Transmission Congestion Management by Optimal Placement of FACTS Devices

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By

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Abstract

This thesis describes the implementation of the Flexible AC Transmission Systems (FACTS) devices to develop a market-based approach to the problem of transmission congestion management in a Balancing Market. The causes, remedies and pricing methods of transmission congestion are briefly reviewed.

Balancing Market exists in markets in which most of the trading is done via decentralized bilateral contracts. In these markets only final adjustments necessary to ensure secure system operation is carried out at a centralized Balancing Market. Each market player can participate in the Balancing Market by submitting offers and bids to increase and decrease its initially submitted active generation output. In this research a method is proposed to reduce costs associated with congestion re-dispatch in a Balancing Market by optimal placement of FACTS devices, and in particular Thyristor Controlled Phase Shifter Transformers (TCPST).

The proposed technique is applicable to both Mixed Integer Linear Programming (MILP) and Mixed Integer Non-Linear Programming (MINLP). In the MILP a power system network is represented by a simplified DC power flow under a MILP structure and the Market participants' offers and bids are also represented by linear models. Results show that applications of FACTS devices can significantly reduce costs of congestion re-dispatch. The application of the method based on the MINLP creates a nonlinear and non-convex AC OPF problem that might be trapped in local sub-optima solutions. The reliability of the solution that determines the optimal placement of FACTS devices is an important issue and is carried out by investigation of alternative solvers. The behavior of the MINLP solvers is presented and finally the best solvers for this particular optimization problem are introduced.

The application of DC OPF is very common in industry. The accuracy of the DC OPF results is investigated and a comparison between the DC and AC OPF is presented.

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Chapter 1. Introduction

1.1 Background to the research

During the last three decades, the old monopoly electricity structures are replaced with deregulated electricity structures open to the competition. Different forces have driven the evolution of power industry from monopoly to the competition in the wholesale generation market and the retail market together with the open access to the transmission network. These forces can be categorized as technical [1], economical [2] and political [3] motivations.

1.1.1 Technical motivations

Although the technological development of high voltage networks during the 1960s and 1970s was a great achievement that made possible transmission of bulk power over long distances, a necessary condition in order the power market to be opened to producers that are located far from the main customers, the electricity industry still remained a monopoly for the next twenty years.

Power generation technology was another technical factor, which has given a stronger impulse towards the deregulation. In 1960s and 1970s, the thermal power plant units had a typical size between 600 and 1000 MW and an average construction time between four and five years. This time for nuclear power plant was doubled. Because of this reason and also the investment size, only a monopolist utility could make the decisions of generation expansion and also act as protection against investment errors, which could have dramatic consequences. The development of gas power plants, and especially of combined circle gas turbines, reduced the size of power production unit up to 300 MW, the investment cost and the construction time. Hence, it is now possible the generation expansion decisions to be taken by smaller enterprises.

Renewable resources are another mixed technical-ecological cause. The emerging of independent producers who operate, mostly, wind power units gives a further competitive character to the power industry despite the fact that such producers survive still due to the subsidies.

The improvement of transmission and distribution technology is another reason. High-efficiency transformers and ultra-high-voltage transmission lines (1,500KV or even higher) reduce the power losses between power plants and consumers, and FACTS devices provide a better control over the electrical features of the grid. With FACTS devices it is possible to control power flow through transmission lines, to regulate voltage, phase angle and line impedance.

The development of new metering systems is absolutely necessary for an electricity market. The price of electricity varies with time in the market and metering must be time-dependent in order to bill the consumers the correct prices and also capable of reading the meter data from a distance radiographically, or by meter communicating with the supply company through the telecommunication or the power grid.

Advances in Information Technology (IT) has a tremendous impact on the many aspects of electricity markets, such as bidding systems, billing systems, market information publishing systems, etc.

1.1.2 Economical motivations

In addition, a set of economical reasons was behind the electricity market reform. A well-operated competitive market can guarantee both cost minimization and average energy prices hold at a minimum level [2]. The second positive characteristic of a well-designed competitive market is its ability to drive the prices towards the marginal costs. Another economical motivation was the privatization of the electricity industry to, firstly, free up public funds and makes them available to serve the national debt or other demands, and secondly, the governments of these countries can collect an essential amount from the sale of state owned utilities.

1.1.3 Political motivations

Political factors are the third category of electricity industry restructures causes. In some countries privatization of the electric industry can attract funds from the private sector to relieve the burden of heavy government subsidies. In the countries formerly under centralized control, the process follows the general trend away from centralized government control and towards increased privatization and decentralization [3]. Among the political circles, the idea that the private companies apply more efficient practices than the public ones, in certain economic sectors, was getting more acceptance. Some organizations such as World Bank were another reason for the deregulation. They set as a requirement the opening of markets including the power sector in order to support financially a country. Consequently, the electricity industry of many countries financed by the World Bank opened to the competition.

Transmission plays a key role in making the electricity market work. In a competitive market that all the parties have a free nondiscriminatory access to the transmission network, a considerable growth in the amount of transactions is inevitable. The existence of transmission bottlenecks is by far the most prevalent cause that will restrict the number of generators who can compete in any market [4]. Studies show that in markets in which a small number of generators compete, those supposed competitors can bid in a manner that keeps prices up [5]. Transmission constraints hinder distant generators from entering the high priced market and add to the market power of local generating incumbents. Congestion management is a crucial function of any system operator and is the process that ensures the security and reliability of market operation. Traditional mandatory dispatching actions (adjust fast-responded generators, curtail loads, etc.) are easy to implement and maybe still necessary in the worst situation, but they are not encouraged in a competitive electricity market as they are not transparent and may prevent the market from further development. With all the new technologies mentioned above, market-based approaches are needed urgently to cope with transmission congestion efficiently, economically, fairly, and transparently [6].

One of the technical motivations behind the regulation, as mentioned above, is the exponential growth of the microprocessor power, information storage capacity, the Internet and software systems. Historically, an explosive growth in the control center of power system has occurred from 1960. Energy Management System (EMS), which is the main software system in this category, consists of four major elements [7]:

- Supervisory Control and Data Acquisition (SCADA), including data acquisition, control, alarm processing, online topology processor, etc.
- Generation scheduling and control applications, including Automatic Generation Control (AGC), Economic Dispatch (ED), Unit Commitment (UC), hydrothermal coordination, short term load forecast, interchange scheduling, etc.
- Network analysis application, including topology processor, state estimator, power flow, contingency analysis, Optimal Power Flow (OPF), security enhancement, voltage and reactive power optimization, stability analysis, etc.
- Dispatch Training Simulator (DTS), including the three stated components but in a separate off-line environment.

In the electricity market some of these functions have to change to meet the new requirements. For example, some generation scheduling applications might be removed or redesigned to be more amenable to energy market trading applications while some other network analysis application, like OPF, should be extended to be able to perform new functions. Besides EMS, some new software subsystems will be needed in the ISO [8]. These new software subsystems are linked tightly with each other and must coordinate with the existing systems in the control room to support the implementation of electricity markets.

The replacement of the low-speed control electronics by a new generation of control devices, the Flexible AC Transmission System (FACTS), is taking place as the control technology develops. It has brought series of opportunities and challenges to power engineers and researchers. Studies that investigate the deployment of FACTS must address the following questions: [9]

- Which type of FACTS devices should be used?
- How many should be used?

- What is their best allocation?
- What should be their parameter settings?
- What is their installation cost?

There are different ways to class the FACTS devices [10]. According to the technology of the used semi- conductor they can be classified as:

- Thyristor-based FACTS Controllers
- IGBT-based FACTS Controllers

The first group employs reactive impedances or a tap-changing transformer thyristor switches as controlled-elements in circuit arrangements which are similar to breaker-switched capacitors and reactors and conventional (mechanical) tap-changing transformers, but have much faster response and are operated by sophisticated controls; the second group uses self-commutated static converters as controlled voltage sources [11]. The STATic synchronous COMpensator (STATCOM), the Static Synchronous Series Compensator (SSSC), the Unified Power Flow Controller (UPFC) and the Interline Power Flow Controller (IPFC) are in this category.

According to the type of compensation the FACTS controllers may be classed in one of three categories:

- series controllers such as TCSC (Thyristor Controlled Series Capacitor), TCPST (Thyristor-Controlled Phase Shifting Transformer) and SSSC **(**Static Synchronous Series Compensator**)**
- shunt controllers such as SVC (Static Var Compensator) and STATCOM (Static Synchronous Compensator)
- combined series-shunt controllers such as TCVR (Thyristor-Controlled Voltage Regulator) and UPFC (Unified Power Flow Controller)

The choice of the appropriate device is important since it depends on the goals to be reached. TCSC and TCPST affect the line reactance and the angle of the voltage and can control the active power flow in the transmission line. The SVC is used to absorb or inject reactive power while the TCVR is picked up to act on the difference between the voltage magnitudes at the sending and receiving ends of the line. The UPFC can independently control real and reactive power by being integrated into a generalized power controller combining the functions of TCSC, TCPST and SVC.

Different approaches and algorithms, as it will be stated in the literature review, are used to investigate the best location, parameter settings, the number and the installation cost of the FACTS devices. The necessity to investigate these issues stems from the fact that this is a useful but expensive technology, so its application has to be well planned and fully justified on technical and economic terms. In this research we will also look at the problem of how to place and use the FACTS devices optimally.

1.2 Aims of the research

The main aim of this research is to implement the Flexible AC Transmission Systems (FACTS) to develop a market-based approach to transmission congestion management with Optimal Power Flow (OPF) as a network analysis application.

The scope of this work covers the real-time operation of the electricity market. The congestion problem should be managed in real-time because the bulk power transmission grid is highly dynamic and predicting constraints, well ahead of time, is therefore difficult. Further to the existence of the many congestion allocation methods dealing with different time scales, ranging from short-term scheduling up to long-term planning, a real-time congestion management is crucial to ensure the secure operation of the system.

A method is proposed to make the generation re-dispatch in the real-time balancing market feasible and to minimize the associated re-dispatch costs by the optimal placement of TCPST devices and their settings. TCPST devices are chosen because the re-dispatch cost of reactive power generation, compared to active power generation is very small and, therefore, only active power is considered in the objective function. TCPST devices are capable of changing the phase angle of the line voltage in a way that affects the active power flow and generation re-dispatch costs by alleviating the congestion. This approach will be first carried out by a DC optimal power flow solution. This simplification has been common in the electricity industry to carry out preliminary design studies. For more accurate further assessments we will develop the scope of our work to the area of AC OPF, which is a non-linear non-convex problem and in combination with integer decision variable, needs special software requirements in the modeling languages and solvers fields.

Existing local optimum points in most of the optimization problems causes a degree of uncertainty about the achieved solutions. FACTS devices, in spite of being cost-effective are expensive and the decision for their optimal placement needs a higher level of certainty. Therefore we will look at appropriate solver/solvers that are capable of producing the best solution for the FACTS devices locations and their settings.

1.3 Literature review

Models and applications of FACTS devices in power system operation have been often analyzed in recent years [11-14]. For example, in [13] Chaung et al propose a load-equivalent model for TCSC, TCPST and UPFC for use in optimal active power flow and Varma in [14] provides an overview of the different FACTS controller configurations and their operating principles. FACTS devices applications to Economic Dispatch (ED) are presented in [15], while applications in Optimal Power Flow (OPF) studies are investigated in [16]. Under restructured operation of power systems, it became even more important to enhance Available Transmission Capacity (ATC) of transmission networks and avoid congestion. Since FACTS devices can affect line flows, they became prime candidates in attempts to resolve these difficulties.

The steady state and dynamic models of these devices is subject of some studies such as references [17-19]. In [17], mathematical models of UPFC for steady state, transient stability and Eigen value studies is provided to investigate the impacts of control strategy, parameters and location of UPFC on power system operating conditions, and [18] demonstrates the effectiveness of TCSC in power swing damping by evaluating the simulation results of the static and dynamic performance of TCSC using the Electro-Magnetic Transient Program (EMTP) digital simulation in the power systems of China. In [19] Canizares presents a comparison between dynamic and steady state of SVC devices using three different optimization-based auction models namely, a standard stability-constrained OPF (SC-OPF), a voltage- stability-constrained OPF

(VSC-OPF) and the Stability-Constrained OPF (SSC-OPF).

Generally, there were two approaches to problems of FACTS utilization. One is based on an assumption that location of FACTS devices is given, while the other looks into the issue of their optimal placement as well as settings.

Some of the research carried out in the first category looked into coordination and influence of various FACTS devices or how to calculate their settings so as to minimize an objective function [20-39]. The second issue regarding optimal placement are investigated in references [40-57].

1.3.1 Preselected Location/coordination

Galiana et al in [20] compare the impact of various FACTS devices on the behavior of power systems. Haugan et al in [21] examine the effects of TCSC and SVC devices on the transaction curtailment and TTC improvement issues by using two OPFs, And Xia in [22] formulates an optimal power-flow (OPF)-based Available Transmission Capacity (ATC) enhancement model to evaluate the influence of all categories of FACTS devices by the predictor-corrector primal-duel interior point linear programming (PCPDIPLP).

Phichaisawat et al in [23] use Power Injection models (PIM) for unified, series and shunt controllers to deal with both active and reactive congestion management under pool and bilateral market models while the objective function of the modified ac OPF is to minimize operating cost. Shi et al in [24] deal with the congestion in a combined pool and bilateral market by re-dispatch method when FACTS devices are included in the network. The aim of their work is to reduce transmission loadings and each type of contracts has a weighting factor that can be viewed as the relative importance of the bilateral market to the pool market.

The influences of FACTS devices are not confined to one bus or line. Therefore some authors work on the coordination of the FACTS devices [25, 26]. Chio and Moon in [25] determine the setting of TCSC devices to relieve the flow congestion by derivation line flow sensitivity to FACTS devices based on the DC flow model while Glanzman and Anderson in [26] derive a supervisory controller based on Optimal Power Flow

(OPF) with multiple objectives to avoid congestion, provide secure transmission and minimize active power losses.

One way to find the best location of FACTS devices is to place them in various lines in turn. Rajderkar and Chandrakar in [27] place TCSC and SSSC devices in different lines to find the optimal locations and compares these two set of FACTS devices for congestion management under normal and abnormal system condition. In [28], Mwanza et al compute an index that gives an indication of the benefits by placement of FACTS in various lines in turn. The benefit-to-cost index for the investment in FACTS devices is calculated for each location of FACTS and the object is to minimize generation re-dispatch costs.

Reddy et al in [29] use TCST and UPFC to maximize social welfare using Genetic algorithm. They represent another classification for congestion management methodologies [30-32]: cost free and non-cost free methods. Cost free means such as Out-aging of congested lines, operation of transformer taps/phase shifters and operation of FACTs devices particularly series devices, relieve the congestion technically and therefore generator and distribution companies doesn't involve in the economical costs. In contrast with the first method, non-cost free methods are related with economics. Re-dispatch of generation and curtailment of loads are among the later methods.

The cost of FACTS devices such as IPFC, which is largely dependent on the capacities of its converters, is taken into account in [33] by defining an objective function with two goals as to minimize the total capacity of the converters of IPFC and also the total active power loss of the system. Zhang and Yokouama weighted each objective according to their importance and use Interline Power Flow (IPFC) devices for congestion management and solve the optimal power flow program by sequential quadratic programming.

One of the goals of deregulation of electricity industry was providing cheaper energy for the consumers. Transmission line congestion has prevented achieving this objective by adding the congestion cost to consumer's locational marginal cost. Haung and Yan in [34] studie a pricing scheme for FACTS devices in congestion management, which addresses both the penalty and the utilization issues. The OPF problem is solved by Lagrangian multiplier method to minimize total biding costs. This issue addressed in

[35] too, where Peng et al in study the spot price behavior with different control mechanism such as generation control, demand control and FACTS control under transmission congestion and use nonlinear interior point algorithm to solve the OPF problem.

In [36], Berizzi et al considered two monodimensional FACTS devices (SPFC and TCPAR) and a bidimensional one (UPFC) in a compact and reduced security-constrained optimal power flow (SCOPF) procedure to minimize the total generation cost. In [37], Momoh and Zhu use TCPST devices to minimum two objective functions to minimize line overloads and to minimize adjustment of numbers of phase shifters. The algorithm is the Extended Quadratic Interior Point (EQIP) method. In [38], Lie and Hui solve an OPF problem to maximize social welfare using Sequential Quadratic Programming (SQP) in the MATLAB environment. UPFC locations are preselected and modeled by a Power Injection Model (PIM).

Yao et al in [39] express a renewable energy sources issue that will compound the congestion problem by increasing power transfers across major regional boundaries or interfaces in the transmission system of England and Wales. Wind energy is usually available and concentrated at some locations away from the load demand centers. For example the large load demands are centered in the South of the UK, while the wind based plants are mainly located along the Western Seaboard running from the North of Scotland and Outer Isles down to the Cornish Peninsula. The need to boost the transfer capability of the transmission system is addressed in the mentioned paper by the application of Static Series Synchronous Compensator (SSSC) and the nonlinear interior point optimization algorithm.

1.3.2 Optimal location/coordination

Singh and David in [40] consider the TCST and TCPST costs along with the production costs in the objective function and solve the optimization problem by a sensitivity-based approach where each transmission line is first rated by using an optimal dispatch without considering the line flow limit and FACTS devices, then the Sensitivity factors are calculated for FACTS devices placed in every line one at a time and finally the optimal dispatch problem is solved to select the optimal location and parameter settings. Some factors such as the capital recovery factor, interest rate and capital recovery plan are among the cost-benefit analysis. These authors in [41] present a two step method where the optimal location of the TCSC and TCPST is ascertained first and in the next step the settings of their control parameters is optimized. The approach is based on the sensitivity of three objectives: loss on a transmission line in which a device is installed, the total system real power loss and the real power flow performance index.

One approach by Fang and Ngan is based on augmented Lagrange multipliers and has an objective to place unified power flow controllers (UPFCs) so as to find a balance between financial costs on capital investments and the cost of network losses [42].

Momoh et al, in [43] use an elimination procedure based on the linearization load flow around base load flow solution for small perturbation to solve the rule based OPF with phase shifter scheme, and the ranking of phase shifter locations is conducted based on contingency analysis and sensitivity analysis. The objective functions are minimum line overloads and minimum adjustment of numbers of phase shifters and the algorithm is extended quadratic interior point (EQIP) method.

Gitizadeh in [44] determines the location, size and number of TCSC and SVC devices to relieve congestion in the transmission lines while increasing static security margin and voltage profile. He uses Sequential Quadratic Programming (SQP) in the first stage to evaluate static security margin considering constraints and a Simulated Annealing (SA) based optimization finds the optimal solution in the next stage.

In [45] alabduljabbar et al use the Low Discrepancy Sequences (LDS) algorithm based optimization for optimal placement of FACTS devices where the active and reactive generation costs should be minimized. A fixed cost of 100 US$/KVA for all type of FACTS is considered in the objective function too.

In [46], Sharma et al deploy DC OPF to maximize system loadability and optimize the location of TCSC and TCPST devices by creating a MILP problem and solve the optimization problem using GAMS solver. This DC simplification is also used by Aygen and Abur in [47] where they use DC OPF to find the optimal placement of TCPST devices by a two-step optimization procedure to obtain the candidate branches for TCPS installments for each contingency. MILP and Integer Programming (IP) are used in each stage. In [48] Kazemi and Sharifi find optimal location of TCPST devices to maximize the social welfare using DC load flow and quadratic programming.

Contingency is incorporated in some other researches [49-51]. In [49] Yorino et al implement Benders decomposition technique to solve a MINLP problem that formulates a reactive power planning including the allocation of SVC and TCSC devices. The objective function is to minimize the sum of the installation costs and the operating costs under the normal and contingency states, which include the costs of load shedding, the cost of other emergency controls, and the expected costs for the voltage collapse. In [50] Minguez et al use a multistart Benders decomposition technique to maximize loading condition and find the optimal placement of SVC devices in a multiscenario framework that includes contingencies and in [51] ElArabi et al use FACTS devices to avoid voltage collapse for the set of contingencies that derive the system to unstable zone. The method is a hybrid method based on genetic algorithm/successive linear programming (GA/SLP) to solve the MINLP problem.

MINLP is used to find optimal location of phase shifters in [52-55]. The difference between [52] and [53] is in the power flow constraints which are based on Transmission Congestion Distribution Factors (TCDFs) in [52] and power flow contribution factor in to the congested line in [53] and the objective function in [54] is the system loadability. In [55] Aminifar et al find the optimal placement of UPFC devices using an AC OPF. The optimization problem is MINLP considering the real power production costs and the UPFCs installation costs to be minimized. The modeling language is GAMS and the solver is DICOPT.

In [56], Benabid et al use Non-dominated Sorting Particle Swarm Optimization (NSPSO) method which is specialized in multi-objective optimization problem, to find the optimal placement of TCSC and SVC devices that maximize static voltage stability margin, reduce real power losses, and load voltage deviation.

In [57] Paterni et al study the application of TCPST devices for the French network and introduce an index for measuring the benefit of a given set of phase shifters by genetic algorithm. The best location is found but the size of the phase shifter is preselected.

1.4 Contents of the thesis

Chapter 2 gives an overview of the conversion of the regulated electricity industry into the deregulated electricity market. Special characteristics of the electricity market components that make it different from other commodities are described: market models, pricing models and restructuring framework. The historic evolution of the UK and the USA electricity restructurings and their markets and pricing models are also discussed.

Chapter 3 focuses on the transmission sector and its congestion management in electricity markets. Some important issues about the transmission sector in the deregulated environment are analyzed, including the physical transmission limits which may cause congestion, the impact of transmission congestion, the required features of a suitable approach for resolving transmission congestion and the various phases of congestion management.

In Chapter 4, some key concepts are reviewed, such as the applications of DC and AC models of FACTS devices, optimization, in general terms, and its role in the electricity market. Then, by combining all the individual concepts, the main contribution of this thesis is made. Optimal placement of FACTS devices and their setting as a solution to transmission congestion problem in real-time balancing market and its impact on generation re-dispatch costs is introduced, formulated and solved by a DC OPF. The simulation results are presented and discussed.

Chapter 5 builds on the previous chapter where the thrust is in the implementing AC OPF as opposed to the DC OPF. Reactive power, bus voltage magnitudes and angles, and more realistic FACTS models, which have been neglected in the DC OPF, are taken into account; hence, more realistic solution is presented. For an "optimal" solution to be trapped in a local minimum is a common problem. In this chapter, the behavior of different MINLP solvers is evaluated, and the optimal locations and settings of TCPST devices using the proper solvers are determined. Finally, the simulation results carried out by DC and AC OPF are compared.

In Chapter 6 the main conclusions of the thesis are presented, and proposals for future work in this area of research, are made.

Chapter 2. Market Structure

2.1 Introduction

A trend toward restructuring[1], privatisation[2] and deregulation of power industry started in the1980s in the UK and some Latin American countries and became worldwide in the 1990s. One of the aims behind the restructuring of the electricity industry was to allow market forces to play a greater role in the operation and planning of power systems. The basic expectations of such a change were that efficiency would increase and that electricity prices would decline without compromising reliability. This ideal vision assumed that the restructuring process would stimulate the development of new technology that would replace old inefficient equipment allowing investors to earn significant profits, notwithstanding the lower electricity rates.

There has been a worldwide trend towards restructuring and deregulation of the power industry over the last decade. The competition in the wholesale generation market brings many new technical problems and challenges to the operation of power system, which was regarded as "natural monopoly" due to the special characteristics of electricity as a commodity. On the other hand, this means real opportunities and challenges to power engineers and researchers.

[1] Restructuring is about commercial arrangements for selling energy: separating or "unbundling" integrated industry structures and introducing competition among producers and choice for customers [58].

[2] Privatisation is a change from government to private ownership, and is the end-point of a continuum of changes in ownership/management [58].

An electricity market is known by its two components: market model and pricing mechanism. The purpose of this chapter is to present an overall review about these concepts of electricity market, different market models, restructuring frameworks and pricing models. A history and background of some electricity structures such as the UK and the US are discussed. California electricity market is presented and its structure before and after melt down interprets some aspects of the market that should be considered.

2.2 Electricity restructuring

Before restructuring, the electricity industry was either a state-owned monopoly like the United Kingdom (UK) or a private-owned monopoly like the United States (US). The main motivation for restructuring in some countries like the UK and the Latin American countries was attracting funds from the private sector to relieve the trouble of heavy government subsidies. In the countries formerly under centralized control (central and eastern Europe) the process followed the general trend away from centralized government control and towards increased privatization and decentralization. In the US and other private-owned countries, the trend is toward increased competition and reduced regulation.

A first step in the restructuring process consisted of unbundling the traditional vertically integrated utilities into separate commercial unit that operated independently of each other, although not necessarily separately owned. These units were generation, transmission and distribution. In addition, the security of the system operation was usually assigned to an independent entity called the System Operator (SO). The economic operation of a power system was managed by a market operator responsible for balancing supply and demand and for setting prices. Several different forms of electricity markets and operators have been developed.

Generation companies and load supplying companies became market participants looking to sell or buy electricity. Various other market players started to appear, mainly traders who bought and sold power. One trend that stood out was to model electricity markets so that in structure they resembled traditional markets for other goods. The problem with this was that there are physical laws that differentiate electricity from other commodities in a number of significant ways:

- The need to instantaneously balance generation and demand;
- No means to effectively store large amounts of electricity;
- Transmission being a natural monopoly;
- Severe limitations in the ability to control the flow of electricity.

These factors make electricity markets more complex to run and call for tighter central coordination. The first feature requires real-time balancing between generation and demand at every bus. The lack of storage means that prices are more volatile and sensitive to market power that means some participants are in a position to influence the market outcome, and thus benefit at the expense of others. The natural monopoly of transmission and the inability to effectively control the flow of electricity distorts perfect market competition. This behavior does not occur in most other markets. Inadequate transmission flow-control can cause unreliable operation and system failure.

2.3 Market Models

There are four models of structuring the industry that correspond to varying degrees of monopoly, competition, and choice in the industry [58].

- Model 1-Monopoly at all levels, Generation is not subject to competition and no one has any choice of supplier; a single monopoly company handles the production of electricity and its delivery over the transmission to distribution companies and/or final consumers. This is the model for traditional power industry.
- Model 2-Purchasing agency. A single buyer, which is the purchasing agency, chooses from a number of different generators to encourage competition in generation sector. Access to transmission grid is not permitted for sales to final consumers. The purchasing agency has a monopoly on transmission networks and on sales to final consumers.

- Model 3-Wolesale competition. Distribution or retail companies (Distcos) buy electricity directly from a producer and deliver it over transmission networks. But the distribution/retail companies still have a monopoly over final consumers. There is open access to transmission grid.
- Model 4-Retail competition. All consumers can choose their suppliers. There is open access to transmission and distribution networks. The distribution is separate from the retail activity which is fully competitive. Most likely, this model is the world of the future of power industry. Retail competition makes the most competitive forces by bringing all final consumers into the market. However, it also greatly increases transaction costs due to requiring more complex trade arrangements and metering.

The four models will lead to very different types of trading arrangements. A brief comparison between them is given in Table 2.1

Table 2.1 Structural alternatives

Characteristic	Model 1 Monopoly	Model 2 Purchasing Agency	Model 3 Wholesale Competition	Model 4 Retail Competition
Definition	Monopoly at all levels	Competition in generation-single buyer	Competition in generation and choice for Distcos	Competition in generation and choice for final consumers
Competition in Generation Sector	✗	✓	✓	✓
Choice for Retailers	✗	✗	✓	✓
Choice for final Consumers	✗	✗	✗	✓

2.4 Restructuring Framework

Fig 2.1 shows a schematic representation of the restructured electricity industry divided into its various components: [3]

- Generation side: Generating companies (G) and Power Marketers (PM);
- Demand side: Retail (R) and Distribution (D) service providers;
- Transmission and Trading Coordination sector: Power eXchange (PX), Transmission Owners (TO), System Operator (SO), Ancillary Service providers (AS), and Scheduling Coordinators (SC).

Each component of this model represents a segment of the emerging electricity market.

It is not necessary for all of these components to exist as separate entities. The task of one component can be assigned and performed by another depending on the market model.

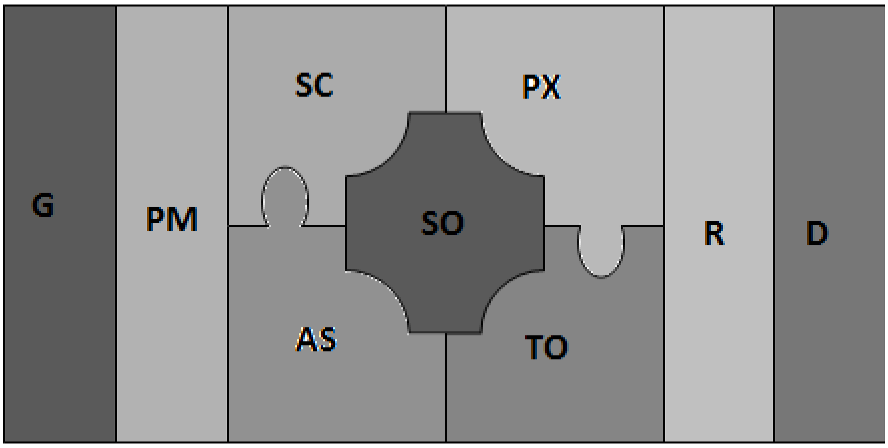

Figure 2.1 Structural components of electricity markets

2.5 Pricing Models

An important component of electricity market design is the pricing model which defines tariffs for electricity as well as for the various ancillary services. Pricing plays a central role in the market, as it sends monetary signals on the value of the resources, signals that strongly influence future investments in the system infrastructure. In addition, from the perspective of the consumer, the price of electricity must be competitive.

The special electricity characteristics make its market inherently imperfect. The two most notable imperfections are: the exercise of market power by generators, and the congestion of the transmission network. Market design, with its pricing schemes and rules, needs to tackle these problems, and discourage market participants from behavior that triggers such imperfections.

Generally, there are two basic pricing methods: bilateral trading and electricity pool [59].

2.5.1 Bilateral Trading

Bilateral trading involves only two parties: a buyer and a seller. Participants thus enter into contracts without involvement, interference or facilitation from a third party. The essential characteristic of bilateral trading is that the price of each transaction is set independently by the parties involved. There is thus no official price. Such agreements can be forwards and futures contracts. In a forward contract the sellers and the buyers are involved in generating and consuming electricity while in the future contract third parties can also take part in the trade. These parties are speculators who want to buy a contract for delivery at a future date, in the hope of being able to sell it later at a higher price. Similarly a speculator can sell a contract first, hopping to buy another one later at a lower price, future contracts are not backed by physical delivery.

Two major types of bilateral contracts can be distinguished:

- Physical
- Financial

Physical contracts specify the parties that generate and consume the power agreed to in the contract, the buses of injection and consumption, as well as the amount of traded power. A selling generator has the obligation to produce power to supply at least all of its physical bilateral contracts, while a load is expected to consume at least all of its physical bilateral contracts.

Financial contracts, on the other hand, are agreements that specify only the amount and the price of the traded power, together with other trading conditions. The points of injection and consumption may or may not be defined. Even if known, these points are not binding. This means that a selling side of the contract is free to appoint any market participant willing to supply the energy, while a buyer can also resell the contract further, and find another party to consume the power. Financial contracts may be resold at the market several times before the expiration date.

From the operational point of view, physical contracts directly affect generation dispatch since a generator has to produce at least the amount of its bilateral obligations. In addition, physical bilateral contracts may affect transmission congestion. Because of these influences on the overall system operation, the network usage resulting from each bilateral contract has to be approved by the System Operator before its actual scheduling.

As defined by the North American Electric Reliability Council (NERC) contracts could be *non-recallable,* also called *firm* or *non-interruptible,* and *recallable*, and usually referred to as *non-firm* or *interruptible.* For a firm contract, the system operator confirms that the full amount of an approved power transfer could be scheduled, except in the case of an emergency. In order to withdraw from such a contract, or curtail it, parties may need not only each other's consent, but also the permission from the system operator. These conditions are of a financial nature allowing for a variety of contract arrangements, and do not pertain to system operation. Alternatively, non-firm contracts are not guaranteed, and would be scheduled only as the operation conditions allow.

Financial contracts do not need to obtain any kind of advanced approval. A system operator does not even have to know about their existence. They are traded in the futures and forwards markets, without any power transfers actually being scheduled. To implement the trades arranged through financial contracts it is, however, necessary to transform them into settlements that firmly define the points of consumption and to specify whether these loads are supplied bilaterally or through the pool.

If the financial agreement is to be fulfilled bilaterally, the parties involved transform their agreement into one or more physical contracts for which permission from the SO is required.

2.5.2 Electricity Pools

The idea of competitive electricity pools derived from the fact that electrical energy is pooled as it flows from the generators to the loads so its trading might be done in a centralized manner and involve all producers and consumers. Pools are a very unusual form of commodity trading but they have well-established roots in the operation of large power systems. Rather than relying on repeated interactions between suppliers and consumers to reach the market equilibrium, a pool provides a mechanism for determining this equilibrium in a systematic way. Generating companies submit bids to supply a certain amount of electrical energy at a certain price for the period under consideration. These bids make a curve which is deemed to be the supply curve of the market. Similarly, the demand curve of the market can be obtained by consumer's offers. Sometimes this step can be omitted and the demand is set as a value determined using a forecast of the load. The intersection of the supply and demand curves represents the market equilibrium.

All the bids submitted at a price lower than or equal to the market clearing price are accepted and generators are instructed to produce the amount of energy corresponding to their accepted bids. Similarly, all the offers submitted at a price greater than or equal to the market clearing price are accepted and the consumers are informed of the amount of energy that they are allowed to draw from the system.

The market clearing price represents the price of one additional megawatt-hour of energy and is therefore called the System Marginal Price or SMP. Generators are paid this SMP for every megawatt-hour that they produce, whereas consumers pay the SMP for every megawatt-hour that they consume, irrespective of the bids and offers that they submitted.

A pool model provides a much more centralized form of system management. It not only handles all the physical electrical energy transactions but also has the responsibility for operating the transmission system.

2.5.3 Managed Spot Market

Imbalances arise between the amount that a party has contracted to buy or sell and the amount that it actually needs or can produce. Spot markets provide a mechanism for handling these imbalances but a conventional spot market mechanism is not feasible to deal with imbalances between generation and load. Instead, the system operator (SO) is given the responsibility to maintain the system in balance. Both generators and loads are allowed to participate in this marked and submit their bids and offers. And these bids and offers are selected by a third party (SO).

In addition to the term “managed spot market”, names such as “reserve market”, “balancing mechanism” and “real-time balancing market” are given to this function too. Fig 2.2 summarizes the operation of a managed spot market.

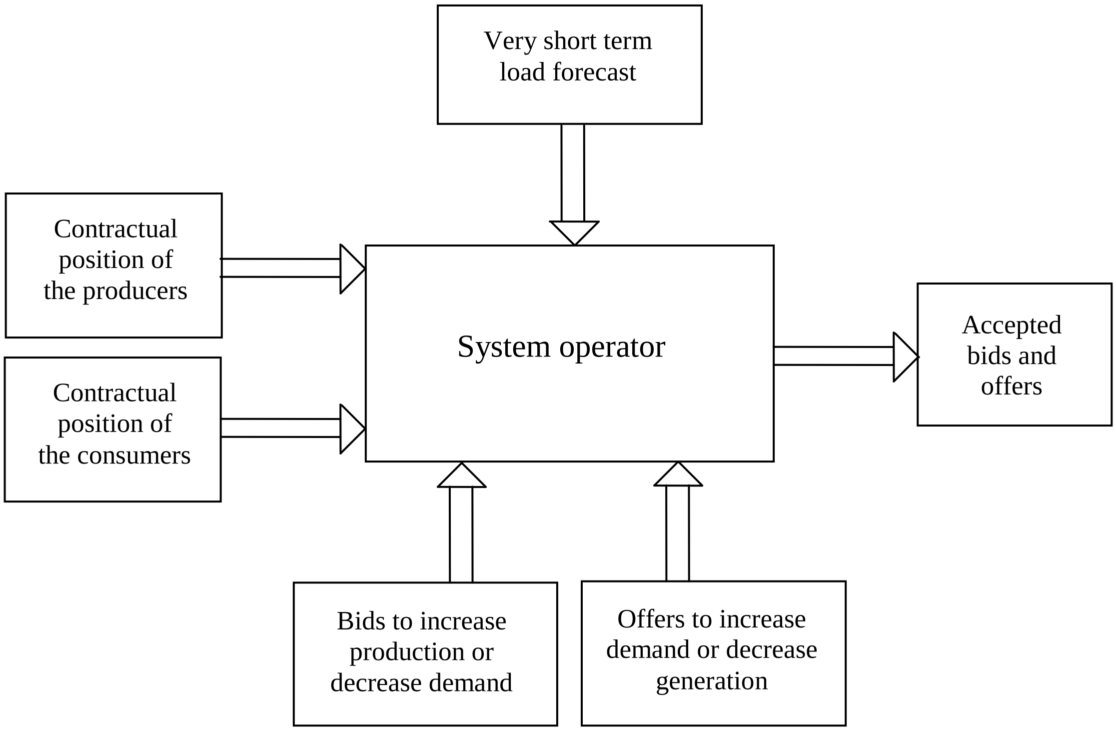

Figure 2.2 Schematic diagram of the operation of a managed spot market for electricity [59]

Pools are more centralized while bilateral markets are less organized. A pool can have a number of advantages over a bilateral market. It can reduce trading costs, increase competition, produce a publicly observable price and facilitate the detection of market power. Under some circumstances it may facilitate market collusion. On the other hand, a bilateral market can provide more flexibility than a pool and it needs little designing. Power marketers often favor bilateral markets because without an exchange there is more room for them to earn commission fees as brokers.

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

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

2.6 The UK Electricity Industry and Market Structure

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

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

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

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

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

- Forward and futures markets,
- Balancing mechanism administered by NGC,
- Settlement process for recouping system operator costs.

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

Under this mew structure, the main mechanism to trade energy became bilateral trading done through forward and futures markets, as well as short-term power exchanges. The forwards and futures markets are bilateral contract markets for firm delivery of energy, that trade from the short term prompt to a long-term agreement. In 2005, NETA was replaced by British Electricity Trading and Transmission Arrangements (BETTA) since Scotland joined the electricity market of England & Wales. Prior to BETTA the transmission system was operated in Scotland by Scottish Power and Scottish and Southern Energy who were the major generator and supply companies. However, there were no major changes in the structure of the market design, as bilateral contracts remained a main trading mechanism.

2.7 The US Electricity Industry and Market Structure

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

Electric power was a natural monopoly. Centralized systems with large generators that reduced costs and attracted business customers were clearly more efficient than specialized generators and masses of wires. After the Public Utility Holding Company Act (PUHCA) of 1935 passed by Congress, electric utilities were established as vertically integrated natural monopolies serving captive markets. Utilities and regulators determined the allowable expenses, which were used to set rates consumers had to pay. Until the early 1970s the vertical monopoly structure provided a stable basis for building an extensive and reliable system. Electric rates were steadily decreasing while electricity demand increased significantly at rates of seven to eight percent each year. Generally speaking, power systems comprise four main components: generation, transmission, distribution and consumption. The integrated utility built the generators that supplied electricity, built the wires that transported the electricity to each community and to each individual consumer, and directly billed the consumer for this bundled service.

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

2.7.1 FERC and NERC

If the industry were to move towards a truly competitive marketplace, the access to the transmission grid has to be opened. The first step toward this was another legislative act, the 1992 Energy Policy Act. Federal Energy Regulatory Commission (FERC) has the national responsibility and authority to design the electric power industry structure. In order to remove impediments to the wholesale electric energy markets and to increase efficiency and reduce energy costs to consumers nationwide, FERC issued two Orders in April of 1996, which became the foundation for open transmission access. These orders apply to public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce. Order 888 requires these utilities to file open access non-discriminatory transmission tariffs. Order 889 requires the utilities to separate transmission and wholesale power merchant functions, and to participate in an Open Access Same-Time Information System (OASIS), which electronically provides all market players with transmission capacity, prices, and other information needed to obtain non-discriminatory open transmission access.

During the following three years, the industry underwent a sweeping restructuring under new federal and state regulations, including divestiture of generation plants by investor owned utilities, a significant number of mergers, and a large number of entrants such as power marketers and independent generation developers. Various independent system operators (ISOs) were established to manage large transmission systems. In December 1999, FERC issued Order 2000 to address transmission pricing, congestion, parallel path flow, planning, and coordination between regulatory agencies. Order 2000 compels the formation of Regional Transmission Organizations (RTOs), requiring all public utilities to be part of an RTO. Order 2000 also defines the minimum characteristics and functions of an RTO.

FERC recently adopted a more hands-on approach to achieve its goal of a seamless national power market place. FERC's role is to issue policy at the highest level, and it is still looking to country, state, and industry organizations to develop and implement reliability and business methods and standards. FERC is also active in bringing all stakeholders together to gain open communications between all and expeditiously coordinate the decision-making process. FERC's role is also to provide the needed authority to compel adherence to rules in the competitive power markets.

FERC is focusing on six top priority items:

1. Congestion management
2. Cost recovery
3. Market monitoring
4. Transmission planning
5. Business and reliability standards
6. Transmission rights

Historically, the vertically integrated utility industry utilized the North American Electric Reliability Council (NERC), a bottom-up, electric-utility-dominated, volunteer organization, to establish reliability rules and monitor compliance. NERC was formed in 1968 in the aftermath of the 1965 Northeast Blackout and in response to the 1967 U.S. Federal Power Commission report on that blackout recommending the formation of an industry-based national reliability organization. NERC is funded by the 10 regional councils, which adapt NERC rules to meet the needs of their regions (NERC

2001a). NERC and the regional councils have largely succeeded in maintaining a high degree of transmission-grid reliability throughout North America.

Until a few years ago, FERC and NERC operated on parallel tracks with little interaction needed between the two institutions. FERC oversaw bulk-power commerce, NERC oversaw bulk-power reliability, and there was little interaction between commerce and reliability. Unbundling generation from transmission and creating competitive markets for electricity are dramatically changing this situation. The industry now recognizes that reliability and commerce are tightly integrated. Increasingly, FERC receives cases in which market participants complain that NERC reliability rules, their implementation, or both competitively disadvantage them. NERC established a Market Interface Committee as a complement to its long-standing Operating and Planning Committees in September of 1998. NERC has been instrumental in making the congestion management issues visible and also in searching for solutions, which reconcile the reliability and physics of the grid with the developing competitive market needs. NERC spearheaded the OASIS Working Groups that developed the standards and communications protocols followed by all transmission providers to post market information and facilitate the Electronic Scheduling Collaborative, which recently filed a report with FERC on its efforts to develop common business practice standards for electronic scheduling (NERC 2001c).

In response to recent NERC requirements, Regional Security Coordinators coordinate within the reliability regions and across the regional boundaries. These security coordinators conduct day-ahead security analysis, analyze current-day operating conditions, and implement NERC's Transmission Loading Relief (TLR) procedures to mitigate transmission overloads.

Recognizing that curtailment is likely to occur when transmission capacity rights are granted at the same time to market participants and to power system operators, but based on totally different rules for each, NERC is promoting the development of a long term plan to address the issues related to congestion management.

2.7.2 An *Overview of North American Network*

The North American electric system is divided into three Interconnections, figure 2.3, including the Western Interconnection (Western Systems Coordinating Council

[WSCC]), the Electric Reliability Council of Texas (ERCOT, which covers most of Texas), and the Eastern Interconnection (all Reliability Councils except WSCC and ERCOT). Within each Interconnection, all the generators operate at the same frequency as essentially one machine connected to each other and to loads primarily by AC lines. The Interconnections are connected to each other by a few DC links. Because these DC connections are limited, the flows of electricity and markets are much greater within each Interconnection than between Interconnections.

Within each Interconnection the fundamental entity responsible for maintaining bulk power reliability is the control area. NERC defines control areas as: "An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Interconnection." (NERC 2001a) Control areas are linked to one another to form Interconnections. Each control area seeks to minimize any adverse effect it might have on other control areas within the Interconnection by (1) matching its schedules with other control areas and (2) helping the Interconnection to maintain frequency at its scheduled value (nominally 60 Hz).

There are approximately 150 control areas in the U.S., most of which are operated by utilities although a few are run by ISOs. Control areas vary enormously in size, with several managing less than 100 MW of generation and others such as the Pennsylvania-New Jersey-Maryland Interconnection (PJM), California ISO, and Electric Reliability Council of Texas (ERCOT) each are managing over 50,000 MW of generation. Control areas are grouped into regional reliability councils, of which there are 10 in North America. The Midwest ISOs encompass more than 10 control areas with peak load over 100,000 MW across multiple reliability regions.

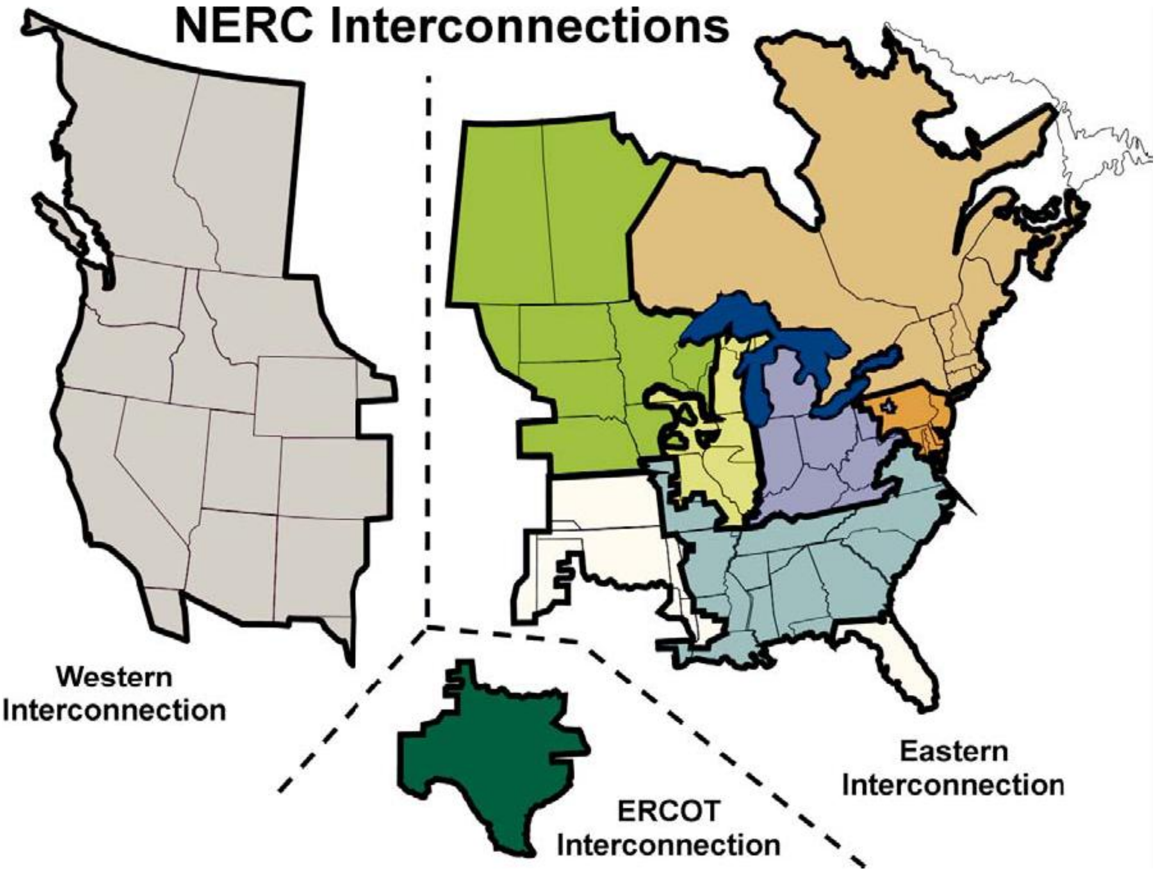

Figure 2.3 NERC's 10 regional councils cover the 48 contiguous states, most of Canada, and a portion of Mexico

2.7.3 California Market Structure

The de-regulation of the electric power industry in the state of California began with a ruling by the California Public Utilities Commission (CPUC) in April 1994 and followed bay State Assembly AB 1890, which was signed by the governor in September 1996, required the establishment of an ISO to coordinate safe and reliable delivery of power and to provide open access to the suppliers and consumers of electric energy. AB 1890 also required the creation of an Independent Power Exchange to create a spot market for energy. The first contract for the implementation of a Power Management System (PMS) for the ISO was awarded in December 1996. The remaining operation contracts, including the Scheduling Infrastructure (SI), Scheduling Applications (SA) and the Balance of Business Systems (BBS) were awarded by March 1997. The ISO commenced operation on Jan. 1, 1998, allowing less than one year for the development, integration, testing, and training of the market participants who would be using the system [60].

The California electric market started with the ISO, the Power Exchange (PX), and the Scheduling Coordinators (SC). The responsibilities of the ISO are defined as:

- Ensure grid reliability
- Provide non-discriminatory and open access to the grid
- Schedule all power through the grid, and balance the grid operation
- Manage transmission congestion and constraints
- Competitively procure and operate ancillary services
- Provide information to market participants
- Settle the real-time energy and ancillary services markets.

Additionally, the ISO is in the process of setting up a market for transmission capacity. As a part of this new service, the ISO will auction transmission capacity on interfaces between the major congestion zones and interfaces with external systems. The transmission capacity rights, referred to as the Firm Transmission Rights (FTR), will be used as a hedge against congestion on specified paths and will entitle the FTR owner to priority scheduling rights and a share of the transmission-use revenues

The main responsibilities of the PX are:

- Provide a competitive spot market for energy
- Determine day-ahead and hour-ahead market clearing price for energy based on a least-cost balanced schedule
- Procure adequate ancillary services on a least cost basis
- Act as Scheduling Coordinator for PX Participants
- Perform settlements process for the market

In 2001, the PX ceased to exist as a result of the California energy crisis.

To qualify as an SC, certain financial and technical requirements must be met to ensure load is met with enough supply. In addition, the SC must have access to and commitment from the supply and demand resources that it is representing. The responsibilities of the SCs are very similar to those of the PX.

At the beginning of the market restructuring, California reformers held out the promise that wholesale prices would fall to 3 cents a kilowatt hour from 7 cents, driven by many small, new, efficient generating plants burning natural gas.

The new wholesale market that began operating in April 1998 came reasonably close to the promised 3-cent power until the state ran into bad luck: dramatically higher gas prices, higher demand, higher emissions credit prices, lower imports from other states. Still, California Spot electricity markets work very poorly when supplies are tight; prices can rise to extraordinary levels and are more susceptible to supplier market power problems. The utilities, locked into purchasing on the spot market, paid up to $1 a kilowatt hour for scarce power on peak days while what they could charge their customers was fixed at about 6 cents a kilowatt hour. After months of buying power for much more than they can charge, the utilities have now approached insolvency. The customers, meanwhile, had no incentive to reduce consumption or to switch to competing retail suppliers. To make matter worse, delays in site approvals has meant that no new generating plants have yet been completed to meet growing demand.

At this time, the California Independent System Operator Corporation (CAISO) plans to implement a new market structure, Market Redesign and Technology Upgrade (MRTU), which has been developed over the years and approved by the Federal Energy Regulatory Commission (FERC).

MRTU provides for a new congestion management system, and establishes a financially binding day-ahead market for trading and scheduling energy, a residual unit commitment process, a real-time market that includes an hour-ahead scheduling process, market power mitigation measures, and resource adequacy requirements. The day-ahead market co-optimizes energy and ancillary services procurement, subject to transmission and other operational constraints. Once the CAISO has established final day-ahead schedules, the CAISO compares them to its projected load forecast, including forecasts for certain local areas, and secure additional resources through a “residual unit commitment” process [61].

The real-time market updates the energy scheduling and capacity procurement, using updated demand forecasts for the next 5 h, and knowledge of outages and other operating conditions. In both the day-ahead and real-time markets, scheduling priorities are recognized. These include priority uses such as supply schedules that maintain system reliability, use of pre-existing transmission contracts, and bids that are submitted as price-takers in an initial “scheduling run.” Penalty prices for these bid segments are kept from affecting final market prices, though, by freezing the affected schedules and re-optimizing by setting prices in a “pricing run,” using economic bids that are limited by caps and floors. Another instance where separate optimization runs serve different purposes is in the real-time market, where a real-time unit commitment process runs on 15-min intervals, and a separate real-time economic dispatch process runs on 5-min intervals to determine output levels.

The CAISO’s implementation of MRTU involves a fundamental change to the way bilateral energy contracts, such as Power Purchase Agreement (PPA), are scheduled and financially settled within the CAISO balancing authority area. Prior to MRTU, sellers scheduled resources under bilateral contracts directly to buyers using balanced Scheduling Coordinator-to-Scheduling Coordinator trades (referred to as “SC to SC trades”) and received payment from buyers according to prices set forth in PPAs. Under the new MRTU framework, sellers now schedule resources into the CAISO’s Day Ahead Market and receive two separate payment streams. One payment is from the CAISO, which pays the seller an hourly derived price specific to the pricing node where the generator injects power into the CAISO system. The second payment is the bilateral contract rate, which the buyer of the energy pays per the pricing provisions of the PPA. On the buyer side of a bilateral transaction, load serving entities that purchase power through PPAs incur two separate charges. One charge is for the purchase of energy to serve load from the CAISO’s Day Ahead Market and the other is the PPA contract rate that is due to the seller of the PPA energy.

To avoid the resulting double payment to sellers and the double charge incurred by buyers/load serving entities, and to facilitate the contractual delivery of bilateral power purchases, the CAISO has developed a settlement mechanism referred to as an Inter-SC Trade. An Inter-SC Trade consists of a quantity of MWs traded between two SCs for particular trading hours at designated locations. When two SCs submit matching Inter-SC Trades to the CAISO, the payment that the seller would otherwise receive from the CAISO is negated and the buyer receives a credit from the CAISO equal to the product of a) the quantity of MWs traded for the hour and b) the hourly derived Day Ahead Locational Marginal Price (LMP) of the pricing node used to settle the Inter-SC Trade.

2.8 Summary

Based on the level of the competition, an electricity market can have different models. These models and the framework of restructuring were reviewed in this chapter. In addition to the market model, which is essential to specify an electricity market, pricing model plays a central role in the market. Bilateral trading and electricity pool, two basic pricing methods are represented and the application of these methods in some well-known electricity markets such as the UK and US are studied.

Chapter 3. Transmission Networks and Congestion

3.1 Introduction

In general, one of the suppositions that define the framework for perfect competition is ‘free entry and exit to the market’, in other words, free market access should be guaranteed in a perfect competition. This prerequisite is not fulfilled in transmission markets therefore it is a natural monopoly. The first important step of power industry restructuring is the transmission open access. Transmission services have been unbundled as separate businesses from generation. However regarded as a natural monopoly, the transmission sector remains more or less regulated to permit a competitive environment for generation and retail services. The operating and planning of transmission network and the pricing of the transmission services are still retained as challenges on both theoretical and practical aspects in the development of electricity markets.

Transmission congestion can be defined as the condition where desired transmission line-flows exceed reliability limits. Following this definition, congestion management can be defined as the actions taken to avoid or relieve congestion. More broadly, congestion management can be considered any systematic approach used in scheduling and matching generation and loads in order to manage congestion. Electricity, unlike many other commodities, can’t be stored easily and its delivery is constrained by some physical transmission limits that have to be satisfied all the time to keep the operating security of the power system. With transmission limits, the deregulation of the power industry is more difficult therefore one of the major responsibilities of any type of SOs in any type of electricity markets is to manage transmission congestion and constraints [30, 31].

The purpose of this chapter is to review the basic concepts of congestion management by describing the monopoly character of transmission network, transmission limits as the cause of congestion and the generic congestion management scheme. The more popular transmission pricing under capacity allocation methods are reviewed and the need for a balancing mechanism in real time to alleviate congestion is emphasized.

3.2 Transmission Network in Electricity Market

The function of transmission system in a vertically integrated structure was to connect the utility's generators to the utility's customers and to operate the system reliably. The transmission systems were interconnected by different utilities to increase reliability, share reserves and take advantage of economic exchanges. If transmission congestion occurred, the utilities solved it by either generation re-dispatch or load-reduction to support reliability and economic transactions. These corrective actions and also expectations for load growth and future electricity prices and availability were a feedback for system evaluation in both a real-time basis and long-term planning purposes. A solution for new transmission facilities could be developed and presented to the regulator for approval and the final decision could then be implemented and the costs passed on to customers. Utilities and regulators made the investments decisions with prudent investment and operational costs borne by customers.

Although, the electric power industry restructuring has moved generation investment and operations decisions into the competitive market but transmission was left out as a communal resource in the regulated environment and despite the widespread experience of restructuring during the past decade, important issues remain open about the best way to operate transmission to support reliability management and market trading. In some models the mixing of competitive generation and regulated transmission makes congestion management difficult, and in some other models the huge quantity of bilateral transactions which could stress the existing transmission network heavily, has made the transmission congestion management one of the toughest problems in electricity market design and operation.

The product or output provided by a transmission system is a transport service: the movement of electricity, from one point on the network to another, at the request of a system user. Before completing such transaction, the generator and the customer must secure the right to transmit electricity. This right can be offered with a stronger or weaker guarantee that the service will be provided when needed. Rights can be combined, to allow transmission to and from a number of points. Any right will have to be accompanied by an assurance of quality, in terms of frequency control and reactive power control and the reliability of the service.

As mentioned in the previous chapter, in most electricity markets a special entity the so-called System Operator (SO) exists. This monopoly can be either a non-profit or a for-profit entity. The for-profit entity in the US is called TransCo (transmission company). It owns, operates and manages the transmission system as a natural monopoly. A TransCo could maximize its profit by withholding transmission capacities, thus it is heavily regulated. The other choice is to introduce a non-profit entity that is usually called Independent System Operator (ISO). In contrast to the TransCo the ISO does not own – but manage – the transmission network. It does not have a motive to withhold transmission capacities in order to maximize its profit. Thus it is only slightly regulated. [2]

The deregulation of the power industry was much easier without transmission limits. These limits are the main causes for transmission congestion and can be listed as [6]:

- Thermal limits - Colliding electrons in the AC power line cause electrical resistance, and resistance interferes with current in a wire, producing heat. As a wire heats up, it softens. Since power lines are heavy, their weight makes them sag as heat builds. Beyond a certain temperature the overloaded line will be permanently damaged. It is caused not only by real power flow but also by reactive power flow.

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

- Stability limits on power lines - Power flows through AC power lines because the voltage at the generator end reaches its maximum slightly ahead of the voltage at the load end. The amount by which the generation voltage is ahead is called the "phase angle." Beyond 90 degrees[1], power flow decreases become completely unstable. This is the line's physical stability limit. Angle stability can be classified into two categories: small-signal stability, which is the ability of the system to maintain synchronism under small disturbance; transient stability, which is the ability to maintain synchronism when subjected to a severe transient disturbance [62].

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

- Contingency constraints - Transmission system operators leave some unused capacity on power lines in case an unexpected event (a contingency) occurs somewhere on the system. If, for example, a large power line drops out of service, the power flows will shift to other lines at the speed of light. The power system operators' job is to ensure that none of those power lines overloads. Contingency constraints are fundamental element of economy-security control. Contingency analysis identifies potential emergencies through extensive "what if?" simulations on the power system network. A more conservative estimation of transmission capability will be obtained after considering the post-contingency constraints

In the research of this thesis, thermal, voltage magnitude and voltage angle limits are considered in the optimal power flow problems. The physical thermal limit on a transmission line is actually on the current magnitude, which causes the heating of the line, and the current is proportional to the apparent power S or the real and reactive

[1] 45 degrees is a more practical limit.

powers P and Q flowing through the branch. Therefore the thermal limit can be expressed as:

$$\left|S_{ij}\right| < S_{ij}^{\max} \tag{3.1}$$

where S_{ij} is the apparent power flow at line *ij* and $S_{ij}^{\max}$ is its limit.

Since the voltage in a power system does not normally deviate much from its nominal value and since the active power flow is usually much larger than the reactive power flow, the thermal limit on a line can also be approximated by the real power flow constrain as:

$$\left|P_{ij}\right| < P_{ij}^{\max} \tag{3.2}$$

where P_{ij} and $P_{ij}^{\max}$ are the transmission active line flow at line *ij* and its limit respectively.

3.3 Congestion management

Congestion is a term that has come to power systems from economics in conjunction with deregulation, although congestion was present on power systems before deregulation. Congestion management, controlling the transmission system so that transfer limits are observed, is perhaps the fundamental transmission management problem. The term “congestion management” comprises all actions and measures that are applied to handle network access in the presence of congestion.

Before regulation, the transmission system was designed so that when the generation was dispatched economically there would be no limit violations. Hence, just solving economic dispatch was usually sufficient. However, with the deregulation of the electric utility industry, the transmission system is becoming increasingly constrained as a result of moving more power through a transmission line (or an interface) than the transmission line (or interface) can accommodate, for either reliability or commercial reasons. A consequence of a congested interface or cross-border is that it creates a bottleneck which prohibits delivery of economic energy supplies to consumers on the high-cost side of the bottleneck. This is the case in some areas such as the European

Union, where the main target of the liberalization of the electricity supply sector is the creation of a truly Internal Electricity Market not only in the domestic markets, but also on an international scale, results impeding the integration of the national electricity markets by the limited amount of cross-border transmission capacity at several borders.

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

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

- *Not discriminate*: Each market participant, a consumer or a producer, should be treated equally and the price for a specific good at a specific place and time should be the same for everybody
- *Give economic signals*: The method should give incentives to producers, consumers and the network operator to improve the systems in order to relieve transmission constraints.
- *Be transparent*: The implementation should be well defined and transparent for

all participants.

- *Be feasible*: The available resources (information, computer systems) need to be capable of producing the necessary quantitative results in the time frame available.
- *Be able to interact with other systems:* In a real system the surrounding ISOs and their specific methodologies have to be taken into account. The implemented system needs to interact with other systems.

Congestion management is usually organized as a sequence of four phases (Figure 3.1) [63]:

1. The capability of the network to transmit power must be expressed as a "transmission capacity". The first phase of congestion management is thus to determine the amount of available transmission capacity according to the definitions and time framed prescribed by the subsequent allocation phase. The physical transmission limits mentioned in the section 3.2, decide the Total Transfer Capability (TTC) and Available Transfer Capability (ATC), which is very important system information to be published in any electricity market.
2. The capacity allocation step is required to distribute the ATC among the network users wishing to utilize it.
3. After the transmission capacity has been allocated and the wholesale energy markets are settled (usually in the afternoon of the day before operation), the ISOs perform a congestion forecast and determine if the foreseen constellation of power generation and consumption will be feasible or if the network security limits will be breached.
4. If during phase 3 a violation of network security limits is foreseen, the ISOs must take measures to relieve the network.

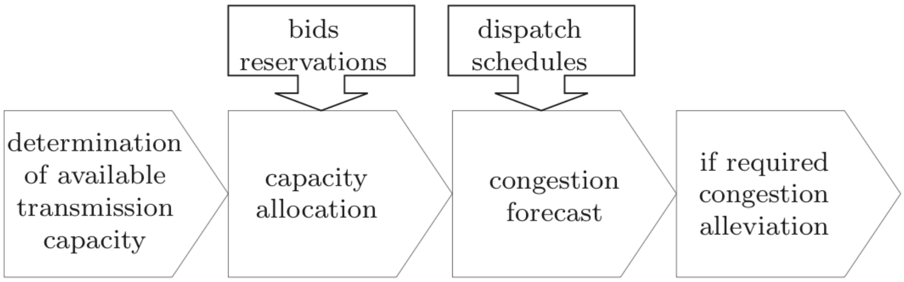

Figure 3.1 Phases of Network Access with Respect to Congestion

Taking account of the key role that the capacity allocation methods in phase 2 and congestion alleviation methods in phase 3 play in the context of congestion management, in the following sections these concepts are outlined.

The above scheme can also be expressed as a combination of several of basic methods for different time scales as shown in Figure 3.2 [6].

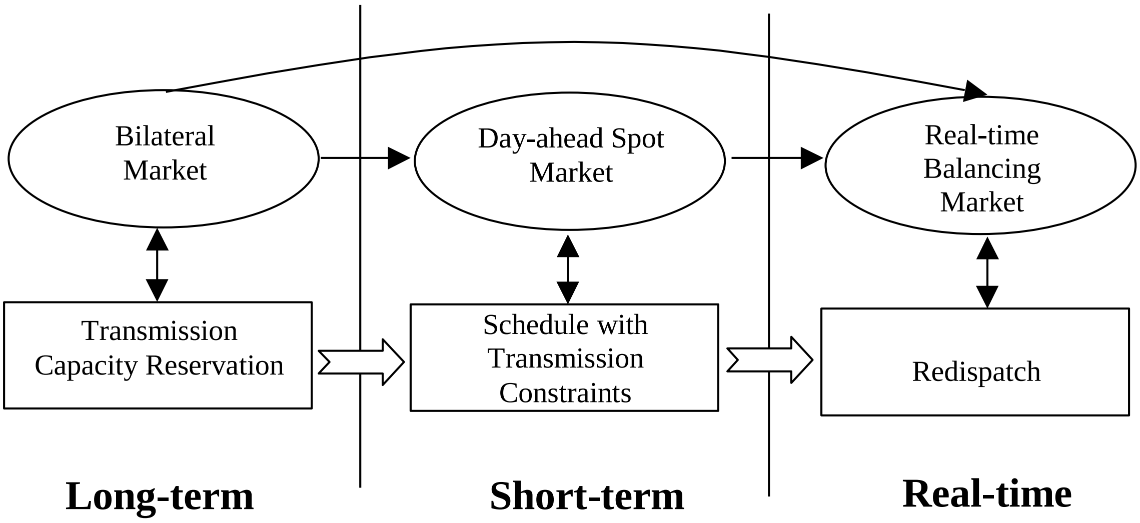

Figure 3.2 Overall congestion management process

In the long-term phase of this process capacity allocation can be made yearly, monthly, weekly, or even daily but no later than the morning of day-ahead. In the short-term scheduling all the transmission constraints are considered using the data collected from all the signed bilateral contracts and all the generation offers and demand bids in the spot market. The last step of this process is real-time re-dispatch in real-time balancing market when transmission congestion may still occur even after the two previous steps due to unpredictable events and fluctuating loads.

3.3.1 Capacity Allocation Methods

Before the physical delivery of the energy takes place, a Capacity allocation method is needed to determine the allocation of transmission capacity. A variety of different capacity allocation methods are in used [32] and although each implementation is unique in detail, they can be roughly grouped as follows:

- *First come, first served:* capacity is allocated according to the order in which the transmission requests have been received by the ISO. Starting from the earliest request, all requested amounts of capacity are fully granted until the available capacity is used up. This method encourages participants to make longer forecasts. Thus, it allows better and sooner security assessment for the ISO who knows accurately the volume of exchanges in advance. However, this method may not leave enough room for short-term trading, which is a requirement to ensure the success of market dynamics. This method is well suited for bilateral trades, but fails to provide an efficient priority mechanism for day-ahead or real-time pool transactions.

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

- *Contribution based on physical flow*. The ISO calculates the contribution of each transaction to the congestion to define its priority. The relative contribution to a transaction is the ratio between the flow induced by the transaction on the congested line and the volume of the transaction. The transactions will be curtailed in accordance with this rank till congestion disappears. This rule is also transparent, but it is not a market-based method. Its long-term efficiency is not ensured, because this physical contribution factor varies with topology, generation and load patterns.

- *Explicit auction:* (or *Willing-to-pay)* along with the requested capacity amount, the applicants have to declare how much they are willing to pay for this capacity. These bids are ordered by price and allocated starting from the highest one until the available capacity is used up. It is a market-based method for transaction curtailment, because it complies with the principle of "allocating the transmission capacity to the users who value it most highly". However, this method may not be efficient for curtailment against published ATC. More likely, it will be combined with some other congestion management approaches.

- *Implicit auction:* with all previously described methods, the electricity spot markets are separated from the transmission capacity allocation procedure and close after the transmission capacity has been allocated (i.e. between phases 2 and 3 of the generic congestion management model according to fig. 3.1). With implicit auctioning transmission capacity is managed implicitly by the spot markets: Network users submit bids or offers for energy in the geographical zone where they wish to generate or consume, and the market clearing procedure determines the most efficient amount and direction of physical power exchange between the market zones. Hence phase 2 of the congestion management model is integrated with the energy market, a separate allocation of transmission capacity is not required.

3.3.1.1 Nodal (Spot) Pricing

Nodal Spot Pricing, also known as LMP (Locational Marginal Price), was first proposed by Schweppe [64] and further developed by Hogan [65 and 66]. The general idea of nodal pricing is to 1) model an electricity market with its various economical and technical specifications, such as generators' cost functions, demand elasticity, generation limits (individual and overall), power flow limits etc. and 2) optimize the system which is synonymous to maximizing social welfare. One crucial outcome of the optimization procedure is the price at each node, the nodal or spot prices. It reflects the temporal and local variations of the energy price relating to the energy demand. The methodology comprehends that electricity has not only to be generated but also that it has to be delivered to a particular node, taking into account transmission constraints and electrical losses.

Nodal spot pricing can be seen as fully coordinated implicit auction. Generators and loads do not explicitly participate into auctions for transmission capacity. Capacity is implicitly allocated through bids for production/consumption at a specific location (bus). Nodal pricing is often used in conjunction with a pool-based market design. The ISO collects all bids and it is then in charge of clearing the market by maximizing social welfare while satisfying network constraints by performing a Security Constrained unit commitment (SCUC).

3.3.1.2 Zonal Pricing

Zonal pricing in accordance with nodal pricing, establishes different electricity prices for different locations in the network. In contrast to nodal pricing where prices in the case of congestion might differ for every node, for zonal pricing a group of nodes is aggregated to one zone. These zones are mostly defined a priori as the concept focuses on certain flow gates, which might be subject to congestion. An example is the Norwegian system, where the system operator splits the national transmission system into two zones (North and South) in the case of congestion. If the demand for transmission services does not exceed system capabilities, different network zones are not established, and thus, there is only one clearing price for the whole network. In the following the market splitting procedure is described.

When congestion is predicted, the ISO declares that the system is split into price areas at predicted congestion bottlenecks. Spot market bidders must submit separate bids for each price area in which they have generation or load. If no congestion occurs during market settlement, the market will settle at one price, which will be the same as if no price areas existed. If congestion does occur, price areas are separately settled at prices that satisfy transmission constraints. Areas with excess generation will have lower prices, and areas with excess load higher prices. Zonal pricing is illustrated with a simple two-zone example in Figure 3.3 [67].

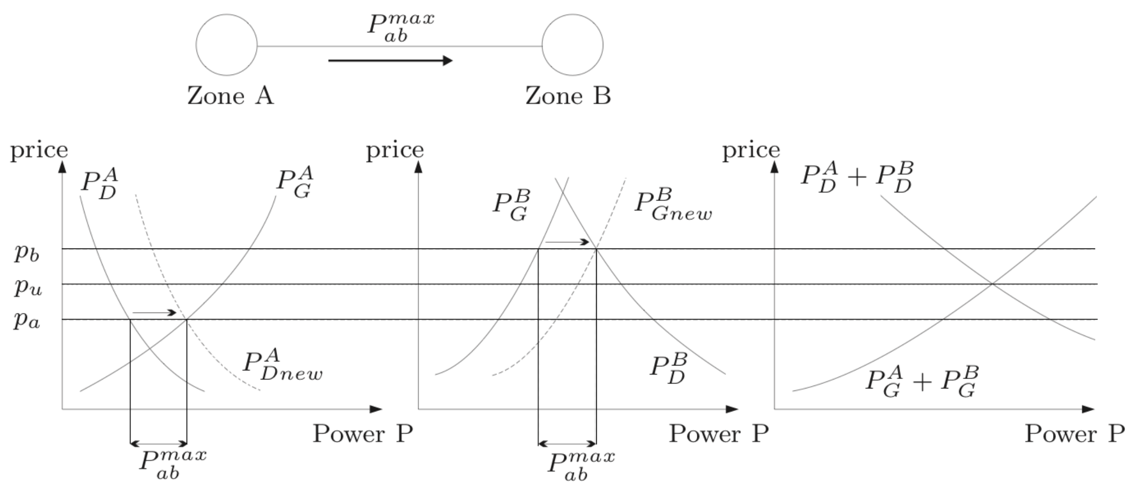

Figure 3.3 Two-zone market splitting example

The transmission line has a maximum capacity of $P_{ab}^{\max}$. In zone A generation facilities with low marginal cost are located (e.g. hydro plants), whereas in zone B there are major load centers with little excess supply. Generators and load bids in each zone are given by P_G^A, P_D^A, P_G^B and P_D^B. With no congestion, the market will settle at a single unconstraint market price p_u, and total generation and load will be equal. If the unconstrained transfer P_{ab}^u, exceeds the transfer limit $P_{ab}^{\max}$, then each zone becomes a separate price area and market will be split. The market operator utilizes transmission capacity to the limit of $P_{ab}^{\max}$ and maximizes arbitrage trade. Thus, it buys energy within the low-price zone A and sells energy to the high-price zone B. These activities may be regarded as a shift of demand and supply curves in zone A and B. The new demand curve in zone A is given by:

$$P_{Dnew}^A = P_D^A + P_{ab}^{\max} \tag{3.3}$$

which means a shift to the right along the x-axis in figure 3.2. And similarly, a shift to the right along the x-axis to create the supply curve in zone B defined through:

$$P_{Gnew}^B = P_G^B + P_{ab}^{\max} \tag{3.4}$$

The transmission capacity between the two zones is now fully utilized. Due to the arbitrage trade between the zones, the price in zone A decreases to p_a and the price in zone B increases to p_b. As the market operator (or the system operator) buys in the low-price area and sells in the high-price area, it collects a congestion rent. As in the nodal pricing system, the rent may be used to invest into the grid or may be allocated among the participants.

3.3.2 Capacity Alleviation Methods

In contrast with capacity allocation methods that place in long term and short term scheduling and are based on foreseen, capacity alleviation methods are often used to relieve congestion in real-time and are also referred to as remedial actions. A centralized balancing mechanism is needed to relieve the real-time congestion problems. Although the real-time balancing is also a market-based method, the ISO can take any mandatory actions to maintain the system security in emergent cases. Two of the most common methods to alleviate congestions are outlined in the following sections.

3.3.2.1 System Re-Dispatch

System re-dispatch is a real-time centralized method for congestion alleviation and as a part of the balancing mechanism is used to ensure power balance and secure system operation and guarantee that power balance equations and system constraints will always be satisfied. It is necessary because the bulk power transmission grid is highly dynamic and predicting constraints well ahead of time is therefore difficult.

The final adjustment between generation and demand in real-time is done through the balancing mechanism. It is a centralized type of market where each market participant can submit offers and bids to participate and provide different types of services. The main advantage of this method is that due to the centralized nature of the dispatch, no delay occurs between the identification of a constraint and the implementation of re-dispatch to control the constraint. However, employing a bid-based auction makes it a market-based system; the congestion management is therefore accomplished based on market participants' offers and their indicated willing to buy through congestion to protect their transactions. In this method, each participant that is selected for re-dispatch will be instructed to either increase or decrease its active power bus injection, and will be paid for this service according to its submitted bid or offer.

3.3.2.2 Countertrade or Buy-Back Procedure

Countertrading is based upon the same principles as re-dispatching [68], but may be considered market-oriented. Rather than applying command and control, the ISO will buy and sell electricity at prices determined by a bidding process. The principle of counter-trading is thus a buy-back principle, which consists in replacing the generation of one generator 'ill-placed' on the grid as regards the congestion by the generation of one 'better-placed' producer [69]. Different from market splitting, within the countertrade or buy-back model the market participants only see one uniform price (apart from the participants involved in the countertrade procedure). Equilibrium points of the day-ahead phase remain unchanged. As the ISO has to buy electricity downstream of the congestion at higher cost and sell it upstream, there is no congestion rent, but congestion cost for the ISO. This cost exposure is also regarded as an incentive for investment into grid capacity. Countertrading is used for real-time congestion relief in the Norwegian system and is used as exclusive Congestion Management concept in the Swedish market.

3.4 Summary

In this chapter, some necessary concepts of transmission system that are needed to study in this particular part of electricity industry, the nature of transmission network that makes it different from other commodities and also problems involved in operating of transmission grid in a deregulated environment such as the causes, remedies, and pricing methods of transmission congestion are discussed.

Because of the monopolistic nature of the transmission system in any electricity market a special entity so-called System Operator (SO) or Transmission Company (TransCo) or Independent System Operator (ISO) or Transmission System Operator (TSO) is needed and this entity plays a vital role in congestion relief, ranging from long-term planning down to real-time operating.

A generic congestion management process has four phases: 1) providing line information such as TTC and ATC based on physical limits of transmission lines including steady state limits, stability limits and contingency limits; 2) capacity allocation; 3) congestion forecast; 4) capacity alleviation. There are a variety of capacity allocation methods; however, the best solution might be a combination of several of the basic methods.

The nodal (spot) pricing or LMP and Zonal Pricing are two of the more popular approaches of capacity allocation methods. Nodal pricing is proposed as FERC standard market design in the US; it is implemented in the PJM-Interconnection, in New York, New England, New Zealand and it has recently been implemented in California under MRTU.

System re-dispatch and countertrade are used to alleviate congestion in real-time. In the last stage of congestion management, a balancing mechanism is needed to ensure power balance and secure system operation. Re-dispatching is a centralized type of market but can be designed in a market-based way, where each market participant submit offers and bids to participate in the market whereas the final decision is made by ISO.

Chapter 4. Optimal Placement of FACTS Devices in Real-Time Congestion Management by DC OPF

4.1 Introduction

A lack of sufficient transmission capacity leads to congested operation and requires re-dispatch of generation. In markets with predominantly centralized operation where majority of trades are done through a pool, congestion re-dispatch is often embedded within the market clearing procedure, although there would be provision for certain generators to submit additional offers to increase or decrease their generation.

Therefore, generation re-dispatch is a usual remedy for a congested operation and this is due to the fact that power flows in a transmission network follow Kirchhoff's laws, and means to control these flows are very limited. Another way would be to use Flexible AC Transmission System (FACTS) devices, which give certain level of line flow controls. Namely, these devices allow certain line parameters to be changed to influence flows along the lined. Although these changes may not be sufficient to completely relieve congestion, they can reduce the costs associated with generation re-dispatch.

The DC power flow, as a simplified model that carries out preliminary design studies is commonly used through the power industry. The well known limitations of this model are: the voltage profile of the system must be solidly maintained close to one per unit, its lines be short with high X/R ratio and the system be tightly meshed so that angle differences across lined are small. In all preliminary studies and simplified models some judgment in the use of such a model and in the interpretation of the results should be considered.

Since in this research we will investigate both AC and DC operation, after a brief review of FACTS devices, the AC and DC mathematical models of TCPST (Thyristor-Controlled Phase-Shifter Transformer) will be presented in the following chapter. Optimization in general as the base of Optimal Power Flow (OPF) solution and its importance in electricity market will be discussed. And by implementing a DC optimal power flow, the problem of congestion in real-time balancing market will be formulated and solved by application of FACTS devices. The ability of these devices to alleviate line congestion and reduce the generation re-dispatch costs will be investigated and by means of a suitable modeling language and solver, optimum location and setting of FACTS devices will be determined.

4.2 The Application and Models of FACTS Devices

Free (non-discriminatory) competition that deregulation emphasizes is an opportunity for power producers to enter the market without any limits and this will considerably increase the number of contracts. The mandatory accommodation of the contracted power by the transmission network will make the parallel- and loop-flow[1] problems

[1] Since with very few exceptions, the flow of power over the various lines in an AC network cannot be controlled, this leads to the result that portions of one system's power flowed through other systems' lines. The distribution of power flows over all parts of an interconnected transmission system results in two phenomena: parallel flow and loop flow. Parallel flow occurs when one utility delivers power to another utility. Because of the laws of physics, some of that power flows through the transmission system of the neighboring utilities, which parallel the transmission systems of the utilities involved in the transaction. Parallel flows may appear on another utility's system without that utility having any knowledge of the circumstances that gave rise of it. Loop flow involves two or more utilities. Each is supplying its own loads from its own sources. But the actual flows on the system from the combined operations result in the use of transmission in other systems in such a way that there is apparent

worse, causing unpredictable line loading (thermal limits), voltage variation and the potential decrease of transient stability. The traditional solution to these problems would be either transmission expansion or upgrading the existing transmission network. Apart from the cost, such a scenario in the present environmental and regulatory constraints may not be possible[2]. The solution is in technological approaches. One approach is the use of Flexible AC Transmission Systems (FACTS), relying on the large scale application of power electronics-based, and real time computer-controlled, compensators and controllers to provide cost effective, “high tech” solutions to the problems.

In 1988, Hingorani proposed the concept of Flexible AC Transmission Systems (FACTS) [12]. FACTS devices have the ability to allow a power system to operate in a more stable, flexible, secure, economic, controlled and sophisticated way. The IEEE defines FACTS as “Alternating current transmission systems incorporating power electronic-based and other static controllers to enhance controllability and increase power transfer capacity.” There are two distinctly different technical approaches in FACTS controllers developments [11]:

1. Thyristor Controlled FACTS Controllers,
2. Converter-Based FACTS Controllers.

The first group of controllers, the Static Var Compensator (SVC), Thyristor-Controlled Series Capacitor (TCSC) and Thyristor-Controlled Phase-Shifter Transformer

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circulating power flow around a closed loop. Obviously this loop flow is unwanted and will have bad effect on the transfer capability.

[2] From the transmission investment point of view there often isn’t enough incentive to invest on new transmission lines for transmission owners. The transmission revenue is a function of the magnitude of the flow or the available capacity of the transmission line [59] therefore the transmission owner may choose to reduce transmission capacity on purpose or do not invest sufficiently to collect more revenue. Either way aggravates transmission congestion.

(TCPST), employ conventional thyristors in circuit arrangements which are similar to breaker-switched capacitors and reactors and conventional (mechanical) tap-changing transformers, but have much faster response and are operated by sophisticated controls. Each of these controllers can act on one of the three parameters determining power transmission, voltage (SVC), transmission impedance (TCSC) and transmission angle (TCPST), as illustrated in Figure 4.1.

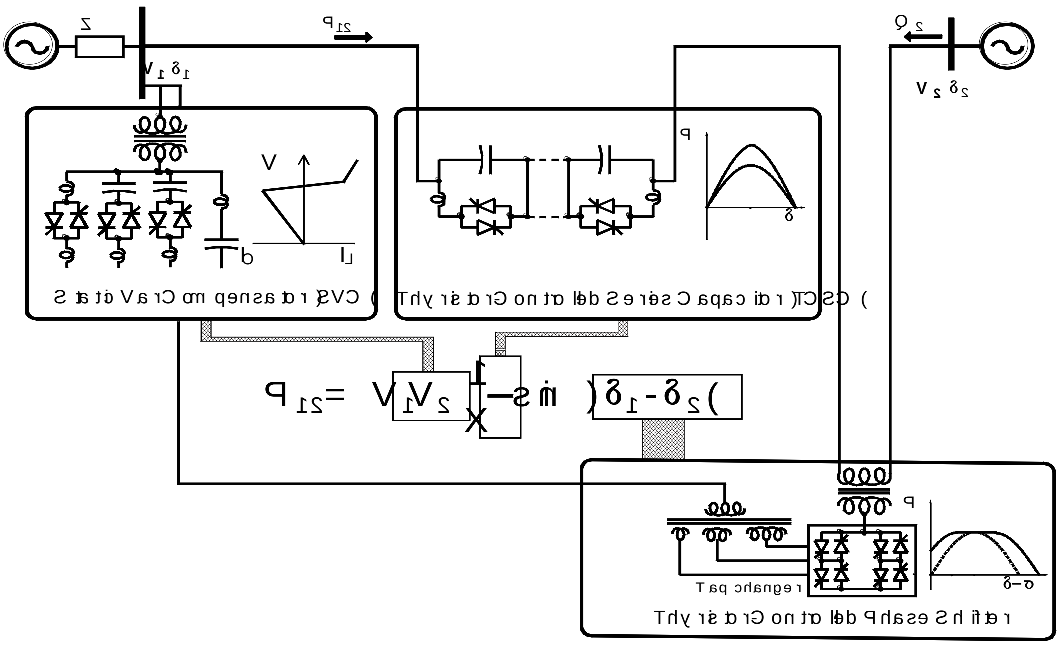

Figure 4.1 Conventional thyristor-based FACTS controllers [11].

In this thesis, we will investigate the application of TCPST in real-time congestion management in both DC and AC models. Therefore in this section the static models of TCPST are presented.

4.2.1 DC TCPST Model

The following TCPST representation is suitable for the DC load flow model of the power system network. Figure 4.2 shows an ideal TCPST connected in series with transmission line ($i-j$), between nodes i and j. The series impedance of the phase shifter is neglected and the line admittance is y_{ij}. The TCPST is modeled by a phase angle φ_{ij}.

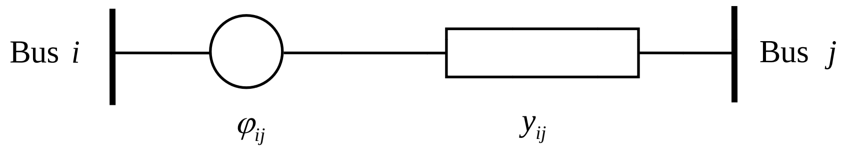

Figure 4.2 DC Model of TCPST

This equivalent circuit model represents the phase shifter as a continuous variable. By introduction a binary variable u_{ij}, the presence of the TCPST in the transmission line enters to the optimization problem as an integer variable. That is:

$$u_{ij} = \begin{cases} 0 & \text{for a line without a device} \\ 1 & \text{for a line with a device} \end{cases} \tag{4.1}$$

4.2.2 AC TCPST Model

The AC static model of a TCPST having a complex tap ratio of $1:1<\varphi_{ij}$ and a transmission line between bus i and bus j is shown in figure 4.3.

The real and reactive power flows from bus i to bus j can be expressed as:

$$P_{ij} = \mathrm{Re}\left\{V_i^* \left[(V_i - V_j)Y_{ij}\right]\right\}$$

$$= -G_{ij}V_i^2 + V_iV_j[G_{ij}\cos(\delta_i - \delta_j \pm \varphi_{ij}) + B_{ij}\sin(\delta_i - \delta_j \pm \varphi_{ij})]$$

(4.2)

and

$$Q_{ij} = -\mathrm{Im}\left\{V_i^* \left[(V_i - V_j)Y_{ij}\right]\right\}$$

$$= G_{ij}V_i^2 + V_iV_j[G_{ij}\sin(\delta_i - \delta_j \pm \varphi_{ij}) - B_{ij}\cos(\delta_i - \delta_j \pm \varphi_{ij})]$$

(4.3)

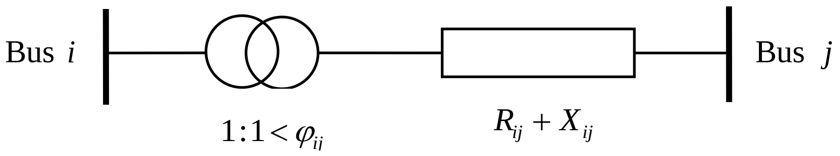

Figure 4.3 AC Model of TCPST

Where Y_{ij}, G_{ij} and B_{ij} are elements ij of the admittance, conductance and susceptance matrices, respectively.

Similar to the DC model, the presence of the TCPST can be considered by equation 4.1.

4.3 Optimization in General

Mathematical Programming is a technique of mathematical optimization and many real-world problems in such different areas as industrial production, transport, telecommunications, finance, or personnel planning may be cast into the form of a *Mathematical Programming problem*: a set of variables, constraints over these variables and an objective or objective function to be maximized or minimized. In other words, optimization is the procedure or procedures used to make a system or design as effective or functional as possible. An optimization problem is first modeled and classified in a mathematical form without making any reference to the implementation with the modeling software. The mathematical model and the results are obviously independent of the software.

The objective can be either a single cost or a multi-objective in some cases. The goal of optimization is to find a value of the decision variables that satisfies some criterion. Decision variables can be a set of continuous or discrete alternatives. In general, optimizing over a discrete set of alternatives is much more difficult than optimizing over a continuous variable because in the discrete case we [70]

- cannot use calculus to derive optimality conditions,
- cannot obtain descent directions from purely local first derivative information,

and

- cannot make use of convexity to establish global optimality.

If the discretization step of the discrete variable is “small,” a good approximate answer can be obtained by assuming that the discrete variables are continuous variables. After solving the continuous problem, we must then convert each continuous solution into a discrete value. A practical approach is to “round-off” to the nearest feasible discrete value, but this does not necessarily produce the best discrete alternative.

Optimization problems can be categorized by the type of their feasible set as three general forms:

- Unconstrained optimization,
- Equality-constrained optimization, and
- Inequality- constrained optimization.

Economic Dispatch (ED) neglecting generator limits and line losses is an unconstrained optimization problem.

Depending on linearity and nonlinearity of the constraints and objective function, and also the domain of decision variables, some of different categories of optimization problems are Linear Programming (LP), Mixed Integer Programming (MIP), Quadratic Programming (QP), Mixed Integer Quadratic Programming (MIQP), Nonlinear Programming (NLP) and Mixed Integer Nonlinear Programming (MINP). Table 4.1 describes an overview of the above classification.

An optimization problem in general can be expressed as:

$$\text{Minimize} \qquad F(\boldsymbol{x},\boldsymbol{u}) \tag{4.4}$$

subject to:

$$\boldsymbol{g}(\boldsymbol{x},\boldsymbol{u}) = \boldsymbol{0} \tag{4.5}$$

$$\boldsymbol{h}(\boldsymbol{x},\boldsymbol{u}) \leq \boldsymbol{0} \tag{4.6}$$

where $g(\boldsymbol{x},\boldsymbol{u})$ is a set of nonlinear equality constraints, and $h(\boldsymbol{x},\boldsymbol{u})$ is a set of nonlinear inequality constraints. The vector $\boldsymbol{x}$ consists of dependent variables while the vector $\boldsymbol{u}$ is a set of controllable quantities.

Table 4.1 A classification of optimization problems

Optimization classification	Decision variables domain	Constraints	Objective function
Linear Programming (LP)	Continuous	Linear	Linear
Mixed Integer Programming (MIP)	Continuous	Linear	Linear
	Discrete		
Quadratic Programming (QP)	Continuous	Quadratic terms	Linear
Mixed Integer Quadratic Programming (MIQP)	Continuous / Discrete	Quadratic terms	Linear
Nonlinear Programming (NLP)	Continuous	Linear	Nonlinear
		Nonlinear	Linear
		Nonlinear	Nonlinear
Mixed Integer Nonlinear Programming (MINLP)	Continuous / Discrete	Linear	Nonlinear
		Nonlinear	Linear
		Nonlinear	Nonlinear

The full sequence of solving an optimization problem is to [71]:

- Formulate a model, the abstract system of variables, objectives, and constraints that represent the general form of the problem to be solved.
- Collect data that define a specific problem instance.
- Generate a specific objective function and constraint equations from the model and data.
- Solve the problem instance by running a program, or *solver*, to apply an algorithm that finds optimal values of the variables.
- Analyze the results.
- Refine the model and data as necessary, and repeat.

Modeling language:

People do not deal with mathematical programming in the same way that solvers do. The “modeler’s form”, the form in which human modelers understand a problem, is different from the “algorithm’s form”, the form in which solver algorithms work with the problem, and conversion from modeler’s form to algorithm’s form is a time-consuming, costly and often error-prone procedure. In the algorithm’s form, the largest part is producing the table of numbers that multiply all the variables in all the constraints, which is a very sparse (mostly zero) matrix with anywhere from hundreds to hundreds of thousands of rows and columns. A computer program that produces this matrix is called a matrix generator. Although matrix generators can successfully automate some of the work of translation from modeler’s form to algorithm’s form, they remain difficult to debug and maintain. Using a modeling language for mathematical programming is a way to avoid these difficulties. A modeling language is designed to express the modeler’s form in a way that can serve as direct input to a computer system. Then the translation to the algorithm’s form can be performed entirely by computer, without the intermediate stage of computer programming. Modeling languages can help to make mathematical programming more economical and reliable; they are particularly advantageous for development of new models and for documentation of models that are subject to change.

Since there is more than one form that modelers use to express mathematical programs, there is more than one kind of modeling language. In this research two modeling languages: 'Mosel' and 'AMPL' are implemented to model the optimization problem. Mosel is an advanced modeling and solving language and environment, where optimization problems can be specified and solved with the utmost precision and clarity. The modeling component of Mosel provides an easy to use yet powerful language for describing optimization problems. Through its modular architecture, Mosel provides access to data in different formats (including spreadsheets and databases) and gives access to a variety of solvers, which can find optimal or near-optimal solutions to a problem [72].

AMPL is an algebraic[3] modeling language for mathematical programming; it was designed and implemented by Fourer, Gay and kernighan around 1985 [71], and has been evolving ever since. AMPL is notable for the similarity of its arithmetic expressions to customary algebraic notation, and for the generality and power of its set and subscripting expressions. AMPL also extends algebraic notation to express common mathematical programming structures such as network flow constraints and piecewise linearities [71].

Mosel is a modeling language appropriate to linear programming (LP). In this chapter, we will use a DC simplification to convert the MINLP problem to a MILP problem; therefore we are faced with a linear programming that can implement Mosel as the modeling language to produce the model's form of the OPF.

[3] An *algebraic* modeling language is a popular variety based on the use of traditional mathematical notation to describe objective and constraint functions. An algebraic language provides computer-readable equivalents of notations that would be familiar to anyone who has studied algebra or calculus. Familiarity is one of the major advantages of algebraic modeling languages; another is their applicability to a particularly wide variety of linear, nonlinear and integer programming models.

4.4 Optimal Power Flow (OPF) in Electricity Market

Economic Dispatch (ED) as an optimization problem had been used in electricity industry for almost 30 years. Traditionally, the transmission system was designed so that when the generation was dispatched economically there would be no limit violations. Hence, just solving economic dispatch was usually sufficient. With the worldwide trend toward deregulation of the electric utility industry, the transmission system is becoming increasingly constrained. As mentioned in the previous chapter, transmission limits affect the amount of power that can be transmitted through it. ED ignores the limits imposed by the devices in the transmission system. Combining ED with the power flow can solve this problem, the result combination is known as the Optimal Power Flow (OPF). Historically in 1962, Carpentier introduced a generalized nonlinear programming formulation of the economic dispatch problem including voltage and other operating constraints [73]. This formulation was later named the optimal power flow problem [74].

OPF has been playing a very important role in power system operation and planning and has perhaps been the most significant technique for obtaining minimum cost generation patterns in a power system with existing transmission and operational constraints. Today OPF has been extended to any problem that involves the determination of the instantaneous optimal steady state of power system.

OPF has a variety of applications in competitive electricity market. Transmission system with its natural monopoly characteristic is the major source of technical complication in a competitive electricity market and therefore has brought about many new potential applications and technical challenges to the OPF. It maximizes the social welfare in spot market clearing and pricing, minimizes generation cost or maximizes consumer net benefit in transmission pricing, minimizes the cost of congestion management in congestion management, maximizes the TTC in ATC evaluation, minimizes the cost of ancillary services in ancillary services procurement, and maximizes the revenue of transmission rights auction in transmission rights allocation.

The progress in numerical optimization techniques and computer technology has brought development to the OPF techniques too [75-79]. These techniques may be classified as Gradient methods, Quadratic Programming (QP), Newton-based methods, Linear Programming (LP), Interior Point methods, Heuristic optimization methods and Nonlinear Programming.

4.5 Optimum location of FACTS devices in real-time balancing market

In chapter 3, we represented generation re-dispatch as a method to alleviate congestion in a real-time balancing market. As we will see in detail in the following chapter, sometimes this solution is not feasible or is very expensive. Therefore we look into the problem of how to place and use FACTS devices optimally to minimize costs associated with generation congestion re-dispatch in a balancing market. The presence of FACTS devices brings integer variables to the problem and creates a Mixed Integer problem. On the other hand, OPF is naturally a nonlinear problem and in combination with integer decision variables becomes very difficult to solve. With the assumption that the network can be sufficiently well described by the DC OPF since only active power flows are investigated in this chapter, a DC simplification is implemented and a MILP problem is mathematically modeled.

As discussed earlier, generators and loads trade most of the energy through bilateral contracts, while the balancing market allows for the adjustments that are necessary in order to ensure secure system operation. Both generators and loads are allowed to participate in this market and submit their offers and bids to increase or decrease power injections and allow system operator to modify submitted schedules. These modifications could be used to re-dispatch certain generators and alleviate network congestion.

An example of such market design with bilateral contract trading can be found in the UK, where New Electricity Trade Agreements (NETA) was introduced in 2001. Under that new structure, the main mechanism to trade energy became bilateral trading done through forward and futures markets, as well as short-term power exchanges. The forwards and futures markets are bilateral contract markets for firm delivery of energy that trade from the short-term arrangement to a long-term agreement. In 2005 Scotland joined the electricity market of England & Wales and British Electricity Trading and Transmission Arrangements (BETTA) replaced NETA. However, there were no major changes in the structure of the market design, as bilateral contracts remained the main trading mechanism.

Therefore, the final adjustment between generation and demand in real-time through the Balancing Mechanism is a necessary physical market whose role is to ensure power balance and secure system operation. It is a centralized type of market where each market participant can submit offers and bids to participate and provide different types of services. Although less than 5% of energy is traded though this market, it is crucial for secure system operation.

This Balancing Market is also used for congestion management. Each participant that is selected for re-dispatch will be instructed to either increases or decreases its active power bus injection, and will be paid for this service according to its submitted bid or offer.

In addition, the incremental and decremental generation costs are assumed to be linear. This is also reasonable assumption, as it is used in practice (for example in the UK Balancing Market generators submit such linear bids and offers).

In this research we are particularly investigating implementation of the Thyristor Controlled Phase Shifter Transformer (TCPST) devices, since a link between active power flows and voltage angle differences is dominant. And also we are neglecting reactive power injections and flows.

4.5.1 Problem Formulation

The objective is to investigate how application of FACTS devices can affect congestion management and congestion re-dispatch, and where to place and how to set these devices so as to minimize the cost of such generation re-dispatch. The problem of finding optimum location of FACTS devices can be expressed through the Mixed Integer Linear Programming (MILP). The idea is to allow for a possibility to install such a device in each transmission line and then formulate a problem to be able to use MILP solver to find the most optimal location. As mentioned before, it requires problem linearization and thus a DC network model is used.

Generation offers to increase, and bids to decrease their active power injections are also linear, as they can submit a few blocks of power at different prices.

Therefore, the above-defined problem can be expressed as the following MILP optimization procedure:

$$\underset{\mathbf{u},\Delta\mathbf{P}_{\mathbf{g}}^{+},\Delta\mathbf{P}_{\mathbf{g}}^{-},\mathbf{P}_{\mathbf{f}},\delta,\varphi}{\mathbf{Min}} \left\{ \sum_{\mathbf{i}=1}^{\mathbf{N}} (\mathbf{C}_{\mathbf{i}}^{+}\Delta\mathbf{P}_{\mathbf{gi}}^{+} + \mathbf{C}_{\mathbf{i}}^{-}\Delta\mathbf{P}_{\mathbf{gi}}^{-}) \right\} \tag{4.7}$$

Subject to,

$$\mathbf{P}_g + \Delta\mathbf{P}_g^{+} - \Delta\mathbf{P}_g^{-} - \mathbf{P}_d = \mathbf{A}\mathbf{P}_f \tag{4.8}$$

$$\mathbf{P}_{\mathbf{f}} = \mathbf{B}_{\mathbf{l}}\mathbf{A}^{\mathbf{t}}\boldsymbol{\delta} + \mathbf{B}_{\mathbf{l}}\boldsymbol{\varphi} \tag{4.9}$$

$$\Delta\mathbf{P}_g^{+\min} \le \Delta\mathbf{P}_g^{+} \le \Delta\mathbf{P}_g^{+\max} \tag{4.10}$$

$$\Delta\mathbf{P}_g^{-\min} \le \Delta\mathbf{P}_g^{-} \le \Delta\mathbf{P}_g^{-\max} \tag{4.11}$$

$$-\mathbf{u}.*\boldsymbol{\varphi}^{\max} \le \boldsymbol{\varphi} \le \mathbf{u}.*\boldsymbol{\varphi}^{\max} \tag{4.12}$$

$$\mathbf{1}^{T}\,\mathbf{u} \le N_{\varphi} \tag{4.13}$$

$$\left|\mathbf{P}_f\right| \le \mathbf{P}_f^{\max} \tag{4.14}$$

Where:

N is the set of buses,

L is the set of transmission lines,

$\mathbf{u}$ is L vector of the binary variables,

$\mathbf{1}$ is L vector of 1's,

.* is element by element vector multiplication,

$\Delta\mathbf{P}_g^{+}$, $\Delta\mathbf{P}_g^{+\min}$and $\Delta\mathbf{P}_g^{+\max}$ are vectors of bus generation increment outputs and limits,

$\Delta\mathbf{P}_g^{-}$, $\Delta\mathbf{P}_g^{-\min}$and $\Delta\mathbf{P}_g^{-\max}$ are vectors of bus generation decrement outputs and limits,

$\mathbf{P}_d$ is the vector of bus loads,

$\mathbf{P}_g$ is the vector of bus generation outputs (known vector),

$\mathbf{A}$ is network node incidence matrix,[4]

$\mathbf{P}_f$ and $\mathbf{P}_f^{\max}$ are vectors of line power flows and limits,

$\boldsymbol{\varphi}$ and $\boldsymbol{\varphi}^{\max}$ are vectors of phase shifter settings and limits,

$N\varphi$ is maximum specified number of TCPST's,

$\mathbf{B}_l$ is the diagonal matrix of line susceptances and

$\boldsymbol{\delta}$ is the vector of bus angles.

In the above formulation, the cost function, (4.7), minimizes the cost of modifying given generation output vector, where C_i^+ is an incremental bid, submitted by a generator for the incremental generation change of ΔP_{gi}^+. Similarly, C_i^- is a decremental bid, submitted by a generator for the decremental generation change of ΔP_{gi}^-.

Furthermore, values of increments, ΔP_{gi}^+, and decrements, ΔP_{gi}^-, have to be within the specified values, as defined by (4.10) and (4.11) (and with the nonnegative lower bound). In the above formulation the initial level of generation output $\mathbf{P_g}$ is known and defined by prearranged agreements between market participants. In this procedure, it is not a decision variable, but a specified parameter, and the objective is to minimize costs associated with modifying these initial values in congestion re-dispatch.

Location of FACTS devices is modeled through a vector of binary variables $\mathbf{u}$, which, as described in (4.1), defines whether a line is selected for the FACTS placement. Influence of the placed device on the system operation is taken into consideration by

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[4] A is an $N \times L$ matrix that shows the topology of the network, the way the buses are connected through the lines with the matrix element being $a_{ij} = \begin{cases} 1, & \text{if flow j leaves node i} \\ -1, & \text{if flow j enters node i} \\ 0, & \text{if flow j is not incident with node i} \end{cases}$

equation (4.9), which defines line power flows. Limits on phase shift angles φ are modeled by (4.12). To limit a number of possible FACTS devices used, we introduce constraint (4.13), while equation (4.14) models line limits.

Limitation on the number of FACTS devices, $N\varphi$, is a useful parameter, as this technology is usually very expensive and it is reasonable to consider installation of only a few of these devices.

Finally, for simplicity the above formulation considers that only generators are participating in congestion management re-dispatch, however, it will not be difficult to extend the model and include participation of demands.

4.5.2 Implementation of Dash_xpress

As mentioned in section 4.3, an optimization problem needs a modeling language and also a solver to produce the optimal solution/solutions. Dash Xpress is one of commercially available solvers able to solve MILP problems that are formulated with the Mosel language. Working with these Mosel models needs a graphical user interface, Xpress-IVE, which is available online [80] and provides a user-friendly environment. As in other windows applications, file menu handles file management. By means of an appropriate command a new blank file opens as shown in Appendix A.

After starting up the Xpress-IVE, the next step is to creating and saving the Mosel file. A Mosel file has three main parts: declarations, initializations, and mathematical formulations. In the declaration section, all the parameters and variables and their domains should be declared and placed between two commands: “declarations” and “end-declarations”. The initializations block is used for reading and writing data in Mosel-specific format and appears between two commands: “initializations from” and “end- initializations”. In the mathematical formulation block, constraints including equality and inequality constraints and the objective function are defined.

Solving the Mosel file can be done after writing and debugging the program. And finally printing the outputs and seeing the results is possible either in a separate file or in the same window shown in Appendix A.

4.5.3 Simulation Results

5-Bus Test System

The derived formulation is first illustrated on a small 5-bus test system (example 11-9 of reference [81]) shown in figure 4.4. The generators are placed in buses 1,2 and 4, while loads are at buses 2,3,4 and 5.

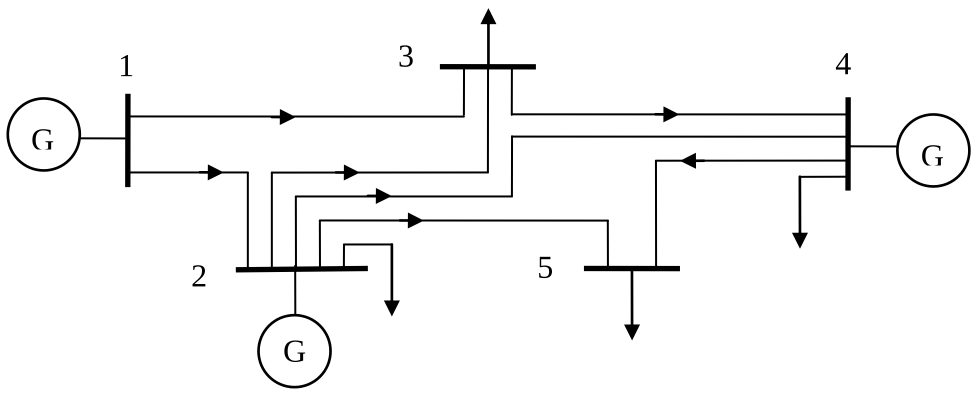


Figure 4.4 System diagram for 5-bus test system

Initial active power output of generators and also their incremental offers and decremental bids are given in Table 4.2. Both bids and offers specify a range of active power decrease or increase and associated price. The total demand given in the second row of Table 4.2 is equal to the total initial generation output of row 1. Thus, the system is in balance, and the generation re-dispatch is only due to network congestion.

Table 4.3 gives values of line impedances, maximum line limits and angle limits of FACTS devices.

Table 4.2 Bus data for 5-bus test system

	BUS				
	1	2	3	4	5
P_{gi} [MW]	142	178	0	80	0
P_{di} [MW]	0	40	150	80	130
$\Delta P_{gi}^{+\max}$ [MW]	40	50	0	30	0
$\Delta P_{gi}^{+\min}$ [MW]	0	0	0	0	0
$\Delta P_{gi}^{-\max}$ [MW]	40	50	0	30	0
$\Delta P_{gi}^{-\min}$ [MW]	0	0	0	0	0
C_i^+ [\$/MWh]	13.9	14.9	0	16	0
C_i^- [\$/MWh]	12.9	13.9	0	15.5	0

Table 4.3 Line data for 5-bus test system

Line	From	To	x_l [p.u]	$P_f^{\max}$ [MW]	$\varphi^{\max}$ [°]
1	1	2	0.06	150	15
2	1	3	0.24	60	15
3	2	3	0.18	120	15
4	2	4	0.18	100	15
5	2	5	0.12	106	15
6	3	4	0.03	50	15
7	4	5	0.24	60	15

Network node incidence matrix for the 5-bus test system shown in figure 4.4 is:

$$A = \begin{bmatrix} 1 & 1 & 0 & 0 & 0 & 0 & 0 \\ -1 & 0 & 1 & 1 & 1 & 0 & 0 \\ 0 & -1 & -1 & 0 & 0 & 1 & 0 \\ 0 & 0 & 0 & -1 & 0 & -1 & 1 \\ 0 & 0 & 0 & 0 & -1 & 0 & -1 \end{bmatrix}$$ and diagonal matrix of line susceptances is:

$$\mathbf{B} = \begin{bmatrix} 16.67 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 4.167 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 5.56 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 5.56 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 8.33 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 33.33 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 4.167 \end{bmatrix}.$$

First, we will analyze a case with no FACTS, which can be obtained by setting the value of the maximum number of devices to zero, i.e. $N_\varphi = 0$. The solution of this case indicates that the transmission line 5, between buses 2 and 5, is congested, and the cost of generations re-dispatch is 1312.6 \$/h. The re-dispatch is carried out by reducing the output of generator 2 by $\Delta P_{g2}^{-} = 45\,\text{MW}$, and increasing the output of generators 1 and 4 by $\Delta P_{g1}^{+} = 15\,\text{MW}$and $\Delta P_{g4}^{+} = 30\,\text{MW}$, respectively. This means that the final values of generation outputs for generators 1, 2 and 4 became $P_{g1} = 157\,\text{MW}$, $P_{g2} = 133\,\text{MW}$ and $P_{g4} = 110\,\text{MW}$. When the number of FACTS devices has increased to $N_\varphi = 1$, the algorithm has chosen to place one device in line 4, between buses 2 and 4. This has reduced the cost of re- dispatch to zero, with the settings of the FACTS device $\varphi_{23} = 4°$. Moreover, all line flows are below the line limits. Table 4.4 shows the above numeric results.

Table 4.4 The effect of FACTS devices on the congested 5-bus test system

Bus number	Without TCPST			With one TCPST			
	Incremental change	Deccremental change	Total Cost	Incremental change	Deccremental change	Total Cost	TCPST Location/ Setting
	MW	MW	$/h	MW	MW	$/h	Degree
1	15	-	1312.6	-	-	0.0	Line 4
2	-	45		-	-		4
3	-	-		-	-		
4	-	-		-	-		
5	30	-		-	-		

Next, we will look into the situation when there is a change in the level of demand and trading. We will investigate the case when a load at bus 5 increases by 10 MW, so that $P_{d5} = 140\text{MW}$. To satisfy this increase this load has entered into a bilateral contract for 10MW with generator 1, which then increases the initial output of this generator to $P_{g1} = 152\text{MW}$. In the case with no FACTS devices, the problem does not have a solution. With one FACTS device the problem becomes feasible, and the cost of congestion re- dispatch is zero. The solution proposes to place FACTS device in line 3 (from bus 2 to bus 3), with a setting of $\varphi_{23} = 9.26°$. The results are shown in Table 4.5.

Table 4.5 The effect of FACTS devices on the 5-bus test system with an imbalance in generation and demand

Bus number	Without TCPST			With one TCPST			
	Incremental change	Deccremental change	Total Cost	Incremental change	Deccremental change	Total Cost	TCPST Location/ Setting
	MW	MW	$/h	MW	MW	$/h	Degree
1	No Solution			-	-	0	Line 3
2	(Infeasible problem)			-	-		9.26
3				-	-		
4				-	-		
5				-	-		

14-Bus Test System

In addition the proposed method is tested on a 14-bus network whose line impedances and load data can be found in the example ‘case14’ of Matpower 3.0 program [82] and also are represented in Appendix B. Bus generation data, which include initial power output of generators, their incremental offers and decremental bids, and also a range of generation output increase and decrease, are specified in Table 4.6. As in the 5-bus system example, a value of a total demand is equal to the total initial generation output. This dispatch is only due to network congestion.

Table 4.6 Bus data for 14-bus test system

	BUS				
	1	2	3	6	8
P_{gi} [MW]	195	36	28	0	0
$\Delta P_{gi}^{+\max}$ [MW]	111.4	102	100	100	100
$\Delta P_{gi}^{+\min}$ [MW]	0	0	0	0	0
$\Delta P_{gi}^{-\max}$ [MW]	199	34.2	0	0	0
$\Delta P_{gi}^{-\min}$ [MW]	0	0	0	0	0
C_i^+ [$/MWh]	31	31	42	42	42
C_i^- [$/MWh]	14.7	14.7	20	20	20

The first analysis is carried out when maximum line flows for all lines are $P_f^{\max} = 50\,\mathrm{MW}$, except for lines 1, 2 and 3 for which $\mathbf{P_f^{\max}} = 100\,\mathrm{MW}$.

For these limits, lines 1 and 4 are congested, and there is need to re-dispatch a generation. As Table 4.7 illustrates, if there are no FACTS devices, the cost of this re-dispatch is 1839.1$/h, and it is achieved by increasing outputs of generators 2 and 8 by $\Delta\mathbf{P}_{\mathbf{g}2}^{+} = 29.2\,\mathrm{MW}$ and $\Delta\mathbf{P}_{\mathbf{g}8}^{+} = 8.9\,\mathrm{MW}$and decreasing the output of generator 1 by the same amount, i.e. $\Delta\mathbf{P}_{\mathbf{g}1}^{-} = 38.1\mathrm{MW}$. If only one FACTS device, with the maximum value $\varphi^{\max} = 15°$, can be installed, the proposed method yields a solution that places it in line 1, and sets the angle limits of $\varphi_1 = \text{-}2.5°$. However, the operation still remains congested, which is managed by reducing the output of generator 1 by $\Delta\mathbf{P}_{\mathbf{g}1}^{-} = 27.9\,\mathrm{MW}$and increasing the output of generator 8 by $\Delta\mathbf{P}_{\mathbf{g}8}^{+} = 27.9\,\mathrm{MW}$. The cost of this re-dispatch is 1579.5 $/h. Increasing the number of FACTS devices to two will reduce the re-dispatch cost to zero by placing them in lines 4 and 5 and settings $\varphi_4 = \text{-}5.3°$ and $\varphi_5 = \text{-}11.6°$.

Table 4.7 The effect of FACTS devices on the congested 14-bus test system

Bus number	Without TCPST			With one TCPST			
	Incremental change	Deccremental change	Total Cost	Incremental change	Deccremental change	Total Cost	TCPST Location/ Setting
	MW	MW	$/h	MW	MW	$/h	Degree
1	-	38.1	1839.1	-	27.9	1579.5	Line 1
2	29.2	-		-	-		-2.5
3	-	-		-	-		
6	-	-		-	-		
8	8.9	-		27.9	-		

The second analysis for this 14-bus network is carried out for a case when limits of lines 1 and 4 are changed to $\mathbf{P}_{\mathbf{f}}^{\max} = 100\,\mathrm{MW}$, with angle limits of $\varphi^{\max} = 15°$ and the results are presented in Table 4.8. Without any FACTS devices a re-dispatch is achieved by decreasing output of generator 1 by $\Delta\mathbf{P}_{\mathbf{g}1}^{-} = 36.7\,\mathrm{MW}$, and increasing outputs of generators 2 and 3 by $\Delta\mathbf{P}_{\mathbf{g}2}^{+} = 31.8\,\mathrm{MW}$and $\Delta\mathbf{P}_{\mathbf{g}3}^{+} = 4.9\,\mathrm{MW}$. The cost of this re-dispatch is 1732.9 $/h, and can be reduced to zero by placing FACTS in line 5 with a setting of $\varphi^{\max} = \text{-}14°$.

Table 4.8 The effect of FACTS devices on the congested 14-bus test system with a change in the line flow limits

Bus number	Without TCPST			With one TCPST			
	Incremental change	Deccremental change	Total Cost	Incremental change	Deccremental change	Total Cost	TCPST Location/ Setting
	MW	MW	$/h	MW	MW	$/h	Degree
1	-	36.7	1732.9	-	-	0	Line 5
2	31.8	-		-	-		-14
3	4.9	-		-	-		
6	-	-		-	-		
8	-	-		-	-		

4.6 Summary

In this chapter, a review of related concepts such as the applications and DC and AC models of FACTS devices, and optimization in general and its role in electricity market has been presented and a congestion remedy method for real-time operation using TCPST's to reduce generation re-dispatch cost has been proposed.

The main feature of this method is: optimal placement of FACTS devices can significantly reduce costs of generation re-dispatch in a Balancing Market, and thus improve system efficiency. Depending on the network topology, values of bilateral trades, as well as on increment and decrement generation limits, in some cases few devices may be needed to reduce these re-dispatch costs to zero.

The method is based on MILP procedure, so that commercially available modeling languages and solvers can be used. These solvers are robust and fast, and therefore can be used in analysis of large networks. Results indicate that application of FACTS devices can effective decrease costs of congestion re-dispatch, and even reduce them to zero.

Chapter 5. Investigation of Alternative Solvers for the AC OPF

5.1 Introduction

Solving the optimal power flow (OPF) problem is of increasing importance in power system operation under deregulated environment of the electricity industry. Power system engineers consider the OPF, which requires the iterative solution of a set of nonlinear algebraic equations, the most heavily used tool in power system operation. The nonlinear nature of power balance equations, convergence problem and non-convexity of the OPF problems have left many solution difficulties for researchers. In certain applications, approximate models such as DC OPF, decoupled and linearized decoupled power flow are often substituted for the power flow equations. These simplifications are useful to carry out preliminary design studies but for more accurate assessment, the necessity of applying a full AC OPF still exists. The non-convexity of the OPF leads to the application of a variety of mathematical algorithms and solvers to prevent trapping in local solutions.

In this chapter, after a review of most common simplification methods of OPF and advantages and disadvantages of using DC OPF, the optimal placement and setting of FACTS devices in real-time congestion management will be formulated by AC OPF as a MINLP problem and will be written by AMPL language. To avoid the local sub-optima points the performance of different commercial solvers will be investigated. And finally a comparison between AC and DC OPF will be presented.

5.2 Power Flow Simplification Methods

The solution of Power flow is the most accurate approach for modeling the steady state behavior of electric power transmission networks. From the power flow solution, which contains the voltage magnitude and phase angles at each bus in the system, all other values can be derived, including the real and reactive flows on all the lines in the system. There are always difficulties to solve the power flow equations which are represented in equations (5.1) and (5.2).

$$P_i(\boldsymbol{\delta},\mathbf{V}) = \sum_{j=1}^{N} |V_i||V_j|[G_{ij}\cos(\delta_i - \delta_j) + B_{ij}\sin(\delta_i - \delta_j)] \tag{5.1}$$

$$Q_i(\boldsymbol{\delta},\mathbf{V}) = \sum_{j=1}^{N} |V_i||V_j|[G_{ij}\,\mathrm{Sin}(\delta_i - \delta_j) - B_{ij}\,\mathrm{Cos}(\delta_i - \delta_j)] \tag{5.2}$$

The root of these difficulties is in the nonlinearity of power balance equations. These equations usually have a large number of alternative solutions or, more rarely, no solutions. So even when the power flow converges it may not have found the desired solution. Most of the time, the power flow algorithm must not only solve the power flow equations but also determine the optimal solution of large number of discrete variable controls such as the values for FACTS devices where in some algorithms the solution is highly dependent on the initial guess.

Many approximate methods have been proposed and widely used to conquer the difficulties in solving the full power flow. The decoupled power flow, the linearized decoupled power flow and the DC power flow are among these models. The decoupled power flow model is based on observations on many typical power systems concluding that whereas the interactions between real power flows and phase angles and between reactive power flows and voltage magnitudes are strong, the interactions between real power and voltage magnitude and between reactive power and phase angles are weak. The Decoupled power flow is derived by the assumptions a) The line conductances are negligible b) The phase angles across branch are small so that $\cos(\delta_i - \delta_j) \approx 1$ and $\sin(\delta_i - \delta_j) \approx (\delta_i - \delta_j)$ c) Voltage magnitudes are close to unity and do not thus affect real power flows. Under these simplifying assumptions power flow equations are:

$$P_i(\boldsymbol{\delta}) = \sum_{j=1}^{N} B_{ij}(\delta_i - \delta_j) \tag{5.3}$$

$$Q_i(\mathbf{V}) = -\sum_{j=1}^{N} |V_i||V_j| B_{ij} \tag{5.4}$$

The decoupled load flow dependency of reactive power on voltage magnitude is nonlinear and it is often convenient to linearize it and this ends with the linearized decoupled power flow simplification [83].

DC simplification:

The DC power flow greatly simplifies the power flow by making a number of approximations including a) completely ignoring the reactive power balance equations, b) assuming all voltage magnitudes are identically one per unit, c) ignoring line losses, and d) ignoring tap dependence in the transformer reactances. Hence the DC power flow reduces the power flow problem to a set of linear equations:

$$P_i = \mathbf{B_l \delta} \tag{5.5}$$

by using some algebraic matrix multiplying rules:

$$P_i = (\mathbf{A B_l A^t})\boldsymbol{\delta} \tag{5.6}$$

$$P_i = \mathbf{A}(\mathbf{B_l A^t \delta}) \tag{5.7}$$

and substituting $\mathbf{B_l A^t \delta}$ by $\mathbf{P_f}$:

$$P_i = \mathbf{A}(\mathbf{P_f}) \tag{5.8}$$

equation (5.8) will be derived which is exactly the same equation as (4.8) in the previous chapter. Where $\mathbf{B_l}$ is the diagonal matrix of line susceptances, $\mathbf{A}$ network node incidence matrix and $\mathbf{A^t}$, its transpose.

Choosing between the simplified and full power flow, depends on the variables under study and the required accuracy. For example, in the cases that the study of reactive power is necessary, both the decoupled and linearized decoupled power flow are effective. And when the reactive power study is not included in the investigation, the DC power flow solution approximates the real power flow solution very well. The effectiveness of DC OPF to find optimal placement of FACTS devices was observed in chapter 4 where reactive power re-dispatch and also bus voltage constraints weren't subject of the study.

The lack of the transmission line losses in the DC OPF is its most obvious difference from AC OPF that can be reasonably compensated for by increasing the total DC load by the amount of the AC losses. Hence, in the DC approach the estimated transmission system losses could be allocated to the bus loads. This requirement to first estimate the losses is usually not burdensome since the specified total control area "load" is actually the true load plus the losses. Indeed, the control area total loads given in the U.S. FERC Form 714 filings are actually load plus losses. Therefore in attempting to duplicate the Form 714 load values with a full power flow the true load must be estimated by taking the reported load and subtracting off the estimated losses [84].

However, simplicity and accuracy are two desirable features in the DC and AC OPF trade-off. DC OPF simplifies and linearizes the power flow equations, (5.5) and (5.8), and since the equations are linear they always have a single solution, which can be directly calculated by eliminating the need for iterations. On the other hand, AC OPF provides more accurate solutions incorporating reactive power and voltage analysis. These features of the AC OPF are not possible unless being involved with some issues such as nonlinearity, convergence, infeasibility, non-convexity and local optimum points. In the next section, the problem of transmission congestion in real-time balancing market that was formulated by implementation of FACTS devices and solved using DC OPF before will be solved using AC OPF.

5.3 AC OPF Problem Formulation (MINLP)

Using the general optimization pattern, equations (4.4) to (4.6), the AC form of equations (4.7) to (4.14) can be derived as equations (5.9) to (5,21). The main difference between these two sets of equations is in the power flow equations, (5.11) and (5.12), which are nonlinear, reactive power generations and their bids and also bus voltage magnitudes and angles. Practically, the variables in OPF problem can be divided into continuous variables, such as generator outputs (P_{gi}, Q_{gi}) and bus voltage magnitude (V_i), and discrete variables, such as phase shifters settings (φ_{ij}) and the binary variables (u_{ij}), that shows the presence of the phase shifter in the transmission line. In addition, considering the nonlinearity of the active and reactive power equality constraints, the problem can be expressed through the Mixed Integer Non-Linear Programming (MINLP).

$$\text{Minimize} \sum_{i=1}^{N} (C^{+}_{pgi}\Delta P^{+}_{gi} + C^{-}_{pgi}\Delta P^{-}_{gi} + C^{+}_{qgi}\Delta Q^{+}_{gi} + C^{-}_{qgi}\Delta Q^{-}_{gi}) \tag{5.9}$$

Subject to, (5.10)

$$P_{gi} + \Delta P^{+}_{gi} - \Delta P^{-}_{gi} - P_{di} = \sum_{j=1}^{N} |V_i||V_j|[G_{ij}\cos(\delta_i - \delta_j \pm \varphi_{ij}) + B_{ij}\sin(\delta_i - \delta_j \pm \varphi_{ij})] \tag{5.11}$$

$$Q_{gi} + \Delta Q^{+}_{gi} - \Delta Q^{-}_{gi} - Q_{di} = \sum_{j=1}^{N} |V_i||V_j|[G_{ij}\sin(\delta_i - \delta_j \pm \varphi_{ij}) - B_{ij}\cos(\delta_i - \delta_j \pm \varphi_{ij})] \tag{5.12}$$

$$0 \le \Delta P^{+}_{gi} \le \Delta P^{+max}_{gi} \tag{5.13}$$

$$0 \le \Delta P^{-}_{gi} \le \Delta P^{-max}_{gi} \tag{5.14}$$

$$0 \le \Delta Q^{+}_{gi} \le \Delta Q^{+max}_{gi} \tag{5.15}$$

$$0 \le \Delta Q^{-}_{gi} \le \Delta Q^{-max}_{gi} \tag{5.16}$$

$$\left|P_{ij}\right| \le P^{max}_{ij} \tag{5.17}$$

$$V_i^{min} \le V_i \le V_i^{max} \tag{5.18}$$

$$\delta_i^{min} \le \delta_i \le \delta_i^{max} \tag{5.19}$$

$$-\mathbf{u_{ij}}\varphi_{\mathbf{ij}}^{\max} \le \varphi_{\mathbf{ij}} \le \mathbf{u_{ij}}\varphi_{\mathbf{ij}}^{\max} \tag{5.20}$$

$$\sum_{ij=1}^{L} u_{ij} \le N_{\varphi} \tag{5.21}$$

Where:

N is the number of buses,

L is the number of lines,

ΔP^{+}_{gi} , ΔP^{+max}_{gi} are the incremental change of active power generation at bus i and the upper limit,

ΔP^{-}_{gi} , ΔP^{-max}_{gi} are the decremental change of active power generation at bus i and the upper limit,

ΔQ^{+}_{gi} , ΔQ^{+max}_{gi} are the incremental change of reactive power generation at bus i and the upper limit,

ΔQ^{-}_{gi} , ΔQ^{-max}_{gi} are the decremental change of reactive power generation at bus i and the upper limit,

C^{+}_{pgi} , C^{-}_{pgi} are the incremental and decremental costs of active power generation at bus i,

C^{+}_{qgi} , C^{-}_{qgi} are the incremental and decremental costs of reactive power generation at bus i,

P_{di} , Q_{di} are the active and reactive loads at bus i,

P_{gi} , Q_{gi} are the active and reactive generation outputs at bus i,

P_{ij} , P^{max}_{ij} are the transmission line flow at line ij and the limit,

V_{i} , V^{max}_{i}, V^{min}_{i} are the voltage magnitude at bus i, the upper and lower limits,

δ_{i} , δ^{max}_{i}, δ^{min}_{i} are the voltage angle at bus i, the upper and lower limits,

G_{ij} is the element ij of the line conductance matrix,

B_{ij} is the element ij of the line susceptance matrix,

φ_{ij} , φ^{max}_{ij} are the phase shifter setting at line ij and the limit,

N_{φ} is the maximum specified number of TCPST devices,

u_{ij} is the binary variables that model the presence of a FACTS device in line ij.

Similar to the DC OPF, the objective function (5.9) minimizes the re-dispatch cost, where C^{+}_{pgi} is an incremental bid, submitted by generator *i* for the incremental active generation change of ΔP^{+}_{gi} and C^{-}_{pgi} is a decremental bid submitted by generator *i* for its decremental active generation change of ΔP^{-}_{gi}. Similarly, C^{+}_{qgi} is an incremental bid, submitted by generator *i* for the incremental reactive generation change of ΔQ^{+}_{gi} and C^{-}_{qgi} is a decremental bid submitted by generator *i* for its decremental reactive generation change of ΔQ^{-}_{gi}. The values of active and reactive power increments, ΔP^{+}_{gi} and ΔQ^{+}_{gi}, and decrements, ΔP^{-}_{gi} and ΔQ^{-}_{gi} have to be within specified values as defined by (5.13) to (5.16). The initial levels of both active and reactive generation outputs P_{gi} and Q_{gi} are not decision variables because they are known and defined by prearranged agreements between market participants. The power flow equations, (5.11) and (5.12), are used as equality constraints; the active and reactive incremental and decremental generation limits in (5.13) to (5.16), active power flow limits in transmission lines (5.17), bus voltage and angle limits (5.18) and (5.19), phase shifter setting and number limits (5.20) and (5.21), are used as inequality constraints. The line active and reactive power flow equations, as were presented in the previous chapter, where the TCPST AC model was introduced, are:

$$P_{ij} = -G_{ij}V_i^2 + V_iV_j[G_{ij}\cos(\delta_i - \delta_j \pm \varphi_{ij}) + B_{ij}\sin(\delta_i - \delta_j \pm \varphi_{ij})] \qquad (5.23)$$

$$Q_{ij} = G_{ij}V_i^2 + V_iV_j[G_{ij}\sin(\delta_i - \delta_j \pm \varphi_{ij}) - B_{ij}\cos(\delta_i - \delta_j \pm \varphi_{ij})] \tag{5.24}$$

The binary variable u_{ij} in (5.20) describes whether a transmission line is selected for the FACTS placement and the influence of the placed device on the system operation is taken into consideration by equations (5.11), (5.12), (5.23) and (5.24). And the limitation on the number of the FACTS devices, N_{φ}, is considered in Equation (5.21).

5.3.1 Reactive Power in Real-time Balancing Market

Reactive power in order to participate in the power market needs to be priced. Analyzing the costs of providing reactive power services and establishing an appropriate price structure are important both financially and operationally for the deregulated electric industry. In general, there are two ways of supplying reactive power and controlling voltage: a) installing facilities as part of the transmission system and b) using generation facilities. Static sources of reactive power such as capacitors generally have their costs rolled into transmission charges or into the regulated retail rate structure. In this study, as equation (5.9) shows, the generation re-dispatch cost in real-time balancing market is the objective of the optimization. Therefore the focus is on the generator reactive production costs.

In [85], Momoh et al calculate the Locational Marginal Prices (LMPs) for real and reactive power. They consider the production cost of reactive power from various generation sources including generators and reactive compensators. In this case study, the reactive power cost concluding both generators and compensators is almost 0.2% of the total cost. This paper indicates that reactive power generation for local control is still on a small-scale level when compared to conventional generation; it does not constitute a market value in the present environment.

In [86], Baughman and siddiqi analyze the real-time pricing of active and reactive power using a modification of the OPF model with the objective of maximizing social welfare. The real-time price of active power at a specific bus at peak hour is almost 25 \$/MWH and this price for reactive power is almost 0.67 \$/MVARH.

There are other researches such as [87-98] that investigate implementation of different tools in reactive power pricing mechanisms. Seifossadat et al in [87] use sequential linear programming method to solve the OPF. The results shows that including the production cost of reactive power in the objective function affects on the reactive power marginal costs and slightly changes the real power marginal costs because the cost of reactive power generation is low in comparison with active power. Hao and Papalexopoulos in [88] note that the reactive power marginal price is typically less than 1% of the active power marginal price and depends strongly on the network constraints, and that the cost of reactive power production should be included in the formulation for calculating the reactive power marginal price. Dia et all in [89] include the production cost of reactive power including capacitor bank and reactive power generation into the objective function of the OPF problem and use sequential quadratic programming method to solve the optimal problem and have come to the conclusion that the active power marginal price sub-problem can be studied with reactive power production cost neglected. Niknam et al in [93] present various objective functions considering the cost of active power and both active and reactive powers produced by generators. The test results show a very small difference in the total cost.

In [99], Papalexopoulos and Angelidis have considered two general ways to compensate generators for providing reactive power. One way is the capacity payment option, in which the generator is paid in advance for the capability of producing or consuming reactive power. The payment could be made through a bilateral contract or through a generally applicable tariff provision. Once the generator is paid, it could be obligated to produce or consume reactive power up to the limits of its commitment without further compensation when instructed by the ISO. To ensure that the generator follows instructions in real time, the generator could face penalties for failing to produce or consume when instructed. The other way is the real-time price option, in which the generator is paid in real-time for the reactive power that it actually produces or consumes. This pricing option falls under the general method of nodal reactive power pricing [86 and 100]. Under this option, the generator is paid only for what it produces or consumes, but it pays no penalty for failing to produce when instructed. It is also possible to combine some of the features of each of these options.

Papalexopoulos, believes that in practice, reactive power cannot be traded like the active power. The reactive power markets suffer from severe market power concerns, therefore competition is very difficult to develop. The reason is that in many areas few generators are available to compete, therefore they have market power. The other key reason is that reactive power cannot travel too far, so reactive power markets are very much localized. For these reasons the ISOs sign long term contracts with these generators to procure reactive power services. There are many academic papers that present methodologies for reactive power markets, but in fact reactive power markets have not been developed in practice.

The cost of the reactive power because of its small amount in compare with active power generation cost is neglected; therefore equation (4.7) can still be used as the objective function.

5.4 How to Implement AMPL

The problem that is initially formulated in section 5.2 by use of the traditional algebraic notation is an algebraic model and must be converted to modeling language statements. The selection of the modeling language depends on its ability to model the Mixed Integer Non-Linear Problems (MINLP). AMPL, A Modeling Language for Mathematical Programming, has this ability and is used to model the problem.

AMPL separates the model, which describes the mathematical program to be solved; from the data, the numbers that specify one instance of the problem [71].

5.4.1 *Writing Model and Data Files*

The five major parts of an algebraic model i.e. sets, parameters, variables, objectives and constraints, are also the five kinds of components in an AMPL model.

- *Sets*

A set can be any unordered collection of objects pertinent to a model. Buses and lines in this study are two different sets:

```
set BUSES;
set LINES within {i1 in BUSES, i2 in BUSES};
```

- *Parameters*

A parameter is any numerical value pertinent to a model. The simplest kind of parameter is a single, independent value, such as the active power generation in each bus. Most AMPL statements that declare parameters also specify certain restrictions on them.

```
param Pg {BUSES}>=0;              # Bus active generation output

param Pd {BUSES}>=0;              # Bus active loads
```

- *Variables*

Continuous variables are declared much like the parameters. The only substantial difference is that the values of the variables are to be determined through optimization, whereas the values of the parameters are data given in advance. Bus voltage magnitudes and line power flows are examples of variable declaration:

```
var V {i1 in BUSES} >= V_min[i1], <= V_max[i1];

var Pf {(i1,i2) in LINES};
```

Binary variables are declared similar to the continuous except for the ‘binary’ that should be stated e.g. the presence of a FACTS device in a line can be declared as:

```
var u {LINES} binary;
```

- *Objectives*

An objective function can be any expression in the parameters and variables such as:

```
minimize total_cost: sum {i1 in BUSES}
Inc_Cost[i1]*delta_Pg_Inc[i1]
       + Dec_Cost[i1]*delta_Pg_Dec[i1];
```

- *Constraints*

A constraint may be any equality or inequality in the parameters and variables. Thus a model’s constraints use all the same kinds of expressions as its objective. The AMPL representation for a collection of constraints must specify two things: the set over which the constraints are indexed, and the expression for the constraints. Thus the limit on the phase shifters number looks like this:

```
subject to Phase_shifter_Number_limit:
                       sum {(i1,i2) in LINES}  u[i1,i2] <= N_Phi;
```

A model file is made up of the above five parts and is recognized by a filename and the extension '.mod'. Appendix C shows the 'OPF1.mod' as an AMPL model file.

- *Data*

Once the AMPL translator has read and processed the contents of OPF1.mod in Appendix C, it is ready to read the data. The data for the 5_bus test system in the previous chapter are represented in the data format with the extension '.dat' in Appendix C.

5.4.2 Running AMPL

Once the data values have been read successfully, the members of all sets and the values of all parameters are known. The AMPL translator can then identify the variables that will appear in the resulting nonlinear program, determine the coefficients and constants in the objective and constraints, and write the output suitable for an algorithm. Running AMPL is very straightforward by simply typing three statements in the command windows shown in Appendix C.

To change the default options, a command line such as:

```
Option solver minos;
```

can be used. For instance, this command changes the default solver to 'minos.'

5.5 MINLP solvers at NEOS

Solving the modeled problem is possible by using either the AMPL solvers in the command window or a server named 'NEOS' [101, 102]. For error handling and debugging purposes, the first option is more beneficent whereas NEOS provides a variety of online solvers, where optimization problems are solved automatically by submitting the model and data file to a suitable solver. On the solver page, [103], a list of different solvers under the type of optimization problem is provided. By choosing MINLP from 'Mixed Integer Nonlinearly Constrained Optimization' category and clicking on 'AMPL Input' a page appears. By submitting the model and data file and an optional command files, the solution, which is the value of the objective function, will be produced and returned in a separate window. Command file is a 'mod' file that contains AMPL commands and can be used to return other outputs to the user. An example of such a file is given in Appendix C.

There are five solvers in the MINLP category that can read AMPL language: Bonmin, Couenne, FilMINT, KNITRO and MINLP. In this research the behavior of these solvers will be investigated.

- *MINLP*

  MINLP implements a branch-and-bound algorithm searching a tree whose nodes correspond to continuous nonlinearly constrained optimization problems and the continuous problems are solved using filter SQP, a Sequential Quadratic Programming solver.

- *Bonmin*

  Bonmin is a hybrid between two classical algorithms for mixed integer nonlinear programming: an outer-approximation-based branch-and-cut-based algorithm and a pure branch-and-bound algorithm [104].

- *Couenne*

  Couenne is a branch and bound algorithm to solve non-convex MINLP problems [105, 106].

- *FilMINT*

  FilMINT is based on the LP/NLP algorithm by Quesada and Grossmann implemented in a branch-and-cut framework [107].

- *KNITRO*

  KNITRO is a solver for nonlinear optimization that provides three algorithms: Interior-point Direct, Interior-point CG and Active Set [108].

5.6 Simulation Results

First of all the performance of the derived mathematical model in section 5.3, regardless of the implemented solver should be investigated. Therefore in the sections 5.6.1 and 5.6.3, the ability of TCPSTs to reduce the re-dispatch costs due to congested lines by implementing MINLP solver are shown and discussed. The 5-bus and 14-bus test system that were used in chapter 4 to investigate the DC OPF applications are used in the AC OPF study too. The necessary data to investigate the AC OPF considering bus voltage limits, line conductance and susceptance matrices, reactive power generations and their incremental and decremental limits are given in Appendix B.

5.6.1 MINLP solver on 5-bus test system

Test1.

The value of the total active power demand, the second column of Table B.1 in Appendix B, is equal to the value of the total initial active power generation output of column four. This means that the system is in balance, and the generation re-dispatch is only due to network congestion.

If we analyze the case with no FACTS, by setting the number of FACTS to zero, running the program shows that line 2-5 is congested and a generation re-dispatch is needed. The new generation re-dispatch and also the cost associated with this re-dispatch is shown in Table 5.1. When the number of FACTS has increased to one, the algorithm has chosen to place one device in line 2-4. This has reduced the re-dispatch cost to 10.64 $/h.

Table 5.1 MINLP solver and 5-Bus test system in test 1

Bus number	Without TCPST			With one TCPST			
	Incremental change MW	Decremental change MW	Total Cost $/h	Incremental change MW	Decremental change MW	Total cost $/h	TCPST Location /Setting Degree
1	18	-	1386.5	0.77	-	10.64	Line 2-4
2	-	47.5	-	-	-	-	
3	-	-	-	-	-	-	3.58
4	30	-	-	-	-	-	
5	-	-	-	-	-	-	

Test2. Now we consider the case with a change in the level of demand and trading. Suppose a load in bus 5 increases by 10 MW, to satisfy this increase, this load enters into a bilateral contract for 10 MW with generator 1, which has the cheapest incremental cost, so the new active power generation values are: $P_{\mathbf{g1}} = 152\text{MW}$, $P_{\mathbf{d5}} = 140\text{MW}$and as Table 5.2 indicates, in the case with no FACTS device, MINLP solver doesn't produce any solution. To investigate the reason, whether the algorithm of MINLP solver doesn't converge or the problem is infeasible, the behaviors of other solvers are also verified and shown in section 5.6.2 in detail and becomes clear that the problem without FACTS devices is infeasible and by adding one TCPST in line 2-3, it becomes feasible.

Table 5.2 MINLP solver and 5-Bus test system in test 2

Bus number	Without TCPST			With one TCPST			
	Incremental change	Decremental change	Total Cost	Incremental change	Decremental change	Total cost	TCPST Location /Setting
	MW	MW	$/h	MW	MW	$/h	Degree
1	No solution (infeasible problem)			1.95	-	27.17	Line 2-3
2				-	-	-	
3				-	-	-	10.15
4				-	-	-	
5				-	-	-	

Test3. When the number of FACTS devices is increased to 2, the re-dispatch cost has still a value of 11.60 $/h. Increasing the number of FACTS devices will decrease re-dispatch costs in a Balancing Market, however, for the given generation dispatch it is impossible to reduce it to zero, even if we use 3 FACTS devices. The results are shown in Table 5.3.

In any optimization problem and especially in non-convex problems such as OPF, there is always a possibility of receiving different local optimum. In the next section, the solutions of MINLP solver are discussed by running other mixed integer nonlinear solvers.

Table 5.3 MINLP solver and 5-Bus test system in test 3

Bus number	With Two TCPSTs			With Three TCPSTs		
	Incremental change MW	Total Cost $/h	TCPST Location /Setting Degree	Incremental change MW	Total cost $/h	TCPST Location /Setting Degree
1	0.83	11.60	Lines 1-2/1.26 4-5/3.74	0.83	11.60	Lines 1-2/1.16 3-4/-0.26 4-5/3.86
2	-			-	-	
3	-			-	-	
4	-			-	-	
5	-			-	-	

5.6.2 Bonmin, FilMINT, KNITRO and COUENNE Solvers

The above results illustrate that optimal placement of FACTS devices can significantly reduce costs of generation re-dispatch in Balancing Market, but whether MINLP solver produces the best solution or not is investigated in this section by using other solvers such as Bonmin, FilMINT, KNITRO and COUENNE that can also read AMPL files.

The data of Test 1 are used in this comparison. With no FACTS devices all the solvers return one solution, and with FACTS devices, except for the FilMINT which doesn't work properly on this problem, the other solvers produce very close results on the 5-bus test system. Results are presented in Table 5.4 and Figure 5.1.

Table 5.4 Comparison between different solvers behaviors on 5-Bus test system

Number of TCPST	Cost of generation re-dispatch ($/h)				
	MINLP	**Bonmin**	**FilMINT**	**KNITRO**	**COUENNE**
0	1386.51	1386.51	1386.51	1386.51	1386.51
1	10.6350	10.6350	1381.51	10.6814	10.6350
2	8.2949	8.3279	1381.51	8.2949	8.2949
3	8.2869	8.3601	1381.51	8.2869	8.2869

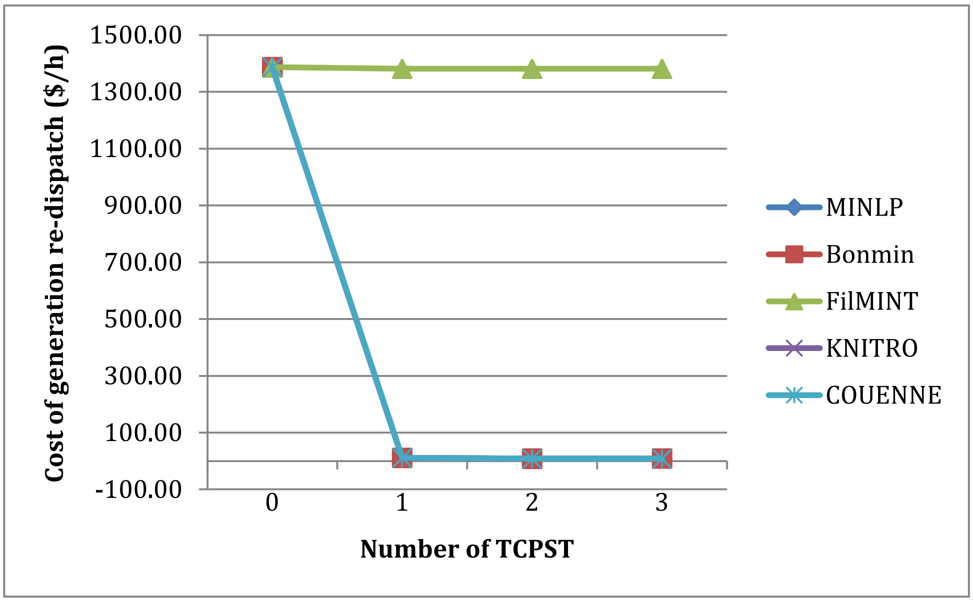


Figure 5.1 A Comparison between different solvers results on 5-Bus test system

MINLP solver in Test 2 with no FACTS devices does not have any solution. Although Bonmin returns a cost function equal to 11937.9 $/h, it also states that the probability of infeasible problem or too expensive solution exists. FilMINT fails and KNITRO returns 1409.73$/h with the possibility of convergence to an infeasible point and also declares that Problem may be locally infeasible. COUENNE returns only ‘infeasible problem’.

5.6.3 MINLP solver on 14-bus test system

Table 5.5 is a summary of Table B.3 in Appendix B and shows the bus data of the 14-bus test system.

Table 5.5 14-Bus test system bus data

	BUS				
	1	2	3	6	8
P_{gi} [MW]	195	36	28	0	0
$\Delta P_{gi}^{+\max}$ [MW]	111.4	102	100	100	100
$\Delta P_{gi}^{+\min}$ [MW]	0	0	0	0	0
$\Delta P_{gi}^{-\max}$ [MW]	199	34.2	0	0	0
$\Delta P_{gi}^{-\min}$ [MW]	0	0	0	0	0
$\mathrm{Q}_{\mathbf{gi}}$ [MVAR]	0	0	0	0	0
$\Delta \mathrm{Q}_{\mathbf{gi}}^{+\max}$ [MVAR]	250	50	40	24	24
$\Delta \mathrm{Q}_{\mathbf{gi}}^{-\max}$ [MVAR]	40	50	40	24	24
C_i^{+} [\$/MWh]	31	31	42	42	42
C_i^{-} [\$/MWh]	14.7	14.7	20	20	20

The maximum line flows for all lines are set to 50 MW, except for lines 1, 2 and 3 for which 150MW, line 7 is congested and there is need to re-dispatch a generation.

5.6.3.1 Non strict voltage limits

By applying the conditions of Test1 to the 14-bus test system where total active power generation and total active power demand are equal and system is in balance and also setting the voltage limits to 0.8 and 1.2 for all the buses, similar results and conclusions are obtained. As the results in Table 5.6 show, a considerable reduction in costs from 2880$/h to 343.5$/h occurs by placing three TCPST in lines 1-2, 1-5 and 3-4.

Table 5.6 MINLP solver and 14-Bus test system with voltage limits as 0.8 and 1.2 for all the buses

Bus number	Without TCPST			With one TCPST			
	Incremental change	Decremental change	Total Cost	Incremental change	Decremental change	Total cost	TCPST Location /Setting
	MW	MW	$/h	MW	MW	$/h	Degree
1	-	45.3	2880	-	9.5	1007	Line 5-6 9.9
2	-	-		-	-	-	
3	-	-		-	-	-	
6	40.4	-		20.6	-	-	
8	12.3	-		-	-	-	

Bus number	With Two TCPSTs			With Three TCPSTs		
	Incremental change	Total Cost	TCPST Location /Setting	Incremental change	Total Cost	TCPST Location /Setting
	MW	$/h	Degree	MW	$/h	Degree
1	-	392.10	Lines 4-7/6.2 5-6/7.5	-	343.5	Lines 1-2/4.8 1-5/6.7 3-4/2.9
2	6.7			11	-	
3	-			-	-	
6	-			-	-	
8	4.4			-	-	

Increasing the number of TCPST devices to 4 and more, Figure 5.2, can't make a considerable change in the generation re-dispatch cost. With no FACTS device, line 4-5 is congested which causes a 2867$/h generation re-dispatch cost. Adding one FACTS device in line 5-6 reduces the power flow of line 4-5 but makes line 5-6 congested. Placing another FACTS devices in line 4-7 improves the re-dispatch cost while lines 2-4 and 5-6 will operate at their upper power flow limits and in the case of 3 TCPSTs, the least cost is achieved yet line 7 operates at its upper limit i.e. 50 MW and remains at this power flow even if more FACTS devices are implemented. The changes in transmission line power flows are shown in Table 5.7. This is the reason why it is not possible to completely reduce re- dispatch costs to zero, even if FACTS devices are placed in each line. This is not a surprising result, considering that the role of these devices in not to replace transmission expansion and upgrade, but rather only help improve transmission capacity to certain extent.

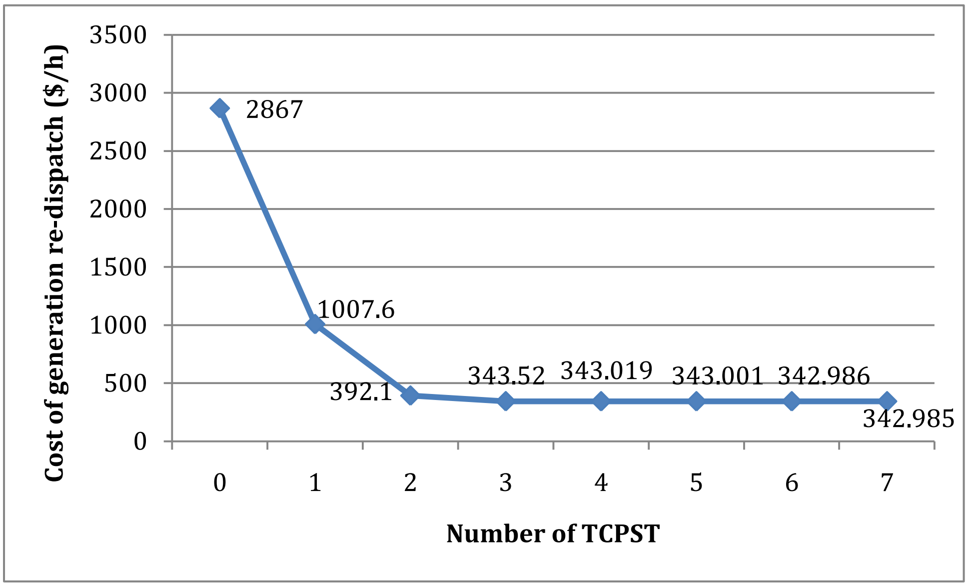


Figure 5.2 The effect of increasing the number of TCPSTs on generation re-dispatch cost

Table 5.7 Transmission line power flow of 14-bus test system in test1

Line Index	From Bus	To Bus	Maximum Line Power Flow [MW]	Line Power Flow [MW] for the number of TCPSTs equal to:			
				0	1	2	3
1	1	2	150	101	123	130	123
2	1	5	150	48	62	66	72
3	2	3	150	51	55	57	67
4	2	4	50	38	45	50	45
5	2	5	50	26	36	40	33
6	3	4	50	16.5	13	11	1
7	4	5	50	50	37	44	50
8	4	7	50	12.5	12	32	29
9	4	9	50	10	7	2	16
10	5	6	50	14	50	50	44
11	6	11	50	13.5	24	11	7
12	6	12	50	9	10	8	8
13	6	13	50	21	26	20	18
14	7	8	50	12.3	0	4	0
15	7	9	50	25	12	37	29
16	9	10	50	1	10	2	6
17	9	14	50	6	0.3	7.2	10
18	10	11	50	10	19	7	3
19	12	13	50	2.4	4	2	2
20	13	14	50	9.5	16	8	6

5.6.3.2 Strict voltage limits

When the voltage limits are changed to the default voltage magnitude limits in [82], i.e. 0.95 and 1.05 p.u for PQ buses and 0.8 and 1.2 p.u for PV buses, a slight reduction in re-dispatch costs, shown in Table 5.8 and Figure 5.3 occurs.

Table 5.8 MINLP solver and 14-Bus test system with strict voltage limits

Bus number	Without TCPST			With one TCPST			
	Incremental change MW	Decremental change MW	Total Cost $/h	Incremental change MW	Decremental change MW	Total Cost $/h	TCPST Location /Setting Degree
1	-	110	6357.81	-	107	6214.01	Line 5-6
2	-	-	-	-	-	-	
3	38	-	-	35	-	-	-3.18
6	51	-	-	53	-	-	
8	25	-	-	23	-	-	

Bus number	With Two TCPSTs			With Three TCPSTs			
	Incremental change MW	Decremental change MW	Total Cost $/h	Incremental change MW	Decremental change MW	Total Cost $/h	TCPST Location /Setting Degree
1	-	105	6117.8	-	104	6085.3	Lines
2	-	-	Lines	-	-	-	2-5/-3.8
3	34	-	2-5/-3.9	33	-	-	4-5/-3.1
6	52	-	4-5/-3.2	52	-	-	6-12/-1.4
8	23	-		23	-	-	

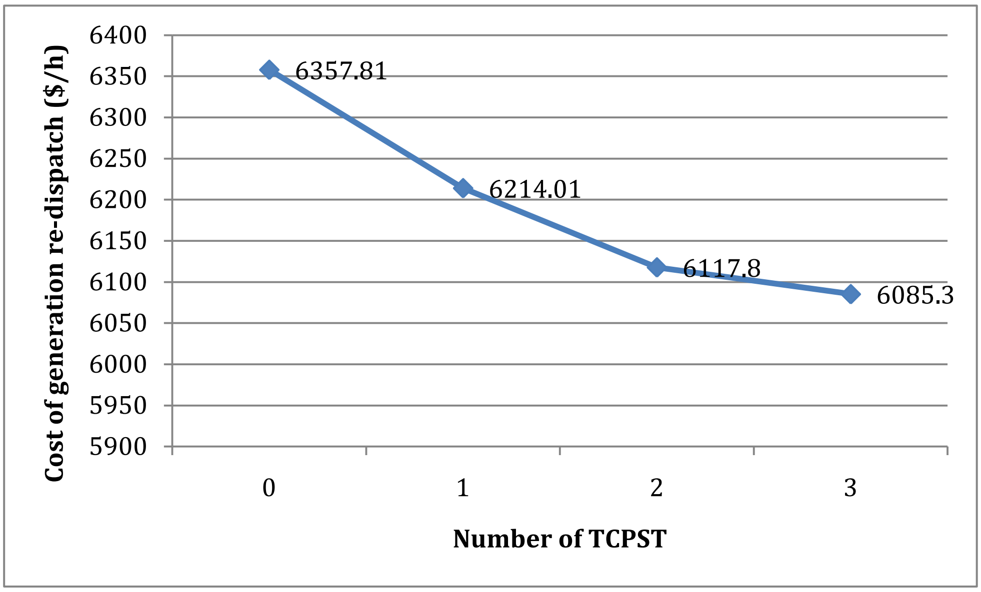


Figure 5.3 Increasing the number of TCPSTs under strict voltage limits

It means that using FACTS devices doesn’t affect the re-dispatch generation cost in the presence of strict voltage limits. As Table 5.9 indicates none of the transmission lines violate their power flow constraints, but bus 14 has reached to its lower voltage limit i.e. 0.95 p.u which remains at this value even after adding 3 TCPST devices, the last row of Table 5.10.

Table 5.9 Transmission line power flow of 14-bus test system in the presence of strict voltage limits

Line Index	From Bus	To Bus	Maximum Line Power Flow [MW]	Line Power Flow [MW] for the number of TCPSTs equal to:			
				0	1	2	3
1	1	2	150	56.1	58.6	43.9	44.7
2	1	5	150	29.3	29.2	45.9	45.6
3	2	3	150	26.6	28.8	27.7	28.1
4	2	4	50	25.5	26.6	23.7	24
5	2	5	50	17.4	16.6	6.2	6.3
6	3	4	50	2.04	3.4	5	5.2
7	4	5	50	34.4	42	46.7	46.6
8	4	7	50	2.9	7.8	8	8.1
9	4	9	50	6.7	9.1	9.1	9.2
10	5	6	50	3.87	4.6	3.7	3.76
11	6	11	50	13.6	10.1	10.1	10.4
12	6	12	50	8.6	8.2	8.2	5.5
13	6	13	50	21	19.2	19.2	21.7
14	7	8	50	24.6	22.8	22.6	22.5
15	7	9	50	27.6	30.6	30.6	30.5
16	9	10	50	0.77	2.8	2.6	2.3
17	9	14	50	5.5	7.6	8	8
18	10	11	50	9.8	6.4	6.4	6.7
19	12	13	50	2.4	2.01	2	0.7
20	13	14	50	9.6	7.4	7.4	7.1

Table 5.10 Bus voltages of 14-bus test system in the presence of strict voltage limit

BUS	V_i^{min} [p.u]	V_i^{max} [p.u]	Bus voltages [p.u] for the number of TCPSTs equal to:			
			0	1	2	3
1	0.8	1.2	1	1	1	1
2	0.95	1.05	1.01	1.01	1.01	1.01
3	0.95	1.05	1.007	1.01	1	1.005
4	0.95	1.05	0.99	0.99	0.99	0.99
5	0.95	1.05	0.994	0.994	0.994	0.994
6	0.8	1.2	0.998	0.996	0.995	0.995
7	0.8	1.2	0.99	0.992	0.992	0.99
8	0.8	1.2	1.03	1.03	1.032	1.032
9	0.95	1.05	0.97	0.97	0.97	0.97
10	0.95	1.05	0.964	0.966	0.966	0.965
11	0.95	1.05	0.977	0.976	0.977	0.976
12	0.95	1.05	0.98	0.979	0.98	0.977
13	0.95	1.05	0.974	0.973	0.972	0.972
14	0.95	1.05	0.95	0.95	0.95	0.95

Reaching to the voltage limits turns the attention to the reactive power concepts and the possibility of using other FACTS devices that can affect the voltage by injecting or absorbing reactive power.

5.6.4 Bonmin, FilMINT, KNITRO and COUENNE Solvers on 14-bus test system

The behaviors of Bonmin, FilMINT, KNITRO and COUENNE in the 14-bus test system with non-strict voltage magnitude limits are compared in Table 5.11 and Figure 5.4. With no FACTS device all the solvers produce one optimum point. When the number of FACTS devices is set to 1, which means the NLP problem is converted to a MINLP problem, Bonmin, MINLP and KNITRO produce the same minimum points, yet with two FACTS devices, MINLP and KNITRO return a cost function equal to 392.10 $/h and select lines 4-7and 5-6 for FACTS placement but Bonmin and COUENNE act differently by finding 454.83 $/h and placing FACTS devices in lines 1-5 and 2-3.

Table 5.11 Comparison between different solvers behaviors on 14-Bus test system

Number of TCPST	Cost of generation re-dispatch ($/h) / TCPST Location				
	MINLP	**Bonmin**	**FilMINT**	**KNITRO**	**COUENNE**
0	2867.0	2867.0	2867.0	2867.0	2867.0
1	1007.6	1007.6	2867.0	1007.6	1462.5
2	392.10	454.83	2867.0	392.10	401.79
3	343.52	402.65	2867.0	343.52	348.15

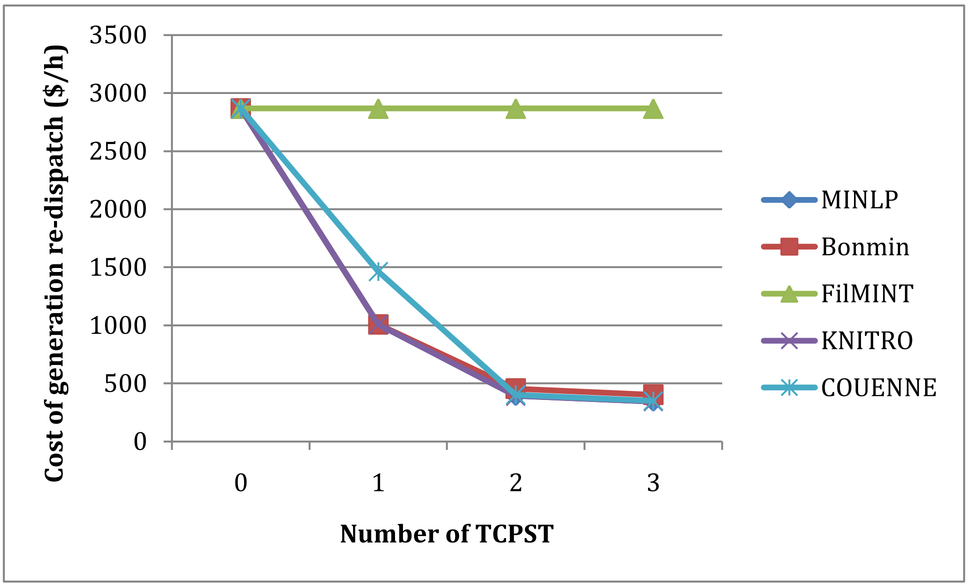


Figure 5.4 Comparison between different solvers results on 14-Bus test system

In general, different solvers can perform differently on different problems and one solver is rarely better than a competing solver for every problem. In this particular optimization problem, getting the same answer in all cases for MINLP and KNITRO solvers gives more confidence, but doesn't prove a global minimum because a minimum point only under very specific mathematical conditions can be proved that is a global minimum.

By adding three FACTS devices, MINLP/KNITRO and COUENNE and Bonmin return three different local minima.

When the number of FACTS devices is set to zero the problem is only a NLP problem where FiLMINT works, otherwise it fails which means it is not a suitable solver for this MINLP problem.

MINLP/KNITRO in all the cases produce the same results and seems to work perfectly for the AC OPF along with FACTS devices.

COUENNE can be downloaded to the AMPL folder and by changing the default solver to 'couenne' in the AMPL environment, the mod and data files can be introduced and solved by this solver. But there is a major problem with the breaking point. After a few hours the user can't decide whether the solution is found or not and the only choice is to break out running the program. There is always an uncertainty on the proper time to stop the program either using the mentioned method or NEOS server to solve the problem with COUENNE.

5.6.5 AC and DC OPF comparison

Because of the complications of AC OPF and difficulties in solution, the applications of DC approximations are very common in industry. The implementation of the proposed method based on DC OPF returns different results that are in an acceptable range. In Table 5.12 the generation re-dispatch costs and FACTS devices settings and locations are compared. In Table 5.13 the focus is on lines power flows.

In this comparison the power generations and demands are in balance and the power flow limits of all buses are 50MW except for lines 1, 2 and 3 for which 100MW. For different number of TCPSTs, a comparison of the line power flows from the AC solution with the line power flows from the DC solution reveals very good correspondence for all lines. The differences are to be expected due to the line losses, which are neglected in the DC algorithm.

As Table 5.12 indicates, the FACTS locations and settings are completely different in the AC and DC solutions. When the number of FACTS devices is set more than two, the DC OPF returns a zero re-dispatch cost while in the AC OPF, adding FACTS devices reduces the amount of re-dispatch cost but never fixes it at zero. Figure 5.5, illustrates this comparison.

Table 5.12 Comparison between the DC and AC OPF in the 14-bus test system

Number of TCPSTs	OPF Model	Cost of Generation Re-dispatch ($/h)	TCPSTs Locations	TCPSTs Settings (degree)
0	DC	1839	-	-
	AC	2963	-	-
1	DC	1580	Line 1	-2.5
	AC	2015	Line 2	6.1
2	DC	0	Lines 4 and 5	-5.3 and -12
	AC	482	Lines 2 and 3	10.3 and 14.4
3	DC	0	Lines 2, 6 and 17	8.6, 13.3 and 3
	AC	361	Lines 1, 2 and 7	3.5, 11.3 and 2.4

Table 5.13 Line power flows in the DC and AC OPF for different number of TCPSTs

Line Index	From Bus	To Bus	Maximum Line Power Flow [MW]	Line Power Flow [MW] for the number of TCPSTs equal to:							
				0		1		2		3	
				AC OPF	DC OPF	AC OPF	DC OPF	AC OPF	DC OPF	AC OPF	DC OPF
1	1	2	100	100	100	85	100	95	95	100	100
2	1	5	100	47	57	81	67	100	100	95	95
3	2	3	100	51	55	48	49	100	80	57	100
4	2	4	50	38	50	31	38	15	50	50	13
5	2	5	50	26	39	19	27	3	20	17	1
6	3	4	50	16	12	19	17	29	13	11	34
7	4	5	50	50	49	50	50	48	32	50	50
8	4	7	50	13	24	3	11.4	28	30	25	31
9	4	9	50	10	15	10	12	16	17	15	18
10	5	6	50	14	40	38	36	41	40	49	39
11	6	11	50	14	5	3	2.9	8	5	10	9
12	6	12	50	10	7	7	7	8	7	8	6
13	6	13	50	21	16	16	15	18	16	19	13
14	7	8	50	12	9	38	28	0	0	0	0
15	7	9	50	25	33	41	39.3	28	30	25	31
16	9	10	50	0	8	10	10	5	7	3	4
17	9	14	50	10	11	12	12	9	11	8	16
18	10	11	50	10	1.4	0	0.6	4	2	6	5
19	12	13	50	1	1	1	1	2	1	2	0
20	13	14	50	10	4	3	3	6	4	7	1

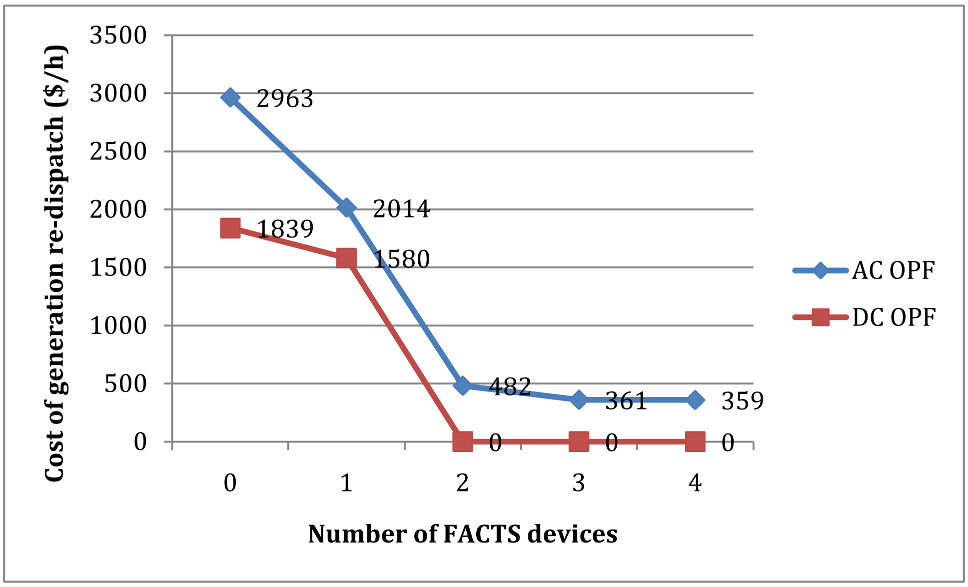


Figure 5.5 A comparison between DC and AC OPF in the 14-bus test system

5.7 Summary

In this chapter, the proposed method to alleviate congestion in real-time balancing market was formulated by implementing AC OPF algorithm and the optimal placements and settings of TCPST devices with the aim of minimizing the generation re-dispatch costs was found.

The main feature of this chapter is the implementation of the AC OPF that is in general non-convex, and as a result, many local minima may exist. This non-convexity is further increased when FACTS devices are included on the network. By selecting a proper modeling language, AMPL, and observing the behaviors of different Mixed Integer Non-Linear solvers the best solution was found and the ability and practicality of the proposed method was determined.

The AC OPF algorithm in spite of the solution difficulties provides the users with some vital aspects of the power system such as voltage magnitude and angle, and reactive power generation and demand. These elements can change the performance of the system under equality and inequality constraints and have been considered in the simulation results.

Concerning the line power flows, as would be expected, differences in the AC and DC solutions are due to the losses that are neglected in the DC OPF. Other results show that the AC OPF in compare with the DC OPF is more accurate and reliable.

Chapter 6. Conclusions and Future Research Work

6.1 Synopsis

In a decentralized market, congestion management including long-term, short-term and real-time phases is one of the most important tasks of the independent system operator (ISO). Real-time transmission congestion is defined as the operating condition where there is no sufficient transmission capability to implement all traded transactions simultaneously due to some unexpected contingencies, and that can be solved under a centralized real-time balancing market where generators and loads submit their offers and bids to participate and provide an increase or decrease in generation or demand in order to ensure a power balance and provide congestion re-dispatch.

FACTS devices can control the power flows in the network by changing transmission lines parameters. Development in high power electronics and also increased loading of power system in the deregulated power industry have made FACTS devices a very cost effective means of dispatching specified power transactions. The optimal location of these devices is very important because of their considerable costs, a task that can be carried out under a mathematical optimization problem.

Optimal Power Flow (OPF) is a widely used method in the system operations to schedule the power system controls to optimize an objective function while satisfying a set of non-linear equality and inequality constraints. The differences between the methods that have been implemented to alleviate the transmission line congestion are in the choice of objective functions for the algorithm, the system reconfiguration operations (i.e. tap changing transformer, capacitor banks, FACTS, etc.), the re-dispatch options (i.e. off-cost generation, price bid, load demand, etc.) and the constraints (i.e. thermal, voltage, stability, etc.).

The focus of this work is on congestion management in real-time balancing market within an OPF framework. The proposed approach is based on generation re-dispatch and the use of FACTS devices. Generation re-dispatch is one of the options that can be adopted by a System Operator in a congested operation. FACTS devices give a certain level of line flow controls. Although these limited controls may not be sufficient to completely relieve congestion, they can reduce the costs associated with generation re-dispatch.

The proposed method is first implemented through the DC OPF algorithm where the objective function is the generation re-dispatch costs, the line flow limits are considered as inequality constraints and the presence of FACTS devices are taken into account as binary variables. Therefore the method is based on the MILP procedure, so that commercially available solvers such as Dash Xpress can be used. The results show that the method is able to determine the optimal placement and settings of TCPST devices and they also indicate that application of FACTS devices can decrease the costs of congestion re-dispatch, even reducing them to zero.

In the DC OPF, reactive power, voltage magnitudes and angles which may change significantly the placement results, cannot be taken into consideration. On the other hand, the AC OPF does provide such a facility. Therefore, for more accurate assessments of the method, the AC OPF algorithm is applied and the effects of voltage constraints on the solutions are observed. Using the AMPL modeling language, the ability of different solvers such as MINLP, Bonmin, FilMINT, KNITRO and COUENNE to solve the full AC OPF based on MINLP procedure is investigated. The non-convex nature of the AC OPF may trap any solver in local sub-optima points. In general, different solvers perform differently on different problems and one solver is rarely better than the rest for all problems. In this particular optimization problem, getting a consistent answer in all cases for the MINLP and KNITRO solvers gives a great deal of confidence. Nevertheless, these solutions are not necessarily global minimums; global minimum points take place under very specific mathematical conditions.

In contrast with the DC OPF, the AC OPF never reduces the generation re-dispatch costs to zero and returns the optimal location of FACTS devices completely different from the DC OPF. Nevertheless, the line power flows in both algorithms are in close agreement, with the differences being within an acceptable ranges.

6.2 Future Research Work

The proposed method captures only one particular operating condition, and therefore a number of cases need to be studied in order to make a final decision as to where to install these devices. Furthermore, FACTS devices are expensive and a decision regarding their application needs to include these costs. The here presented model does not include such analysis because it yields solutions for only one operation condition, and for one point in time. However, these more complex analyses can be considered as an extension of the work.

The simulation results carried out on the 5-bus and 14-bus test networks show the feasibility of the approach on these test systems. Results should be produced for a greater solution space, such as the one associated to a more realistic system power grid.

In the presence of more strict voltage limits, the voltage of some buses reach their limits and the re-dispatch costs are no longer due to the line limit violation and therefore the TCPST devices are not able to reduce the associated costs by affecting the line flows. The impact of other FACTS devices that change the bus voltages by injecting or absorbing reactive power such as SVC or STATCOM devices along with TCPSTs can be the subject of future investigations. Another option is to substitute UPFC for TCPST. UPFC is a versatile FACTS controller with all encompassing capabilities of voltage regulation, series compensation and phase shifting that can control both the real and reactive power flow in a transmission line at an extremely rapid rate. HVDC based on voltage source converters can be another appropriate solution to both thermal limits and also voltage level problems.

Appendix A. Dash Xpress IVE

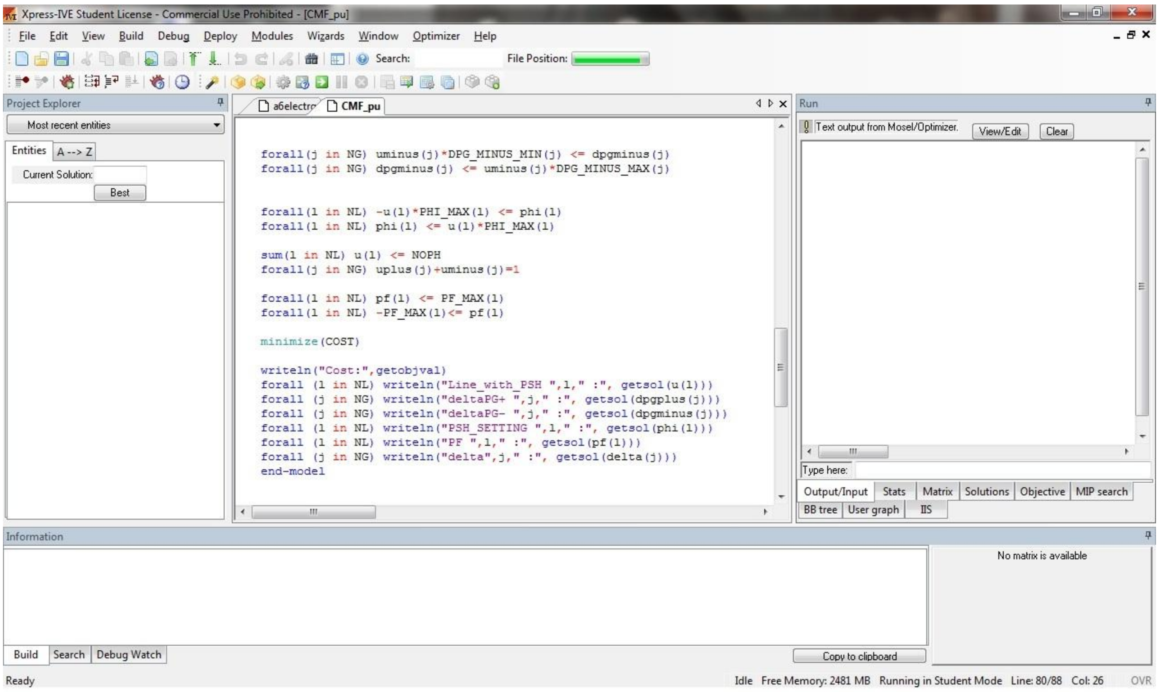


Figure A.1 Dash Xpress IVE main window

Appendix B. Data of Test Systems

B.1 5-bus test System

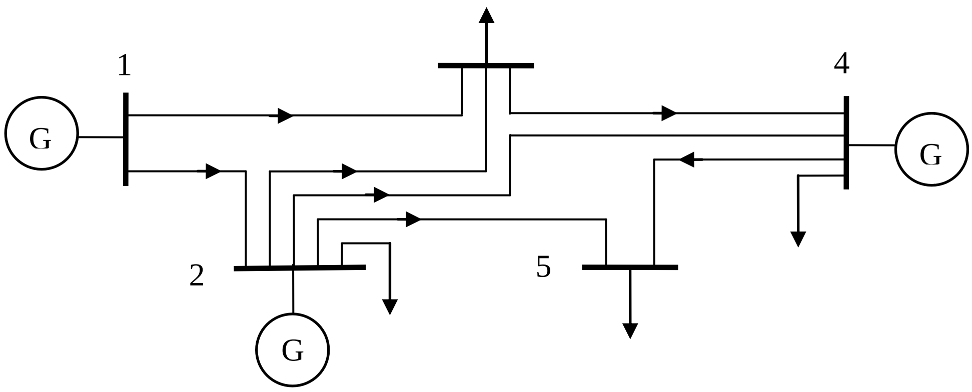


Figure B.1 Network configuration of the 5-bus test system

Table B.1 Bus data of the 5-bus test system

Bus Index	MW Load	MVAr Load	MW Gen	MVAr Gen	Base KV	Max Gen MW Increment	Max Gen MW Decrement	Max Gen MVAR Increment	Max Gen MVAR Decrement	Incremental Bid ($/MWh)	Decremental Bid ($/MWh)
1	0	0	142	15	100	40	40	40	40	13.9	12.9
2	40	20	178	106	100	50	50	50	50	14.9	13.9
3	150	39	0	0	100	0	0	0	0	0	0
4	80	29	80	6	100	30	30	30	30	16	15.5
5	130	39	0	0	100	0	0	0	0	0	0

Table B.2 Line data of the 5-bus test system

Line Index	From Bus	To Bus	R (pu)	X (pu)	Maximum Line Power Flow [MW]	Maximum Phase Shifter Angle [Degree]
1	1	2	0.00244	0.06	150	15
2	1	3	0.00101	0.24	60	15
3	2	3	0.01473	0.18	120	15
4	2	4	0.01473	0.18	100	15
5	2	5	0.00204	0.12	106	15
6	3	4	0.00110	0.03	50	15
7	4	5	0.00101	0.24	60	15

B.2 14-bus test System

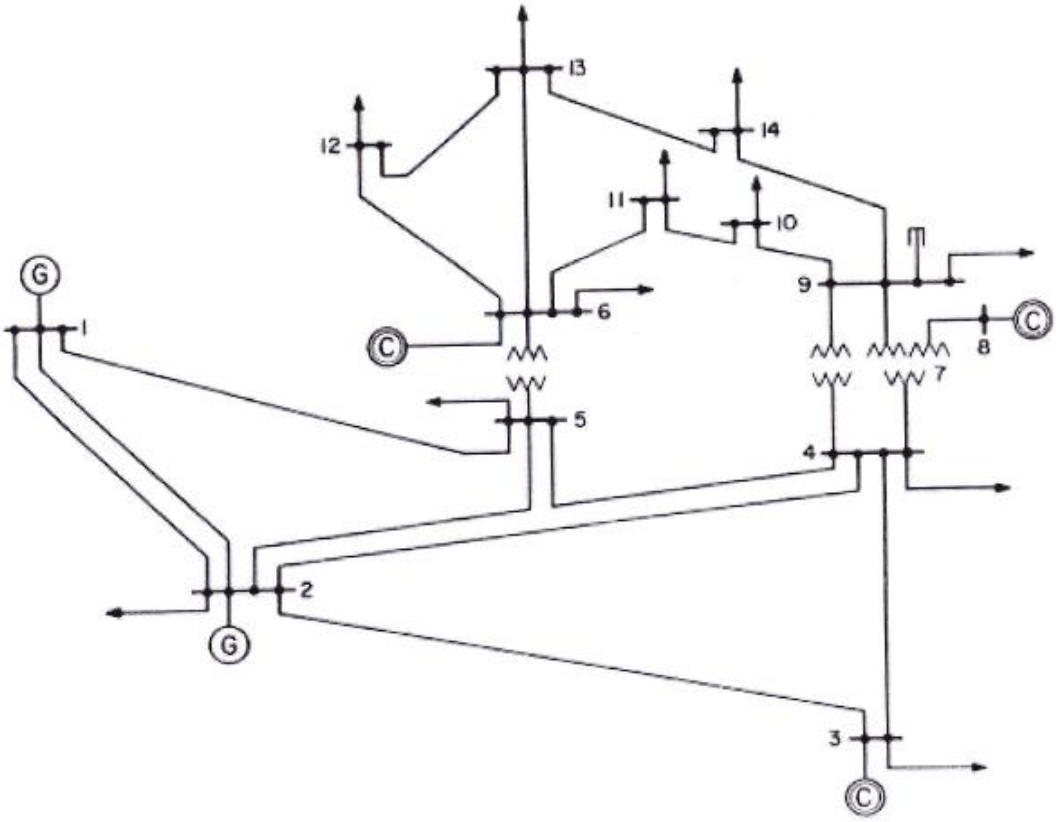


Figure B.2 Network configuration of the IEEE 14-bus system

Table B.3 Bus data of the IEEE 14-bus system

Bus Index	MW Load	MVAr Load	MW Gen	MVAr Gen	Max Gen MW Increment	Max Gen MW Decrement	Max Gen MVAR Increment	Max Gen MVAR Decrement	Incremental Bid ($/MWh)	Decremental Bid ($/MWh)
1	0	0	195	0	111.4	199	250	40	31	14.7
2	21.7	12.7	36	0	102	34.2	50	50	31	14.7
3	94.2	19	28	0	100	0	40	40	42	20
4	47.8	-3.9	0	0	0	0	0	0	0	0
5	7.6	0.18	0	0	0	0	0	0	0	0
6	11.2	7.5	0	0	100	0	24	24	42	20
7	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	100	0	24	24	42	20
9	29.5	16.6	0	0	0	0	0	0	0	0
10	9	5.8	0	0	0	0	0	0	0	0
11	3.5	1.8	0	0	0	0	0	0	0	0
12	6.1	1.6	0	0	0	0	0	0	0	0
13	13.5	5.8	0	0	0	0	0	0	0	0
14	14.9	5.6	0	0	0	0	0	0	0	0

Table B.4 Line data of the IEEE 14-bus system

Line Index	From Bus	To Bus	R (pu)	X (pu)	Maximum Line Power Flow [MW]	Maximum Phase Shifter Angle [Degree]
1	1	2	0.01938	0.05917	150	15
2	1	5	0.05403	0.22304	150	15
3	2	3	0.04699	0.19797	150	15
4	2	4	0.05811	0.17632	50	15
5	2	5	0.05695	0.17388	50	15
6	3	4	0.06701	0.17103	50	15
7	4	5	0.01335	0.04211	50	15
8	4	7	0	0.20452	50	15
9	4	9	0	0.53894	50	15
10	5	6	0	0.23488	50	15
11	6	11	0.09498	0.19890	50	15
12	6	12	0.12291	0.25581	50	15
13	6	13	0.06615	0.13027	50	15
14	7	8	0	0.17615	50	15
15	7	9	0	0.11001	50	15
16	9	10	0.03181	0.08450	50	15
17	9	14	0.12711	0.27038	50	15
18	10	11	0.08205	0.19207	50	15
19	12	13	0.22092	0.19988	50	15
20	13	14	0.17093	0.34802	50	15

Appendix C. AMPL Implementation

C.1 Model file

```
# Full Optimal Power Flow
# the last version
# works with the data: 5_bus.dat and 14_bus.dat and 14_bus_Vlimits.dat fine


set BUSES;
set LINES within {i1 in BUSES, i2 in BUSES};
set LINES_S within {i1 in BUSES, i2 in BUSES};

param Pg {BUSES}>=0;                    # Bus active generation output
param Pd {BUSES}>=0;                    # Bus active loads
param delta_Pg_Inc_max {BUSES}>=0;      # Bus active generation increment output limit
param delta_Pg_Dec_max {BUSES}>=0;      # Bus active generation decrement output limit
param delta_Qg_Inc_max {BUSES}>=0;      # Bus reactive generation increment output limit
param delta_Qg_Dec_max {BUSES}>=0;      # Bus reactive generation decrement output limit
param Qd {BUSES}>=0;                    # Bus reactive loads
param Qg {BUSES}>=0;                    # Bus reactive generation output
param Inc_Cost {BUSES}>=0;              # Increment Cost
param Dec_Cost {BUSES}>=0;              # Decrement Cost
param delta_min {BUSES};
param delta_max {BUSES};
param V_min {BUSES};
param V_max {BUSES};

param Pf_max {LINES}>=0;                # Line power flow limit
param Phi_max {LINES}>=0;               # Phase shifter setting limit
param S {LINES_S}>=0;

param Gmatrix {BUSES,BUSES};
param Bmatrix {BUSES,BUSES};

param N_Phi >=0;

var delta_Pg_Inc {i1 in BUSES} >=0, <= delta_Pg_Inc_max[i1];
var delta_Pg_Dec {i1 in BUSES} >=0, <= delta_Pg_Dec_max[i1];
var delta {i1 in BUSES} >= delta_min[i1], <= delta_max[i1];
var V {i1 in BUSES} >= V_min[i1], <= V_max[i1];
var delta_Qg_Inc {i1 in BUSES} >=0, <= delta_Qg_Inc_max[i1];
var delta_Qg_Dec {i1 in BUSES} >=0, <= delta_Qg_Dec_max[i1];
var Pf {(i1,i2) in LINES};
var Phi {LINES};
var Phi_s {LINES_S};
var u {LINES} binary;

minimize total_cost: sum {i1 in BUSES}  100*(Inc_Cost[i1] * delta_Pg_Inc[i1] + Dec_Cost[i1] * delta_Pg_Dec[i1]);


subject to slack_voltage_value{i1 in {"one"}}: V[i1]=1;
subject to slack_angle_values{i1 in {"one"}}: delta[i1]=0;

subject to Phase_shifters {(i1,i2) in LINES_S}: Phi_s[i1,i2] = -Phi[i2,i1];

subject to active_power_equation_load {i1 in BUSES }:  Pg[i1] + delta_Pg_Inc[i1] - delta_Pg_Dec[i1] - Pd[i1]
                              = sum {(i1,i2) in LINES} V[i1]*V[i2]*(Gmatrix[i1,i2]*cos(delta[i1]-delta[i2]+Phi[i1,i2])
                              + Bmatrix[i1,i2]*sin(delta[i1]-delta[i2]+Phi[i1,i2]))
                              + sum {(i1,i2) in LINES_S} V[i1]*V[i2]*(Gmatrix[i1,i2]*cos(delta[i1]-delta[i2]+Phi_s[i1,i2])
                              + Bmatrix[i1,i2]*sin(delta[i1]-delta[i2]+Phi_s[i1,i2]))
                              + V[i1]*V[i1]* Gmatrix[i1,i1];


subject to reactive_power_equation_load {i1 in BUSES }:  Qg[i1] + delta_Qg_Inc[i1] - delta_Qg_Dec[i1] - Qd[i1]
                              = sum {(i1,i2) in LINES} V[i1]*V[i2]*(Gmatrix[i1,i2]*sin(delta[i1]-delta[i2]+Phi[i1,i2])
                              - Bmatrix[i1,i2]*cos(delta[i1]-delta[i2]+Phi[i1,i2]))
                              + sum {(i1,i2) in LINES_S} V[i1]*V[i2]*(Gmatrix[i1,i2]*sin(delta[i1]-delta[i2]+Phi_s[i1,i2])
                              - Bmatrix[i1,i2]*cos(delta[i1]-delta[i2]+Phi_s[i1,i2]))
                              - V[i1]*V[i1]* Bmatrix[i1,i1];

subject to power_flow_equation {(i1,i2) in LINES}: Pf[i1,i2]= -Gmatrix[i1,i2]*V[i1]^2
                                   + Gmatrix[i1,i2]*V[i1]*V[i2]*cos(delta[i1]-delta[i2]+Phi[i1,i2])
                                   + Bmatrix[i1,i2]*V[i1]*V[i2]*sin(delta[i1]-delta[i2]+Phi[i1,i2]);

subject to power_flow_lower_limit {(i1,i2) in LINES}:  abs(Pf[i1,i2]) <= Pf_max[i1,i2];

subject to Phase_shifter_Number_limit: sum {(i1,i2) in LINES} u[i1,i2] <= N_Phi;
subject to Phase_shifter_angle_upper_limits {(i1,i2) in LINES}:  Phi[i1,i2] <= u[i1,i2]*Phi_max[i1,i2];
subject to Phase_shifter_angle_lower_limits {(i1,i2) in LINES}:  Phi[i1,i2] >= -u[i1,i2]*Phi_max[i1,i2];
```

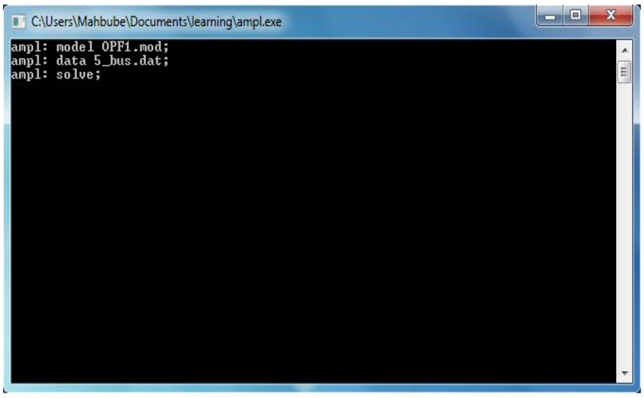
C.2 Data file

```
data;

param: BUSES:   Pg      Pd      delta_Pg_Inc_max  delta_Pg_Dec_max   Qg      Qd      delta_Qg_Inc_max     delta_Qg_Dec_max Inc_Cost     Dec_Cost
        one     1.42     0          0.40              0.40           0.15     0       0.40                 0.40            13.9         12.9
        two     1.78    0.40        0.50              0.50           1.06    0.20     0.50                 0.50            14.9         13.9
        three    0      1.50        0.00              0.00           0.0     0.39     0.00                 0.00            0.00         0.00
        four    0.80    0.80        0.30              0.30           0.06    0.29     0.30                 0.30            16.0         15.5
        five     0      1.30        0.00              0.00           0.0     0.39     0.00                 0.00            0.00         0.00

                Pg_Dec_max    Qg      Qd     delta_Qg_Inc_max    delta_Qg_Dec_max Inc_Cost    Dec_Cost    delta_min    delta_max  V_max     V_min:=
                  0.40        0.15     0       0.40                 0.40            13.9        12.9        -0.2          0.2       1.2       0.8
                  0.50        1.06    0.20     0.50                 0.50            14.9        13.9        -0.2          0.2       1.2       0.8
                  0.00        0.0     0.39     0.00                 0.00            0.00        0.00        -0.2          0.2       1.2       0.8
                  0.30        0.06    0.29     0.30                 0.30            16.0        15.5        -0.2          0.2       1.2       0.8
                  0.00        0.0     0.39     0.00                 0.00            0.00        0.00        -0.2          0.2       1.2       0.8;


param: LINES:           Pf_max     Phi_max :=
        one two          1.50       0.26
        one three        0.60       0.26
        two three        1.20       0.26
        two four         1.00       0.26
        two five         1.06       0.26
        three four       0.50       0.26
        four five        0.60       0.26;

param: LINES_S:        S:=
        two one     0.15
        three one   0.15
        three two   0.15
        four  two   0.15
        four three  0.15
        five two    0.15
        five four   0.15;


 param N_Phi:=1;

 param Gmatrix: one     two     three      four    five  :=
       one      0.69  -0.68   -0.02        0       0
       two     -0.68   1.72   -0.45     -0.45   -0.14
       three   -0.02  -0.45    1.69     -1.22     0
       four      0    -0.45   -1.22      1.69   -0.02
       five      0    -0.14     0       -0.02    0.16;
```

C.3 Command file

```
solve;

display total_cost;
display u, Pf, Phi;
display delta_Pg_Inc, delta_Pg_Dec;
```

C.4 Command window



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Nomenclature and Abbreviations

Nomenclature

Superscript and subscript:

d	index of demands (consumers),
g	index of generators,
i,j	index of network buses,
ij	transmission line flow from bus i to bus j,
f	transmission line flow,
l	index of branches,
max	upper limit,
min	lower limit,
t	transpose,
φ	index of TCPSTs (phase shifters),
.*	element by element vector multiplication,
+	incremental adjustment on generators or loads in the balancing market,
–	decremental adjustment on generators or loads in the balancing market,

Prefix:

Δ	change of variables based on scheduled points,

Matrices and Parameters:

A network node incidence matrix,

$\mathbf{B}_l$ diagonal matrix of line susceptances,

G_{ij} element *ij* of the conductance matrix,

B_{ij} element *ij* of the susceptance matrix,

$N\varphi$ maximum number of TCPST's,

Sets:

N the set of buses,

G the set of generators,

L the set of transmission lines,

Vectors:

u L vector of the binary variables,

1 L vector of 1's,

P vectors of active powers,

Φ vectors of phase shifter settings,

Variables:

V bus voltage magnitude,

δ bus voltage angle,

$\Delta P_{\mathbf{g}}^{+}$ incremental change of active power generation,

ΔP_g^-	decremental change of active power generation,
ΔQ_g^+	incremental change of reactive power generation,
ΔQ_g^-	decremental change of reactive power generation,
P_f / P_{ij}	line power flow,
Φ	phase shifter angle,
u	the presence of a FACTS device in a line.

Abbreviations

AGC	Automatic Generation Control
AMPL	A Modeling Language for Mathematical Programming
AS	Ancillary Service providers
ATC	Available Transmission Capability
BBS	Balance of Business Systems
BETTA	British Electricity Trading and Transmission Arrangements
CAISO	California Independent System Operator Corporation
CEB	Central Electricity Board
CEGB	Central Electricity Generation Board
CPUC	California Public Utilities Commission
D	Distribution service providers
Distcos	Distribution or retail companies
DTS	Dispatch Training Simulator
ED	Economic Dispatch

EMS	Energy Management System
EMTP	Electro-Magnetic Transient Program
EQIP	Extended Quadratic Interior Point
ERCOT	Electric Reliability Council of Texas
FACTS	Flexible AC Transmission System
FERC	Federal Energy Regulatory Commission
FTR	Firm transmission rights
G	generating companies
IP	Integer Programming
IPFC	Interline Power Flow Controller
ISO	Independent System Operator
IT	Information Technology
LDS	Low Discrepancy Sequences
LMP	Locational Marginal Price
LP	Linear Programming
MILP	Mixed Integer Linear Programming
MINLP	Mixed Integer Non-Linear Programming
MIP	Mixed Integer Programming
MIQP	Mixed Integer Quadratic Programming
MRTU	Market Redesign and Technology Upgrade
NERC	North American Electric Reliability Council
NETA	New Energy Trading Arrangement
NGC	National Grid Company

NSPSO	Non-dominated Sorting Particle Swarm Optimization
OASIS	Open Access Same-Time Information System
OFFER	Office of Electricity Regulation
OFGEM	Office of Gas and Electricity Markets
OPF	Optimal Power Flow
PPA	Power Purchase Agreement
PIM	Power Injection Model
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PCPDIPLP	predictor-corrector primal-duel interior point linear programming
PM	Power Marketers
PMS	Power Management System
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
PX	Power Exchange
QF	Qualifying Facilities
RBM	Real-time Balancing Market
RTO	Regional Transmission Organization
R	Retail service providers
RECs	Regional Electricity Companies
SA	Simulated Annealing/ Scheduling Applications
SI	Scheduling Infrastructure
SC	Scheduling Coordinators
SC-OPF	stability-constrained OPF

SCADA	Supervisory Control and Data Acquisition
SCOPF	security-constrained optimal power flow
SMP	System Marginal Price
SO	System Operator
SQP	Sequential Quadratic Programming
SSC-OPF	Stability-Constrained OPF
SSSC	Static Synchronous Series Compensator
STATCOM	STATic synchronous COMpensator
SCUC	Security Constrained unit commitment
SVC	Static Var Compensator
TCDF	Transmission Congestion Distribution Factors
TCPST	Thyristor Controlled Phase Shifter Transformator
TCSC	Thyristor Controlled Series Capacitor
TCVR	Thyristor-Controlled Voltage Regulator
TLR	Transmission Loading Relief
TO	Transmission Owners
TSO	Transmission System Operator
TTC	Total Transfer Capability
UC	Unit Commitment
UPFC	Unified Power Flow Controller
VSC-OPF	voltage- stability-constrained OPF
WSCC	Western Systems Coordinating Council

Publications Related to the Thesis

[1] M. Zeraatzade, I. Kockar, Y.H. Song, "Minimizing balancing market congestion re-dispatch costs by optimal placements of FACTS devices," in proc. of IEEE Conference, Power Tech, July 2007, pp. 873-878.

[2] M. Zeraatzade, M. R. Irving, "Comparison of MINLP Solvers for Optimal Placement of FACTS Devices," submitted to Electric Power Systems Research Journal.