Congestion management and LMP

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Declaration of Author's Right

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DEDICATION

THIS THESIS IS DEDICATED TO

MY PARENTS AND MY HUSBAND

FOR THEIR

PURE AND UNCONDITIONAL LOVE TO ME

AND TO

MY GRANDDAD AND MY GRANDMOTHER

GLOSSARY OF TERMS

ARR…………Auction revenue rights

Rights or entitlements to the proceeds the ISO receives from the sale of FTR at auction

DG…………...Distribution Generation

Any electricity generating technology installed by a customer and is connected at the distribution system level of the electric grid

FGR………….Flowgate Right

Flow-based FTR is Fowgate right

FTR………….Financial Transmission Right

A financial instrument that entitles the holder to receive compensation for Transmission Congestion Charges

ISO/SO……...Independent System Operator / System Operator

An organization formed to coordinate, control and monitors the operation of the Electrical Power System

LHRs………..Loss Hedging Rights

It is a financial instrument that entitles the holder to receive compensation by returning marginal-loss-related over collected revenue to the LHR owners using the Marginal loss components of the LMP

LMP…………Locational Marginal Price

The cost of serving the next MW of load at a given location

NCGC……….North China Power Grid (North China Grid Company)

OPF…………Optimal power flow

A load flow that employs techniques to automatically adjust the *power system control settings while simultaneously solving the load flows and optimizing operating conditions within specific constraints*

PTR………….Physical Transmission Rights

Exclusive right to transport a predefined quantity of power between two locations on the network, and accordingly, the right to deny access to the network by market participants who do not hold the rights

RTO………….Regional transmission organizations

An organization that is responsible for moving electricity over large interstate areas

SMD………...Standard Market Design

Standard Market Design is a set of established guidelines governing the sale of electrical power and the operations of electrical transmission lines in the United States of America.

TO…………...Transmission Option

Point-to-point FTR from the point of clearing model can fall into two categories, FTR Obligations and FTR Options they have different economic values.

ABSTRACT

Traditional power industry is a monopoly through the establishment of regional power generation, transmission and power supply management system and is of vertical structure. Since the late 1980's, electric power supply industry in different countries have experienced varying degrees of deregulation. In the subsequent 20 years many countries have set up electricity market in accordance with its own requirement and adapt the electricity market model to their country's needs.

This thesis presents a more transparent and fairer method for financial settlement for congestion using load distributed slack bus. It has shown that by changing the angle reference bus it doesn't change the value of the cost of energy, the cost of marginal loss component and the cost of marginal congestion component at all buses. Most importantly, it has shown that the differences between cost of marginal loss component and the cost of marginal congestion component remain the same irrespective of the reference bus. The effects of Locational Marginal Pricing (LMP) of power network with and without distributed generation (DG) installation under constrained and unconstrained system operational system conditions have also been investigated. An important property of LMP systems is that they provide efficient price signals not only for short-term operations but also for long-term investments.

To illustrate the practical application of the LMP method, the North China Power Grid (NCGC-North China Grid Company) is chosen as a sample study. The gradual process of liberalizing the power grid to a fully market economy is studied. Four gradual steps are used. The restructuring of the electricity supply industry in NCGC, and further in China, is likely to take a gradual progressive path, and the study of the NCGC fully illustrates the steps and the benefits of the progressive path.

The characteristics of financial transmission right (FTR) and transmission option (TO) are compared and analyzed in this thesis. A simple network is used to illustrate the differences and importance of transmission congestion right and transmission option. Market participants can use the analysis the benefits by hedging against congestion risk. In method of usage will depend on the situation of individual market participants.

CHAPTER 1
INTRODUCTION

1.1 INTRODUCTION

Traditional power industry is a monopoly though the establishment of regional power generation, transmission and power supply management system and is of vertical integration. Typical features are a: the whole area in the grid can have only one generation, transmission and distribution “power enterprise” with one or more control centers in order to achieve the planning, operation, and scheduling, such as load forecasting, state estimates, power generation scheduling, reactive power control, automatic generation control, open plan downtime, accident and emergency security control of the desired functions. It is a monopoly of the electricity supply industry, the monopoly of one or more geographical electricity production, transmission, distribution and sales. The costing to individual department can have cross subsidy as in final price of electricity for sale to the customer of a combined cost. There could also be heavy financial subsidy from the government.

Since the late 1980’s, the world’s electric power industry in different countries and regions has experienced varying degrees of deregulation. In change has opened up the electricity market. This is done in order to achieve ration al allocation of resources and to protect the electric power industry as the goal of sustainable development. The traditional power generation, transmission, and distribution the vertically integrated electricity monopoly-based business is broken down into independent power generation companies, transmission companies and distribution companies. Market competition is introduced to reduce costs，optimize the allocation of resources, improve efficiency and facilitate the development of the long-term stability of the power system. The electricity market develops rapidly to face all aspects of the many new challenges, such as emerged new technologies and socio-economic concerns[1][2].

Electricity is an essential and basic commodity in modem society. The demand to electricity is rising continuously and in some developing countries the continuous construction of new power stations is unable to satisfy the rapid rise is demand. With be new electricity market, new generating companies have emerged and new transmission lines are needed. Nevertheless it is very difficult to have right-of-way for the construction of new transmission lines and the main reason is the objection of the environmental lobby. Transmission capacity of existing line is of limited capacity and the allowed right of access to all generators creates a phenomenon known as network congestion. When the network is congestion the transmission network done not have the capacity to transmit all the contracted power from the generators to be customers. The investment in transmission line to relieve congestion is on approach, but as mentioned previously there are environmental lobby's objections. Another way forward is be use of network management to priorities transactions. The power network is then a body of contradictions between market economy and power network management. How well the coordination of there contradictions, so that both sides can benefit from conflict management is an important component of congestion [3].

In the traditional power industry, the power generation entities schedule the average profit-sharing and when the actual operation of power lines appears near its limit a short-term approach is to use administrative orders to adjust the generator output. If this can not be adjusted to meet the safe operation of power systems it can only rely on the forced removal of load in order to reduce power flow. A Long-term solution to the problem is the expansion of the power grids and equipment renewal and replacement. These methods need financial investment. The correct allocation of this investment to participants and in what proportion each participant should contribute is not a clear and definite procedure.

One aim of the electricity market is to rationally allocate resources in a just, fair and open treatment of all participants. The more traditional solutions to limit power flows are no longer applicable is the new environment, so new issue is congestion management. The distinction of responsibilities between network participants, and how and when to give correct and timely information and signals to protect security and stability of power system operation and in a fair and reasonable manner to alleviate congestion is the focus point of this thesis.

Professor F. C. Schweppes of Massachusetts Institute of Technology in 1979 published the paper “in 2000 the power” and raised “electricity market” concept. In the subsequent 20 years many countries have set up electricity market in accordance with its own_characteristics and to adapt the market model to their countries needs their own electricity market model. Although the model has a variety of forms but a common characteristic is that electricity market participants are independent entities and are no longer subject to unified control. The management of transmission and distribution networks between the bridges, in the electricity market plays an important role. The transactions are completed in the network, so to ensure safe operation of transmission networks, a fair, just and open the network management is a prerequisite for healthy development. Different with other commodity markets, the electricity market belongs to the network economy, and its exchange of commodities by the natural attributes of power transmission network constraints, such constraints is to transmit power within the safe limit.

Congestion management and the importance of the characteristics can be expressed in the following areas:

(1) The rational use of transmission networks resources: electricity market introduces new management model and new operating system, but its evolvement is form the original traditional power industry, and the underlying technical support at the same time remains unchanged. In the new environment how to make full use of existing resources management are the key points of consideration. The relive of congestion though the expansion of the transmission networks is not the optimal solution.

(2) Maintain a safe and stable operation of the system: congestion from the point of view of physics is that the power transmission lines are used beyond their loading limits. Frequent overload will cause decline of long-term mechanical strength, increased contact resistance, reduce insulation performance and is severe cases may cause power system faults. For example, the 2003 Canada's August 14 blackout was is the suburb of Cleveland when one of the five lines was overloaded. Excessive current caused the conductor to sag touching a tree and was tripped out of service. Load was transferred to another line, resulting in overloading of other lines and caused the second line to trip. This led to a cascade tripping of one line after another. The power outage caused outage of more than 100 power plants, dozens of high-voltage transmission lines and a loss of load of 61.8GW, sustained over a time period of 29 hours. It effected an area of 24 thousand square kilometers and a

population of about 50 million with an estimated economic losses of 30, 000,000,000 U.S. dollars [4].

(3) To protect the healthy development of the electric power industry: the first rule of the healthy market development is a have a fair and reasonable treatment of all participants. The use of the average cost-sharing method for network reinforcement creates cross subsidy and is unfair to many market participants. Congestion management is to identify the causes of congestion, and then allocate a reasonable proportion of costs to the participants who cause congestion.

(4) Optimize system operation: participating entities after system restructuring are commercial companies and their aim is to maximize benefits for their own company. These participants are independent power companies and their not trading pattern may creation network congestion. It is important to be operates market to give economic signals to encourage participates to improve their trading strategy and to is take congestion into consideration. In this way the secure operation of the system may the achieved.

1.2 MOTIVATION OF RESEARTCH

In an electricity market environment, in order to ensure safe and economic operation of power system, transmission system needs to be effectively managed. Congestion management is the core. With the deepening of the electricity market research, use of economic instruments to mitigate transmission congestion has become a research hotspot.

Reconstructing of the electric power industry and the introduction of competition mechanism, the transmission network has become the bottleneck of the optimal use of resources, and in such circumstances, the transmission network will experience transmission congestion phenomenon [5]. By congestion it means that the power transmission capacity of line is unable to meet the power exchange agreement without exceeding its limits. How to solve the transmission network congestion problem, as well as how to proceed with congestion management has become the forefront of the subject areas of research.

In traditional verticals management model, the dispatch center has the autonomy to carry out generation scheduling and should have the authority to relive the congestion line, but in the power market environment the decision making very different. The power transactions are carried by various market participants directly. The elimination of congestion not only needs the necessary technical support, but also must implement fairly and effectively.

One of the congestion management objectives is to formulate a series of rules to have effective control of generators and load and allowing the system to run is the short term with certain degree of safety and reliability, while at the same time for the system to provide effective long-term investment planning. In the short run, congestion management needs to develop a fair plan to reduce transaction and adjust the new loadings in order to achieve secure operation of power system. A safe and reliable operation of the system in the long term, congestion management should be resolved through price signals for the system to provide incentives to develop long-term health.

The elimination of congestion consists of technical and economical methods:

(1) Technically, as far as possible to adjusting the network structure and control parameters to change the network flow trend to resolve congestion, so as to avoid changes to power generation schedules and additional congestion cost.

(2) Economic methods are used on a price mechanism. At the micro-economics level, the law of value plays a decisive role to allow the market to self-adjust the supply and demand for commodities, regulating the distribution of resources. In the electricity market environment, it can make use of price signals to enable market participants adjust to their own volume of sale to avoid the obstruction. This is an important approach with the elimination of congestion by economic means. This thesis will focus on transmission congestion required to be solved use of economic methods.

1.3 OBJECTIVE OF THE THESIS

Congestion affects effective and efficient operate of electricity market and weakens competition, which causes lack of optimal use of generating resources in the whole network. Congestion also increases generating costs, and thus makes market less efficient. Although there are a lot of literatures discussing congestion, the issue of congestion management is still not well solved. This dissertation studies congestion management along the fathoming following lines.

(1) To eliminate congestion based on the main types of technical and economic methods. Technically methods rely mainly on methods of scheduling, on control using FACTS technology to alleviate flow limitation problem. Economic methods use the price mechanism and a number of economic contracts such as transmission

congestion contracts [3]. These two types of methods used are not independent of each other, as there are no specific boundaries but the degree and proportion of usage is different on different occasion. The world's current electricity market transactions and major trading mechanism are either pool or bilateral trading models of a combination of both. Congestion management methods proposed offer different solutions based on different models.

(2)When a network is congested, locational marginal price (LMP) consists of three components: the marginal cost of generation at the system, the marginal cost of losses and the congestion cost. The LMPs at all other buses of the network can be expressed as a weighted average of the LMPs at the two buses of the congested line. Two decomposed methods are proposed to calculate the effect factor. The economic meaning of Lagrange multiplier is illustrated and the relation between this multiplier and congestion charge is explained [6].

(3) North China Power Grid Market Simulation of LMP. Simulation Results of LMP Based Markets in North China Power Grid (North China Grid Company, NCGC). The electricity restructuring in NCGC and other grids in China is likely to follow a progressive path. Along this progressive path, generation capacities and loads that are subject to market based competitive rates may be relatively low in the beginning, such as 5%. The percentage of generations and loads subject to market based competitive rates is likely to gradually increase, to 10%, 20%, 50% and eventually reaches the state of full market competition, where all the energy transactions are traded on the competitive market. The projected outcomes are quantified and analyzed in terms of several criteria, as follows: Power flow patterns; Generator dispatches; Total system variable operating cost; Locational marginal prices;

Transmission congestion revenues; Average energy cost. Study scenarios are constructed to emulate the NCGC system operation with different levels of competition. The bid-based, security-constrained economic dispatch application is executed for each of the constructed scenarios.

(4) Transmission congestion plays an important role in network safety and electricity price. It is a research focus to hedge against price uncertainty due to transmission congestion. The mechanism, character and defects of Financial Transmission Right (FTR) are studied and Transmission Option (TO) is thus introduced for hedging against the risk brought by transmission congestion and overcoming the defects of FTR. The characteristics of FTR and TO are compared and analyzed.

1.4 MAIN ORIGINAL CONTRIBUTIONS OF THE THESIS

Based on the objectives above, the main original contributions of this thesis can be stated briefly as follows:

1. Identify the cores of a successful electricity market and the issue of congestion in a power network which can erode fair competition amongst generators and disadvantage customers.

2. Identify network congestion can be managed by technical or economic methods. Successful method would involve a combination of both methods and it is difficult to state where technical methods cease to be effective and economic methods should begin. Successful methods are likely to need a combination of both.

3. Propose the use of Locational Marginal Price for congestion management. The

LMP is decomposed into three cost components: energy cost, marginal loss cost and marginal congestion cost. It is also illustrated that LMP can be used to assist the choice of choosing locations for Distribution Generation (DG). This is illustrated by a six bus system.

4. The study applying LMP for the North China Power Grid. This is illustrated at four different load levels and should the Grid be deregulated the effect of using LMP on their revenue income.

5. Propose the use of LMP as a more transparent way for financial settlement for congestion cost. This is illustrated using a six bus system.

6. Propose the use of Financial Transmission Right (FTR) for congestion management and also the use of Transmission Option (TO).

1.5 ORGANISATION OF THE THESIS

The thesis is organised in seven chapters with Chapter 1 being the main introduction to the overall project. Chapter 2 identifies the core elements of a successful electricity market and identifies the importance of resolving network congestion to make the market more fairly in competition for both the generators and customers.

Chapter 3 proposes the use of locational marginal price for congestion management. The LMP is decomposed into three cost components: energy cost, marginal loss cost and marginal congestion cost. The proposal is supported by the computer simulated results of a six bus system. Chapter 4 demonstrates the application of LMP method on a practical power network. The network is that of the North China Power Grid and it is applied at four different load levels. The analysis on the revenue income of the power Grid is also included should the Grid be deregulated. Chapter 5 demonstrates the use of LMP as a more transparent way of financial settlement for congestion cost. The decomposed LMP cost components would allow the system operator to administer the congestion cost in an efficient way for financial settlement and to provide a non-discriminatory transmission pricing to each market participant. A six bus system is employed to demonstrate the approach.

Chapter 6 introduces the use of Financial Transmission Right and Transmission Option for congestion management.

Chapter 7 contains the main conclusion and suggestion for future work.

1.6 PUBLICATION OF RESEARCH FINDINGS

In first two papers are published from the results of this reveal. In third paper is step under preparation.

(1) Yun Liu, C.S. Tan, K. L. Lo, “The Effects of Locational Marginal Price on Electricity Market with Distributed Generation”, Proceeding of Chinese Society for Electrical Engineering, CSEE, Nov 2007 ISSN: 0258-8013(2007)31-0089-09

(2) Tan, C.S.; Yun Liu; Lo, K.L, “A More Transparent Way of Financial Settlement for Congestion Cost in Electricity Markets”, Electric Utility Deregulation and Restructuring and Power Technologies, DRPT2008. Third International Conference on Volume, Issue, 6-9 April 2008 Page(s): 291- 296 Digital Object Identifier 10.1109/DRPT.2008.4523420

(3) Yun Liu; K.L.Lo, "In use of FTR and TO for congestion management". Under preparation for submit to CSEE journal.

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CHAPTER 2

CORE ELEMENTS OF SUCCESSFUL ELECTRICITY MARKET AND CONGESTION MANAGEMENT

2.1 INTRODUCTION

From the last century since the eighties, the world have carried out or about to carry out the electric power industry reform. This main purpose of the reform, through the introduction of market mechanisms, is to increase competition reduces costs, improve efficiency, optimize the allocation of resources and promote long-term stability of the electric power industry development. Competition in the electricity market are the three pillars of competitive power generation and transmission system, opening up and the user to choose [1]. Transmission systems because of economies of scale and geographical characteristics as well as safety, control of technical issues such as consideration. In power generation and offer lateral side business and after the introduction of competition conditions, the transmission system is still in the monopoly position. However, the electricity market in order to ensure a fair and effective competition, the transmission system must be non-discriminatory basis to all users of power plants and that all market participants have an equal right to use the transmission system. Any user can purchase electric power from any power plant who can also supply to any users. The transmission network not only affects the normal operation of system security and reliability, but also on market competition, market efficiency. However, inadequate capacity in the transmission network will lead to congestion. The system operation personnel in order to guarantee the security of the transmission network have to impose had to be limits and constrain. With these bound conditions, on the one hand, to some extent, limit the distance of cheap electric power plants into the local electricity market. But on the other hand, a decrease of local power plants for the electricity market competition, thus weakening the power of competition in the market mechanism.

In electricity restructuring, competitive markets are used as a common vehicle to achieve economic efficiency in electricity production and consumption. The success in electricity market restructuring requires dealing with a broad range of technical and non-technical issues (Figure 2-1). These issues include legal framework, physical system coordination and commercial activity management, short-term network security and long-term investment, etc. Among these many complicated issues, it is crucial to focus attention at the center of the problem, that is, real-time delivery of reliable and affordable electricity services to end consumers. This is the core value that electricity restructuring promises to bring to the society.

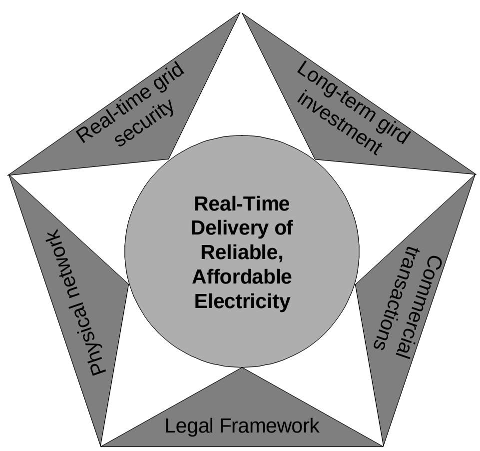


Figure 2-1 Core Elements of a Competitive Electricity Market

Competition in electricity market centers on generation and retail services with transmission and distribution operated as a monopoly. Network interactions complicate the design of a successful electricity market that allows for open access to the wires for both wholesale and retail competition while recognizing the special requirements of grid reliability.

System operator coordinates the short-term electricity markets which have been adopted in international restructuring as a working foundation for open access and grid security. Coordination through the system operator is necessary due to network interactions. A bid-based spot market built on the principles of economic dispatch creates the setting in the wholesale market for competition among the market participants. The associated Locational Marginal Prices (LMP) defines the appropriate incentives for secure and economic transmission usage. A system of financial contracts can provide the connection between short-term operations and long-term investment built on market incentives.

The core elements of a successful whole market design include the following:

- A system operator coordinated spot market built on bid-based, security-constrained economic dispatch (SCED).
- Locational marginal prices for spot market transactions considering marginal losses and congestion.
- Financial transmission rights to hedge short-term transmission usage charges evaluated as the difference in the LMP at source and sink.
- Ancillary service markets that allows simultaneous optimization of multiple products.
- Financial instruments supported in the wholesale market for risk management.
- Appropriate market mechanisms facilitating long-term investments.

In the following sections, a description core element is presented.

2.2 DESCRIPTION OF EACH OF THE CORE ELEMENTS IS PRESENTED

2.2.1 System Operator Coordinated Spot Market

Electricity market restructuring typically requires functional unbundling of the vertically integrated system. The usual separation into generation, transmission, and distribution is a solid starting point, but is insufficient. In an electricity market, the transmission network is a natural monopoly and coordinated grid dispatch is the most effective, if not the only, way to guarantee grid security.

Because of the strong and complex interactions in electric networks, transmission uses by the many market participants must be coordinated. Control of transmission usage means control of dispatch or re-dispatch, which has been practiced at control centers for many years and will continue to be used, but likely in a stricter manner. Therefore, the requirement of electricity restructuring on open access to the transmission network leads immediately to the requirement on central dispatch coordinated by system operator.

The system operator is assigned with the sole responsibility for grid reliability. In the U.S., the system operator is typically independent of both market participants and transmission owners, though this is not absolutely necessary. There are indeed alternatives to the system operator institutional setting, such as the cases in New Zealand and other European countries, where the system operator is also the owner of the transmission grid. In either institutional setting, the key points are that system operator typically does not compete in the electricity market, it ensures provision of equal services to all market participants, and it has the authority and responsibility for grid security.

2.2.2 Bid-Based, Security-Constrained Economic Dispatch with Locational Marginal Prices

Security-constrained economic dispatch has been a long-time industry practice with real-time generation and transmission network operation, though the traditional approach to real-time generation dispatch is much looser than what would be required under a competitive market environment. Real-time economic dispatch and generation control are routinely performed in the system operator's computer system, that is, Energy Management System (EMS). The EMS based economic dispatch is typically based on the equal λ method [2]. The equal lambda economic dispatch method lacks the capability to deal with transmission security constraints. Manual overrides of generating units' limits are the usual approach to reflecting the impact of transmission congestion on the real-time generation dispatch, based on the information provided in real-time state estimator solution and contingency analysis results.

The traditional economic dispatch (TED) may be described with the following mathematical formulation [2]:

(TED) $$\min \sum_i c_i(P_i)$$

Subject to

System power balance constraint:

(λ) $$\sum_i P_i - FD - P_L = 0$$

Generator minimum limit constraint:

$(\tau_i^{\min})$ $$P_i \geq P_i^{\min}(K)$$

Generator maximum limit constraint:

$(\tau_i^{\max})$ $$P_i \leq P_i^{\max}(K)$$

Here consider shadow prices [28] (The constraint shadow price (λ) represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint) constraint;

$c_i(P_i)$: Production cost function for unit *i*;

P_i: Generation dispatch for unit *i*;

$P_i^{\min}(K)$, $P_i^{\max}(K)$: Minimum and maximum dispatch limits for unit *i*. These unit limits may be modified to reflect transmission security requirements (*K*).

FD, P_L: Fixed demand and transmission losses.

The following observations can be made from this TED formulation:

Transmission security constraints are not explicitly included in the traditional dispatch process. Rather, transmission security analyses are conducted outside the TED process, and unit's minimum and maximum limits are modified, typically manually, to account for transmission constraint impacts on dispatch.

The traditional economic dispatch is achieved at equal system lambda [3]:

$$\frac{\dfrac{\partial C_i}{\partial P_i} - \tau_i^{\min} + \tau_i^{\max}}{1 - \dfrac{\partial P_L}{\partial P_i}} = \lambda \qquad (2\text{-}1)$$

The TED formulation is not able to give marginal price information with locational differences to reflect the distinctive impacts of individual units on transmission security concerns.

Locational marginal prices are however fundamental to successful operation of a secure grid in a competitive market environment. In a competitive environment, units make generation offers to produce energy, and load customers may provide bids to purchase different quantities of demand, depending on market prices. The system operator controls operation of the grid to achieve an efficient dispatch of supply and demand based on the preferences of market participants as expressed in their bids and offers. In a competitive market environment, market participants have the choices to make decisions as to how much to generate and consume by responding to market prices. Market incentives must be provided to market participants in the form of prices so that their responses to market prices will naturally lead to generation and consumption decisions that are consistent with the requirements on supply-demand balance and transmission security control.

Market incentives for secure grid operation are reflected in the locational marginal prices derived from the bid-based, security constrained economic dispatch (SCED) framework. The SCED problem for a competitive energy market is described in the following [4].

(SCED) $\min \sum_i c_i(P_i)$

Subject to

(λ) $\sum_i P_i - FD - P_L = 0$

$(\tau_i^{\min})$ $P_i \geq P_i^{\min}(K)$

$(\tau_i^{\max})$ $P_i \leq P_i^{\max}(K)$

$(\mu_l) \qquad K_l(P_i) \le K_l^{\max}$

Here consider shadow prices [28] (The constraint shadow price (λ) represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint) constraint;

$P_i^{\min}, P_i^{\max}$: Original or bid-in operational minimum and maximum dispatch limits for unit *i*.

$K_l(P)$: Transmission security constraints represented as functions of nodal real-power injections. These constraints can include base and contingency transmission security constraints as well as transient and voltage stability security constraints. $K_l^{\max}$ is the security limits of constraint *l*.

In contrast to the TED approach, the following observations are made from this SCED formulation:

Transmission security constraints are explicitly included in the SCED process.

The optimal solution to this SCED problem determines the market clearing quantities and market clearing prices by location.

The LMPs are derived as follows [5]:

$$LMP_i = \lambda - \lambda \frac{\partial P_L}{\partial P_i} - \sum_l \mu_l \frac{\partial K_l}{\partial P_i} \qquad (2\text{-}2)$$

The LMPs and the corresponding generation dispatches are consistent in that market participant responses to market LMPs will lead to generation and consumption decisions that match the SCED MW dispatch values in a perfectly competitive market.

The SCED provides grid operators with the in formation to manage changes in load, generation, interchange and transmission security constraints simultaneously in real-time operation. Transmission system security is continuously monitored and analyzed with the state estimator (SE) and contingency analysis (CA) functions in the EMS using detailed network models. Potential transmission security breaches are resolved through re-dispatch with the SCED algorithm. Evidently, explicit incorporation of modeling details that are consistent with the physical network into the SCED is critical to the efficiency and effectiveness of the re-dispatch, which has ultimate impact on network security.

While sufficient confidence has been built in the SCED derived MW re-dispatch signals, it has been proved in practice that the counterparts of the MW re-dispatch controls, that is, LMPs, can also serve as control signals for real-time secure grid operation. The key to the substitutability of the LMPs for MW re-dispatch controls hinges upon the requirements that LMPs and MW re-dispatches be fully consistent. In mathematical terms, the LMPs must be determined with the dual solution of the SCED problem [6]. In this case, the duality theory dictates that the LMPs and the MW re-dispatches are both the optimal solution to the same constrained optimization problem, just expressed in different forms. It is no surprise that the LMP based energy markets have achieved its current successes and is being considered for other markets.

The MW dispatches and real-time prices are used as real-time generation control signals in some LMP based markets in the US. In the PJM market, zonal dispatch rates (ZPR) derived from real-time LMPs are communicated every five minutes to local control centers that control generators within their zones. In the ISO-NE market, desired dispatch points (DDP), the MW dispatches derived from the SCED algorithm, are sent to generators. No matter either DDPs or LMPs are used as control signals, the key is that generators' real-time productions shall be paid at their respective LMPs, or generators' respective LMPs must be used to determine their real-time DDPs, and that the consistency between MW and LMP calculations must be maintained in order to achieve grid reliability and market efficiency.

2.2.3 Financial Transmission Rights (FTR) [7][8][9]

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:

$$ARR\ Credit = (ARR\ MW\ /\ \#of\ rounds) * (LMP_{Sink} - LMP_{Source}) \qquad (2\text{-}3)$$

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:

$$FTRCredit = (FTR \text{ MW}) \times (LMP_{\text{sink}} - LMP_{\text{source}}) \qquad (2\text{-}4)$$

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

2.2.4 Ancillary Services [7] [10]

Ancillary services (AS) are necessary for secure and reliable grid operation. In the development of AS markets, different market designs have been attempted. Compared to the development of energy markets, AS market designs tend to have more variations from market to market due to different reliability standards, operational practices, and mixes of resources able to provide these ancillary services. AS market differences lies in the approaches to energy and AS dispatch as well as operational philosophies.

The following three approaches to energy and AS dispatch have been attempted:

1. Independent Merit Order Dispatch: Independent merit order based market clearing ignores the capacity coupling between energy production and supply of ancillary services. Each product is cleared separately from other products based on a separate merit order stack. This approach is simple, but it easily leads to solutions that are physically infeasible.

2. Sequential Market Clearing: The sequential approach recognizes that energy and reserves compete for the same generating capacity. in essence, a priority order is defined for each product. Available capacity of a resource (e.g. generating unit) is progressively reduced as higher priority products are dispatched from that resource. The degree of sophistication of recognizing the coupling varies from market to market.

3. Joint Optimization: In the joint optimization approach, the objective is to minimize the total cost of providing ancillary services along with energy offers to meet forecast demands as well as AS requirements. The allocation of limited capacity among energy and ancillary services for a resource is determined in terms of its total cost of providing all the products relative to other resources. The effective cost for a resource to provide multiple products depends on its offer prices as well as the product substitution cost. Product substitution cost arises when a resource has to reduce its use of capacity for one product so that the capacity can be used for a different product (leading to an overall lower cost solution). The product substitution cost is determined internally as part of the joint optimization. This product substitution cost plus its bid price reflects the marginal value of a specific product on the market. The marginal value, which is typically the market clearing price, represents the price for an extra unit of the product that is consistent with the

marginal pricing principle for the energy product. Joint optimization of energy and AS market has been accepted in many electricity markets, including PJM, New York and ISO-NE markets.

Markets also differ in the time frame in which AS assignment decisions are made. In the PJM market, AS market including regulation and ten-minute spinning reserve services are operated during the time frame from two-hours to thirty-minutes ahead of real-time. At two-hours ahead of real-time, SCED based look-ahead analysis is conducted which projects the amount of remaining capacities available from partially loaded on-line units and the remaining transmission capabilities of critical transfer interfaces. These projected quantities are used by grid operators to determine the AS requirements for the system and import-constrained local zones. The same information also helps generators prepare for offering AS services. At thirty-minute ahead of real-time, the AS dispatch is performed based on the projected real-time grid conditions by minimizing the total cost of energy and AS bids to meet system demand, system and local AS requirements. PJM’s AS market clearing is conducted ahead of real-time as a separate process from the real-time energy dispatch. This is because fast response combustion turbine generators are major resources providing the required spinning services and advance notification is considered necessary for regulation unit to prepare for regulation services. In the ISO-NE market, spinning services are mainly supplied from on-line partially loaded generators due to its existing resource mixes. As a result, ISO-NE is moving toward jointly optimizing energy and AS dispatches five minutes ahead of real-time in the real-time market dispatch every five minutes [11].

2.2.5 Market Mechanisms for Risk Management

Central market's provision of risk hedging products is another salient feature of a successful market design. In addition to FTRs, market mechanisms for risk hedging purposes offered in the PJM, ISO-NE and MISO markets includes: multi-settlement scheme, virtual bidding and bilateral contracts. They are discussed below.

- Multi-Settlement Scheme: Multi-settlement market consists of a day-ahead market (DAM) and a real-time market (RTM). Day-ahead market is a financially binding forward market that allows participants to obtain price certainty for services scheduled to be delivered in real-time. The real-time market settlement on real-time deviations from day-ahead schedules creates incentives for participants to follow dispatch instructions, thereby enhancing grid security and reliability.

The LMP based DAM is intended to achieve the following objectives:

- Enhance reliability: Demands are encouraged to reveal their realistic load consumptions for each hour of next day. Generators are encouraged to follow ISO's/RTO's real-time dispatch instructions.
- Provide price certainty: Energy bids/offers are settled against day-ahead LMP, which shields the participants from real-time prices to certain extent or fully if the day-ahead schedules are followed through in real-time. The FTR hedging instrument reduces exposure to congestion-incurred LMP volatility.
- Provide market liquidity: Commercial trading locations, such as hubs, zones, and aggregated price nodes, are created with requests from market participants. Compared to individual bus LMPs, LMPs at hubs, zones and aggregated price nodes are more stable, encouraging bilateral trading.

The RTM is operated using the same SCED algorithm and the LMP method as the DAM, except that virtual bids are not allowed. The RTM includes two main functions:

- The real-time SCED computes zonal dispatch rates (energy price signals) and generator desired dispatch points (DDP);
- The ex-post LMP calculator performs the after-the-fact LMP calculations based on the zonal dispatch rates, actual transmission congestion; state estimator (SE) calibrated real-time generation outputs and generators' compliance.

• Virtual Bidding: Virtual bidding is allowed in the DAM at PJM, ISO-NE, MISO, and NY ISO. It is an important mechanism for the convergence of DAM prices and RTM prices. This convergence improves not only price certainty on a forward basis, but the DAM resource schedules as well.

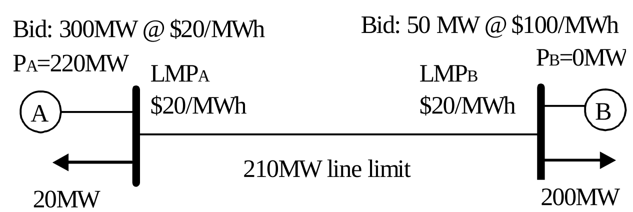


Figure 2-2 MW Dispatch with LMPs without Congestion

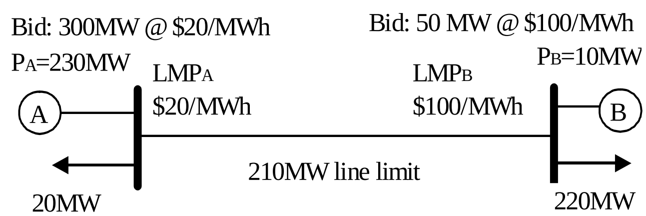


Figure 2-3 MW Dispatch with LMPs with Congestion

Assume that the results in Figure 2-2 represent typical DAM bidding patterns and the results in Figure 2-3 is the actual RTM results. In this case, an arbitrage opportunity exists between DAM and RTM. Since virtual bidding is permitted, participants who realize this opportunity, even though they may not have physical load at B, will be able to submit virtual decremented bids up to the DAM 10MW remaining capacity on the transmission line. Say, a participant submits a 15MW decremented bid at $50/MW. The 10MW decremented bid will be awarded. The LMPs are now $20/MW at A and $50/MW at B respectively. Apparently, the virtual bid will not consume in RTM. This means that it sells back to RTM its 10MW cleared in the DAM and receive the RTM price of $100/MW, making a profit of $500. Similar arbitrage opportunity exists when loads over-bid demand in the DAM, which encourages incremental offers that benefit from selling at DAM higher prices and buying back (virtual incremental offers do not deliver) at lower prices in RTM.

Participants' taking advantage of DAM and RTM arbitrage opportunities creates convergences of the DAM LMPs to the RTM LMPs. When DAM and RTM LMPs converges, the DAM resource schedules will better reflect the project real-time operational needs.

- Bilateral Contracts: Bilateral contracts may be constructed as financial or physical. A financial bilateral contract provides insurance of the price for delivered electricity and it may not impact grid dispatch. A physical contract guarantees physical delivery of service at a given price. Physical delivery guarantee can be implemented by submitting self-scheduled generation and load bids to the DAM and RTM, in which case the parties are the price takers. The commonly utilized bilateral energy contracts are in the form of contract for differences. CfD can be a one-way or two-way hedge. In the one-way CfD, energy sellers provide purchaser with assurance of a certain strike price. When the market price is higher than the strike price, the sellers pay the purchasers the difference between the market and the strike price. In the two-way hedge, the purchasers also pay the sellers the price difference so that the strike price is guaranteed for both parties. While it is straightforward to utilize CfDs in a LMP market, they, along with FTRs, can also be used to an LMP market

2.2.6 Long-Term Investments

While the LMP based market design along with FTRs and ancillary services provides the key elements necessary for secure grid operations in the short-term, the restructured market must also maintain long-term grid reliability by encouraging timely and cost-effective investments in generation and transmission expansions. This issue is also referred to as capacity market or resource adequacy.

In a perfectly competitive market, spot market short-run prices would provide sufficient incentives to signal the needs for generation or transmission investments at appropriate locations. A perfectly competitive market requires complete elasticity from both generations and loads. The current reality is that loads are almost completely inelastic. The incomplete competition of today's market is the cause for application of bid caps in most existing markets. The existence of bid caps implies that spot market prices only are not sufficient to incur new investments or even sustain existing generation facilities.

The need for a capacity market construct that can provide guidance for long-term expansion investments is recognized in recent years. Such a capacity market construct is intended to achieve the following objectives:

- Provide additional revenues required to sustain existing capacity resources and to maintain grid reliability.

- Provide price signals that encourage long-term investments to meet projected grid reliability requirements in terms of both generation and transmission capacities.
- Reflect Locational valuations by recognizing projected grid congestion.

Based on experiences with installed/unforced capacity markets, the existing capacity market mechanism is undergoing a redesign stage in the US. The redesigned capacity market construct is proposed to include the following features:

- Demand curves: The demand curve is constructed in terms of projected resource requirements and the cost of adding new capacity expansion in the future. The shape of the demand curve reflects the value of capacities meeting varying levels of reliability.
- Tangible: Locational capacity requirements must account for projected major transmission congestion.
- Reliability contribution: New capacity additions with greater contribution to maintaining reliable grid operation shall receive a higher valuation.
- Equitability for generation and transmission expansions: Generation and transmission expansions shall be treated equitably when either investment will provide the same resource adequacy.

However, it is worthwhile to note that not all potential transmission expansions can be conducted through a competitive process. Potential transmission expansions may be characterized as economic or reliability expansions. An exact delineation between economic and reliability expansion is hard to be drawn. In general, when a transmission expansion will potentially impact large number of participants in an excessive geographical region, it may better be classified as reliability expansion. It is considered appropriate that reliability expansions be handled as a coordinated planning process subject to due regulatory procedures, as this type of investments may be considered for public good. However, for economic transmission expansions, beneficiaries can be identified explicitly due to its impacts on limited number of participants within a well defined geographic area. Economic transmission expansions should be conducted using a market based mechanism.

An appropriate design for a capacity market construct is an important element of a successful market design. The objective of a capacity market should be to address long-term market sustainability and grid reliability in a more cost-effective fashion.

2.3 CONGESTION MANAGEMENT

Transmission Congestion refers to the transmission system due to various restrictions on the network itself, can not completely meet the desired state of the transmission plan. It usually refers to the transmission system in the normal operation or conduct security checks when the accident occurred the following two cases closed [12]:

(1) Transmission line or transformer tide over permit limits;

(2) The more limited node voltage.

After the implementation of the electricity market, it is generally the use of point of view of economics and economic instruments to deal with transmission congestion. However, prior to the implementation of the electricity market, transmission congestion on the existence as early as others. In the traditional monopoly of the power system model, integration generation, transmission, distribution and each of the marginal cost of generating units, the system personnel to minimize the total cost of production as the goal, a unified security economic dispatch. As a result of transmission congestion and had to use high-cost power generation capacity caused by the additional cost of power generation, with electricity included, do not have to be considered in isolation congestion cost. Different from other networks of power networks and power different merchandise other merchandise. They have many unique characteristics, such as:

(l) Changes in electricity demand at all times and can not accurately predict, in particular large-scale economic power can not be stored;

(2) In an interconnected electricity network, electricity supply and demand must always maintain a balance to ensure that the frequency, voltage and system stability, to avoid blackouts and accidents;

(3) The trend of the distribution system from Kirchhoff's law and the impedance of the entire network, rather than from the sale / purchase of electricity contract decisions, and thus difficult to control; parallel trend or circulation can lead to power generation costs and the actual cost of bias, thus it is difficult to determine the transmission system available transfer capability ATC (availed transfer capabilities), will lead to potential power system failure optimal distribution of resources;

(4) Electricity network of the phenomena, through the network of mutual influence. The local electricity demand and supply, through the electricity network, the impact of other trends. Network, a place of failure, may lead to the collapse of the entire

network. In order to meet the new demand for electricity may be involved to adjust the distance of the generating unit output. In order to ensure system security, system operating personnel must ensure that transmission lines or in between the two regions a group of power transmission lines can not be too high and that such transmission constraints must be set in advance. System operation personnel in advance through a series of studies, the imposition of a series of disturbances, through simulation, decided to limit the transmission lines. In actual operation, when the transmission power to reach or exceed this limit, say, the transmission congestion happened. Congestion management is to control the flow to meet the transmission limits (thermal limit, stability limit and voltage limit, etc.) process.

In the electricity market, transmission congestion management is management. Congestion to prevent a new contract to increase the transmission may also be made of existing transmission contracts can not be implemented according to plan, an increase of the possibility of blackouts. Congestion may be made in the power system in some areas of monopoly price formation. Therefore, if there is a more serious congestion on the electricity market may be influenced by certain market participants. If the congestion is not removed, the system, it is impossible to have fair competition, efficient electricity market.

In the electricity market, the purpose of congestion management [13]:

(l) The development of active planning, to meet the system safety standards;

(2) For market participants to provide appropriate economic signals;

(3) An effective means to offset the risks arising from congestion.

In the electricity market, congestion management is a challenging task. Need to develop strict rules of the market to ensure the production and consumption (power generation and load) the effective control, making the maximum under the conditions of market efficiency, and ensure power system short-term (real-time operation) and long-term (construction of transmission and power generation equipment) are in a acceptable level of safety and reliability of [14].

Market rules must be binding, it is because the huge profits, driven by market participants may have tried to use to create transmission congestion or even congestion, the use of market forces, which benefits at the expense of others under the premise of increasing their own profits; market rules must be fair, because it affects the cost-effectiveness of different market participants; market rules must be transparent, that is, market participants need to know the reasons for expenditure and income and algorithms.

Electricity market	The methods of congestion management
California	Zoning & Re-dispatching & Firm transmission right (FTR)
PJM	Locational Marginal Pricing & nodal pricing
UK	uplift
Norway,	Buy-back
Finland, Sweden, Denmark	Capacity charge s &buy-back
New England	Transmission Congestion Right (TCR)
Now York	Locational-based marginal pricing (LBMP) & TCR

Table 2-1 the methods of congestion management

Table 2-1 shows in different electricity markets, the application of different congestion management methods to solve congestion problems. In reference[29] present California, New England, PJM and New York electricity market used different congestion management methods for solved congestion problems. The California used zonal pricing and Firm Transmission Right (FTR) congestion management procedures are used by the ISO to deal with and relieve congestion. The PJM used Locational Marginal Pricing and Nodal pricing congestion management methods. New England electricity market usually used transmission congestion right (TCR). Now York electricity market used Locational-based marginal pricing (LBMP) and TCR congestion management methods. Reference [30] indicates Finland, Sweden, Denmark used Buy-back methods; in reference [31] it presents Norway used Buy-back methods to solve congestion problems. Reference [32] presents the uplift cost method used in UK.

2.3.1 Transmission Congestion Management OF POOL MODEL

In the pool model, the power suppliers and users to the Power Pool Center submitted their power / price curve, by the Power Pool Center, according to a different target to meet a variety of constrained generation scheduling. When included in the constraint equation in the network security constraints, the received power after a congestion management plan is the power generation plan.

2.3.1.1 Nodal marginal pricing

Nodal prices are the basic framework of the law by Schweppe et al in 1988 first proposed, it is essentially an algorithm based on optimal power flow. Only consider the power can be set up mathematical model of optimal scheduling:

$$\begin{cases} \min(\max) f(u,x) \\ st \quad g(u,x) = 0 \\ \qquad h(u,x) < 0 \end{cases} \tag{2-5}$$

Where: $f(u,x)$ to optimize the objective function

$g(u,x)$ that the algorithm to meet the conditions of equality constraints;

$h(u,x)$ that the algorithm to meet the conditions of inequality constraints;

u for the control variable vector, x for the state variable vector.

Optimization algorithm to solve a purely mathematical problem is, according to the different mathematical models set up, select the algorithm are also different. Optimization algorithms can broadly the divided into: linear optimization, and nonlinear optimization, intelligent optimization algorithm. The sophist of linear optimization algorithm is the simplex method; it is extensively, and most widely applications. However, the power system is a nonlinear system if the application of this algorithm is bound to do some simplification. Linear optimization algorithm will be applied to power system may be a certain loss of accuracy. Nonlinear optimization of a generic, there are no algorithms. Such as according to the issues of the different mathematical models have been proposed: gradient method, Newton method, conjugate gradient method, Pearson algorithm, Powell Method etc [15]. Intelligent optimization algorithms are developed in recent years, new algorithms, which can cater for the model uncertainty or complex issue. Different from the traditional optimization algorithm, intelligent optimization algorithm often mock people's way of thinking such as expert systems or simulation of natural evolutionary processes such as genetic algorithm, the emergence of this type of algorithm for solving optimization problems has provided another piece of tool.

Linear optimization was used for DC power flow of combining many of the optimization algorithms. For example, Ontario, Canada Station applies to the congestion management program (Probabilistic Composite System Evaluation program) is the application of a linear optimization method [16]. The program's core algorithm for choosing a bus blocking the region by increasing one unit load constant iteration until the congestion disappeared. Such methods have easy modeling, computing speed, the advantages of non-convergence problem. However, due to the power system for a nonlinear system will be simplified to linear systems it is bound to loss of accuracy, and sometimes may get the wrong results. Nonlinear optimization algorithm have been used is in the traditional unit commitment, hydro-economic dispatch, and optimal power flow and has a wide range of applications [17]. Optimal power flow model in which modification can be per termed to reflect deformation can be a little direct application of electricity in the nodes of congestion management is, therefore, such methods have broad prospects. However, optimal power flow solution of complex and sophisticated non-linear optimization is not the best solution; the results of the calculation may be partial optimal solution. So how the characteristics of the power system and explore the utilisation of non-linear optimization algorithm is a not topic of extensive study of the hot spots. Intelligent optimization algorithm applications is broad, when the model can not deal with precise mathematical model of the conditions of expression or model variable can not be determined and which the application of intelligent optimization algorithms may yield can often be satisfied with the results.

2.3.1.2 Zonal marginal pricing

It is found that transmission congestion is usually only frequently obviously happens in certain regions. In other areas, the probability of transmission congestion happened smaller, the situation is relatively minor. A tie-line is characterized by frequent congestion of the congestion phenomenon derived from the zonal electricity law. The method has been used is Norway, Sweden and the United States, Florida, to adopt. The general steps are as follows:

(1) First define a set of regions; the entire network will be divided into multiple areas. Regional breakdown is based on engineering studies and can be the experience based or historical data based. Congestion can also be in accordance with the node prices to determine the borders of the region [18].

(2) Use an optimal power flow approach to scheduling, to solve the issue of inter-regional congestion. Network security constraints only consider inter-regional lines, but not all lines.

(3) In the above-mentioned scheduling and on the basis of re-using optimal power flow method to adjust within the region power suppliers and users of power, to resolve the issue of congestion in the region. At this point the region as a result of the smaller networks may consider the exchange of network model, but must ensure that inter-regional power remains unchanged. In reference [19] the Lagrange relaxation method applied to multi-regional congestion management, but only in the region between the iterative exchanges of a Lagrange multiplier can be achieved between the results of the calculation region. The regional electricity tariff, in resolving the transmission congestion may result is the collected impact fees from users often exceed the cost of large power producers, thereby creating a trading surplus. Clearly, the grid companies should not have trading that result is a congestion revenue, because this is not conducive to solving transmission congestion.

To Deal with the surplus, there exists two ways: 1 If the power supply side and users signed a Contract for Difference or Transmission Congestion Contract, then the surplus can be used to pay the owners of these contracts [20]; 2 to used for grid expansion and transformation. In reference [21] a power flow tracing melted in used to trace directly trading surplus to the user. It is a reasonable and effective elimination of the transaction surplus.

2.3.1.3 Method of Constrained-on and constrained-off (Pool system)

As a short summary generators put their bids to the pool which avenges the bids is an ascending order with the lowest bids (costs) et the bottom. The cost of the last generator that satisfies the load demand is the system marginal price. The system marginal price is the pool purchasing price. After consideration of loss of load probability and value of loss value the system marginal price is modified. These costs of are then added and the resulting price is termed the pool selling price.

In ell owe price determination does not take congestion into consideration. Should congestion exists is the network, some of the generators would be regencies to reduce their generation to ease congestion. These generators are “constraint off”. On the other hand some generators who may not be successful, the bidding process are regained to generate to meet the load balance, these generators are “constraint on”. All there “constraint off” and “constraint on” generators would be financially compensated.

2.3.2 Transmission Congestion Management of Bilateral contract model

In bilateral contract mode, power generation and distribution side (or users) make their own arrangements for trading. There contracts or transaction the then submitted to the ISO for management. If there is a transmission congestion, according to a certain target, the outputs the generator are optimizes is order to ease congestion is an optimal manner the mathematical model is described (2-6).

The congestion management methods adopted by the ISO are to buy power generation ΔP^- and sale power ΔP^+ to solve the congestion problem. How to adjust the cost of congestion should be reasonably assessable to market participants. The cause of congestion has become key issues in the bilateral transaction mode of transmission management. This cost is the "uplift cost" and is pro-rata allocated to the system load. However, the economic significance of this method is not clear, there is a lack of reward and punishment mechanism.

$$\begin{cases} \min(C^+\Delta P^+ - C^-\Delta P^-) \\ \quad st \quad g(u,x)=0 \\ \quad\quad\quad h(u,x)<0 \end{cases} \qquad (2\text{-}6)$$

Type in: C^+ additional electricity price vector

ΔP^+ is the additional power sale vector

C^- additional power price vector

ΔP^- additional power purchased vector

2.3.3 Transmission Congestion Management of Combined pool and bilateral contract model

When bilateral, multilateral trading patterns of transactions and pool transactions mode co-exist, in the event of congestion of model of bilateral trade transactions and pool transactions model is needed. Currently, there are three kinds of situations: to reduce or adjust only pool transactions; abatement only bilateral transactions; and two modes of transactions are adjusted with no absolute priority for any mode. The first two cases are equivalent to a single mode of operation of congestion re-dispatching. It is determine the weightings to each type of transaction to adjust to can congestion. In reference [22] proposed the use is bilateral trading mode "willing to pay factor" (willingness to pay) and the scheduling constraints in the corresponding Lagrange multipliers (shadow prices) as a measure of cost-effective news of. When a bilateral transaction's "is willing to pay factor" when multiplied by the am out of transaction on the sensitivity of line congestion is less than the line shadow prices, the bilateral trade will be the first for abatement. In reference [23] introduces the concept of joint venture transactions, and to pool the economic distribution and with the right to reduce the weight of the various transactions at the same time as the optimum objective faction. The above line of thought is different from a number of. In reference proposing the use of a dealer submitted to increase capacity. Reduce unit transaction pricing approach and to blocking scheduling, such methods are bilateral transactions in the draw method of congestion management. The balance of how deceive combined bilateral trade transactions and pool transactions model is still a focus of study.

In short, the study of scheduling problems has made a number of scheduling strategies and methods conducive to the elimination of congestion, but such study lacks of an in-depth feasibility analysis. End scheduling strategy has its own advantages and disadvantages.

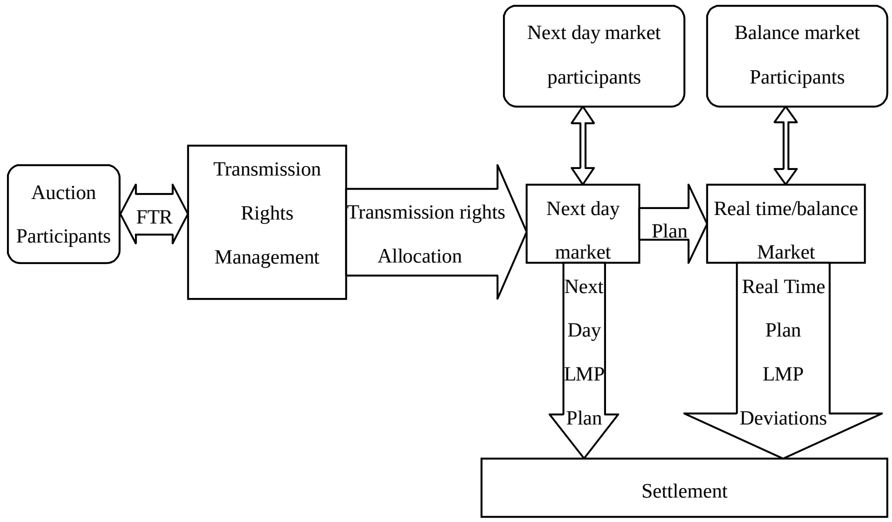
2.4 DEVELOPMENT TRENDS OF CONGESTION MANAGEMENT

2.4.1 The United States "standard market design" [24] [25] [26] [27]

The United States has the respective states or regions independent of the electricity market. The market, the market model and market structure is different, so the market can not communicate, and lead to redundant construction. Especially the United States, California power crisis has exposed some of the problems of the original market. Therefore, in March 2002, the United States Federal Energy Regulatory Commission together with a number of experts and scholars wrote of two reports [19] [20]. The reports concluded the United States over the years, the electricity market reform based on lessons learned, and the future of electricity reform in the United States Standard Market Design (SMD) bill.

The bill states the United States 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.

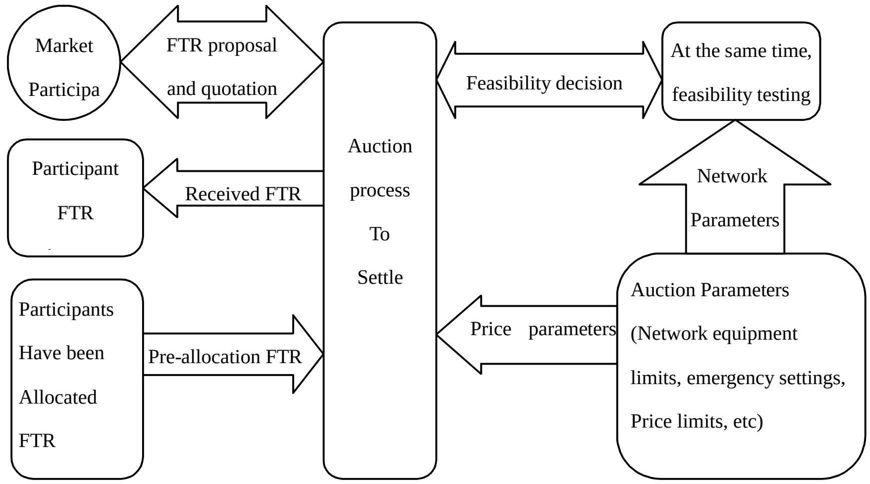
The so-called “standard market design” at the regional marginal prices, market regulation, operating reserve, transmission power, intermittent power, the day after the energy market, regional transmission organizations for government participation in demand response, energy imbalance market, network 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. Finger 2-4 is a described showing trading management.



Finger 2-4 Components of standard transmission market

2.4.2 "Standard market design" of congestion management methods

"Standard market design" proposed the use of marginal price node LMP treatment congestion phenomenon. In LMP, the energy imbalance in the market and the market must be considered with the states of the network transmission. Electricity price signals in this response time and position signal, generated by the LMP price signals, which must guide short-term benefits (energy) and long-term benefits (at an appropriate time and location, the impact of power generation and transmission planning). The LMP system with mainly to relies on rescheduling for congestion management, and the right to offset the use of transmission can reduce the risk. Transmission rights can be in the secondary market through the auction transactions and is described is Finger 2-5.



Finger 2-5 Transmission right option

2.5 SUMMARY

The chapter describes the core elements of a successful electricity market design based on existing international experiences. Designing a successful market is a challenging task. Experiences point to starting with secure real-time grid operation requirements. Real-time secure grid operational requirements dictate the importance of locational marginal prices. The SCED based real-time dispatch and its dual LMP solutions harmonize the requirements for grid reliability and market efficiency. Provision of FTRs allows participants to manage congestion risks and they may also be used as means to protect transmission rights derived from transmission expansions. Joint optimization of energy and ancillary service markets makes it possible to meet demand and reserve requirements in accordance with reliability standards at least cost.

Risk management mechanisms are also necessary for a successful market design. These mechanisms used in existing markets include the multi-settlement scheme, virtual bidding and bilateral contracts. New mechanisms may be created. But addition of new mechanisms should not conflict with grid security requirements.

A successful market design must support long-term grid reliability by guaranteeing long-term resource adequacy. Similar to the AS market design, it is expected that the capacity market design details may vary from market to market due to differences in load growth, resource mixes, strategic policies on fuels and others.

Last, but not least, market design and its technical support must give sufficient consideration of the evolutionary nature of an electricity market design. While market design should include specific rules to deal with design changes, the technical support must provide enough flexibility to accommodate market rule changes without compromise continuous grid and market operation.

The electricity market requires not only the corresponding congestion management approach to eliminate congestion, but also must pass the appropriate pricing mechanism for the transmission system for fair use and long-term planning to provide correct price signals, that is, through the transmission system effective pricing mechanism to alleviate congestion and to promote the normal development of the network.

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CHAPTER 3

CONGESTION MANAGEMENT: LOCATIONAL MARGINAL PRICE ANALYSIS AND USAGE

3.1 INTRODUCTION

In the traditional power industry, the power grid is not an independent economic entity, so the problem of transmission pricing is an urgent matter. After deregulation of generating plant, power transmission and distribution grids are split into economic entities. These entities as independent conventional companies must rely on the transmission service costs charged to maintain their own grids operation. In transmission service charges are not only applicable to generating companies but also to end users. Its percentage of shaving of revenue cost depends on economic and market conditions.

Transmission cost calculation is a very complex task, requiring technical, economic and intensive computing techniques. Transmission pricing under the market environment should meet the following three requirements [1].

(1) Effectiveness: the price contains sufficient information to effectively guide a fair access to distribution of transmission capacity, and reflect the fairness among members.

(2) Rationality: it should be fully included into the cost of the operation and maintenance of power grids. The power grid companies must show a good basic balance between revenue and expenditure to ensure that their own operation and development.

(3) The published results should able to be verified in order to facilitate the electricity market in a fair and open manner.

The maintenance of the hardware of the grid is only one part of the transmission system. However the stable and reliable operation of the grid in a competitive electricity market occupies an important position. It is the co-operation between power generation companies, transmission and distribution companies and large users of electricity transactions that guarantee the electricity. The transmission prices must include a reasonable level of economic signals, to reflect the effective power grid expansion, and guide all users in the most cost-effective use of the power grid. In a competitive electricity market environment, transmission prices must be able to recoup investments. But also to promote the effective operation of the electricity market, to encourage the Grid Corporation to invest in expansion at the most appropriate competitive locations [2].

At present, in various countries, different markets have different patterns of transmission pricing methods. Each method has its advantages and disadvantages, with the necessary technological advances and the gradual development of the electricity market. The most common and the simplest way is the postage stamp method [3]. This method does not consider the transmission distance. This method is simple, but for those short-distance transport users it is not fair. Another method is the contract path method [3], [4] this method assumes that each transaction is guided along certain path of the network without considering the actual flows. There is also another approach known as is MW-km method [5], [6], [7] this method takes into account the actual flows and the transmission distance, but it is based on the DC model.

The locational marginal price decomposition of financial settlement for congestion cost. The paper [8] explains the underlying principles of LMP decomposition and enables the system operator to administrate the congestion cost in an efficient way for financial settlement and to provide a non-discriminatory transmission pricing to each market participant. Three LMP cost decomposition approaches are discussed and are illustrated on a simple six-bus system.

Different electricity markets models have been developed and are being used in many countries all over the world such as uniform marginal pricing, zonal marginal pricing and nodal marginal pricing which is also known as locational marginal pricing (LMP). Amongst these three pricing systems, LMP is the most fundamental principle in the electricity markets [9]. This pricing mechanism is applied by many system operators in the world including electricity markets such as those in Chile, Argentina, Pennsylvania-New Jersey-Maryhill (PJM), New York, California, New England and Singapore. LMP at a location is defined as a cost of serving the next MW of load at that location. It reflects the cost of producing energy and also the effects of loss and congestion.

The LMP based market is usually very volatile, which results in a significant price risk. Therefore financial instruments such as Financial Transmission Rights (FTRs) and Loss Hedging Rights (LHRs) have been introduced to help to hedge against the price risks by refunding the over-collected revenues to FTR and LHR owners. Hence it is very important to decompose the LMP into its components reflecting the cost of marginal loss and cost of marginal congestion components so that the value of FTRs and LHRs could be distributed back to the rights owners. However, the conventional LMP decomposition method is dependent on the angle reference bus which in turn gives different values of loss and congestion components between locations when the angle reference bus is changed. Therefore one of the motivations of this chapter is to present a more transparent way of calculating the financial settlement for congestion components between locations so that they are not dependent on the angle reference bus. For comparison purposes, this chapter presents three ways of LMP decomposition which are based on conventional, load weighted average and distributed slack bus. The distributed slack bus method does not only solve the angle reference bus dependency but also promotes a transparent electricity market by producing better and fairer FTR revenue independent of the position of the slack bus. [10]

3.2 LOCATIONAL MARGINAL PRICE (LMP)

3.2.1 LMP defined

LMP at a location is defined as the marginal cost to supply an additional incremental of load to a location without violating any system security limits. Usually LMP varies throughout the system because of the effect of both transmission losses and transmission system congestion.

There are some concerns when using LMP in the electricity market design. One of the concerns is the high LMPs in a constrained area of the grid, where the cost of delivering energy to consumers is increased due to congestion line. Nevertheless, market participants can make appropriate financial arrangements to protect or hedge themselves from high priced locations due to this uncertainty pattern of LMPs. Another concern of LMP is to identify the market power where some suppliers may be uniquely situated to relieve transmission constraints and therefore have incentives to profit from the constraints through their strategic bidding. If a market participant has market power because of transmission constraints, this market power will be exercised and would impose costs on consumers in LMP or zonal system, since transmission congestion must be recognized and relieved in the market design. For example, a generator located in the load area will have market power with respect to incremental dispatch to clear the area congestion while the generator located in the generation area will have market power with respect to decreasing its dispatches.

3.2.2 Optimal power flow (OPF) formulation

OPF algorithm was formulated in 1960,s [11], 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 generation 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.

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 is expressed as:

$$\mathrm{Min}\sum_{i=1}^{N} C_{gi}(P_{gi}) \quad \text{(Energy bids)} \qquad (3\text{-}1)$$

Subject to

$$\sum_{i=1}^{N} P_{gi} = \sum_{i=1}^{N} P_{di} + P_{Loss} \quad \text{(Active power balance)} \qquad (3\text{-}2)$$

$$P_{gi}^{\min} \le P_{gi} \le P_{gi}^{\max} \quad \text{(Active power limit)} \qquad (3\text{-}3)$$

$$g_k \le g_k^{\max} \quad \text{(Network constraint limit)} \qquad (3\text{-}4)$$

Generator cubic cost model at bus *i,* is given as

$$C_{gi}(P_{gi}) = a + bP_{gi} + cP_{gi}^2 + dP_{gi}^3 \qquad (3\text{-}5)$$

where a, b, c and d are cubic cost coefficients with their unit in £/MWh, $£/(\text{MWh})^2$, $£/(\text{MWh})^3$, $£/(\text{MWh})^4$ respectively.

The equality constraint in equation (3-2) is the active power balance equation, where total supply is equal to total demand plus system losses. The inequality constraint in equation (3-3) corresponds to the active power generation limit. Equation (3-4) is the inequality constraint for line flow limits of the system.

The Lagrange multipliers corresponding to power balance equations in OPF play an important role in spot pricing of electricity. Basically, they are the shadow prices of the power injections node, therefore can be adopted as spot prices of active power and reactive power directly from the generators and loads. Furthermore they can be decomposed into different components to reflect the effects of system marginal cost, loss compensation and congestion managements as well as voltage support. They are all important price 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.

3.2.3 Mechanism of Locational Marginal Price

Using equation (3-1) to equation (3-4), LMP for a location within a network can be determined. The total value of LMP for a location in the network can be decomposed into three components, which are the energy, loss and congestion components. Basically, the decomposition of LMP components can be calculated using the following steps:

(1) Run the AC OPF to get the total LMPs

(2) Calculate the system's energy cost component referring to slack bus or distributed-slack bus (i.e., based on load, generation or mix between load and generation)

$$\lambda_i^{energy} = \lambda_0 \qquad (3\text{-}6)$$

(3) The cost of loss component is calculated by multiplying the system's energy cost component with the loss sensitivities of the system,

$$\lambda_i^{loss} = \lambda_0 \frac{\partial P_{loss}}{\partial P_i} \qquad (3\text{-}7)$$

(4) Subtracting from the LMP the system's energy cost component and cost of loss component will produce the cost of congestion component.

$$\lambda_i^{cong} = \lambda_i - \lambda_i^{energy} - \lambda_i^{loss} \qquad (3\text{-}8)$$

$$= \sum_{k=1}^{nl} \mu_k T_{k,i} \qquad (3\text{-}9)$$

Generally, LMP is expressed as follows:

$$\lambda_i = \lambda_0 - \lambda_0 \frac{\partial P_{loss}}{\partial P_i} - \sum_{k=1}^{nl} \mu_k T_{k,i} \qquad (3\text{-}10)$$

$$= \lambda_i^{energy} + \lambda_i^{loss} + \lambda_i^{cong} \qquad (3\text{-}11)$$

Where λ_i is the marginal cost/LMP at bus *i*

λ_0 is the Lagrange multiplier associated to the power balance equation, cost of energy

λ_i^{loss} is the marginal congestion component at bus *i*

$\dfrac{\partial P_{loss}}{\partial P_i}$ is the real power loss sensitivity factor at bus *i*, denotes as L_i

μ_k is the vector of Lagrange multiplier associated to network constraints on line *k*

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

The marginal cost in equation (3-10) can be summarized into two parts

a) λ_0 represents marginal generation cost, also called 'system lambda' and

b) Second and third in equation (3-10) are call 'lambda differential' also known as 'delivery cost' that varies within a network which is dependent on the marginal cost of losses and network constraints. Under unconstrained condition, the third term will be equal zero leaving the cost of lambda differential just depending on the cost of marginal losses.

As a result of application using marginal pricing, generators get paid and loads are charged at their own bus marginal cost. 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. In the process to understand the mechanism of

LMP decomposition, it is important to distinguish three separate reference variables that affect AC OPF results:

(1) Angle reference:

In power flow calculation, the distribution of flows throughout the network involves calculation of phase angles, which are measured from a single reference location to maintain a balance between supply and demand. Therefore it is necessary to have a slack bus for the entire system unless the system has multiple islands. In this case each island would have its own slack bus. Although the slack bus is essential in power flow calculations, it is very important that the selection of slack bus would not affect the prices result from the market. Keeping the market results independent of the selection of slack bus involves the definition of other reference variables (distributed-slack bus) that can maintain the system power balance between supplies.

(2) System power balance:

In an AC power flow model, the solution options for system power balance are to have a single slack bus or a distributed slack bus. When a single slack bus is used in AC OPF calculation, it is common to use the LMP as this slack bus as the system energy cost because it is used to maintain the system power balance. Since changes in load at the slack bus will be met by the changes in generation at the same bus, marginal losses are zero at the slack bus, and the marginal losses at other buses are measured relatively to the slack bus.

When distributed slack variable is used either distributed generation slack or distributed load slack, adjustments to maintain the system power balance are independent of the choice of angle reference bus because they occur throughout the network. This is because a distributed load slack variable makes proportional adjustment to loads throughout the system in order to maintain system balance.

(3) LMP desegregations

The system cost of energy will be the same at all location in the network using weighted-average load distributed slack bus, and the loss component is defined as a measurement of the system's response to the changes in injections or withdrawals which are distributed throughout the network. The concept of computing LMP components at single reference bus versus using distributed reference bus reflects the adjustments that are spread throughout the network for system balance. When a distributed slack variable is used for maintaining power system balance, bus because the reference variable is distributed throughout the system so that the angle reference bus is not affecting the price that result from the market.

In an AC power flow model, a single slack bus is used to maintain system balance between supple and demand. Basically, a slack bus will be used in the power flow calculation when running AC OPF market simulation. It is common to use the LMP at the slack bus as the system marginal price, since it is where the incremental adjustments to supply occur to maintain the system power balance. The changes in load at the slack bus will be met by changes in generation at the same bus. At the slack bus the marginal losses are zero and marginal losses at other buses are measured relative to the slack bus. This calculation of the LMP components is valid if and only if the change in supply occurs at the same location as the change in load.

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 slack bus is used as the reference for LMP decomposition, the relative size of the energy, loss and congestion components and the revenues that are assigned to them have limited meaning. Besides, in the LMP decomposition for unconstrained system, the marginal cost of transmission losses at bus i, represents the marginal cost of the losses when the source is at bus i and the sink is at the slack bus. However, such assumption for the sink bus may not be acceptable in a market environment because the selection of the single slack bus may have an adverse impact on the financial interests of some market participants. Therefore an arguably more acceptable solution would be to use a distributed-slack bus in the power-flow formulation for obtaining a similar LMP decomposition.

Therefore, we proposed a method using AC power flow formulation for distributed-slack variable to determine. A generation distributed-slack variable makes adjustments to all generation to maintain the balance between supply and demand, instead of adjusting a single generator. 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. Similarly, the use of weighted-load average in each LMP components is to define the system energy cost by weighting the nodal LMPs in the calculation in proportion to the MW load values. 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.

3.3 A MORE TRANSPARENT WAY OF FINANCIAL SETTLEMENT FOR CONGESTION COST IN ELECTRICITY MARKETS

3.3.1Optimal power flow (OPF) formulation

Following section 3.2.2, the objective function in a centralized dispatch is to minimize the system operating cost subject to equality and inequality constraints. Hence the Lagrange function of the OPF problem can be written as:

$$\begin{aligned} L = & \sum_{k=1}^{N} C_{gen,\,k}(P_{gen,\,k}) + \sum_{k=1}^{N} \lambda_k \left[\sum_{Gen} P_{,k} - \sum_{load} P_{load,k} - \sum_{Transfer} P_{Transfer} \right] \\ & + \sum_{l=1}^{nl} \mu_l \left[g_{line,\,l} - g_{line,\,l}^{\max flow} \right] + \sum_{k=1}^{N} \pi_k^{\max} \left[P_{gen,k} - P_{gen,\,k}^{\max} \right] \\ & + \sum_{k=1}^{N} \pi_k^{\min} \left[P_{gen,\,k}^{\min} - P_{gen,\,k} \right] \end{aligned} \tag{6}$$

where $C_{gen,\,k}(P_{gen,\,k})$ denotes the energy bid function of bus *k*; λ_k denotes the Lagrange multiplier for the marginal value of the active power balance constraint at bus *k*; $\pi_k^{\max}$ denotes the Lagrange multiplier of upper limit of active power at bus *k*; $\pi_k^{\min}$ denotes the Lagrange multiplier of lower limit of active power at bus *k*; μ_l denotes the Marginal (shadow) cost of transmission constraint at line *l*; $P_k^{\max}$ denotes the upper limit of active power injection at bus *k*; $P_k^{\min}$ denotes the lower limit of active power injection at bus *k*;

Applying Karush-Kuhn-Tucker (KKT) theorem [4], the LMP can be expressed as follows [8]:

$$\lambda_k = \lambda_k^{energy} + \lambda_k^{loss} + \lambda_k^{cong} \tag{7}$$

$$\text{or } \lambda_k = \lambda_0 - \lambda_0 \frac{\partial P_{Loss}}{\partial P_k} - \sum_{l=1}^{nl} \mu_l T_{l,\,k} \qquad (8)$$

where λ_k is the marginal price or Locational Marginal Price at bus *k*; λ_0 is the Lagrange multiplier associated to the power balance equation which is the cost of energy component (i.e., λ_k^{energy}); λ_k^{loss} is the marginal cost of loss component at bus *k*; λ_k^{cong} is the marginal cost of congestion component at bus *k*; $\frac{\partial P_{Loss}}{\partial P_k}$ 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 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 addition energy (£/MWh) to that bus in the power system. This marginal cost is 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.

LMP for a location within a system can be determined by running AC OPF using Equation (1) to Equation (4). The LMP for a location in the network can then be decomposed into three components, which are the energy, loss and congestion components. In the following section, three LMP decomposition methods which are conventional approach, load-weighted average approach and distributed slack bus approach are outlined.

3.3.2 Decomposition of LMP

3.3.2.1 Decomposition of LMP based on Single Bus Reference

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

STEP1: Run the AC OPF to get the total Locational Marginal Price (LMP), real power loss sensitivity, sensitivity factor due to network constraints on line *l* and the Lagrange multiplier associated to the line constraint.

STEP2: The system's energy cost component is obtained by referring to the angle reference bus. The LMP at the angle reference bus is normally taken as the energy cost [8， 13, 14].

$$\lambda_k^{energy} = \lambda_0 \qquad (9)$$

STEP3: The cost of loss component is calculated by multiplying the system's energy cost component with the real power loss sensitivities of the system.

$$\lambda_k^{loss} = -\lambda_0 \frac{\partial P_{Loss}}{\partial P_k} \qquad (10)$$

The term in the right-hand side of Equation (10) is the marginal cost of transmission losses from the reference bus to bus *k*

STEP4: 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 (11). The cost of congestion component can also be calculated using Equation (12) from the results obtained in STEP1.

$$\lambda_k^{cong} = \lambda_k - \lambda_k^{energy} - \lambda_k^{loss} \qquad (11)$$

$$= -\sum_{l=1}^{nl} \mu_l T_{l,k} \qquad (12)$$

The term in the right-hand side of Equation (12) is the marginal cost of transmission congestion from the reference bus to bus *k*

STEP5: STEP1 to STEP4 is repeated by changing the bus reference from bus #2 until *N* bus system to obtain similar decomposition for single bus reference methodology.

3.3.2.2 Decomposition of LMP based on Load Weighted Average

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 [15]

STEP1: 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 Section 3.1.

STEP2: Recalculate system average energy component at bus *k* based on single reference bus #1

$$EnergyLMP_k^{new,1} = \frac{\sum_{k=1}^{N}(\lambda_k^1 x \mathrm{MW}_{load,k})}{\sum_{k=1}^{N}\mathrm{MW}_{load,k}} \qquad (13)$$

STEP3: The system average for the cost of marginal loss component at bus *k* based on reference bus #1 is calculated as follows

$$LossLMP_k^{average,1} = \frac{\sum_{k=1}^{N}(\lambda_k^{loss,1} x \mathrm{MW}_{load,k})}{\sum_{k=1}^{N}\mathrm{MW}_{load,k}} \qquad (14)$$

where λ_k^1 is the LMP at bus *k* based on single reference bus #1(the superscript refer to the bus number reference); $MW_{load,\,k}$ is the amount of load at bus *k* in the system; $\lambda_k^{loss,1}$ is the cost of marginal loss component at bus *k* based on single reference bus #1.

STEP4: The marginal cost of loss component of each bus relative to the load-weighted average based on reference bus #1 is recalculated as

$$LossLMP_k^{new,1} = \lambda_k^{loss,1} - LossLMP_k^{average,1} \qquad (15)$$

STEP5: Recalculate the marginal cost of congestion component of each bus based on single reference bus #1 as:

$$CongLMP_k^{new,1} = \lambda_k^{1} - EnergyLMP_k^{new,1} - LossLMP_k^{new,1} \qquad (16)$$

STEP6: STEP1 to STEP5 is repeated with single bus reference at bus #2 until N bus system to obtain similar decomposition for load-weighted average methodology.

3.3.2.3 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 unfavourable impact to some market participants due to the selection of slack bus location. 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, a LMP decomposition method independent of 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. The decomposition of LMP components using distributed slack bus are calculated in a post-processing step after OPF is run. This approach is summarised as follows [16].

STEP1: Run AC Optimal Power Flow using single bus reference at bus #1 to obtain total LMP. The LMP value are obtained as described in Section 3.4.2.1

STEP2: The system cost of energy component at bus k is calculated as

$$\lambda_k^{energy} = \frac{\sum\limits_{n \in N}^{N} \alpha_n \lambda_n}{\sum\limits_{n \in N}^{N} \alpha_n} \qquad (17)$$

α_n is the contribution weight of load n from a group of N load buses with respect to the total MW load in the system and is given as

$$\alpha_n = \frac{P_{Dn}}{\sum\limits_{n=1}^{N} P_{Dn}} \qquad for\ n = 1,2,3...N \qquad (18)$$

STEP3: The loss sensitivities referenced at load distributed slack bus is calculated using Equation (19) and the marginal cost of loss component of each bus relative to the system wide reference is calculated using Equation (20)

$$L_k^* = L_k^{dist} = 1 - \left(\frac{1 - L_k^{\text{basecase,single}}}{\sum\limits_{n \in N} \alpha_n} \right) \left(\sum_{n \in N} \frac{\alpha_n}{(1 - L_n^{\text{basecase,single}})} \right) \qquad (19)$$

$$\lambda_k^{loss} = -L_k^{dist} \lambda_k^{energy} \qquad (20)$$

where L_k^{dist} is the loss sensitivities referenced to load distributed slack bus.

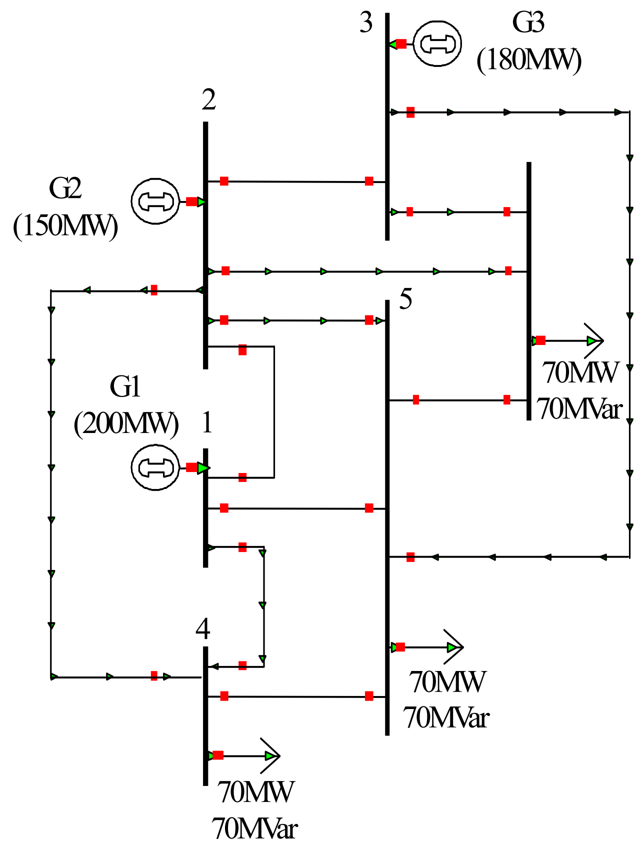
STEP4: The marginal cost of congestion component of each bus relative to the system wide reference is calculated as follow:

$$\lambda_k^{cong} = \lambda_k - \lambda_k^{energy} - \lambda_k^{loss} \qquad (21)$$

3.3.3 Simulations and results

A simple six-bus system [10, 12] is used to illustrate the decomposition of LMP using a conventional, load-weighted average and a distributed slack based on load for comparison purposes between these three approaches. AC OPF is used instead of DC OPF because it is more accurate. To illustrate the LMP cost decomposition with different approaches outlined in Section 3.4.2, all the calculation shown in the following section will be performed at bus #2 and is based on angle reference bus #1 unless otherwise stated.

In this Section, POWERWORLD™ simulation is used to run AC OPF for a six-bus system [16] to analyze the effect of LMP with different cases. In AC OPF, the formulation in Section 1 is reinforced by the inclusion of voltage limit constraints and reactive power balance equation. The locational marginal price at each bus is calculated using the standard OPF formulation of the POWERWORLD™ simulation package [17]. The OPF formulation has been briefly discussed in Section 3.3.1. The one-line diagram of the six-bus system is shown in Figure 3-1. Input data and line date for the six-bus sample system are shown in Table 3-1 and Table 3-3 respectively. Table 3-3 gives the simplified generators' cost parameters for the six-bus test system. One-part bid is used to simplify the market structure. Fuel cost is set equal to £1.00/MBtu.



Finger 3-1 Six-bus system with three generators [13]

From Bus	To Bus	R/pu	X/pu	BCAP/pu	Line Limit/ MVA
1	2	0.10	0.20	0.04	20
1	4	0.05	0.20	0.04	40
1	5	0.08	0.30	0.06	25
2	3	0.05	0.25	0.06	45
2	4	0.05	0.10	0.02	75
2	5	0.10	0.30	0.04	30
2	6	0.07	0.20	0.05	50
3	5	0.12	0.26	0.05	40
3	6	0.02	0.10	0.02	75
4	5	0.20	0.40	0.08	20
5	6	0.10	0.3	0.06	20

Table 3-1 Transmission parameter for six-bus sample power system

Bus No.	Bus Type	Volt Sched/pu	P_{gen}/MW	P_{load}/MW	Q_{load} /MWar
1	Swing	1.05	-	-	-
2	Gen	1.05	-	0.0	0.0
3	Gen	1.07	-	0.0	0.0
4	Load	-	-	0.7	0.7
5	Load	-	-	0.7	0.7
6	Load	-	-	0.7	0.7

Table 3-2 Input data for six-bus sample power system

Gen.No.	Generator Cost Co-efficient	P_{min}/MW	P_{max}/MW
	b/(£/(MWh))		
#1	13	0	200
#2	12	0	150
#3	15	0	180

Table 3-3 Generator's cost parameters

Solving AC OPF from Equation (1) to Equation (5) gives the results for the LMP values at bus k, λ_k, real power loss sensitivity at bus k, L_k, sensitivity factor due to network constraints on line l at bus k, $T_{l,k}$ and the Lagrange multiplier associated to the line constraint l, μ_l as below.

λ_k :	λ_1=13.00	λ_2=14.05	λ_3=15.00	λ_4=14.88	λ_5=18.59	λ_6=15.65
L_k :	L_1=0.0000	L_2=0.0390	L_3=0.0195	L_4=-0.0189	L_5=-0.0245	L_6=-0.0029
$T_{l,k}$:	$T_{15,1}$=0.0000	$T_{15,2}$=-0.0579		$T_{15,3}$=-0.0838		
	$T_{15,4}$=-0.0606	$T_{15,5}$=-0.1956		$T_{15,6}$=-0.0970		
μ_l :			μ_{15}=26.89			

From the results shown above, the LMP cost decomposition using single reference bus as described in Section 3.1 is illustrated on bus #2. The system's energy cost component in this case is equal to the LMP of the angle reference bus #1 which is λ_0=£13/MWh. The cost of marginal loss component and the cost of marginal congestion component at bus#2 are calculated using Equation (10) and Equation (12) yields

$$\lambda_2^{loss} = -\lambda_0 \frac{\partial P_{Loss}}{\partial P_2}$$

$$\lambda_2^{loss} = -(£13/MWh)(0.0390) = -£0.51/MWh$$

$$\lambda_2^{cong} = -\sum_{l=1}^{nl} \mu_l T_{l,2} = -\mu_{15} T_{15,2}$$

$$= -(£26.89/MWh)(-0.0579) = -£1.56/MWh$$

Similarly, using Equation (11) will give the same value for the cost of marginal congestion component at bus #2 as calculated above.

$$\lambda_2^{cong} = \lambda_2 - \lambda_2^{energy} - \lambda_2^{loss}$$

$$=£14.05/MWh - 13.00/MWh - (-£0.51/MWh)$$

$$=£1.56/MWh$$

The LMP cost decomposition for other buses is calculated in a similar way and the results are tabulated from column three to column eight of Table 1. This calculation is repeated for angle reference bus #2 to bus#6 and are tabled in column 3 to column 8 of Table 1 respectively

Bus No.	Ref Bus #1				Ref Bus #2				Ref Bus #3				Ref Bus #4				Ref Bus #5				Ref Bus #6			
	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP
Bus #1	13.00	0	0	13.00	14.05	0.57	-1.62	13.00	15.00	0.30	-2.30	13.00	14.88	-0.28	-1.60	13.00	18.59	-0.45	-5.14	13.00	15.65	-0.05	-2.60	13.00
Bus #2	13.00	-0.51	1.56	14.05	14.05	0	0	14.05	15.00	-0.3	-0.65	14.05	14.88	-0.85	0.02	14.05	18.59	-1.16	-3.38	14.05	15.65	-0.66	-0.94	14.05
Bus #3	13.00	-0.25	2.25	15.00	14.05	0.29	0.66	15.00	15.00	0	0	15.00	14.88	-0.57	0.69	15.00	18.59	-0.80	-2.79	15.00	15.65	-0.35	-0.30	15.00
Bus #4	13.00	0.25	1.63	14.88	14.05	0.85	-0.02	14.88	15.00	0.59	-0.71	14.88	14.88	0	0	14.88	18.59	-0.1	-3.61	14.88	15.65	0.25	-1.02	14.88
Bus #5	13.00	0.32	5.27	18.59	14.05	0.93	3.61	18.59	15.00	0.68	2.91	18.59	14.88	0.08	3.63	18.59	18.59	0	0	18.59	15.65	0.34	2.60	18.59
Bus #6	13.00	0.04	2.61	15.65	14.05	0.61	0.99	15.65	15.00	0.34	0.31	15.65	14.88	-0.24	1.01	15.65	18.59	-0.40	-2.54	15.65	15.65	0	0	15.65

Table 3-4: LMP cost decomposition based on single bus reference approach

Using the results tabulated in Table 3-4, the LMP cost decomposition using load weighted average approach is determined as described in Section 3.2. Similarly, this decomposition approach will be illustrated on bus #2. The loads are at bus #4, bus#5 and bus#6 with 70MW on each bus. The system's average energy cost component at angle reference bus #1 is then calculated using Equation (13) yields:

$$EnergyLMP_2^{new,1} = \frac{(14.88)(70)+(18.59)(70)+(15.65)(70)}{70+70+70}$$

$$= £16.37\,/\,MWh$$

Next the system average for the cost of marginal loss component is calculated using Equation (14) gives

$$LossLMP_2^{average,1} = \frac{(0.25)(70)+(0.32)(70)+(0.04)(70)}{70+70+70}$$

$$= £\,0.20\,/\,MWh$$

The marginal cost of loss component at bus#2 relative to the load-weighted average is calculated using Equation (15)

$$LossLMP_2^{new,1} = \lambda_2^{loss,1} - LossLMP_2^{average,1}$$

$$= (-£\,0.51\,/\,MWh) - £\,0.20\,/\,MWh = -\ 0.71\,/\,MWh$$

Using Equation (16) the marginal cost of congestion component at bus #2 gives,

$$CongLMP_2^{new,1} = \lambda_2^{1} - EnergyLMP_2^{new,1} - LossLMP_2^{new,1}$$

$$= £\,14.05\,/\,MWh - £\,16.37\,/\,MWh - (-£\,0.71\,/\,MWh)$$

$$= -£\,1.61\,/\,MWh$$

The LMP cost decomposition using load weighted average for other buses is calculated in a similar way and the results are tabulated from the third column to the eighth column of Table 3-5. This calculation is repeated for angle reference bus #2 to bus#6 and the results are tabled in column 3 to column 8 of Table 3-5 respectively

Bus No.	Ref Bus #1				Ref Bus #2				Ref Bus #3				Ref Bus #4				Ref Bus #5				Ref Bus #6			
	Energy	Loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP
Bus #1	16.37	-0.20	-3.17	13.00	16.37	-0.23	-3.15	13.00	16.37	-0.24	-3.14	13.00	16.37	-0.23	-3.15	13.00	16.37	-0.28	-3.09	13.00	16.37	-0.25	-3.13	13.00
Bus #2	16.37	-0.71	-1.61	14.05	16.37	-0.80	-1.53	14.05	16.37	-0.84	-1.49	14.05	16.37	-0.80	-1.53	14.05	16.37	-0.99	-1.33	14.05	16.37	-0.86	-1.47	14.05
Bus #3	16.37	-0.45	-0.92	15.00	16.37	-0.51	-0.87	15.00	16.37	-0.54	-0.84	15.00	16.37	-0.52	-0.86	15.00	16.37	-0.63	-0.74	15.00	16.37	-0.55	-0.83	15.00
Bus #4	16.37	0.05	-1.54	14.88	16.37	0.05	-1.55	14.88	16.37	0.05	-1.55	14.88	16.37	0.05	-1.55	14.88	16.37	0.07	-1.56	14.88	16.37	0.05	-1.55	14.88
Bus #5	16.37	0.12	2.10	18.59	16.37	0.13	2.08	18.59	16.37	0.14	2.07	18.59	16.37	0.13	2.08	18.59	16.37	0.17	2.05	18.59	16.37	0.14	2.07	18.59
Bus #6	16.37	-0.16	-0.56	15.65	16.37	-0.19	-0.54	15.65	16.37	-0.20	-0.53	15.65	16.37	-0.19	-0.54	15.65	16.37	-0.23	-0.49	15.65	16.37	-0.20	-0.53	15.65

Table 3-5: LMP cost decomposition based on load-weighted average approach

Finally, a more transparent and fairer approach based on distributed slack bus approach is shown as below. This approach is illustrated at bus #2 on angle reference bus #1 in the following section. The bus load contribution weights $\alpha_{n,}$ is equal to the load at bus *n* over the total demand as in Equation (18). Since all the loads are in equal MW value, hence their contribution weighting will be the same. Therefore, the load contribution weighting α_n at bus #4, bus #5 and bus #6 yields

$$\alpha_4 = \frac{70}{70+70+70},\ \alpha_5 = \frac{70}{70+70+70},\ \alpha_6 = \frac{70}{70+70+70}$$
$$\alpha_4 = 0.3333, \qquad \alpha_5 = 0.3333, \qquad \alpha_6 = 0.3333$$

From Equation (17) the cost of energy based on load distributed slack bus gives

$$\lambda_0^{energy} = \frac{\sum_{n\in N}^{N} \alpha_n \lambda_n}{\sum_{n\in N}^{N} \alpha_n} = \frac{\alpha_4\lambda_4 + \alpha_5\lambda_5 + \alpha_6\lambda_6}{\alpha_4 + \alpha_5 + \alpha_6}$$

$$= \frac{(0.3333)(14.88)+(0.3333)(18.59)+(0.3333)(15.65)}{0.3333+0.3333+0.3333}$$

$$= £16.37 / MWh$$

The base case real power loss sensitivity at angle reference bus #1 obtained from the AC OPF simulation gives the real power loss sensitivities as follows:

$$L_k : L_1 = 0.0000\ L_2 = 0.0390\ L_3 = 0.0195\ L_4 = -0.0189\ L_5 = -0.0245\ L_6 = -0.0029$$

From Equation (19), the real power loss sensitivity for each bus referenced to a distributed slack bus based on load is calculated as follow. For example, the new real power loss sensitivity at bus #2 referenced to a distributed slack bus based on load is calculated as follow:

$$L_k^* = L_k^{dist} = 1 - \left(\frac{1 - L_k^{basecase,single}}{\sum_{n \in N} \alpha_n} \right) \left(\sum_{n \in N} \frac{\alpha_n}{\left(1 - L_n^{basecase,single}\right)} \right)$$

$$L_2^* = 1 - \left(\frac{1 - L_2}{\alpha_4 + \alpha_5 + \alpha_6} \right) \left(\frac{\alpha_4}{\left(1 - L_4\right)} + \frac{\alpha_5}{\left(1 - L_5\right)} + \frac{\alpha_6}{\left(1 - L_6\right)} \right)$$

$$= 1 - \left(\frac{1 - 0.0390}{0.3333 + 0.3333 + 0.3333} \right) \left(\frac{0.3333}{\left(1 - (-0.0189)\right)} + \frac{0.3333}{\left(1 - (-0.0245)\right)} + \frac{0.3333}{\left(1 - (-0.0029)\right)} \right)$$

$$= 1 - (0.961)(0.3271 + 0.3253 + 0.3323) = 0.0537$$

The cost of marginal loss component is equal to the system energy cost component multiply by the real power loss sensitivity referenced to a distributed slack bus based on load as follows

$$\lambda_2^{loss} = -\lambda_2^{energy} L_2^{dist} = -(\text{£}16.37 / \text{MW}h)(0.0537) = -\text{£}0.88 / \text{MW}h$$

The cost of marginal congestion component is calculated using Equation (21)

$$\lambda_2^{cong} = \lambda_2 - \lambda_2^{energy} - \lambda_2^{loss}$$

$$= \text{£}14.05 / MWh - \text{£}16.37 / MWh - (-\text{£}0.88 / MWh)$$

$$= -\text{£}1.44 / MWh$$

The LMP cost decomposition based on load distributed slack bus for other buses is calculated in a similar way and the results are tabulated from the third column to the eighth column of Table 3-6. This process is repeated for angle reference bus #2 to bus#6 and the results are tabled in column 3 to column 8 of Table 3-6 respectively

Bus No.	Ref Bus #1				Ref Bus #2				Ref Bus #3				Ref Bus #4				Ref Bus #5				Ref Bus #6			
	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP
Bus #1	16.37	-0.25	-3.12	13.00	16.37	-0.25	-3.12	13.00	16.37	-0.25	-3.12	13.00	16.37	-0.25	-3.12	13.00	16.37	-0.25	-3.12	13.00	16.37	-0.25	-3.12	13.00
Bus #2	16.37	-0.88	-1.44	14.05	16.37	-0.88	-1.44	14.05	16.37	-0.88	-1.44	14.05	16.37	-0.88	-1.44	14.05	16.37	-0.88	-1.44	14.05	16.37	-0.88	-1.44	14.05
Bus #3	16.37	-0.56	-0.81	15.00	16.37	-0.56	-0.81	15.00	16.37	-0.56	-0.81	15.00	16.37	-0.56	-0.81	15.00	16.37	-0.56	-0.81	15.00	16.37	-0.56	-0.81	15.00
Bus #4	16.37	0.06	-1.55	14.88	16.37	0.06	-1.55	14.88	16.37	0.06	-1.55	14.88	16.37	0.06	-1.55	14.88	16.37	0.06	-1.55	14.88	16.37	0.06	-1.55	14.88
Bus #5	16.37	0.15	2.07	18.59	16.37	0.15	2.07	18.59	16.37	0.15	2.07	18.59	16.37	0.15	2.07	18.59	16.37	0.15	2.07	18.59	16.37	0.15	2.07	18.59
Bus #6	16.37	-0.20	-0.52	15.65	16.37	-0.20	-0.52	15.65	16.37	-0.20	-0.52	15.65	16.37	-0.20	-0.52	15.65	16.37	-0.20	-0.52	15.65	16.37	-0.20	-0.52	15.65

Table 3-6: LMP cost decomposition based on load distributed slack bus approach

A comparison of the results from Table 3-4， Table 3-5，Table 3-6 shows the changes of LMP cost components are due to the change in the selection of angle reference bus. Table 3-4 shows that the LMP loss and congestion component changes with the different selection of locations of the angle reference bus. When selecting a different bus as reference, all the buses LMP cost components are different. When bus#1was selected as the angle reference bus, the bus#1 LMP cost components marginal loss cost and marginal congestion cost are zero. This phenomenon is the same when a different reference bus is selected. In other words, LMP cost components differ with different selection of reference bus. Table 3-5 shows the results of the using the load weighted average approach, the buses LMP cost components results are very similar, so the LMP cost decomposition based on load weighted average approach is more consistent than that base on single bus reference approach. Table 3-6 shows the used of distributed slack bus. In the distributed slack bus the differences in congestion and loss components between two buses are not dependent on the selection of angle reference bus. It has shown that by changing the angle reference bus it doesn't change the value of the cost of energy, the cost of marginal loss component and the cost of marginal congestion component at all buses. Compare these three ways for LMP cost decomposition, the one base on distributed slack bus method is invariant to the selection of the angle reference bus for losses and constraint sensitivities once the real power loss sensitivities factors are fixed.

Table 3-5 shows that the load-weighted average approach is an approximation to the distributed slack based on load. However, it does not eliminate the differences in LMP loss component and LMP congestion component between two connecting buses as shown in Figure 3-2 and Figure 3-3 respectively. Nonetheless the cost of energy, loss and congestion components have been brought to approximately to the same value as to the usage of the load distributed slack bus as tabulated in Table 3-6. The decomposition of LMP cost based on load distributed slack approach manages to eliminate the differences among the loss LMP components as well as the congestion LMP components with the approach based on different selection of angle reference bus.

Under conventional approach of different selection of reference bus and the load-weighted average approach the differences between LMP loss components are relatively small compared to the differences between LMP congestion component with different angle reference bus as shown in Figure 3-3 and Figure 3-2 respectively. From these two figures, it shows that the differences between LMP congestion components are more important than the differences between LMP loss components in financial settlement for congestion. Therefore, distributed slack bus based on load is proposed for LMP decomposition so that both loss and congestion components can be accurately compared and are also independent of the selection of angle reference bus.

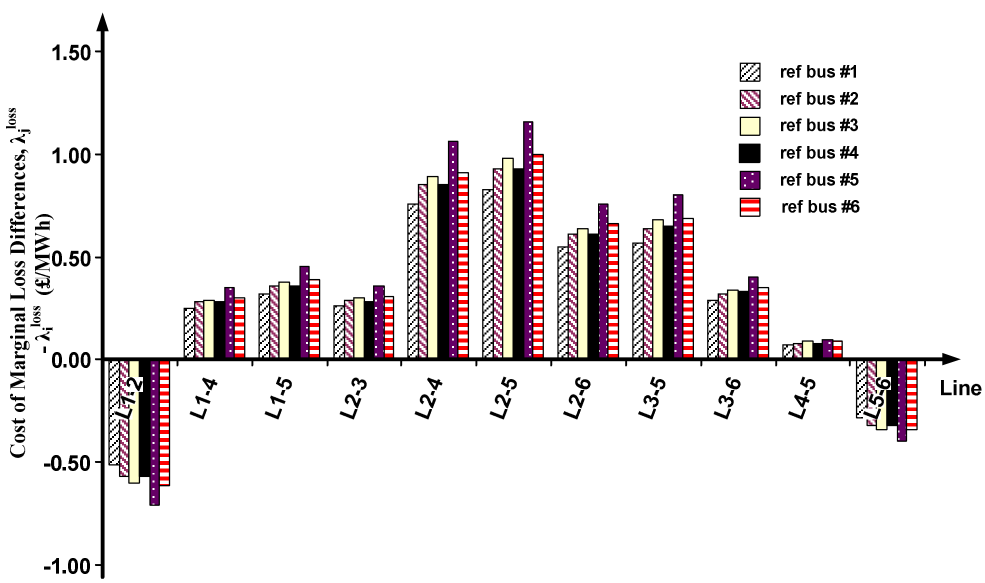


Figure 3-2: Cost of Marginal Loss differences between two connecting buses

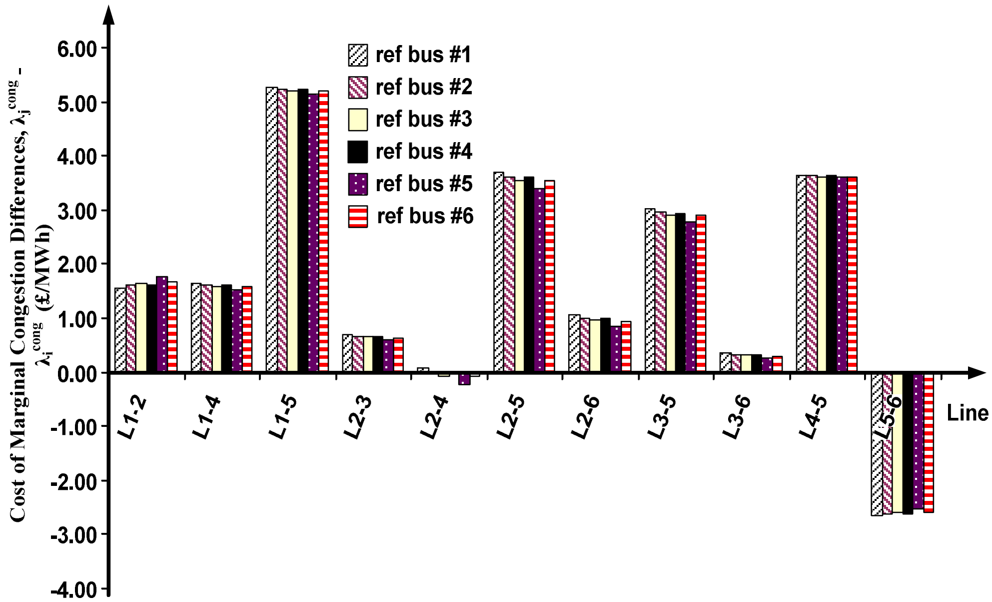


Figure 3-3: Cost of Marginal Congestion differences between two connecting buses

Under distributed slack bus the differences in congestion and loss components between two buses are not dependent on the selection of angle reference bus and are more meaningful and consistent to system operator in order to calculate the congestion revenue and the values of FTRs as well as LHRs.

3.4 SUMMARY

This chapter presents a more transparent and fairer method for financial settlement for congestion using load distributed slack bus. It has shown that by changing the angle reference bus it doesn't change the value of the cost of energy, the cost of marginal loss component and the cost of marginal congestion component at all buses. Most importantly, it has shown that the differences between cost of marginal loss component and the cost of marginal congestion component remain the same with different angle reference bus. In other words, the proposed method is invariant to the selection of the angle reference bus for losses and constraint sensitivities once the real power loss sensitivities factors are fixed. Thus each market participant will pay the same rates independent of the selection of angle reference bus.

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CHAPTER 4

LMP USED IN NORTH CHINA POWER GRID

4.1 INTERODUCTION

North China Power Grid（North China Grid Company, NCGC）, covers the capital city Beijing, Tianjin and Hebei, Shanxi, Shandong, Inner Mongolia, Owen a is on power supply area of 1,630,000 square kilometers with a population 230 million. Currently it has a 500kV network as the backbone and a 220kV grid its main regional power grids. In 2001 and 2003, North China Power Grid completed the Northeast and Huazhong Power Grid connection.

North China network control area is divided into 5 sub networks, Beijing-Tianjin-Tangshan network, Hebei South network, Inner Mongolia network, Shanxi network and Shandong network. In recent years, North China Power Grid load, and power generation have growth considerably. At the end is 2005, North China Power Grid has reached a maximum load of 80350MW, an increase of 16.70% over two years (2003-2005), Beijing-Tianjin-Tangshan power grid 2005 has a summer peak of 26233MW, an increase of 18.17% over two years. Hebei, Shanxi, Inner Mongolia and Shandong, all recorded double-digit load growth rate. Network in North China by the end of 2005 has a total installed capacity of 89505MW, an increase of 16.08 %.

North China Power Grid has two prominent characteristics: First it has large-capacity long-distance transmission pattern in the regional network to achieve optimal allocation of resources; secondly, it is responsible of the security and stability for the Beijing electric power supply.

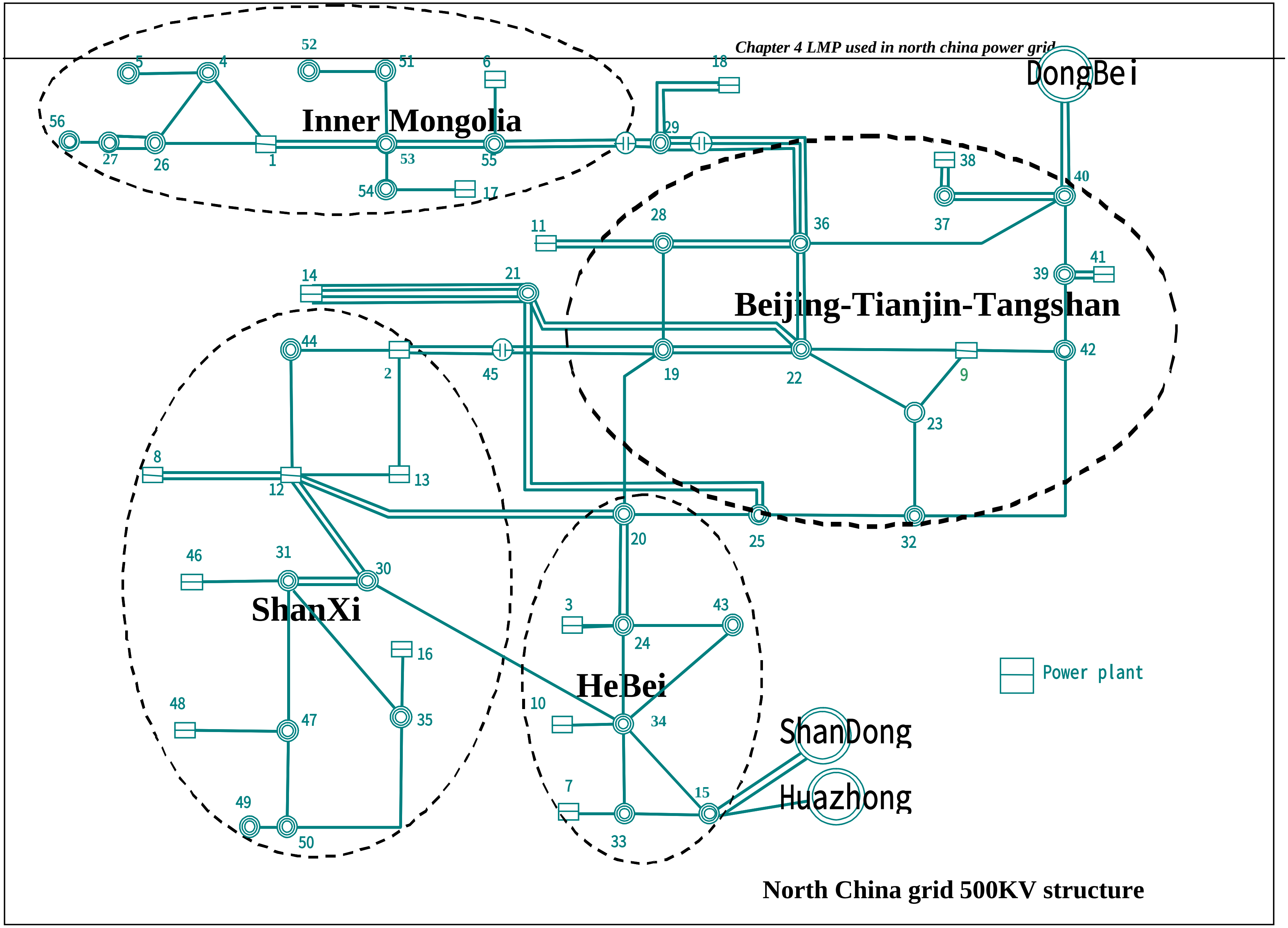
4.2 EXPECTED RESULTS FROM THE PROJECT

From this research project, I expect to achieve the following results:

1. Build generator and transmission network models: Based on NCGC's generator and transmission network models, the advanced LMP based market clearing and congestion management application will be used.

2. Study LMP based congestion management: Through numerical simulations, study the mechanism of LMP based congestion management. The objective of congestion management will be to meet load demand and satisfy network thermal security and stability limit constraints.

3. Study the feasibility of applying the LMP based market model in NCGC: Based on the simulation results, the focus will be on congestion management and network security.



North China grid 500KV structure

4.3 SIMULATION RESULTS OF LMP BASED MARKETS IN NCGC SYSTEM

The restructuring of the power electricity in NCGC, and further in China, is likely to follow a progressive path. Along this progressive path, generation capacities and loads that are subject to market based competitive rates may be relatively lower in the beginning, such as 5%. The percentage of generations and loads subject to market based competitive rates is likely to gradually increase, to 10%, 50% and eventually reach as the state of full market competition, where all the energy transactions are traded on the competitive market.

It is considered desirable that the simulation approach adopted for this study shall be able to project the outcomes of the NCGC markets in various stages of the progressive restructuring process. The projected outcomes are quantified and analyzed in terms of several criteria, as follows:

- Power flow patterns
- Generator dispatches
- Total system variable operating cost
- Locational marginal prices
- Transmission congestion revenues
- Average energy cost

Study scenarios are constructed to emulate the NCGC system operation with different levels of competition. The bid-based, security-constrained economic dispatch application is executed for each of the constructed scenarios.

4.4 SIMULATION RESULTS FOR EACH SCENARIO

This section presents the simulation results for each scenario. The objective of the simulation studies is to understand the potential impacts of market based operation under different levels of competitive bidding by analyzing these simulation results. The potential impacts are studied in terms of generator dispatches, power flow patterns, variable operational costs, LMPs, transmission congestion costs, and average energy cost.

In recent years, the rapid development of North China Power Grid, transient stability and thermal stability problem is the main reason for transmission capacity constraints. Therefore, the simulation must consider these two questions.

A total of 4 scenarios are constructed with each of the scenarios representing one assumed stage of the restructuring process. The starting scenario corresponds to the current state of generation scheduling and the last scenario corresponds to the fully competitive market with 100% generation capacity offered for competitive market.

Scenario 1: Current state of the NCGC generation scheduling

In this scenario, it is assumed that load demand served on the main 500kV network is 18000MW for the Beijing-Tianjin-Tangshan region. All the generations are scheduled to meet this given demand based on NCGC's existing generation scheduling process. A simulation study of this scenario will be conducted on defined 500kV transmission network model.

Scenario 2: Assume 5% of generation capacity for competitive bidding

In this scenario, it is assumed that the load demand served on the main 500kV network is 18000MW for the Beijing-Tianjin-Tangshan region. The 95% of the total generations are scheduled to their planned levels, and the other 5% is dispatched according to their projected offer prices to meet this given demand using the security-constrained economic dispatch algorithms.

A simulation study of this scenario will be conducted on defined 500kV transmission network model. In this scenario study, two types of security constraints are modeled: transmission line thermal limits and transfer interface limits.

Scenario 3: Assume 10% of generation capacity for competitive bidding

This scenario 3 is similar to scenario 2. In this scenario, the load demand served on the main 500kV network is 18000MW for the Beijing-Tianjin-Tangshan region. The 90% of the total generations are scheduled to their planned levels, and the other 10% is dispatched according to their projected offer prices to meet this given demand using the security-constrained economic dispatch algorithms.

A simulation study of this scenario will be conducted on defined 500kV transmission network model. In this scenario study, two types of security constraints are modeled: transmission line thermal limits and transfer interface limits.

Scenario 4: Assume 100% of generation capacity for competitive bidding

With 100% of generation subject to competitive bidding, this scenario emulates the NCGC generation dispatch under full competitive market based operation. In this scenario, the load demand served on the main 500kV network is 18000MV for the Beijing-Tianjin-Tangshan region. 100% is dispatched according to their projected offer prices to meet this given demand using the security-constrained economic dispatch algorithms.

A simulation study of this scenario will be conducted on the defined 500kV transmission network model. In this scenario study, two types of security constraints are modeled: transmission line thermal limits and transfer interface limits.

4.4.1 Scenario 1: Current state of the NCGC generation scheduling

Scenario 1 is developed to simulate the current state of the NCGC generation scheduling process. In the current generation scheduling process, generation energy production is decomposed into individual generators according to the pre-determined allocation rules. In this scenario, generation allocations are determined to serve 18000MW load on the main 500KV network for the Beijing-Tianjin-Tangshan region.

4.4.1.1 Generation Dispatches

Basis on chapter 2, section 2.2.2 bid-based, security-constrained economic dispatches with Locational marginal price.

Using NCGC's current generation decomposition/allocation process, the generation dispatches are determined as shown in Table 4.1-1.

Unit Name	Dispatch MW	Unit Name	Dispatch MW
1	965.0	10	287.0
2	1904.0	11	1856.0
3	0.0	12	857.0
4	208.0	13	743.0
5	1224.0	14	2221.0
6	708.0	15	1065.0
7	628.0	16	1324.0
8	1139.0	17	928.0
9	1527.0	18	413.0

Table 4.1-1 NCGC Generation dispatches

4.4.1.2 Power Flow Results

With the dispatch results determined using the NCGC allocation method, power flows are computed using the linearized power flow method for the 500kV main network. Branch flows are described in Figure 4.1-1. As is shown, all branch flows are within their thermal limits.

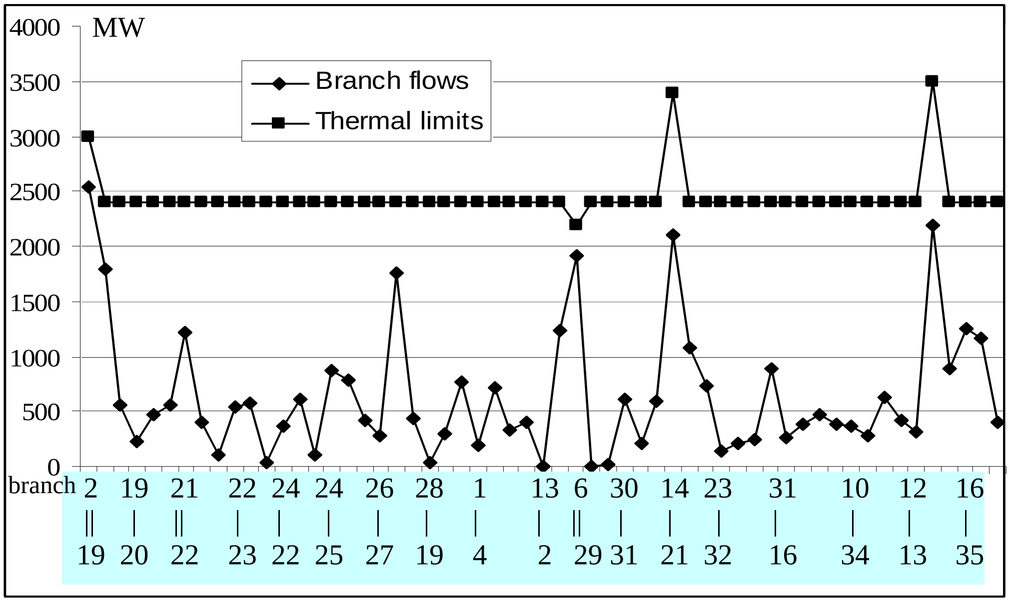


Figure 4.1-1 Branch flows and thermal limits (|| is Double-circuit lines)

In generation dispatch, NCGC also observes two transfer interface constraints that are surrogate constraints to consider the 500kV network voltage and stability. The power flows over the two transfer interfaces are shown in Figure 4.1-2. As is shown, both transfer interface flows are within their security limits.

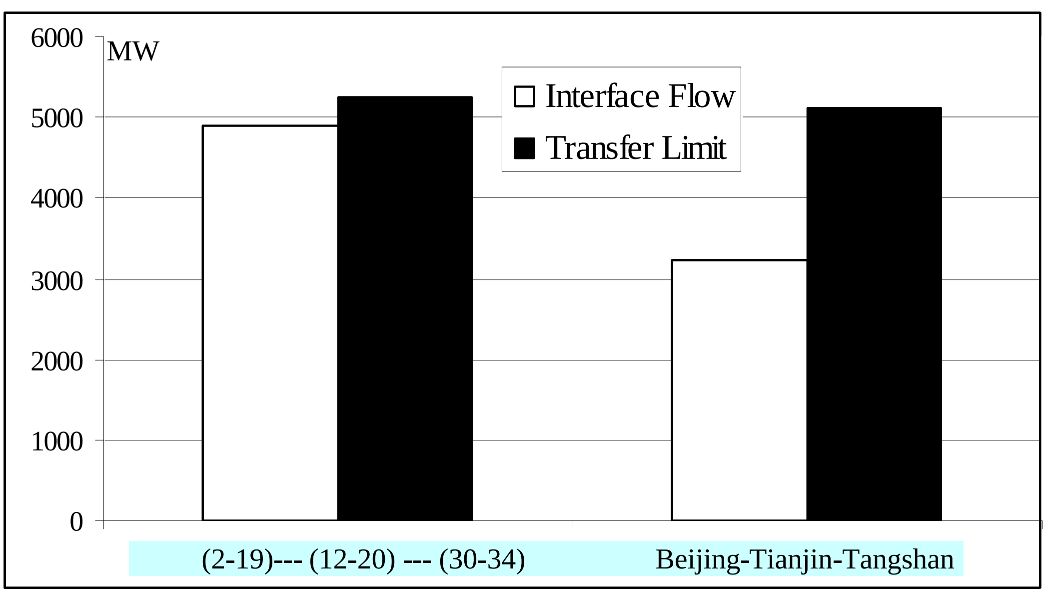


Figure 4.1-2 Transfer interface flows and thermal limits

As is shown in the figure, the flow over transfer interface (2-19)-(12-20)-(30-34) is 4950MW，under its constrained limit of 5250MW, while the 3250MW flow over the other interface constraint is within its security limit of 5100MW.

4.4.1.3 Total Variable Operational Costs

The generation dispatches are shown in Table 4.1-1, the total generation cost is computed based on individual incremental costs and their dispatch MW values. The results are included in Table 4.1-2.

Unit Name	Dispatch MW	generation Cost (¥/MWh)	Total Cost (¥/h)
1	965	330	¥318,450.00
2	1904	248	¥472,192.00
3	0	0	¥0.00
4	208	294	¥61,152.00
5	1224	297	¥363,528.00
6	708	294	¥208,152.00
7	628	300	¥188,400.00
8	1139	298	¥339,422.00
9	1527	390	¥595,530.00
10	287	300	¥86,100.00
11	1856	358	¥664,448.00
12	857	297	¥254,529.00
13	743	276	¥205,068.00
14	2221	296	¥657,416.00
15	1065	314	¥334,410.00
16	1324	276	¥365,424.00
17	928	294	¥272,832.00
18	413	296	¥122,248.00
		All generations Total Cost	¥5,510,207.00

Table 4.1-2 Total variable operational cost

4.4.1.4 LMPs

This scenario is a close simulation of the regulated environment, where generators do not respond to market price signals. Under the current generation scheduling process, competitive bidding does not exist. Generations are paid and loads are charged using the regulated rate schedules. Since generators are guaranteed a regulated rate, they are therefore obligated to follow dispatch instructions regardless of the actual spot cost of energy production, which is eventually borne by end users.

4.4.1.5 Transmission Congestion Cost

As the power flow solutions are shown in Figures 4.1-1 and 4.1-2, all branch flows and transfer interface flows are within their respective limits, and there is no congestion. Therefore transmission congestion cost is zero in this case.

4.4.1.6 Average Energy Cost

Average energy cost is defined as the per MWh cost to serve load on a system wide average basis, and computed as the ratio of the total variable operational cost to the total system load demand.

Assume that generator incremental costs reflect their permissible cost rates paid to generators for their energy production. Then, the total variable operational cost to serve the load demand of 18000MW in this scenario is ¥5,510,207.00.

Therefore, the average energy cost is ¥$\left(\frac{5,510,207.00}{18000}\right)$= ¥306.12/MWh in this case.

4.4.2 Scenario 2: 5% of generation capacity for competitive bidding

Scenario 2 is developed to simulate the impacts on NCGC generation scheduling and transmission operations when 5% of the total generation is permitted for competitive bidding. The load demands are the same as scenario 1. In this scenario, 5% of generating capacity in the auction and its minimum cost is achieved by economic dispatch.

4.4.2.1 Generation Dispatches

All the generators are dispatched to meet the 18000MW load demand on the 500kV main network for the Beijing-Tianjin-Tangshan region. Unit dispatches are computed using the security-constrained dispatch method. In the SCED, unit dispatches observe their economic minimum and maximum limits and transmission network security limits. The unit dispatch results are shown in Table 4.2-1.

Unit Name	Dispatch MW	Economic dispatch Min	Economic dispatch Max	Generation cost (¥/MWh)	LMP (¥/MWh)
1	917.00	917.0	1200.0	330.00	294.00
2	2212.59	1809.0	2400.0	248.00	248.00
3	0.00	0.0	600.0	0.00	296.00
4	491.95	198.0	4200.0	294.00	294.00
5	1163.00	1163.0	1600.0	297.00	296.00
6	687.00	673.0	800.0	294.00	294.00
7	597.00	597.0	660.0	300.00	296.00
8	1082.00	1082.0	1200.0	298.00	248.00
9	1451.00	1451.0	2200.0	390.00	296.00
10	273.00	273.0	500.0	300.00	296.00
11	1763.00	1763.0	2400.0	358.00	296.00
12	814.00	814.0	1000.0	297.00	248.00
13	706.00	706.0	1000.0	276.00	248.00
14	2153.00	2110.0	3600.0	296.00	296.00
15	1012.00	1012.0	2025.0	314.00	296.00
16	1258.00	1258.0	1550.0	276.00	248.00
17	900.00	882.0	900.0	294.00	294.00
18	519.46	392.0	600.0	296.00	296.00

Table 4.2-1 Generation dispatches by the SCED method

From the unit dispatch solution, unit generation cost, and LMPs are listed in the table. It can be seen that units are dispatched in their merit order cost and their impacts on transmission security constraints. For instance, Units 1, 5, 7, 8, 9, 10,11, 12, 13, 15, and 16 are dispatched to their economic minimum limits respectively. The other units are dispatched to either their economic maximum limits or between their economic minimum and maximum limits. In this scenario, units are dispatched using the SCED method to meet both load demand and to resolve the transmission congestions in the most cost-effective fashion.

Unit dispatch differences between the scenarios 1 and 2 are shown in Figure 4.2-1 below. The MW dispatch differences shows additional unit dispatches needed to meet the increased load, where the cheaper units (2, 4, 6, 14, 17 and 18) receives increase generation dispatch.

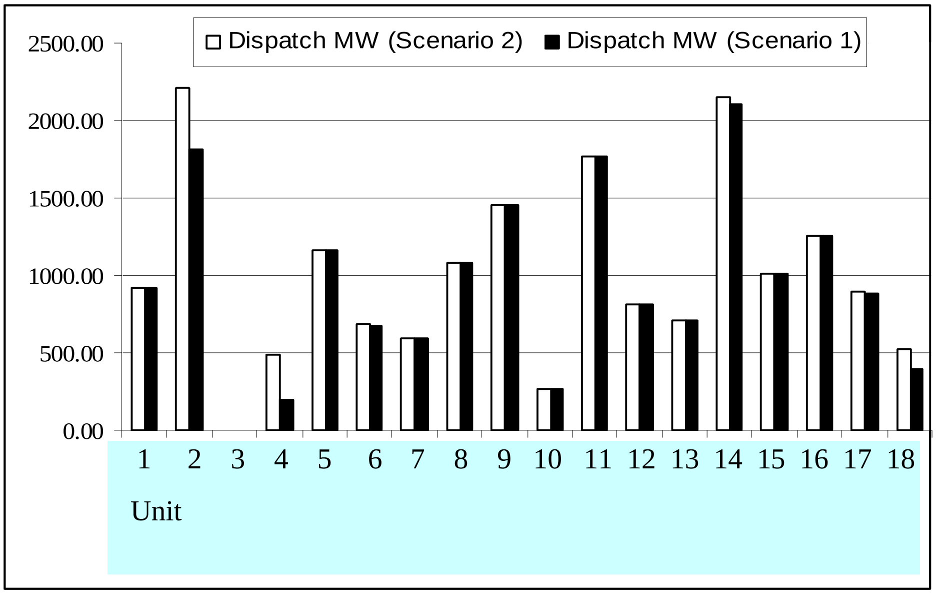


Figure 4.2-1 Unit dispatches under Scenario 1 and Scenario 2

It is important that unit MW dispatches are consistent with the market incentives represented in the form of LMPs. In this scenario, it can be noted from Table 4.2-1 that units are dispatched to their economic minimum limits when LMPs at the units are less than their generation cost; whereas units are dispatched to their economic maximum limits when LMPs at the units are greater than their generation costs; units are dispatched between their economic minimum and maximum limit range when the LMPs at the units are equal to their generation costs. Assume that units are bid in their marginal costs, which is generally true for a competitive market. The relationship between LMPs, marginal incremental costs, and MW dispatches are compatible with market incentives. In other word, when the LMPs are used to settle the real-time generations, generators are encouraged to follow the MW dispatch instructions, because following the dispatch instructions helps generation to reach their respective objectives of maximizing their operational profits.

4.4.2.2 Power Flow Results

With the generation dispatch results determined using the SCED method, power flows are computed for the 500KV main network in terms of the linearized power flow model. Branch flows are described in Figure 4.2-2. As is shown, all branch flows are within their thermal limits, except for branch “6-29” over which the flow is at its limit of 2200MW.

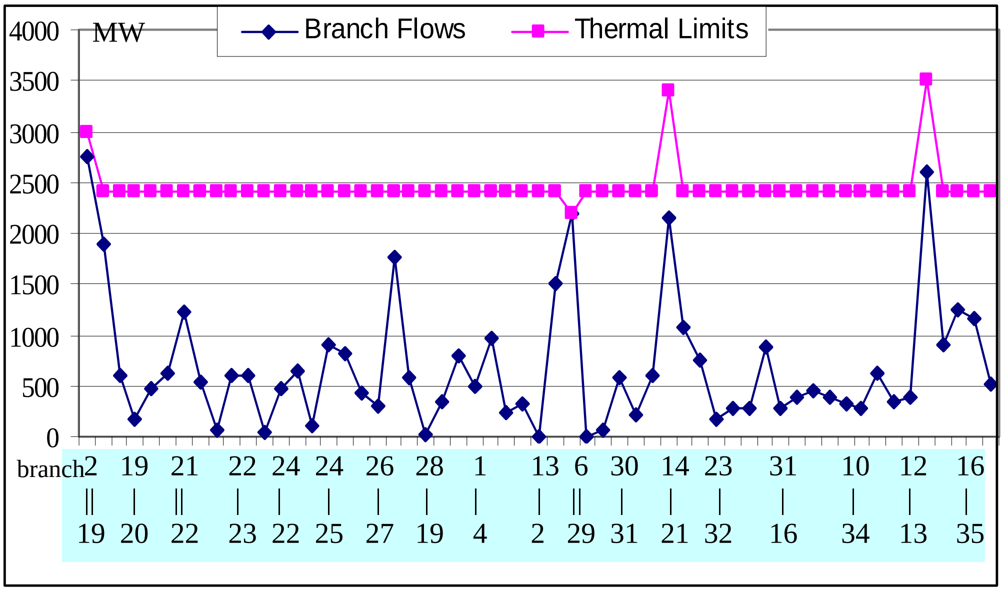


Figure 4.2-2 Branch flows and thermal limits (|| is Double-circuit lines)

In the SCED based generation dispatch, the same two transfer interface constraints, (2-19)-(12-20)-(30-34) and Beijing-Tianjin-Tangshan, as considered in scenario 1, are enforced. The power flows over the two transfer interfaces are described in Figure 4.2-3. As is shown in the figure, the flow over transfer interface (2-19)-(12-20)-(30-34) is constrained by its limit of 5250MW, while the 3394MW flow over the other interface constraint is within its security limit of 5100MW.

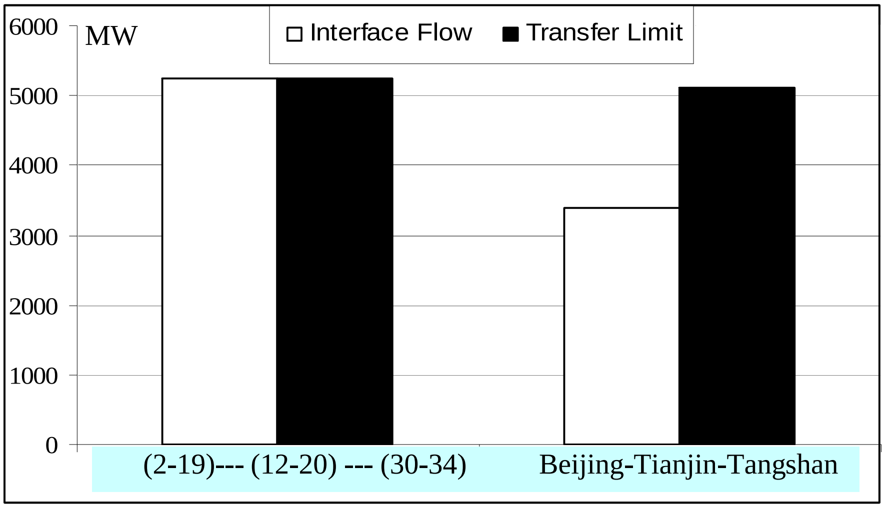


Figure 4.2-3 Transfer interface flows and thermal limits

4.4.2.3 Total Variable Operational Costs

For the generation dispatches as are shown in Table 4.2-1, the total generation cost is computed based on individual incremental costs and their dispatch MW values. The results are included in Table 4.2-2.

Unit Name	Dispatch MW	Generation Cost (¥/MWh)	total Cost (¥/h)
1	917.00	330.00	¥302,610.00
2	2212.59	248.00	¥548,722.13
3	0.00	0.00	¥0.00
4	491.95	294.00	¥144,633.59
5	1163.00	297.00	¥345,411.00
6	687.00	294.00	¥201,978.00
7	597.00	300.00	¥179,100.00
8	1082.00	298.00	¥322,436.00
9	1451.00	390.00	¥565,890.00
10	273.00	300.00	¥81,900.00
11	1763.00	358.00	¥631,154.00
12	814.00	297.00	¥241,758.00
13	706.00	276.00	¥194,856.00
14	2153.00	296.00	¥637,288.00
15	1012.00	314.00	¥317,768.00
16	1258.00	276.00	¥347,208.00
17	900.00	294.00	¥264,600.00
18	519.46	296.00	¥153,760.09
		All generation Total Cost	¥5,481,072.81

Table 4.2-2 Total variable operational cost

Similarly, the cost values shown in Table 4.2-2 include only the variable operational costs for the energy production, which is the product of the values in columns “Dispatch MW” and “generation cost”.

4.4.2.4 LMPs

LMPs at all the buses (nodes) are by-product of the SCED solution. LMPs reflect the aggregate value of the marginal cost of energy production to meet the last MW demand and the locational impacts of injections (generation and load) on the constraining (binding) transmission security constraints. Nodal LMPs computed for scenario 2 are graphed in Figure 4.2-4 below.

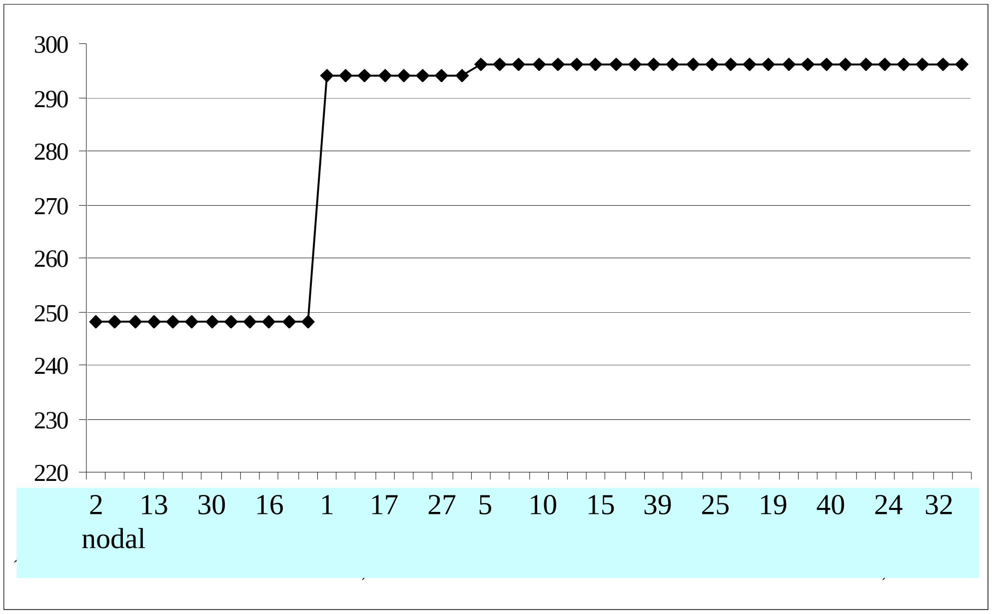


Figure 4.2-4 Nodal LMPs

LMPs in the above figure show that, in this scenario, there are in effect three distinct groups of prices, which are ¥248/MWh, ¥294/MWh, and ¥296/MWh. Respectively this observation is consistent with the solution of two binding transmission security constraints that limits the power transfers from 2 and 6 to the Beijing-Tianjin-Tangshan region. These two binding transmission constraints basically divide the 500kV transmission network into three generation-load balancing sub-regions.

4.4.2.5 Transmission Congestion Cost

When there is no transmission congestion on the grid, units are dispatched in their merit order. This merit order based dispatch starts with the cheapest unit to more expensive units until enough units are dispatched and the given load demand is met. The incremental cost corresponding to the last MW of the most expensive unit dispatched to meet the load determines the well-known system lambda, or system marginal price in the market terminology. As both generations and loads see the same SMP (system marginal price, uniform LMP in this case), load charges are just enough to pay generators. Transmission congestion cost is zero under the unconstrained case.

For an LMP based market, generators and loads are settled for their MW injections and withdrawals against their respective LMPs. When there is congestion on the network, LMPs are different from location to location. Settlements under LMPs with transmission congestion cause settlement residues generally, which may be called transmission congestion rentals/cost. In this scenario 2, two transmission security constraints, branch “6-29” and transfer interface constraint (2-19)-(12-20)-(30-34), are binding. Constraint flows, limits, shadow prices, and congestion cost are shown in Table 4.2-3. In this scenario, the flow congestion over branch 6-29 causes increase of the operational cost by ¥4,400.00 per hour; the congestion cost due to the transfer interface (2-19)-(12-20)-(30-34) is ¥252,000.00 per hour.

Branch/Constraint Name	MW Flow	WM Limit	Shadow Price (¥/MWh)	Congestion Cost (¥/h)
6-29(bilateral line)	2200.0	2200.0	2.00	¥4,400.00
(2-19)---(12-20)---(30-34)	5250.0	5250.0	48.00	¥252,000.00
		Total congestion cost		¥256,400.00

Table 4.2-3 Transmission congestion cost

There are two general approaches to the handling of the transmission congestion cost. One approach is to distribute this money back to load participants using some agreed-upon distribution formula. This approach is used in markets where transmission rights are not available. Another approach is to create a risk management instrument, called financial transmission rights or congestion revenue rights. With the transmission rights, the transmission congestion cost money is used to reimburse transmission right owners for them to hedge transmission congestion related price risks. The latter approach is used in ISO-NE, PJM, NY-ISO, and Midwest ISO markets in the US.

Furthermore, the capability to compute explicitly transmission congestion cost is one key characteristic of the LMP based market. This explicit quantification of transmission congestion cost to generation dispatch and system operation provides a direct valuation of potential transmission network enhancements. While this is a short-term pricing signal, which in itself may not be sufficient to cause transmission investment, it is indeed an indication of the value of potential transmission investment, especially when the short-term valuation of transmission investment can be converted into a long-term revenue stream for potential investors through certain financial instruments, such as long-term financial transmission rights.

4.4.2.6 Average Energy Cost

Average energy cost is defined as the per MWh cost to serve load on a system wide average basis, and is computed as the ratio of the total variable operational cost to the system load demand. This formula is still valid under this scenario 2 with the existence of transmission congestion. This is because that the transmission congestion cost, one way or another, will be reimbursed back to load participants, as was discussed previously in Section4.4.2.5.

Assume that generator incremental costs reflect their permissible cost rates paid to generators for their energy production, then, the total variable operational cost to serve the load demand of 18000MW in this scenario is ¥5,481,072.81 obtained from Table 4.2-2.

Therefore, the average energy cost is ¥304.50/MWh in this case. This average energy cost is ¥1.62/MWh lower than the average energy cost of ¥306.12/MWh for Scenario 1 (refer to Section 4.4.1.6). This lower average energy cost is a result of from the SCED solution framework. In this framework, even 5% of the load demand is subject to competitive market bidding and generators are economically dispatched to meet this 5% of the demand, the average energy price for loads is reduced by 0.5%.

4.4.3 Scenario 3: 10% of generation capacity for competitive bidding

This scenario 3 is developed to simulate the impacts on NCGC generation scheduling and transmission operations when 10% of the total generation is permitted for competitive bidding. With the load demand maintained at the same level as in scenario 2. This 10% percent competitive bidding market is simulated by decreasing unit lower dispatch limits. In this scenario 3, unit dispatch lower limits are calculated as 95% of the limits used in scenario 2.

With this scenario, we continue to study the impact of increased competitive bidding on grid security and variable energy production costs.

4.4.3.1 Generation Dispatches

All the generators are dispatched to meet the 18000MW load demand on the 500kV main network for the Beijing-Tianjin-Tangshan region. Compared to the scenario 2, all the units have greater dispatchable ranges due to reduced lower dispatch limits. Unit dispatches are computed using the security-constrained dispatch method. In the SCED, unit dispatches observe their economic minimum and maximum limits as well as transmission network security limits. The unit dispatch results are shown in Table 4.3-1.

Unit Name	Dispatch MW	Economic dispatch Min	Economic dispatch Max	Generation Cost(¥/MWh)	LMP (¥/MWh)
1	869.00	869.0	1200.0	330.00	294.00
2	3332.68	2314.0	3600.0	248.00	248.00
3	0.00	0.0	600.0	0.00	279.25
4	539.95	188.0	4200.0	294.00	294.00
5	1517.37	1101.0	1600.0	297.00	297.00
6	687.00	638.0	800.0	294.00	294.00
7	566.00	566.0	660.0	300.00	276.96
8	1025.00	1025.0	1200.0	298.00	262.26
9	1374.00	1374.0	2200.0	390.00	296.54
10	258.00	258.0	500.0	300.00	276.96
11	1671.00	1671.0	2400.0	358.00	298.72
12	771.00	771.0	1000.0	297.00	262.26
13	669.00	669.0	1000.0	276.00	262.08
14	1999.00	1999.0	3600.0	296.00	295.64
15	958.00	958.0	2025.0	314.00	276.96
16	263.00	263.0	1550.0	276.00	265.25
17	900.00	836.0	900.0	294.00	294.00
18	600.00	371.0	600.0	296.00	298.46

Table 4.3-1 Generation dispatches by the SCED method

From the unit dispatch solution, unit marginal incremental cost, and LMPs in the above table, it can be seen that units are dispatched in their merit order cost and their impacts on transmission security constraints. For instance, Units 1, 7, 8, 9, 10, 11, 12, 13, 14, 15, and 16 are dispatched to their economic minimum limits respectively. The other units are dispatched to either their economic maximum limits or between their economic minimum and maximum limits respectively. Units are dispatched to meet both load demand and to resolve the transmission congestions at the least cost.

Unit dispatch differences between scenarios 2 and 3 are shown in Figure 4.3-1 below. The MW dispatch differences show the additional unit dispatches needed to meet the increased load, where the cheaper units (2, 4, 5, 6, 14, 17 and 18) receive increase generation dispatch.

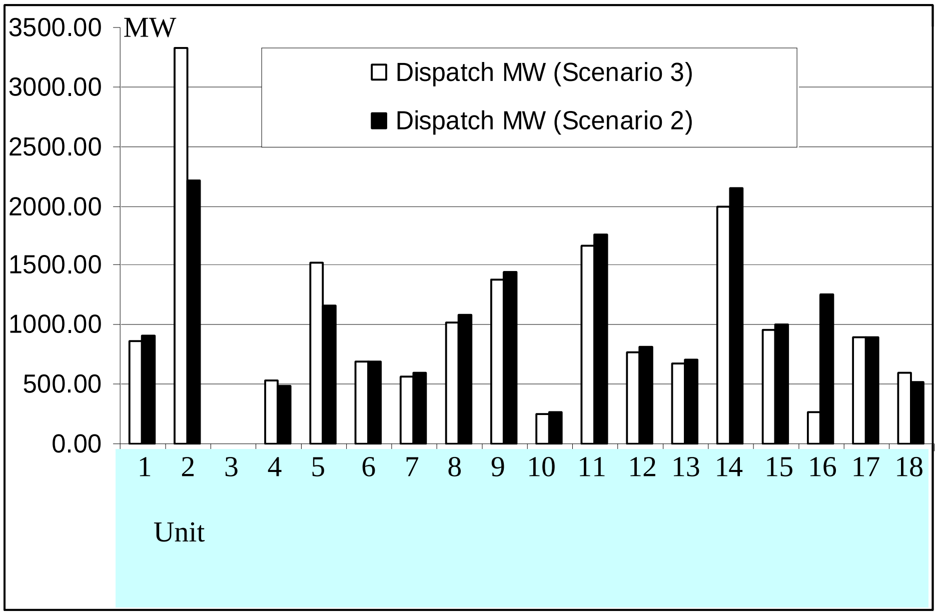


Figure 4.3-1 Unit dispatches compared to Scenarios 2 and 3

With the increased dispatch ranges, unit re-dispatches are observed from the different bar heights for individual unit outputs. Some of the re-dispatches are quite visible, such as the re-dispatches for units 2 and 16. Unit 2 is dispatched up to 3332.7MW in this scenario from 2212.6MW in scenario 2.

Even though many units are dispatched differently under the two scenarios (1 and 2), it is important to notice that unit MW dispatches continue to be consistent with the market incentives represented in the form of LMPs. From Table 4.3-1, it can be noted that units are dispatched to their economic minimum limits when LMPs at the units are less than their generation cost; whereas units are dispatched to their economic maximum limits when LMPs at the units are greater than their generation costs; units are dispatched between their economic minimum and maximum limit range when the LMPs at the units are equal to their generation costs. The relationship between LMPs, marginal incremental costs, and MW dispatches are compatible with market incentives under greater competition of 10% capacity bidding. When the LMPs are used to settle the real-time generations, generators will continue to be encouraged to follow the MW dispatch instructions, because following the dispatch instructions helps generation to reach their respective objectives of maximizing their operational profits.

4.4.3.2 Power Flow Results

With the generation dispatch results determined from 10% capacity for bidding, power flows are computed for the 500KV main network using the linearized power flow model. Branch flows from scenarios 2 and 3 are included in Figure 4.3-2. As is shown, all branch flows are within their thermal limits, except for the following two branches:

- Branch "6-29" flow is at its limit of 2200MW, which is true under both scenarios 2 and 3.
- Branch "2-19" flow is at its limit of 3000MW. Under scenario 2, the flow over this branch is 2754MW.

Even though some branches show different flows, their power flows are all below their thermal limits and these flow pattern changes shall not exert any negative impacts on transmission thermal security.

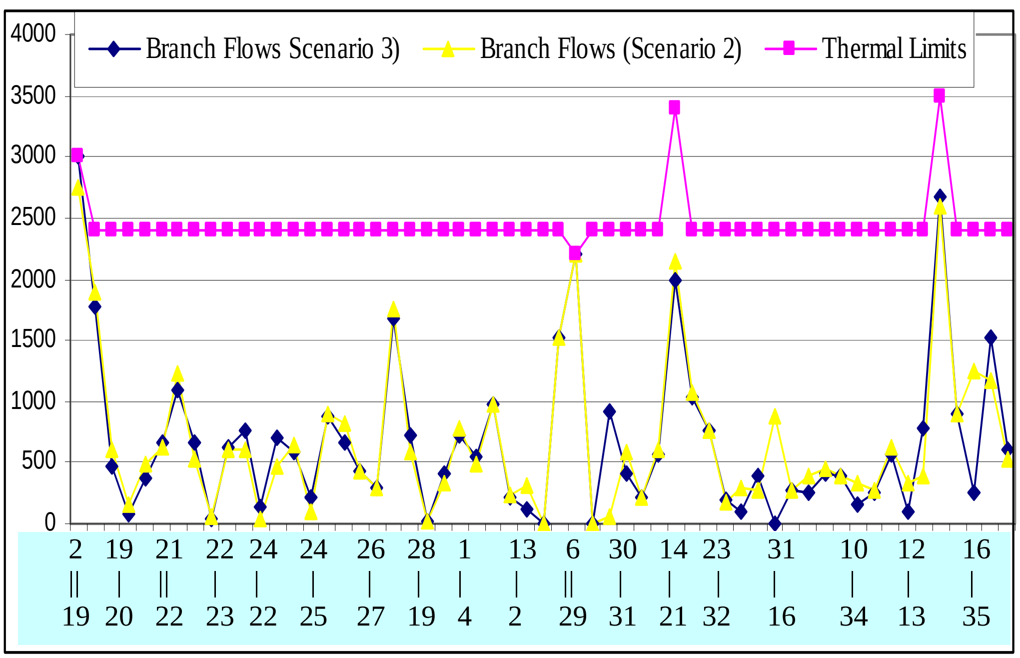


Figure 4.3-2 Branch flows and thermal limits

In this scenario, the same two transfer interface constraints, (2-19)-(12-20)-(30-34) and Beijing-Tianjin-Tangshan, as considered in the previous two scenarios 1 and 2, are also enforced. The power flows over the two transfer interfaces are described in Figure 4.3-3. As is shown in the figure, the flow over transfer interface (2-19)-(12-20)-(30-34) is 5238MW, slightly lower than its limit of 5250MW, while the 3394MW flow over the other interface constraint is far below its security limit of 5100MW.

Comparing scenarios 2 and 3, power flow solutions show that the limiting transfer interface constraint (2-19)-(12-20)-(30-34) in scenario 2 is switched to the limiting branch "2-19". This is understandable because "2-19" is one of the branch components included in this interface constraint definition. When the underlying branch flow is more limiting, the interface constraint is not binding. This limiting constraint difference is considered to be more of the modeling approximations in the transfer interface definition. But this result indicates that use of detailed transmission models is important do as not to miss important constraints.

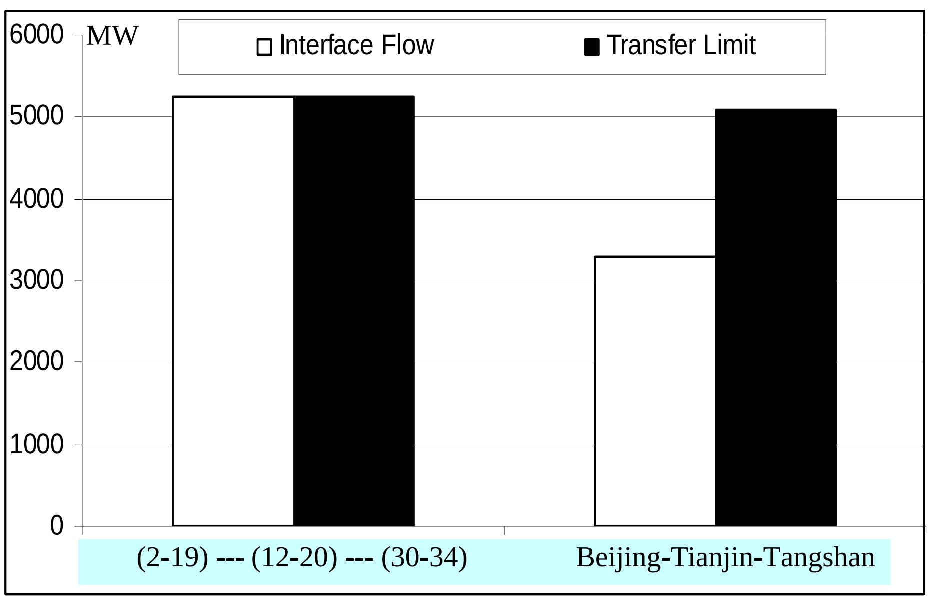


Figure 4.3-3 Transfer interface flows and thermal limits

It is important to note that, in comparison to the solution in scenario 2 (results are shown in Figure 4.2-3), the flow over transfer interface (2-19)-(12-20)-(30-34) decreases from 5250MW to 5238MW. These power flow results demonstrate that grid security will continue to be maintained under increased competition, which results from the fact that system operators will have a broader pool of resources to minimize production costs as well as manage transmission bottleneck problems.

4.4.3.3 Total Variable Operational Costs

For the generation dispatches as are shown in Table 4.3-1, individual unit energy production cost and total generation cost are computed based on individual incremental costs and their dispatch MW values. The results are included in Table 4.3-2.

Unit Name	Dispatch MW	generation Cost (¥/MWh)	total Cost (¥/h)
1	869.00	330.00	¥286,770.00
2	3332.68	248.00	¥826,504.84
3	0.00	0.00	¥0.00
4	539.95	294.00	¥158,745.59
5	1517.37	297.00	¥450,658.35
6	687.00	294.00	¥201,978.00
7	566.00	300.00	¥169,800.00
8	1025.00	298.00	¥305,450.00
9	1374.00	390.00	¥535,860.00
10	258.00	300.00	¥77,400.00
11	1671.00	358.00	¥598,218.00
12	771.00	297.00	¥228,987.00
13	669.00	276.00	¥184,644.00
14	1999.00	296.00	¥591,704.00
15	958.00	314.00	¥300,812.00
16	263.00	276.00	¥72,588.00
17	900.00	294.00	¥264,600.00
18	600.00	296.00	¥177,600.00
		All generation total Cost	¥5,432,319.78

Table 4.3-2 Total variable operational cost

As is discussed for the previous scenarios, the cost values shown in Table 4.3-2 includes only the variable operational costs for the energy production, which is the product of the values in columns “Dispatch MW” and “generation Cost”.

Compared to the total cost in Table 4.2-2, the total cost for scenario 3 decreases by ¥48,753.03. This cost decrease is due to the greater competition with 10% capacity bidding than the 5% capacity bidding simulated in scenario 2.

4.4.3.4 LMPs

The LMPs computed for scenario 3 are graphed in Figure 4.3-4 below along with the LMPs from scenario 2.

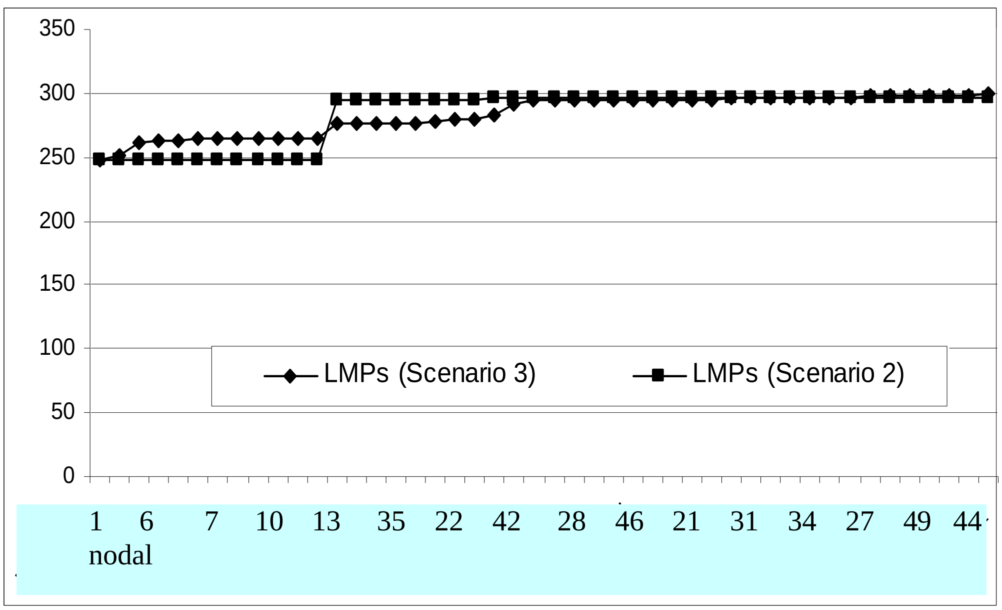


Figure 4.3-4 LMPs from scenarios 2 and 3

From the above figure, more variances are observed in the LMPs in this scenario, when they are compared to the LMPs in scenario 2. The higher variances result from the fact that the limiting transfer interface constraint in scenario 2 changes to a limiting branch. Because the transfer interface is defined as a clear cut of the transfer interface from Shanxi to the Beijing-Tianjin-Tangshan area, the impacts of the limiting transfer interface constraint on locational prices are either 0 or 1. On the other hand, the impacts of the limiting branch on locational prices are determined based on admittance and connection related sensitivities, which are typically numbers between -1 and 1. These differences in limiting constraint definitions lead to the LMP differences in the two scenarios.

4.4.3.5 Transmission Congestion Cost

In this scenario 3, two transmission security constraints, branches “2-19” and “6-29”, are binding. Constraint flows, limits, shadow prices, and congestion cost are shown in Table 4.3-3. In this scenario, the flow congestion over branch 6-29 causes increases of the operational cost by ¥5,500.00 per hour; the congestion cost due to the transfer interface (2-19)-(12-20)-(30-34) is ¥252,000.00 per hour. When generations and loads are settled at their respective LMPs, there will be settlement residues left. As is discussed in previous section 4.4.2.5, these congestion rentals are typically re-allocated to load participants.

Branch/Constraint Name	MW Flow	WM Limit	Shadow Price (¥/MWh)	Congestion Cost (¥/h)
2-19(bilateral line)	3000.0	3000.0	66.28	¥198,840.00
6-29(bilateral line)	2200.0	2200.0	4.46	¥9,812.00
		Total congestion cost		¥208,652.00

Table 4.3-3 Transmission congestion cost

The congestion cost for this scenario is lower than the congestion of ¥256,400.00 from scenario 2. This reduction in congestion cost can be explained as the benefits from increased dispatchable ranges of 10% capacity for bidding, where resources can be better utilized to meet both load demand and transmission congestion management.

4.4.3.6 Average Energy Cost

The definition for average energy cost as used in the previous two scenarios is used for this scenario.

From Table 4.3-2, the total variable operational cost to serve the load demand of 18000MW in this scenario is ¥5,432,319.78. Therefore, the average energy cost is ¥301.80. This average energy cost is ¥2.70/MWh lower than the average energy cost of ¥304.50/MWh for Scenario 2 (refer to Section 4.4.2.6), and ¥4.33/MWh lower than the average energy cost of ¥306.12/MWh with a bidding. The results from the scenario study indicate that, when 10% generation capacity is subject to market competition, the average energy price for loads is reduced by 1.4%.

The average energy costs for the three scenarios are plotted in Figure 4.3-5.

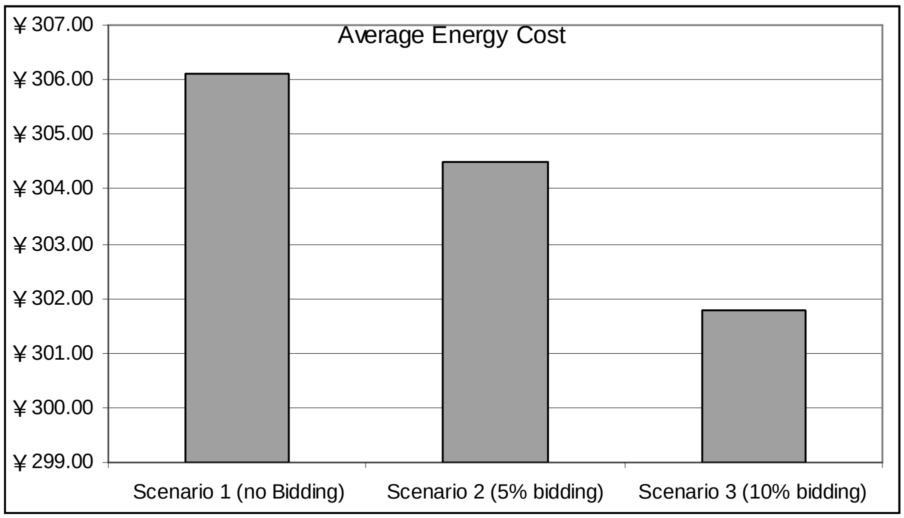


Figure 4.3-5 Average energy costs under different bidding percentages

4.4.4 Scenario 4: Full competitive bidding

This scenario 4 is developed to simulate the impacts on NCGC generation scheduling and transmission operations when 100% of the total generation is permitted for competitive bidding. With the load demand maintained at the same level of 18000MW, this 100% capacity bidding market is simulated by modeling unit lower dispatch limits with their physical economic minimum limits.

With this scenario, we continue to study the impact of increased competitive bidding on grid security and variable energy production costs.

4.4.4.1 Generation Dispatches

With their physical operational lower limits observed all the generators are dispatched to meet the 18000MW load demand on the 500kV main network for the Beijing-Tianjin-Tangshan region. The same SCED method is executed to determine unit dispatches. In the SCED, unit dispatches observe their economic minimum and maximum limits as well as transmission network security limits. The unit dispatch results are shown in Table 4.4-1.

Unit Name	Dispatch MW	Economic dispatch Min	Economic dispatch Max	Generation Cost (¥/MWh)	LMP(¥/MWh)
1	600.00	600.0	1200.0	330.00	294.00
2	3600.00	1200.0	3600.0	248.00	264.59
3	0.00	0.0	600.0	0.00	285.26
4	695.95	188.0	4200.0	294.00	294.00
5	1075.21	800.0	1600.0	297.00	297.00
6	800.00	400.0	800.0	294.00	294.00
7	330.00	330.0	660.0	300.00	283.74
8	600.00	600.0	1200.0	298.00	274.02
9	1100.00	1100.0	2200.0	390.00	296.70
10	250.00	250.0	500.0	300.00	283.74
11	1200.00	1200.0	2400.0	358.00	298.13
12	500.00	500.0	1000.0	297.00	274.02
13	500.00	500.0	1000.0	276.00	273.90
14	3400.00	800.0	3600.0	296.00	296.00
15	1013.00	1013.0	2025.0	314.00	283.74
16	835.84	263.0	1550.0	276.00	276.00
17	900.00	450.0	900.0	294.00	294.00
18	600.00	300.0	600.0	296.00	297.97

Table 4.4-1 Generation dispatches by the SCED method

From the unit dispatch solution, unit generation cost, and LMPs are listed in the above table, it can be seen that units are dispatched in their merit order cost and their impacts on transmission security constraints. For instance, Units 1, 7, 8, 9, 10, 11, 12, 13, and 15 are dispatched respectively at their economic minimum limits, which different from the solution in scenario 3. The other units are dispatched to either their economic maximum limits or between their economic minimum and maximum limits. Units are dispatched to meet both load demand and to resolve the transmission congestions at the least cost.

Unit dispatch differences of the scenario from the scenarios 3 and 4 are shown in Figure 4.3-2 below. The MW dispatch differences shows the additional unit dispatches needed to meet the increased load, where the cheaper units (2, 4, 6, 14, 16) receives increase generation dispatch.

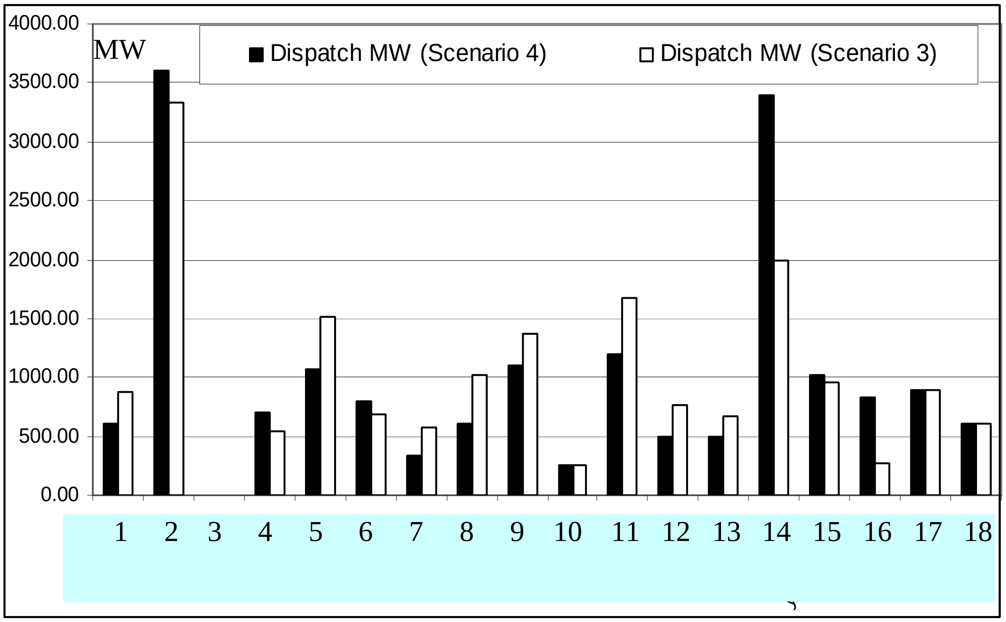


Figure 4.4-1 Unit dispatches compared to Scenarios 3 and 4

With their full dispatch ranges, unit re-dispatches are observed from the different bar heights for individual unit outputs. Some of the re-dispatches are quite visible, such as the re-dispatches for units 5, 8, 11, 14, and 16. Unit 14 is dispatched up to 3400MW in this scenario from 1999MW in scenario 3.

Even though many units are dispatched differently under the two scenarios (3 and 4), it is important to notice that unit MW dispatches continue to be consistent with the market incentives represented in the form of LMPs. From Table 4.4-1, it can be noted that units are dispatched to their economic minimum limits when LMPs at the units are less than their marginal incremental cost; whereas units are dispatched to their economic maximum limits when LMPs at the units are greater than their marginal incremental costs; units are dispatched between their economic minimum and maximum limit range when the LMPs at the units are equal to their marginal incremental costs. The relationship between LMPs, marginal incremental costs, and MW dispatches are compatible with market incentives under the full competition of 100% capacity bidding. When the LMPs are used to settle the real-time generations, generators will continue to be encouraged to follow the MW dispatch instructions, because following the dispatch instructions helps generation to reach their respective objectives of maximizing their operational profits.

4.4.4.2 Power Flow Results

With the generation dispatch results determined from 100% bidding capacity, power flows are computed for the 500KV main network using the linearized power flow model. Branch flows from scenarios 3 and 4 are included in Figure 4.4-2. As is shown, all branch flows are within their thermal limits, except for the following three branches:

- Branch “6-29” flow is at its limit of 2200MW, which is true under scenarios 2, 3, and 4.
- Branch “2-19” flow is at its limit of 3000MW. This is also true under scenarios 3 and 4, but not in scenario 2.
- Branch “14-21” flow is at its limit of 3400MW. This constraint did not occur in the previous scenarios.

Even though some branches show different flows, their power flows are all below their thermal limits and these flow pattern changes shall not exert any negative impacts on transmission thermal security.

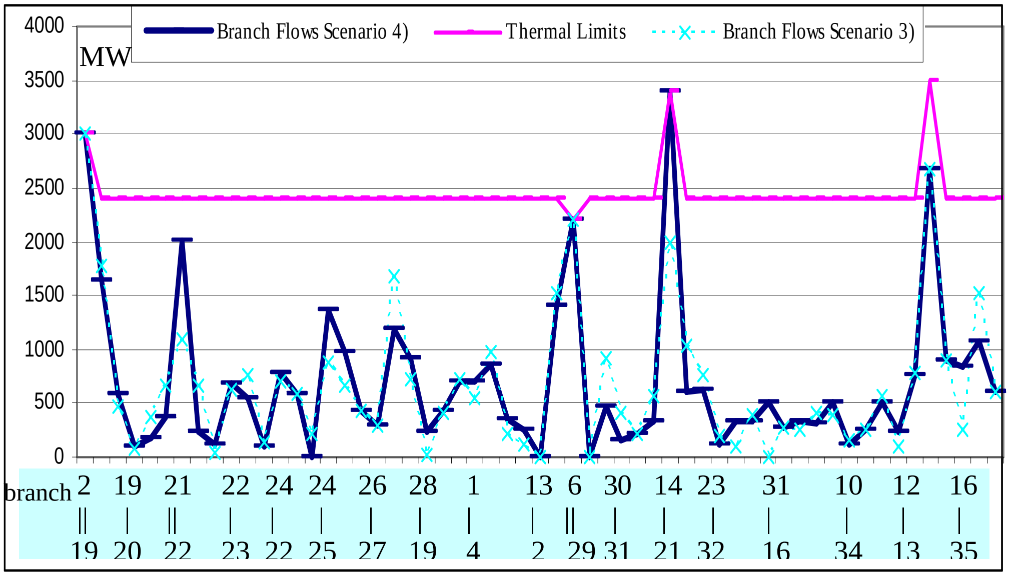


Figure 4.4-2 Branch flows and thermal limits

In this scenario, the two transfer interface constraints, (2-19)-(12-20)-(30-34) and Beijing-Tianjin-Tangshan, as considered in the previous scenarios, are also enforced. The power flows over the two transfer interfaces are:

- The flow over transfer interface (2-19)-(12-20)-(30-34) is 5213MW,
- And the flow over transfer interface Beijing-Tianjin-Tangshan is 3068MW.

The flows over both interface constraints are lower than its limit of 5250MW and 5100MW respectively. So neither transfer interface constraints are binding.

Comparing these scenarios 2, 3, and 4, power flow patterns does change. However, under the security constrained economic dispatch framework, the pre-defined grid security requirements are always observed and satisfied. The new limiting branch in this scenario, “14-21”, is caused by dispatching more of the cheaper generation at the sending end of the branch.

4.4.4.3Total Variable Operational Costs

The generation dispatches are as shown in Table 4.4-1, individual unit energy production cost and total generation cost for all the units are computed based on individual incremental costs and their dispatch MW values. The results are included in Table 4.4-2.

Unit Name	Dispatch MW	generation Cost (¥/MWh)	total Cost (¥/h)
1	600.00	330.00	¥198,000.00
2	3600.00	248.00	¥892,800.00
3	0.00	0.00	¥0.00
4	695.95	294.00	¥204,609.59
5	1075.21	297.00	¥319,336.59
6	800.00	294.00	¥235,200.00
7	330.00	300.00	¥99,000.00
8	600.00	298.00	¥178,800.00
9	1100.00	390.00	¥429,000.00
10	250.00	300.00	¥75,000.00
11	1200.00	358.00	¥429,600.00
12	500.00	297.00	¥148,500.00
13	500.00	276.00	¥138,000.00
14	3400.00	296.00	¥1,006,400.00
15	1013.00	314.00	¥318,082.00
16	835.84	276.00	¥230,692.29
17	900.00	294.00	¥264,600.00
18	600.00	296.00	¥177,600.00
		All generation total Cost	¥5,345,220.47

Table 4.4-2 Total variable operational cost

As is discussed for the previous scenarios, the cost values shown in Table 4.4-2 includes only the variable operational costs for the energy production, which is the product of the values in columns “Dispatch MW” and “generation Cost”.

Compared to the total cost in Tables 4.2-2 and 4.3-2, the total cost for scenario 4 decreases by ¥135,852.34 for scenario 2, and ¥87,099.36 for scenario 3 respectively. These cost decreases are enabled from the better resource dispatches under greater competition with 100% capacity bidding than the 5% and 10% capacity bidding simulated in scenarios 2 and 3 respectively.

4.4.4.4 LMPs

The LMPs computed for scenario 4 are graphed in Figure 5.4-3 below along with the LMPs from scenarios 2 and 3.

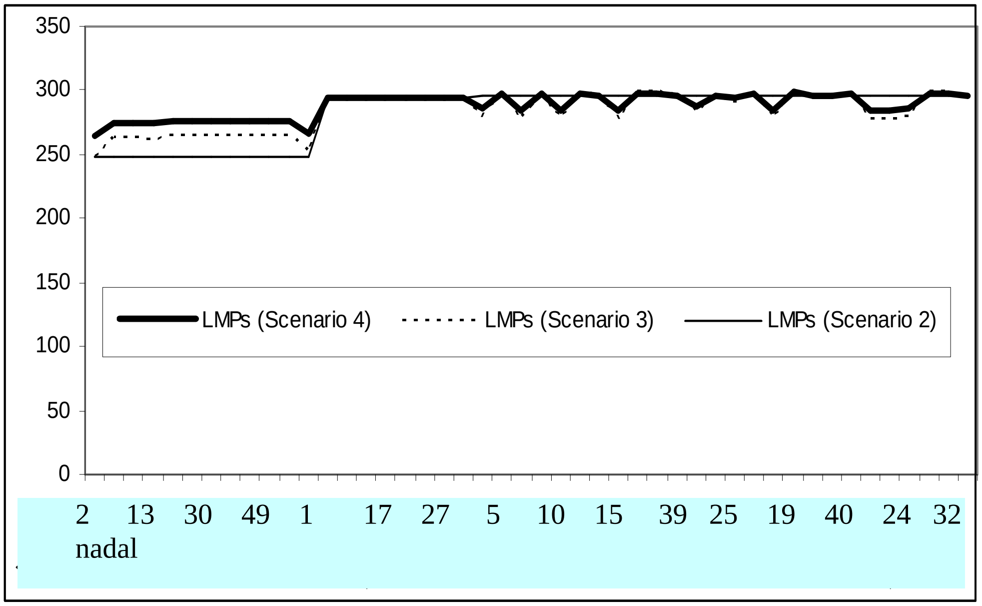


Figure 4.4-3 LMPs from scenarios 2, 3 and 4

From the above figure, the LMP patterns for scenarios 3 and 4 are relatively more similar than for scenarios 2 and 4. The reason is that scenarios 3 and 4 have a similar transmission congestion pattern. However, it is also noticed that the LMPs at some locations for the scenarios 3 and 4 are quite different. The latter differences are caused by the greater dispatch a able generations. To better understand the differences, the marginal unit information for the two scenarios is listed below.

Scenario 3		Scenario 4	
2	¥248/MWh	4	¥294/MWh
4	¥294/MWh	5	¥297/MWh
5	¥297/MWh	14	¥296/MWh
6	¥294/MWh	16	¥276/MWh

Table 4.4-3 Marginal units in scenarios 3 and 4

The differences in marginal units in the above table explains the LMP differences in certain locations; but the LMP pattern similarity results from the similar transmission congestion patterns.

4.4.4.5 Transmission Congestion Cost

In this scenario 4, three transmission security constraints, branches "2-19", "6-29" and "14-21", are binding. Constraint flows, limits, shadow prices, and congestion cost are shown in Table 4.4-4. The congestion costs resulting from each of the transmission bottlenecks are included in this table.

Branches	MW Flow	WM Limit	Shadow Price (¥/MWh)	Congestion Cost (¥/h)
2-19(bilateral line)	3000.0	3000.0	43.84	¥131,520.00
6-29(bilateral line)	2200.0	2200.0	3.97	¥8,734.00
14-21(double bilateral line)	3400	3400	0.1	¥340.00
		Total congestion cost		¥140,594.00

Table 4.4-4 Transmission congestion cost

The congestion cost for this scenario is lower than the congestion costs of ¥256,400.00 and ¥208,652.00 from scenarios 2 and 3 respectively. This reduction in congestion cost can be explained as the benefits from increased dispatchable to 100% capacity bidding, where resources can be better utilized to meet both load demand and transmission congestion management.

4.4.4.6 Average Energy Cost

From Table 4.4-2, the total variable operational cost to serve the load demand of 18000MW in this scenario is ¥ 5,345,220.47. The average energy cost is ¥ 296.96/MWh. This average energy cost is ¥7.55/MWh and ¥4.84/MWh lower than the average energy cost of ¥304.50/MWh for Scenario 2 (refer to Section 4.4.2.6) and also that of ¥301.80/MWh Scenario 3 (refer to Section 4.4.3.6), respectively.

The average energy costs for the three scenarios are plotted in Figure 4.4-4.

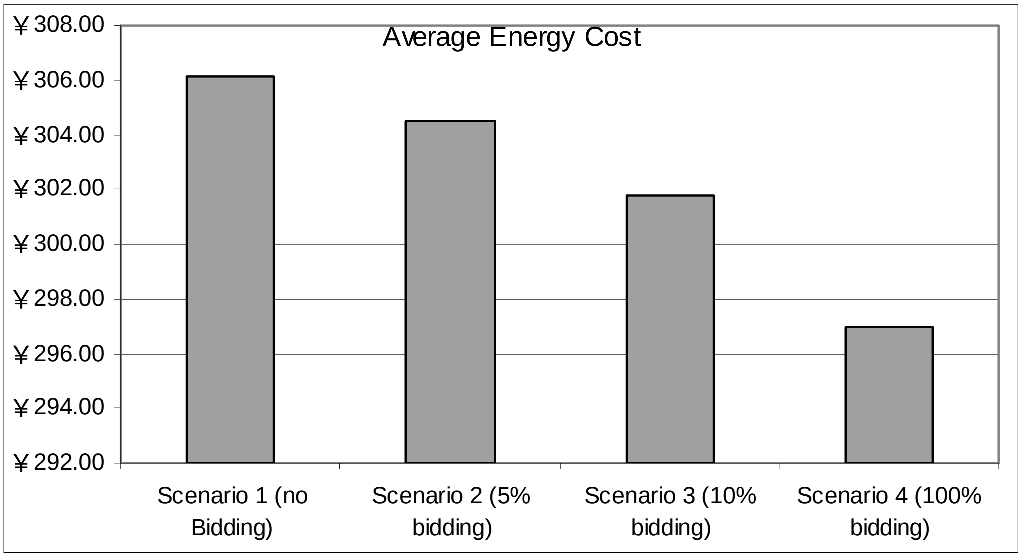


Figure 4.4-4 Average energy costs under different bidding percentages

4.5 Alternative Pricing Methods for Generation

In the previous sections of this chapter, I have analyzed the simulation results from four scenarios with different levels of competitive bidding. The analyses have focused on the aspects of individual generating unit dispatches, power flows and network security constraints, LMPs, transmission congestion costs, and average energy costs. The simulation results have indicated that SCED solutions enhance NCGC grid security and improve average energy production cost.

In a typical LMP based market, energy production and consumption are settled at LMPs level. We understand that the NCGC market restructuring may very well adopt this spot market pricing method at the end of its state market reform. I also understand that NCGC market restructuring will more likely take an evolutionary approach. During different stages of NCGC market restructuring, only a portion of generation capacity may be subjected to market competition and the remaining portion will continue to be regulated. As a result of this, it is interest to analyze alternative spot market pricing methods to evaluate the energy purchasing costs and their implications.

In this section, two alternative spot market pricing methods are analyzed: regulated-market hybrid pricing method and LMP method. The regulated-market hybrid pricing method settles the portion of regulated energy production at the regulated prices and the portion of energy subjected to market competition at the LMPs. The LMP method settles all the energy production at LMPs.

4.5.1 The Regulated-Market Hybrid Pricing Method

In simulating the different levels of competition, unit economic minimum limits are adjusted to reflect the different levels of competition. In this scenario setup, portions of units' energy up to their economic minimum limits are settled at their bid-in prices (or equivalently, the regulated prices); the other portions of energy dispatched above their economic minimum limits are settled at their respective LMPs. The numerical results are shown in the following tables.

In this scenario without competitive bidding, all generations are dispatched according to certain predefined planning and scheduling procedures. Since generations are exposed to market prices, they are operated under the command and control scheme. The average energy purchase cost is ¥306.12/MWh.

Unit Name	Dispatch MW	generation Cost (¥/MWh)	Total Cost (¥/h)
1	965	330	¥318,450.00
2	1904	248	¥472,192.00
3	0	0	¥0.00
4	208	294	¥61,152.00
5	1224	297	¥363,528.00
6	708	294	¥208,152.00
7	628	300	¥188,400.00
8	1139	298	¥339,422.00
9	1527	390	¥595,530.00
10	287	300	¥86,100.00
11	1856	358	¥664,448.00
12	857	297	¥254,529.00
13	743	276	¥205,068.00
14	2221	296	¥657,416.00

15	1065	314	¥334,410.00
16	1324	276	¥365,424.00
17	928	294	¥272,832.00
18	413	296	¥122,248.00
		All generations total cost (¥/h)	¥5,510,207.00
Load Demand:	18000MW	Average Prices:	¥306.12

Table 4.5-1: No Bidding – All Scheduled Generation Paid by Cost

The total cost $=\text{dispatch(MW)}\times\text{generation cost}$

The average prices = $\dfrac{\text{all generations total cost}}{\text{load demand}}$ =¥$\left(\dfrac{5,510,207.00}{18000}\right)$ = ¥306.12/MWh.

In this scenario without competitive bidding, all generations are dispatched according to certain predefined planning and scheduling procedures. Since generations are exposed to market prices, they are operated under the command and control scheme. The average energy purchase cost is ¥306.12/MWh.

Table 4.5-2: 5% Bidding - Scheduled Generation Paid by Cost and Market Dispatched Generation Paid by LMPs

Unit Name	Dispatch MW	Economic dispatch Min	Economic dispatch Max	Generation Cost (¥/MWh)	LMP (¥/MWh)	Pay for scheduled gen	Pay for Market Dispatched Gen	Total Pay
1	917.00	917.0	1200.0	330.00	294.00	¥302,610.00	¥0.00	¥302,610.00
2	2212.59	1809.0	2400.0	248.00	248.00	¥448,632.00	¥100,090.32	¥548,722.32
3	0.00	0.0	600.0	0.00	296.00	¥0.00	¥0.00	¥0.00
4	491.95	198.0	4200.0	294.00	294.00	¥58,212.00	¥86,421.30	¥144,633.30
5	1163.00	1163.0	1600.0	297.00	296.00	¥345,411.00	¥0.00	¥345,411.00
6	687.00	673.0	800.0	294.00	294.00	¥197,862.00	¥4,116.00	¥201,978.00
7	597.00	597.0	660.0	300.00	296.00	¥179,100.00	¥0.00	¥179,100.00
8	1082.00	1082.0	1200.0	298.00	248.00	¥322,436.00	¥0.00	¥322,436.00
9	1451.00	1451.0	2200.0	390.00	296.00	¥565,890.00	¥0.00	¥565,890.00
10	273.00	273.0	500.0	300.00	296.00	¥81,900.00	¥0.00	¥81,900.00
11	1763.00	1763.0	2400.0	358.00	296.00	¥631,154.00	¥0.00	¥631,154.00
12	814.00	814.0	1000.0	297.00	248.00	¥241,758.00	¥0.00	¥241,758.00
13	706.00	706.0	1000.0	276.00	248.00	¥194,856.00	¥0.00	¥194,856.00
14	2153.00	2110.0	3600.0	296.00	296.00	¥624,560.00	¥12,728.00	¥637,288.00
15	1012.00	1012.0	2025.0	314.00	296.00	¥317,768.00	¥0.00	¥317,768.00
16	1258.00	1258.0	1550.0	276.00	248.00	¥347,208.00	¥0.00	¥347,208.00
17	900.00	882.0	900.0	294.00	294.00	¥259,308.00	¥5,292.00	¥264,600.00
18	519.46	392.0	600.0	296.00	296.00	¥116,032.00	¥37,728.16	¥153,760.16
					Totals:	¥5,234,697.00	¥246,375.78	¥5,481,072.78
		Load Demand:		18000MW			Average Prices:	¥304.54

Pay for scheduled gen =

$$(\text{economic dispatch min=schduled generation capacity})\times\text{generation cost}$$

Pay for Market Dispatched Gen =

$$\left[\text{Dispatch-(economic dispatch min=schduled generation capacity)}\right]\times\text{LMP}$$

When 5% generation capacity are subjected to competitive bidding and LMP based settlement, it is interesting to observe from the results in the above table4.5-2 that, some units may have the incentive to over-generate, such as units 1, 5, 7, 8, 9, 10, 11, 12,13, 15, and 16, as payment by their bid-in costs may still incur substantial profits. This could cause complications in market based operation.

The other unit MW dispatches are still consistent with the LMP market signals. The average energy purchase cost is ¥$\left(\frac{5,481,072.78}{18000}\right)$ = ¥304.54/MWh, compared to the no-bidding scenario of ¥306.12/MWh.

Table 4.5-3: 10% Bidding - Scheduled Generation Paid by Cost and Market Dispatched Generation Paid by LMPs

Unit Name	Dispatch MW	Economic dispatch Min	Economic dispatch Max	Generation Cost (¥/MWh)	LMP (¥/MWh)	Pay for scheduled gen	Pay for Market Dispatched Gen	Total Pay
1	869.00	869.0	1200.0	330.00	294.00	¥286,770.00	¥0.00	¥286,770.00
2	3332.68	2314.0	3600.0	248.00	248.00	¥573,872.00	¥252,632.64	¥826,504.64
3	0.00	0.0	600.0	0.00	279.25	¥0.00	¥0.00	¥0.00
4	539.95	188.0	4200.0	294.00	294.00	¥55,272.00	¥103,473.30	¥158,745.30
5	1517.37	1101.0	1600.0	297.00	297.00	¥326,997.00	¥123,661.89	¥450,658.89
6	687.00	638.0	800.0	294.00	294.00	¥187,572.00	¥14,406.00	¥201,978.00
7	566.00	566.0	660.0	300.00	276.96	¥169,800.00	¥0.00	¥169,800.00
8	1025.00	1025.0	1200.0	298.00	262.26	¥305,450.00	¥0.00	¥305,450.00
9	1374.00	1374.0	2200.0	390.00	296.54	¥535,860.00	¥0.00	¥535,860.00
10	258.00	258.0	500.0	300.00	276.96	¥77,400.00	¥0.00	¥77,400.00
11	1671.00	1671.0	2400.0	358.00	298.72	¥598,218.00	¥0.00	¥598,218.00
12	771.00	771.0	1000.0	297.00	262.26	¥228,987.00	¥0.00	¥228,987.00
13	669.00	669.0	1000.0	276.00	262.08	¥184,644.00	¥0.00	¥184,644.00
14	1999.00	1999.0	3600.0	296.00	295.64	¥591,704.00	¥0.00	¥591,704.00
15	958.00	958.0	2025.0	314.00	276.96	¥300,812.00	¥0.00	¥300,812.00
16	263.00	263.0	1550.0	276.00	265.25	¥72,588.00	¥0.00	¥72,588.00
17	900.00	836.0	900.0	294.00	294.00	¥245,784.00	¥18,816.00	¥264,600.00
18	600.00	371.0	600.0	296.00	298.46	¥109,816.00	¥68,347.34	¥178,163.34
					Totals:	¥4,851,546.00	¥581,337.17	¥5,432,883.17
		Load Demand:		18000MW			Average Prices:	¥301.83

Pay for scheduled gen =

$$(\text{economic dispatch min=schduled generation capacity})\times\text{generation cost}$$

Pay for Market Dispatched Gen =

$$\left[\text{Dispatch-(economic dispatch min=schduled generation capacity)}\right]\times\text{LMP}$$

When 10% generation capacity are subjected to competitive bidding and LMP based settlement, Similar to the case of 5% bidding, some units may have the incentive to not follow dispatch instructions, such as units 1, 7, 8, 9, 10, 11, 12,13, 14, 15 and 16. This can also cause complications in market operation. The other unit MW dispatches are consistent with the LMP market signals.

The average energy purchase cost is ¥$\left(\frac{5,432,883.17}{18000}\right)$= ¥301.83/MWh, compared to ¥304.54/MWh for 5% bidding and ¥306.12/MWh for no-bidding respectively.

Table 4.5-4: 100% Bidding - Scheduled Generation Paid by Cost and Market Dispatched Generation Paid by LMPs

Unit Name	Dispatch MW	Economic dispatch Min	Economic dispatch Max	Generation Cost (¥/MWh)	LMP (¥/MWh)	LMP Pay	Uplift Pay	Total Pay
1	600.00	600.0	1200.0	330.00	294.00	¥176,400.00	¥21,600.00	¥198,000.00
2	3600.00	1200.0	3600.0	248.00	264.59	¥952,524.00	¥0.00	¥952,524.00
3	0.00	0.0	600.0	0.00	285.26	¥0.00	¥0.00	¥0.00
4	695.95	188.0	4200.0	294.00	294.00	¥204,609.30	¥0.00	¥204,609.30
5	1075.21	800.0	1600.0	297.00	297.00	¥319,337.37	¥0.00	¥319,337.37
6	800.00	400.0	800.0	294.00	294.00	¥235,200.00	¥0.00	¥235,200.00
7	330.00	330.0	660.0	300.00	283.74	¥93,634.20	¥5,365.80	¥99,000.00
8	600.00	600.0	1200.0	298.00	274.02	¥164,412.00	¥14,388.00	¥178,800.00
9	1100.00	1100.0	2200.0	390.00	296.70	¥326,370.00	¥102,630.00	¥429,000.00
10	250.00	250.0	500.0	300.00	283.74	¥70,935.00	¥4,065.00	¥75,000.00
11	1200.00	1200.0	2400.0	358.00	298.13	¥357,756.00	¥71,844.00	¥429,600.00
12	500.00	500.0	1000.0	297.00	274.02	¥137,010.00	¥11,490.00	¥148,500.00
13	500.00	500.0	1000.0	276.00	273.90	¥136,950.00	¥1,050.00	¥138,000.00
14	3400.00	1800.0	3600.0	296.00	296.00	¥1,006,400.00	¥0.00	¥1,006,400.00
15	1013.00	1013.0	2025.0	314.00	283.74	¥287,428.62	¥30,653.38	¥318,082.00
16	835.84	263.0	1550.0	276.00	276.00	¥230,691.84	¥0.00	¥230,691.84
17	900.00	450.0	900.0	294.00	294.00	¥264,600.00	¥0.00	¥264,600.00
18	600.00	300.0	600.0	296.00	297.97	¥178,782.00	¥0.00	¥178,782.00
					Totals:	¥5,143,040.33	¥263,086.18	¥5,406,126.51
		Load Demand:		18000MW			Average Prices:	¥300.34

When 100% generation capacity are subjected to competitive bidding and LMP based settlement, Similar to the case of 5% and 10% bidding, unit MW dispatches are consistent with the LMP market signals. There will be minimum, if any, incentives that units deviate from dispatch instructions.

When 100% generation capacity are subjected to competitive bidding and LMP based settlement, if $\text{LMP} \geq \text{generation cost}$, the generation do not need uplift pay, against $\text{LMP} < \text{generation cost}$, the generation need uplift pay,.

$$\text{Uplift Pay} = \left(\text{generation cost - LMP}\right) \times \text{dispatch MW}$$

The average energy purchase cost is ¥300.34/MW, which is the lowest compared to ¥301.83/MWh for 10% bidding, ¥304.54/MWh for 5% bidding and ¥306.12/MWh for no-bidding respectively. Please note that in Table4.5-4, the “Uplift Pay” is to account for the typical LMP market settlement practices that units that are dispatched by the market will be guaranteed to at least cover their bid-in costs.

4.5.2 LMP Method

When all the generations are paid at LMPs, the typical practices that units that dispatched by the market will be guaranteed to receive energy payment at least equal to their bid-in costs. As a result, uplift payment will be considered in the following numerical analyses. As the LMP method is not applicable to the no-bidding scenario, and the LMP method is already applied to the 100% bidding scenario, the following tables describes the results for the 5% and 10% bidding scenarios.

Table 4.5-5: 5% Bidding – All Generations Paid by LMPs

Unit Name	Dispatch MW	Economic dispatch Min	Economic dispatch Max	Generation Cost (¥/MWh)	LMP (¥/MWh)	Pay for Market Dispatched Gen	Uplift Pay	Total Pay
1	917.00	917.0	1200.0	330.00	294.00	¥269,598.00	¥33,012.00	¥302,610.00
2	2212.59	1809.0	2400.0	248.00	248.00	¥548,722.32	¥0.00	¥548,722.32
3	0.00	0.0	600.0	0.00	296.00	¥0.00	¥0.00	¥0.00
4	491.95	198.0	4200.0	294.00	294.00	¥144,633.30	¥0.00	¥144,633.30
5	1163.00	1163.0	1600.0	297.00	296.00	¥344,248.00	¥1,163.00	¥345,411.00
6	687.00	673.0	800.0	294.00	294.00	¥201,978.00	¥0.00	¥201,978.00
7	597.00	597.0	660.0	300.00	296.00	¥176,712.00	¥2,388.00	¥179,100.00
8	1082.00	1082.0	1200.0	298.00	248.00	¥268,336.00	¥54,100.00	¥322,436.00
9	1451.00	1451.0	2200.0	390.00	296.00	¥429,496.00	¥136,394.00	¥565,890.00
10	273.00	273.0	500.0	300.00	296.00	¥80,808.00	¥1,092.00	¥81,900.00
11	1763.00	1763.0	2400.0	358.00	296.00	¥521,848.00	¥109,306.00	¥631,154.00
12	814.00	814.0	1000.0	297.00	248.00	¥201,872.00	¥39,886.00	¥241,758.00
13	706.00	706.0	1000.0	276.00	248.00	¥175,088.00	¥19,768.00	¥194,856.00
14	2153.00	2110.0	3600.0	296.00	296.00	¥637,288.00	¥0.00	¥637,288.00
15	1012.00	1012.0	2025.0	314.00	296.00	¥299,552.00	¥18,216.00	¥317,768.00
16	1258.00	1258.0	1550.0	276.00	248.00	¥311,984.00	¥35,224.00	¥347,208.00
17	900.00	882.0	900.0	294.00	294.00	¥264,600.00	¥0.00	¥264,600.00
18	519.46	392.0	600.0	296.00	296.00	¥153,760.16	¥0.00	¥153,760.16
					Totals:	¥5,030,523.78	¥450,549.00	¥5,481,072.78
		Load Demand:		18000 MW			Average Prices:	¥304.54

Comparing the results from this table to those in Table 4.5-2, it is interesting to note that the average energy purchase cost is the same under the two energy pricing methods. This is not coincidental and can be explained by the uplift payment component in the LMP method.

Table4.5-6: 10% Bidding - All Generations Paid by LMPs

Unit Name	Dispatch MW	Economic dispatch Min	Economic dispatch Max	Generation Cost (¥/MWh)	LMP (¥/MWh)	Pay for Market Dispatched Gen	Uplift Pay	Total Pay
1	869.00	869.0	1200.0	330.00	294.00	¥255,486.00	¥31,284.00	¥286,770.00
2	3332.68	2314.0	3600.0	248.00	248.00	¥826,504.64	¥0.00	¥826,504.64
3	0.00	0.0	600.0	0.00	279.25	¥0.00	¥0.00	¥0.00
4	539.95	188.0	4200.0	294.00	294.00	¥158,745.30	¥0.00	¥158,745.30
5	1517.37	1101.0	1600.0	297.00	297.00	¥450,658.89	¥0.00	¥450,658.89
6	687.00	638.0	800.0	294.00	294.00	¥201,978.00	¥0.00	¥201,978.00
7	566.00	566.0	660.0	300.00	276.96	¥156,759.36	¥13,040.64	¥169,800.00
8	1025.00	1025.0	1200.0	298.00	262.26	¥268,816.50	¥36,633.50	¥305,450.00
9	1374.00	1374.0	2200.0	390.00	296.54	¥407,445.96	¥128,414.04	¥535,860.00
10	258.00	258.0	500.0	300.00	276.96	¥71,455.68	¥5,944.32	¥77,400.00
11	1671.00	1671.0	2400.0	358.00	298.72	¥499,161.12	¥99,056.88	¥598,218.00
12	771.00	771.0	1000.0	297.00	262.26	¥202,202.46	¥26,784.54	¥228,987.00
13	669.00	669.0	1000.0	276.00	262.08	¥175,331.52	¥9,312.48	¥184,644.00
14	1999.00	1999.0	3600.0	296.00	295.64	¥590,984.36	¥719.64	¥591,704.00
15	958.00	958.0	2025.0	314.00	276.96	¥265,327.68	¥35,484.32	¥300,812.00
16	263.00	263.0	1550.0	276.00	265.25	¥69,760.75	¥2,827.25	¥72,588.00
17	900.00	836.0	900.0	294.00	294.00	¥264,600.00	¥0.00	¥264,600.00
18	600.00	371.0	600.0	296.00	298.46	¥179,076.00	¥0.00	¥179,076.00
					Totals:	¥5,044,294.22	¥389,501.61	¥5,433,795.83
		Load Demand:		18000MW			Average Prices:	¥301.88

Comparing the results from this table to those in Table4.5-3, the average energy purchase (5% differences are caused by LMP rounding errors) costs are the same under the two energy pricing methods. This can similarly be explained by the uplift payment component in the LMP method.

4.5.3 Compare regulated-market hybrid pricing method and LMP method

As the LMP method is not applicable to the no-bidding scenario, and the LMP method is already applied to the 100% bidding scenario. Compare regulated-marked hybrid pricing method and LMP method, the following tables describes the results for the 5% and 10% bidding scenarios.

Table 4.5.-7: 5% bidding - Compare regulated-marked hybrid pricing (RMHP) method and LMP method

Unit Name	Dispatch MW	Generation Cost (¥/MWh)	LMP (¥/MWh)	Pay for scheduled Gen (RMHP)	Pay for Market Dispatched Gen (RMHP)	Total Pay (RMHP)	Pay for Market Dispatched Gen (LMP)	Uplift Pay (LMP)	Total Pay (LMP)
1	917.00	330.00	294.00	¥302,610.00	¥0.00	¥302,610.00	¥269,598.00	¥33,012.00	¥302,610.00
2	2212.59	248.00	248.00	¥448,632.00	¥100,090.32	¥548,722.32	¥548,722.32	¥0.00	¥548,722.32
3	0.00	0.00	296.00	¥0.00	¥0.00	¥0.00	¥0.00	¥0.00	¥0.00
4	491.95	294.00	294.00	¥58,212.00	¥86,421.30	¥144,633.30	¥144,633.30	¥0.00	¥144,633.30
5	1163.00	297.00	296.00	¥345,411.00	¥0.00	¥345,411.00	¥344,248.00	¥1,163.00	¥345,411.00
6	687.00	294.00	294.00	¥197,862.00	¥4,116.00	¥201,978.00	¥201,978.00	¥0.00	¥201,978.00
7	597.00	300.00	296.00	¥179,100.00	¥0.00	¥179,100.00	¥176,712.00	¥2,388.00	¥179,100.00
8	1082.00	298.00	248.00	¥322,436.00	¥0.00	¥322,436.00	¥268,336.00	¥54,100.00	¥322,436.00
9	1451.00	390.00	296.00	¥565,890.00	¥0.00	¥565,890.00	¥429,496.00	¥136,394.00	¥565,890.00
10	273.00	300.00	296.00	¥81,900.00	¥0.00	¥81,900.00	¥80,808.00	¥1,092.00	¥81,900.00
11	1763.00	358.00	296.00	¥631,154.00	¥0.00	¥631,154.00	¥521,848.00	¥109,306.00	¥631,154.00
12	814.00	297.00	248.00	¥241,758.00	¥0.00	¥241,758.00	¥201,872.00	¥39,886.00	¥241,758.00
13	706.00	276.00	248.00	¥194,856.00	¥0.00	¥194,856.00	¥175,088.00	¥19,768.00	¥194,856.00
14	2153.00	296.00	296.00	¥624,560.00	¥12,728.00	¥637,288.00	¥637,288.00	¥0.00	¥637,288.00
15	1012.00	314.00	296.00	¥317,768.00	¥0.00	¥317,768.00	¥299,552.00	¥18,216.00	¥317,768.00
16	1258.00	276.00	248.00	¥347,208.00	¥0.00	¥347,208.00	¥311,984.00	¥35,224.00	¥347,208.00
17	900.00	294.00	294.00	¥259,308.00	¥5,292.00	¥264,600.00	¥264,600.00	¥0.00	¥264,600.00
18	519.46	296.00	296.00	¥116,032.00	¥37,728.16	¥153,760.16	¥153,760.16	¥0.00	¥153,760.16
Total	18000MW			¥5,234,697.00	¥246,375.78	¥5,481,072.78	¥5,030,523.78	¥450,549.00	¥5,481,072.78
					Average Prices:	¥304.54			¥304.54

Table 4.5.-8: 10% bidding - Compare regulated-marked hybrid pricing method and LMP method

Unit Name	Dispatch MW	Generation Cost (¥/MWh)	LMP (¥/MWh)	Pay for scheduled Gen (RMHP)	Pay for Market Dispatched Gen (RMHP)	Total Pay (RMHP)	Pay for Market Dispatched Gen (LMP)	Uplift Pay (LMP)	Total Pay (LMP)
1	869.00	330.00	294.00	¥286,770.00	¥0.00	¥286,770.00	¥255,486.00	¥31,284.00	¥286,770.00
2	3332.68	248.00	248.00	¥573,872.00	¥252,632.64	¥826,504.64	¥826,504.64	¥0.00	¥826,504.64
3	0.00	0.00	279.25	¥0.00	¥0.00	¥0.00	¥0.00	¥0.00	¥0.00
4	539.95	294.00	294.00	¥55,272.00	¥103,473.30	¥158,745.30	¥158,745.30	¥0.00	¥158,745.30
5	1517.37	297.00	297.00	¥326,997.00	¥123,661.89	¥450,658.89	¥450,658.89	¥0.00	¥450,658.89
6	687.00	294.00	294.00	¥187,572.00	¥14,406.00	¥201,978.00	¥201,978.00	¥0.00	¥201,978.00
7	566.00	300.00	276.96	¥169,800.00	¥0.00	¥169,800.00	¥156,759.36	¥13,040.64	¥169,800.00
8	1025.00	298.00	262.26	¥305,450.00	¥0.00	¥305,450.00	¥268,816.50	¥36,633.50	¥305,450.00
9	1374.00	390.00	296.54	¥535,860.00	¥0.00	¥535,860.00	¥407,445.96	¥128,414.04	¥535,860.00
10	258.00	300.00	276.96	¥77,400.00	¥0.00	¥77,400.00	¥71,455.68	¥5,944.32	¥77,400.00
11	1671.00	358.00	298.72	¥598,218.00	¥0.00	¥598,218.00	¥499,161.12	¥99,056.88	¥598,218.00
12	771.00	297.00	262.26	¥228,987.00	¥0.00	¥228,987.00	¥202,202.46	¥26,784.54	¥228,987.00
13	669.00	276.00	262.08	¥184,644.00	¥0.00	¥184,644.00	¥175,331.52	¥9,312.48	¥184,644.00
14	1999.00	296.00	295.64	¥591,704.00	¥0.00	¥591,704.00	¥590,984.36	¥719.64	¥591,704.00
15	958.00	314.00	276.96	¥300,812.00	¥0.00	¥300,812.00	¥265,327.68	¥35,484.32	¥300,812.00
16	263.00	276.00	265.25	¥72,588.00	¥0.00	¥72,588.00	¥69,760.75	¥2,827.25	¥72,588.00
17	900.00	294.00	294.00	¥245,784.00	¥18,816.00	¥264,600.00	¥264,600.00	¥0.00	¥264,600.00
18	600.00	296.00	298.46	¥109,816.00	¥68,347.34	¥178,163.34	¥179,076.00	¥0.00	¥179,076.00
Total	18000MW			¥4,851,546.00	¥581,337.17	¥5,432,883.17	¥5,044,294.22	¥389,501.61	¥5,433,795.83
					Average Prices:	¥301.83			¥301.88

Comparing the results from Table4.5-7 and Table 4.5-8, is interesting to note that the average energy purchase cost is the same under the two energy pricing methods. This can similarly be explained by the uplift payment component in the LMP method.

4.6 SUMMARY

It is feasible to apply the LMP based market model at NCGC. Today, the world largest RTO grid is operated under an LMP based market mode. These RTO grids include PJM with an installed generation capacity of about 140,000MW, and Mid West ISO with a transmission network of about 30,000 buses. Simulation results indicate that the LMP based market dispatch and congestion management enhance grid security and improve generation production efficiency.

LMP based market model creates market incentives that are compatible with short-term grid security and long-term resource adequacy requirements. LMPs represent the spot market value of energy production and supply at a given location that reflects the requirements to meet load demand and satisfy grid security requirements. Market incentives that induce short-term security and long-term adequacy responses from market participants are critical for creation of competitive markets that allow participant choices.

Implementation of an LMP based market shall follow an evolutionary path. The experiences with the existing LMP markets indicated that it works better when market functions are incrementally added. Existing successful markets, such as PJM, provided insights as to where to start with in implementation. In PJM, real-time LMP market was first implemented, followed by FTR market, day-ahead market, real-time dispatch system, and ancillary service market.

Market system technology must be able to accommodate the nature market evolution. Market based operation have two critical tasks: physical grid operation and market operation. The adopted system technology must be able to handle evolving system change requirements and at the same time maintain a stable technology platform for the secure operation of the physical grid.

Increased competition improves grid security and reduces generation cost. Our simulation studies indicate that as market competition increases from no bidding to 100% generation capacity bidding, grid security requirements are continuously maintained, but generation production cost decreases substantially. The latter measure is demonstrated with decreases in average energy cost.

Local realities must be checked in choosing a pricing method. Analyses of alternative spot market energy pricing methods indicate that it is possible to apply either a regulated-market hybrid pricing method or an LMP method. However, it should be pointed out that the hybrid method may result in participants' responses to market incentives that are not desirable for secure grid operation. This effect is likely to require stricter and more complicated market surveillances.

It is interesting to note that the simulation results have demonstrated that the average energy purchase costs continuously to decrease with the increases of competitive bidding.

Some recommendations for future efforts:

- With an advanced understanding of the LMP based energy market model, it is beneficial to conduct studies of other LMP market related models, such FTR market and ancillary service market.

- It will also be beneficial to study further real-time pricing alternatives. In the existing LMP based market, two pricing methods for real-time market are used: ex ante and ex post pricing. With the ex ante pricing method, real-time market prices are determined based on the real-time look-ahead dispatch in terms of projected system conditions. The ex post real-time pricing method determines real-time LMPs based on the actual system conditions that have happened on the grid during real-time operation. The ex ante pricing method is used in NY ISO, and the ex post method is used at PJM, ISO NE and MISO.

CHAPTER 5

THE EFFECTS OF LOCATIONAL MARGINAL PRICE ON ELECTRICITY MARKET WITH DISTRIBUTED GENERATION

5.1 INTRODUCTION

Conventionally, there are two different paths electricity generators can be connected into the electricity supply system. These two paths are at the level of the high voltage transmission network and at the low voltage distribution network respectively. The first method is known as centralized generation where all the large generators dispatch its power into the national grid. The second method is known as distributed generation where all the power is fed directly into the distribution network.

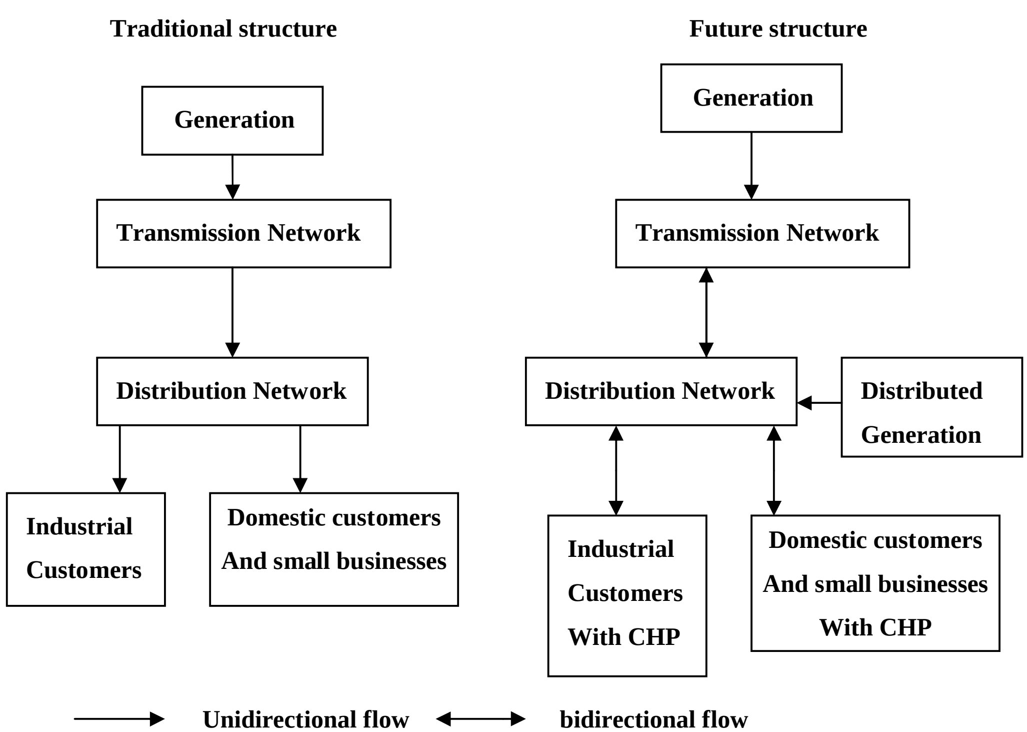


Figure 5-1 the changing structure of distribution system with and without distributed generation

Distributed generation takes place on two-levels: the local level and the end-point level. Local level and end point are really disrupting the plan of connections of generators to the network. End-point connections are used to describe connections at or near the end of distribution feeders, and may even be at the low voltage level. Local connections tend to be near at the HV side of the distribution network. Power generation plants often include renewable energy technologies that are site specific, such as wind turbines, geothermal energy production, solar systems (photovoltaic and combustion), and some hydro thermal plants. These plants tend to be smaller and less centralized than the traditional model plants, but they can be cost efficient and can be more reliable. Since these local level DG producers often take into account the local context, the usually produce less environmentally damaging or disrupting energy than the larger central model plants [1].

The objectives for electricity sector are to ensure that electricity is produced and delivered to the consumers in an efficient, fair, reliable and environmentally sustainable manner and also to promote and facilitate the efficient use of energy. Distributed generation (DG) can help to achieve these objectives, particularly in terms of efficiency and security of supply. Therefore, the impact (i.e., costs and benefits) of DG should be recognized, allocated and valued properly in order to efficiently manage the network.

In this chapter, a method to calculate the locational marginal price (LMP) and its cost components of electricity in a power network with distributed generation (DG) was proposed. The cost components include energy cost, marginal loss cost and marginal congestion cost. The values of these cost components can provide the correct price signals for the choice of site for distribution generation. Through a six-bus study case, and by altering the data input to simulate system changing conditions, the results of the proposed method clearly demonstrate the changing values of the cost components.

5.2 DEFINITION OF DISTRIBUTED GENERATION (DG)

In literature, a lot of terms and definitions are used in relation to distributed generation. For example, in North America, it is called dispersed generation, in South America they are called embedded generation while in Europe and some Asian countries they are called decentralized generation [2]. Nevertheless, dispersed generation, embedded generation, or decentralised generation, all referred to the same term as distributed generation [3] [4] [5] [6].

Distributed generation is an approach that employs small-scale technologies to produce electricity close to the end users of power. DG technologies often consist of modular (and sometimes renewable-energy) generators, and they offer a number of potential benefits. In many cases, distributed generators can provide lower-cost electricity and higher power reliability and security with fewer environmental consequences than can traditional power generators.

Voltage level at grid connection (transmission/distributions) [7]

Although some authors allow distributed generation to be connected to the transmission grid, most authors see distributed generation as being connected to the distribution network, either on the distribution or on the consumers' side of the meter. In all cases, the idea is accepted that distributed generation should be located closely to the load. The problem is that a distinction between distribution and transmission grid, based on voltage levels, is not always useful, because of the existing overlap of these voltage levels for lines in the transmission and distribution grid. Moreover, the ‘legal’ voltage level that distinguishes distribution from transmission can differ from region to region. Therefore, it is best not to use the voltage level as an element of the definition of distributed generation. It would be more appropriate to use the concepts ‘distribution network’ (usually radial) and ‘transmission network’ (usually mashed) and to refer to the legal definition of these networks as they are used in the country under consideration.

Generation capacity (MW) [7]

One of the most obvious criteria would be the generation capacity of the units installed. However, the short survey of definitions illustrated that there is no agreement on maximum generation capacity levels and the conclusion is that generation capacity is not a relevant criterion. The major argument is that the maximum distributed generation capacity that can be connected to the distribution grid is a function of the capacity of the distribution grid itself. Because this latter capacity can differ widely, it is not possible to include it as an element of the definition of distributed generation. However, this does not imply that the capacity of the connected generation units is not important. On the contrary, many of the policy issues and benefits are related to the capacity of the generation units.

Thus, a narrowed definition of distributed generation could, among other things, be based on the generation capacity criterion.

Services supplied [7]

Generation units should by definition by at least supply active power in order to be considered as distributed generation. The supply of reactive power and/or other ancillary services is possible and may represent an added value, but it is not necessary.

Generation technology [7]

In some cases, it can be helpful to clarify the general definition of distributed generation by summing up the generation technologies that are taken into account. It would however be difficult to use this approach to come to a definition because the availability of (scalable) technologies and of capacities, especially in the field of renewables, differs between countries. Also conventional systems such as gas turbines are available over wide ranges (a few kW to 500 MW).

Sometimes, it is claimed that distributed generation technologies should be renewable. However, it should be clear from section 1 that many small-scale generation technologies exist not using renewables as a primary source. On the other hand, not all plants using 'green' technologies are supplying distributed generation. This would, for example, depend on the plant size or on the grid to which the installation is connected (transmission or distribution). Should a large offshore wind farm of 100 MW be considered as distributed generation? And what about a large hydro power plant located in the mountains?

Operation mode [7]

Ackermann et al. (2001) do not consider the operation mode (being scheduled, subject to pool pricing, dispatchable…) as a key element in the general definition of distributed generation. This is a correct view, but at the same time it must be recognised that many of the problems related to distributed generation, essentially have to do with the fact that these generation units are beyond control of grid operators. So, it can be meaningful to use (elements of) the operation mode as a criterion to narrow the definition.

Power delivery area [7]

In some cases, distributed generation is described as power that is generated and consumed within the same distribution network. As correctly stated by Ackermann, Andersons et al. (2001), it would be difficult to use this as a criterion, even for a narrowed definition, because it requires complex power flow analyses.

Ownership [7]

Ackermann et al. (2001) do not consider ownership as a relevant element for the definition of distributed generation. Thus, customers, IPPs and traditional generators can own distributed generation units.

5.3 IMPACT OF DISTRIBUTED GENERATION [18]

A lot of new DG technologies have been used at the distribution level. When the penetration of this distributed generation is low, the impacts of the DG on the transmission system transient stability may be neglected. However, when the penetration of DG increases, its impact is no longer confined to the distribution network but it can influence the whole system. Some of the impacts of distributed generation are discussed as below.

5.3.1 Impact on voltage levels

Distributed generation connected to the distribution network can improve the voltage levels in the network that suffer large drops at high loads. DG can also regulate voltage by balancing loads fluctuation with generation output. Due to the presence of DG the distribution network has become on active network (bilateral flow) as well as the voltage profile in the network. The voltage problems occur typically in rural areas where distribution network is weak. There are number of standard voltages in use on the distribution system and load can be connected at one of these levels as in table (5-1). DG that helps to provide reactive power and improves distribution network voltage profile should be able to offset the cost of connection.

Voltage level	Nominal V	DG rated power
Lower Voltage (LV)	230V(single phase)	< 5KW
	400V(three phase)	<100KW
Medium Voltage (MV)	10KV	<5MW
	20KV	<20MW
	38KV	>20MW (HV)
High Voltage (HV)	110KV	>20MW

Table 5-1 various voltage level on distribution network

5.3.2 Impact on Network Losses

The relationship between DG and network losses could be complex and dependent on the location of the connection, its operation, the type of network and the interaction between demand and generation. DG connections may reduce the losses at some voltage levels while increasing the losses at other voltage levels as shown in [8]. DG unit which is connected to the substation with a dedicated feeder are likely to increase network losses because the power is transmitted to the substation before delivered to the customers. However, in the case of DG unit connected to the local demand on an existing feeder, the network losses are likely to decrease as the power transmitted from the substation reduces. If the level of power generation exceeding the demand, the power is then fed upwards to the substation and the network losses and would start to increase again at a certain point.

5.3.3 Impact on Network Protection

Traditionally distribution networks have been designed to operate racially (unidirectional) so that the power flows from upper voltage levels through main transformers down to customers situated along the radial feeders. This has enabled a relatively straightforward protection strategy. When applying over-current protection, for example, it has been possible to assume that the fault current can have only one direction [9] so that the feeder protection is easily achieved. However, this is not applicable if there are distributed generation units such as wind turbines that cause bi-directional flow on the network. In the presence of DG, the current amplitude will change resulting in unwanted operation of protection scheme [10]. Some of the typical feeder protection problems such as false tripping of feeders, blinding protection, unwanted islanding, automatic and unsynchronized reclosing has been studied in [11].

5.3.4 Impact on Fault Levels and Power Quality

Power qualities include frequency, amplitude, fast voltage transients, waveform, symmetry, service interruptions and different kinds of network disturbances. In the presence of distributed generation, it will increase the fault level at the connection point and thereby strengthen the distribution network, so that the magnitude of the voltage flicker is reduced. The strength of the network is directly related to its short circuit level. The higher the short circuit level, the stronger the network will be hence it is better to accommodate any disturbances to the network such as switching of major equipments like generators, capacitors and reactors.

5.3.5 Impact on Transmission Fees

The cost of providing the transmission and distribution systems include capital expenditure (e.g. asset replacement) and revenue expenditure (e.g. system operation and losses) and these costs are recovered through the Use of System (UoS) charges collected by the network operators. DG connected close to an existing grid or distribution network may increase or reduce network tariff (i.e., connection charges or use of system charges) and also system charges (i.e., charges for balancing, reserves and ancillary services). Furthermore, DG allows network reinforcement to be delayed or avoided in such a way that contracted power can be delivered to the network without any constraints and hence reduce the power transported from transmission system to the distribution system. It also provides benefits to the end customer by offsetting some of the system operating cost at the times of peak demand.

5.4 APPLICATION FOR DISTRIBUTED GENERATION

Distributed generation can be used for many application, such as generating power providing standby service or reserve capacity, reduce customer's overall cost of power by shaving peak demand, providing ancillary services and serving as a standalone generation and co-generation (i.e., CHP).

Some customers are sensitive to power outage that they need standby generation onsite to supply power themselves until utility service is restored. These standby generators are highly underutilized generating resources. However, they are required by law to maintain public health and safety such as for hospitals.

Applying DG during peak demand could reduce customer's overall cost of power. By reducing or eliminating demand during peak demand, customers can reduce or avoid purchasing power when it is the most expensive where DG helps to reduce the need for purchasing power from expensive spot markets and also helps to stabilize energy prices.

Another application of DG is to provide grid support to the power system which is also part of the ancillary service in order to maintain a sustained and stable operation of the grid. These grid supports include stabilizing voltage and frequency drop due to a sudden generation under capacity or excess demand, reduced reserve requirement of central generating station and avoid or defer network reinforcement. In some cases, grid isolation with DG may be more economical than integrating with power grid. It serves as a standalone back-up power source ensuring continued operations during grid failures and avoiding economic losses.

5.5 BENEFITS OF DISTRIBUTED GENERATION[18]

The benefit of Distributed Generation (DG) was not noticed until about became almost extinct in the period to 1990. The primary reason for this was that the economies gained by building larger power stations outweighed the additional costs of transporting the electricity to consumers (i.e. via the transmission system). The fundamental benefit of DG remains that it promises significant reductions in this transportation cost. The precise potential for efficiency gains and emissions savings varies depending on the generation technology and the location of the generation unit. Technologies using renewable energy sources often need to be located near consumers in order for them to take advantage of localised energy resources. Overall, as smaller generation technologies reduce their capital and operating costs compared with larger generators their transportation benefits will encourage their further growth.

Distributed generation can be used for many applications, such as generating power, providing standby service or reserve capacity, reduce customer overall cost of power by shaving peak demand, providing ancillary services and serving as a stand-alone generation and co-generation (i.e., CHP). However the most common use of DG is as a backup power whenever the normal source of electricity fails.

Given the potential applications, distributed generation provides several benefits to both developers and end-use customers. DG helps to meet the growth in demand under small-scale distributed generation projects. It also has the advantage relative to the grid connected generation of being more closely connected to customers. This proximity can help reduce distribution and transmission losses, reduce constraints on lines that are at or near the capacity, and potentially defer the need for new investment in constrained parts of the transmission or distribution network.

There is also a potential in enhancing network security of power supply with the investment of DG since it is closely located to the load center and is more dispersed compared to traditional centralized generation. The effects of any unexpected outage at a single generation plant or constraint on a transmission line may be reduced. To some extent, DG based on renewable energy may also assist in meeting government's climate change objective. Furthermore, any reduction in network losses with DG would reduce carbon contributions from thermal generation that is displaced. In general, as more market participants enter the generation market, competition increases hence a lower electricity price can be offered to consumer.

5.6 THE EFFECTS OF LOCATIONAL MARGINAL PRICE ON DISTRIBUTED GENERATION [19]

The spot price of electricity in a deregulated market often experiences high price volatility because of uncertainties in available transmission lines capacities, weather, fuel prices, electricity demand and generation, transmission and distribution costs [12]. Therefore, in addition to a transparent and non- discriminatory pricing framework it is important to have the ability to predict the effects on the price with respect to changing system condition.

In order to efficiently use generation resources and the transmission grid in a competitive environment, spot pricing has become the most widely used approach for scheduling and pricing non-discriminatory transmission access and assists the operation of wholesale electricity spot markets, particularly through the use of locational-based marginal pricing [13][14]. LMP at a location is defined as the marginal cost to supply an addition of one MW of load demand at that location without violating any system security limits. Usually LMP varies throughout the system because of the effect of transmission losses and transmission system congestion [15].

An important feature of LMP is that it provides an efficient price signal not only for short-term operations but also for long-term investments [12][13][16]. The advantages of LMP are that, they reflect the actual cost of actual power flow in a system and LMP changes with the changes of system conditions and thereby it provides an appropriate signal for resources to adapt to those changes.

5.6.1 Test systems

In this Section, POWERWORLD^{TM} simulation is used to run ACOPF for a six-bus system (the test system similar to the one described in section (3.4.3)) to analyze the effect of LMP with different cases.

5.6.2 Market model for an unconstrained network with and without losses

Figure (5-2(a)) gives the results of the unconstrained optimization without loss case. In an unconstrained and lossless system the LMP is the same at all buses throughout the system and in this case it is set by the marginal generator #1 at £13/MWh as illustrated in Figure (5-3). The cost of marginal losses, in this case, is equal to zero. If losses are to be included the LMP is no longer uniform across the system, but takes a different value at each bus as shown in Figure (5-2(b)). This is because losses have caused the prices at each node to vary relative to the single bus reference. Generator #1 is still the marginal generator because it will meet the next incremental of demand in the system. The price differences on each bus in the system are due to the cost of energy at the angle reference bus plus the cost for sending the energy across the transmission system (i.e., losses on the line).

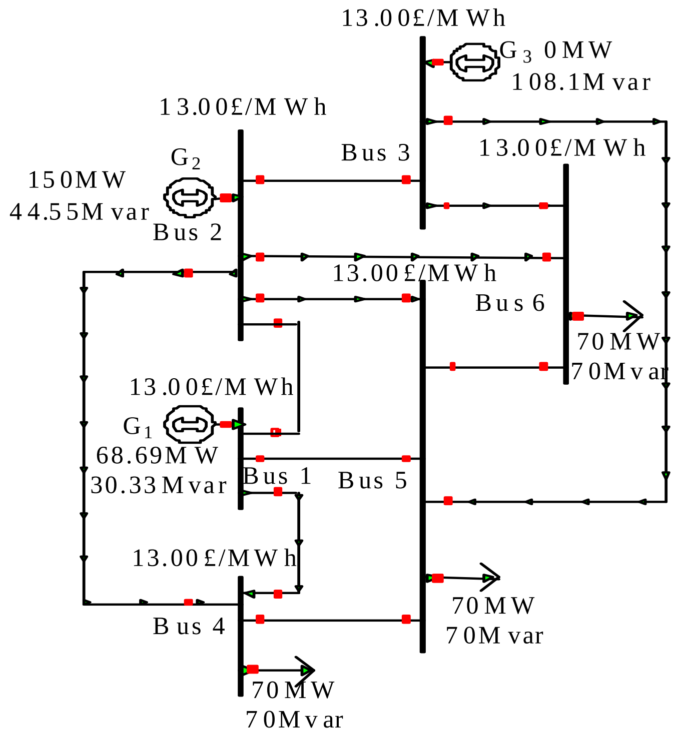


Figure 5-2(a) unconstrained without losses

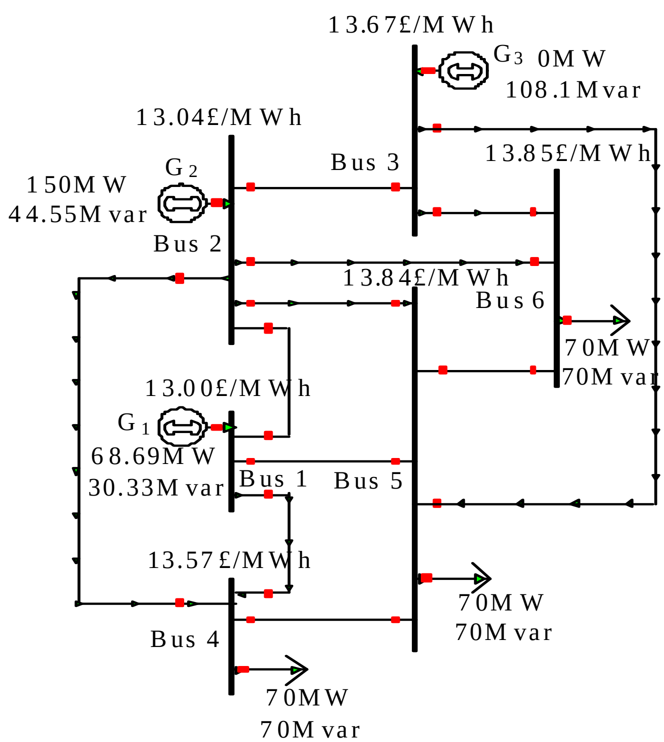


Figure 5-2(b) unconstrained with losses

Table (5-2) gives a clearer picture; the LMP at the receiving end bus of a line is slightly higher than that at the sending end bus. This is due to the cost of transmission losses across the line. It is worth noting that the power flows in Figure (5-2(a)) and Figure (5-2(b)) both satisfied the active power balance of chapter (3) Equation (3-2). This may seem contradictory to the captions in the diagram, but if one looks closely the total losses in the network is 8.69MW and if it is necessary to be excluded, it is simply necessary to reduce the generation of G1 to 60 MW in Figure (5-2(a)). All the discussion and explanation are still fully valid.

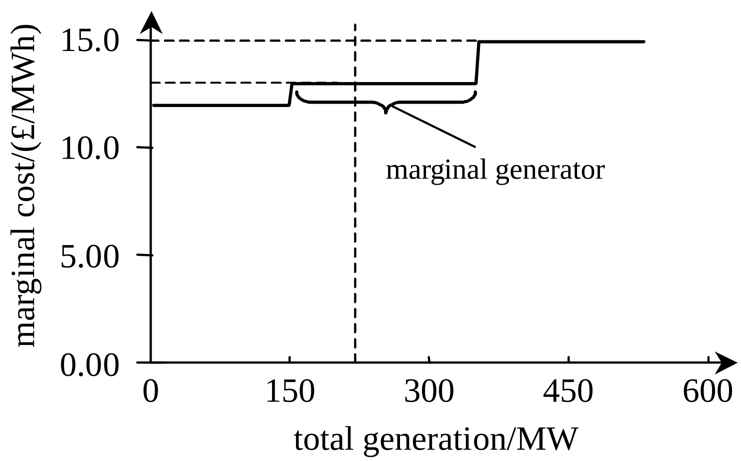


Figure 5-3 Marginal generator control for six-bus system

Line	Fr bus, λ_i / (£ / MWh)	To bus, λ_i / (£ / MWh)	$\lambda_{ij} = \lambda_j - \lambda_i$
L1-2	13.00	13.04	0.04
L1-4	13.00	13.57	0.57
L1-5	13.00	13.84	0.84
L2-3	13.04	13.67	0.63
L2-4	13.04	13.57	0.53
L2-5	13.04	13.84	0.80
L2-6	13.04	13.85	0.81
L3-5	13.67	13.84	0.17
L3-6	13.67	13.85	0.18
L4-5	13.57	13.84	0.27
L5-6	13.84	13.85	0.01

Table 5-2 Price comparison between two buses under unconstrained network with losses

5.6.3 Market model for a constrained network

In this section the effects of transmission line limits on LMPs will be investigated. The same data for the six-bus, three-supplier system with thermal limit of each line, as defined in the last column of chapter (3) Table (3-1), was enforced. The results are shown in Figure (5-2).

In Figure (5-4(a)) the percentage of line loadings are indicated but the line thermal limits are not enforced. This means that the LMPs and generator outputs should be similar to those in Figure (5-2(b)). Some of the flows over the transmission lines have exceeded their upper limits. In order to give a better illustration of the results AC OPF is used. The results are shown in Figure (5-4(b)). The imposition of line limits resulted in a different LMP at each node. The differences at some nodes could be significant and this is because of 'transmission line congestion'. The outputs of generators will be different from those of 'no line limits' and these are given in

Table (5-3); Table (5-4) gives the results of line flows prior to and after line limits imposition. It might be worth noting that the flows of line 1-5 and 2-5 are sitting on their upper limits.

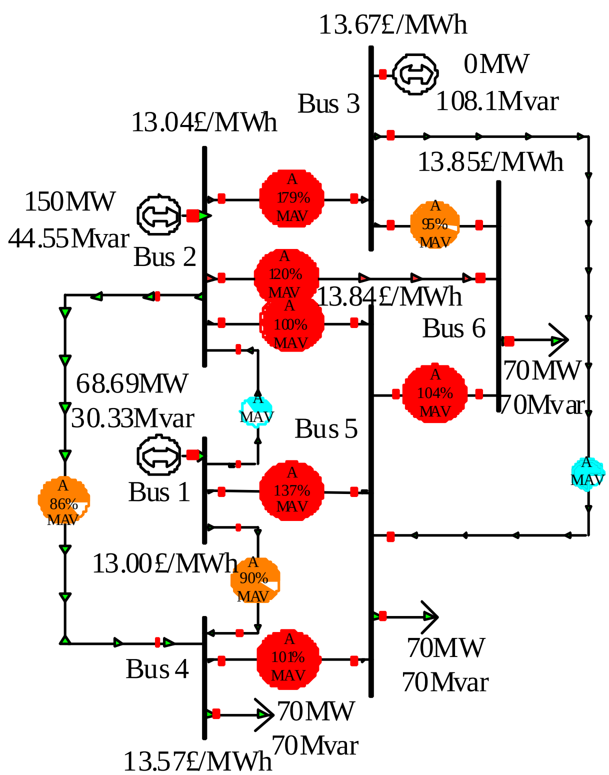


Figure 5-4 (a) constrained six bus system: thermal limit not enforce

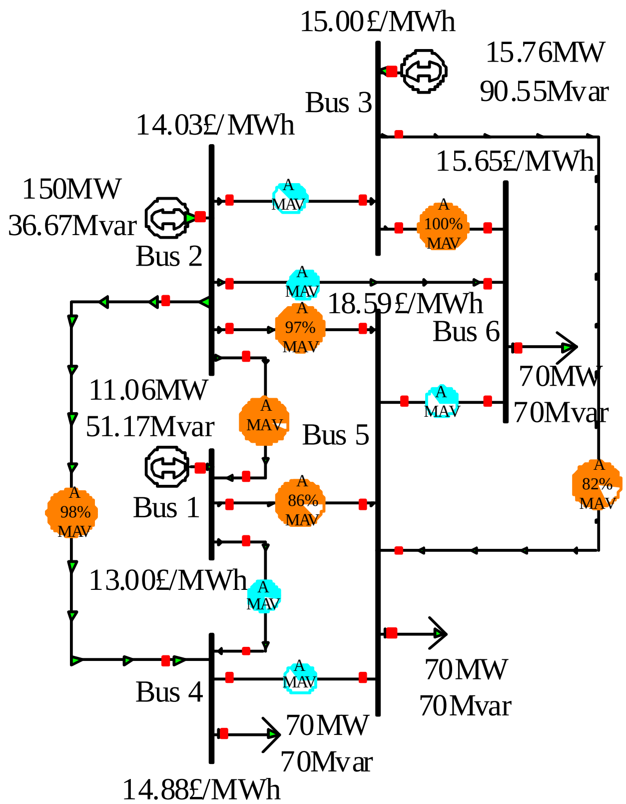


Figure 5-4 (b) constrained six bus system: thermal limit not enforce

Another important issue is the selection of angle reference bus. The variation of choice for the angle reference bus does not affect the LMP value at a given node. However it could have a big effect on the component costs of LMP at some nodes. This is demonstrated in Table (5-5) where each node in the system is chosen in turn to be the angle reference node. It is clearly illustrated that the component costs are not the same when the angle reference node is changed but the LMP at a given node remains the same.

Gen	Line Limits not Enforced		Line Limits Enforced	
	P(MW)	*Q*(MVar)	*P*(MW)	*Q*(MVar)
#1	68.69	30.33	11.06	51.17
#2	150.00	44.55	150.00	36.67
#3	0.00	108.1	56.76	90.55

Table 5-3 Generators outputs with and without line limits enforced in constrained system

Line	Line Flows without Line Limits Enforced(MVA)		Line Flows with Line Limits Enforced(MVA)		Limit(MVA)
	To(MVA)	Fr(MVA)	To(MVA)	Fr(MVA)	
L1-2	7.05	8.96	18.46	16.49	20
L1-4	38.31	37.99	33.32	31.56	40
L1-5	34.56	34.31	25.00	21.58	25
L2-3	33.54	35.75	12.58	17.07	45
L2-4	61.70	64.29	70.20	73.83	75
L2-5	29.90	30.00	29.24	29.19	30
L2-6	46.83	48.14	35.46	35.26	50
L3-5	31.95	29.48	33.65	32.84	40
L3-6	68.36	70.91	71.84	74.76	75
L4-5	7.36	10.06	4.17	6.37	20
L5-6	5.35	10.37	4.57	9.05	20

Table 5-4 Line flows before and after line limits enforced on the six-bus test system

Ref Bus	Bus #1				Bus #2				Bus #3				Bus #4				Bus #5				Bus #6			
	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP	Energy	loss	cong	LMP
Bus #1	13.00	0	0	13.00	14.05	0.57	-1.62	13.00	15.00	0.30	-2.30	13.00	14.88	-0.28	-1.60	13.00	18.59	-0.45	-5.14	13.00	15.65	-0.05	-2.60	13.00
Bus #2	13.00	-0.51	1.56	14.05	14.05	0	0	14.05	15.00	-0.3	-0.65	14.05	14.88	-0.85	0.02	14.05	18.59	-1.16	-3.38	14.05	15.65	-0.66	-0.94	14.05
Bus #3	13.00	-0.25	2.25	15.00	14.05	0.29	0.66	15.00	15.00	0	0	15.00	14.88	-0.57	0.69	15.00	18.59	-0.80	-2.79	15.00	15.65	-0.35	-0.30	15.00
Bus #4	13.00	0.25	1.63	14.88	14.05	0.85	-0.02	14.88	15.00	0.59	-0.71	14.88	14.88	0	0	14.88	18.59	-0.1	-3.61	14.88	15.65	0.25	-1.02	14.88
Bus #5	13.00	0.32	5.27	18.59	14.05	0.93	3.61	18.59	15.00	0.68	2.91	18.59	14.88	0.08	3.63	18.59	18.59	0	0	18.59	15.65	0.34	.60	18.59
Bus #6	13.00	0.04	2.61	15.65	14.05	0.61	0.99	15.65	15.00	0.34	0.31	15.65	14.88	-0.24	1.01	15.65	18.59	-0.40	-2.54	15.65	15.65	0	0	15.65

Table 5-5 LMP components of a constrained six-bus system

5.6.4 Market model on congested network with distributed generation

Under the traditional vertically integrated energy market, utilities normally predict and estimate future energy demand in their area so that new generation capacity or transmission upgrades can be built accordingly. All these actions are taken centrally and there could well be hidden cross subsidies between generation, transmission and/or distribution departments.

However in a deregulated energy market, generation, transmission and distribution are separate businesses and no hidden cross subsidies are tolerated. A generator normally knows the current demand from the published network historical data and will bid in an appropriate way into the market to supply a certain proportion of the load demand. The energy demand prediction which in this case will be done by the system operator as well as independently by the generator will provide an incentive for generator to build a new power plant (e.g., distributed generation) or for system operator or transmission network owner to reinforce existing transmission capacities in accordance with changing demand.

Although the capacity of the distributed generations is inherently small-scale, this has some distinct advantages such as increased flexibility in sitting, operation and planning. It could also increase the system security. The recent actions by governments around the world to combat global warming have resulted in an increased interest in the renewable distributed generation. The capacity of an individual DG generator is usually small and it is also more expensive to construct. Its location or sitting or point of system connection becomes crucial to its economic viability. In the following two sections two important factors are analysed: the effects of the marginal cost of the generator and the effects of the installed capacity.

In the constrained network with line limits enforced, Table (5.5.4) shows that bus #5 has the highest LMP at £18.59/MWh. Therefore, it is logical from the generator point of view that by installing a generator at this node it should give the highest return of revenue.

The cost of the generator is reflected as the marginal cost of the generator. It has already been demonstrated in Section (5.5.3) that the selection of angle reference bus will only change the LMP component values but will not change the LMP value itself, hence all the following results are based on angle reference bus #1 unless otherwise stated.

(1) Effects of Marginal Cost of DG.

Generally, the equivalent cost of a DG from renewable sources is more expensive than that from a conventional power source [17]. This is a disadvantage for DG when it comes to integrating into the grid system as it doesn't promote competition. This will likely to result in a reduced role for renewable in the grid system if the generator marginal cost of distributed generator is very high. In the following example three different one-part bid generator cost curves are used and the costs are shown in Figure (5-5). This DG is to be connected at node #5 with a maximum installed capacity of 100MW.

The simulated results for LMPs are plotted in Figure (5-6). The LMP values for the base case are shown in row 1 of Table (5-6). The values vary over a wide spectrum ranging from £13.00/MWh to £18.59/MWh, a variation of 43.0% over the lower end, and they are unevenly distributed across the network. When a DG is added at bus #5 with a marginal price of £10/MWh and £12/MWh respectively the resulting LMP values are much more evenly distributed across the network. This can be seen from Figure (5-6) where the two distribution curves almost overlap with each other. The spectrum of LMP variation is also much narrower ranging only from £11.96/MWh to only £12.54/MWh a variation of only 4.8% based on the lower end. A closer examination of Table (5-7) which gives generation distribution and system losses reveals some interesting information. The generation distribution pattern had, when the DG was added, changed to G2 and G5 from G1, G2 and G3 with £10/MWh and £12/MWh respectively. In other words G5 had replaced G1 and G3 which were more expensive than G5 and also G5 had somehow relieved the congestion in the network. This also explained why the LMPs profile had become more uniform and the system losses were reduced from 7.82MW to 6.36MW. When the marginal cost of G5 was raised to £14/MWh, the LMPs profile took a step jump to a range between £13/MWh to £14.06MWh. The variation was increased to 8.2% from the lower end.

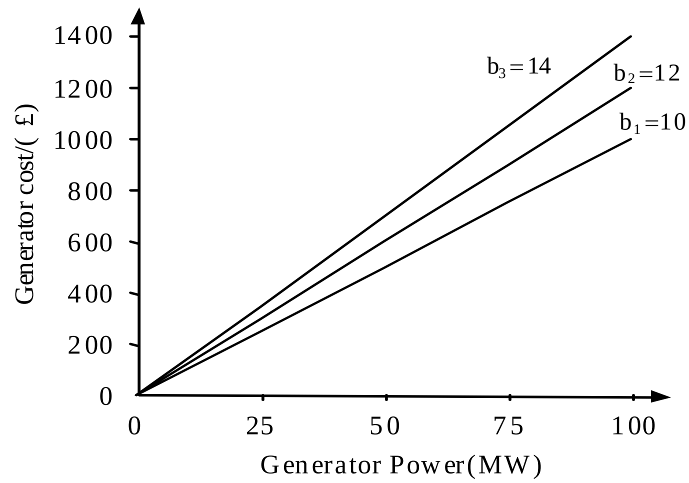
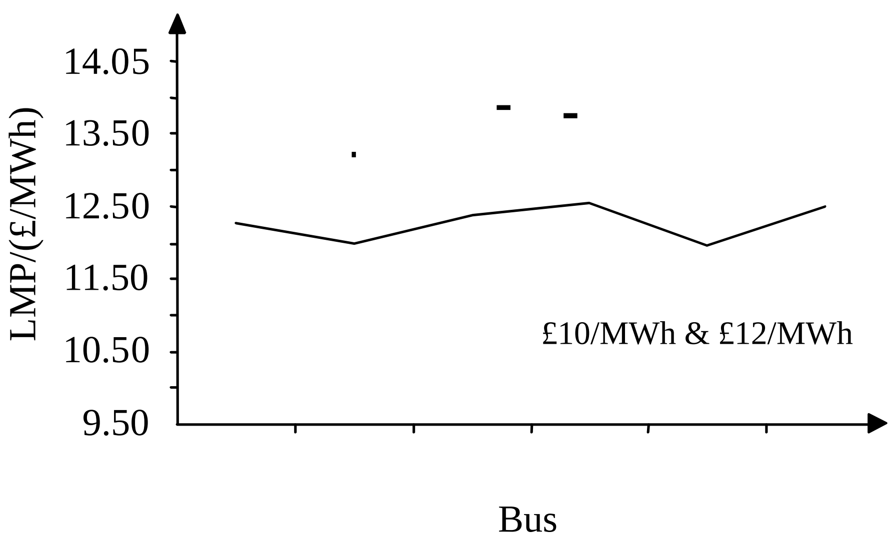


Figure 5-5 Generator cost curves for generator #G5 with marginal cost in 10, 12 and 14 £/MWh



Genrg.Cost,G5 /(£/MWh)	Bus #1				Bus #2				Bus #3				Bus #4				Bus #5				Bus #6			
	LMP	Energy	Cong	Loss	LMP	Energy	Cong	Loss	LMP	Energy	Cong	Loss	LMP	Energy	Cong	Loss	LMP	Energy	Cong	Loss	LMP	Energy	Cong	Loss
0	13.00	13.00	0	0.00	14.05	13.00	1.56	-0.51	15.00	13.00	2.25	-0.25	14.88	13.00	1.63	0.25	18.59	13.00	5.27	0.32	15.65	13.00	2.61	0.04
10	12.26	12.26	0	0.00	12.00	12.26	0	-0.26	12.38	12.26	0	0.12	12.54	12.26	0	0.28	11.96	12.26	0	-0.30	12.49	12.26	0	0.23
12	12.26	12.26	0	0.00	12.00	12.26	0	-0.26	12.38	12.26	0	0.12	12.54	12.26	0	0.28	11.96	12.26	0	-0.30	12.49	12.26	0	0.23
14	13.00	13.00	0	0.00	13.20	13.00	0.34	-0.14	13.92	13.00	0.49	0.43	13.72	13.00	0.29	0.43	14.00	13.00	0.66	0.34	14.06	13.00	0.49	0.57

Table 5-6 LMP with different values of generator marginal cost for G5

The system losses shown in Table (5-7) had increased to 6.95MW and G1 had re-entered the generation distribution and the output of the DG was reduced to 24.4MW, an indication that DG had become too expensive to be fully utilised. The high LMPs profile also indicates that a new congestion pattern in the network had resulted. The overall results clearly imply that, when the marginal cost of DG is below a certain level, the DG can help to eliminate the existing congested lines. On the other hand if its marginal cost rises above a certain level then new congestion could be created. This observation is true for other networks but the marginal cost level at which this will occur varies from one system to another.

(1) Effects of DG Capacity.

Table (5-7) has shown that when the marginal generator cost is at £14/MWh the DG total generation capacity become too expensive to be fully utilised. However, when the marginal generator cost is at £12/MWh, the total generation capacity of 100MW is fully utilised as depicted in Table (5-7). Hence it is interesting to investigate the LMP values and the generation distribution pattern from 10MW to 120MW as part of the centralized dispatch. The total generation capacity of generator G5 is increased from 10MW to 120MW with a 10MW incremental step on generator G5 to investigate its effects on the whole system. The simulated results for LMPs are plotted in Figure (5-7). Again Figure (5-7) shows that, by integrating DG into the grid system it is possible to reduce the volatility of LMP prices of the network. When a DG was added at bus #5 with a total generation capacity of 10MW, the LMP values vary from £13.00/MWh to £15.78/MWh, a variation of 21.4% over the lower end.

Gen Marg.Cost,G5/ (£)	Real Power(MW)				Reactive Power(Mvar)				System Losses(MW)
	G1	G2	G3	G5	G1	G2	G3	G5	
0	11.06	150.00	56.76	-	51.17	36.67	90.55	-	7.82
10	0.00	116.36	0.00	100.00	45.24	41.35	101.40	–14.00	6.36
12	0.00	116.36	0.00	100.00	45.24	41.35	101.40	–14.00	6.36
14	42.55	150.00	0.00	24.40	31.96	33.14	99.08	12.62	6.95

Table 5-7 Real and reactive power generation and total system losses with different generator marginal costs for G5

An interesting result of Figure (5-7) is that the spectrum of LMP variation was much narrower when the total DG capacity was increased from 30MW up to 100MW. This phenomenon also shows that the base case system congestion had been relieved which could explain why the LMPs profile had become narrower with a variation of less than 10%. The generation distribution pattern had changed to G2 and G5 from G1, G2, and G5 when the total generation increased from 70MW to 100MW as shown in Table 10. At a total DG generation capacity of 110MW, only 104.24MW was needed.

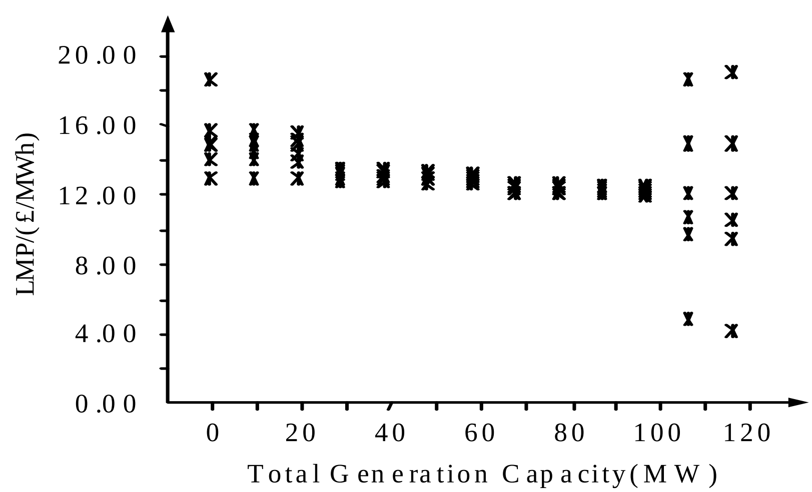


Figure 5-7 spread of LMP values with different installed generator capacity of G5

However, if the DG was obligated to generate at 110MW the LMP profiles again took a step jump to a range between £4.79/MWh to £18.77/MWh a variation of 291.9% over the lower end and the distribution generation pattern had again changed to G2, G3 and G5 from G2 and G5. Generator G3 had entered the generation distribution and the output of G2 was reduced and also the LMP prices became unevenly distributed across the network. Similarly, when the DG was obligated to generate at 120MW, the variation of LMP prices became even higher ranging from £4.20/MWh to £19.01/MWh a variation of 352.6% based on lower end. This would indicate that a new congestion pattern in the network had occurred.

The system loss in Figure (5-8) decreased from 6.82MW to 6.37MW as the total DG generation capacity increased from 10MW to 100MW. Similarly the system loss was further reduced when the DG was obligated to generate at 110MW and 120MW respectively.

The overall results clearly imply that by installing DG at bus #5 and at a certain level of DG capacity the volatility of LMP is reduced but at another level of DG capacity the volatility is increased.

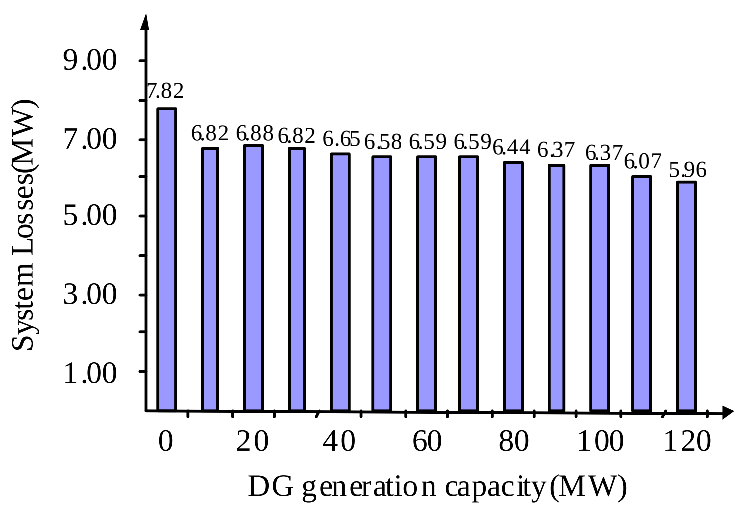


Figure 5-8 System losses with different DG generation capacity (MW)

Gen Marg.Cost,G5/ (£/MWh)	Real Power(MW)				Reactive Power(Mvar)				System Losses(MW)
	G1	G2	G3	G5	G1	G2	G3	G5	
0	11.06	150.0	56.76	-	51.17	36.67	90.55	-	7.820
10	36.93	150.00	19.89	10.00	34.38	31.06	92.18	18.39	6.820
20	40.68	150.00	62.0	20.00	32.75	32.47	96.89	14.35	6.880
30	36.82	150.00	0.00	30.00	33.82	32.74	99.18	10.54	6.820
40	26.65	150.00	0.00	40.00	37.19	32.06	99.39	6.91	6.650
50	16.58	150.00	0.00	50.00	40.65	31.46	99.60	3.39	6.580
60	6.59	150.00	0.00	60.00	44.20	30.93	99.83	–0.03	6.590
70	0.00	146.59	0.00	70.00	46.43	31.68	100.12	–3.47	6.590
80	0.00	136.44	0.00	80.00	46.00	34.84	100.52	–7.07	6.440
90	0.00	126.37	0.00	90.00	45.59	38.09	100.95	–10.58	6.370
100	0.00	116.37	0.00	100.00	45.23	41.36	101.40	–14.00	6.370
110	0.00	112.14	0.00	104.24	45.09	42.75	101.61	–15.42	6.380
110(obligated to generate)	0.00	91.42	14.65	110.00	44.70	48.44	97.25	–17.34	6.070
120(obligated to generate)	0.00	55.96	40.00	120.00	44.10	58.87	90.28	–20.39	5.960

Table 5-8 Real, reactive power generation and total system losses with different generation capacity for G5

From the above analyses it would become apparent that individual business could utilise the results to their own advantage but to the detriment of others. For example if the independent system operator (ISO) was responsible for transmission and distribution losses in the network, it would logical for the ISO to utilise more DG as this would reduce losses. However such an action would increase LMP volatility. Another example is that a DG company would want to install large capacity and generate to the maximum to take advantage of green power subsidy in some countries. This again would also lead to LMPs volatility. To overcome the effects of all these uneven actions, a good regulatory body is needed.

5.6 SUMMARY

This chapter examined the effects of locational marginal pricing of power network with and without DG installation under constrained and unconstrained system operational system. 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. New generation will have an incentive to site where locational marginal prices are high. The proposed method is able to break the LMP prices into its components which could allow market participants to hedge against congestion costs.

LMPs can reflect the actual cost of the system, with the changes of system conditions and thereby provide appropriate signals for allocating resources to adapt to those changes. It is important to note that LMP prices are governed by system conditions and are a reflection of the data and assumptions used in the studies.

The effects of the level of DG penetration in generation output and installed capacity can affect favourably as well as unfavourably in LMP prices. As illustrated in the results market participants, operators and utility businesses could manipulate them to maximize their profits. To avoid adverse market conditions and to protect consumers it is necessary to have a fair, strong and transparent regulatory body.

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CHAPTER 6

FINANCIAL TRANSMISSION RIGHT（FTR）

6.1 INTRODUCTION

Transmission congestion is an important electricity market issue and cannot be ignored. When compared to other congestion management methods, financial transmission rights (FTR) is essentially a different mechanism. It is a tool for financial risk management and does not change the actual dispatch. It has been applied to a number of countries and regions. Nowadays, the full development of the mechanism of individual financial transmission rights, and financial transmission rights market will help to provide the future development of electricity support.

In the United States in 1992 at Harvard University Professor William W. Hogan first proposed the concept of transmission capacity and the right to form a basic financial transmission right [1]. In 1997 he proposed Transmission Congestion Contracts (TCC), and it only considered the point-to-point transmission rights [2]. His research is the forefront and development and are contained is in his book [3], [4], [5]. They describe two types of FTR's basic theory, point-to-point and the based power flow patterns, and analyse incentives effect of power grid investment. Since then, Richard D. Tabors designed a dispatch priority of the right of transmission. Hung-po Chao and Stephen Peck introduced the Flowgate Right (FGR) for based power flow [6]. With the financial transmission rights market development, market participants required a more flexible variety of trade, rights-based point-to-point FTR has been already used. As the FTR trading system is now becoming more complete, the auction mechanism has now been applied.

The United States Federal Energy Regulatory Commission in the "Order 2000" proposed RTO (regional transmission organizations) to develop a market-oriented model to solve the electricity market congestion environment [7]. At present, the concentration is on the idea of establishment of transmission rights markets. The electricity supervision institution recognized the need to introduce financial transmission rights trading model the United States.

Different regional electricity market in the United States selects a different mode of financial transmission rights market. Some financial transmission rights can be used for the transmission system to provide coordination mechanisms, it is able to obtain the corresponding congestion financial benefits and also can have dispatch priority, and such as those is California, the fixed transmission right. Other financial transmission rights system does not affect the actual dispatch. The use of point-to-point financial transmission rights, and is under PJM and the New York markets.

Operating rules of the FTR market is also different between market as an example, Texas and New York markets deal directly through the FTR auction market. PJM introduces a mechanism for allocating of FTR auction revenue directly to the right of the auction proceeds and is allocated to transmission users. The market of financial transmission right can have different names; in the New York electricity market it is known as the transmission congestion contracts (TCC). In the Texas market, it is known as the transmission congestion right (TCR). In the PJM market, it is known as financial transmission rights (FTR). In the California market it is known as the fixed transmission rights and in the New England market as the financial congestion rights (FCR).

With the PJM, New York, ERGOT markets financial transmission rights have been in the running for many years and have accumulated considerable experience. Academics are also very interested about the operation of the FTR market assessment, References [8], [9], [10], [11] review the operating effectiveness of FTR market of the PJM and New York markets.

The current academic focus is on financial transmission rights on the operation of the electricity market and their deep impact. References [12], [13], [14], [15], [16], [17], [18] involved study of FTR market power issues, FTR grid investment incentives and the question of their relationship, the new forms of financial transmission right design, FTR market rules to improve the operation and including how to upgrade the FTR market participants of market strategy.

6.2 FINANCIAL TRANSMISSION RIGHTS OVERVIEW

6.2.1 Financial Transmission Rights (FTR) and Auction Revenue Right (ARR) definitions

6.2.1.1 FTR definitions

Under standard market design, load, or demand, pays for electricity based on the locational marginal price (LMP), and when transmission congestion occurs, LMPs will vary throughout the power grid. This price separation may cause the ISO to collect more revenue from demand in congested areas than it will pay to generators supplying electricity to those areas. The excess collection is called “congestion revenue.”

To hedge, or protect, against the adverse impacts of having to pay higher LMPs, market participants can bid for the rights to receive a share of the congestion revenue. These rights are called Financial Transmission Rights, or FTRs.

An FTR is a financial instrument that entitles the holder to receive a share of the excess payments collected for congestion costs that arise when the transmission grid is congested in the day-ahead market (FTRs are not offered in the real-time market). This financial amount can be used to offset congestion costs incurred for higher LMPs that market participants may have to pay, or it can be an additional source of revenue for FTR market speculators.

Congestion component of zonal LMP (loads paid) minus congestion component of nodal LMP (generators paid) equals transmission congestion revenue. This is the amount FTR holders can obtain.

FTRs can be acquired in three ways:

- **FTR Auction -** The ISO conducts periodic auctions to allow bidders to acquire and sell monthly and long-term FTRs. All FTRs are initially defined by the bidders in the FTR auction.
- **Secondary Market -** The FTR secondary market is an ISO-administered bulletin board where existing FTRs are electronically bought or sold on a bilateral basis.
- **Unregistered Trades -** FTRs can be exchanged bilaterally outside the ISO-administered process. However, the ISO only compensates FTR holders on record and does not recognize business done in this manner for settlement purposes.

Each FTR is defined in megawatts flowing in one direction between any two locations on the system—between nodes, zones or the hub, in any combination. For each hour in which congestion exists on the transmission system between the two locations as defined by the FTR (from point A to point B, for example), the holder of the FTR is awarded a share of the congestion revenue collected for that hour. If there is no congestion, the congestion component of the LMP will be zero, and no payment will be made to the FTR holder.

An FTR is a benefit when congestion occurs in the same direction as the defined FTR. If the FTR is defined from point A to point B, the congestion component of the LMP at point B must be higher than that at point A for the FTR holder to receive the congestion revenue. An FTR would have the greatest value if it were defined from a negative congestion location (such as an export constrained area where prices are lowest) to a high positive congestion location (such as an import constrained area where prices are highest).

An FTR is a liability when the congestion component of the LMP is in the opposite direction from the defined FTR. If the congestion component of the LMP at point A becomes higher than that at point B, the FTR holder is then obligated to pay the congestion cost. Holding FTRs can be a risk because congestion is not always predictable. An outage or other changes in the power system can cause the congestion component of the LMP to change value.

Because FTRs are financial entitlements, not physical rights, the FTR holder does not have to be involved in the energy market. Any entity that meets certain financial assurance requirements, including non-New England POOL market participants such as banks or other financial institutions, can register to buy and sell FTRs. FTRs are consistent with the Congestion Revenue Rights outlined in the Federal Energy Regulatory Commission's standard market design Notice of Proposed Rulemaking. [29]

6.2.1.2 Auction Revenue Rights

ISO New England collects the revenue generated from the sale of FTRs at auction. This revenue is not retained by the ISO but is distributed through Auction Revenue Rights (ARRs).

ARRs are rights or entitlements to the proceeds the ISO receives from the sale of FTR at auction. Auction revenues are allocated first to entities that pay for transmission upgrades, if and to the extent that the upgrade makes it possible to award additional FTRs in the FTR auction (by virtue of increasing transfer capability on the transmission system). These revenues are called Qualified Upgrade Awards, or QUAs.

After the QUAs are allocated, the remaining auction revenues are then distributed to entities that pay the congestion costs associated with supplying electricity to serve demand. This is done through a four-stage process designed to allocate auction revenues in relation to the amount of load served in the standard market design load zone areas (while recognizing certain grand fathered transactions) and to where congestion occurs. In essence, the auction revenue allocation provides these entities a revenue stream that could be used to help insulate them against congestion costs or the costs incurred with acquiring FTRs at auction.

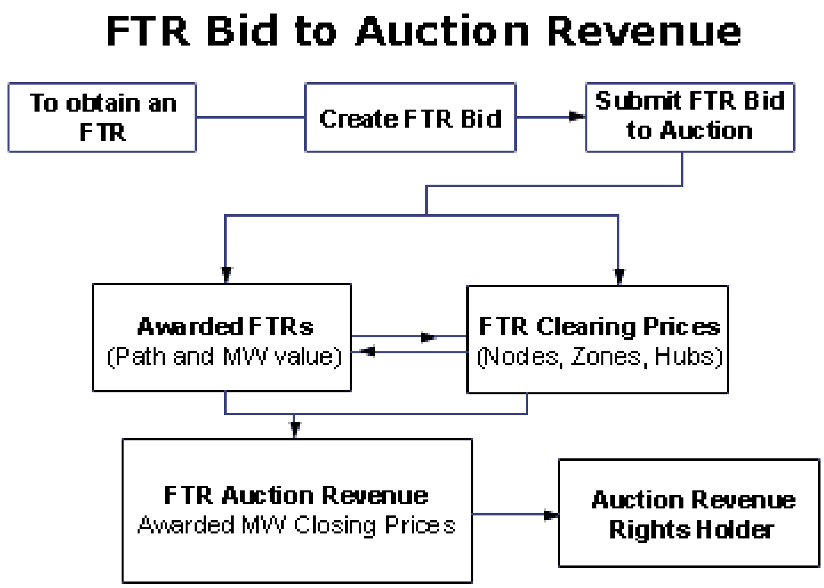

Figure 6-1 FTR bid to Auction Revenue [29]

While variations in LMPs can provide incentive for efficient market operation, this volatility also creates uncertainty for market participants, especially for those responsible for serving demand in congested areas. Financial hedging instruments such as FTRs help market participants manage their congestion-related risks. FTRs provide certainty to market participants in the face of variations in day-ahead LMPs by helping them offset potentially higher costs caused by congestion.

ARRs provide congestion-paying load serving entities a revenue stream that can be used to help insulate them against congestion costs or to defray costs incurred with acquiring FTRs at auction.

6.2.2 The significance of the establishment of financial transmission rights market

Transmission congestion problem in the performance of market-oriented environment is more complicated. In electricity market, the introduction of competition, the congestion problem becomes more serious, the main reason is that electricity power has created a lot of trade are not expected to power flow, but the transmission system has not made enough changes [7]. At the same time, transmission congestion problem of market power is also one of the main reasons.

6.2.3 Transmission capability from the perspective of the definition

The transmission power corresponding to the transmission capacity can be used in the following two definitions: 1, calculation of point-to-point transmission capacity, such model covers between point-to-point and the effect on the network power flow. 2, calculation of specific lines of transmission capacity, such a model is less sensitive to other network power flows.

So from this perspective to design two kinds of financial transmission rights: (1) point-to-point financial transmission rights. (2) flow-based financial rights, also known as flowgate right (FGR).

6.2.4 The practical application of the financial transmission right model

Practical application of financial transmission rights, in the nodal price market using point-to-point financial transmission rights, define specific input node and output node. This model avoids the clear definition of transmission capacity. In the zonal price market, a clear definition of the transmission capacity of the Flowgate rights is needed and it is from region-to-region for high frequency congestion of certain lines. Point-to-point FTR from the point of clearing model can fall into two categories, FTR Obligations and FTR Options they have different economic values. In the former case the FTR model can claim the benefit of the congestion surplus is the path of than. If the path is from A to B it means the LMP at B is higher than the LMP at A. In the event that LMP at A is higher than the one at B; the congestion is in the opposite direction. The FTR holder will not only unable to collect from the congestion surplus, but will be responsible for the new congestion cost. To hedge against this eventuality, the FTR option offers the protection of the change of congestion direction and the holder can still collects from the congestion surplus.

6.3 THE OPERATING MECHANISM OF FINANCIAL TRANSMISSION RIGHTS

6.3.1 FTR basic price model

Financial transmission rights are matched with the nodal price mechanism, and its starting point is based on the bids and security constraints of the economic dispatch problem [3]. Neglecting losses and considers the load and line capacity limits, the economic dispatch model become as follows [20]

$$\underset{Pgi}{Min}\sum_{i}[MC_i(Pg_i)\ Pg_i] \quad (6\text{-}1)$$

Subject to:

$$\sum_i Pg_i = \sum_i Pd_i \quad (6\text{-}2)$$

$$Fl = \sum_i A_{i,l}(Pg_i - Pd_i) \le Fl^{\max} \quad (6\text{-}3)$$

$$Pg_i^{\min} \le Pg_i \le Pg_i^{\max} \quad (6\text{-}4)$$

(1) $MC_i(Pg_i)$ is marginal cost of production or bid function for generator i ;

(2) Pg_i and Pd_i are generation and demand respectively;

(3) Fl is power flow on the line l .

(4) $FL^{\max}$ is an maximum capacity limit on line l

(5) $p_g^{\min}, p_g^{\max}$ are minimum and maximum generation limits.

(6) $A_{i,j}$ is the sensitivity of power flow on line l due to injection at bus i.

After solving this optimization problem, the standard locational marginal price for location i and time t is calculated as;

$$P_i = \lambda + \sum_i \mu l A_{i,l} \qquad (6\text{-}5)$$

Where λ is shadow price associated with equality constraint (6-2), μl is shadow price associated with transmission constraint for line l (6-3)

The price spread between two locations can be calculated as

$$P_j - P_i = \sum_i \mu l (A_{j,l} - A_{i,l}) \qquad (6\text{-}6)$$

which represents congestion risk between i and j. It is important to emphasize that this spread is only function of μl for a particular snapshot of topology.

This price spread can be considerable when transmission shadow price is different from zero (congestion), and difference in sensitivities in absolute value is greater than zero (electrically close to congested element). The value of μl is always negative or zero. It is negative because an increment in transmission capacity $Fl^{\max}$ results in reduction of system's total cost (objective function (6-1)). μl's value is function of re-dispatch cost incurred to solve the particular binding constraint *l*. $A_{i,l}$'s value is function of transmission topology. $(A_{j,l} - A_{i,l})$, is negative when an injection at *i* and withdraw at *j* contributes with power flow on line *l* in the same direction as the congestion, and takes positive value when creates counter flow.

6.3.2 Analysis use FTR obviation congestion risk [20]

The zonal (regional) electricity market in the United States in the bilateral contracts is mostly financial. A market participant that has a contract with delivery and compensation in different locations under LMP rules is subject to congestion risk. However, the same market participant with a proper hedge tool between those locations and for the same capacity and period of time should have its exposure reduced.

For example, *j* represents a location where there is a liquid forward market, e.g. a Hub, and *i* is a location where a generator produces and sells power in real time. If the generator sells forward power X_F in t_0 for delivery between times *t* and *T*, at price F_j; then during delivery time, it buys back the forward position X_F at real time price (assuming that this contract settles in real time) P_j; finally it generates in real time X_{RT} and sells its production at real time price P_i. Under this setup, the generator's revenue results

$$R_t = \sum_t (X_F F_j - X_F P_j + X_{RT} P_i) = \sum_t [X_F F_j + (X_{RT} P_i - X_F p_j)] \quad (6\text{-}7)$$

Assuming no volumetric $X_F = X_{RT}$, then

$$R_t = X_{RT} \sum_t (F_j + (P_j - P_i)) \quad (6\text{-}8)$$

and without congestion risk $P_j = P_i$

$$R_t = X_{RT} \sum_t F_j = X_{RT} F_j T \quad (6\text{-}9)$$

Therefore, the generator produces and sells power in real time and receives forward price fixed in t_0 for it. This price certainty is one of the major incentives for participating in forward markets.

However, if there is congestion, both prices are not equal anymore $P_j \neq P_i$, and in particular if $P_j < P_i$ the generator is going to lose revenue (with respect to the revenue obtained under unconstrained scenario (6-9))

$$\sum_t X_{RT}(P_j - P_i)_t = \sum_t X_{RT}(\sum_t \mu l \ (A_{j,l} - A_{i,l}))_t \quad (6\text{-}10)$$

Similar situation takes place when a consumer buys forward power in location *j* and consumes it in real time in location *i*; or when two parties sign a bilateral contract with production and consumption at different locations and priced at a hub location.

For these reasons, it is necessary to have a hedge tool to manage congestion risks. In northeast US, Financial Transmission Right has been used as a feasible solution to this problem.

Financial Transmission Right for path $k, FTR_k(i, j, MW_k, T)$ between locations *i* and *j*, for MW_k capacity, and settlement period *T*, is the right to receive during *T* the sum of the congestion charge. Mathematically,

$$FTR_k(i, j, MW_k, T) = \sum_t MW_k(P_j - P_i)_t = \sum_t MW_k(\sum_t \mu l \ (A_{j,l} - A_{i,l}))_t \quad (6\text{-}11)$$

which is exactly the exposure of market participant *i* analyzed in the example above (5-10), assuming $X_F = X_{RT} = MW_k$. The analysis of volumetric risk, $X_F \neq X_{RT} \neq MW_k$, is not analyzed here. In reality, FTR is a Day Ahead financial tool, but it can be moved to Real Time market through virtual bidding.

6.3.3 Point-to-point financial transmission rights [3]

Financial transmission rights are defined in terms of payments related to market prices. Although many years were spent in the search for well-defined and workable physical transmission rights, the complexity of the grid and rapidly changing conditions of the real market outcomes made it impossible to design physical rights that could be used to determine the use of the transmission system. By contrast, financial transmission rights specify payments that are connected to the market outcomes but do not control use of the system. Rather, the actual dispatch or spot market produces a set of market-clearing prices, and these prices in turn define the payments under the FTRs. The system operator accepts schedules and coordinates the spot market as a bid-based, security-constrained, economic dispatch. The resulting locational prices apply to purchases and sales through the spot market, or the difference in the locational prices defines the price for transmission usage for bilateral schedules. The need for transmission rights to hedge the locational price differences leads to the interest in FTRs.

The definition of point-to-point (PTP) forward obligations as FTRs follows closely the notion of bilateral transmission schedules. A generic definition includes both balanced and unbalanced rights. Given a vector of inputs and outputs by location, the *kth* PTP forward obligation is defined by

$$PTP_k^F = \begin{Bmatrix} 0 \\ -g_i \\ 0 \\ \ldots \\ d_j \\ 0 \\ \ldots \end{Bmatrix} \qquad (6\text{-}12)$$

With a corresponding vector of market clearing prices, this FTR is a contract to receive

When g_i and d_j are generation and demand at node *i* and *j* respectively

$$p^t PTP_k^F = p^i * \begin{Bmatrix} 0 \\ -g_i \\ 0 \\ \ldots \\ d_j \\ 0 \\ \ldots \end{Bmatrix} = p_j d_j - p_i g_i \qquad (6\text{-}13)$$

Although any such vector could be allowed, it is clear that any such FTR could be restated as a mix of balanced and unbalanced rights:

$$PTP_k^F = \begin{Bmatrix} 0 \\ -d_i \\ 0 \\ \ldots \\ d_j \\ 0 \\ \ldots \end{Bmatrix} + \begin{Bmatrix} 0 \\ d_i - g_i \\ 0 \\ \ldots \\ 0 \\ 0 \\ \ldots \end{Bmatrix} \qquad (6\text{-}14)$$

Motivated by the discussion of options below, it is convenient to define two types of forward obligations, balanced and unbalanced such as

$$\text{Balanced}\begin{Bmatrix} 0 \\ -d_i \\ 0 \\ \ldots \\ d_j \\ 0 \\ \ldots \end{Bmatrix}, \quad \text{Unbalanced}\begin{Bmatrix} 0 \\ d_i - g_i \\ 0 \\ \ldots \\ 0 \\ 0 \\ \ldots \end{Bmatrix} \qquad (6\text{-}15)$$

We can think of the balanced PTP-FTRs providing for the same input and output at different locations. More generally, all that is required of a balanced PTP-FTR is that the inputs and outputs sum to zero, t^t balance= 0. The unbalanced FTRs can be thought of as forward energy sales at any location and would be a contribution towards losses to balance the system. The notation suggests that individuals could hold either or both types of PTP-FTR forward obligations, and here is no need that the locations be the same.

The intended role of the PTP-FTR is to provide a hedge against variable transmission costs. If a market participant has a balanced FTR between two locations and schedules a corresponding bilateral transaction with the same inputs and outputs (x), then the charge for using the system would be $(p_j - p_i)x$, which is exactly the payment that would be received under the FTR. Hence, the balanced FTR provides a perfect hedge of the variable transmission charge for the bilateral transaction.

The holder of an unbalanced forward obligation FTR has an obligation to make the payment equal to the value of the energy at the relevant location. If the holder also sells an equal amount of energy at the same location in the actual dispatch, the payment received for the energy is $p_j g$, equal to the payment required under the FTR. Hence, we can think of the unbalanced FTR as a forward sale of energy. Although in principle there would be no difficulty in allowing negative unbalanced PTP-FTRs, equivalent to forward purchases of energy, it is convenient to interpret unbalanced PTP-FTR obligations as forward sales of energy.

In this case of obligations, the PTP-FTRs are easily decomposable. For example, an FTR from bus 1 to bus 2 can be decomposed into two PTP-FTR obligations from 1 to a Hub and the Hub to 2. The total payment is $(p_2 - p_{HUB}) + (p_{HUB} - p_1) = (p_2 - p_1)$. This provides support for trading at market hubs and the associated trading flexibility. Periodic FTR auctions provide other opportunities to obtain other reconfigurations of the pattern of FTRs.

An attraction of the FTR is that the spot market can operate to set the actual use of the transmission system and the FTRs operate in parallel through the settlements system to administer financial hedges. Importantly, the system of payments will be consistent as long as the set of PTP-FTRs satisfies a simultaneous feasibility condition.

Therefore, it can be from a wider perspective the definition of two types of point-to-point FTR

$$m_k^F = \begin{Bmatrix} 0 \\ -x \\ 0 \\ \ldots \\ x \\ 0 \\ \ldots \end{Bmatrix} \qquad n_k^F = \begin{Bmatrix} 0 \\ y \\ 0 \\ 0 \\ \ldots \\ 0 \\ \ldots \end{Bmatrix} \qquad (6\text{-}16)$$

Left side m_k^F is balanced point-to-point FTR. Right side n_k^F is unbalanced point-to-point FTR. Balanced point-to-point FTR for different nodes inject the same energy and outflows can be bilateral trade transmission cost fluctuations to provide a good risk control [3].

Unbalanced point-to-point FTR can be any node corresponding to the energy injected into or out of; FTR holders receive the corresponding node energy prices corresponding to earnings, used to balance the issue of transmission loss. If the holder of the actual dispatch of the sale of the same amount of power, obtain benefit is "$n_k^F * P^t$". Therefore, we can also extend the Unbalanced FTR for obviate energy trading risk. If "y" is negative, it is energy purchase [3].

If unbalanced FTR in used, also will extend the scope of obviate risk to the electric energy market, will be electric energy market price fluctuations in obviate risk and obviate market power transmission congestion risk unified again.

6.3.4 Flowgate rights

Flow-based FTR is flowgate right (FGR). The definition of a particular transmission flowgate and its design are the starting point for trading schemes.

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

The most prominent recent example of such a decentralized congestion management model is the so-called "flowgate" approach. This is interesting as both a theoretical argument [21][22][23] and because it is the procedure embraced by North American Electric Reliability Corporation as a principal market alternative to its disruptive administrative Transmission Loading Relief (TLR) procedures [24]. The details can be complicated, but the basic idea is simple. The argument begins with the recognition that the contract path model is flawed. Power does not flow over a single path from source to sink, and it is this fact that causes the problems that lead to the need for TLR in the first place. If a single contract path is not good enough, perhaps many paths would be better. Since power flows along many parallel paths, there is a natural inclination to develop a new approach to transmission services that would identify the key links or "flowgates" over which the power may actually flow, and to define transmission rights according to the capacities at these flowgates. This is a tempting idea with analogies in markets for other commodities and echoes in the many electricity industry MW-mile proposals, rated-path methodologies, the General Agreement on Parallel Paths (GAPP), and related efforts that could go under the heading of transmission services built on link-based rights.

For any given total set of power injections and withdrawals, it is possible to compute the total flows across each line in the transmission network. Under certain simplifying assumptions, it would be possible further to decompose the flows on the lines and allocate an appropriate share of the flows to individual transactions that make up the total load. If we also knew the capacity on each line or groups of lines, then presumably it would be possible to match the flows against the capacities and define transmission services. Transmission users would be expected to obtain rights to use the lines, perhaps from the transmission line owner or from others who owned these capacity rights.

In principle, these rights on each line might be seen as supporting a decentralized market. Associated with each line would be a set of capacity allocations to (many) capacity right holders who trade with the (many) users of the system who must match their allocated flows with corresponding physical capacity rights. Within this framework there are at least two interesting objectives. First, that the trading rules should lead to an efficient market equilibrium for a short period; and second, that the allocated transmission capacity rights would be useful for supporting long-term transactions in the competitive market for geographically dispersed buyers and sellers of power.

As a theoretical matter, it is likely that the first objective could be met. Ignoring transaction costs and the question of timely convergence, there should be some system of tradable property rights that would be sought by users of the system, and in so doing would lead to an efficient short-run dispatch of the system. This would seem to be nothing more than an application of the principles of competitive markets with well-defined property rights and low transactions costs. There is a general belief that this short-run efficiency would be available in principle: "Efficient short-run prices are consistent with economic dispatch, and, in principle, short-run equilibrium in a competitive market would reproduce both these prices and the associated power flows [25] The problem has always been with the natural definitions of the "physical" rights: these are cumbersome to trade and enforce. The property rights are hard to define, and the transaction costs of trading would not be low.

The second objective is perhaps more important. Presumably the allocated transmission capacity rights would extend over many short-run periods, for example, even only a few days, weeks or months of hourly dispatch periods [26]. Presumably a natural characteristic that would be expected of these physical rights would be that a seller of power with a known cost of power production could enter into an agreement with a distant buyer to deliver a known quantity of power at a fixed price, including the out-of-pocket cost for transmission using the transmission right. Many other contracts could be envisioned, but this minimal possibility would seem to be essential; and it is broadly taken for granted that this capability will exist in the open-access transmission regime. However, any approach that defines tradable physical capacity rights based on flows on individual lines faces obstacles that appear to make it impossible to meet this minimal test.

6.4 THE COMPARISON OF FINANCIAL TRANSMISSION RIGHTS WITH PHYSICAL TRANSMISSION RIGHT

6.4.1 Disadvantages of physical transmission right [27]

Physical Transmission Rights (PTR) is simple in theory. They involve the exclusive right to transport a predefined quantity of power between two locations on the network, and accordingly, the right to deny access to the network by market participants who do not hold the rights.

Physical transmission rights, however, can have potential problems. The most serious of these is that the right of a PTR owner to self-dispatch can interfere with the system operator's efforts to schedule and dispatch the system efficiently. If market participants must hold physical rights to be dispatched, the rights need to be tradable in very short time periods, so that output from one plant may be substituted for output from another in real time. However, as the moment of actual dispatch approaches and many market participants use the spot market for their trading needs, it is not easy or necessarily even possible for them to identify their exact transmission needs in advance. They will, therefore, not be able to make PTR trades fast enough. Thus, PTR holders, and not the system operator, end up dictating the use of the transmission system.

Another problem is the incompatibility of PTRs and locational energy prices. PTRs could allow market participants to raise prices to uncompetitive levels in some locations and/or to depress them in others by withholding access. For example, a holder of PTRs from A to B who has generation at B might prevent generators at A from using the transmission system. The holder of PTRs would do this to maintain a high price at B. Withholding access could thus lead to production inefficiencies. In the scenario above, the most efficient and cheapest generators might be located at A, but as long as generator B withholds its transmission capacity from them, they will not be able to participate in the market. Practice, regulators would develop rules that would impede such a situation from arising. In order to make PTRs compatible with locational prices, they would implement rigid eligibility standards for PTR holders (i.e., market participants that are in a position to exercise market power would be ineligible) or strict rules concerning the use of PTRs. In either case, these would be difficult to determine and equally difficult to enforce.

6.4.2 Advantages of FTR [27]

Financial transmission rights can deal with both of the potential PTR problems listed above. FTRs are contracts that exist between market participants in fact, any individual or organization and the system operator. FTRs are defined in a way similar to physical transmission rights: from a source location to a destination location. They are also denominated in a MW amount corresponding to the transfer capability between these locations. However, FTRs do not entitle their holders to an exclusive right to use the transmission system. Instead, FTRs exist in an environment of open access to the transmission system for all market participants regardless of whether they hold a transmission right.

FTRs solve both of the problems of PTRs discussed above. First, FTRs do not lead to inefficient dispatches, but rather to efficient dispatches. New generators are not stopped from bidding below existing generators and open access is not denied to anyone on the transmission system. The system operator does not even need to take

FTRs into account in its operation of the system because FTRs are purely financial instruments that can be settled outside of the spot market.

FTR payments represent exactly the financial benefit that would accrue to a market participant that owned its own line, or to the owner of a PTR that sold its right to the highest bidder. In effect, FTRs are tradable rights that are automatically assigned to those users who provide the system with the highest value. For example, if the holder of an FTR is a generator that does not have a low-enough offer price to be dispatched, the generator will nonetheless receive the financial equivalent of having sold the right to the generator that does get dispatched. And the FTR holder receives this payment without having to scurry about to find a participant to buy the right. Rents are paid irrespective of who uses the transmission system. Second, FTRs are completely compatible with locational marginal prices and, in fact, are dependent upon them. FTRs give their holders the right to payments equal to the energy price difference between the source location and the destination location for the denominated MW. These payments are funded by the natural “congestion rent” that arises when energy is purchased from lower-priced regions and transmitted to and sold in higher priced regions. Therefore, there must be price differences between locations, i.e., a locational price system. In a single-price system, FTRs have no meaning, since these price differences will not formally exist. FTRs are also beneficial because they provide a convenient way to deal with these congestion rents that the system operator collects. In a worst-case scenario, the system operator would be allowed to keep the congestion rents. This would give the system operator an incentive to dispatch the system inefficiently, and impede grid expansion in an attempt to increase congestion and thus its revenue. While this situation would never be permitted by regulators, congestion rents do arise, as does the need to decide how to allocate them. FTRs provide a simple solution to this problem.

6.5 compare Financial transmission Right (FTR) with transmission option (TO)

Transmission congestion plays an important role in power network safety and electricity price. It is an important research area to hedge against the price uncertainty due to transmission congestion. Mechanism, character and defects of financial transmission right are studied and transmission option is thus introduced for hedging against the risk brought by transmission congestion and overcoming the defects of financial transmission right. The characteristics of financial transmission right and transmission option are compared and analyzed in this section.

Example for how to hedge against of transmission congestion risk use FTR (neglect network loss).

In the example a simple network is used to illustrate the differences and important of transmission congestion right and transmission option. In Figure (6-2), generator G1 is connect to node A and generator G2 and a load L is connect to node B.

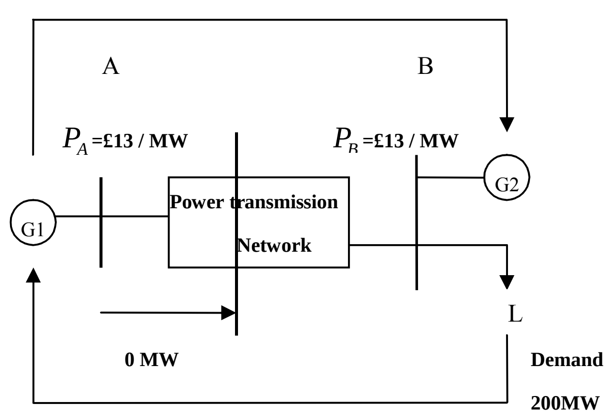

Figure 6-2 example for network no congestion

Case 1: In this example it is assumed that the network has no transmission congestion. This means that the LMP at node A and node B are the same. The LMP at node A and node B are P_A and P_B are set at £13/MW respectively. A bilateral agreed between G1 and the L for a supply of 200MW.

As there is no congestion G1 can fulfil the contractual obligation fully of delivering 200MW (losses are neglected). Under the situation of no congestion the calculation of revenue by the various participants is tabulated-table (6-1).

Power transfer (MW)	LMP at node A /£	LMP at node B/£	Load payment (£)	Generator revenue G1(£)
200	13	13	2600	2600

Table 6-1 network with no congestion

This is an ideal condition and no power is taken from G2 and hence it receives no revenue.

When congestion occurs in the network the LMP at node A and node B are different. The values of the price are illustrated is Figure (6-2).

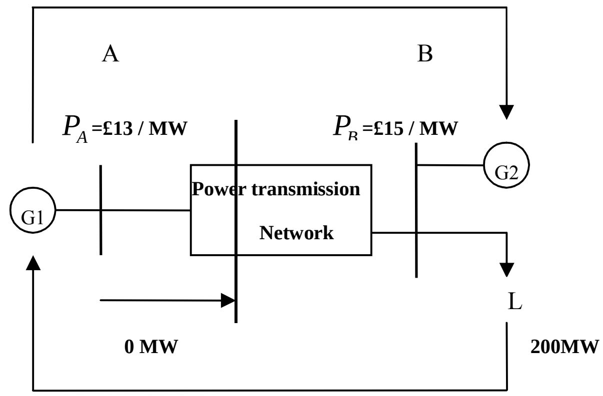

Figure 6-3 network with congestion

As there is congestion G1 cannot completely fulfil the contractual obligation of delivering 200MW. The amount that it can deliver depends on the transmission capacity through the network. Two cases are considered: in the fist the maximum allowable transmission capacity for G1 is 150MW whilst in the second case it is only 80MW, a much more serious congestion. In example the first case of 150MW, load L would need to take 50MW from G2 to meet its demand. The calculations of revenue by the various participants are given Table (6-2).

Congestion constrain (MW)	LMP at node A / £	LMP at node B / £	Load payment (£)	Revenue collected by G1 (£)	Revenue collected by G2 (£)
150	13	15	2600	1850	750
80	13	15	2600	800	1800

Table 6-2 network with congestion

As G1has a transmission contract with the demand L, it is under contract to supply 200MW to L at a price of £13, hence payment by to demand to G1 is

$$\pounds 200 \times 13 = \pounds 2600$$

But there is congestion in the network and G1 can only deliver 150 MW to the demand, and is order to fulfil its contract obligation it have to commission G2 to deliver 50MW to L, there its revenue return

$$\pounds 13 \times 200 - \pounds 15 \times 50 = \pounds 1850$$

Because of the congestion G1 suffers a final shortage of £750.

It is worth noting that if the trading is only based on LMP and no bilateral contract exits, then the payment by the load L

$$\pounds 15 \times 200 = \pounds 3000$$

This is higher than the case of bilateral contract of £2600.

In the second case of maximum allowable transfer of 50MW, the revenue returns can be calculated in a similar

In the situation discussed above although there is congestion but the instrument of FTR is not used.

Case 2: The calculation for the shown two a repeated with incorporation of FTR.

In order to protect itself against network congestion. G1 choose to perchance 200MW of FTR. The price is assumed to £1/MW. The revenue collected by G1 is shown is Table (6.3)

Reduce when network with congestion because of price uncertainty at node B by the congestion cost, then G1 can choose to purchase a 200MW of FTR, the price assumed to be £1/MW. The revenue collected by G1 is showing in table (6-3).

Power transfer (MW)	LMP at node A /£	LMP at node B /£	FTR (MW)	FTR price/ £	Payment by G1 for FTR (£)	Congestion cost (£)	ISO back to G1 CC (£)/h	Revenue collected by G1 (£)/h
200	13	13	200	1	200	0	0	2400

Table 6-3 network no congestion and use FTR

Therefore, when network has no congestion, the final revenue collected by G1 is:

$$£13 \times 200 - 1 \times 200 = £2400$$

When congestion occurs in the network, the LMP will be different at node A and B as illustrated is Fig (6-3). Again it is assumed the G1 has purchased a 200MW FTR at a price of £1/MW

An FTR gives the holder its share of congestion cost that the ISO receives during transmission congestion: [10]

$$congestion\cos t(cc) = p(P_B - P_A)$$

in which P_A is the LMP price at node A, P_B is the LMP price at node B and p is the directed quantity specified for the path from *A* to *B*. If the contractual volume matches the actual traded volume between the two locations, an FTR is a perfect hedge against volatile locational prices.

Congestion constrain (MW)	LMP at node A/£	LMPat node B /£	FTR (MW)	FTR price/£	Payment by G1 for FTR (£)	Congestion cost (£)	ISO back to G1 CC (£)/h	Revenue collected by G1 (£)/h
150	13	15	200	1	200	100	100	2400
150	13	10	200	1	200	150	0	2300

Table 6-4 network with congestion and use FTR

When the LMP at node B greater than LMP at node A, G1 has to pay to ISO a congestion cost of:

$$£\ (15-13)\times 50 = £100\,/\,\text{h}$$

But since G1 has perchance 200MW FTR, it can seek for return of the congestion cost £100. It is worth that if the network is 'fully' congested, the G1 has to pay $£200\times(15-13) = \ £400\,/\,\text{h}$ congestion cost which it can seek full refund.

The revenue return for G1 is this:

$$£13 \times 200 - 1 \times 200 - 400 + 400 = £2400$$

But when the LMP at node A is greater than the LMP at node B, and because of the existence of reverse power flow, the purchase FTR is also as the reverse direction, assumed that LMP at B is now £10/MWh. Under such a citationG1 is liable to a congestion cost up to a maximum of $£(13-10) \times 200 = £600/h$, of course this is the maximum risk and the actual risk could be smaller. In the case consider if the maximum allowable flow is £150, the congestion cost to G1 would be $£(13-10) \times 50 = £150/h$ which G1 cannot reclaim back from ISO.

In real market situation G1 can auction some of its FTR to hedge against its own risk.

In this time, with maximum risk revenue collect by G1 is:

$$£13 \times 200 - 1 \times 200 - (13-10) = £1800$$

Case 3: The following use the same examples to discuss the situation with transmission option (TO).

TO can protect forward power flow as well as reverse power flow, the cost for purchasing TO is higher than FTR because it protects both way. G1 can choose to purchase a 200MW of TO, the price assumed to be £1.5/MWh. The revenue collected by G1 is showing in table (6-5)

Power transfer (MW)	LMP at node A/£	LMPat node B /£	TO (MW)	TO price/£	Payment by G1 for TO (£)	Congestion cost (£)	ISO back to G1 CC (£)/h	Revenue collected by G1(£)/h
200	13	13	200	1.5	300	0	0	2300

Table 6-5 network no congestion and use TO

Therefore, when the network has no congestion, the final revenue collected by G1 is:

$$£13 \times 200 - 1.5 \times 200 = £2300$$

Congestion constrain (MW)	LMP at node A/£	LMPat node B /£	TO (MW)	TO price/£	Payment by G1 for TO (£)	Congestion cost (£)	ISO back to G1 CC (£)/h	Revenue collected by G1 (£)/h
150	13	15	200	1.5	300	100	100	2300
150	13	10	200	1.5	300	150	150	2300

Table 6-6 network with congestion and use TO

When the LMP at node A less than the LMP at node B, and assume case 1 when allowable payment is 150MW, the revenue collect by G1 is as follows:

$$£13 \times 200 - 1.5 \times 200 - (15 - 13) \times 50 + 100 = £2300$$

In the reverse case when the LMP at node A is greaten than the LMP at node B, and because G1 holds the TO, is reverse power flow has no effect congestion costs. So, the revenue collected by G1 is also £2300. The revenue collected by G1 is showing in table (6-6)

Case 4: The same examples are used to discuss the situation when FTR and TO used simultaneously. Some generation may be at the same time use FTR and TO.

In this case, G1 to purchase a 100MW of FTR prices for £1/MW, 100MW of TO price for £1.5/MW, revenue collected by G1 is as shown in Table (6-7).

Power transfer (MW)	LMP at node A/£	LMP at node B/£	FTR (MW)	FTR price /£	Payment by G1 for FTR (£)	TO (MW)	TO price /£	Payment by G1 for TO (£)	Congestion cost(£)	ISO back to G1 CC(£)/h	Revenue collected by G1 (£)/h
200	13	13	100	1	100	100	1.5	150	0	0	2350

Table 6-7 both of use FTR and TO when the network no congestion

Both of use FTR and TO, when the network no congestion, the revenue collected by G1 is: $£13 \times 200 - 1 \times 200 - 1.5 \times 200 = £2350$

Congestion constrain (MW)	LMP at node A/£	LMP at node B/£	FTR (MW)	FTR price /£	Payment by G1 for FTR (£)	TO (MW)	TO price /£	Payment by G1 for TO (£)	Congestion cost (£)/h	ISO back to G1 CC(£)/h	Revenue collected by G1 (£)/h
150	13	15	100	1	100	100	1.5	150	100	100	2350
150	13	10	100	1	100	100	1.5	150	150	150	2350
80	13	10	100	1	100	100	1.5	150	360	300	2290

Table 6-8 networks with congestion, FTR and TO used simultaneously

In the first case when LMP at node B is higher than LMP at node A and maximum allowable transferred is 150MW, the revenue collected by G1 is:

$$£13\times200-1\times200-1.5\times200-\left(15-13\right)\times50+100=£2350$$

In the second case when the LMP at node A is greaten than the LMP at node B and maximum allowable transferred is 150MW, and because G1 to hold 100MW of TO, it is not affected reverse power flow. So, the revenue collected by G1 is still £2350.

In the third case when the LMP at node A is greater than the LMP at node B and maximum allowable transferred is only 80MW, the congestion is 120MW. In this situations, decompose congestion cost is very important for ensure revenue collected by G1. Hence, 120MW congestion, 100MW use TO for obviate congestion const, another 20MW uses FTR. It is the congestion cost is:

$$£\left(13-10\right)\times120=£360/\mathrm{h}$$

Which the TO share is: $£\left(13-10\right)\times100=£300/\mathrm{h}$, because G1 holds the TO 100MW, is reverse power flow has no effect this part congestion costs. So, ISO would return £300/h to G1.

Which the FTR share is: $£\ \left(13-10\right)\times20=£60/\mathrm{h}$, ISO will not returned this part because FTR returned only applies in the forward direction. Of course some market may operate a different set of rules.

So, in this case the revenue collected by G1 is

$$£13\times 200-1\times 100-1.5\times 100-\left(13-10\right)\times 120+300=£2290$$

Compare tables (6-3) and (6-5) and (6-7) it can be seen, that when the network has no congestion, the results showed that the revenue collect by G1 is very similar. But when network congestion occurs, there are two different situations. In the first situation when LMP at node A is less than LMP at node B then the revenue collected by G1 is the same. The protection by FTR depends on the degree of congestion and on the amount of FTR purchased. As long as the amount of FTR purchased is greaten than the un-transferable power, the revenue collected by G1 still remains unchanged. In the event of serious congestion and the un-transferable power is greaten than the amount purchased by FTR, the revenue collected by G1 would start to full.

In the second situation LMP at node A is higher than LMP at node B, a reverse power flow situation, and it is not protected by FTR. Hence G1 would suffer a full in revenue return. But if G1 also purchased TO, its revenue return is also protected.

6.6 SUMMARY

There are many possible definitions of financial transmission rights, each with its advantages and disadvantages. Further, the basic building blocks of financial transmission rights could support a secondary market with a wide variety of other trading instruments, just as a forward contract can be decomposed into a variety of elements with different risk properties.

The basic building blocks under different definitions have different properties. The purpose here is to summarize the four different types of financial transmission rights. The fundamental approach is to bridge the electrical engineering and economic market formulations. The four types of financial transmission rights appear as combinations of two configurations of rights, point-to-point and flowgate, and the two financial treatments, obligations and options.

How to decide which tools to choose to hedge against congestion risk will depend on market participants.

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CHAPTER 7

CONCLUSIONS AND FUTURE WORK

7.1 CONCLUSION

From the research it is understood that a successful electricity market consists of certain core elements, and they include the following:

- A system operator coordinated spot market built on bid-based, security-constrained economic dispatch (SCED).
- Locational marginal prices for spot market transactions considering marginal losses and congestion.
- Financial transmission rights to hedge short-term transmission usage charges evaluated as the difference in the LMP at source and sink.
- Ancillary service markets that allow simultaneous optimization of multiple products.
- Financial instruments supported in the wholesale market for risk management.
- Appropriate market mechanisms facilitating long-term investments.

In the electricity market, the purpose of congestion management is to achieve:

(l) The development of active planning, to meet the system safety standards;

(2) For market participants to provide appropriate economic signals;

(3) An effective means to offset the risks arising from congestion.

Transmission congestion problem is due to electricity energy trading of transmission capacity demand more than the transmission network capacity constraints. Therefore, in order to solve the congestion problem, so must for increase is additional congestion cost. Congestion costs; what are the definition of congestion costs, congestion costs sharing and their principle. These problems with the market trading model and congestion management methods are closely related. It should be noted that, congestion cost sharing and congestion pricing are related problem. The former concern is how to determine the congestion cost, that is, how much are the congestion prices; for latter determines how to fairly and equitably share the congestion cost between market participants.

Chapter 3 explains the underlying principles of LMP decomposition and enables the system operator to administrate the congestion cost in an efficient way for financial settlement and to provide a non-discriminatory transmission pricing to each market participant. Three LMP cost decomposition approaches are discussed and are illustrated on a simple six-bus system. This chapter presents a more transparent and fairer method for financial settlement for congestion using load distributed slack bus. It has shown that by changing the angle reference bus it doesn't change the value of the cost of energy, the cost of marginal loss component and the cost of marginal congestion component at all buses. Most importantly, it has shown that the differences between cost of marginal loss component and the cost of marginal congestion component remain the same with different angle reference bus. In other words, the proposed method is invariant to the selection of the angle reference bus for losses and constraint sensitivities once the real power loss sensitivities factors are fixed. Thus each market participant will pay the same rate and is independent of the selection of angle reference bus.

The application of LMP method on a practical power network demonstrates is Chapter 4. The network is that of the North China Power Grid and it is applied at four different load levels. The analysis on the revenue income of the Power Grid is also included should the Grid be deregulated. The restructuring of the electricity supply industry in NCGC, and further in China, is likely to take a progressive path. Along this progressive path, generation capacities and loads that are subject to market based competitive rates may be relatively lower in the beginning, such as 5%. The percentage of generations and loads subject to market based competitive rates is likely to gradually increase, to 10%, 50% and eventually reach the state of full market competition, where all the energy transactions are traded on the competitive market.

A distributed slack bus for LMP cost decomposition is proposed is chapter 5 to serve as the market reference so that there is no ambiguity on the value of each LMP component should different bus reference is used, because LMP cost components at each location will be the same no matter where the reference bus is selected. The proposed method for LMP cost decomposition can be based on generation, based on load and also based on a mixture between generation and load. In other words, the proposed method distributes the cost of energy and the cost of marginal losses component corresponding to a group of buses so that both cost components are well distributed on the network with the use of weight contribution from the generators or loads.

One of the reasons for LMP costs decomposition is to allow transmission customers to buy FTRs to recover congestion charges between two points specified in the FTRs.

The value of FTRs is measured by the difference in the congestion components of LMP. Basically FTRs are introduced to be used as a hedging tool or protection from congestion charges in the event of congestion on the network between two locations. FTRs may be acquired by transmission customers in several ways including: direct allocation of FTRs based on existing transmission service contracts (i.e., grand fathering) or through market mechanisms such as bid based auctions. They are two types of FTRs, obligations and options. Transmission congestion plays an important role in power network safety and electricity price. It is an important research area to hedge against the price uncertainty due to transmission congestion. Mechanism, character and defects of financial transmission right are studied and transmission option is thus introduced for hedging against the risk brought by transmission congestion and overcoming the defects of financial transmission right. The characteristics of financial transmission right and transmission option are compared and analyzed in chapter 6. How to decide which tools to choose to hedge against congestion risk will depend on market participants.

7.2 FUTURE WORK

Chinese power industry market-oriented reform is under way, the market model and the rules of the market have not yet been finalized. With the electricity market gradually being set up and operation of transmission congestion study will be more focus, the actual problem practiced will continue to emerge, which will promote research in this area to continue to deepen and develop, to promote China electricity market healthy development.

Chinese power will introduce competition mechanism, and all conditions of power generation enterprises and users directly involved in the market competition, will need to carry out energy trading financial contracts, FTR set up some of the main conditions for a more complete market. Node-based electricity spot market demands more sophisticated operations. Separate transmission and distribution in the region to form a substantial purchase of electricity in the form multi-lateral contracts. At this point, the distribution companies, the sale of electricity by companies and large electricity users will become the main purchasers. A mechanism is required to coordinate the generation companies, large electricity users and placing the interests of enterprises, effective congestion management and earnings distribution. Power suppliers and users of bilateral transactions become the main body of the volume of market transactions, market participants need to circumvent the node price volatility risk and use risk management tools.

In a market design it should plan carry out energy financial contracts. Traded contracts will be transformed into a “flexible form”, and do not follow the physical lows. ISO can be the centre of transacting of bilateral contracts in advance of contract agreement. A day ahead market congestion price to determine the process of transactions. If the network congestion problem at certain time is more serious, and the grid structure is also stable, one can introduce financial transmission rights trading.

The following are areas desire further investigation:

1. Congestion Cost sharing analysis

Nowadays, it is recognized that congestion cost sharing has two steps: (1) the total congestion cost sharing to the each congestion line (or transformer); (2) the lines congestion cost sharing to the transaction contract holder. Because of the characteristics of the power system itself, the power flow tracking there is no absolute right way. Also is congestion cost sharing there is no absolute right way. For this reason, the fairness of sharing, transparency and simplicity have been the focus of the study. Congestion pricing and allocation method as follows: hidden congestion pricing and cost sharing, overt congestion pricing and cost sharing.

2. FTR and the associated market designs

The Locational Marginal Price for a network is usually very volatile, which result in a significant price risk to market participants. Therefore, financial price hedging instruments are used to reduce this price risk. With the introduction of financial instruments in the LMP-based market, decomposition of the LMP value into three components, which are the energy, loss and congestion cost components are very important for the market settlement of FTRs and LHRs. FTR is a big issue. It is not as simple as reviewed and discussed in the thesis. Therefore further research into FTRs is very important for designing a non-discriminatory FTR auction markets.

3. Try to use Flowgate right (FGR) in China

Moreover, China is stepping up the power station construction programmer. Load centers and power centers asymmetry control these constructions could change the power distribution characteristics. The introduction of suitable Flowgate right (FGR) should be investigated. China regional electricity market after the separation of electricity distribution from the transmission network could follow the design rule of the current zoning pricing. If a day-ahead market follows the design rule of the current zoning pricing, it could be considered as the basis for the concatenation of congestion sections divided into a number congestion location, and use FGR control the congestion risk. In addition, FGR market transactions with few number of transmission rights, could make market operators let volatile is more suitable for situation in China. Further research in this area is necessary.

4. Wind Generations in Congestion Management and Transmission Right Markets:

The LMP model assumes that in the absence of transmission congestion, the least expensive electricity source would be used to serve the next incremental load. However, in the presence of congestion, a more expensive generator needs to be re-dispatched. Under LMP approach, market participants can obtain financial rights to hedge against price risk between defined nodes. Wind generators tend to favour the LMP approach. This is because wind generators are not required to schedule in advance or to purchase transmission rights at the moment is China. They operate and provide energy to the grid as the wind resource is available. Therefore further research on penetration of the wind generations based on LMP approach should be carried out.