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Congestion Management: Re-dispatch and Application of FACTS

Master of Science Thesis in the International Master Degree Programme, Electric Power Engineering

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Abstract

This thesis deals with the transmission congestion problem arising from multiple transactions in deregulated electricity markets. Two congestion management approaches (re-dispatch and the application of Flexible ac transmission systems (FACTS)) have been studied in three market models (pool, bilateral and the combined (hybrid)). An optimal power flow (OPF) framework has been used to simulate the considered market models and the congestion problems. The IEEE 14-bus and the CIGRE 32-bus test systems have been used to demonstrate the robustness of the approaches. The objectives of congestion management are different in different market. In the pool market, the objective function is the minimisation of the amount of re-dispatched power. In the bilateral market, minimising the transaction deviations is considered as the objective. In the hybrid model, the objective function is two pronged, minimising the pool re-dispatch and minimisation of deviations of the bilateral contracts. Furthermore, the objective of minimising the cost of congestion is applied in all the market models. The use of series FACTS devices to alleviate congestion is also demonstrated.

In the pool market, congestion requires re-dispatch of generation hence deviating from the market settlement. It has been shown that re-dispatch increases the system cost since the out of merit generators are involved more than scheduled. The minimisation of re-dispatch in the pool therefore ensures that the deviation from the economical settlement of the market is minimised. In the bilateral market, the interest is to maintain the desired transactions between contracting parties. To solve the arising congestion in this market model, the rescheduled transactions are forced to be as close to the scheduled transactions as possible. The changes to contracts are non-discriminatory, hence only contracts that affect the congestion are modified. In order to meet the load requirements, power has to be supplied from the regulation market. In the hybrid market model, a weighting factor is used between the pool and bilateral re-dispatch. The pool could be re-dispatched more than the transactions and vice versa, depending on the weighting factor.

It has been found that when FACTS are included in the network, the amount of re-dispatched power in the pool is greatly reduced resulting in an optimal operating point closer to that dictated by the market settlement. In the bilateral market, the results show that the transactions may not need to be modified when we have FACTS. The cost of congestion to the ISO also reduces when FACTS are employed. In order to justify the use of FACTS with regards to congestion management, a simple cost benefit analysis has been proposed where the benefit from FACTS is considered as avoided congestion costs that the system would have to bear otherwise.

The resulting re-dispatched generation schedules are only optimal as far as congestion is concerned under normal operating conditions *i.e.,* N-0 contingency. The schedule is therefore tested for security under the N-1 criterion. The contingency cases have been simulated and ranked using an overload index and total power violations arising from the outages. A dc load flow and line outage distribution factors have been used for testing system behaviours under various contingency conditions. A comparison of the dc and ac load flow methods has been made and the results indicate a small average absolute error.

Keywords: congestion management, FACTS, TCPAR, TCSC, electricity market

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1 Introduction

In this chapter we introduce the different electricity market models and briefly discuss the changes that have taken place in the electricity market. We also look at what congestion is and the different methods used for its management. The optimal power flow as a tool for re-dispatch is also introduced. Lastly we give an outline and organisation of the thesis.

1.1 Present status of electricity industry

The traditional electricity utility can be described as a vertically integrated company (VIC) where generation, transmission and distribution are under the umbrella of one management. The modern trend and practice is for open markets. This calls for separation (unbundling) of the generation, transmission and distribution functions. The reasons for the reforms are many and varied both for the developing and developed countries [1]. The main motivation for the unbundling, in the developed countries, stems from the desire of governments and policy makers to foster competition in power generation thus drive the cost of electricity down while enhancing supply quality and reliability [2]. In developing countries the main issues have been high demand growth which could not be matched with investments in generation and transmission. The financiers for the required investments have forced the governments of these countries to under go restructuring with the hope of achieving efficiency in these companies [1]. The success of the reforms in the communication sector and airlines also gave impetus to the deregulation process [3]. The underlying argument has been that an open market system is more efficient than a monopoly.

The market mechanisms that have arisen out of deregulation can be classified into Pool and Bilateral. In most of the restructured electric power systems both the pool and bilateral market models coexist with variation from one system to another [4]. In this thesis we call this combined market the hybrid market [5]. In the next section, different market structures will be discussed.

At present the deregulated electricity market comprises of generating companies (Gencos), Transmission companies (Trancos) and Distribution Companies (Discos) and these entities are independent. Due to the economies of scale inherent in the transmission system the Trancos are natural monopolies and operate under the authority of a regulator. In the deregulated environment, therefore planning for generation capacity investment and location of the same is therefore market driven. There may not be any coordination between transmission and generation investment. This has resulted in a marked increase in the level of risk and uncertainty associated with transmission operation and investment [2].

1.2 Market Structures

1.2.1 Pool based market

A pool market is defined as a centralized market place that clears the market for buyers and sellers of electricity [5]. The market may be operated as a double auction or single auction. In a double auction system the market operator or the independent system operator (ISO) receives both sell bids (from Gencos) and buy bids (from Discos). The market price is obtained by stacking the supply bids in increasing order of prices and the demand bids in decreasing order of their prices, the intersection point determines the market clearing price [1]. In single auction only the sell bids are received and the price is determined by the highest accepted sell bid to intersect with the forecasted demand. The seller and buyer do not have any interaction in the pool market mechanism. Price determination is an optimisation problem where the objective function is the maximisation of the social welfare.

1.2.2 Bilateral Market

In the bilateral market the buyers and sellers negotiate the price and amount of power traded between them. These contracts set the terms and conditions of agreements independent of the ISO. The ISO is responsible for ensuring that the bilateral agreements are feasible i.e. transmission capacity is available.

1.2.3 Hybrid Market

The hybrid model combines the various features of the previous two market models. The participation of a GENCO in the Pool is not obligatory. Some GENCOs will therefore have contracts and they can trade the excess capacity on the pool market. GENCOs without contracts submit their sell bids to the pool market. The customers therefore have a choice to negotiate a power supply agreement directly with suppliers or may choose to accept the spot market price [5]. This market model is the closest to the established markets for other goods and services.

In all the market mechanisms the ISO has to execute the schedules and ensure the reliability and security as well as handling the emergencies like congestion in the system.

1.3 Congestion Management in Deregulated Markets

The delivery of electrical energy from point to point is partly governed by the capacity of the transmission lines and transformers. Congestion is said to occur whenever the system state of the grid is characterised by one or more violations of the physical operational or policy constraints under which the grid operates in the normal state or under any one of the contingency cases in a set of specified contingencies [6]. In other words congestion occurs when the transmitted power exceeds the capacity or transfer limit of the transmission line or transformer. The capacity of a transmission line or transformer may have different values under different conditions. Congestion, needless to say, is undesirable. A system without congestion will have a uniform price (in nodal pricing). As soon as we have congestion, prices in some areas will increase and in others decrease. Congestion therefore distorts the market. Another disadvantage of congestion is increased risk of market manipulation by some participants [7].

In the VIC the economic load dispatch was normally formulated as an optimal power flow (OPF) problem with the objective of minimising total generation cost subject to, generation lower and upper limits, bus voltage limits, power flow limits of lines and transformers and etc. Congestion was therefore intrinsically managed at the dispatch stage. This would result in different marginal costs at different buses in the system in the case that congestion exists otherwise the marginal cost will be the same system wide. If we assume that the VIC charges a uniform price for power at all the buses, congestion would lead to higher marginal costs and hence reduced revenues (if the uniform price is lower than the highest marginal cost). Persistent congestion would therefore signal to the VIC to invest in transmission or generation.

In the deregulated market, congestion is likely to occur more often since the market for the selling and buying of energy may be settled without the constraints of the power system imposed. The ensuing generation schedules may result in some transmission paths being congested. Congestion management remains the central issue in transmission management in deregulated power systems [3]. Congestion management (CM) includes both the congestion relief actions and the associated pricing mechanisms [6]. In the past, cross border power trading was carried out between utilities with full knowledge of the constraints of the inter-connectors. In the deregulated market participants can make bilateral contracts with parties across borders and such transactions may not have any regard for the available capacity on the inter-connectors. Congestion across these inter-connectors may occur more in the deregulated than in the pre-deregulated era. The advent of the common carrier role for the transmission brought about by open access has therefore resulted in very different uses of the transmission system than those for which it was originally planned and designed [6]. Since investment in and location of generation is market driven in a deregulated environment and may not be coordinated with transmission planning congestion is more likely to occur. Without careful attention to the interaction of congestion management and the economics of the energy market, market inefficiencies can take away the savings deregulation promises to society [3].

Congestion may be alleviated through various ways. Among the technical solutions we have outaging of congested lines, operation of FACTS devices and operation of transformer tap changers. Among the non technical solutions we have market based and non market based methods of CM [8].

Non market based methods are those where no form of market mechanism is used to allocate the scarce transmission capacity but use other reasonable criteria. These include sharing of capacity on a pro rata basis where users share in proportion to their requirements, first come first serve and preference for certain types of contracts [8]. The non market based methods for congestion management do not send any signals for investment and have no measure of the value of the congested line. Market based methods are based on market mechanisms and hence give an indication of the value of the scarce resource of transmission capacity. These methods are briefly discussed below.

1.3.1 Nodal and Zonal pricing

In the nodal pricing scheme every bus in the grid is treated as a zone. The locational marginal price (LMP) for each bus is determined by the ISO by carrying out an economic dispatch with the flow limits. The LMP becomes the price and payment that buyers pay and the generators receive respectively. The market is settled with the network constraints hence congestion does not arise. This method of CM is practised by the PJM in the USA [9].

In Zonal pricing system buses with similar LMPs are aggregated into zones. The market is first settled constraint free. Each zone will have a price for energy that buyers can pay and sellers receive. In the case that congestion occurs the ISO receives supplementary bids for increase and decrease of generation. The most expensive supplemental bid for increase of generation becomes the price for that zone and the cheapest supplemental bid for decrease of generation becomes the price for that zone. In this way the ISO earns congestion rent over the congested lines. In case that there is no congestion the zonal prices will be the same. The California market migrated from this CM mechanism to the zonal pricing method [10].

1.3.2 Re-dispatching

In this method of CM the market is settled without the constraints of the transmission system being applied. If congestion occurs the ISO re-dispatches the generation in such a way that congestion is gotten rid of. This will entail the ISO purchasing power from high price areas. The generators in the low price areas will be commanded to regulate downwards. Since the ISO in essence is buying power at a high price and selling it at a lower price he incurs a cost. The net cost incurred by the ISO is an indication of the congestion charge and is a signal for investment. The ISO directly commands generators to up regulate or down regulate without the use of the market [11].

1.3.3 Counter trading

Counter trading is a modified form of re-dispatching the difference being that up and down regulation power is obtained from the market. The generators submit bids for up and down regulation on the balancing market. Similar to the re-dispatch the ISO will incur net cost in the purchase of regulation power since he has to use more expensive power for up regulation. Sweden uses this form of CM [12]. counter trading may be viewed as a special type of re-dispatching. In this thesis we shall use these methods for clearing congestion.

1.3.4 Market Splitting

In market splitting the market is first settled without constraints applied. If the resulting schedules cause congestion on some line(s) the market is then split and settled separately with the transfer limit applied. The ISO purchases power from the low price area and sells it in the high price area. The ISO thus makes a profit. Norway uses this CM method [11].

1.3.5 Auctioning

In auctioning the available capacity of a normally constrained path is auctioned by the ISO receiving bids from parties willing to use the path. The lowest marginal bid accepted becomes the price for transmission on the path. Two forms of auctioning are in use i.e. implicit and explicit [11].

1.3.6 Load curtailment

By managing load, congestion can also be effectively relieved. The benefits result from reduced peak demand and reduced pressure on both electricity generation and distribution systems. The amount of curtailed load should be as small as possible and the price in the congested area should fall as much as possible. While there are many different kinds of curtailment algorithms, a parameter termed as willingness-to-pay-to-avoid-curtailment was introduced in [8] which is regarded as a highly effective instrument in setting the transaction curtailment.

1.3.7 FACTS

Flexible AC transmission systems (FACTS) is a new technology developed in recent two decades, and it has been widely put in practice in the world. FACTS is defined by the IEEE as a power electronic-based system and other static equipment that has the ability to enhance controllability, increase power transfer capability. Nowadays, power producers and system operators all over the world are faced with increasing demands for bulk power transmission, low-cost power delivery and higher reliability, to some extent; such issues are being alleviated by the developing technology of FACTS. FACTS could be connected either in series or in shunt with the power system or even in a combined pattern to provide compensation for the power system. Variable series capacitors, phase shifters and unified power flow controllers as the most used FACTS devices can be utilized to change the power flow which result in many benefits like losses reduced, stability margin increased etc. Due to such features of FACTS, integrating it into the congestion management becomes more and more popular.

Figure 1-1 below has listed most of the methods utilised in CM. The light-shaded methods are always considered as remedial methods which let the market function as if there are no constraints and leave it to the TSO to take measures to maintain system security. By raising the price of the congested part of the network in order to reduce trade to relieve the congestion, the heavy-shaded methods are so called pricing methods.

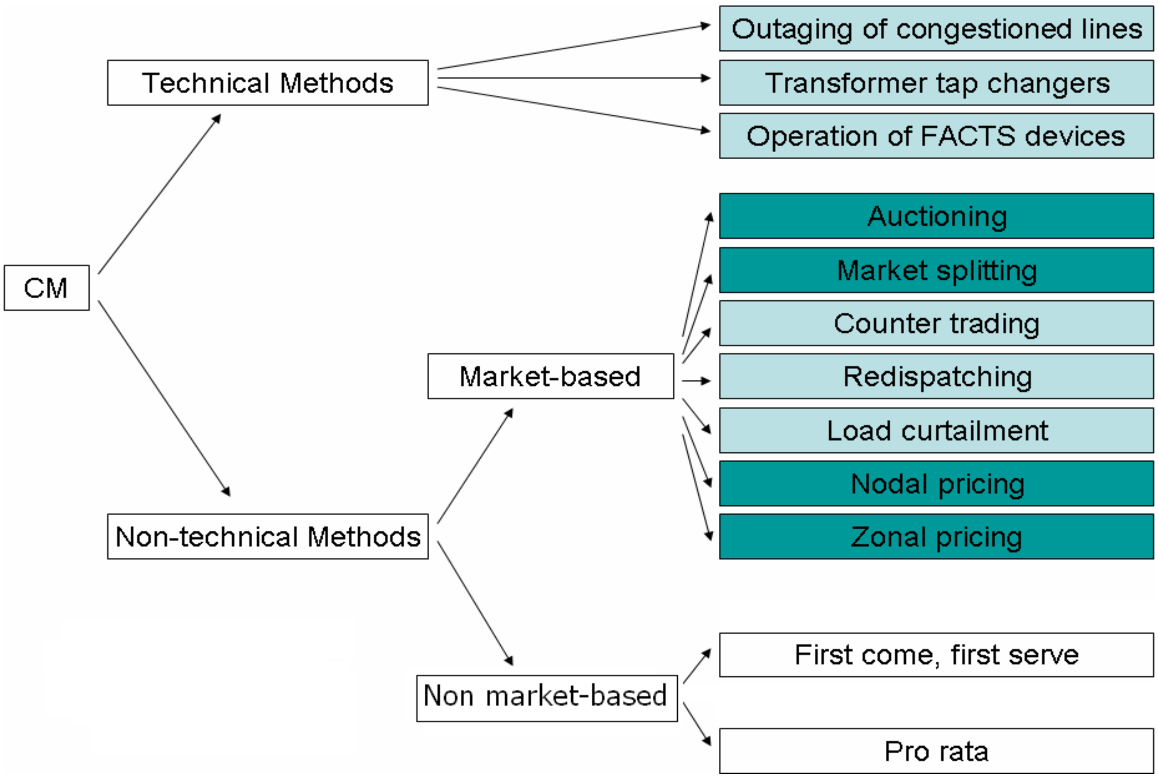

Figure 1-1 Summary of Congestion management methods.

1.3.8 Layout of the thesis

The report is divided into seven chapters. In the next three chapters, congestion management by re-dispatch is simulated using three market models, pool, bilateral and the hybrid. The results of the simulations for the 14-bus test system are discussed in these chapters and conclusions specific to the chapters made. In chapter 5 we test the algorithms developed on the Cigre Nordic 32-bus test system for the pool and hybrid markets. Contingency analysis using dc flow methods and linear sensitivity factors is carried out both on the IEEE 14-bus and the Cigre 32-bus test systems. The conclusion and proposals for future work are presented in chapter 7.

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2 Re-dispatch and FACTS for Congestion Management: Theoretical Background

In this chapter we first introduce the Optimal Power Flow as a tool for re-dispatch since we are able to incorporate different objective functions in it. The DC power flow method is also presented as an alternative to the full ac flow method where speed of computation may be of concern such as in contingency analysis. We introduce FACTS in general and describe the TCPAR and the TCSC. We also introduce the equations for the modelling of these devices.

2.1 Optimal Power flow

Optimal Power Flow (OPF) was defined in the early 1960s as an extension of the conventional economic load dispatch (ELD) problem to determine the optimal settings for control variables while satisfying various operating constraints [1]. Based on the physical laws of flow of electricity, all kinds of desired objectives, such as cost minimization, power losses minimization in the transmission system etc, are achieved by incorporating corresponding control variables and system constraints. Commonly, OPF are also expressed as a minimization of the shift of generation and other controls from an optimum operating point when maximizing system performance.

2.1.1 Modelling OPF

In this project, re-dispatch is firstly considered to alleviate congestion problems. Market models involving Pool, Bilateral and Hybrid are established with the common objectives being minimization of the absolute MW of re-dispatch. A constrained OPF model is utilized to force the system to operate in a defensive manner by re-dispatching the generation of each unit in case of congestion. FACTS devices as another effective way to manage congestion are incorporated and examined in the OPF model.

An OPF Model can include the following [1]:

1) Objective Function: Due to the respective features of different market structures and different intentions, the objective functions maybe different. For instance, the objective function in Pool market model is to minimize the re-dispatched power while in the Bilateral market is to minimize the transaction deviation. Further descriptions on the objective functions in each Market model are given chapters that follow.

2) Network equations: Figure 2-1 shows a simplified transmission line using a π equivalent circuit model. Let complex voltages at bus-i and bus-j are $V_i\angle\delta_i$ and $V_j\angle\delta_j$ respectively. Two port equations for the power flow computation are derived as follows:

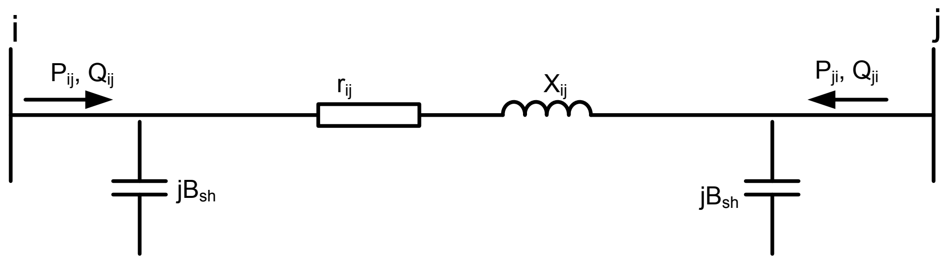

Figure 2-1 Model of Transmission line

The current flow from bus i to bus j can be expressed as:

$$I_{ij} = \frac{V_i e^{j\delta_i} - V_j e^{j\delta_j}}{jX} \cdot \left(G_{ij} + jB_{ij}\right) \tag{2-1}$$

Where

$G_{ij} + jB_{ij} = \dfrac{1}{r_{ij} + jx_{ij}}$ — r_{ij} and x_{ij} form the series impedance of the line

The apparent power flow from i to j can be expressed as:

$$S_{ij}^{*} = V_i^{*} I_i \tag{2-2}$$

The asterisk indicates the conjugate.
From (2-1) and (2-2) it can be shown that the active and reactive power flows P_{ij} and Q_{ij} respectively can be expressed by:

$$P_{ij} = V_i^2 G_{ij} - V_i V_j \left[G_{ij} Cos\left(\delta_i - \delta_j\right) + B_{ij} Sin\left(\delta_i - \delta_j\right)\right] \tag{2-3}$$

and

$$Q_{ij} = -V_i^2 \left(B_{ij} + B_{sh}\right) + V_i V_j \left[B_{ij} Cos\left(\delta_i - \delta_j\right) - G_{ij} Sin\left(\delta_i - \delta_j\right)\right] \tag{2-4}$$

Similarly P_{ji} and Q_{ji} are given by

$$P_{ji} = V_j^2 G_{ij} - V_i V_j \left[G_{ij} Cos\left(\delta_i - \delta_j\right) - B_{ij} Sin\left(\delta_i - \delta_j\right)\right] \tag{2-5}$$

and

$$Q_{ji} = -V_j^2 \left(B_{ij} + B_{sh}\right) + V_i V_j \left[B_{ij} Cos\left(\delta_i - \delta_j\right) + G_{ij} Sin\left(\delta_i - \delta_j\right)\right] \tag{2-6}$$

3) Power balance: In the economic load dispatch problem, we have a single constraint which holds the total generation to equal the total load plus losses. Since the losses are incorporated in the power flow equations, the power balance equations could be expressed as:

$$PG_i - PD_i = \sum_j P_{ij} \quad \textbf{(2-7)}$$

$$QG_i - QD_i + V_i^2 B_{shi} = \sum_j Q_{ij} \quad \textbf{(2-8)}$$

Where, PG_i and QG_i are the generated active and reactive powers whilst PD_i and QD_i are the corresponding active and reactive power demand at each bus i respectively. B_{shi} is any shunt device connected at bus i.

4) General constraints: A set of power system limits, such as limits on generator active and reactive power, limits on the voltage magnitude at each bus, and power flow limits on transmission lines are included in the OPF model. These operating constraints guarantee that the dispatch of generation does not force the transmission system into violating any limits, which may lead to a danger to the system.

Voltage limits

$$V_i^{\min} \le |V_i| \le V_i^{\max}, \forall i \in NB \quad \textbf{(2-9)}$$

NB is the set of all generation and load buses.

Generation limits

$$P_i^{\min} \le |P_i| \le P_i^{\max}, \forall i \in NG \quad \textbf{(2-10)}$$

$$Q_i^{\min} \le |Q_i| \le Q_i^{\max}, \forall i \in NG \quad \textbf{(2-11)}$$

Transmission limits

$$\sqrt{\left(P_{ij}^2 + Q_{ij}^2\right)} \le S_{i,j}^{\max} \quad \textbf{(2-12)}$$

Regulation angle of TCPAR

$$\sigma^{\min} \le \sigma \le \sigma^{\max} \quad \textbf{(2-13)}$$

Adjustable reactance of TCSC

$$x_{TCSC}^{\min} \le x_{TCSC} \le x_{TCSC}^{\max} \quad \textbf{(2-14)}$$

5) Contingency constraints: Constraints that represent operation of the system after contingency outage could also be included in the OPF model. By incorporating contingency constraints, if contingency happened, the resulting voltages and power flows would still be within limits. The contingency constraints are based on general constraints such as followings:

$$V_i^{\min} \le |V_i| \text{ (with some line out) } \le V_i^{\max}, \forall i \in NB \quad \textbf{(2-15)}$$

$$S_{i,j} \text{ (with some line out) } \le S_{i,j}^{\max} \quad \textbf{(2-16)}$$

When these post-contingency constraints are contained in an OPF model, this special type is called a “preventive-dispatch OPF”.

For different applications, OPF model has a flexible manner to achieve different objectives. When we use OPF model to solve some specific problems in which the fast computation is highly appreciated, a dc power flow method instead of full ac power flow method is used.

2.1.2 DC Flow Modeling

A full ac flow is the most accurate method of calculation, but its complexity can obscure relationships and prolong the computation time. Owing to the foregoing, the dc model becomes useful in specific cases. The dc model greatly simplifies the power flow by making a number of approximations including:

1) completely ignoring the reactive power balance equations
2) assuming all voltages magnitudes are identically one per unit and
3) ignoring line losses by setting line resistance to zero and assuming that the transmission angles are small. Hence the dc model reduces the power flow problem to a set of linear equations[2]

the power flow over a transmission line then becomes:

$$P_{ij} = \frac{1}{x_{ij}}(\delta_i - \delta_j) \le P_{ij}^{\max} \tag{2-17}$$

where

x_{ij} line reactance in per unit

δ_i phase angle at bus i

δ_j phase angle at bus j

The total power flowing into bus i, P_i is the sum of generation and load at bus i which equals the sum of the power flowing away from the bus on transmission line

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}}(\theta_i - \theta_j) \tag{2-18}$$

When a TCPAR is inserted in a line the dc power flow equation (2-17) becomes:

$$P_{ij} = \frac{1}{x_{ij}}(\delta_i - \delta_j + \sigma) \le P_{ij}^{\max} \tag{2-19}$$

2.1.3 Comparison between DC and AC flow method

The accuracy of DC power flow solution depends upon the power system. It is easy to find cases in which the results are identical, such as a two bus system with generators at each bus, regulating their terminal to 1.0 per unit, connected by a lossless transmission line. Alternatively, it is also easy to conceive cases in which the DC power flow results are totally wrong. For instance, in a two bus system with a generator at one end and a constant power load at the other end which is greater than the total generation of this system, the solution for AC power flow is infeasible while the DC power flow will indicate a normal solution. For a large system, such errors introduced with DC power flow are hard to be detected.

Power losses, as one of the most obvious difference between DC and AC power flow algorithm, can be reasonably compensated by increasing the total dc load by the amount of the ac losses. Hence when the transmission losses are allocated to the bus loads, in other words, the accuracy of DC powder flow is highly increased.

Computationally the dc power flow has at least three advantages over the standard full ac power flow. First, by just solving the real power balance equation, the amount of equations is about half the size of full ac problem. Second, the dc power flow is non-iterative and saves much more time than full ac power flow. Third, because the B matrix depends on the configuration of system and it only need to be calculated once. Therefore, getting initial solution with the dc power flow is about ten times faster [3] than the regular ac power flow initialization. For subsequent solutions, the dc flow is even faster since solving for θ with a modified P would only require a forward or backward substitution. For contingency analysis, these speedup advantages of dc load flow are seriously taken into account.

2.2 An Overview of FACTS

The transmission system of an electric power network forms the delivery system of electric power from the generation centres to the load centres. The transmission network is also needed to pool power plants and load centres in order to minimize the total power generation capacity and fuel cost [4]. The transmission interconnections make it possible to make available generation resources in one part of the network to other parts of the network. This may translate to economic advantage through the lowering of electricity price because of the use of low cost generation which would otherwise not be accessible. The building of transmission network can at times be a substitute to building new generation capacity. This is true where generation in other parts of the network may be in excess but transmission of the power is limited by the capacity of the transmission network. Building or increasing the transmission capacity in this scenario may be more cost effective than the building of a new generation station [4].

The interconnections of the transmission networks, called the grid, may result in overloads of certain transmission paths while others are relatively light loaded. The flow of power in a circuit is inversely proportional to the impedance of the circuit. The low impedance paths therefore may get overloaded before the higher impedance paths reach their capacity loading. This results in a limitation of the amount of power that can be transmitted through a network though enough capacity may be available! Furthermore due to this physical law of the flow of electric current, power does not flow in accordance to predetermined contract paths! Inadvertent line flows, called loop flows, are inevitable.

In order to increase the amount of power to be transmitted one is faced with the option of either upgrading the existing transmission lines or building new ones. The upgrade of transmission lines by upgrading the conductor may not be effective if loop flows already exist. This action may be self defeating [4]. The building of new transmission lines, apart from being expensive is being met by objections from environmental activists. The time taken to acquire servitudes from land owners and consents from the different publics can be very long. This has made construction of new transmission lines an almost impossible task.

The power system comprises of control devices that are largely mechanical in operation. In dynamic events the power system is therefore uncontrollable to a large extent due to the slow response of mechanical devices. Furthermore the mechanical devices cannot be operated as often as desired owing to the mechanical wear resulting from such duty.

The foregoing difficulties of upgrading existing lines and construction of new transmission lines and control of the power system can be partly overcome by the use of power electronic devices collectively referred to as Flexible AC Transmission System controllers (FACTS). FACTS help to increase the use of available capacity of the existing lines (*e.g.* elimination of loop flows, control of power flow etc). These devices are not an alternative to constructing new transmission networks or upgrading transmission links but make it possible to use existing transmission network up to or close to their thermal limits.

The IEEE define FACTS as alternating current transmission systems incorporating power electronic-based and other static controllers to enhance controllability and increase power transfer capability. A FACTS controller is defined as a power electronic-based system and other static equipment that provide control of one or more AC transmission parameters. FACTS devices can broadly be categorized as shunt, series, combined series-series and combined series-shunt [4].

In this thesis, we shall demonstrate the use of FACTS devices, specifically the thyristor controlled series capacitor (TCSC) and the thyristor controlled phase angle regulator (TCPAR) in managing congestion in the various electricity market models.

Some benefits of FACTS include [4]:

- Control of power flow as ordered
- Increase the loading of lines to their thermal capabilities.
- Increase system security through the raising the transient stability limit, limiting short circuit currents and overloads.
- Provide greater flexibility in locating new generation since line flows can be controlled
- Reduce reactive power flows allowing the lines to carry more active power
- Reduce loop flows
- Increase utilization of lowest cost generation as shall be demonstrated in this thesis

2.3 Control of Power flow over a line

In order to understand the principles of operation of the FACTS we need to understand the parameters that flow of power depends on. Consider a two bus system in Figure 2-1. For a lossless line (2-3) can be expressed as:

$$P_{ij} = -V_i V_j \left[B_{ij} Sin(\delta_i - \delta_j) \right]$$

or

$$P_{ij} = \frac{V_i V_j Sin(\delta_i - \delta_j)}{X_{ij}} \tag{2-20}$$

Since the transmission line considered is lossless P_{ij} and P_{ji} will have the same absolute value.
If we make the magnitudes of the voltages at both buses equal
$V_i = V_j = V$
Then (2-20) becomes

$$P_{ij} = \frac{V^2 Sin\delta}{X_{ij}} \tag{2-21}$$

Where $\delta = \delta_i - \delta_j$

Active power flow can be regulated by varying one of the parameters in (2-21). Increased flow can be achieved by reducing X, hence making the line electrically shorter. This principle is utilized in the thyristor controlled series capacitor. Power flow can also be regulated by varying the transmission angle. The thyristor controlled phase angle regulator uses this principle. The variation of the active power P against variation of the transmission angle for various values of the series reactance of the line is shown in Figure 2-2.

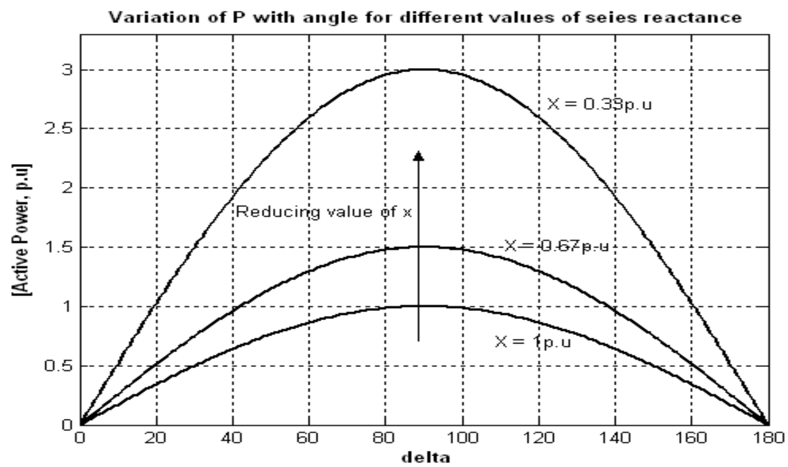

Figure 2-2 Power angle curves for different values of series reactance

The series impedance of a transmission line is dominated by the reactance from the inductance. It is generally acceptable to assume that the series impedance of a transmission line is inductive. Control of impedance can therefore be achieved by inserting a variable series capacitor, referred to as a thyristor controlled series capacitor (TCSC).
The angle difference between the sending end and receiving end of a transmission line can be controlled by inserting a thyristor controlled phase angle regulator (TCPAR). Other FACTS devices include STATCOM, SSG, SVC, TSC, TSR SVG, SSSC, IPFC, TSSC, TCSR, TSSR, UPFC, IPC [4]. In this thesis we look at the TCSC and the TCPAR to alleviate congestion in a power market.

2.3.1 Thyristor-Controlled Phase Angle Regulator (TCPAR)

The TCPAR is also called a thyristor controlled phase shifting transformer (TCPST) and is defined by IEEE as a phase-shifting transformer adjusted by thyristor switches to provide a rapidly variable phase angle. The TCPAR controls power flow through a transmission line by regulating the effective phase angle between the two buses of the line. TCPARS can help eliminate loop flows. The TCPAR apart from the steady state voltage and power flow control can also be used to handle dynamic events on the power system. This function is however beyond the scope of this thesis and shall not be discussed any further.

The phase angle of the system voltage is controlled by injection of a quadrature component to one of the terminal bus voltage [4]. Figure 2-3 shows the concept and basic implementation of a phase angle regulator, only a single phase is shown. The windings of the three phase transformer are connected in delta on the primary side. A proportion of this voltage (which is line to line) is injected in the appropriate phase through a series insertion transformer as shown in the figure below. For small angular adjustments between the terminal bus voltage and the regulated voltage (*i.e.* V_a and $V_a+\Delta V_{bc}$), the resultant angular change will be proportional to the injected voltage and the voltage magnitude will remain the same. When the angle is appreciably large the magnitude of the system voltage will increase ($V_a+\Delta V_{bc}$ will be appreciably larger than V_a) and, for this reason the TCPAR is often referred to as a quadrature booster transformer (QBT).

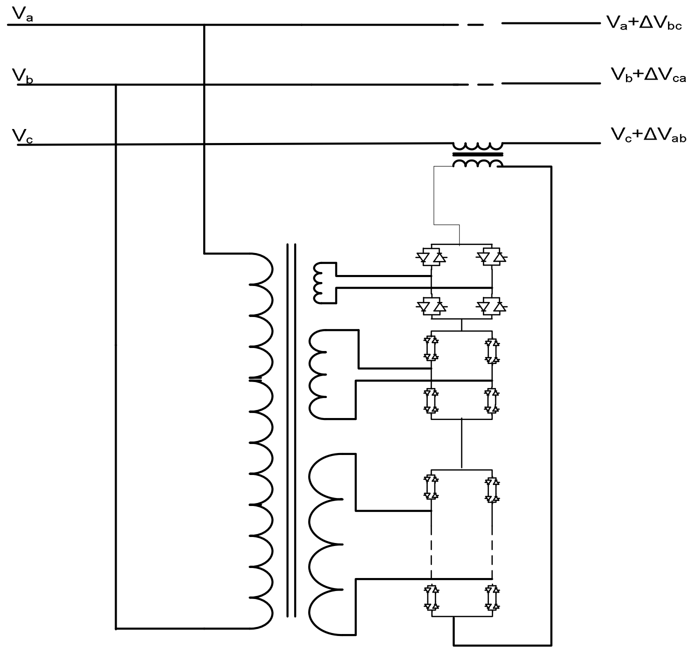

Figure 2-3 TCPAR using thyristor tap changer and ternary proportioned windings for discrete voltage control

For power flow control the TCPAR can be considered as a voltage source with a controllable amplitude and phase angle. Figure 2-4 shows a two machine system with a phase angle regulator inserted at the sending end bus.

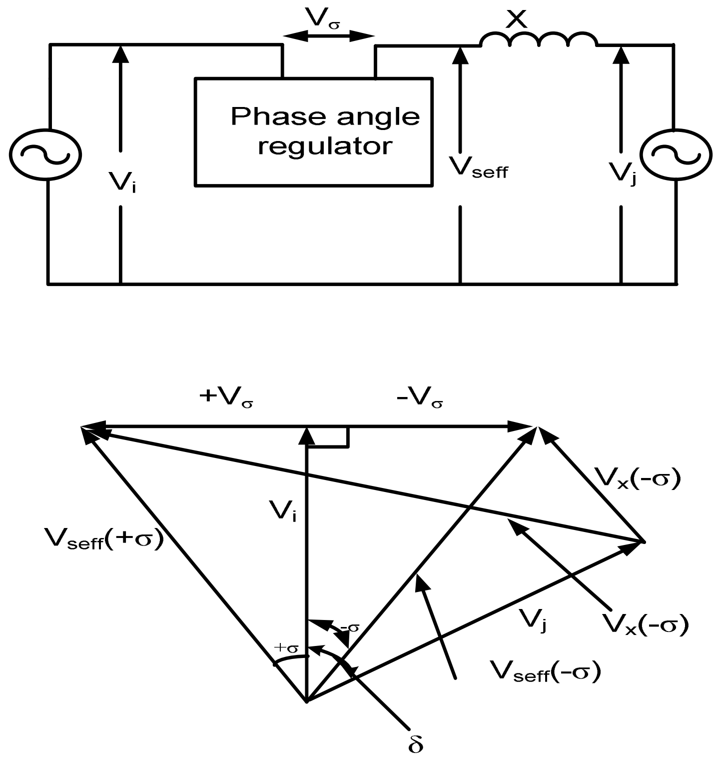

Figure 2-4 Two machine model with a TCPAR and the corresponding phasor diagram for a quadrature booster

From Figure 2-4 the mathematical relationships of the voltages are:

$$\boldsymbol{V}_{seff} = \boldsymbol{V}_i + \boldsymbol{V}_\sigma \quad \textbf{(2-22)}$$

$$V_{seff} = \sqrt{\left(V_i^2 + V_\sigma^2\right)} \quad \textbf{(2-23)}$$

$$Cos\sigma = \frac{V_i}{V_{seff}} \quad \textbf{(2-24)}$$

$$Sin\sigma = \frac{V_\sigma}{V_{seff}} \quad \textbf{(2-25)}$$

In the above equations the symbols in bold denote vectors or complex quantities while the ones not in bold are scalars and therefore denote magnitude only.

If a lossless line has a TCPAR installed the power transfer is then governed by:

$$P_{ij} = \frac{V_i . V_{seff}}{X} Sin(\delta - \sigma) \quad \textbf{(2-26)}$$

In (2-26) we want to decrease the effective angle between Vs and Vr.
From (2-24) and (2-25) it can easily be shown that (2-26) can be simplified to:

$$P_{12} = \frac{V^2}{X}\left(Sin\delta + \frac{V_\sigma}{V} Cos\delta \right) \quad \textbf{(2-27)}$$

Assuming $V_i = V_j = V$.

When we insert a TCPAR in a line with losses (2-3) is modified thus:

$$P_{ij}^s = V_{seff}{}^2 G_{ij} - V_{seff} V_j \left[G_{ij} Cos(\delta_{ij} + \sigma) + B_{ij} Sin(\delta_{ij} + \sigma) \right] \quad \textbf{(2-28)}$$

Where P_{ij}^s denotes active power flow with a TCPAR inserted and V_{seff} is the effective sending end voltage (refer to Figure 2-4). Using the relationships in (2-24), (2-25) and other well known trigonometry identities, (2-28) can be reduced to:

$$P_{ij}^s = V_i{}^2 T^2 G_{ij} - V_i V_j T \left[G_{ij} Cos(\delta_{ij} + \sigma) + B_{ij} Sin(\delta_{ij} + \sigma) \right] \quad \textbf{(2-29)}$$

Using the same arguments as above (2-4), (2-5) and (2-6) for P_{ji}, Q_{ij},Q_{ji} can be modified to incorporate a TCPAR and the resulting expressions are:

$$P_{ji}^s = V_j^2 T^2 G_{ij} - V_i V_j T \left[G_{ij} Cos(\delta_{ij} + \sigma) - B_{ij} Sin(\delta_{ij} + \sigma) \right] \quad \textbf{(2-30)}$$

$$Q_{ij}^s = -V_i^2 T^2 (B_{ij} + B_{sh}) + V_i V_j T \left[B_{ij} Cos(\delta_{ij} + \sigma) - G_{ij} Sin(\delta_{ij} + \sigma) \right] \quad \textbf{(2-31)}$$

$$Q_{ji}^s = -V_j^2 (B_{ij} + B_{sh}) + V_i V_j T \left[B_{ij} Cos(\delta_{ij} + \sigma) + G_{ij} Sin(\delta_{ij} + \sigma) \right] \quad \textbf{(2-32)}$$

Where $T = \dfrac{1}{Cos(\sigma)}$

The difference between P^s_{ij} (2-29) and P_{ij} (2-3) gives the additional power flow over the line and this can be considered as an injection of additional power at bus i.

$$\Delta P_{ij} = P_{ij}^s - P_{ij}$$

The bus injection at bus i is then given by:

$$P_i^s = -\Delta P_{ij}$$

$$P_i^s = -V_i{}^2 K^2 G_{ij} - V_i V_j K \left[G_{ij} Sin\delta_{ij} - B_{ij} Cos\delta_{ij} \right] \quad \textbf{(2-33)}$$

Similarly active power injection at bus j is given by:

$$P_j^s = -V_i V_j K \left[G_{ij} Sin\delta_{ij} + B_{ij} Cos\delta_{ij} \right] \quad \textbf{(2-34)}$$

Following the same reasoning as above the bus injections for reactive power at bus i and j are given by:

$$Q_i = V_i^2 K^2 (B_{ij} + B_{sh}) + V_i V_j K \left[G_{ij} Cos\delta_{ij} + B_{ij} Sin\delta_{ij} \right] \quad \textbf{(2-35)}$$

$$Q_j = -V_i V_j K \left[G_{ij} Cos\delta_{ij} - B_{ij} Sin\delta_{ij} \right] \quad \textbf{(2-36)}$$

Where $K = \tan\sigma$

The admittance matrix of the system need not be modified when using the injection model above. The two port equations can then be written generally as:

$$P_{ij}^{s} = P_{ij} - P_i - P_j \qquad \textbf{(2-37)}$$

And similarly

$$Q_{ij}^{s} = Q_{ij} - Q_i - Q_j \qquad \textbf{(2-38)}$$

The equations are no longer symmetric. When considering P_{ij}, P_j is zero and for P_{ji} , P_i is zero. The injection model for the TCPAR can now be represented as shown in Figure 2-5.

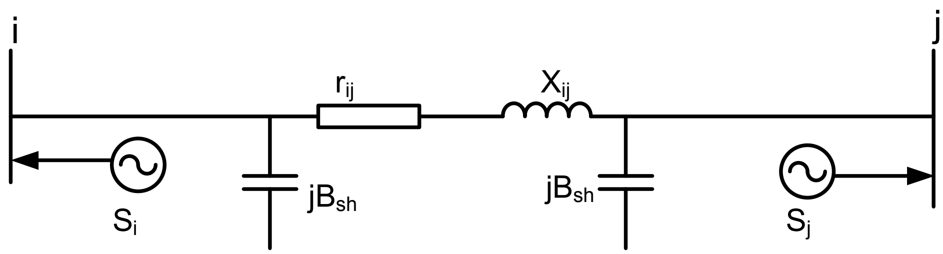

Figure 2-5 Injection model for TCPAR

As earlier discussed the loading of a transmission line may be restricted by the transmission angle. In such cases a TCPAR can be employed. With a QBT the transmitted real power is plotted against the phase angle difference of the bus voltages of the transmission line for various values of the regulation angle in Figure 2-6.

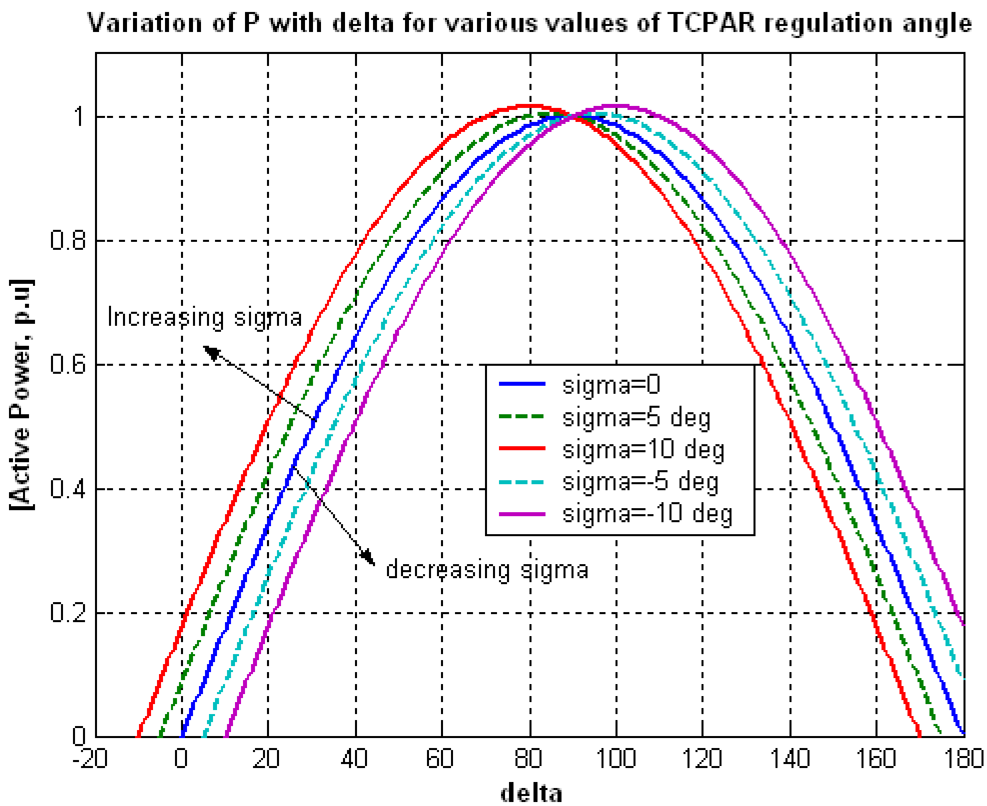

Figure 2-6 Variation of transmitted active power with transmission angle for various values of TCPAR regulation angle

We observe that the transmitted power increases with increase regulation angle since the effective sending voltage has increased. The maximum power transmitted on an uncompensated line occurs at a transmission angle of 90 degrees. From Figure 2-6 we observe that with a regulation angle of 10 degrees the maximum power transfer is achieved at 80 degrees. It is important to note from Figure 2-6 that the amount of power transmitted over a line with a natural phase angle difference of say 20 degrees can be increased by increasing the regulation angle and at the same time the power can be reduced by decreasing the regulation angle. Overall the QBT does not increase the maximum transmittable power for the line significantly but makes it possible to increase the power flow at a given prevailing phase angle difference. Transmission lines are normally operated in a defensive manner meaning that the system needs to be stable even after a contingency. Transmission angles of less than 45 degrees are typical for stability reasons.

The rating of the TCPAR is given by:

$$VA = V_{\sigma} * I_{\max} \tag{2-39}$$

Where I_{max} is the maximum continuous line current. It should be noted that the rating of the TCPAR is much less than the rating of the circuit since the injected voltage is small compared to the circuit voltage.

The result of the use of the TCPAR is that the transmitted power can be increased or decreased for a given transmission angle. The flow of power is therefore not totally restricted to the prevailing transmission angle as is the case in an uncompensated line.

2.3.2 Thyristor-Controlled Series Capacitor (TCSC)

The IEEE defines the TCSC as a capacitive reactance compensator which consists of a series capacitor bank shunted by a thyristor-controlled reactor in order to provide a smooth variable series capacitive reactance. Series capacitive compensation works by reducing the effective series impedance of the transmission line by cancelling part of the inductive reactance. Hence the power transferred is increased as earlier demonstrated in Figure 2-2. A basic set up of a TCSC is shown in Figure 2-7.

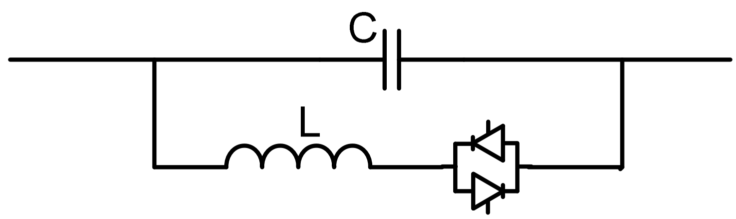

Figure 2-7 Set up of TCSC

The impedance of this circuit is that for a parallel LC circuit and is given by:

$$X_{TCSC}(\alpha) = \frac{X_c X_l(\alpha)}{Xl(\alpha) - Xc} \tag{2-40}$$

Where

$$X_l(\alpha) = X_L \frac{\pi}{\pi - 2\alpha - Sin\alpha} \tag{2-41}$$

α is the firing angle ,
X_L is the reactance of the inductor and X_l is the effective reactance of the inductor at firing angle α and is limited thus:

$X_L \le X_l(\alpha) \le \infty$

Care is taken for the circuit in Figure 2-7 not to resonate otherwise the transmission line would be an open circuit! In our simulations the TCSC is taken as continuous varying capacitor.
The effective series transmission impedance is given by:

$$X_{eff} = (1-k) * X$$

where k is the degree of series compensation

$$k = \frac{X_{TCSC}}{X} \qquad 0 \le k \le 1$$

As the delay angle is varied X_l varies as given by (2-41) and also X_{TCSC} varies as in (2-40). The TCSC has two modes of operation around the circuit resonance depending on the value of the firing angle. The TCSC can operate in the inductive mode, *i.e.* for firing angles greater than zero but less than the upper limit, dictated by the resonance band but less than 90 degrees. In the capacitive mode, the firing angle is greater than a lower limit, dictated by the resonance band and less than 90 degrees. In our simulations, we use only the capacitive region hence the compensation level varies from zero to the maximum level of 0.7. Figure 2-8 shows a transmission line with a TCSC.

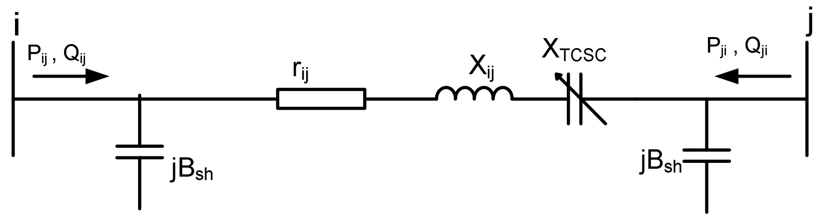

Figure 2-8 Transmission line with TCSC

The injection model for the TCSC is derived in a similar way as for the TCPAR. The modified 2 port equations and the power injections are given in the following equations:

$$P_{ij}^{C} = V_i^2 G_{ij}' - V_i V_j (G_{ij}' \cos\delta_{ij} + B_{ij}' \sin\delta_{ij}) \quad \textbf{(2-42)}$$

$$Q_{ij}^{C} = -V_i^2 (B_{ij}' + B_{sh}) - V_i V_j (G_{ij}' \sin\delta_{ij} - B_{ij}' \cos\delta_{ij}) \quad \textbf{(2-43)}$$

$$P_{ji}^{C} = V_j^2 G_{ij}' - V_i V_j (G_{ij}' \cos\delta_{ij} - B_{ij}' \sin\delta_{ij}) \quad \textbf{(2-44)}$$

$$Q_{ji}^{C} = -V_j^2 (B_{ij}' + B_{sh}) + V_i V_j (G_{ij}' \sin\delta_{ij} + B_{ij}' \cos\delta_{ij}) \quad \textbf{(2-45)}$$

Power injections can therefore be expressed as:

$$P_i^c = V_i^2 \Delta G_{ij} - V_i V_j (\Delta G_{ij} \cos\delta_{ij} + \Delta B_{ij} \sin\delta_{ij}) \quad \textbf{(2-46)}$$

$$P_j^c = V_j^2 \Delta G_{ij} - V_i V_j (\Delta G_{ij} \cos\delta_{ij} - \Delta B_{ij} \sin\delta_{ij}) \quad \textbf{(2-47)}$$

$$Q_i^c = -V_i^2 \Delta B_{ij} - V_i V_j (\Delta G_{ij} \cos\delta_{ij} - \Delta B_{ij} \sin\delta_{ij}) \quad \textbf{(2-48)}$$

$$Q_j^c = -V_j^2 \Delta B_{ij} + V_i V_j (\Delta G_{ij} \sin\delta_{ij} + \Delta B_{ij} \cos\delta_{ij}) \quad \textbf{(2-49)}$$

Where

$$\Delta G_{ij} = \frac{x_C r_{ij} (x_C - 2x_{ij})}{(r_{ij}^2 + x_{ij}^2)(r_{ij}^2 + (x_{ij} - x_C)^2)}$$

$$\Delta B_{ij} = \frac{-x_C (r_{ij}^2 - x_{ij}^2 + x_C r_{ij})}{(r_{ij}^2 + x_{ij}^2)(r_{ij}^2 + (x_{ij} - x_C)^2)}$$

$$\Delta G_{ij}' = \frac{r_{ij}}{r_{ij}^2 + (x_{ij} - x_c)^2} \quad \text{and}$$

$$\Delta B_{ij}' = \frac{-(x_{ij} - x_c)}{r_{ij}^2 + (x_{ij} - x_c)^2}$$

From the expressions for the injections *i.e.* (2-46) through (2-49) we observe that the TCSC results in symmetric expressions for the injections. The final power flow on a line can therefore be written as:

$$P_{ij}^{c} = P_{ij} + P_{i}^{c}$$

$$Q_{ij}^{c} = Q_{ij} + Q_{i}^{c}$$

Figure 2-5 can also be used to represent the injection model of the TCSC.

2.4 Conclusion

This chapter has given an introduction on OPF modelling as well as DC flow method. In this project, a constrained OPF incorporated with full ac flow is used for simulating and analyzing congestion management in IEEE 14-bus system, while a security-constrained OPF incorporated with dc flow is used when analyzing the contingency problems and simplifying intricate multiple bus systems like CIGRE 32-bus system.

We have also introduced FACTS devices such as TCPAR and TCSC which can be used in power systems to control power flow over lines. Without FACTS installed the power flows are governed solely by Kirchoff's Laws. This may result in undesirable loading levels i.e. congestion of some corridors whilst other lines are lightly loaded. Congestion in a counter trade or re-dispatch environment is solved by down regulating the cheaper generators and up regulating the more expensive ones until the congestion is cleared. By directing power flow congestion can be alleviated by minimal use of out of merit generators.

FACTS devices can be incorporated in power flow algorithms using the injection models. The injection models do not require the modification of the system admittance matrix. Using the TCPAR we have demonstrated that power flow in a congested line can be reduced. It has also been shown that installation of a TCSC in a transmission line can increase the power flow on that line. Installation of FACTS devices may increase the losses on the line in which they are installed if the resulting power is more than in the case without FACTS.

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3 Optimal Redispatch And Congestion Management: Pool Market Perspective

In this chapter the pool market is described in detail and the equations describing the market are developed. We formulate the objective of the market settlement. It is also explained why the market settlement generation schedule may not be the preferred generation schedule for the network when we take technical constraints in consideration. Re-dispatch is described in the presence of congestion on transmission lines. Two objective functions for re-dispatch are formulated: minimisation of absolute generation re-dispatch and minimisation of net payment by ISO. The results for the simulation of the 14bus IEEE test case are presented. The use of FACTS devices for congestion management is also investigated. The use of the TCPAR and TCSC to manage congestion is investigated. An economic assessment for the optimal location of the FACT device is proposed.

3.1 Characteristics of a Pool Market

A pool market is characterized by many producers and accompanied by many consumers. Of all the electricity markets the pool market tries to emulate a true competitive market. The producers of the tradable commodity are the generating companies (GENCOs). They compete for the right to supply energy to the grid, and not to specific customers [1]. The competition is by way of sell bids comprising of the amount of energy and its price. The buyers also compete for buying power and bid as high as possible to ensure participation in the trades. If a GENCO's sell offer is too high it may be rejected. In the same way if a customer's buy bid is tool low it may be rejected in the market. [1].

This market type is complex since it requires an organised market structure. The players in this market are: market operator (as the market administrator), GENCOs, marketers, aggregators, traders, DISCOs, consumers and others. In this market all dealings i.e. buying and selling of electricity is transparent and is managed by the market operator or the ISO whatever the case may be. The market operator will receive sell offers from GENCOs detailing the amount of energy blocks and the respective unit prices. The offers from the generator, in the light of competition, will be reflective of the marginal cost of the GENCO. If we assume that the cost function of the GENCO is quadratic as in (3-1), then the price of the bid will be based on a marginal cost function of the form given in equation (3-2).

$$C(i) = aP_{g(i)}^2 + bP_{g(i)} + c \tag{3-1}$$

$$\rho(i) = 2a\mathrm{P}_{g(i)} + b \tag{3-2}$$

Where a, b and c are cost coefficients for the generator.

In a double auction market, the market operator will also receive buy bids from the consumers. The buying price by the consumer is equal to the marginal benefit derived from using electricity. In a single auction market no demand bids are received and the demand is taken as inelastic. In this thesis, the single auction market mechanism has been used. The results can however be easily extended to the double auction mechanism. Figure 3-1 shows a simplified pool market model.

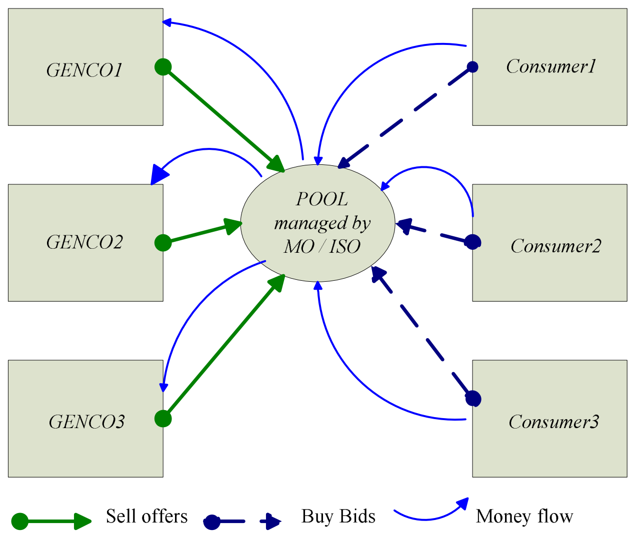

Figure 3-1. A pool market with double auction

3.1.1 Price determination

One of the assumptions in economics regarding perfect competition is the need for the product on demand to be homogeneous. Other assumptions for a perfect competition include availability of information to all participants, large enough producers and participants, free market entry and exit by participants *etc*. We naturally expect a single market clearing price. Some markets however pay the participating GENCOs according to the bid price (this is known as pay as bid). In determining the market clearing price, the market operator solves an optimization problem. The objective of the problem is to maximize the social welfare which in essence in a single sided auction market is similar to minimization of the cost of producing the electricity assuming that GENCOs' sell offers are at marginal costs [2]. The sell bids are arranged in ascending order of price and the marginal cost of the bid that intersects the inelastic demand curve becomes the market price. All bids above this price are rejected and the ones below this price are accepted to take part in the trades. Figure 3-2 shows a case where four bid blocks have been submitted at prices of $20, 50, 80 and 120 per unit MWh and the blocks are of size 50, 100, 50 and 50 MWh respectively.

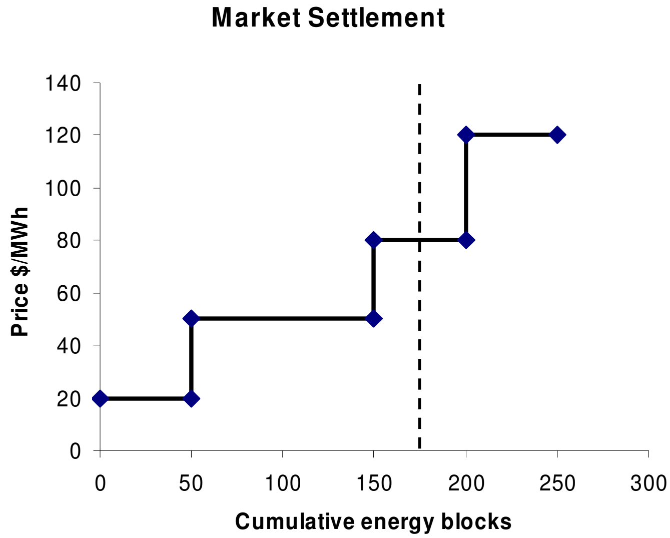

Figure 3-2. Single sided auction.

The demand for this market is 175MWh indicated by the broken vertical line. The market would be cleared at a price of $80 units per MWh with one bid of 50MWh and a part bid of 25MWh rejected. The sum of the areas of the shaded portions to the left of the demand line gives the total cost o f the system to supply the load.

3.1.2 Modelling of the pool market

The price of a bid block will be given by:

$$\rho(i,t) = 2 * a * \sum_{t=1}^{t} blocksize(i,t) + b \tag{3-3}$$

Subject to:

$$\sum_{t=1}^{t\max} blocksize(i,t) \le P_{gi}^{\max} \tag{3-4}$$

Where
ρ(i,t) is the unit price of block number t of generator i,
blocksize(i,t) is the size of the block t in MWh,
a and b are the cost characteristics of the generator unit,
t_{max} is the maximum number of blocks and $P_{gi}^{\max}$ is upper limit generation for unit i.
The power demand and supply balance is given by:

$$\sum_{i=1}^{NL} Pd(i) + Ploss = \sum_{i=1}^{NG} P_{g(i)} \tag{3-5}$$

Where
Pd(i) is the active load at bus i,
Pg(i) is the generation at at bus i,

NL is the number of buses with loads,
NG the number of generator buses and
Ploss is the system active losses.

The demand balance in equation (3-5) also includes the active system losses, but this may be ignored in the market settlement. If we take the active losses into account in the market settlement then we need to determine the losses from the use of the so called loss coefficients [3]. Equation (3-6) gives the expression for the system active losses.

$$Ploss = \sum_{i=1}^{NB} \sum_{j=1}^{NB} \left[\alpha(i,j) * \left(P_i * P_j + Q_i * Q_j \right) + \beta(i,j) * \left(Q_i * P_j - P_i * Q_j \right) \right] \qquad \textbf{(3-6)}$$

Where

$$\alpha(i,j) = \frac{R(i,j) * Cos\left(\delta_i - \delta_j\right)}{V_i * V_j} \qquad \textbf{(3-7)}$$

And

$$\beta(i,j) = \frac{R(i,j) * Sin\left(\delta_i - \delta_j\right)}{V_i * V_j} \qquad \textbf{(3-8)}$$

P_i, P_j and Q_i, Q_j are the injected active and reactive powers at bus i and j respectively,
R(i, j) is the real part of the Z_{bus} matrix of the network,
δ_i is the phase angle of the voltage at bus i and
V_i is the voltage magnitude at bus i.

The coefficients α and β are network dependent and are constant for a particular configuration of the network. They are determined from a load flow and can be stored as system parameters for calculating losses. The market model for the pool market is an optimization model which consists of the objective function and constraints. The objective function for a 24 hour period now becomes:

$$Minimise: \qquad \textbf{(3-9)}$$

$$F(u) = \left(\sum_{k=1}^{24} \sum_{i=1}^{NG} \sum_{t=1}^{t\max} \left\{ \rho(i,t) * Buyblock(i,t,k) + ST(i) * Us(i,k) + SD(i) * Ud(i,k) \right\} \right)$$

Where:
Buyblock(i,t,k) is the accepted block at hour k for generator i,
ST(i) and *SD(i)* are the start up and shutdown costs for generators and
Us(i) and *Ud(i)* are binary variables for the start up and shut down decisions.
The objective function F(u) represents the total system cost including shut down and start up costs for the entire 24 hour period. The constraints for this optimization include:

1) The supply and demand balance given by (3-5).
2) The upper and lower generation limits:

$$w(i,k) * P_{gi}^{\max} \leq \sum_{t=1}^{t\max} Buyblock(i,t,k) \leq w(i,k) P_{gi}^{\min} \tag{3-10}$$

3) The ramp up rates for the generator units:

$$P_{gi}(k) - P_{gi}(k-1) \leq RUP_{gi} \tag{3-11}$$

4) The ramp down rates for the generator units:

$$P_{gi}(k-1) - P_{gi}(k) \leq RDN_{gi} \tag{3-12}$$

5) The block size bought:

$$Buyblock(i,t,k) \leq Blocksize(i,t) \tag{3-13}$$

6) Minimum up time of the unit and

$$\sum_{h=1}^{MUT} Ud(i,k-h+1) \leq 1, k > MUT \tag{3-14}$$

7) Minimum down time of the unit

$$\sum_{h=1}^{MDT} Us(i,k-h+1) \leq 1, k > MDT \tag{3-15}$$

Where
w(i,k) is a binary variable and indicates whether generator i is running at hour k,
RUP_{gi} and RDN_{gi} is the ramp up and ramp down rates for the generator in MW/hr,
MUT is the minimum up time for the generator and
MDT is the minimum down time of the generator.

This optimization problem is solved using the General Algebraic Modeling System (GAMS) [4]. When the system loss is taken into account the market settlement problem is formulated as a mixed integer nonlinear problem whereas if we ignore the losses then the problem becomes a mixed integer programming problem. We use a GAMS solvers XA and MINOS for a mixed integer programming problem and a mixed integer nonlinear problem respectively.

The market settlement determines which generators will supply electricity for the period being considered. This schedule of generators is used by the ISO for dispatch of generation. The ISO is responsible for among other things the security of the system. The market participants have no regard for the constraints of the electrical network and if no care is taken to check the feasibility of the trades, the security of the network can be compromised. The ISO therefore has to check that from the scheduled generation, all the network constraints such as voltage limits, line capacity limits, spinning reserves *etc.* are not violated. A load flow is therefore carried out by the ISO with the scheduled generation from market settlement to check if there are any violations of the network constraints. The correction of these violations may require market participation but depends on the operations of that particular market.

In this thesis, we are mostly concerned with violations of transmission line capacity limits. It should be noted that the scheduled generation from the market settlement is the most economical dispatch schedule since it minimizes the total system costs. The constraints imposed by the network can be viewed as to distort or shift the market away from an optimal operation point, as far as costs are concerned. If a constraint of the network is violated, then the trade as settled by the market has to be corrected. Another settlement should be sought to correct this. The violation of the technical constraints is what is referred to as congestion as introduced in Chapter 1. The actions taken by the ISO to relieve or correct congestion is what we are referring to as congestion management. In our simulations, we use the method of re-dispatch or counter trade to relieve congestion. In practice these two methods of congestion management are not the same. In re-dispatch the ISO does not use the market but intervenes in the dispatch of the generators directly whereas in counter trade the ISO uses the market to determine which generators should be re-dispatched. Counter trading may be considered a more market oriented form of re-dispatching [5]. The generation is rescheduled until the line flow is just below the line capacity limit. In the presence of congestion, re-dispatch is formulated as an optimization problem whose objective is to minimize the total absolute deviation from the market scheduled generation. The objective in re-dispatch can also be to minimize the cost of re-dispatch. In the latter method, the ISO needs bids for the up and down regulation. If the ISO needs to increase generation he looks for the cheapest bids for up regulation and the same is true for down regulation. Some generators may have very little effect in relieving congestion in particular lines. The relationship between generation at bus i and power flow in line mn is described by the so called generation shift factor [6]. This has not been used in this project since re-dispatch is realized through an OPF and will therefore not be referred to again. In this project the objective of re-dispatch is to minimize the absolute deviation from scheduled generation and also minimization of congestion cost. The problem is mathematically formulated as:

Objective function for minimizing absolute re-dispatch is
Minimise: **(3-16)**

$$J = \left(\sum_{i=1}^{NG} \left(\Delta P_{gi}^{+} \right) + \sum_{j=1}^{NG} \left(\Delta P_{gj}^{-} \right) \right) \qquad i \neq j$$

Where

ΔP_{gi}^{+} is up regulation by generator i

ΔP_{gj}^{-} is down regulation by generator j

The constraints for this optimization are:

1) Line flow limits:

$$\sqrt{\left(P_{ij}^{2} + Q_{ij}^{2} \right)} \leq S_{ij}^{\max} \qquad \textbf{(3-17)}$$

2) Bus voltage limits

$$V_i^{\min} \leq V_i \leq V_i^{\max} \qquad \textbf{(3-18)}$$

3) Generator active power generation limits

$$P_i^{\min} \leq P_{sched(i)} + w(i) * \Delta P_{gi}^{+} + (1 - w(i)) * \Delta P_{gi}^{-} \leq P_i^{\max} \qquad \textbf{(3-19)}$$

4) Generator reactive power limit

$$Q_i^{\min} \leq Q_{gi} \leq Q_i^{\max} \qquad \textbf{(3-20)}$$

5) Active and reactive power flow equations (2-3) and (2-4)
6) Power balance at every bus (2-7, 2-8).

The variable *w(i)* is binary and ensures that when a generator is called up for say up regulation it will not be used for down regulation.

When the objective of the re-dispatch in the congested network is to minimize the cost of re-dispatch, equation (3-16) is modified to reflect cost of regulation. The cost of congestion can be viewed from two vantage points. One is in terms of societal costs and the other is the cost borne by the ISO to eliminate congestion. From a societal point of view the cost of congestion would be the difference between the system cost as settled by the market and that of the re-dispatch. As earlier argued the market settlement schedule is the most economical schedule of the system to meet the load and therefore the re-dispatch schedule is more expensive.

The ISO pays for congestion using the regulation market. After market settlement given by (3-9) the participants can submit bids for regulation of power. For up regulation the GENCOs use their rejected bids from the market settlement and for down regulation the accepted bids. The up regulation bids are what GENCOs are willing to be paid per unit of energy supplied during that period. The down regulation bids indicate how much a GENCO is willing to pay the ISO should their generation be curtailed by the bid block amount. In the regulation market all down regulation bids have to be priced lower than or equal to the market price and vice versa for the up regulation bids. The bidders for regulation power may use the same bids as for market settlement or they may choose to revise the prices.

In the case that there is congestion the ISO will buy power from the more expensive generators (using up regulation bids) and technically sell it to cheaper generators (using down regulation bids). Observe that the load is taken as inelastic. After each hour of operation the ISO comes up with a uniform price for down regulation and another for up regulation. The regulation price for down regulation is the price of the lowest bid activated during that hour and the uniform up regulation price is that of the highest priced bid activated in that hour. The net payment by the ISO for congestion can therefore be formulated as:

$$Net\ Payment = \sum_{i=1}^{NG} \left(\Delta P_i^+\right) * \rho^+ + \sum_{j=1}^{NG} \left(\Delta P_j^-\right) * \left(\rho_m - \rho^-\right) \qquad \textbf{(3-21)}$$

Where

ΔP_i^+, ΔP_j^- is the up and down regulation by generator i and j respectively.

ρ_m is the market spot price and

ρ^+, ρ^- are the up and down regulation prices.

The objective function for minimization of cost of re-dispatch may be formulated as:

$$\min, J = \S \sum_{i \neq j}^{NG} \sum_{block}^{T\max} \left(\rho_{(i,block)}^+ * \Delta P_i^+(block)\right) + \sum_{j \neq i}^{NG} \sum_{block}^{T\max} \left(\left(\rho_m - \rho_{(j,block)}^-\right) * \Delta P_j^+(block)\right) \qquad \textbf{(3-22)}$$

Where

$\rho^{+}_{(i,block)}$ is the up regulation price for a block by generator i

$\rho^{-}_{(j,block)}$ is the down regulation price of block for generator j and

Tmax is the maximum number of blocks submitted by generator

Equation (3-22) is a proxy to equation (3-21). The uniform up and down regulation price is then obtained as:

$\rho^{+} = \max(\rho^{+}_{(i,block)})$ and $\rho^{-} = \min(\rho^{-}_{(i,block)})$ respectively.

The cost of congestion will depend on the definition adopted. Since the up regulated generators are not paid at their marginal cost and the down regulated generators do not pay the ISO at the marginal cost, the congestion cost will be different when compared to the societal view. In this thesis, we shall interpret the congestion cost as the net payment by the ISO for regulation power defined by equation (3-21).
Figure 3-3 shows a summary of the congestion management procedures in the pool market.

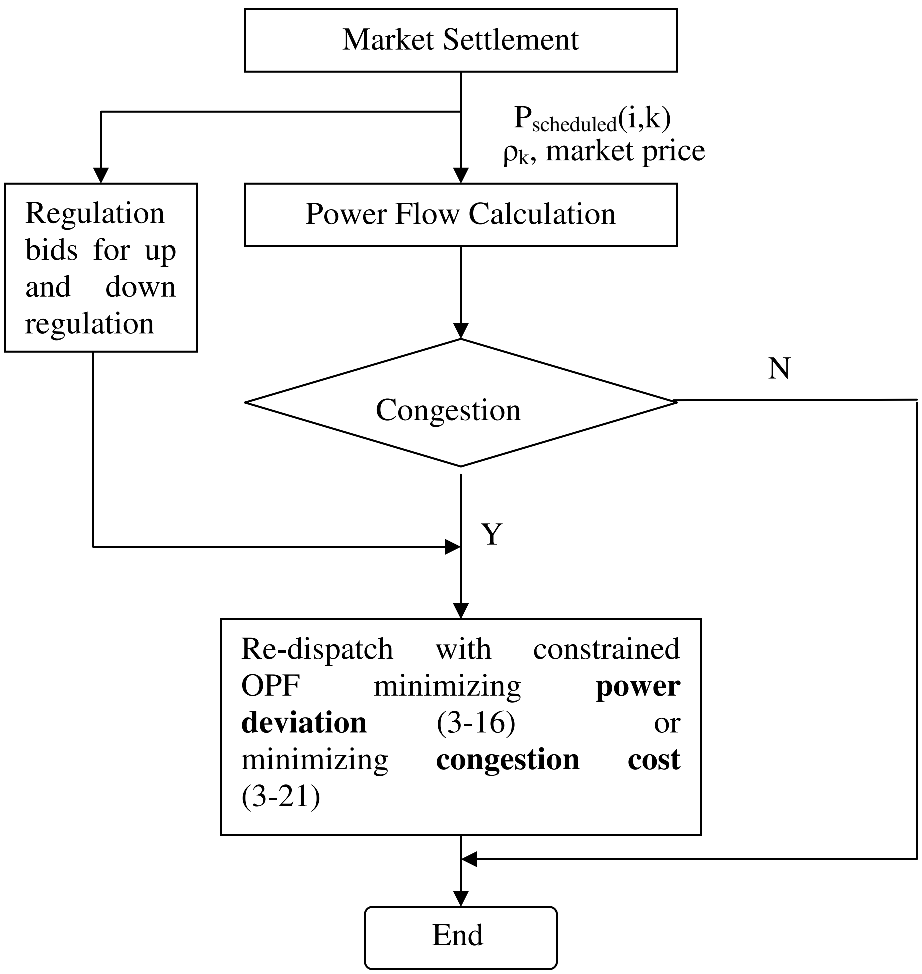

Figure 3-3. Flow chart for congestion management in a pool market

3.2 Congestion Management on IEEE 14 bus system

3.2.1 Description of the network

The IEEE 14 bus test case [7] was used to simulate the pool market. The network consists of fourteen buses, two generators and three condensers. The total system load is 259.6MW and is distributed on eleven buses. A generator was added at bus 3 to increase the number of generators in the system. The modified network is shown in Figure 3-4 below. The test case archive does not give transmission limits for the lines in this network. If one is given the line limits congestion can be simulated by either outaging a single line or de-rating a line. In the absence of line ratings one can observe the normal flows on the lines and choose ratings that match ones purpose. The parameters for the network including the line ratings as used in this project are shown in table.. All impedances are given per unit on a 100MVA base. This base is used through out this report.

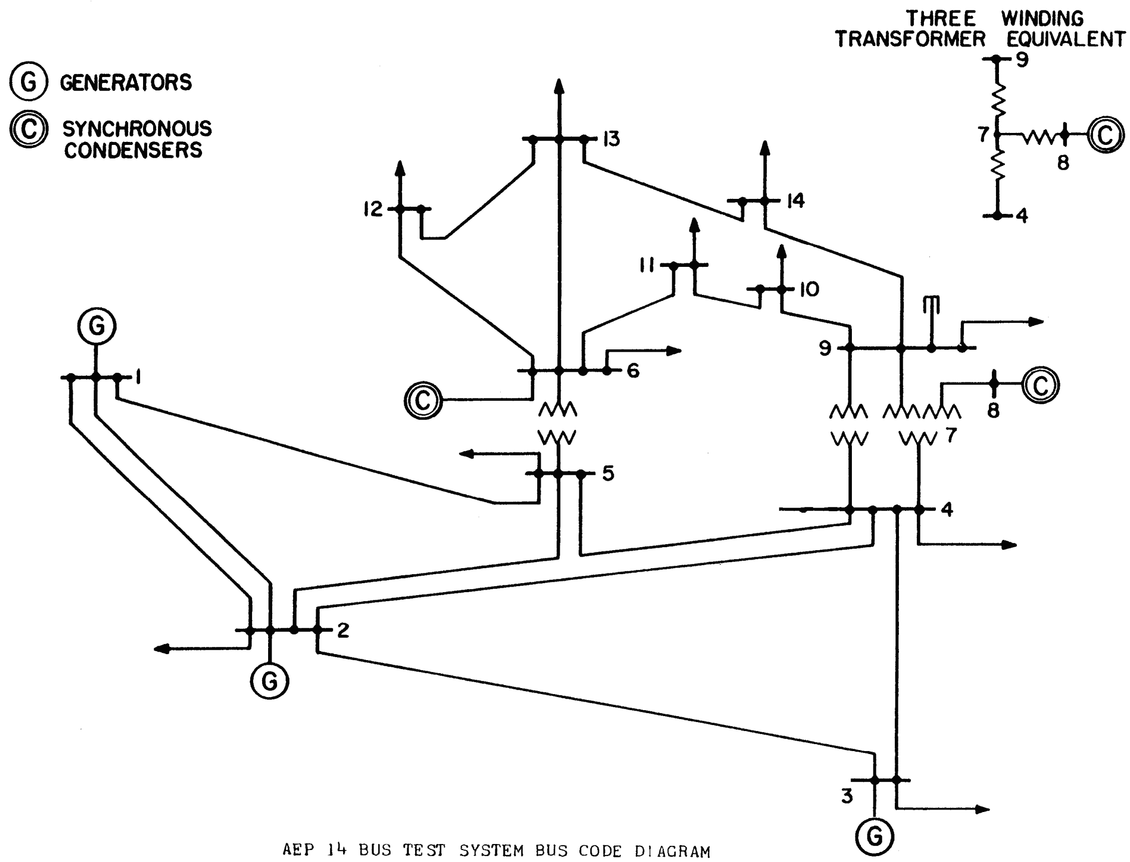

Figure 3-4 Modified IEEE 14-bus test case

Table 3-1. Parameters for lines in IEEE 14 bus test case

Line	r_{ij}	x_{ij}	B_{sh}	Flow limit MVA
1.2	0.00969	0.029585	0.0528	100
1.5	0.05403	0.22304	0.0246	100
2.3	0.04699	0.19797	0.0219	100
2.4	0.05811	0.17632	0.017	100
2.5	0.05695	0.17388	0.0173	100
3.4	0.06701	0.17103	0.0064	100
4.5	0.01335	0.04211	0	100
4.7	0	0.20912	0	60
4.9	0	0.55618	0	60
5.6	0	0.25202	0	60
6.11	0.09498	0.1989	0	30
6.12	0.12291	0.25581	0	30
6.13	0.06615	0.13027	0	30
7.8	0	0.17615	0	40
7.9	0	0.11001	0	50
9.1	0.03181	0.0845	0	30
9.14	0.12711	0.27038	0	30
10.11	0.08205	0.19207	0	30
12.13	0.22092	0.19988	0	30
13.14	0.17093	0.34802	0	30

The generator characteristics including cost coefficients are shown in
Table *3-2* below. ST(i) and SD(i) are the start up and shut down costs for unit i respectively.

Table 3-2. Generator characteristics for 14 bus test case

Bus No.	a	b	Pmax /MW	Pmin /MW	ST(i)/$	SD(i)/$
1	1	8.5	300	100	0	0
2	3.4	25.5	150	20	70	30
3	25	100	20	5	95	95

3.2.2 Market settlement

The submitted bids from three generators are as given in Table 3-3 below. The same bids are used through out the discussion of the 14-bus test case.

Table 3-3. Submitted bids

i,t (generator no., block number)	Block size (MW)	Unit Price($)
1.1	100	208.5
1.2	75	358.5
1.3	125	608.5
2.1	20	161.5
2.2	100	841.5
2.3	30	1045.5
3.1	10	600.0
3.2	5	850.0
3.3	5	1100.0

When we settle the market in a single hour we have to neglect the start up and shut down costs, as well as the ramp up and down rates. The bids for hour eight arranged in increasing order of price are shown in Figure 3-5.

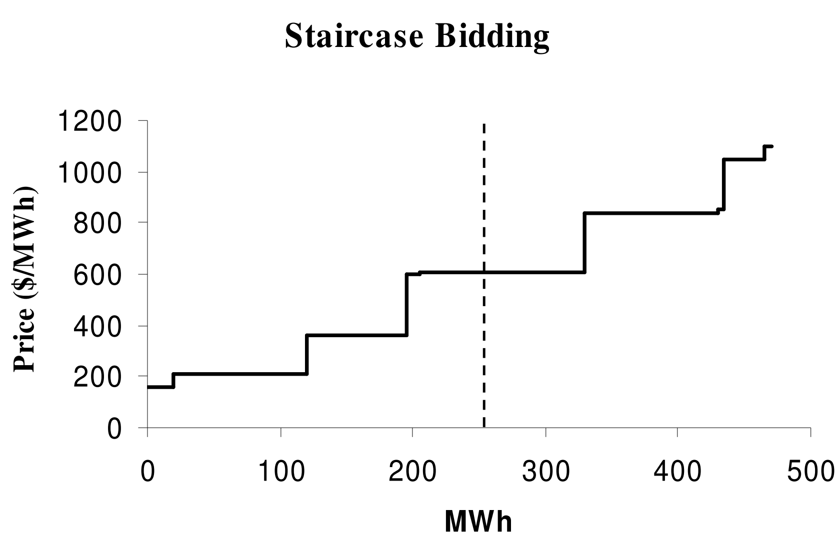

Figure 3-5 Bids for the 14 bus system arranged in order of price

The vertical broken line indicates the total demand at hour eight. From Figure 3-5 we expect the accepted bids to be the first block from all the generators and the second block from generator 1 and part of third block from generator 3. The price would be that of the highest accepted bid i.e.

$608.5/MWh. The total cost would then be $89,826.5/hr. We therefore expect our market model to give this result. The result from the model is given in Table 3-4.

Table 3-4. Accepted bids for the 14 bus system for hour eight

Generator	$P_{scheduled}$ (MW)	Accepted Block (MWh)		
		Block 1	Block 2	Block 3
1	229	100	75	54
2	20	20	0	0
3	10	10	0	

The results shown in Table 3-4 agree exactly with the expected output. The marginal cost which is the Langrangian multiplier of the equality constraint (equation (3-5)) gives the unit price and is equal to $608.5/MWh as deduced earlier. The total cost given by our simulation is also $89,826.5/hr as expected.

When we include the losses in the market settlement by using equation (3-6) the results are as given in Table 3-5.

Table 3-5 Accepted bids for the 14 bus, accounting for losses

Generator	$P_{scheduled}$ (MW)	Accepted Block (MWh)		
		Block 1	Block 2	Block 3
1	239.8	100	75	64.8
2	20.0	20	0	0.0
3	10.0	10	0	0.0

The losses are estimated at 10.8MW and the total system cost becomes 96,401/hr. Naturally the extra amount of power required to cover the losses is scheduled from the cheapest generator and thus generator 1 increases its scheduled generation from 229MW to 239.8MW. In our simulation the losses will not be taken into account. The losses will be assumed to be taken up by the regulation market.

When the market is settled over a 24-hr period, we include the shutdown and start up costs and also the minimum up and minimum down time constraints. The ramp up and down rates have to be observed as well. The load scaling factor (LSF) for each hour is given in Table 3-6. The results of the unit commitment problem over the 24hrs are shown in Table 3-7.

Table 3-6. Load scaling factors for each hour

Hr	LSF	Hr	LSF	Hr	LSF	Hr	LSF
1	0.80	7	0.92	13	0.90	19	0.94
2	0.79	8	1.00	14	0.88	20	0.93
3	0.79	9	1.00	15	0.86	21	0.91
4	0.79	10	0.96	16	0.87	22	0.89
5	0.81	11	0.95	17	0.86	23	0.79
6	0.85	12	0.92	18	0.88	24	0.79

Table 3-7. Scheduling of generation in over 24 hour period

Hr	1	2	3	4	5	6	7	8	9
Generator									
1	1.86	1.84	1.84	1.85	1.79	1.91	2.10	2.29	2.28
2	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
3					0.10	0.10	0.10	0.10	0.10
Hr	10	11	12	13	14	15	16	17	18
Generator									
1	2.19	2.148	2.09	2.03	1.97	1.94	1.95	1.92	1.99
2	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
3	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Hr	19	20	21	22	23	24			
Generator									
1	2.12	2.11	2.07	2.00	1.84	1.84			
2	0.20	0.20	0.20	0.20	0.20	0.20			
3	0.10	0.10	0.10	0.10					

The scheduled generation in Table 3-7 above are in p.u. on a 100MVA base.

We observe that in the results for the market settlement over the period of 24 hours generator 3 is constrained off in the first four hours and is committed from hour 5 to hour 22 after which it is turned off. We wish to verify with our intuitive thinking that the results of the market model are correct. In the first hour the total load is 205.65MW. From *Table 3-3* we expect generator 2 and 1 to have their first blocks accepted (a total of 120MW). The balance of 85.65MW can be made up from generator 2's second block (the cheapest available block) of 75MW therefore leaving a balance of 10.65MW. At this stage it may seem that the natural block to pick is that of generator 3, which is the cheapest block at $600/MWh compared to that of generator 1 at 608.5/MWh. If we pick generator 3 first block of 10MW and 0.65MW from generator 1's third block the cost for this portion is $6,393.09. If instead we pick generator 1's third block we will spend 6,478.091 for the 10.646MW. So we may conclude that it is favourable to get 10MW from generator 3 and 0.646MW from No.1. Now let's consider hour 2 where the load has dropped to

203.57MW. The first 195MW are scheduled the same way as before i.e. generator 1 provides its first two blocks and generator 2 its first block. The balance of 8.57MW can either be obtained from the third block of generator 1 at $608.5/MWh or from generator 3 at $600/MWh. But generator 3's minimum generation is 10MW and if we chose to run it then we have to down regulate generator 1 whose price for the second block is only $358.5units/MWh (we would buy 2MWh at $600/MWh instead of $358.5/MWh)! This is unacceptable of course and so we naturally choose to supply the balance from generator 1 though more expensive than generator 3. If we had chosen to run generator 3 in the first hour we would have incurred a shutdown cost in the second hour and the total cost for the first two hours would have been $10 more expensive than the schedule produced by the model. So we conclude that when the scheduling is considered over the 2 hour period it is favourable not to run generator 3 in the first hour. The model therefore gives a correct solution when the whole scheduling period is considered.

3.2.3 Results of Load flow

After the Market settlement, the ISO checks the feasibility of the scheduled generation by carrying out a load flow. In the 14-bus test system an AC load flow is employed. We therefore consider line loadings in MVA. A load flow is carried out for each hour to check the feasibility of the generation schedule in *Table 3-7*. The results for the load flow for hour eight are shown in Table 3-8 for selected lines. We have congestion on line 1.2 whilst all the other lines are below their capacity. In the load flow, generator 1 is taken as the slack bus and takes up the losses.

Table 3-8. Line loadings from load flow with market schedule

Line	Loading %	Line	Loading %
1.2	180	2.5	46
1.5	62	3.4	17
2.3	70	4.5	53
2.4	59		

It is easy to appreciate the cause of the congestion. Generator 1 is the cheapest generator and is served by two transmission lines with a total capacity of 200MVA. If the two transmission lines were of the same impedance then they would be equally loaded and we would expect that generator 1 can produce up to 200MW without causing congestion. The two lines (1.2 and 1.5) are not equally loaded due to the difference in impedance and the result is that line 1.2 is loaded to 180% of its capacity while line 1.5 is only loaded to 62% of its capacity. The losses after the load flow are 0.11pu. Clearly the network cannot be operated in this way since security of the network is violated. In this project, as earlier explained in Chapter 1, we are going to use re-dispatch of generation to manage congestion.

3.2.4 Results of Re-dispatch

Re-dispatch is carried out by using an Optimal Power Flow (OPF). Whereas the load flow module does not consider line flow limits, the OPF considers this constraint. The objective function of re-dispatch is as set out in equation (3-16) i.e. minimisation of absolute re-dispatch subject to the constraints given for (3-16).

With these constraints the OPF results in a generation schedule shown in Table 3-9 below. We observe that generator 1 is down regulated to 153.7MW while generator 2 is up regulated to 104.1MW.

Table 3-9. Comparison of re-dispatch and scheduled generation

Generator	$P_{scheduled}$ (MW)	Actual (OPF)(MW)	Total absolute re-dispatch (MW)	System system cost before re-dispatch ($/hr)	System system cost after re-dispatch ($/hr)
1	229	153.7	159.4	89,826	120,046
2	20	104.1			
3	10	10.0			

Because in the re-dispatch we are using the out of merit generators more (generator 2), the result is that the system cost has increased to $120,000/hr compared to a market settlement system cost of $89,826/hr. The difference between the two costs is what we are referring to as the cost of congestion from the societal point of view. In solving the congestion we have to give up 75.3MW (representing a reduction in system cost of about $40,000) from generator 1 (cheaper unit) and purchase 84.1MW (an increase in system cost of $70,000) from generator 2 (more expensive unit). The resulting increase in system cost is about $30,000.

With the re-dispatch schedule the line flows are brought within limits of the line capacities. Table 3-8 shows the new line loadings after re-dispatch.

Table 3-10. Line loadings after re-dispatch

Line	Loading %	Line	Loading %
1.2	100	2.5	50
1.5	54	3.4	17
2.3	71	4.5	51
2.4	62		

In order to solve the congestion on line 1.2 we have to re-dispatch a total of 159.4MW. The ISO would order the generators to down or up regulate until the congestion is solved.

When we use re-dispatch for CM, the ISO incurs a cost since he has to commit the out of merit generation and down regulate the cheaper generators. In a perfect competitive market the suppliers have to bid at their marginal cost since there is no incentive for bidding higher than the marginal cost. The ISO would then compensate the up regulated generators at the price of the most expensive generator up regulated i.e. price of block 2.2 at $841.5/MWh. The generators which have been down regulated would pay the ISO at $308.5/MWh, which is the price of the lowest down regulation bid activated for hour eight. Using equation (3-21), the ISO would pay a net amount of $70,770 to the generators that have up regulated and $18,000 for down regulation. Whilst the increase in system cost from societal point of view is only $30,000/hr the ISO pays out about $89,000/hr. As earlier stated the cost of congestion, according to our definition, would be $70,000 for hour eight.

The cost incurred by the ISO to solve congestion would be an indicator for need of investment in the transmission system. If the congestion is persistent then the investment in the transmission system has to be made. An economic study needs to be carried out to determine whether we need investment in the system reinforcement. If the benefits of the investment are greater than the congestion cost to the ISO, then the investment is justified. Such an analysis is considered in detail later in this chapter.

3.2.5 Re-dispatch: Minimisation of cost

In re-dispatch, with the objective of minimising the cost of congestion the objective function is formulated as given by equation (3-22) and the associated constraints as in the case of minimising re-dispatched amount. Since we are starting with the same market settlement i.e. Table 3-7 we will notice that we have congestion after carrying out a load flow. The results of the load flow are the same as those already given in Table 3-8. We therefore re-dispatch the generation to clear the congestion but the cost of the regulation bids are of concern since we are minimising the congestion cost. The regulation bids submitted by the GENCOs for hour eight are shown in Table 3-11. The pricing of the regulation blocks are as earlier given in Table 3-3.

Table 3-11. Regulation bids for hour eight for the 14 bus system.

Up regulation		Down regulation	
Generator.block	Amount (p.u)	Generator.block	Amount(p.u)
1.3	0.71	1.1	1.00
2.2	1.00	1.2	0.75
2.3	0.30	1.3	0.54
3.2	0.05	2.1	0.20
3.3	0.05	3.1	0.10

Again we start with the market schedule and the load flow results shown in Table 3-8. This time we re-dispatch using the objective function of equation (3-22) with the same constraints as for minimisation of absolute re-dispatch. The new generation schedule is shown in Table 3-12.

Table 3-12. Re-dispatched schedule with minimisation of cost as objective function.

Generator	$P_{scheduled}$ (MW)	Actual (OPF)(MW)	Total absolute re-dispatch (MW)	System cost before re-dispatch ($/hr)	Cost of Congestion ($/hr)
1	229	153.6	159.4	89,826	89,560
2	20	104.0			
3	10	10.0			

From the results of the re-dispatch in Table 3-12 we observe that the amount of re-dispatch is the same as for the case of minimisation of absolute re-dispatch. The cost of congestion is also the same in both cases (compare Table 3-12 and Table 3-9) since the re-dispatch schedules are almost the same. The result is coincidence as we shall see later when we include FACTS in the system. When we re-dispatch with the objective being minimisation of absolute re-dispatch we involve generators which have a high generation shift factor (or coupling) for the congested line. At the same time, the generators with a high incremental loss are disfavoured for up regulation. Due to the location of generator 2 it is clear to conclude that it has a higher coupling to the congestion on line 1.2 compared to generator 3. Coincidentally generator 2's up regulation bids are cheaper than those for generator 3 hence generator 2 becomes a favoured choice for up regulation both for cost and re-dispatch minimisation.

3.3 Application of FACTS for congestion management in the Pool Market

In order to see the effect of installation of series FACTS in the system on congestion we simulate a FACTS device. The FACTS device is inserted in line 1.2. We will simulate operation of the TCPAR and the TCSC. Without an exhaustive analysis, we can conclude that the FACTS device has to be installed in the lines in the neighbourhood of the congestion [9]. The optimal location of FACTS shall be treated in more detail in the section on economic consideration in the placement of FACTS.

3.3.1 TCPAR

The generation schedule used for the load flow with FACTS is that of Table 3-7. The TCPAR is first installed on line 1.2. With a compensation angle of the TCPAR set to -10 degrees the resulting load flow for hour eight is as given in Table 3-13.

Table 3-13 Load flow result: Line loadings TCPAR in line 1.5, schedule of generation from Table 3-5

Line	Loading %	Line	Loading %
1.2	135	2.5	27
1.5	113	3.4	26
2.3	63	4.5	77
2.4	43		

In Table 3-13 the loading of line 1.2 has reduced to 135% from the previous 180% in the case without FACTS (Table 3-8). Line 1.5 has increased its loading to 113% from the previous 62%. Though we still have congestion we have reduced it significantly, needless to say that the amount of re-dispatch required to clear the congestion is smaller compared to a scenario without FACTS. The effective angle between the sending bus 1 and receiving bus 2 has reduced thereby reducing the power flow on that line.

When we re-dispatch the angle of regulation of the TCPAR becomes a control variable controlled by the optimisation program. The additional constraints to the objective function in (3-16) are:

$\sigma^{mia} \leq \sigma \leq \sigma^{\max}$ where σ is angle of regulation and
equations (2-33), (2-34), (2-35) and (2-36)

The results of the re-dispatch for the eighth hour can now be seen Table 3-14.

Table 3-14. Re-dispatch of generation with TCPAR in line 1.2, the objective function being minimisation of absolute re-dispatch

Generator	$P_{scheduled}$ (MW)	Actual (OPF)(MW)	Total absolute re-dispatch (MW)	System cost before re-dispatch ($/hr)	System cost after re-dispatch ($/hr)
1	229.0	200.0			
2	20.0	48.8	67.9	89,826	106,187
3	10.0	20.0			

The angle of regulation for the TCPAR when inserted in line 1.5 is +7.6 degrees. When the TCPAR is inserted in line 1.5 instead, the amount of re-dispatched is 67.7MW and the system cost is $106,087/hr. The TCPAR in lines 1.2 or line 1.5 reduces the amount of power re-dispatched. Consequently the system cost after re-dispatch is lower than in the case without the TCPAR. The congestion cost when the TCPAR is in line 1.2 would be about $42,000 for hour eight since the up regulation price is $1,100/MWh and the total up regulation is 38.8MW. The ISO would not pay for down regulation in this case since the market price is equal to the down regulation price. The most important benefit of the FACTS device in this case is the reduction in congestion and the amount of re-dispatch required to clear the congestion. If we measure congestion in terms of total re-dispatch then the FACTS reduces the congestion by about 60%. The net payment by ISO for regulation remains about the same as in the previous case without FACTS. A comparison of the results for the entire 24 hour period for the cases with FACTS and without FACTS is shown in Figure 3-6.

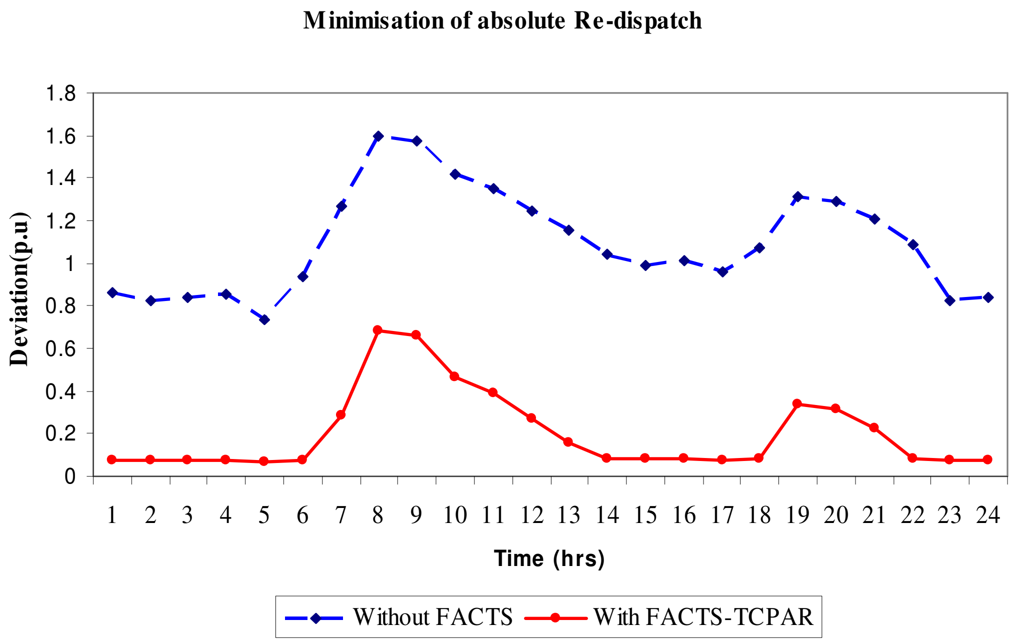

Figure 3-6 Minimisation of Re-dispatch TCPAR on line 1.2

When we re-dispatch generation with the objective function being minimising congestion cost in the presence of a TCPAR on line 1.2 the re-dispatch results are shown in Table 3-15. The regulation bids used are as given before in Table 3-11.

Table 3-15 Re-dispatch of generation with TCPAR on line 1.2 objective function minimisation of cost of congestion.

Generator	$P_{scheduled}$ (MW)	Actual (OPF)(MW)	Total absolute re-dispatch (MW)	System cost before re-dispatch ($/hr)	Cost of Congestion ($/hr)
1	229	200.00	68.16	89,826	33,258
2	20	54.13			
3	10	15.00			

The minimisation of ISO payment for congestion in the presence of FACTS results in a congestion cost which is much lower than that without FACTS ($33,258 compared to $89,560 without FACTS). Furthermore the re-dispatched amount is now about 60% of the previous case without FACTS. The results in Table 3-15 and Table 3-14 clearly show the differences in the effects of the objective functions of the re-dispatch. The amounts re-dispatched in both cases i.e. for minimisation of re-dispatch and minimisation of congestion cost are almost the same but the generators chosen for up regulation are different. In the case for cost minimisation, Generator 3 has been picked for up regulation for only 5MW because it is more expensive. Generator 2 has been up regulated by 34.13MW compared to 28.8MW for re-dispatch minimisation. The result is that in cost minimisation the amount re-dispatched is slightly more than in the case of minimising the re-dispatch amount but the cost to the ISO is lower. In cost minimisation the generation schedule results in more losses compared to the minimisation of re-dispatched amount. The results for the entire 24 hour period are shown in Figure 3-7 for the cases of with FACTS and without FACTS.

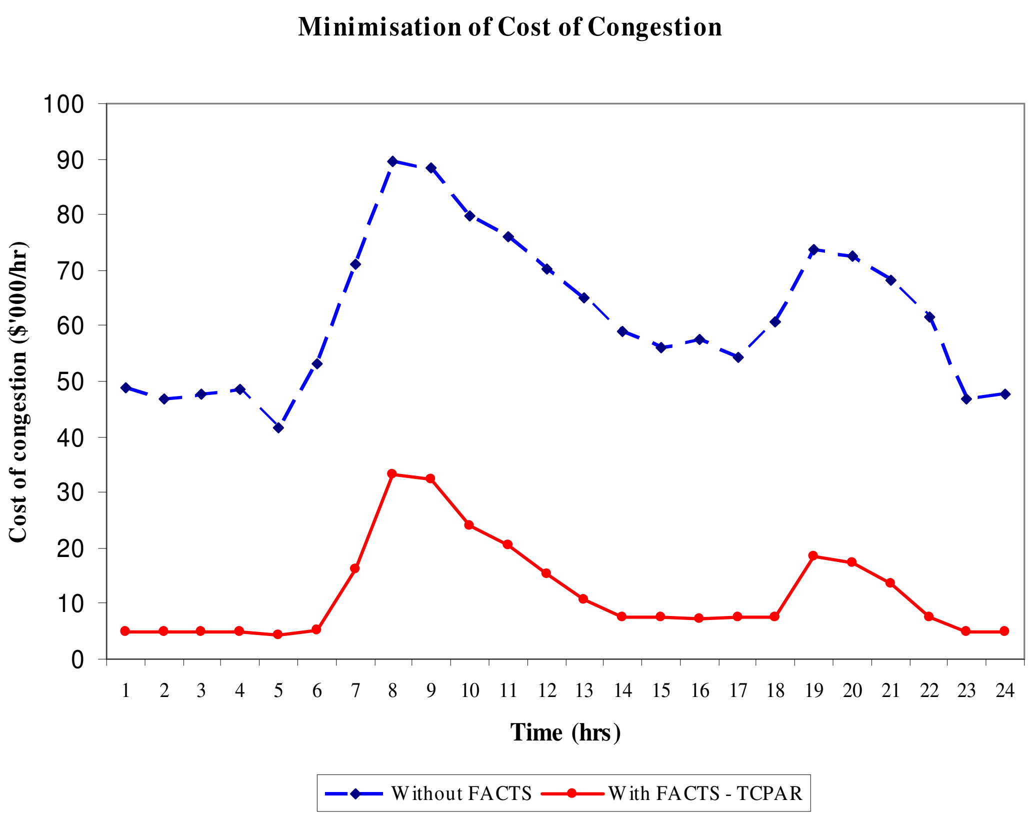

Figure 3-7 Minimisation of congestion cost TCPAR on line 1.2

3.3.2 TCSC

The principle of operation of the TCSC has been covered in detail in Chapter 2. When the TCSC is inserted in a line, it modifies the series reactance of the line. Since the reactance dominates the series impedance of the line, the TCSC therefore reduces the impedance of the line. The line therefore becomes electrically shorter and this increases the maximum power flow on the line. If we insert the TCSC on line 1.5 we can reduce its effective reactance and hence be able to have more power flow through it, thereby decongesting line 1.2. We again use the generation schedule of Table 3-4 to see the effect of the TCSC on line flows. The compensation level is chosen at 0.7. The resulting line loadings are given in Table 3-16.

Table 3-16. Line loadings before re-dispatch with TCSC on line 1.5

Line	Loading %	Line	Loading %
1.2	138	2.5	27
1.5	109	3.4	25
2.3	64	4.5	76
2.4	44		

Congestion of line 1.2 has now reduced to 138% from the initial 180% in the case without FACTS (see *Table 3-8*). Line 1.5 is now loaded to 109% which is much higher than in the case without FACTS. The TCSC reduced the series impedance of the line 1.5 hence power flow on the line increases. When we re-dispatch generation to get rid of the congestion in the presence of the TCSC on line 1.5 the re-dispatched amount is only 68.5MW compared to 159MW in the case without FACTS. The loadings of the lines 1.2 and 1.5 are both at 100%. In the case without FACTS the re-dispatch loadings of lines 1.2 and 1.5 are 100% and 54%. The TCSC thus makes it possible to utilise line 1.5 more than in the case without it. The cost of the re-dispatched system (from Table 3-17) is only \$106,000/hr compared to \$120,000/hr for the case without FACTS (Table 3-9). Again the difference in the system costs gives the societal benefit of using the TCSC. The ISO would make a net payment of \$54,000 to alleviate congestion going by the schedule in Table 3-17. This is lower than that paid in the case without FACTS (\$89,000).

Table 3-17. Re-dispatch with TCSC in line 1.5 objective function 'minimisation of absolute re-dispatch'

Generator	$P_{scheduled}$ (MW)	Actual (OPF)(MW)	Total absolute re-dispatch (MW)	System cost before re-dispatch	System cost after re-dispatch (\$/hr)
1	229	200	68.5	89,826	105,954
2	20	52.5			
3	10	17.0			

The variation of the re-dispatch over a 24 hour period is plotted in Figure 3-8. The re-dispatch with TCSC in the system is also shown in the same figure.

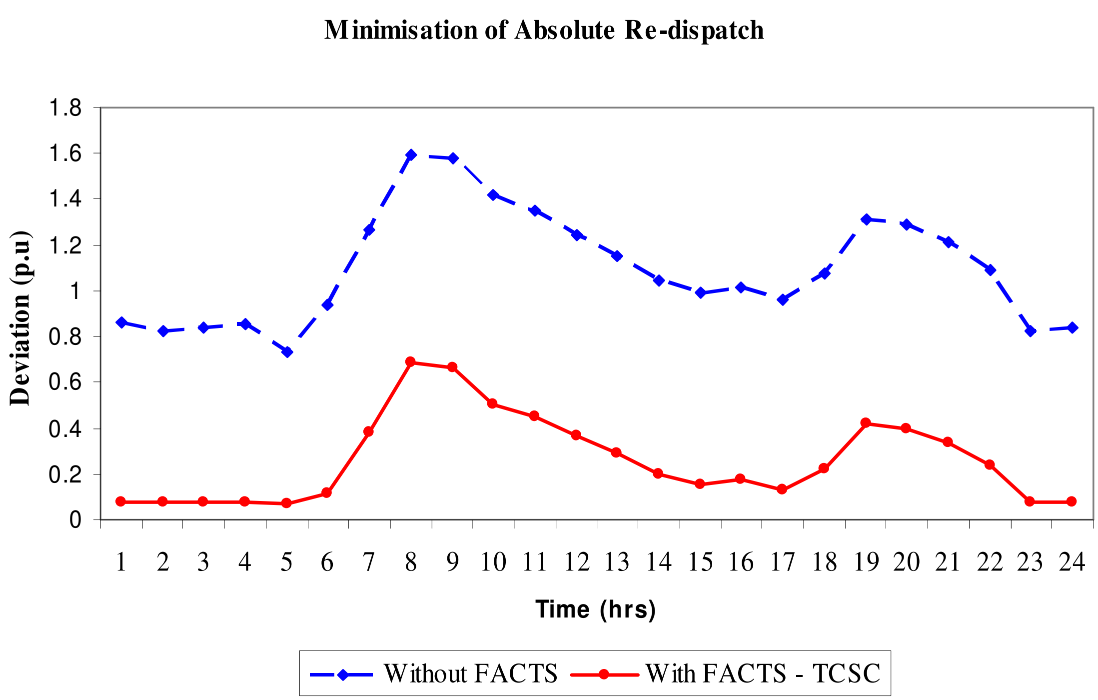

Figure 3-8 Minimisation of re-dispatch TCSC on line 1.5

As can be seen from Figure 3-8 the effect of the TCSC on the re-dispatched generation is very similar to that with the TCPAR. Alleviating congestion by the use of the TCSC with the objective of minimising congestion cost produces similar results with the TCPAR and will not be presented here.

3.4 Economic consideration for placement of FACTS

Management of congestion by use of the method of re-despatch or counter trade costs the system operator money since he has to buy power from more expensive out of merit generators and sell the power at a cheaper price to low cost generators. Unlike other market based methods of CM, in re-despatch the market players continue their behaviour as though there was no congestion. The market therefore does not change its behaviour and there are no 'punitive' actions taken by the ISO. The costs incurred by the ISO in CM by re-despatch are a signal of the need for system expansion. As discussed above, system expansion can be achieved not necessarily by construction of new transmission lines but also by utilising the existing transmission lines closer to their thermal rating or stability limits whichever is limiting. FACTS devices as explained before help us to utilize existing transmission infrastructure more fully compared to a case where we have no controllability as to the flow of power in the system. As demonstrated in the 14-bus test system, we can have congestion on one part of the system (line 1.2) while other transmission paths are lightly loaded! Corridor 1-2 was overloaded by 80% while the alternative path 1-5 was only about 60% loaded! This is due to the natural laws that govern flow of electricity (Kirchoff's and Ohms Law). FACTS bring controllability as to how much power should flow on which path. By using FACTS, we are able to decrease the loading of line 1-2 (naturally preferred path) and increase loading on line 1-5.

The re-dispatched amount in the presence of FACTS is greatly reduced and so is the cost of CM to the ISO. The decision of whether to install FACTS or not is apart from being a technical matter also an economic decision. Normally investment is made when the benefits of the investment are overall positive when all the costs are considered i.e. both initial investment and operations and maintenance. In the analysis that follows we only consider the initial costs. The operations and maintenance costs of FACTS are very low [8] stemming from the fact that there are no moving parts since the switches are static. Various literatures in print advance different methods for the optimal location of FACTS in the power system. In [8] a method based on a loss sensitivity factor is considered. As our method of CM is re-despatch we look at the installation of FACTS in various lines in turn and compute an index that gives us an indication of the benefits. Apart from the cost of FACTS we also need the life span of the installation. We have estimated the lifespan to ten years though cases of FACTS lasting for more than 10 years are known (in Zambia SVC at one of the major substations has been in existence for more than 10 years). For this chosen period the capital recovery factor (CRF) is computed and the recurring annual payments determined. The CRF tell us the equivalent uniform payments that can be made towards a loan in the life of the loan. The annual payment is then divided over the number of hours in a year to compare with the CM costs which are given per hour. Taking an interest rate of 10% and capital outlay of US$5million [13] (FACTS of throughput of 200MW) the CRF is calculated thus:

$$CRF = \frac{i*(1+i)^n}{(1+i)^n - 1} \quad \textbf{(3-23)}$$

where i is the discount factor rate and n is the number of years, during which FACTS is in operation.

The recurring annual payment is then given as

$$R = CRF * P \quad \textbf{(3-24)}$$

where P is the principal amount and R the recurring payments.

The benefit to cost index (BCI) will then be:

$$\frac{Annual\ Benefit\ from\ FACTS}{Annual\ Cost\ of\ FACTS}$$

$$BCI = \frac{(CM\ \cos ts\ without\ FACTS - CM \cos ts\ with\ FACTS) * 8760 * DLF * ALF}{R} \quad \textbf{(3-25)}$$

Where DLF and ALF are the daily and annual load factors for the system. In the use of the DLF factor it has been assumed that the congestion cost will vary according to the variation of load over a 24-hr period. It has also been assumed that the congestion cost over the year will be similar to load variations over the year, hence the use of the annual load factor.

The higher the computed index the more beneficial the investment is. If the index is greater than unity then it is beneficial to make the investment. For values of the index less than one it is not advisable to make the investment since the savings in the CM costs cannot pay for the investment! The procedure for choosing an optimal location for FACTS based on this method is given in Figure 3-9

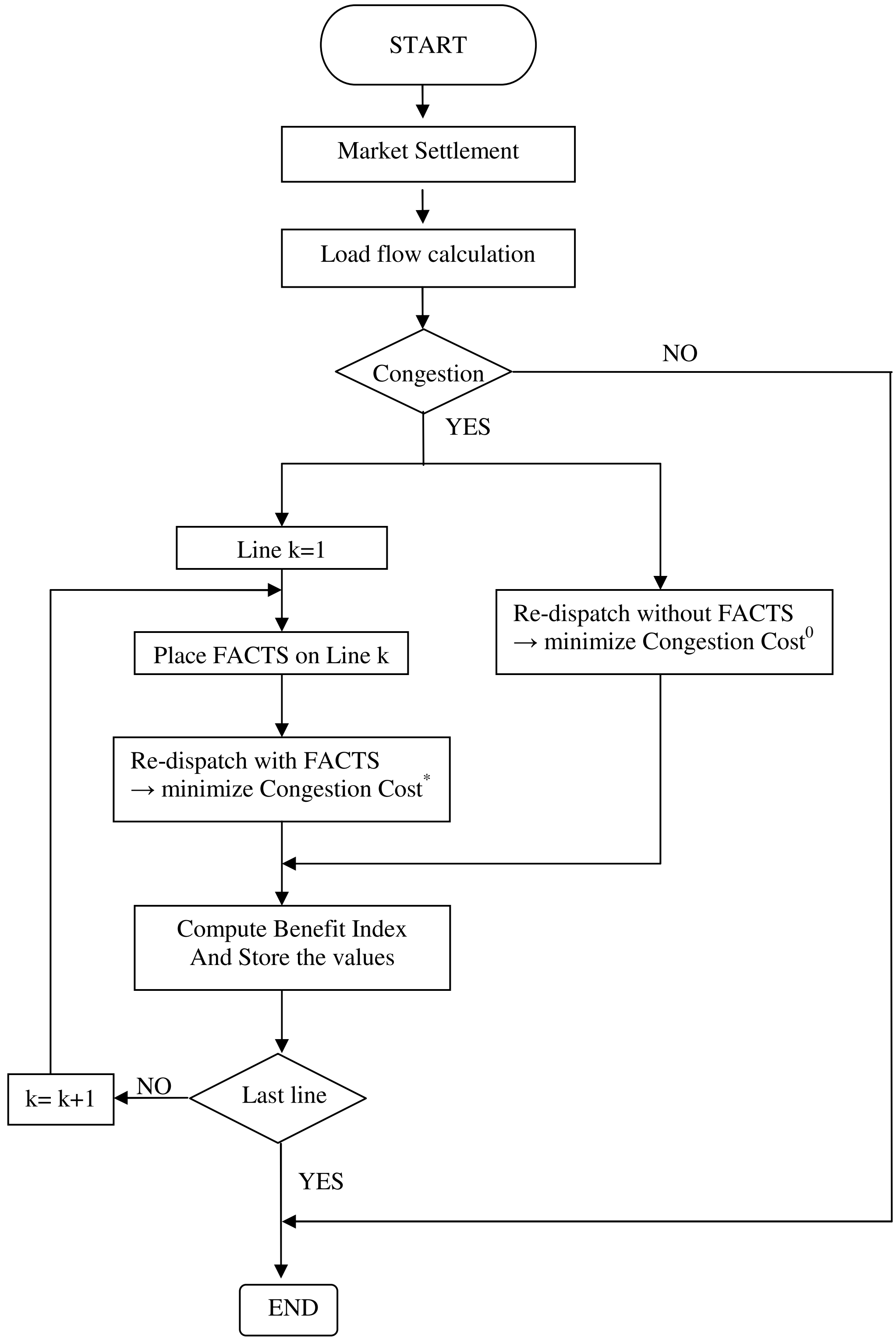

Figure 3-9 Flow chart for procedure of choosing optimal location of FACTS

For the 14-bus system we use the pool market to compute the benefit index for different locations of FACTS. We shall use the TCPAR for the calculations. We therefore use the generation schedule of Table 3-4. The TCPAR is then inserted in each line in turn the re-dispatch carried out. For each of the locations of the TCPAR we compute the benefits. The computed benefits have to be corrected for daily and seasonal variations as explained above. The load scaling factors are taken from the Svenska Kraftnät and are slightly modified to conform to our use. The annual load factor is calculated from [12]. The daily and annual load factors are 0.88 and 0.6 respectively.

From (3-24) and (3-23), R = $814,000
In the case of the 14 bus test system the results for the calculation of the benefit index in various selected locations of FACTS are given in Figure 3-10. The key to the line no. used in the figure is given in the Table 3-18 below. The cost coefficients of the generators from
Table *3-2* have been modified by dividing by 8 to get a market price of electricity for hour eight around $74.21/MWh which is closer to the spot price of the Swedish market.

Table 3-18 Key to line numbers shown in Figure 3-10 below.

Line	Line number	Line	Line number
1.2	1	6.11	11
1.5	2	6.12	12
2.3	3	6.13	13
2.4	4	7.8	14
2.5	5	7.9	15
3.4	6	9.10	16
4.5	7	10.11	17
5.6	8	12.13	18
4.7	9	9.14	19
4.9	10	13.14	20

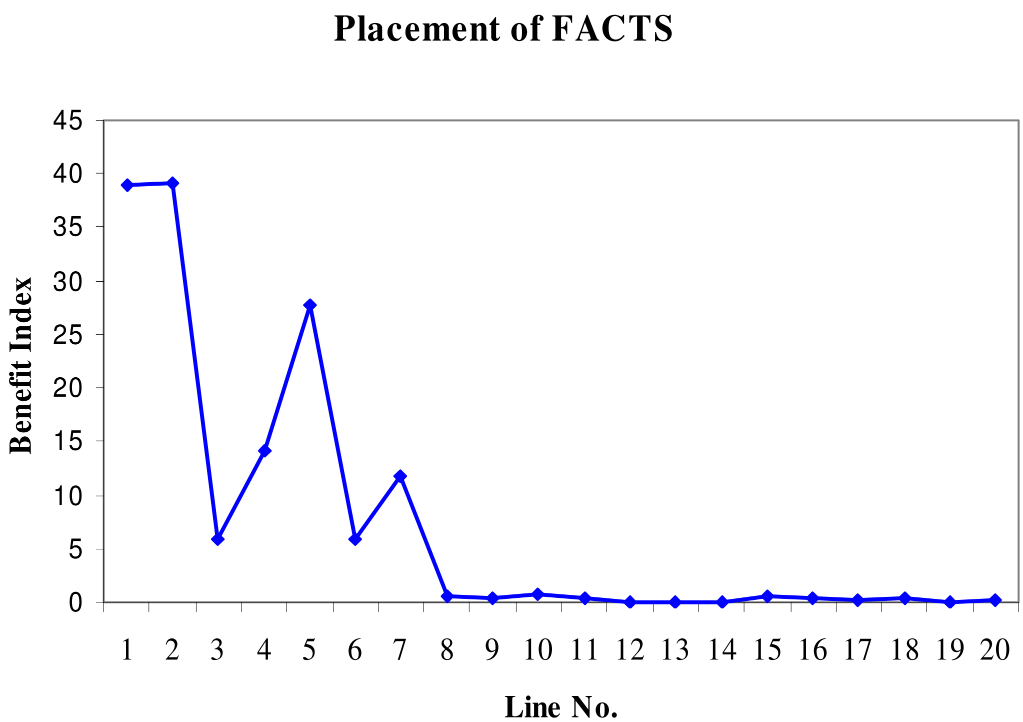

Figure 3-10 Benefit index computed for different locations of the TCPAR.

Clearly for the TCPAR in locations 1 through 7 are possible locations for the FACTS since they give a benefit index greater than 1. The maximum benefit is when the TCPAR is in location 1.5 followed by 1.2. It is interesting to note that locations in the vicinity of the congestion all have a benefit index close to or greater than unity while locations farther from the congested line give a lower index. The benefit index does not imply that the ISO has to invest in FACTS but that it is economical to do so. This has to be weighed against other available options for congestion management. The financing for the FACTS device is a second step after the location has been picked. In [11] financing of the FACTS is considered in different methods of congestion management. In this thesis, we assume that the ISO charges connection fees and that he uses these fees to pay for the congestion management. When the FACTS device is installed, the CM costs are reduced and ideally the ISO is supposed to reduce the connection fees. In the period that the ISO is servicing the loan for the FACTS, he can continue charging the connection fee as though there was congestion. When the loan is fully repaid then the connection fees can be revised downwards to reflect the new status of the system. In the case that the benefit index is very high like the case simulated the ISO may be required to reduce the connection fees immediately to a level that makes it possible for him to make loan repayments.

Transmission expansion by construction of new lines and by reinforcing existing lines is another way of reducing CM costs. Whether the ISO needs to invest in new transmission lines or employ FACTS for existing transmission lines depends on the prevailing situation [10]. Where CM can be solved by redirecting power flows FACTS are potential candidates to employ. Excellent papers are in print on economic considerations of using FACTS versus new transmission lines [10].

3.5 Conclusion

In a pool market the market price and hence the schedule of generation is determined from submitted bids by the GENCOS and consumer bids by the loads. The scheduled generation is determined from the total amount of power sold by a GENCO in the market. Market settlement is carried out without network constraints though losses may be accounted for by using the loss formula. The market only considers the generation limits.

It has been found that the market settlement schedule may lead to violation of the line capacity limits since these are not taken into account in arriving at the dispatch schedule. To solve this congestion the ISO re-dispatches generation. The re-dispatch is an optimisation problem and has been simulated with two objectives:

- minimisation of total absolute re-dispatch and
- minimisation of cost of congestion or net payment by ISO.

It is important to appreciate that the market settlement gives the most economical schedule and deviation from this schedule should be minimised. In re-dispatching the system there is a system cost increase owing to the increase in power output of generators which are less favourable and reduction of output of preferred generators. The increase in system cost is the cost of congestion from a societal point of view. The ISO has to pay for congestion based on the regulation bids. It is concluded that when congestion is managed by re-dispatch there is an increase in system cost and also the ISO incurs a cost. This cost incurred by the ISO is an indication for the need of investment for transmission capacity in the system. Congestion management is the most important roles that the ISO plays in the electricity market. He ensures that the system is operated safely. The presence of congestion on a regular basis can be used by generators to distort the market. The generators that are regularly up regulated may submit very expensive bids since they know that their generators are required for congestion management. Persistent congestion is therefore undesirable. The market participants i.e. GENCOS and loads are oblivious to the cost of congestion if we employ re-dispatch as the mode for solving congestion. The market carries on as if there was no congestion. This behaviour may be desirable but may encourage gaming by some generators. We expect market behaviour in the short run to be repetitive and hence some GENCOS may take advantage as earlier stated by bidding higher for regulation power than their marginal costs.

It has been observed that the use of FACTS devices such as TCSC and TCPAR is able to reduce congestion and the amount of re-dispatched power or the cost of congestion. This ensures that the system is run as close to the market settlement schedule as possible. By using FACTS in the 14 bus system it was demonstrated that lines are more optimally loaded. The result is that we get a smaller deviation from the market generation schedule and the resulting schedule is cheaper than that without FACTS. The difference in re-dispatch costs for the case with and without FACTS gives a measure of the benefit of using FACTS. The benefits of using FACTS can also be viewed as the reduction in congestion costs when FACTS are used.

While FACTS can reduce the costs of congestion we need to economically analyse the benefits of FACTS against the investment cost. A benefit index for determining whether investment in FACTS is economical or not has been proposed. The benefit calculated as the difference between the CM costs without FACTS and with FACTS is a gross benefit[10]. The benefit index reflects the net benefits which are defined in [10] as the gross benefit minus the cost of FACTS. The benefit index also shows that installation of the FACTS in lines in the neighbourhood of the congestion may alleviate congestion.

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4 Optimal Re-dispatch and FACTS Application For Congestion Management: Bilateral and Hybrid Market Perspective

In this chapter, congestion management methodologies are incorporated in Bilateral and Hybrid market models respectively. The modified IEEE 14-bus system is used to illustrate the approaches.

4.1 Optimal Red-dispatch and FACTS Application for Congestion Management in Bilateral Market

4.1.1 Characteristics of a Bilateral Market

The conceptual model of a bilateral market structure shown in Figure 4-1 is that the amount of power, the time and duration of the service, and the associated price etc. are negotiated and agreed upon between the suppliers and consumers. The broker doesn't own the commodity in the bilateral market but acts as a middle man. The ISO in bilateral market is only responsible for system security management, congestion management and reliability aspects through monitoring the trades. Once the transactions are negotiated by the two transacting parties, they will be submitted to ISO who has to ensure the transactions don't endanger the system. In this project, the system load is considered as inelastic, in other words, no load could be curtailed during re-dispatch.

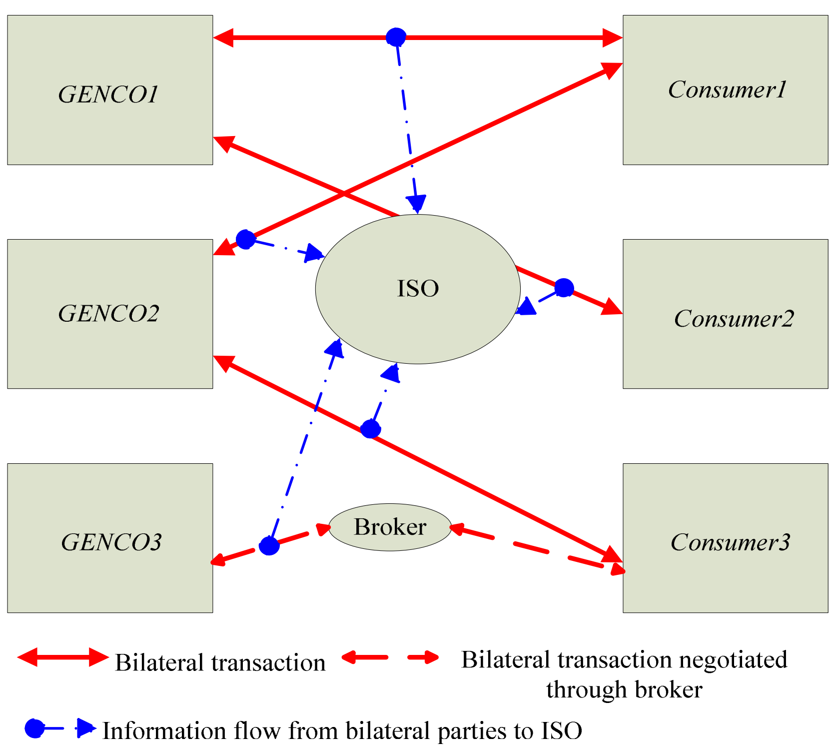

Figure 4-1 Bilateral market structure

Establishing the bilateral transaction matrix as proposed below is the first step of modeling a bilateral transaction matrix. The elements $T_{i,j}$ over a row define the bilateral contract of a generator i with all possible loads j. Similarly, the elements $T_{i,j}$ over a column identify the bilateral contract of a load j with all possible generators i.

$$T = \begin{bmatrix} T_{1,1} & T_{1,2} & \ldots\ldots & T_{1,n} \\ T_{2,1} & T_{2,2} & \ldots\ldots & T_{2,n} \\ \ldots. & \ldots. & \ldots\ldots & \ldots. \\ T_{n,1} & T_{n,2} & \ldots\ldots & T_{n,n} \end{bmatrix} \quad \textbf{(4-1)}$$

Due to the constraints of demand supply balance, the construction of the bilateral transaction matrix has to adhere to a set of intrinsic rules as follows:

$$\sum_i T_{i,j} = PD_j \quad \textbf{(4-2)}$$

$$P_i^{Min} \le \sum_j T_{i,j} = P_i^{SCH} \le P_i^{Max} \quad \textbf{(4-3)}$$

PD is the demand at bus j whilst P_i^{SCH} is the scheduled generation of the generator located at bus i. Equation (4-2) as an expression of the column rule indicates that for a fixed total system demand and a known load distribution PD_j, the sum of each column of T has to equal to the total load at bus j, in other words, a load has to purchase the exact amount of its consumption. Similarly, equation (4-3) as an expression of the row rule implies that the sum of each row of T should be equal to the scheduled generation at bus i which is within the upper and lower generation limit. That's to say, no supplier can sell more than he can produce.

In this project, two different objective functions are introduced. One of them is given in equation (4-4), the purpose of the optimal transmission dispatch is to minimize the deviations from transaction requests made by the market players. The goal is to acquire all ideal transactions without adjusts arising from operation constraints. The new set of the rescheduled transactions $T^{Allowable}$ thus obtained are supposed to be the closet to the set of desirable transaction.

Model 1: $$\min TRDIFF = \sum_{ij} (T_{i,j} - T_{i,j}^{Allowable})^2 \quad \textbf{(4-4)}$$

Where $T_{i,j}^{Allowable}$ is the allowable transaction decision variable determined by ISO after running a constrained OPF model

The other objective function is to minimize the congestion cost paid by ISO which is defined in equation (4-5). For up regulated generators, the ISO will pay for the up regulated power, on the contrary, the down regulated generators will be charged by ISO for the down regulated power.

Model 2: $$Congesion\_Cost = \sum_{i=1}^{NG} \left(\Delta P_i^+\right) * \rho^+ + \sum_{j=1}^{NG} \left(\Delta P_i^-\right) * \left(-\rho^-\right) \quad \textbf{(4-5)}$$

Where
ΔP_i^+, ΔP_j^+ is the up and down regulation by generator i and j respectively.

ρ^{+}, ρ^{-} are the up and down regulation prices, which is the based on the generation bids which have been demonstrated in Chapter 4

During the rescheduling of transactions under congestion conditions, any rescheduled transactions $T^{Allowable}$ should first be altered among the existing transactions. If only rescheduling of the existing transactions fails to alleviate the congestion, new transactions can be introduced in to contribute to manage the congestion.

The flow chart of congestion management incorporated into the bilateral market is illustrated below. In Figure 4-2, first of all, a transaction matrix is recognized which should assure the power balance; therefore a generation schedule could be generated. Based on the scheduled generation, a full ac power flow model is run to check the existence of congestion. If there is congestion, two constrained OPF models with different objective functions are carried out respectively for different purposes.

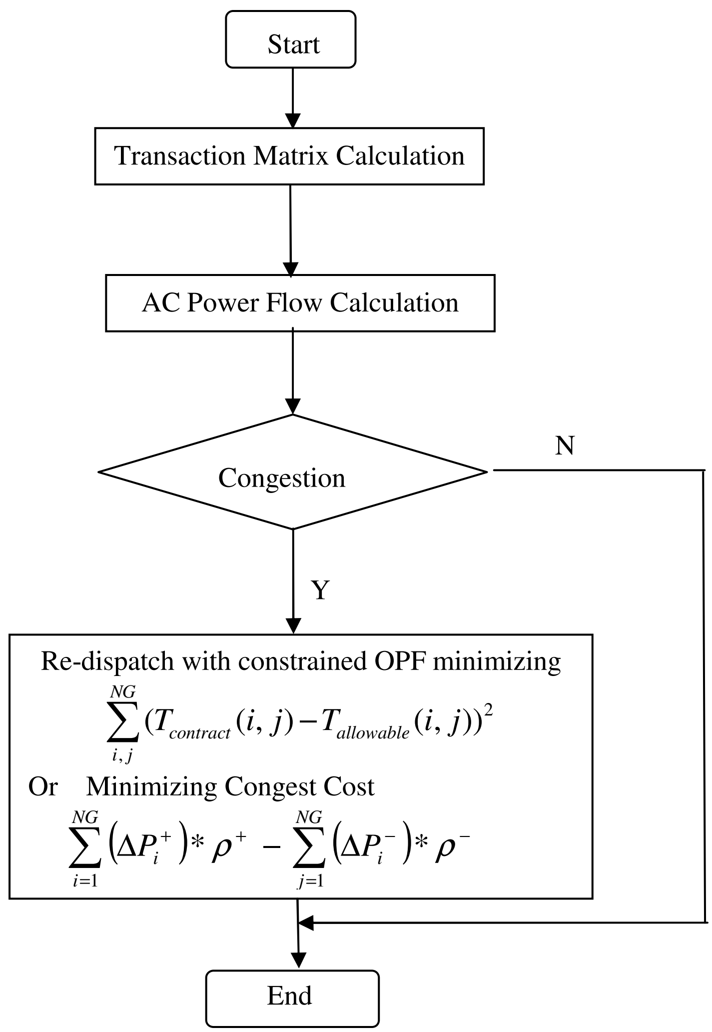

Figure 4-2 Flow chart for market operation in bilateral market

4.1.2 Congestion Management on IEEE 14-Bus System in Bilateral Market

Transaction Formulation

The construction of the system applied to the test of bilateral market model is identical to the one engaged in the test of pool market model. Not like the market settlement applied to pool market model, the unit commitment model is not incorporated in the bilateral model. Transmission losses are not taken into account when formulating the transactions. All third parties like brokers in this model are also ignored; therefore all transactions are restricted to the Gencos and consumers. The bilateral transaction matrix at hour eight of a day when peak load occurs is formulated at random as shown below. As expected, the elements of transaction matrix firmly satisfy the column rule and row rule.

Table 4-1 Bilateral transaction matrix at peak load hour 8

$T_{i,j}$ / Hour	8
1.3	0.369
1.4	0.478
1.5	0.076
1.6	0.112
1.9	0.295
1.10	0.090
1.11	0.035
1.12	0.061
1.13	0.135
1.14	0.149
2.2	0.117
2.3	0.573
3.2	0.100

After the bilateral transaction matrix is acquired, in other words the market is settled, the corresponding scheduling of generation is found.

Table 4-2 Accepted bids for the 14 bus, accounting for losses

Gen / Hour	8
1	1.800
2	0.690
3	0.100

Results of Load Flow

Once the transactions are proposed, the full ac load flow program is operated to check the feasibility of the scheduled transactions. The loading in percent of the line transfer capacity is given in table 3, from that it's easy to find out the locations of congestion. The solution shows that line 1-2 is the only congested line caused by the scheduled generation. While the bilateral transaction is generated erratically, the congestion is also supposed to take place at random. Nevertheless, as being discussed in the pool market model, some co inherent features of the system can also cause congestion. Although line 1-2 and line 1-5 have the transmission limit, they are not equally loaded due to the different line impedances.

Table 4-3 Line loadings from load flow with market schedule

Line	Loading %	Line	Loading %
1.2	140	2.4	62
1.5	59	2.5	49
2.3	73	3.4	18

Minimisation of absolute contract deviation

Re-dispatch is carried out by a constrained OPF model, in which the transmission limits as general constraints are taken into account. The object function is set as equation 3 to minimize the tariff. The new transaction matrix $T^{Allowable}$ is formed which has an overall minimum deviation from the scheduling transaction matrix T. Compared with the scheduling transaction, in order to relieve the congestion on line 1-2, all the contracts with generator 1 are reduced. Due to requirement of supply and demand balance, contracts with both generator 2 and generator 3 are increased to compensate the reduction on generator 1.

Table 4-4 $T^{Allowable}$ after re-dispatch in model 1

1.2	0.000	2.2	0.120	3.2	0.097
1.3	0.342	2.3	0.590	3.3	0.010
1.4	0.451	2.4	0.017	3.4	0.010
1.5	0.049	2.5	0.017	3.5	0.010
1.6	0.085	2.6	0.017	3.6	0.010
1.9	0.268	2.9	0.017	3.9	0.010
1.10	0.063	2.10	0.017	3.10	0.010
1.11	0.008	2.11	0.017	3.11	0.010
1.12	0.034	2.12	0.017	3.12	0.010
1.13	0.108	2.13	0.017	3.13	0.010
1.14	0.122	2.14	0.017	3.14	0.010

The results after re-dispatch are shown in Table 4-5 and Table 4-6 below. We observe that congestion disappears as generation reallocates. Line 1-2 is still the most serious loading transmission line; however, it is not overloaded after re-dispatch.

Table 4-5 Line loadings after re-dispatch in model 1

Line	Loading %	Line	Loading %
1.2	100	6.11	22
1.5	53	6.12	26
2.3	65	6.13	61
2.4	60	7.8	58
2.5	49	7.9	62
3.4	15	9.10	29
4.5	48	9.14	38
4.7	52	10.11	9
4.9	28	12.13	5
5.6	71	13.14	16

Table 4-6 Comparison of re-dispatch and scheduled generation in model 1

Generator	$P_{scheduled}$ (MW)	Actual (OPF) (MW)	Total absolute re-dispatch (MW)	Absolute Contract Deviation (MW)
1	180	152.5	63.1	55.6
2	69	94.6		
3	10	20		

Minimisation of congestion cost

The scheduled generation and resulting load flow accrued from transaction formulation for Objective function 2 are identical to the values calculated in Objective function 1 which are given in Table 4-2 and Table 4-3 respectively. Since the objective for model 2 is to minimize congestion cost, the results for loading after re-dispatch given below are completely different from that calculated in model 2; however, the congestion is also eliminated after re-dispatch.

Table 4-7 line-loading after re-dispatch for model 2

Line	Loading %	Line	Loading %
1.2	100	6.11	22
1.5	54	6.12	26
2.3	71	6.13	61
2.4	62	7.8	58
2.5	50	7.9	62
3.4	16	9.10	29
4.5	51	9.14	38
4.7	52	10.11	10
4.9	28	12.13	5
5.6	71	13.14	16

All the generators in the regulation market bid at the marginal costs. The regulation bids submitted by the GENCOs for hour eight are shown in Table 4-8 which is obtained by using the same strategy used in Pool Market. Table 4-9 shows the results of model 2. A congestion cost at 18,777$/hr is paid by the ISO using regulation market.

Table 4-8 regulation bids for hour 8

Up regulation		Down regulation	
Generator.block	Amount (p.u)	Generator.block	Amount(p.u)
1.3	1.20	1.1	1.00
2.2	0.51	1.2	0.75
2.3	0.30	1.3	0.05
3.2	0.05	2.1	0.20
3.3	0.05	2.2	0.49
		3.1	0.10

Table 4-9 results after re-dispatch for model 2

Generator	$P_{scheduled}$ (MW)	Actual (OPF)(MW)	Total absolute re-dispatch (MW)	Absolute Contract Deviation (MW)	Congestion Cost ($/hr)
1	180	153.6	61.4	55.2	18,777
2	69	104.0			
3	10	10.0			

4.1.3 Use of FACTS in Bilateral Market

TCPAR for minimisation of absolute contract deviation

As another efficient way to mitigate congestion, the Thyristor Controlled Phase Angle Regulator (TCPAR) is introduced in bilateral market model 1. After install one TCPAR on the most over-loaded line 1-2 in hour 8, it can be seen from Table 4-10 that the congestion can also be delimited through operating re-dispatch, although the loading on other lines has increased a bit compared with Table 4-5.

Table 4-10 line-loading with TCPAR installed on Line1-2

Line	Loading %	Line	Loading %
1.2	100	2.4	52
1.5	80	2.5	37
2.3	67	3.4	23

Table 4-11 shows the comparison of the results after TCPAR applied and scheduled generation. Compare with Table 4-6, both the contract deviation and the active power deviation in Table

4-11 are much smaller, in other words TCPAR is very helpful not only in congestion alleviation but also to minimize the transaction and power deviation. The regulation angle for TCPAR when inserted in line 1-2 is -5.3 degrees. The amount of absolute power generation deviation and contract deviation are reduced to 9.3 MW and 0.02W separately. It can be seen that the total absolute re-dispatched power is identical to the system losses which means the re-dispatch is carried out cover the system losses. Simultaneously, this explains the tiny transaction deviation since the re-scheduled transaction $T^{Allowable}$ is load independent.

Table 4-11 Results from Model 1 with FACTS

Generator	$P_{scheduled}$ (MW)	Actual with TCAPR (OPF)(MW)	Total absolute re-dispatch (MW)	Absolute Contract Deviation (MW)	System loss (MW)
1	180	180	9.30	0.02	9.30
2	69	78			
3	10	10			

A comparison of absolute transaction deviation over 24 hours between system with FACTS and without FACTS is illustrated in Figure 4-3. It can be seen that the absolute transaction deviation is very close to 0 over 24 hours due to the significant assistance of FACTS.

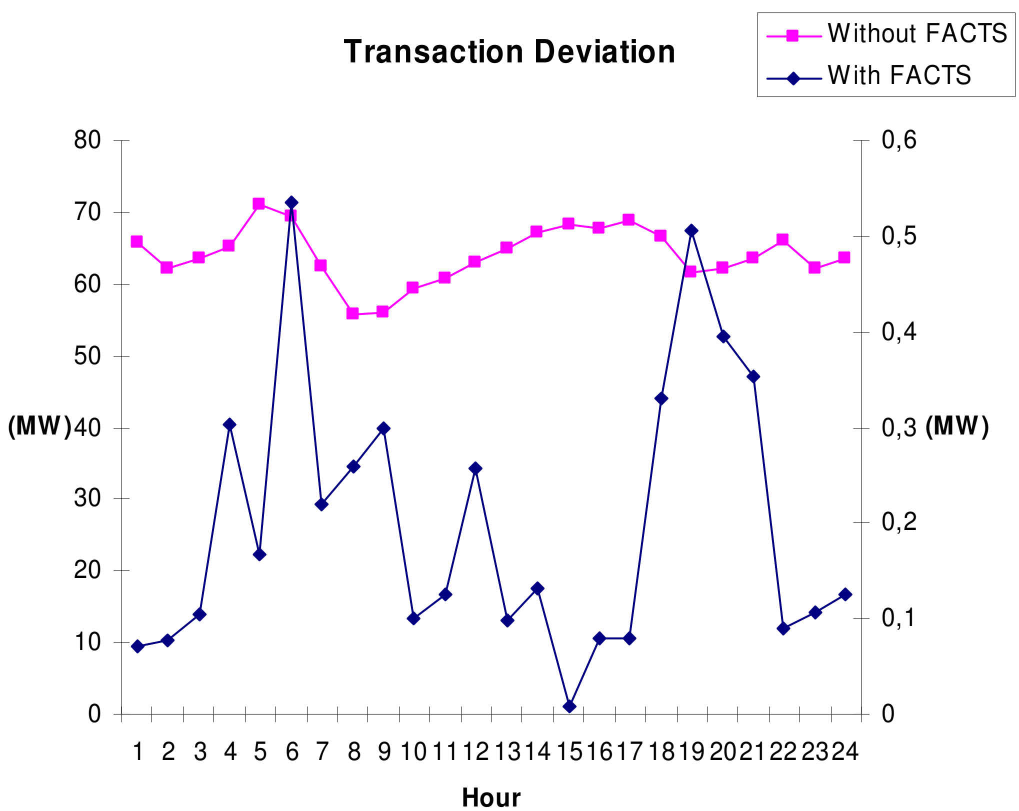

Figure 4-3 Comparison of Absolute Transaction Deviation between system with FACTS and without FACTS over 24 hours

TCPAR for minimisation of congestion cost

TCPAR is introduced in bilateral market model 2 and installed on line 1-2 in hour 8. When the regulation angle of TCPAR is adjusted to -7.97 degrees, the lowest congestion cost is achieved. The details of the results are given in Table 4-12 as following.

Table 4-12 Results from Model 1 with FACTS

Generator	$P_{scheduled}$ (MW)	Actual with TCAPR (OPF)(MW)	Total absolute re-dispatch (MW)	Absolute Contract Deviation (MW)	System cost before re-dispatch ($/hr)	Congestion Cost ($/hr)
1	180	194.9				
2	69	55.7	39.7	29.7	105,111	3,867
3	10	15.0				

From Table 4-12, it can be found that the congestion cost as well as the contract deviation is hugely reduced. In Figure 4-4, the comparison of congestion cost between with and without FACTS is illustrated over 24 hours. The benefit incurred by bringing FACTS devices into congestion management is significant in bilateral market.

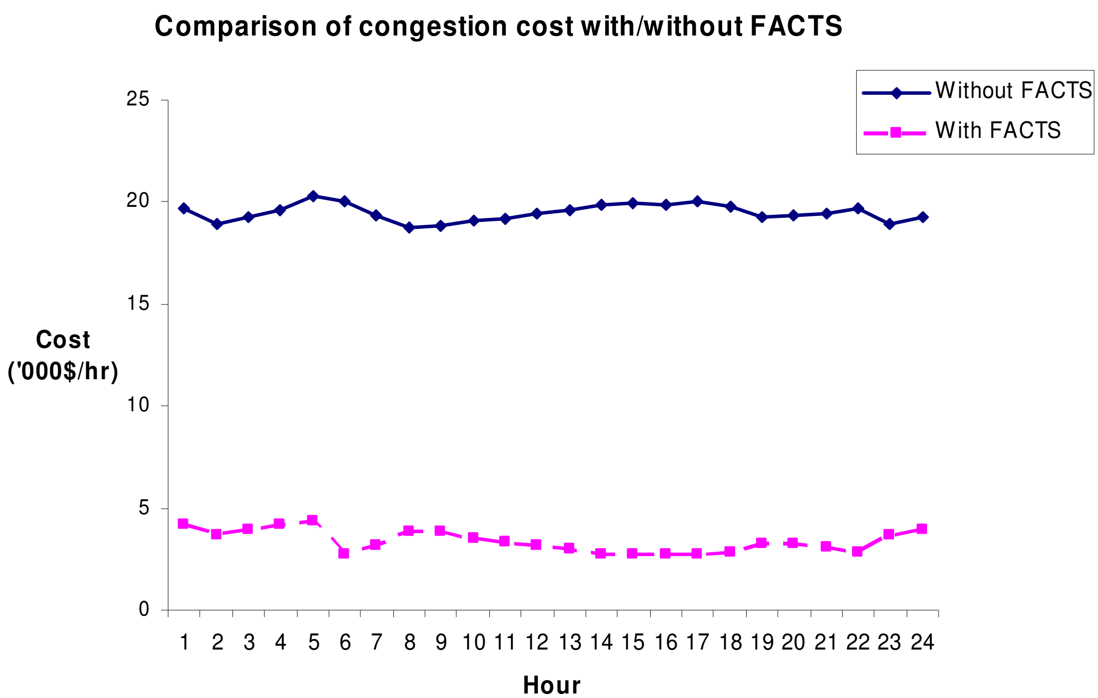

Figure 4-4 Comparison of Congestion cost between system with FACTS and without FACTS over 24 hours

4.2 Optimal Red-dispatch and FACTS Application for CM in Bilateral Market

4.2.1 Characteristics of a Hybrid Market

The hybrid market is a two part market comprising of the pool load and generation and the bilateral transactions. It may also be described as a mixed pool/bilateral market [1]. This market model brings into play other entities in the market apart from the ISO, GENCO and DISCO and end user customers found in the pool. Other entities include RETAILCOs, aggregators, brokers, marketers, and customers. A RETAILCO obtains legal approval to sell retail electricity. A RETAILCO takes title to the available electric power and resells it in the retail customer market. The retailer may combine electricity products and services in various packages for sail. A retailer may also deal indirectly with customers through aggregators. An aggregator may be formed from a group of customers who are then able to negotiate cheaper prices since they buy in bulk. At times the aggregator may be a negotiator or agent representing many customers. A broker is a middleman who facilitates transactions between buyers and sellers; it does not buy power or indeed sell power. A marketer is a firm that buys and re-sells electric power but does not own generating facilities.[2] A marketer acts as a wholesaler and may handle both marketing and retailing functions. These entities detailed here are operative in a bilateral market as well. A customer therefore has a choice whether to buy power from the pool at the spot price or to negotiate with a GENCO through a broker. A group of customers can also form a group so that they increase there negotiating power. The customer can also buy power through a retailer who may have attractive incentives such as post payment, off peak usage tariffs etc. A GENCO also has the choice of whether to sell its power through bilateral contracts to a marketer or a retailer or to the spot market.

The Nord pool electricity market is of this form. It allows the coexistence of the bilateral model and the pool model. This market is illustrated in Figure 4-5.

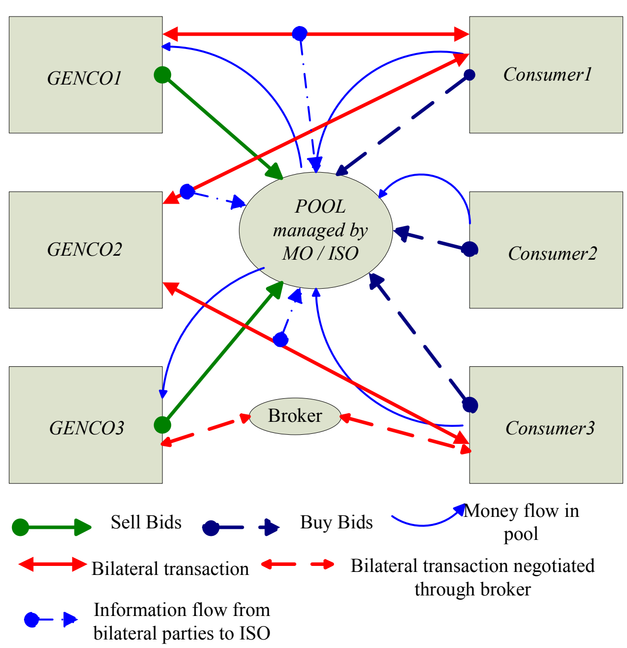

Figure 4-5 An illustration of the hybrid market

In this market the load at bus j is made up of two components viz. bilateral contracts and pool demand. The load can therefore be expressed as:

$$P_{dj} = P_{dj}^{p} + P_{dj}^{b} \tag{4-6}$$

As earlier explained in the bilateral market, the bilateral component of the load at bus j can be expressed as the sum of its bilateral contracts with the supplying generators as:

$$P_{dj}^{b} = \sum_{i=1}^{NG} T_{ij} \tag{4-7}$$

Where T_{ij} is a contract between generator i and load bus j. The pool load is then

$$P_{dj}^{p} = P_{dj} - \sum_{i=1}^{NG} Tij \tag{4-8}$$

The proportion of the pool load to the bilateral transaction load is determined by using a random number generator so that the proportion is different at the different buses. We however ensure that the resulting hybrid market is dominated by the bilateral transactions as is the case in the Swedish power market. [3]

$$P_{dj}^{p} = \tau P_{dj} \tag{4-9}$$

Where $\tau = random(0,\ 0.65)$

After determination of the pool and contract loads we generate the transaction matrix as explained in the chapter on bilateral market. In formulating the transaction matrix we also ensure that

$$P_{i}^{b} = \sum_{j}^{NL} T_{ij} \tag{4-10}$$

And that

$$P_{i}^{\max} \leq P_{i}^{b} \leq P_{i}^{Min} \tag{4-11}$$

P_{i}^{b} is the scheduled bilateral generation by generator i. The resulting matrix for hour eight is given in appendix A1.

In settling the pool market we have to make an assumption concerning the submitted bids to the pool. We assume that since the bilateral transactions are priority the pool will receive the balance of the power from a GENCO and hence the submitted bids will be more expensive. In other words the bilateral transactions use up the cheaper energy blocks and the pool takes the balance. We determine for each generator the bids that are available for the pool. Since we know that the energy bids from the pool market are based on the marginal cost we can easily work out the new bids for the pool part of the hybrid market.

Table 4-13 Submitted bids for pool for the 14 bus system.

Generator.block No.	Size(p.u.)
1.2	0.350
1.3	1.25
2.2	0.939
2.3	0.300
3.2	0.050
3.3	0.050

Table 4-13 shows the bids from the GENCOs for the pool market part of the hybrid market for hour eight. Blocks that are not shown have been used up in the bilateral part of the market. In the bilateral part of the market generator 1 is scheduled to produce 1.4p.u and thus has used up its block 1 bid and part of the block 2 bid. It therefore submits the balance given in Table 4-13. Similarly generator 2 is scheduled for 0.261p.u in the bilateral part of the market and therefore has used up its first block and part of the second block. Generator 2 therefore submits the balance as given in Table 4-13 to the pool part of the market. Generator 3 has used up its first block in the bilateral market and therefore only submits the last two blocks to the pool market.

The pricing for the submitted bids are as given in Table 3-3. The market is then settled as an optimisation problem with the objective function being minimisation of the cost. The same equations for market settlement for the pure pool market apply in the pool part of the market for the hybrid.

The resulting generation schedule for the pool is such that generator 1 will produce 82.9 MW and generators 2 and 3 will not take part in the trade since their bids are more expensive. This is obvious since the pool load for the system is 82.9MW and this has to come from the cheapest submitted bids. Generator 1 has the cheapest submitted bids. Generator 1 therefore uses up the whole balance of the second block and part of the third block. The resulting price is the marginal cost of the third block i.e. $608.5/MWh.

Table 4-14 Generation schedule for the combined market

Generator	Pool-part	Bilateral-part	Combined Schedule
1	0.829	1.400	2.229
2	0.00	0.261	0.261
3	0.00	0.100	0.100

The intentions of the bilateral parties i.e. volumes of power to be traded in each transaction are made known to the ISO. The ISO has no role in the bilateral transaction agreements between GENCOs and buyers. The system scheduled generation can now be compiled as in Table 4-14. The feasibility of the market settlement and the bilateral transactions are then checked by running a load flow. If congestion exists system re-dispatch has to be carried out. The objective function of the re-dispatch is to minimise the deviations of the contracts and of the pool scheduled generation. The bilateral contracts take precedence over the pool market. The weighting of the deviations in the combined objective function reflect this. The objective function is written as:

$$\min, J = \sqrt{\gamma \sum_{i=1}^{NG} \sum_{j=1}^{NL} \left(T_{ij} - T_{ij}^{allowable}\right) + \sum_{i}^{NG} \left(P_i^{p} - P_i^{pactual}\right)^2} \tag{4-12}$$

where $T_{ij}^{allowable}$ is the actual allowable transaction between generator i and load bus j under the conditions of congestion,

P_i^{p} is the scheduled pool generation for generator i,

$P_i^{pactual}$ is the actual pool generation under congestion for generator i and γ is the weighting factor. The objective function is subject to the following constraints:

$S_{ij}^{\max} \geq abs\left(S_{ij}\right)$ the line capacity rating in MVA,

$V_i^{\min} \leq V_i \leq V_i^{\max}$ system voltage limits,

$P_i^{\min} \leq \left(\sum_{j}^{NL} T_{ij}^{allowable} + P_i^{pactual}\right) \leq P_i^{\max}$ generator active upper and lower limits

$Q_i^{\min} \leq Q_{gi} \leq Q_i^{\max}$ generator reactive power limits,

$0 \leq \sum_{i}^{NG} T_{ij}^{allowable} \leq P_{dj}$ and at every bus,

$P_i - P_{di} - \sum_{j=1}^{NB} P_{ij}(\theta) = 0$ active power balance at every bus,

$Q_{g\,i} - Q_{di} - \sum_{j=1}^{NB} Q_{ij}(\theta) = 0$ reactive power balance and the two port equations.

The system losses are lumped on the pool part of the market [1].
The flow chart for the hybrid market is shown in Figure 4-6.

The weighting factor can be viewed as the relative importance of the bilateral market to the pool market. These bilateral markets would normally be long term contracts between GENCOS and some important loads. Each bilateral contract is viewed as the same i.e. they will have equal weighting. When gamma is too large the problem may become impossible to solve meaning that the pool re-dispatch alone is not able to clear the congestion and the transactions need to be curtailed.

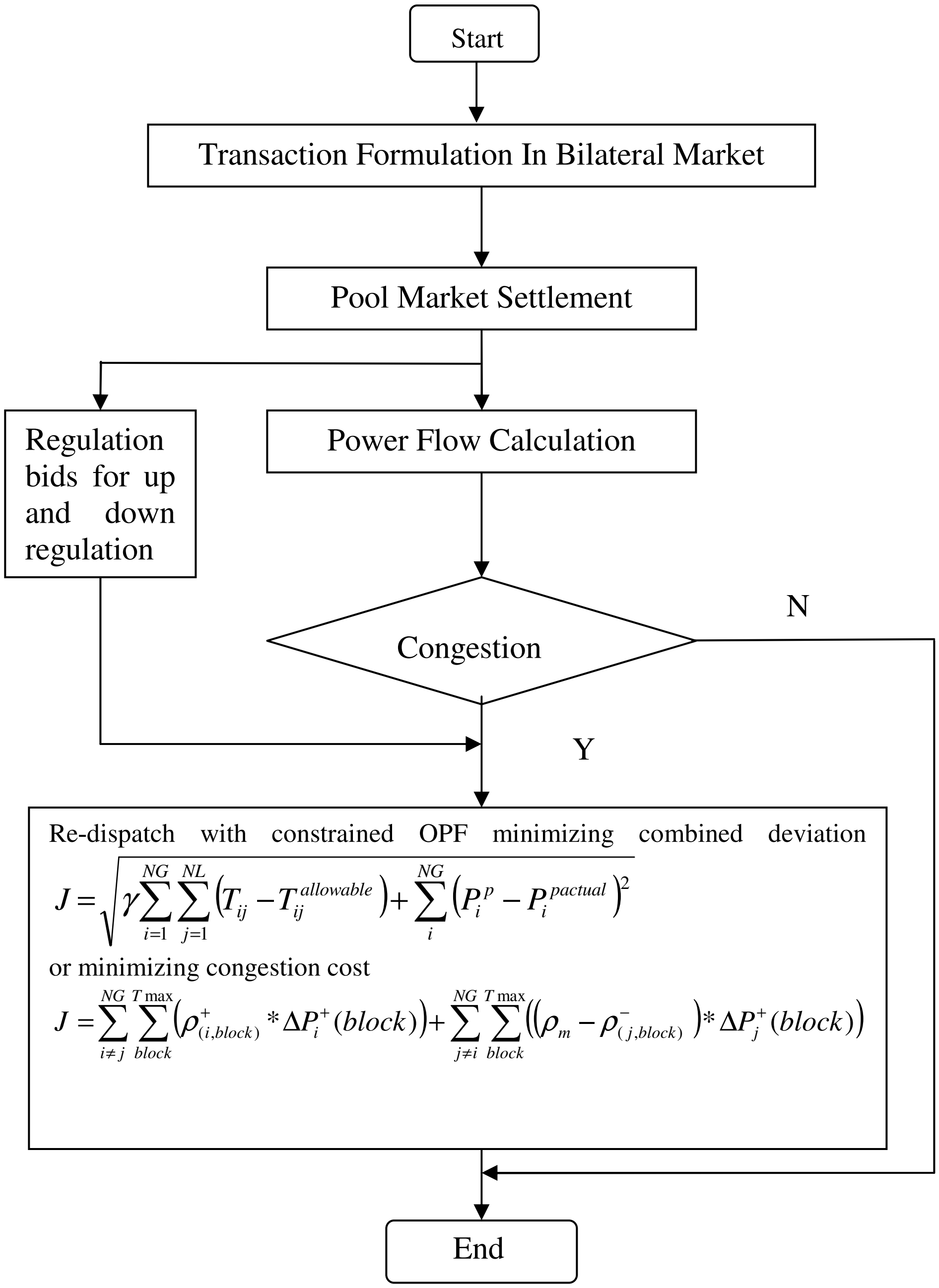

Figure 4-6 Flow Chart for Hybrid Market Simulation

4.2.2 Congestion Management on IEEE 14-Bus System in Hybrid Market

Results of Load Flow

Using the scheduled generation in Table 4-14 the resulting line loadings for selected lines are shown in Table 4-15. Generator 1 is taken as the slack. All other network constraints are observed except for the transmission line capacity limits.

Table 4-15 Line loadings for 14 bus from load flow using system generation schedule

Line	Loading %	Line	Loading %
1.2	174	2.4	59
1.5	62	3.4	17
2.3	70	2.5	47

We observe that corridor 1.2 is congested. The ISO will not allow this scenario since it compromises the security of the network. The congestion occurs because lines 1.2 and 1.5 cannot be equally loaded due to the differences in their impedances. When no power flow control devices are installed the flow of power between circuits is in inverse proportion to their impedances. The generation needs to be re-dispatched in such a way that congestion is cleared.

Minimisation of absolute contract and pool generation deviations

In alleviating the congestion generator 1 is down regulated until the loading of line 1.2 reaches its rated capacity. Generator 2 is up regulated to balance the increase in generator 1 output. Since generator 3 was scheduled at its upper limit no action is taken in re-dispatch.

Table 4-16 Re-scheduled generation and the total absolute deviations in contracts and the scheduled pool generation for 14 bus system

Generator		$\gamma = 10$		$\gamma = 100$	
	Actual generation	$\sum_{j=1}^{NB}\sum_{i=1}^{NG} abs(\Delta T_{ij})$	$\sum_{i=1}^{NG} abs(\Delta P_i^p)$	$\sum_{j=1}^{NB}\sum_{i=1}^{NG} abs(\Delta T_{ij})$	$\sum_{i=1}^{NG} abs(\Delta P_i^p)$
1	1.525				
2	0.945	0.75	0.74	0.14	1.35
3	0.200				

The proportions of the re-dispatched power i.e. between the pool and the contracts can be varied by changing the weighting factor as illustrated in Table 4-16. We note, as expected, that by increasing the weighting factor to 100 from 10 the amount of re-dispatch for the contracts reduces significantly and that of the rescheduled pool generation increases but the total re-dispatched power remains the same.

Minimisation of congestion cost

When the re-dispatch objective function is changed to minimisation of the congestion cost the regulation blocks and their prices are taken into account. The objective function is formulated as:

$$\min, J = \sum_{i \neq j}^{NG} \sum_{block}^{T\max} \left(\rho_{i,block}^{+} * \Delta P_i^{+}(block)\right) + \sum_{j \neq i}^{NG} \sum_{block}^{T\max} \left(\left(\rho_m - \rho^{-}(j, block)\right) * \Delta P_j^{+}(block)\right) \tag{4-13}$$

Equation (4-13) is used as a proxy for the actual net payment by ISO for regulation power as earlier explained in the pool market chapter. The regulation market in the hybrid model market operates exactly in the same way as the regulation market in the pool. When we minimise the cost of re-dispatch in the hybrid market the contracts no longer matter. A generator which has its generation curtailed will have its load served by an up-regulated generator. With the schedule of Table 4-14 we try to re-dispatch generation to clear congestion but the objective is to minimise the cost of congestion. The load flow results are the same as given in Table 4-15. The results for the re-dispatch for hour eight are shown in Table 4-17.

Table 4-17 Minimisation of congestion cost in hybrid market

Generator	Schedule	Re-dispatch	Congestion cost
1	2.229	1.536	
2	0.261	1.04	$82,883
3	0.100	0.100	

We observe that in the minimisation of congestion cost only generator 2 is up regulated and generator 1 is down regulated. Because the regulation bids for generator 3 are more expensive than those of generator 2 it is excluded in the eighth hour trade for the regulation market. If we compare the re-dispatched schedule for the minimisation of absolute re-dispatch as in Table 4-16 and for the minimisation of congestion cost as in Table 4-17, we see that in the former case both generators 2 and 3 have been up regulated. The minimisation of re-dispatch does not take into account the cost of the regulation power.

4.2.3 Use of FACTS in Hybrid Market

TCSC for minimisation of absolute deviations of contracts and pool generation

The results of the load flow indicate that if we could force more power to flow in line 1.5 then we could alleviate congestion to some degree and the re-dispatch can be reduced. We therefore test the 14 bus by inserting a TCSC with a compensation value of 70% on line 1.5. With the same schedule of generation as in Table 4-14 we run a load flow of the system with the TCSC in line 1.5. The optimal location of the TCSC is done in the same way as described in section 4.5. The resulting line loadings are shown in Table 4-18.

Table 4-18 Load flow results, selected line loadings with TCSC in line 1.5

Line	Loading %	Line	Loading %
1.2	132	2.4	44
1.5	106	3.4	25
2.3	63	2.5	27

The congestion in line 1.2 has reduced drastically from 174 to 132% while that of line 1.5 has increased from 62 to 106%. Clearly this scenario though not acceptable is better than the case without the TCSC. The amount of generation re-dispatch required to clear the congestion is much lower than in the original case. The objective function in the re-dispatch in presence of the

TCSC remains the same as given (4-13. In addition to the constraints already cited for the objective function we also include the constraints for the TCSC:

$0 \leq Xt\,\mathrm{csc}(i, j) \leq f$ where f is the maximum compensation level.

The results of the new re-dispatch are given in Table 4-19.

Table 4-19 Re-scheduled generation and the total absolute deviations in contracts and pool generation for 14 bus system with TCSC inserted in line 1.5

Generator		$\gamma = 10$		$\gamma = 100$	
	Actual generation	$\sum_{j=1}^{NB}\sum_{i=1}^{NG} abs(\Delta T_{ij})$	$\sum_{i=1}^{NG} abs(\Delta P_i^p)$	$\sum_{j=1}^{NB}\sum_{i=1}^{NG} abs(\Delta T_{ij})$	$\sum_{i=1}^{NG} abs(\Delta P_i^p)$
1	2.000				
2	0.497	0.29	0.27	0.05	0.51
3	0.200				

The line loadings resulting from the above re-dispatch are such that both lines 1.5 and 1.2 are loaded to their full capacity! With the TCSC we have been able to equally load line 1.5 and line 1.2. Line 1.5 is seen by the system as having smaller impedance than before hence more power flows through it. When we compare Table 4-16 and Table 4-19 we observe that the deviations from the bilateral contracts are much lower in the case with TCSC. The deviation in the pool generation also experiences a similar result. The TCSC thus has helped to keep the bilateral transactions closer to their schedules than in the case without the TCSC. The pool part of the market has also resulted in less pool re-dispatch. Figure 4-7shows the variation of the deviations of the contracts and the pool generation for a case with FACTS and the other without FACTS. Both cases are for minimisation of deviations and the weighting factor used is one hundred. From appendix A1 and appendix A2 we can see that the allowable contracts under congestion are closer to the scheduled market agreements when we use FACTS even when the weighting factor is set to 10.

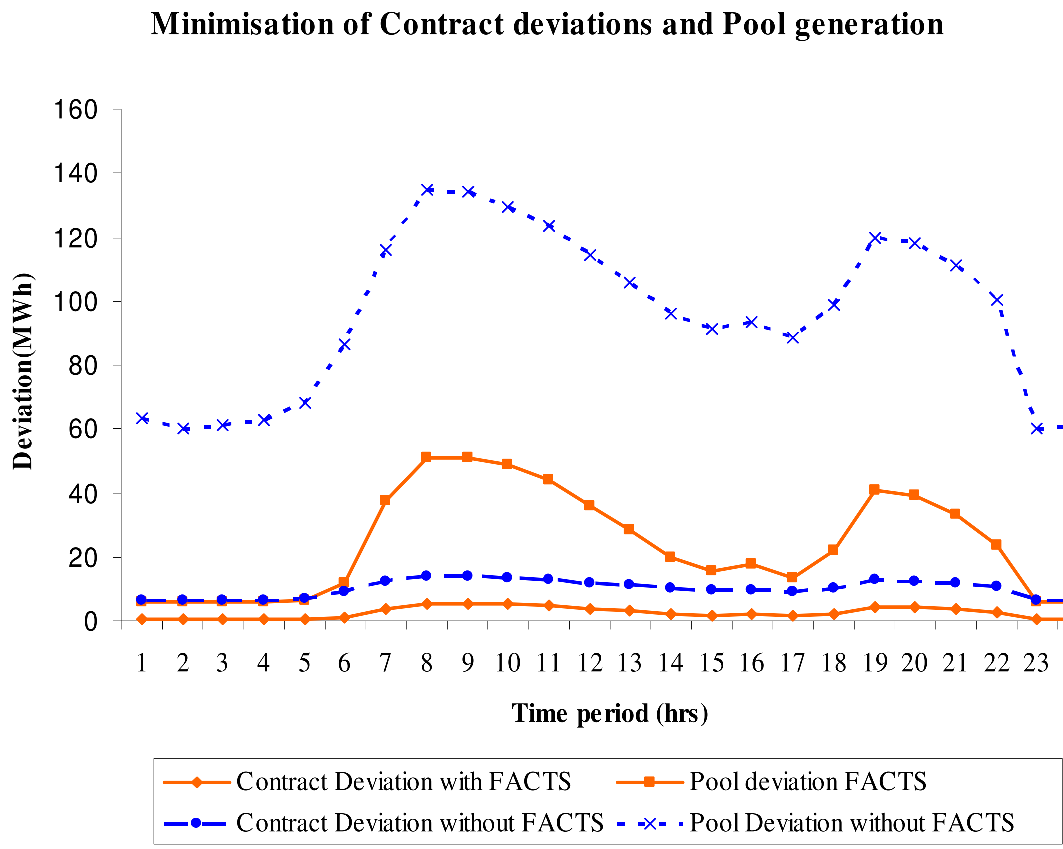

Figure 4-7 Minimisation of Contract Deviations and Pool re-dispatch: With and without FACTS

4.2.4 TCSC for minimisation of cost of congestion

Since the TCSC can help in controlling the power flow as illustrated above and has reduced the amount of re-dispatched power it is expected that the congestion cost can be reduced as well. The objective function is again formulated as in equation (4-13) but we include the constraint for the TCSC i.e. $0 \le Xt\csc(i, j) \le f$ where f is the maximum compensation level. The results for the re-dispatch for hour eight are shown in Table 4-20 below.

Table 4-20 Re-scheduled generation for the case of minimising cost of congestion for 14 bus system with TCSC inserted in line 1.5

Generator	Schedule	Re-dispatch	Congestion cost
1	2.229	1.999	
2	0.261	0.5455	$28,422
3	0.100	0.1500	

The congestion cost has been reduced significantly with the use of the FACTS in line 1.5. When the results for the re-dispatch are analysed for the whole 24 hours we notice that with FACTS in the network we do not have congestion in the first 5 hours. The congestion cost shown for these hours is simply the cost of power to cover losses as the losses are not taken into account when settling the market. Figure 4-8 shows the variation of the congestion cost over a 24 hour period for the cases of with FACTS and without FACTS.

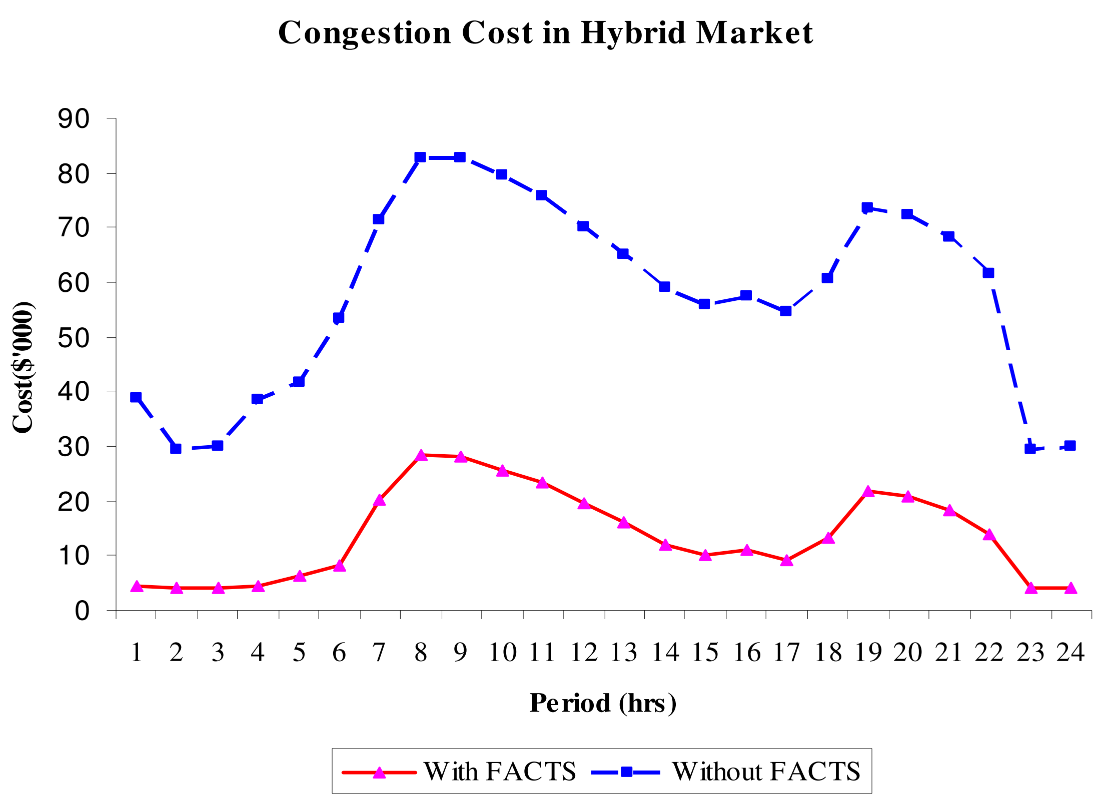

Figure 4-8 Minimisation of congestion cost: With FACTS and Without FACTS

The installation of a TCPAR will give similar results as the TCSC and will therefore not be investigated in the hybrid market.

4.3 Conclusion

Under a deregulated power market, all parties will be permitted to set up various bilateral contracts. The transmission company is only responsible for execute these contracts as far as operating conditionally permit. After the transaction is proposed, the ISO has to check for its feasibility, any incurred congestion requires remedies being carried out. In order to meet different requirements, different objective function, like minimizing contract deviation and minimizing congestion cost, are integrated in the bilateral market models separately. In both models, re-dispatch as a first considered remedy is incorporated in bilateral market model and manages to alleviate the congestion as expected.

In the hybrid market the load buses can accommodate both contract loads and pool loads and similarly generation can be apportioned to the contracts and the pool. So far we have assumed that that the cheaper power of a generator is sold via contracts and the balance is what is floated on the pool. This is a logical deduction since a buyer would have no incentive to buy under contract if the situation was otherwise. As in other market types already analysed in this thesis, the ISO has to ensure that the final generation schedule i.e. that of bilateral transactions and the pool market settlement is feasible. In case of congestion, re-dispatch is carried out in such a way that the bilateral transactions are given priority over the pool scheduled generation. In modelling this, a combined objective function (also called multi variable objective function) which is to minimise the absolute re-dispatch of the pool market and of the bilateral transactions with the appropriate weighting is introduced. When the objective function of the OPF in the re-dispatch is the minimisation of congestion cost, the schedule of re-dispatched generation depends on the prices of regulation bids.

Compare to re-dispatch, installing FACTS devices on certain locations in either Bilateral or Hybrid market is more effective in congestion management. In Bilateral market, the contracts incurred after market re-dispatch are more or less the same as the scheduled contracts therefore is highly appreciated by both suppliers and customers. The congestion cost is also reduced vastly after mounting FACTS devices. In Hybrid market, the use of FACTS devices can alleviate congestion and therefore reduce the amount of re-dispatch and consequently the cost of congestion is reduced.

If congestion is persistent, the ISO is faced with the possibility of constructing a new line, upgrading the existing congested line or installing a FACT device. To make a decision as to which option to adopt is an economic problem [4].

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5 Results from the 32-Bus Test System

In this chapter, the models developed in the preceding chapters are tested on the Cigre 32-bus test system. The main results are presented for the pool and hybrid market models. The re-dispatch objectives have remained the same as in the 14-bus test case.

5.1 Pool Market

The Cigre Nordic 32-bus test network has 32 buses and comprises of nineteen generators and twenty one loads. The system can be divided into 4 main areas:

- *North:* mostly consists of hydro power plants and some load centers.
- *Central*: consists of a large amount of load and large thermal power plants
- *Southwest*: consists of some thermal power plants and some load
- *External*: connects to the North, it has a mix of generation and load

The bus #4011 is considered as the slack bus. The main power transfer is from "north" to "central". The main transmission system is designed for 400 kV. There are also regional systems at the voltage levels of 220 kV and 130 kV . A single line diagram of the same is shown in F below.

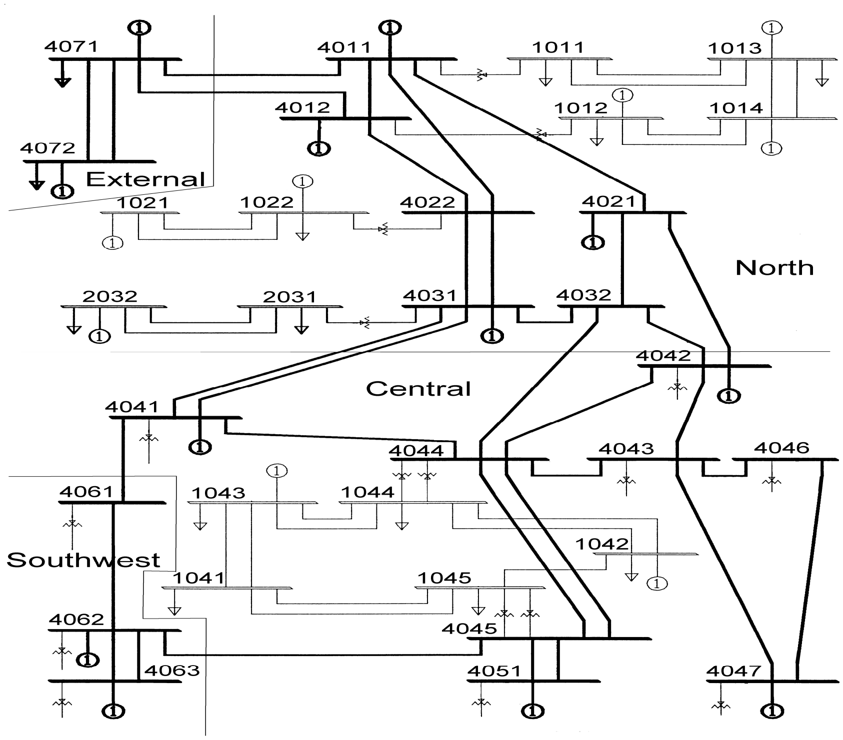

Figure 5-1 The Cigre Nordic 32-bus Test system

5.1.1 Market settlement

The modified cost characteristics of the generators are given in Table 5-1 below:

Table 5-1 Generator characteristics for 32 bus test case

Generator	Pmax	a	b	c			a	b	c
4072	4500	0.001	0.552	0.1	4051	700	0.00025	0.052	0.1
4071	500	0.001	0.552	0.2	4047	1200	0.001	0.052	0.3
4011	1000	0.001	0.052	0.9	2032	850	0.001	0.052	0.4
4012	800	0.001	0.052	0.3	1013	600	0.0005	0.872	0.3
4021	300	0.001	0.054	0.3	1012	800	0.001	0.052	0.9
4031	350	0.001	0.752	0.1	1014	700	0.001	0.052	0.3
4042	700	0.001	0.052	0.3	1022	250	0.001	0.252	0.3
4041	300	0.001	0.062	0.2	1021	600	0.001	0.062	0.6
4062	600	0.001	0.752	0.3	1043	200	0.001	0.032	0.6
4063	1200	0.001	0.052	0.5	1042	400	0.001	0.652	0.3

The cost curve is quadratic. The generators do not have a minimum generation requirement hence lower limit for all generators is zero. The total peak load for this system is 10940MW. The load scaling factor used for the different hours is the same as given in Table (3-6).

The line data and transfer limits as used in this thesis are given in the appendix B1. Each generator is allowed up to three bid blocks in this simulation. The ideal situation is to have the bid blocks as small in size as possible. When the bid blocks are large, the price is higher and hence smaller generators are likely to be preferred in the market settlement. The limitation of three blocks per generator is imposed by the GAMS program. The submitted bid blocks and the accompanying price are given in the Table 5-2 below.

Table 5-2 Submitted bids for 32 bus test case

i,t (generator. block number)	Block size (MW)	Unit Price	i,t (generator no. block number)	Block size (MW)	Unit Price
4072.1	1000	50.552	4012.1	500	50.052
4072.2	1250	113.052	4012.2	200	70.052
4072.3	2250	225.552	4012.3	100	80.052
4071.1	175	35.552	4021.1	100	20.054
4071.2	225	80.552	4021.2	200	60.054
4071.3	100	100.552	4031.1	200	40.752
4011.1	200	40.052	4031.2	150	70.752
4011.2	300	100.052	4063.1	400	80.052
4011.3	500	200.052	4063.2	500	180.052
2032.1	150	30.052	4063.3	300	240.052
2032.2	300	90.052	4051.1	300	60.052

i,t (generator. block number)	Block size (MW)	Unit Price	i,t (generator no. block number)	Block size (MW)	Unit Price
2032.3	400	170.052	4051.2	150	90.052
4042.1	200	40.052	4051.3	250	140.052
4042.2	400	120.052	4047.1	200	40.052
4042.3	100	140.052	4047.2	300	100.052
4041.1	300	60.062	4047.3	700	240.052
4062.1	100	20.752	1022.1	250	50.252
4062.2	200	60.752	1021.1	250	50.062
4062.3	300	120.752	1021.2	100	70.062
1013.1	200	40.872	1021.3	250	120.062
1013.2	150	70.872	1043.1	200	40.032
1013.3	250	120.872	1042.1	100	20.652
1012.1	300	60.052	1042.2	150	50.652
1012.2	300	120.052	1042.3	150	80.652
1012.3	200	160.052	1014.2	250	80.052
1014.1	150	30.052	1014.3	200	120.052

The submitted bids arranged in increasing order of price for the determination of market price is shown in Figure 5-2.

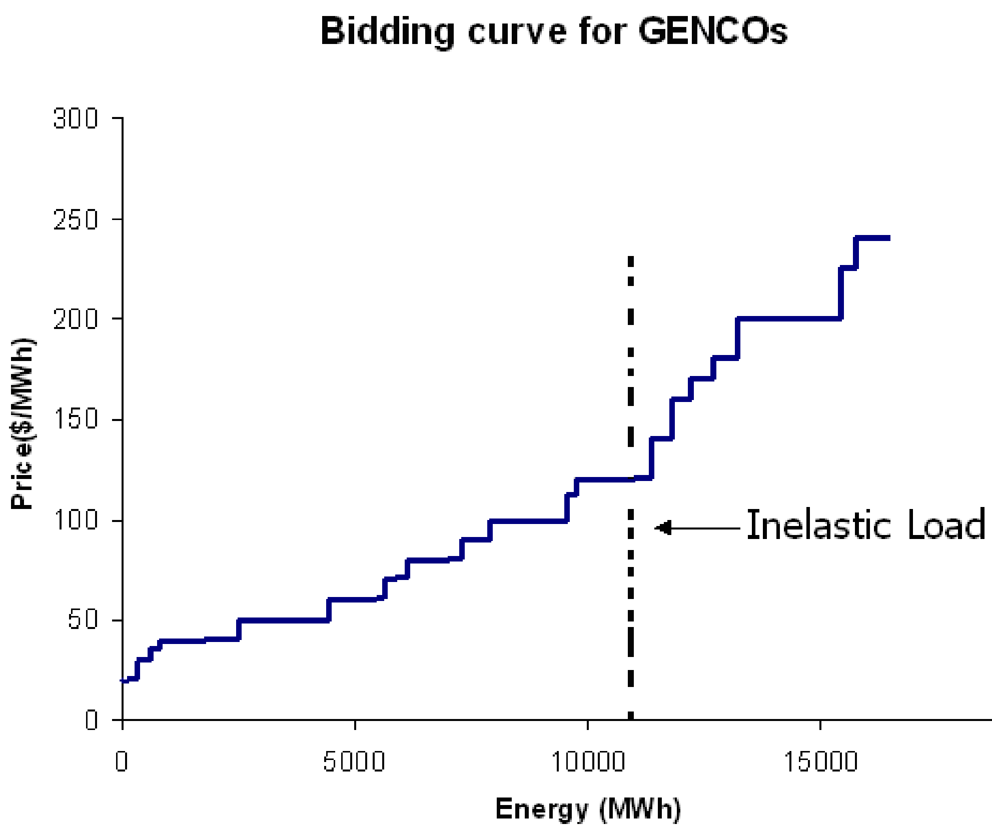

Figure 5-2 Staircase bidding curves for GENCOs and the load at hour eight.

The price of the bid blocks are calculated using (3-3). The market is settled in the same way as in the 14 bus test case. In the 32 bus system we do not consider shut down and start up costs and losses. The resulting market schedule over a twenty four hour period in the pool model is given in the appendix B2. The schedule for hour eight is reproduced here in Table 5-3 for convenience.

Table 5-3 generation schedule for hour eight.

Generator	Schedule(p.u)	Generator	Schedule(p.u)
4072	22.5	4051	4.5
4071	5.0	4047	5.0
4011	5.0	2032	4.5
4012	8.0	1013	3.5
4021	3.0	1012	6.0
4031	3.5	1014	6.0
4042	6.0	1022	2.5
4041	3.0	1021	6.0
4062	5.4	1043	2.0
4063	4.0	1042	4.0

The market clearing price is the price of the most expensive bid accepted in settling the market. The most expensive bid accepted is that of generator 4062's third block priced at \$120.752/MWh and becomes the market spot price.

After the settlement of the market the GENCO's are allowed to bid for regulation power. This includes both the up and down regulation. The GENCOs may use the already submitted bids without any adjustments or may adjust their bids. In this simulation we assume perfect competition hence the guiding principle for pricing is the marginal costs of the GENCO. In our case then the GENCOs submit their earlier rejected bids for up regulation and the earlier accepted bids for down regulation. Naturally if a GENCO had all its bids rejected in the pool market it cannot submit bids for down regulation. The bidding curve for regulation power will look like Figure 5-2 but the interpretation is thus: All bids to the right of the load line are for up regulation and all bids to the left are for down regulation.

5.1.2 Loadflow

As in the case of the 14 bus after the market settlement a loadflow is carried out to check for any possible violations. Since we are using a DC load flow we only check for congestion on lines. Without any FACTS installed the line violations are observed on the lines shown in Table 5-4 below.

Table 5-4 Congested lines for market generation schedule for hour eight

Line	Loading(%)
4021.4011	105
4022.4031	123
4032.4031	113
4043.4042	106

Since we have congested lines the ISO will have to order a re-dispatch of generation. As discussed in the 14 bus test case an OPF is carried out. The objective of the OPF can either be to minimise the amount of re-dispatch or to minimise costs. Both objective functions are used in turn.

5.1.3 Minimisation of Re-dispatch

The re-dispatch is realised by carrying out an OPF whose objective function is to minimise the total amount of re-dispatched power. The objective function is formulated by (3-16). The new schedule of generation after re-dispatch is given in Table 5-5 . The figures in bold indicate generation that has been re-dispatched.

Table 5-5 Generation schedule for 32 bus test case after re-dispatch

Generator	New Schedule(p.u)	Generator	New Schedule(p.u)
4072	22.5	4051	4.5
4071	5.0	4047	5.0
4011	5.0	2032	**4.8**
4012	8.0	1013	3.5
4021	3.0	1012	6.0
4031	3.5	1014	6.0
4042	6.0	1022	**0.0**
4041	3.0	1021	**3.3**
4062	5.4	1043	2.0
4063	**8.9**	1042	4.0

In order to clear the congestion generators 4063 and 2032 are up regulated while 1021 and 1022 are down regulated. As expected the violations in Table 5-4 are all cleared with the above schedule.

The resulting congestion cost for hour eight is given in Table 5-6.

Table 5-6 Costing of re-dispatch for hour eight.

Total amount re-dispatched(p.u)	ρ^+	ρ^-	Net payment by ISO ($)
10.423	180.052	50.062	130,675

Minimisation of re-dispatch with FACTS

When we insert FACTS on lines 4031.4022 and 4021.4032, the re-dispatched amount decreases from 10.423pu to 5.002p.u for the eighth hour. The cost of re-dispatch reduces to $ 77,713 for the same hour. With FACTS in the network the congestion only appears from hour eight onwards compared to from hour six when we do not have FACTS.

Over the twenty four hour period the amount re-dispatched for both cases with and without FACTS is shown in Figure 5-3.

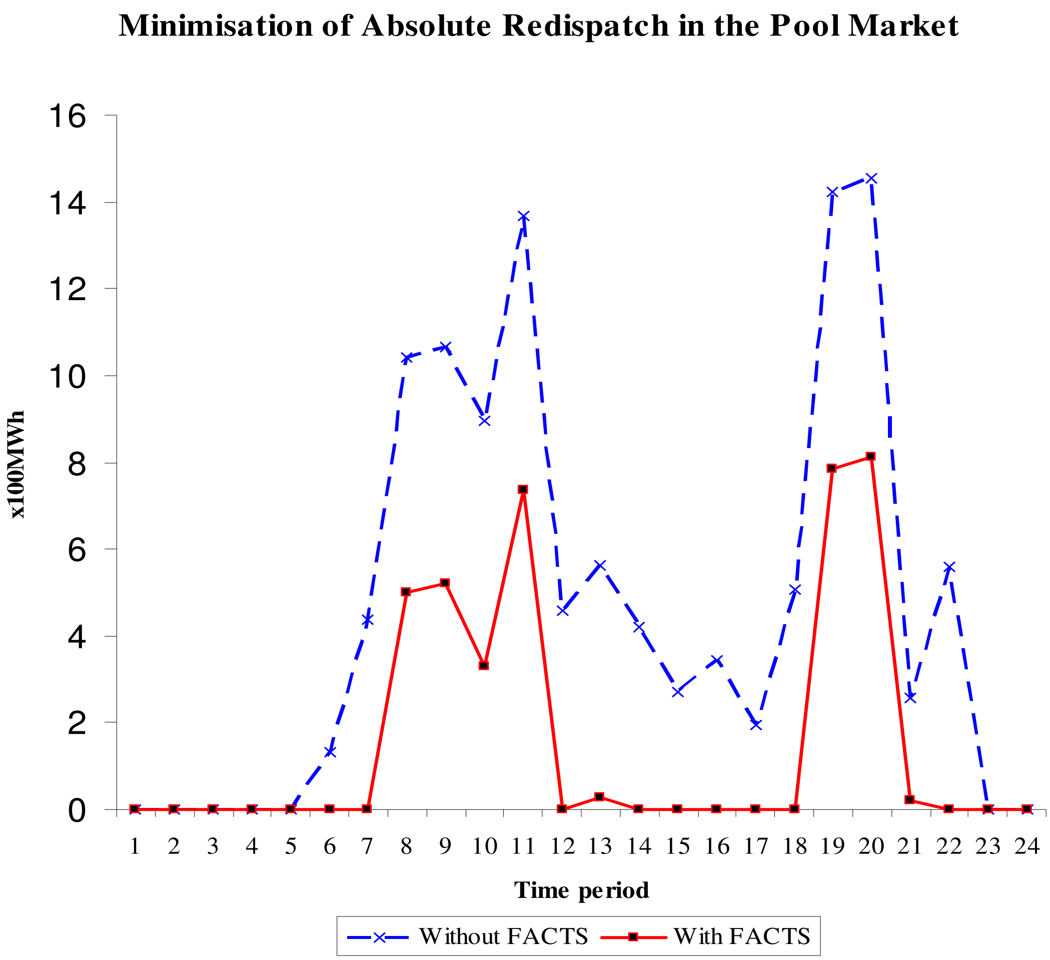

Figure 5-3 Minimisation of re-dispatch with and without FACTS in the system

5.1.4 Cost Minimisation

We again re-dispatch to solve congestion but our objective function for the OPF is minimisation of cost borne by the ISO i.e., expression (4-16). As a proxy to expression (4-16) the objective function is formulated as:

$$\min, J = \sum_{i \neq j}^{NG} \sum_{block}^{T\max} \left(\rho^{+}(i, block) * \Delta P_i^{+}(block) \right) + \sum_{j \neq i}^{NG} \sum_{block}^{T\max} \left(\left(\rho_m - \rho^{-}(j, block) \right) * \Delta P_j^{+}(block) \right) \quad \textbf{(5-1)}$$

Where

$\rho^{+}(i, block)$ is the up regulation bid price

$\rho^{-}(j, block)$ is the price for down regulation bid by generator j

Tmax is the maximum number of blocks submitted by generator

The above problem is solved as an optimisation problem subject to:
Power flow equations,

Line limits
FACTS parameter limits when used.

The first term in equation (5-1) represents the additional system cost for the additional generation. The second term represents the lost profits by a generator for which the ISO would have to compensate. The up and down regulation price is then determined as explained before in chapter 3 but restated here for completeness.

$$\rho^{+} = \max(\rho^{+}(i, block)) \text{ and } \rho^{-} = \min(\rho^{-}(i, block)) \quad \textbf{(5-2)}$$

where
ρ^+ is the price of an accepted up regulation block and
ρ^- is the price of an accepted down regulation block.

5.1.4.1 Re-dispatch results

Since the market settlement is carried out in the same way as for the minimisation of absolute re-dispatch the schedule of generation and the loadflow results remain the same as before. The re-dispatch amounts and the generators taking part in the re-dispatch will change because of the different objective function.

The total re-dispatched amount is 11.55p.u. The generators up regulated during the eighth hour are 4062, 4063, 4051 and 4051. Generators 1012, 1014 and 1021 have been down regulated. Table 5-7 shows the results for the re-dispatch with cost minimisation as an objective.

Table 5-7 Cost minimisation: Costing of re-dispatch for hour eight

Total amount re-dispatched (p.u)	ρ^+($/MWh)	ρ^-($/MWh)	Net payment by ISO ($)
11.55	180.052	120.052	104,383

When FACTS are included in the system and in the same positions as for the case for minimisation of re-dispatch, the cost of congestion for hour eight is $40,474. Figure 5-4 shows a comparison of the variation of the congestion cost over a 24 hour period for a case without FACTS and with FACTS.

In both Figure 5-3 and Figure 5-4 the results for hour nineteen may seem odd. Normally we expect congestion to be at the worst point during the peak hour. In our case however both the congestion cost and re-dispatched amount is highest at hour nineteen. Congestion depends which generators are scheduled for that period and for hour nineteen, the schedule causes congestion in a different set of lines (compared to those in Table 5-4). The required re-dispatch to solve this congestion is more costly both in terms of the amount of re-dispatched and the cost of doing so.

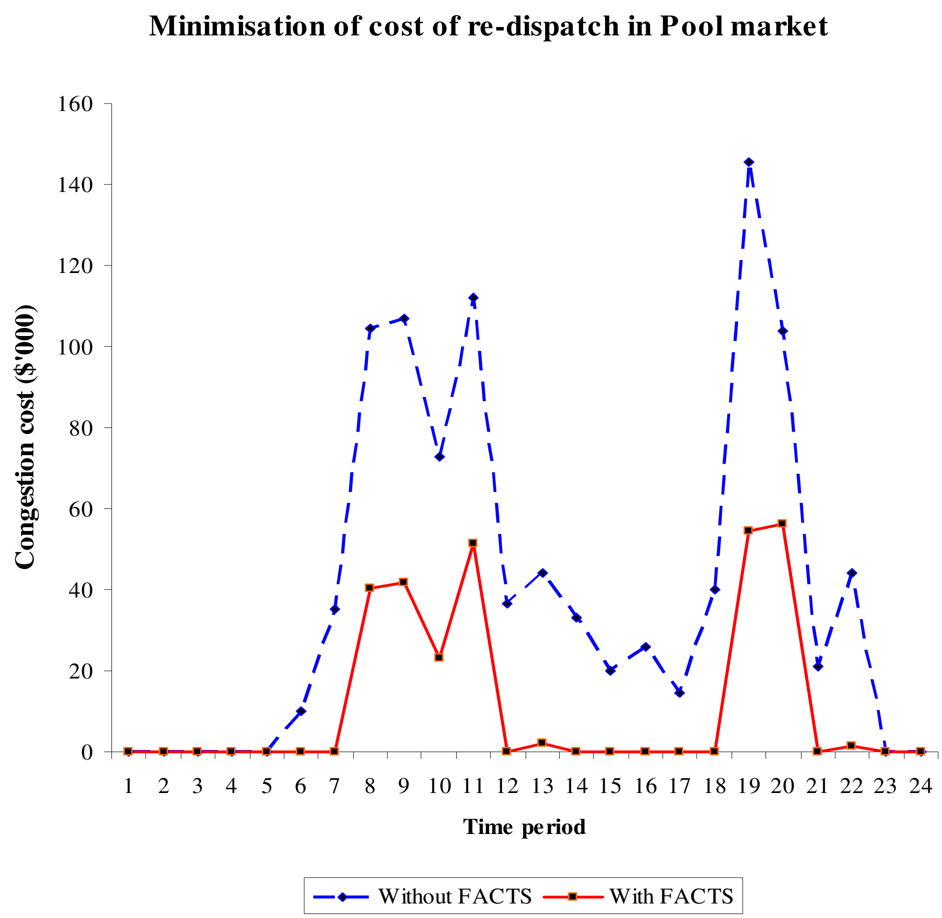

Figure 5-4 Cost minimisation: Congestion cost with and without FACTS for pool market.

5.2 Hybrid Market

The hybrid market has been discussed in detail in chapter 3 of this report in reference to the 14-bus test case. The equations used in the simulation of the hybrid market in the 32 bus remains the same as those formulated for the 14 bus. Where equations have been changed to accommodate a special feature in the 32 bus these will be restated.

5.2.1 Transaction formulation and Market settlement

5.2.1.1 Transaction formulation

The formulation of the transaction matrix follows the procedure discussed in chapter 4. Again the bus load is segregated into pool load and bilateral load and the ratio of these ranges from 0 to 0.6. The total load is however about 70% bilateral, close enough to the Swedish market scenario. The transactions are formed for hour eight and scaled through the load scaling factor to give transactions for other hours.

From the complete transaction table, we observe that some generators do not take part in the bilateral transactions. This would be close to real life situation though the desirable situation for a generator would be to have a guaranteed contract of supply and then any excess capacity can be submitted to the pool. There is no guarantee that a generator's bid will be accepted in the pool. Priority then for the generator would be to secure a bilateral contract.

5.2.1.2 Market settlement

The generators that have taken part in bilateral contracts also take part in the pool market if they have excess capacity. The generators which may not have contracts submit their sell bids to the pool. The bids submitted by GENCOs are based on the balance of capacity if the GENCO had taken part in the bilateral market. The resulting bids for this market are shown in Table 5-8 below. The market is then settled based on these bids. The market spot price is determined in exactly the same way as described above for the pool market.

The resulting market spot price for hour eight is $70.752/MWh. Similar to the discussion on the pool market, the bids whose prices are higher than the market price are rejected. Notably generator 4063 has no bilateral transactions and all its bids have been rejected in the pool.

Table 5-8 Submitted bids for the pool in the hybrid market for hour eight.

Generator.block	Size (p.u)	Price ($/MWh)	Generator.block	Size (p.u)	Price ($/MWh)
4072.3	11.3	225.552	4031.1	2.0	40.752
4071.2	0.3	80.552	4031.2	1.5	70.752
4071.3	1.0	100.552	4042.1	2.0	40.052
4011.3	2.5	200.052	4042.2	4.0	120.052
4012.1	5.0	50.052	4042.3	1.0	140.052
4012.2	2.0	70.052	4041.1	3.0	60.062
4012.3	1.0	80.052	4062.1	1.0	20.752
4021.1	1.0	20.054	4062.2	2.0	60.752
4021.2	2.0	60.054	4062.3	3.0	120.752
4063.1	4.0	80.052	1012.3	2.0	160.052
4063.2	5.0	180.052	1014.3	0.8	120.052
4063.3	3.0	240.052	1022.1	2.5	50.062
4051.3	1.8	140.052	1021.2	0.3	70.062
4047.3	3.0	240.052	1021.3	2.5	120.062
2032.3	2.1	170.052	1043.1	0.5	40.032
1013.3	1.5	120.872	1042.1	1.0	20.652
1012.1	3.0	60.052	1042.2	1.5	50.652
1012.2	3.0	120.052	1042.3	1.5	80.652

The resulting schedule of generation therefore comprises of the pool part and the bilateral part. The combined schedule is shown in Table 5-9 below.

Table 5-9 Schedule of generation for hybrid market for hour eight

Generator	Schedule (p.u)	Generator	Schedule (p.u)
4072	33.8	4047	9.0
4071	3.8	2032	6.4
4011	7.5	1013	4.5
4012	7.0	1012	3.0
4021	3.0	1014	5.3
4031	2.5	1022	2.5
4042	2.0	1021	3.5
4041	3.0	1043	2.0
4062	3.0	1042	2.5
4051	5.3		

The rejected bids from the pool market are re-submitted for up regulation and the accepted bids are also re-submitted for down regulation. Generators which only have bilateral contracts can also submit bids for down regulation. If a generator with a contract has a price higher than the spot market it is not allowed to submit down regulation bid. Naturally all up regulation bids are either equal to or higher than the market price. Table 5-10 below shows regulation bids for hour eight.

Table 5-10 Bids for up and down regulation

Up Regulation Bids			Down regulation Bids		
Generator.block	Size (p.u)	Price ($/MWh)	Generator.block	Size (p.u)	Price ($/MWh)
4072.3	13.7	225.552	4072.1	10.0	50.552
4071.2	0.5	80.552	4071.1	1.8	35.552
4071.3	1.0	100.552	4011.1	2.0	40.052
4011.3	3.1	200.052	4012.1	5.0	50.052
4012.2	1.5	70.052	4012.2	2.0	70.052
4012.3	1.0	80.052	4021.1	1.0	20.054
4031.2	1.5	70.752	4021.2	2.0	60.054
4042.2	4.0	50.652	4031.1	2.0	40.752
4042.3	1.0	80.652	4031.2	0.5	70.752
4062.3	3.0	120.752	4042.1	2.0	40.052
4063.1	4.0	80.052	4041.1	3.0	60.062
4063.2	5.0	180.052	4062.1	1.0	20.752
4063.3	3.0	240.052	4062.2	2.0	60.752
4051.3	2.1	140.052	4051.1	3.0	140.052
4047.3	3.7	240.052	4047.1	2.0	40.052
2032.3	2.6	170.052	2032.1	1.5	30.052
1013.3	1.8	120.872	1013.1	2.0	40.872
1012.2	3.0	120.052	1012.1	3.0	60.052
1012.3	2.0	160.052	1014.1	1.5	30.052

Up Regulation Bids			Down regulation Bids		
Generator.block	Size (p.u)	Price ($/MWh)	Generator.block	Size (p.u)	Price ($/MWh)
1022.1	2.5	50.252	1043.1	2.0	40.032
1021.1	2.5	50.062	1042.1	1.0	20.652
1021.2	1.0	70.062	1042.2	1.5	50.652
1042.3	1.5	80.652			

In Table 5-9 it is worth noting that though generator 4051 is scheduled for 5.25p.u (from Table 5-10) we expect it to submit bid blocks 3, 2 and 1 for down regulation and part of block 3 for up regulation. Only bid block 1 is submitted for down regulation and part of bid block 3 for up regulation. This is because bid block 2 for generator 4051 has a price higher than the market price and cannot therefore be submitted for down regulation in the regulation market.

5.2.2 Loadflow

In order to check feasibility of the resulting generation schedule a loadflow study is carried. If the schedule results in violations of the line limits the generation has to be re-dispatched in such a way that the congestion is cleared. Using the schedule in Table 5-9 results in the congestion of the lines shown in Table 5-11.

Table 5-11 Congested lines for system schedule from Table 5-9

Line	Loading(%)
4071.4072	138
4022.4011	100
4022.4012	125
4022.4031	143
4032.4031	125

5.2.3 Minimisation of re-dispatch

Since we have congestion the generation has to be re-dispatched. Objective of the OPF for the re-dispatch is to two fold and may be stated as minimise re-dispatch of the pool and if necessary re-dispatch the contract generation. This is captured in the combined objective function stated in (see discussion in chapter 4). In the 32 bus system the objective function has been formulated as:

$$Min, J = \gamma * \left(\sum_{i}^{NG} \left(\Delta P_i^{+}\right) + \sum_{j}^{NG} \left(\Delta P_j^{-}\right) \right) + \sum_{i}^{NG} \sum_{j}^{NB} \left(\Delta T_{ij}\right) \tag{5-3}$$

In (5-3) the first term in the brackets $i \neq j$. The objective function is subject to the following:
Power flow equations
Line limits and
Actual dispatched contract cannot be greater than the contract.

Since every transaction has equal importance i.e., the transactions are not weighted, deviation of transactions can be computed from deviation of contract generation from the scheduled. If a generator's contract schedule has been curtailed, its load will be met from the pool market. The results of the re-dispatch for hour eight are given in Table 5-12. From the results, we observe that contract generation has been re-dispatched by only 3.75p.u., whilst the pool generation has been re-dispatched by 18.582p.u.

Table 5-12 Minimisation of Re-dispatch: Re-dispatched generation for the pool and the bilateral parts of the market

Generator	Pool Schedule	Actual Pool generation	Contract schedule	Actual contract generation
4072	0.0	0.0	33.8	30.0
4071	0.0	0.0	3.8	3.8
4011	0.0	0.0	7.5	7.5
4012	7.0	2.4	0.0	0.0
4021	3.0	3.0	0.0	0.0
4031	2.5	2.5	0.0	0.0
4042	2.0	2.0	0.0	0.0
4041	3.0	3.0	0.0	0.0
4062	3.0	3.0	0.0	0.0
4063	0.0	8.1	0.0	0.0
4051	0.0	1.6	5.3	5.3
4047	0.0	0.0	9.0	9.0
2032	0.0	0.0	6.4	6.4
1013	0.0	0.0	4.5	4.5
1012	3.0	3.0	0.0	0.0
1014	0.0	0.0	5.3	5.3
1021	0.3	0.0	3.2	3.2
1022	2.5	0.0	0.0	0.0
1043	0.5	0.5	1.5	1.5
1042	2.5	4.0	0.0	0.0

For the eighth hour the cost of congestion is \$ 224,000 and the prices for up and down regulation are \$180.052 and \$50.052 respectively.

When FACTS (TCPAR) are inserted in the same lines as in the pool market the total re-dispatched amount is 15.4p.u. compared to 22.332p.u without FACTS. The congestion cost with FACTS in the system is $154,183. As earlier stated the objective is to minimise the re-dispatch and the FACTS have helped to reduce the amount re-dispatched. The variation of the re-dispatched amount for the pool and bilateral portions of the market for various hours is shown in Figure 5-5 below. The figure also shows the re-dispatch with FACTS in the system. The amount re-dispatched for the pool is considerably lower in the case with FACTS compared to that without FACTS.

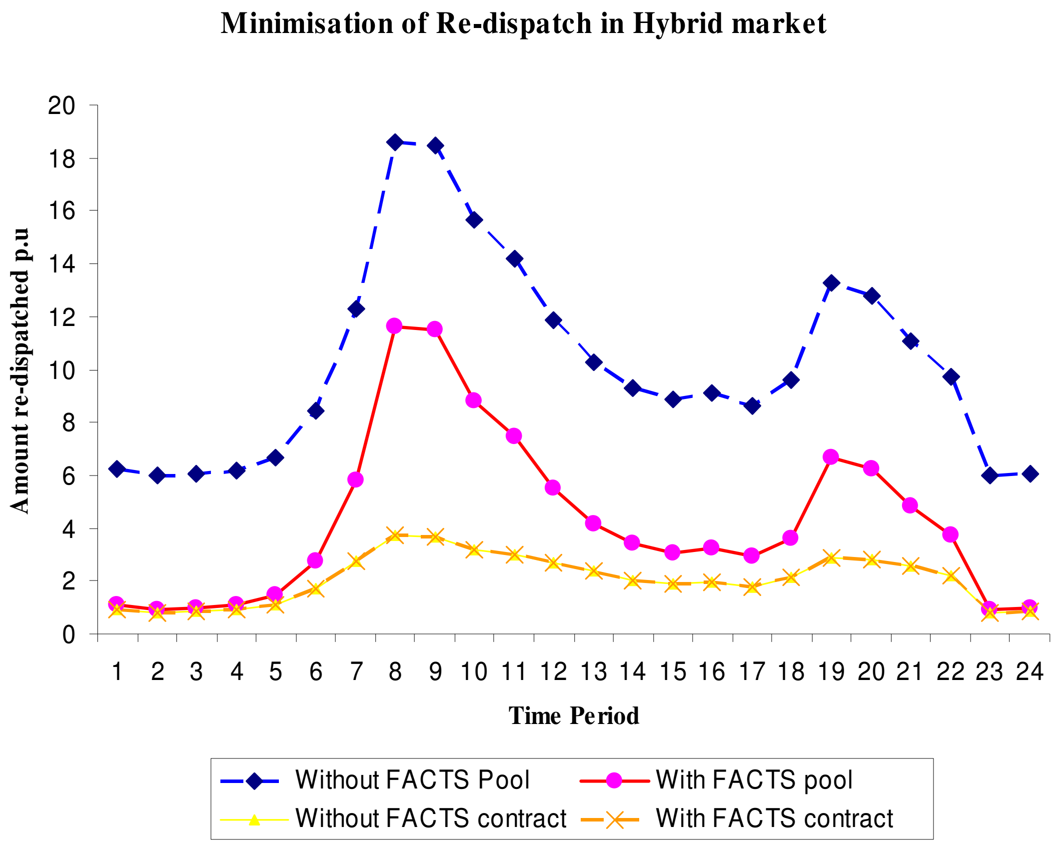

Figure 5-5 Minimisation of re-dispatch in Hybrid market: Amount re-dispatched for the pool and bilateral portions of the market.

Cost Minimisation

The objective function for the cost minimisation is formulated as:

$$\min J = \sum_{i}^{NG} \sum_{t}^{T\max} \left(\Delta P_{(i,t)}^{+}\right) * \rho^{+} + \sum_{j=1}^{NG} \sum_{t}^{t\max} \left(\Delta P_{(j,t)}^{-}\right) * \left(\rho_m - \rho_{(i,t)}^{-}\right) \tag{5-4}$$

Subject to:
The power flow equations,
Generator power limits
Line capacity limits and
FACTS parameter limits when employed.

Where
$\Delta P_{(i,t)}^{+}$ and $\Delta P_{(i,t)}^{-}$ is the up and regulation block accepted for generator I and j respectively,
ρ_m is the market clearing price
ρ^+ is the market price for up regulation and
$\rho^-_{(j,t)}$ is the price of the down regulation bid for generator j respectively.

The generation is re-dispatched such that the cost of congestion is minimised. For the eighth hour the cost of congestion is $156,000 and the re-dispatched amount is 22.1p.u. The up and down regulation prices are $120.752/MWh and $50.062/MWh respectively. Needless to mention that with the objective function being minimisation of cost of congestion the generators are up or down regulated based on the cost of their bids in the regulation market. The objective function does not have any reference whatsoever to the contract or pool schedules. The re-dispatch is carried out as though the market was a pool type. Table 5-13 shows the generators which have been re-dispatched.

Table 5-13 Cost minimisation: re-dispatched generation for hybrid market for hour eight

Generator	Schedule(p.u)	Actual (p.u.)
4072	33.75	30.0
4012	7.0	5.0
4031	2.5	3.2
4042	2.0	3.9
4062	3.0	6.0
4063	0.0	4.0
1012	3.0	1.2
1022	2.5	0.0
1021	3.5	2.5
1042	2.0	4.0

When FACTS are inserted in the same locations as in the minimisation of re-dispatch the cost of congestion reduces to $109,679 and the re-dispatched amount is 15.5p.u for hour eight. The variation of cost of congestion for the whole 24 hour period is shown in Figure 5-6 below. Two cases are considered with FACTS and without FACTS.

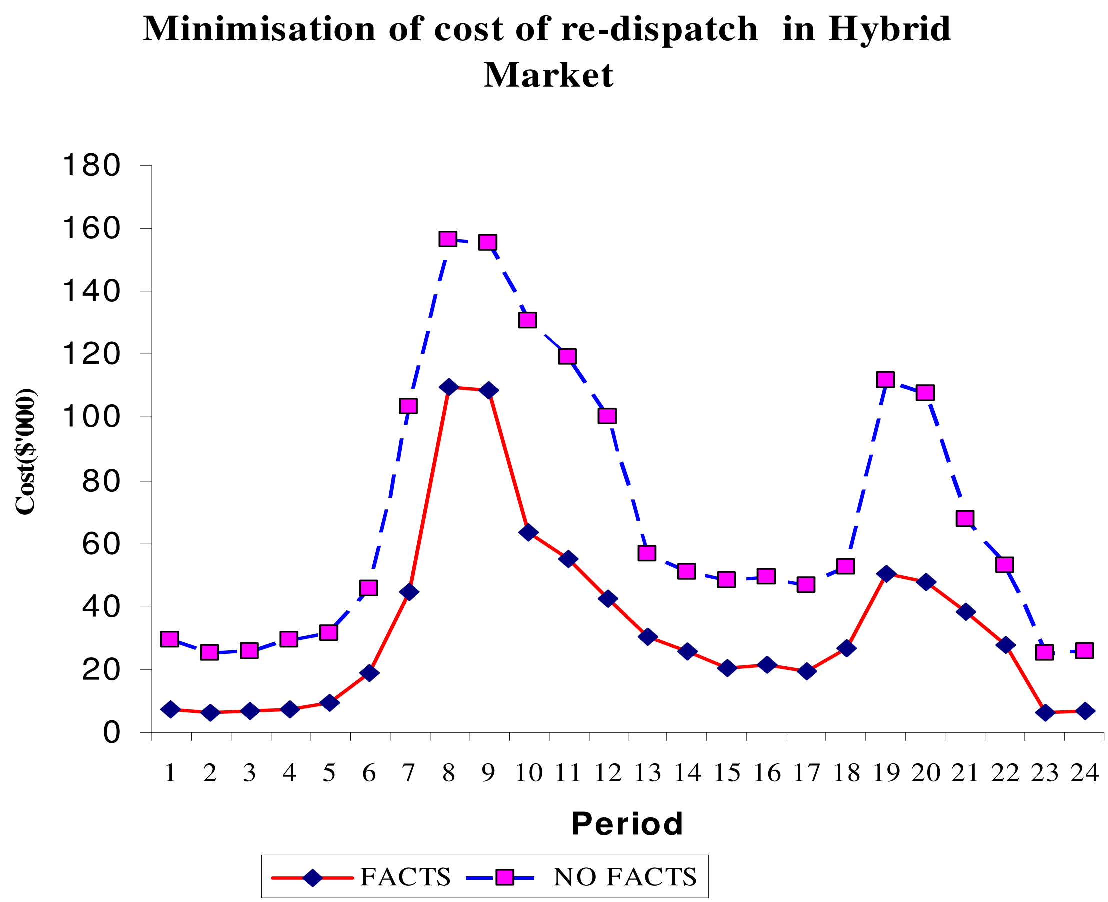

Figure 5-6 Minimisation of congestion cost in hybrid market

5.3 Conclusion

When we dispatch the pool following the market settlement schedule of Table 5-3 we find that we have congestion on the lines depicted in Table 5-4. The ISO or the TRANSCO is vested with the duty of ensuring system security and reliability and will have to intervene to ensure that these are adhered to. As earlier discussed in the introduction chapter 1 various methods are available and practiced for the relief of congestion. We however use re-dispatch of generation to solve congestion. Two strategies can be used i.e. minimisation of cost and minimisation of absolute amount of re-dispatch. When we minimise re-dispatch the regulation blocks are chosen such that the amount of regulation is minimised. In the minimisation of cost the blocks used for regulation are ranked in order of price. The difference in the amount re-dispatched in the two cases is small. In this simulation we have used a dc loadflow implying that generators contribution to losses is ignored and the choice of generators for the regulation will be purely dependent on their coupling with the congested lines. When FACTS are used (in this case TCPAR) on selected lines the amount of re-dispatched generation is reduced. In the minimisation of cost the use of FACTS reduces the cost of congestion.

In the hybrid market similar conclusions can be made regarding the minimisation of re-dispatched amount and minimisation of cost. In this model however we do not want to curtail contract schedules. The objective function is therefore two fold i.e. minimise the total amount re-dispatched and also minimise the curtailment of contracts. Figure 5-5 clearly shows the results of the re-dispatch where the pool has a much larger deviation than the bilateral part of the market. When we re-dispatch the hybrid market with the objective being to minimise the cost of congestion the hybrid market is treated like the pool market. The regulation bids are considered on the merit of price. The use of FACTS in the hybrid market has resulted in the reduction of the amount of re-dispatch and also led to a reduction in the congestion cost for the minimisation of re-dispatch and minimisation of cost strategies respectively.

The market models and the algorithms for re-dispatch developed for the IEEE 14-bus test system has been tested on the Cigre Nordic 32-bus system. The conclusions drawn from the 32 bus system agree with those earlier observed from the 14 bus system. The methods used are therefore robust and give reliable results.

6 Contingency Analysis

6.1 Introduction

Contingency analysis (CA) as an inherent function of system security assessment is critical for detecting underlying problems in a power system. When the elements (either transmission line or generator or even both of them) in a power system are outaged, the effect on the power flow is tremendous and sometimes may violate the security constraints. Operators must know precisely which line or generator outages will cause flows or voltages to exceed limits and take appropriate actions. Contingency analysis models usually include single element outage (one-transmission line or one-generator outage), multiple-element outage (two-transmission line outage, one transmission line and one generator outage, etc), and sequential outage (one outage after another) [1]. Limit checking is done after each contingency to determine whether the system is secure. The ratings of lines and equipment in a contingency situation are normally different from a normal scenario. An increase in rating of lines by say 10% of their normal may be acceptable in a contingency [2]. In this chapter we also test the loading of lines after the contingency using this approach apart from the normal rating.

Since the most logical problem to cope with in contingency analysis is to speed up the calculation time, a

dc power flow method is always utilized when an approximate analysis of the effect of each outage is desired. One of the easiest ways to provide a quick calculation of possible overloads is to use linear sensitivity factors like generation shift factor and line outage distribution factor which show the approximate change in line flow after a generation outage or a line outage respectively [1]. In this chapter, the most typical CA model single element outage based on dc flow is simulated via line outage distribution factor method for both IEEE 14-bus system and CIGRE 32-bus system. The aim of this analysis is not to produce a secure dispatch for the N-1 criterion but to test the dispatch for the N-1 criterion. When we have congestion due to the contingency, we try to re-dispatch. The operators of the system need to know which contingencies require no action and which ones require a re-dispatch.

6.2 Methodology

Line outage distribution factor (LODF) method [1] is utilized in this project, and the expression of LODF is given below

$$d_{i-j,m-n} = \frac{\Delta f_{i-j}}{f^{0}_{m-n}} = -\frac{\dfrac{N_{m-n}x_{m-n}}{N_{i-j}x_{i-j}}(X_{in} - X_{jn} - X_{im} + X_{jm})}{N_{m-n}x_{m-n} - (X_{nn} + X_{mm} - 2X_{nm})} \quad \text{if } i \neq m, j \neq n \tag{6-1}$$

Where

$d_{i-j,m-n}$: line outage distribution factor when monitoring line i-j after an outage on line m-n

Δf_{i-j} : change of power flow on line i-j

f_{m-n}^{0} : the original flow on line m-n before it was opened

x_{m-n} : reactance of line m-n,

X_{in} : element from the inverse matrix of B matrix

N_{i-j}, N_{m-n} is the number of lines in the circuit ij and mn respectively

(Note, from the practical meaning of line outage distribution factor, it's obvious to see that for a corridor with a single line $d_{i-j,i-j}$ =-1)

The line flow across line i-j after the outage of line m-n can be expressed as,

$$f_{i-j}^{new} = f_{i-j}^{0} + d_{i-j,m-n} \bullet f_{m-n}^{0} \quad \textbf{(6-2)}$$

Where

f_{m-n}^{0}, f_{i-j}^{0} are pre-outage flows on line i-j and line m-n respectively

f_{i-j}^{new} is the flow on line i-j when line m-n out

By calculating the line outage distribution factors, a very fast procedure can be set up to test all lines in the network for overload for the outage of a particular line. The LODFs are dependent on the configuration of the network. It may therefore be necessary for an operator to keep different sets of LODFs corresponding to different system configurations. Some line outages may not lead to any violations of the system constraints whereas others will. There is need to rank the outages that lead to overlods and other system violations. This ranking is normally done via performance indices. One such index is the overload performance index [3] given by (6-3). A lengthy discussion on the use of this index can be found in [1] but will not be used in this thesis. We will use an index defined in[3] and given by (6-4) and (6-5). This index uses the amount of overload on a line and the total power violations for congested lines after a contingency. Therefore, the approximate security level ranking for each transmission line can be acquired by calculating the power violations for each line outage.

$$PI = \sum_{allbranches\, l} \left(\frac{P_{flow,l}}{P_l^{\max}} \right)^{2n} \quad \textbf{(6-3)}$$

$$PI_{ij,mn} = \frac{P_{ij} - P_{ij\max}}{P_{ij\max}} \quad i, j \in NB \quad \textbf{(6-4)}$$

$$PV_{mn} = \sum_{NB} P_{ij\max} * PI_{ij,mn} \quad \textbf{(6-5)}$$

Where

PV_{mn} : total power violation when line m-n is outaged

$PI_{ij,mn}$: performance index of congested line ij due to outage of line mn

P_{ij} : the overloaded flow on transmission line i-j

$P_{ij\max}$: transmission limit for line i-j

NB : set of congested lines when line m-n is outaged.

As shown in Figure 6-1, a security-constrained OPF model is established to run contingency analysis. Before acquiring line distribution factor, a secure generation schedule where all the system security constrains are satisfied is introduced to determine the base power flow. At the beginning of each loop, one transmission line is outaged. After checking the existence of any overloading lines, a re-dispatch is carried out in case of congestion. If the solution of re-dispatch is feasible, a new security-constrained generation schedule could be got, otherwise the troublesome line is displayed. The objective function for the re-dispatch is the minimisation of deviation from the initial secure generation schedule. This procedure is repeated for the outage of each line in turn. Where a corridor has more than one line e.g. corridor 1.2 in 14 bus system only one of the lines is outaged.

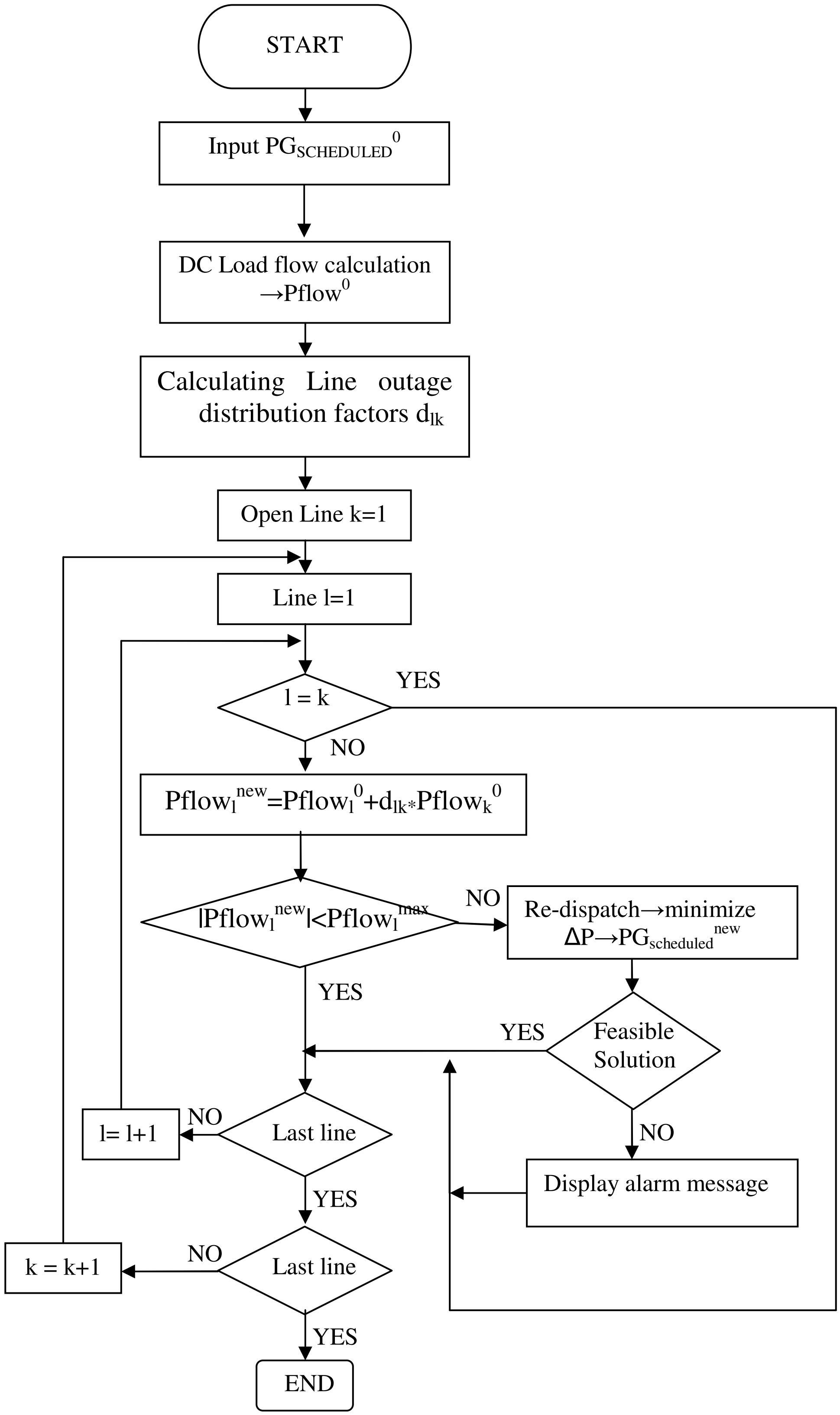

Figure 6-1 Contingency analysis using line outage distribution factors

6.3 Results for IEEE 14-bus system

Contingency analysis is first studied in IEEE 14-bus system. The scheduled generation applied to calculate the base flow in contingency analysis program is shown below. This schedule is an optimal generation schedule as far as the N-0 situation, and it results in no violations to any of the constraints such as voltage limit and transmission limit etc.

Table 6-1 Generation schedule used in contingency analysis for IEEE 14-bus system

Gen	Gen1	Gen2	Gen3
$PG_{SCHEDULED}^{0}$ (Pu)	1.45	0.95	0.2

Table 6-2 Solution Status for line outage contingency test in IEEE 14-bus system

Outaged line	1-2	1-5	2-3	2-4	2-5	3-4	4-5	4-7	4-9	5-6
Solution Status	2	2	0	0	0	0	2	0	0	5

Outaged line	6-11	6-12	6-13	7-8	7-9	9-1	9-14	10-11	12-13	13-14
Solution Status	0	0	0	0	0	0	0	0	0	0

Values of Solution Status	Indicated implication
0	line limits not violated from use of LODFs
2	Re-dispatch is required and optimal solution achieved
5	Re-dispatch is required and infeasible solution found

In Table 6-2, the Solution Status to the program is listed where different values of the attribute represent different solution status. Based on the input generation schedule, only 4 line outage cases call for re-dispatch and one of them fails to eliminate the congestion by re-dispatch. Details of contingency calculation under peak load at hour 8 are given in Table 6-3.

Table 6-3 Results of contingency analysis at hour 8 in IEEE 14-bus system

Outage Line (m-n)	Over-loaded Line(i-j)	Line Flow Limit (MW)	Over load index ($P_{ij,mn}$)	Power Violation (MW)	Line Loading (%) After Re-dispatch	Ranking
1-5	1-2	100	0.44	44	100	1
1-2	1-2	50	0.74	37.2	100	2
4-5	1-2	100	0.10	10	100	3
5-6	7-9	50	0.11	5.4	Fail	4
	9-10	30	0.05	1.5		

It can be observed from Table 6-3 that lines 1-2, 1-5, 4-5 and 5-6 are the four lines whose outage could result in congestions. By carrying out re-dispatch, the first three contingency cases can be removed; however, the line 5-6 outage is the most serious contingency case which is irremediable while the power violation is the least among these four cases. It may appear confusing that we after outage of line 1-2 we still have flows on the same line. This is because the corridor has two lines so when one of them is outaged the rating of the corridor is reduced to half the normal rating. Line 1-5 has the highest power violation but interestingly not the highest over load index.

The failure of re-dispatch when line 5-6 is out is credited to the system structure. When line 5-6 is open, parallel lines line 4-9 and line 4-7-9 are the only two lines connecting the generation area with the load area in the system. According to the physical laws of electricity, when line 7-9 is overloaded, the power flow on line 4-9 is simultaneously fixed, therefore the demand in load area can not be met if no generator is installed in that area when line 5-6 is outage.

If we however increase the rating of the branches in the system during contingency to say 1-1 times the normal rating only the outages of lines 1-5 and 1-2 are significant. The other outages cause no congestion at all except for 5-6 which is still infeasible.

6.4 Results for CIGRE 32-bus system

Contingency analysis is also studied in CIGRE 32-bus system which approximately represents the Swedish grid. There are 20 generator buses and 22 load buses in the system. The main transmission system is designed for 400kv as well as the regional systems at the voltage level of 220kV and 130kV. The same scenario applied for IEEE 14-bus system is utilized in CIGRE 32-bus system. In this thesis, the analysis is limited to the lines which do not result in islanding buses e.g. lines 4031-2031 is not tested and neither are lines 4022-1022, 1021-1022 , 2032-2031 and all transformers connected to loads such as 4041-41, 4061-61 etc.

The scheduled generation used to calculate the base flow in contingency analysis is from the result at hour 8 of CIGRE 32-bus market re-dispatch model. As before all the security constraints (for the N-0 situation) are satisfied when generators are under this schedule of Table 6-4.

Table 6-4 Generation schedule in contingency analysis for CIGRE 32-bus system

Gen No.	$PG_{SCHEDULED}^{0}$(pu)	Gen No.	$PG_{SCHEDULED}^{0}$(pu)
4072	22.500	4051	4.500
4071	5.000	4047	5.000
4011	5.000	2032	4.779
4012	8.000	1013	3.500
4021	3.000	1012	6.000
4031	3.500	1014	6.000
4042	6.000	1022	0.000
4041	3.000	1021	3.288
4062	5.400	1043	2.000
4063	8.933	1042	4.000

Table 6-5 indicates the outage lines and consequential results. The solution status indicates whether a re-dispatch was necessary and also whether the re-dispatch was feasible to clear congestion. The key to the solution status is as was given before for the 14 bus system. As stated before only one of the lines in double circuit was outaged.

Table 6-5 Solution Status for line outage contingency test in CIGRE 32-bus System

Outage line	Solution Status	Outage line	Solution Status
4072-4071	0	4041-4061	2
4071-4011	2	4062-4063	0
4071-4012	0	4062-4045	2
4011-4012	2	4062-4061	2
4011-4021	2	4051-4045	0
4011-4022	2	4047-4043	0
4011-1011	2	4047-4046	0
4012-1012	2	1013-1014	2
4012-4022	2	1013-1011	2
4021-4042	2	1012-1014	0
4021-4032	2	1043-1041	0
4031-4041	2	1043-1044	0
4031-4022	2	1042-1044	2
4031-4032	2	1042-1045	0
4042-4032	2	4032-4044	2
4042-4043	2	4043-4044	2
4042-4044	2	4043-4046	0
4041-4044	2	4044-4045	2
1041-1045	5	4044-1044	5
		4045-1045	5

Since the generation schedule is an optimal schedule for the N-0 condition many contingency cases will lead to congestions. From Table 6-5, it can be seen that, among the thirty nine line outage cases, only eleven of them do not result in congestion. Twenty eight of the cases require re-dispatch and for three of these cases the re-dispatch is infeasible. A similar table as Table 6-3 is given in the appendix C1 for the 32 bus system.

As can be seen in appendix C1, based on the given generation schedule, it's very easy to cause congestions for one line outage. Most of the congestions can be removed by generation re-dispatch. For the cases where we fail to clear the congestion using re-dispatch it is easy to understand why it is so. If we outage one of the transformers 1044-4044 we have to redirect 5.6MW through the remaining transformer and the other transformers on 4045-1045. the generator in that part of the system ie. 1043 and 1042 are already loaded to the maximum so is generator 4041. The only remedy is to increase loading on generator 4051 but this overloads the branch 4045-1045 hence there is no feasible solution to the congestion. A similar explanation holds for the other outages that cause congestion and cannot be cleared through re-dispatch. The bottleneck to this part of the network is that it is fed through only two points 4044-1044 and 4045-1045 and all its internal generators are scheduled for maximum output.

When we raise the limit for the line ratings during a contingency to 110% of the normal we only have congestion for nineteen of the thirty nine outage cases and only two of these cannot be solved by re-dispatch. The insoluble cases are as a result of outages of transformers 4044-1044 and 4045-1045.

6.5 Conclusion

From the results of contingency analysis for IEEE 14-bus system, we could see the potential crisis for this specific construction of this power system as well as the implemented generation schedule. The approximate security ranking is listed where the outage of line5-6 leads to an irremediable problem since the connection between generation area and load area is not powerful enough (If we had rated link 7-9 to say 60MW instead of 50MW the re-dispatch could have worked). When line ratings are increased to 110% of the normal rating we find that most of the over loads clear and the cases of congestion that could not be cleared before are easily solved.

The same conclusion as above can be drawn for the Cigre 32 bus system. As the system grows the number of contingency cases to test increases hence the LODFs become very handy. A method for the ranking for the effect of the contingencies on the network needs to be agreed upon. In this thesis we have used a method based on an overload index and the accompanying total power violation. This method cannot distinguish between a contingency that can be mitigated by re-dispatch and one that cannot. It simply ranks the contingencies based on the amount of power violations. Good human judgement based on experience on the network in question is invaluable in realistic ranking of contingencies. The aspect of switchings to alleviate congestion after a contingency has not been investigated in this thesis. Some contingencies that have shown infeasibility in tackling congestion by re-dispatch maybe cleared by switching actions in the network.

The next step in the foregoing analysis would be to carry out a security constrained optimal generation dispatch. This dispatch schedule would incorporate the envisaged outages so that should these occur the generation need not be re-dispatched. Such an analysis is left for future work. Furthermore FACTS devices can be incorporated in the contingency analysis to investigate their effects. This also is left for future work.

References

[1] Wood, A., J., "Power generation, operation and control", pp411-450
[2] Christie, R., D., Wollenberg, B., F., Wangensteen, I., "Transmission Management in Deregulated Environment", Proceedings of the IEEE, Vol 88, No.2, Feb. 2000
[3] Jams A. Momoh and Jizhong Zhu, "Power System Security Enhancement by OPF with Phase Shifter", IEEE Trans on Power Systems, Vol. 16, pp287-293, 2001

7 Conclusion and Future Work

7.1 Conclusion

The restructuring of the electricity business has brought about different market structures *i.e.* Pool, bilateral and the hybrid market which is a combination of the first two. Congestion is more likely to occur in the new era of deregulation compared to the era of the vertically integrated electricity utilities. The ISO or TSO is vested with the obligation of ensuring system security and reliability. Congestion management remains one of the most important functions of the ISO since the network can be compromised by market players who may not have an economic stake in the infra structure.

Various methods of congestion management exist. In this thesis we have used the method of re-dispatching generation otherwise referred to as counter trade as practiced in Sweden. When congestion occurs in a market, despite the market model adopted, it increases the system cost by using out of merit generators more and cutting down on the output of low cost generators. The ISO in our case incurs a cost since he has to procure power from expensive generators and sell it at a cheaper price to low cost generators. Of course the cost of congestion management is passed on to the market players through the connection fees. If congestion in a system is persistent the market may be open to gaming by those who provide the regulation service. Congestion is not all bad since it also provides a signal for the need of investment in the transmission network, the higher the cost of congestion the greater the need for investment.

It has been observed that in the pool market re-dispatch due to congestion leads to a higher system cost. It is therefore vital that the re-dispatch be carried out with the objective of minimising the amount of deviation from the market settlement. The market mechanism in the pool always ensures the most economical despatch schedule. Any deviations from this schedule should therefore be minimised as concluded herein. In the bilateral market the objective function for the re-dispatch is the minimisation of transaction deviation. Since the load in our case was inelastic it has been found that the re-dispatch objective produces similar results to minimising generation deviation. In the hybrid market, it has been found that the results of the re-dispatch are greatly influenced by the relative weighting of the pool and the bilateral parts of the market. If the bilateral contracts are weighted much higher the re-dispatch may fail if the pool portion of the generation is not able to manage the re-dispatch. The bilateral contracts should be treated as priority over the pool generation but the relative importance still needs to be specified in the opf formulation of the re-dispatch.

Re-dispatching of generation in a network with persistent congestion may be regarded as a short term solution. The long term solution may be to upgrade congested corridors, build new transmission lines or utilize the existing infrastructure more fully by the use of FACTS devices. Owing to the short installation times, flexibility to power flow control and reduction of prices over the years FACTS devices are becoming popular. Commercial pressures on obtaining greater returns from existing assets suggest an increasingly important role for FACTS. The use of series compensation FACTS can be used to reduce congestion. In the different market models it has been demonstrated that FACTS can reduce the amount of re-dispatched power and concomitantly the cost of congestion. The placement of these devices in the network has to be assessed for maximum net benefit. Whilst FACTS have been used in this thesis for congestion management they are also used for improvement of dynamic performance of the network by increasing the margins for transient stability and voltage stability. The economic assessment for the placement of FACTS has only involved the static considerations but it should be borne in mind that other benefits are possible.

The dispatch schedule after re-dispatch has been considered as optimal from an economical point of view and the N-0 condition. We have tested both the 14 bus and 32 bus systems for N-1 criterion. Contingency analysis is an important part of system security. An AC load flow is the ideal tool to use for the contingency test but due to the slow speed of the computations and the large number of cases to be tested the DC flow is normally used. Line outage distribution factors which are predetermined from a network configuration are also used to speed up the computations. Only those cases that result in congestion by use of LODFs can further be investigated by an ac load flow. Since the number of outage cases to test is large, the results of these tests need to be ranked. The ranking should give some indication of the effect that the outage has on the system. In this thesis we used a method of ranking based on an overload index and total power violations. This method has a draw back since we cannot distinguish between cases that can be cleared by re-dispatch and those that can.

7.2 Future Work

Congestion management will remain an important role for the ISO in the deregulated electricity market. Simulation of different methods other than re-dispatch or counter trading can also be done for the various market models. We propose the following to be included in future work on this subject:

- For the bilateral market it would be useful to have the loads elastic so that a transaction curtailment will result in changes in both power injections and extractions for contract parties without formulation of new contracts
- For FACT devices that increase the amount of transmittable power, the line limits can be increased after installation of FACTS. In this thesis we kept the line limits the same before and after the insertion of FACTS
- Other FACT devices like the UPFC can also be incorporated in the simulations
- Incorporation of security in the re-dispatch.
- Incorporate FACTS in contingency test of the system.

Appendices

A.1

Table A.1 Transaction matrix and allowable contracts for hour eight for hybrid market without FACTS

Contract, T_{ij}	Amount (p.u)	$T_{allowable}$ (p.u) $\gamma = 10$	$T_{allowable}$ (p.u) $\gamma = 100$
1.3	0.34	0.31	0.34
1.4	0.38	0.35	0.38
1.5	0.06	0.03	0.06
1.6	0.10	0.06	0.09
1.9	0.28	0.25	0.28
1.10	0.06	0.02	0.05
1.11	0.01	0	0
1.12	0.04	0	0.03
1.13	0.05	0.01	0.04
1.14	0.08	0.04	0.07
2.3	0.26	0.29	0.27
3.2	0.10	0.100	0.10
2.2	0	0.03	0
2.4	0	0.03	0
2.5-2.6	0	0.03	0
2.9-2.14	0	0.03	0

A.2

Table A.2 Transaction matrix and allowable contracts for hour eight for hybrid market with FACTS. The contracts in bold are new contracts formulated during re-dispatch.

Contract, T_{ij}	Amount (p.u)	$T_{allowable}$ $\gamma = 10$	$T_{allowable}$ $\gamma = 100$
1.3	0.34	0.33	0.34
1.4	0.38	0.37	0.38
1.5	0.06	0.05	0.06
1.6	0.10	0.08	0.09
1.9	0.28	0.27	0.28
1.10	0.06	0.05	0.06
1.11	0.01	0	0.01
1.12	0.04	0.03	0.04
1.13	0.05	0.04	0.05
1.14	0.08	0.06	0.07
2.3	0.26	0.27	0.26
2.4		0.01	
2.5-2.6, 2.9-2.14		0.01	
3.2	0.10	0.1	0.1
3.3			0.0028

Appendix B1

Table B1. Line data for 32-Bus test system

Line	Resistance (Ohms)	Reactance (Ohms)	Charging (p.u)	Capacity (MVA)
4011.4012	1.6	12.8	0.4	1000
4011.4021	9.6	96	3.58	1500
4011.4022	6.4	64	2.39	1000
4011.4071	8	72	2.79	1000
4012.4022	6.4	56	2.09	1000
4012.4071	8	80	2.98	1000
4021.4032	6.4	64	2.39	1000
4021.4042	16	96	5.97	1000
4031.4022	3.2	32	1.2	1800
4031.4032	1.6	16	0.6	1000
4031.4041	4.8	32	2.39	2000
4042.4032	16	64	3.98	1000
4032.4044	9.6	80	4.77	1000
4041.4044	4.8	48	1.79	1000
4041.4061	9.6	72	2.59	1000
4042.4043	3.2	24	0.99	1000
4042.4044	3.2	32	1.19	1000
4043.4044	1.6	16	0.6	1000
4043.4046	1.6	16	0.6	1000
4043.4047	3.2	32	1.19	1000
4044.4045	1.6	16	0.6	2000
4045.4051	3.2	32	1.2	1000
4045.4062	17.6	128	4.77	1000
4046.4047	1.6	24	0.99	1000
4062.4063	2.4	24	0.9	2000
4071.4072	2.4	24	3	1000
2031.2032	2.9	21.78	0.05	700
1011.1013	0.85	5.9	0.13	600
1012.1014	1.2	7.6	0.17	600
1013.1014	0.59	4.23	0.1	600
1021.1022	2.54	16.9	0.29	600
1041.1043	0.85	5.07	0.12	600
1041.1045	1.27	10.14	0.24	600
1042.1044	3.21	23.66	0.57	600
1042.1045	8.45	50.7	1.13	600
1043.1044	0.85	6.76	0.15	600
4061.4062	9.6	72	2.59	1000
Transformers	Resistance (p.u)	Reactance (p.u)	Charging (p.u)	Capacity(p.u)
1011.4011	0	0.008	0	5

Line	Resistance (Ohms)	Reactance (Ohms)	Charging (p.u)	Capacity (MVA)
1012.4012	0	0.008	0	10
1022.4022	0	0.012	0	10
1044.4044	0	0.005	0	15
1045.4045	0	0.005	0	15
2031.4031	0	0.012	0	5
4042.42	0	0.013	0	10
4041.41	0	0.01	0	10
4047.47	0	0.04	0	10
4043.43	0	0.007	0	10
4046.46	0	0.01	0	10
4051.51	0	0.007	0	10
4061.61	0	0.013	0	10
4062.62	0	0.02	0	10
4063.63	0	0.01	0	10

Appendix B2

Table B2 Generation schedule (p.u) for pool market

Hr Generator	1	2	3	4	5	6
4072	13.9	13.0	13.3	13.8	15.2	20.3
4071	5.0	5.0	5.0	5.0	5.0	5.0
4011	5.0	5.0	5.0	5.0	5.0	5.0
4012	8.0	8.0	8.0	8.0	8.0	8.0
4021	3.0	3.0	3.0	3.0	3.0	3.0
4031	3.5	3.5	3.5	3.5	3.5	3.5
4042	2.0	2.0	2.0	2.0	2.0	2.0
4041	3.0	3.0	3.0	3.0	3.0	3.0
4062	3.0	3.0	3.0	3.0	3.0	3.0
4063	4.0	4.0	4.0	4.0	4.0	4.0
4051	4.5	4.5	4.5	4.5	4.5	4.5
4047	5.0	5.0	5.0	5.0	5.0	5.0
2032	4.5	4.5	4.5	4.5	4.5	4.5
1013	3.5	3.5	3.5	3.5	3.5	3.5
1012	3.0	3.0	3.0	3.0	3.0	3.0
1014	4.0	4.0	4.0	4.0	4.0	4.0
1022	2.5	2.5	2.5	2.5	2.5	2.5
1021	3.5	3.5	3.5	3.5	3.5	3.5
1043	2.0	2.0	2.0	2.0	2.0	2.0
1042	4.0	4.0	4.0	4.0	4.0	4.0
Hr	7	8	9	10	11	12
Generator						
4072	22.5	22.5	22.5	22.5	22.5	22.5
4071	5.0	5.0	5.0	5.0	5.0	5.0
4011	5.0	5.0	5.0	5.0	5.0	5.0

4012	8.0	8.0	8.0	8.0	8.0	8.0
4021	3.0	3.0	3.0	3.0	3.0	3.0
4031	3.5	3.5	3.5	3.5	3.5	3.5
4042	5.8	6.0	6.0	6.0		5.4
4041	3.0	3.0	3.0	3.0	3.0	3.0
4062	3.0	5.4	5.0	3.0	5.4	3.0
4063	4.0	4.0	4.0	4.0	4.0	4.0
4051	4.5	4.5	4.5	4.5	4.5	4.5
4047	5.0	5.0	5.0	5.0	5.0	5.0
2032	4.5	4.5	4.5	4.5	4.5	4.5
1013	3.5	3.5	3.5	3.5	3.5	3.5
1012	3.0	6.0	6.0	6.0	6.0	3.0
1014	6.0	6.0	6.0	6.0	6.0	6.0
1022	2.5	2.5	2.5	2.5	2.5	2.5
1021	3.5	6.0	6.0	4.0	6.0	3.5
1043	2.0	2.0	2.0	2.0	2.0	2.0
1042	4.0	4.0	4.0	4.0	4.0	4.0
Hr	13	14	15	16	17	18
Generator						
4072	22.5	22.5	21.5	22.2	20.9	22.5
4071	5.0	5.0	5.0	5.0	5.0	5.0
4011	5.0	5.0	5.0	5.0	5.0	5.0
4012	8.0	8.0	8.0	8.0	8.0	8.0
4021	3.0	3.0	3.0	3.0	3.0	3.0
4031	3.5	3.5	3.5	3.5	3.5	3.5
4042	3.1	2.0	2.0	2.0	2.0	2.0
4041	3.0	3.0	3.0	3.0	3.0	3.0
4062	3.0	3.0	3.0	3.0	3.0	3.0
4063	4.0	4.0	4.0	4.0	4.0	4.0
4051	4.5	4.5	4.5	4.5	4.5	4.5
4047	5.0	5.0	5.0	5.0	5.0	5.0
2032	4.5	4.5	4.5	4.5	4.5	4.5
1013	3.5	3.5	3.5	3.5	3.5	3.5
1012	3.0	3.0	3.0	3.0	3.0	3.0
1014	6.0	4.3	4.0	4.0	4.0	5.1
1022	2.5	2.5	2.5	2.5	2.5	2.5
1021	3.5	3.5	3.5	3.5	3.5	3.5
1043	2.0	2.0	2.0	2.0	2.0	2.0
1042	4.0	4.0	4.0	4.0	4.0	4.0

Hr	19	20	21	22	23	24
Generator						
4072	22.5	22.5	22.5	22.5	13.0	13.3
4071	5.0	5.0	5.0	5.0	5.0	5.0
4011	5.0	5.0	5.0	5.0	5.0	5.0
4012	8.0	8.0	8.0	8.0	8.0	8.0
4021	3.0	3.0	3.0	3.0	3.0	3.0
4031	3.5	3.5	3.5	3.5	3.5	3.5
4042			6.0	2.0	2.0	2.0
4041	3.0	3.0	3.0	3.0	3.0	3.0
4062	4.4	3.9	3.0	3.0	3.0	3.0
4063	4.0	4.0	4.0	4.0	4.0	4.0
4051	4.5	4.5	4.5	4.5	4.5	4.5
4047	5.0	5.0	5.0	5.0	5.0	5.0
2032	4.5	4.5	4.5	4.5	4.5	4.5
1013	3.5	3.5	3.5	3.5	3.5	3.5
1012	6.0	6.0	3.0	3.0	3.0	3.0
1014	6.0	6.0	4.5	5.5	4.0	4.0
1022	2.5	2.5	2.5	2.5	2.5	2.5
1021	6.0	6.0	3.5	3.5	3.5	3.5
1043	2.0	2.0	2.0	2.0	2.0	2.0
1042	4.0	4.0	4.0	4.0	4.0	4.0

Appendix C1

Table C1. Contingency analysis results for CIGRE 32-bus under peak load at hour 8

Outaged Line	Overloaded line	PI index	PV (MW)	Ranking
4011.4021	4011.402	0.24	1449.2	1
	4012.402	0.46		
	4031.403	0.75		
4041.4044	4031.403	0.54	756.7	2
	4042.404	0.15		
	4032.404	0.06		
4031.4041	4031.404	0.05	716.9	3
	4031.403	0.49		
	4042.404	0.14		
4011.4022	4012.402	0.55	569.5	4
	4042.404	0.02		
4012.4022	4011.402	0.49	518.2	5
4042.4044	4012.402	0.01	451.1	6
	4042.404	0.44		
4021.4032	4012.402	0.1	446.6	7
	4021.404	0.05		
	4031.403	0.24		
	4042.404	0.06		
4042.4043	4012.402	0.02	389.1	8
	4042.404	0.37		
4031.4032	4041.404	0.35	351.9	9
4011.4012	4012.402	0.28	333.9	10
	4031.403	0.06		
*4044.1044	4044.104	0.42	317.1	11
4032.4044	4042.404	0.21	274.5	12
	4041.404	0.07		
4012.1012	4042.404	0.0008	224.8	13
	1013.101	0.37		
4043.4044	4031.403	0.02	220.2	14
	4042.404	0.2		
4062.4045	4031.403	0.11	147.7	15
	4042.404	0.03		

Outaged Line	**Overloaded line**	**PI index**	**PV (MW)**	**Ranking**
	4041.404	0.0011		
4021.4042	4012.402	0.11	140	16
	4021.403	0.03		
*4045.1045	4031.403	0.0012	132.8	17
4041.4061	4031.403	0.1	128.3	18
	4042.404	0.03		
1013.1011	4012.402	0.02	116.8	19
	4031.403	0.0045		
4042.4032	4032.404	0.06	58	20
4031.4022	4042.404	0.05	49.7	21
4011.1011	4012.402	0.03	36.3	22
	4031.403	0.006		
4071.4011	4012.402	0.03	35.7	23
	4031.403	0.006		
1013.1014	4012.402	0.0078	9.5	24
	4031.403	0.0017		
4062.4061	4012.402	0.0037	3.7	25
*1041.1045	4031.403	0.0025	2.5	26
4044.4045	4012.402	0.0011	1.1	27
1042.1044	4031.403	0.0003	0.3	28

Appendix C2

Table C2. Line Outage Distribution Factors for IEEE 14 Bus system

d_{ijmn}	LODF	d_{ijmn}	LODF	d_{ijmn}	LODF	d_{ijmn}	LODF
1 .2 .1 .2	0.838	2 .4 .1 .5	0.353	3 .4 .13.14	0.026	4 .9 .13.14	0.186
1 .2 .1 .5	0.5	2 .4 .2 .3	0.447	4 .5 .1 .5	0.493	5 .6 .1 .2	0.005
1 .2 .5 .6	0.032	2 .4 .2 .5	0.415	4 .5 .2 .5	0.58	5 .6 .2 .3	0.031
1 .2 .6 .11	0.02	2 .4 .3 .4	0.447	4 .5 .4 .7	0.414	5 .6 .2 .4	0.04
1 .2 .6 .12	0.002	2 .4 .5 .6	0.108	4 .5 .4 .9	0.304	5 .6 .3 .4	0.031
1 .2 .6 .13	0.006	2 .4 .6 .11	0.065	4 .5 .7 .9	0.414	5 .6 .4 .7	0.492
1 .2 .12.13	0.002	2 .4 .6 .12	0.007	4 .5 .9 .10	0.509	5 .6 .4 .9	0.361
1 .2 .13.14	0.016	2 .4 .6 .13	0.019	4 .5 .9 .14	0.423	5 .6 .7 .9	0.492
1 .5 .1 .2	0.162	2 .4 .12.13	0.007	4 .5 .10.11	0.509	5 .6 .9 .10	0.606
1 .5 .2 .3	0.225	2 .4 .13.14	0.054	4 .7 .1 .5	0.018	5 .6 .9 .14	0.503
1 .5 .2 .4	0.294	2 .5 .1 .5	0.478	4 .7 .2 .5	0.021	5 .6 .10.11	0.606
1 .5 .2 .5	0.386	2 .5 .2 .3	0.327	4 .7 .4 .5	0.149	6 .11.1 .2	0.003
1 .5 .3 .4	0.225	2 .5 .2 .4	0.427	4 .7 .4 .9	0.639	6 .11.2 .3	0.018
1 .5 .4 .5	0.311	2 .5 .3 .4	0.327	4 .7 .5 .6	0.631	6 .11.2 .4	0.024
1 .5 .4 .7	0.032	2 .5 .4 .5	0.453	4 .7 .6 .11	0.382	6 .11.3 .4	0.018
1 .5 .4 .9	0.023	2 .5 .4 .7	0.046	4 .7 .6 .12	0.042	6 .11.4 .7	0.296
1 .5 .7 .9	0.032	2 .5 .4 .9	0.034	4 .7 .6 .13	0.111	6 .11.4 .9	0.217
1 .5 .9 .10	0.039	2 .5 .7 .9	0.046	4 .7 .12.13	0.042	6 .11.6 .12	0.066
1 .5 .9 .14	0.033	2 .5 .9 .10	0.057	4 .7 .13.14	0.318	6 .11.6 .13	0.173
1 .5 .10.11	0.039	2 .5 .9 .14	0.047	4 .9 .1 .5	0.011	6 .11.7 .9	0.296
2 .3 .1 .5	0.169	2 .5 .10.11	0.057	4 .9 .2 .5	0.012	6 .11.9 .10	1
2 .3 .2 .4	0.279	3 .4 .1 .5	0.169	4 .9 .4 .5	0.087	6 .11.10.11	1
2 .3 .2 .5	0.198	3 .4 .2 .4	0.279	4 .9 .4 .7	0.508	6 .11.12.13	0.066
2 .3 .5 .6	0.051	3 .4 .2 .5	0.198	4 .9 .5 .6	0.369	6 .11.13.14	0.497
2 .3 .6 .11	0.031	3 .4 .5 .6	0.051	4 .9 .6 .11	0.223	6 .12.2 .3	0.003
2 .3 .6 .12	0.003	3 .4 .6 .11	0.031	4 .9 .6 .12	0.025	6 .12.2 .4	0.004
2 .3 .6 .13	0.009	3 .4 .6 .12	0.003	4 .9 .6 .13	0.065	6 .12.3 .4	0.003
2 .3 .12.13	0.003	3 .4 .6 .13	0.009	4 .9 .7 .9	0.508	6 .12.4 .7	0.044
2 .3 .13.14	0.026	3 .4 .12.13	0.003	4 .9 .12.13	0.025	6 .12.4 .9	0.032

d_{ijmn}	LODF	d_{ijmn}	LODF	d_{ijmn}	LODF
6 .12.6 .11	0.088	9 .10.6 .11	1	13.14.2 .4	0.016
6 .12.6 .13	0.652	9 .10.9 .14	0.497	13.14.3 .4	0.012
6 .12.7 .9	0.044	9 .14.1 .5	0.011	13.14.4 .7	0.196
6 .12.9 .14	0.222	9 .14.2 .5	0.013	13.14.4 .9	0.144
6 .13.1 .2	0.001	9 .14.4 .5	0.094	13.14.6 .11	0.394
6 .13.2 .3	0.009	9 .14.5 .6	0.398	13.14.7 .9	0.196
6 .13.2 .4	0.012	9 .14.6 .12	0.132	13.14.9 .14	1
6 .13.3 .4	0.009	9 .14.6 .13	0.348		
6 .13.4 .7	0.152	9 .14.9 .10	0.394		
6 .13.4 .9	0.112	9 .14.10.11	0.394		
6 .13.6 .11	0.307	9 .14.12.13	0.132		

d_{ijmn}	LODF	d_{ijmn}	LODF	d_{ijmn}	LODF
6 .13.6 .12	0.868	9 .14.13.14	1		
6 .13.7 .9	0.152	10.11.1 .5	0.017		
6 .13.9 .14	0.778	10.11.2 .5	0.02		
6 .13.12.13	0.868	10.11.4 .5	0.142		
7 .9 .1 .5	0.018	10.11.5 .6	0.602		
7 .9 .2 .5	0.021	10.11.6 .11	1		
7 .9 .4 .5	0.149	10.11.9 .14	0.497		
7 .9 .4 .9	0.639	12.13.2 .3	0.003		
7 .9 .5 .6	0.631	12.13.2 .4	0.004		
7 .9 .6 .11	0.382	12.13.3 .4	0.003		
7 .9 .6 .12	0.042	12.13.4 .7	0.044		
7 .9 .6 .13	0.111	12.13.4 .9	0.032		
7 .9 .12.13	0.042	12.13.6 .11	0.088		
7 .9 .13.14	0.318	12.13.6 .13	0.652		
9 .10.1 .5	0.017	12.13.7 .9	0.044		
9 .10.2 .5	0.02	12.13.9 .14	0.222		
9 .10.4 .5	0.142	13.14.1 .2	0.002		
9 .10.5 .6	0.602	13.14.2 .3	0.012		

d_{ijmn} means line outage factor for line i,j when we outage line m,n