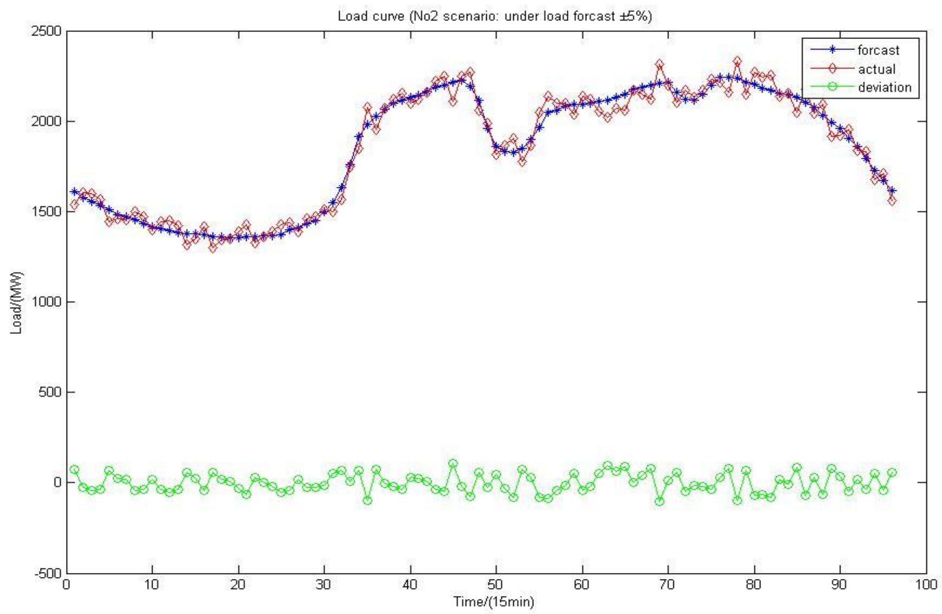

Figure 6. 6 the load curve with ±5% total load imbalance

In the Figure 6.7, the blue curve is stand for the SBP and the green curve is the SSP. The reason causing the difference between SBP and SSP is the imbalance energy between the forecast and the actual demand. The same calculation for the different percentage of imbalance energy would be taken below.

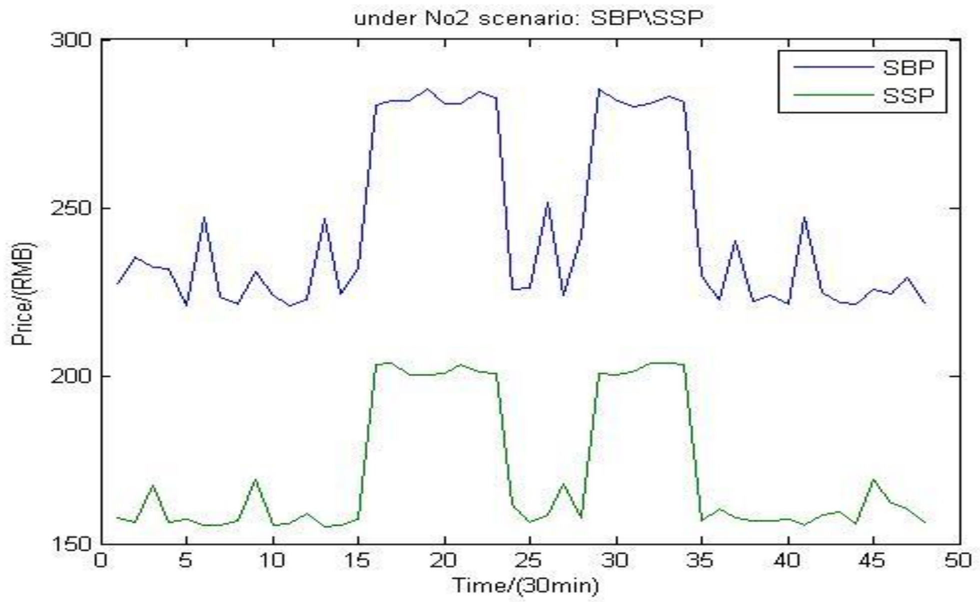

Figure 6. 7 the SSP/SBP with ±5% total load imbalance

6.3.1.3 with ±8% total load imbalance

Figure 6.8 shows the output of the six generators over 24 hours when the system with ±8% total load imbalance.

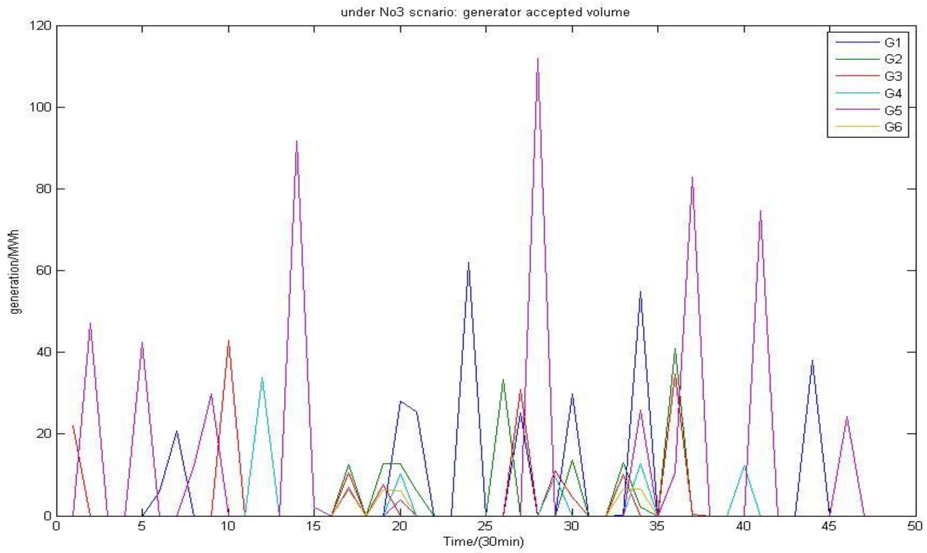

Figure 6. 8 the generation curve with ±8% total load imbalance

Figure 6.9 is the load curve on 24 hours basis, the blue line is the forecast value, the red line is the actual value, and the green line is the difference between the two values.

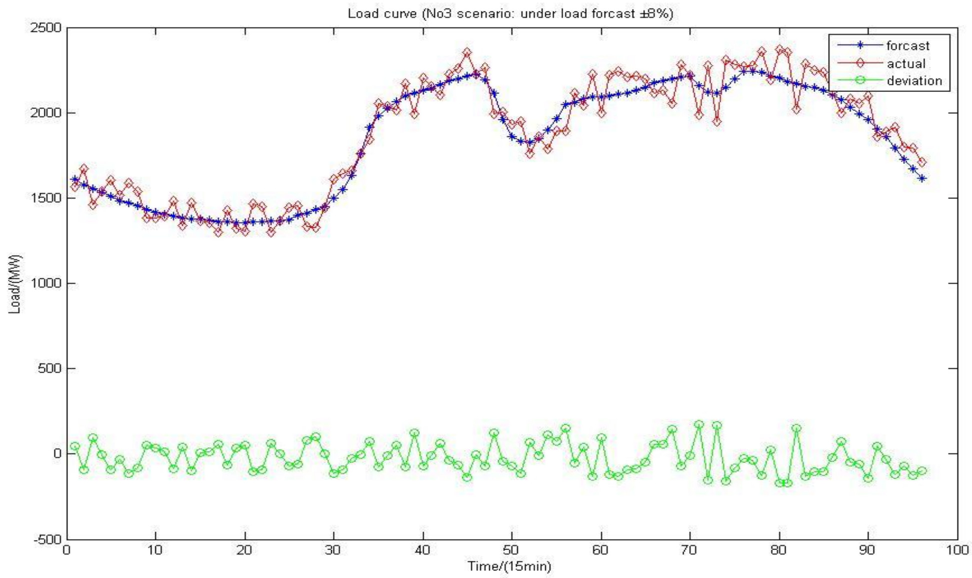

Figure 6. 9 the Load curve with ±8% total load imbalance

In the Figure 6.10, the blue curve stands for the SBP and the green curve is the SSP. The reason causing the difference between SBP and SSP is the imbalance energy between the forecast and the actual demand.

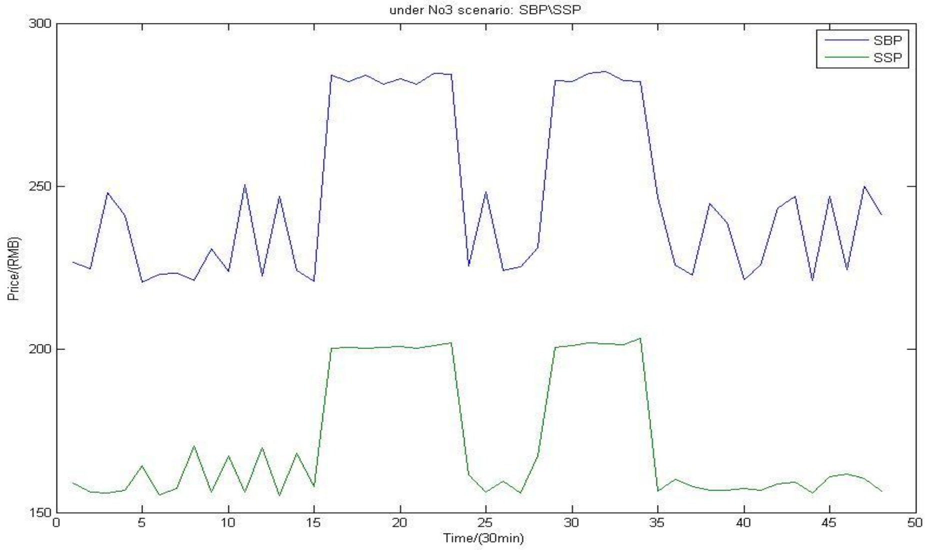

Figure 6. 10 the SSP/SBP with ±8% total load imbalance

6.3.1.4 with ±10% total load imbalance

Figure 6.11 shows the output of the six generators over 24 hours when the system with ±10% total load imbalance.

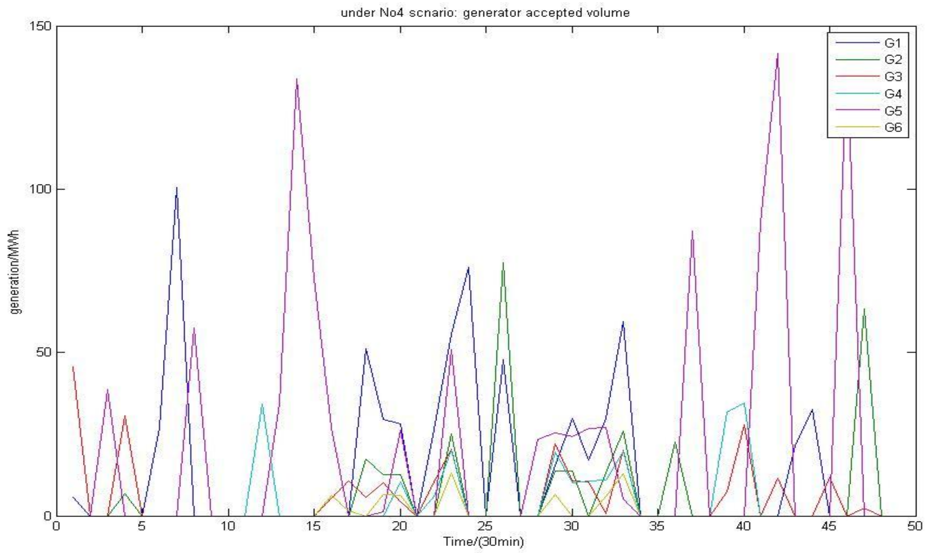

Figure 6. 11 the generation curve with ±10% total load imbalance

Figure 6.12 is the load curve on 24 hours basis, the blue line is the forecast value, the red line is the actual value, and the green line is the difference between the two values.

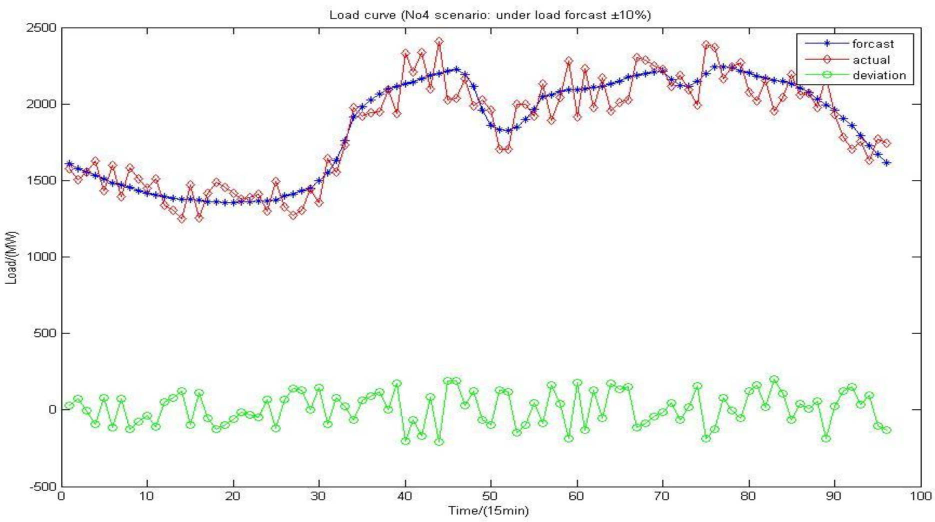

Figure 6. 12 the Load curve with ±10% total load imbalance

In the Figure 6.13, the blue curve stands for the SBP and the green curve is the SSP. The reason causing the difference between SBP and SSP is the imbalance energy between the forecast and the actual demand.

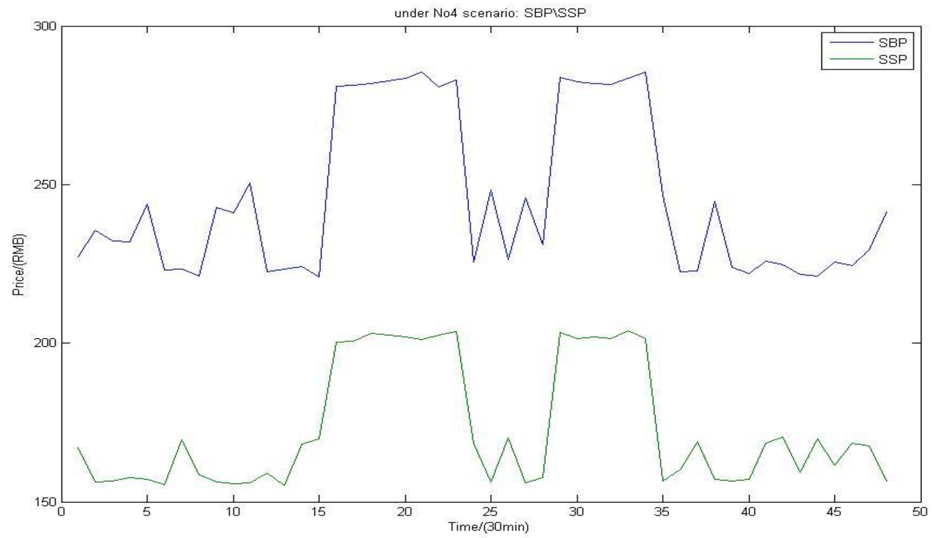

Figure 6. 13 the SSP/SBP with ±10% total load imbalance

6.3.1.5 with ±20% total load imbalance

Figure 6.14 shows the output of the six generators over 24 hours when the system with ±20% total load imbalance.

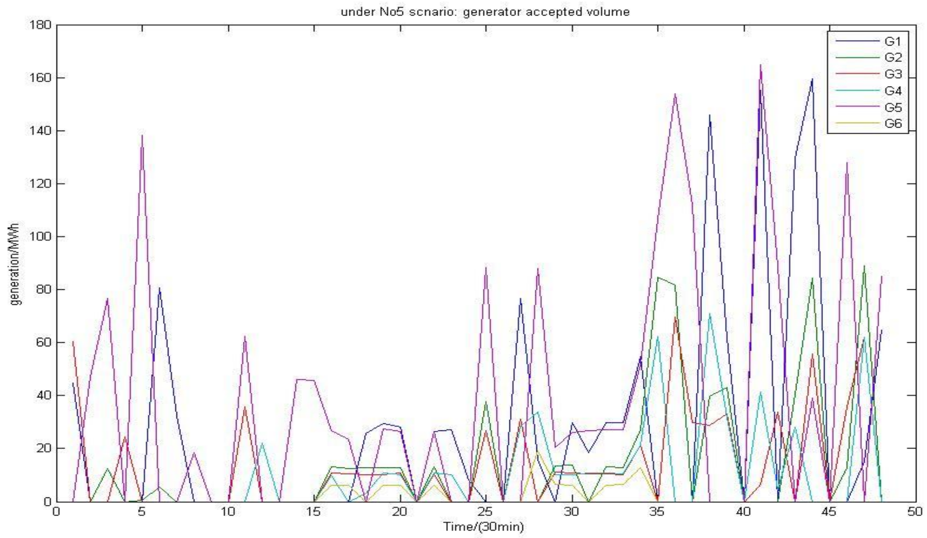

Figure 6. 14 the generation curve with ±20% total load imbalance

Figure 6.15 is the load curve on 24 hours basis, the blue line is the forecast value, the red line is the actual value, and the green line is the difference between the two values.

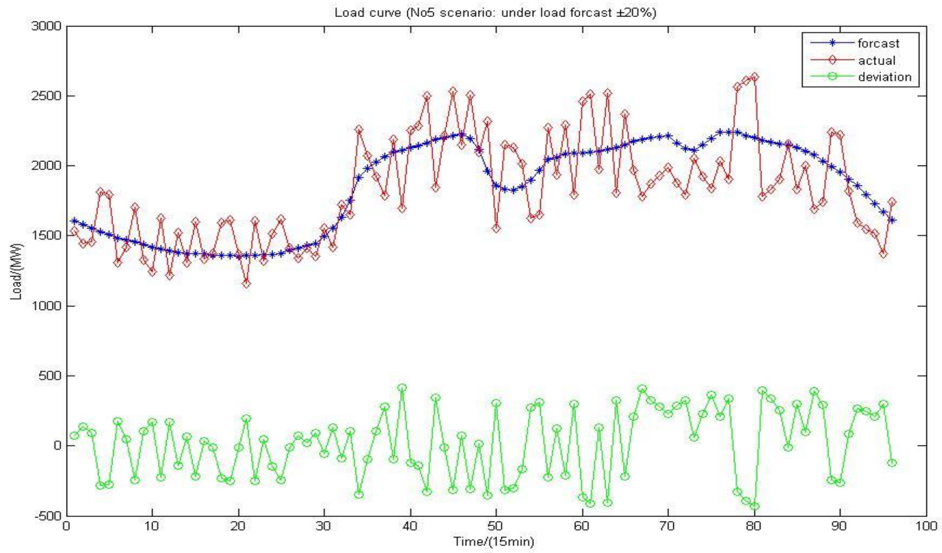

Figure 6. 15 the Load curve with ±20% total load imbalance

In the Figure 6.16, the blue curve stands for the SBP and the green curve is the SSP. The reason causing the difference between SBP and SSP is the imbalance energy between the forecast and the actual demand.

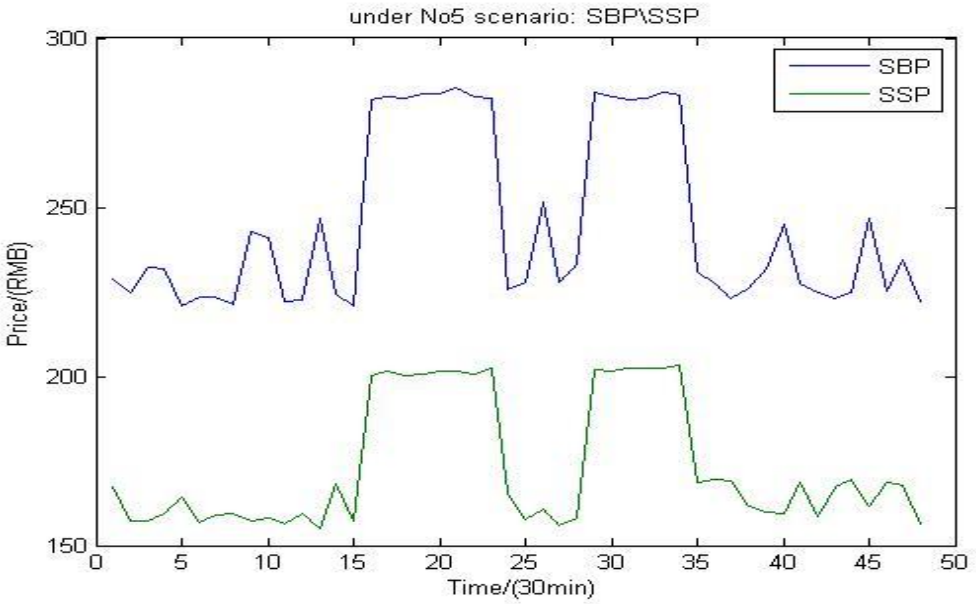

Figure 6. 16 the SSP/SBP with ±20% total load imbalance

The results of SSP and SBP value for each bus will be given in the Appendix.

Figure 6.17 is shown as the offer/bid curves for generator 1to 6 respectively.

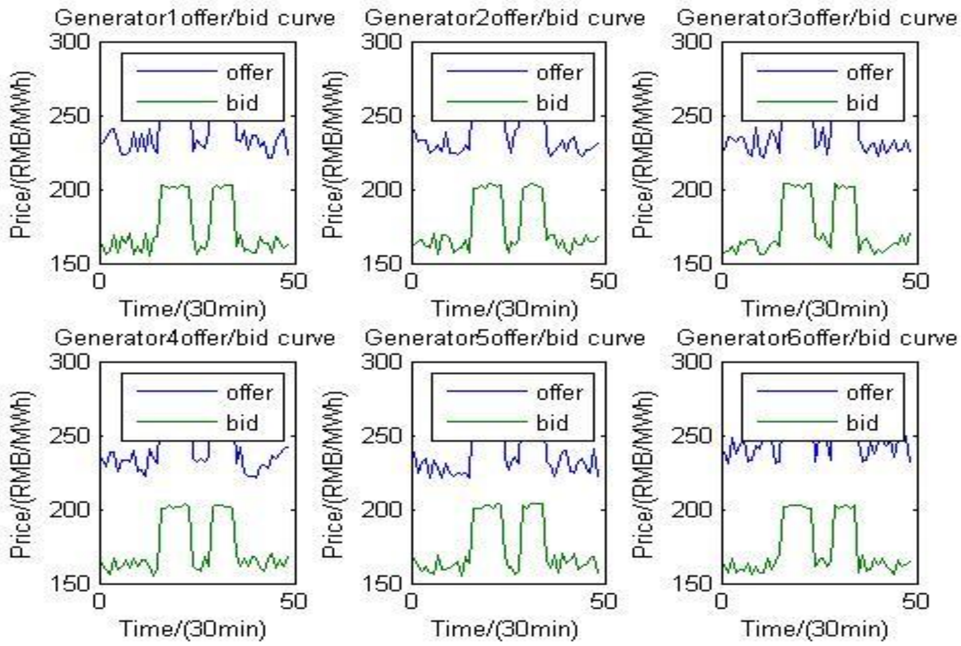

Figure 6. 17 bid and offer curves for all generators

6.3.2 Revenue income for all the generators

In this section, it is calculated that the total revenue income for all the generators with five probability imbalance settlements.

6.3.2.1 Total revenue income on base case

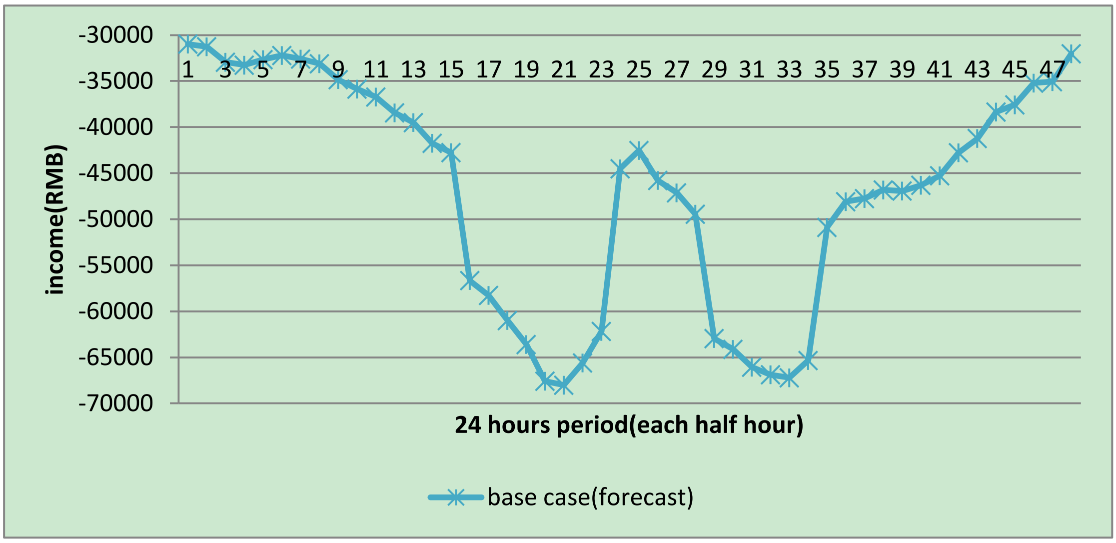

Figure 6. 18 Total revenue income on base case

It can be seen from the Figure 6.18, which is shown that the total revenue income value in RMB on base case (one single curve). It is through 24 hours containing 48 periods for the whole day, and it is the forecast revenue income on base case which is assumed to calculate by day-ahead.

6.3.2.2 Total unbalance revenue income for unbalance settlements

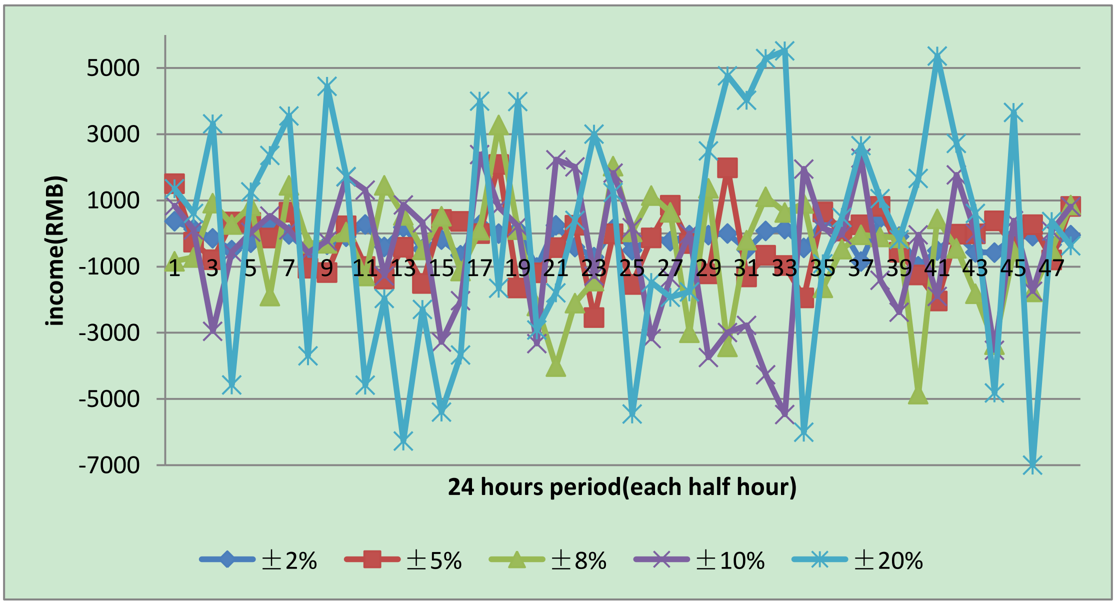

Figure 6. 19 Total unbalance revenue income for unbalance settlements

The unbalance revenue income for all generators is shown in Figure 6.19, which is given the extra generator income for incorrect forecast containing all six generators over the 24 hours period on each half hour basis. And in the Figure 6.19, it can be seen that the total unbalance revenue income contains five curves demonstrating each case of ±2%、±5%、±8%、±10%、±20% unbalance volume respectively.

6.3.2.3 Total revenue income for all generators

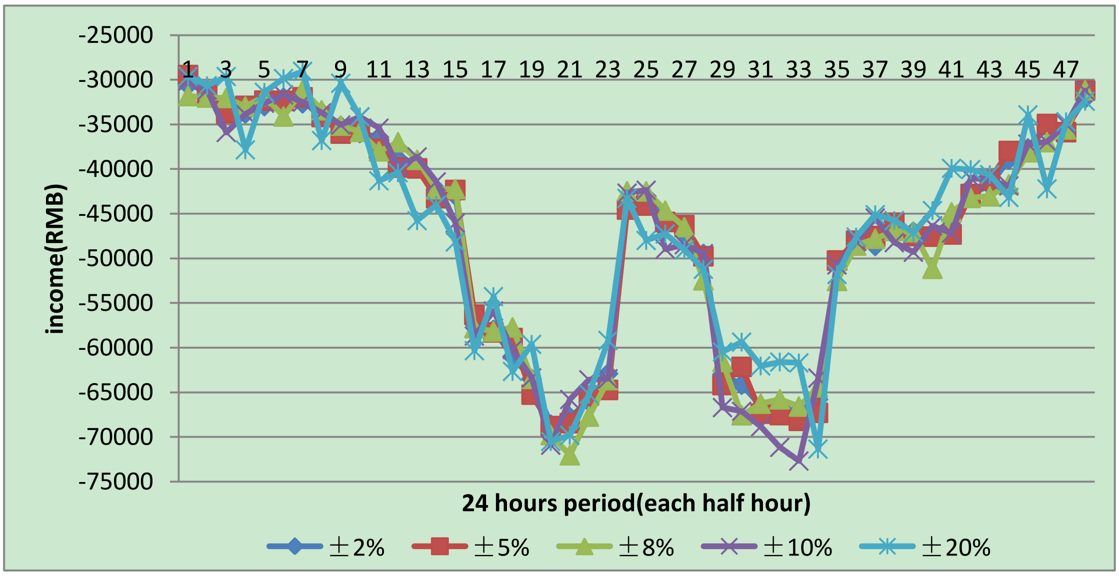

Figure 6. 20 Total revenue income for all generators

In Figure 6.20, which is plotted the five curves containing each case of ±2%、±5%、±8%、±10%、±20% unbalance volume respectively, it is the total revenue income for all generators with five imbalance cases. The light blue with star-dotted curve is shown that, the higher imbalance volume the fluctuations of the total income over 24 hour's period (each half hour slots) will be greater. On the other hand, the smaller amount of the imbalance volume for all generators, the smaller the fluctuations of the total income, which is shown by the dark blue with diamond-dotted curve.

6.3.3 Load payments by all load

6.3.3.1 Total load payments on base case

It is the figure showing that the base case for the total load payments, which is covered over 24 hours (containing 48 periods for the whole day) and is calculated using with a canton typical forecast day profile (shown in figure 6.21).

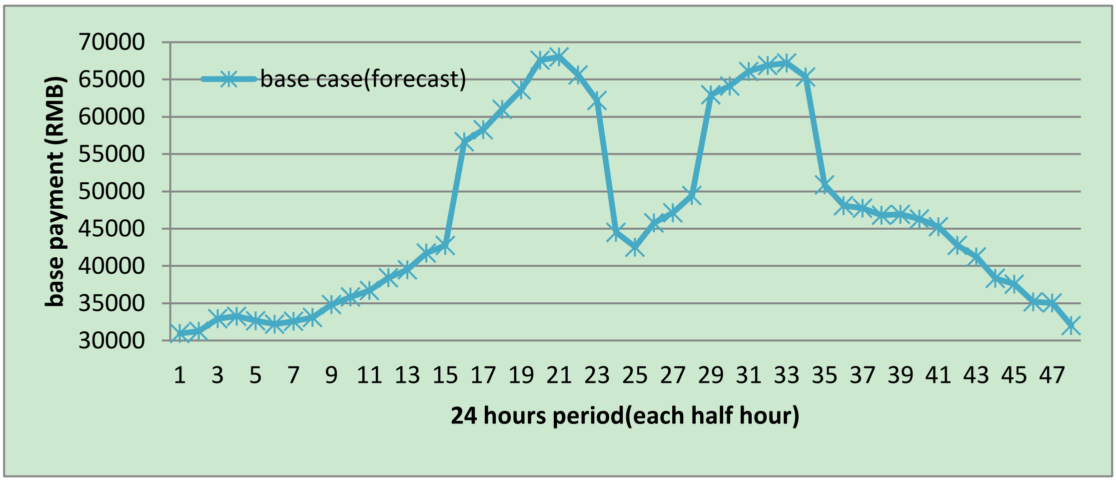

Figure 6. 21 Total load payments on base case

6.3.3.2 Total unbalance load payment for each case of unbalance

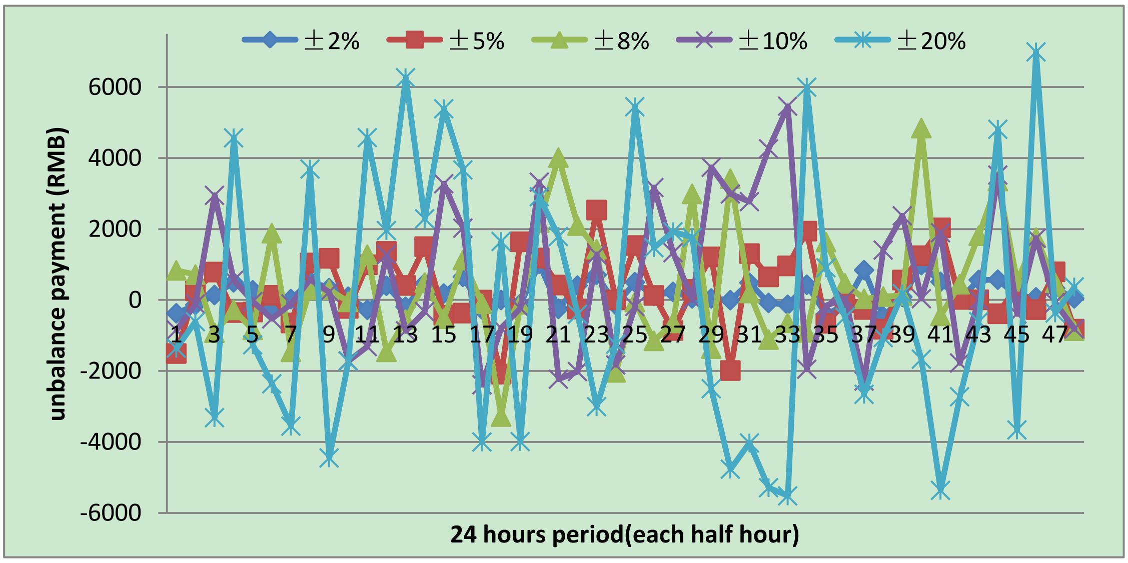

Figure 6. 22 Total unbalance load payment for each case of unbalance

It is the figure expressed that the unbalance payments for all load over 24 hours period based on each half hour a point. There are consisted of five curves which are indicated each case with ±2%、±5%、±8%、±10%、±20% unbalance volume respectively. It can be seen that from ±2% to ±20% imbalance volume, the unbalance payments for all loads are becoming larger fluctuation.

6.3.3.3 Total load payments for all cases

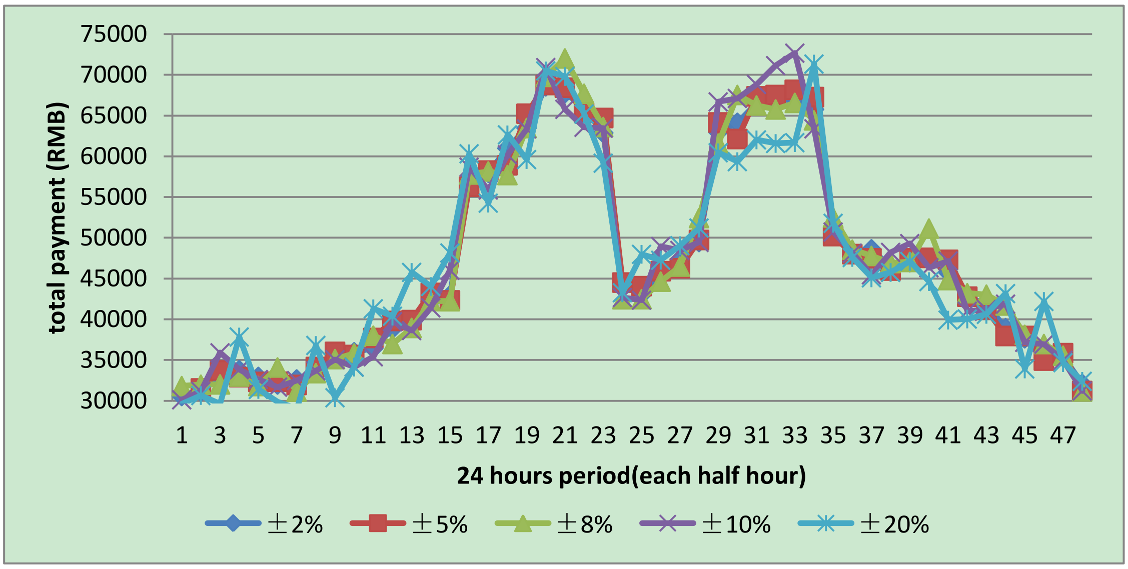

Figure 6. 23 Total load payments for all cases

Figure 6.23 is the results of total load payments for all loads over 48 half hours period, and the sum of the payment based on forecasted load payments and unbalance load payments. There are the forecasted payments and the amounts of the penalty and compensation by incorrect forecast. The figures are consist of five curves with ±2%、±5%、±8%、±10%、±20% unbalance volume case respectively.

6.4 Imbalance settlement in demonstrate system by the US Electricity market settlement method

This part will use the same IEEE30 system with part 6.3, and the same load forecast and actual load value. The equations of LMP mentioned in Chapter 3 will be used to calculate the LMP of each bus. Since there are thirty buses of the system, the results will be thirty lines in a diagraph, it is difficult to compare the forecast LMP and the thirty buses LMP, and so the average value of 30 buses actual demand LMP has also been calculated to compare with the forecast demand LMP. The Figures below will show all the results of different percentages in sections.

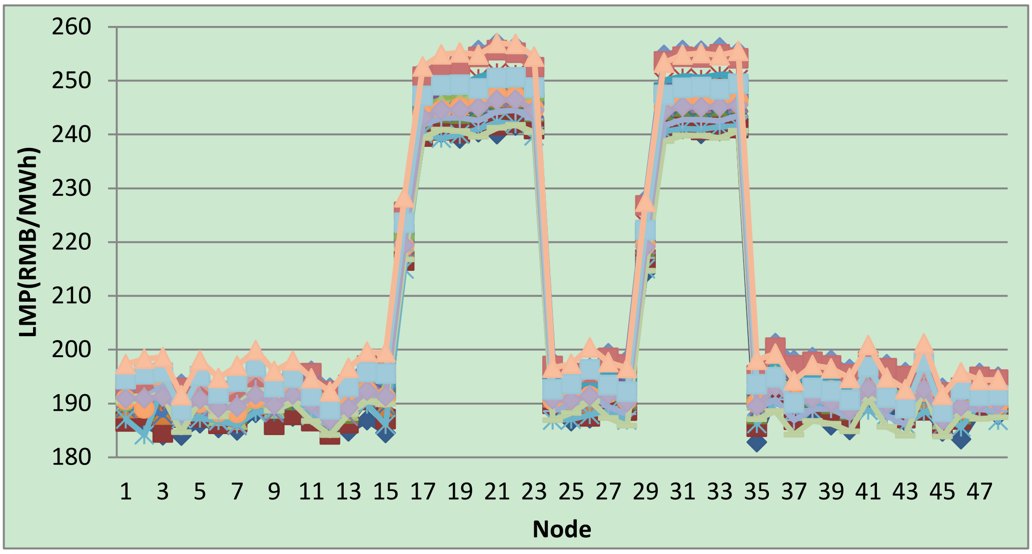

Figure 6. 24 Forecast LMP of 30 Buses

Figure 6.24 is the picture showing that the forecast LMP of 30 buses respectively over 48 time slots (half hourly basis).

6.4.1 LMP Calculation

6.4.1.1 Scenario 1: with ±2% total load imbalance

In figure 6.25, there are 30 curves indicating the LMP value with ±2% total load imbalance scenario.

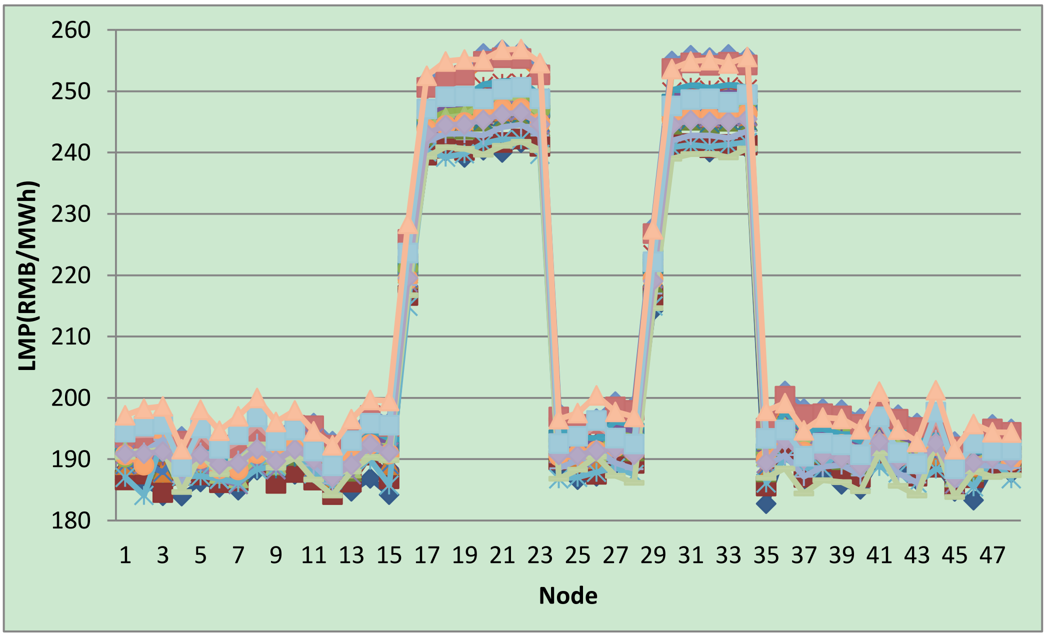

Figure 6. 25 LMP with ±2% total load imbalance

The Figure 6.26 below is stated the curves of the average LMP value and the forecast LMP values.

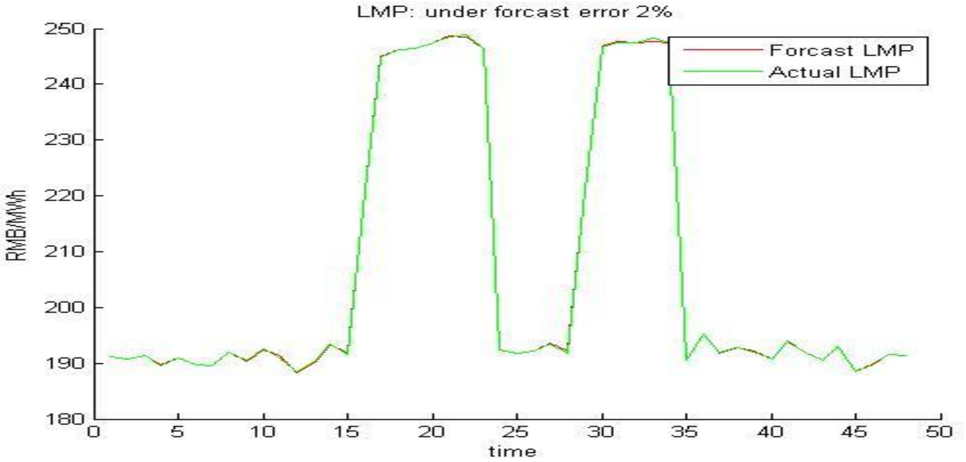

Figure 6. 26 Average LMP with ±2% total load imbalance

6.4.1.2 with ±5% total load imbalance

Figure 6.27 is the results of LMP value with ±5% total load imbalance.

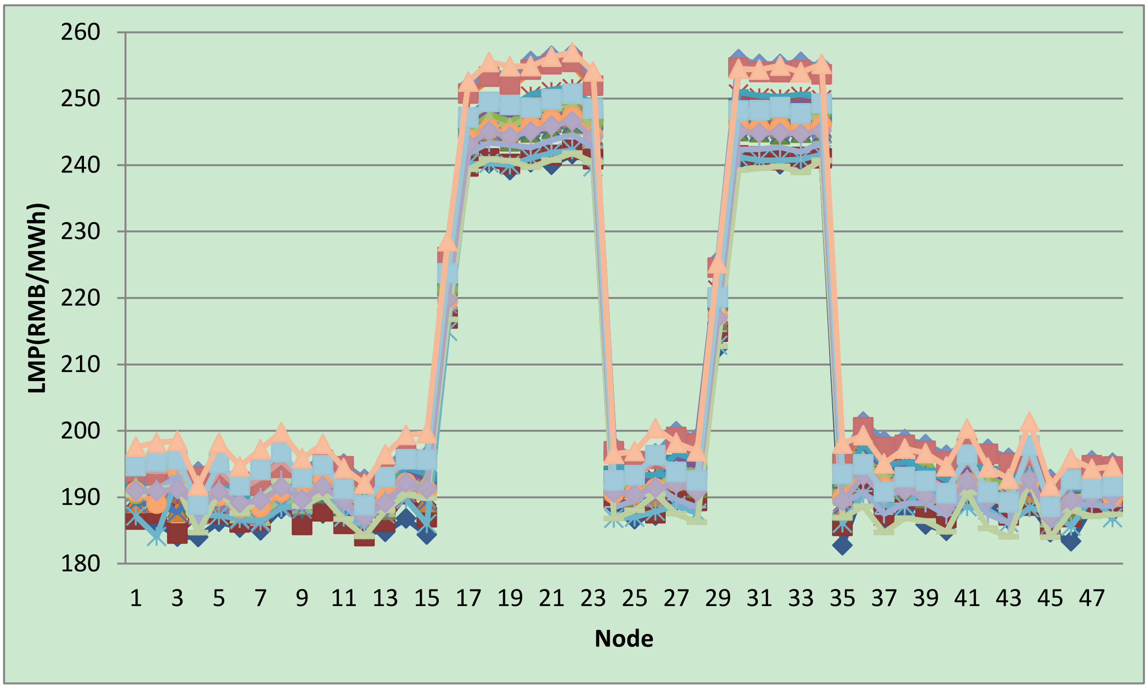

Figure 6. 27 LMP with ±5% total load imbalance

The Figure 6.28 shown below is stated the curves between the average LMP value and the forecast LMP value.

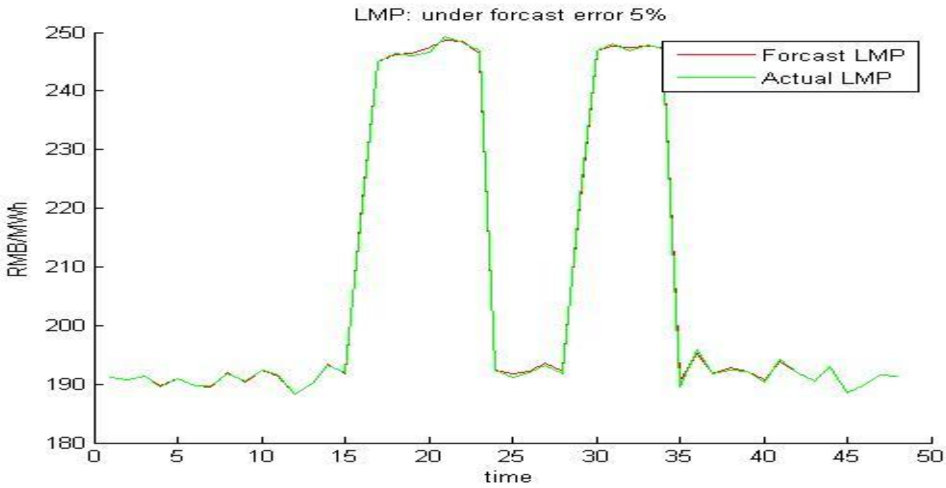

Figure 6. 28 Average LMP with ±5% total load imbalance

6.4.1.3 with ±8% total load imbalance

Figure 6.29 is as the values of LMP under ±8% total load imbalance case.

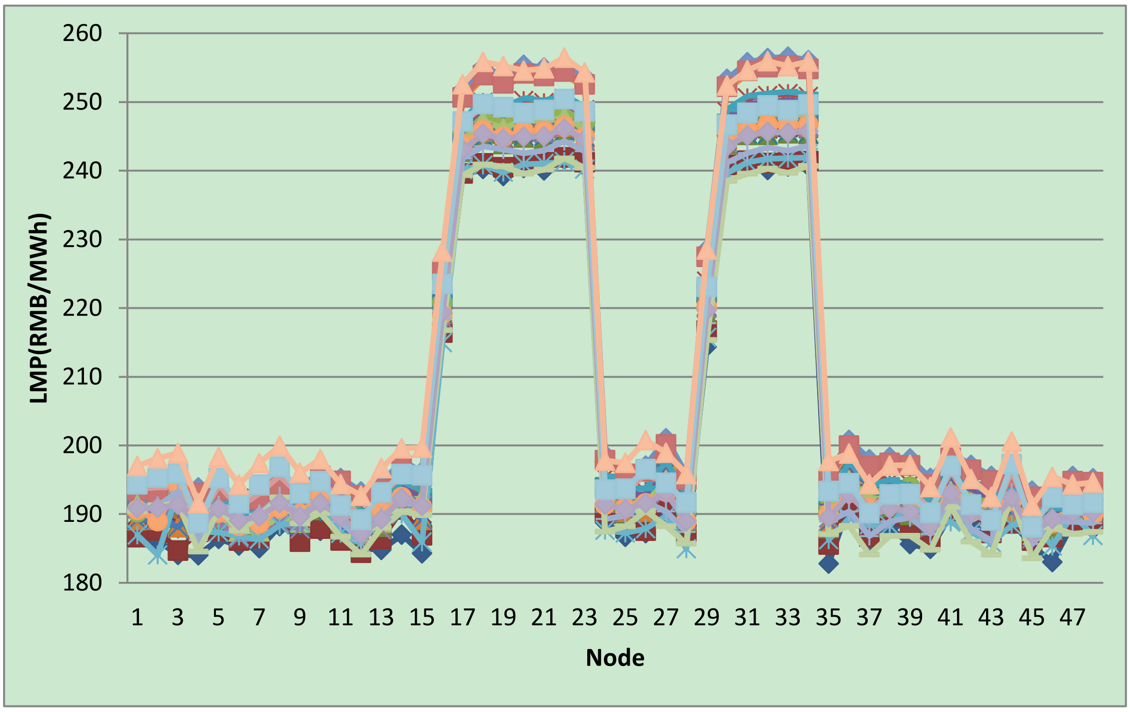

Figure 6. 29 LMP with ±8% total load imbalance

The Figure 6.30 shown is stated the curves between the average LMP value and the forecast LMP value.

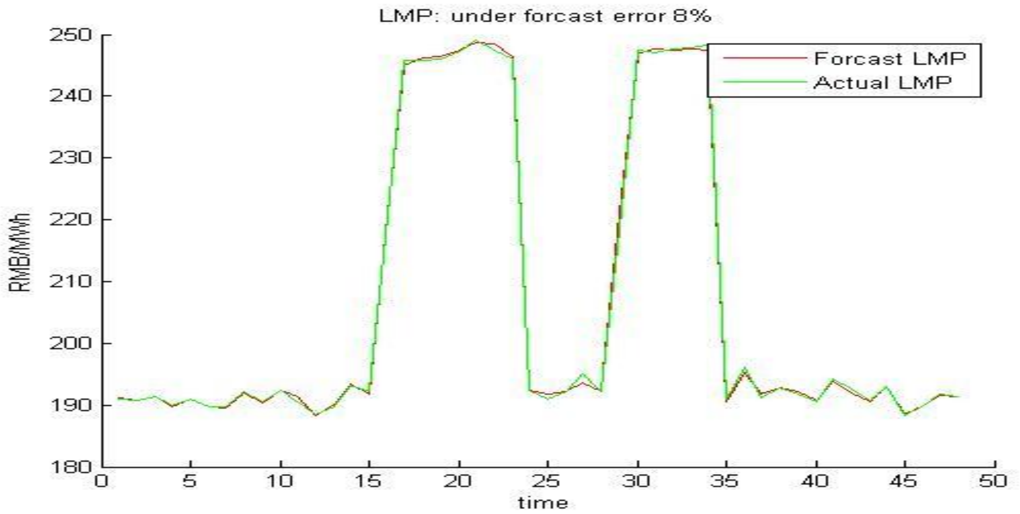

Figure 6. 30 Average LMP with ±8% total load imbalance

6.4.1.4 with ±10% total load imbalance

Figure 6.31 is as the values of LMP under ±10% total load imbalance case.

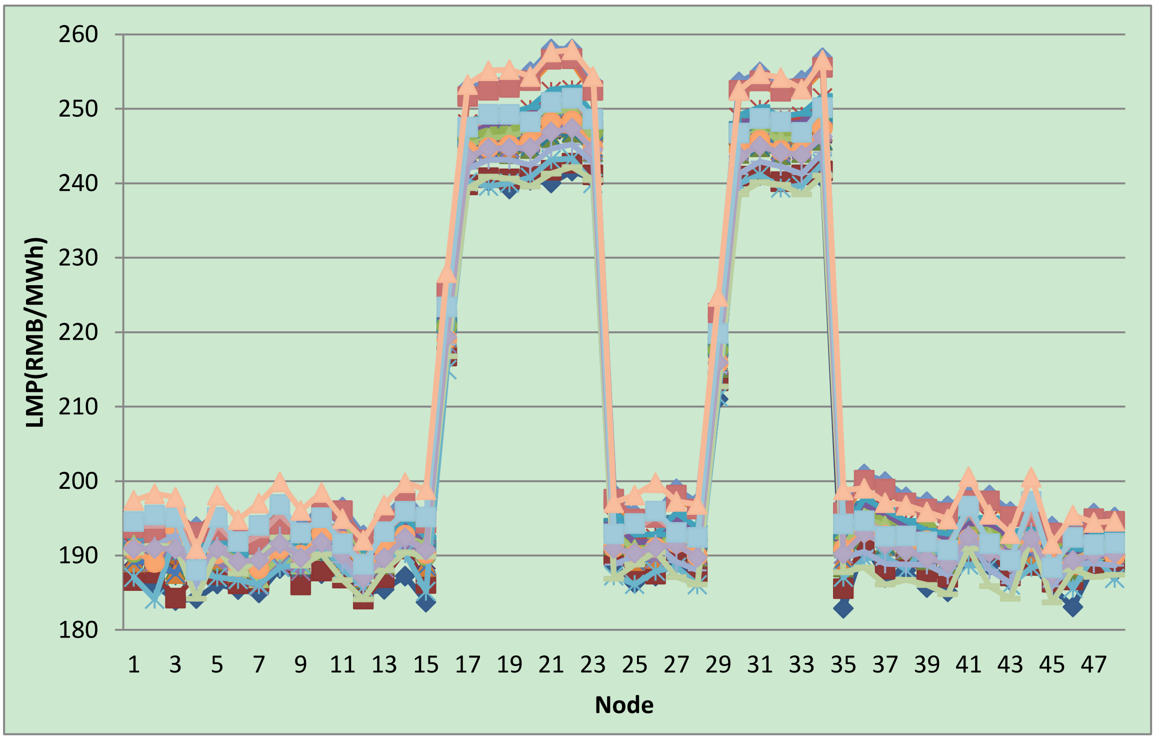

Figure 6. 31 LMP with ±10 % total load imbalance

The Figure 6.32 shown below is stated the curves between the average LMP value and the forecast LMP value.

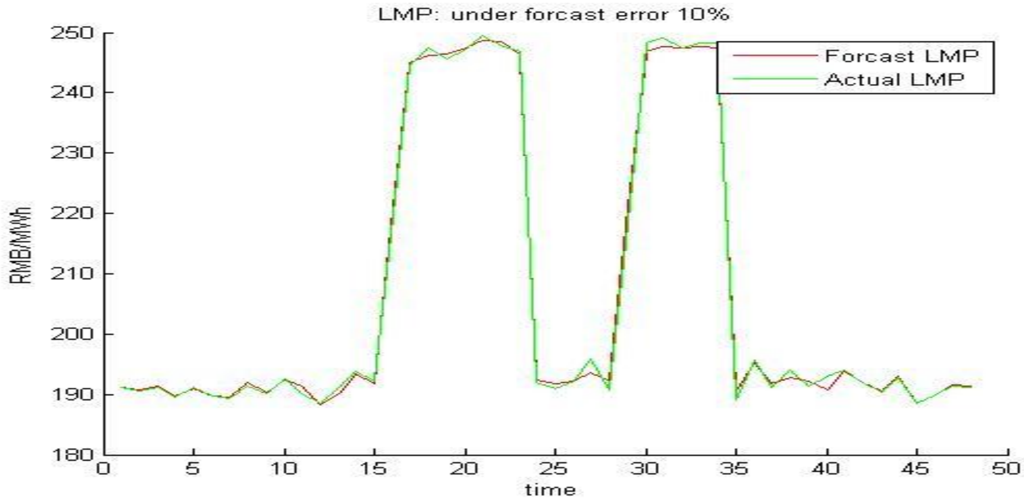

Figure 6. 32 Average LMP with ±10 % total load imbalance

6.4.1.5 with ±20% total load imbalance

Figure 6.33 is as the values of LMP under ±20% total load imbalance case.

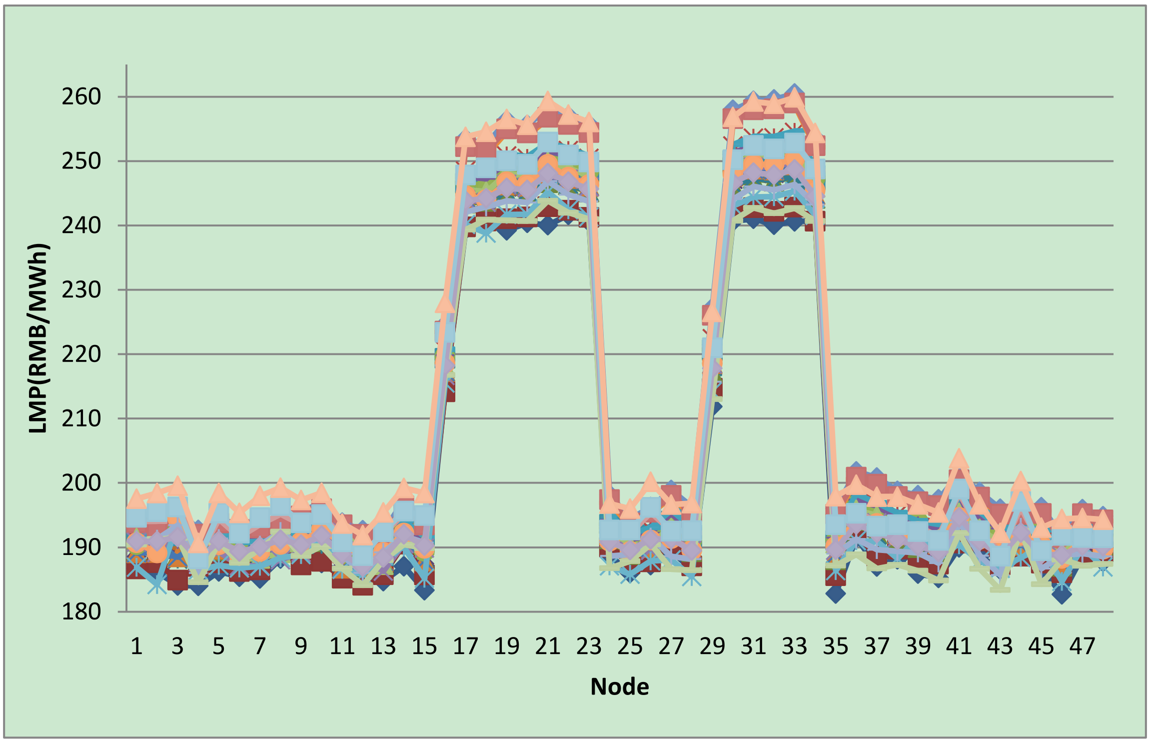

Figure 6. 33 LMP with ±20% total load imbalance

The Figure 6.34 shown is stated the curves between the average LMP value and the forecast LMP value.

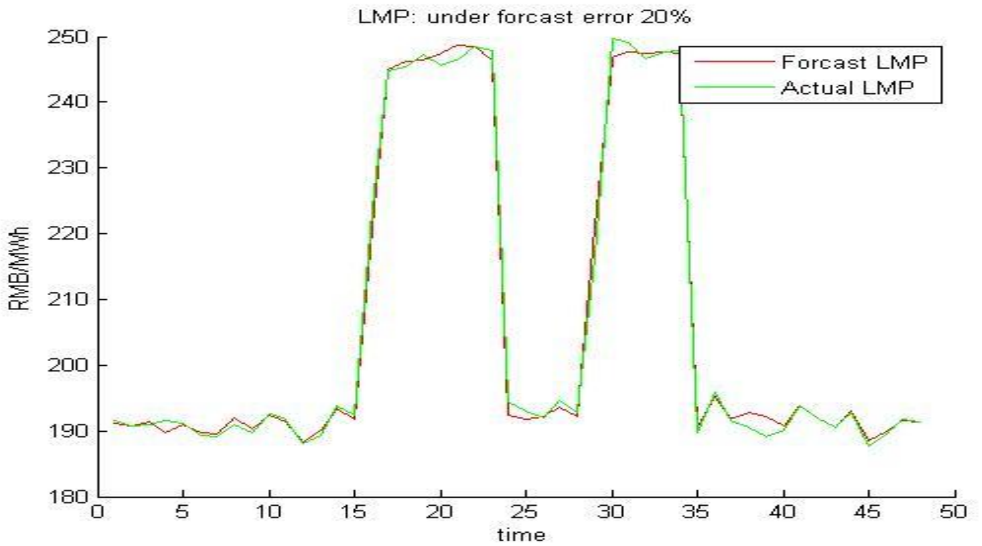

Figure 6. 34 Average LMP with ±20% total load imbalance

6.4.2 Revenue income for all the generators

6.4.2.1 Total revenue income on base case

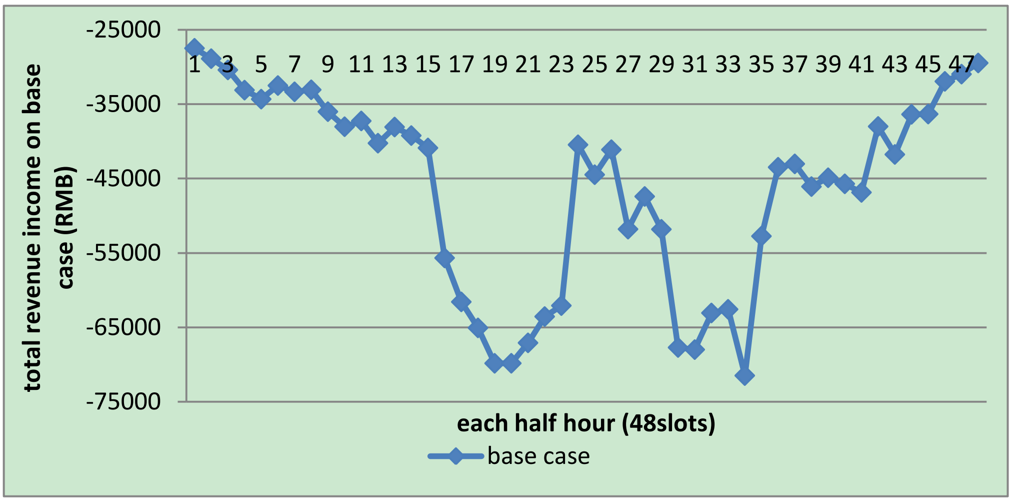

Figure 6. 35 Total revenue income on base case

It can be seen from the Figure 6.35 with single blue curve, which is shown that the total revenue income value in RMB on base case. It is covered by 24 hours containing 48 periods for the whole day, and it is the forecast revenue income on base case which is assumed to calculate by day-ahead.

6.4.2.2 Total unbalance revenue income for unbalance settlements

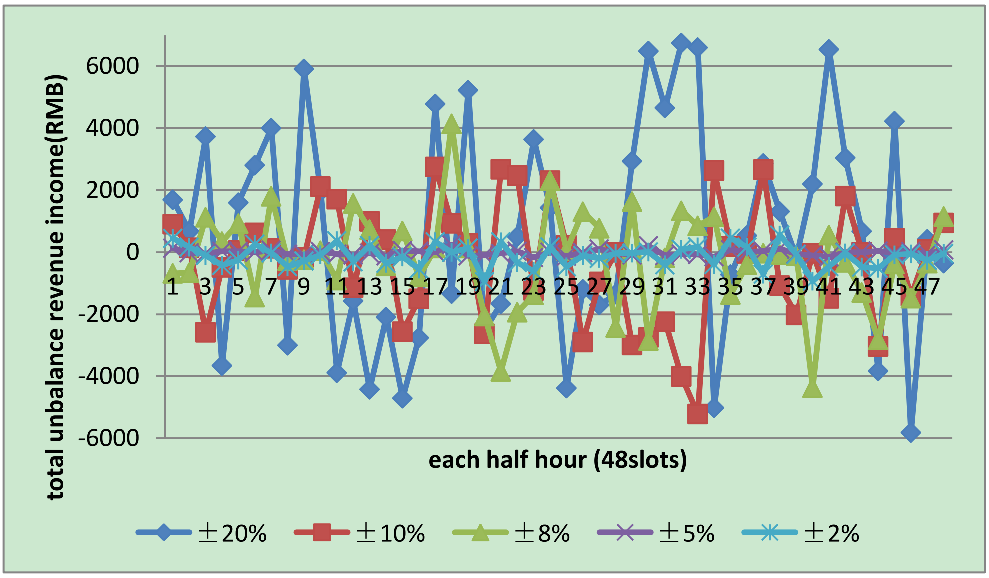

Figure 6. 36 Total unbalance revenue income for unbalance settlements

The unbalance revenue income for all generators is shown in Figure 6.36, it can be seen that the total unbalance revenue income contains five curves demonstrating each case of ±2%、±5%、±8%、±10%、±20% unbalance volume respectively. And in the Figure 6.36, it is given the extra generator income for incorrect forecast containing all six generators over the 24 hours period on each half hour basis.

6.4.2.3 Total revenue income for all generators

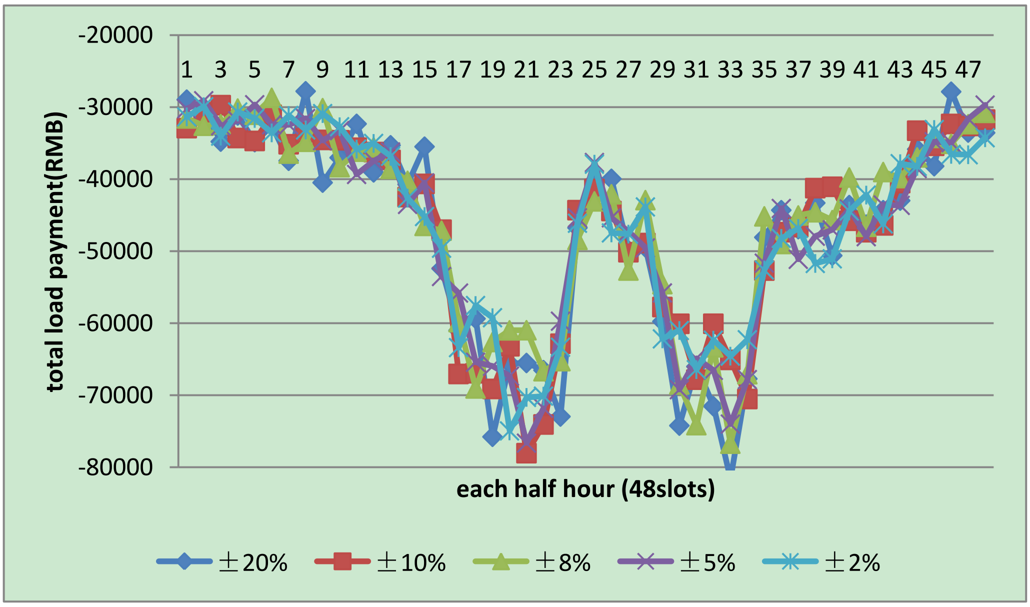

Figure 6. 37 Total revenue income for all generators

In figure 6.37, which is pictured the five curves containing each case of ±2%、±5%、

±8%、±10%、±20% unbalance volume respectively, it is the total revenue income for all generators with five imbalance cases. From the figure, it can be seen that he smaller amount of the imbalance volume for all generators, the smaller the fluctuations of the total income over 24 hour's period (each half hour slots), which is shown by the dark blue with diamond-dotted curve. On the other hand, the light blue with star-dotted curve is shown that, the higher imbalance volume the fluctuations of the total income will be greater.

6.4.3 Load payments by all load

6.4.3.1 Total load payments on base case

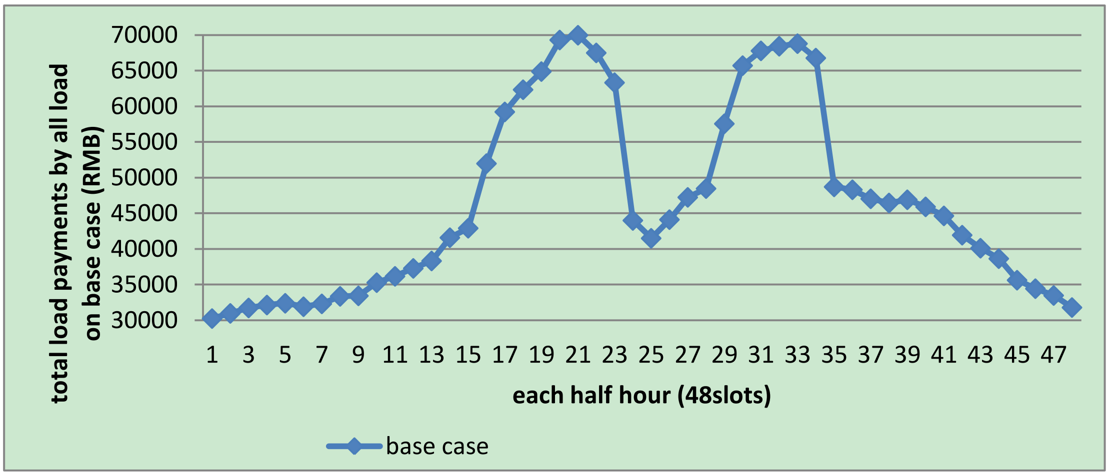

Figure 6. 38 Total load payments on base case

It is the picture showing that the base case for the total load payments, which is covered over 24 hours (containing 48 slots for the whole day) and is calculated using with a canton typical forecast day profile.

6.4.3.2 Total unbalance load payment for each case of unbalance

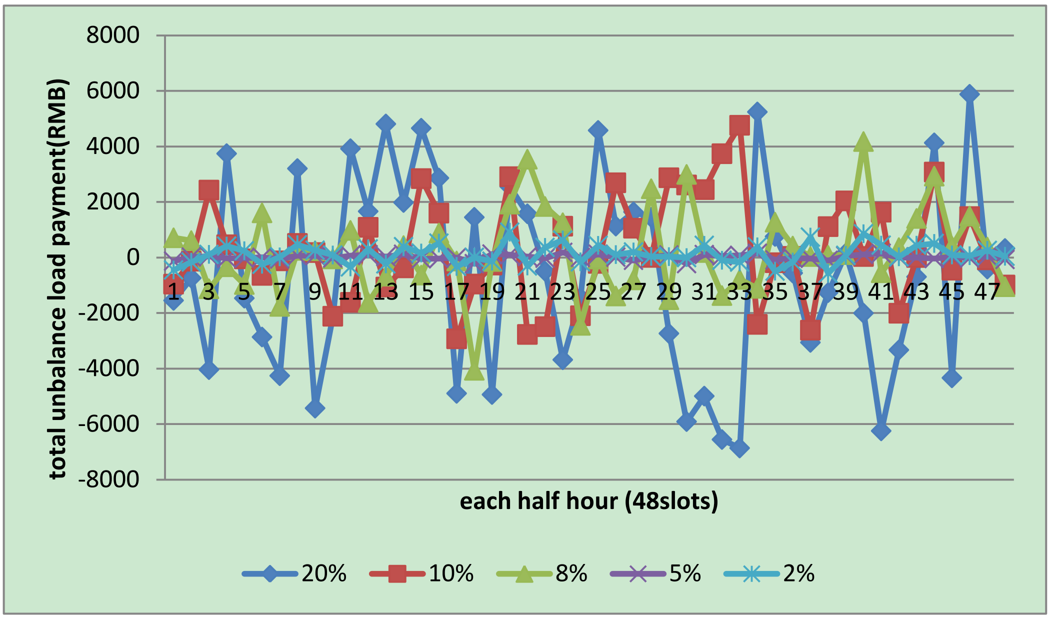

Figure 6. 39 Total unbalance load payment for each case of unbalance

It is the figure shown that the unbalance payments for all load over 24 hours period based on each half hour a point. There are consisted of five curves which are indicated for each case with ±2%、 ±5%、 ±8%、 ±10%、 ±20% unbalance volume respectively. It can be seen that from ±2% to ±20% imbalance volume, the unbalance payments for all loads are becoming larger fluctuation.

6.4.3.3 Total load payments for all cases

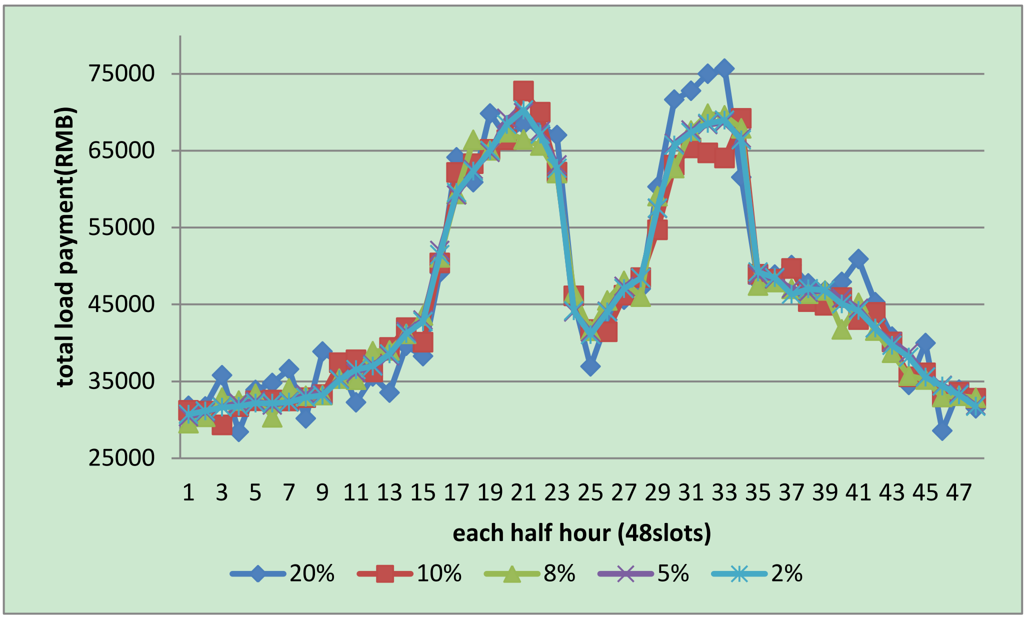

Figure 6. 40 Total load payments for all cases

Figure 6.40 is shown the result curves of total load payments for all loads over 48 half hours period, and the sum of the payment based on forecasted load payments and unbalance load payments. There are the forecasted payments and the amounts of the penalty and compensation by incorrect forecast. The figures are consist of five curves with ±2%、 ±5%、 ±8%、 ±10%、 ±20% unbalance settlement cases respectively.

6.5 Australian Electricity market imbalance settlement in the demonstrate system

This part will use the same IEEE30 system within part 6.3, and the same load forecast and actual load value. The equations of ZMP mentioned in Chapter 4 will be used to calculate the ZMP of each zone. The IEEE 30 system assumed is divided into 3 zones by geography below.

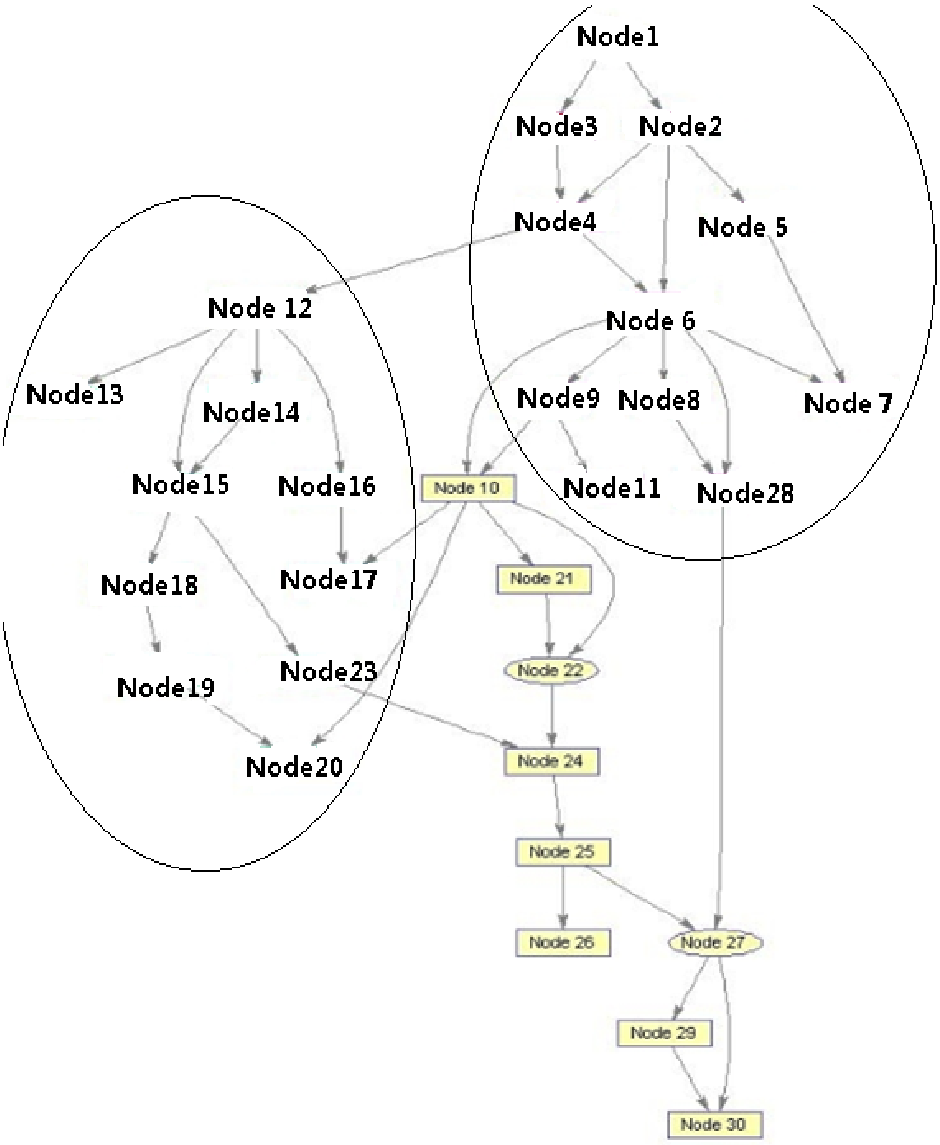

Figure 6. 41 the Zones of the IEEE 30 System

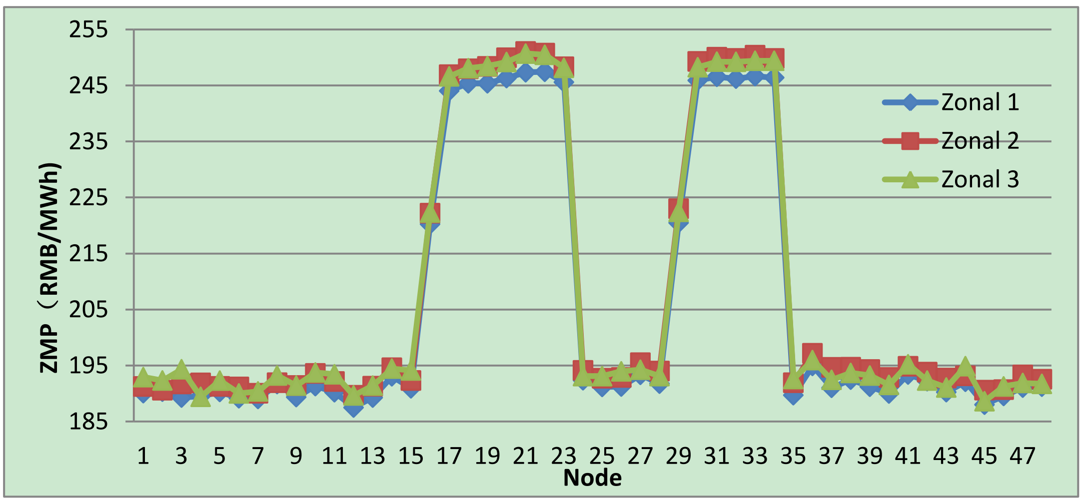

Figure 6. 42 Forecast ZMP with three zones

In the figure 6.42, it is shown that the forecast ZMP with three zones respectively.

6.5.1 ZMP Calculation

6.5.1.1 with ±2% total load imbalance

In the figure 6.43, it is shown that the ZMP value with ±2% total load imbalance for three zones respectively.

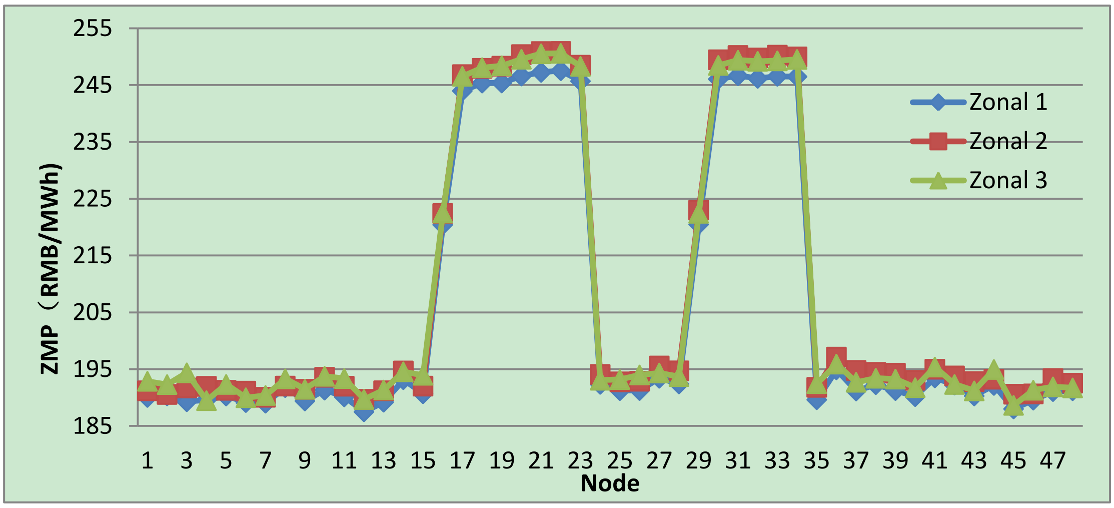

Figure 6. 43 ZMP with ±2% total load imbalance

6.5.1.2 with ±5% total load imbalance

Figure 6.44, it is shown that the ZMP value with ±5% total load imbalance for three zones respectively.

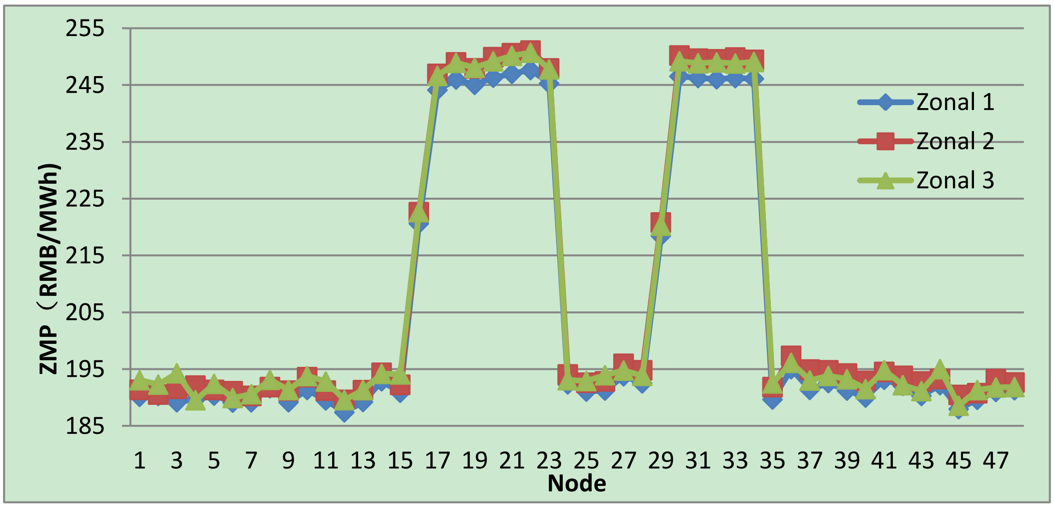

Figure 6. 44 ZMP with ±5% total load imbalance

6.5.1.3 with ±8% total load imbalance

It is results shown in Figure 6.45 that the ZMP value with ±8% total load imbalance for three zones respectively.

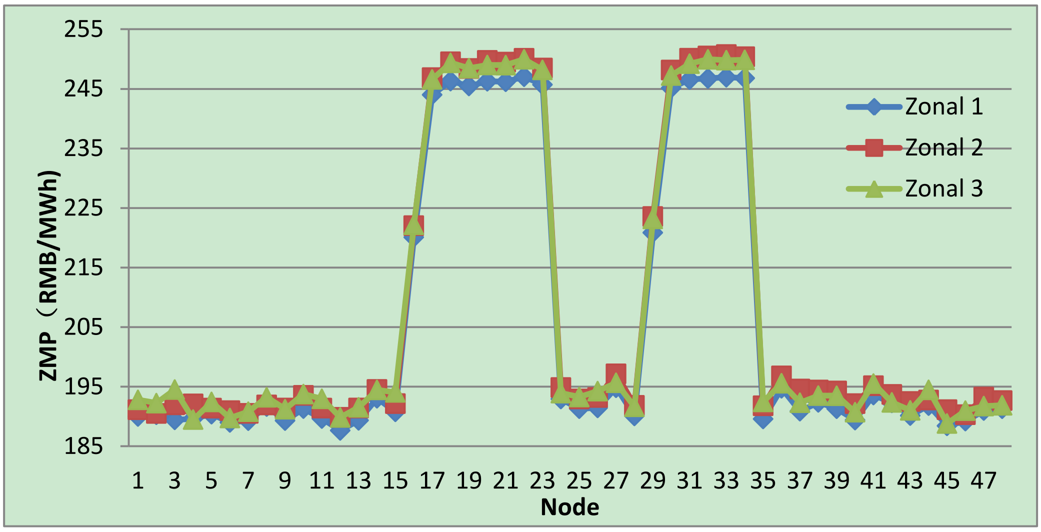

Figure 6. 45 ZMP with ±8% total load imbalance

6.5.1.4 with ±10% total load imbalance

Figure 6.46, it is stated that the ZMP value with ±10% total load imbalance for three zones respectively.

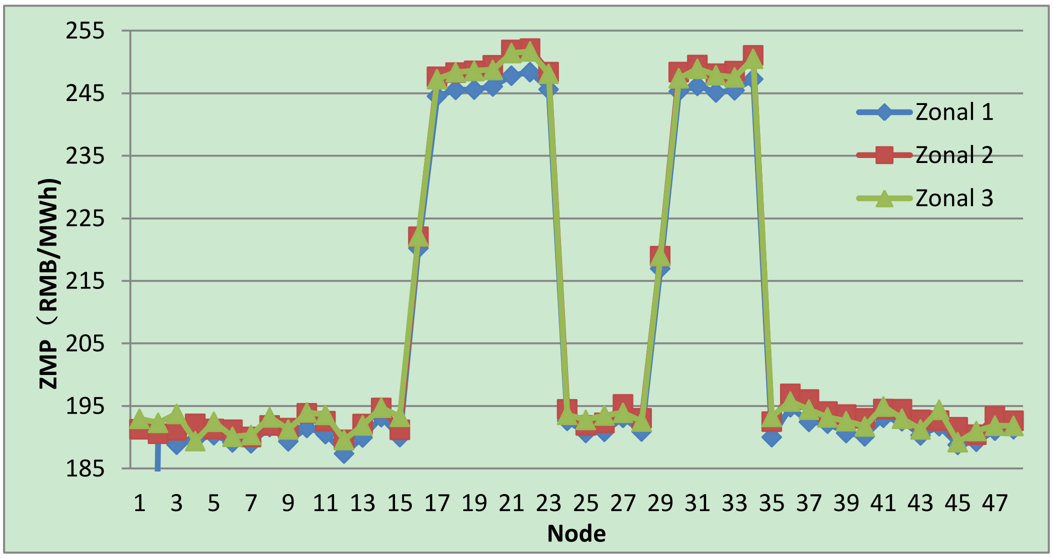

Figure 6. 46 ZMP with ±10 % total load imbalance

6.5.1.5 with ±20% total load imbalance

Figure 6.47, it is shown that the ZMP value with ±20% total load imbalance for three zones respectively.

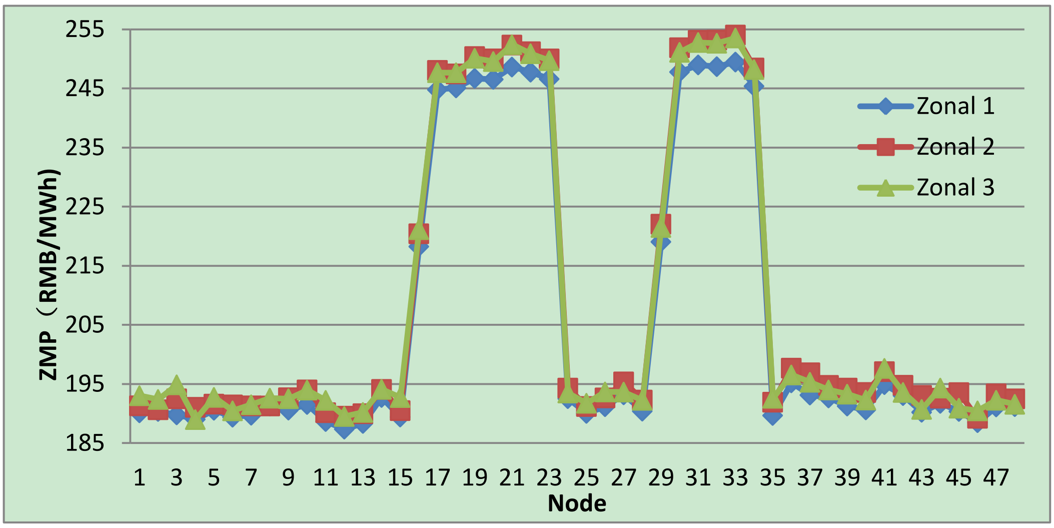

Figure 6. 47 ZMP with ±20% total load imbalance

6.5.2 Revenue income for all the generators

6.5.2.1 Total revenue income on base case

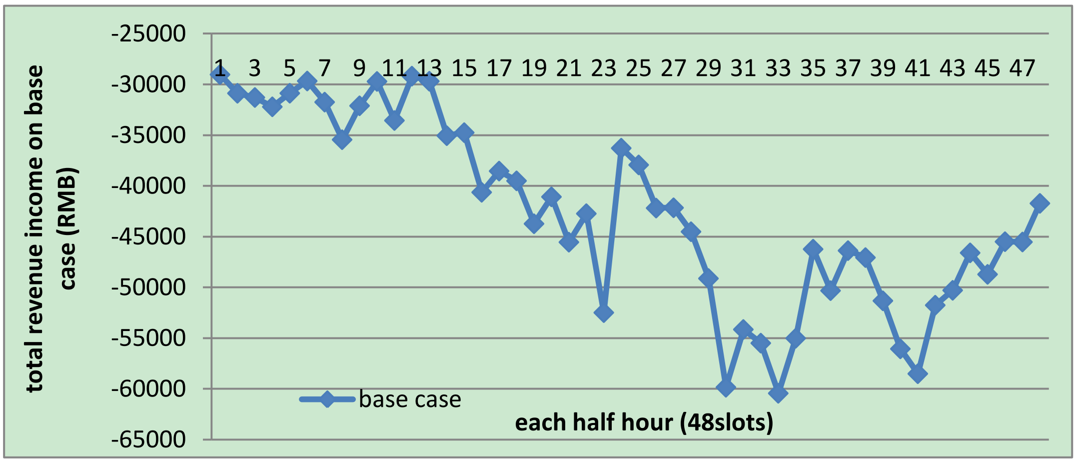

Figure 6. 48 Total revenue income on base case

It can be seen from the Figure 6.48 with the single blue curve, which is shown that the total revenue income value in RMB on base case. It is covered by 24 hours containing 48 periods for the whole day, and it is the forecast revenue income on base case which is assumed to calculate by day-ahead.

6.5.2.2 Total unbalance revenue income for unbalance settlements

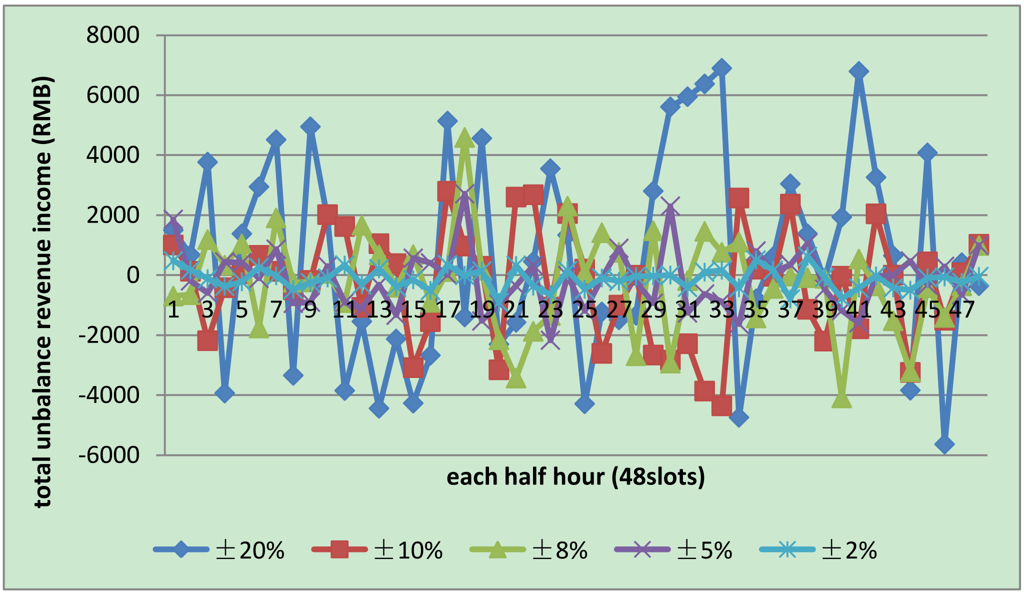

Figure 6. 49 Total unbalance revenue income for unbalance settlements

The unbalance revenue income for all generators is shown in Figure 6.49, it can be seen that the total unbalance revenue income contains five curves demonstrating each case of ±2%、±5%、±8%、±10%、±20% unbalance volume respectively. And in the Figure 6.49, it is given the extra generator income for incorrect forecast containing all six generators over the 24 hours period on each half hour basis.

6.5.2.3 Total revenue income for all generators

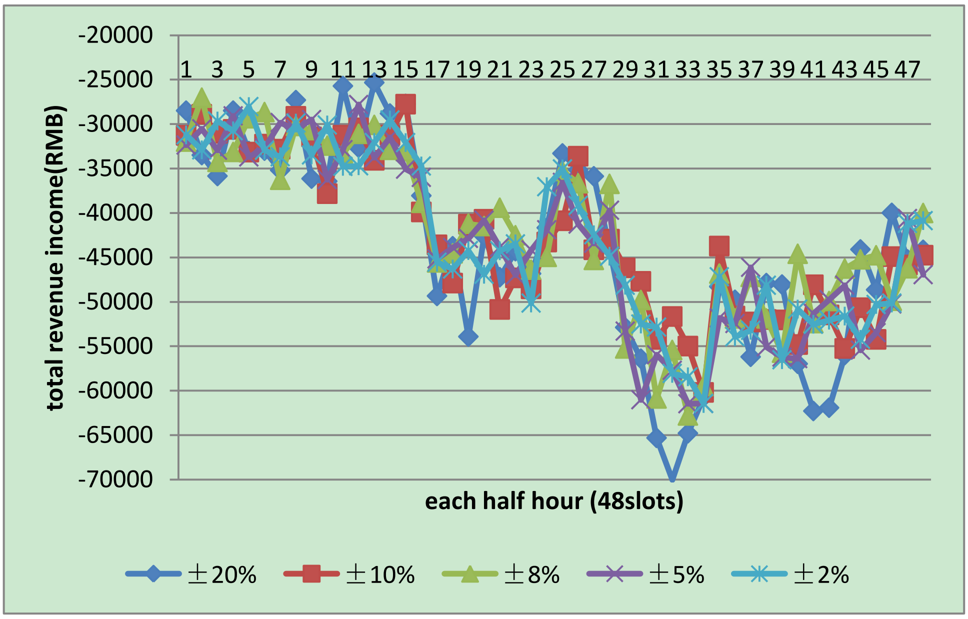

Figure 6. 50 Total revenue income for all generators

In figure 6.50, which is pictured the five curves containing each case of ±2%、±5%、

±8%、±10%、±20% unbalance volume respectively, it is the total revenue income for all generators with five imbalance cases. From the figure, it can be seen that he smaller amount of the imbalance volume for all generators, the smaller the fluctuations of the total income over 24 hour's period (each half hour slots), which is shown by the dark blue with diamond-dotted curve. On the other hand, the light blue with star-dotted curve is shown that, the higher imbalance volume the fluctuations of the total income will be greater.

6.5.3 Load payments by all load

6.5.3.1 Total load payments on base case

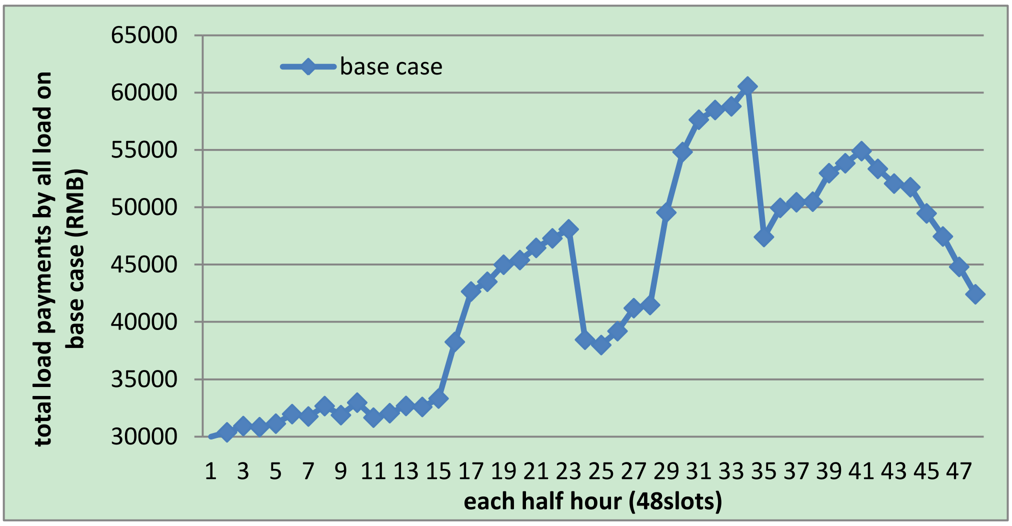

Figure 6. 51 Total load payments on base case

It is the picture showing that the base case for the total load payments, which is on each half hour basis (containing 48 slots over 24 hours) and is calculated using with a canton typical forecast day profile.

6.5.3.2 Total unbalance load payment for each case of unbalance

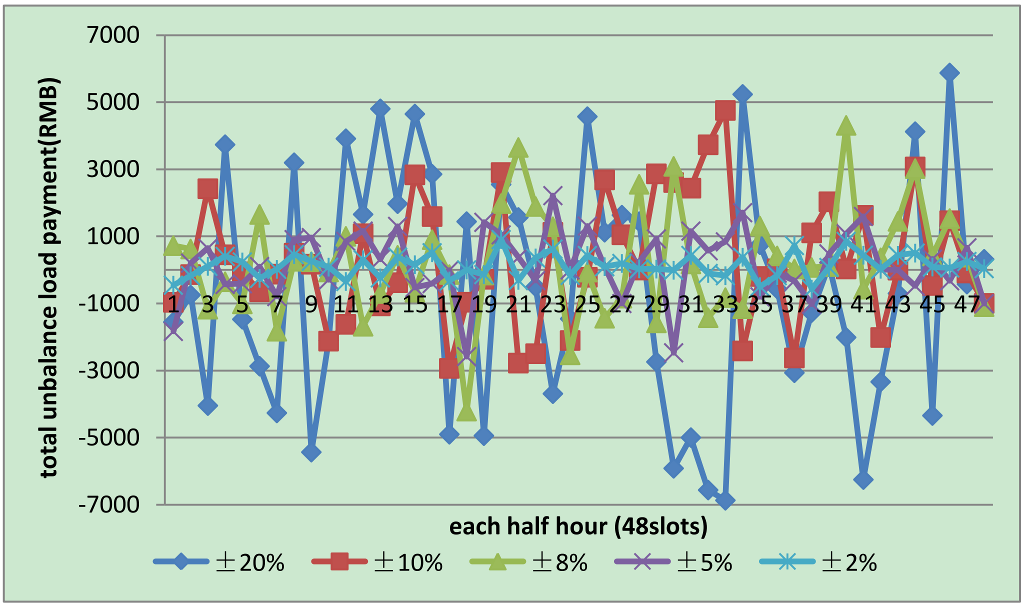

Figure 6. 52 Total unbalance load payment for each case of unbalance

It is the figure shown that the unbalance payments for all load over 24 hours period based on each half hour a point. There are consisted of five curves which are indicated for each case with ±2%、±5%、±8%、±10%、±20% unbalance volume respectively. It also can be seen that from ±2% to ±20% imbalance volume, the unbalance payments for all loads are becoming larger fluctuation.

6.5.3.3 Total load payments for all cases

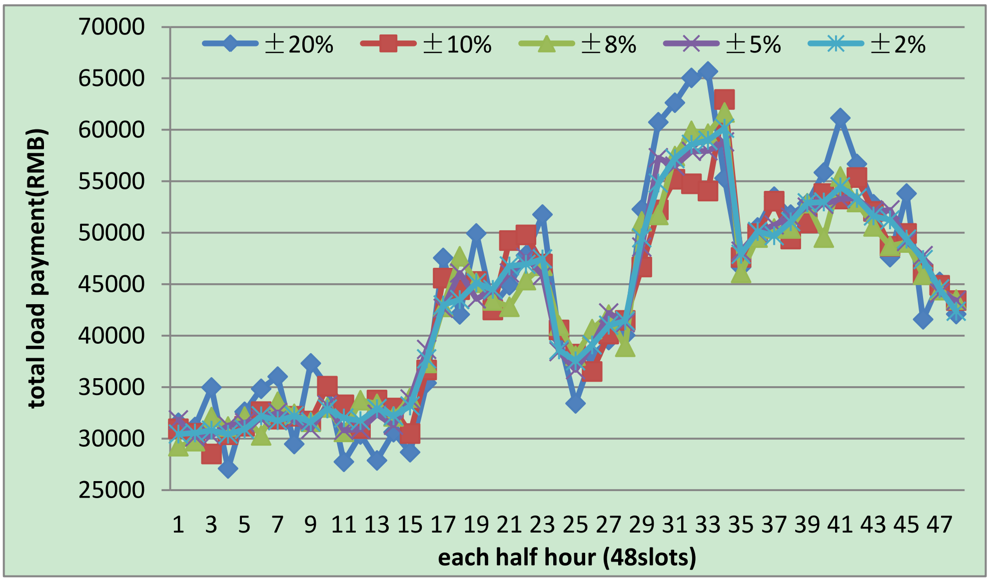

Figure 6. 53 Total load payments for all cases

Figure 6.53 is shown the result curves of total load payments for all loads over 48 half hours period, and the sum of the payment based on forecasted load payments and unbalance load payments. There are the forecasted payments and the amounts of the penalty and compensation by incorrect forecast. The figures consist of five curves with ±2%、±5%、±8%、±10%、±20% unbalance settlement cases respectively.

6.6 Comparison of the Three Typical Methods

From the results of the three typical pricing methods, it can be seen that when the percentage of imbalance energy is higher, the fluctuation between the forecast price and the actual price is larger. There are several advantages of various pricing schemes. Uniform pricing approach (eg.SSP/SBP pricing method) provides a simple and straightforward implementation for competitive electricity market. Under unconstrained network, the uniform pricing which is adopted in the former England and Wales pool provides a single uniform price for generation and demand which encourage generators and suppliers to build new and inexpensive resources to ensure the lowest cost to consumers. Uniform pricing approach also provides strong incentives to reduce the costs of supply and operated when needed so that efficient and reliable generators are dispatched all the time.

However, uniform pricing does not guarantee capital cost recovery. In order to recover the capital and construction costs, operating cost for generator has to be set below the market clearing price. The transparent pricing structure of uniform pricing allows cheap generators to enter into long-term contracts outside the spot market. (i.e., Bilateral Contract).

Nodal pricing approach (e.g. LMP pricing method) is expected to promote efficient trading and reflect the opportunity costs of using the transmission paths. It can further facilitate the efficient use of the transmission system by developing a competitive electricity market that send signals to encourage additional new generation resources or transmission investment to cope with scarce transmission capacities and to ensure security if supply in the proper locations. It can also improve dispatch efficiencies by dispatching at the optimum resource level so that lower overall cost of power supply can be obtained.

Nodal pricing approach reflects the actual situation in the grid and is more transparently than uniform prices and represents adequate allocation signals. The use of nodal pricing provides direct assignment of local generation as settlement prices are based on locational marginal price.

Zonal pricing approach (e.g. ZMP pricing method) believes to be able to balance the equity concerns with efficiency goals. For instance, zonal model would have the effect of averaging prices across a larger region and at least, would reduce process in the high price region. Zonal pricing does not subject the market participants to unnecessary complexity or facilitates the operation and it is far simpler to implement than nodal model. Furthermore they believe that the nodal model unnecessarily entangles the transmission service market and the generation market instead of unbundling them in order to facilitate market players' desire for flexibility, innovation and development of niche products.

Every pricing scheme has flaws in electricity market when dealing within the imbalance settlement. In the situation of energy imbalance, the prices under uniform pricing market design can be very high and volatile to the customers. This market design does not provide adequate market price signals to alleviate the capacity payment (i.e., uplift) and provide poor signals for network reinforcement therefore is not able to ensure an optimal allocation of energy and transmission capacities. Uniform pricing had limited demand-side participation therefore it doesn't respond to customer's concerns. In the former E&W pool market, all generators with a capacity if more than 100MW were required to trade through the pool. This means that all the generators are make compulsory to trade into pool and can reduce the flexibility for the market participant to compete in generation due to market power. The most significant of this market design is its incapability to achieve the harmony between market liquidity and efficient pricing.

Several limitations have been identified with the current zonal model. Zonal model is said to have insufficient price transparency because it treats different locations as though they were the same. It is very difficult to define zones and zone-boundaries under zonal market design. However, there are two methods used to define zone. The first method is based on Power Transfer Distribution Factor (PTDF) or also known as shift factor-based. This method defines zone by clustering similar shift factors in all potentially binding constraints into a single zone. The second method is based on locational price. In this method, locations with hourly prices that fall within a small range of each other for longer time duration are clustered into a single zone.

Some of the disadvantages using locational marginal price is that most of the investment in generation doesn't driven by the high price of LMP. For example, wind is built were the wind is and not where the high LMPs are, coal is built where it is permitted usually not near the customer area and nuclear reactors are to be build far away from the load center even though LMPs shows that the resources has to be build at the load. This is due to political, environmental and safety reasons.

For each case, the total unbalance load payments are calculated by the sums of the forecasted load payments and unbalance volume penalty or compensation payments. For the total revenue income of all generators, it is the amounts of income based on forecasted generation and revenue or compensation income. It can be seen from the Figure 6.19\ Figure 6.34\Figure 6.47, these are the imbalance generator revenue income, and in Figure 6.22\ Figure 6.37\Figure 6.50 there are the imbalance load payment for all loads. All of these figures are showing that with the larger incorrect forecast volume, the total value with fluctuation is much larger.

6.7 Conclusions

In the emerging world of competitive electricity markets, the Balancing Mechanism has to provide the market participants with a pricing policy and send the market parties the right economic signals through the different imbalance settlement pricing methods. Uniform marginal pricing is assumed to be efficient and does not cause any financial problem, because the load payments will be the same with generator revenue incomes (assuming no loss is concluded). But when the energy imbalance occurs in a network, uniform marginal price fails to deliver an efficient signal in a competitive market. Similarly with zonal marginal pricing, even though it provides a simple, transparent and easy to implement market design, it still can bring some operating issues.

So it is difficult to define the identically efficient imbalance settlement pricing mechanism that could fit all market structures within different systems. Each electricity market should choose a method based on the features of its grid.

The focus of the electricity industry has shifted to ‘smart grid’, from technical efficiency to economic efficiency. It is important to further studies whether a competitive electricity market would bring improvement in economic efficiency such as lower prices along with enhancement in technical efficiency.

Chapter 7 Application in Dual Use of Electricity Storage dealing with Imbalance Settlement

7.1 Introduction

Although some of the settlement methods mentioned in previous chapters are very reliable and have been used extensively, as the limitation of the fuel and development of the renewable source, green power grids are to be built is the same purpose worldwide. The renewable energy Distributed Generator (DG) access may not be economical given the probability of contingencies and changes in the market environment. As a new application, a Dual Use of Electricity Storage (DUES) is broadly participated in the practical power network, which is the new form of power transmission. The DUES could access to the real time market for balancing the errors from the demand forecast, no matter the increased demand or the reduced demand, with a profit for the whole system.

7.2 Dual Use of Electricity Storage

What is dual use of renewable energy storage?

DUES means that the generator could not only generate power, but also could store power. As the development the renewable energy, the energy storage technology becomes more and more important. There are several main kinds of energy storage technology, such as the pumped hydro-electric storage, Vehicle to Grid (V2G), the battery energy storage etc.

Current large scale electricity energy storage is in the form of pumped hydro-electric storage in Great Britain which has a generating capacity of 2,728MW and an estimated usable energy storage capacity of 20.5GWh, which is 2.3% of the typical daily electricity grid energy consumption [1]. By contrast, currently there are some 33.3 million vehicles registered within GB, including some 26.5 million cars and 3.1

million light goods vehicles [2]. The current estimated power available in the form of engine power for private cars is 1.98TW, with associated 'energy storage' in the form of on board fuel reserves of 13.2TWh.

For example, First Hydro Company (FHC) operates 10 pumped storage units (4 at Ffestiniog and 6 at Dinorwig) in the GB market. FHC chooses to participate in three main sectors of the market, Trading, Balancing Mechanism and Balancing Services [3]. FHC buy and sell electricity (Trading) in all time scales from an hour ahead of delivery through to several years ahead of delivery on the power exchange and bilaterally with counterparties either directly or through brokers, and submit bids and offers in the Balancing Mechanism. Thus also tender for the dynamics and operating regime of the plant in the Balancing Services (BS) section.

However pumped hydro-electric storage has high initial construction costs and has significant restrictions on plant location. By contrast EVs are likely to be practical, highly distributed and accountable in large numbers and able to provide BS through V2G capability.

Vehicle to Grid (V2G) [4] is a concept whereby the electrical energy storage onboard Electric Vehicles (EVs), i.e. the vehicle main traction batteries, has the power flow of this element controlled bi-directionally. This means that the vehicle batteries can be recharged with power flow *from the grid to the vehicle*, and power flow can also be reversed to deliver power directly *from the battery back to the grid* if necessary/appropriate[5].

Hence, wide scale take up of EVs, and V2G enabled EVs, would be expected to make significant demands on the electricity supply infrastructure, however it could comfortably be predicted to offer at least proportional grid control, stability and peak lopping functionality compared to current pumped storage hydro electric schemes.

EVs have the potential to become an important power resource for the electricity system, improving power system reliability and delivering economic benefits. The concept of dual use energy storage will allow the vehicle batteries to contribute to network services based on the fact that EVs naturally have considerable energy storage capacity. In principle DUES can permit power flow in both directions. And which are more likely to assist the adoption of renewable energy sources, such as wind and solar photovoltaic.

7.3 Illustration of the Proposed Method

As a new application, consider the dual use energy storage generator as a distributed generator access to the power system to deal with the imbalance settlement problem. The case study below will illustrate, with one dual use energy storage generator in the illustrate system when the system with ±5% total load forecast. The system calculates LMP by using the POWERWORLD software LP OPF programme, which has been mentioned in chapter 5 before. The generator revenue income and load total payment also will be calculated, the comparison will be made by the results of when system with and without dual use energy storage generator.

7.4 Case Study

In this section, the case study on the 7-bus system is carried out, and the dual use of storage is taken into account when the imbalance settlement is calculated.

7.4.1 Test system

Figure 7.1 is shown as the 7-bus system including 11 branches (in Table 7.1) and 5 generators (in Table 7.2) and containing 6 load demands, that the Table 7.2 and Table 7.3 are showing the forecast demand with half hourly periods and the actual demand (assuming within the ±5% of the forecast errors). And simulation on the test system is done through the PowerWorld software.

In the picture, there is energy storage that is put aside, and is ready to be grid-connected. Both on the forecast case and imbalance settlement without storage case, the DUES is disconnected. When on the imbalance settlement with storage case, the DUES is connected.

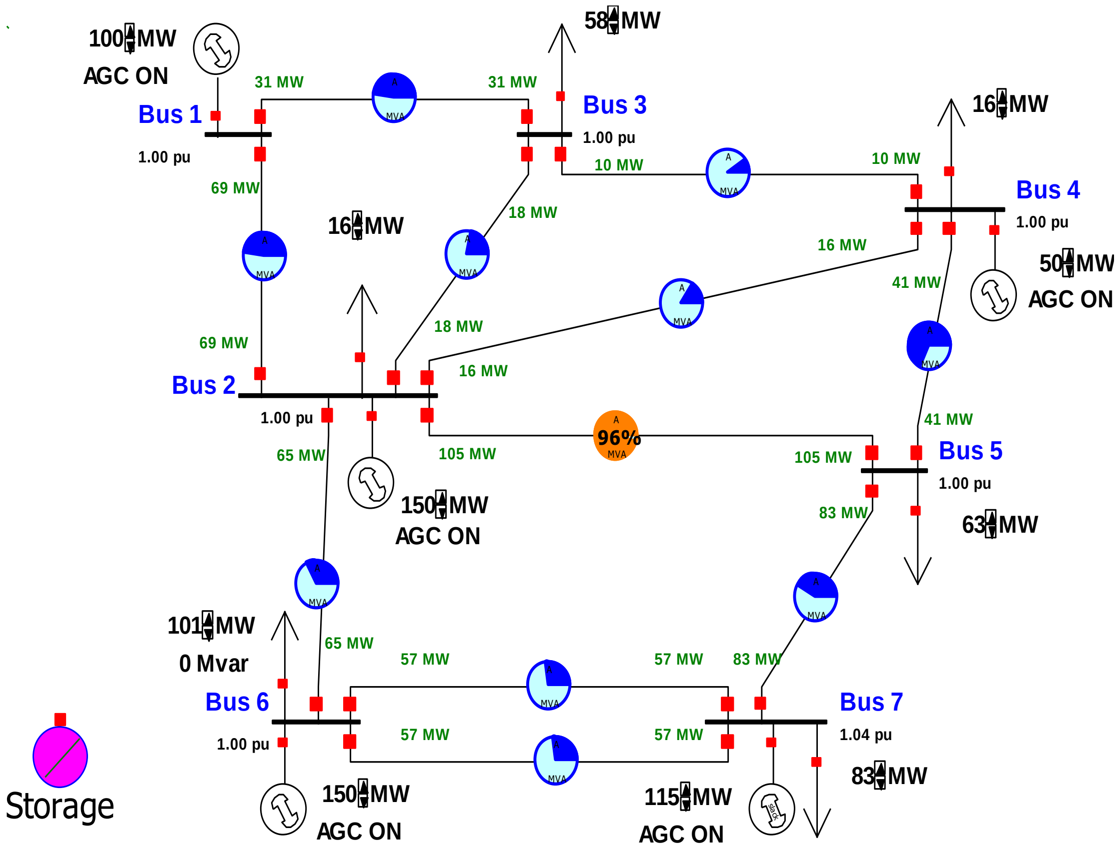

Figure 7. 1 the 7-bus test system (the storage aside)

Table 7. 1 Line Records

Branch	From Name	To Name	R	X	line limit
1	Bus 1	Bus 2	0	0.06	150
2	Bus 1	Bus 3	0	0.24	65
3	Bus 2	Bus 3	0	0.18	80
4	Bus 2	Bus 4	0	0.18	100
5	Bus 2	Bus 5	0	0.12	110
6	Bus 2	Bus 6	0	0.06	200
7	Bus 3	Bus 4	0	0.03	100
8	Bus 4	Bus 5	0	0.24	60
9	Bus 7	Bus 5	0	0.06	200
10	Bus 6	Bus 7	0	0.24	200
11	Bus 6	Bus 7	0	0.24	200

Table 7. 2 generators data

Gen	Min MW	Max MW	Cost Model	Fixed Cost(RMB /hr)	IOB*	IOC*	Fuel Cost(RMB/ hr)
Bus 1	100	400	Cubic	105	12	0.018	2.061
Bus 2	150	500	Cubic	95	10	0.018	2.061
Bus 4	50	200	Cubic	78	11	0.018	2.061
Bus 6	0	500	Cubic	130	8	0.018	2.061
Bus 7	150	600	Cubic	111	9.8	0.018	2.061

* are used to model the generator's input-output (I/O) curve

Table 7. 3 Forecast loads data

Hour	Total MW load	Bus 2 #1 MW	Bus 3 #1 MW	Bus 4 #1 MW	Bus 5 #1 MW	Bus 6 #1 MW	Bus 7 #1 MW
0:00:00	357.06	16.53	46.42	14.90	62.85	107.61	108.74
0:30:00	351.07	16.00	59.10	12.62	48.48	101.41	113.47
1:00:00	333.27	21.71	42.58	14.08	57.65	105.81	91.43
1:30:00	326.76	16.19	46.71	13.51	59.22	100.37	90.76
2:00:00	340.83	22.17	56.62	12.18	54.89	114.63	80.34
2:30:00	369.40	16.70	61.16	11.17	57.69	108.49	114.19
3:00:00	326.83	18.27	49.37	11.96	50.51	100.44	96.28
3:30:00	332.10	18.93	57.07	12.39	55.93	83.54	104.25
4:00:00	308.66	17.72	43.41	13.01	54.32	81.60	98.60
4:30:00	327.91	19.85	47.75	12.74	59.19	111.45	76.93
5:00:00	364.72	17.99	57.20	11.89	56.39	107.87	113.39
5:30:00	357.03	23.18	59.66	14.60	59.11	107.23	93.24
6:00:00	289.31	18.26	47.56	15.65	45.78	83.69	78.37
6:30:00	317.80	19.84	55.19	11.57	56.83	86.29	88.08
7:00:00	324.13	16.63	49.94	12.24	48.65	82.13	114.55
7:30:00	353.41	22.84	57.54	12.09	65.76	83.65	111.53
8:00:00	521.55	36.01	94.06	13.40	46.00	171.17	160.91
8:30:00	562.48	39.02	102.60	22.93	100.98	137.95	158.99
9:00:00	550.09	35.18	89.91	25.12	92.76	149.52	157.59
9:30:00	572.91	36.06	90.71	24.58	98.22	162.62	160.72
10:00:00	581.22	35.18	89.02	23.59	98.65	170.39	164.39
10:30:00	576.02	37.07	98.17	22.23	88.07	141.11	189.37
11:00:00	553.52	38.14	94.17	25.30	97.32	136.87	161.72
11:30:00	610.06	34.44	86.02	23.63	104.33	171.59	190.04
12:00:00	570.27	34.25	98.55	24.04	97.85	137.14	178.43
12:30:00	546.51	31.29	93.23	23.37	89.53	148.95	160.14
13:00:00	582.33	34.24	88.71	24.12	85.52	158.34	191.40
13:30:00	491.66	22.17	59.87	14.73	63.47	151.39	180.02
14:00:00	463.54	20.38	59.11	13.98	65.21	143.33	161.52
14:30:00	334.21	18.21	53.09	14.05	52.05	99.72	97.08

15:00:00	320.92	16.20	46.94	14.53	62.74	82.34	98.17
15:30:00	310.28	21.85	41.83	12.80	55.27	93.71	84.82
16:00:00	337.19	17.30	62.68	11.56	52.08	81.02	112.55
16:30:00	336.15	22.66	54.54	13.01	46.38	112.82	86.74
17:00:00	483.87	15.58	56.80	13.11	66.57	188.19	143.62
17:30:00	556.01	28.28	47.74	30.10	77.00	199.78	173.11
18:00:00	594.11	30.17	92.56	26.03	74.05	204.43	166.87
18:30:00	586.50	30.60	106.45	29.90	73.25	177.95	168.35
19:00:00	580.83	27.71	97.79	26.71	69.54	189.07	170.00
19:30:00	588.46	26.45	95.45	26.30	78.45	192.64	169.17
20:00:00	594.38	28.08	98.40	29.67	61.05	202.75	174.43
20:30:00	593.00	28.65	106.54	29.09	73.18	181.29	174.25
21:00:00	358.60	23.56	87.37	26.78	51.54	89.92	79.44
21:30:00	324.93	19.67	48.74	14.15	61.41	90.30	90.66
22:00:00	328.69	18.53	57.99	12.68	58.20	80.10	101.18
22:30:00	331.40	21.58	48.74	11.45	59.09	79.96	110.58
23:00:00	317.18	21.68	57.16	14.90	50.71	91.41	81.32
23:30:00	334.36	15.43	56.88	15.19	62.40	97.62	86.84

Table 7. 4 Actual loads data (±5% imbalance)

Hour	Total MW load	Bus 2 #1 MW	Bus 3 #1 MW	Bus 4 #1 MW	Bus 5 #1 MW	Bus 6 #1 MW	Bus 7 #1 MW
0:00:00	360.57	16.27	46.53	14.36	61.60	112.52	109.29
0:30:00	352.96	15.90	60.75	12.87	50.70	98.27	114.46
1:00:00	332.90	20.82	42.27	13.89	57.47	105.91	92.53
1:30:00	322.35	16.55	46.29	13.86	61.53	96.76	87.35
2:00:00	343.04	22.25	58.30	12.44	55.25	113.29	81.50
2:30:00	375.26	15.89	63.22	10.77	58.26	110.74	116.37
3:00:00	330.12	18.65	51.20	12.08	49.64	98.81	99.74
3:30:00	329.01	18.77	54.78	12.31	57.64	85.53	99.97
4:00:00	308.73	18.51	44.66	12.49	53.49	80.22	99.36
4:30:00	322.89	19.82	45.38	12.24	56.42	108.41	80.62
5:00:00	371.26	17.69	57.84	12.30	55.77	111.15	116.52
5:30:00	356.41	22.96	60.78	15.10	58.35	109.89	89.34
6:00:00	291.26	19.11	48.78	15.47	47.30	83.14	77.46
6:30:00	320.14	19.71	55.18	11.38	58.06	88.90	86.91
7:00:00	329.31	16.19	50.34	11.95	47.83	85.39	117.61
7:30:00	351.87	21.85	56.86	12.22	64.90	86.47	109.58
8:00:00	520.86	35.88	98.22	13.48	46.57	172.22	154.50
8:30:00	553.36	39.99	106.90	21.95	96.45	136.92	151.15
9:00:00	555.47	34.21	90.72	26.37	94.79	155.40	153.98
9:30:00	583.09	37.06	88.13	23.99	98.38	167.80	167.74
10:00:00	594.03	36.74	92.67	22.98	93.77	176.57	171.30

10:30:00	583.50	36.24	97.55	22.69	88.84	147.38	190.80
11:00:00	557.71	37.50	98.50	25.84	101.67	131.45	162.74
11:30:00	611.23	35.67	83.36	23.30	107.36	178.47	183.07
12:00:00	573.62	34.33	103.21	25.16	95.61	142.11	173.21
12:30:00	530.45	32.63	94.71	22.44	85.59	142.92	152.17
13:00:00	577.45	33.51	84.37	24.16	88.86	159.14	187.40
13:30:00	481.55	21.36	60.44	14.15	62.80	149.93	172.87
14:00:00	455.72	20.80	56.50	13.33	63.28	139.57	162.24
14:30:00	332.72	17.36	50.74	13.76	50.98	104.38	95.50
15:00:00	319.00	15.83	47.13	14.17	65.39	79.87	96.62
15:30:00	311.55	21.70	40.78	12.66	57.07	98.32	81.03
16:00:00	336.94	17.51	59.61	11.05	49.51	82.04	117.22
16:30:00	342.11	21.66	54.38	12.77	48.65	114.45	90.20
17:00:00	481.44	15.45	54.69	13.03	65.20	186.67	146.40
17:30:00	564.85	29.03	48.08	29.99	79.81	207.45	170.49
18:00:00	609.38	29.87	90.89	25.26	76.44	214.45	172.45
18:30:00	588.32	30.49	105.11	30.92	72.81	180.20	168.79
19:00:00	581.11	27.04	96.74	27.44	71.41	188.75	169.73
19:30:00	595.05	26.06	97.77	25.37	80.86	192.87	172.12
20:00:00	600.68	28.42	101.62	29.76	59.95	208.77	172.17
20:30:00	604.03	28.77	108.71	29.93	72.14	182.08	182.40
21:00:00	358.64	23.12	89.90	26.13	49.51	88.86	81.12
21:30:00	326.76	20.10	48.07	13.57	59.00	91.37	94.65
22:00:00	325.17	18.73	57.84	13.10	56.27	77.54	101.69
22:30:00	331.86	20.99	50.13	11.58	58.93	83.30	106.93
23:00:00	318.13	20.95	56.48	15.49	52.51	90.70	82.00
23:30:00	335.45	15.60	58.15	15.57	62.83	100.57	82.72

7.4.2 Forecast results in the 7-Bus test System

7.4.2.1 Generator Incomes

Figure 7.2 is the results of the generator incomes for 5 generators respectively, which is covering 48 half hourly periods over a typical day.

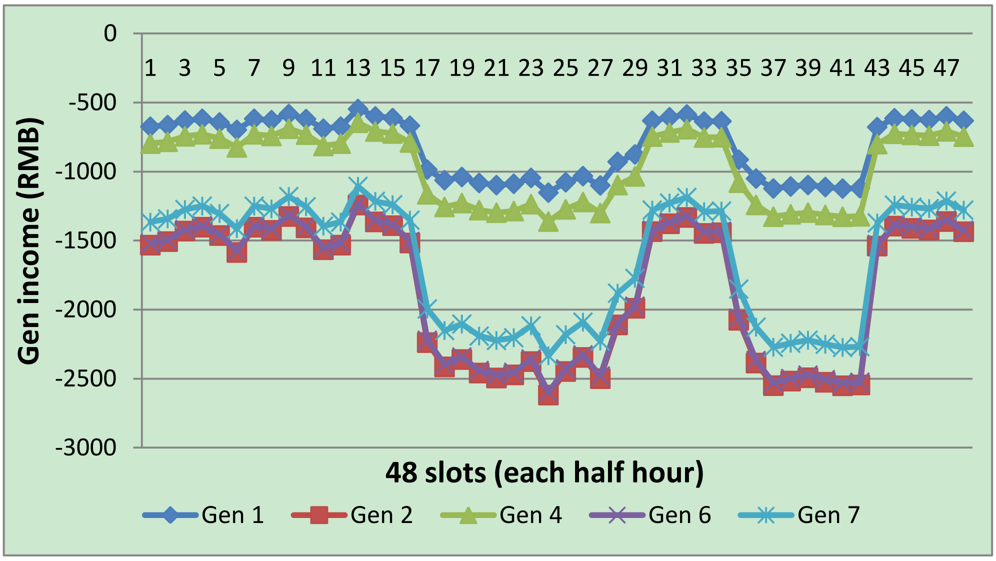

Figure 7. 2 Generator incomes

It can be seen from the Figure 7.3, which is the curve of the total revenue income for all generators, shows that the revenue incomes for generators are ranging from nearly RMB 5000 to over RMB 10000 per half hour.

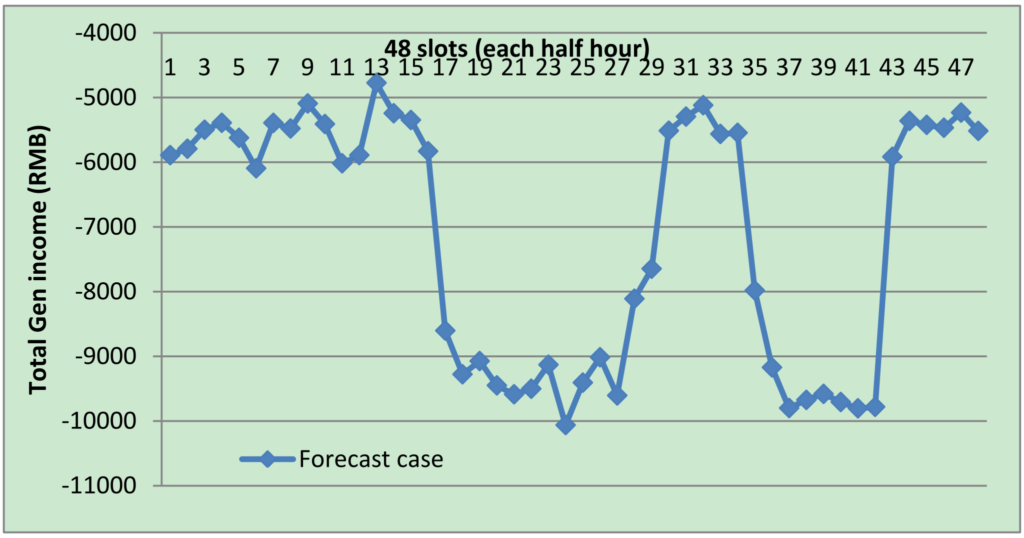

Figure 7. 3 Income for all generators

7.4.2.2 Load payments

In the Figure 7.4, the curve is shown that the payments for 6 loads (the blue diamond-dotted line is for load 2; the red square-dotted curve stands for load 3; the triangle dotted line as load 4; the cross-dotted line for load 5; the star-dotted for load 6 and the round dotted is for load 7) varied greatly.

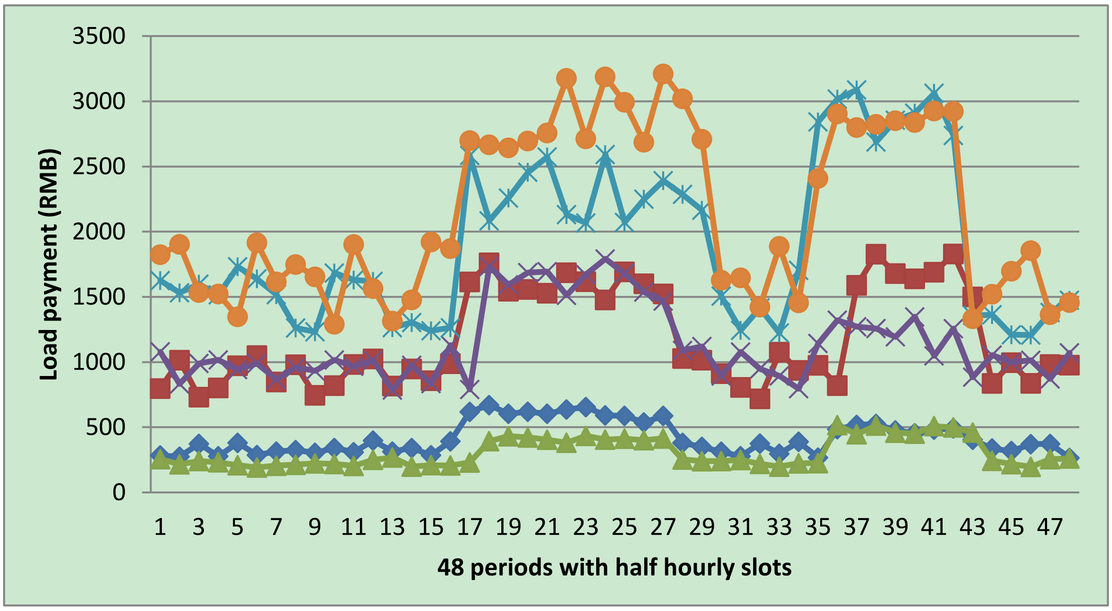

Figure 7. 4 Demand customer payments

Figure 7.5 is reflecting the total payments by all demand customers in the forecast case covering a whole day with 48 slots.

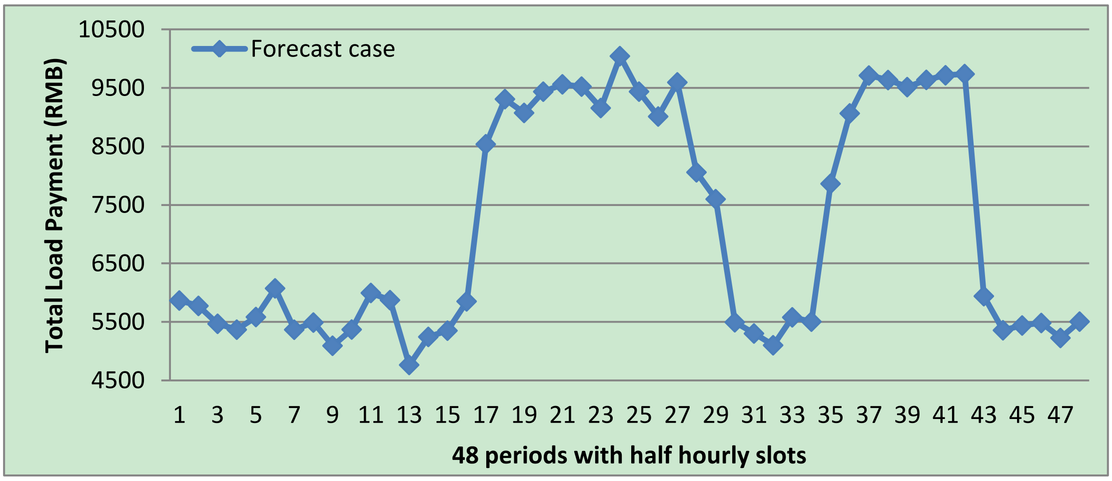

Figure 7. 5 Payments for all demand customers

7.4.3 The 7-Bus test System without storage (original case)

In this section 7.4.3, the maximum ±5% of the forecast errors is assuming occurred through the typical day on the 7-bus test system.

7.4.3.1 Revenue income for generators

Figure 7.6 is demonstrated that there are five curves displaying 5 generators' incomes on 48 slots over the typical day respectively.

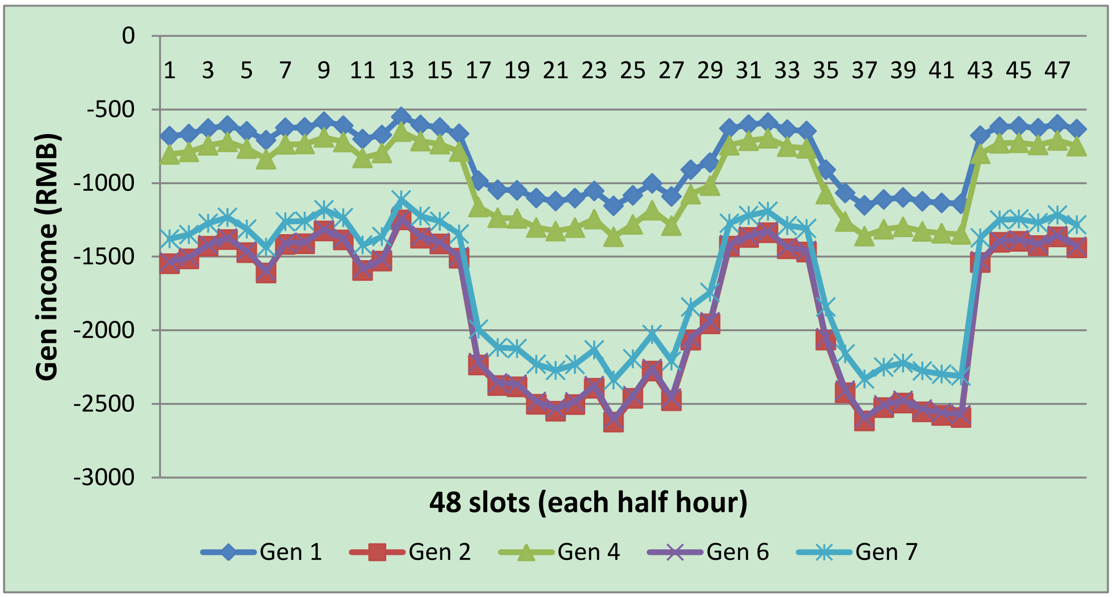

Figure 7. 6 Generators revenue income

It can be seen from the Figure 7.7, which is the curve of the total revenue incomes for all generators, shows that the revenue incomes for generators are ranging from over RMB 4500 to nearly RMB 10500 per half hour. Which are showing a little bit larger fluctuation than the Figure 7.3 (the forecast case).

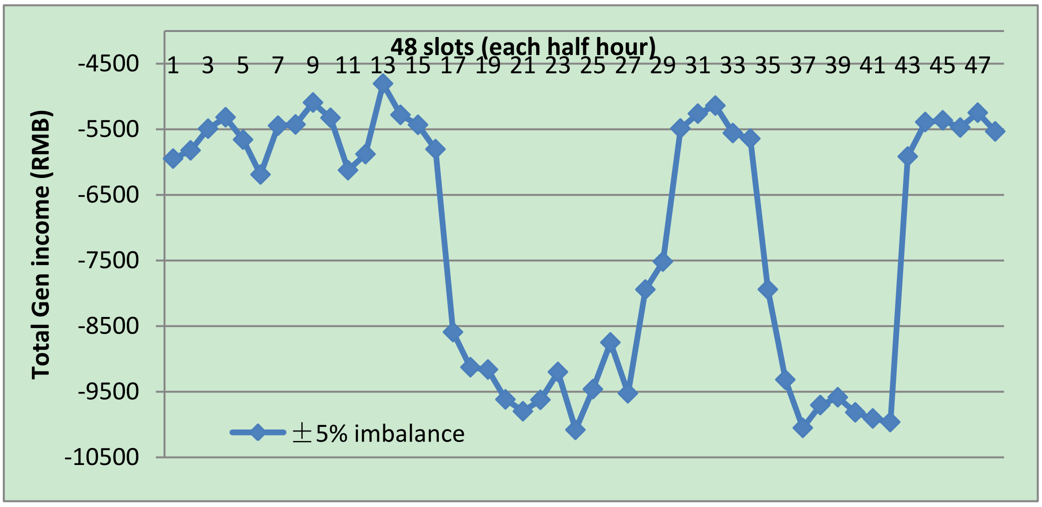

Figure 7. 7 Revenue incomes for all Generators

7.4.3.2 Payments by load demand

Similar to the Figure 7.4, the Figure 7.8 is shown that the payments for 6 loads (the blue diamond-dotted line is for load 2; the red square-dotted curve stands for load 3; the triangle dotted line as load 4; the cross-dotted line for load 5; the star-dotted for load 6 and the round dotted is for load 7) are quite different.

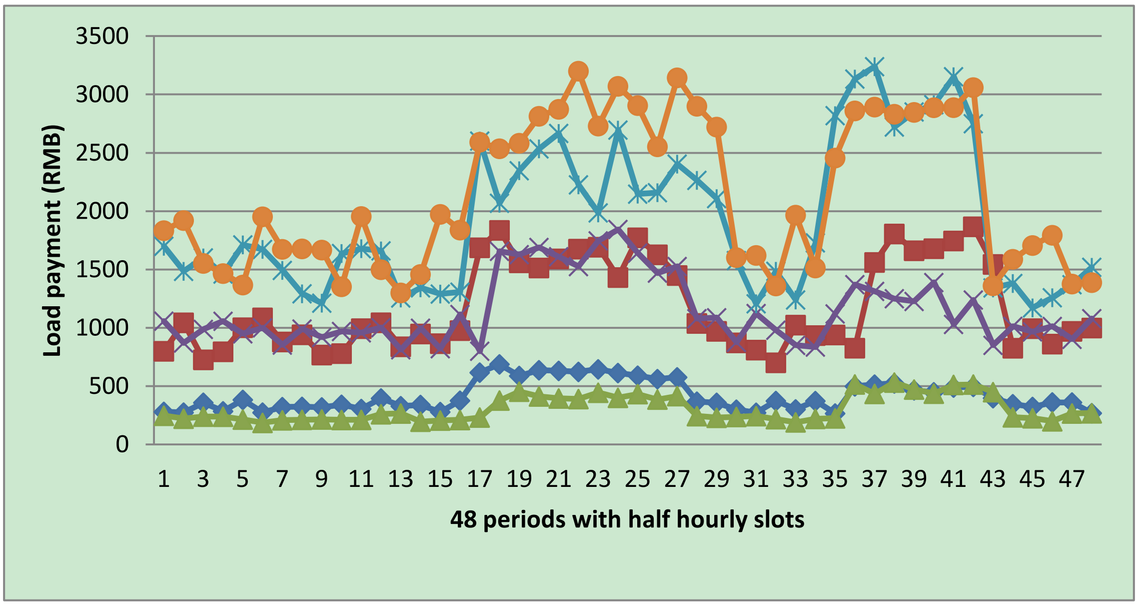

Figure 7. 8 Demand payments

Figure 7.9 is also reflecting total payments for all demand customers in the forecast case covering a whole day with 48 slots, where the detailed comparison between Figure 7.5 and Figure 7.9 will be made on section 7.4.5.

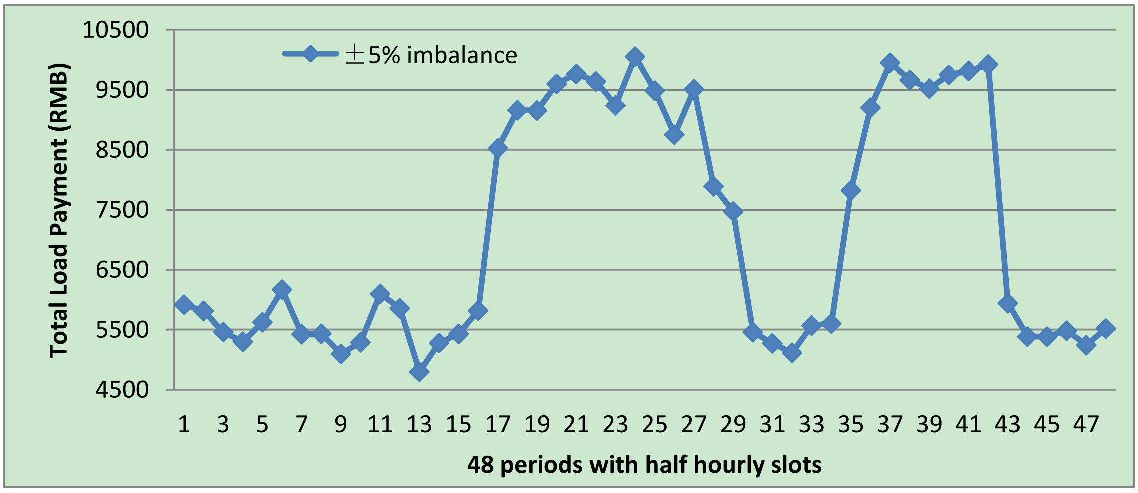

Figure 7. 9 Payments by all loads

7.4.4 The 7-Bus test System with Storage

In this section, the storage is taking part of the role in balancing the system, and the DUES will be simulated on the same 7-bus test system. And the storage will be connected to the Bus 6. When the system is short of energy, it could inject generation into the system to discharge, on the other hand, if the system is long of energy, it could absorb the energy from the system to charge itself.

7.4.4.1 The storage connected into the Bus 6

Table 7.5 is the results for the storage usage over 48 periods connected on the bus 6 from time to time on 48 periods.

Table 7. 5 storage plays in role within 48 periods

Time	storage usage (MW)	Time	storage usage (MW)	Time	storage usage (MW)
0:00:00	-0.46	8:00:00	0.09	16:00:00	0.03
0:30:00	-0.24	8:30:00	1.19	16:30:00	-0.77
1:00:00	0.05	9:00:00	-0.70	17:00:00	0.32
1:30:00	0.57	9:30:00	-1.32	17:30:00	-1.15
2:00:00	-0.29	10:00:00	-1.67	18:00:00	-1.98
2:30:00	-0.76	10:30:00	-0.97	18:30:00	-0.24
3:00:00	-0.43	11:00:00	-0.54	19:00:00	-0.04
3:30:00	0.40	11:30:00	-0.15	19:30:00	-0.86
4:00:00	-0.01	12:00:00	-0.44	20:00:00	-0.82
4:30:00	0.65	12:30:00	2.09	20:30:00	-1.43
5:00:00	-0.85	13:00:00	0.63	21:00:00	-0.01
5:30:00	0.08	13:30:00	1.31	21:30:00	-0.24
6:00:00	-0.25	14:00:00	1.02	22:00:00	0.46
6:30:00	-0.30	14:30:00	0.19	22:30:00	-0.06
7:00:00	-0.67	15:00:00	0.25	23:00:00	-0.12
7:30:00	0.20	15:30:00	-0.17	23:30:00	-0.14

*usage(+): is standing for the injection to the system by the storage
usage(-): is standing for the absorbing from the system by the storage

7.4.4.2 Revenue incomes for the generators including storage

Although the storage can be used as generators or treated as the load demand, but for the simplicity of calculation in this case study, this storage results are calculated into the generators together with the generator on bus No.6.

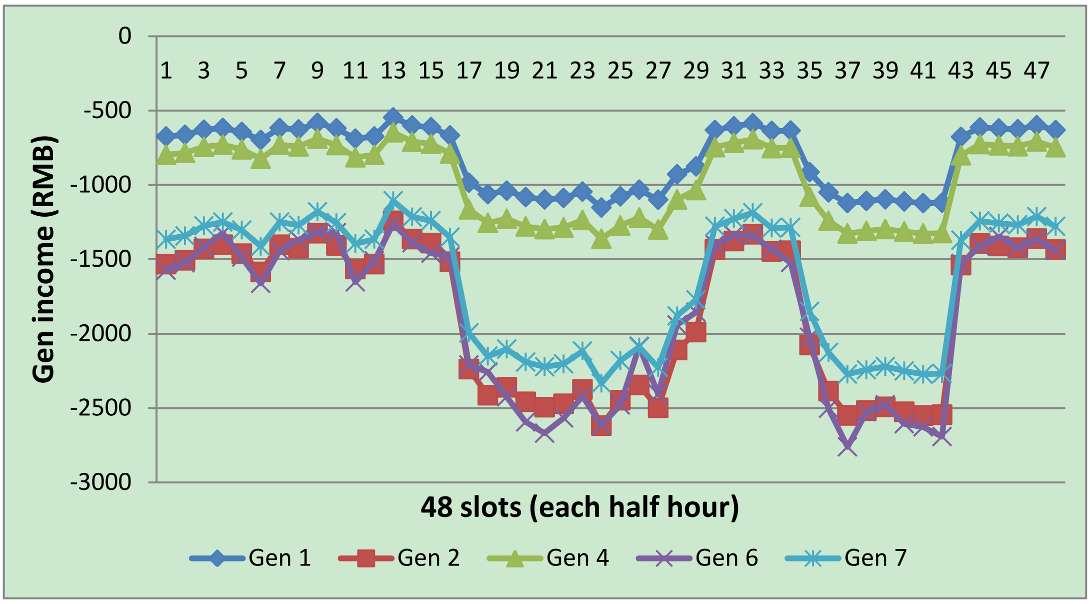

Figure 7. 10 revenue incomes for generators individually including storage

It can be seen from the Figure 7.11 which is the single curve of the total revenue incomes for all generators including storage, shows that the revenue incomes for generators are ranging greatly. The comparison between original case and imbalance case will be made on section 7.4.5.

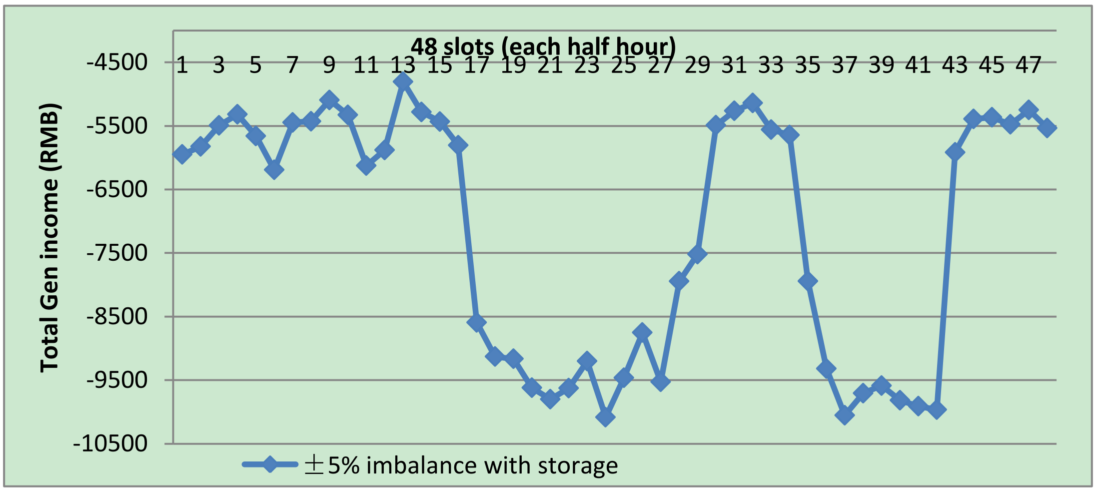

Figure 7. 11 revenue incomes for all

7.4.5 Comparison

7.4.5.1 Comparison between the forecast case and original case

Figure 7.12 is the picture showing that the payment deviation between the forecast case and the actual imbalance case, which are containing ±5% of forecast errors.

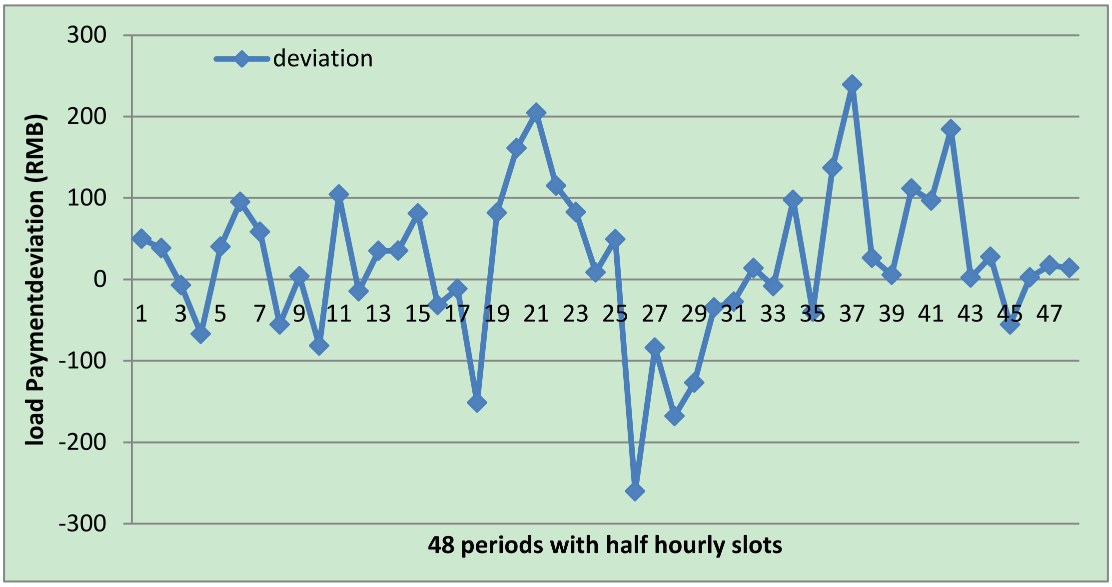

Figure 7. 12 load payment deviations

Below is the Figure 7.13 that is the Figure comparing the income deviation between the forecast case without storage and the original case, which are containing ±5% of forecast errors.

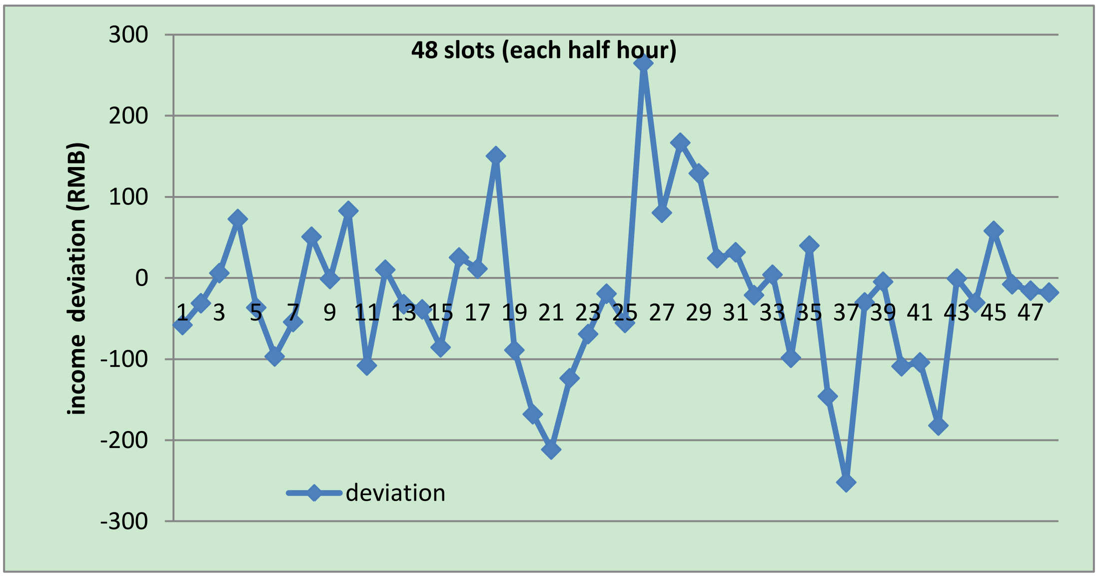

Figure 7. 13 revenue income deviations

7.4.5.2 Imbalance settlement comparison

The generation incomes comparison between the forecast case and the actual imbalance case with and without storage is tabulated in Table 7.6. It can be seen that the results without storage is the highest at RMB343799, that the value is RMB1085 higher than the forecast case. When the storage plays the role in the system, it can be seen that it had lowered the system payments to generators down to RMB343707.

Table 7. 6 imbalance settlement comparison between forecast case and storage application

time	forecast gen income (RMB)	Results without storage (RMB)	Results with storage (RMB)
0:00:00	-5890.62	-5948.51	-5943.62
0:30:00	-5791.89	-5822.96	-5820.34
1:00:00	-5498.2	-5492.09	-5492.61
1:30:00	-5390.71	-5317.94	-5324.09
2:00:00	-5622.89	-5659.3	-5656.23
2:30:00	-6094.21	-6190.91	-6182.74
3:00:00	-5391.92	-5446.13	-5441.56
3:30:00	-5478.79	-5427.89	-5432.18
4:00:00	-5092.09	-5093.3	-5093.2
4:30:00	-5409.75	-5326.89	-5333.89
5:00:00	-6017.07	-6124.96	-6115.85
5:30:00	-5890.13	-5879.9	-5880.76
6:00:00	-4772.85	-4805.1	-4802.38
6:30:00	-5242.9	-5281.55	-5278.29
7:00:00	-5347.35	-5432.79	-5425.58
7:30:00	-5830.38	-5805.03	-5807.17
8:00:00	-8604.39	-8592.97	-8593.94
8:30:00	-9279.53	-9129.1	-9141.8
9:00:00	-9075.16	-9163.98	-9156.48
9:30:00	-9451.67	-9619.56	-9605.38
10:00:00	-9588.67	-9800.11	-9782.26
10:30:00	-9502.93	-9626.43	-9616
11:00:00	-9131.76	-9200.84	-9195.01
11:30:00	-10064.5	-10083.8	-10082.2
12:00:00	-9408.15	-9463.44	-9458.77
12:30:00	-9016.03	-8751.12	-8773.48
13:00:00	-9607.02	-9526.53	-9533.33
13:30:00	-8111.25	-7944.4	-7958.48
14:00:00	-7647.29	-7518.25	-7529.14
14:30:00	-5513.59	-5489.12	-5491.19
15:00:00	-5294.48	-5262.68	-5265.37
15:30:00	-5118.82	-5139.91	-5138.13
16:00:00	-5562.83	-5558.74	-5559.08
16:30:00	-5545.72	-5644.02	-5635.73
17:00:00	-7982.62	-7942.62	-7945.99
17:30:00	-9172.79	-9318.63	-9306.32
18:00:00	-9801.47	-10053.3	-10032.1
18:30:00	-9675.84	-9705.9	-9703.37
19:00:00	-9582.25	-9586.86	-9586.47
19:30:00	-9708.1	-9816.88	-9807.7
20:00:00	-9805.8	-9909.79	-9901.01

20:30:00	-9783.16	-9965.02	-9949.67
21:00:00	-5916.11	-5916.77	-5916.72
21:30:00	-5360.5	-5390.83	-5388.27
22:00:00	-5422.61	-5364.45	-5369.36
22:30:00	-5467.24	-5474.91	-5474.26
23:00:00	-5232.79	-5248.35	-5247.04
23:30:00	-5516.18	-5534.09	-5532.58
Sum	**-342713**	**-343799**	**-343707**

The results are shown that the DUES participating had positive effects on the system payment. But it also should notice that the benefit is brought from the specific location and the certain marginal cost caused by the storage.

7.5 Conclusions

When the DUES is broadly participated in the practical power network, more and more attentions should be made when dealing with the imbalance settlement. From the test results, it is shown that the DUES could access to the real time market for balancing the errors from the demand forecast, no matter the increased demand or the reduced demand, and could lower the system payments to generators, with a profit for the whole system.

Because the DUES tested is chosen from the specific location and there is a certain marginal cost, the actual results could be different. And also different ways to solve the imbalance settlement, the results could be varied.

7.6 References

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Chapter 8 Conclusions and Future Work

8.1 Conclusions

As the power industry evolves into a competitive environment, power system economics continues to be an important function because system operation and settlement method uncertainties have increased significantly. In this thesis, various settlement methods based market designs are discussed. This thesis has reviewed five electricity markets in the world, which represents three different methodologies of allocating the electricity cost. A simple analysis of the imbalance settlement price has been given as case study for each chapter by different settlement methodologies. The calculation of the total revenue income and load total payment by the same IEEE30 Bus system with different settlement methodologies is demonstrated in details. This has involved, the different percentages ($\pm 2\%, \pm 5\%, \pm 8\%, \pm 10\%, \pm 20\%$) of total load energy imbalance prices, calculated by different settlement methodologies (Uniform Price SSP/SBP, Locational Marginal Price, and Zonal Marginal Price), while providing a better understanding of the behavior of prices and the forces which drive that behavior.

The success of an electricity market is determined by a number of key design features. The implementation of electricity markets around the world has raised some practical problems and presented new challenges to the system operation and system settlements of power system. This thesis has highlighted some significant subjects under the restructuring power industry:

- Well functioning market structures to improve the performance of electricity Markets should be established.
- Pricing mechanisms to relieve and manage imbalance settlement in a fair, effective and economic manner are needed.
- Market designs to create more stable long-term price signals in order to encourage investments in generation and transmission capacity are needed.

- A clear understanding on the relationship between electricity price and its physical drivers are needed.

Based on the important issues above, this thesis also has presented and discussed the key features regarding the design and implementation of energy, ancillary services, settlement systems and capacity markets. The operation experiences in the UK POOL and NETA system, the US PJM markets, the Australian NEM market, and the New Zealand Market etc. have also been presented.

In the world competitive electricity markets, the Balancing Mechanism has to provide the market participants with a pricing policy and send the market parties the right economic signals through the different imbalance settlement pricing methods. Uniform marginal pricing is assumed the whole system in one zone, it is efficient and does not cause any financial problem, because the load payments will be the same with generator revenue incomes (assuming no loss is concluded). But when the energy imbalance occurs in a network, uniform marginal price fails to deliver an efficient nodal signal in a competitive market. Similarly with zonal marginal pricing, it assumed several buses in one zone, it provides a simple, transparent and easy to implement market design, it still can bring some operating issues. So it is difficult to define the identically efficient imbalance settlement pricing mechanism that could fit all market structures within different systems.

Each electricity market should choose a method based on the features of its grid. Uniform pricing approach provides a simple and straightforward implementation for competitive electricity market. However, uniform price does not guarantee capital cost recovery. In order to recover the capital and construction costs, operating cost for generator has to be set below the market clearing price. The transparent pricing structure of uniform pricing allows cheap generators to enter into long-term contracts outside the spot market.

Zonal pricing approach believes to be able to balance the equity concerns with efficiency goals. For instance, zonal model would have the effect of averaging prices across a larger region and at least, would reduce process in the high price region. Nodal pricing approach is expected to promote efficient trading and reflect the opportunity costs of using the transmission paths. It can further facilitate the efficient use of the transmission system by developing a competitive electricity market. Nodal pricing approach reflects the actual situation in the grid and is more transparently than uniform prices and represents adequate allocation signals. The use of nodal pricing providers' direct assignment of local generation a settlement prices are based on locational marginal price.

8.2 Future Work

This section suggests possible improvements or ways to expand the research work in this thesis.

Advanced imbalance settlement schemes: A complete imbalance settlement schemes should combine bilateral, multilateral, and pool transactions. In addition, contingency analyses and bidding auction designs also have to be taken into account. For example, if the market design is based on single-part bids, a simple market-clearing process based on the intersection of supply and demand bid curves is sufficient to determine the imbalance price for each half-hour. However, if the market design is based on multi-part bids, a combination of unit commitment and OPF algorithm taking into account security constraints may be needed. A multi-part bid may include separate prices for ramps, start-up costs, shutdown costs, no-load operation, and energy. This kind of bid is complex but could reflect the cost structure and technical constraints of generation units, which would result in smaller overall costs of schedules. Therefore, different bid types would result in different imbalance settlement schemes.

Electricity price forecasting: It is necessary to identify potential electricity price drivers and the relationship between these physical drivers and prices. These fundamental components driving the price volatility would include generation reserves, bidding patterns, system constraints and outages. This analysis would help market traders predict market prices more accurately and effectively. In deregulated markets, electricity price forecasting is becoming more important. In the short-term, knowledge of the estimated prices would help traders determine their bidding strategies and unit commitments. In the long-term, accurate price forecasting would enable traders to make correct decisions on the location of sitting generators.

Renewable Energy DG Access: As the limitation of the fuel and development of the renewable source, the renewable energy Distributed Generator (DG) access become necessary to solve the imbalance settlement problem, they may not be economical given the probability of contingencies and changes in the market environment. As new application, Dual use of electricity storage method could use to solve part of the imbalance settlement problem. The Dual Use Distributed Generator (DUDG) such as battery storage, electric vehicle to grid, or hydro power station, could access to the real time market for balancing the errors from the demand forecast, no matter the increased demand or the reduced demand, with a reasonable price both for generation side and the distribution side.

Appendix A

—SBP and SSP value (RMB/MWh) under five imbalance Cases

T	±2%		±5%		±8%		±10%		±20%	
	SBP	**SSP**	**SBP**	**SSP**	**SBP**	**SSP**	**SBP**	**SSP**	**SBP**	**SSP**
1	239.3	157.5	227.4	157.5	226.6	159.0	227.1	167.2	228.5	167.2
2	224.6	156.3	235.4	156.3	224.6	156.3	235.4	156.3	224.6	157.1
3	247.9	155.7	232.2	167.1	247.9	156.1	232.2	156.6	232.4	157.4
4	231.9	169.2	231.9	156.5	241.1	156.9	232.1	157.5	231.9	159.3
5	220.7	157.1	220.7	157.1	220.7	164.3	244.0	157.1	220.7	164.3
6	223.1	155.5	247.1	155.5	223.1	155.5	223.1	155.5	223.3	156.6
7	223.3	155.6	223.3	155.6	223.3	157.3	223.3	169.6	223.3	159.1
8	221.1	156.4	221.1	156.9	221.1	170.4	221.1	158.4	221.1	159.2
9	242.6	156.2	230.8	169.2	230.8	156.2	242.6	156.2	242.6	157.2
10	223.8	167.3	223.8	155.5	223.8	167.3	241.2	155.7	241.2	158.3
11	220.7	156.1	220.7	156.1	250.5	156.2	250.5	156.1	222.0	156.4
12	248.4	159.1	222.6	159.1	222.6	169.9	222.6	159.1	222.6	159.5
13	223.2	155.1	246.9	155.1	246.9	155.1	223.2	155.1	246.9	155.2
14	234.7	155.3	224.2	155.3	224.2	168.1	224.2	168.1	224.2	168.1
15	220.9	157.1	231.7	157.1	220.9	157.8	220.9	170.0	220.9	157.1
16	280.5	200.3	280.6	203.3	284.0	200.4	280.9	200.4	281.8	200.4
17	281.1	200.6	281.9	203.9	282.1	200.6	281.2	200.6	282.6	201.5
18	281.6	200.1	281.8	200.3	284.2	200.2	281.9	203.2	282.1	200.3
19	285.3	200.1	285.3	200.1	281.4	200.6	282.6	202.5	283.3	200.8
20	280.3	203.7	280.8	200.7	282.8	201.0	283.5	202.0	283.6	201.5
21	280.9	203.2	280.9	203.2	281.3	200.2	285.5	201.2	285.5	201.6
22	280.5	203.7	284.6	201.1	284.6	201.1	280.7	202.5	282.5	200.9
23	281.7	203.5	282.5	200.8	284.5	202.1	283.1	203.5	282.2	202.4
24	225.5	168.5	225.5	161.6	225.5	161.6	225.5	168.5	225.5	165.4
25	226.2	166.1	226.2	156.3	248.4	156.3	248.4	156.3	227.7	157.6
26	224.1	170.0	251.7	158.6	224.1	159.5	226.5	170.0	251.7	160.8
27	223.4	155.8	223.8	167.7	225.4	155.8	245.7	155.8	227.6	156.1
28	231.0	157.8	241.6	157.8	231.0	167.4	231.0	157.8	233.0	158.3
29	282.4	200.7	285.4	200.7	282.4	200.7	283.8	203.3	283.8	201.9
30	281.9	200.3	281.9	200.3	282.0	201.1	282.4	201.5	282.5	201.5
31	280.1	203.9	280.1	201.1	284.5	202.0	281.8	202.1	281.9	202.5
32	285.3	200.1	280.9	203.7	285.3	201.7	281.7	201.3	282.1	202.5
33	282.0	200.9	283.1	203.9	282.5	201.3	283.5	203.9	283.9	202.6
34	281.4	203.4	281.6	203.4	282.0	203.4	285.5	201.5	283.0	203.4
35	246.6	156.6	229.7	156.7	246.6	156.6	246.6	156.6	231.0	168.8
36	241.9	160.1	222.4	160.1	225.7	160.1	222.4	160.1	227.5	169.5
37	222.7	168.9	240.2	157.8	222.7	157.8	222.7	168.9	223.0	168.9
38	222.3	156.8	222.3	156.8	244.7	156.8	244.7	157.0	226.0	161.6

39	222.4	156.4	224.1	156.7	238.8	156.7	224.0	156.4	231.9	159.8
40	221.4	166.7	221.4	157.1	221.4	157.2	222.0	157.1	245.0	159.3
41	226.0	168.5	247.2	155.5	226.0	156.8	226.0	168.5	227.4	168.5
42	243.4	158.4	224.6	158.4	243.4	158.8	224.6	170.5	224.9	158.4
43	247.0	159.2	221.7	159.3	247.0	159.4	221.7	159.3	223.2	167.3
44	221.2	155.6	221.2	156.1	221.2	155.8	221.2	169.7	224.9	169.7
45	225.5	169.0	225.7	169.0	246.9	160.8	225.5	161.4	246.9	161.6
46	224.5	161.7	224.5	162.1	224.5	161.7	224.5	168.6	225.1	168.6
47	249.9	160.4	229.3	160.4	249.9	160.4	229.5	167.7	234.3	167.7
48	221.8	156.6	221.8	156.6	241.4	156.6	241.4	156.6	222.3	156.6