THESIS APPROVAL

GRADUATE SCHOOL, KASETSART UNIVERSITY

Doctor of Engineering (Electrical Engineering)

DEGREE

Electrical Engineering

FIELD

Electrical Engineering

DEPARTMENT

TITLE: Optimal Operations in Mixed Pool-Bilateral Electricity Markets with Step Bidding Cost Function by Hybrid Computational Method

NAME: Mr. Pornthep Panyakaew

THIS THESIS HAS BEEN ACCEPTED BY

______________________________ **THESIS ADVISOR**

(Assistant Professor Parnjit Damrongkulkamjorn, Ph.D.)

______________________________ **DEPARTMENT HEAD**

(Associate Professor Vichai Surapatana, M.Eng.)

APPROVED BY THE GRADUATE SCHOOL ON ______________________________

______________________________ **DEAN**

(Associate Professor Gunjana Theeragool, D.Agr.)

THESIS

OPTIMAL OPERATIONS IN MIXED POOL-BILATERAL ELECTRICITY MARKETS WITH STEP BIDDING COST FUNCTION BY HYBRID COMPUTATIONAL METHOD

PORNTHEP PANYAKAEW

A Thesis Submitted in Partial Fulfillment of
the Requirements for the Degree of
Doctor of Engineering (Electrical Engineering)
Graduate School, Kasetsart University
2013

Pornthep Panyakaew 2013: Optimal Operations in Mixed Pool-Bilateral Electricity Markets with Step Bidding Cost Function by Hybrid Computational Method. Doctor of Engineering (Electrical Engineering), Major Field: Electrical Engineering, Department of Electrical Engineering. Thesis Advisor: Assistant Professor Parnjit Damrongkulkamjorn, Ph.D. 112 pages.

This thesis presents the hybrid computational method (HCM) to solve step bidding price optimal power flow (SPOPF) in pool, mixed pool-bilateral electricity markets and SPOPF with transmission congestion management (SPOPF-TCM) in mixed pool-bilateral electricity markets; and HCM for step bidding price security-constrained unit commitment (SP-SCUC) in pool electricity markets. The general set of problem formulation is created based on HCM for SPOPF-TCM in mixed pool-bilateral electricity markets, which is the most complicated formulation, where as it can be simply modified to solve SPOPF in other market models as well. The objective of SPOPF-TCM is to minimize the total generation cost consisting of several step bidding prices from participated generators and the total willingness to pay functions from participated loads in pool, bilateral and multilateral contracts. The objective of HCM for SP-SCUC within 24 hours in pool electricity markets is to minimize the total generation cost within 24 hours consisting of several step bidding prices, startup costs and minimum load costs in each hour from participated generators. The proposed method is tested on the modified IEEE 30 bus system with four different cases of transmission line limits for SPOPF in pool, with two different cases of real power load assigned to pool, bilateral and multilateral transactions for SPOPF in mixed pool-bilateral and SPOPF-TCM in mixed pool-bilateral electricity markets and with four different cases of transmission line limits in some hours for SP-SCUC in pool electricity markets. The studies showed that the proposed method gave the optimal results for every case.

____________________ ________________________________ ____ / ____ / ____

Student’s signature Thesis Advisor’s signature

ACKNOWLEDGEMENTS

I would like to grateful thank and deeply indebted to Asst. Prof. Dr. Parnjit Damrongkulkamjorn my thesis advisor for advice, encouragement and valuable suggestion for completely writing of thesis.

I would like to thank the Office of the Higher Education Commission, Thailand for supporting by grant fund under the program Strategic Scholarships for Frontier Research Network for the Join Ph.D. Program Thai Doctoral degree for this research.

I am especially appreciated my parents for their continuing encouragements. Finally, I am deeply appreciated to Mrs. Paiwan Panyakaew who always devotes time and support during my graduate study.

Pornthep Panyakaew

April 2013

TABLE OF CONTENTS

LIST OF TABLES

LIST OF TABLES (Continued)

LIST OF FIGURES

LIST OF FIGURES (Continued)

Figure **Page**

LIST OF ABBREVIATIONS

α_{imh} = transmission line operation factor of transmission line connecting between buses *i* and *m* in hour *h*

$\delta_{i,h}$ = voltage angle at bus *i* in hour *h*

$\delta_{m,h}$ = voltage angle at bus *m* in hour *h*

ρ_{Limh} = real power loss factor of transmission line connecting between buses *i* and *m* in hour *h*

$\mu^{M}_{Dk,j}$ = load curtailment weight of the k^{th} multilateral contract at bus *j* which the summation of all load in transaction k equals 1

μ^{M}_{Dkjh} = load curtailment weight of the k^{th} multilateral contract at bus *j* in hour *h* which the summation of all load in transaction k equals 1

b = bidding block index

$\hat{c}_i$ = pseudo high cost at bus *i*

c_i^{+} = selected bidding price for under-dispatched real power generation of generator at bus *i*

c_i^{-} = inverse of selected bidding price for over-dispatched real power generation of generator at bus *i*

$c_{i,b}$ = bidding price at block *b* of generator at bus *i*

c_{ibh} = bidding price at block *b* of generator at bus *i* in hour *h*

h = hour index

i = bus index

IF_i = number of periods generator at bus *i* must be initially offline due to its minimum down time constraint

j = load bus index

k = transaction index in multilateral contract

m = bus index

$MLC_{i,h}$ = minimum load cost of generator at bus *i* in hour *h*

LIST OF ABBREVIATIONS (Continued)

N = set of buses

NB_i = set of bidding blocks of generator at bus i

ND = set of load buses

NG = set of generator buses

N_G^B = set of generator buses for bilateral contracts

N_{Gh}^B = set of generator buses for bilateral contracts in hour h

$N_{i,D}^B$ = set of load buses for bilateral contracts at bus i

$N_{ih,D}^B$ = set of load buses for bilateral contracts at bus i in hour h

N^M = set of transactions in multilateral contracts

N_h^M = set of transactions in multilateral contracts in hour h

$N_{k,D}^M$ = set of load buses for the k^{th} multilateral contract

$N_{kh,D}^M$ = set of load buses for the k^{th} multilateral contract in hour h

$N_{k,G}^M$ = set of generator buses for the k^{th} multilateral contract

$N_{kh,G}^M$ = set of generator buses for the k^{th} multilateral contract in hour h

Nl = set of transmission lines connecting between buses i and m

Pc_{imh} = slack variable of P_{imh} to correct real power flowing in the transmission

Pc_{mih} = slack variable of P_{mih} to correct real power flowing in the transmission

P_{Di} = real power load at bus i

$P_{Di,h}$ = real power load at bus i in hour h

$P_{Di,j}^B$ = bilateral contract between generator at bus i and real power load at bus j

P_{Dijh}^B = bilateral contract between generator at bus i and real power load at bus j in hour h

$P_{Di,j}^{B,sch}$ = bilateral contract schedule between generator at bus i and real power load at bus j

LIST OF ABBREVIATIONS (Continued)

$P_{Dijh}^{B,sch}$ = bilateral contract schedule between generator at bus *i* and real power load at bus *j* in hour *h*

P_{Dj} = real power load at bus *j*

$P_{Dj,h}$ = real power load at bus *j* in hour *h*

P_{Dj}^{P} = real power load at bus *j* for pool includes real power load at bus *j* for bilateral and/or multilateral contract to buy real power from pool due to transmission lines congested

$P_{Dj,h}^{P}$ = real power load at bus *j* for pool in hour *h* includes real power load at bus *j* for bilateral and/or multilateral contract to buy real power from pool due to transmission lines congested in hour *h*

$P_{Dk,j}^{M}$ = real power load at bus *j* for the k^{th} multilateral contract

P_{Dkjh}^{M} = real power load at bus *j* for the k^{th} multilateral contract in hour *h*

$P_{Dk,j}^{M,sch}$ = real power load schedule at bus *j* for the k^{th} multilateral contract

$P_{Dkjh}^{M,sch}$ = real power load schedule at bus *j* for the k^{th} multilateral contract in hour *h*

P_{DT} = total system real power load

P'_{Gi} = summation of chosen blocks of real power generation of generator at bus *i* resulting from market dispatch

$\overline{P}_{Gi}$ = real power generation of generator at bus *i* resulting from power flow dispatch

$\overline{P}_{Gi}^{B}$ = real power generation of the generator that trades in bilateral at bus *i* resulting from power flow dispatch

$\overline{P}_{Gi}^{M}$ = real power generation of the generator that trades in multilateral at bus *i* resulting from power flow dispatch

P_{Gi}^{+} = increased real power generation from P'_{Gi} of generator at bus *i*

P_{Gi}^{-} = decreased real power generation from P'_{Gi} of generator at bus *i*

LIST OF ABBREVIATIONS (Continued)

P_{Gi}^{B} = real power generation of the generator that trades in bilateral at bus i

$P_{Gi,h}^{B}$ = real power generation of the generator that trades in bilateral at bus i in hour h

$P_{Gi}^{B,sch}$ = real power generation schedule of the generator that trades in bilateral at bus i

$P_{Gi,h}^{B,sch}$ = real power generation schedule of the generator that trades in bilateral at bus i in hour h

$P_{Gk,i}^{M}$ = real power generation at bus i for the k^{th} multilateral contract

P_{Gkih}^{M} = real power generation at bus i for the k^{th} multilateral contract in hour h

$P_{Gk,i}^{M,sch}$ = real power generation schedule at bus i for the k^{th} multilateral contract

$P_{Gkih}^{M,sch}$ = real power generation schedule at bus i for the k^{th} multilateral contract in hour h

P_{Gi}^{S} = slack variable for real power generation at bus i

$P_{Gi,b}$ = real power generation at bidding block b of generator at bus i

P_{Gibh} = real power generation at bidding block b of generator at bus i in hour h

$P_{Gi,b\Delta}$ = size of real power generation at bidding block b of generator at bus i

$P_{Gibh,\Delta}$ = size of real power generation at bidding block b of generator at bus i in hour h

$P_{Gi,h}$ = real power generation of generator at bus i in hour h

$P_{Gi,\max}$ = maximum limit of real power generation at bus i

$P_{Gi,\max}^{+}$ = maximum limit of P_{Gi}^{+}

$P_{Gi,\max}^{-}$ = maximum limit of P_{Gi}^{-}

$P_{Gi,\min}$ = minimum limit of generator at bus i

P_{i} = injected real power at bus i

$P_{i,h}$ = injected real power at bus i in hour h

LIST OF ABBREVIATIONS (Continued)

P_{imh} = real power flowing in transmission line from bus i to bus m in hour h

$P_{imh,\max}$ = maximum limit of real power flowing in transmission line connecting between buses i and m in hour h

P_{mih} = real power flowing in transmission line from bus m to bus i in hour h

P_{Limh} = real power loss in transmission line connecting between buses i and m in hour h

P_{LT} = total system real power loss resulting from power flow dispatch

Ps_{imh} = slack variable of P_{imh} to correct real power flowing in the transmission

Ps_{mih} = slack variable of P_{mih} to correct real power flowing in the transmission

Q_{Di} = reactive power load at bus i

Q_{Gi} = reactive power generation at bus i

Q_i = injected reactive power at bus i

RF_i = number of periods generator at bus i has been offline prior to the first period of the time span

r_{im} = resistance of transmission line connecting between buses i and m

$S^{B}_{Gi,h}$ = status of the generator that trades in bilateral at bus i in hour h (the value equals to 1 means the generator having bilateral in hour h and the value equals to 0 otherwise)

$S^{BM}_{Gi,h}$ = status of the generator that trades in bilateral and/or multilateral at bus i in hour h (the value equals to 1 means the generator having bilateral and/or multilateral in hour h and the value equals to 0 otherwise)

$S^{M}_{Gi,h}$ = status of the generator that trades in multilateral at bus i in hour h (the value equals to 1 means the generator having bilateral in hour h and the value equals to 0 otherwise)

$Sc_{i,h}$ = startup cost of generator at bus i in hour h

SUC_i = cost of generator at bus i to startup

LIST OF ABBREVIATIONS (Continued)

T = set of hours in the time horizontal

T_{Di} = minimum down time of generator at bus i

T_{Ui} = minimum up time of generator at bus i

$U_{i,0}$ = initial binary variable for today that is equal to $U_{i,T^{bf}}$

$U_{i,h}$ = binary variable that is equal to 1 if generator at bus i is online in hour h and 0 other wise

$U_{i,T^{bf}}$ = binary variable that is equal to 1 if generator at bus i is online at 24th hour yesterday and 0 other wise

$W_{i,j}^{B}$ = willingness to pay by bilateral contract between generator at bus i and load at bus j

W_{ijh}^{B} = willingness to pay by bilateral contract between generator at bus i and load at bus j in hour h

$W_{k,j}^{M}$ = willingness to pay by multilateral contract at bus j for the k^{th} transaction

W_{kjh}^{M} = willingness to pay by multilateral contract at bus j for the k^{th} transaction in hour h

x_{im} = reactance of transmission line connecting between buses i and m

¢ = vector of voltage angles in the system

$\mathbf{B}_S$ = secure operating limits such as voltage and line limits, reactive powers limits and tap changer settings

Q = vector of reactive power generations in the system

S = vector of power flow in transmission lines in the system

T = vector of transformer tap ratios in the system

V = vector of voltage magnitudes in the system

OPTIMAL OPERATIONS IN MIXED POOL-BILATERAL ELECTRICITY MARKETS WITH STEP BIDDING COST FUNCTION BY HYBRID COMPUTATIONAL METHOD

INTRODUCTION

It has been widely known that electric utilities all over the world have been under major changes of transforming from vertically integrated utilities to deregulated and competitive electricity markets (Loi Lei Lai, 2001; Shahidehpour *et al*., 2002), however, in different places. The changes to competitive electricity markets have been based on the ideas that generation and distribution companies could be operated under competitive environment along with new technologies in power generation and information technology to provide cost reduction in electricity, and the increase of fuel availability and stability (Loi Lei Lai, 2001).

The models in the electricity markets include the pool model, the bilateral contracts and the hybrid model where both are mixed. Although the pool is an unusual way to trade a commodity, it has been a foundation in the coordinative operation of monopoly utility companies with adjacent service territories (Kirschen and Strbac, 2004). The pool can be viewed as a centralized operation unit that clears the market for electric power producers and consumers (Shahidehpour *et al*., 2002). The trade of electrical energy including transmission and other ancillary services in the pool (Singh *et al*., 1998; Fang and David, 1999; Ma *et al*., 2002; Wang *et al*., 2002; Yamina and Shahidehpour, 2003, Kumar *et al*., 2004; Stamtsis and Erlich, 2004; Litvinov 2010; Ma and Sun, 1998; Cheung *et al*., 2000; Wen and David, 2002; Lin *et al*., 2003; Wu *et al*., 2004; Ugedo *et al*., 2006) is a central auction where power producers and consumers submit bids to the pool for the amounts of power that they are willing to trade.

An independent operational control of transmission grid in a restructured industry would facilitate a competitive market for power generation and direct retail access. However, the independent operation of the grid cannot be guaranteed without an independent entity such as the independent system operator (ISO).

The ISO is required to be independent of individual market participants, such as transmission owners, generators, distribution companies, and end-users. In order to operate the competitive market efficiently while ensuring the reliability of a power system, the ISO, as the market operator, must establish sound rules on energy and ancillary services markets, manage the transmission system in a fair and nondiscriminatory fashion, facilitate hedging tools against market risks, and monitor the market to ensure that it is free from market power. The ISO must be equipped with powerful computational tools, involving market monitoring, ancillary services auctions, and congestion management, for example, in order to fulfill its responsibility (Shahidehpour *et al*., 2002).

Unit commitment (UC) is the main function in power system operation and control due to electrical energy consumption in daily life has changed over the years. In order to “commit” or “turn it on” all generating units to meet total load of the system will result in the price of electricity is more expensive. Therefore, it must be allocated to startup and shutdown the generating units to meet total load of the system for the lowest price of electricity.

Unit commitment schedule is equal to total load of the system may result in incorrect, because it did not consider total loss of the system. The results mentioned above may not be sent through the power grid to the load due to the limits of the system such as bus voltage limits, transmission line limits and transformer tap setting limits etc. Therefore, to obtain the correct results and can transfer power to the load. Unit commitment problem must incorporate optimal power flow. The above problem is called Security-constrained unit commitment (SCUC).

Optimal power flow is implemented by ISO to assign the amount of dispatched power to participated generators in the market. The power producers who bid low prices will be dispatched to sell power to the grid, but not directly to the consumers. All the dispatched generators will be rewarded the same spot price which is the highest bidding price of the selected generators.

Transmission congestion management problem is the management of electric power transfer from generating units to loads in a power system with competitive electricity market operation when the transmission line system operates at maximum limits. The ISO must allocate electric power transfer in the system by decreased the desired power generation of some sellers and increased to the desired power generation of some sellers with fairly rules.

This thesis presents optimal operations in mixed pool-bilateral electricity markets with step bidding cost function by hybrid computational method to solve the complexity of security-constrained unit commitment problem and transmission congestion management problem, where the objective is to minimize the total generation cost consisting of several step bidding prices, startup cost, minimum load cost and the willingness to pay functions from participated generators within 24 hours.

OBJECTIVES

1. To find the step bidding price optimal power flow in pool electricity markets by hybrid computational method.

2. To find the step bidding price optimal power flow in mixed pool-bilateral electricity markets by hybrid computational method.

3. To find the step bidding price optimal power flow with transmission congestion management in mixed pool-bilateral electricity markets by hybrid computational method.

4. To find the daily security-constrained unit commitment in pool electricity markets by hybrid computational method.

LITERATURE REVIEW

1. The reason for the changes of electricity market

Many electricity markets around the world are currently in transition towards more electricity markets. The changes were initiated by (Loi Lei Lai, 2001):

1.1 A realization that generation and distribution functions need not be monopolies.

1.2 A feeling that public service obligations are no longer necessary.

1.3 The cost reduction potential of competition.

1.4 Increased fuel availability and fuel supply stability.

1.5 The development of new technologies in power generation and information technology.

2. Structure and operation of electricity market

Structure and operation of electricity market consists of six parts: objective of electricity market operation, electricity market models, kind of electricity market, category of electricity market, key electricity market entities and electricity market operations (Shahidehpour *et al*., 2002).

2.1 Objective of electricity market operation

There are two objectives for establishing an electricity market: ensuring a secure operation and facilitating an economical operation. Security is the most important aspect of the power system operation be it a regulated operation or a restructured power market. In a restructured environment, security could be facilitated by utilizing the diverse services available to the market. The economical operation of the electricity market would reduce the cost of electricity utilization. This is a primary motive for restructuring, and a way to enhance the security of a power system through its economics. To do this, proper strategies must be designed in the markets based on power system requirements. For example, financial instruments such as transmission congestion contracts (TCCs) and firm transmission rights (FTRs) could be considered in hedging volatility risks. Besides, monitoring tools are being devised in several markets to avoid a possible market power.

2.2 Electricity market models

In order to achieve electricity market goals, several models for the market structure have been considered. Three basic models are outlined as follows.

2.2.1 Pool model

A Pool is defined as a centralized marketplace that clears the market for buyers and sellers. Electric power sellers/buyers submit bids to the pool for the amounts of power that they are willing to trade in the market. Sellers in a power market would compete for the right to supply energy to the grid, and not for specific customers. If a market participant bids too high, it may not be able to sell. On the other hand, buyers compete for buying power, and if their bids are too low, they may not be able to purchase. In this market, low cost generators would essentially be rewarded. An ISO within a Pool would implement the economic dispatch and produce a single (spot) price for electricity, giving participants a clear signal for consumption and investment decisions. The market dynamics in the electricity market would drive the spot price to a competitive level that is equal to the marginal cost of most efficient bidders. In this market, winning bidders are paid the spot price that is equal to the highest bid of the winners.

2.2.2 Bilateral contracts model

Bilateral contracts are negotiable agreements on delivery and receipt of power between two traders. These contracts set the terms and conditions of agreements independent of the ISO. However, in this model the ISO would verify that a sufficient transmission capacity exists to complete the transactions and maintain the transmission security. The bilateral contract model is very flexible as trading parties specify their desired contract terms. However, its disadvantages stem from the high cost of negotiating and writing contracts, and the risk of the creditworthiness of counterparties.

2.2.3 Hybrid model

The hybrid model combines various features of the previous two models. In the hybrid model, the utilization of a Pool is not obligatory, and any customer would be allowed to negotiate a power supply agreement directly with suppliers or choose to accept power at the spot market price. In this model, Pool would serve all participants (buyers and sellers) who choose not to sign bilateral contracts. However, allowing customers to negotiate power purchase arrangements with suppliers would offer a true customer choice and an impetus for the creation of a wide variety of services and pricing options to best meet individual customer needs. In our discussion of market structure, we assume the use of a hybrid model.

2.3 Types of electricity market

Types of electricity market can be divided into three parts: energy market, ancillary services market and transmission market as follows.

2.3.1 Energy market

The energy market is where the competitive trading of electricity occurs. The energy market is a centralized mechanism that facilitates energy trading between buyers and sellers. The energy market's prices are reliable prices indicators, not only for market participants but for other financial markets and consumers of electricity as well. The energy market has a neutral and independent clearing and settlement function. The market participants must submit extensive information similar to that required by a regulated industry, such as energy offer, start-up cost, no-load cost, ramp rates, and minimum ON/OFF time. From these data, the ISO implements security-constrained unit commitments that maximize social welfare. The ISO will either set transmission congestion prices as dual variables corresponding to the transmission capacity constraints or obtain locational marginal prices (LMPs) as the dual variables corresponding to the load balance constraints as in the PJM market (PJM Independent system operator, 2012).

2.3.2 Ancillary services market

Ancillary services are needed for the power system to operate reliably. In the regulated industry, ancillary services are bundled with energy. In the restructured industry, ancillary services are mandated to be unbundled from energy.

Ancillary services are procured through the market competitively. In the United States, competitive ancillary services markets are operated in California, New York, and New England. In general, ancillary services bids submitted by market participants consist of two parts: a capacity bid and an energy bid. Usually, ancillary services bids are cleared in terms of capacity bids. The energy bid represents the participants' willingness to be paid if the energy is actually delivered.

2.3.3 Transmission market

In a restructured power system, the transmission network is where competition occurs among suppliers in meeting the demands of large users and distribution companies. The commodity traded in the transmission market is a transmission right. This may be the right to transfer power, the right to inject power into the network, or the right to extract power from the network. The holder of a transmission right can either physically exercise the right by transferring power or be compensated financially for transferring the right for using the transmission network to others. The importance of the transmission right is mostly observed when congestion occurs in the transmission market. In holding certain transmission rights, participants can hedge congestion charges through congestion credits. The auction is conducted by the ISO or an auctioneer appointed by the ISO.

2.4 Category of electricity market

Category of electricity market can be divided into two parts: forward market and real-time market as follows.

2.4.1 Forward market

In most electricity markets, a day-ahead forward market is for scheduling resources at each hour of the following day. An hour-ahead forward market is a market for deviations from the day-ahead schedule. Both energy and ancillary services can be traded in forward markets. Whenever energy schedules in a forward market can be accommodated without congestion management, the ISO would procure ancillary services through a systemwide auction. However, if a congestion exists somewhere in the system, the auction for ancillary services would be implemented on a zonal basis.

2.4.2 Real-time market

To ensure the reliability of power systems, the production and consumption of electric power must be balanced in real-time. However, real-time values of load, generation, and transmission system can differ from forward market schedules. Therefore, the real-time market is established to meet the balancing requirement.

2.5 Key electricity market entities

The restructuring of electricity has changed the role of traditional entities in a vertically integrated utility and created new entities that can function independently. Here, we categorize market entities into market operator (ISO) and market participants. The ISO is the leading entity in a power market and its functions determine market rules. The key market entities discussed here include GENCOs and TRANSCOs. Other market entities include DISCOs, RETAILCOs, aggregators, brokers, marketers, and customers as follows.

2.5.1 ISO

A competitive electricity market would necessitate an independent operational control of the grid. The control of the grid cannot be guaranteed without establishing the ISO. The ISO administers transmission tariffs, maintains the system security, coordinates maintenance scheduling, and has a role in coordinating long-term planning. The ISO should function independent of any market participants, such as transmission owners, generators, distribution companies, and end-users, and should provide nondiscriminatory open access to all transmission system users. The ISO has the authority to commit and dispatch some or all system resources and to curtail loads for maintaining the system security (i.e., remove transmission violations, balance supply and demand, and maintain the acceptable system frequency). Also, the ISO ensures that proper economic signals are sent to all market participants, which in turn, should encourage efficient use and motivate investment in resources capable of alleviating constraints.

2.5.2 GENCOs

A GENCO operates and maintains existing generating plants. GENCOs are formed once the generation of electric power is segregated from the existing utilities. A GENCO may own generating plants or interact on behalf of plant owners with the short-term market (power exchange, power pool, or spot market). GENCOs are not affiliated with the ISO or TRANSCOs. A GENCO may offer electric power at several locations that will ultimately be delivered through TRANSCOs and DISCOs to customers. In the restructured power market, the objective of GENCOs is to maximize profits. To do so, GENCOs may choose to take part in whatever markets (energy and ancillary services markets) and take whatever actions (arbitraging and gaming). It is a GENCO's own responsibility to consider possible risks.

2.5.3 TRANSCOs

A TRANSCO transmits electricity using a high-voltage, bulk transport system from GENCOs to DISCOs for delivery to customers. The use of TRANSCO assets will be under the control of the regional ISO, although the ownership continues to be held by original owners in the vertically integrated structure. TRANSCOs are regulated to provide non-discriminatory connections and comparable service for cost recovery. A TRANSCO has the role of building, owning, maintaining, and operating the transmission system in a certain geographical region to provide services for maintaining the overall reliability of the electrical system.

2.5.4 DISCOs

A DISCO distributes the electricity, through its facilities, to customers in a certain geographical region. A DISCO is a regulated (by state regulatory agencies) electric utility that constructs and maintains distribution wires connecting the transmission grid to end-use customers. A DISCO is responsible for building and operating its electric system to maintain a certain degree of reliability and availability. DISCOs have the responsibility of responding to distribution network outages and power quality concerns. DISCOs are also responsible for maintenance and voltage support as well as ancillary services.

2.5.5 RETAILCOs

A RETAILCO is a newly created entity in this competitive industry. It obtains legal approval to sell retail electricity. A RETAILCO takes title to the available electric power and re-sells it in the retail customer market. A retailer buys electric power and other services necessary to provide electricity to its customers and may combine electricity products and services in various packages for sale. A retailer may deal indirectly with end-use customers through aggregators.

2.5.6 Aggregators

An aggregator is an entity or a firm that combines customers into a buying group. The group buys large blocks of electric power and other services at cheaper prices. The aggregator may act as an agent (broker) between customers and retailers. When an aggregator purchases power and re-sells it to customers, it acts as a retailer and should initially qualify as a retailer.

2.5.7 Brokers

A broker of electric energy services is an entity or firm that acts as a middleman in a marketplace in which those services are priced, purchased, and traded. A broker does not take title on available transactions, and does not generate, purchase, or sell electric energy but facilitates transactions between buyers and sellers. If a broker is interested in acquiring a title on electric energy transactions, then it is classified as a generator or a marketer. A broker may act as an agent between a GENCO, or an aggregation of generating companies, and marketers.

2.5.8 Marketers

A marketer is an entity or a firm that buys and re-sells electric power but does not own generating facilities. A marketer takes title, and is approved by FERC, to market electric energy services. A marketer performs as a wholesaler and acquires transmission services. A marketer may handle both marketing and retailing functions.

2.5.9 Customers

A customer is the end-user of electricity with certain facilities connected to the distribution system, in the case of small customers, and connected to transmission system, in the case of bulk customers. In a restructured system, customers are no longer obligated to purchase any services from their local utility company. Customers would have direct access to generators or contracts with other providers of power, and choose packages of services (e.g., the level of reliability) with the best overall value that meets customers' needs. For instance, customers may choose providers that would render the option of shifting customer loads to off-peak hours with lower rates.

2.6 Electricity market operations

Electricity market operations consist of two parts: ISO operation and GENCOs operation as follows.

2.6.1 ISO operation

The responsibilities of the ISO are to operate the market securely and efficiently, and to monitor the market free from market power. ISO operation consists of three parts: market forecasting, market operation and market monitoring as follows.

2.6.1.1 Market forecasting

ISO needs to forecast the system load accurately to guarantee that there is enough energy to satisfy the load and enough ancillary services to ensure the reliability of the physical power system. Load forecasting has several applications, including generation scheduling, prediction of power system security, generation reserve of the system, providing information to the dispatcher, and market operation. Price forecasting for the ISO is the same as determining MCP. That is the case in the National Energy Market (NEM) in Australia and the Power Pool in Albert in Canada. Price forecasting for the ISO is not a true forecasting process because, once the ISO receives the participants' bids, it can calculate the MCP numerically.

2.6.1.2 Market operation

The operational responsibilities of the ISO include the energy market, the ancillary services market, and the transmission market. The ISO must be equipped with powerful tools to fulfill those responsibilities. Thus, first, security-constrained unit commitment (SCUC): ISO plans the day-ahead schedule using SCUC. ISO collects detailed information on each generating unit including characteristics such as start-up and no-load costs, minimum start-up and shut-down times, minimum and maximum unit outputs, and bids representing incremental heat rate and ISO also obtains information from TRANSCOs via the OASIS on transmission line capability and availability. Then, the ISO uses the SCUC model to determine the optimal allocation of generation resources. Second, ancillary services auction: ancillary services are necessary to support the transmission of power from sellers to buyers given the obligation of control areas and transmission utilities to maintain a reliable operation of the interconnected transmission system. In the restructured power market, ancillary services should be procured competitively through market auctions. Third, transmission congestion management and pricing: the transmission network plays a vital role in competitive electricity markets. In a restructured power system, the transmission network is the key mechanism for generators to compete in supplying large users and distribution companies. A proper transmission pricing scheme that considers transmission congestion could motivate investors to build new transmission and/or generating capacity for improving the efficiency. In a competitive environment, proper transmission pricing could meet revenue expectations, promote an efficient operation of electricity markets, encourage investment in optimal locations of generation and transmission lines, and adequately reimburse owners of transmission assets.

2.6.1.3 Market monitoring

Power market authorities must identify and correct situations in which some companies possess market power. Methodologies based on game theory, which can be used to identify noncompetitive situations in the restructured energy marketplaces.

2.6.2 GENCOs operation

GENCOs are key players in the power market. The sole objective of a GENCO is to maximize its profit. GENCOs operation consists of three parts: forecasting, bidding strategy and risk management as follows.

2.6.2.1 Forecasting

GENCO must make an accurate forecast about the system, including its load and its price. In most situations, load forecasting is the basis for price forecasting since the load is the most important price driver. Price forecasting is most important for the GENCO in the restructured power industry, since the price reflects the market situation. Price is a signal that should lead every action the GENCO may take.

2.6.2.2 Bidding strategy

To achieve the maximum profit, the GENCO should have a good bidding strategy based on the forecasted system information. In the restructured power market, the price-based unit commitment (PBUC), replacing the traditional unit commitment, would be the basis for a good bidding strategy. In addition, identifying arbitrage opportunities in the market and exploiting those opportunities to achieve maximum profit should be one of the capabilities of the GENCO. In most cases, the identification of arbitrage opportunities depends on PBUC. Because of the uncertainty and the competitiveness of the market, a game strategy would be an indispensable tool for the GENCO.

2.6.2.3 Risk management

Enough attention must be paid to risk management, and the various risk factors. Asset valuation is an important issue in risk management, and this would utilize PBUC, arbitrage, and gaming. There are two types of valuation for generating units. One is the valuation based on the daily scheduled generation. The other is the valuation based on the available capacity of generating units. Generation asset valuation is based on the spot market price and not on a forecasted market price. In addition to the market price, the bidding strategy (i.e., commitment and bidding of units) has a major impact on the value of generating units. Generation capacity valuation is based on the available capacity for trading in the market. Hence, the physical characteristics of the units such as maximum/minimum capacity, force outage rate (i.e., availability), fuel consumption function (i.e., efficiency), and ramp rate (i.e., response capability) are among factors used in determining the value of generating units.

The details of a market design for restructured electricity market operations as shown in Figure 1.

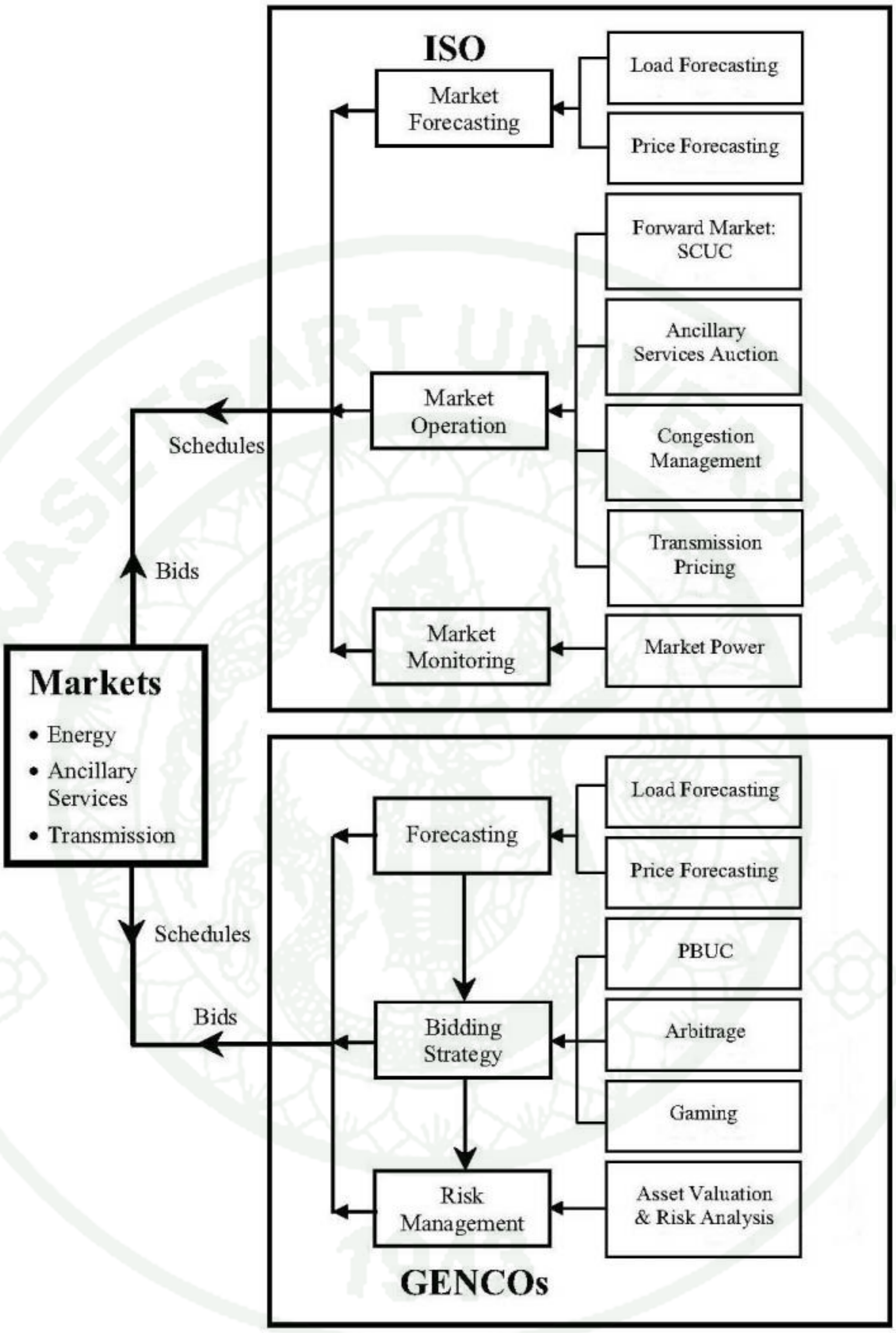

Figure 1 Restructured electricity market operations

3. Security-constrained unit commitment methods

Security-constrained unit commitment is utilized by ISO to clear the daily/weekly-ahead market. The objective of SCUC is to minimize the system operating cost while meeting the prevailing constraints, such as power balance, system spinning and operating reserve requirements, minimum on/off time limits, ramping up/down limits, limits on state and control variables including real and reactive power generation, controlled voltages, settings of tap-changing and phase-shifting transformers, and so on (Shahidehpour *et al*., 2002). Such SCUC problem is a nonconvex, nonlinear, large-scale, mixed-integer optimization problem with a large number of 0–1 variables, continuous and discrete control variables, and a series of prevailing equality and inequality constraints. Various optimization techniques (Shahidehpour *et al*., 2002; Wood and Wollenberg, 1984; Senjyu *et al*., 2003; Fu and Shahidehpour, 2005; Guan *et al*., 2005; Martinez-Crespo *et al*., 2006; Fu and Shahidehpour, 2007; Eslamian *et al*., 2009; Lotfjou *et al*., 2010) were applied to solve this problem. However, lagrangian relaxation (LR) and mixed-integer programming (MIP) methods are the most widely applied methods to solve SCUC.

(Sioshansi *et al*., 2008) state that lagrangian relaxation (LR) algorithm was the practical means of solving a commercial-scale unit commitment. However, (Johnson *et al*., 1997) demonstrate that centralized scheduling of resources owned by multiple parties by means of an LR algorithm may face difficulties that do not arise when resources are centrally owned. A case study based on load data and a stylized generator set from Pacific Gas and Electric Company shows that variations in near-optimal unit commitments that have negligible effects on total system costs could yield significantly different payoffs to individual resources—meaning the details underlying the solution methodology could impact which generators are "winners" and "losers" in dispatch determination. (Guan *et al*., 2003) state, for example, that the 1%–2% duality gaps achieved with LR were sufficient for monopoly utilities but that the development of competitive markets in which generators compete to provide their products has increased the need for more accurate unit commitment solutions. (Streiffert *et al*., 2005) demonstrate, however, that recent advances in computing capabilities and improvements in optimization algorithms now allow MIP to be a viable alternative to LR. Even if the B&B algorithm times-out before finding an optimum, one is still left with a primal-feasible solution and a bound on the optimality gap. These intermediate solutions are often found within the same amount of time an

LR-based algorithm takes, and they typically have optimality gaps of the same size or smaller than LR commitments. Moreover, (Streiffert *et al*., 2005) and (Li and Shahidehpour, 2005) note that B&B benefits more in comparison to LR from having additional solution time, as the B&B algorithm is able to find better solutions or tighten the optimality gap with additional time. (Sioshansi *et al*., 2008) state that A MIP-based solution algorithm allows ISOs to easily introduce new types of unit-operating and system constraints to the formulation of the problem, whereas LR-based techniques generally require extensive reprogramming of the feasibility heuristics to ensure that the final commitment satisfies all the necessary conditions. The advantage and the tractability of MIP algorithms have led several ISOs, such as PJM, to implement MIP-based solution methods as opposed to LR. Moreover, the California ISO's Market Redesign and Technology Update and the new ERCOT nodal market will feature centralized commitment solved using MIP, and ISO New England (ISONE) is similarly exploring the switch from LR to MIP.

4. Bidding prices based optimal power flow

4.1 Optimal power flow with continuous quadratic cost functions

Optimal power flow (OPF) is the problem to minimize the total generation cost of the power system and satisfied the power system security in normal operation. (Carpentier, 1962) proposed the first concept of optimal power flow problem in 1962. After that, there have been several methods (Happ, 1997; Momoh *et al*., 1999; Momoh *et al*., 1999) proposed to improve the performance to find the results and to solve the complexity of optimal power flow problem due to the modern power system models. The methods can be classified as:

4.1.1 Nonlinear programming

Nonlinear programming (NLP) (Dommel and Tinney, 1968; Shen and Laughton, 1969; El-Abiad and Jaimes, 1969; Sasson, 1969; Sasson, 1970; Sasson *et al*., 1973; Alsac and Stott, 1974; Billinton and Sachdeva, 1972; Barcelo *et al*., 1977; Housos and Irisarri, 1982; Shoults and Sun, 1982; Divi and Kesavan, 1982; Talukdar *et al*., 1983; Momoh, 1989; Lin *et al*., 1987; Rehn *et al*., 1989; Habiabollahzadeh *et al*., 1989; Ponrajah and Galiana, 1989) deals with problems involving nonlinear objective and constraint functions. The constraints may consist of equality and/or inequality formulations. The inequality can be specified by being bounded both above and below. Several methods such as Sequential Unconstrained Minimization Technique (SUMT) and Lagrange multiplier based. The OPF formulations employed general purpose packages applied for both real-time on-line and off-line operational problems.

4.1.2 Quadratic programming

Quadratic programming (QP) (Reid and Hasdorf, 1973; Wollenberg and Stadlin, 1974; Giras *et al*., 1977; Burchett *et al*., 1982; Aoki and Satoh, 1982; Contaxis *et al*., 1983; Talukdar *et al*., 1983; Burchett *et al*., 1984; El-Kady *et al*., 1986; Aoki *et al*., 1987; Papalexopoulos *et al*., 1989) is a special form of nonlinear programming whose objective function is quadratic with linear constraints. Several QP methods have been used to solve OPF (loss, voltage economic dispatch) type of problems. Quasi-Newton and sensitivity-based methods have been employed for solving real on-line OPF problems.

4.1.3 Newton-based solution of optimality conditions

In this approach (Rashed and Kelly, 1974; Happ, 1974; Sun *et al*., 1984; Pereira *et al*., 1987; Sanders and Monroe, 1987; Monticelli *et al*., 1987), the necessary conditions of optimality commonly referred to as the Kuhn-Tucker conditions are obtained. In general, these are nonlinear equations requiring iterative methods of solution. The Newton method is favored for its quadratic convergence properties.

4.1.4 Linear programming

Linear programming (LP) (Wells, 1968; Shen and Laughton, 1970; Stott and Hobson, 1978; Stott and Marinho, 1979; Stadlin and Fletcher, 1982; Irving and Sterling, 1983; Housos and Irisarri, 1983; Farghal *et al*., 1984; Mota-Palomino and Quintana, 1984; Mota-Palomino and Quintana, 1986; Santos-Neito and Quintana, 1987) treats problems with constraints and objective function formulated in linear forms with non-negative variables. The simplex method is known to be quite effective for solving LP problems. The most commonly used technique is the revised simplex method. The objective functions (voltage, loss, economic dispatch and VAR) are linearized to enable an LP solution.

4.1.5 Hybrid versions of linear programming and integer programming

Mixed integer programming (MIP) is a particular type of linear programming whose constraint equations involve variables restricted to being integer. Integer programming and mixed integer programming, like nonlinear programming are extremely demanding of computer resources and the number of discrete variables is an important indicator of how difficult an MIP problem will be to solve. Literatures (Nabona and Ferris, 1973; Contaxis *et al*., 1986) in this section employ a mixture of linear and mixed integer programming used to solve typical OPF problems such as VAR planning. The mathematical optimization technique assumes linear objectives and the constraints are a combination of linear and nonlinear with discrete or integer variables.

4.1.6 Interior point methods

The interior point method (Clements et al., 1991; Ponnambalam *et al*., 1991; Vargas *et al*., 1993; Momoh *et al*., 1992; Momoh *et al*., 1992; Lu and Unum, 1993; Granville, 1994; Momoh *et al*., 1994; Granville, 1994; Wu *et al*., 1994; Torres and Quintana, 2000; Castronuovo *et al*., 2001; Jabr *et al*., 2001; Qiu *et al*., 2005), recently re-discovered by Karmarkar, has stunned the operational research community since the scheme solves linear programming faster and is perhaps better than the conventional simplex algorithm. The extension of the interior point method to apply to NLP and QP problems has shown superior qualities and promising results.

4.2 Optimal power flow with step bidding prices

Despite the advancements being made, the full AC OPF has not been widely adopted in real-time operations of large-scale power systems. Instead, system operators often use simplified OPF tools that are based on linear programming (LP) and decoupled (DC) system models (PJM Energy Market Manuals, 2012). Historically, this is mainly due to the lack of powerful computer hardware and efficient AC OPF algorithms. With the advent of fast low-cost computers, however, speed has now become a secondary concern, after algorithm robustness. The remaining prevalent argument for using LP-based DC OPF instead of NLP-based AC OPF is that LP algorithms are deterministic and always yield solutions, albeit not necessarily the desired ones, while NLP algorithms are less robust and often experience convergence problems. OPF computation is now part of the core pricing mechanism for electricity trading in deregulated markets, where real energy, reactive energy, voltage support, and other system resources and services can all be traded in discrete bids and offers (PJM Energy Market Manuals, 2012; Australian Energy Market Operator, 2012; California Independent System Operator, 2012; New York Independent System Operator, 2012; Murillo-Sanchez, 2000; Federal Energy Regulatory Commission, 2005). In order to meet their legal obligations of providing timely market settlements and to ensure market fairness and efficiency, independent system operators (ISOs) must adopt OPF tools that provide a) deterministic convergence; b) accurate computation of nodal prices; c) support of both smooth and nonsmooth costing of a variety of resources and services, such as real energy, reactive energy, voltage support, etc.; d) full active and reactive power flow modeling of large-scale systems; and e) satisfactory worst-case performance that meets the real-time dispatching requirement. Most prior research on OPF has focused on performance issues in the context of regulated systems, without giving much emphasis to requirements a)–c). For bidding prices based optimal power flow, there have been several methods proposed to optimally dispatch real power generations from participated generators when the bidding power and prices are step functions, and not continuous quadratic functions. (Wang *et al*., 2007) showed that the allocation of real power produced with discrete bids using nonlinear programming methods may be unable to find the results in some cases. When such cases arise, the formulations for objective functions need to be improved. (Gomes and Saraiva, 2008) proposed the active/reactive bid based dispatch models which divide the calculations into two steps. The first step is the allocation of power generation at each bus with the simple bidding prices submitted to the market operator where the power system operational conditions and limits are not yet considered. The second step is the allocation of power generation at each bus with the adjustment bidding prices submitted to the market operator where synchronous generator capability diagram and the power system operational conditions and limits are considered.

5. Transmission congestion management in electricity market

Existence of transmission system constraints dictates the finite amount of power that can be transferred between two points on the electric grid. In practice, it may not be possible to deliver all bilateral and multilateral contracts in full and to supply all pool demand at least cost as it may lead to violation of operating constraints such as voltage limits and line over-loads (congestion). The presence of such network or transmission limitation is referred to as Congestion. With difficulties in building new transmission lines due to problem of right-of-the-way and financial crunch and the significant increase in the power transactions associated with the competitive electricity markets, maintaining system security has become one of the main concerns for market and system operators than ever. Transmission congestion may prevent the existence of new contracts, lead to additional outages, increase the electricity prices in some regions of the electricity markets, and can threaten system security and reliability.

Transmission congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load, higher cost units must be dispatched to meet that load. Transmission congestion management methods in electricity market can be divided into four methods (Kumar *et al*., 2005) as follows.

5.1 Sensitivity factors based methods

In this method, power system is divided into groups. Each group has the order. By order of the sensitivity factors to consider in each group was calculated in each case with a transmission line in the power system operates at maximum limits. Then sort the order of the various groups in the power system in ascending value. Generator in the group with the lower order must decrease the power generation at bus first and then consider the power generation of the generator in the group with the next higher order (Kumar *et al*., 2004; Yu and Ilic, 1999; Bialek *et al*., 2000; Vlachogiannis, 2000; Overbye and Weber, 2001; Kumar *et al*., 2003).

5.2 Auction based congestion management

This method is based on the financial approach. The power producer in the system can buy the transmission line credit of the expect transmission line that operates at maximum limits, in order to offset the financial when that transmission line operates at maximum limits. But the power producer is not the credit of the transmission line that operates at maximum limits, it will be charged according to the ISO rating (Hogan, 1992; Chao and Peck, 1996; Bushnell, 1999; Alomoush and Shahidehpour, 2000; Chao *et al*., 2000; Hogan, 2000; Yu and Ilic, 2000; Liu and Gross, 2004; Tuan *et al*., 2005).

5.3 Pricing based methods

In this method, ISO allows the power producers can send the bidding prices many times. From the second onwards, before the power producers send the new bidding prices, ISO will announce the transmission congestion prices. Then, the power producers send the new bidding prices to ISO for their increasing the profit and decreasing the transmission congestion prices. And then, ISO announce the transmission congestion prices and a loop like this until the last sending (Finney *et al*., 1997; Glavitsch and Alvarado, 1997; Stoft, 1998; Glavitsch and Alavardo, 1998; Gedra, 1999; Bompard *et al*., 2000; Chen *et al*., 2000; Chen *et al*., 2002; Papalexopoulos, 2002; Hao and Shirmohammadi, 2002). Another method uses locational marginal price (LMP) based congestion management which ISO allows the power producers can send the bidding prices one time only and calculates congestion prices thought the congestion component of LMP (CLMP) such as PJM (PJM Energy Market Manuals, 2012; Ott, 1999; Balmat and DiCapiro, 2002).

5.4 Re-dispatch and willingness to pay methods

In this method, the buyer at each bus sends the willingness to pay to avoid curtailment both the pool and the bilateral contracts. The buyer that sends the higher willingness to pay to avoid curtailment will be not decreased the power generation of the according seller. While, the buyer that sends the lower willingness to pay to avoid curtailment will be decreased the power generation of the according seller when the system can not transfer power equals the desired power generation (Fang and David, 1999; David, 1998; Fang and David, 1999; Lie *et al*., 2001; Grgic and Gubina, 2001; Grgic and Gubina, 2002; Phichaisawat *et al*., 2002; Yamin and Shahidehpour, 2003; Canizares *et al*., 2004; Talukdar *et al*., 2005).

MATERIALS AND METHODS

Materials

1. Notebook computer
2. MATLAB program
3. Printer

Methods

To find the results of security-constrained unit commitment within 24 hours in pool electricity markets in this thesis, we need to get the results from step bidding price optimal power flow in each hour. Therefore, this thesis proposes hybrid computational method (HCM) to solve step bidding price optimal power flow (SPOPF) in electricity markets; and hybrid computational method for step bidding price security-constrained unit commitment (SP-SCUC) in pool electricity markets. The HCM for SPOPF proposed in this thesis can be categorized in to three types based on electricity market models i.e. a) HCM for SPOPF in pool electricity markets b) HCM for SPOPF in mixed pool-bilateral electricity markets and c) HCM for SPOPF with transmission congestion management (SPOPF-TCM) in mixed pool-bilateral electricity markets.

1. HCM for SPOPF in pool, mixed pool-bilateral and SPOPF-TCM

The section presents a single set of problem formulation that can be used for all HCMs for SPOPF in pool electricity markets, SPOFP in mixed pool-bilateral electricity markets and SPOPF-TCM in mixed pool-bilateral electricity markets. This general set of problem formulation is created based on HCM for SPOPF-TCM in mixed pool-bilateral electricity markets, which is the most complicated formulation, where as it can be simply modified to solve SPOPF in other market models as well.

The objective of SPOPF-TCM is to minimize the total generation cost consisting of several step bidding prices from participated generators and the total willingness to pay functions from participated loads in pool, bilateral and multilateral contracts. For simplicity of developing the hybrid computational method, the real power demands in the system are forecasted and assumed to be constant in the model. There are direct power purchased agreements between power producers and consumers that are bilateral contract and multilateral contract. Bilateral contract is the direct power purchased agreement between a power producer and a consumer, while multilateral contract is direct power purchased agreement between one or more power producers and a group of two or more consumers or between a group of two or more power producers and a consumer. ISO requires the amount of purchased power from both sides (generation side and demand side) of bilateral and multilateral contracts and power losses according to the transactions are compensated by generators in pool. The hybrid computational method separates the calculations into two parts: the market dispatch part; and the power flow dispatch part. The market dispatch part gives the results in terms of allocation of the bids of real power generations at each bus based only on the price offered and real power generation from both bilateral and multilateral contracts without considering physical limits of the power systems. The power flow dispatch part minimizes the changes of real power generations resulting from the market dispatch part and the willingness to pay functions while satisfying power balanced equations and system operating limits. The hybrid computational method finds the optimal solution when the results from the market dispatch part no longer violate power system limits. The market clearing price (MCP) (Kirschen and Strbac, 2004) can then be obtained from the highest price of selected bidding blocks.

The proposed hybrid computational method separates the problem formulation into two parts: the market dispatch part and the power flow dispatch part, which are explained in details as follows.

1.1 Market Dispatch

In the market dispatch part, the allocation of real power generation at each bus is computed based on the bidding prices submitted to the market operator and real power generation from both bilateral and multilateral contracts. Several blocks of bidding prices offered by participated generators are listed from the lowest to the highest ones. Initially, the blocks of real power generations will be dispatched from the lower prices upward plus real power generation from both bilateral and multilateral contracts until the amount of forecasted system load and estimated losses are met. At this point, the power system operational conditions and limits are not yet considered. The mathematical model for dispatching the blocks of real power generations and real power generation both of bilateral and multilateral contracts by the market operator can be expressed as:

Minimize
$$\sum_{i \in NG} \sum_{b \in NB_i} \left(c_{i,b} \times P_{Gi,b} \right) \quad (1)$$

Subject to
$$\left[\sum_{i \in NG} \left[\left(\sum_{b \in NB_i} P_{Gi,b} \right) + \overline{P}_{Gi}^{B} + \overline{P}_{Gi}^{M} \right] \right] - P_{LT} - P_{DT} = 0 \quad (2)$$

$$\left(\sum_{b \in NB_i} P_{Gi,b} \right) \le \overline{P}_{Gi} \; ; \forall i \in NG \quad (3)$$

$$0 \le P_{Gi,b} \le P_{Gi,b\Delta} \; ; \forall i \in NG, \forall b \in NB_i \quad (4)$$

Note that for the first iteration, $\overline{P}_{Gi}$ is set to be the capacity of generator *i*, or $P_{Gi,\max}$, $\overline{P}_{Gi}^{B}$ is set to be the real power generation schedule of the generator that trades in bilateral at bus *i*, or $P_{Gi}^{B,sch}$, $\overline{P}_{Gi}^{M}$ is set to be the summation of real power generation schedule at bus *i* for every multilateral contract, or $\sum_{k \in N^M} P_{Gk,i}^{M,sch}$ and P_{LT} is equal to zero.

The optimal results from the market dispatch are $P_{Gi,b}$ and $c_{i,b}$, which are the generation dispatch of chosen bidding blocks and their bidding prices, respectively. The market dispatch results, which yield the minimum cost of power generation, must be checked to see if they satisfy the system operating constraints in the following power flow dispatch.

1.2 Power Flow Dispatch

The power flow dispatch problem is similar to the standard optimal power flow where the constraints are power balanced equations and system operating limits. However, instead of a quadratic generation cost function, the objective function is now the total penalty cost of some slack variables, willingness to pay functions in demand side of pool, bilateral and multilateral contracts and penalty cost of real power load for bilateral and/or multilateral contract to buy real power from pool due to congested transmission lines. Since the parameters used in the power flow dispatch problem are obtained from the market dispatch, they may not satisfy the required constraints, and the power flow dispatch problem may not converge. Therefore, some slacks for real power generation $\left(P_{Gi}^{+}, P_{Gi}^{-} \text{ and } P_{Gi}^{S}\right)$ must be added to the power balanced equations along with their corresponding penalty costs $\left(c_i^{+}, c_i^{-} \text{ and } \hat{c}_i\right)$ in the objective function.

The slack variables P_{Gi}^{+} and P_{Gi}^{-} represent the increasing and decreasing real power generation needed for generator at bus *i* in order to satisfy the power balanced equations. It is obvious that P_{Gi}^{+} and P_{Gi}^{-} will not be nonzero at the same time in the power balanced equation at bus *i*. The extra slack variable, P_{Gi}^{S}, only exists when P_{Gi}^{+} or P_{Gi}^{-} has reached its upper limit but the power balanced equation is not yet satisfied. These slack variables, if being nonzero, will send the signal to the market dispatch to adjust the optimal results in order to satisfy the power flow constraints. The penalty costs corresponding to these slack variables are the chosen block bidding prices expressed as follows:

$$c_i^{+} = \begin{cases} \max\left(c_{i,b};\ \sum_{b \in NB_i} P_{Gi,b} = P_{Gi,\max}\right) \\ \min\left(c_{i,b}; 0 \le P_{Gi,b} < P_{Gi,b\,\Delta}\right) \end{cases} \tag{5}$$

$$c_i^{-} = \min\left(\frac{1}{c_{i,b}};\ \text{for } P_{Gi,b} = P_{Gi,b\,\Delta}\right) \tag{6}$$

From (5), if the power dispatch of generator *i* from market dispatch reaches its maximum limit, the penalty cost for increasing real power (c_i^+) is set to the highest bidding price of generator at bus *i* so that the increasing slack variable (P_{Gi}^+) will always be zero. In other cases, the penalty cost is equal to the bidding price of the last chosen block of generator *i*, or the next block if the last chosen block is full.

The penalty cost for decreasing real power (c_i^-) is equal to the inverse of the block bidding price of the last full chosen block as expressed in (6).

The real power generation from generator at bus *i*, P'_{Gi}, which is set to be constant in the power flow dispatch, comes from the market dispatch with some modification. It is equal to the sum of all the full chosen blocks of real power generation as expressed in (7).

$$P'_{Gi} = \sum_{b \in NB_i} P_{Gi,b}; \text{for } P_{Gi,b} = P_{Gi,b\Delta} \tag{7}$$

The slack variables for real power generation must be nonnegative and have upper limits, $P_{Gi,\max}^+$ and $P_{Gi,\max}^-$, as shown in (8) and (9). The upper limits of P_{Gi}^+ and P_{Gi}^- are the sizes of real power generation of bidding blocks *b* corresponding to their chosen penalty c_i^+ and c_i^-, respectively. In the case where $c_i^+ = \hat{c}_i$, or the real power generation reaches its maximum limit, the upper limit of P_{Gi}^+ is zero. However, the extra slack variable, P_{Gi}^S, has no limit and can be any positive or negative number.

$$P_{Gi,\max}^+ = \begin{cases} P_{Gi,b\Delta} & ; \text{where } b \text{ corresponds to } c_i^+ \\ 0 & ; \text{for } \sum_{b \in NB_i} P_{Gi,b} = P_{Gi,\max} \end{cases} \tag{8}$$

$$P_{Gi,\max}^- = P_{Gi,b\Delta}\ ; \text{where } b \text{ corresponds to } c_i^- \tag{9}$$

When all necessary parameters from market dispatch are redefined, the power flow dispatch problem is therefore computed by the following optimization problem.

Minimize
$$\left[\sum_{i\in NG}\left(\left(c_i^{+}\times P_{Gi}^{+}\right)+\left(c_i^{-}\times P_{Gi}^{-}\right)+\left(\hat{c}_i\times\left(P_{Gi}^{S}\right)^2\right)\right)\right]$$
$$-\left[\sum_{i\in N_G^B}\sum_{j\in N_{i,D}^B}\left(W_{i,j}^B\times P_{Di,j}^B\right)\right]-\left[\sum_{k\in N^M}\sum_{j\in N_{k,D}^M}\left(W_{k,j}^M\times P_{Dk,j}^M\right)\right] \tag{10}$$

Subject to
$$P'_{Gi}+P_{Gi}^{+}-P_{Gi}^{-}+P_{Gi}^{S}+P_{Gi}^{B}+\sum_{k\in N^M}P_{Gk,i}^{M}-P_i(\mathrm{V},\delta,\mathrm{T})-P_{Di}=0\ ;\forall i\in N \tag{11}$$
$$Q_{Gi}-Q_i(\mathrm{V},\delta,\mathrm{T})-Q_{Di}=0\ ;\forall i\in N \tag{12}$$
$$P_{Dj}^{P}+P_{Di,j}^{B}+\sum_{k\in N^M}\left(\mu_{Dk,j}^{M}\times\sum_{j\in N_{k,D}^M}P_{Dk,j}^{M}\right)-P_{Dj}=0\,;\forall i\in N_G^B,\forall j\in ND \tag{13}$$
$$P_{Gi}^{B}-\sum_{j\in N_{i,D}^B}P_{Di,j}^{B}=0\ ;\forall i\in N_G^B \tag{14}$$
$$\sum_{i\in N_{k,G}^M}P_{Gk,i}^{M}-\sum_{j\in N_{k,D}^M}P_{Dk,j}^{M}=0\ ;\forall k\in N^M \tag{15}$$
$$P_{Gi,\min}\le\left(P'_{Gi}+P_{Gi}^{+}-P_{Gi}^{-}+P_{Gi}^{S}+P_{Gi}^{B}+\sum_{k\in N^M}P_{Gk,i}^{M}\right)\le P_{Gi,\max}\ ;\forall i\in NG \tag{16}$$
$$0\le P_{Gi}^{+}\le P_{Gi,\max}^{+}\ ;\forall i\in NG \tag{17}$$
$$0\le P_{Gi}^{-}\le P_{Gi,\max}^{-}\ ;\forall i\in NG \tag{18}$$
$$-\infty\le P_{Gi}^{S}\le\infty\ ;\forall i\in NG \tag{19}$$
$$0\le P_{Gi}^{B}\le P_{Gi}^{B,sch}\ ;\forall i\in N_G^B \tag{20}$$
$$0\le P_{Di,j}^{B}\le P_{Di,j}^{B,sch}\ ;\forall i\in N_G^B,\forall j\in N_{i,D}^B \tag{21}$$
$$0\le P_{Gk,i}^{M}\le P_{Gk,i}^{M,sch}\ ;\forall i\in N_{k,G}^M,\forall k\in N^M \tag{22}$$
$$0\le P_{Dk,j}^{M}\le P_{Dk,j}^{M,sch}\ ;\forall j\in N_{k,D}^M,\forall k\in N^M \tag{23}$$
$$0\le P_{Dj}^{P}\le P_{Dj}\ ;\forall j\in ND \tag{24}$$
$$(\mathbf{V},\mathbf{T},\mathbf{Q},\mathbf{S})\in\mathbf{B}_S \tag{25}$$

The objective function as expressed in (10) is the total penalty cost of slack variables of real power generation and willingness to pay functions in demand side of bilateral and multilateral contracts. Willingness to pay functions are offered prices for avoid curtailment of real power load in the case of transmission congested. The power flow dispatch will be allowed to move the real power generation from the optimal market dispatch as small as possible in order to satisfy the power flow equations and to choose from the higher willingness to pays downward until satisfy the transmission congestion management. The equality constraints, (11) and (12) are modified power balanced equations including necessary slack variables and real power generation from both bilateral and multilateral contracts.

Equation (13) represents the real power load balance at each bus of pool, bilateral and multilateral. In the case where real power load for bilateral and/or multilateral contracts cannot be met at their schedules due to transmission lines congestion, they must buy real power from pool through the variable, P_{Dj}^{P}, which represents real power load of pool.

The real power balance of bilateral contracts in each power producer is expressed as (14), while the real power balanced of each multilateral contract is expressed as (15).

The limits on real power generation are expressed as (16), while the limits of slack variables are written as (17)-(19).

The limit on real power generation of the generator that trades in bilateral is expressed as (20), while the limit on real power load of bilateral contract is expressed as (21).

The limits of each multilateral contract are expressed as (22)-(23).

The limit of real power load in pool is expressed as (24).

The other secure operating limits such as voltage and line limits, reactive powers limits and tap changer settings, are included in (25).

The results from this power flow dispatch part show the minimal adjusting of real power generations and the minimum willingness to pay functions while satisfying power flow balanced equations and other system security constraints. Resulting of nonzero slack variables implies that the optimal market dispatch has not yet satisfied power flow constraints. The adjusting of real power generations by their corresponding nonzero slack variables however may not be the optimal dispatch solution since the power flow dispatch part does not take into account the order of the bidding price blocks. For example, the adjusted amount of real power generation from generator "*i*" may require two more bidding blocks, but the price of the second block may not be next to the first one. In this case, the market dispatch should not redispatch generator *i* by the whole amount given from the power flow dispatch since the chosen blocks of bidding prices may not be in the right order, i.e. some blocks in the middle may be skipped. Therefore, the market dispatch must be recomputed based on the adjusted real power generation of each generator from the power flow dispatch, which is defined by $\overline{P}_{Gi}$ and given as followed:

$$\overline{P}_{Gi} = \begin{cases} P'_{Gi} + P^{+}_{Gi}, \text{for } P^{+}_{Gi} < P^{+}_{Gi,\max} \\ P'_{Gi} - P^{-}_{Gi}, \text{for } P^{-}_{Gi} > 0 \end{cases} \tag{26}$$

From (26), the adjusted real power generation for each generator allows the increasing or decreasing of only one bidding block since the P^{+}_{Gi} and P^{-}_{Gi} are bounded by (8) and (9), respectively. If the market dispatch needs more real power generation to cover total load and losses, it will determine to dispatch the generation of the next bidding block.

The real power generation of the generator that trades in bilateral can be updated from the power flow solution and given back to the market dispatch as a parameter $\overline{P}^{B}_{Gi}$, which comes from:

$$\overline{P}^{B}_{Gi} = P^{B}_{Gi} \tag{27}$$

The real power generation of the generator that trades in multilateral can be updated from the power flow solution and given back to the market dispatch as a parameter $\overline{P}_{Gi}^{M}$, which comes from:

$$\overline{P}_{Gi}^{M} = \sum_{k \in N^M} P_{Gk,i}^{M} \tag{28}$$

In addition, the system losses can be updated from the power flow solution and given back to the market dispatch as followed.

$$P_{LT} = \sum_{i \in N} P_i \tag{29}$$

The whole hybrid computational method will end when the following convergence criteria for power flow dispatch part are met simultaneously.

1. The slack for decreasing real power generation of the generator that trades in pool is equal to zero, $P_{Gi}^{P-} = 0$.

2. The extra slack variable is equal to zero, $P_{Gi}^{S} = 0$.

The increasing slack variable, P_{Gi}^{+}, needs not be zero for the convergence criteria since it is required for system losses compensation. The optimal dispatch for each generator is therefore the summation of its real power generation blocks resulting from market dispatch, P'_{Gi}, the increasing slack variable, P_{Gi}^{+}, the real power generation of the generator that trades in bilateral, P_{Gi}^{B}, and the summation of real power generation for every multilateral contract, $\sum_{k \in N^M} P_{Gk,i}^{M}$, of the last iteration.

The steps in proposed hybrid computational method are as follows:

Step 1: For the first iteration, $\overline{P}_{Gi}$ is set to be the capacity of generator *i*, or $P_{Gi,\max}$, $\overline{P}_{Gi}^{B}$ is set to be the real power generation schedule of the generator that trades in bilateral at bus *i*, or $P_{Gi}^{B,sch}$, $\overline{P}_{Gi}^{M}$ is set to be the summation of real power generation schedule at bus *i* for every multilateral contract, or $\sum_{k \in N^M} P_{Gk,i}^{M,sch}$ and P_{LT} is equal to zero.

Step 2: Solve optimization problem for market dispatch according to equations (1)-(4).

Step 3: Define parameters for solving optimization problem of power flow dispatch according to equations (5)-(9).

Step 4: Solve optimization problem for power flow dispatch according to equations (10)-(25).

Step 5: The whole hybrid computational method will end when the following convergence criteria for power flow dispatch part are met simultaneously i.e. 1) The slack for decreasing real power generation is equal to zero, $P_{Gi}^{-} = 0$, and 2) the extra slack variable is equal to zero, $P_{Gi}^{S} = 0$; otherwise define parameters for solving optimization problem of market dispatch according to equations (26)-(29), and go to step 2 for the next iteration.

Once HCM for SPOPF-TCM with mixed pool-bilateral electricity markets is formed, it can be modified to solve for SPOPF in mixed pool-bilateral electricity markets by eliminating those parameters related to transmission congestion management. In power flow dispatch part, $W_{i,j}^{B}$ and $W_{k,j}^{M}$ in equation (10) is then set to zero, while market dispatch part stays the same since it does not contain those parameters. Therefore, the equation (10) of the HCM for SPOPF-TCM with mixed pool-bilateral electricity markets must be modified to solve for SPOPF in mixed pool-bilateral electricity markets as follows.

$$\left[\sum_{i \in NG} \left(\left(c_i^{+} \times P_{Gi}^{+} \right) + \left(c_i^{-} \times P_{Gi}^{-} \right) + \left(\hat{c}_i \times \left(P_{Gi}^{S} \right)^2 \right) \right) \right] \qquad (10\text{-a})$$

Finally, the HCM for SPOPF-TCM with mixed pool-bilateral electricity markets can be modified to solve for SPOPF in pool electricity markets by eliminating those parameters related to transmission congestion management, and bilateral and multilateral contracts. In market dispatch part, $\overline{P}_{Gi}^{B}$ and $\overline{P}_{Gi}^{M}$ in equation (2) must be initially set to zero. In power flow dispatch part, $W_{i,j}^{B}$ and $W_{k,j}^{M}$ in equation (10), $P_{Gi}^{B,sch}$ in equation (20), $P_{Di,j}^{B,sch}$ in equation (21), $P_{Gk,i}^{M,sch}$ in equation (22) and $P_{Dk,j}^{M,sch}$ in equation (23) must be set to zero. Moreover, in the case where the convergence criteria for power flow dispatch part are not met simultaneously as we said above, $\overline{P}_{Gi}^{B}$ in equation (27) will always equal to zero because the lower and upper limits of P_{Gi}^{B} are equal to zero and $\overline{P}_{Gi}^{M}$ in equation (28) will always equal to zero because the lower and upper limits of $P_{Gk,i}^{M}$ are equal to zero.

Therefore, equation (2), equation (10) and equations (20)-(23) of the HCM for SPOPF-TCM with mixed pool-bilateral electricity markets must be modified to solve for SPOPF in pool electricity markets as follows.

$$\left[\sum_{i \in NG}\left[\left(\sum_{b \in NB_i} P_{Gi,b}\right)\right]\right] - P_{LT} - P_{DT} = 0 \tag{2-b}$$

$$\left[\sum_{i \in NG}\left(\left(c_i^{+} \times P_{Gi}^{+}\right) + \left(c_i^{-} \times P_{Gi}^{-}\right) + \left(\hat{c}_i \times \left(P_{Gi}^{S}\right)^2\right)\right)\right] \tag{10-b}$$

$$0 \le P_{Gi}^{B} \le 0 \; ; \forall i \in N_G^B \tag{20-b}$$

$$0 \le P_{Di,j}^{B} \le 0 \; ; \forall i \in N_G^B, \forall j \in N_{i,D}^B \tag{21-b}$$

$$0 \le P_{Gk,i}^{M} \le 0 \; ; \forall i \in N_{k,G}^M, \forall k \in N^M \tag{22-b}$$

$$0 \le P_{Dk,j}^{M} \le 0 \; ; \forall j \in N_{k,D}^M, \forall k \in N^M \tag{23-b}$$

2. HCM for SP-SCUC in pool electricity markets

This section presents a set of problem formulation for solving HCM for SP-SCUC within 24 hours in pool electricity markets, where the objective is to minimize the total generation cost within 24 hours consisting of several step bidding prices, startup costs and minimum load costs in each hour from participated generators. For simplicity of developing the hybrid computational method with mixed integer programming, the real power demands in the system within 24 hours are forecasted and assumed to be constant in the model. Moreover, there is no direct power purchased agreement between power producers and consumers. The proposed hybrid computational method with mixed integer programming separates the calculation into two parts: the part that calculates the daily security-constrained unit commitment of dc load flow with approximate losses (DC-SCUC); and the part that calculates SPOPF in each hour. The DC-SCUC gives the results in terms of the generating unit status (online or offline) and allocation of the bids of real power generations at each bus based on the price offered while considering physical limits of the power systems in dc load flow with approximate losses within 24 hours. The HCM for SPOPF in each hour is computed based on the generating unit status (online or offline) in each hour resulting from the DC-SCUC part. This part gives the results in terms of allocation of the bids of real power generations at each bus based on the price offered while considering physical limits of the power systems in full ac load flow model in each hour. If the results of the generating unit status (online or offline) within 24 hours from current iteration are the same as those from previous iteration, they are optimal solutions for HCM for SP-SCUC. If the results of the generating unit status from the current iteration are different from all previous iterations, all transmission line loss factors for each hour, all transmission line operation factors and maximum limits of transmission lines must be updated from the results of SPOPF and sent back to the DC-SCUC part.

The proposed hybrid computational method with mixed integer programming separates the calculation into two parts: the DC-SCUC part and the SPOPF in each hour part as follows.

2.1 The DC-SCUC

In the part of daily security-constrained unit commitment of dc load flow with approximate losses, the allocation of the generating units status (online or offline) and real power generation at each bus are computed based on the startup cost, minimum load cost and the bidding prices submitted to the market operator while satisfying minimum up time limits, minimum down time limits, dc load flow model with transmission line losses of power balanced equations and system operating limits within 24 hours. Several blocks of bidding prices offered by participated generators are listed from the lowest to the highest ones.

The objective function of this part consists of startup cost, minimum load cost and the bidding prices submitted to the market operator within 24 hours. The term of startup cost represents the cost for starting up the generating unit when the generating unit is offline at the previous hour. The term of minimum load cost represents the cost for the generating unit to be running at minimum limits in each hour. And the term of the bidding prices represents the bidding prices of the generating unit in each hour. The mathematical model for this objective function can be expressed as followed.

$$\sum_{h \in T} \sum_{i \in NG} \left[\left(SUC_i \times \left(1 - U_{i,h-1}\right) \times U_{i,h} \right) + \left(MLC_{i,h} \times U_{i,h} \right) + \left(\sum_{b \in NB_i} \left(c_{ibh} \times P_{Gibh} \right) \right) \right] \tag{30}$$

The constraints of this part consist of the followings:

a) Real power balanced.

The real power balanced at each bus is based on dc load flow model including minimum limits of committed generator indicated by binary variables as follows.

$$\left(\left(P_{Gi,\min} \times U_{i,h} \right) + \sum_{b \in NB_i} P_{Gibh} \right) - P_{i,h} - P_{Di,h} = 0 \; ; \forall i \in N, \forall h \in T \tag{31}$$

The injected real power at bus i in hour h in equation (31) can be expressed as.

$$P_{i,h} = \sum_{m \in N, i \neq m} P_{imh} \; ; \forall i \in N, \forall h \in T \tag{32}$$

b) Variable on real power generation of each generator.

A variable on real power generation, $P_{Gi,h}$, is introduced in order to simplify the function of real power generation of each generator as follows.

$$P_{Gi,h} - \left(\left(P_{Gi,\min} \times U_{i,h} \right) + \sum_{b \in NB_i} P_{Gibh} \right) = 0 \ ; \forall i \in NG, \forall h \in T \tag{33}$$

c) Approximate real power losses in transmission lines.

This thesis proposes a way to include approximate real power losses of dc load flow model as follows.

$$P_{imh} + P_{mih} - P_{Limh} = 0 \ ; \forall i, m \in Nl, \forall h \in T \tag{34}$$

The real power flowing in transmission line from bus *i* to bus *m* in hour *h* in equation (34) can be expressed as.

$$P_{imh} = Pc_{imh} \times \alpha_{imh} \times \left(\delta_{i,h} - \delta_{m,h} \right) \ ; \forall i, m \in Nl, \forall h \in T \tag{35}$$

The real power flowing in transmission line from bus *m* to bus *i* in hour *h* in equation (34) can be expressed as.

$$P_{mih} = Pc_{mih} \times \alpha_{imh} \times \left(\delta_{m,h} - \delta_{i,h} \right) \ ; \forall i, m \in Nl, \forall h \in T \tag{36}$$

The real power loss in transmission line connecting between buses *i* and *m* in hour *h* in equation (34) can be expressed as.

$$P_{Limh} = \sqrt{\left(\left(\rho_{Limh} \times \alpha_{imh} \times \left(\delta_{i,h} - \delta_{m,h} \right) \right)^2 \right)} \ ; \forall i, m \in Nl, \forall h \in T \tag{37}$$

d) Minimum up time.

The minimum up time of each generator is the group of equations controlling the generator minimum run time for changing the status of generator from offline to online as follows.

$$\sum_{n=h}^{h+T_{Ui}-1} U_{i,n} \geq T_{Ui} \times \left[U_{i,h} - U_{i,h-1} \right] \; ; \forall i \in NG, \forall h = 1,\ldots,T - T_{Ui} + 1 \qquad (38)$$

$$\sum_{n=h}^{T} U_{i,n} \leq \left[(T - h + 1) \times U_{i,h-1} \right] \; ; \forall i \in NG, \forall h = T - T_{Ui} + 2,\ldots,T \qquad (39)$$

e) Minimum down time.

The minimum down time of each generator is the group of equations controlling the generator minimum shutdown time for changing the status of generator from online to offline as follows.

$$\sum_{h=1}^{IF_i} U_{i,h} = 0 \quad , \text{ for } IF_i > 0 \; ; \forall i \in NG \qquad (40)$$

$$\sum_{n=h}^{h+T_{Di}-1} \left[1 - U_{i,n} \right] \geq T_{Di} \times \left[U_{i,h-1} - U_{i,h} \right] \; ; \forall i \in NG,$$

$$\forall h = IF_i + \min(IF_i, 1) + 1,\ldots,T - T_{Di} + 1 \qquad (41)$$

$$\sum_{n=h}^{T} \left[1 - U_{i,n} - \left(U_{i,h-1} - U_{i,h} \right) \right] \geq 0 \; ; \forall i \in NG, \forall h = T - T_{Di} + 2,\ldots,T \qquad (42)$$

Equation (42) specifies that the final $T_{Di} - 1$ period in which if the generator at bus *i* is shut down, it remains offline until the end of its time span.

The number of periods for generator at bus *i* which must be initially offline due to its minimum down time constraint in equation (41) can be expressed as.

$$IF_i = \max \left[0, \left(T_{Di} - RF_i \right) \times \left(1 - U_{i,0} \right) \right] \; ; \forall i \in NG \qquad (43)$$

f) Limits of real power generation.

The real power generation for each generator at each hour is controlled by not only the limits of generator but also the status of generator (online or offline) as follows.

$$\left[P_{Gi,\min} \times U_{i,h}\right] \leq P_{Gi,h} \leq \left[P_{Gi,\max} \times U_{i,h}\right] \;;\forall i \in NG, \forall h \in T \tag{44}$$

g) Bidding block limits.

The size of real power generation at each bidding block of the generator can be expressed as.

$$0 \leq P_{Gibh} \leq P_{Gibh,\Delta} \;\;;\forall i \in NG, \forall b \in NB_i, \forall h \in T \tag{45}$$

h) Line flow limits.

The limits of real power flowing in the transmission line equations are used to control the maximum real power flowing in the transmission line in bidirectional flow.

$$-P_{imh,\max} \leq P_{imh} \leq P_{imh,\max} \;\;;\forall i, m \in Nl, \forall h \in T \tag{46}$$

$$-P_{imh,\max} \leq P_{mih} \leq P_{imh,\max} \;\;;\forall i, m \in Nl, \forall h \in T \tag{47}$$

i) Limits of slack variables.

The limits of slack variables are used to control the value of real power flowing in the transmission line and in the range between zero and one.

$$0 \leq Pc_{imh} \leq 1 \;;\forall i, m \in Nl, \forall h \in T \tag{48}$$

$$0 \leq Pc_{mih} \leq 1 \;;\forall i, m \in Nl, \forall h \in T \tag{49}$$

Therefore, the whole optimization problem of mixed integer programming for the daily security-constrained unit commitment in pool electricity markets can be summarized as:

Min $$\sum_{h\in T}\sum_{i\in NG}\left[\left(SUC_i \times \left(1-U_{i,h-1}\right)\times U_{i,h}\right)+\left(MLC_{i,h}\times U_{i,h}\right)+\left(\sum_{b\in NB_i}\left(c_{ibh}\times P_{Gibh}\right)\right)\right]$$

Subject to

$$\left(\left(P_{Gi,\min}\times U_{i,h}\right)+\sum_{b\in NB_i}P_{Gibh}\right)-P_{i,h}-P_{Di,h}=0\ ;\forall i\in N,\forall h\in T$$

$$P_{Gi,h}-\left(\left(P_{Gi,\min}\times U_{i,h}\right)+\sum_{b\in NB_i}P_{Gibh}\right)=0\ ;\forall i\in NG,\forall h\in T$$

$$P_{imh}+P_{mih}-P_{Limh}=0\ ;\forall i,m\in Nl,\forall h\in T$$

$$\sum_{n=h}^{h+T_{Ui}-1}U_{i,n}\geq T_{Ui}\times\left[U_{i,h}-U_{i,h-1}\right]\ ;\forall i\in NG,\forall h=1,\ldots,T-T_{Ui}+1$$

$$\sum_{n=h}^{T}U_{i,n}\leq\left[\left(T-h+1\right)\times U_{i,h-1}\right]\ ;\forall i\in NG,\forall h=T-T_{Ui}+2,\ldots,T$$

$$\sum_{h=1}^{IF_i}U_{i,h}=0\quad,\ \text{for } IF_i>0\ ;\forall i\in NG$$

$$\sum_{n=h}^{h+T_{Di}-1}\left[1-U_{i,n}\right]\geq T_{Di}\times\left[U_{i,h-1}-U_{i,h}\right]\ ;\forall i\in NG,$$

$$\forall h=IF_i+\min(IF_i,1)+1,\ldots,T-T_{Di}+1$$

$$\sum_{n=h}^{T}\left[1-U_{i,n}-\left(U_{i,h-1}-U_{i,h}\right)\right]\geq 0\ ;\forall i\in NG,\forall h=T-T_{Di}+2,\ldots,T$$

$$\left[P_{Gi,\min}\times U_{i,h}\right]\leq P_{Gi,h}\leq\left[P_{Gi,\max}\times U_{i,h}\right]\ ;\forall i\in NG,\forall h\in T$$

$$0\leq P_{Gibh}\leq P_{Gibh,\Delta}\ ;\forall i\in NG,\forall b\in NB_i,\forall h\in T$$

$$-P_{imh,\max}\leq P_{imh}\leq P_{imh,\max}\ ;\forall i,m\in Nl,\forall h\in T$$

$$-P_{imh,\max}\leq P_{mih}\leq P_{imh,\max}\ ;\forall i,m\in Nl,\forall h\in T$$

$$0\leq Pc_{imh}\leq 1\ ;\forall i,m\in Nl,\forall h\in T$$

$$0\leq Pc_{mih}\leq 1\ ;\forall i,m\in Nl,\forall h\in T$$

where

$$P_{imh} = Pc_{imh} \times \alpha_{imh} \times \left(\delta_{i,h} - \delta_{m,h}\right) \;;\forall i,m \in Nl, \forall h \in T$$

$$P_{mih} = Pc_{mih} \times \alpha_{imh} \times \left(\delta_{m,h} - \delta_{i,h}\right) \;;\forall i,m \in Nl, \forall h \in T$$

$$P_{Limh} = \sqrt{\left(\left(\rho_{Limh} \times \alpha_{imh} \times \left(\delta_{i,h} - \delta_{m,h}\right)\right)^2\right)} \;;\forall i,m \in Nl, \forall h \in T$$

$$P_{i,h} = \sum_{m \in N, i \neq m} P_{imh} \;;\forall i \in N, \forall h \in T$$

$$IF_i = \max\left[0, \left(T_{Di} - RF_i\right) \times \left(1 - U_{i,0}\right)\right] \;;\forall i \in NG$$

Note that for the first iteration, ρ_{Limh} is equal to zero, α_{imh} is set to be the inverse of transmission line reactance connecting between buses *i* and *m*, or $(1/x_{im})$ and the limits of real power flowing in the transmission line in equations (46) and (47) are not considered. Moreover, due to the limit on the efficient mixed integer nonlinear programming tools, this thesis uses mixed integer linear programming technique in CPLEX version 12.4 (The IBM ILOG CPLEX Optimizer Website, 2011) as the solver for mixed integer programming. The appendix shows the converting of optimization problem for the DC-SCUC in pool electricity markets into linear formulation for CPLEX solver.

The optimal results from mixed integer programming for the DC-SCUC in pool electricity markets are the generating units status (online or offline) and allocation of the bids of real power generations at each bus based on the price offered with considering physical limits of the power systems in dc load flow model within 24 hours. We use only the generating units status (online or offline) as the input to the SPOPF by HCM (step bidding price optimal power flow by hybrid computational method) for every hour. The results of that part are used in the case that there are no the duplicated results of the generating units status (online or offline) within 24 hours from the first whole iteration to the current whole iteration. Therefore, we must run two whole iterations at least.

2.2 Hourly SPOPF by HCM

The calculation of this part is the same as the calculation of hybrid computational method for step bidding price optimal power flow in pool electricity markets (SPOPF) in section 1 to find the optimal solution in each hour where the input are the generating units status (online or offline) in each hour, which are obtained from DC-SCUC part.

The whole hybrid computational method for SP-SCUC in pool electricity markets will end when the results of the generating units status (online or offline) for 24 hours at the end of the whole iteration repeat themselves.

In the case where generating units status (online or offline) from the current iteration are different from all previous iterations, the results from hourly SPOPF are used to update hourly transmission lines loss factors, hourly transmission lines operation factors and maximum limits of transmission lines. The updated parameters are then sent back to DC-SCUC part. The updating procedures for those parameters are detailed as follows.

a) Updating hourly transmission lines loss factors.

The loss factor for transmission line between buses *i* and *m* for hour *h*, ρ_{Limh}, can be updated by the following equation.

$$\rho_{Limh} = \begin{cases} \dfrac{P_{Limh}}{P_{Pimh}}, \text{for } r_{im} \neq 0 \text{ and/or } P_{Pimh} \neq 0 \\ 0 \quad , \text{for } r_{im} = 0 \text{ and/or } P_{Pimh} = 0 \end{cases} \tag{50}$$

b) Updating hourly transmission lines operation factors.

The operating factor for transmission line between buses *i* and *m* for hour *h*, α_{imh}, can be updated by the following equation.

$$\alpha_{imh} = \begin{cases} \dfrac{P_{Pimh}}{\left|\delta_{i,h} - \delta_{m,h}\right|}, \text{for } r_{im} \neq 0 \text{ and/or } \left|\delta_{i,h} - \delta_{m,h}\right| \neq 0 \\ \dfrac{1}{x_{im}} \quad , \text{for } r_{im} = 0 \text{ and/or } \left|\delta_{i,h} - \delta_{m,h}\right| = 0 \end{cases} \tag{51}$$

c) Updating maximum limits of transmission lines.

Since dc load flow does not include reactive power, the maximum line limits in DC-SCUC must consider the maximum real power flow resulting from maximum apparent power flow in SPOPF. If the transmission lines do not violate their apparent power flow limits in SPOPF, the maximum real power flow in DC-SCUC could be assumed to be the maximum apparent power flow limits. Therefore, the maximum limits of transmission lines are updated by:

$$P_{imh,\max} = \begin{cases} P_{Pimh} \quad , \text{for } S_{Pimh} = S_{imh,\max} \\ S_{imh,\max} \text{ , for } S_{Pimh} < S_{imh,\max} \end{cases} \tag{52}$$

The algorithm for proposed HCM for SP-SCUC in pool electricity markets are summarized as follows:

Step 1: For the first iteration, ρ_{Limh} is equal to zero, α_{imh} is set to be the inverse of reactance of transmission line connecting between buses *i* and *m*, or $(1/x_{im})$ and the limits of real power flowing in the transmission line in equations (46) and (47) are not considered.

Step 2: Solve optimization problem of the DC-SCUC according to equations (30)-(49).

Step 3: Set the generating units status (online or offline) in each hour according to DC-SCUC for solving hourly SPOPF.

Step 4: Solve hourly SPOPF as explained in section 1 for 24 hours.

Step 5: Check for convergence of the SP-SCUC by comparing the results from previous iterations with the current one.

- If the results of the generating unit status from the current iteration are the same as those from any previous iteration, the whole algorithm for SP-SCUC converges.

- If the results of the generating unit status from the current iteration are different from all previous iterations, all transmission line loss factors for each hour, all transmission line operation factors and maximum limits of transmission lines must be updated according to equations (50)-(52), and go to step 2 for the next iteration.

RESULTS AND DISCUSSION

Results

The proposed hybrid computational method for step bidding price optimal power flow and transmission congestion management (HCM for SPOPF-TCM) in electricity markets and hybrid computational method with mixed integer programming for the daily security-constrained unit commitment (HCM for DC-SCUC) in pool electricity markets are tested on a modified IEEE 30 bus system as shown in Figure 2. One of the synchronous condensers in the original system at bus 5 is modified to be a generator. All generators are capable of producing reactive power in a range between -40 to 80 MVar. The ranges of reactive power generated from all synchronous condensers are as given in the original IEEE 30 bus (Department of Electrical Engineering at University of Washington, 2008). Voltage magnitudes for all buses are bounded between 0.95 and 1.05 pu. Transformer tap ratios are all bounded between 0.9 and 1.1 pu. Transmission line limits are modified from the original IEEE 30 bus as shown in Table 1.

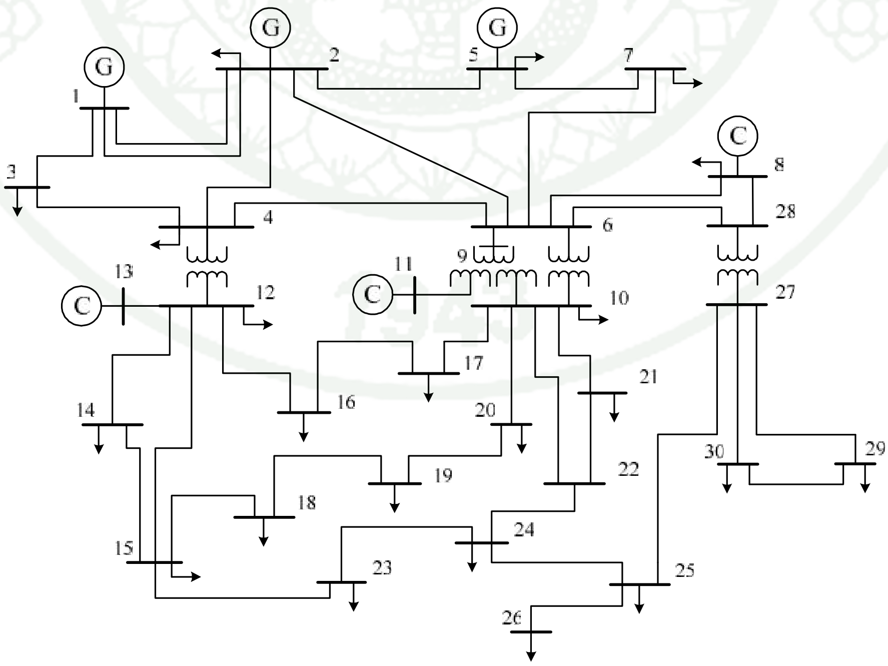

Figure 2 Modified IEEE 30 bus test system

Table 1 Branch rating data of modified IEEE 30 bus test system

Branch No.	Bus No's	Rating MVA	Branch No.	Bus No's	Rating MVA
1	1-2	120	22	15-18	16
2	1-3	100	23	18-19	16
3	2-4	100	24	19-20	32
4	3-4	100	25	10-20	32
5	2-5	65	26	10-17	32
6	2-6	65	27	10-21	32
7	4-6	65	28	10-22	32
8	5-7	100	29	21-22	32
9	6-7	65	30	15-23	16
10	6-8	32	31	22-24	16
11	6-9	65	32	23-24	16
12	6-10	32	33	24-25	16
13	9-11	65	34	25-26	16
14	9-10	65	35	25-27	16
15	4-12	65	36	28-27	65
16	12-13	65	37	27-29	16
17	12-14	32	38	27-30	16
18	12-15	32	39	29-30	16
19	12-16	32	40	8-28	32
20	14-15	16	41	6-28	32
21	16-17	16			

1. Test results of HCM for SPOPF-TCM in electricity markets

In Figure 2, all generators are capable of producing real power from 30 to 200 MW.

1.1 Test results of HCM for SPOPF in pool electricity markets

Besides the modified IEEE 30 bus system data, The additional data required in this case study is the bidding price-power block of the system, which are given in Figure 3, where $G_{i,b}$ is the bidding price of block *b* for generator at bus *i*.

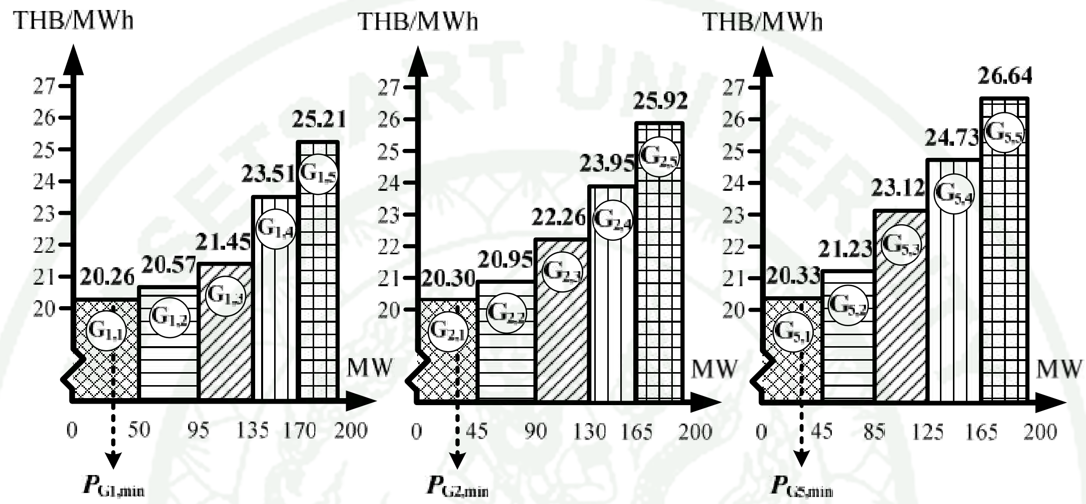

Figure 3 Data of bidding price-power block for the system generators in pool electricity markets

Four interesting case studies are presented. The differences among the four cases are transmission line limits. In order to illustrate the proposed algorithm, the transmission line limits are modified from the original basecase as followed:

Case 1.1.a: Transmission line limits are as shown in Table 1, which is considered basecase.

Case 1.1.b: The maximum limit of transmission line between buses 2 and 4 is changed to 40 MVA.

Case 1.1.c: The maximum limit of transmission line between buses 2 and 5 is changed to 30 MVA.

Case 1.1.d: The maximum limit of transmission line between buses 3 and 4 is changed to 43 MVA, and between buses 4 and 12 is changed to 32 MVA.

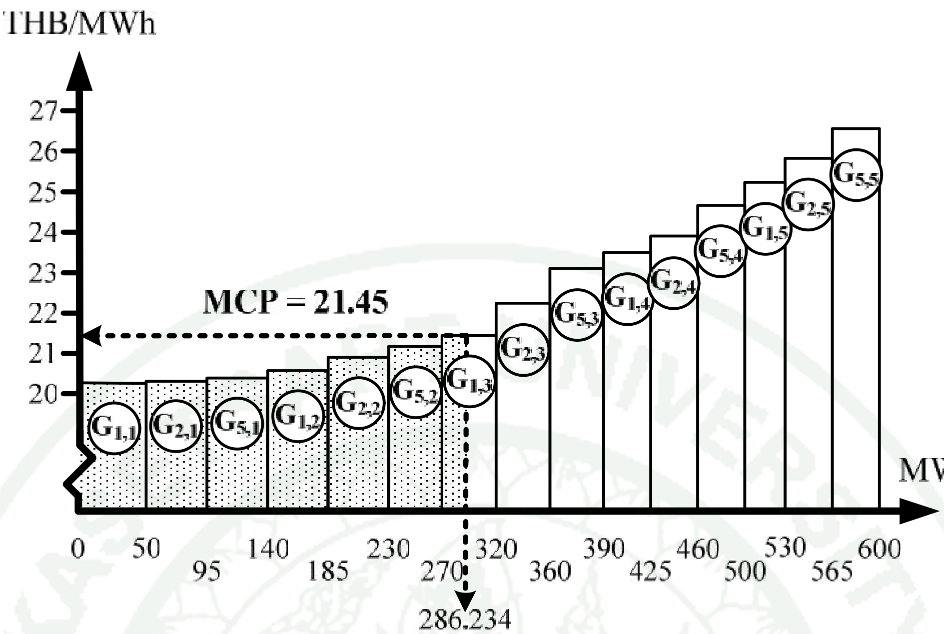

Figure 4 Result of market dispatch in pool electricity markets

The real power generations obtained from the first iteration of market dispatch are shown in Figure 4, where Figure 5 shows the optimal dispatch from SPOPF for basecase with calculated system losses. The results from HCM for SPOPF are the same as the market dispatch except for the additional losses. This is due to the redundant in transmission line capacity in the IEEE 30 bus system. In other words, the redundant in transmission line capacity allows the system to dispatch real power generators in the most economical way.

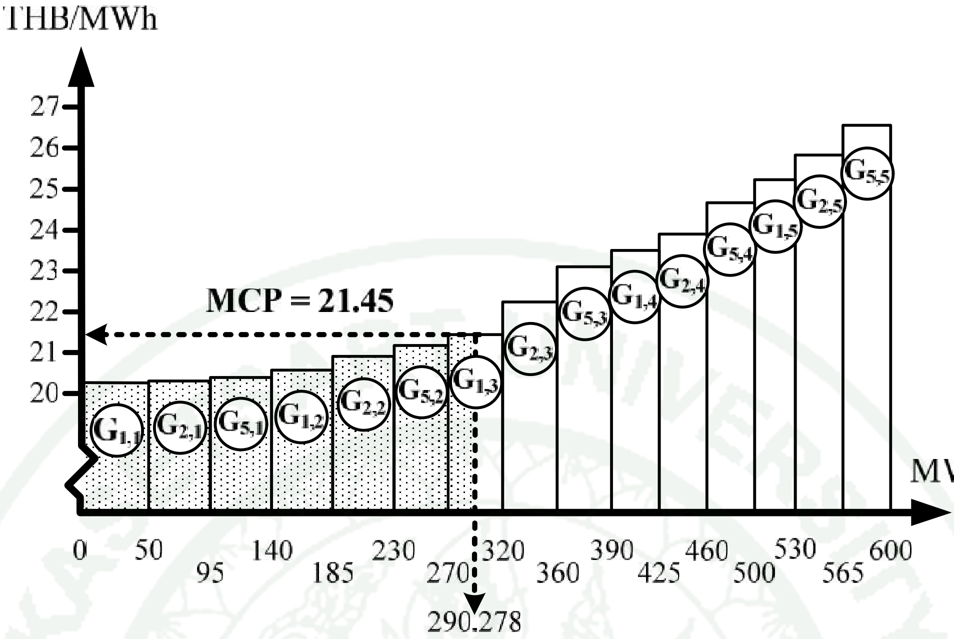

Figure 5 Results of basecase market and power flow dispatch in pool electricity markets

It would be interesting to modify some transmission line capacities to illustrate how the algorithm works when power flow constraints are met. In Case 1.1.b, the transmission line limit between buses 2 and 4 is changed from 100 MVA to 40 MVA. The power flow in that transmission line now violates the capacity limit and the optimal real power generations must be adjusted. The optimal results of Case 1.1.b are shown in Figure 6.

In the next case study, the transmission line limit between buses 2 and 5 is changed from 65 MVA to 30 MVA, while the limit on line 2-4 is back to 100 MVA. The optimal results of Case 1.1.c are shown in Figure 7.

In the last case study, the transmission line limit between buses 3 and 4 is changed from 100 MVA to 43 MVA, and the line limit between buses 4 and 12 is changed from 65 MVA to 32 MVA, while the other line limits are the same as those from basecase. The optimal results of Case 1.1.d are shown in Figure 8.

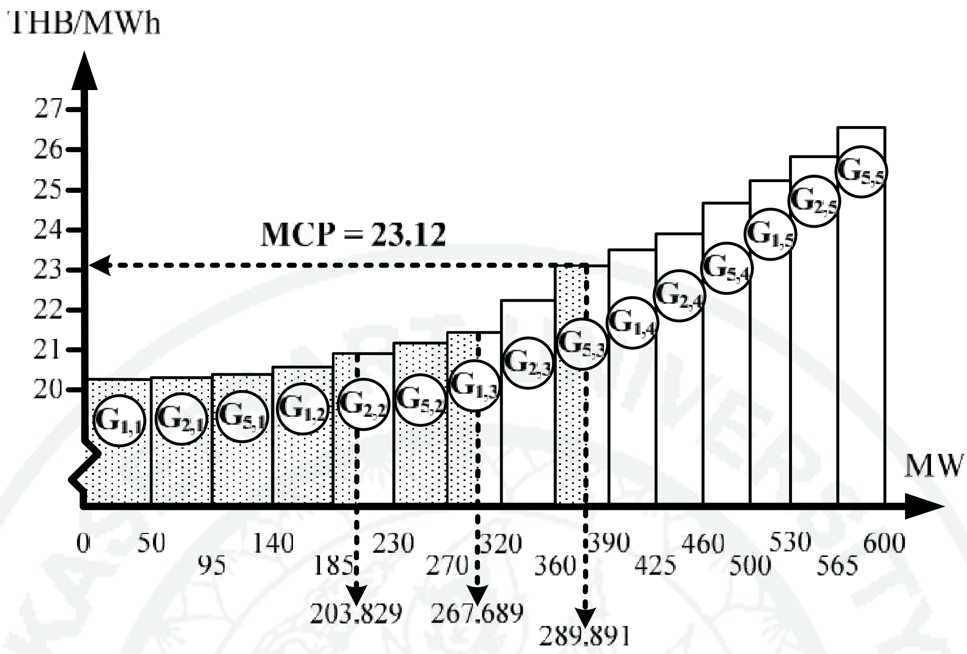

Figure 6 Results of market and power flow dispatch when limit of line 2-4 is 40 MVA in pool electricity markets

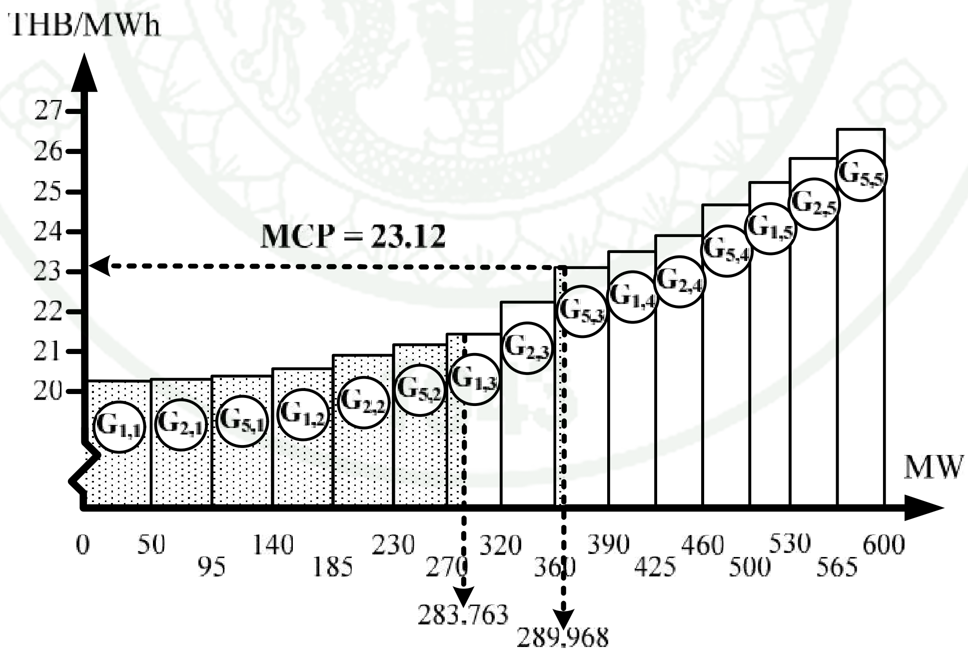

Figure 7 Result of market and power flow dispatch when limit of line 2-5 is 30 MVA in pool electricity markets

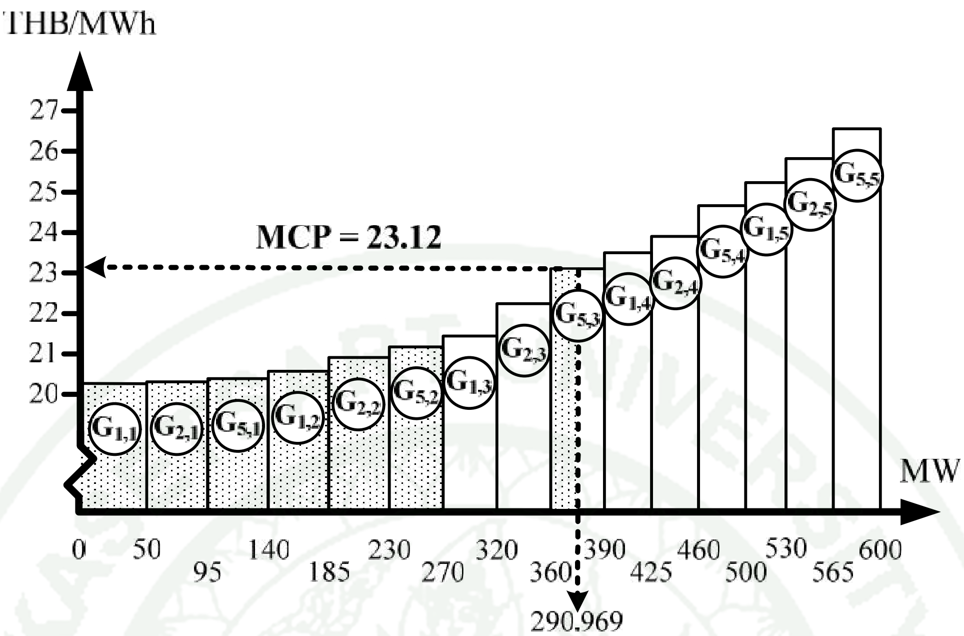

Figure 8 Result of market and power flow dispatch when limit of line 3-4 is 43 MVA and line 4-12 is 32 MVA in pool electricity markets

1.2 Test results of HCM for SPOPF in mixed pool-bilateral electricity markets

Two interesting case studies are presented to illustrate this algorithm. The differences among the two cases are power purchase agreement. The additional data for these case studies are the purchase agreements for bilateral and multilateral contracts, and bidding price-power block in the system.

The details for case studies are as followed:

Case 1.2.a: There are one bilateral contract and multilateral contracts from one generator to several loads.

Power purchase agreement on the pool for Case 1.2.a is equal to 173.4 MW. The data for bilateral contract and multilateral contracts for Case 1.2.a are given as shown in table 2 and table 3, respectively. The data for bidding price-power block in Case 1.2.a are given as shown in Figure 9, where $G_{i,b}$ is the bidding price of block *b* for generator at bus *i*.

Table 2 Data of bilateral contract in Case 1.2.a in mixed pool-bilateral electricity markets

Gen. at bus	Load at bus	Power purchase agreement (MW)
1	5	94.2

Table 3 Data of multilateral contracts in Case 1.2.a in mixed pool-bilateral electricity markets

Contract No.	Gen. at bus	Load at bus	Power purchase agreement (Gen.) (MW)	Power purchase agreement (Load) (MW)	Curtailment weight
		3		2.4	0.1519
1	1	4	15.8	7.6	0.4810
		10		5.8	0.3671

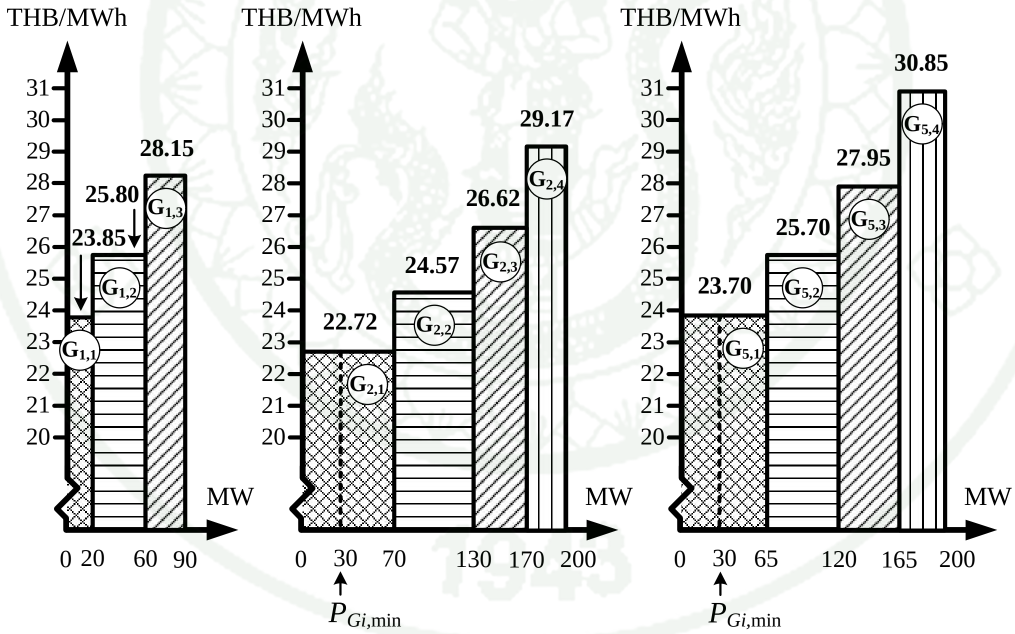

Figure 9 Data of bidding price-power block for the system generators in Case 1.2.a in mixed pool-bilateral electricity markets

Case 1.2.b: There are several bilateral contracts and multilateral contracts from one generator to several loads.

Power purchase agreement on the pool in Case 1.2.b is changed to 83.4 MW. The data for bilateral contracts and multilateral contracts for Case 1.2.b are given as shown in table 4 and table 5, respectively. The data for bidding price-power block in the system in Case 1.2.b, which are given as shown in Figure 10, where $G_{i,b}$ is the bidding price of block *b* for generator at bus *i*.

Table 4 Data of bilateral contracts in Case 1.2.b in mixed pool-bilateral electricity markets

Gen. at bus	Load at bus	Power purchase agreement (MW)	
1	2	21.7	168.7
	5	94.2	
	7	22.8	
	8	30	

Table 5 Data of multilateral contracts in Case 1.2.b in mixed pool-bilateral electricity markets

Contract No.	Gen. at bus	Load at bus	Power purchase agreement (Gen.) (MW)	Power purchase agreement (Load) (MW)	Curtailment weight
1	1	10	31.3	5.8	0.1853
		14		6.2	0.1981
		24		8.7	0.2779
		30		10.6	0.3387

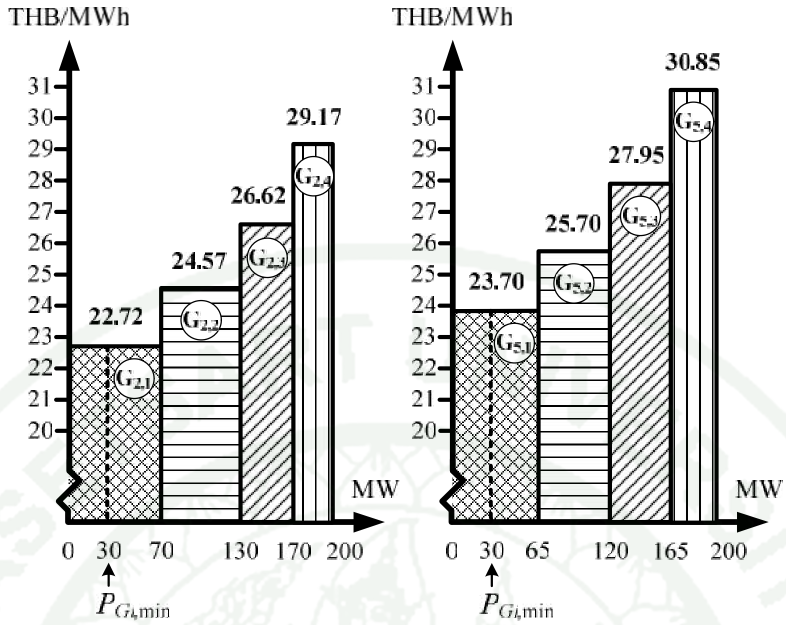

Figure 10 Data of bidding price-power block for the system generators in Case 1.2.b in mixed pool-bilateral electricity markets

The optimal results of real power dispatch for Case 1.2.a are shown in Table 6, where system losses are compensated by the pool. Results of real power dispatch on pool for Case 1.2.a with compensated system losses are illustrated in Figure 11. The corresponding bilateral contract and multilateral contracts for this case could be dispatch successfully as shown in table 7 and table 8, respectively.

Table 6 Results of real power dispatch for pool in Case 1.2.a

Gen. at bus	Real power dispatch in the system (MW)			
	Bilateral	Multilateral	Pool	Total
1	94.20	15.80	20	130
2	0	0	96.401	96.401
5	0	0	65	65
Total	94.20	15.80	181.401	291.401

Table 7 Result of real power dispatch for bilateral contract in Case 1.2.a

Gen. at bus	Load at bus	Power purchase agreement (MW)	Power purchased (MW)
1	5	94.2	94.2

Table 8 Results of real power dispatch for multilateral contracts in Case 1.2.a

Contract No.	Gen. at bus	Load at bus	Power purchase agreement (Gen.) (MW)	Real power generated (Gen.) (MW)	Power purchase agreement (Load) (MW)	Real power received (Load) (MW)
1	1	3	15.8	15.8	2.4	2.4
		4			7.6	7.6
		10			5.8	5.8

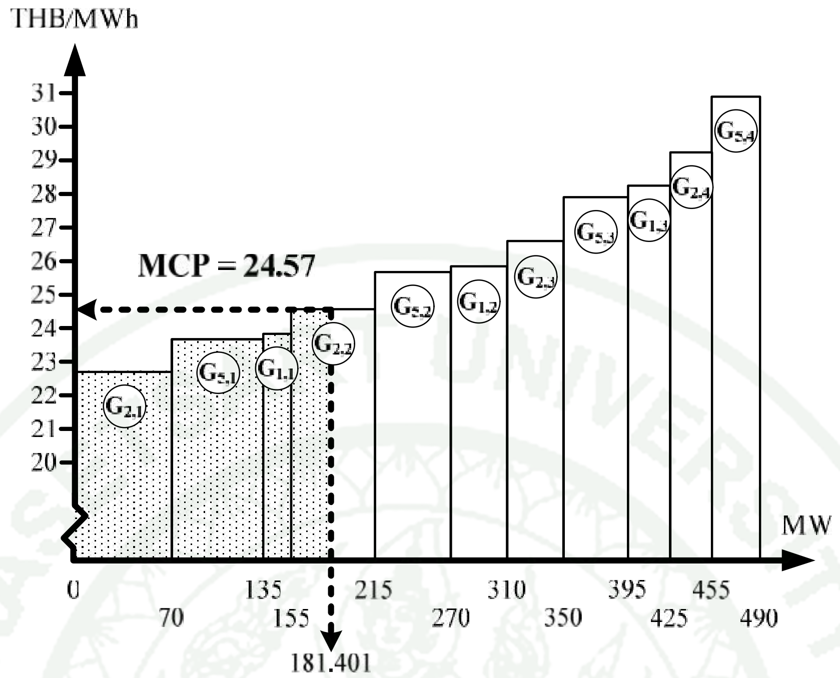

Figure 11 Results of real power dispatch on pool in Case 1.2.a in mixed pool-bilateral electricity markets

In Case 1.2.b, the power purchase agreement on pool is changed from 173.4 MW to 83.4 MW, bilateral contracts are changed from 94.2 MW to 168.7 MW and multilateral contracts are changed from 15.8 MW to 31.3 MW.

The optimal results of real power dispatch for Case 1.2.b are shown in Table 9, where system losses are still compensated by the pool. Results of real power dispatch on pool for Case 1.2.b with compensated system losses are illustrated in Figure 12. The corresponding four bilateral contracts and multilateral contracts for this case are dispatch as shown in table 10 and table 11, respectively.

Table 9 Results of real power dispatch for pool in Case 1.2.b

Gen. at bus	Real power dispatch in the system (MW)			
	Bilateral	Multilateral	Pool	Total
1	161.147	28.639	0	189.786
2	0	0	76.633	76.633
5	0	0	30.623	30.623
Total	161.147	28.639	107.256	297.042

Table 10 Results of real power dispatch for bilateral contracts in Case 1.2.b

Gen. at bus	Load at bus	Power purchase agreement (MW)		Power purchased (MW)	
1	2	21.7	168.7	20.045	161.147
	5	94.2		91.718	
	7	22.8		21.133	
	8	30		28.251	

Table 11 Results of real power dispatch for multilateral contract in Case 1.2.b

Contract No.	Gen. at bus	Load at bus	Power purchase agreement (Gen.) (MW)	Real power generated (Gen.) (MW)	Power purchase agreement (Load) (MW)	Real power received (Load) (MW)
1	1	10	31.3	28.639	5.8	5.3068
		14			6.2	5.6734
		24			8.7	7.9588
		30			10.6	9.7000

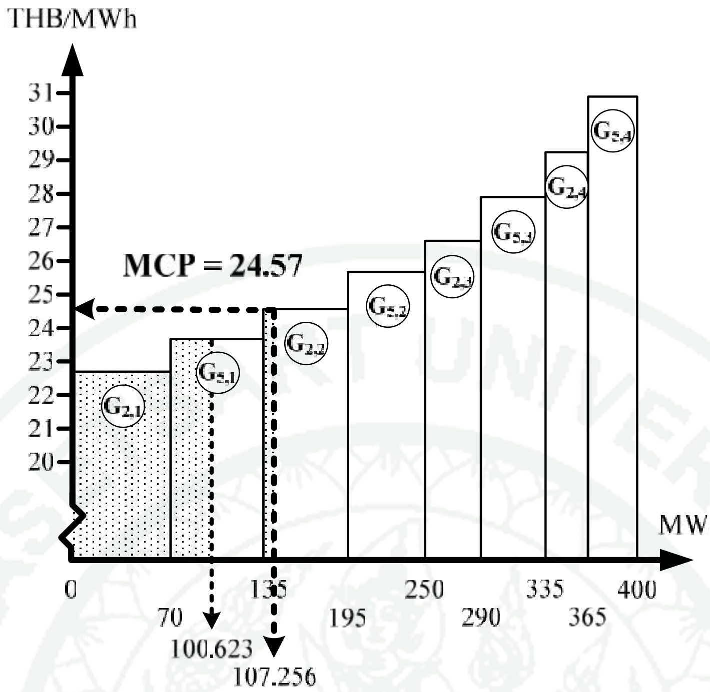

Figure 12 Results of real power dispatch on pool in Case 1.2.b in mixed pool-bilateral electricity markets

1.3 Test results of HCM for SPOPF-TCM in mixed pool-bilateral electricity markets

Two case studies are presented to illustrate this algorithm. The additional data for these case studies are bilateral contracts and multilateral contracts with willingness-to-pay and bidding price-power block.

The details for these case studies are:

Case 1.3.a: Power purchase agreement on the pool is equal to 173.4 MW. The bilateral contracts and multilateral contracts with generator at bus 1 is 110 MW. The data for bilateral contracts and multilateral contracts with willingness-to-pay in Case 1.3.a are given as shown in table 12 and table 13, respectively.

The data for bidding price-power block are given as shown in Figure 13, where $G_{i,b}$ is the bidding price of block *b* for generator at bus *i*.

Table 12 Data of bilateral contracts with willingness-to-pay in Case 1.3.a

Gen. at bus	Load at bus	Power purchase agreement (MW)	Willingness-To-Pay (THB/MWh)
1	5	94.2	1.75

Table 13 Data of multilateral contracts with willingness-to-pay in Case 1.3.a

Contract No.	Gen. at bus	Load at bus	Power purchase agreement (Gen.) (MW)	Power purchase agreement (Load) (MW)	Willingness-To-Pay (THB/MWh)	Curtailment weight
1	1	3	15.8	2.4	1.45	0.1519
		4		7.6	1.68	0.4810
		10		5.8	1.55	0.3671

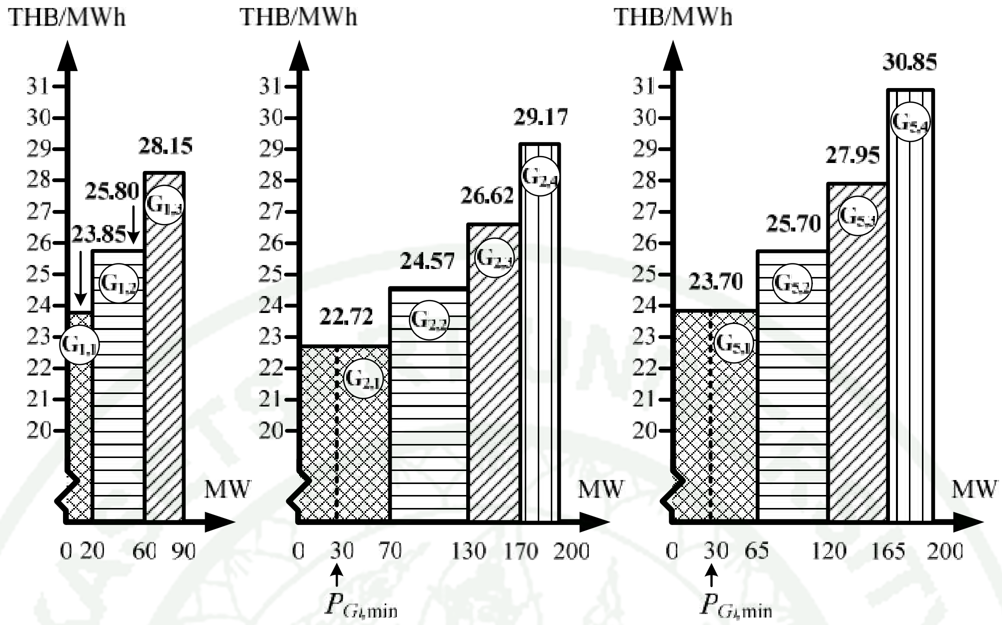

Figure 13 Data of bidding price-power block for the system generators in Case 1.3.a in mixed pool-bilateral electricity markets considering transmission congestion management

Case 1.3.b: Power purchase agreement on the pool is changed to 83.4 MW. The bilateral contracts and multilateral contracts with generator at bus 1 are changed to 200 MW. The data for bilateral contracts and multilateral contracts with willingness-to-pay in Case 1.3.b is given as shown in table 14 and table 15, respectively.

The data for bidding price-power block in the system, which are given as shown in Figure 14, where $G_{i,b}$ is the bidding price of block *b* for generator at bus *i*.

Table 14 Data of bilateral contracts with willingness-to-pay in Case 1.3.b

Gen. at bus	Load at bus	Power purchase agreement (MW)		Willingness-To-Pay (THB/MWh)
1	2	21.7	168.7	1.68
	5	94.2		1.75
	7	22.8		1.70
	8	30		1.72

Table 15 Data of multilateral contracts with willingness-to-pay in Case 1.3.b

Contract No.	Gen. at bus	Load at bus	Power purchase agreement (Gen.) (MW)	Power purchase agreement (Load) (MW)	Willingness-To-Pay (THB/MWh)	Curtailment weight
1	1	10	31.3	5.8	1.52	0.1853
		14		6.2	1.55	0.1981
		24		8.7	1.65	0.2779
		30		10.6	1.71	0.3387

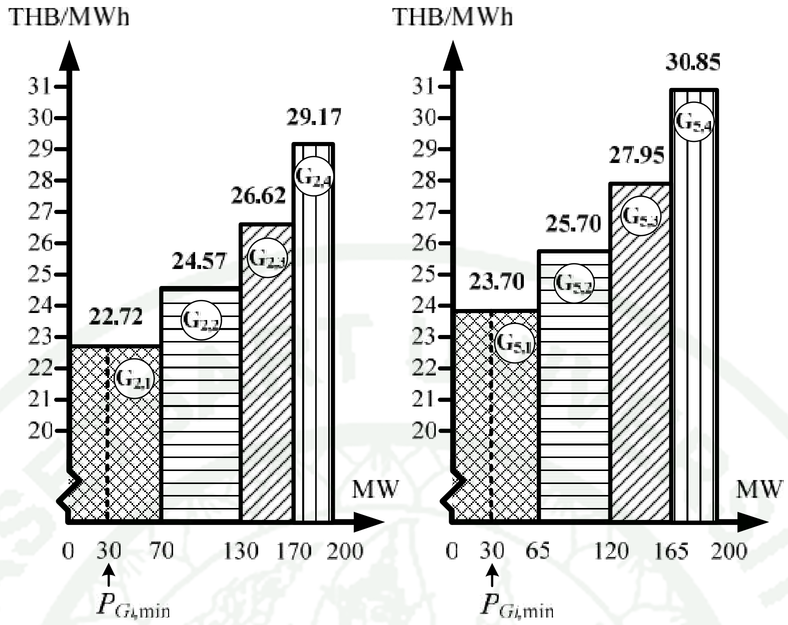

Figure 14 Data of bidding price-power block for the system generators in case 1.3.b in mixed pool-bilateral electricity markets considering transmission congestion management

The optimal results of real power dispatch for Case 1.3.a are shown in Table 16, where system losses are compensated by the pool. Results of real power dispatch on pool for Case 1.3.a with compensated system losses are illustrated in Figure 15. The corresponding bilateral contract and multilateral contracts for this case could be dispatch as shown in table 17 and table 18, respectively.

Table 16 Result of real power dispatch in Case 1.3.a in mixed pool-bilateral electricity markets considering transmission congestion management

Gen. at bus	Real power dispatch in the system (MW)			
	Bilateral	Multilateral	Pool	Total
1	94.20	15.80	20	130
2	0	0	96.401	96.401
5	0	0	65	65
Total	94.20	15.80	181.401	291.401

Table 17 Results of real power dispatch on bilateral contract with willingness-to-pay in Case 1.3.a

Gen. at bus	Load at bus	Power purchase agreement (MW)	Power purchased (MW)
1	5	94.2	94.2

Table 18 Result of real power dispatch on multilateral contracts with willingness-to-pay in Case 1.3.a

Contract No.	Gen. at bus	Load at bus	Power purchase agreement (Gen.) (MW)	Real power generated (Gen.) (MW)	Power purchase agreement (Load) (MW)	Real power received (Load) (MW)
1	1	3 4 10	15.8	15.8	2.4 7.6 5.8	2.4 7.6 5.8

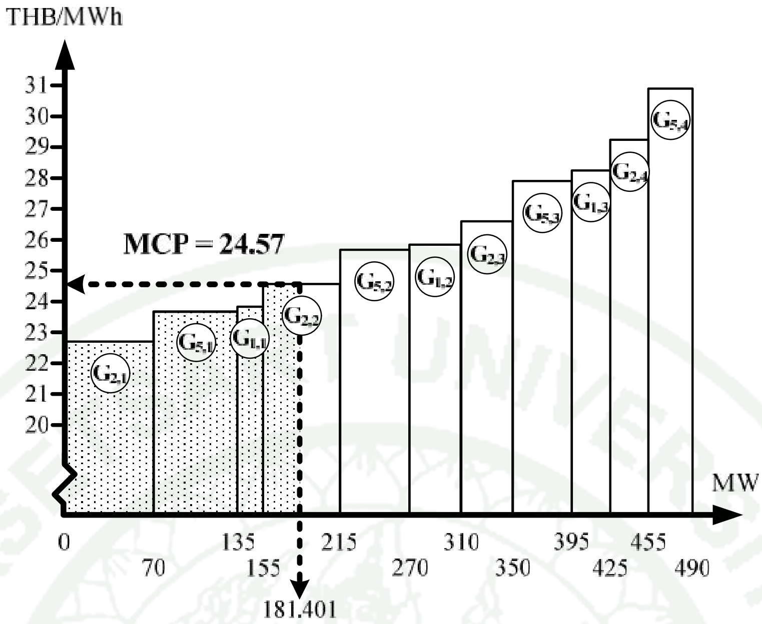

Figure 15 Results of real power dispatch on pool in Case 1.3.a in mixed pool-bilateral electricity markets considering transmission congestion management

In some cases, power purchase agreements on bilateral and multilateral contracts between cheaper generator and load buses may cause transmission congestions in the system. In such cases, ISO will manage the transmission congestions using willingness-to-pay obtained from bilateral and multilateral contracts. Case 1.3.b is an example of such case, where the propose algorithm can give the results as follows.

The optimal results of Case 1.3.b for real power dispatch in mixed pool-bilateral electricity markets considering transmission congestion management are shown in Table 19. Results of real power dispatch on pool for Case 1.3.b with compensated system losses are illustrated in Figure 16.

Table 19 Result of real power dispatch in Case 1.3.b in mixed pool-bilateral electricity markets considering transmission congestion management

Gen. at bus	Real power dispatch in the system (MW)			
	Bilateral	Multilateral	Pool	Total
1	168.70	21.0864	0	189.786
2	0	0	76.633	76.633
5	0	0	30.623	30.623
Total	168.70	21.0864	107.256	297.042

The results of real power dispatch on bilateral contracts with willingness-to-pay for Case 1.3.b are shown in Table 20, where the amount of power purchase agreement from generator 1 is met.

However, the real power dispatches on multilateral contracts with willingness-to-pay in Case 1.3.b are not met with the agreement due to transmission line congestions as shown in Table 21. The curtailment on multilateral contracts are subject to the willingness-to-pay.

Table 20 Results of real power dispatch on bilateral contracts with willingness-to-pay in Case 1.3.b

Gen. at bus	Load at bus	Power purchase agreement (MW)		Power purchased (MW)	
1	2	21.7	168.7	21.7	168.7
	5	94.2		94.2	
	7	22.8		22.8	
	8	30		30	

Table 21 Results of real power dispatch on multilateral contracts with willingness-to-pay in Case 1.3.b

Contract No.	Gen. at bus	Load at bus	Power purchase agreement (Gen.) (MW)	Real power generated (Gen.) (MW)	Power purchase agreement (Load) (MW)	Real power received (Load) (MW)
1	1	10	31.3	21.0864	5.8	3.9074
		14			6.2	4.1769
		24			8.7	5.8611
		30			10.6	7.1411

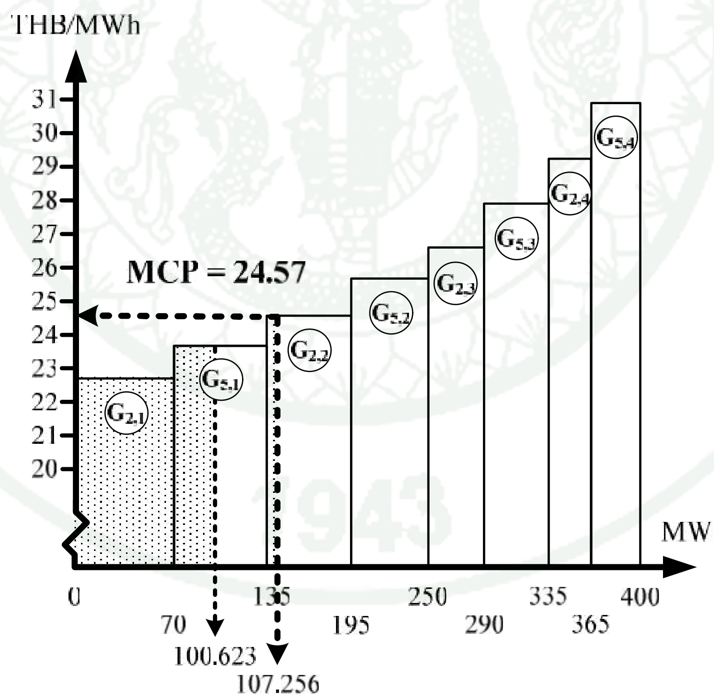

Figure 16 Result of real power dispatch on pool in Case 1.3.b in mixed pool-bilateral electricity markets considering transmission congestion management

2. Test results of HCM SP-SCUC in pool electricity markets

The additional data that are used for HCM SP-SCUC in pool electricity markets are bidding price-power block, minimum load and startup cost, minimum uptime and downtime and hourly load for one day.

The data for bidding price-power block used in DC-SCUC are given as shown in Figure 17, where $G_{i,b}$ is the bidding price of block *b* for generator at bus *i*. The minimum load and startup costs for generators in DC-SCUC are given in table 22. The minimum uptime and downtime for generators in DC-SCUC are given in table 23. Finally, the hourly load of the system in DC-SCUC are given as shown in table 24, where Pd is the system real power load in each hour and Qd is the system reactive power load in each hour.

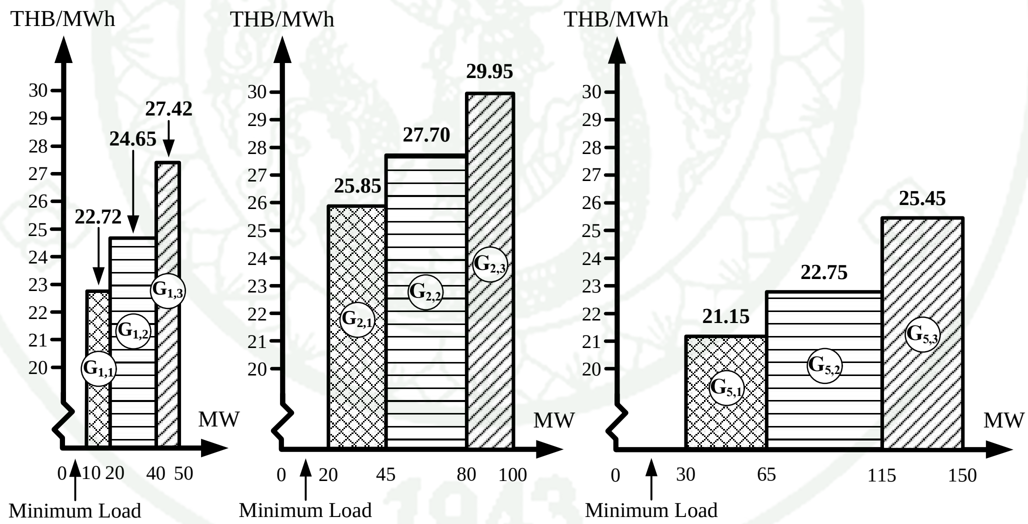

Figure 17 Data of bidding price-power block for the system generators in DC-SCUC

Table 22 Data of minimum load and startup cost for generators in DC-SCUC

Gen. at bus	Minimum load (MW)	Minimum load cost (THB/h)	Startup cost (THB)
1	10	275	65
2	20	600	150
5	30	750	185

Table 23 Data of minimum uptime and downtime for generators in DC-SCUC

Gen. at bus	Minimum uptime (h)	Minimum downtime (h)
1	2	2
2	2	2
5	3	3

Table 24 Data for hourly load within 24 hours of the modified IEEE 30 bus in DC-SCUC

Hour no.	Pd (MW)	Qd (Mvar)	Hour no.	Pd (MW)	Qd (Mvar)
1	190.577	84.865	13	289.198	128.782
2	185.439	82.577	14	293.602	130.743
3	177.718	79.139	15	289.198	128.782
4	189.285	84.290	16	283.297	126.154
5	184.147	82.002	17	256.256	114.113
6	195.243	86.943	18	252.381	112.387
7	191.722	85.375	19	271.700	120.990
8	240.754	107.209	20	272.992	121.565
9	265.270	118.126	21	263.978	117.551
10	280.713	125.004	22	247.243	110.099
11	293.602	130.743	23	226.632	100.921
12	279.451	124.441	24	195.128	86.892

Four interesting case studies are presented. The differences among the four cases are transmission line limits in some hours. In order to illustrate the proposed algorithm, the transmission line limits are modified from the original basecase as followed:

Case 2.a: Transmission line limits are as shown in Table 1 for every hour, which is considered basecase.

Case 2.b: In hour 1, the maximum limit of transmission line between buses 5 and 7 is changed to 50 MVA.

Case 2.c: In hour 5, the maximum limit of transmission line between buses 5 and 7 is changed to 40 MVA.

Case 2.d: In hour 1, the maximum limit of transmission line between buses 5 and 7 is changed to 50 MVA. And in hour 5, the maximum limit of transmission line between buses 5 and 7 is changed to 40 MVA.

The results for Case 2.a or basecase can be shown as follows.

The results of the committed schedule from hour 0 to 24 and the daily cost in the case of SCUC without considering transmission line limits and losses are shown in Table 25, where U is the generator bus number. Table 26 shows the results of the commitment schedule from hour 0 to 24 and the daily cost for SCUC in basecase, where U is the generator bus number. Table 27 shows the results of real power dispatch of each generator within 24 hours for SCUC in basecase.

Table 25 DC-SCUC without considering transmission line limits and losses

Daily cost = 143638.309 THB																									
U	Hours (0-6)							Hours (7-12)						Hours (13-18)						Hours (19-24)					
1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
5	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Table 26 SP-SCUC in basecase

Daily cost = 146726.226 THB																									
U	Hours (0-6)							Hours (7-12)						Hours (13-18)						Hours (19-24)					
1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
5	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Table 27 Generation dispatch in basecase

Hour no.	Generator at bus (MW)			Total
	1	2	5	(MW)
1	44.159	0	150	194.159
2	40	0	148.921	188.921
3	40	0	140.849	180.849
4	42.850	0	150	192.850
5	40	0	147.569	187.569
6	48.893	0	150	198.893
7	45.320	0	150	195.320
8	50	45.061	150	245.061
9	50	70.197	150	270.197
10	50	86.132	150	286.132
11	50	99.494	150	299.494
12	50	84.826	150	284.826
13	50	94.921	150	294.921
14	50	99.494	150	299.494
15	50	94.921	150	294.921
16	50	88.805	150	288.805
17	50	60.933	150	260.933
18	50	56.958	150	256.958
19	50	76.822	150	276.822
20	50	78.155	150	278.155
21	50	68.868	150	268.868
22	50	51.695	150	251.695
23	40	45	145.502	230.502
24	48.777	0	150	198.777

It would be interesting to modify some transmission line capacities to illustrate how the algorithm works. In Case 2.b, in hour 1, the transmission line limit between buses 5 and 7 is changed from 100 MVA to 50 MVA. The power flow in the transmission line now violates the capacity limit and the optimal real power generations and commitment schedule must be adjusted. Table 28 shows the results of the commitment schedule from hour 0 to 24 and the daily cost for SCUC in Case 2.b, where U is the generator bus number.

Table 29 shows the results of real power dispatch of each generator within 24 hours for SCUC in Case 2.b.

Table 28 SP-SCUC in Case 2.b

Daily cost = 147017.961 THB																									
U	Hours (0-6)							Hours (7-12)						Hours (13-18)						Hours (19-24)					
1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
5	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Table 29 Generation dispatch in Case 2.b

Hour no.	Generator at bus (MW)			Total
	1	2	5	(MW)
1	40	20	133.581	193.581
2	40	20	128.238	188.238
3	40	0	140.849	180.849
4	42.850	0	150	192.850
5	40	0	147.569	187.569
6	48.893	0	150	198.893
7	45.320	0	150	195.320
8	50	45.061	150	245.061
9	50	70.197	150	270.197
10	50	86.132	150	286.132
11	50	99.494	150	299.494
12	50	84.826	150	284.826
13	50	94.921	150	294.921
14	50	99.494	150	299.494
15	50	94.921	150	294.921
16	50	88.805	150	288.805
17	50	60.933	150	260.933
18	50	56.958	150	256.958
19	50	76.822	150	276.822
20	50	78.155	150	278.155
21	50	68.868	150	268.868
22	50	51.695	150	251.695
23	40	45	145.502	230.502
24	48.777	0	150	198.777

In the next case study, in hour 5, the transmission line limit between buses 5 and 7 is changed from 100 MVA to 40 MVA, while the other line limits and hours are the same as those from basecase. Table 30 shows the results of the commitment schedule from hour 0 to 24 and the daily cost for SCUC in Case 2.c, where U is the generator bus number.

Table 31 shows the results of real power dispatch of each generator within 24 hours for SCUC in Case 2.c.

Table 30 SP-SCUC in Case 2.c

Daily cost = 146929.441 THB																									
U	Hours (0-6)							Hours (7-12)						Hours (13-18)						Hours (19-24)					
1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
5	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Table 31 Generation dispatch in Case 2.c

Hour no.	Generator at bus (MW)			Total (MW)
	1	2	5	
1	44.159	0	150	194.159
2	40	0	148.921	188.921
3	40	0	140.849	180.849
4	42.850	0	150	192.850
5	40	32.503	114.135	186.638
6	40	20	138.441	198.441
7	40	20	134.773	194.773
8	50	45.061	150	245.061
9	50	70.197	150	270.197
10	50	86.132	150	286.132
11	50	99.494	150	299.494
12	50	84.826	150	284.826
13	50	94.921	150	294.921
14	50	99.494	150	299.494
15	50	94.921	150	294.921
16	50	88.805	150	288.805
17	50	60.933	150	260.933
18	50	56.958	150	256.958
19	50	76.822	150	276.822
20	50	78.155	150	278.155
21	50	68.868	150	268.868
22	50	51.695	150	251.695
23	40	45	145.502	230.502
24	48.777	0	150	198.777

In the last case study, in hour 1, the transmission line between buses 5 and 7 is changed from 100 MVA to 50 MVA and in hour 5, the transmission line limit between buses 5 and 7 is changed from 100 MVA to 40 MVA, while the other line limits and hours are the same as those from basecase. Table 32 shows the results of the commitment schedule from hour 0 to 24 and the daily cost for SCUC in Case 2.d, where U is the generator bus number.

Table 33 shows the results of real power dispatch of each generator and in the system within 24 hours for SCUC in Case 2.d.

Table 32 SP-SCUC in Case 2.d

Daily cost = 147221.176 THB																									
U	Hours (0-6)							Hours (7-12)						Hours (13-18)						Hours (19-24)					
1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	0	1	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
5	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Table 33 Generation dispatch in Case 2.d

Hour no.	Generator at bus (MW)			Total (MW)
	1	2	5	
1	40	20	133.581	193.581
2	40	20	128.238	188.238
3	40	0	140.849	180.849
4	42.850	0	150	192.850
5	40	32.503	114.135	186.638
6	40	20	138.441	198.441
7	40	20	134.773	194.773
8	50	45.061	150	245.061
9	50	70.197	150	270.197
10	50	86.132	150	286.132
11	50	99.494	150	299.494
12	50	84.826	150	284.826
13	50	94.921	150	294.921
14	50	99.494	150	299.494
15	50	94.921	150	294.921
16	50	88.805	150	288.805
17	50	60.933	150	260.933
18	50	56.958	150	256.958
19	50	76.822	150	276.822
20	50	78.155	150	278.155
21	50	68.868	150	268.868
22	50	51.695	150	251.695
23	40	45	145.502	230.502
24	48.777	0	150	198.777

Discussion

1. Discussion of HCM for SPOPF in pool, mixed pool-bilateral and SPOPF-TCM

1.1 Discussion of HCM for SPOPF in pool electricity markets

The real power generations obtained from the first iteration of market dispatch are shown in Figure 4. They are the same for every case study since they result from selecting the combination of bidding price blocks offered by all generators in ascending order to cover the total system demand of 286.234 MW. The system losses have not yet taken into account in the first iteration. The MCP for this case is equal to 21.45 THB/MWh, which is the bidding price at block 3 of generator 1.

The results from the market dispatch are checked for violations of any operational constraints with the power flow dispatch part, where system losses are also obtained. Figure 5 shows the results from the power flow dispatch for basecase with calculated system losses. The chosen blocks and the MCP are the same as those from the market dispatch part with slightly higher value in the last chosen block due to the additional real power losses.

The optimal results of Case 1.1.b are shown in Figure 6. The power flow dispatch part in this case limits the real power generation of generator 1 and reduces the real power generation of generator 2 since they cause the overflow in line 2-4. The shortfall demand must be compensated by dispatching the next available bidding block. Unfortunately, the next bidding block is the block of generator 2, $G_{2,3}$, which has been limited as well. Clearly, the available bidding block with the lowest price is $G_{5,3}$, which belongs to generator 5. The power flow dispatch part thus recalculates the amount of real power generation for generator 5. The redispatched amount of generator 5 stays within the block $G_{5,3}$, which also agrees with the market dispatch result. Therefore, the optimal results of the hybrid computational method are found. The MCP of 23.12 THB/MWh in this case is the price at block 3 of generator 5, which is higher than the basecase's due to the redispatch to avoid the overloaded transmission line.

The optimal results of Case 1.1.c are shown in Figure 7. The real power generation dispatched from generator 2 is greater than that of Case 1.1.b due to the large capacity on line 2-4. However, it is still limited because the capacity limit on line 2-5 is met. Moreover, the real power generation of generator 1 is reduced. Therefore, The additional block to compensate for the reduced real power generation must be from generator 5 resulting in the dispatching of the block $G_{5,3}$ with the MCP of 23.12 THB/MWh.

The optimal results of Case 1.1.d are shown in Figure 8. In this case, the real power generations from generators 1 and 2 are limited at exactly two blocks by the power flow dispatch part. As a result, the real power generation from generator 5 must rise to meet the shortfall demand. The MCP of this case comes from the last bidding price block for the real power generation requirement, which is the block $G_{5,3}$ with the price of 23.12 THB/MWh.

1.2 Discussion of HCM for SPOPF in mixed pool-bilateral electricity markets

The real power dispatch for Case 1.2.a is shown in table 6. Generator 1 produces real power as power purchase agreements on bilateral and multilateral contracts, while system losses are compensated by generators in pool. The total real power generation in the system is 291.401 MW. Table 7 shows the results on the bilateral contract for Case 1.2.a, where generator 1 and load at bus 5 have a contract of 94.2 MW of real power generation. Table 8 shows the results on multilateral contract for Case 1.2.a, where generator 1 and a group of loads (buses 3, 4 and 5) have multilateral contracts of 15.8 MW. Figure 11 shows the results of real power generation for Case 1.2.a with system losses. The MCP for this case is equal to 24.57 THB/MWh, which is the bidding price at block 2 of generator 2. The generator at bus 1 produced 20 MW with $P_{G1,1}$. Generator 2 produced 96.401 MW with $P_{G2,1}$ and $P_{G2,2}$. Generator 5 produced 65 MW with $P_{G5,1}$. The total real power generation on the pool is 181.401 MW.

The real power dispatch in Case 1.2.b is shown in table 9. Generator 1 cannot produce real power as agreed on bilateral and multilateral contracts because transmission lines reach their maximum limits. These transmission lines are the transmission lines between bus 1 and bus 2, between bus 2 and bus 5 and between bus 6 and bus 8. System losses are compensated by generators in the pool. The total real power generation in the system is 297.042 MW. Table 10 shows the results on the bilateral contracts for Case 1.2.b, where generator 1 and load at bus 2, bus 5, bus 7 and bus 8 have bilateral contracts for real power of 20.045 MW, 91.718 MW, 21.133 MW and 28.251 MW, respectively. The total real power generation on generator at bus 1 is 161.147 MW. Table 11 shows the results on multilateral contracts for Case 1.2.b, where generator 1 and the group of loads (buses 10, 14, 24 and 30) transfer the total amount of real power of 28.639 MW. The real power purchased from multilateral contracts at load buses (buses 10, 14, 24 and 30) are 5.3068 MW, 5.6734 MW, 7.9588 MW and 9.7000 MW, respectively. The dispatch results for multilateral contracts are according to their curtailment weights. Figure 12 shows the results of real power generation for Case 1.2.b with calculated system losses. The real power generation of generator 5 is limited due to the overflow in the lines mentioned above. The MCP for this case is equal to 24.57 THB/MWh, which is the bidding price at block 2 of generator 2. Generator 2 produced 76.633 MW with $P_{G2,1}$ and $P_{G2,2}$. Generator 5 produced 30.623 MW with $P_{G5,1}$. The total real power generation on the pool is 107.256 MW.

1.3 Discussion of HCM for SPOPF-TCM in mixed pool-bilateral electricity markets

The real power dispatch in the system in Case 1.3.a is shown in table 16. Generator 1 can produced real power at the amount of power purchase agreements on bilateral and multilateral contracts, while generators on the pool compensated for system losses. The total real power generation in the system is 291.401 MW. Table 17 shows the results on a bilateral contract for Case 1.3.a, where generator 1 and load at bus 5 successfully transfer real power of 94.2 MW as agreed on the bilateral contract. Table 18 shows the results on multilateral contracts for Case 1.3.a, where generator 1 and the group of loads (buses 3, 4 and 5) have multilateral contracts of 15.8 MW. Figure 15 shows the results of real power generation for Case 1.3.a with calculated system losses. The MCP for this case is equal to 24.57 THB/MWh, which is the bidding price at block 2 of generator 2. Generator 1 produced 20 MW with $P_{G1,1}$. Generator 2 produced 96.401 MW with $P_{G2,1}$ and $P_{G2,2}$. Generator 5 produced 65 MW with $P_{G5,1}$. The total real power generation on the pool is 181.401 MW.

The real power dispatch in Case 1.3.b is shown in table 19. Generator 1 can produce real power at the amount of power purchase agreements on bilateral contracts, but not on multilateral contracts because some transmission lines reach their maximum limits. These transmission lines are the transmission lines between bus 1 and bus 2, between bus 2 and bus 5 and between bus 6 and bus 8. The total real power generation in the system is 297.042 MW. Table 20 shows the results on bilateral contracts for Case 1.3.b. Generator 1 and load at bus 2, bus 5, bus 7 and bus 8 successfully transfer real power of 21.7 MW, 94.2 MW, 22.8 MW and 30 MW respectively as agreed on the bilateral contracts. The total real power generation on generator 1 is 168.7 MW. Table 21 shows the results on multilateral contracts for Case 1.3.b, where generator 1 and the group of loads (buses 10, 14, 24 and 30) transfer the total amount of real power of 21.0864 MW. The power purchased at load buses (buses 10, 14, 24 and 30) are 3.9074 MW, 4.1769 MW, 5.8611 MW and 7.1411 MW, respectively. The dispatch results for multilateral contracts are according to their curtailment weights. This is because the load at bus 10 and bus 14 send their willingness-to-pay lower than the others. Therefore, the amount of real power agreement in multilateral contracts that cannot be met by generator 1 is equal to 10.214 MW. Figure 16 shows the results of real power generation from generators for Case 1.3.b with calculated system losses. The real power generation of generator 5 is limited due to the overflow in the lines mentioned above. The MCP for this case is equal to 24.57 THB/MWh, which is the bidding price at block 2 of generator 2. Generator 2 produced 76.633 MW with $P_{G2,1}$ and $P_{G2,2}$. Generator 5 produced 30.623 MW with $P_{G5,1}$. The total real power generation on the pool is 107.256 MW.

2. Discussion of HCM for SP-SCUC in pool electricity markets

The commitment schedule obtained from the first iteration of the DC-SCUC is shown in Table 25. It is the same for every case study since it results from selecting the combination of bidding price blocks in ascending order, startup cost and minimum load cost offered by all generators to cover the total system demand in each hour. The system losses and transmission line limits have not yet taken into account in the first iteration. The daily generation cost for this case is equal to 143638.309 THB, which is the least daily cost compared to every case study. The generator at bus 2 is offline at hour 24 because it follows the condition in equation (42). Therefore can be offline for h equal to $T - T_{Di} + 2$ to T .

The commitment schedule of the whole SP-SCUC for basecase (Case 2.a) is shown in table 26. The daily generation cost is equal to 146726.226 THB. The real power generations of all generators within 24 hours are shown in table 27, which they are considering transmission line limits and losses. In hours 11 and 14, the transmission line between buses 6 and 8 is congested since the total loads in these hours are the peak load of the day.

The commitment schedule of Case 2.b is shown in table 28. Generator 2 must be started in hour 1 because it makes the power flow in the transmission line between buses 5 and 7 remain within its capacity limit. However, generator 2 must stay on until hour 2 because of its minimum uptime. The daily cost is equal to 147017.961 THB. The real power generations of all generators within 24 hours are shown in table 29 with considering transmission line limits and losses. In hours 11 and 14, the transmission line between buses 6 and 8 is congested the same as in basecase. Generator 2 produces real power at its minimum load in hours 1 and 2.

The commitment schedule of Case 2.c is shown in table 30. Generator 2 must be started in hour 5 because it makes the power flow in the transmission line between buses 5 and 7 stay at its capacity limit. Generator 2 must continue running in hour 6 because of its minimum uptime. It must continue running in hour 7 because it has to satisfy its minimum downtime while it must be online again in hour 8 for requirement of real power generations to meet the total load at that hour. The daily cost in this case is equal to 146929.441 THB. The real power generations of all generators within 24 hours are shown in table 31 with considering transmission line limits and losses. In hours 11 and 14, the transmission line between buses 6 and 8 is congested the same as in basecase. Generator 5 is limited because the overflow in the lines that explained above in hour 5. Generator 2 produces real power at its minimum load in hours 6 and 7.

The commitment schedule of Case 2.d is shown in table 32. Generator 2 must be started at hour 1 and continue running to hour 2 as in Case 2.b. It must be shut down in hours 3 and 4 due to the economic reasons, however satisfying its minimum downtime. Moreover, it must be restarted in hour 5 and run continuously to hours 6, 7, 8 and so on until hour 23 as in Case 2.c. The daily cost is equal to 147221.176 THB. The real power generations of all generators within 24 hours are shown in table 33 with considering transmission line limits and losses. In hours 11 and 14, the transmission line between buses 6 and 8 is congested the same as in basecase. Generator 5 is limited its real power generation in hour 5 while generator 2 produces real power at its minimum load in hours 6 and 7 as we explained in Case 2.c.

CONCLUSION AND RECOMMENDATION

Conclusion

1. Conclusion of HCM for SPOPF in pool, mixed pool-bilateral and SPOPF-TCM

1.1 Conclusion of HCM for SPOPF in pool electricity markets

The proposed hybrid computational method is based on the deterministic methods, for optimal power dispatch in electricity markets with objective function of nonderivative step bidding prices. The hybrid computational method separated problem formulation into two parts: the market dispatch part and the power flow dispatch part. The market dispatch and the power flow dispatch worked coordinately to optimally dispatch participated generators based on submitted bidding prices and physical limits of the system. The proposed method was tested on a modified IEEE 30 bus system with four different cases of transmission line limits. The studies showed that the proposed method gave the optimal results for every case. In the case where there was no line limit violation, the optimal power dispatch in the system was consistent with the ascending bidding prices. In the cases where line limits were violated, the output from some generators may be limited due to the line flow limits, resulting in the increasing of the generation output at other generators in the more expensive bidding price blocks. The next bidding price block was chosen by the power flow dispatch part based on the system optimal power flow.

1.2 Conclusion of HCM for SPOPF in mixed pool-bilateral electricity markets

This method includes the variables and functions for bilateral and multilateral contracts into the former HCM for SPOPF. The proposed method was tested on a modified IEEE 30 bus system with two different cases of real power load assigned to pool, bilateral and multilateral transactions. The studies showed that the proposed method gave the optimal results for every case. In the case where there was no congestion on transmission lines, generators from bilateral and multilateral transactions can produce the real power generations as promised, while the real power generations in pool were consistent with the offering prices in ascending order. However, in the case where transmission lines were congested, bilateral and/or multilateral contracts may not receive the amount of agreement. In this case, the output from some generators in the pool may be limited due to the line flow limits, resulting in the increasing of the generation output at other generators in the more expensive bidding price blocks. The next bidding price block was chosen by the power flow dispatch part based on the system optimal power flow.

1.3 Conclusion of HCM for SPOPF-TCM in mixed pool-bilateral electricity markets

This method includes transmission congestion management into the HCM for SPOPF with bilateral and multilateral contracts. The congestion management is based on the willingness-to-pay bidding submitted by bilateral and multilateral participants. The proposed method was tested on a modified IEEE 30 bus system with two different cases of real power load assigned to pool, bilateral and multilateral transactions. The studies showed that the proposed method gave the optimal results for every case. In the case where there was no congestion on transmission lines, generators from bilateral and multilateral transactions can produce the real power generations as promised, while the real power generations in pool were consistent with the offering prices in the ascending order. In addition, the willingness to pay does not affect the real power dispatch in the system. However, in the case where transmission lines were congested, the willingness to pay offered by bilateral and multilateral transactions was the indicator for optimal power dispatch. The transactions with the higher willingness to pay were considered by ISO to fully generate the generation output under the power purchase agreement. Moreover, in the case of congestions, the real power dispatch by pool may be affected. The output from some generators may be limited due to the line flow limits, resulting in the increasing of the generation output at other generators in the more expensive bidding price blocks. The next bidding price block was chosen by the power flow dispatch part based on the system optimal power flow.

2. Conclusion of HCM for SP-SCUC in pool electricity markets

The proposed hybrid computational method with mixed integer programming is based on the deterministic methods, for optimal commitment schedule and power dispatch in pool electricity markets with objective function of nonderivative step bidding prices, startup cost and minimum load cost in each hour from participated generators within 24 hours. The hybrid computational method with mixed integer programming separates the calculation into two parts: the daily security-constrained unit commitment by mixed integer programming part; and the step bidding price optimal power flow by hybrid computational method in each hour part. The daily security-constrained unit commitment by mixed integer programming and the step bidding price optimal power flow by hybrid computational method in each hour worked coordinately to optimally commitment schedule and dispatch participated generators based on submitted bidding prices, startup cost, minimum load cost and physical limits of the system within 24 hours. The proposed method was tested on a modified IEEE 30 bus system with four different cases of transmission line limits in some hours. The studies showed that the proposed method gave the optimal results for every case. In the case where there was no line limit change, the optimal commitment schedule in the system within 24 hours was the same as the schedule where there was no considering transmission line limits and losses. However, their daily cost are different because the effect of transmission line losses in each hour and transmission line violations in some hours that increase the amount of real power generations in each hour. In the cases where line limits were changed in some hours, the output from some generators in some hours may be limited due to the line flow limits, resulting in the starting some generators to produce real power at its minimum load and involved increasing of the generation output at other generators in the more expensive startup costs, minimum load costs and bidding price blocks. Moreover, some generators must run continuously in the next hour due to its minimum uptime. In some cases, some generators must be run at some hours because they must satisfy its minimum downtime, resulting in the running of the generators at that hour.

Recommendation

1. Recommendation of HCM for SPOPF in pool, mixed pool-bilateral and SPOPF-TCM

The proposed hybrid computational method could be extended by considering ancillary services in the future work.

2. Recommendation of HCM for SP-SCUC in pool electricity markets

The proposed hybrid computational method with mixed integer programming could be extended by considering bilateral and multilateral contracts along with the pool model in the system. Moreover, the optimal commitment schedule can take into account both ancillary services and transmission congestion management in the future work.

LITERATURE CITED

Loi Lei Lai. 2001. **Power System Restructuring and Deregulation: Trading, Performance and Information Technology**. John Wiley & Sons, Ltd., West Sussex.

Shahidehpour, M., H. Yamin and Z. Li. 2002. **Market Operations in Electric Power Systems: Forecasting, Scheduling and Risk Management**. John Wiley & Sons, Inc., New York.

Kirschen, D. and G. Strbac. 2004. **Fundamentals of Power System Economics**. John Wiley & Sons, Ltd., West Sussex.

Singh, H., S. Hao and A. Papalexopoulos. 1998. Transmission congestion management in competitive electricity markets. **IEEE Transactions on Power Systems** 13 (2): 672-680.

Fang, R. S. and A. K. David. 1999. Transmission congestion management in an electricity market. **IEEE Transactions on Power Systems** 14 (3): 877-883.

Ma, J., Y. H. Song, Q. Lu and S. Mei. 2002. Framework for dynamic congestion management in open power markets. **IEE Proceedings Generation, Transmission and Distribution** 149 (2): 157-164.

Wang, X., Y. H. Song, Q. Lu and Y. Z. Sun. 2002. Optimal allocation of transmission rights in systems with FACTS devices. **IEE Proceedings Generation, Transmission and Distribution** 149 (3): 359-366.

Yamina, H. Y. and S. M. Shahidehpour. 2003. Congestion management coordination in the deregulated power market. **Electric Power System Research** 65: 119-127.

Kumar, A., C. Srivastava and S. N. Singh. 2004. A zonal congestion management approach using real and reactive power rescheduling. **IEEE Transactions on Power Systems** 19 (1): 554-562.

Stamtsis, G. C. and I. Erlich. 2004. Congestion analysis and participants' behaviour in a pool market. **IEE Proceedings Generation, Transmission and Distribution** 151 (1): 127-131.

Litvinov, E. 2010. Design and operation of the locational marginal prices-based electricity markets. **IET Generation, Transmission and Distribution** 4 (2): 315-323.

Ma, X., and D. Sun. 1998. Energy and ancillary service dispatch in a competitive Pool. **IEEE/PES Power Engineering Review** 18: 54-56.

Cheung, K. W., P. Shamsollahi, D. Sun, J. Milligan and M. Potishnak. 2000. Energy and ancillary service dispatch for the interim ISO New England electricity market. **IEEE Transactions on Power Systems** 15 (3): 968-974.

Wen, F. S. and A. D. David. 2002. Optimally co-ordinated bidding strategies in energy and ancillary service markets. **IEE Proceedings Generation, Transmission and Distribution** 149 (3): 331-338.

Lin, X., A. K. David and C. W. Yu. 2003. Reactive power optimization with voltage stability consideration in power market systems. **IEE Proceedings Generation, Transmission and Distribution** 150 (3): 305-310.

Wu, T., M. Rothleder, Z. Alaywan and A. D. Papalexopoulos. 2004. Pricing energy and ancillary services in integrated market systems by an optimal power flow. **IEEE Transactions on Power Systems** 19 (1): 339-347.

Ugedo, A., E. Lobato, A. franco, L. Rouco, J. Fernandez-Caro and J. Chofre. 2006. Strategic bidding in sequential electricity markets. **IEE Proceedings Generation, Transmission and Distribution** 153 (4): 431-442.

PJM Independent system operator. 2012. **Market Operations**. Available Source: http://www.pjm.com, February 15, 2012.

Wood, A. J. and B. F. Wollenberg. 1984. **Power Generation, Operation and Control**. 2nd ed. John Wiley & Sons, Inc.

Senjyu, T., H. Yamashiro, K. Shimabukuro, K. Uezato and T. Funabashi. 2003. Fast solution technique for large-scale unit commitment problem using genetic algorithm. **IEE Proceedings Generation, Transmission and Distribution** 150 (6): 753–760.

Fu, Y., M. Shahidehpour and Z. Li. 2005. Security-constrained unit commitment with AC constraints. **IEEE Transactions on Power Systems** 20 (3): 1538-1550.

Guan, X., S. Guo and Q. Zhai. 2005. The conditions for obtaining feasible solutions to security-constrained unit commitment problems. **IEEE Transactions on Power Systems** 20 (4): 1746–1756.

Martinez-Crespo, J., J. Usaola and J. L. Fernandez. 2006. Security-constrained optimal generation scheduling in large-scale power systems. **IEEE Transactions on Power Systems** 21 (1): 321–332.

Fu, Y. and M. Shahidehpour. 2007. Fast SCUC for large-scale power systems. **IEEE Transactions on Power Systems** 22 (4): 2144-2151.

Eslamian, M., S. H. Hosseinian and B. Vahidi. 2009. Bacterial foraging-based solution to the unit-commitment problem. **IEEE Transactions on Power Systems** 24 (3): 1478-1488.

Lotfjou, A., M. Shahidehpour and Y. Fu. 2010. Security-constrained unit commitment with AC/DC Transmission Systems. **IEEE Transactions on Power Systems** 25 (1): 531-542.

Sioshansi, R., R. O'Neill and S. S. Oren. 2008. Economic consequences of alternative solution methods for centralized unit commitment in day-ahead electricity markets. **IEEE Transactions on Power Systems** 23 (2): 344-352.

Johnson, R. B., S. S. Oren and A. J. Svoboda. 1997. Equity and efficiency of unit commitment in competitive electricity markets. **Utilities Policy** 6: 9-19.

Guan, X., Q. Zhai, and A. Papalexopoulos. 2003. Optimization based methods for unit commitment: Lagrangian relaxation versus general mixed integer programming, pp. 1095-1100. *In* **Proceedings of IEEE Power Engineering Society General Meeting**. 13-17 July 2003. China.

Streiffert, D., R. Philbrick, and A. Ott. 2005. A mixed integer programming solution for market clearing and reliability analysis, pp. 2724-2731. *In* **Proceedings of IEEE Power Engineering Society General Meeting**. 12-16 June 2005. San Francisco, CA, USA.

Li, T. and M. Shahidehpour. 2005. Price-based unit commitment: A case of Lagrangian relaxation versus mixed integer programming. **IEEE Transactions on Power Systems** 20 (4): 2015-2025.

Carpentier, J. 1962. Contribution a. 'l'etude du Dispatching Economique. **Bulletin de la Societe Francaise des Electriciens** 3: 431-447.

Happ, H. H. 1977. Optimal power dispatch a comprehensive survey. **IEEE Transactions on Power Apparatus and Systems** 96: 841-851.

Momoh, J. A., M. E. El-Hawary and R. Adapa. 1999. A review of selected optimal power flow literature to 1993 part I: nonlinear and quadratic programming approaches. **IEEE Transactions on Power Systems** 14 (1): 96-104.

Momoh, J. A., M. E. El-Hawary and R. Adapa. 1999. A review of selected optimal power flow literature to 1993 part II: newton, linear programming and interior point methods. **IEEE Transactions on Power Systems** 14 (1): 105-111.

Dommel, H. W. and W. F. Tinney. 1968. Optimal power flow solutions. **IEEE Transactions on Power Apparatus and Systems** 87: 1866-1876.

Shen, C. M. and M. A. Laughton. 1969. Determination of optimum power system operating conditions. **Proceedings of IEEE** 116 (2): 225-239.

El-Abiad, A. H. and F. J. Jaimes. 1969. A method for optimum scheduling of power and voltage magnitude. **IEEE Transactions on Power Apparatus and Systems** 88 (4): 413-422.

Sasson, A. M. 1969. Combined use of the parallel and Fletcher-Powell non-linear programming methods for optimal load flows. **IEEE Transactions on Power Apparatus and Systems** 88 (10): 1530-1537.

Sasson, A. M. 1970. Decomposition technique applied to the non-linear programming load flow method. **IEEE Transactions on Power Apparatus and Systems** 89 (1): 78-82.

Sasson, A. M., F. Viloria and F. Aboytes. 1973. Optimal load flow solution using the hessian matrix. **IEEE Transactions on Power Apparatus and Systems** 92: 31-41.

Alsac, O. and B. Stott. 1974. Optimal load flow with steady state security. **IEEE Transactions on Power Apparatus and Systems** 93: 745-754.

Billinton, R. and S. S. Sachdeva. 1972. Optimal real and reactive power operation in a hydro-thermal system. **IEEE Transactions on Power Apparatus and Systems** 91: 1405-1411.

Barcelo, W. R., W. W. Lemmon and H. R. Koen. 1977. Optimization of the real-time dispatch with constraints for secure operation of bulk power systems. **IEEE Transactions on Power Apparatus and Systems** 96 (3): 741-757.

Housos, E. C. and G. D. Irisarri. 1982. A sparse variable metric optimization applied to the solution of power system problems. **IEEE Transactions on Power Apparatus and Systems** 101: 195-202.

Shoults, R. R. and D. T. Sun. 1982. Optimal power flow based on P-Q decomposition. **IEEE Transactions on Power Apparatus and Systems** 101: 397-405.

Divi, R. and H. K. Kesavan. 1982. A shifted penalty function approach for optimal load-flow. **IEEE Power Engineering Review** 2 (9): 67-68.

Talukdar, S. N., T. C. Giras and V. K. Kalyan. 1983. Decompositions for optimal power flows. **IEEE Transactions on Power Apparatus and Systems** 102 (12): 3877-3884.

Momoh, J. A. 1989. A generalized quadratic-based model for optimal power flow, pp, 261-271. *In* **Proceedings of IEEE International Conference on Systems, Man and Cybernetics**. 14-17 November 1989. Cambridge, MA, USA.

Lin, C. E., Y. Y. Hong and C. C. Chuko. 1987. Real-time fast economic dispatch. **IEEE Transactions on Power Systems** 2 (4): 968-972.

Rehn, C. J., J. A. Bubenko and D. Sjelvgven. 1989. Voltage optimization using augmented lagrangian functions and quasi-newton techniques. **IEEE Transactions on Power Systems** 4 (4): 1470-1483.

Habiabollahzadeh, H., G. X. Luo and A. Semlyen. 1989. Hydrothermal optimal power flow based on a combined linear and non-linear programming methodology. **IEEE Transactions on Power Systems** 4 (2): 530-537.

Ponrajah, R. A. and F. D. Galiana. 1989. The minimum cost optimal power flow problem solved via the restart homotopy continuation method. **IEEE Transactions on Power Systems** 4 (1): 139-148.

Reid, G. F. and L. Hasdorf. 1973. Economic dispatch using quadratic Programming. **IEEE Transactions on Power Apparatus and Systems** 92: 2015-2023.

Wollenberg, B. F. and W. O. Stadlin. 1974. A real time optimizer for security dispatch. **IEEE Transactions on Power Apparatus and Systems** 93: 1640-1649.

Giras, T. C., N. Sarosh and S. N. Talukdar. 1977. A fast and robust variable metric method for optimum power flows. **IEEE Transactions on Power Apparatus and Systems** 96 (3): 741-757.

Burchett, R. C., H. H. Happ and K. A. Wirgau. 1982. Large scale optimal power flow. **IEEE Transactions on Power Apparatus and Systems** 101: 3722-3732.

Aoki, K. and T. Satoh. 1982. Economic dispatch with network security constraints using parametric quadratic programming. **IEEE Transactions on Power Apparatus and Systems** 101 (9): 3502-3512.

Contaxis, G. C., B. C. Papadias and C. Delkis. 1983. Decoupled power system security dispatch. **IEEE Transactions on Power Apparatus Systems** 102: 3049-3056.

Talukdar, S. N., T. C. Giras and V. K. Kalyan. 1983. Decompositions for optimal power flows. **IEEE Transactions on Power Apparatus and Systems** 102 (12): 3877-3884.

Burchett, R. C., H. H. Happ and D. R. Vierath. 1984. Quadratically convergent optimal power flow. **IEEE Transactions on Power Apparatus and Systems** 103: 3267-3276.

El-Kady, M. A., B. D. Bell, V. F. Carvalho, R. C. Burdhett, H. H. Happ and D. R. Vierath. 1986. Assessment of real-time optimal voltage control. **IEEE Transactions on Power Systems** 1 (2): 99-107.

Aoki, K., A. Nishikori and R. T. Yokoyana. 1987. Constrained load flow using recursive quadratic programming. **IEEE Transactions on Power Systems** 2 (1): 8-16.

Papalexopoulos, A. D., C. F. Imparato and F. F. Wu. 1989. Large scale optimal power flow: effects of initialization decoupling and discretization. **IEEE Transactions on Power Systems** 4 (2): 748-759.

Rashed, A. M. H. and D. H. Kelly. 1974. Optimal load flow solution using lagrangian multipliers and the hessian matrix. **IEEE Transactions on Power Apparatus and Systems** 93: 1292-1297.

Happ, H. H. 1974. Optimal power dispatch. **IEEE Transactions on Power Apparatus and Systems** 93 (3): 820-830.

Sun, D. I., B. Ashley, B. Brewer, A. Hughes and W. F. Tinney. 1984. Optimal power flow by newton approach. **IEEE Transactions on Power Apparatus and Systems** 103: 2864-2880.

Pereira, M.V.F., L.M.V.G. Pinto, S. Granville and A. Montlcelli. 1987. A decomposition approach to security-constrained optimal power flow with post contingency corrective rescheduling, pp. 585-591. *In* **Proceedings of the 9th PSCC Conference**. 30 August – 4 September 1987. Cascais, Portugal.

Sanders, C. W. and C. A. Monroe. 1987. An algorithm for real-time security constrained dispatch. **IEEE Transactions on Power Systems** 2 (4): 175-182.

Monticelli, A., M. V. F. Pereira and S. Granville. 1987. Security constrained dispatch. **IEEE Transactions on Power Systems** 2 (4): 175-182.

Wells, D. W. 1968. Method for economic secure loading of a power system. **Proceedings of IEEE** 115 (8): 606-614.

Shen, C. M. and M. A. Laughton. 1970. Power system load scheduling with security constraints using dual linear programming. **Proceedings of IEEE** 117 (1): 2117-2127.

Stott, B. and E. Hobson. 1978. Power system security control calculation using linear programming: parts I and II. **IEEE Transactions on Power Apparatus and Systems** 97: 1713-1731.

Stott, B. and J. L. Marinho. 1979. Linear programming for power system network security applications. **IEEE Transactions on Power Apparatus and Systems** 98: 837-848.

Stadlin, W. O. and D. L. Fletcher. 1982. Voltage versus reactive current model for dispatch and control. **IEEE Transactions on Power Apparatus and Systems** 101 (10): 3751-3758.

Irving, M. R. and M. J. H. Sterling. 1983. Economic dispatch of active power with constraints relaxation., pp. 172-177. **IEE Proceedings Generation, Transmission and Distribution** 130 (4): 172-177.

Housos, E. and G. Irisarri. 1983. Real and reactive power system security dispatch using a variable weights optimization method. **IEEE Transactions on Power Apparatus and Systems** 102: 1260-1268.

Farghal, S. A., M. A. Tantawy, M. S. Abou-Hussein, S. A. Hassan and A. A. Abou-Slela. 1984. Fast technique for power system security assessment using sensitivity parameters of linear programming. **IEEE Transactions on Power Apparatus and Systems** 103 (5): 946-953.

Mota-Palomino, R. and V. H. Quintana. 1984. A penalty function-linear programming method for solving power system constrained economic operation problems. **IEEE Transactions on Power Apparatus and Systems** 103 (6): 1414-1442.

Mota-Palomino, R. and V. H. Quintana. 1986. Sparse reactive power scheduling by a penalty-function-linear programming technique. **IEEE Transactions on Power Systems** 1 (3): 31-39.

Santos-Neito, M. and V. H. Quintana. 1987. Linear reactive power studies for longitudinal power systems, pp. 783-787. *In* **Proceedings of the 9th PSCC Conference**. 30 August – 4 September 1987. Cascais, Portugal.

Nabona, N. and L. L. Ferris. 1973. Optimization of economic dispatch through quadratic and linear programming. **Proceedings of IEEE** 120 (5): 574-580.

Contaxis, G. C., C. Delkis and G. Korres. 1986. Decoupled optimal load flow using linear or quadratic programming. **IEEE Transactions on Power Systems** 1 (1): 1-7.

Clements, K. A., P. W. Davis and K. D. Frey. 1991. An interior point algorithm for weighted least absolute value power system state estimation. *In* **Proceedings of IEEE PES Winter Meeting 1991**.

Ponnambalam, K., V. H. Quintana and A. Vannelli. 1991. A fast algorithm for power system optimization problems using an interior point method. **IEEE Transactions on Power Systems** 7 (2): 892-899.

Vargas, L. S., V. H. Quintana and A. Vannelli. 1993. A tutorial description of an interior point method and its application to security-constrained economic dispatch. **IEEE Transactions on Power Systems** 8 (3): 1315-1324.

Momoh, J. A., R. A. Austin and R. Adapa. 1992. Application of interior point method to economic dispatch, pp. 1096-1101. *In* **Proceedings of IEEE International Conference on Systems Man & Cybernetics**. 18-21 October 1992. Chicago, IL, USA.

Momoh, J. A., R. A. Austin and R. Adapa. 1992. Feasibility of interior point method for var planning. *In* **Proceedings of North American Power Symposium (NAPS)**.

Lu, C. N. and M. R. Unum. 1993. Network constrained security control using an interior point algorithm. **IEEE Transactions on Power Systems** 8 (3): 1068-1076.

Granville, S. 1994. Optimal reactive dispatch through interior point methods. **IEEE Transactions on Power Systems** 9 (1): 136-146.

Momoh, J. A., S. X. Guo, C. E. Ogbuobiri and R. Adapa. 1994. The quadratic interior point method for solving power system optimization problems. **IEEE Transactions on Power Systems** 9 (3): 1327-1336.

Granville, S. 1994. Optimal reactive dispatch through interior point method. **IEEE Transactions on Power Systems** 9 (1): 136–146.

Wu, Y., A. S. Debs and R. E. Marsten. 1994. A direct nonlinear predictor-corrector primal-dual interior point algorithm for optimal power flows. **IEEE Transactions on Power Systems** 9 (2): 876–882.

Torres, G. L. and V. H. Quintana. 2000. Optimal power flow by a nonlinear complementarity method. **IEEE Transactions on Power Systems** 15 (3) 1028–1033.

Torres, G. L. and V. H. Quintana. 2000. On a nonlinear multiple-centrality-corrections interior-point method for optimal power flow. **IEEE Transactions on Power Systems** 16 (2): 222–228.

Castronuovo, E. D., J. M. Campagnolo and R. Salgado. 2001. On the application of high performance computation techniques to nonlinear interior point methods. **IEEE Transactions on Power Systems** 16 (3): 325-331.

Jabr, R. A., A. H. Coonick and B. J. Cory. 2001. A primal-dual interior point method for optimal power flow dispatching. **IEEE Transactions on Power Systems** 17 (3): 654–662.

Qiu, W., A. J. Flueck and F. Tu. 2005. A new parallel algorithm for security constrained optimal power flow with a nonlinear interior point method, pp. 447-453. *In* **Proceedings of IEEE Power Engineering Society General Meeting 2005**. 12-16 June 2005.

PJM Energy Market Manuals. 2012. **Market Operations**. Available Source: http://www.pjm.com/documents/manuals.aspx, May 3, 2012.

Australian Energy Market Operator. 2012. **Market Operations**. Available Source: http://www.aemo.com.au, May 5, 2012.

California Independent System Operator. 2012. **Market Operations**. Available Source: http://www.caiso.com, May 8, 2012.

New York Independent System Operator. 2012. **Market Operations**. Available Source: http://www.nyiso.com, May 11, 2012.

Murillo-Sanchez, C. E. 2000. **On the Integration of Unit Commitment and Optimal Power Flow.** Ph.D. dissertation, School of Electrical and Computer Engineering, Cornell University, Ithaca, NY, USA.

Federal Energy Regulatory Commission. 2005. **Principles for Efficient and Reliable Reactive Power Supply and Consumption**. Available Source: http://www.ferc.gov/legal/staff-reports.asp, June 14, 2012.

Wang, H., C. E. Murillo-Sanchez, R. D. Zimmerman and R. J. Thomas. 2007. On computational issues of market-based optimal power flow. **IEEE Transactions on Power Systems** 22 (3): 1185-1193.

Gomes, M. H. and J. T. Saraiva. 2008. Active/reactive bid based dispatch models to be used in electricity markets. **Electric Power System Research** 78: 106-121.

Kumar, A., S.C. Srivastava and S.N. Singh. 2005. Congestion management in competitive power market: a bibliographical survey. **Electric Power System Research** 76: 153-164.

Yu, C. N. and M. Ilic. 1999. Congestion clusters-based markets for transmission management, pp. 821-832. *In* **Proceedings of IEEE PES Winter Meeting**. January 1999. New York, NY, USA.

Bialek, J. W., A. Germond and R. Cherkaoui. 2000. Improving NERC transmission loading relief procedures. **Electricity J.** 13 (5): 11–19.

Vlachogiannis, J.G. 2000. Accurate model for contribution of generation to transmission system effect on charges and congestion management. **IEE Proceedings Generation, Transmission and Distribution** 147 (6): 342-348.

Overbye, T. J. and J. D. Weber. 2001. Visualizing the electric grid. **IEEE Spectrum** 20: 52–58.

Kumar, A., S. C. Srivastava and S.N. Singh. 2003. A zonal congestion management approach and impact of phase angle regulator. *In* **Proceedings of ISAP**. October 2003. Lemnos, Greece.

Hogan, W. H. 1992. Contract networks for electric power transmission. **Journal of Regulatory Economics** 4: 211–242.

Chao, H. and S. Peck. 1996. A market mechanism for electric power transmission. **Journal of Regulatory Economics** 10: 25–59.

Bushnell, J. 1999. Transmission rights and market power. **Electricity J**. 12: 77–85.

Alomoush, M. I. and S. M. Shahidehpour. 2000. Generalized model for fixed transmission rights auction. **Electric Power System Research** 54: 207-220.

Chao, H. P., C. Peck, S. Oren and R. Wilson. 2000. How based transmission right and congestion management. **Electricity J.** 13 (8): 38–58.

Hogan, W. W. 2000. **Transmission right and wrong, working paper, Harward University**.

Yu, C. N. and M. D. Ilic. 2000. An algorithm for implementing transmission rights in a competitive power industry, pp. 1708-1714. *In* **Proceedings of IEEE PES Winter Meeting**. 23-27 January 2000.

Liu, M. and G. Gross. 2004. Framework for the design and analysis of congestion revenue rights. **IEEE Transactions on Power Systems** 18 (1): 243–251.

Tuan, L. A., K. Bhattacharya and J. Daalder. 2005. Transmission congestion management in bilateral markets: an interruptible load auction solution. **Electric Power System Research** 74 (3): 379-389.

Finney, J. D., H. A. Othman and W. L. Rutz. 1997. Evaluating transmission congestion constraints in system planning. **IEEE Transactions on Power System** 12 (3): 1143–1149.

Glavitsch, H. and F. Alvarado. 1997. Management of multiple congested conditions in unbundled operation of a power system, pp. 374-380. *In* **Proceedings of the 20th International Power Industry Computer Applications**. 11-16 May 1997. Columbus, OH, USA.

Stoft, S. 1998. Congestion pricing with fewer prices than zones. **Electricity J.** 11 (4): 23–31.

Glavitsch, H. and F. Alavardo. 1998. Management of multiple congested conditions in unbundled operation of a power system. **IEEE Transactions on Power Systems** 13 (3): 1013-1019.

Gedra, T. W. 1999. On transmission congestion and pricing. **IEEE Transactions on Power Systems** 14 (1): 241–248.

Bompard, E., E. Carpenato, G. Chicco and G. Gross. 2000. The role of load demand elasticity in congestion management and pricing, pp. 2229-2234. *In* **Proceedings of IEEE PES Summer Meeting**. 16-20 July 2000. Seattle, WA, USA.

Chen, L., H. Suzuki, T. Wachi and Y. Shimura. 2000. Decomposition of nodal price for Electric power system, pp. 2156-2161. *In* **Proceedings of IEEE PES Summer Meeting**. 16-20 July 2000.

Chen, L., H. Suzuki, T. Wachi and Y. Shimura. 2002. Component of nodal prices for electric power systems. **IEEE Transactions on Power Systems** 17 (1): 41–49.

Papalexopoulos, A. 2002. Power system expansion planning and pricing in a deregulated environment, pp. 1168. *In* **Proceedings of IEEE PES Summer Meeting**. 21-25 July 2002.

Hao, S. and D. Shirmohammadi. 2002. Congestion management with Ex Ante pricing for decentralized markets, **IEEE Transactions on Power Systems** 17 (4): 1030–1036.

Ott, A. 1999. PJM: a full service ISO market evolution (panel on evolution of electricity market structures), pp. 746-748. In **Proceedings of IEEE PES Summer Meeting**. 18-22 July 1999.

Balmat, B. M. and A. M. DiCapiro. 2002. The PJM energy market (U.S.), pp. 1479-1481. *In* **Proceedings of IEEE PES Transmission and Distribution Conference and Exhibition Asia Pacific**. October 2002.

David, A. K. 1998. Dispatch methodologies for open access transmission systems. **IEEE Transactions on Power Systems** 13 (1): 46–53.

Fang, R. S. and A. K. David. 1999. Optimal dispatch under transmission contracts. **IEEE Transactions on Power Systems** 14 (2): 732–737.

Lie, J., Y. Deng, R. Zhang and Y. Wu. 2001. Congestion management for generator scheduling in a deregulated Chinese power system, pp. 1262-1265. *In* **Proceedings of IEEE PES Winter Meeting**. 28 January – 1 February 2001.

Grgic, D. and F. Gubina. 2001. Implementation of the congestion management schemes in unbundled Slovenian power system, vol. 1. *In* **Proceedings of IEEE Porto Power Technology Conference**. 10-13 September 2001. Porto, Portugal.

Grgic, D. and F. Gubina. 2002. Congestion management approach after deregulation of the Slovenian power system, pp. 1661-1665. *In* **Proceedings of IEEE PES Summer Meeting**. 21–25 July 2002.

Phichaisawat, S., Y. H. Song and G. A. Taylor. 2002. Congestion management considering voltage security constraints, pp. 1819-1823. *In* **Proceedings of International Conference on Power System Technologies**. 13-17 October 2002.

Yamin, H. Y. and S. M. Shahidehpour. 2003. Transmission congestion and voltage profile management coordination in competitive electricity markets. **International Journal of Electrical Power & Energy Systems** 25: 849-861.

Canizares, C. A., H. Chen, F. Milano and A. Singh. 2004. Transmission congestion management and pricing in simple auction electricity markets. **International Journal of Emerging Electric Power Systems** 1 (1): 1-28.

Talukdar, B. K., A. K. Sinha, S. Mukhopadhyay and A. Bose. 2005. A computationally simple method for cost-efficient generation rescheduling and load shedding for congestion management. **International Journal of Electrical Power & Energy Systems** 27: 379–388.

The IBM ILOG CPLEX Optimizer Website. 2011. **CPLEX Optimizer**. Available Source: http://www-01.ibm.com/software/integration/optimization/cplex-optimizer/, July 10, 2011.

Department of Electrical Engineering at University of Washington. 2008. **IEEE Bus Test**. Available Source: http://www.ee.washington.edu/research/pstca/, March 14, 2010.

APPENDIX

The optimization problem of mixed integer linear programming for the DC-SCUC

Due to the limited of the efficient mixed integer nonlinear programming tools. Therefore, this thesis uses mixed integer linear programming technique in CPLEX version 12.4 (The IBM ILOG CPLEX Optimizer Website, 2011) as the solver of mixed integer programming. The optimization problem of mixed integer programming for the daily security-constrained unit commitment in pool electricity markets need to be modified to the optimization problem of mixed integer linear programming for the DC-SCUC. The equations that need to be modified are the objective function, real power flowing in transmission lines, real power loss in transmission line connecting between buses *i* and *m* and limits of slack variable.

The startup cost term in the objective function is modified to a variable which has two constraints as follows.

$$\sum_{h\in T}\sum_{i\in NG}\left[Sc_{i,h}+\left(MLC_{i,h}\times U_{i,h}\right)+\left(\sum_{b\in NB_i}\left(c_{ibh}\times P_{Gibh}\right)\right)\right] \tag{A-1}$$

$$Sc_{i,h}\geq SUC_i\times\left[U_{i,h}-U_{i,h-1}\right]\ ;\forall i\in NG,\forall h\in T \tag{A-2}$$

$$0\leq Sc_{i,h}\leq SUC_i\ ;\forall i\in NG,\forall h\in T \tag{A-3}$$

The real power flowing in transmission lines connecting between buses *i* and *m*, P_{imh} and P_{mih}, are modified to variables and have its constraint as follows.

$$P_{imh}+Ps_{imh}-\left(\alpha_{imh}\times\left(\delta_{i,h}-\delta_{m,h}\right)\right)=0\ ;\forall i,m\in Nl,\forall h\in T \tag{A-4}$$

$$P_{mih}+Ps_{mih}-\left(\alpha_{imh}\times\left(\delta_{m,h}-\delta_{i,h}\right)\right)=0\ ;\forall i,m\in Nl,\forall h\in T \tag{A-5}$$

The real power loss in transmission line connecting between buses *i* and *m* is modified to a variable with bound limit which has two constraints as follows.

$$P_{Limh} \geq 0 \;;\forall i,m \in Nl,\forall h \in T \qquad \text{(A-6)}$$

$$\left(\rho_{Limh} \times \alpha_{imh} \times \left(\delta_{i,h} - \delta_{m,h}\right)\right) - P_{Limh} \leq 0 \;;\forall i,m \in Nl,\forall h \in T \qquad \text{(A-7)}$$

$$-P_{Limh} - \left(\rho_{Limh} \times \alpha_{imh} \times \left(\delta_{i,h} - \delta_{m,h}\right)\right) \leq 0 \;;\forall i,m \in Nl,\forall h \in T \qquad \text{(A-8)}$$

And the limits of slack variables are modified as follows.

$$Ps_{imh} \leq 0 \;;\forall i,m \in Nl,\forall h \in T \qquad \text{(A-9)}$$

$$Ps_{mih} \leq 0 \;;\forall i,m \in Nl,\forall h \in T \qquad \text{(A-10)}$$

The optimization problem of mixed integer linear programming for the DC-SCUC can be expressed as.

Min $$\sum_{h \in T} \sum_{i \in NG} \left[Sc_{i,h} + \left(MLC_{i,h} \times U_{i,h}\right) + \left(\sum_{b \in NB_i} \left(c_{ibh} \times P_{Gibh}\right) \right) \right]$$

Subject to

$$\left(\left(P_{Gi,\min} \times U_{i,h}\right) + \sum_{b \in NB_i} P_{Gibh} \right) - P_{i,h} - P_{Di,h} = 0 \;;\forall i \in N,\forall h \in T$$

$$P_{Gi,h} - \left(\left(P_{Gi,\min} \times U_{i,h}\right) + \sum_{b \in NB_i} P_{Gibh} \right) = 0 \;;\forall i \in NG,\forall h \in T$$

$$P_{imh} + P_{mih} - P_{Limh} = 0 \;;\forall i,m \in Nl,\forall h \in T$$

$$P_{imh} + Ps_{imh} - \left(\alpha_{imh} \times \left(\delta_{i,h} - \delta_{m,h}\right)\right) = 0 \;;\forall i,m \in Nl,\forall h \in T$$

$$P_{mih} + Ps_{mih} - \left(\alpha_{imh} \times \left(\delta_{m,h} - \delta_{i,h}\right)\right) = 0 \;;\forall i,m \in Nl,\forall h \in T$$

$$\left(\rho_{Limh} \times \alpha_{imh} \times \left(\delta_{i,h} - \delta_{m,h}\right)\right) - P_{Limh} \leq 0 \;;\forall i,m \in Nl,\forall h \in T$$

$$-P_{Limh} - \left(\rho_{Limh} \times \alpha_{imh} \times \left(\delta_{i,h} - \delta_{m,h}\right)\right) \leq 0 \;;\forall i,m \in Nl,\forall h \in T$$

$$Sc_{i,h} \geq SUC_i \times \left[U_{i,h} - U_{i,h-1}\right] \;;\forall i \in NG,\forall h \in T$$

$$\sum_{n=h}^{h+T_{Ui}-1} U_{i,n} \geq T_{Ui} \times \left[U_{i,h} - U_{i,h-1}\right] \;;\forall i \in NG,\forall h = 1,\ldots,T - T_{Ui} + 1$$

$$\sum_{n=h}^{T} U_{i,n} \le \left[\left(T-h+1 \right) \times U_{i,h-1} \right] \;;\forall i \in NG, \forall h = T - T_{Ui} + 2, \ldots, T$$

$$\sum_{h=1}^{IF_i} U_{i,h} = 0 \quad , \text{ for } IF_i > 0 \;;\forall i \in NG$$

$$\sum_{n=h}^{h+T_{Di}-1} \left[1 - U_{i,n} \right] \ge T_{Di} \times \left[U_{i,h-1} - U_{i,h} \right] \;;\forall i \in NG,$$

$$\forall h = IF_i + \min(IF_i, 1) + 1, \ldots, T - T_{Di} + 1$$

$$\sum_{n=h}^{T} \left[1 - U_{i,n} - \left(U_{i,h-1} - U_{i,h} \right) \right] \ge 0 \;;\forall i \in NG, \forall h = T - T_{Di} + 2, \ldots, T$$

$$0 \le Sc_{i,h} \le SUC_i \;;\forall i \in NG, \forall h \in T$$

$$\left[P_{Gi,\min} \times U_{i,h} \right] \le P_{Gi,h} \le \left[P_{Gi,\max} \times U_{i,h} \right] \;;\forall i \in NG, \forall h \in T$$

$$0 \le P_{Gibh} \le P_{Gibh,\Delta} \;;\forall i \in NG, \forall b \in NB_i, \forall h \in T$$

$$-P_{imh,\max} \le P_{imh} \le P_{imh,\max} \;;\forall i, m \in Nl, \forall h \in T$$

$$-P_{imh,\max} \le P_{mih} \le P_{imh,\max} \;;\forall i, m \in Nl, \forall h \in T$$

$$P_{Limh} \ge 0 \;;\forall i, m \in Nl, \forall h \in T$$

$$Ps_{imh} \le 0 \;;\forall i, m \in Nl, \forall h \in T$$

$$Ps_{mih} \le 0 \;;\forall i, m \in Nl, \forall h \in T$$

where

$$P_{i,h} = \sum_{m \in N, i \ne m} P_{imh} \;;\forall i \in N, \forall h \in T$$

$$IF_i = \max \left[0, \left(T_{Di} - RF_i \right) \times \left(1 - U_{i,0} \right) \right] \;;\forall i \in NG$$

CURRICULUM VITAE

NAME : Mr. Pornthep Panyakaew

BIRTH DATE : December 19, 1976

BIRTH PLACE : Chiangmai, Thailand

EDUCATION :

YEAR	INSTITUTE	DEGREE
1998	MUT	B.Eng. (E.E.)
2002	KMITL	M.Eng. (E.E.)

POSITION/TITLE : Lecturer
WORK PLACE : Faculty of Industry and Technology, RMUTI
SCHOLARSHIP/AWARD : Office of Higher Education Commission Scholarship 2007-2010

List of publications

- **Panyakaew, P.** and Damrongkulkamjorn, P. 2008. Optimal loss allocation of multiple wheeling transactions in a deregulated power system. Proceeding of the 5th International Conference on Electrical and Computer Engineering, 343-348.
- **Panyakaew, P.** and Damrongkulkamjorn, P. 2010. Optimal power dispatch with step bidding cost function in electricity markets by hybrid method. Proceeding of the 33rd Electrical Engineering Conference, 213-216. (in Thai)
- **Panyakaew, P.** and Damrongkulkamjorn, P. 2013. Optimal power dispatch with step-bidding price in mixed pool-bilateral-multilateral electricity markets by hybrid computational method. Engineering Journal Chiang Mai University, 20 (3). (Accepted, in Thai)

List of publications (Continued)

- **Panyakaew, P.** and Damrongkulkamjorn, P. 2013. Hybrid computational method for step-bidding price optimal power flow. International Review of Electrical Engineering, 8 (1), 369-378.