OPTIMAL RESCHEDULING OF ACTIVE POWER GENERATION UNDER CONGESTION MANAGEMENT USING PARTICLE SWARM OPTIMIZATION

Thesis submitted towards the partial fulfillment of the requirements of the degree of

Master of Engineering

in

Power Systems & Electric Drives

Submitted by

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CERTIFICATE

I hereby certify that the work which is being presented in the thesis entitled **"Optimal Rescheduling of Active Power Generation Under Congestion Management Using Particle Swarm Optimization"**, in partial fulfillment of the requirements for the award of degree of Master of Engineering in Power systems and Electric Drives submitted in Electrical & Instrumentation Engineering Department of Thapar University, Patiala, is an authentic record of my own work carried out under the guidance of **Ms. Manbir Kaur**, Associate Professor, EIED.

The matter presented in the thesis has not been submitted for the award of any other degree of this or any other university.

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It is certified that the above statement made by the student is correct to the best of our knowledge and belief.

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ABSTRACT

The restructuring of the electricity industry in the word has made the problem of transmission congestion increasingly significant. It aggravates the smooth functioning of competitive markets and typically high costs are associated with it, which have to be eventually borne by the consumers. Therefore, investigation of techniques for congestion-free wheeling of power is of paramount interest. This thesis presents a congestion management (CM) algorithm by optimal rescheduling of active powers of generators which minimize the redispatch cost of participating generators satisfying power balance, generator operating limit and line flow limits constraints while managing congestion effectively. Contributions made in this thesis are twofold. Firstly a technique for optimum selection of participating generators has been introduced using generator sensitivities to the power flow on congested lines. Secondly it proposes an algorithm based on particle swarm optimization (PSO) which minimizes the deviations of rescheduled values of generator power outputs from scheduled levels. The effectiveness of the proposed methodology has been analyzed on modified IEEE 30 and modified IEEE 57-bus system. The thesis concludes with a set of recommendations for future work.

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ACRONYMS

g	Participating generator.
N_g	Number of participating generators.
ΔC_g	Incremental and decremental cost of generator g.
ΔP_g	Active power adjustment at bus g.
ΔP_g^{min}	Minimum adjustment limit of generator g.
ΔP_g^{max}	Maximum adjustment limit of generator g.
P_g	Active power output
P_g^{min}	Minimum generation limit of generator g.
P_g^{max}	Maximum generation limit of generator g.
F_k^0	Power flow caused by all contracts requesting the transmission service.
F_k^{max}	Power flow limit of line l.
ΔP_{ij}	Change in active power flow on the line connected between buses i and j.
ΔP_{Gg}	Change in active power of generator g.
V_i, V_j	Voltage magnitude at buses i and j.
θ_i, θ_j	Phase angle at buses i and j.
G_{ij}	Conductance of the line connected between buses i and j.
B_{ij}	Susceptance of the line connected between buses i and j.
w	Inertia Weight.
c_1	Cognitive acceleration coefficient.
c_2	Social acceleration coefficient.

CHAPTER 1

INTRODUCTION

1.1 OVERVIEW

The restructuring of the electricity industry has brought huge shifts in the planning, operations and management of power systems. The introduction of competitive markets did not only bring benefits, but also made the industry face unprecedented problems. Unlike other markets, the electricity market has salient characteristics, which make the operation of competitive markets a major challenge. The lack of major storage capability, the just-in-time-manufacturing nature of electricity and the central role that is played by the transmission and distribution networks, are some of the principal complexities in electricity.

With the increasing number of market participants in terms of generation, transmission and distribution owners, the number of desired transactions between the various players is growing. Each transaction requires energy to be transferred from a sending point to a point of receipt. The sellers and buyers of electric energy rely on the transmission network for its transportation. In the days before restructuring, the power grid used to be operated by vertically integrated utilities, who had control over both generation and transmission facilities. Since the unbundling of generation and transmission and the advent of more decentralized decision-making, it has become a challenge to operate the system in synchronism. The current transmission networks were not originally planned for trading in a competitive market. A problem that is becoming more and more significant nowadays is transmission congestion In addition, one of the key characteristics of the electricity market is that the energy flow will not necessarily take the direct route from the sender to the receiver, but will travel across the transmission system according to the laws of physics and is especially in a highly interconnected network likely to result in loop flows and affect various parts of the power system. If market participants intend to undertake a high number of transactions to transfer energy between various points in the network, the realization of all schedules might lead to violations of one or more limits of the transmission system. This situation is called transmission congestion. Whenever this is the case, not all of the desired transactions can be realized. The market players value the transmission of energy differently and the fact of not being able to realize certain transactions can have severe impacts and cause high additional costs. Energy that cannot be purchased from the supplier who offers it at the lowest price because the current state of the transmission system does not allow the transfer, has to be purchased from an alternative resource at a higher price. The situation is especially severe if an area with high demand does not possess sufficient generation and relies on the import of energy from neighboring systems to serve the network load. In this case, congestion on the tie lines between the two regions can significantly endanger the ability of the system to meet its demand. [6]

After some years of restructuring, operating rules and procedures are still constantly changing. The main effort lies in providing an effective market design for the restructured environment. One of the key requirements for the implementation of competitive markets is an effective management of congestion.

1.2 LITERATURE SURVEY

Several studies have explored the impacts of congestion and different transmission and congestion management approaches.

Christie *et al*. [1] have described the methods of combining decentralized market solutions with operational use of optimal power flow which provide better solutions to existing and emerging problems.

Kumar *et al.* [2] has proposed a new zonal/cluster-based congestion management approach in which the zones have been determined based on lines real and reactive power flow sensitivity indexes also called as real and reactive transmission congestion distribution factors.

Song *et al.* [3] has proposed a model in which the system stability is incorporated into the congestion management, and the concept of market-based congestion management is extended into the dynamic scenario.

Alsac and Stott. [4] have discussed the problem formulation of optimal power-system load flows and solution scheme by incorporating exact outage-contingency constraints into the method, to give an optimal steady-state-secure system operating point.

Fu and Lamont. [5] have proposed an approach to identify the services of reactive support and real power loss while managing congestion using the upper bound cost minimization.

Huang and Yan. [7] have investigated the impacts of Thyristor Controlled Series Capacitor (TCSC) and Static Var Compensator (SVC) on this re-dispatch method with the objective of minimizing the total amount of transactions being curtailed.

Rau. [8] has analyzed the effect of congestion, and the economic signals of allocating congestion costs on the energy market and on transmission investment.

Meena and Selvi. [9] have developed optimal power flow model in which congestion is eliminated by rescheduling both real and reactive power generation.

Fang and David. [10] have considered an open transmission dispatch environment in which pool and bilateral/multilateral dispatches coexist and proceeds to develop a congestion management strategy for this scenario.

Yu and Ilic. [11] have introduced a method for effective grouping of system users according to their impact on the transmission constraints of interest into congestion clusters.

Yuen *et al.* [13] has evaluated congestion management in different deregulated electricity industries and illustrates how congestion is managed under privatization.

Conejo *et al.* [15] have addressed the congestion management problem avoiding offline transmission capacity limits related to stability. These limits on line power flows are replaced by optimal power flow-related constraints that ensure an appropriate level of security, mainly targeting voltage instabilities.

Kennedy and Eberhart. [21] have described the particle swarm optimization concept in terms of its precursors, briefly reviewing the stages of its development from social simulation to optimizer.

Yoshida *et al.* [22] has presented a particle swarm optimization for reactive power and voltage control considering voltage security assessment.

Abido *et al.* [24] proposed a novel evolutionary algorithm-based approach to optimal design of multi machine power-system stabilizers (PSS) which employs a particle-swarm-optimization technique to search for optimal settings of PSS parameters.

1.3 SCOPE AND CONTRIBUTION OF THE THESIS

There are two objectives involved in the thesis work:

(i) To propose a technique for reducing the number of participating generators and optimum rescheduling of their outputs while managing congestion in a pool at minimum rescheduling cost with the consideration that, there is no need to reschedule the outputs of generators whose generations are less critical to the congested line flow. To optimally select the generators participating in congestion management, the sensitivities of the generators to the congested line are used.

(ii) To explore the ability of particle swarm optimization technique in solving the congestion management problem. The congested system is modeled as an optimization problem.

The work carried out in this thesis has been summarized in six chapters.

Chapter 1: It deliberates on the overview of the problem, brief literature review, scope and contribution of the thesis.

Chapter 2: It discusses overview of congestion, congestion management and various congestion management techniques that address the congestion management problem in deregulated electricity markets.

Chapter 3: It includes the overview of particle swarm optimization and its fundamental algorithm.

Chapter 4: It emphasizes on congestion management problem formulation.

Chapter 5: Numerical results on two test systems namely Modified IEEE 30 and Modified IEEE 57 Bus System are presented for illustration purposes.

Chapter 6: Summarize conclusion and scope for future work.

CHAPTER 2

CONGESTION MANAGEMENT IN A DEREGULATED ENVIRONMENT

2.1 CONGESTION: AN OVERVIEW

Congestion occurs whenever one or more constraints are violated under which the system operates in the “normal” state or in any of the contingency cases in a list of specified contingencies. These constraints can either be physical limits like thermal or voltage limits or specified limits to ensure system security and reliability [1].

The basic notion of congestion is illustrated with respect to the simple 2-bus system shown in fig.2.1. The system has a seller at bus 1 and a seller at bus 2. A buyer intending to buy 150 MW is located at bus 2. The seller at bus 1 offers to sell power at a price of 5 $/MWh and the seller at bus 2 offers power for 10 $/MWh.

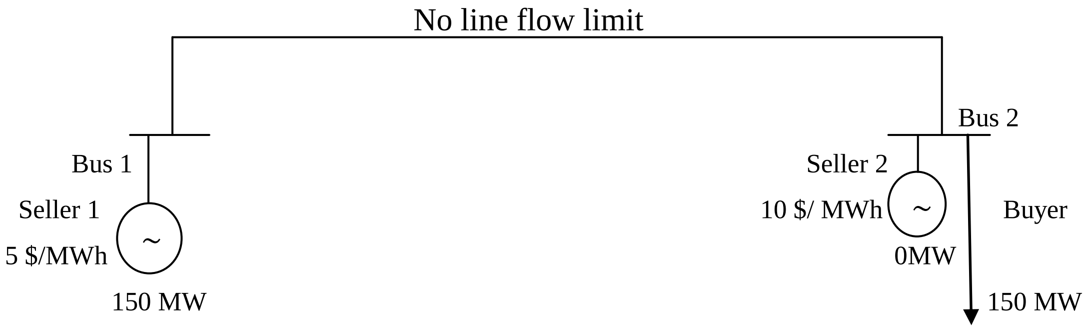

Figure 2.1: Unconstraint 2- Bus System

The transactions are determined for the transmission-unconstrained market. Seller 2 offers more expensive power than seller 1 and will therefore not be dispatched. Seller 1 sells 150 MW to the buyer at bus 2. Thus the total energy costs per hour are $750.

Now, we assume a more realistic situation with simple system shown in fig. 2.2, where a limit on the power transfer of 100MW on the line between bus 1 and bus 2 is imposed. The optimal dispatch points to minimize total cost are still the same as in the previous example: the seller at bus 1 at 150 MW and the seller at bus 2 not dispatched. But in this case a transaction of 150 MW between the seller at bus 1 and the buyer at bus 2 is not feasible, since it would result in a line overload of 50 MW.

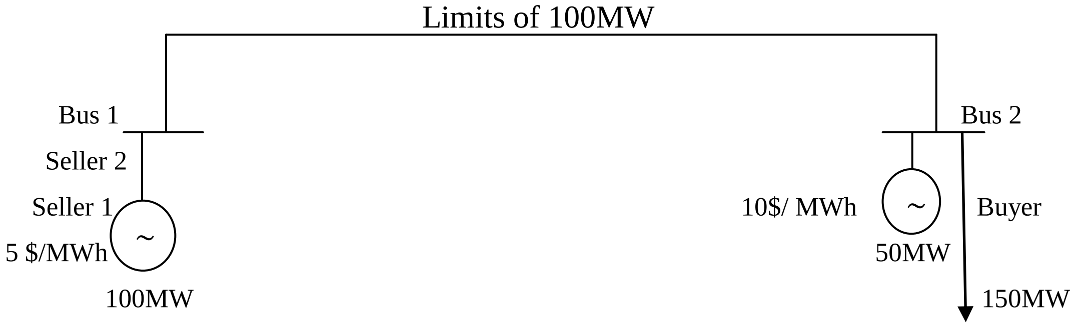

Figure 2.2: Constraints 2- Bus System

To eliminate this overload, we reduce the sale from seller 1 by 50 MW and instead dispatch the higher priced power of seller 2. With this new dispatch, total costs amount to $1,000. The additional constraint on the transmission line led to congestion and an increase in system costs by 33%.

Congestion is, on the one hand, the difference in megawatts of the power scheduled to flow on a transmission line and the actual transfer which is allowed on the line without violating any constraints. On the other hand, we can determine congestion costs as the difference in the costs for securing power to serve the system load without having to consider any constraints and the costs to serve the load without violating existing limits.

In the 2-bus system in fig. 2.2, congestion in the amount of 50 MW occurs, resulting in congestion costs of $250.

2.2 CONGESTION MANAGEMENT IN ELECTRICITY MARKETS

Transmission congestion may be defined as the condition where more power is scheduled or flows across transmission lines and transformers than the physical limits of those lines and transformers. The objective of congestion management is to take actions or control measures to relieve the congestion of transmission networks. In principle, congestion management can be considered at different timescales, such as:

i. long-term transmission capacity reservation that can be made yearly, monthly, weekly or daily;
ii. short-term scheduling of transmission constraints in the day-ahead market; or
iii. Re-dispatching of generation in the real time balancing market.

Depending on market structures and market rules, one or more of these congestion management processes may be applied.

Effective congestion management is crucial for the efficient operation of any electricity market where congestion exists. However, it has been recognized that completely eliminating all transmission congestion is neither necessary nor efficient. In other words, congestion management should compromise between the benefits and costs of solutions. In the short term, the objective of congestion management is to maintain the physical and operational reliability and security of the electricity transmission network and facilitate a competitive electricity market. Basically, congestion management has an important impact on spot prices, the degree of competition and the bidding incentives for energy market participants. In the long term, congestion management will impact on the investment decisions of new generators, load, network transmission infrastructure and the opportunities for integration of alternative generation sources (e.g. renewable sources) into electricity transmission networks.

The problem of congestion has increased in recent years due to a number of reasons:

i. First, deregulation of the electricity industry has brought the benefits of possible lower electricity prices and better service quality and large-volume electricity trade can be conducted cross-border in competitive electricity markets. However, such electricity trade may cause large-scale transmission of electric power across regions where the unexpected power flows may push electricity networks towards their physical limits.
ii. Second, in deregulated environments there is a lack of investment in electricity networks in order to meet demand and generation where there is a lack of transmission capacity. In other words, transmission capacity, relative to peak load, has been declining in many countries. It is anticipated that this trend may continue in deregulated environments.
iii. Third, with the continuous large-scale integration of wind generation into electricity transmission networks, there are difficulties in managing congestion due to the fast-changing power flows of electricity networks.
iv. Fourth, the continuous development of an internal electricity market, with increased cross border electricity trade, is making congestion management an even bigger challenge.

2.3 SCOPE OF CONGESTION MANAGEMENT IN A DEREGULATED ENVIRONMENT

When the producers and consumers of electric energy desire to produce and consume in amounts that would cause the transmission system to operate at or beyond one or more transfer limits, the system is said to be congested. Congestion management controls the transmission system so that transfer limits are observed. Congestion is a term that has come to power systems from economics in conjunction with deregulation, although congestion was present on power systems before deregulation.

Then it was discussed in terms of steady-state security, and the basic objective was to control generator output so that the system remained secure (no limits were violated) at the lowest cost. When dealing with power flow within its operating area, one entity, the vertically integrated utility, controlled both generation and transmission, gained economically from lower generation costs, and was responsible for the consequences and expected costs when less secure operation resulted in power outages. Conflicts between security and economics could be traded off within one decision making entity. While this process sounds quite exact, the expected costs of less secure operation could not be accurately quantified, and the limits themselves could develop a great deal of flexibility when there was money to be saved by pushing them. In the pre deregulation power system, most energy sales were between adjacent utilities. The transaction would not go forward unless each utility agreed that it was in their best interests for both economy and security. Only when the transaction had an impact on the security of an uninvolved utility, a situation known as third-party wheeling, did problems that would now be called congestion arise.

In the deregulated power system, the challenge of congestion management for the transmission system operator is to create a set of rules that ensure sufficient control over producers and consumers (generators and loads) to maintain an acceptable level of power system security and reliability in both the short term (real-time operations) and the long term (transmission and generation construction) while maximizing market efficiency. The rules must be robust, because there will be many aggressive entities seeking to exploit congestion to create market power and increased profits for themselves at the expense of market efficiency. The rules should also be fair in how they affect different participants, and they should be transparent, that is, it should be clear to all participants why a particular outcome has occurred. The form of congestion management is dependent on the form of the energy market, and congestion management itself cannot be separated from market considerations.

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 [1]. Congestion management (CM) includes both the congestion relief actions and the associated pricing mechanisms. 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 interconnectors 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. 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 [1]. Congestion may be alleviated through various ways. Among the technical solutions we have out aging 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 [10].

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 [10]. 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.

2.3.1 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 Independent System Operator (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.

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.

2.3.2 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 [17].

2.3.3 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. Counter trading may be viewed as a special type of re-dispatching.

2.3.4 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 [17].

2.3.5 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. [17]

2.3.6 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 [10] which is regarded as a highly effective instrument in setting the transaction curtailment.

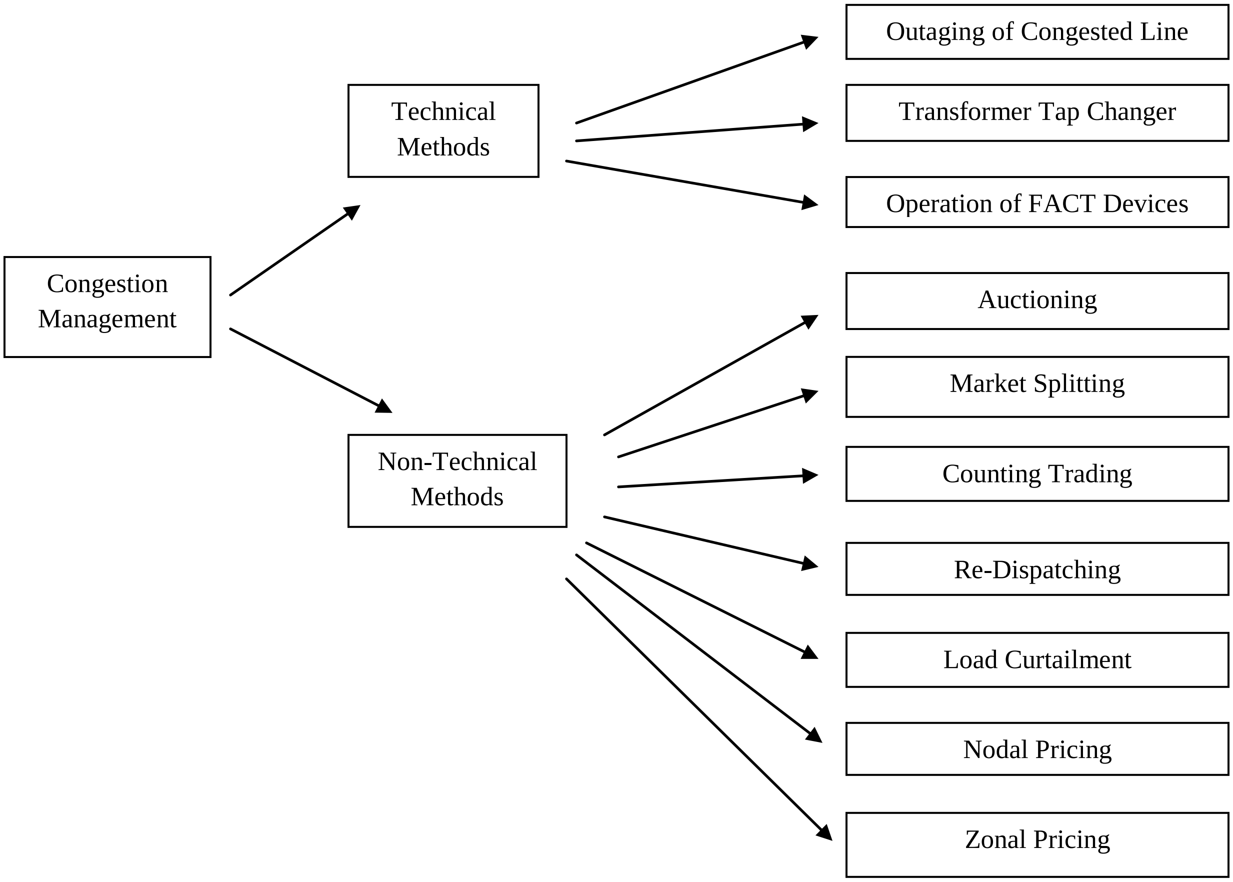

Figure 2.3: Congestion Management Methods

2.3.7 FACTS

Flexible AC transmission systems (FACTS) are 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.

2.4 MARKET ECONOMICS AND CONGESTION

The performance of a market is measured by its social welfare. Social welfare is a combination of the cost of the energy and the benefit of the energy to society as measured by society's willingness to pay for it. If the demand for energy is assumed to be independent of price, that is, if demand has zero price elasticity, then the social welfare is simply the negative of the total amount of money paid for energy. Real markets always operate at lower levels of social welfare. The difference in social welfare between a perfect market and a real market is a measure of the efficiency of the real market.

The conditions required for perfect competition are:

i) there are a large number of generators, each producing the same product;
ii) each generator attempts to maximize its profits;
iii) each generator is a price taker—it cannot change the market price by changing its bid;
iv) market prices are known to all generators;
v) transmissions are costless.

Arguably none of these conditions ever exists in a real market.

When a generator is a price taker, it can be shown that maximizing its profit requires bidding its incremental costs. When a generator bids other than its incremental costs, in an effort to exploit imperfections in the market to increase profits, its behavior is called strategic bidding. If the generator can successfully increase its profits by strategic bidding or by any means other than lowering its costs, it is said to have market power. The obvious example of market power is a non-regulated monopoly with a zero elasticity demand, where the generator can ask whatever price it wants for electric energy. Market power results in market inefficiency.

Historically, vertically integrated utilities managed this condition by constraining the economic dispatch of generators with the objective of ensuring security and reliability of their own and/or neighboring systems. Electric power industry restructuring has moved generation investment and operations decisions into the competitive market but has left transmission as a communal resource in the regulated environment. This mixing of competitive generation and regulated transmission makes congestion management difficult. The difficulty is compounded by increases in the amount of congestion resulting from increased commercial transactions and the relative decline in the amount of transmission.

Congestion does occur in both vertically bundled and unbundled systems but management in the bundled system is relatively simple as Generation, Transmission and distribution are managed by one utility. In a deregulated power system, the challenge of congestion management is to deliver the traded transactions while maintaining an acceptable level of power system security and reliability. The congestion in a system cannot be allowed to persist for a long time, as it can cause sudden rise in electricity price and threaten system security and reliability.

2.4.1 Vertically Integrated Operation

Unbundling implies opening to competition those tasks that are, in a vertically integrated structure, coordinated jointly with the objective of minimizing the total costs of operating the utility. In such a traditional organizational structure, all the control functions, like automatic generation control (AGC), state estimation, generation dispatch, unit commitment, etc., are carried out by an energy management system. Generation is dispatched in a manner that realizes the most economic overall solution. In such an environment, an optimal power flow can perform the dual function of minimizing production costs and of avoiding congestion in a least-cost manner. Congestion management thus involves determining a generation pattern that does not violate the line flow limits. Line flow capacity constraints, when incorporated in the scheduling program, lead to increased marginal costs. This may then be used as an economic signal fore-scheduling generation or, in the case of recurring congestion, for installation of new generation/transmission facilities. [1]

2.4.2 Unbundled Operation

In a competitive power market scenario, besides generation, loads, and line flows, contracts between trading entities also comprise the system decision variables. The following pool and bilateral competitive structures for the electricity market have evolved/are evolving:

(i) Single auction power pools, where wholesale sellers (competitive generators) bid to supply power in to a single pool. Load serving entities (LSEs or buyers) then buy wholesale power from that pool at a regulated price and resell it to the retail loads.

(ii) Double auction power pools, where the sellers put in their bids in a single pool and the buyers then compete with their offers to buy wholesale power from the pool and then resell it to the retail loads.

(iii) In addition to combinations of (i) and (ii), bilateral wholesale contracts between the wholesale generators and the LSEs without third-party intervention.

(iv) Multilateral contracts, i.e., purchase and sale agreements between several sellers and buyers, possibly with the intervention of third parties such as forward contractors or brokers. In both (iii) and (iv), the price-quantity trades are up to the market participants to decide, and not the ISO. The role of the ISO in such a scenario is to maintain system security and carry out congestion management.

2.4.3 Congestion Management in an Economic Dispatch Framework

Congestion may occur in a system due to unexpected contingencies such as generation outage, line outage, overloading of lines, or failure of equipment’s etc. There are many possible causes of market power. One of the main reasons is congestion. Consider a system shown in figure 2.4. Let each zone have a 100MW constant load. Zone A has 200 MW generator with an incremental cost of Rs.100/MWh. Zone B has a 200 MW generator with an incremental cost of Rs.200/MWh. Assume both generators bid their incremental cost. If there is no transfer limit between zones, all 200 MW of load will be brought from generator A at Rs.100/MWh as shown in Fig(2.4a). If there is a 50 MW transfer limit, then 150 MW will be brought from A at Rs.100/MWh and the remaining 50 MW must be brought from generator B at Rs.200/MWh, as shown in Fig(2.4b). The total cost of 200 MW in un-congested market is Rs.20000/h and that in the congested market is Rs.25000/h. Congestion has created a market inefficiency of 25% of the optimal cost, even without strategic behavior of the generator. Congestion has also created unlimited market power for generator at B.

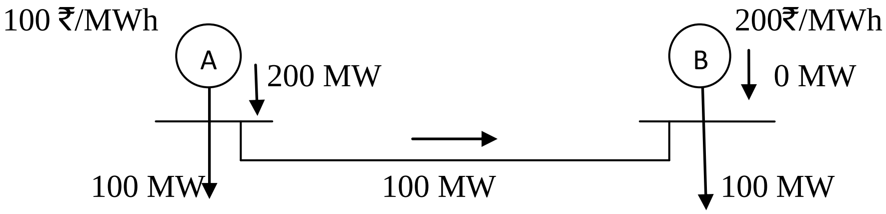

Figure 2.4a: No-Congestion

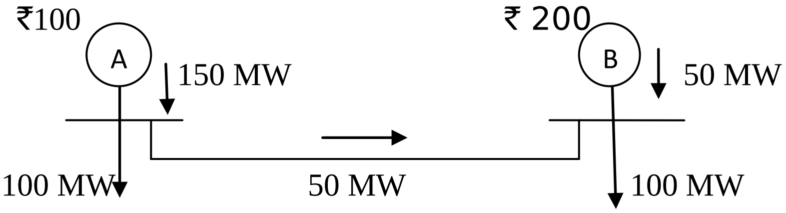

Figure 2.4b: With 50 MW transfer limit

Figure 2.4: Two Zone System Connected by an Interface.

2.5 CONGESTION MANAGEMENT STRATEGIES

In deregulated power system, transmission companies (TRANSCOs), Generation companies (GENCOs) and distribution companies (DISCOs) are under different organizations. To maintain the coordination between them there will be one system operator in all types of deregulated power system models, generally it is Independent System operator (ISO). Several utilities join together to form a pool, with a central broker in place, to coordinate the operation on an hour-to-hour basis. In a pool market GENCOs and DISCOs submit the sell and purchase decision in the form of sell and buy bids to the market operator, who, in turn, clears the market using an appropriate market clearing procedure. Finally it results in 24 hours energy prices to be paid by consumers and to be charged by producers. More often than not, pool market results originate network congestion problem which may results in preventing new contracts, infeasibility in existing and new contracts, additional damages to the system components. When such scenario arises, the ISO should determine the minimal changes in the market results that ensure a secure operation. In this work congestion management is done by means of optimal rescheduling of generator based on the incremental and decremental price bids submitted by GENCOs to alter the schedule productions from initial market clearing values.

2.6 CONGESTION MANAGEMENT METHODOLOGIES

There are two broad paradigms that may be employed for congestion management. These are the cost-free means and the not-cost-free means [18]. The former include actions like outages of congested lines or operation of transformer taps, phase shifters, or FACTS devices. These means are termed as cost-free only because the marginal costs involved in their usage are nominal. The not-cost-free means include:

i. Rescheduling Generation- This leads to generation operation at an equilibrium point away from the one determined by equal incremental costs. Mathematical models of pricing tools may be incorporated in the dispatch framework and the corresponding cost signals obtained. These cost signals may be used for congestion pricing and as indicators to the market participants to rearrange their power injections/extractions such that congestion is avoided.

ii. Prioritization and Curtailment of Loads/Transactions- A parameter termed as willingness-to-pay-to-avoid-curtailment was introduced in [10]. This can be an effective instrument in setting the transaction curtailment strategies which may then be incorporated in the optimal power flow framework.

Several methods have been reported that address the congestion management problem in deregulated electricity markets. These can be classified into broad groups, as

2.6.1 *Security-Constrained Generation Re-dispatch:* One of the most common approaches to alleviate congestion in the network is to re-schedule of the generation by the optimal power flow model with transmission constraints as well as bus-voltage constraints to maintain the system security.

2.6.2 *Congestion Pricing and Market-Based Methods:* Price signals were used for the generators to manage congestion and the solution under rational behavior assumption is identical to an OPF solution. The main feature of this method is that system stability is incorporated into the congestion management, and the concept of market-based congestion management is extended into the dynamic scenario. The total dynamic congestion management cost will be minimized, and system security as well as the scheduled transactions is maintained.

2.6.3 *Network Sensitivity Factors Methods:* Other method for congestion management proved to be efficient is the use of network sensitivity factors, which is the relationship between the change in power injection and the change in power flow in the network. In a deregulated electricity market, it may always not be possible to dispatch all of the contracted power transactions due to congestion of the transmission corridors. System operators try to manage congestion, which otherwise increases the cost of the electricity and also threatens the system security and stability. The zones have been determined based on lines real and reactive power flow sensitivity indexes also called as real and reactive transmission congestion distribution factors. The generators in the most sensitive zones, with strongest and non-uniform distribution of sensitivity indexes, are identified for rescheduling their real power output for congestion management.

2.6.4 *Application of FACTS Devices:* An alternative to building new transmission lines to solve the frequently occurred congestion problems is to use Flexible AC Transmission System (FACTS). FACTS devices such as thyristor controlled series compensators and thyristor controlled phase angle regulators, by controlling the power flows in the network, can help to reduce the flows in heavily loaded lines resulting in an increased loadability of the network and reduced cost of production. Congestion management using FACTS devices requires a two step approach. First, the optimal location of these devices in the network must be ascertained and then, the settings of their control parameters optimized. The development of simple and efficient models for optimal location of FACTS devices that can be used for congestion management by controlling their parameters optimally.

CHAPTER 3

PARTICLE SWARM OPTIMIZATION

3.1 INTRODUCTION

Particle swarm optimization is an optimization tool that provides a population based search procedure in which individual called particles change their position (states) with time. It is a stochastic, population-based search and optimization algorithm for problem solving. It is a kind of swarm intelligence that is based on social psychological principles and provides insights into social behavior, as well as contributing to engineering applications. The particle swarm optimization algorithm was first described in 1995 by James Kennedy and Russell C. Eberhart [21]. The techniques have evolved greatly since then, and the original version of the algorithm is barely used at present. Social influence and social learning enable a person to maintain cognitive consistency. People solve problems by talking with other people about them, and as they interacts their beliefs, attitudes, and behavior changes, the changes could typically be depicted as the individuals moving toward one another in a socio-cognitive space. The motivation was social behavior of organisms such as fish schooling and bird flocking. It was observed that a flock of birds stochastically find food in an area. Not all birds in a flock know the exact location of food but they know the position closest to it (the food). The simplest and most effective way to search for food is to search the area around the present best position, i.e., the position closest to food. Similar to seeking food, the solution to an optimization problem or the best solution is found out from a solution space with a population based search procedure in which the particles, like birds, change their positions (states) with time. Each particle represents a potential solution to a problem in an N dimensional space (where the number of dimensions corresponds to the number of variables). The particles are randomly generated (a particle size between 10 to 100 is usually considered sufficient) initially with two parameters

Each position and velocity in the N dimensional space such as position $X_i = (x_{i1}, x_{i2}, x_{i3} \dots \dots \dots x_{in})$ and velocity Vi = $V_i = (v_{i1}, v_{i2}, v_{i3} \dots \dots \dots v_{in})$. Each particle is then flown over the search space in order its flying velocity and direction according to its own flying experience as well as that of its neighbors. Positions of the particles (tentative solutions) are evaluated at the end of every iteration relative to an objective or fitness value. Particles are assumed to retain memory of the best positions they have achieved in course of flying and share this information among the rest. The collective best positions of all the particles taken together is termed as the global best position given as$GB = (gb_1, gb_2 \dots \dots \dots gb_n)$ and the best position achieved by the individual particle is termed as the local best or position best and for the i_{th} particle given as $P = (p_{i1}, p_{i2}, p_{i3} \dots \dots \dots p_{in})$. Particles use both of these information to update their positions and velocities as given in the following equations:

$$V_i^{j+1} = wV_i^j + C_1 * r_1 * \left(P_i^j - X_i^j\right) + C_1 * r_1 * \left(GB^j - X_i^j\right) \quad --- \quad (3.1)$$

$$X_i^{j+1} = X_i^j + V_i^{j+1} \quad --- \quad (3.2)$$

Where w is the inertia weight;
$r_1$and r_2 are random values between 0 and 1;
C_1 and C_2 are two positive constants, called acceleration constants; generally $C_1=C_2=2$.
j represents iteration number.
i represents population.
The particles continue flying and seeking solution and hence the algorithm continues until a pre-specified number of maximum iterations are exceeded or exit criteria are met. The accuracy and rate of convergence of the algorithm depends on the appropriate choice of particle size, maximum velocity of particles and the inertia weight. However, no specific guideline is available to select the particle size. Moreover, it also varies from problem to problem. As a result, one has to choose it by trial and error. The maximum velocity of individual particles should be chosen very judiciously. If the maximum velocity is too high, the particles may fly past the best solution without discovering it and if it is too low particles may fail to explore sufficiently beyond local solutions. The inertia weight parameter is considered important for the convergence of the algorithm. It controls the impact of previous history of velocities on the current velocities of particles and hence regulates the local and global exploration capabilities of the particles. A large inertia weight facilitates exploration, i.e., searching newer areas while a small value tends to facilitate exploitation, i.e., a finer searching of current search area. The value of the inertia weight parameter is normally kept between 0.4 and 0.9. Thus, the choice of inertia weight should be carefully made.

Compared with traditional optimization algorithms, PSO does not need the information of the derivative of functions in the process model. The algorithm can work as long as fitness values for optimization model can be calculated. Besides, the algorithm of PSO is simple enough for people to understand it easily and has a profound intellectual background at the same time.

The technique of PSO has already been applied in several problems of optimization in the power system. In [20], PSO has been applied to solve the economic dispatch of generators in a power system.

In a PSO algorithm, particles change their positions by flying around in a multidimensional search space until a relatively unchanged position has been encountered, or until computational limitations are exceeded. In social science context, a PSO system combines a social-only model and a cognition-only model. The social-only component suggests that individuals ignore their own experience and fine tune their behavior according to the successful beliefs of the individual in the neighborhood. On the other hand, the cognition-only component treats individuals as isolated beings. A particle changes its position using these models.

Each particle keeps track of its coordinates in the problem space, which are associated with the best solution, fitness, it has achieved so far. The fitness value is also stored. This value is called pbest. Another best value that is tracked by the particle swarm optimizer is the best value, obtained so far by any particle in the neighbours of the particle. This location is called lbest. When a particle takes all the population as its topological neighbours, the best value is a global best and is called gbest.

The concept of the PSO consists of, at each time step, changing the velocity of(accelerating) each particle toward its pbest and lbest locations (local version of PSO). Acceleration is weighted by a random term, with separate random numbers being generated for acceleration toward pbest and lbest locations. In past several years, PSO has been successfully applied in many research and application areas. It is demonstrated that PSO gets better results in a faster, cheaper way compared with other methods. As in the literature, PSO algorithm has been successfully applied to various problems.

Another reason that PSO is attractive is that there are few parameters to adjust. One version, with slight variations, works well in a wide variety of applications. Particle swarm optimization has been used for approaches that can be used across a wide range of applications, as well as for specific applications focused on a specific requirement.

3.2 ADVANTAGES OF PSO

Many advantages of PSO over other traditional optimization techniques can be summarized as follows:

i. PSO is a population-based search algorithm (i.e., PSO has implicit parallelism). This property ensures PSO to be less susceptible in being trapped on local minima.
ii. PSO uses payoff (performance index or objective function) information to guide the search in the problem space. Therefore, PSO can easily deal with non-differentiable objective functions.
iii. PSO uses probabilistic transition rules and not deterministic rules. Hence, PSO is a kind of stochastic optimization algorithm that can search a complicated and uncertain area. This makes PSO more flexible and robust than conventional methods.
iv. Unlike Genetic Algorithm (GA) and other heuristic algorithms, PSO has the flexibility to control the balance between the global and local exploration of the search space. This unique feature of a PSO overcomes the premature convergence problem and enhances the search capability.
v. Unlike the traditional methods, the solution quality of the proposed approach does not depend on the initial population. Starting anywhere in the search space, the algorithm ensures the convergence to the optimal solution.

3.3 BASIC FUNDAMENTALS OF PARTICLE SWARM OPTIMIZATION

The basic fundamentals of the PSO technique are stated and defined as follows [21]:

1. **Particle X (i):** It is a candidate solution represented by a k-dimensional real-valued vector, where k is the number of optimized parameters. At iteration i, the jth particle X (i, j) can be described as:

$$X_j(i) = \left[X_{j,1}(i); X_{j,2}(i); \ldots\ldots; X_{j,k}(i); \ldots\ldots; X_{j,d}(i)\right] \quad --- \quad (3.3)$$

Where: x's are the optimized parameters x_k(i,j) is the k_{th} optimized parameter in the j_{th} candidate solution d represents number of control variables

2. **Population:** It is a set of n particles at iteration i.

$$Pop(i) = [X_1(i); X_2(i); \ldots\ldots; X_n(i) \quad --- \quad (3.4)$$

Where: n represents the number of candidate solutions.

3. **Swarm:** it is an apparently disorganized population of moving particles that tend to cluster together while each particle seems to be moving in a random direction.

4. **Particle Velocity V (i):** It is the velocity of the moving particles represented by

a d-dimensional real-valued vector. At iteration i, the j_{th} particle V_j (i) can be described as:

$$V_j(i) = [V_{j,1}(i);\ V_{j,2}(i); \dots \dots V_{j,k}(i); \dots \dots ; V_{j,d}(i)] \qquad --- \qquad (3.5)$$

Where: $v_{j,k}$ (i) is the velocity component of the j_{th} particle with respect to the k_{th} dimension.

5. Inertia Weight w (i): It is a control parameter, which is used to control the impact of the previous velocity on the current velocity. Hence, it influences the trade-off between the global and local exploration abilities of the particles. For initial stages of the search process, large inertia weight to enhance the global exploration is recommended while it should be reduced at the last stages for better local exploration. Therefore, the inertia factor decreases linearly from about 0.9 to 0.4 during a run. In general, this factor is set according to the following equation:

$$W = \frac{W_{max} - (W_{max} - W_{min})}{iter_{max}} \qquad --- \qquad (3.6)$$

Where: $iter_{max}$ is the maximum number of iterations and iter is the current number of iterations.

6. **Individual Best X* (i):** During the movement of a particle through the search space, it compares its fitness value at the current position to the best fitness value it has ever reached at any iteration up to the current iteration. The best position that is associated with the best fitness encountered so far is called the individual best X*

i. For each particle in the swarm, X*
ii. can be determined and updated during the search. For the j_{th} particle, individual best can be expressed as:

$$X_j^*(i) = [X_{j,1}^*(i), X_{j,2}^*(i), \dots \dots \dots X_{j,d}^*(i)] \qquad --- \qquad (3.7)$$

In a minimization problem with only one objective function f, the individual best of the j_{th} particle $X_j^*(i)$is updated whenever f $(X_j^*(i)) <$ f $(X_j^*(i-1))$. Otherwise, the individual best solution of the j_{th} particle will be kept as in the previous iteration.

7. **Global Best X* (t):** It is the best position among all of the individual best positions achieved so far.

8. **Stopping Criteria:** The search process will be terminated under whenever one of the following criteria is satisfied:

   i. The number of the iterations since the last change of the best solution is greater than a pre-specified number.
   ii. The number of iterations reaches the maximum allowable number.

The particle velocity in the kth dimension is limited by some maximum value,

V_{kmax} . This limit enhances the local exploration of the problem space and it realistically simulates the incremental changes of human learning. The maximum velocity in the k_{th} dimension is characterized by the range of the k_{th} optimized parameter and given by:

$$V_{kmax} = \frac{X_{kmax} - X_{kmin}}{N} \quad --- \quad (3.8)$$

Where, *N* is a chosen number of intervals in the k_{th} dimension.

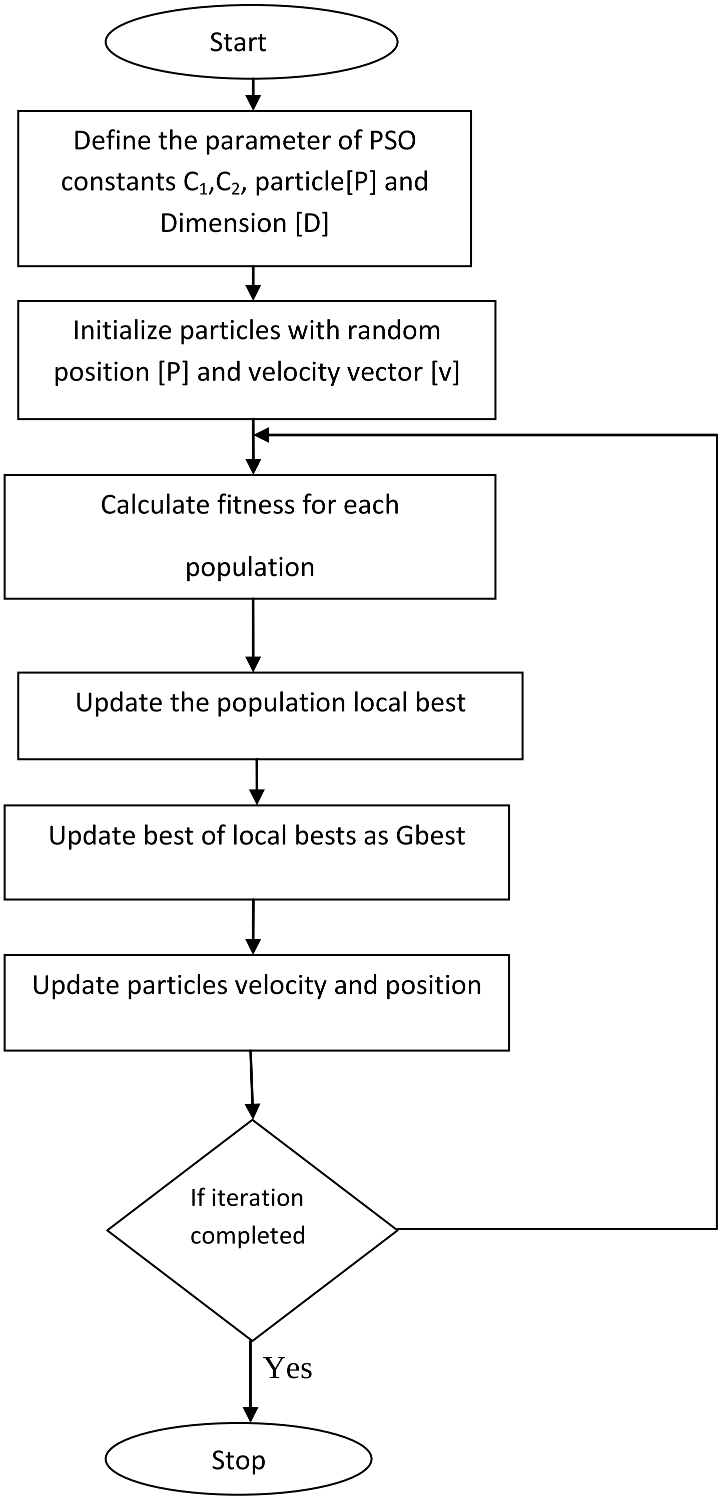

Figure 3.1: Flow Chart for PSO

CHAPTER 4

CONGESTION MANAGEMENT PROBLEM FORMULATION

4.1 PROBLEM FORMULATION

The optimal congestion management minimizing redispatch cost can be expressed as [19]

Minimize $\sum_{g}^{Ng} = C_g(\Delta P_g)\Delta P_g$ --- (4.1)

Subject to:

$\sum_{g}^{Ng} \Delta P_g = 0$ --- (4.2)

ΔC_g = Incremental and decremental cost of generator g.

ΔP_g = Active power adjustment at bus g.

Operating limit constraints

$\Delta P_g^{min} \leq \Delta P_g \leq \Delta P_g^{max}$; $g = 1,2 \ldots \ldots \ldots N_g$ --- (4.3)

$\Delta P_g^{min} = P_g - P_g^{min}$ and

$\Delta P_g^{max} = P_g^{max} - P_g$

ΔP_g^{min} = Minimum adjustment limit of generator g.

ΔP_g^{max} = Maximum adjustment limit of generator g.

P_g = Active power output

P_g^{min} = Minimum generation limit of generator g.

P_g^{max} = Maximum generation limit of generator g.

Line flow constraints

$\sum_{g}^{Ng}[(GS_g(\Delta P_g) + F_k^0] \leq F_k^{max}$; $l = 1,2, \ldots \ldots \ldots n_l$ ------ (4.4)

F_k^0 = Power flow caused by all contracts requesting the transmission service.

F_k^{max} = Power flow limit of line l.

4.2 SELECTING REDISPATCHED GENERATORS

The generator sensitivity (GS) technique indicates the change of active power flow due to change in active power generation. The generators in the system under consideration have different sensitivities to the power flow on the congested line. A change in real power flow in a transmission line k connected between bus i and bus j due to change in power generation by generator g can be termed as generator sensitivity to congested line (GS). Mathematically, GS for line k can be written as [19]

$$GS_g = \frac{\Delta P_{ij}}{\Delta P_{Gg}} \qquad --- \qquad (4.5)$$

Where P_{ij} is the real power flow on congested line-k;

P_{Gg} is the real power generated by the ith generator.

The basic power flow equation on congested line can be written as

$$P_{ij} = -V_i^2 G_{ij} + V_i V_j G_{ij} \cos(\theta_i - \theta_j) + V_i V_j B_{ij} \sin(\theta_i - \theta_j) \qquad --- \qquad (4.6)$$

Where $V_i$and θ_i are the are the voltage magnitude and phase angle respectively at the i$_{th}$ bus; G_{ij} and Brepresent, respectively, the conductance and susceptance of the line connected between buses i and j; neglecting P-V coupling, (4.1) can be expressed as

$$GS_g = \frac{\partial P_{ij}}{\partial \theta_i} * \frac{\partial \theta_i}{\partial P_{Gg}} + \frac{\partial P_{ij}}{\partial \theta_j} * \frac{\partial \theta_j}{\partial P_{Gg}} \qquad --- \qquad (4.7)$$

The first terms of the two products in (4.3) are obtained by differentiating (4.2) as follows:

$$\frac{Pij}{\partial \theta_i} = -V_i V_j G_{ij} \sin(\theta_i - \theta_j) + V_i V_j B_{ij} \cos(\theta_i - \theta_j) \qquad --- \qquad (4.8)$$

$$\frac{Pij}{\partial \theta_j} = -V_i V_j G_{ij} \sin(\theta_i - \theta_j) - V_i V_j B_{ij} \cos(\theta_i - \theta_j) \qquad --- \qquad (4.9)$$

$$= -\frac{\partial Pij}{\partial \theta_i} \qquad --- \qquad (4.10)$$

The active power injected at a bus-s can be represented as

$P_s = PG_s - P_{Ds}$ --- (4.11)

Where, P_{Ds} is the active load at bus s and P_s can be expressed as

$$P_s = |V_s| \sum ((G_{st} cos\,(\theta_s - \theta_t) + B_{st} sin(\theta_s - \theta_t)|V_t|$$

$= |V_s|^2 G_{ss} + |V_s| \sum((|V_s| cos\,(\theta_s - \theta_t) + B_{st} sin(\theta_s - \theta_t)|V_t|$ --- (4.12)

Where n is the number of buses in the system.

Differentiating (10) w.r.t. θ_s and θ_t, the following relations can be obtained:

$\frac{\partial P_s}{\partial \theta_t} = |V_s||V_t|[G_{st} sin(\theta_s - \theta_t) - B_{st} sin(\theta_s - \theta_t)$ --- (4.13)

$\frac{\partial P_s}{\partial \theta_s} = |V_s|[-G_{st} cos(\theta_s - \theta_t) + B_{st} sin(\theta_s - \theta_t)|V_t|]$ --- (4.14)

Neglecting P-V coupling, the relation between incremental change in active power at system buses and the phase angles of voltages can be written in matrix form as

$[\Delta P]_{n*1} = [H]_{n*n}[\Delta\theta]_{n*1}$ --- (4.15)

$$[H]_{n*n} = \begin{bmatrix} \frac{\partial P_1}{\partial \theta_1} & \frac{\partial P_1}{\partial \theta_2} \dots\dots\dots & \frac{\partial P_1}{\partial \theta_n} \\ \frac{\partial P_2}{\partial \theta_1} & \frac{\partial P_2}{\partial \theta_2} \dots\dots\dots & \frac{\partial P_2}{\partial \theta_n} \\ \frac{\partial P_n}{\partial \theta_1} & \frac{\partial P_n}{\partial \theta_2} \dots\dots\dots & \frac{\partial P_n}{\partial \theta_n} \end{bmatrix} \qquad --- \qquad (4.16)$$

$[\Delta\theta] = [H]^{-1}[\Delta P]$

$= [M]\ [\Delta P]$

Where

$[M] = [H]^{-1}$

To find the value of $\frac{\partial \theta_i}{\partial P_{Gg}}$ and $\frac{\partial \theta_j}{\partial P_{Gg}}$in (4.3), [M] needs to be found out. However, [H] is a singular matrix of rank one deficiency. So it is not directly invertible. The slack bus in the present work has been considered as the reference node and assigned as bus number 1. The elements of first row and first column of [H] can be eliminated to obtain a matrix [H_{-1}] which can be inverted to obtain a matrix [M_{-1}]. Using these relations the following equation can be obtained:

$$[\Delta\theta_{-1}] = [M_{-1}]^{-1}[\Delta P_{-1}]$$

The actual vector $[\Delta\theta]$ can be found by simply adding the elements $[\Delta\theta_1]$ to the above equation as shown I the relation:

$$[\Delta\theta]_{n*1} = \begin{bmatrix} 0 & 0 \\ 0 & [M_{-1}]_{n*n} \end{bmatrix} [\Delta P_{n*1}] \qquad \text{---} \qquad (4.17)$$

In (4.13), the modified [M] represents the values of $\partial\theta_i/\partial PGg$ and $\partial\theta_j/\partial PGg$ to calculate GS values. Large GS generators will be selected for redispatch since they are more influential on the congested line.

The system operator selects the generators having non uniform and large magnitudes of sensitivity values as the ones most sensitive to the power flow on the congested line and to participate in congestion management by rescheduling their power outputs.

4.3 GENERATOR SHIFT SENSITIVITY FACTORS (REACTANCE METHOD)

For the calculation of generator shift sensitivity factor, the linear load flow model is considered

$$\theta = [X]\ \mathrm{P} \qquad \text{---} \qquad (4.18)$$

This is the standard matrix calculation for the DC load flow. Since the DC power-flow model is a linear model, the calculation of perturbations about a given set of system conditions by use of the same model can be done. [20]

The incremental changes of the bus voltage angles for perturbations of power injections

$$\Delta\theta = [X]\ \Delta \mathrm{P} \qquad \text{---} \qquad (4.19)$$

For calculating the generation shift sensitivity factors for the generator on bus i, the perturbation is set on bus i to + 1and the perturbation on all the other buses to zero. The change in bus phase angles is found using matrix calculations

$$\Delta\theta = \Delta[X]\begin{bmatrix} +1_{atrowi} \\ -1_{atrefrow} \end{bmatrix} \qquad --- \qquad (4.20)$$

This is equivalent to a 1 pu power increase at bus i with a compensating 1 pu power decrease at the reference bus. The $\Delta\theta$ values are equal to the derivative of the bus angle with respect to a change in power injection at bus i. Then, the required sensitivity factors for the change in power of line *l* with respect to a change in generation at bus *i* is:

$$GS_g = \frac{d\theta_l}{dP_i} = \frac{d}{dP_i}\left[\frac{1}{x_l}(\theta_n - \theta_m)\right]$$

$$= \frac{1}{x_l}\left[\frac{d}{dP_i}\theta_n - \frac{d}{dP_i}\theta_m\right]$$

$$= \frac{1}{x_l}[X_{ni} - X_{mi}] \qquad --- \qquad (4.21)$$

Where

$X_{ni} = \frac{d}{dP_i}\theta_n$ = nth element from the $\Delta\theta$ vector in Eq. 4.20

$X_{mi} = \frac{d}{dP_i}\theta_m$ = mth element from the $\Delta\theta$ vector in Eq. 4.20

x_l= line reactance for line *l*

4.4 COMPUTATIONAL ALGORITHM

Step 1: Line and bus data are input to obtain power flow analysis solution.

Step 2: Check whether any line is overloaded.

Step 3: If overload exists, find the GS values at generator buses.

Step 4: Rank the generators based on the sensitivity factor such that generator with highest positive value is ranked at the top followed by others in decreasing order of their sensitivity values.

Step 5: Select participating generator buses based on the generation sensitivity calculated in step 3.

Step 6: PSO parameters such as inertia weight, acceleration coefficients, and number of particles and iterations are specified.

Step 7: Perturb the change in power generation of participating generators randomly.

Step 8: Particle's positions are randomly initialized and the iteration counter is set as 1.

Step 9: Particle’s fitness is evaluated by the objective function in (4.1).

Step 10: Particle positions and velocities are updated by (3.1) and (3.2), respectively.

Step 11: If the maximum PSO iteration is reached, the optimal solution is the position of the global best particle. Otherwise increase the iteration counter by 1 and go to Step 7.

Step 12: Obtain the rescheduling cost.

Step 13: Check, whether with new allocation of active power generation to participating generators, any line is congested. If yes, go to step 5, otherwise stop.

Step 14: Calculate the cost of generation and total system losses.

CHAPTER 5

RESULTS AND DISCUSSION

5.1 TEST CASE 1: MODIFIED IEEE 30 BUS SYSTEM

Considering IEEE Modified 30 Bus System, which consist of 6 generator buses and 24 load buses. Slack node has been assigned as bus number 1. The numbering of bus has been done in a way that the generator buses are numbered first followed by load bus. Generator data is given in appendix A.

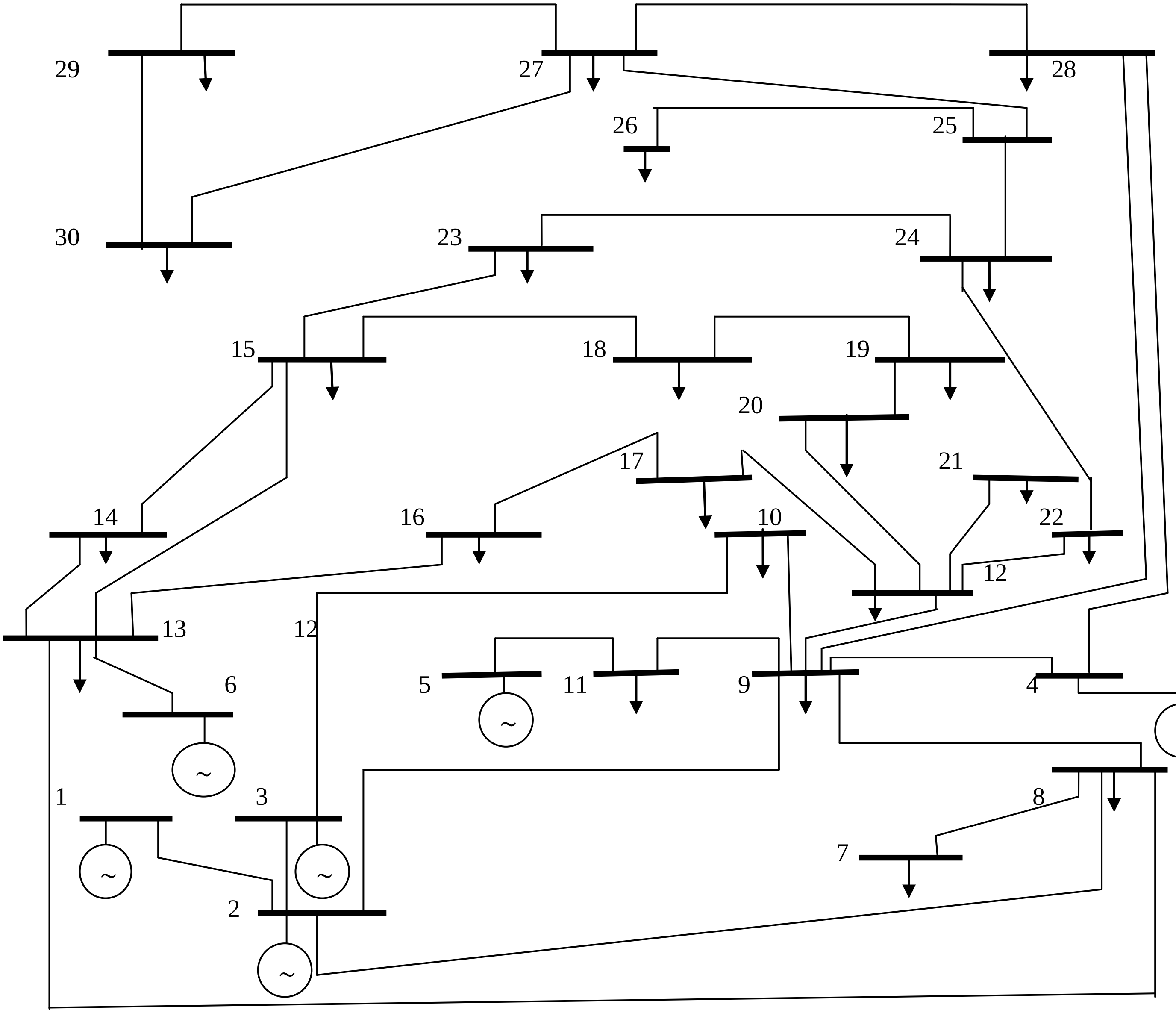

Figure5.1: Single Line Diagram of Modified IEEE 30 Bus

Contingency analysis conducted under base load condition to identify the harmful contingencies. Here we are considering outage of line 1-2 with normal loading. The results of optimal power flow carried out using Newton Raphson method are reported in table 5.1 for 30 bus system under the contingency.

TABLE 5.1: Real Power Flow Obtained From OPF on 30 bus system

From bus	To bus	Power flow in MW
1	**7**	**147.444**
2	8	-13.612
7	**8**	**136.292**
2	3	44.177
2	9	5.295
8	9	79.922
3	10	-26.342
9	10	50.254
9	4	-1.051
9	11	11.995
9	12	10.384
11	5	-17.910
11	12	29.905
8	13	32.283
13	6	-16.930
13	14	8.558
13	15	20.121
13	16	9.334
14	15	2.267
16	17	5.727
15	18	7.229
18	19	3.966
19	20	-5.547
12	20	7.817
12	17	3.317

12	21	15.758
12	22	7.598
21	22	-1.857
15	23	6.645
22	24	5.686
23	24	3.382
24	25	0.298
25	26	3.546
25	27	-3.251
28	27	16.564
27	29	6.193
27	30	7.095
29	30	3.705
4	28	3.947
9	28	12.654

In this case, line such as 1-7 and 7-8 get overloaded as consequence of outage of line 1-2. The actual power flow in those lines is 147.44 MW & 136.29 MW (flow limit is 130 MW in each case). Net power violation is found to be 23.73MW as given in table 5.2. For secure system, the power flow in the transmission line should not exceed their permissible limit. Hence suitable corrective action should be carried out to alleviate the above said overloads.

Table 5.2: Simulated Case

Type of Contingency	**Congested Lines**	**Line Power (MW)**	**% Overload**	**Total Power Violation (MW)**
Outage of line 1-2	1-7	147.44	13.41	23.73
	7-8	136.29	4.83	

The generation sensitivities are computed corresponding to overloading of line 1-7. The values computed are given in table 5.3. The generation sensitivities for all the generators are almost in the closely enclosed in the small range. Hence this indicates that all the generators are chosen to be participating for rescheduling to tackle congestion.

TABLE 5.3: GS for Modified IEEE30-Bus System (Congested Line 1-7)

GENERATOR NUMBER	GENERATOR SENSITIVITY
1 (SLACK)	0.00
2	-0.178
3	-0.276
4	-0.387
5	-0.414
6	-0.439

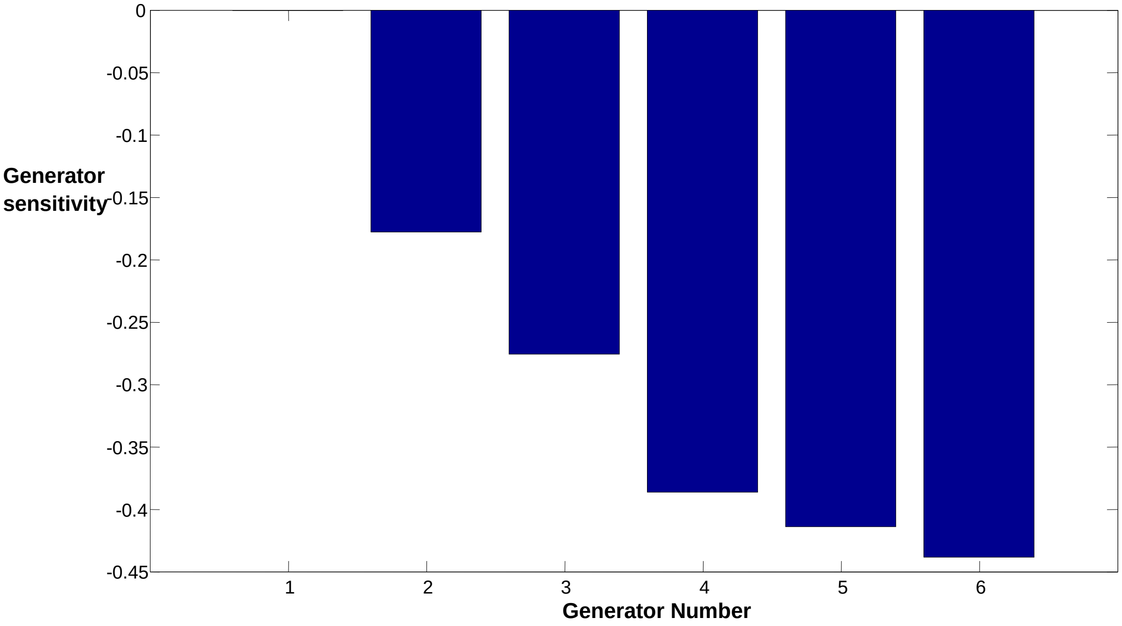

Figure 5.2: Plot of Generator Sensitivities for Generators of modified 30-Bus System

The minimum change in active power generation is computed using particle swarm optimization algorithm subjected to the bidding cost of increase or decrease in power generated so that the total cost of generation is minimized. Although slack bus generator is considered to take into account the losses. In this work the change in power is computed including slack generator. The results obtained for change in power generation of participating generators are given in table 5.4.

TABLE 5.4: Adjustment of Active Power Generation of Participating Generator (MW)

ΔP_{G1}	-9.22
ΔP_{G2}	9.84
ΔP_{G3}	3.06

ΔP_{G4}	0.017
ΔP_{G5}	0.85
ΔP_{G6}	-0.02
Total Rescheduling	**23.007 MW**
COST($/h)	**539.18**

Table 5.4 provides the best solution to relieve the congested lines completely without causing overloading of any other line. The rescheduling of active power generation requires the decrease in active power generation from generator 1 and generator 6 and increase the power generation from generator 2,3,4,5. The cost incurred for relieving congestion is 539.18$/hr. based on the bidding cost of generators for change in power generation.

Table 5.5 gives total system losses before congestion management are found to be 16.004 MW, while the system losses after congestion management are decreased to 13.112 MW**.**

TABLE 5.5: System Losses

Before Congestion Management (MW)	After Congestion Management(MW)
16.004	13.112

5.2 TEST CASE 2: MODIFIED IEEE 57 BUS SYSTEM

IEEE 57 bus system consists of 7 generators and 80 branches. The generator and line data is given in Appendix A. The power flow results obtained from optimal power flow are given in Table 5.6. The results show that lines 5-6 and 6-12 are overloaded.

TABLE 5.6: Real Power Flow of IEEE 57 Bus System

From bus	To bus	Power flow in MW
1	2	-47.983
2	3	35.160
3	8	-15.794
8	9	-16.573
8	4	-30.983
4	10	-9.515
4	5	-37.370
5	**6**	**195.240**
6	11	41.313
6	**12**	**47.404**

6	7	24.837
6	13	38.180
13	14	17.956
13	15	-13.26
1	15	47.455
1	16	35.475
1	17	49.584
3	15	51.471
8	18	31.654
8	18	31.654
9	4	-29.814
10	5	-77.208
11	7	1.346
12	13	26.670
7	13	-7.681
7	16	8.079
7	17	-7.007
14	15	-35.185
18	19	-4.454
19	20	1.056
21	20	1.248
21	22	-1.248
22	23	3.406
23	24	-2.905
24	25	13.960
24	25	13.960
24	26	-16.995
26	27	-16.995
27	28	26.833
28	29	-31.904

10	29	67.674
25	30	7.660
30	31	3.954
31	32	-1.912
32	33	3.808
34	32	7.363
34	35	-7.363
35	36	-13.41
36	37	-14.487
37	38	-16.58
37	39	1.986
36	40	0.962
22	38	-4.656
12	41	8.041
41	42	5.667
41	43	-10.084
38	44	-14.313
15	45	26.8
14	46	42.567
46	47	42.567
47	48	12.311
48	49	-3.030
49	50	5.143
50	51	-15.904
11	51	34.269
13	49	32.676
29	52	18.330
52	53	12.899
53	54	-7.244
54	55	-11.553

12	43	12.084
44	45	-26.371
40	56	0.956
56	41	-5.943
56	42	-5.464
39	57	1.982
57	56	-4.718
38	49	-6.283
38	48	-15.036
6	55	18.725

In this case, the flow lmit of line 5-6 is taken as 175MW while for the line 6-12 it is taken as 35MW. The actual flow in this lines is 195.24 MW and 49.31MW which leads to the voilation of 34.55MW as given in table 5.7.

TABLE 5.7: Simulated Case

Type of Contingency	Congested Lines	Line Power (MW)	% Overload	Total Power Violation (MW)
Overload simulation by reducing the capacity of the line 5-6	5-6	195.24	11.56	34.55
	6-12	49.31	40.88	

Table 5.8: GS for Modified IEEE 57-Bus System (Congested Line 5-6)

GENERATOR NUMBER	GENERATOR SENSITIVITY
1 (SLACK)	0.00
2	0.02
3	0.08
4	0.39
5	0.63
6	-0.229
7	-0.093

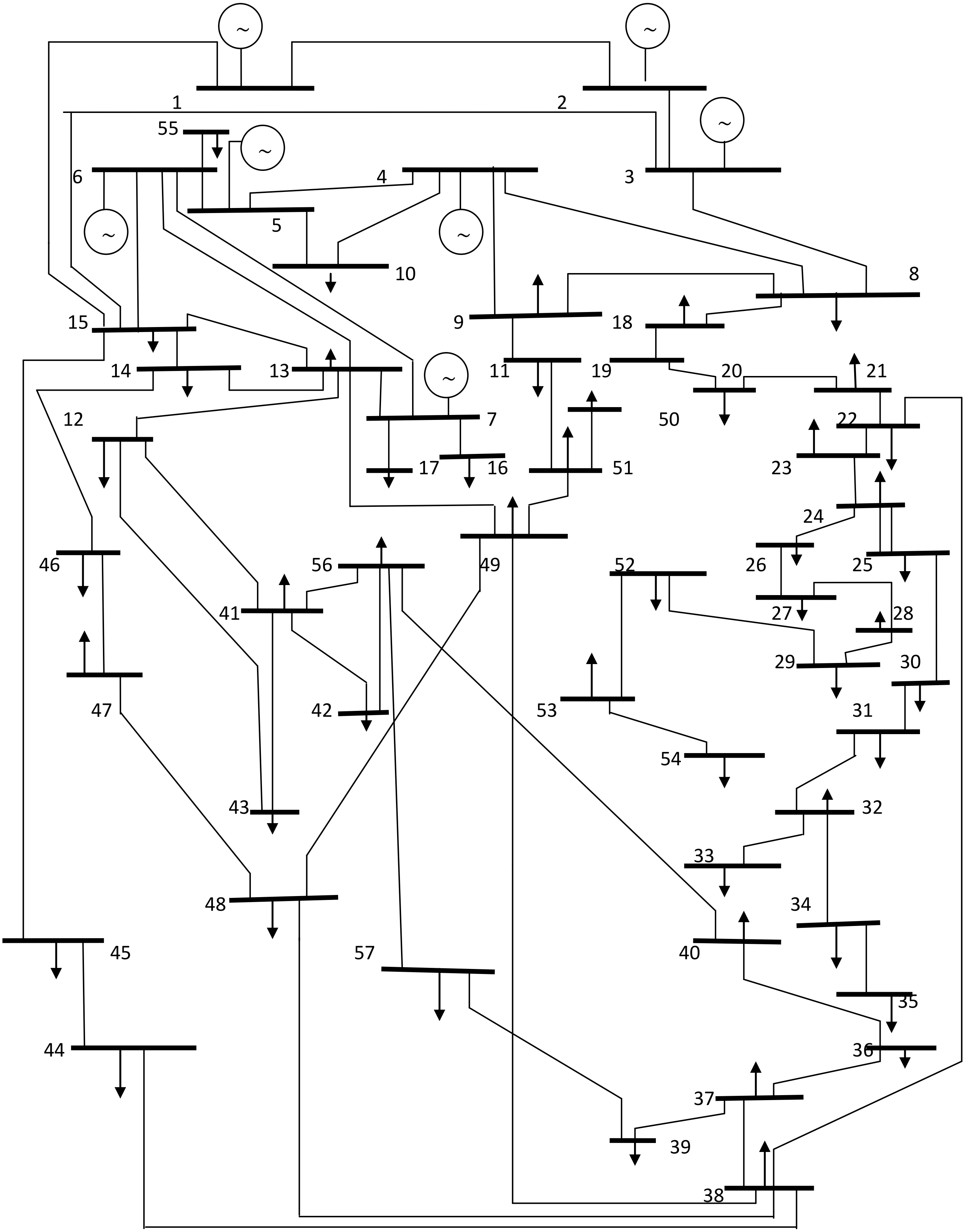

Figure5.3: Single Line Diagram of Modified IEEE 57 Bus

The values of generator sensitivies computed for congested line 5-6 are presented in table 5.8. The plot of generator sensitivity for the generator sensitivities for the generators in 57 bus system is depicted in figure 5.4.

As given inTable 5.8 generator number 5 is most sensitive with the highest positive value whereas generator 6 is least sensitive with highest negative value to congested line power flow.The generator which are highly sensitive are choosen to participate for congestion management thus generator number 1 ,2 ,3,4,5 & 7 are selected for rescheduling purpose.

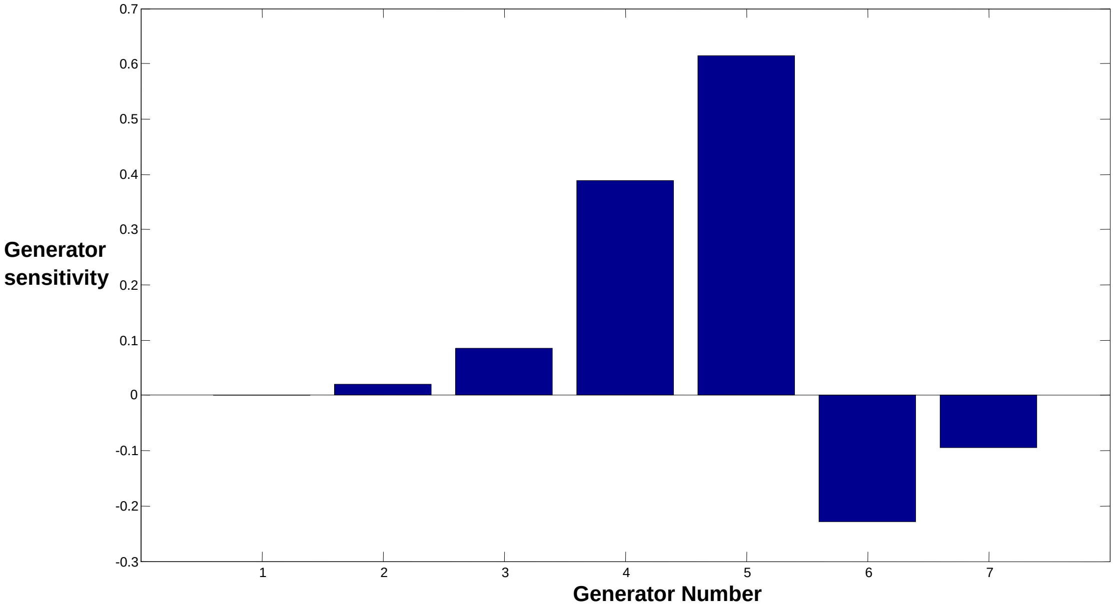

Figure 5.4: Plot of Generator Sensitivities for Generators of 57-Bus System

TABLE 5.9: Adjustment of Active Power Generation of Participating Generator (MW)

ΔP_{G1}	+23.13
ΔP_{G2}	+12.44
ΔP_{G3}	+6.92
ΔP_{G4}	-6.08
ΔP_{G5}	-79.24
ΔP_{G6}	NOT PARTICIPATING
ΔP_{G7}	41.78
TOTAL Rescheduling	**169.59**
COST($/h)	**6997.6**

The table 5.9 provides the best solution to relieve the overload of 34.55 completely without causing overloading of any other line. The cost incurred for relieving congestion is 6997.6 $/hr.

Total system losses before congestion management were found to be 21.181 MW, while the system losses after congestion management decreased to 16.518 MW**.**

TABLE 5.10: System Losses

Before Congestion Management (MW)	**After Congestion Management(MW)**
21.181	16.518

CHAPTER 6

CONCLUSION AND FUTURE SCOPE

6.1 CONCLUSION

In this thesis work, the optimal congestion management approach based on PSO is efficiently minimizing redispatch cost. The problem of congestion is modeled as an optimization problem and solved by particle swarm optimization technique. Redispatched generators are selected based on the large magnitude of generator sensitivity. Line outage due to unexpected line outage & sudden load variation is considered in this work. The method has been tested on modified IEEE 30-bus and modified IEEE 57-bus systems successfully. The proposed approach is useful for ISOs in managing the transmission congestion in a deregulated electricity environment.

6.2 SCOPE FOR FUTURE WORK

This work can be further extended by considering rescheduling of reactive power generation and its compensation using FACTS/STATCOMs at appropriate locations in the system. Secondly the work can also be extended in bilateral transaction environment of deregulated system. Further the performance of the intelligent optimization technique used based on evolutionary methods can be enhanced by optimizing its control parameters.

APPENDIX

TABLE A.1
BUS DATA FOR MODIFIED IEEE 30-BUS SYSTEM

Bus No.	**Bus code**	**Voltage Mag.**	**Angle degree**	**Gen MW**	**Gen MVAR**	**Load MW**	**Load MVAR**	**Gen Qmin**	**Gen Qmax**
1	1	1.06	0	138.59	0	0	0	-30	100
2	2	1.043	0	57.56	50.0	21.7	12.7	-30	100
3	2	1.01	0	24.56	37	94.2	19	-30	100
4	2	1.01	0	35	37.3	30	30	-30	100
5	2	1.082	0	17.91	16.2	0	0	-30	100
6	2	1.071	0	16.93	10.6	0	0	-30	100
7	0	1.0	0	0	0	2.4	1.2	0	0
8	0	1.01	0	0	0	7.6	1.6	0	0
9	0	1.0	0	0	0	0	0	0	0
10	0	1.0	0	0	0	22.8	10.9	0	0
11	0	1.802	0	0	0	0	0	0	0
12	0	1.0	0	0	0	5.8	2	0	0
13	0	1.071	0	0	0	11.2	7.5	0	0
14	0	1.0	0	0	0	6.2	6.2	0	0
15	0	1.0	0	0	0	8.2	2.5	0	0
16	0	1.0	0	0	0	3.5	1.8	0	0
17	0	1.0	0	0	0	9.0	5.8	0	0
18	0	1.0	0	0	0	3.2	0.9	0	0
19	0	1.0	0	0	0	9.5	3.4	0	0
20	0	1.0	0	0	0	2.2	0.7	0	0
21	0	1.0	0	0	0	17.5	11.2	0	0
22	0	1.0	0	0	0	0	0	0	0
23	0	1.0	0	0	0	3.2	1.6	0	0
24	0	1.0	0	0	0	8.7	6.7	0	0
25	0	1.0	0	0	0	0	0	0	0

26	0	1.0	0	0	0	3.5	2.3	0	0
27	0	1.0	0	0	0	0	0	0	0
28	0	1.0	0	0	0	0	0	0	0
29	0	1.0	0	0	0	2.4	0.9	0	0
30	0	1.0	0	0	0	10.6	1.9	0	0

TABLE A.2
LINE DATA FOR MODIFIED IEEE 30-BUS SYSTEM

Start bus	**End bus**	**R (p.u)**	**X (p.u)**	**B/2 (p.u)**	**Tap set value**	**Line Limit (MW)**
1	2	0.0192	0.0575	0.0264	1	130
1	7	0.0452	0.1652	0.0204	1	130
2	8	0.0570	0.1737	0.0184	1	65
7	8	0.0132	0.0379	0.0042	1	130
2	3	0.0472	0.1983	0.0209	1	130
2	9	0.0581	0.1763	0.0187	1	65
8	9	0.0119	0.0414	0.0045	1	90
3	10	0.0460	0.1160	0.0102	1	70
9	10	0.0267	0.0820	0.0085	1	130
9	4	0.0120	0.0420	0.0045	1	32
9	11	0	0.2080	0.0	0.978	65
9	12	0	0.5560	0.0	0.969	32
11	5	0	0.2080	0.0	1	65
11	12	0	0.1100	0.0	1	65
8	13	0	0.2560	0.0	0.932	65
13	6	0	0.1400	0.0	1	65
13	14	0.1231	0.2559	0.0	1	32
13	15	0.0662	0.1304	0.0	1	32
13	16	0.0945	0.1987	0.0	1	32
14	15	0.2210	0.1997	0.0	1	16

16	17	0.0824	0.1923	0.0	1	16
15	18	0.1073	0.2185	0.0	1	16
18	19	0.0639	0.1292	0.0	1	16
19	20	0.0340	0.0680	0.0	1	32
12	20	0.0936	0.2090	0.0	1	32
12	17	0.0324	0.0845	0.0	1	32
12	21	0.0348	0.0749	0.0	1	32
12	22	0.0727	0.1499	0.0	1	32
21	22	0.0116	0.0236	0.0	1	32
15	23	0.1000	0.2020	0.0	1	16
22	24	0.1150	0.1790	0.0	1	16
23	24	0.1320	0.2700	0.0	1	16
24	25	0.1885	0.3292	0.0	1	16
25	26	0.2544	0.3800	0.0	1	16
25	27	0.1093	0.2087	0.0	1	16
28	27	0.0	0.3960	0.0	0.968	65
27	29	0.2198	0.4153	0.0	1	16
27	30	0.3202	0.6027	0.0	1	16
29	30	0.2399	0.4533	0.0	1	16
4	28	0.0636	0.2000	0.0214	1	32
9	28	0.0169	0.0599	0.065	1	32

TABLE A.3
PRICE BIDS SUBMITTED BY GENCOS (IEEE 30)

BUS NUMBER	INCREMENT($/MWH)	DECREMENT($/MWH)
1	22	18
2	21	19
3	42	38
4	43	37
5	43	35
6	41	39

TABLE A.4
LINE DATA FOR MODIFIED 57 BUS SYSTEM

Start bus	End bus	R (p.u)	X (p.u)	B/2 (p.u)	Line Limit (MW)
1	2	0.0083	0.0280	0.0645	150
2	3	0.0298	0.0850	0.0409	85
3	8	0.0112	0.0366	0.0190	100
8	9	0.0625	0.132	0.0129	100
8	4	0.0430	0.148	0.0174	50
4	10	0.0200	0.102	0.0138	40
4	5	0.0339	0.173	0.0235	100
5	6	0.0099	0.050	0.0274	200
6	11	0.0369	0.167	0.0220	50
6	12	0.0258	0.0848	0.0109	50
6	7	0.0648	0.0295	0.0386	50
6	13	0.0481	0.158	0.0203	50
13	14	0.0132	0.0434	0.0055	50
13	15	0.0269	0.0869	0.0115	100
1	15	0.0178	0.0910	0.0494	200
1	16	0.0454	0.2060	0.0273	100
1	17	0.0238	0.1080	0.0143	100
3	15	0.0162	0.0530	0.0272	100
8	18	0.0	0.5550	0.0	100
8	18	0.0	0.4300	0.0	100
9	4	0.0302	0.0641	0.0062	100
10	5	0.0139	0.0712	0.0097	100
11	7	0.0277	0.1262	0.0164	100
12	13	0.0223	0.0732	0.0094	100
7	13	0.0178	0.0580	0.0302	100
7	16	0.0180	0.0813	0.0108	100
7	17	0.0397	0.1790	0.0238	100
14	15	0.0171	0.0547	0.0074	100
18	19	0.4610	0.6850	0.0	100
19	20	0.2830	0.4340	0.0	100
21	20	0.0	0.7767	0.0	100
21	22	0.0736	0.1170	0.0	100
22	23	0.0099	0.0152	0.0	100
23	24	0.1660	0.2560	0.0042	100
24	25	0.0	1.1820	0.0	100
24	25	0.0	1.23	0.0	100
24	26	0.0	0.0473	0.0	100
26	27	0.1650	0.2540	0.0	100
27	28	0.0618	0.0954	0.0	100
28	29	0.0418	0.0587	0.0	100

10	29	0.0	0.0648	0.0	100
25	30	0.1350	0.2020	0.0	100
30	31	0.3260	0.4970	0.0	100
31	32	0.5070	0.7550	0.0	100
32	33	0.0392	0.0360	0.0	100
34	32	0.0	0.9530	0.0	100
34	35	0.0520	0.0780	0.0016	100
35	36	0.0430	0.0537	0.0008	100
36	37	0.0290	0.0366	0.0	100
37	38	0.0300	0.1009	0.0010	100
37	39	0.0192	0.0379	0.0	100
36	40	0.0	0.0466	0.0	100
22	38	0.2070	0.0295	0.0	100
12	41	0.0	0.7490	0.0	100
41	42	0.0289	0.3520	0.0	100
41	43	0.0	0.4120	0.0	100
38	44	0.0	0.0585	0.0010	100
15	45	0.0230	0.1042	0.0	100
14	46	0.0182	0.0735	0.0	100
46	47	0.0834	0.0680	0.0016	100
47	48	0.0801	0.0233	0.0	100
48	49	0.1386	0.1290	0.0024	100
49	50	0.0	0.1280	0.0	100
50	51	0.0	0.2200	0.0	100
11	51	0.1442	0.0712	0.0	100
13	49	0.0762	0.1910	0.0	100
29	52	0.1878	0.1870	0.0	100
52	53	0.1732	0.0984	0.0	100
53	54	0.0	0.2320	0.0	100
54	55	0.0624	0.2265	0.0	100
12	43	0.0	0.1530	0.0	100
44	45	0.5530	0.1242	0.0020	100
40	56	0.2125	1.1950	0.0	100
56	41	0.0	0.5490	0.0	100
56	42	0.1740	0.3540	0.0	100
39	57	0.1150	1.3550	0.0	100
57	56	0.0312	0.2600	0.0	100
38	49	0.0	0.1770	0.003	100
38	48	0.0	0.0482	0.0	100
6	55	0.0	0.1205	0.0	100

TABLE A.5
BUS DATA FOR MODIFIED IEEE 57-BUS SYSTEM

Bus No.	Bus code	Voltage Mag.	Angle degree	Gen MW	Gen MVAR	Load MW	Load MVAR	Gen Qmin	Gen Qmax
1	1	1.040	0	146.39	0	55	17	-140	200
2	2	1.010	0	87.55	0	3	88	-40	50
3	2	0.985	0	41.97	0	41	21	-40	60
4	2	0.980	0	89.67	0	75	2	-30	25
5	2	1.005	0	461.21	0	150	22	-140	200
6	2	0.980	0	100	0	121	26	-30	9
7	2	1.015	0	344.95	0	377	24	-150	155
8	0	1	0	0	0	0	0	0	0
9	0	1	0	0	0	13	4	0	0
10	0	1	0	0	0	0	0	0	0
11	0	1	0	0	0	5	2	0	0
12	0	1	0	0	0	0	0	0	0
13	0	1	0	0	0	18	2.3	0	0
14	0	1	0	0	0	10.5	5.3	0	0
15	0	1	0	0	0	22	5	0	0
16	0	1	0	0	0	43	3	0	0
17	0	1	0	0	0	42	8	0	0
18	0	1	0	0	0	27.2	9.8	0	0
19	0	1	0	0	0	3.3	0.6	0	0
20	0	1	0	0	0	2.3	1	0	0
21	0	1	0	0	0	0	0	0	0
22	0	1	0	0	0	0	0	0	0
23	0	1	0	0	0	6.3	2.1	0	0
24	0	1	0	0	0	0	0	0	0
25	0	1	0	0	0	6.3	3.2	0	0
26	0	1	0	0	0	0	0	0	0
27	0	1	0	0	0	9.3	.5	0	0
28	0	1	0	0	0	4.6	2.3	0	0
29	0	1	0	0	0	17	2.6	0	0
30	0	1	0	0	0	3.6	1.8	0	0
31	0	1	0	0	0	5.8	2.9	0	0
32	0	1	0	0	0	1.6	0.8	0	0
33	0	1	0	0	0	3.8	1.9	0	0
34	0	1	0	0	0	0	0	0	0
35	0	1	0	0	0	6	3	0	0
36	0	1	0	0	0	0	0	0	0
37	0	1	0	0	0	0	0	0	0
38	0	1	0	0	0	14	7	0	0
39	0	1	0	0	0	0	0	0	0
40	0	1	0	0	0	0	0	0	0

41	0	1	0	0	0	6.3	3	0	0
42	0	1	0	0	0	7.1	4	0	0
43	0	1	0	0	0	2.0	1	0	0
44	0	1	0	0	0	12	1.8	0	0
45	0	1	0	0	0	0	0	0	0
46	0	1	0	0	0	0	0	0	0
47	0	1	0	0	0	29.7	11.6	0	0
48	0	1	0	0	0	0	0	0	0
49	0	1	0	0	0	18	8.5	0	0
50	0	1	0	0	0	21	10.5	0	0
51	0	1	0	0	0	18	5.3	0	0
52	0	1	0	0	0	4.9	2.2	0	0
53	0	1	0	0	0	20	10	0	0
54	0	1	0	0	0	4.1	1.4	0	0
55	0	1	0	0	0	6.8	3.4	0	0
56	0	1	0	0	0	7.6	2.2	0	0
57	0	1	0	0	0	6.7	2	0	0

TABLE A.6
PRICE BIDS SUBMITTED BY GENCOS (IEEE 57)

BUS NUMBER	**INCREMENT($/MWH)**	**DECREMENT($/MWH)**
1	44	41
2	43	39
3	42	38
4	43	37
5	42	39
6	44	40
7	44	41

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