THE OPERATION PLATFORM RECOMMENDATION FOR THE DEREGULATED UTILITY INDUSTRY IN THAILAND

by

CHAI CHOMPOO-INWAI

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ABSTRACT

THE OPERATION PLATFORM RECOMMENDATION OF THE

DEREGULATED UTILITY INDUSTRY IN THAILAND

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Transmission Congestion Management (TCM) plays a significant role in power system operation under today deregulated environment. It has two major functions of an apparatus to keep power system running within acceptable security limits, and of a tool allocating financial obligation to market participants then paying back to transmission grid investors. TCM issue has been widely debating during a past decade, until now, it is still an opened issue extensively discussed in the current structure of competitive environment.

In the United State, there are existing two successful stories of TCM under different operation schemes, the former is PJM with Nodal Congestion Management (NCM) based on the renowned Location Marginal Price (LMP), while the latter is Zonal

Congestion Management (ZCM) deploying in Electricity Reliability Council of Texas (ERCOT). Though PJM model is adopted in some developing countries where the processes of restructuring of Electricity Supply Industry (ESI) is still under the beginning phase, many concerns such as: advance in an information technology, energy security, social equity, price volatility, and the need to subsidize the poor consumers, are necessary to be considered before the establishment of TCM and settlement processes.

Thailand is a developing country located in the heart of South-east Asia, and now being on the processes of transformation in ESI structure. Although the first initiation in this issue has been discussed since 1999 by government and related agencies, however, there is still unclear direction for the new reforming paradigm. Taking into account all above concerns, together with the studying of Transmission Congestion Management Techniques, Power System Security, and System wide economic benefit, this dissertation proposes a recommendation platform of the deregulated utility industry in Thailand during its transformation stage in order to have a smooth transition moving from the traditional vertically integrated system to a new competitive environment.

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CHAPTER 1

INTRODUCTION

1.1 Background and emerging problems

Almost all the Electricity Supply Industries (ESI) around the world is currently under the developing and restructuring stage to a competitive environment. The traditional vertically integrated utility setting is unavoidably being changed with the believing in better efficiency of the new competitive structure. The power system operation will become more aggressive and many challenges will arise due to the dynamic and unpredictable of power flow pattern. The traditional philosophy of power system planning and operation are now being revolutionized by applying new concepts in the unit commitment (UC) and economic dispatch (ED). Conventionally, a major task of system operators under the traditional vertically integrated system is to operate and maintain system security providing a minimum operation and maintenance (O&M) cost to maximize the social welfare. In the new era, additional tasks of managing the system congestion and allocating a fair congestion cost to all market participants (MPs) are new challenges under the competitive environment.

For the past decade, rapid economic growth in Thailand has resulted in the exponential growth of electricity demand especially in load center areas. Unfortunately, the transmission infrastructure and the generation supply of the whole country did not follow the suite. It requires transferring a bulk of energy over the long transmission grid to serve the demand in the load center. Consequently, the transmission congestion issue arises. To address this problem, the National Energy Policy and Planning (EPPO) issued a new rule of Power Purchase Agreement (PPA). Under this rule, Electricity Generating Authority of Thailand (EGAT) has to purchase the power from the Independent Power Producers (IPPs), and Small Power Producers (SPPs) then resell bulk power to the customer. This scheme encourages the involvement of private entities in power generation business. Traditional Thailand system, the electricity price is based on the "embedded costs" which is the average cost of electricity production and transmission. In 1997, the year of economy crisis, the momentum of ESI restructuring was accelerated because it is believed to be the best solution to improve the efficiency of Thailand's ESI.

Moving to the new environment of highly competitive paradigm, the huge generation companies (GENCOs) with their economic scale can exercise their market power to create unpredictable power flow patterns. With large number of power transactions among market participants, maintaining power flow within a satisfied security limit throughout power system presents challenges to the system operators.

To mitigate the transmission constraints problems, Transmission Congestion Management (TCM) seems to be a crucial mechanism to maintain the system security under the competitive market. It is not only reflects the transmission usage cost but also allocates the cost to all market participants in the justice fashion. It is fair to say that

TCM creates a financial incentive to market participants by changing the approach of electricity pricing.

1.2 Chronology of events in Electricity Supply Industry

In the past, almost all of traditional power system is operated and controlled under the vertically integrated system. In some countries, to ensure the security level of infra-structure utilization both on the generation or transmission facilities, therefore majority of generation and transmission belong to state-owned enterprises. The natural monopoly structure of the vertically integrated system is in a way such that utilities bundled with generation, transmission, and distribution, and obligated to provide electricity to all customers. On the other hand, electricity consumer had only one choice of electricity provider, and the energy price was regulated by the regulatory body.

Deregulation of power industry has initially implemented in Chile in 1982 [1-3], followed by the United Kingdom in 1988 when UK Department of Energy issued a white paper which set out the proposal to deregulate power industry of England and Wales [4]. A more concrete structure of UK system was written in legal framework for the electricity industry 1989. Originally, main purpose of power industry deregulation is to promote competition in generation industry. Mostly, transmission and distribution system are not the major intention of deregulation. They are expected to be the second or third stage of deregulation. Therefore, these businesses are usually seen as regulated business under supervision of non-profit organization or nondiscriminatory transmission providers.

After the introduction of deregulated in 1989, the unbundled processes of generation, transmission, and distribution entities has transformed the traditional paradigm to newly competitive environment. It is believed that, from the demand side, many benefits will arise under the new operation paradigm, i.e. more choices of supply, better services, and lower electricity prices. At the meantime, cost reduction through efficient electricity production process is the ultimate goal of the electricity supply side.

Figure 1.1 shows the sequence of transformation processes of the three systems. In the United State, the Federal Energy Regulatory Commission (FERC) issued the Order No. 888 to initiate the processes of deregulation by requiring all public utilities to provide open access to transmission facilities. Three years later, FERC issued the Order No. 2000 to request all transmission owning entities placing their transmission facilities under the control of Regional Transmission Organizations (RTOs). At the first stage, FERC has defined ten RTOs to cover the whole country. The initiation of Standard Market Design (SMD) was also set off in the year 2002.

In response to Order 888, Electric Reliability Council of Texas (ERCOT) ISO was formed in 1996. Governor Bush signed the Senate Bill 7 (SB7) to initiate the restructuring electricity utilities in the state of Texas in June 1999. As a result, ERCOT response to this action by preparing and modifying the traditional power system structure before the opening of the retail market in January 1, 2002. Whereas in Thailand, there was an initial discussion about restructuring model in 1996, Energy Policy and Planning Organization (EPPO) was the key organization taking care of the feasibility study of this issue. In 1997, the economic crisis in Asia has accelerated the momentum of deregulated in the country. EPPO has asked Arthur Anderson Consultant and Kema Consultant to prepare feasibility study of ESI deregulation in the country in 2000 and 2002 respectively. However, till now, the final structure of the utility deregulation has not yet been determined.

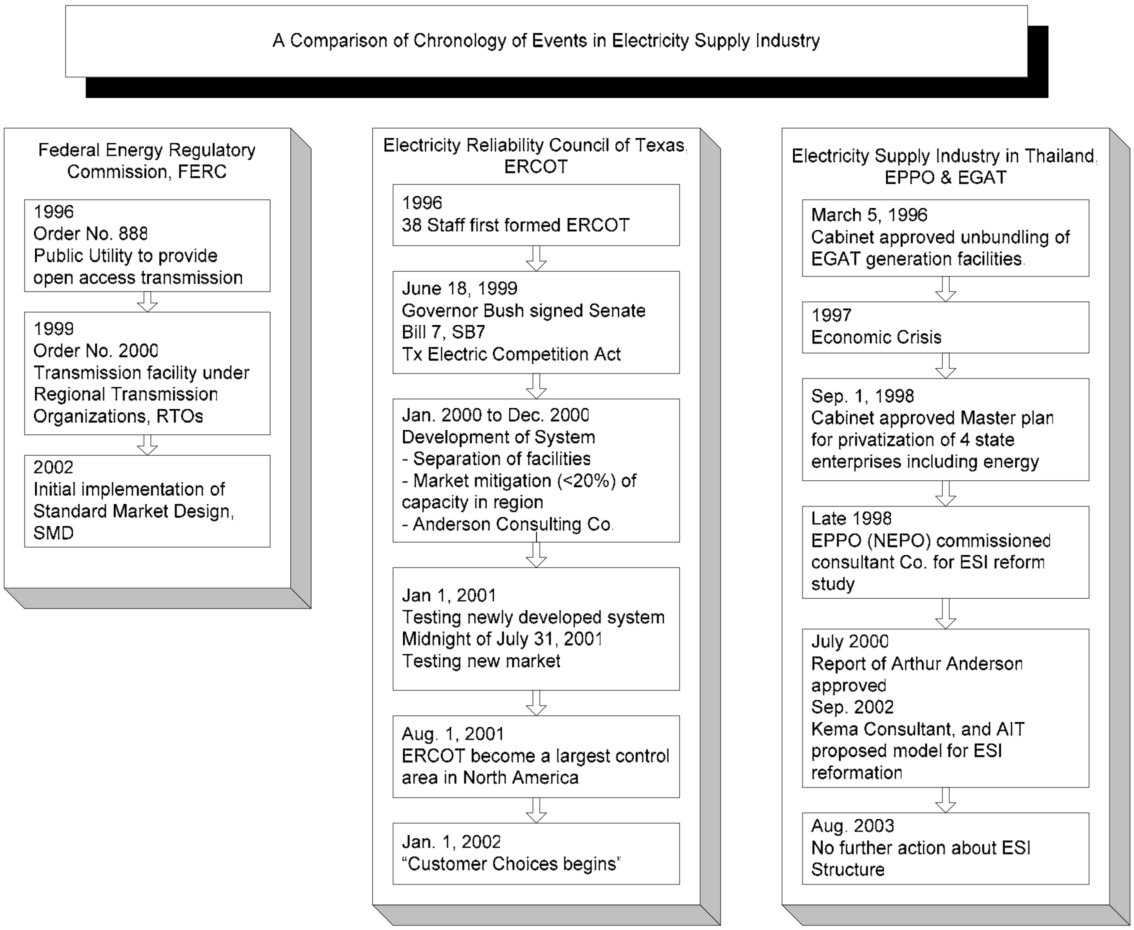

Figure 1.1 Chronologies of events in Electricity Supply Industry

1.3 Survey of literatures

Electricity deregulation is a blistering issue which has been widely debating around the world since 1980s. Even now, it is still an open topic that has drawn a wide area of interesting from many power engineers and other related fields. There are many related areas regarding to ESI deregulation both in the revolutionized of the traditional operation, and newly operation ideas emerged after the new paradigm was introduced. This process has revitalized both technical senses and economic perspectives. Therefore, wide areas of power engineering study were directly influenced by this new ESI transformation. This is including power system modeling, operations and planning, congestion management techniques, power system security, and also power system economic.

Before deregulation, most electric power utilities throughout the world operated with one controlling authority. The utility operated the generation, transmission and distribution system in a fixed geographic area under a vertically integrate monopoly system [5]. The initiated key issue that triggered the deregulated activity was from the question of inefficient operating under the monopoly system. Encouraged by the economic benefit from the deregulation of other industries such as telecommunication and airlines, Chile was the first country to implement the idea of deregulation of power industry in 1982, followed by the United Kingdom in 1988. A more concrete structure of UK system was written in legal framework for the electricity industry 1989. The deregulation followed in Norway, Australia, and New Zealand respectively, and until 1992, National Energy Policy Act (NEPA) in the United States was originally formed. A wide area discussion of deregulation activities in many countries including the United States were report in [6]. These topics include debating about the potential impacts of electricity deregulation to market participants (MPs) in the system both the power industry sector and other industrial sectors. Under the new competitive environment, the traditional designed structure of transmission grid would not be able to fully support a bulk of power transactions therefore the problem of transmission congestion arises. In order to relief the congestion and operate power system within an acceptable security level, researchers have studied and proposed many transmission congestion management schemes. According to [7-9], the review of transmission congestion management (TCM) in the competitive market regarding to TCM modeling have been discussed and implemented. Moreover, the comparison of cost associated with transmission constraints between nodal pricing and cost allocation procedures for a bilateral model was also presented. In North America, FERC Order 888 requires all public utilities to file open access nondiscriminatory transmission tariffs and functionally unbundled wholesale power services [10], and Order 889 requires all public utilities establish or participate in an Open Access Same-Time Information System (OASIS) that meets certain specifications [11]. As a result, [12] identifies the roles of different players in a restructured system, and suggests the decision support tools for each player based on their roles. In 2002, FERC initiated the implementation of standardized market design (SMD), and the evolution toward the SMD is presented and discussed in [13] with references to the market development in New Zealand, Australia, PJM, NE-ISO, and ERCOT. In that discussion, two main objectives of SMD, market liquidity facilitating bilateral trading and pricing efficiency facilitating congestion management, have been pursued. Furthermore, the SMD recognizes several functions essential for operating a robust and competitive electricity market as well as maintaining reliable and secure operation of a power system. Thus, SMD may include several key functions such as: an LMP-based energy market with security constraint economic dispatch (SCED), an ancillary service market, and a transmission right market. Likewise, the future of electronic scheduling and congestion management in North America was also discussed in [14].

In the United States, the debating of problems and challenges for implementing market-Based congestion management is still being discussed. Although there are several alternative proposals for incorporating congestion management into competitive markets for a bulk power, they can be divided into two types: centralized and decentralized system [15]. The centralized approach is exemplified by the PJM Interconnection which is considered to be the largest centrally dispatched system in North America. PJM achieves CM through its centralized control of generation resources. The system operator utilizes a computer program to minimize the cost of dispatching generation resources subject to the transmission constraints. Market incentives for power generation and transmission are combined through the Locational Marginal Prices (LMPs). On the other hand, for a decentralized system implementing in ERCOT relies on forward market that generates bilateral transactions as key factor for efficient operation. ERCOT is one of the successful stories of a decentralized market. It defines transmission right based on flow-gates or Commercially Significant Constraints (CSCs). Zones may be defined based on areas in which there tends to be relatively little congestion inside the zone (intra-zonal congestion). As a result, only congestion between the zones (inter-zonal congestion) must be priced and allocated as opposed to all potentially congested paths. Whether a centralized or decentralized system is better for congestion management is debatable because of their distinguish characteristics. Researchers in [16] have discussed the congestion management and transmission rights (TRs) in centralized electric markets while the framework to design and analysis the congestion revenue rights (CRRs) is discussed in [17]. In addition, a proposed method to provide detailed description of nodal price and its components were offered in [18].

In the different perspective of zonal congestion management, scholarly article [19] proposed the new zonal/cluster-based congestion management approach based on the sensitivity indexes of real power transmission congestion distribution factors (PTCDFs) and reactive transmission congestion distribution factors (QTCDFs). The author states that the proposed approach is simple but computationally efficient as it utilizes the sensitivity factors which easily to update the dispatching pattern. In addition, the study results of [20] claim that the new scheme of area-decomposed OPF to multi-zone congestion management can give an efficient way to relieve inter/intra-zonal congestion without exchanging too much information between zonal operators. Additionally, one of the good successful models of Zonal Congestion Management (ZCM) implemented by ERCOT was presented and discussed in [21-22]. The detail description of ZCM, basic assumptions, objective functions, and procedures of real time balancing energy and settlement processes were presented.

Under the various proposed model of TCMs, the secure operation of the power system is the basic requirement. Because the load is more uncertainty, and keeps changing under the new environment, this situation potentially creates a disturbance to power system. As a result, system with insufficient damping torque, together with weak transmission resources, may experience with dynamic instability problems. Therefore, power system dynamic study becomes more important issue for power engineering under newly competitive environment. It should be noted that all key terms, definition and classification of power system stability mentioned in this dissertation will base on [23].

Natural characteristic of power system is related to both linear and non-linear function, and many constraints can cause an uncertainty to its behavior. Practically, in real time operation, demand subjects to change due to the many voluntary factors i.e. set index forecast, load forecast, and weather forecast. Therefore, in order to guarantee the dynamic stability of power system, the Small Signal Stability Analysis (SSSA) is an important study topic. Normally, SSSA or eigen analysis is used to study the damping of the power system. Theoretically basic concepts and details can be found in [23-25]. Since power system turn into more dynamic and more complicate due to its scale, the technique to calculate eigenvalues of a large system happen to be difficulty and time consuming. Study result of [26] shows the investigation of the instability problem in the industrial power system due to the interconnection of new cogenerations. The study applies both time domain and frequency domain analysis to determine the fundamental characteristics of system and major problem causing system oscillation. In addition, [27] proposed methodologies for calculation of critical eigenvalues in the small signal stability analysis of large power systems, while [28] presented a comprehensive evaluation of the performance of the reduction techniques and established procedures for model reduction to be utilized in dynamic reduction of large scale power system.

Moreover, the study report of [29] is a complete example of SSSA under deregulated environment. Another employment of SSSA is found in [30] for purpose of more accurately calculation of available transfer capability (ATC). The author proposed the sensitivity-based rescheduling methods to dispatch the system generation to maximize the power transfer subject to the small-signal stability constraint under a set of contingencies. In addition, [31] proposed a method of rescheduling, based on the sensitivity of the corrected transient energy margin (CTEM) in order to enhance the dynamic security in power-market systems.

In Thailand, majority of scholarly articles have been discussed about conventional system operation i.e., [32] propose a neural network based power system stabilizer (PSS) model to obtain a better system damping in both local and inter-area mode of oscillation as compare to the conventional PSS. Furthermore, the conventional operation issue of units commitment was reinforced by using adaptive lagrangian relaxation (ELR) technique yield both lower generation production cost, and consume less CPU time [33]. In addition, some articles have been discussing issue of moving to the new environment. The transmission pricing issue will become more serious due to the possible cost component of congestion and how to allocating transmission cost to MPs in the justice fashion. A good example and commonly used wheeling calculation methods used by utility companies in the United State have been summarized in [34], whereas in Thailand, the comparison of transmission pricing techniques both before and after the emerging of power pool are to presented in [35]. In addition, to allocate a fair transmission usage cost to all MPs, it is required to know the contribution from each parties to the power flow in the transmission line. Hence, the concept of transmission pricing method based on electricity tracing was studied and presented in Thailand system [36]. Another related topic to the newly deregulated environment is of the system reliability. System operators (SOs) need to balance generation resources and demand of the entire the system to maintain system frequency. In this sense, reliability must run (RMR) units play this important role to assure a satisfied reliability level of system. In [37], the procedures to determine the RMR units and their amount of capacities were proposed and verified by Thailand power system.

Although many scholars have studied in various areas regarding electricity supply industry (ESI) after deregulation in Thailand, none of them have done the comprehensive study about the appropriate timing, methods, and implementation procedure of potentially transmission congestion management models which can be utilized in Thailand system. Therefore, it is believed that this dissertation is the first extensive discussion in detail processes of ESI restructuring during the transition period in Thailand.

1.4 Motivations, Objectives, and Approaches

Under the new deregulated archetype, it is clear that Electricity Supply Industry will become more competitive, and all power system facilities will be forced to operate closer to their limits. As a result, the security level of the system is declining. The situation can become worse when many private parties of generation companies i.e., Independent Power Producers (IPPs) and Small Power Producers (SPPs), have an opened opportunity in joining the new market environment. The reason is because they may cause a stability problem to the original system after experienced with disturbances. The impact study result of interconnection of 120 MW wind generation and utility system shows the possibility of voltage stability problem which can be developed by the new generation units after system experience a disturbance [38]. Another possibility of operation and stability problem results from interconnection of new generation facilities into the system can be found in [39]. This study reveals that the intermittent of wind speed can cause the fluctuation of power turbine output. Unfortunately, majority of wind farm will install fixed capacitor to compensate the reactive power. Then, this situation may develop the voltage problem to power system. Therefore, although integration on new generation facilities to the system yields the benefit of secure system reserve margin, it should also noted that those new units might create the operation or stability problem to the original system if they experience with some disturbances.

According to Power Development Plan 2003-2004 (PDP03-04), Thailand has plans to upgrade the existing infrastructure both in the generation and transmission facilities. Up to the year 2010 planning, the whole country plans to have approximately 15 percent generation reserve, and plan to build more transmission lines to relief the congestion problem both in the load center areas, and in the bottleneck areas of the country. However, it requires a large amount of time and financial investment to implement this planning action. Therefore, it is important to investigate the potential problems, develop possible solutions or remedy actions regarding power system operation and planning including transmission congestion issues.

The main objective of this dissertation is to propose the recommendation framework of the Electricity Supply Industry deregulation in Thailand system. Two keys questions have to be answered for this proposed framework. The first question is to find the proper timing for Thailand system to move to the new competitive environment. The second question is to find out a proper starting recommendation model of Transmission Congestion Management for a smooth transition to all market participants (MPs) in Thailand system.

To answer those two questions, this dissertation performs four main studied areas covering both the power engineering technical ground and the economic financial aspect. As shown in figure 1.2, the first study is of generation planning and demand growth for long term planning. Then, the study of various transmission congestion management techniques potentially to be utilized in Thailand system during the transformation periods are to be implemented in Thailand system. Result of different generation patterns from different operation strategies obtained from the second study will be an input for power system security analysis. To guarantee the security system operation, this dissertation will cover power system stability in both transient and dynamic stability analysis in which system subjects to severe disturbance and small disturbance respectively. This security analysis will be achieved in both frequency domain and time domain analysis. Finally, in the economic perspective, two concepts in economic theory are used as the decision tools for justifying a proper timing of ESI restructuring for Thailand system.

As discussion in section above, four main studies will be implemented in this dissertation. The hierarchy of the entire processes and the flow direction of raw data, studied data, and simulation result are presented in figure 1.2.

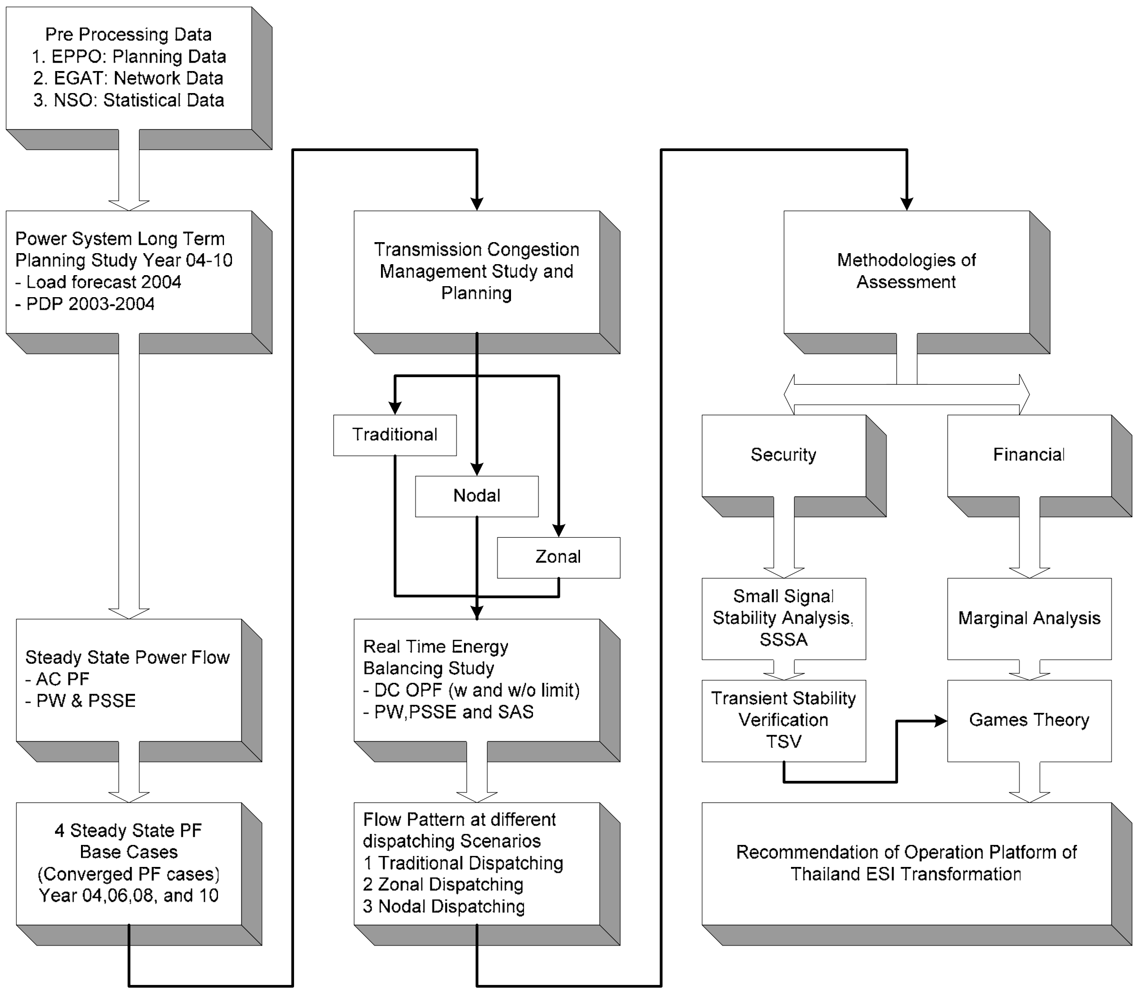

Figure 1.2 Study approach and hierarchy

It should be noted that the raw data of power system network topology is obtained from EGAT, the power development plan data is acquired from EPPO, and the statistical data of several types of fuel prices for generation are received from National

Statistical Office (NSO). All study results presented in this dissertation are base on the current available data at the time of doing this dissertation in the year 2004.

1.5 Synopsis of chapters

The material in this dissertation is organized as follows:

Chapter 1 introduces the general background and the chronology of deregulated events in the US and in Thailand. The problem emerging in Thailand deregulation situations are discussed and the ideas of possible remedy are proposed. Besides, the motivations, objectives, and study approaches of this dissertation are also illustrated.

Chapter 2 discusses the general idea of two TCMs in such the way of their purposes, modeling techniques, congestion management schemes, and congestion cost allocation. The implementation procedure of these two TCMs: zonal approach and nodal approach are focused.

Chapter 3 provides the two main methodologies of assessment. The system security is a mandatory, and is a pre-requisite before study in the financial perspective. In security study, the Small Signal Stability Analysis (SSSA) is the major tool to reflect the security level of power system under the competitive fashion. Time domain simulation also use for verify the result of SSSA. In an economy perspective, two studies of marginal analysis and game theory are used as decision making tools.

Chapter 4 initiates with the introduction of current status of Thailand Electricity Supply Industry, and then result of steady state power flow study following the Power Development Plan (PDP03-04) was reported in the sequential manner. The complete steady state power flow study including long term generation and load growth, area interchange, and N-1 contingency study were performed and reported.

Chapter 5 first proposes the model of RTO/ISO functions in the deregulated environment. The typical day ahead and real time energy balancing market structure are also focused. The pre assumptions to set up the candidacy of Commercially Significant Constraints (CSCs) were proposed. Then, the implementation of both TCMs models (Zonal and Nodal) are applied to Thailand system. Result of generation cost obtained from different dispatching pattern of traditional operation mode, zonal congestion management, and nodal congestion management are to be compared.

Chapter 6 is the study of power system stability. This security study includes both frequency domain and time domain analysis. Power system respond subjects to severe and small disturbance are to be focused. The creation of different scenarios of disturbances is performed to observe the system behavior after experiencing with disturbances to guarantee the secure operation.

Chapter 7 is the proposed framework for the deregulated utility industry in Thailand. Proper timing and recommendation platform are presented together with economic supporting tools. Finally, chapter 8 provides dissertation conclusions, contributions and possible further works.

CHAPTER 2

TRANSMISSION CONGESTION MANAGEMENT

2.1 Introduction and problem in Regulatory System

The electricity supply industries (ESI) all over the world have been operated in the vertically integrated system since the originating of power industry. Under this regulatory structure, utilities bundled with generation, transmission, distribution and obligated to provide electricity to all customers. Due to generation and transmission are bundled, the transmission planning is closely coupled to generation planning. Utilities (or monopolists) can optimize investments across both kinds of assets. Basic function of operating power system under this structure is to minimize total system cost while maintaining system security operation. To achieve these goals, utilities regularly schedule generation in day-ahead and re-dispatch generating units in real time operation. As a result, costs of those activities were spread out to all customers as an average tariff rate depending on utilities' aggregated cost during a period of time under the control of the regulatory agency. Under the tradition system, customers have only one choice of electricity provider, in other word, utilities operate in the monopoly fashion.

Similar to other business firm, profit maximization is the ultimate goal for utilities. There exists a conflict between regulators and monopolists. The regulator is trying to maximize social welfare while monopolist is trying to maximize their profit. The regulator controls the price by providing many options for monopolists to perform a cost minimization. The cost of service regulation seems to be the most popular mechanism that can hold electricity price down to long run average cost however it is lack of incentive to minimize the cost. Another method is using price cap regulation, but issue of how to set cap is the key question. Usually, it is found that the final electricity price for this strategy is higher than long run cost as well. Therefore, vertically integrated utilities can recover their costs no matter they operate system in efficient way or not.

These emerging problems have trigged the idea of electricity supply industry deregulation with considering that it can lead to efficiency improvement in system operation. It is also believe that under the new unbundling structure of generation, transmission and distribution, many benefits to customers will emerge. These may include more choices in service providers, cheaper electricity price, and better service quality.

2.2 Power system operation in Competitive Environment

Under the unbundled electricity market, due to generation, transmission, and system control are owned and operated by different players therefore operating power system becomes much more complex. During the restructuring phase of the electric power industry, the traditional vertically integrated utility environment is inevitably being changed. The power system operation will become more competitive and many challenges will arise [38]. Moreover, the significant number of transactions among MPs can also complicate the system, and cause a difficulty in power flow prediction. It is found that under the highly competitive environment, transmission lines are pushed to operate close to their limit, and it is most likely to introduce a congestion situation.

Practically, Transmission congestion is referred to the situation that no additional power can be transferred through interfaces and/or transmission lines. Therefore, more expensive generating units have to be online to serve the demand. The raise of congestion management concept is to solve this congestion problem. This process can be accomplished by re-dispatching generation pattern, modifying demand, or both combinations to avoid the overload in congested transmission lines. Definitely, there is a cost corresponding to solve the congestion. System operators (SOs) need to minimize this cost while maintain the security operation requirement. A proper allocation of this congestion cost is also the main responsibility of ISO/SOs.

Therefore, Transmission Congestion Management (TCM) plays a significant role in power system operation under today deregulated environment. It has two major functions of a tool to keep power system operating within acceptable security limits, and of a tool collecting monetary responsibilities from MPs then pay back to transmission grid investors. In regarding to transmission pricing, issues of how to allocate transmission usage cost and congestion cost are the main challenge for ISO/SOs. Normally, transmission usage cost is referred to the capital investment cost including operation and maintenance (O&M) cost. This cost component is collected by transmission grid investor to reimburse their investment and operating cost, and to obtain a reasonable profit. Apparently, there are several methods of transmission usage cost allocation for example postage-stamp method, contract part method, MW Mile method, unused transmission capacity method, MVA-mile method and counter-flow method etc. Transmission congestion cost, on the other hand, is the additional costs when more expensive units have to be online in order to solve the transmission congestion problem. It should be noted that this cost component are not collected by transmission owners. This cost component plays a key role in managing transmission usage under the competitive environment. Therefore, this dissertation will focus on this cost component and their structures.

This chapter discusses the two successful stories of transmission congestion managements (TCMs) utilized in the US. The first is, the Electric Reliability Council of Texas (ERCOT) with zonal congestion management (ZCM), and the second is PJM with nodal congestion management (NCM) base on renowned location marginal price (LMP). Their key structures, requirements, methods of operation will be discussed, and to be employed for the study of ESI deregulation in Thailand system.

2.3 Congestion Management process and two settlement system

Theoretically, managing transmission congestion in real world situation, MPs should have freedom to employ various mechanisms to maximize their profit. Therefore, the combination of several basic methods corresponding to time frames should be offered to all MPs. Figure 2.1 show the overall transmission congestion management process. According to the figure, three different time scales are categorized as followed.

a) Long term transmission capacity reservation

This process could be made yearly, monthly, weekly or daily. MPs can obtain the transmission rights from ISO through a centralized auction or exchange. The transmission rights can be either physical or financial. After occupying transmission right, MPs can create new, or revise existing bilateral transaction.

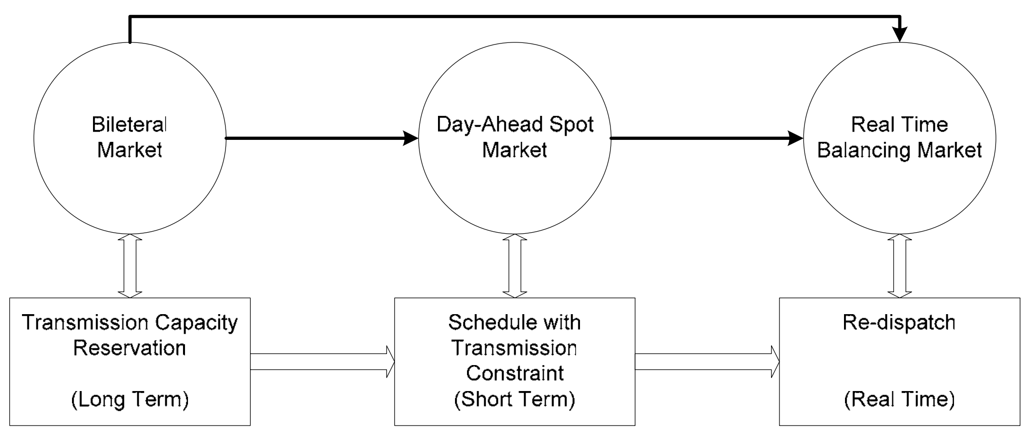

Figure 2.1 Congestion Management processes [40]

b) Short term scheduling in the day-ahead spot market

These schedules are accomplished by considering transmission constraints. Input data can be composed of the signed bilateral contract, generation offers, and demand bids in the spot market. This contact can be curtailed if congestion occurs.

c) Real time dispatching in real-time balancing market

In real time, transmission congestion may occur due to the uncertainty of demand. Therefore, a centralized balancing mechanism is needed to relieve real-time congestion to maintain system frequency. It should be noted that although this process is considered as market-based method, ISO have a right to take actions to maintain system security in emergency cases.

According to the above discussion, trading for the power delivered in any particular time begins year in advance, month in advance and continues until before real time will be classified as forward market whereas spot market which often include day-ahead (DA) and hour-ahead (HA) markets can be referred to as real time (RT) market. It should be noted that all markets except RT market are financial markets which mean delivery of power is optional. In this forward market, traders need not to own a generator to sell power. The RT market, on the other hand is the physical market which depending on power flow. It reflects the operational realities and related prices of generation and transmission. In conclusion, RT price are true marginal cost at a particular snapshot time, while forward prices are the predictions of future averaging RT prices for the particular length of the contract. Consequently, RT prices always differ from forward prices. This arrangement is called a two settlement system. Since RT price is reflect the operational realities, therefore this dissertation will focus on this price as to be discussed in chapter 5.

2.4 Market-based Congestion Management

Currently, there are many alternatives for incorporating congestion management into competitive markets. However, they can be categorized into two main structures which are decentralized and centralize market base.

2.4.1 Centralized approach based on Locational Marginal Pricing

The centralized market is exemplified by The PJM interconnection. Historically, PJM has been a centrally dispatched power pool. MPs put their generation resources at the pool then they are centrally dispatched to minimize system costs. PJM achieves congestion management through its centralized control. Market incentive for electric power and transmission are combined through a Locational Marginal Prices (LMPs). These LMPs are determined for all buses in the PJM system. They reflect the system marginal generating cost plus the shadow price on the transmission constraints at specific location of generation and load buses. These LMPs are posted on the OASIS system every five minutes to notify MPs on real time base.

2.4.2 Decentralized approach based on Zonal Pricing

Practically, the decentralized market relies on forward markets that generate bilateral contract based on some form of transmission right. This market combines with a centralized spot market to do a balancing adjustment for the scheduled transmission. Defining transmission right is a key factor of efficiently operated market. This transmission right must be reflect the marginal value of transmission availability and need to be clearly understood and accepted by MPs. The current successfully decentralized market is exemplified in ERCOT. Transmission rights are defined based on flow-gates or Commercially Significant Constraints (CSCs) or interfaces that may potentially become congested.

Debating whether a centralized or decentralized system is better for congestion management has generated a significant difficulty to answer. Each ISO with their congestion management scheme has their owned benefit. PJM’s centralized system can provide a very accurate accounting congestion costs for the entire system if the costs to dispatch generation resources are accurate. However, under this mechanism, congestion charge can only be known after transactions have taken place, thus this situation do not allow the advantage for the forward markets where MPs can negotiate the price of transmission prior to the transaction. Decentralized market on the other hand, are criticized as potentially unworkable without significant uplift charges for unanticipated congestion. However, it is believe to be a good model for MPs due to its simplicity. MPs can have more flexibility to control their financial risk during the real time market.

In summary, due to the difference in physical systems of geographic layout, generation mix and historical of formation, therefore both ISOs put the guidance provided by FERC and NERC into the practice under different schemes. The implementation of both congestion management schemes are discussed below. Sections cover a generalized summary of important concepts of both ISOs and their specific congestion management models.

2.5 Zonal Congestion Management

2.5.1 ERCOT System

ERCOT is a unique system as it is an interconnection, a NERC region, and also an ISO. ERCOT's service area covers the area within the borders of Texas, serving approximately 85 percent of the state's electric load with around 70,000 MW. of generation. Because there is no synchronously interconnect across state lines, thus ERCOT is not under FERC's jurisdiction. Instead, ERCOT is under the control of a single Public Utility Commission of Texas (PUCT). Historically, ERCOT's role as a regional reliability council was to maintain the reliability of the bulk power system in Texas. At the present time, as an ISO, ECCOT is responsible for providing a fair and open market for wholesale and retail competition [41].

ERCOT has operated DA ancillary service markets and the RT balancing energy market since July 31, 2001. ERCOT began monthly and annual Transmission Congestion Rights (TCRs) auction market in February 2002. ERCOT major Day-Ahead ancillary services include services of regulation up, regulation down, responsive (spinning) reserves, and non-spinning reserves.

2.5.2 ERCOT Congestion Management

ERCOT employs a zonal commercial model and two steps to manage zonal and local congestion in conjunction with a security-constraint dispatch. In the first step, ERCOT clear the predefined CSCs congestion, dispatches zonal balancing energy, and determine the market clearing price for each congestion zone. The balancing Energy Service offers are obtained by ERCOT in each zone for zonal load balancing and for inter-zonal congestion relief. Then Market Clearing Price for Energy (MCPE) is determined in each zone based on the zonal offer curves for balancing energy. If there is no interzonal congestion, the MCPE is the same for the entire ERCOT region. The second step is for local congestion. ERCOT uses resource specific premiums to clear local constraints and to issue resource specific instructions to relieve local congestion. Generators submit resource-specific premium that specify the additional payments (other than the zonal MCPE) that they require for the deployment of incremental (INC) or detrimental (DEC) balancing energy from the resources.

2.5.3 Markets for Transmission Congestion Rights

For MPs to hedge against the risk of volatile price in the RT balancing energy, ERCOT implemented Transmission Congestion Rights (TCRs) along with implementation of direct assignment of interzonal congestion charges since February 2002. ERCOT initially adopted a simple flow-based transmission right approach and flow-based congestion charges. ERCOT is moving toward a combination auction of TCRs. Congestion charge are obliged on QSEs based on the flow that their scheduled interzonal transactions induce on constraint on pre-defined CSCs. ERCOT provides MPs and annual and monthly based TCR auctions.

2.5.4 Processes to implement Zonal Congestion Management in ERCOT

As state earlier, ERCOT use a flow-based zonal approach to manage congestion in their system. The congestion management zones (CMZs) are defined such that each generator or load within the zone has a similar effect on the loading of transmission lines between zones. Once CMZs are defined, the imbalance between generation and load within zone is assumed to have the same impact on inter-zonal congestion. There are four sequential steps to determine ERCOT’s CMZs for each fiscal year. Analysis of zone boundaries is reexamined annually due to the change in generation, load, and transmission facilities. An advisory committee then analyzes the lists of constraints and determines which are the commercially significant. A DC power flow model is then used to determine the impact of each generation and load change for each buses in system on the predefined CSCs. Statistical clustering is then used to aggregate buses into zones based on their having similar impacts on the congestion paths (CSCs). The last step is to determine the number of CMZs. The main objective is to obtain a balancing between minimum number of CMZs while still accurately capturing the impact of each load and generation on the CSCs. Once the CMZs are defined, the zonal shift factors (ZSF) or zonal average weighted shift factor are calculated to obtain the impacts of each load and generation within the zone on each CSCs. It should be noted that these ZSFs are calculated base on the peak load condition, and to be recalculated annually. They will be significant tools in calculating congestion charge for each defined CMZs, for each MPs. Followings are four sequential steps of ERCOT's congestion management zones determinations processes [42]. The similar process will be implemented for Thailand system for purpose of TCM study and completely studied result are presented in chapter 5.

2.5.4.1 Determination of CSCs

For ERCOT system, this step is annually accomplished by July of each operating year. Due to it is a subjective step, thus it requires an engineering judgment base on annual analysis by ERCOT subcommittee. When implemented in Thailand, since it is an initial stage moving toward deregulation, it should take a more conservative approach in determining CSCs, and EPPO subcommittee should take a main responsible for this action. The new CSCs for the upcoming year, as well as the electrical network topology, should be defined annually by September 30th to match the fiscal year of the Thailand. The analysis should based on "Summer Peak Load Flow Case" and performing AC line contingencies, steady state power flow, and dynamic stability analysis. Load flow case used in determining CSCs should be posted on the ISO's website. From the operation record, the preliminary potential candidacy for CSCs in Thailand system will be focused on the high voltage transmission level of 230 kV. and 500 kV.

2.5.4.2 Calculation of Generation Shift Factor (GSFs)

Unlike the previous step, step 2 is purely mathematical processes. The main purpose of calculating the generation shift factor (GSF) is to determine the impact of transferring one MW of real power from a specific bus to the system slack/reference bus on the power flow of each interface (CSC).

The GSF are to be calculated for all buses for the entire studied system. The theoretical background for a GSF can be found in [43-44]. The generation shift factor is defined as equation (2.1)

$$GSF_{km,i} = \frac{\overline{X}_{ki} - \overline{X}_{mi}}{X_{km}} = (\overline{X}_{ki} - \overline{X}_{mi}) \times (-B_{km}) \tag{2.1}$$

Where, $GSF_{km,i}$: generation shift factor on CSC_{km} to reference bus i

k, i : from bus, and to bus index respectively

$\overline{X}_{ki}$: element of inverse of *B'* matrix. (If i = swing bus number, $\overline{X}_{ki} = 0$)

$\overline{X}_{mi}$: element of inverse of *B'* matrix. (If i = swing bus number, $\overline{X}_{mi} = 0$)

B_{km} : element of *B* matrix

X_{km}: reactance of line (from bus k to bus m)

The full AC power flow (ACPF) equation is defined in equation (2.2), and the process for linear approximation DC model for Thailand reference bus are shown in equation (2.3) through (2.11).

$$P_k = \Sigma E_k{}^2 g_{ki} - g_{ki} E_k E_i \cos(\theta_k - \theta_i) - |E_k||E_i| \sin(\theta_k - \theta_i) \tag{2.2}$$

Where, P_k: active power into bus k

Q_k : reactive power into bus k

E_k: complex voltage at bus k

Y_{ki}: complex admittance between bus k and i

Y_{kk}: complex admittance between bus k and reference bus

I_{ki}: complex current from bus k to i

Following three assumptions are used for linear a DC approximation:

1. The bus voltages are all near 1 pu. , thus $|E_k| = 1$

2. The line resistance is small compared to the reactance, thus the Y terms become

$$Y_{ki} = g_{ki} + jb_{ki} = \frac{r_{ki}}{r_{ki}^{\ 2} + x_{ki}^{\ 2}} + \frac{-jx_{ki}}{r_{ki}^{\ 2} + x_{ki}^{\ 2}} \tag{2.3}$$

Where, r, x: is per unit line resistance, reactance respectively.

$$g_{ki} \approx 0 \text{ and } b_{ki} = \frac{1}{x_{ki}} \tag{2.4}$$

3. The angle across the lines are small, thus

$$\sin(\theta_k - \theta_i) = \theta_k - \theta_i \text{, and } \cos(\theta_k - \theta_i) \approx 1 \tag{2.5}$$

According to the above three assumptions, the full AC power flow equation in (2.2) can be reduced to the linear DC power flow shown in (2.6) and (2.7)

$$P_k = \sum \frac{1}{x_{ki}} (\theta_k - \theta_i) \tag{2.6}$$

$$\text{or } P_k = \sum B'_{ki} \theta_i \tag{2.7}$$

In addition, with the setting of zero to the slack bus, the DC power flow equation and the bus angle equation can be reduced to equations (2.8) and (2.9) respectively.

$$P_k = \sum B_{ki}\theta_i \tag{2.8}$$

$$\theta_k = \sum \overline{X}_{ki} P_i \tag{2.9}$$

Where $\overline{X}_{ki}$ is the inverse of the B_{ki} matrix. The power flow from bus k to m can be expressed in equation (2.10)

$$\sum_i \left(\overline{X}_{ki} P_i - \overline{X}_{mi} P_i\right) * \frac{1}{x_{km}} = \sum_i \frac{\left(\overline{X}_{ki} - \overline{X}_{mi}\right)}{x_{km}} * P_i \tag{2.10}$$

Equation (2.10) shows that the term in front of P_i is refer to the GSF therefore the DC line flow on a particular line is equal to the summation of the shift factor at each individual bus in the system multiplied by the power injected at that bus (equation 2.11).

$$\sum_i GSF_{km,i} \times P_i \tag{2.11}$$

It should be noted that the output of step 2 would be the set of GSFs of approximately 1500 buses (for Thailand) impact on CSCs candidacies as mentioned in step 1.

2.5.4.3 Clustering GSFs

The purpose of the clustering analysis is to group the shift factors into zones or clusters. This is also a non-subjective step. Basically, clusters are defined by minimizing the “in-cluster” sum of squares for each shift factor within a cluster while simultaneously maximizing the variance between the cluster means.

In Thailand situation, for the initial stage of deregulation, it is recommended the minimum number of 2 – 4 clusters. These numbers of cluster could be changed due to the appearance of new CSCs in the up coming year.

2.5.4.4 Defining the number of CMZs

The last step is the most subjective step in the entire process. This step involves reviewing and interpreting the data from step 3 and determining the appropriate number of zones that will define the annual commercial model.

Since the result of this step will directly affect the financial obligation for all MPs in the system, the final decision should be left up to a task force with members from ISO, academia, stakeholders, and EPPO (for Thailand situation). Once the number of CMZs are defined, the Average Weighted Shift Factor (AWSF) or Zonal Shift Factor, used to predict potential congestion on CSCs can be calculated by equation (2.12)

$$AWSF_{CSC_z} = \frac{[\sum_Z (SF_{iCSC} \times P_{Gi})]}{[\sum_Z P_{Gi}]} \tag{2.12}$$

Where, $AWSF_{CSCz}$: the average weighted shift factor for CSC for zone z.

SF_{iCSC} : the shift factor at bus i for CSC

P_{Gi}: the generation at bus i

i: all busses in zone z

After finishing all four steps, the annual data of the next year CSCs would be posted to MPs on the OASIS.

2.6 Nodal Congestion Management

2.6.1 PJM System

PJM market covers the area of Pennsylvania, New Jersey, and Maryland. PJM interconnection became the first operational ISO in the U.S. since January 1998. PJM operates the DA energy market, RT energy market, daily capacity market, monthly and multi-monthly capacity markets, regulation market and the monthly Financial Transmission Rights (FTRs) auction market. The PJM staff centrally forecasts, schedules and coordinates the operation of generation units, bilateral transactions, and the spot energy market to meet demand requirement. It should be noted that PJM's two settlement system consists of DA market and RT balancing market which separatelly accounting settlements are performed for each market [45].

2.6.2 Congestion Management and Locational Marginal Pricing

PJM manages congestion through a market design based on Locational Marginal Pricing (LMPs). The LMP is defined as "the marginal cost of supplying the next increment of electric demand at a specific location on the system with taking into account both generation marginal cost and the physical aspects of transmission system" [46]. In practical system, LMPs are calculated based on the actual system conditions obtained from system state estimator at five minute interval and immediately posted on PJM's OASIS.

2.6.3 Markets for Fixed Transmission Rights

The Fixed Transmission Rights (FTRs) is not a physical right to transmission service. It actually gives the holder the right to be compensated for the difference between the LMP at generation source and the LMP at the load. FTRs are originally obtained in auctions by network transmission service holders or with Firm Point-to-Point transmission reservation. They can be traded in secondary market. These FTRs provide MPs to hedge against their risk from congestion cost

2.6.4 Processes to implement Nodal Congestion Management and LMPs in PJM

In PJM, the LMPs are calculated for 1,750 PJM buses plus 5 interface busses into the PJM control area. When there are no congestion constraints in the PJM system, LMPs are the same for all buses and equal to the marginal cost to serve load in the control area. Since LMPs are calculated by minimizing the difference between the bids for generation and load subject to transmission constraints. Therefore, for buses where there are transmission constraints, the dispatched units will have higher costs than the lowest marginal cost generating unit.

This dissertation discusses the LMPs calculation processes based on [46]. Equation (2.13)-(2.18) used to calculate of bus LMP. All steps of calculation were discussed below:

$$LMP_i = LMP^{ref} + LMP_i^{loss} + LMP_i^{cong} \tag{2.13}$$

Where, LMP^{ref} : Incremental fuel cost at the Reference bus.

LMP_i^{loss} : Incremental fuel cost at bus “i” associated with losses.

LMP_i^{cong} : Incremental fuel cost at bus “i” associated with congestion.

The loss and congestion components are defined as follows:

$$LMP_i^{loss} = (DF_i - 1) \times LMP^{ref} \tag{2.14}$$

$$LMP_i^{cong} = -\sum_{k \in K} (GSF_{ik} \times \beta_k) \tag{2.15}$$

Where,

$DF_i = \left(1 - \frac{\partial P_L}{\partial P_i}\right)$ *:* Delivery factor of bus "i" relative to the reference bus

GSF_{ki} *:* Generation Shift Factor at bus "i" on line "k". This is also referred to as the sensitivity factor relating a change in flow in line "k" when a 1 MW injection change occurs at bus "i" [i.e., $S_{(k),i}$]

β_k *:* Constraint incremental cost (shadow price) associated with line "k".

K: Set of congested transmission lines (i.e., lines with binding constraints).

Substituting the definition for DF_i into equation (2.14) yields the following:

$$LMP_i^{loss} = \left(1 - \frac{\partial P_L}{\partial P_i} - 1\right) \times LMP^{ref} = -\frac{\partial P_L}{\partial P_i} \times LMP^{ref} \tag{2.16}$$

Add the first two terms for LMP_i in equation (2.13) yields the equation (2.17)

$$LMP^{ref} + LMP_i^{loss} = \left(1 - \frac{\partial P_L}{\partial P_i}\right) \times LMP^{ref} = DF_i \times LMP^{ref} = \frac{LMP^{ref}}{PF_i} \tag{2.17}$$

Where, PF_i *:* The Penalty Factor term for bus "i".

$$LMP_i = \frac{LMP^{ref}}{PF_i} - \sum_{k \in K} (GSF_{ik} \times \beta_k) \tag{2.18}$$

Finally, combining equation (2.16) and (2.17) result in equation (2.18) which uses to calculate the buses LMP for the entire system.

2.7 Chapter summary

Two distinguish stories of transmission congestion management (TCM) in the United State have been implemented in ERCOT and PJM market. Due to the difference in physical systems of geographic layout, generation mix and historical of their formation, therefore both ISOs put the guidance provided by FERC and NERC into the practice in different fashions. ERCOT implements decentralized market while PJM employ centralized market. Both TCM models provide their owned advantages and disadvantages. None of ISOs have yet finished developing their perfect TCM procedures. They are still trying to develop for a better system. At the present time, the implementation of both TCM models has been considered as imperfect model. They both are considered as the second best model compare to the ideal perfect model. However, both markets are widely accepted as successful markets in the world. Therefore, these two TCM models will be used as a guidance for the study of ESI deregulation in Thailand. Studying procedure, pre-assumptions, and complete studied result of these two congestion management schemes applied to Thailand system will be presented in chapter 5.

CHAPTER 3

METHODOLOGIES FOR ASSESSMENT

3.1 Introduction

The entire study processes of power industry deregulation especially regarding to transmission congestion management (TCM) involve a wide area of knowledge. Therefore, many disciplines will be mentioned and discussed in this chapter. Unlike the goal of other business agents to maximize their profit, security concern is the first priority for power system operation. Decision making on any business activities that would impact to Electricity Supply Industry (ESI) requires a security assessment as a pre-requisite. Since the transformation of traditional operating structure to the newly deregulated environment involves a significant amount of monetary investment from the government, economic and financial analysis is also an area of interest. Following sections discuss two methodologies of assessment for ESI deregulation in Thailand.

3.2 Security Assessment

Power system stability has been recognized as an important problem for secure system operation since the 1920s [47], [48]. Many major blackouts caused by power system instability have illustrated the importance of this phenomenon [49]. According to [23], power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact.

Since synchronous generator is the major source of electricity generation. Then, traditional power system stability was focused on the ability of synchronous generator to maintain synchronous operation among generators. A stable system should satisfy necessary conditions that all generators and coherent machines [50] in the system remain in synchronism at any circumstances. This study referred to as rotor angle stability.

In modern power system operation, instability may occur even when machines remain in synchronism [51]. Combined characteristics of load with high proportion of motor may result in difficulties in control of voltage if reactive power requirement is insufficient. This situation may cause instability problem by substantially reduce in voltage magnitude while synchronism of synchronous machines are maintained. In this fashion, instability is not influenced by generators synchronism but rather by the ability to supply reactive power to load which known as voltage stability problem.

Security assessment studies in this chapter start with the classification of power system stability including important terms used in this dissertation. Basic concepts of stability phenomena as well as factors affecting system stability are also discussed. Finally, summary of theoretical backgrounds are provided.

3.2.1 Classification of Power System Stability

A typical modern power system is a high-order multivariable process whose dynamic response is influenced by a wide array of devices with different characteristics and response rates. Power system stability, therefore, is a condition of equilibrium between opposing forces depending on network topology, system operating condition, and form of disturbances. This dissertation classifies power system stability problem into two main categories and subcategories as shown in figure 3.1. All terms and definitions exploited in the entire dissertation will base upon this chart.

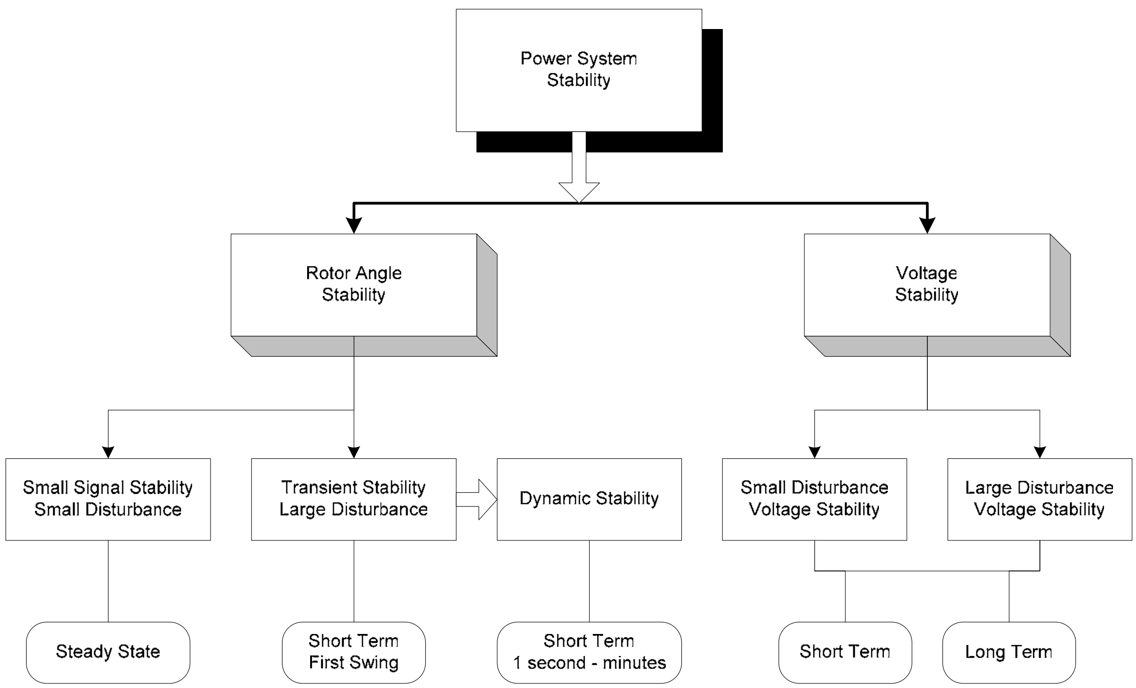

Figure 3.1 Classification of Power System Stability

Figure 3.1 presents the categories of power system stability studies based on following considerations: the physical nature of the resulting mode of instability, the size of considering disturbances, and processes and time span that taken into consideration to assess stability. Taking into account these considerations, this dissertation addresses power system stability problem into two main issues as followed.

A. Rotor Angle Stability

Rotor angle stability refers to the ability of synchronous machines of an interconnected power system to remain in synchronism after being subjected to a disturbance [23]. Since major concern in this dissertation is on system wide security, therefore rotor angle stability will be focused. The studies will include small signal stability analysis, transient and dynamic stability analysis. Further detail definitions, descriptions, and study procedures for rotor angle stability used in the whole dissertation are discussed in section 3.2.2.

B. Voltage Stability

Voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition [23]. Since the dispatching pattern study in chapter 5 is base on DC power flow (DCPF) then steady state voltage problem will be ignored.

3.2.2 Rotor Angle Stability

Basically, operating point of power system is the equilibrium between two opposing forces [51], a force tend to decelerate one or more synchronous generators that caused by load and the counter force produced by synchronous generators. When conditions in power system changed, system will try to re-adjust itself to a new operating equilibrium. However, this capability of power system is applicable within a specific range depend on generation and transmission capacity. When the load is increased, a generator or a group of generators tend to respond and increase angular separation. If this situation continues, it may lead to loss of synchronism of generators or “fall out of step” result in isolating these generators from the system by protective devices.

In electric power system, the change of the electrical torque in synchronous generator comes from torque change due to rotor angle perturbation $\Delta\delta$ and rotor speed perturbation $\Delta\omega$ that can be expressed as follows:

$$\Delta T_e = T_S \Delta\delta + T_D \Delta\omega \tag{3.1}$$

Where,

$T_S \Delta\delta$: Torque change due to rotor angle perturbation

$T_D \Delta\omega$: Torque change due to rotor speed perturbation

$\Delta\delta$: Rotor angle perturbation

$\Delta\omega$: Rotor speed perturbation

T_S : Synchronizing torque coefficient

T_D : Damping torque coefficient

The first component in equation (3.1) is related to rotor angle separation that determines the synchronism of generators in the system, thus this term is also known as “Synchronizing Torque”. Similarly, the second term is called “Damping toque” since it is the result from the change in rotor speed compared to the synchronous speed that is controlled by damping coefficient of generators.

The evaluation of stability problems requires studying the respond of power system during and after the disturbances. As shown in figure 3.1, this dissertation characterizes rotor angle stability in terms of the two different subcategories.

3.2.2.1 Small signal stability

This topic concentrates on the respond of power system when disturbances are small and continuously such as slightly change in load demand or generation dispatch. It should be noted that disturbances are considered to be sufficient small so that the linearization of system equations is allowable for purposes of analysis.

Normally, power system instability can be characterized into two different unstable types. They are usually found as 1) increasing in rotor angle through a non-oscillatory or aperiodic mode due to lack of synchronizing torque, or 2) increasing in amplitude of rotor oscillation due to lack of sufficient damping torque. Basically, non-oscillatory instability can be alleviated or eliminated by the operation of automatic voltage regulator (AVR) since this equipment maintains suitable voltage magnitude at generators terminal for delivering sufficient power to supply load. As soon as load demand is satisfied, generator's rotor angle is controllable. Since AVR is the basic equipment in generator control loop, non-oscillatory instability problem is not a significant stability problem in modern power system [51].

On the contrary, oscillatory instability due to insufficient damping torque is the most frequently seen of the small signal stability in power system. This problem, ranging from oscillation to instability, may be categorized in several modes depend on the characteristics of instability as the following:

A. Local mode oscillations

This mode of rotor angle stability normally involves a small part of power system, and usually represents the swinging of generators inside a power plant against the rest of the system. The stability of this mode depends on the strength of the transmission system seen by the power plant, excitation system, and plant output.

B. Interarea mode oscillations

This mode is caused by interactions among large groups of generators and has widespread effects. Interarea oscillation occurs when at least two groups of generation units in different areas are swinging against each other. This situation is normally taken place when two groups of machine are interconnected by weak transmission system. In addition, load characteristics are the other influences on the stability of interarea mode.

Due to the above reasons, small signal stability studied in this dissertation will focus on the oscillatory instability of Thailand power system. All study result of small signal stability problem found in Thailand will be presented and discussed in Chapter 6.

3.2.2.2 Transient stability

Transient stability phenomenon is the respond of power system when it subjects to severe disturbances. This phenomenon is about the period of time during which the action of the governor is not yet effective [52]. Generally, large disturbances cover several abnormal conditions that may occur in the system such as short circuit, heavy load switching etc. However, three-phase to ground fault is accepted as the standard simulation condition for general transient stability study since it is the most severe case of system disturbance. Therefore, this fault will be used as a standard simulation condition in transient stability study throughout this dissertation. These disturbances result in large electromechanical transient in the system that may exceed the withstand ability of generators. Many factors, such as initial conditions, generators parameters, strength of transmission lines, and protection scheme determine the stability of power system under this circumstance.

Transient stability study focuses on the moment 3 to 5 seconds [51] following the disturbances. Instability may occur within the first swing of transient stability period that rotor angle increase progressively until loss of synchronism. Another possibility is the action of stable during the first swing but contains the oscillations in the extended time scale. However, first swing instability is relatively rare in practical system, association between oscillations during the first swing and the extended time period are regularly recognized as the common transient instability in practical power system.

3.2.2.3 Dynamic stability

Dynamic stability refers to the ability of the power system to remain in synchronism after the several initial swings of the rotor. This take place after the governor begins to function [52]. Usually, dynamic stability starts about 1 second after disturbance and continues until several seconds to several minutes. In this dissertation, dynamic stability study is of the extended studying time of transient stability to 15 seconds.

3.2.3 Study approaches and Theoretical Background

Historically, the most common form of power system instability between interconnected generators was a loss of synchronism in the first few seconds following a large disturbance. This instability is caused by the non-linear nature of interconnected generators, therefore understanding this phenomenon requires solving incremental time step of non-linear differential equations of the system. Newsday, modern power systems are getting more complex due to many fast response control devices have been installed. As a result, low damping and low frequency oscillation becomes an observable problem in many power utility's system. Though it involves some nonlinear phenomenon of the power system, using linearized model to perform frequency domain analysis is a commonly adopted technique to obtain useful information and explain the nature of this problem.

In this dissertation, rotor angle stability study is approached by both time domain and frequency domain analysis. Time domain analysis provides the behavior of the system quantities such as voltage, frequency, and generator speed etc. On the other hand, frequency domain analysis provides system eigenvalues, eigenvectors and participation factors which describe oscillation modes and the contribution of each state variable to oscillation modes. Since frequency domain analysis is to calculate eigenvalues and eigenvectors of power system based on linearization system model, therefore this analysis is sometimes called eigen analysis or small signal analysis. Throughout this dissertation, theses two terms may be used interchangeable.

The stability study of a medium size power system such as Thailand in this dissertation will start with frequency domain analysis. Performing this study yield the necessary information about system oscillation modes. Then, time domain analysis will be used to verify results of frequency domain analysis and to observe system responses from potentially contingencies and severe disturbances. The following two sections include the theoretically background, and basic assumptions regarding the frequency domain and time domain analysis respectively.

3.2.4 Linearized system technique for Frequency Domain Analysis

3.2.4.1 State space formulation

Physical nature of power system is nonlinear which composes of a number of nonlinear and algebraic equations. However, the stability of nonlinear system can be approximated to the properties of linearized system at a certain operating point when system subjects to small disturbance. In this manner, dynamic performances of system can be represented by a set of differential equations and algebraic equations as followed.

$$\dot{x} = Ax + Bu \tag{3.2}$$

$$v = Hx + Fu \tag{3.3}$$

Where, *x:* real state vector of generators and their controllers

u: real input vector or disturbance

v: vector of real system outputs or measured variables

A: the system state matrix

B: the input matrix

H: the output coefficient matrix

F: the direct feed forward matrix

The first step in linear system analysis is to form system state equations. This process is known as state space formulation. Equation 3.2 and 3.3 are system state equations. Both equations are considered to be linear time invariant (LTI) if system coefficient matrices *A, B, H,* and *F* are constant. Otherwise, these linear state equations would be linear time variant (LTV).

3.2.4.2 Eigenvalues and system stability

The solution of state equations in (3.2) and (3.3) can be obtained by taking Laplace Transforms. Thus,

$$x(s) = (SI - A)^{-1}\left[x(0) + Bu(s)\right] = \frac{\left[x(0) + Bu(s)\right]\left[Adj(SI - A)\right]}{Det(SI - A)} \tag{3.4}$$

$$Y(s) = H(SI - A)^{-1}\left[x(0) + Bu(s)\right] + Fu(s) \tag{3.5}$$

Where, *I:* the identity matrix of the same dimensions as matrix *A*

Det(SI-A): the determinant matrix of *(SI-A)*

Adj(SI-A): the ad-joint of matrix *(SI-A)*

x(0): state at time = 0

It should be noted that eigenvalues or poles of *x(s)* are the roots of equation (3.6). The eigenvalues, typically denoted by λ, are function of the system state matrix *A*. The number of eigenvalues is equal to the number of system states.

$$Det(SI - A) = 0 \text{ or } Det(A - SI) = 0 \tag{3.6}$$

The stability of system can be determined by the eigenvalues in two different perspectives. From frequency domain viewpoint, eigenvalues are good indicator of system characteristics. A system is stable if all poles are in the left half of S-plane. In other word, if there is one pole on the right half side of S-plane then the system is unstable. Theoretically, time dependent characteristic of a mode for each eigenvalue (λ_i) can be given by $e^{\lambda i}$ as shown in equation (3.7). This time function normally provides solution for state equations in time domain. It is usual to associate each eigenvalue with a mode of system state matrix *A* therefore eigenvalue is sometime called modal frequency.

$$C_i e^{-\lambda_i t} = C_i e^{-(\alpha_i + \beta_i)t} = C_i e^{-\alpha_i t} (\cos \beta_i t + \sin \beta_i t) \tag{3.7}$$

Where, *x(t):* is the solution for state equations in time domain

C_i: constant coefficient

From time domain viewpoint, if all eigenvalues have a negative real part, then system modes will decay with time and system is said to be stable. On the other hand, if there is any mode with positive real part, the corresponding mode will grow with time and dominates system behaviors. This system is said to be unstable.

In summary, the stability of system determined by eigenvalues can be categorized into two following types:

a) A real eigenvalue corresponds to a non-oscillatory mode. A negative real part represents a decaying mode while the positive real part implies aperiodic instability.

b) Complex conjugate eigenvalue corresponds to an oscillatory mode. The real component gives the damping while imaginary component provide angular frequency of oscillation. Thus for any complex pair of eigenvalues in equation (3.7), there exists the frequency of oscillation, and damping ration as shown in equation (3.8) and (3.9) respectively.

$$\lambda = \alpha + j\beta \tag{3.7}$$

$$f = \frac{\omega}{2\pi} = \frac{\beta}{2\pi} \tag{3.8}$$

$$\xi = \frac{-\alpha}{\sqrt{\alpha^2 + \omega^2}} \times 100 \tag{3.9}$$

Where, f: the actual frequency of oscillation or damping frequency

ζ: the damping ratio (in percent)

3.2.4.3 Eigenvectors and mode shape

The mode shape is the relative activity of the state variables when a particular mode is excited. Normally, for each eigenvalue (mode) there exists a vector, t_i which satisfied the equation (3.10)

$$At_i = \lambda_i t_i \tag{3.10}$$

The vector t_i is called a right eigenvector of system matrix A associates with eigenvalue λ_i. There is another row vector satisfying equation (3.11). This vector is called a left eigenvector of a system matrix A.

$$Z_i A = \lambda_i Z_i \tag{3.11}$$

While a right eigenvector gives a mode shape of system telling how each mode of the system is distributed throughout the state vector, a left eigenvector on the other hand provides the magnitude of mode.

3.2.4.4 Participation factors

Practically, it is helpful to determine the magnitude of the influence of a particular state on any particular mode because it provides a proper location for install a controller for the interested mode of oscillations. The participation factor is defined as

$$P_{ik} = |t_{ik} Z_{ki}| \tag{3.12}$$

Where, P_{ik}: participation factor measure influence of state i on mode k

t_{ik}: the i^{th} element of the k^{th} column of matrix t

Z_{ki}: the i^{th} element of the k^{th} row of matrix Z

The above discussion is a brief review of basic concept of linear system analysis which will be applied in small signal stability analysis (SSSA) in this dissertation. The detail theoretically background can be found in [51]. Difficulty in formulation of system state matrix and calculation of eigenvalues for a large scale power system are the two main challenges for SSSA. The basic assumptions, studying procedures, scenarios creation, and studied result of Thailand SSSA will be discussed in chapter 6.

3.2.5 Transient Stability Study for Time Domain Analysis

Transient stability is the ability of power system to maintain synchronism after severe disturbances. General speaking, severe disturbances in transient stability study represent the situation when power system loss a significant facility such as transmission line, generator, or large load due to short circuit of equipment (faults). These interruptions result in electromechanical transient that may cause stability problem in the systems. Since transient stability study considers the system behavior right after the disturbances, only generator and network response are fast enough to react to this change and become two major factors to affect the ability of power system to remain stable conditions.

Differ from voltage stability, transient stability is a rotor-angle stability problem that results in loss of synchronism of generator. A transient instability situation is observed by the uncontrollable increasing of rotor angles that finally trigger the protection system to disconnect generator from the system before it is damaged. Figure 3.2 presents a comparison between power system under transient stability stable and transient stability unstable situations. It is seen that rotor angles among buses clearly explain the phenomena of transient stability. In figure 3.2 a), rotor angles of machines system remain in synchronism, whereas in b) there is a rotor angle separation between two groups of machine referred to as rotor angle instability.

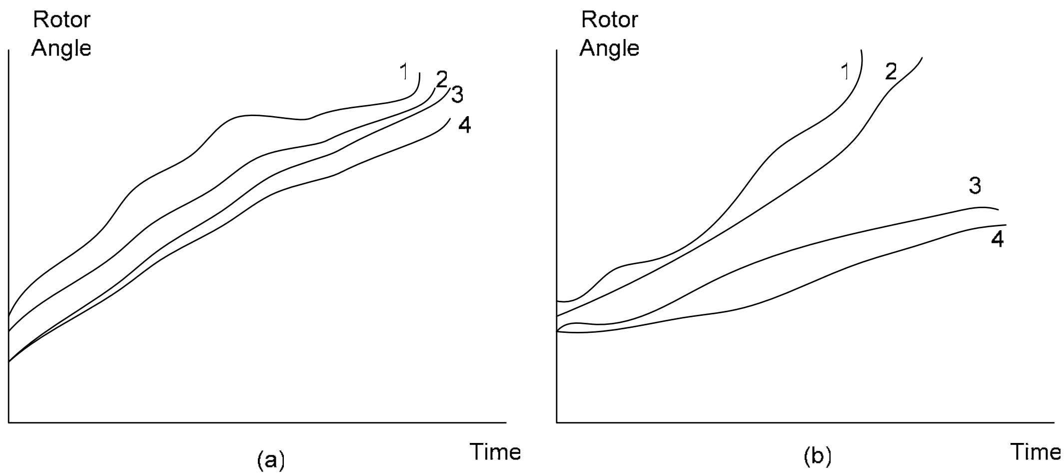

Figure 3.2 Rotor angles of stable and unstable of a 4-machines power system [53]:
a) Stable system and b) unstable system.

Disturbances of power system during transient period are represented by short-circuit which results in outage of transmission line and/or generator. Though more than 70% of transmission lines faults are single-line-to-ground-fault, the most severe fault, three phases to ground fault, is used to simulate the transient respond of the system. This dissertation will focus on the situation when transmission line or generator is disconnected from the system due to the fault.

There are many well established techniques to analyze the characteristics and responses of power system during transient period. Equal-area criterion and direct method are two well-known approaches where responses of power system after the major disturbance are presented by graphical and numerical approaches respectively. However, the equal-area criterion is not suitable for calculation of large-scale power system due to difficulty in formulating of system components into consideration. Time domain simulation is the most practical method to study transient stability since response of power system due to major disturbances is dominant in very short period of time after the incidents. Therefore, details of numerical approaches which considered as a useful technique in time-domain analysis will be discussed below.

3.2.5.1 Numerical methods

Numerical approach is the most practical tools based on step-by-step integration to analyze power system transient stability. Since power system is highly nonlinear, accurate responds of power system can be obtained by time-domain analysis starting from pre-fault operating point until post-fault period. From this approach, non-linearity characteristics of power system are automatically included in the results.

There are several numerical techniques in time-domain analysis used for transient stability study. Explicit methods such as Euler method, Modified Euler method and Runge-Kutta method are examples of well-known methods that result of the next step calculation (n+1) based on the current solution (n). On the other hand, the implicit method is an alternative way to calculate the result by employing interpolation technique. In this section, the Runge-Kutta (R-K) methods and implicit integration methods will be explained as example of practical methods for Transient Stability study.

3.2.5.2 Runge-Kutta (R-K) Method

Development of the R-K method is based on Taylor series expansion. R-K method is divided into several methods depend on the order of solution. Second-order

R-K method and Fourth-order R-K method will be mentioned as the foundation of transient stability study. Primary, before the calculation, changes in power system can be modeled by different functions

$$\frac{dx}{dt} = f(x,t) \tag{3.13}$$

Where,

x: the state vector (rotor angle, voltage, current, etc)

Equation (3.13) gives information of a function at the initial condition. In order to calculate the next movement of calculation (time domain), second-order R-K can be applied as shown below

$$x_1 = x_0 + \Delta x = x_0 + \frac{k_1 + k_2}{2} \tag{3.14}$$

Where,

$k_1 = f(x_n, t_n)\Delta t$

$k_2 = f(x_0 + k_1, t_0 + \Delta t)\Delta t$

It is seen that second-order R-K method employs second order derivative to calculate the next solution. Error given in this method is in the order 3(x^3). For more accurate R-K method, an appropriate technique must be applied to this formula. The general formula of fourth-order R-K which rely on higher order of derivative and weighting technique is shown below

$$x_{n+1} = x_n + \frac{1}{6}(k_1 + 2k_2 + 2k_3 + k_4) \tag{3.15}$$

Where,

$k_1 = f(x_n, t_n)\Delta t$ *:* Slope at the beginning

$$k_2 = f(x_n + \frac{k_1}{2}, t_n + \frac{\Delta t}{2})\Delta t : \text{Slope at the mid-step}$$
$$k_3 = f(x_n + \frac{k_2}{2}, t_n + \frac{\Delta t}{2})\Delta t : \text{Slope at the mid-step}$$
$$k_4 = f(x_n + x_3, t_n + \Delta t)\Delta t : \text{Slope at the end}$$

Equation (3.15) is therefore, used to calculate time domain characteristics of the system for the next step of simulation time interval. Another technique to calculate the next solution function can be found in the following discussion.

3.2.5.3 Implicit Integration Method (IIM)

IIM calculate the next solution of function by employing interpolation technique. The simplest approach of IIM approximates the next solution by Trapezoidal rule [51]. Integration of a function is calculated by area under the integral as shown in figure 3.3.

Normally, the transient respond of any state variable in the system can be found in the form of differential equation shown in (3.16)

$$\frac{dx}{dt} = f(x,t) \tag{3.16}$$

The answer of power system in the next incremental time Δt is obtained by integration of equation (3.16)

$$x_1 = x_0 + \int_{t_0}^{t_1} f(x,\tau)d\tau \tag{3.17}$$

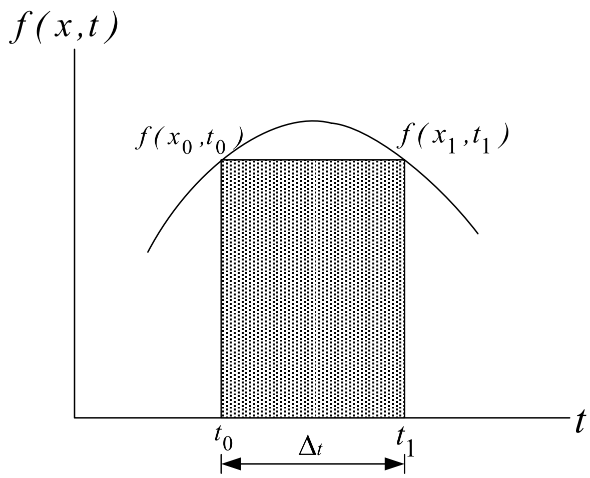

Figure 3.3 Implicit Integration Methods

Applying Trapezoidal rule, the integral of equation (3.17) is equal to

$$x_1 = x_0 + \frac{\Delta t}{2}\left[f(x_0,t_0) + f(x_1,t_1)\right] \tag{3.18}$$

Since transient stability study by numerical method based on iterative calculation. The general form on the answer at time *(t+1)* compared to the answer at time *t* is given by

$$x_{n+1} = x_n + \frac{\Delta t}{2}\left[f(x_n,t_n) + f(x_{n+1},t_{n+1})\right] \tag{3.19}$$

It should be noted that equation (3.15) and (3.19) are widely utilized in today available commercial software to handle a calculation problem of a large scale power system. Calculation time depends significantly on the size of the studied system, including the system conditions. All time domain simulation result in this dissertation is obtained through this numerical calculation technique.

3.3 Economy and Financial Assessment

The ultimate goal of power system operation is to maintain power balance between supply and demand under the secure and reliable operation. Historical reports show that the electricity blackouts impact both power system and social activities including the economy structure. Therefore, system security is the first priority and pre-requisite when concerning issue of power system operation and control. However, similar to other business entities, generation companies (GenCos) are seeking profits for their operation. Therefore, many decision making tools in economic theory have been utilized to formulate the objective function.

In this dissertation, the proposed frameworks of moving ESI structure in Thailand from traditional operation to deregulated environment requires feasibility studies to cover both security and economy/financial aspects. Following sections introduce two economic concepts used as decision making tools for a smooth transition in Thailand deregulation process.

3.3.1 Marginal Analysis

In running any business activities, since resources are scare thus firms can not easily generate maximum profit as they want. The trade off between economic choices must be made through difficulty in decision [54-55]. One of the most powerful tools for an economic decision making is to weight marginal benefit against marginal cost. This idea is known as marginal analysis. Its key profits composed of 1) analysis organization cost and benefit, 2) evaluating economic efficiency and 3) maximizing organization profits and utility. Marginal analysis is based on the principal of utilitarianism saying that key principal for any decision making is to achieve "the greatest good for the greatest number" [56].

Mathematically, marginal analysis can be started from the concept of profit maximization of product's output and input. Since this dissertation treats EGAT as a monopoly in electricity generation for the whole country, the employment of decision making under monopoly situation is therefore valid for the whole study. Profit maximization of any business agent under monopoly market structure can be addressed by an optimization principal as

$$\textit{Profit} = \textit{Total revenue} - \textit{Total cost} \tag{3.20}$$

Mathematically, we can treat equation (3.20) as the set of optimization equations as followed

$$\pi = Px(x) \cdot x - C(x) \tag{3.21}$$

Where, *π:* the profit of business agent

x: unit of output (product or service)

Px(x): unit price of output

C(x): capital cost of output

Taking derivative of equation (3.21) to obtain the maximum value of the function, thus

$$\frac{d\pi}{dx} = (Px + x\frac{dPx}{dx}) - \frac{dC(x)}{dx} = 0 \tag{3.22}$$

$$0 = Px(1 + \frac{dPx}{dx} \cdot \frac{x}{Px}) - \frac{dC(x)}{dx} \tag{3.23}$$

$$0 = Px(1 + \frac{1}{Ed}) - MC(x) \tag{3.24}$$

$$0 = MR(x) - MC(x) \tag{3.25}$$

Where, *MR(x):* is defined as the change in total revenue that is derived from undertaking some economic activity.

MC(x): is defined as the change in total cost that occurs from undertaking some economic activity

As a result, the criterion for profit maximization is obtained when the marginal revenue (MR) equal to marginal cost (MC), or

$$\textit{Marginal revenue} - \textit{Marginal cost} = 0 \tag{3.26}$$

Further discussion on monopoly structure can be viewed from another perspective of elasticity of demand side. Let's define the term demand elastic side by Ed, thus term in equation (3.23) can be viewed as:

$$Ed = \frac{dx}{dPx} \cdot \frac{Px}{x} = (\frac{dx}{x} \Big/ \frac{dPx}{Px}) \tag{3.27}$$

Where, Ed is the elastic in demand refer to the rate of change in output (products or services) corresponds to the change rate in output's price. It should be noted from equation (3.24) that at the point Ed= -1, yield marginal revenue of the firm = 0, while Ed > -1 result in the firm negative marginal revenue. From the economic viewpoint, the situation of Ed > -1 refers to as the inelastic in demand whereas Ed < -1 represents elastic demand. The monopoly market will not operate in the inelastic range of demand curve.

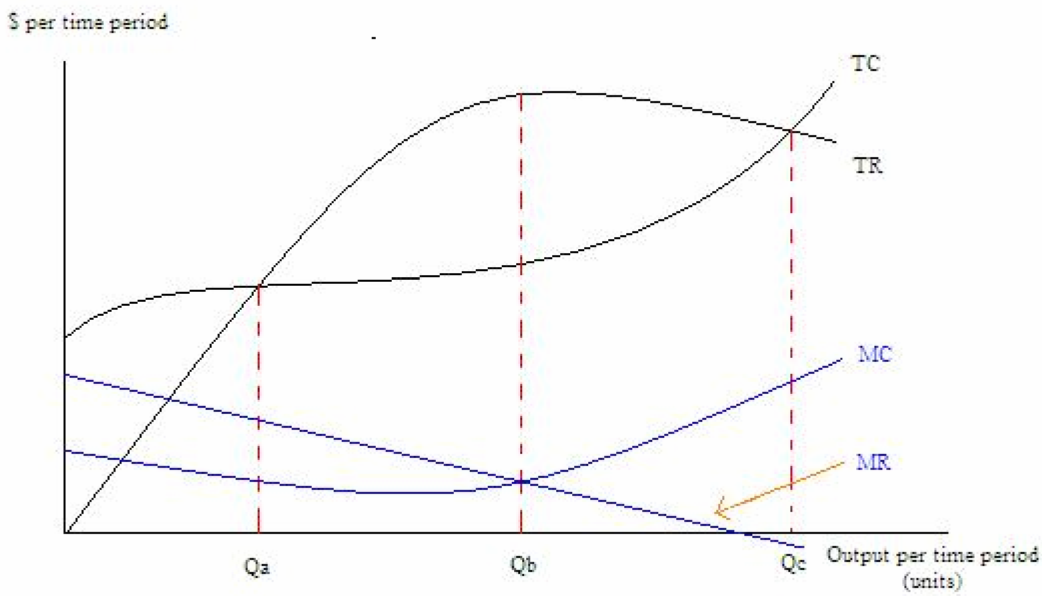

Figure 3.4 Marginal Analysis

Marginal analysis can be viewed as another perspective of the factor demand curve (input demand curve). As shown in figure 3.4, total revenue (TR) and total cost (TC) of any business agent can be a function of output quantities (Q) per time period. The trend of both TR and TC curve is increase when firms increase the output quantities. Marginal cost (MC) is the additional cost imposed when one more unit of output is produced. The slope of MC tends to rise when the output is increased. This situation can be true because the growing in business structure yield the more difficult in organization management, and problem of resource constraints can arise when produce more output. Marginal revenue (MR) on the other hand, is the additional revenue received when one more unit of output is produced. The slope of MR tends to fall when the consumption of output or product is increased. This is because customers prefer to have a variety in consuming the product or services. Main observation from this curve is that the economic efficiency occurs where the MR and MC curves intersects. In other word, the efficient output level is obtained at the point of MR equals to MC. In this graph, if firm produces the output quantities at Qb, this output level will result in profit maximization.

In summary, the business entities should expand their economic activity when marginal revenue is greater than marginal cost. On the other hand, they should reduce business activity when marginal revenue falls behind marginal cost. When apply this marginal concept to Thailand situation, it is important to have both historical financial data and the future forecasted data. The full study result for Thailand situation is provided in chapter 7.

3.3.2 Game Theory

Game theory is one of the economic strategies that useful for decision making process. Economists use this technique to approach the study of human behavior. The disciplines involved in game theory may include mathematics, economics, and other social behavior science [57-58]. Originally, game theory was founded by mathematician, John von Newmann. Since then, game theory was contributed by many research scholars. There are two main types of games i.e. cooperative and non-cooperative games. A cooperative game is situation in which players collude or coordinate their actions. On the other hand, players in the non-cooperative game will play the game independently with recognize that their payoff depends on the action of other players. Since this dissertation will use game theory to justify when will be a good time for ESI transformation in Thailand, the model of a non-cooperative game of two players is adopted The first player in the game is the electricity supply side (EGAT), while the second player is demand side which refers to customers all the whole country in this respect.

To identify equilibrium strategies for each player is the key idea of game solution. Many techniques can be used to find this balance point. The following section presents two techniques to find equilibrium solution. Mathematics terms and definition will be first explained. This dissertation then employs the arrow technique which typically used in "payoff table" to determine the equilibrium point for each player in Thailand deregulated situation.

3.3.2.1 Equilibrium in non-cooperative games

The normal form of an N-players game [59] consist of a set of N players, N strategy sets X_i, $i=1,\ldots,N$ and the N-tuple payoff function $G(X_1,\ldots,X_N)$. The value of $G_i(x_1,\ldots,x_N)$ is the payoff function of player i when player 1 plays the mixed strategy $x_1 \in X_1,\ldots$, while player N plays the strategy $x_N \in X_N$. Each player can choose only one strategy in this manner. An N-tuple of strategies $x_1,\ldots,x_N$ is an equilibrium N-tuple if the condition in equation (3.28) is true for all i, for all strategies y_i for player i.

$$G_i(x_1,\ldots,y_i,\ldots,x_N) \leq G_i(x_1,\ldots,x_N) \tag{3.28}$$

In a two-players game, the two-dimensional set $G = \{G_1(X_1,X_2),G_2(X_1,X_2)\}$ is called the non-cooperative payoff region. The points in G are called payoff pairs. If (u,v) and (u',v') are two payoff pairs, (u,v) dominates (u',v') if $u \geq v$ and $v \geq v'$. Typically, the characteristic function or the max-min value gives player 1 the expected payoff by assuming that player 2 will act to minimize player 1's payoff as shown in equation (3.29).

$$v_1 = \max_{X_1} \min_{X_2} G_1(X_1, X_2) \tag{3.29}$$

Where, v_1: characteristic function of player 1

X_1, X_2: range over all mixed strategies for player 1 and 2 respectively

v_2: is defined in a similar way of v_1

However, it is possible for player 2 to think in the way of maximizing his payoff instead of minimizing player 1's payoff. This situation found to be true in the study of Thailand situation presented in chapter 7.

3.3.2.2 Arrow techniques

The arrow technique applied in the payoff matrix is found to be a promising tool and simple to understand. A typically format of payoff table (table 3.1) is originally proposed in the famous example of the game theorist, A.W. Tucker. His remarkable invention of Prisoner's dilemma example is considered to be a most influential illustration in social science in the latter half of twentieth century [58].

Table 3.1 Standard format of payoff table in game theory (2 players)

Two players game		Al (Player 2)	
		Confess	Don't confess
Bob (Player1)	Confess	10,10	0,20
	Don't confess	20,0	1,1

In this table, player 1 chooses the row, while player 2 chooses column. The number in the in each cell indicate the payoff for both player when corresponding pair of strategies is chosen. The left number belong to player 1 and right number belong to player 2. In this prisoner's dilemma example, numbers in the cell are the number of years for each prisoner to be put in jail. Therefore, solution for this game will be based on a rational strategy of both prisoners to minimize their time in jail. Final strategies for both of them will fall into the category of both prisoners confess. In this situation, both prisoners choose their own strategy to maximize their payoff and it is found that the same strategy is chosen from both players. This situation referred to the dominant strategy. Beside, it is possible for some games to have two optimal equilibrium solutions. This is referred to as Nash equilibrium. Other techniques can also be used to find optimal solution in game theory such as focal point equilibrium, mixed strategies, sequential interaction etc. This dissertation proposes the payoff matrix for the two players in Thailand system and employs the dominant strategy or Nash equilibrium to justify the optimal solution for both players.

CHAPTER 4

THE STUDY OF THAILAND POWER SYSTEM

4.1 Introduction

Thailand is a developing country located at the heart of Southeast Asia with about 65 million of population as of 2004. The ESI structure under the government of Thailand has been managed by the Electricity Generating Authority of Thailand (EGAT), Metropolitan Electricity Authority (MEA), and Provincial Electricity Authority (PEA) for almost 50 years. EGAT is responsible for electricity generation and operating transmission system in the entire country, while MEA and PEA's responsibilities are in the distribution system. MEA handles electric power to Bangkok and its vicinity, whereas PEA serves the customers for the rest of the country.

4.2 Overview of Thailand Power System

4.2.1 Current Electricity Infra-Structures

As of August 2004, the whole country total generating installed capacity is approximately 25,969 MW with 19325 MW of peak demand. Approximately 59.11% of installed capacity owned by EGAT whereas another 38.43% belongs to other domestic IPPs and SPPs, and 2.5% imports from neighboring countries. EGAT's generating capacities consist of 24.53% thermal plants, 18.08% combine cycle, 13% hydro power plants, and 3% gas turbine and other renewable energy [60]. EGAT system is geographically divided into seven regions, as shown in figure 4.1, R1, R2, R3, R4, R5, R6, and R7. R1 covers the capital city, Bangkok, and 4 provinces at its vicinity. R2, R3, R4, R5, R6, and R7 cover northeastern (19 provinces), southern (16 provinces), northern (14 provinces), central (11 provinces), eastern (7 provinces), and western (5 provinces) part of Thailand, respectively. In addition, there are two regions belongs to the neighboring countries. R8 is Laos, which locating on the east side of Thailand. EGAT imports power from hydro units from Laos to serve their load in area 2. For security reason, there is an HV DC links between area 3 and Malaysia which considered as area 9.

Figure 4.1 Thailand's map of current EGAT regional divisions

EGAT manages all transmission lines with various voltage levels ranged from 500 kV, 230 kV, 132 kV, 115 kV, and 69 kV. On the other hand, MEA is responsible for distribution level of 24 kV and 12 kV, while PEA's voltage levels are 33 kV and 22 kV. The 500 kV backbone transmission line connects the northern and the central regions. However, the rest of inter-regional transmission line is at 230 kV. Due to their transfer capability, 500 kV and 230 kV transmission lines would be the candidacy for commercially significant constraints (CSC) selection in chapter 5.

4.2.2 Existing Electricity Supply Industry

EGAT has been being a monopoly in controlling bulk power generation, and transmission since 1968. EGAT gathers electric power from its owned generations, power purchase agreement (IPPs, and SPPs), and import power from neighboring countries as shown in figure 4.2. EGAT then resells all power to the distribution bodies, i.e., MEA and PEA, and to its direct customers. In this manner, EGAT is the single buyer in the system. EGAT is also responsible for system power balance, along with transmission lines management.

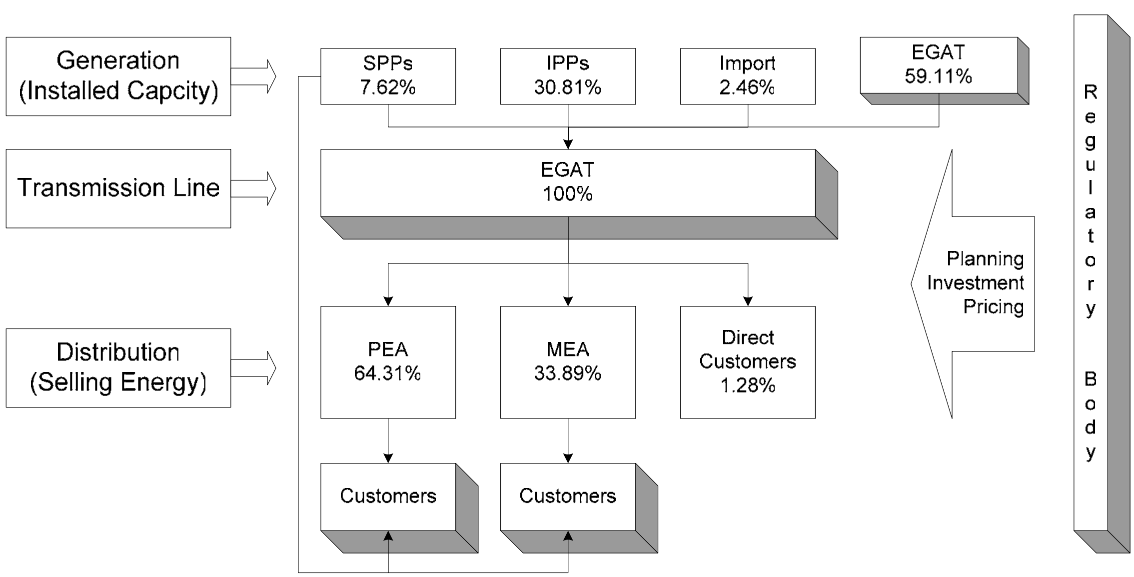

Figure 4.2 Current ESI structure (year 2004)

4.2.3 Competitive ESI models proposed by EPPO

Since 1998, after the economic crisis, the cabinet approved a Master Plan for privatization of state enterprises in fours sectors including energy sector. NEPO responded to this situation by commission the international consultant company for ESI reform study. In the year 2000, NEPO first introduced a restructuring model based on the model used in UK prior to 2002, known as prices-based power pool model.

4.2.3.1 Price based Power Pool [61-63]

Under this proposed model, consumers have choices to buy power either from the regulated regional retailers (SupplyCo) or competitive retailers (RetailCos) by using the distributed facilities of the Regulated Electricity Delivery Company (REDCo). The power pool serves as a place for power trading controlled by Independent System Operator (ISO) with two main functions as system operator (SO), and settlement administrator (SA). ISO is responsible for managing physical transactions of electricity according to economic merit order dispatch, ensuring system security, physically balancing the system, and managing financial settlement for bulk power purchases. In this model, as shown in figure 4.3, the pool is compulsory. Generators compete to sell electricity to the pool, and receive energy payment according to the market clearing price (MCP) or system marginal price from the pool. It is possible to trade power outside the pool by using the physical bilateral contracts or financial contract. In order to minimize a disagreement of interest in operation, it was recommended that the transmission owner (GridCo) need to be separated from the ISO. In the retail sector, the Spot Price Pass through by the REDCo, through its supply function (SupplyCo), was recommended. As a result, customers will buy electricity at wholesale price plus the regulated charges for wires and other services.

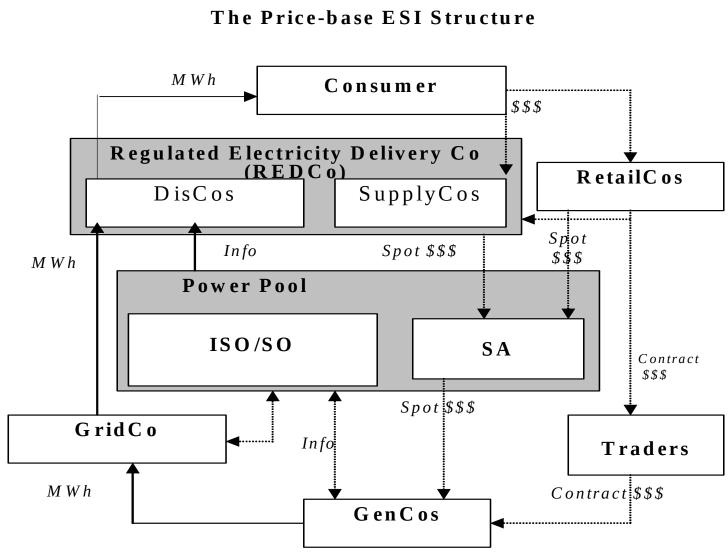

Figure 4.3 Price-based Power Pool model

However, the price-based model gets strong objections from the utilities, and other participants. There are concerns regarding the price volatility, system reliability, and the complexity of physical power system of the proposed model. Moreover, factors regarding to energy security, social equity, and the need to subsidize rural and poor customers, are also the main subjects of debating. Therefore, NEPO revised its proposal and proposed a new develop model called NESA which is similar to NETA model adopted in UK since 2001.

4.2.3.2 New Electricity Supply Arrangement (NESA) [63-65]

Unlike price-based model, the NESA model allows buyers and sellers entering bilateral contracts to ensure sufficient supply and achieve price stability. In the proposed NESA model, the SO takes care of all bids and offers in a balancing market called Power Exchange (PE). Power imbalance needs to be reported to Energy Contract Volume Notification Agent (ECVNA) for imbalance settlement before the gate closure. In addition, the power exchange will provide signal to market participants through the announced prices. These prices include system selling price (SSP), system buying price (SBP), average traded price from the power exchange, and average price from future markets.

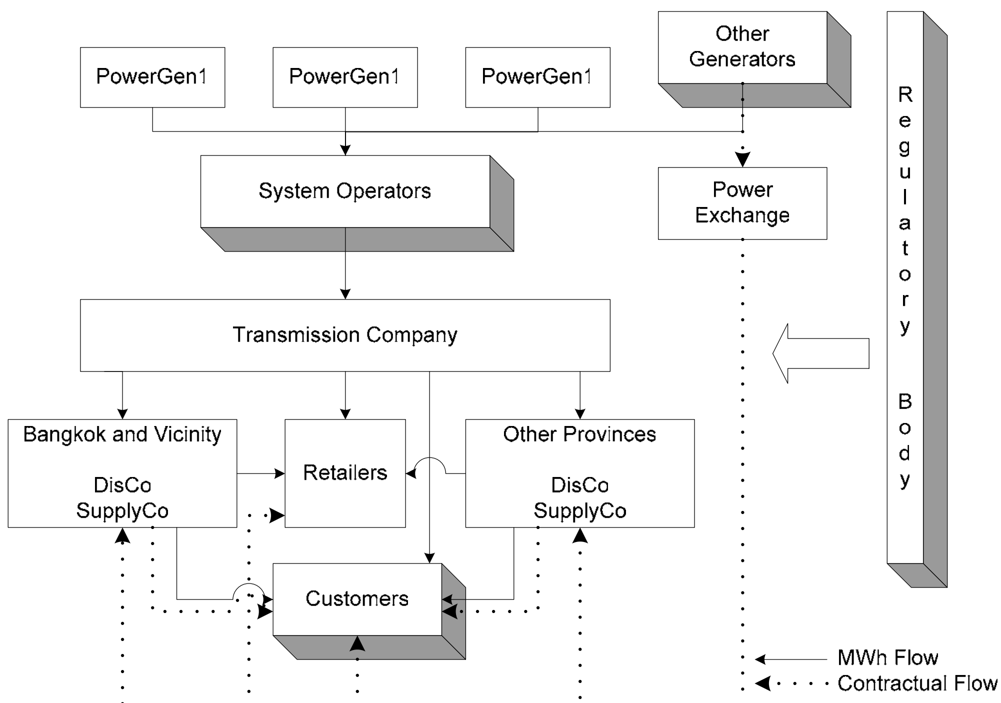

Figure 4.4 NESA Model

In this proposed model, EGAT's generators are categorized into three generation companies for future competition while hydro power plants will stay with transmission entity and will be maintained as a state enterprise as shown in figure 4.4 The GenCos are subjected to sell power to retailers and SupplyCo which is restructured from MEA and PEA. Finally, it is expected that consumers will have choices to buy power at both retailing and generating levels.

4.2.4 Generation and Demand Forecasting

In January 2004, the load forecasting subcommittee at EPPO has issued the new peak demand forecasting result based on Low, Medium, and Targeted Economic Growth (LEG, MEG, and TEG respectively) scenarios. The forecast result is described in table 4.1. MEG will be used in studied cases throughout this dissertation.

Table 4.1 Peak demand forecast by load forecasting subcommittee, EPPO

Year	Installed Capacity (MW)	Reserve Margin (%)	January 2004 LEG		January 2004 MEG		January 2004 TEG	
			Peak Demand (MW)	Load Factor (%)	Peak Demand (MW)	Load Factor (%)	Peak Demand (MW)	Load Factor (%)
2002		25	16,681*	76.17*	16,681*	76.17*	16,681*	76.17*
2003	25,480	25	18,121*	74.57*	18,121*	74.57*	18,121*	74.57*
2004	26,073	25	19,326*	73.90	19,326*	73.86	19,326*	73.84*
2005	26,093	20	20,162	73.94	21,143	73.85	22,262	73.86
2006	26,766	17	21,123	74.31	22,738	74.13	24,290	74.03
2007	27,824	15	22,129	74.40	24,344	74.19	26,359	74.06
2008	29,924	15	23,132	74.47	26,048	74.19	28,534	74.06
2009	32,024	15	24,192	74.49	27,852	74.16	30,869	74.03
2010	33,644	15	25,274	74.50	29,808	74.12	33,471	73.97
2011	35,744	15	26,404	74.53	31,844	74.09	36,190	73.93
2012	37,844	15	27,546	74.56	33,945	74.07	39,039	73.89
2013	39,944	15	28,740	74.61	36,173	74.06	42,119	73.86
2014	42,044	15	29,972	74.66	38,515	74.05	45,410	73.83
2015	44,844	15	31,225	74.71	40,978	74.04	48,948	73.80
2016		15	32,489	74.77	43,558	74.03	52,720	73.76
Average Growth	Year		Increase (%)		Increase (%)		Increase (%)	
9th plan	02-06		5.55		7.11		8.54	
10th plan	07-11		4.56		6.97		8.3	
11th plan	12-16		4.23		6.47		7.81	
Actual data*								
Thailand load forecast subcommittee, Energy Policy and Planning Office, January 2004[66]								

This dissertation covers the study period from year 2002-2011 (Nation Budget Plan 9^{th} – 10^{th}). It is clear from table 4.1 that the average growth in demand during the studying period is approximately 7 percent per year (MEG). It should also be noted that data of year 2002 – 2004 is the actual data. Therefore, actual summer peak demand of year 2004, latest actual data, will be used as a system base case for steady state power flow and stability study.

4.2.5 Power Development Plan 2003-2004 [60]

According to power development plan, EGAT plans to upgrade its infrastructure on both generation and transmission facilities. Most of new thermal generation units to be online will use the natural gas as the primary fuel due to their economical and environmental benefits. Table 4.2 shows the list of projects following the PDP 03-04.

Table 4.2 Projects list in PDP 03-04

Project and Capacity	Total MW increasing during fiscal year (MW)						
	2004	2005	2006	2007	2008	2009	2010
Lam Takhong #1-2 each 250MW, SPP 93, 20 MW	593						
BLCP#1 (673 MW)		673					
BLCP#2 (673 MW), Khanom (385 MW)			1,058				
Gulf#1, Union#1, and Southern (3x700 MW)				2,100			
North Bkk, South Bkk, Union#2 (3x700 MW)					2,100		
NT II (920 MW), Bang Pakong#5 (700 MW)						1,620	
New Capacity (3x700 MW)							2,100
Total Install capacity (MW)	26,073	26,093	26,766	27,824	29,924	32,024	33,644

For the purpose of long term planning, the study of generation and demand growth in section 4.3 will focus on the power flow case start from year 2004 since it is the most recently available data at the time of this study. However, the study will limit up to year 2010 power flow case because it is the last year that the installed location of new generation facilities are given.

4.3 Thailand Power System: Steady State Power Flow Study

4.3.1 Basic Assumptions

4.3.1.1 Hydro Units

From the historical data, hydro unit has served around 6% of the total demand. Practically, the primary objective of hydro units in Thailand system is to serve the agricultural purposes. Due to its quick response, to fulfill the demand during the peak hour is the secondary function of the hydro units. Therefore, in this study, hydro units are treated as a fixed cost, and excluded from the automatic generation control (AGC) procedures.

4.3.1.2 Pattern and rate of load growth

According to load forecasting data from EPPO as shown in table 4.1, it is assumed that the uniform load growth for the whole country. Therefore, an identical scaling factor will be applied to all load buses throughout the system. From the conservative viewpoint, the medium economic growth (MEG) will be used in this study.

4.3.1.3 Transmission line limit

According to the definition of NERC, the term transmission capacity differs from transfer capability. Capacity refers to a specific limit of thermal or voltage that describes a single component of transformer or line whereas capability refers to the ability of a system to transfer power and usually depends on the configuration of generations, demands, and transmission systems. Therefore, capability is more like in the dynamic term while capacity is a static term. In this power flow study, the transmission normal operating limit (Rate A) will use as a benchmark.

4.3.2 Processes of Power Flow Study for a Long Term Planning

Figure 4.5 shows the entire processes of steady state power flow study for a long term planning proposed in this dissertation. This dissertation comply required data from three main sources. The first is the Thailand Power Development Plan (PDP) from EPPO which consists of the planning year's summer peak loads, the planning year's scheduled generating units addition, retirement and rating, and the planning year's scheduled transmission facilities addition, retirement, and re-rating. The other two are Thailand power system network data and topology from EGAT and Thailand statistical data of fuel consumption from NSO. Fundamentally, the initial step in power flow study is to generate an acceptable base case. In this study, as discussed in 4.2.5, summer peak load of 2004 was selected to be a power flow base case for the entire study. This dissertation proposes a systematic procedure to create a reasonable base case as described in section 4.3.3 and the flow chart is presented in figure 4.6. Since the study boundary ranges from year 2004 to 2010, the scaling techniques of loads and generations need to be considered in order to reflect the system growth pattern and guarantee converged power flow base cases after year 2004. To do so, the generation expansion technique corresponding to assumed uniform load growth is discussed in section 4.3.4. Result from this study would be the input to the dispatching study in chapter 5. In addition, to assure system security, it is recommended to perform contingency analysis in order to observe security level of system. Therefore, N-1 contingency study is applied to all power flow base case from year 2006 to 2008.

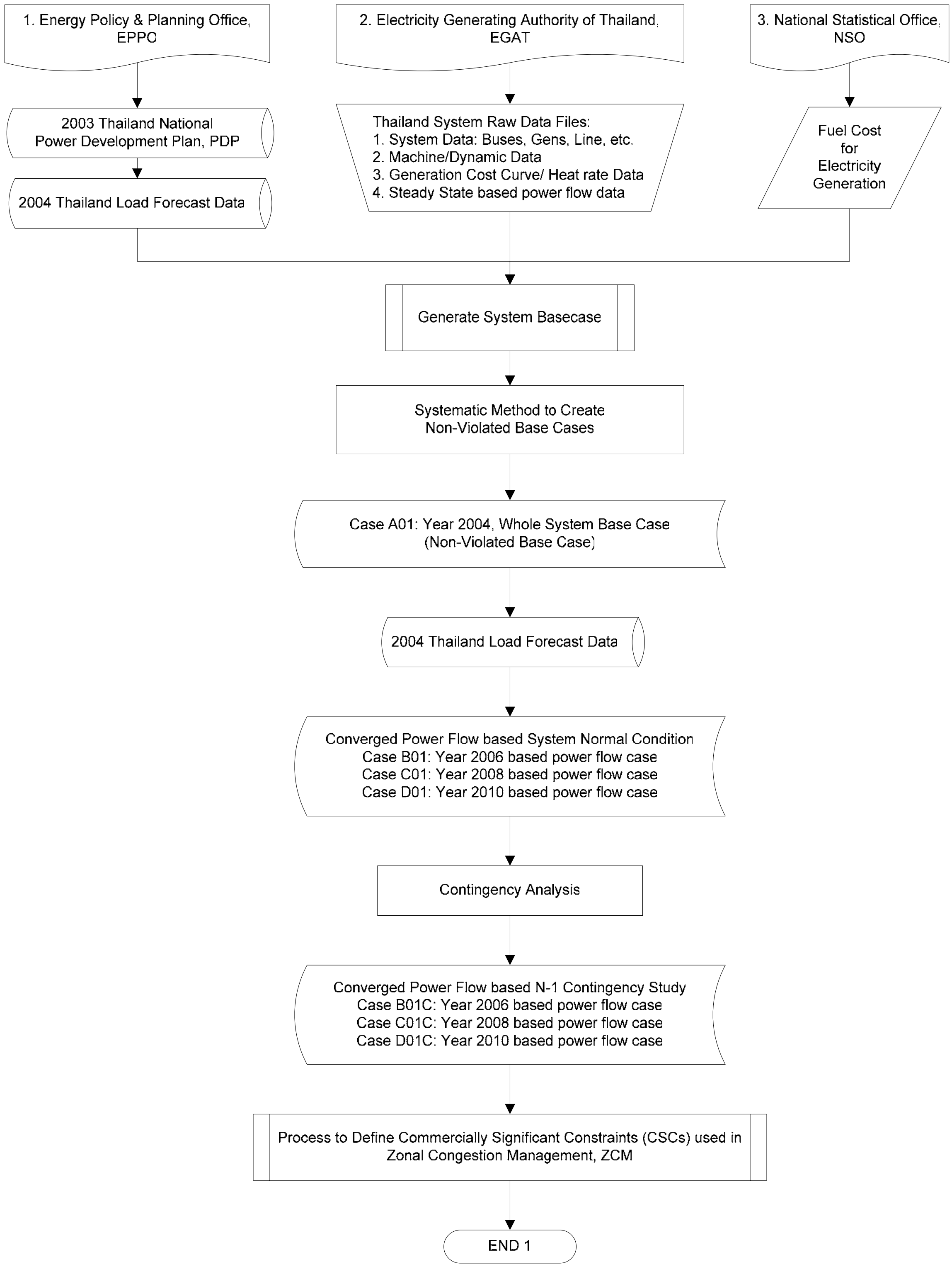

Figure 4.5 Power flow study processes for a long term planning

4.3.3. Systematic method to create a Power Flow Base Case

Power flow study is the most commonly used tool in transmission planning process. Its two basic functions are to calculate steady state flow through lines and transformers, and bus voltages throughout power system under normal or contingency conditions.

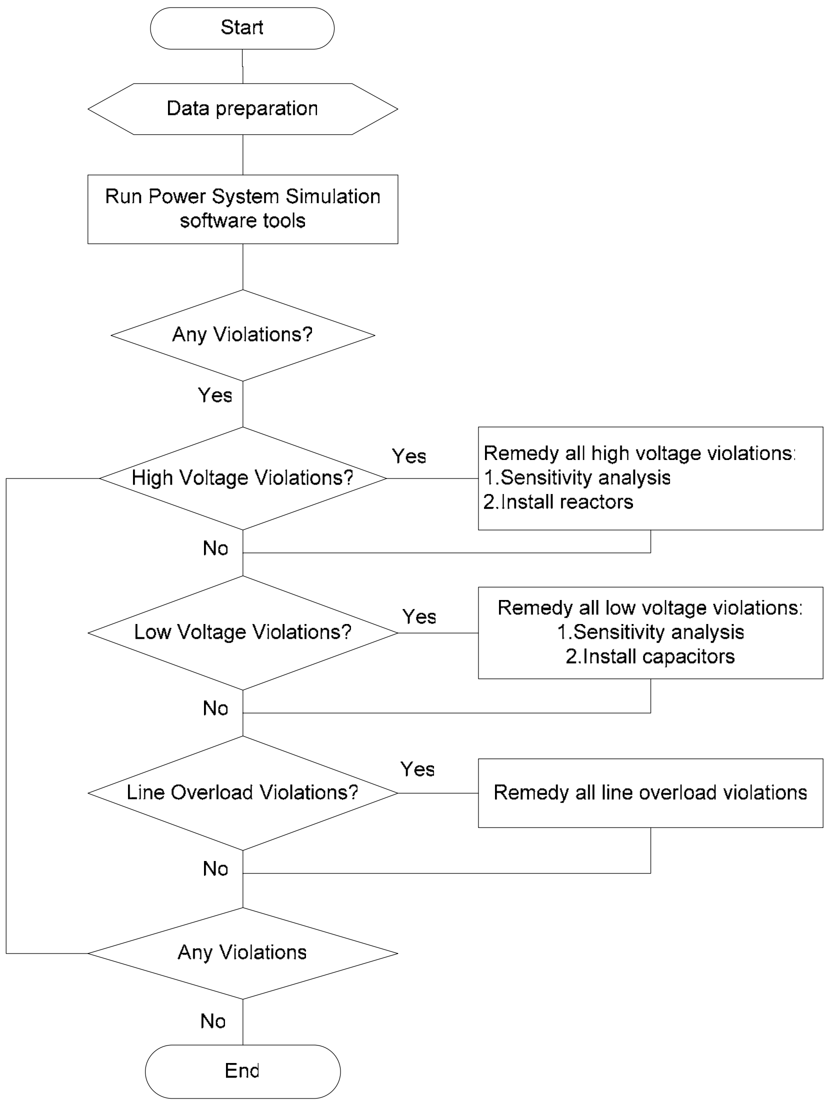

Figure 4.6 Systematic methods to create reasonable power flow base case.

The first step of power flow study is to generate a reasonable base case with acceptable mismatch level and violation free operation condition. Normally, possible major violations, emerged after system planner performs power flow study, include high voltage bus, low voltage bus, and transmission overload problems. During the process of generating 2004 power flow base case, several repetitive steps of capacitors and reactors switching need to be executed in order to bring the bus voltage within the range from 0.95 per unit to 1.05 per unit and eliminate any transmission thermal rating violation.

As shown in the second block of figure 4.6, all system data including network topology and 2004 summer peak load are first manually checked and verified. Consistencies of system base MVA, base kV, and base frequency are the primary concerns. Of course, there are violations after the initial execution of full AC power flow (ACPF). The procedure described in figure 4.6 is followed to eliminate high voltage, low voltage, and overloading situations through capacitor/reactor switching, re-dispatching, load curtailment and/or generation rejection.

4.3.4. Generation expansion techniques for a uniform Demand Growth

The process of scaling up the system load based on the assumption of uniform load growth starts from year 2004 summer peak load with 184 generators. According to PDP 03-04 in table 4.2, 195 generators are scheduled to be online by 2010. In other words, 11 new generations will be online between year 2004 and 2010. Normally, study is needed to investigate the potential impact of the new generation facilities on the existing system before parallel operation.

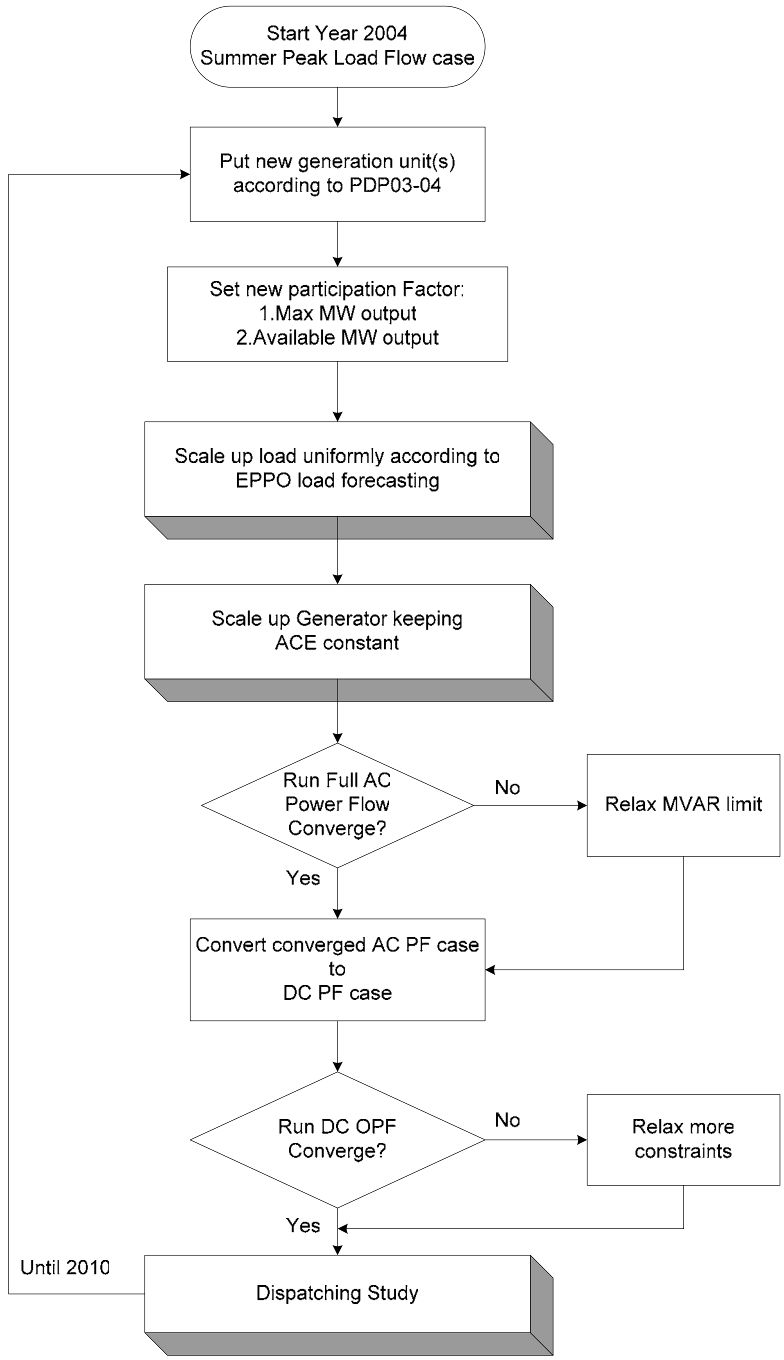

Figure 4.7 Generation expansion procedures

Once obtaining the required information, it is necessary to perform steady state power flow study with the integration of the new unit(s) according to the scheduling plan. A readjustment participation factor of online units is necessary to obtain a reasonable solution. The process of uniformly scaling up load is then performed followed by scaling up generators to maintain the area control error (ACE) as constant.

During performing a full ACPF, it is common to get a diverged solution due to system constraints. One of the most important factors to cause the divergence is the reactive power limit (MVAR limit) of the online generators. Therefore, if necessary, it may need to relax MVAR limit of some generators to obtain the converged ACPF case. Following the converged ACPF case, converting process to DC optimal power flow (DCOPF) case is the next importance because later on, these series of DCOPF cases will be used in the congestion management study. Due to the unavailable installed location of the new generation facilities of totally 2100 MW in year 2010, therefore the converged power flow case for this year can not be accurately generated. However, for the comparison purpose, the generation pattern of year 2008 will be adopted and apply to year 2010.

4.4 Steady State Power Flow Result

4.4.1 Summer peak demand forecast and generation requirement

Following the proposed procedures in figures 4.5 – 4.7, the result of generation requirements for each studied year from 2004-2010 are presented in table 4.3

The study starts at year 2004 power flow base case. There are 184 online generators to serve 19326 MW and 8495 MVAR of peak demand with 449 MW of system losses. Result from table 4.3 shows that system reserve margin is decreasing from 25 percent to 15 percent during the year 2004 to 2010. It can be found that while the reserve margin observed to decrease, on the other hand total system loss increase. As a result, the system may encounter difficulty if contingency situations persist.

Table 4.3 System peak demand forecast and generation requirement

Year	Peak Demand Forecast (MEG)		Generation Requirement		System Losses (MW)	Install Shunt (MVAR)	Reserve Margin (%)	Online Units
	MW	MVAR	MW	MVAR				
2004	19,326	8495	19775	4108	449	5678	25	184
2006	22,738	10015	23439	8306	731	6260	17	189
2008	26,048	11483	27152	14763	1108	6254	15	193
2010	29,808	-	-	-	-	-	15	194

4.4.2 Area distribution of generation and load

Showing in table 4.4, 4.5 and 4.6 are results of area distribution for generation and load in the year 2004, 2006, and 2008 respectively.

Table 4.4 Area distribution of Generation and Load (2004 peak load)

Area number & name	# of Buses	Load		Generation		Losses MW	Inter-change
		MW	MVAR	MW	MVAR		
1.Metropolitan	223	8038.77	3986.35	1609.3	764.46	72.1	-6501.57
2.North-eastern	217	1675.96	516.48	1085.82	-41.31	74.41	-664.55
3.Southern	173	1280.22	331.29	1196.84	-30.65	38.73	-122.1
4.Northern	222	1713.97	592.69	1910.21	287.87	50.35	145.9
5.Central	126	1943.84	876.53	2280.15	671.34	44.13	292.18
6.Eastern	282	2540.67	1219.9	6287.62	1301.22	89.08	3657.87
7.Western	186	2034.58	914.99	5018.73	1173.61	74.44	2909.71
8.Laos	23	98.08	56.84	356.64	18.5	6	252.56
9.Malaysia	3	0	0	30	-54.84	0	30
Total	1455	19326.1	8495.07	19775.3	4090.2	449.24	0

In the year 2004, it can be seen that the area 1, 2, 3 are the power importers, while area 4, 5, 6, 7, 8 and 9 are the exporter. However, as states previously, area 8 and 9 are Thailand's neighboring country, therefore, majority of discussion will focus only on area 1-7. Although, area 1 the biggest importer because it serves a significant number of demand in the metropolitan area, however, its in-area generation capacity is still not high enough to serve its demand because it is real difficult to have an addition of new generation facilities in the metropolitan area. On the other hand, area 6 have a largest generation capacity due to the appropriate geographically location which close to the seashore, and many supporting raw material, such as natural gas and crude oil, for electricity generation process from petrochemical industrial companies. Moreover, generation and load is observed to balance within area 3 and are 4.

Table 4.5 Area distribution of Generation and Load (2006 peak load)

Area number & name	# of Buses	Load		Generation		Losses MW	Inter-change
		MW	MVAR	MW	MVAR		
1.Metropolitan	223	9406.54	4664.62	1495.94	1649.21	168.39	-8078.99
2.North-eastern	217	1961.12	604.36	1060.82	333.24	144.76	-1045.06
3.Southern	173	1498.04	387.66	1542.65	269.35	64.27	-19.67
4.Northern	222	2005.59	693.54	2213.25	802.85	82.72	124.94
5.Central	126	2274.58	1025.67	2167.31	1138.94	85.08	-192.34
6.Eastern	282	2972.95	1427.46	8511.63	2806.9	119.3	5419.38
7.Western	186	2503.62	1146.03	6115.46	1255.68	85.13	3526.71
8.Laos	23	114.77	66.51	356.64	102.12	6.83	235.04
9.Malaysia	3	0	0	30	-51.58	0	30
Total	1455	22737.2	10015.8	23493.7	8306.71	756.48	0

As shown in Table 4.5, area generating pattern in year 2006 is slightly different from year 2004. Area 5 now becomes the power importer because there is no new generation facility in this area between 2004 and 2006. However, in table 4.6, area 3 becomes an exporter due to two newly installed-generation facilities in southern area between 2006 and 2008. Area 4 needs to import power from areas 1 and 5 to supply its owned demand and to serve demand in area 2. From table 4.4 – 4.6, one can see that area 2 always imports power from area 4, 5, and 8. This is because there are no new planned generation facilities in this area. In addition, the geographic of area 2 is appropriate for only hydro plant, and unfortunately hydro power plant is also difficult to implement in system due to the conservative reason. Therefore, there is a high possibility for the tie lines between area 2 and area 4 to experience with the congestion problem in the near future. It should be a good indicator for those distributed generators, or other novel sources of electricity generation from renewable energy to get promoting in area 2 to alleviate the possible transmission congestion problem.

Table 4.6 Area distribution of Generation and Load (2008 peak load)

Area number & name	# of Buses	Load		Generation		Losses MW	Inter-change
		MW	MVAR	MW	MVAR		
1.Metropolitan	223	10789.5	5358.19	2879.85	3229.75	133.56	-8043.19
2.North-eastern	217	2244.21	691.6	1103.17	1220.64	270.01	-1411.06
3.Southern	173	1716.97	444.96	2073.23	1133.38	117.87	238.39
4.Northern	222	2295.11	793.65	2391.81	1613.25	134.03	-37.33
5.Central	126	2602.92	1173.72	2294.9	2066.85	138.11	-446.13
6.Eastern	282	3402.11	1633.52	9415.01	3428.61	179.04	5833.85
7.Western	186	2865.03	1311.46	6582.48	1744.16	120.86	3596.59
8.Laos	23	131.34	76.11	381.88	381.72	11.67	238.86
9.Malaysia	3	0	0	30	-54.84	0	30
Total	1455	26047.1	11483.2	27152.3	14763.5	1105.15	0

4.4.3 Area interchange during normal condition

In this section, detail of area interchange between 9 studied areas are summarized and presented in tables 4.7 – 4.9.

Table 4.7 Area interchange under normal condition (2004 peak load)

Area	Actual tie lines flow (MW)								
To From	Area1	Area2	Area3	Area4	Area5	Area6	Area7	Area8	Area9
Area1				89.5	-876	-3302	-2412		
Area2				-483.1	71.1			-252.6	
Area3							-92.1		-30
Area4	-89.5	483.1			247.8				
Area5	876	-71.1		247.8		-355.2	-405.3		
Area6	3302				355.2				
Area7	2412		92.1		405.3				
Area8		252.6							
Area9			30						

As discuss in table 4.4 – 4.6, area 1 is the largest power importer in the country. It is found that sources of import power come from area 6, 7, and 5 corresponding to the amount of import power. However, result from table 4.7, it can be noticed that 1.5% of power from area 1 is transferred to area 4 to serve the demand in area 2. Almost 65% of import power to area 2 is from area 4, and 35% is from hydro-electricity power from Laos. For grid's security reason, area 3 import 30 MW power via DC transmission line from Malaysia.

Table 4.8 Area interchange under normal condition (2006 peak load)

Area	Actual tie lines flow (MW)								
To From	Area1	Area2	Area3	Area4	Area5	Area6	Area7	Area8	Area9
Area1				208.4	-716	-4553	-3017		
Area2				-764	-45.7			-235	
Area3							10.3		-30
Area4	-208.4	764			-431				
Area5	716	45.7		431		-866	-519.2		
Area6	4553.3				866				
Area7	3017.9		-10.3		519.2				
Area8		235							
Area9			30						

Table 4.9 Area interchange under normal condition (2008 peak load)

Area	Actual tie lines flow (MW)								
To From	Area1	Area2	Area3	Area4	Area5	Area6	Area7	Area8	Area9
Area1				305.9	-164.8	-4906	-3277		
Area2				-1003	-168.3			-238.9	
Area3							268.4		-30
Area4	-305.9	1003.9			-735.3				
Area5	164.8	168.3		735.3		-927.5	-587.1		
Area6	4906				927.5				
Area7	3277		-268.4		587.1				
Area8		238.9							
Area9			30						

The trend of power flow pattern in year 2006 – 2008 remains almost the same as of year 2004. Therefore, in the long term, there is a high possibility for an inter-area tie line to have a congestion problem, especially tie lines between area 1 and 6, and tie lines between area 1 and 7. It is recommended to keep monitoring those lines closely to prevent any incident situations.

4.4.4 Major lines flow during normal condition

Since EGAT manages all its owned transmission lines by transferring bulk power among their operating-regions via 500 kV and 230 kV transmission lines however, study result shows that most of 500 kV lines are currently use only 30 percent of their limit. Therefore, these 500 kV line level have a less chances to face with congestion problem compare to 230 kV lines. As a result, major lines flow result discussing in table 4.10 – 4.12 will focus on major 230 kV lines.

Result from 2004 base case shows that there is no overloading on the transmission lines. Major tie lines that transfer power from area 5, 6, and 7 to area 1 are still operated approximately at 66 percent of their ratings. However, in 2006, the loadings of nine 230 kV lines reach 80 percent of their limit. As shown in table 4.11, two of them are using exceed 100 percent of their limit. Therefore, they have already experienced with an overloading situations. The overloading situations become worst when system experience with contingency condition as shown in table 4.14.

Table 4.10 Major lines flow during 2004 normal condition (above 230 kV)

Lines				Circuit	Line limit (MVA)	Percent use of line limit (%) (under normal condition)			
From bus		To bus				Year			
no.	kV	no.	kV			2004	2006	2008	2010
6802	234.8	6891	233.4	2	429.4	81.4	-	-	-
6802	234.8	6891	233.4	1	429.4	81.4			
6801	231.8	6802	234.8	1	429.4	80			
6801	231.8	6802	234.8	2	429.4	80			
6802	234.8	6806	235.5	1	429.4	72.7			
6802	234.8	6806	235.5	2	429.4	72.7			
1804	229.4	6801	231.8	1	858.9	66			
1804	229.4	6801	231.8	2	858.9	66			
2801	228.7	2807	230	1	429.4	61.5			
2801	228.7	2807	230	2	429.4	61.5			
6802	234.8	6804	235.1	1	429.4	61			
5804	229.9	5806	233.4	2	858.9	53.3			
5804	229.9	5806	233.4	1	858.9	53.3			
6804	235.1	6807	235.1	2	858.9	52.8			
6804	235.1	6807	235.1	1	858.9	52.8			
1807	228.9	7816	225	1	858.9	50.6			
6891	233.4	18111	229.8	2	858.9	49.6			
1809	230.4	1835	229.4	2	1717.7	49.6			
1809	230.4	1835	229.4	1	1717.7	49.6			
1811	229.8	6891	233.4	1	858.9	49.6			
7801	228.6	7804	236.9	1	429.4	49.2			
7801	228.6	7804	236.9	2	429.4	49.2			
7801	228.6	7804	236.9	3	429.4	48.8			
7801	228.6	7804	236.9	4	429.4	48.8			
1810	234	6891	233.4	1	858.9	48			

Other two tie lines that become more important in year 2006 are tie lines that link between area 1 to area 5, and area 2 to area 4. This circumstance happen because area 4 will need to import power from area 1 via transmission line in area 5, then export the excess power to area 2. This situation becomes clearer in the year 2008 of which lines usage reach to 90 percent of their limit shown in table 4.12.

Table 4.11 Major lines flow during 2006 normal condition (above 230 kV)

Lines				Circuit	Line limit (MVA)	Percent use of line limit (%) (under normal condition)			
From bus		To bus				Year			
no.	kV	no.	kV			2004	2006	2008	2010
6801	231.8	6802	234.5	2	429.4	-	102.5	-	-
6801	231.8	6802	234.5	1	429.4		102.5		
6802	234.5	6806	235.4	1	429.4		96.7		
6802	234.5	6806	235.4	2	429.4		96.7		
6802	234.5	6891	233.4	1	429.4		95.6		
6802	234.5	6891	233.4	2	429.4		95.6		
6802	234.5	6804	235.1	1	429.4		81.2		
1804	227.9	6801	231.8	2	858.9		81.1		
1804	227.9	6801	231.8	1	858.9		81.1		
2801	223.6	2807	230	1	429.4		71.8		
2801	223.6	2807	230	2	429.4		71.8		
5804	228.4	5806	233.5	1	858.9		65.3		
5804	228.4	5806	233.5	2	858.9		65.3		
1808	230.3	5802	229.8	1	429.4		63.7		
1808	230.3	5802	229.8	2	429.4		63.7		
1811	226.8	6891	233.4	1	858.9		62.4		
6891	233.4	18111	226.8	2	858.9		62.4		
1807	226.2	7816	221.9	1	858.9		59.9		
3802	236	3803	237.5	1	429.4		59.6		
3802	236	3803	237.5	2	429.4		59.6		
2802	230.9	4804	240.5	1	429.4		57.7		
2802	230.9	4804	240.5	2	429.4		57.7		
1810	231.1	6891	233.4	1	858.9		57		
1809	227.7	1835	226.2	1	1717.7		57		
1809	227.7	1835	226.2	2	1717.7		57		
1803	225.2	18111	226.8	4	858.9		56.9		
1803	225.2	18111	226.8	3	858.9		56.9		
6808	230.5	6823	234.4	1	429.4		56.7		
6808	230.5	6823	234.4	2	429.4		56.7		
1803	225.2	1811	226.8	2	858.9		56.3		
1803	225.2	1811	226.8	1	858.9		56.3		
3803	237.5	3804	232.7	1	429.4		54.6		
3803	237.5	3804	232.7	2	429.4		54.6		
6806	235.4	6824	235.6	1	858.9		54.2		
6806	235.4	6824	235.6	2	858.9		54.2		

Showing in year 2008, at least four major 230 kV lines in area 6 will experience congestion situation. Moreover, power flow for those two tie lines between areas 1 to 5 and tie line between areas 2 to 4 become more stress as seen from percent of lines loading has been increased from 60% in year 2006 to 90% in year 2008.

Main observation from load growth study is that , if monitoring at the same transmission lines, the average load growth is approximately 14 percent for every two years (7 percent a year according to MER), while the increasing in line loading is about 10 percent every two years. Therefore, there is a high possibility, for Thailand system, to have at least ten 230 kV transmission lines facing the congestion problem within the next few years. The lines flow study under system normal operation presents that, major transmission lines in area 6 and those inter-area tie lines link with area 1 have a high possibility, in the near future, to confront with congestion problem. Although all of them found not to be a severe congestion case at the present time, yet the conditions become more serious if the system happens to experience with any single contingency, worse contingencies, or unexpected severe fault.

Table 4.12 Major lines flow during 2008 normal condition (above 230 kV)

Lines				Circuit	Line limit (MVA)	Percent use of line limit (%) (under normal condition)			
From bus		To bus				Year			
no.	kV	no.	kV			2004	2006	2008	2010
6801	237.7	6802	234.8	1	429.4	-	-	108.9	-
6801	237.7	6802	234.8	2	429.4			108.9	
6802	234.8	6806	235.2	2	429.4			100.3	
6802	234.8	6806	235.2	1	429.4			100.3	
6802	234.8	6891	237.4	1	429.4			96.7	
6802	234.8	6891	237.4	2	429.4			96.7	
2801	208.7	2807	228.5	1	429.4			91.3	
2801	208.7	2807	228.5	2	429.4			91.3	
1808	232.7	5802	222.7	1	429.4			90.9	
1808	232.7	5802	222.7	2	429.4			90.9	
5804	230	5806	239.4	1	858.9			86.3	
5804	230	5806	239.4	2	858.9			86.3	
1804	234.1	6801	237.7	1	858.9			85	
1804	234.1	6801	237.7	2	858.9			85	
6802	234.8	6804	235.1	1	429.4			80.1	
2802	214.1	4804	231.5	2	429.4			76.2	
2802	214.1	4804	231.5	1	429.4			76.2	
3802	228.6	3803	237.5	2	429.4			72	
3802	228.6	3803	237.5	1	429.4			72	
1811	230.4	6891	237.4	1	858.9			69.5	
6891	237.4	18111	230.4	2	858.9			69.5	
1810	233.9	6891	237.4	1	858.9			66.8	
1803	228.2	18111	230.4	4	858.9			65.7	
1803	228.2	18111	230.4	3	858.9			65.7	
1807	231.7	7816	227.2	1	858.9			65.1	
1803	228.2	1811	230.4	2	858.9			65	
1803	228.2	1811	230.4	1	858.9			65	
5802	222.7	5805	218.1	2	429.4			64.3	
5802	222.7	5805	218.1	1	429.4			64.3	
1805	242.3	1806	234.2	1	858.9			63	
6808	235.8	6823	239.8	1	429.4			61.2	
6808	235.8	6823	239.8	2	429.4			61.2	
5801	224.3	5804	230	2	429.4			60.4	
5801	224.3	5804	230	1	429.4			60.4	
1805	242.3	1806	234.2	3	858.9			59.7	
1805	242.3	1806	234.2	2	858.9			59.7	
3808	222.3	3811	227	2	429.4			59.5	
3808	222.3	3811	227	1	429.4			59.5	
6806	235.2	6824	235.5	2	858.9			58.8	

4.4.5 Major lines flow during N-1 contingency condition

Main purpose of contingency analysis is to observe the impact of any single facility outage on other facilities in power system. Showing in table 4.13 – 4.16, is the result of contingency study showing lines limit due to the worst single contingency (N-1), that still deliver the converged power flow solution. Theoretically, contingency situation can be happened due to the outage of any single generator, transmission line, or power transformer. However, result of table 4.13 – 4.16 will focuses on the single transmission line outage because it has a potential of creation more severe overloading situation to other lines in the system.

Table 4.13 Contingency events, screening, and ranking result (year 2006)

Activities Description	Related contingencies and Result				
1. N-1 line contingency 2. Method of Calculation 3. Unsolved case(s)	- 785 contingency cases - Full AC power flow - 2 unsolved cases: 1. Open line from bus 5701 to 5720 CKT1 2. Open line from bus 3803 to 38032 CKT1				
Contingencies Screening & Ranking	Related contingencies open line between (from bus – to bus), circuit number	Result from contingencies event			
		Number of violations	Min. Volt	Max. Volt	max % of line usage
1. Open the most heaviest line loading	6801 – 6802, CKT1	144	0.903	1.223	295
2. Contingency with max. number of violations	2726 – 2747, CKT1	161	0.796	1.221	295
3. Contingency with max. % of line usage	6927 – 6929, CKT1	137	0.896	1.215	437

Table 4.13 and 4.15 show the contingency events, screening and ranking result of N-1 lines contingency happen to original power system. There are 785 possible cases of single line outage in Thailand system. By employing the full AC power flow study for those 785 cases, there are two existing unsolved cases result from open single line in

area 5 and area 3 respectively. Due to a large number of contingency cases, techniques of contingency screening and ranking need to be deployed in order to reduce the number of studied-cases. Thus, in this dissertation, three contingency scenarios are focused i.e. 1) open single line with the largest line loading, 2) open one line with generating the maximum number of violations, and 3) open a line with causing other lines to confront with the most severe overloading. The result of contingencies screening in table 4.13 and 4.14 shows that opening a single line in area 6 appears to create more severe violation cases of lines overloading, and to increase the loading level of other lines in the same area.

The similar trend of contingency events is found in table 4.15 and 4.16 for the year 2008. There are 785 cases of N-1 line contingencies to be considered. After performing a full ACPF for all contingency cases, there are 8 cases of diverged power flow solutions. This situation implies the more complexity of power system pattern in year 2008 compare to year 2006, and some delicate quantities need to be addressed such as: reactive power supply and voltage issue, power system protection issues, and power quality issue.

Table 4.14 Major lines power flow during N-1 contingency (year 2006)

Lines				Circuit	Line limit (MVA)	Percent use of line limit (%) (under contingency condition)			
From bus		To bus				Year			
no.	kV	no.	kV			2004	2006	2008	2010
6801	233.4	6802	234.6	2	429.4		143.5		
6802	234.6	6891	235.4	1	429.4		112.8		
6802	234.6	6891	235.4	2	429.4		112.8		
6802	234.6	6806	235.7	2	429.4		91.3		
6802	234.6	6806	235.7	1	429.4		91.3		
2801	224.4	2807	230	2	429.4		71.1		
2801	224.4	2807	230	1	429.4		71.1		
1804	229.9	6801	233.4	2	858.9		71		
1804	229.9	6801	233.4	1	858.9		71		
6802	234.6	6804	235.4	1	429.4		69.8		
6891	235.4	18111	228.7	2	858.9		66.9		
1811	228.7	6891	235.4	1	858.9		66.9		
5804	229.9	5806	234.7	1	858.9		64.4		
5804	229.9	5806	234.7	2	858.9		64.4		
1808	231.5	5802	230.9	2	429.4		62.7		
1808	231.5	5802	230.9	1	429.4		62.7		
1810	232.6	6891	235.4	1	858.9		62.1		
1807	227.9	7816	223.7	1	858.9		59.6		
3802	236.1	3803	237.5	2	429.4		59.5		
3802	236.1	3803	237.5	1	429.4		59.5		
2802	232.4	4804	241.6	1	429.4		57.1		
2802	232.4	4804	241.6	2	429.4		57.1		
6808	232	6823	236	1	429.4		56.6		
6808	232	6823	236	2	429.4		56.6		
1803	227.2	18111	228.7	4	858.9		56.5		
1803	227.2	18111	228.7	3	858.9		56.5		
1809	229.2	1835	227.8	2	1717.7		56.1		
1809	229.2	1835	227.8	1	1717.7		56.1		
1803	227.2	1811	228.7	2	858.9		55.9		
1803	227.2	1811	228.7	1	858.9		55.9		
3803	237.5	3804	232.8	2	429.4		54.3		
3803	237.5	3804	232.8	1	429.4		54.3		
6806	235.7	6824	235.9	1	858.9		54		
6806	235.7	6824	235.9	2	858.9		54		
1804	229.9	1813	230.8	2	858.9		51.8		
1804	229.9	1813	230.8	1	858.9		51.8		
7801	226.4	7804	236.9	1	429.4		49.1		

Table 4.15 Contingency events, screening, and ranking result (year 2008)

Activities Description	Related contingencies and Result
1. N-1 line contingency 2. Method of Calculation 3. Unsolved case(s)	- 785 contingencies - Full AC power flow - 8 unsolved cases: 1. Open line from bus 2726 to 2747 CKT1 2. Open line from bus 7706 to 7707 CKT1 3. Open line from bus 4741 to 4744 CKT1 4. Open line from bus 2705 to 2707 CKT1 5. Open line from bus 4808 to 4812 CKT1 6. Open line from bus 4808 to 4812 CKT2 7. Open line from bus 5701 to 5720 CKT1 8. Open line from bus 7706 to 7708 CKT1

Contingencies Screening & Ranking	Related contingencies open line between (from bus – to bus), circuit number	Result from contingencies event			
		Number of violations	Min. Volt	Max. Volt	max % of line usage
1. Open most heaviest line loading	6801 – 6802, CKT1	600	0.502	1.361	865.8
2. Contingency with max. number of violations	6908 – 6909, CKT1	602	0.463	1.362	865.2
3. Contingency with max. % of line usage	2726 – 2746, CKT2	589	0.440	1.361	872.3

Due to the higher in electricity demand, and uncertainty of newly installed generation locations, result of N-1 contingencies cases from table 4.15 – 4.16 of year 2008 is more severe than those cases in year 2006. Comparing result of 4.13 and 4.15, it is found that 2008 contingency cases potentially create up to 600 violations while only 150 violations were observed in year 2006. Besides, two major observations obtained from these contingency studies are 1) single transmission facilities outage in area 6 tends to create the overloading problem to system due to inadequate transmission lines to transfer power to load center and 2) single transmission outage in area 2 is likely to create low voltage problem due to insufficient generation facilities within this area. This outcome can be verified from table 4.9 where 1000 MW of transfers from area 4 to area 2.

Table 4.16 Major lines power flow during N-1 contingency (year 2008)

Lines				Circuit	Line limit (MVA)	Percent use of line limit (%) (under contingency condition)			
From bus		To bus				Year			
no.	kV	no.	kV			2004	2006	2008	2010
6801	239.7	6802	234.7	2	429.4			157.2	
6802	234.7	6891	237.2	1	429.4			113.8	
6802	234.7	6891	237.2	2	429.4			113.8	
6802	234.7	6806	235.2	2	429.4			95.4	
6802	234.7	6806	235.2	1	429.4			95.4	
2801	209.3	2807	229.2	2	429.4			91.6	
2801	209.3	2807	229.2	1	429.4			91.6	
1808	233.6	5802	223.8	1	429.4			90.6	
1808	233.6	5802	223.8	2	429.4			90.6	
5804	231.4	5806	240.5	1	858.9			85.7	
5804	231.4	5806	240.5	2	858.9			85.7	
2802	214.4	4804	232.4	1	429.4			76.4	
2802	214.4	4804	232.4	2	429.4			76.4	
1811	231.2	6891	237.2	1	858.9			75.2	
6891	237.2	18111	231.2	2	858.9			75.2	
1804	235.5	6801	239.7	2	858.9			75.2	
1804	235.5	6801	239.7	1	858.9			75.2	
1810	234.5	6891	237.2	1	858.9			73.7	
3802	229.2	3803	237.5	2	429.4			71.8	
3802	229.2	3803	237.5	1	429.4			71.8	
6802	234.7	6804	234.8	1	429.4			68.8	
1803	229.1	18111	231.2	4	858.9			65.6	
1803	229.1	18111	231.2	3	858.9			65.6	
1807	233.1	7816	228.7	1	858.9			65	
1803	229.1	1811	231.2	2	858.9			64.9	
1803	229.1	1811	231.2	1	858.9			64.9	
5802	223.8	5805	219.2	2	429.4			64.2	
5802	223.8	5805	219.2	1	429.4			64.2	
1805	243.7	1806	235.6	1	858.9			62.9	
1804	235.5	1811	231.2	1	429.4			62.1	
1804	235.5	18111	231.2	2	429.4			61.9	
6808	237.7	6823	241.7	1	429.4			61.3	
6808	237.7	6823	241.7	2	429.4			61.3	
5801	226.2	5804	231.4	2	429.4			59.7	
5801	226.2	5804	231.4	1	429.4			59.7	
1805	243.7	1806	235.6	3	858.9			59.7	
1805	243.7	1806	235.6	2	858.9			59.7	

4.5 Chapter summary

The study of steady state power flow in Thailand system, according to EPPO's load forecasting result and Thailand power development plan (PDP03-04) indicate that, under the traditional operation, the country could experience with transmission congestion problem in year 2006. The situations become worse if system will experience with any contingency conditions. All result in section 4.4 designates the power balance between generation and load in each pre-defined study areas. Area 1, metropolitan and its vicinity is the biggest power importer area, while area 2 located in the north-east part of the country is showing consistent growing in power importer since there is no new generation facilities projects to be online within this area. Area 6 and area 7 have a similar ratio of generation and demand within their areas and considered to be a significant power supplier for other areas in the country. Moreover, due to a high transfer between area 1 and its supplier areas (area 5, 6, and 7), it is most likely for interfaces between area 1 and its supplier can be good candidacies for CSCs selection.

Finally, all study result in chapter 4 including: converged power flow cases, area distribution of generations and loads, and tie lines flow study, will be used as primary input for the transmission congestion management study in chapter 5.

CHAPTER 5

PROPOSED TCM MODELS DURING TRANSITION PERIOD

5.1 Introduction and relevant limitations

Changing from the traditional vertically integrated system to a deregulated environment creates numerous challenging tasks to system operators (SOs). Significant number of electricity transactions both in day ahead and real time market lead to the difficulty in power flow prediction. Therefore, the concept of congestion management is emerged. Theoretically, the idea of TCM is to alleviate the amount of power flow in the congested transmission lines by changing the flow pattern. This process of re-dispatch can be done by modifying generation, or modifying load, or both without compromising the system security and service quality [15].

As a developing country with the gross income disparity among the population, social equity policy should and would be pursued by the government. In this respect, equitable access to electricity irrespective of geographical location is desirable and some form of subsidy for lower income groups should still be implemented [61]. In addition, the current structure of OASIS, computer information technology including the high speed internet services is still under the developing stage. These factors could become vital limitations for congestion management processes proposed in this chapter.

Main ideas of this chapter are to discuss and propose the implementation procedures of two CM schemes which are Zonal Congestion Management (ZCM) and Nodal Congestion Management (NCM). Chapter starts with the proposed modified ERCOT-model regarding to RTO/ISO's core businesses. Then, required-data and implementation procedures of ZCM and NCM will be proposed, followed by generation cost comparison of three dispatching scenarios which results from different CM schemes. These three scenarios are composed of 1) EGAT stays with traditional operation mode, 2) EGAT moves to deregulated environment with NCM, and 3) EGAT utilizes ZCM for managing transmission congestion.

5.2 Proposed modified-ERCOT model for RTO/ISO core-functions

The deregulated power market is a brand-new concept to MPs in Thailand. Without well defined rules to control and monitor all MPs, it can lead to another disaster similar to California crisis in 2000. Hence, it is a root important to establish a structure of core-functions responsible by the regulatory body. Fig. 5.1 is the typical core-functions of Regional Transmission Organization/Independent System Operator (RTO/ISO). According to this chart, the primary mission of RTO/ISO is to ensure security of system operation. According to the operation timeframe of ISO, the bilateral contract market and load forecasting would be main charges for ISO in the pre-Day ahead market. Day Ahead (DA) energy market, DA ancillary services, and DA reliability unit commitment are three main tasks in the Day Ahead Market. The balancing energy market would be implemented on real time (RT) market with the ancillary services deployment. Finally, settlement process (SA) will be handled after the real time market.

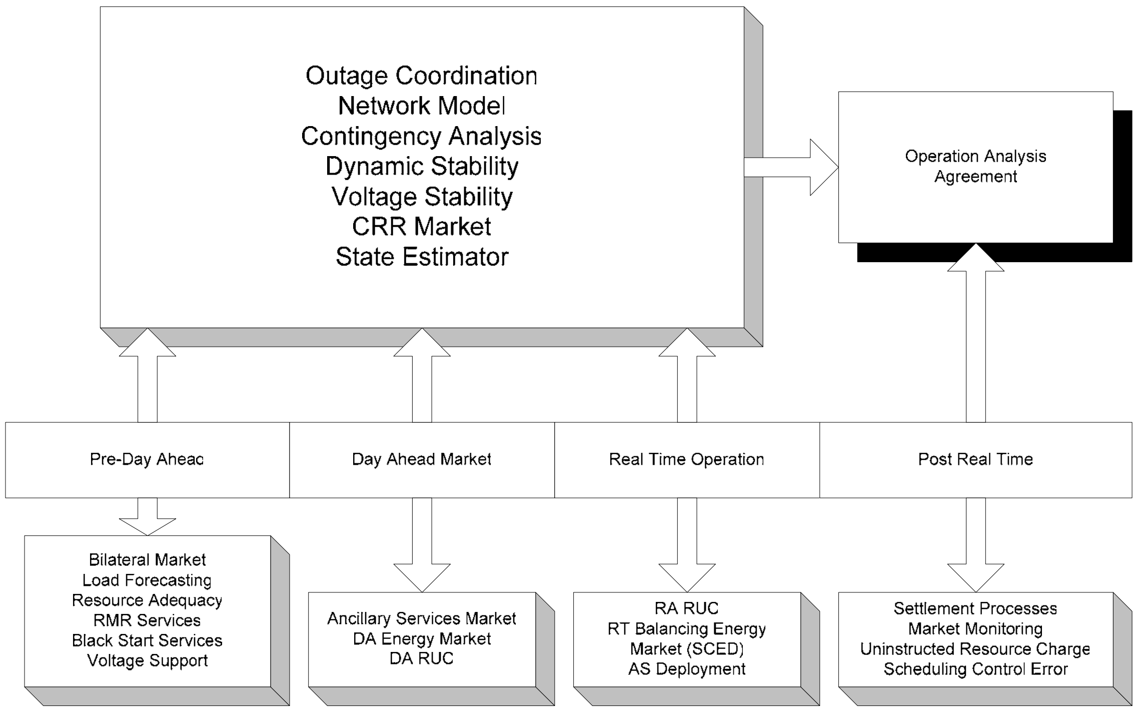

Figure 5.1 RTO/ISO core-functions [modified 41]

For all MPs, financial incentive is the most important factor for them to justify whether to join the market at the particular time. Typically, there are at least 4 main cost components for each MP. As shown in Fig. 5.2, the basement of this cost component is bilateral contract cost between two parties. DA cost component will be provided to all MPs after DA clearing process. Since the real time cost can vary significantly, MPs can control their risk in real time pricing by using other options such as FTR or TCR. The last component is from the uninstructed resource charge. Depending on the different between actual and scheduling power in which they commit to provide and/or consume, this element can cost or award MPs.

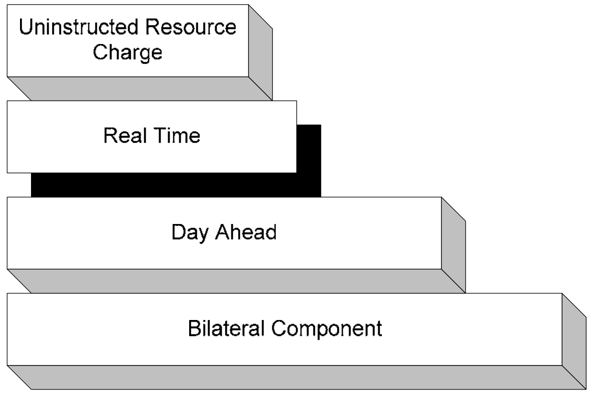

Figure 5.2 Typical cost components for all MPs

5.3 Discussion on typical Market Structures

5.3.1 Day-Ahead Market

The primary objective of DA market is to create a financial binding schedule for both energy and ancillary service. According to ERCOT 95% confidence level, ERCOT has obtained energy market as close to 95% after settled DA transactions. In this manner, ERCOT can operate system with a high level of security confident. At the mean time, for MPs, knowing 95% of scheduling transaction would provide less risk in their financial obligation. Typically, there are two types of DA market i.e., DA with transmission constraints and without transmission constraints. The former is more complicate due to ISO needs to know all outage scheduling and run all contingency cases. The latter is less complicate because ISO will clear market base on network topology as well as supply and demand bids.

For the DA market in the ISO/RTO, Security Constraints Unit Commitment (SCUC) will be used as a main tool to assure the adequacy of generation resources for the next-day in order to have a good solution of economic dispatch (ED) in RT market.

Then, Security Constraint Economic Dispatch (SCED) is deployed to obtain the converged power flow case and a good dispatching pattern. During the DA price calculation, the process can be different depending on whether ZCM or NCM be utilized in the system. In addition, DA price components in the settlement bill can include energy price, transmission price, load zone price, HUB price, and Point to Point price. Figure 5.3 shows the typical structure of DA market mentioned above.

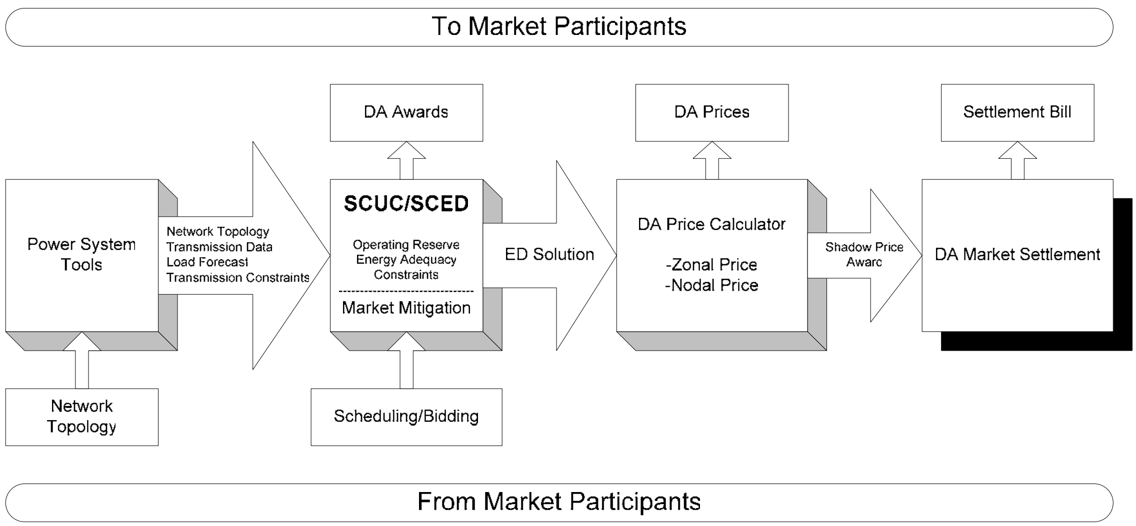

Figure 5.3 Typical Day Ahead market structure

To apply in the Thailand system, it is recommend that DA market structure with considering transmission constraints be used because it reflects more realistic situations and ISO can have better confidence in operating and controlling system.

5.3.2 Real Time Energy Balancing Market

In order to maintain the system frequency in real time operation, ISO needs to keep balancing between generation resources and demand for the entire the system. Therefore, RT market can be considered as the most important market because it provides the last resource of energy transaction to generations and consumers. It is clear from figure 5.3 and 5.4 that typical structure of RT and DA markets are similar. In the RT operation, real time data from SCADA system would be the basic data for the RT market clearing price process. ISO then, deploys SCED subject to unit ramp rate, energy reserve, and energy balance constraints to obtain a feasible, and fast enough dispatching instruction. The SCED solution will be used in the process of RT price calculation. Similar to DA market, RT pricing can be based on either ZCM or NCM depend on the system congestion management structure. Throughout the process of SCED, ISO will use bid curve from MPs instead of heat rate curve as used in the traditional ED. Since it requires fast converged solution, all calculation will base only on real power flow concept. Figure 5.4 illustrates the typical configuration of RT market.

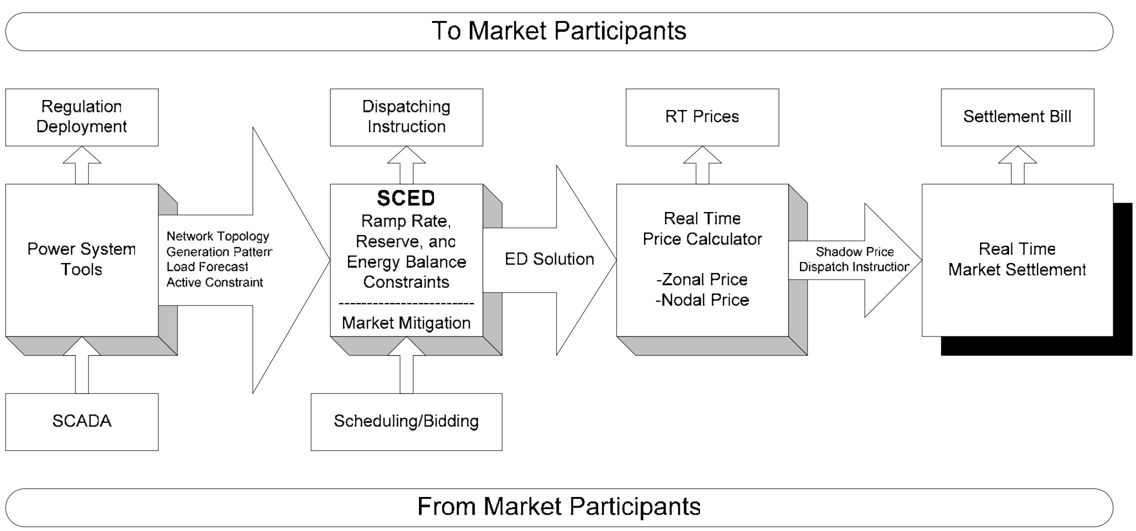

Figure 5.4 Typical Real Time Balancing Energy market structure

5.4 Basic Assumptions

5.4.1 Power Flow Study

As stated in chapter 4, power flow study is to determine the 1) steady-state flows through lines and transformers and 2) bus voltages throughout the system under specific conditions. These values are examined to assure that no line flow is above its normal limits (95 percent of the nominal limit) and no bus voltage is outside its normal operating range (0.95 pu. to 1.05 pu.). It should be noted that the summer peak load was selected as the power flow base case for the entire dissertation since it has higher possibility to cause transmission congestion problem.

5.4.2 Optimal Power Flow Study

Theoretically, the main purpose of Optimal Power Flow (OPF) is to optimize the objective function which is total operating cost in this dissertation. This objective function is accomplished by changing different system control variables while meeting power balance constraints and enforcing operating limits. OPF program will adjust the generation level automatically to find the least-cost or least-price generation dispatch while observing the transmission limits. Thus, while power flow simulates performance of system under specified conditions, the OPF optimizes system performance to meet specified objective function.

In general, solving optimization problems involve two types of constraints which are equality and inequality constraints. Equality constraints always have to be enforced such as real and reactive power balance equations and area MW interchanges constraints. Inequality constraints, on the other hand, may or may not be binding. For example, a line MVA flow or generator real power output may or may not be at its maximum limit. Since OPF is solved by iterating between a power flow (PF) solution and linear programming (LP) solution, therefore it is possible for some constraints to be enforced during PF solution, and some constraints are enforced during LP solution.

In order to solve a nonlinear and constraints-optimization problem, OPF requires the cost curve of each generator to perform an economically optimal power flow. In this dissertation, linear piecewise cost curves are the input data of the OPF study processes. In addition, to guarantee a converged and fast power flow solution during the real time operating condition, a DC power flow (DCPF) model was utilized. Therefore, for comparison purpose, a DCPF model will be used for the traditional operation pattern. On the other hand, DCOPF model will be applied for both ZCM and NCM. Following objective function and constraints will be taken into consideration when performing DCOPF.

5.4.2.1 OPF objective function

A main objective function for this dissertation is to maximize social welfare. In other words, it is to minimize total generation cost from all online generating units. This objective function can be expressed as,

$$\min J = \sum_{i=1}^{NG} C_i(P_i) \tag{5.1}$$

Where, J: total system generation cost

$C_i(P_i)$: units' generating cost

NG: set of all generating units including slack bus.

5.4.2.2 Network equations

Since the study of generation cost comparison in this dissertation is based on DC model, real power generation equation at each node obtained from basic Kirchoff's Laws will be included in the OPF problem. These real power balance equations can be treated as equality constraints and can be expressed as,

$$P_i - PD_i = \sum_j |V_i||V_j|Y_{i,j}\cos(\theta_{i,j} + \delta_j - \delta_i) \quad \forall i = 1,\ldots,N : i \notin slack \qquad (5.2)$$

Where, *V:* the bus voltage

δ *:* the angle associated with *V*

$Y_{i,j}$ *:* the element of bus admittance matrix

θ*:* the angle associated with $Y_{i,j}$

P_i: real power generation at bus *i*

PD_i: real power demand at bus *i*

N: the number of buses in system

5.4.2.3 Generation limits

The generation real power limit is considered to be an inequality constraint which may or may not be binding, and can be presented as,

$$P_i^{\min} \le P_i \le P_i^{\max} \quad \forall i \in NG \qquad (5.3)$$

Where, P^{min} *and* P^{max}*:* the lower and upper limits on real power generation

5.4.2.4 Transmission lines limits

In this study, transmission line limit is based on rate A (normal operating) which is usually determined by the thermal limit capacity of lines. This limit is considered as an inequality constraints and can be expressed as,

$$P_{i,j} \leq P_{i,j}^{Max} \qquad \forall Y_{i,j} \neq 0 \tag{5.4}$$

Where, $P_{i,j}$ *:* the power flow over a line *i-j*

$P^{Max}{}_{i,j}$ *:* the maximum limit on power flow over the line.

5.5 Implementation of Zonal Congestion Management in Thailand System

Main purposes of ZCM are to 1) predict potential congestion on those Commercial Significant Constraints (CSCs), 2) perform necessary adjustment in the day-ahead market and notify the market participants, and 3) determine if replacement resources should be purchased in a congestion zone [67]. When implement in Thailand system, ISO will have the responsibilities to manage transmission congestion, and will categorize the cost of congestion as either Zonal Congestion Management (ZCM), or Local Congestion Management (LCM). ZCM costs are those costs that ISO used to manage congestion on CSCs.

5.5.1 Required Data

The most important data required before performing CMZs determination is the power flow base case data. The responsible-committee or working group needs to provide the upcoming year's summer peak power flow base case (planning data). This power flow base case should contain following important information:

a) The planning year's peak summer load.

b) The planning year's scheduled generating unit additions, retirement, and ratings.

c) The planning year's scheduled transmission facility additions, retirement, and ratings.

d) The list of actual contingency events over the past twelve months, with associated cost impact on the system. This data, if provided, will be used as a pilot data for CSCs determination processes.

It should be noted that if there is no significant system changes for the upcoming year and there is no significant cost impact from contingencies, the upcoming year's CMZs will remain the same. Otherwise, it is ISO's responsibility to determine the potential CSCs and re-clustering new CMZs to be used in the upcoming year.

5.5.2 CM Zones Determination based on ERCOT's Method

In this section, the proposed steps of defining CMZs within Thailand system will be similar to processes in ERCOT [42, 67-68]. CMZs are to be determined by subjectively evaluating results of cluster analysis. The input data for the cluster analysis is a set of Generation Shift Factors (GSFs) which obtains from a DCPF analysis. The shift factors are associated with each bus in the system and collectively determine the line flow on the CSC [42]. Following are four main steps in CMZs determination proposed in this dissertation:

5.5.2.1 Determination of CSCs

Since Thailand is at its initial stage moving toward deregulation, it should take a more conservative approach in determining CSCs. Because CSC determination is a subjective step, it requires engineering judgment based on the annual technical and financial analysis. A subcommittee from ISO and EPPO should be a proper starter team to take the responsibility of this task. New CSCs for the upcoming year, as well as the electrical network topology, should be defined annually by September 30th to match the fiscal year of Thailand. The analysis should be based on "Summer Peak Load Flow Case" and performing steady state power flow, contingency analysis, and dynamic stability analysis. After the completion of all studies, load flow cases used in determining CSCs should be posted on the ISO's website.

Since this is the first time that the zonal congestion management is implemented in Thailand, it is recommend that a minimum number of congestion zones be implemented to minimize the complexity in operation and control for SO and simple for MPs. The selection of CSCs candidacies will be start at year 2006 because there is a first emergence of transmission congestion problem. The same CSCs candidacies will be used in the CMZs determination for year 2008 as well.

The simulation results in table 5.1 indicate that the loading of the 500 kV lines are approximately 20% of their limit, therefore these 500 kV lines are unlikely to have congestion problem in the near future. According to the results from table 5.1 – 5.5, the potential candidates for CSCs should be the major high voltage inter-area tie lines which carry heavy flows. Although there are 9 studied regions for the original system as introduced in Chapter 4, area 8 and 9 are the neighboring countries. Therefore, only 7 domestic regions will be focused in CSCs determination processes. It is found that all 7 areas can generate 12 combination scenarios of tie lines flow as listed in table 5.1 – 5.5.

Table 5.1Inter-area power transfer from area 1 (Year 2006)

Scenarios of Interfaces or CSCs candidacies							Circuit	Line limit (MVA)	From bus	
No.	From bus			To bus					Actual MW Flow	% use of MVA
	Area	kV	No.	Area	kV	No.				
1	1	230.3	1808	5	229.8	5802	1	429.4	273.1	63.7
	1	230.3	1808	5	229.8	5802	2	429.4	273.1	63.7
	1	227.7	1809	5	234.7	58061	3	858.9	-389.2	47
	1	227.7	1809	5	234.7	58061	4	858.9	-389	47
	1	227.7	1809	5	233.5	5806	2	858.9	-248.8	30.4
	1	227.7	1809	5	233.5	5806	1	858.9	-248.8	30.4
	1	500.6	1908	5	503.4	5906	1	3734.1	147.7	5.4
	1	500.6	1908	5	503.4	5906	3	3734.1	120.7	4.6
	1	500.6	1908	5	503.4	5906	2	3734.1	147.7	4.6
2	1	227.9	1804	6	231.8	6801	2	858.9	-683.9	81.1
	1	227.9	1804	6	231.8	6801	1	858.9	-683.9	81.1
	1	226.8	1811	6	233.4	6891	1	858.9	-521.8	62.4
	1	231.1	1810	6	233.4	6891	1	858.9	-484	57
	1	498.6	6661	6	501.5	6911	1	2833.6	-1085	38.8
	1	227.7	1809	6	230.5	6808	2	858.9	-282	33.2
	1	227.7	1809	6	230.5	6808	1	858.9	-282	33.2
3	1	226.2	1807	7	221.9	7816	1	858.9	444.5	59.9
	1	227.2	1806	7	221.9	7816	1	858.9	243.9	38.2
	1	226.4	25	7	225.9	7801	2	1717.7	-506.3	29.7
	1	226.4	24	7	225.9	7801	1	1717.7	-506.3	29.7
	1	500.6	1908	7	509.2	7902	3	3734.1	-897.9	24.8
	1	500.6	1908	7	509.2	7902	2	3734.1	-897.9	24.5
	1	500.6	1908	7	509.2	7902	1	3734.1	-897.9	24.5

Scenario 1 – 3 in table 5.1 is potentially CSCs candidates between area 1 and areas 5, 6, and 7. The most likely CSC candidates within table 5.1 are two lines link between area 1 and area 6 from in scenario no. 2. This CSC candidacy currently reaches 81 percent of its 860 MVA limit. Another possible candidacy is the interface from scenario no. 1 which is the 230 kV lines between bus 1808 and bus 5802. The loading of this line is 65 percent of its maximum 430 MVA limit. The last possible candidacy is the interface from scenario no. 3 which is the 230 kV line between bus 1807 and bus 7816 with the current loading at 60 percent of its maximum 860 MVA.

Table 5.2 Inter-area power transfer from area 2 (Year 2006)

Scenarios of Interfaces or CSCs candidacies							Circuit	Line limit (MVA)	From bus	
No.	From bus			To bus					Actual MW Flow	% use of MVA
	Area	kV	No.	Area	kV	No.				
4	2	230.9	2802	4	230.9	4804	1	429.4	-237.6	57.7
	2	230.9	2802	4	230.9	4804	2	429.4	-237.6	57.7
	2	231.4	2803	4	231.4	4807	1	429.4	-132.3	32.1
	2	231.4	2803	4	231.4	4807	2	429.4	-132.3	32.1
5	2	112.7	2701	5	117.8	5708	1	117.5	-77.9	69.2
	2	113.8	2702	5	117.8	5708	1	117.5	-55.5	49.8
	2	230	2807	5	229.3	5803	2	429.4	46.8	11
	2	230	2807	5	229.3	5803	1	429.4	46.8	11
6	2	116.9	2723	8	118	2888	1	119.5	16.6	33
	2	113	2736	8	112.6	8736	1	57.1	2	24.4
	2	237.2	2811	8	237.9	8000	1	429.4	-77.4	18.4
	2	230.6	2808	8	230	8004	1	429.4	-65	16.4
	2	230.6	2808	8	230	8004	2	429.4	-65	16.4
	2	117.5	2740	8	117.6	8705	1	119.5	-18.6	15.8
	2	113	2736	8	113.1	8734	1	119.5	-11.2	9.9
	2	114.2	2733	8	113.1	8734	1	119.5	8.7	7.5
	2	237.9	2810	8	237.9	8000	1	429.4	-25	6.3

Results of table 5.2 are tie lines link between area 2 and its supply areas. Majority of import power comes from area 4, therefore, the most likely to be a candidacy for CSC should be lines between bus 2802 and 4804. The loading of these 230 kV lines are 60 percent of their 430 MVA maximum limit.

It is clear from scenario no. 7 in table 5.3 that the tie line between area 3 and area 7 still has enough room for transferring power in the near future. Therefore, this scenario will not create any CSC candidacy in this year.

Table 5.3 Inter-area power transfer from area 3 (Year 2006)

Scenarios of Interfaces or CSCs candidacies							Circuit	Line limit (MVA)	From bus	
No.	From bus			To bus					Actual MW Flow	% use of MVA
	Area	kV	No.	Area	kV	No.				
7	3	116.7	3701	7	117.4	7721	1	119.5	-22.7	19.6
	3	116.7	3701	7	117.4	7721	2	119.5	-22.7	19.6
	3	236	3802	7	243.2	7829	2	429.4	27.9	11.2
	3	236	3802	7	243.2	7829	1	429.4	27.9	11.2

Table 5.4 Inter-area power transfer from area 4 (Year 2006)

Scenarios of Interfaces or CSCs candidacies							Circuit	Line limit (MVA)	From bus	
No.	From bus			To bus					Actual MW Flow	% use of MVA
	Area	kV	No.	Area	kV	No.				
8	4	502.7	4441	1	498.6	6661	1	2833.6	-232.4	9.8
9	4	240.5	4804	5	227.5	5805	2	858.9	191.5	23.8
	4	240.5	4804	5	227.5	5805	1	858.9	191.5	23.8
	4	240.5	4804	5	230.4	5801	2	429.4	-25.6	14.6
	4	240.5	4804	5	230.4	5801	1	429.4	-25.6	14.6
	4	502.7	4441	5	503.4	5906	2	2833.6	-392.2	14.4
	4	502.7	4441	5	503.4	5906	1	2833.6	-392.2	14.4
	4	237.4	4803	5	229.8	5802	2	429.4	8.5	9.8
	4	237.4	4803	5	229.8	5802	1	429.4	8.5	9.8

Results of table 5.4 and 5.5 show no potential line to be a CSC candidacy. In summary, from the operation record and power transfer study result shown in table 5.1 – 5.5, the most likely potential interfaces to become CSCs candidacies in Thailand system can be priority listed as shown in table 5.6

Table 5.5 Inter-area power transfer from area 5 (Year 2006)

Scenarios of Interfaces or CSCs candidacies							Circuit	Line limit (MVA)	From bus	
No.	From bus			To bus					Actual MW Flow	% use of MVA
	Area	kV	No.	Area	kV	No.				
10	5	503.4	5906	1	498.6	6661	2	2833.6	201.4	9.6
	5	503.4	5906	1	498.6	6661	1	2833.6	201.4	8.6
11	5	503.4	5906	6	501.5	6911	1	2833.6	-866	30.8
12	5	503.4	5906	7	509.2	7902	1	3734	-519.2	14.3

Table 5.6 CSCs candidacies for Year 2006

CSC no.	CSC Name	Scenario, (circuit)	Between Areas	Loading (MW)	MVA	
					Limit	%Loading
CSC1	CSC Metro-East	2, (2)	1 and 6	684	860	81
CSC2	CSC Metro-West	3, (1)	1 and 7	444	860	60
CSC3	CSC Metro-Central	1, (2)	1 and 5	273	430	65
CSC4	CSC North-North East	4, (2)	4 and 2	238	430	58

After finishing CSCs determination process in step 1, it is necessary to calculate generation shift factor and re-cluster the system to create new CMZs if there is any potential for new lines or interfaces to experience congestion problems in the coming year.

5.5.2.2 Power Transfer Distribution Factor (PTDF) or Shift Factor Calculation

Unlike the previous step, this step is mathematical processes. The main purpose of calculating the Power Transfer Distribution Factor (PTDF) or shift factor (SF) is to determine the impact of transferring one MW from a specific bus to the system slack/reference bus on the power flow of each pre-defined interfaces (CSCs) from previous step. Two existing concepts for SFs calculations are explained below [67]:

Type 1—defines as effect of 1 MW of transfer from a particular bus to system slack bus on a specified line or CSC.

Type 2—defines as effect of 1 MW of transfer from a particular bus to a designated reference bus on a specified line or CSC.

This dissertation adopts the type 1 SF calculation for Thailand system in the initial stage of classifying CMZs. It should be noted that for Thailand system, the system slack bus is located in area 6. The SFs are to be calculated for all buses for the entire system. Since 1 MW will not change the system operation condition significantly, linear lossless DC model is used for calculating PTDF for proposed CSCs interfaces.

Currently, there are almost 1500 buses in Thailand system. It can generate a large number of numerical results of shift factors therefore not all of them will be listed in this dissertation. Table 5.7 shows some of PTDFs impact on four pre-defined CSCs (table 5.6). The shift factors listed in Table 5.7 are the impact of transferring additional 1 MW from a particular bus to system slack bus (bus 6003 in area 6) on four CSCs. For example, if 1 MW transfers from bus 7005 to system slack bus, it will increase flow by 0.038 MW, 0.03 MW, and 0.198 MW on CSC1, CSC2, and CSC4 respectively. However, this 1 MW transfer will, at the same time, reduce the flow on CSC3 by 0.225 MW.

Table 5.7 Example of PTDF or SF calculating for each CSC

Bus No.	Bus Name	Area No.	Power Transfer Distribution Factor (PTDF) or Generation Shift Factor (GSF) on CSCs			
			CSC1 Metro to East	CSC2 Metro to West	CSC3 Metro to Central	CSC4 North east to North
1013	SB-T3	1	-0.113	0.032	-0.333	0.199
1021	SB-C11	1	-0.113	0.032	-0.313	0.271
1022	SB-C12	1	-0.113	0.032	-0.299	0.321
1023	SB-C10	1	-0.113	0.032	-0.299	0.321
1031	SB-C21	1	-0.113	0.032	-0.298	0.323
1032	SB-C22	1	-0.113	0.032	-0.298	0.323
1033	SB-C20	1	-0.113	0.032	-0.29	0.335
2011	LTK-H1	2	-0.001	0.031	-0.257	0.386
2012	LTK-H2	2	-0.001	0.031	-0.257	0.386
2014	LTK-H4	2	-0.001	0.031	-0.257	0.386
2203	SKI-1	2	-0.001	0.031	-0.257	0.387
2204	SKI-2	2	-0.001	0.031	-0.257	0.387
2205	NR2-1	2	-0.001	0.031	-0.257	0.387
2206	NR2-2	2	-0.001	0.031	-0.257	0.387
6001	BPK-T1	6	0.445	0.032	-0.001	0
6002	BPK-T2	6	0.445	0.032	-0.001	0
6801	BPK-A	6	0.445	0.032	-0.001	0
631	KLM-1J	6	0.405	0.032	-0.001	0
632	KLM-2J	6	0.405	0.032	-0.001	0
633	KLM-3J	6	0.405	0.032	-0.001	0
6104	EPEC-CC1	6	0.405	0.031	-0.256	0.389
7005	SNR-H5	7	0.038	0.03	-0.225	0.198
7006	TTN-H1	7	0.037	0.03	-0.225	0.198
7011	VRK-H1	7	0.038	0.03	-0.221	0.169
7007	TTN-H2	7	0.037	0.03	-0.221	0.169
7804	SNR	7	0.038	0.033	-0.354	0.125
7723	RB3-WP	7	0.028	0.033	-0.354	0.125
7720	PKK	7	0.025	0.033	-0.354	0.125

5.5.2.3 Clustering the SFs

The purpose of the cluster analysis is to group SFs into zones or clusters. The SFs within the same zone will have a similar effect on CSCs. This is a non-subjective step. Usually, criterion for clustering is defined by minimizing the “within-cluster” variance while simultaneously maximizing the “between-cluster” variance [69].

However, additional criterions for final CMZs determination will be included and discussed in the next section. In this dissertation, Statistical Analysis System (SAS) is used as a main tool to perform clustering analysis. During the clustering procedure, disjoint clustering technique is utilized to ensure that any bus in the system only lies in one CMZ. The main input of clustering analysis is four set of SFs based on pre-defined CSCs which obtained from the previous step. The recommended number of CMZs for each studied cases should lie between the number of CSCs and CSCs+2 zones to minimize number of CMZs during the transition period.

Table 5.8 Optional CMZs result due to selection of 2 CSCs

Scenario no.	Number of CMZs	Congestion Management Zone's Properties				
		Number of buses	Number of generators	Total MW generation	Total MW load	Approx. Expected Overall R^2
1	2	Z1 = 1156 Z2 = 65	181 9	21975 1494	19618 3118	0.38447
2	3	Z1 = 17 Z2 = 63 Z3 = 1141	- 17 173	- 3774 19696	680 1457 20599	0.66777
3	4	Z1 = 1095 Z2 = 96 Z3 = 17 Z4 = 13	175 9 - 6	20247 1494 - 1728	15816 5608 680 632	0.75129

Since it will be an initial phase of electricity deregulation in Thailand, this dissertation recommends the minimum number of clusters to be implemented. 2 to 4 clusters should be a good start number for Thailand system because it is less complicate for MPs. The number of cluster could be changed due to the appearance of new CSCs in the future year. The summary results of optional CMZs scenarios are presented in table 5.8 – 5.10.

Table 5.9 Optional CMZs result due to selection of 3 CSCs

Scenario no.	Number of CMZs	Congestion Management Zone's Properties				
		Number of buses	Number of generators	Total MW generation	Total MW load	Approx. Expected Overall R^2
4	2	Z1 = 1204 Z2 = 17	190 -	23469 -	22056 680	0.44686
5	3	Z1 = 727 Z2 = 17 Z3 = 477	146 - 44	20699 - 2770	15940 680 6155	0.56932
6	4	Z1 = 17 Z2 = 676 Z3 = 465 Z4 = 63	- 130 43 17	- 17036 2659 3774	680 15098 5500 1457	0.65634

Table 5.10 Optional CMZs result due to selection of 4 CSCs

Scenario no.	Number of CMZs	Congestion Management Zone's Properties				
		Number of buses	Number of generators	Total MW generation	Total MW load	Approx. Expected Overall R^2
7	2	Z1 = 1063 Z2 = 158	173 17	20922 2547	22678 7660	0.32137
8	3	Z1 = 843 Z2 = 265 Z3 = 113	162 19 9	20306 1668 1495	13124 3323 6288	0.51501
9	4	Z1 = 225 Z2 = 717 Z3 = 262 Z4 = 17	69 102 19 -	6066 15734 1668 -	3474 15289 3292 680	0.58082

Followings are three main observations obtained from the results of clustering analysis in table 5.8 – 5.10.

a) Comparing the number of CSCs selection, it is found that the less number of CSCs yield the uneven number of buses within the studied-zones. For example, in table 5.8, if 2 CSCs were selected, result from SAS will show one dominant zone that comprise of more than one thousand buses while other zones will have a small number of buses. This situation is found to be true for all cases of CMZs defined. As a result, a small zone (less generation) will have less flexibility in power transaction if deregulated environment is implemented.

b) Comparing the cases with the same number of CSCs it is observed that defines higher number of CMZs yield an evenly distributed buses and generation facilities between CMZs. These properties can be verified from result in table 5.9 and 5.10.

c) The Approximated Expected Over-all Variance, R^2, shown in all three tables can be used as a statistical index to justify the appropriate number of CMZs to be defined. The higher value of R^2 is more recommended because this R^2 value reflects the objective function of minimizing the "within-cluster" variance while simultaneously maximizing the "between-cluster" variance as mentioned before.

This dissertation suggests that this cluster may need to be redefined if SAS output indicates a cluster with less than twenty buses. Moreover, the number of CMZs should not change significantly from one year to the next year without justifiable reasons.

5.5.2.4 Define number of CMZs

The last step is the most subjective step in the entire process. This step involves reviewing and interpreting the result data from the previous step and determining the appropriate number of zones that will be used to define the annual commercial model. It should be noted that clustering analysis partitions the set of input data into mutually exclusive groupings, but it is not able to guarantee the validity of these groupings.

Therefore, following additional criterions should be considered to ensure the validity of clustering result.

a) Each CMZ should contain both generation and load buses.

b) Maintain the minimum number of CMZs necessary to generate a reasonable market price signal.

c) Maintain power balance between generations and load within CMZ to minimize potentially inter-zonal congestion.

d) Preparing the generation capacity within the CMZ capable of providing at least 3 independent balancing energy bids to minimize market power of some big Gencos.

Since the result of this step will directly affect the financial obligation of MPs in the country, the final decision should be left up to a task force with members from ISO, academia, stakeholders, and EPPO. Once the number of CMZs are defined, the Average Weighted Shift Factor (AWSF) or Zonal Shift Factor, used to predict potential congestion on CSCs can be calculated by using the equation 2.11.

After taking into account the social concerns, relevant limitation in section 5.1, and the above criterions, it is recommend that a minimum number of congestion zones be used because it is less complex in operation and control for ISO and simpler for MPs. This dissertation thus, selects scenario number 9 in table 5.10 to be a reference case for dispatching study. In this reference case, after performing some adjustment results from SAS, final output for clustering analysis will base on 4 CSCs selection and

3 final CMZs. This scenario is recommended for the first implementation in Thailand system.

5.6 Implementation of Nodal Congestion Management in Thailand System

It has been widely accepted that the concept of ZCM provides a good benefit for MPs because of its simplicity and flexibility to control the financial risks. With fewer defined zones and smaller price differences within the entire system at the initial phase, MPs will be able to familiar with the new environment and hedge against the risk from price volatility. Since it reflects actual system operation and provides better price signal for generations and transmission investment, it is recommended that Nodal Congestion Management (NCM) should be implemented after MPs in Thailand are familiar with the semi-competitive environment under ZCM. Similar to the PJM approach, the proposed Thailand NCM is also composed of two settlement system to deal with the day-ahead and real time energy market. This two settlement structures offer key benefits to system in the form of enhancing robustness and competitive market, providing additional price certainty to market participants, and offering financial binding of day-ahead schedule. LMP has to be calculated for both day-ahead energy market (DAEM) and real time energy market (RTEM). The important tool in DAEM is Security Constrained Unit Commitment (SCUC), whereas Security Constrained Economic Dispatch (SCED) utilized in RTEM. Theoretically, LMP is an integrated dispatch/spot market process that uses voluntary bids to simultaneously determine the security constrained economic dispatch and the price for energy (P_A) at each grid node A [70-71]. Practically, LMP is the marginal price of the cost to serve the next MW of load at a specific location using the lowest production cost of all available generation and observing all transmission limits. Therefore, the proposed NCM with two settlement structures, LMP term can be previewed as equation (5.5)

$$LMP_i = LMP^{ref} + LMP_i^{loss} + LMP_i^{cong} \quad (5.5)$$

Where, LMP^{ref} = Incremental fuel cost at the Reference bus.

LMP_i^{loss} = Incremental fuel cost at bus "i" associated with losses

LMP_i^{cong} = Incremental fuel cost at bus "i" associated with congestion

In addition to LMP, Financial Transmission Right (FTR) should also be included into the new paradigm. FTR is a financial risk-hedge instrument against congestion. FTR entitles the holders to be charged or receive compensation, depending on whether the FTR is an option or obligation, for congestion costs that arise when transmission grid is congested.

Once NCM is implemented in Thailand, then ISO will need to achieve congestion management through the centralized control of generation resources. In the other word, single control area will be implemented instead of several CMZs in ZCM. In this manner, ISO should deploy the computer program to minimize the cost of dispatching generation patterns subject to transmission constraints. Therefore, this dissertation will calculate the generation production cost of NCM base on a single control area for the entire country. Similar to the procedure of ZCM, DCOPF subject to transmission constraints will be a main tool for this generation cost calculation.

5.7 Generation cost comparison and discussion on different generation dispatching patterns

Data of peak demand forecast from EPPO 2004 and power development plan (PDP04) from EGAT, are two main sources for a long term steady state power flow study for Thailand power system. In this study, year 2004 is selected to be the base case with peak demand of 19326 MW. Steady state power flow study for year 2006, 2008, and 2010 are performed respectively. The results were previously shown in Table 4.8 and 4.9

As states in section 5.2, to guarantee a converged power flow solution case that fast enough for RT market clearing process DCPF is applied for all cases of traditional dispatching patterns. While, handling the total generation cost with different dispatching patterns under deregulated environment (both NCM and ZCM), OPF base DCPF is deployed.

Table 5.11 shows the generation cost comparison for 1) EGAT stays with traditional operation mode, 2) EGAT moves to deregulated environment with NCM, and 3) EGAT utilizes ZCM for congestion management. The difference between Table 5.11 and 5.12 is the number of congestion management zones (CMZs) which obtained from different clustering methods. In table 5.11, result of two CMZs acquired from the geographical clustering while result of three CMZs in table 5.12 achieved from the similar processes of ERCOT congestion management zones determination discussed in section 5.5.2.

Table 5.11 Generation Cost Comparison for 2 CMZs (Geographical Clustering)

Year	Demand Forecast (MW)	Generation Production Cost at Different Generation Patterns ($/hour)						
		Traditional		Nodal		Zonal (2 Zones)		Reference
		ACPF	DCPF	DCOPF	DCOPF w/o line limit*	DCOPF	DCOPF w/o line limit*	ACOPF
2004	19326	213763	210380	197153	192775	200959	195189	202209
2006	22738	238114	234252	222335	214122	222754	214911	230185
2008	26048	270916	262921	258043	236455	258499	232767	269814
2010	29808	-	284751	286108	253288	286248	254918	-

Table 5.12 Generation Cost Comparison for 3 CMZs (CSCs Clustering)

Year	Demand Forecast (MW)	Generation Production Cost at Different Generation Patterns ($/hour)						
		Traditional		Nodal		Zonal (3 CMZs)		Reference
		ACPF	DCPF	DCOPF	DCOPF w/o line limit*	DCOPF	DCOPF w/o line limit*	ACOPF
2004	19326	213763	210380	197153	192775	202316	196477	202209
2006	22738	238114	234252	222335	214122	223106	215662	230185
2008	26048	270916	262921	258043	236455	258204	234482	269814
2010	29808	-	284751	286108	253288	285810	256652	-

Results from table 5.11 and 5.12 reveal several key points that can be discussed below:

a) To create a reference case for this study, ACOPF is a tool used for calculating the optimal dispatching pattern solution for all online units in Thailand system. It can be seen from both tables that generation costs obtained from ACOPF will consistently less than generation costs from traditional dispatching patterns because OPF can help to create the minimum generation cost.

b) Comparing various generation cost patterns acquired from deregulated environment, NCM show consistently less cost than ZCM. Moreover, it can be seen that if transmission lines limit can be relief, total generation cost can be reduce up to 10% for both types of CM schemes.

c) The results in both Table 5.11 and 5.12 indicate that total generation cost under deregulated environment is consistently less than the traditional operation mode during year 2004 to 2008. In addition, lower generation cost is observed with smaller number of CMZs. However, the results in year 2010 show the opposite trend due to lack of generation and transmission facilities in the system. This is a good indicator for infrastructure improvement.

5.8 Chapter summary

This Chapter implements two TCM models for the electrical utility industry in Thailand during the transition period to the deregulated environment. Taking into account several social concerns and relevant limitations in the country. These concerns are addressing of an advance in an information technology, energy security, social equity, price volatility, and the need to subsidize poor consumers in the rural areas. The proposed model of ISO/RTO core functions is first introduced and discussed. Subsequently, proposed models of two market structures, DA and RT, are presented. Main idea and implementation procedures of ZCM are then proposed together with detail of basic assumptions, related equations, and studying results. Considering the above concerns, the 3 CMZs model is recommended for Thailand system during the transitioning stage to regulated environment. On the other hand, if NCM would be implemented in Thailand, two market settlement system to deal with the day-ahead and real time energy market is to be a recommended model. Finally in this Chapter, the generation cost comparison due to different dispatching patterns is compared. Result of less generation cost is consistently found under the deregulated environment both NCM and ZCM compare to the traditional operation model.

CHAPTER 6

THAILAND POWER SYSTEM STABILITY STUDY

6.1 Brief review of Power System Stability Study

The stability problem has been developed for a long time since the development of power industry. Traditionally, stability study focuses on the ability of synchronous generator to maintain synchronous operation during the first swing after severe disturbance. In modern power system, due to many fast response devices have been installed for a better control purpose. This focus has been shifted to deal with those situations that may create a low frequency oscillation due to insufficient damping torque as discussed in chapter 3. The evaluation of stability problems then requires the study of power system responds during the transient period right after fault, the post fault condition, and during the steady state operation condition. In addition to the information that is required for power flow study, information concerning the dynamic response of generators and their controller devices, including generator inertia, transient and sub-transient impedance, governor-control (GOV) characteristic, automatic voltage regulator (AVR) characteristics, and protective device response time, are necessary for stability analysis. It should be noted that the accuracy of the input parameters will affect the simulation results significantly.

Therefore, analyzing power system's dynamic stability is more complex than modeling steady-state performance because it requires a simulation tools that can handle large amount of algebra and differential equations.

6.2 Stability Study Process

The main objective of this chapter is to perform a full stability study for Thailand power system in various system conditions ranging from normal operation, and during and after fault conditions. While the power flow study result in chapter 4 examines the power system under steady-state conditions, dynamic study inspects for the system responds to various types of disturbance. These dynamic studies analyze system behavior over time intervals ranging from cycles to seconds.

The whole processes of stability studies proposed in this dissertation are presented in figure 6.1. Frequency domain analysis will be first executed. Typically, issues of identifying initial condition, formulating system state matrix *A* and calculating eigenvalues for a large scale system are three main challenges for engineers. Through this process, eigenvalues and the mode of oscillation for each scenario will be presented. In addition, system damping factor and oscillation modes for each scenario will be compared.

Result from frequency domain analysis will be verified by time domain analysis. Issues of initial condition, boundary condition, types and location of disturbances, and time consuming are basic problems causing a difficulty in generating the case. This dissertation will use the provided generation patterns of the 2004 summer peak as the base case. 2006 and 2008 summer peak power flow cases will then be created for further system analysis. Results of time domain analysis illustrate time-variance characteristics response of the generators when the system is under a severe disturbance. The impact of power flow patterns, due to system configuration change, to transient performances of each generator are to be compared for each transient studying scenario.

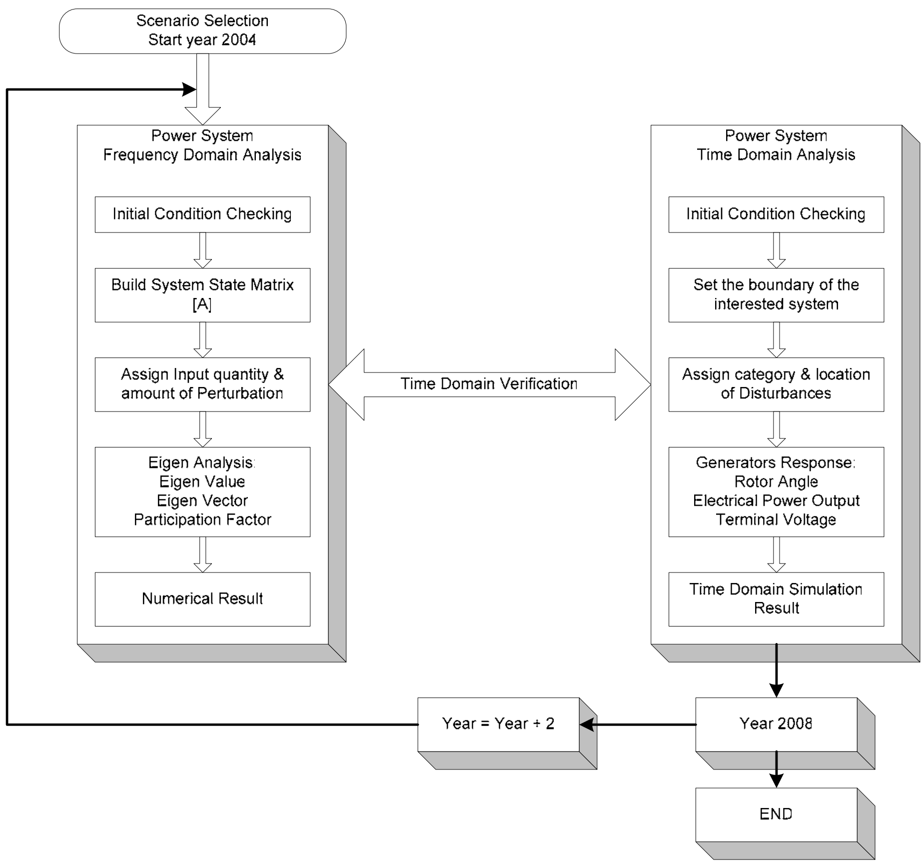

Figure 6.1 Processes of Stability Study

6.3 Frequency Domain Analysis

6.3.1 Objectives

Small signal stability analysis (SSSA) is usually obtained from frequency domain analysis, and it can be considered as one type of rotor angle stability as mentioned in chapter 3. The problem usually appears in the form of poorly damped or undamped oscillations in the system. Since disturbance is assumed to be sufficient small so that the system can be linearized. Therefore, modal analysis based on eigenvalues technique is the enabling tool. The main objective of this study is to examine the small signal stability behavior of the Thailand interconnected system.

6.3.2 Scenarios creation

Since this study examines the Thailand interconnected system from SSSA perspective, critical modes should be identified for various system loading conditions, configurations, and contingencies. In this dissertation, a scenario is defined as the combination of system re-configurations and/or contingencies that change system operating condition. Based on the available base case data of year 2004, 9 scenarios have been created to cover configurations change and N-1 contingencies.

In contingencies study, the unavailability of single facility is focused on the large generation facility near Bangkok area and those heavily loaded lines in the system. These two types of contingencies have a high potential to cause system instability. Following are the definition of factors affecting to each scenario.

a) Configuration changes scenario

Scenarios which include changes in loading conditions, generation patterns, and available transmission lines will refer to as “configuration change scenarios”.

b) Contingencies changes scenario

Scenarios which result from the change in generation patterns and available transmission lines due to contingencies will refer to as “contingency change scenarios”.

6.3.3 Define small perturbation for SSSA

The process of defining location and amount of small perturbation is important for creation of a system state matrix *A*. Since SSSA employs the linearized technique regarding to a small disturbance. This small disturbance can usually be treated as a small load change or generation level change to balance the load. For simulation purpose, a small variation of mechanical power input was applied to an online unit near Bangkok area to create a small perturbation to a system.

Since the main objective of this study is to examine the oscillation modes in Thailand power system, only complex conjugate eigenvalues will be focused. The criterions for oscillation modes justification used in this dissertation are as following:

a) Interarea or global mode oscillation

These phenomena involve a group of generators in one area swinging against another group of generators in another area. The typical oscillation frequency is approximately 0.1 – 0.4 Hz.

b) Intraarea or local mode oscillation

Generally, local mode oscillation is the behavior of one machine swinging against the rest of the system. The typical oscillation frequency for this type of oscillation is approximately 1.0 – 2.0 Hz.

6.3.4 Small signal stability result

6.3.4.1 Interarea or global mode

As mention in section 6.3.2, there are 9 scenarios to be included in this SSSA. Table 6.1 shows all scenarios and their descriptions.

Table 6.1 Scenarios for SSSA and interarea modes of oscillation

no.	Cases Description	Config. change	Contingencies		Interarea Oscillation		Stable	Location of Modes
			N-1 Gen.	N-1 Line	Freq. (Hz)	Damping (%)		
1	Y04 Base case	×	×	×	0.42	2.78	Yes	South1
2	Y04 N-1 Gen	×	√	×	0.43	2.52	Yes	South1
3	Y04 N-1 Line	×	×	√	0.41	3.68	Yes	South1
4	Y06 Normal	√	×	×	0.36	8.39	Yes	South2
5	Y06 N-1 Gen	√	√	×	0.42	3.10	Yes	South2
6	Y06 N-1 Line	√	×	√	0.4	4.73	Yes	South2
7	Y08 Normal	√	×	×	0.41	2.67	Yes	South2
8	Y08 N-1 Gen	√	√	×	0.44	0.23	Yes	South2
9	Y08 N-1 Line	√	×	√	0.4	4.3	Yes	South2

The 2004 summer peak power flow case is used as a base case. Various scenarios showing in table 6.1 are result from configurations changes and system contingencies. The scenario no. 2, Y04 N-1 Gen, referred to as the unavailability of the largest generation facility in system (in area 7), while scenario no. 3 represents the absence of the heaviest tie line (between area 6 and Bangkok) in the system. The creation of these scenarios was intended to investigate the impact of unavailability of a significant facility on the interarea oscillation mode. Base on the current available data, when compare result for year 2004, the oscillation frequency for the interarea mode is approximately 0.41 Hz, with less than 3 percent of system damping. The group of generator in the southern part is dominant in this mode. System damping for cases of year 2006 found to be improved when compare to year 2004. The possible reason is the installation of new units during year 2004 to 2006. However, the unavailability of largest generator in year 2008 results in the worst case situation with the system damping at only 0.23 percent. It can be seen for most of cases that major oscillation modes are located at the southern part of Thailand. In addition, the absence of generation facility deteriorates system damping factor worse than the line does. The main reason is because the selected base case is the summer peak load which means generator facilities become very important.

In summary, generators in the southern area have a significant effect on interarea oscillation modes in Thailand system. The observable oscillation is around 0.4 Hz with less than 4 percent damping factor. In other word, generation plants in the southern area should be a good location for install power system stabilizers (PSSs). Of course, further system analysis for PSS's parameter selection should be performed before real implementation.

6.3.4.2 Intraarea or local mode

Similar to scenarios in table 6.1, all cases description remain the same yet the result of table 6.2 focus on intraarea or local oscillation modes. It is found in year 2004 that generators in the central and east part of the country experience intraarea mode with 1.9 Hz of oscillation frequency at around 6.6 percent of damping factor. The same oscillation frequency was observed for year 2006, but generating units in the northern happen to encounter with this oscillation problem. It should be noted that, similar to the trend in interarea mode, the unavailability of any single generation have a tendency of giving a poor damping to a system when compare to the case of an absence of transmission lines.

Table 6.2 Scenarios for SSSA and intraarea modes of oscillation

no.	Cases Description	Config. Change	Contingencies		Interarea Oscillation Freq & Location (1)		Interarea Oscillation Freq & Location (2)	
			N-1 Gen.	N-1 Line	Freq. (Hz)	Damping (%)	Freq. (Hz)	Damping (%)
1	Y04 Base case	×	×	×	1.65 East	6.56	1.27 West	6.87
2	Y04 N-1 Gen	×	√	×	1.93 Central	6.24	1.92 East	6.60
3	Y04 N-1 Line	×	×	√	1.93 East	6.50	1.92 Central	6.70
4	Y06 Normal	√	×	×	1.96 North	6.47	1.94 North	6.74
5	Y06 N-1 Gen	√	√	×	1.95 North	6.19	1.94 North	6.85
6	Y06 N-1 Line	√	×	√	1.96 North	6.40	1.94 North	6.75
7	Y08 Normal	√	×	×	2.00 East	5.93	1.97 North	6.35
8	Y08 N-1 Gen	√	√	×	1.98 East	5.90	1.97 North	6.50
9	Y08 N-1 Line	√	×	√	2.00 East	8.25	1.97 North	9.26

6.3.4.3 Observation of worst case scenario

Figure 6.2 is the partial list of the eigenvalues while figure 6.3 shows the corresponding participation factor of the selected modes. According to result in table 6.1, scenario no. 8 can be considered as a worst case scenario because it has a worst damping factor of 0.23 percent. As presented in figure 6.2, mode no. 248 is corresponding to this damping factor. For a selected mode of interest, their top ten corresponding participation factors are presented in figure 6.3. It is found that the generator which has a significant effect on mode no. 248 is the generator at bus no. 3051 located in the southern part of the country.

a) Eigenvalues result (partial listed)

```
2008 SUMMER PEAK LOAD PEAK LOAD AT 26048 MW.
EIGENVALUES:

MODE    REAL          IMAG         DAMP          FREQ
  1  -2.7044        19.126       0.14000       3.0440
  2  -2.7044       -19.126       0.14000       3.0440

  3  -2.4607        18.456       0.13216       2.9373
  4  -2.4607       -18.456       0.13216       2.9373

  5  -1.6889        17.131       0.98115E-01   2.7264
  6  -1.6889       -17.131       0.98115E-01   2.7264

  7  -2.1624        13.369       0.15967       2.1277
  8  -2.1624       -13.369       0.15967       2.1277

  9 -0.98878        12.456       0.79132E-01   1.9824
 10 -0.98878       -12.456       0.79132E-01   1.9824

 11  -1.1242        12.399       0.90299E-01   1.9733
 12  -1.1242       -12.399       0.90299E-01   1.9733

 13  -1.1241        12.399       0.90297E-01   1.9733
 14  -1.1241       -12.399       0.90297E-01   1.9733

.........
.........

243 -0.33464        4.7672       0.70024E-01  0.75873
244 -0.33464       -4.7672       0.70024E-01  0.75873

245 -0.85413E-01   3.4013       0.25104E-01  0.54133
246 -0.85413E-01  -3.4013       0.25104E-01  0.54133

247 -0.62695E-02   2.7529       0.22774E-02  0.43814
248 -0.62695E-02  -2.7529       0.22774E-02  0.43814
```

Figure 6.2 Example of eigenvalues result (scenario no.8)

b) Modes of interest and top ten participation factor result (partial listed)

2008 SUMMER PEAK LOAD PEAK LOAD AT 26048 MW.

NORMALIZED PARTICIPATION FACTORS FOR MODE 248: -0.62695E-02 -2.7529

FACTOR	ROW	STATE	MODEL	BUS	X-- NAME --X		ID
1.00000	198	K+5	GENROU	3051	KA-T1	24.0	1
0.99881	197	K+4	GENROU	3051	KA-T1	24.0	1
0.97928	164	K+5	GENROU	3013	KN-C13	11.5	13
0.97925	152	K+5	GENROU	3011	KN-C11	11.5	11
0.97918	163	K+4	GENROU	3013	KN-C13	11.5	13
0.97918	158	K+5	GENROU	3012	KN-C12	11.5	12
0.97916	151	K+4	GENROU	3011	KN-C11	11.5	11
0.97909	157	K+4	GENROU	3012	KN-C12	11.5	12
0.67472	170	K+5	GENROU	3015	KN-C10	15.0	10
0.67402	169	K+4	GENROU	3015	KN-C10	15.0	10

NORMALIZED PARTICIPATION FACTORS FOR MODE 9: -0.98878 12.456

FACTOR	ROW	STATE	MODEL	BUS	X-- NAME --X		ID
1.00000	433	K+4	GENROU	6001	BPK-T1	22.0	1
0.99985	439	K+4	GENROU	6002	BPK-T2	22.0	2
0.99903	434	K+5	GENROU	6001	BPK-T1	22.0	1
0.99889	440	K+5	GENROU	6002	BPK-T2	22.0	2
0.05605	432	K+3	GENROU	6001	BPK-T1	22.0	1
0.05604	438	K+3	GENROU	6002	BPK-T2	22.0	2
0.03579	430	K+1	GENROU	6001	BPK-T1	22.0	1
0.03579	436	K+1	GENROU	6002	BPK-T2	22.0	2
0.03295	431	K+2	GENROU	6001	BPK-T1	22.0	1
0.03294	437	K+2	GENROU	6002	BPK-T2	22.0	2

NORMALIZED PARTICIPATION FACTORS FOR MODE 10: -0.98878 -12.456

FACTOR	ROW	STATE	MODEL	BUS	X-- NAME --X		ID
1.00000	433	K+4	GENROU	6001	BPK-T1	22.0	1
0.99985	439	K+4	GENROU	6002	BPK-T2	22.0	2
0.99903	434	K+5	GENROU	6001	BPK-T1	22.0	1
0.99889	440	K+5	GENROU	6002	BPK-T2	22.0	2
0.05605	432	K+3	GENROU	6001	BPK-T1	22.0	1
0.05604	438	K+3	GENROU	6002	BPK-T2	22.0	2
0.03579	430	K+1	GENROU	6001	BPK-T1	22.0	1
0.03579	436	K+1	GENROU	6002	BPK-T2	22.0	2
0.03295	431	K+2	GENROU	6001	BPK-T1	22.0	1
0.03294	437	K+2	GENROU	6002	BPK-T2	22.0	2

Figure 6.3 Participation Factor Result of interested modes

6.4 Time Domain Analysis

6.4.1 Objectives

Transient stability analysis was performed to determine the potential stability problems due to system configurations changed following severe disturbances. The transmission line base case model used in this study was the 2004 summer peak condition. Main objective of this transient stability study is to examine the system response, especially for important generation units, following a severe disturbance. This process is accomplished by time domain simulation technique.

6.4.2 Scenarios creation

Similar to processes in SSSA, this transient stability study shall be performed for various system loading conditions, configurations, and contingencies. A scenario is defined as a combination of configuration changes and/or contingencies that alter system operating condition. Based on the available base case data and the creation of two subsequent years, 18 scenarios were created and compared the result. Similar to the SSSA, same terms of factor affecting each scenario were adopted for this transient study.

a) Configuration changes scenario

Scenarios which include changes in loading condition, generation patterns, and available transmission lines will refer to as “configuration change scenarios”.

b) Contingencies changes scenario

Scenarios which result from the change in generation patterns and available transmission lines due to contingencies will refer to as “contingency change scenarios”.

6.4.3 Define severe disturbances for TSA

Various system configurations and faults were considered to determine the possible stability issues. In this dissertation, similar to typical standard simulation for a severe disturbance, a 5 cycle three-phase fault is deployed for the study cases. Followings are two main types of disturbances focused in this study.

a) The unavailability of single generation facility is focused on the outage of two main generation units. The first one is the unit in the load center (Bangkok) and another one is the largest generator in the system (in area 7). The disturbances were based on a 5-cycles three-phase fault on those two generators' buses followed by tripping the unit for the system protection.

b) Another contingency is concentrated on the outage of heaviest tie line following critical disturbances. The disturbance was also based on a 5-cycles three-phase fault on the line followed by removing the fault through tripping the line.

6.4.4 Transient stability result

6.4.4.1 Scenarios summary

As mention in section 6.4.2, there are 18 scenarios to be included in this TSA. Table 6.3 shows all cases study (scenarios) and their disturbances' description including summary of transient simulation result

Table 6.3 List of studied scenarios for TSA

no.	Cases Description	Configu-ration change	Types of Disturbances					System Stable?
			Gen1 Fault	Gen1 Fault & Trip	Gen2 Fault	Gen2 Fault & Trip	Tie line Fault & Trip	
1	Y04 Base case	×						Yes
2	Y04 Fault 1	×	√					Yes
3	Y04 Fault 2	×		√				Yes
4	Y04 Fault 3	×			√			Yes
5	Y04 Fault 4	×				√		Yes
6	Y04 Fault 5	×					√	Yes
7	Y06 Base case	√						Yes
8	Y06 Fault 1	√	√					Yes
9	Y06 Fault 2	√		√				Yes
10	Y06 Fault 3	√			√			Yes
11	Y06 Fault 4	√				√		Yes
12	Y06 Fault 5	√					√	Yes
13	Y08 Base case	√						Yes
14	Y08 Fault 1	√	√					Yes
15	Y08 Fault 2	√		√				Yes
16	Y08 Fault 3	√			√			Yes
17	Y08 Fault 4	√				√		Yes
18	Y08 Fault 5	√					√	Yes

Base on available data of the 2004 peak summer load and the result of different traditional dispatching patterns from chapter 5, the first stability case is “Y04 Base case”. The reason to generate scenario no.1 (table 6.3) is to assure the accuracy of initial condition of the system. For each studied case, to guarantee if there is enough time for system to achieve the new equilibrium after disturbance, the extended simulation time to 15 seconds was performed.

It is clear from table 6.3 that power system can regain to the new equilibrium point following disturbance in most of studied cases. The following sections show simulation results and detail discussions regarding to scenarios in table 6.3.

6.4.4.2 Time domain simulation result for year 2004

Showing in figure 6.4 to 6.9 are time domain simulation results for year 2004 scenarios. As a basic rule, initial condition checking is a pre-requisite. Showing in figure 6.4, power output of 6 generation units located in the metropolitan, eastern, western, northern, central, and southern areas are monitored. This dissertation will monitor these 6 units for all the transient stability study cases.

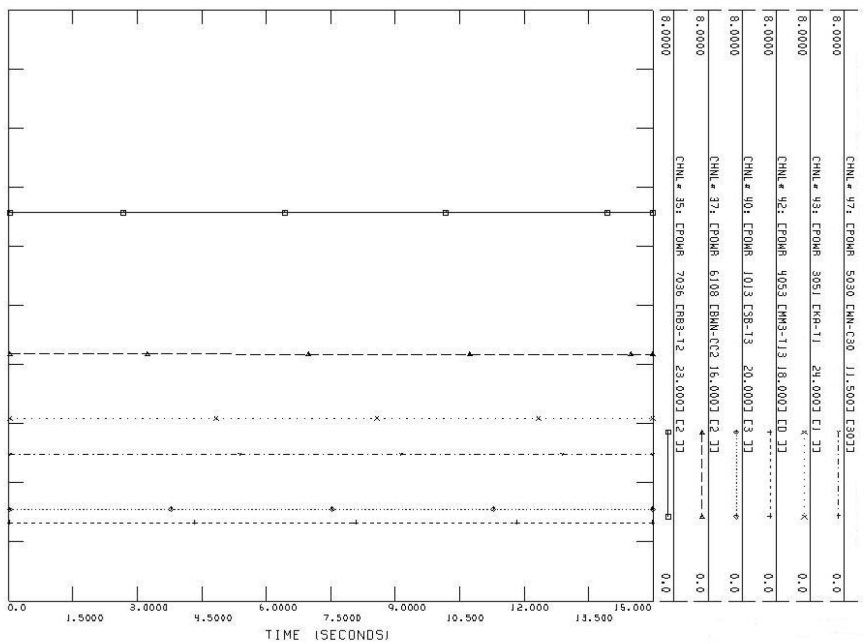

Figure 6.4 Initial condition checks for TSA (2004)

From figure 6.4, one can see that all generation units are in the equilibrium initial condition. It should be noted that the largest generation delivers 520 MW for the peak demand of year 2004.

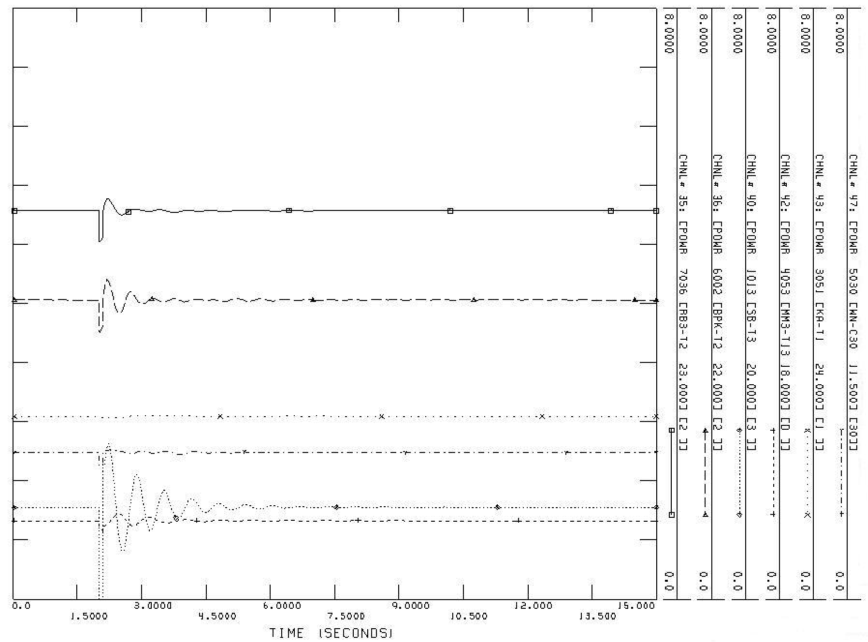

Figure 6.5 Momentary fault at a generator in load center area (2004)

Figure 6.5 is the response of the system due to a momentary fault at a generator bus near the load center. The power swings decay very quick which indicate a good system damping. The system can still regain to the new equilibrium point if this particular generator has experienced with a permanent fault and is taken out of service. However, as shown in figure 6.6, two units from the eastern and western area deliver more power to make up the generation deficiency due to the tripping of a generation unit at the load center.

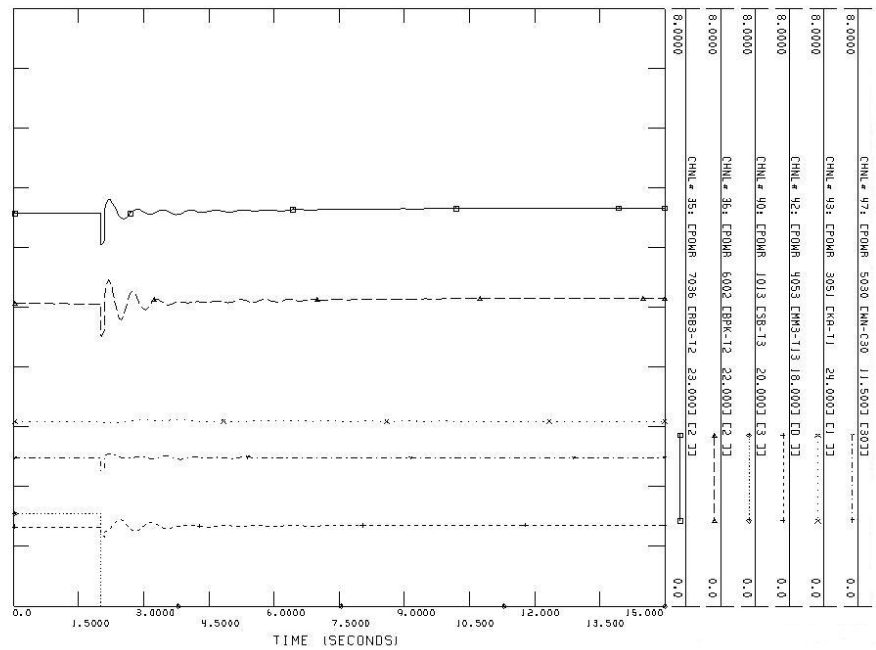

Figure 6.6 Fault at a generator in load center area followed by unit trip (2004)

In figure 6.7, a temporally fault at the largest generation unit gives a more severe oscillation of power output compare to the figure 6.5. This is because the largest generation can have a more contribution in fault current. In other word, it has a higher potential to create a more unbalance situation to the system. In figure 6.8, it can be seen that the similar trend of two units in eastern and western area deliver more power to make up the generation deficiency due to the tripping of a largest generation unit in area 7.

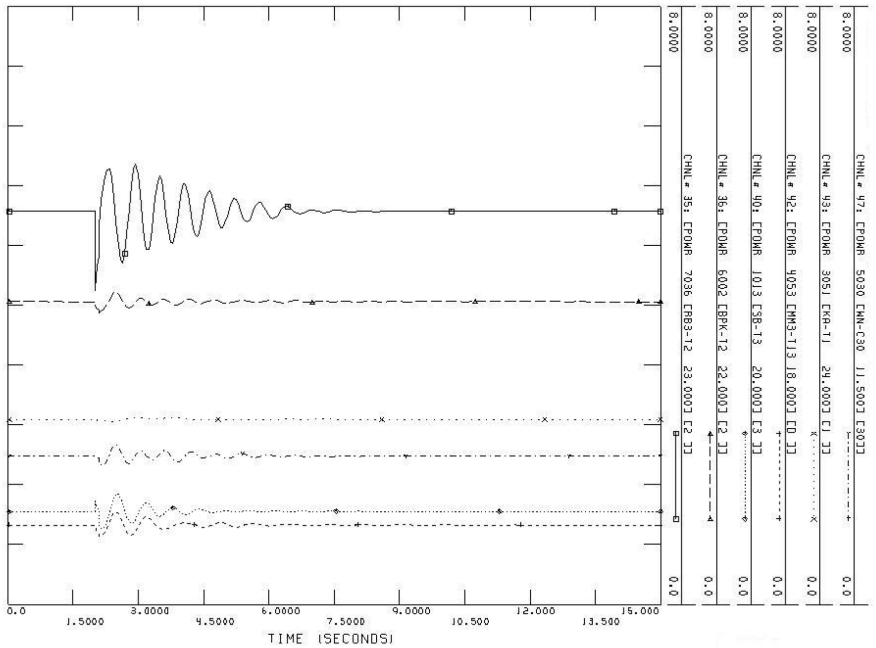

Figure 6.7 Momentary fault at a largest generator (2004)

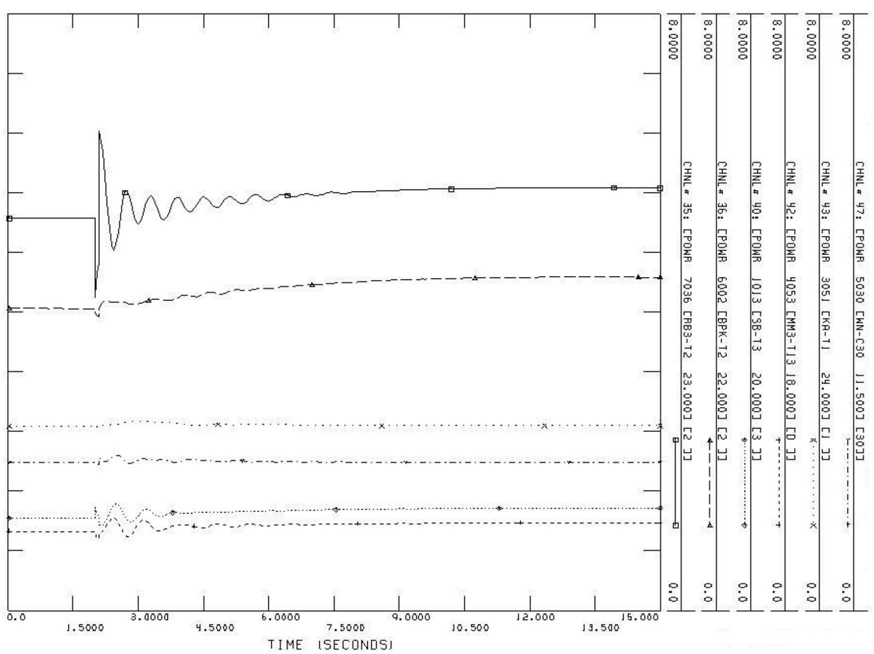

Figure 6.8 Fault at a largest generator followed by unit trip (2004)

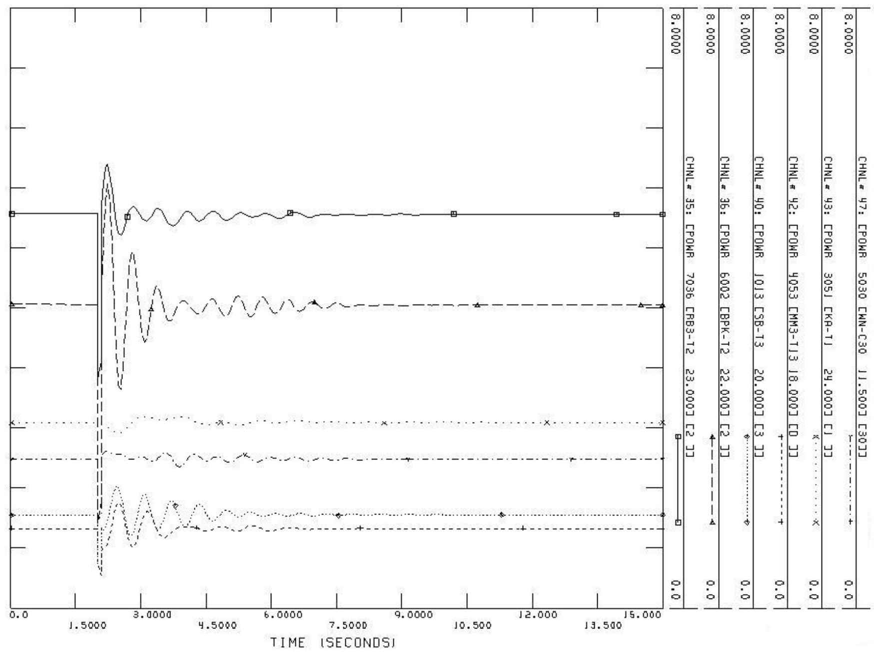

Figure 6.9 Fault at a heaviest loading tie line followed by line trip (2004)

The last case for transient stability case of year 2004 is the response of system when a severe disturbance happens at the heaviest tie line following trip the line to clear the fault. Showing in figure 6.9, it is found that this case create more oscillation to system when compare with previous cases. However, the system can still recover to the new stable point in approximately 12 seconds.

6.4.4.3 Time domain simulation result for year 2006 and 2008

The simulation result for the year 2006 and 2008 are basically the same trend as presented in year 2004. The observable difference is an output level of the units. At the normal operating condition, output power delivered from the largest unit of year 2004, 2006 and 2008 are at 520 MW, 560 MW, and 720 MW respectively. This situation causes the higher amplitude of oscillation for those cases in year 2008 compare to those cases in year 2004. Time domain simulation result for all cases in year 2008 can be found in figure 6.10 – 6.15.

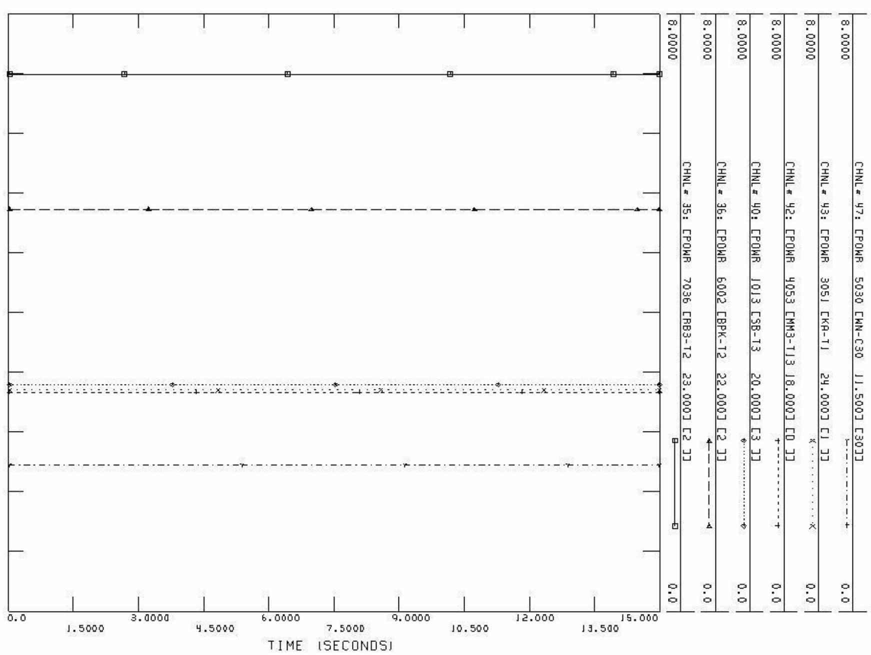

Figure 6.10 Initial condition checks for TSA (2008)

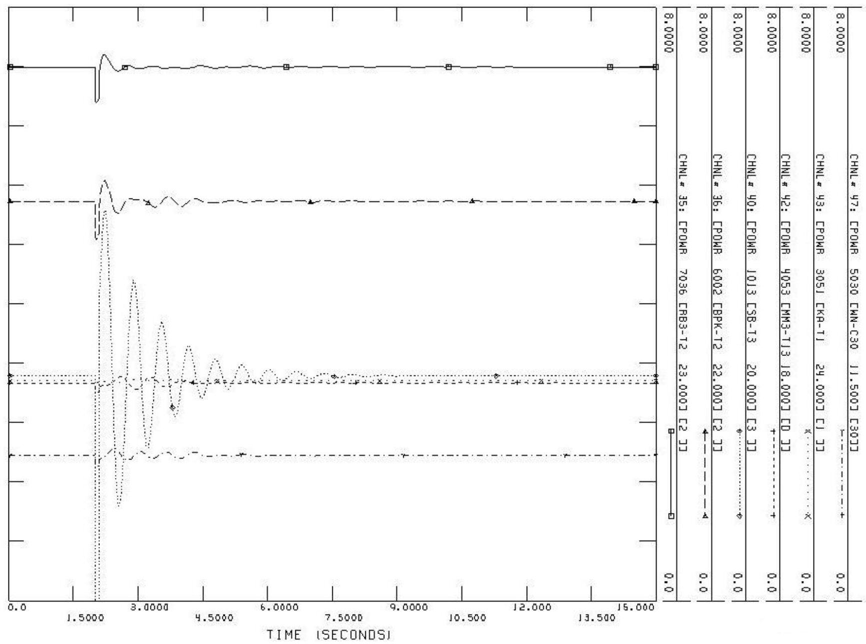

Figure 6.11 Momentary fault at a generator in load center area (2008)

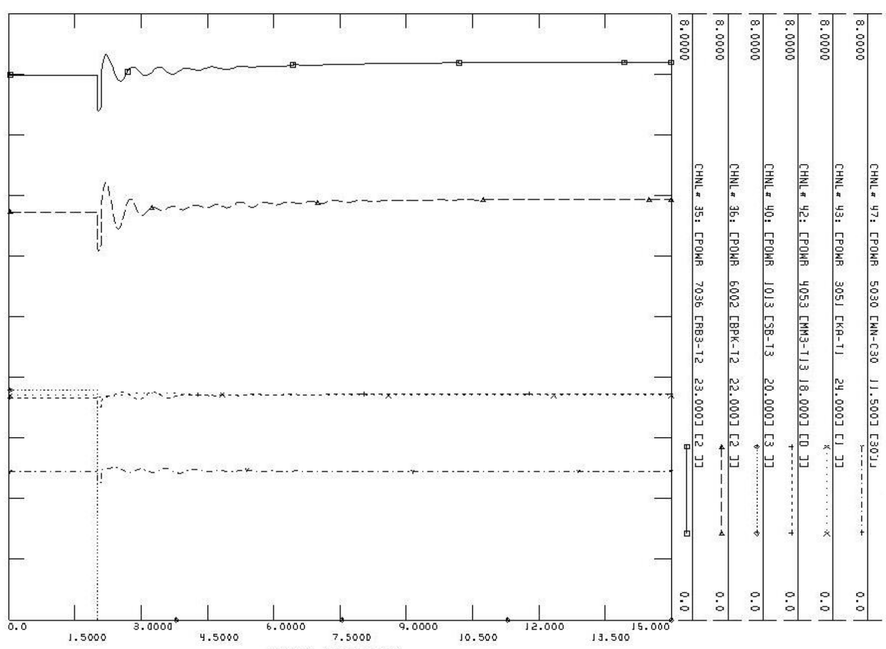

Figure 6.12 Fault at a generator in load center area followed by unit trip (2008)

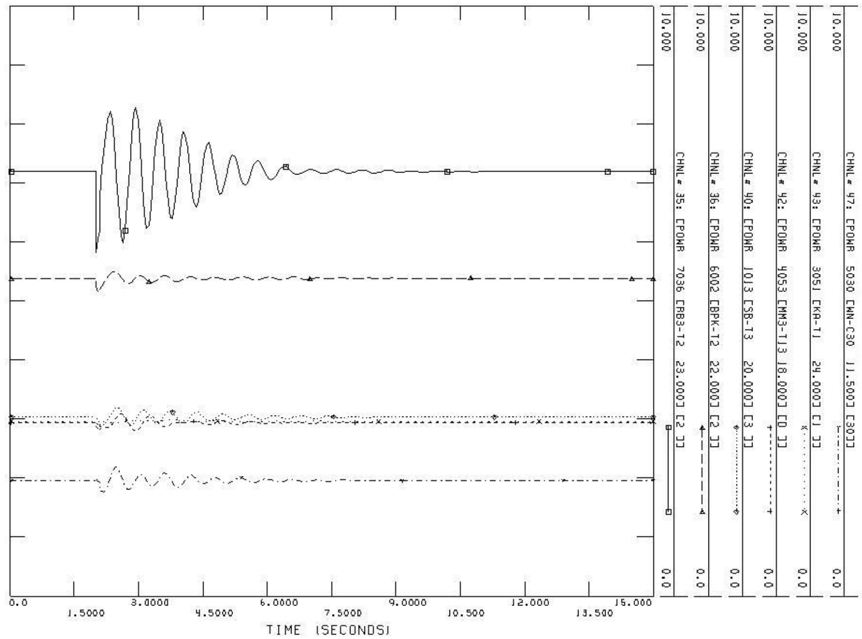

Figure 6.13 Momentary fault at a largest generator (2008)

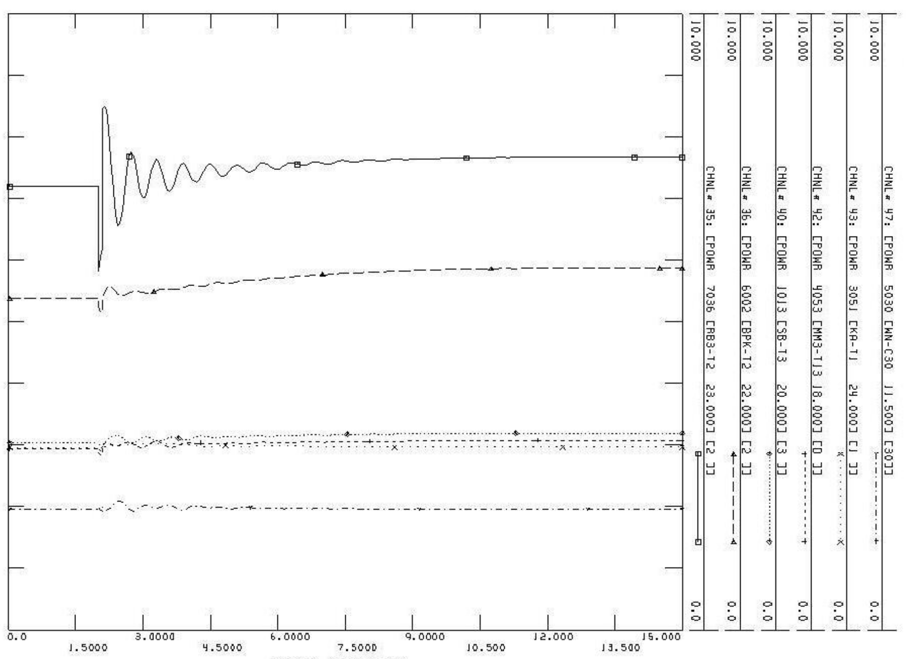

Figure 6.14 Fault at a largest generator followed by unit trip (2008)

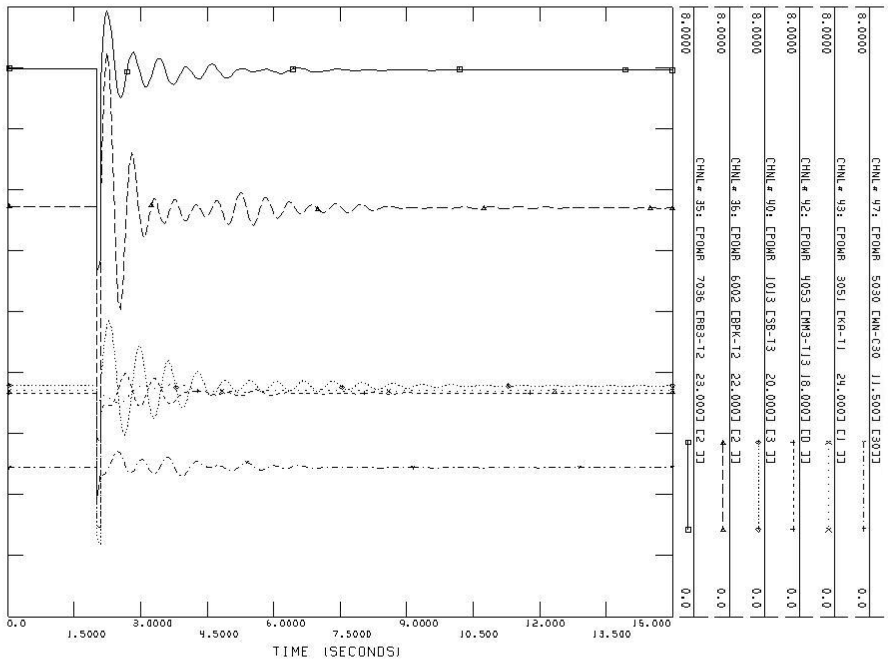

Figure 6.15 Fault at a heaviest tie line followed by line trip (2008)

6.5 Chapter summary

Frequency domain analysis or small signal analysis is first performed in this chapter. The main objective is to examine the possible low frequency oscillation mode in Thailand system. Throughout the whole study, there is no positive complex eigenvalue emerge on the right side of S-plan. However, there is potential interarea low frequency oscillation at 0.4 Hz with damping factor less than 4 percent. Most of the cases, generators in the southern area have more influence on interarea oscillation modes. The critical scenario is observed when the largest generation unit is tripped in year 2008. According to the simulation results, system will experience a relatively poor damping factor of 0.23 percent.

Time domain analysis was performed to determine the potential stability problems that can be originated by the system configurations changed following severe disturbances. There are five categories of disturbance of interest. Base on the available actual data of year 2004, and study result from chapter 5, it is found that system can regain to the new equilibrium condition following severe disturbances.

In conclusion, base on the available data of summer peak 2004 case, all stability study results in both frequency domain and time domain analysis for Thailand power system indicate that Thailand power system still has a stability safety margin until 2008. Simulation results reveal that the unavailability of generation facilities can cause more severe problem to system than transmission facility does.

CHAPTER 7

VISION FOR ELECTRICITY SUPPLY INDUSTRY OF THAILAND

7.1 Introduction

Since 1998, right after the economic crisis, the cabinet of Thailand approved a master plan for privatization of state enterprises in fours sectors including energy sector. Similar to any other businesses agency, the electricity supply industry in Thailand have to perform a comprehensive study not only a technical side but also a financial aspect to assure the minimum impact from this privatization and/or transformation planning. The concerns for demand side are more important for the government because the new operation structure may fail or may be difficult to implement without the acceptance from the customers in the country.

The main objective of this chapter is to propose a possible procedure as a decision tool to determine the proper timing for the new operating paradigm. The possible framework for ESI structure is also recommended. In this dissertation, two main justifications for the transformation are proposed. The first one is based on system security, and second one is economic and financial justification. As stated in chapter 3, security assessment is the pre-requisite before any paradigm change. Therefore, before any deregulation activities take action, system-wide operation conditions have to meet minimum security requirements as discussed in chapter 4 and 6. The economic and financial analysis is then become the second significant issue. Usually, the financial incentive is the most powerful tool for controlling all market participants (MPs). Any strong objection, or support for the new market structure will depend directly on the financial impact to MPs. It should be noted that the more acceptance from MPs, the better the possibility to success in the new operation paradigm.

To accomplish the objective function, this dissertation classifies two types of market participants (players) in Thailand power system for the purpose of the justification. It should be noted that this procedure is only to determine when to transform the system to the new environment. Later, different participants' rights and roles have to be re-defined by the regulatory before the new structure can be operated. In this manner, player 1 is the electricity supply side which refers to the Electricity Generating Authority of Thailand (EGAT). The second player is the demand side which refers to as the electricity consumers in the whole country.

This chapter deploys the economic concept to identify a proper transformation year to new market environment. It should be the year where the equilibrium between both players in the system is met. From the perspective of supply side, the concept of marginal analysis will be used as a decision-tool for answer this question. For demand side, result of generation dispatching costs from chapter 5 which directly reflect their electricity bill, will be used as an indicator to decide when to enter the new market operation. It needs to reach an optimization condition between these two parties because they hold the responsibilities for power system security operation and financial obligation for all MPs. Therefore, the game theory is utilized for creating the transformation matrix. This matrix reasonably determines the proper timing for a smooth transformation.

7.2 Marginal Analysis (An Economy Index for a supply side)

It is to be noted that this marginal analysis is based on financial aspect of the supply side only. The consideration of technical part is excluded. Historical data from EGAT annual reports [60], energy consumption forecasted data from EPPO including the trend of fuel cost for electricity generation are main sources of this analysis. Since the final ruling requires more extensive analysis, results from this study only provide a general recommendation procedure for the study.

7.2.1 Basic assumptions

Three main assumptions are required before accomplishing the study processes.

a) EGAT as a monopoly in ESI structure

In economic theory, there are usually four main types of market structure as shown in figure 7.1. They composed of monopoly, oligopoly, monopolistic competition, and perfect competition. The marginal analysis can be more successful when applying to the monopoly market structure rather than the others. Historical data from EGAT's annual reports show that EGAT has produced more than 60 percent of total energy consumption in the whole country at the present time. In addition, with the power purchase agreement (PPAs), EGAT has the right to buy produced-energy from other IPPs and SPPs and then resell them to other customers. In this respect, EGAT is the single buyer in the system. Therefore, this dissertation considers EGAT as a monopoly in the electricity supply industry in Thailand system.

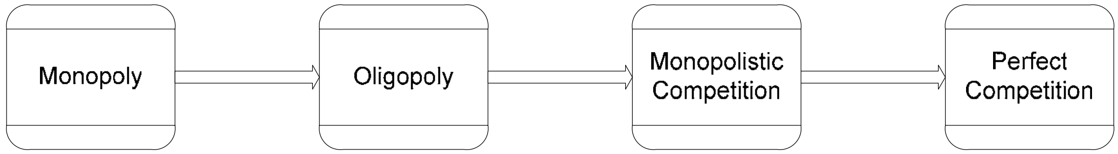

Figure 7.1 Four different types of market structure

b) Electricity generation department is dominance

Though there are many sub-organizations and departments inside EGAT, the electricity generation department is considered as the most significant division because more than 90 percent of EGAT total revenue is generated from this department. Therefore, this dissertation will treat this department as one independent business organization and its ultimate goal is profit maximization.

c) Other correlated considerations

Usually, there are many factors related to financial analysis for any business organization. This dissertation tries to simplify the calculation analysis yet still obtain the reasonable result. Therefore, other related assumptions were included prior to have a final result in table 7.1. The following are of those considerations.

c.1 Demand forecast is based on the 2004 EPPO load forecast subcommittee. The demand growth rate is approximately 7% per year according to MEG.

c.2 The calculation of total revenue (TR) is based on EGAT average selling price to customer, assuming that this selling price is 5% increasing each year.

c.3 Four types of fuel cost are used for estimating EGAT's total generation cost. They composed of natural gas (NG), fuel oil (FO), lignite (LN), and diesel oil (DO).

c.4 Considering total cost (TC) of electricity generation department, there are two main cost components i.e. electricity generation cost and administration cost.

Electricity generation cost composed of four cost components, which are purchase energy cost (55%), fuel cost (30%), generation cost (10%) and transmission cost (5%).

c.5 The cost of hydro units can be covered by the difference between revenue from selling power and expense from purchasing power from IPPs and SPPs.

c.6 According to ten years planning in PDP 03-04, starting at year 2003, EGAT plans to reduce the market share of its own generation from 50% down to 42% at the end of year 2011. This action implies 1% declining in generation capacity each year.

c.7 Though lignite provides the least expensive generation cost (0.75 – 1.0 cent/kWh), almost of new generation units will base on the natural gas (2.0 – 2.5 cents/kWh) due to the economic and environmental reasons (PDP 04).

Based on these assumptions, complete marginal analysis result both in numerical and graphic format are presented in the following sections.

7.2.2 Study results

Table 7.1 shows the financial result after performing marginal analysis. It can be observed that EGAT can maximize net profit when its marginal revenue is equal to its marginal cost. Theoretically (refer to chapter 3), the marginal revenue is defined as “the change in total revenue that are derived from undertaking some economic activity”, while marginal cost is defined as “the change in total cost that occurs from undertaking some economic activity”. Ideally, if marginal revenue still greater than marginal cost, this situation imply the expansion of an economic activity. On the other hand, when marginal revenue is less than marginal cost, the downsizing of economic activity should be applied. However, if they are equal, it reaches the stage of profit maximization. Therefore, the business organization should maintain their current economic status.

Table 7.1 Marginal analysis result (supply perspective)

Fiscal Year	Energy Demand Forecast (M kWh)	Estimated Total Revenue (M Baht)	Estimated Total Cost (M Baht)	Marginal Revenue (M Baht)	Marginal Cost (M Baht)
2000	98536	160240.49	111615.31	-	-
2001	103868	185509.49	131557.09	25269	19941
2002	111299	211335.87	154320.42	25826	22763
2003	118374	231445.23	180182.91	20109	25862
2004	126811	257477.05	203201.24	26031	23018
2005	136784	288012.39	232840.01	30535	29638
2006	147658	322012.56	266482.74	34000	33642
2007	158212	356926.30	302160.40	34913	35677
2008	169280	394625.50	341538.10	37699	39377
2009	180942	435418.80	385039.50	40793	43501
2010	193530	480264.00	433697.50	44845	48658

From the supply perspective, results from table 7.1 imply that EGAT should modify their operation strategy after year 2007 because its marginal revenue will fall below marginal cost. Figure 7.2 show the graphical result of estimated EGAT total revenue and total cost, while figure 7.3 presents the marginal analysis result.

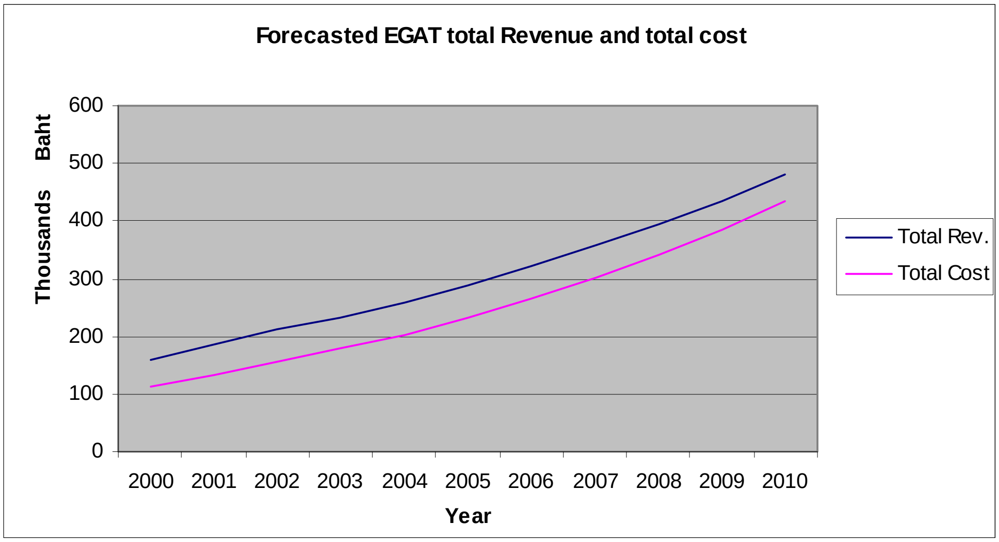

Figure 7.2 EGAT total revenue and total cost estimation

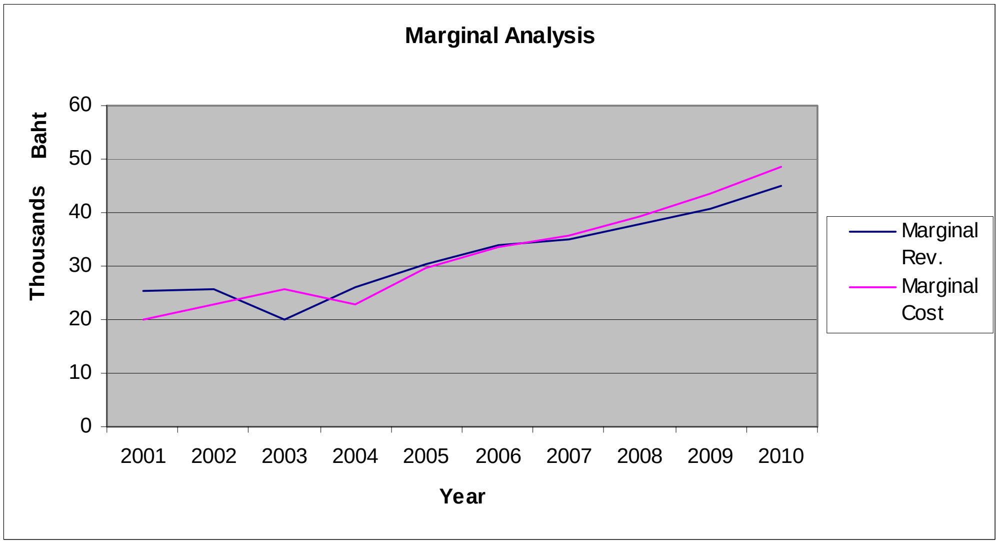

Figure 7.3 Marginal analysis graphical results

Additional discussions on the marginal analysis focus on factors that could have significant impact on the result. The analysis outcomes were presented in figure 7.4 and 7.5. In figure 7.4, if EGAT could have a re-engineering process within its organization, the administration cost and depreciation cost can be reduced. Thus, it is found from figure 7.4 that EGAT can delay process of transformation from year 2007 to year 2009.

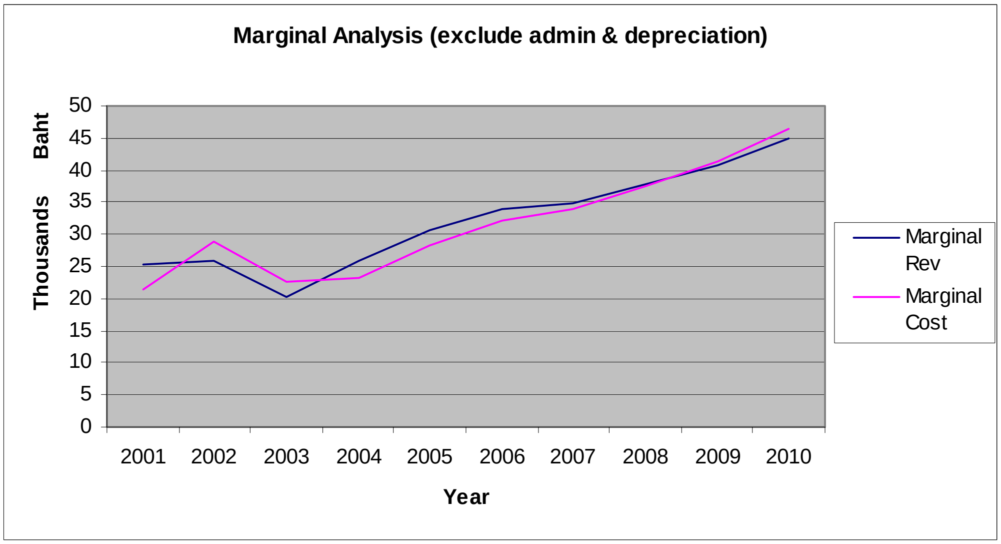

Figure 7.4 Marginal analysis graphical result (exclude administration cost)

However, due to majority of EGAT expense is come from the fuel cost, these fuels cost depend the foreign factors such as supply and demand, world economy situation etc. In other word, these factors are uncontrollable and they can be considered as uncertainty factors. Therefore, taking into account the uncertainty of fuel cost, result of marginal analysis can be obtained in a more conservative fashion. If the fuel cost is increasing 5% more than expected value, year 2008 is the optimal year for EGAT to modify their operation strategy to maintain the ultimate economic goal.

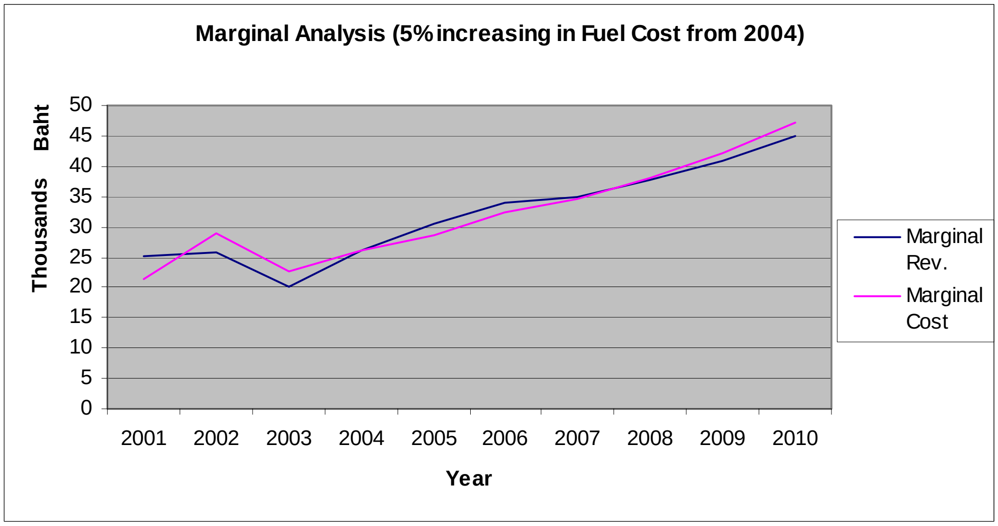

Figure 7.5 Marginal analysis graphical result (include effect of uncertainty in fuel cost)

7.3 Game theory (A transformation matrix)

One of the powerful tools in economic strategy is the game theory. The main idea is to identify the equilibrium situation or solution among several players in the game. As discuss in chapter 3, the arrow technique is utilized in this dissertation due to its simplicity yet powerful characteristic for determining optimal strategy. Usually, many situations can happen among players in the game. Dominant strategy seems to be the easiest way to identify the solution. On the other hand, if there is existing more than one dominant solution in some game, then the concept of Nash equilibrium can be used to handle this situation.

7.3.1 Basic assumptions

It is first assumed a two-player game during a decision stage to determine the timing to transform the ESI structure in Thailand. This dissertation applies the concept of payoff table in game theory to create the so called "transformation matrix". The purpose of such matrix is to identify the optimal year for both players in Thailand system for a smooth transition to the new environment. Final result of this problem can be found in table 7.2 to 7.4. Since the result of this game will create a direct impact to all MPs in Thailand, it is recommended that dominant strategy should be the best solution for this game.

7.3.2 Define payoff for each player

The most significant component in creating transformation (payoff) matrix is to find the payoff for each player. It is found that the common indicator which can represent payoff for both players is their satisfied level. In this dissertation, payoff for each player is defined as the level of satisfaction corresponding to their financial obligation. Following are considerations for assigning payoff to each player.

7.3.2.1 Payoff for the supply side

In this respect, the supply side is referred to as EGAT who is a single buyer in Thailand system. The marginal analysis result from section 7.1 concludes that EGAT should modify their operation strategy at year 2008. This situation implies that before year 2008, EGAT satisfies with their traditional operation due to their MR is greater than MC. Therefore, if EGAT keeps staying in the same course, thus their payoff is equal to 1 (satisfy). In other word, if EGAT has to move to the new operation strategy before year 2008, its payoff will be -1 (dissatisfy). However, after year 2008, the situation is reversed. EGAT will be satisfied under the deregulated environment because they can accomplish their profit maximization. Whereas, if EGAT stay in the traditional operation, they will generate less profit yield the dissatisfy situation.

7.3.2.2 Payoff for the demand side

This dissertation assumes that the financial obligation of electricity consumers depend on the total cost of electricity generation from EGAT. Therefore, the generation pattern that offer the least generation cost will provide the highest level of satisfaction for consumers. From the system-wide viewpoint, the least electricity generation cost yield the maximizing in social welfare. The generation cost resulted from different dispatching patterns in chapter 5 will be the significant indicator for the demand side to find their willingness time frame to accept the new operation paradigm. Result from table 5.11 and 5.12 reveal that under deregulated environment, ISO/SO utilizes optimal power flow (OPF) to find the optimal generation dispatching patterns. As a result, better instruction dispatching patterns (cheaper in generation cost) were accomplished. Therefore, for demand side, as soon as the time of implementing new environment, they should have more benefits when compare to the traditional operation. These benefits may include the lower in electricity price, more choices of electricity supplier, and better service quality. Thus, according to the result in chapter 5, year 2006 should be the first year for demand side to feel comfortable to accept the new operation environment. This situation means that the payoff for demand side should be 1 (satisfy) after year 2006 if the new operation strategy successfully implemented. On the other hand, -1 (dissatisfy) should be assigned in the payoff matrix for demand side if traditional operation still valid.

7.3.3 Study results

Based on all economic assumptions, technical considerations, and defined payoff values, these factors can be used to form the transformation matrix as shown in table 7.2 to table 7.4. Table 7.2 shows the transformation matrix of year 2004. It is clear that player 1 (supply) will choose traditional operation strategy because it gives a better payoff for them. Whereas, player 2 (demand) will prefer the deregulation environment due to the lower in electricity price. As a result, there is no equilibrium result between these two players.

Table 7.2 Transformation table (year 2004 payoff table)

Year 2004		Demand Player 2			
		Traditional		Deregulation	
Supply Player 1	Traditional	1	-1	1	1
	Deregulation	-1	-1	-1	1

Table 7.3 is transformation matrix for year 2006. It can be found that the same payoff for both players as in a year 2004. Therefore, there is also no dominant solution for this year either.

Table 7.3 Transformation table (year 2006 payoff table)

Year 2006		Demand Player 2			
		Traditional		Deregulation	
Supply Player 1	Traditional	1	-1	1	1
	Deregulation	-1	-1	-1	1

Unlike previous years result, payoff table for year 2008 reveals that supply side is willing to move to deregulated environment, while demand side also feels comfortable to accept the new deregulated market. Therefore, the dominant strategy was found. Applying arrow technique, it is clear that both players will get 1 (satisfy) for their payoff. This situation creates dominant strategy to be an optimal solution for Thailand system.

Table 7.4 Transformation table (year 2008 payoff table)

Year 2008		Demand Player 2			
		Traditional		Deregulation	
Supply Player 1	Traditional	-1	-1	-1	1
	Deregulation	1	-1	1	1

In conclusion, the equilibrium year for both players of this game should be in the year 2008 because both players accomplish their level of satisfaction. However, others concerns of secure operation considerations, operation frameworks, possible settlement processes should be addressed before the real implementation of the new system. The following section proposes and discusses the possible operation framework by taking into account all the relevant limitations including social concerns in Thailand system. Summarized table of the recommendation framework is presented in table 7.5

7.4 The operation framework recommendation for ESI restructuring in Thailand during the transition stage

Although transmission congestion management (TCM) issue has been widely debated for the decade, it is still an opened issue extensively discussed in the current competitive environment. For Thailand, the processes of restructuring of Electricity Supply Industry is still under the beginning phase, many concerns, such as advance in an information technology, energy security, social equity, price volatility, and the need to subsidize poor consumers, are necessary to be considered before the establishment of TCM and settlement processes.

Taking into account the gross income disparity among the population, social equity policy should and would be pursued by the government. In this respect, equitable access to electricity irrespective of geographical location is desirable and the need to subsidy for lower income groups should still be implemented. In addition, the current structure of OASIS, computer information technology including the high speed internet services is still under the developing stage. It may take a while for Thailand to fully upgrading the computer information technology especially the high speed internet to support the operation requirement (OASIS) under competitive environment.

Following section summarizes the proposed recommendation framework for the utility industry deregulation processes in Thailand. For simplicity, this summary will base upon FERC's standard market design (SMD), and market design of ERCOT.

Table 7.5 presents the proposed framework of ESI structure during the transition period in Thailand. The first recommended market element is about the requirement of balancing schedule. This element creates more confident in operation and control for

ISO/SO during the beginning stage. Another consideration is to strengthen the system security operation. If possible, the design for a new structure should minimize the complexity in operation. Therefore, it is not recommend for the virtual bids and virtual offers during the transition stage because they have a potential to create complexity and difficulty in power flow prediction.

Table 7.5 Recommendation framework for ESI transformation in Thailand in comparing to FERC's SMD and ERCOT market

Market structures			
Market design element	FERC's SMD (2005)	ERCOT (2005)	Thailand (Transition period)
Balance schedule	Not require	Required	Required
Day ahead schedule	Financial binding	Not financial binding	Not financial binding
Settlement	Two	One	One
Congestion management	Nodal	Zonal	Zonal
Spot energy market	Yes	No	No
Virtual bids/offers	Yes	No	No

Though PJM model gains lots of ground in the deregulated market, this dissertation suggests that zonal congestion management (ZCM) should be implemented to Thailand system during the transition period to the deregulated market because MPs can have more flexibility and easier to hedge against the risk from price volatility under the ZCM model. According to the analysis result, year 2008 should be the optimal time for Thailand system to move to the new environment. After experiencing the semi-competitive market under ZCM for a while, MPs should be ready to get into the fully competitive environment in which Nodal congestion management (NCM) would be employed in the TCM process due to a superior in accurate indicating for future system expansion and planning.

CHAPTER 8

CONCLUSION

Transmission congestion management (TCM) issue has been widely debated during the past decade. It is still an opened issue extensively discussed in the current competitive environment. In the United State, PJM with nodal congestion management (NCM) base on renowned location marginal price (LMP) and the Electric Reliability Council of Texas (ERCOT) with zonal congestion management (ZCM) are two successful stories of TCM under different operation schemes. Though PJM model is adopted in some developing countries where the processes of restructuring of Electricity Supply Industry (ESI) is still under the beginning phase, many concerns, such as advance in an information technology, energy security, social equity, price volatility, and the need to subsidize poor consumers, are necessary to be considered before the establishment of TCM and settlement processes.

For Thailand, as a developing country with the gross income disparity among the population, social equity policy should and would be pursued by the government. In this respect, equitable access to electricity irrespective of geographical location is desirable and some form of subsidy for lower income groups should still be implemented. In addition, the current structure of OASIS, computer information technology including the high speed internet services is still under the developing stage.

Taking into account the above concerns, this dissertation proposes the recommendation framework for transmission congestion management scheme that would be possible to implement in Thailand during its transformation to deregulated environment. Although NCM model gains lots of ground in the deregulated market better than ZCM model, price uncertainties at different locations can complicate the situations. From the conservative viewpoint, ZCM would be a better starting tool for managing congestion in Thailand system. Adopting the concept from ERCOT, this dissertation proposes four sequential steps to define the congestion zones for the entire system. After the transition period, NCM should be utilized for the fully competitive environment due to its theoretically sound and ability to accurately reflect the operation conditions of the system.

8.1 Contributions

It is believed that this dissertation will be the first comprehensive study addressing to Electricity Supply Industry (ESI) deregulation in Thailand. Though some of proposed concepts and pre-assumptions might not be complete due to realities situations require more update and more precisely data. In addition, operation rules and operation situations may be different from reported in this dissertation. Therefore overall detail process may need to carry out by committee which can be composed of the Government, EPPO, EGAT, stakeholders, and academia. Since the main objective of this dissertation is to help the transition from current traditional operation to the new deregulated environment go smoothly in Thailand, therefore all the frameworks, system security study result, and economic and financial study result reported in this dissertation make the following contributions to ESI deregulation in Thailand system.

a) Main contribution is the proposed framework study for ESI deregulation in Thailand system which integrating both security and economy concerns into proposed framework. This study framework can be applied to other systems which trying to move to the new deregulated environment.

b) The defined and proposed ISO/RTO's role, responsibilities, and operation function in the new deregulated environment. This is including the proposed idea of two market settlement for the transition stage in Thailand.

c) Security study for a long term planning in Thailand system has been implemented in both time domain and frequency domain analysis. The detail analysis of system stability both from a severe disturbance and small signal disturbance can help SOs to understand and beware the system weak point. This study result also gives the idea to SOs for a location to install PSS devices or others system protection devices.

8.2 Possible Future Researches

Since this dissertation provide the recommendation guideline and framework in the deregulated issue in Thailand. There still have a plenty room of research related area for other scholars which can be partial listed as followed:

a) The detail development of TCM scheme and the settlement processes.

b) Development of SCUC and SCED process to optimize system cost

c) The technique to calculate LMPs including the effect of system losses

d) The optimization of DA energy market together with an ancillary service market.

e) System state estimation for determine real time Available Transfer Capability (ATC).

f) Reactive power dispatching and control under the deregulated environment.

g) The study of interconnection of new generation facility to improve a reliability of the system.

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BIOGRAPHICAL INFORMATION

Chai Chompoo-inwai received the Bachelor and Master degrees in Electrical Engineering from Department of Electrical Engineering, Faculty of Engineering, King Mongkut's Institute Technology of Ladkrabang (KMITL) Bangkok, Thailand in 1995 and 1997 respectively. He has joined KMITL as a faculty in Electrical Engineering Department since 1995. He has been involved in distributed system, particular in Illumination engineering.

He pursued his Ph.D. program at the Energy Systems Research Center (ESRC), The University of Texas at Arlington since 2001. His major interests include electric power system analysis, deregulated power system, power system transient and dynamic stability, and Congestion Management Schemes in power system.