Chapter 6

Senstivity and PSO based congestion management

6.1 Introduction

Congestion is defined as the overloading of one or more transmission lines and/or transformers in the power system. In the deregulated electricity market, congestion occurs when the transmission system is unable to accommodate all of their desired transactions due to violation of MVA limits of transmission lines. In such market, most of the time, the transmission lines operate near to their stability limits as all market players try to maximize their profits from various transactions by fully utilizing transmission systems. Congestion may also occur due to various factors like lack of coordination between GENCOs and TRANSCOs, contingency like generator or line outage, sudden change in load demand and failure of various equipments. Congestion may lead to rise in cost of electricity, tripping of overloaded lines and consequential tripping of other healthy lines. It may also create voltage instability related problems. It should be relieved to maintain power system stability and security, failing which result into system blackout with heavy loss of revenue. So, congestion management is given the top priority followed by cost recovery etc. by Federal Energy Regulatory Commission (FERC) [43] and other utilities. Following actions are taken to relieve congestion:

1. Active and reactive power rescheduling of generators,
2. Action of phase shifting transformers,

3. Use of FACTs devices and HVDC lines,

4. Line switching, and

5. Load shedding.

Various algorithms and methods for congestion management have been proposed so far. In[104], Relative Electrical Distance based concept was introduced for real power rescheduling. But, the generators with same RED would contribute same power to congested line. In this case, the cost was not optimized if both generators had different cost functions. In [99], multiobjective PSO was used to alleviate congestion from maximum number of lines and minimize cost of generation. In[108], PSO was used to minimize rescheduling cost of active power. However, the effects of rescheduling cost of reactive power and voltage stability constraints were ignored.

The purpose of this work is to suggest an efficient method for selecting number of participating generators and optimum rescheduling of active and reactive power output of generators for managing congestion at minimum rescheduling cost. Generally, all generators do not have the same effect (sensitivity) on the power flow of a congested line. So in practical situation, only a few generators take part in removing congestion. So firstly, active power and reactive power sensitivity factors of generators to the congested line are found out. The number of participating generators is selected from sensitivity factors. Secondly, active and reactive power rescheduling of participating generators are optimally done in such a way that the total active and reactive power rescheduling costs get minimized. Sometimes, congestion alleviation results into larger voltage deviations or very low voltage profile at load buses, which may invite voltage collapse. So, voltages of generators have been rescheduled to keep load bus voltages within permissible limits. The PSO based algorithm has been tested on IEEE 30-bus test system and UPSEB 75-bus test systems. Obtained results have been compared with those of other published papers.

6.2 Formulation of sensitivity factors

All generators have different sensitivities to the power flow of a congested line. A change in active power flow (ΔP_{ij}) in a transmission line k connected between bus i and bus j due to unit change in active power injection (ΔPG_{gn}) at bus-n by generator-g can be defined as an active power generator sensitivity factor (GS^k_{Pgn}). Mathematically, it can be written for line k as equ. 6.1

$$GS^k_{Pgn} = \frac{(\Delta P_{ij})}{(\Delta PG_{gn})} \tag{6.1}$$

Detailed theory of equ. 6.1 is given in [108] .

Similarly, reactive power generator sensitivity factor[78] for line k can be written as equ. 6.2

$$GS^k_{Qgn} = \frac{(\Delta Q_{ij})}{(\Delta QG_{gn})} \tag{6.2}$$

The reactive power flow equation of line k can be written as equ. 6.3

$$Q_{ij} = -V_i^2 B_{ij} + V_i V_j G_{ij} sin(\theta_i - \theta_j) - V_i V_j B_{ij} cos(\theta_i - \theta_j) \tag{6.3}$$

Where,

V_i and $\theta_i$are voltage magnitude and voltage angle of bus i respectively,

$G_{ij}$and B_{ij} are conductance and susceptance of the line k connected between bus i and bus j, respectively.

Neglecting Q-δcoupling, equ. 6.2 can be written as equ. 6.4

$$GS^k_{Qgn} = \frac{(\partial Q_{ij})}{(\partial V_i)} \frac{(\partial V_i)}{(\partial QG_{gn})} + \frac{(\partial Q_{ij})}{(\partial V_j)} \frac{(\partial V_j)}{(\partial QG_{gn})} \tag{6.4}$$

The first and third terms of equ. 6.4 can be obtained by differentiating equ. 6.3 as follows:

$$\frac{(\partial Q_{ij})}{(\partial V_i)} = -2V_iB_{ij} + V_jG_{ij}sin(\theta_i - \theta_j) - V_jB_{ij}cos(\theta_i - \theta_j) \tag{6.5}$$

$$\frac{(\partial Q_{ij})}{(\partial V_j)} = V_iG_{ij}sin(\theta_i - \theta_j) - V_iB_{ij}cos(\theta_i - \theta_j) \tag{6.6}$$

The reactive power injected at bus i can be expressed as equ. 6.7

$$Q_i = Q_{Gi} - Q_{Di} \tag{6.7}$$

Where, Q_{Gi} and $Q_{Di}$are reactive power generation and reactive power demand at bus i respectively.

The equation of injected bus power Q_i can be written as equs. 6.8 and 6.9

$$Q_i = |V_i| \sum_{j=1}^{n} \{(G_{ij}sin(\theta_i - \theta_j) - B_{ij}cos(\theta_i - \theta_j))|V_j|\} \tag{6.8}$$

$$\therefore Q_i = -|V_i|^2B_{ii} + |V_i| \sum_{j=1, j\neq i}^{n} \{(G_{ij}sin(\theta_i - \theta_j) - B_{ij}cos(\theta_i - \theta_j))|V_j|\} \tag{6.9}$$

$$\therefore \frac{(\partial Q_i)}{(\partial V_i)} = -2B_{ii}V_i + \sum_{j=1, j\neq i}^{n} \{(G_{ij}sin(\theta_i - \theta_j) - B_{ij}cos(\theta_i - \theta_j))|V_j|\} \tag{6.10}$$

and

$$\frac{(\partial Q_i)}{(\partial V_j)} = |V_i| \sum_{j=1, j\neq i}^{n} \{(G_{ij}sin(\theta_i - \theta_j) - B_{ij}cos(\theta_i - \theta_j))\} \tag{6.11}$$

Equs. 6.10 and 6.11 are the matrices of partial derivatives of bus injected reactive powers at bus i and bus j with respect to bus voltage magnitudes at bus i and bus j respectively. Taking inverse of equs. 6.10 and 6.11, we get:

$$\frac{\partial V_i}{\partial QG_{gn}} = \left[\frac{\partial Q_i}{\partial V_i}\right]^{-1} \tag{6.12}$$

$$\frac{\partial V_j}{\partial QG_{gn}} = \left[\frac{\partial Q_i}{\partial V_j}\right]^{-1} \tag{6.13}$$

Equs. 6.12 and 6.13 are second and fourth terms of equ. 6.4 respectively. So, generator sensitivity factors could be obtained by using equ. 6.4 .

6.2.1 Optimal power flow problem formulation

The active and reactive power redispatching cost of generators for congestion management in a pool model is formulated as a nonlinear OPF problem and has been solved by PSO method.

$$Min. \left\{ \sum_{g}^{N_g} C_{Pg}(\Delta P_g)\Delta P_g + \sum_{g}^{N_g} C_{Qg}(\Delta Q_g)\Delta Q_g + k_1 L_{max} + k_2 \sum_{i=1}^{N_d} |1 - V_i| + PF \right\} \tag{6.14}$$

This OPF is subjected to various equality constraints (power flow balance equations)

$$\left\{ P_{Gm} - P_{Dm} - \sum_{n=1}^{N_b} |V_m||V_n||Y_{mn}|cos(\delta_m - \delta_n - \theta_{mn}) = 0 \right\}, For \; each \; PV \; bus \; except \; slack \; bus \tag{6.15}$$

$$\left\{ Q_{Gm} - Q_{Dm} - \sum_{n=1}^{N_b} |V_m||V_n||Y_{mn}|sin(\delta_m - \delta_n - \theta_{mn}) = 0 \right\}, \; For \; each \; PQ \; bus \tag{6.16}$$

Various inequality constraints (operating constraints)

$$P_g\_P_g^{min} = \Delta P_g^{min} \leq P_g \leq \Delta P_g^{max} = P_g^{max} - P_g,\ g \in N_g \tag{6.17}$$

$$Q_g\_Q_g^{min} = \Delta Q_g^{min} \leq \Delta Q_g \leq \Delta Q_g^{max} = Q_g^{max} - Q_g,\ g \in N_g \tag{6.18}$$

$$|S_k| \leq S_k^{max},\ k \in N_l \tag{6.19}$$

$$V_i - V_i^{min} = \Delta V_i^{min} \leq \Delta V_i \leq \Delta V_i^{max} = V_i^{max} - V_i\ i \in N_b \tag{6.20}$$

The effect of generator sensitivity factors is considered as an inequality constraint as follows:

$$\left\{\left\{\left(\sum_{g}^{N_g} GS_{Pgn}^k \times \Delta P_g\right) + P_{ij}\right\}^2 + \left\{\left(\sum_{g}^{N_g} GS_{Qgn}^k \times \Delta Q_g\right) + Q_{ij}\right\}^2\right\} \leq (S_{ij}^{max})^2, ij \in N_l \tag{6.21}$$

Where,

C_{pg}: Cost of the active power rescheduling corresponding to the incremental/decremental price bids submitted by generator-g participating in congestion management. These are the prices at which the generators are willing to adjust their real power outputs.

ΔP_g: Active power adjustment of the generator-g

ΔQ_g: Reactive power adjustment of the generator-g

$C_{Qg}\,(\Delta Q_g)$: Cost of the reactive power rescheduling (opportunity cost) of generator-g participating in congestion management. It is expressed as follows:

$$C_{Qg}(\triangle Q_g) = \left\{C_g^P(S_{Gmax}) - C_g^P\left(\sqrt{S_{Gmax}^2 - \triangle Q_g^2}\right)\right\} \times \psi \tag{6.22}$$

where,

$$C_g^P(\triangle PG_{gn}) = a_n(\triangle PG_{gn}^2) + b_n(\triangle PG_{gn}) + c_n \tag{6.23}$$

where,

a_n, b_n and c_n : Predetermined cost coefficients of g^{th} generator

S_{Gmax} : The maximum apparent power limit of generator-g

ψ is the profit rate of active power generation taken between 5 and 10%. Here, it is taken as 7.5%.

k_1: A constant=10,000

L_{max}: Maximum value of voltage stability indicator (L-index). L index gives a scalar value to each load bus and it lies in the range from zero (no load case) to unity (voltage collapse point)

k_2: A constant=1,000

Voltage profile improvement criterion (i.e summation of load bus voltage deviations from 1.0 pu) is given as follows:

$$\sum_{i=1}^{N_d} |1 - V_i| \tag{6.24}$$

PF: Penalty function

P_{Gi} , Q_{Gi}: Active and reactive power generation at bus i

P_{Di}, Q_{Di}: Active and reactive power demand at bus i

$|V_i|\angle\delta i$: Complex voltage at bus i

$|Y_{ij}|\angle\theta_{ij}$: ij^{th}element of bus admittance matrix

P_g^{min}, P_g^{max}: Minimum and maximum active power generation limits of generator g, respectively

$\triangle P_g^{min}$, $\triangle P_g^{max}$: Minimum and maximum limits of the change in generator active power outputs, respectively

Q_g^{min}, Q_g^{max}: Reactive power generation limits of generator g.

$\triangle Q_g^{min}$, $\triangle Q_g^{max}$: Minimum and maximum limits of the change in generator reactive power outputs, respectively

S_k: power flow in the transmission line k caused by all contracts requesting the transmission service

S_k^{max}=S_{ij}^{max}: MVA flow limit of k^{th}transmission line connected between bus-i and bus-j

V_i^{min}, V_i^{max}: Minimum and maximum voltage magnitude limits at bus i respectively

ΔV_i^{min},ΔV_i^{max}: Minimum and maximum limits of the change in bus voltage magnitude at bus i respectively

L_{index}^i: Voltage stability indicator (L-index) of bus i

N_l: Total number of transmission lines

N_b: Total number of buses

N_g: Total number of generator buses

N_d: Total number of load buses

P_{ij},Q_{ij}: Original active power and reactive power flow in line-k (between bus-i and bus-j) caused by all transactions requesting the transmission service

Square penalty function is used to handle inequality constraints such as active power output of slack bus generator, reactive power output of generator buses, voltage magnitude of all buses and transmission line MVA limits as shown in equs. 6.25 and 6.26.

$$PF = k_3 \times f(P_1) + k_4 \times \sum_{i=1}^{N_g} f(Q_{gi}) + k_5 \times \sum_{i=1}^{N_b} f(V_i) + k_6 \times \sum_{k=1}^{N_l} f(S_k) \tag{6.25}$$

$$f(x) = \begin{cases} 0,\ if\ x^{min} \leq x \leq x^{max} \\ (x - x^{max})^2, if\ x > x^{max} \\ (x^{min} - x)^2, if\ x < x^{min} \end{cases} \tag{6.26}$$

Where,

k_3, k_4, k_5, and k_6 : The value of each penalty coefficient is equal to 1000.

x^{min}, x^{max}: Minimum and maximum limits of variable x.

6.2.2 PSO based algorithm for congestion management

1. Run Newton-Raphson load flow to identify the overloaded lines.

2. Find out the sensitivity of all generators to the congested lines. i.e. find active power generator sensitivity factors and reactive power generator sensitivity factors of all generators corresponding to each con-gested line.

3. Based upon obtained sensitivity factors, identify the generators which will take part in managing congestion.

4. In PSO, initialize particles with values of position and velocity. Each particle is made of continuous variables. The values of these variables are the amount of active power rescheduling ($\Delta P_{gNG,i}$) and amount of generator voltage rescheduling ($\Delta V_{gNG,i}$) required by generators to manage congestion. As the reactive power output of a generator is a function of generator voltage, any rescheduling in generator voltage will reschedule its reactive power. These variables are generated randomly within their permissible minimum and maximum limits. The particles can be presented in matrix form as shown in Table 6.1

5. Run Newton-Raphson load flow to get line flows, active power rescheduling, reactive power rescheduling, line losses and voltage magnitude of all buses.

6. Find constraint violation and calculate penalty function of each particle using eqn. 6.25.

7. Calculate the fitness function of each particle using eqn. 6.14

8. Find out the "global best" particle having minimum value of fitness function in the whole population and "personal best" of all particles.

9. Generate new population using eqns. 2.1 and 2.2.

10. Go to step 5 until convergence criterion is satisfied.

11. Stop the simulation.

Table 6.1: Representation of a particle

Particle No.	Generator active power rescheduling			Generator voltage rescheduling (reactive power rescheduling)		
1	$\triangle P_{g1,1}$	...	$\triangle P_{gNG,1}$	$\triangle V_{g1,1}$	...	$\triangle V_{gNG,1}$
2	$\triangle P_{g1,2}$	...	$\triangle P_{gNG,2}$	$\triangle V_{g1,2}$	...	$\triangle V_{gNG,2}$
...	...	...	...	...	...	...
...	...	...	...	...	...	...
i	$\triangle P_{g1,i}$	...	$\triangle P_{gNG,i}$	$\triangle V_{g1,i}$	...	$\triangle V_{gNG,i}$

Where,
$\Delta P_{g1,i}$,$\Delta P_{gNG,i}$: Active power rescheduling of participating generators of i^{th}particle,

$\Delta V_{g1,i}$, $\Delta V_{gNG,i}$: Voltage rescheduling (reactive power rescheduling) of participating generators of i^{th}particle.

If there are total i number of particles and if each particle consists of j number of control variables, then dimension of a population becomes $i * j$.

6.3 Results and Discussions

To establish the effectiveness of the proposed method, the simulation studies were conducted on the following two sample test systems.

1. IEEE 30-bus test system as described in Appendix B

2. A practical 75-bus UP state electricity board (UPSEB) system representing 220KV and 400KV network as described in Appendix C.

This work has suggested an efficient method for selecting number of participating generators and optimum rescheduling of active and reactive power output of generators for managing congestion at minimum rescheduling cost. Generally, all generators do not have the same effect (sensitivity) on the power flow of a congested line. So in practical situation, only a few generators take part in removing congestion. So firstly, active power and reactive power sensitivity factors of generators to the congested line are found out. The number of participating generators is selected from sensitivity factors. Secondly, active and reactive power rescheduling of participating generators are optimally done in such a way that the total active and reactive power rescheduling costs get minimized. Sometimes, congestion alleviation results into larger voltage deviations or very low voltage profile at load buses, which may invite voltage collapse. So, voltages of generators have been rescheduled to keep load bus voltages within permissible limits. The PSO based algorithm has been tested on IEEE 30-bus test system and UPSEB 75-bus test systems. Obtained results have been compared with those of other published papers.

6.3.1 IEEE 30-bus test system

The IEEE 30-bus system has been used to test effectiveness of the proposed algorithm and obtained results have been compared with those of [108] and [85]. It consists of 6 generator buses, 24 load buses and 41 transmission lines. Slack bus generator is assigned number 1. Remaining generators are assigned numbers 2,3,4,5 and 6 respectively. Load buses are numbered from 7 to 30. Here, two lines i.e. line no. 1(between buses 1 and 2) and line no. 6(between buses 2 and 9) are found to be congested. Details of power flow of congested lines are given in table 6.2

Table 6.2: Details of power flow of congested lines of IEEE 30-bus system

Congested line	Power flow (MW)	Line flow limit (MW)
1-2	170.30	130
2-9	68.75	65

The values generators sensitivity factors computed for the lines 1-2 and 2-9 are given in Table 6.3

Table 6.3: Generator sensitivity factors of congested lines of IEEE 30-bus system

Congested lines		Generator no.					
		1	2	3	4	5	6
Line 1(bus 1-2)	GS^1_{Pgn}	-0.000	-0.077	-0.127	-0.105	**+0.17**	-0.420
	GS^1_{Qgn}	-0.779	-0.867	-0.744	-0.788	-0.761	-0.775
Line 6 (bus 2-9)	GS^6_{Pgn}	-0.000	-0.014	-0.029	-0.029	**+0.326**	-0.116
	GS^6_{Qgn}	-0.356	-0.351	-0.327	-0.368	-0.354	-0.357

A negative value of sensitivity factor of a generator indicates that an increase in generation for that generator decreases the power flow in the congested line. Whereas, a +ve sensitivity factor of a generator indicates that an increase in generation increases power flow in the congested line. From the table 3, it is seen that the generators 1,2,3,4 and 6 have negative sensitivity factors, while the generator 5 has positive sensitivity factor. So, only generators 1,2,3,4 and 6 would take part in removing congestion from the congested lines. The generator 5 does not take part in removing congestion. Now, PSO is applied to optimally reschedule the output powers of generators to manage congestion. It is to be noted that the sensitivity factors obtained are with respect to the slack bus which is considered as the reference bus and change in phase angle ($\Delta\delta = 0$) of slack bus is zero during the load flow execution. So, the active power generator sensitivity factors of a slack bus generator is zero for both congested lines. But, reactive power generator sensitivity factors of a slack bus generator may not be zero for congested lines, because during load flow execution, a non-zero voltage is specified at a slack bus.

Table 6.4 shows the comparison of results obtained by PSO with those of other published papers. It can be seen that cost of active power rescheduling and total active power rescheduling obtained by the proposed method is lesser than those of [108] and [85]. Also, it is interesting to note that the total rescheduling cost (active power rescheduling cost +reactive power rescheduling cost) obtained by the proposed method is still lesser than those of [108] and [85]. So, it is preferable to reschedule reactive power output of generators for removing congestion. Overloading of both congested lines was sufficiently removed by the proposed method. Also, obtained active power losses by the proposed method were lesser than that of [108].

Furthermore, Reactive power rescheduling helped in improving voltage stability of the load buses and it took the system far away from voltage collapse point. It is clear from Fig. 6.1 that voltage stability has increased because L-index values of load buses have considerably decreased in post-rescheduling state.

Reactive power rescheduling also decreased deviation in voltage of load buses from the rated 1.0 pu. value. Thus, it improved voltage profile of the load buses. The results are given in Table 6.5

Table 6.4: Comparison of results obtained by PSO for congestion management of IEEE 30-bus system

		Proposed method	Results reported in [108]	Results reported in[85]
Cost of active power rescheduling ($/day)		**31,286**	**50,466**	**50,700**
Cost of reactive power rescheduling ($/day)		**7,641**	Not reported	Not reported
Resultant power flow (MW)	Line 1	**128.16**	129	130
	Line 6	**63.24**	60	60
Active power rescheduling (MW)	ΔP_1	-43.20	-59	-58
	ΔP_2	+16.67	+19.9	+20.5
	ΔP_3	+10.06	+13	+14.5
	ΔP_4	+14.20	+6	+8
	ΔP_5	Not *participated*	+6.5	+9.2
	ΔP_6	+2.75	+7	...
Total active power rescheduling (MW)		**86.88**	111.4	110.2
Reactive power rescheduling (MVAR)	ΔQ_1	-29.99	Not reported	Not reported
	ΔQ_2	+80.00		
	ΔQ_3	+00.94		
	ΔQ_4	00.00		
	ΔQ_5	Not*participated*		
	ΔQ_6	-31.42		
Total reactive power rescheduling (MVAR)		**142.35**		
Total active power losses (MW)		**11.39**	**15**	Not reported

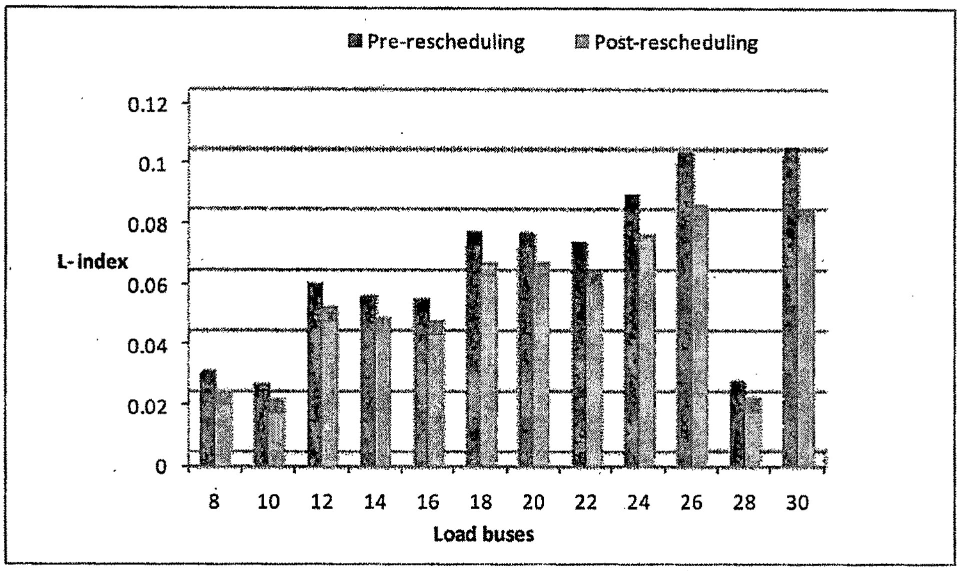

Figure 6.1: L-index values of some load buses before and after rescheduling for IEEE 30 bus system

Table 6.5: Voltage stability and voltage deviation indicators in pre-rescheduling and post-rescheduling states of 30-bus system

	Pre-rescheduling	Post-rescheduling
$\mathbf{L}_{\mathbf{max}}$	0.1007	0.0815
$\sum Voltage\ deviation$	1.205	0.659

Table 6.6: Selected parameters of PSO for IEEE 30-bus system

PSO parameters	30-bus system
Population size	50 particles
Acceleration constants (C_1, C_2)	2.1 and 2.0
Constriction factor (χ)	0.729
Max. and Min. inertia weights(w_{max}, w_{min})	1 and 0.2
Max. and Min. velocity of particles(v_{max}, v_{min})	0.45 and -0.45
Convergence criterion	Removal of congestion from congested lines

Table 6.7: Statistical results of rescheduling costs for IEEE 30-bus system

Rescheduling cost ($/day)	Worst cost	Best cost	Average cost
Active power rescheduling cost	41,000	28,130	**31,286**
Reactive power rescheduling cost	8,200	6,051	**7,641**

6.3.1.1 Statistical results and convergence characteristic of PSO

The tunable parameters of PSO have great influence on its convergence characteristic. So, tuning of parameters is quite essential. Thus, the effect of different values of various parameters (i.e. population size, acceleration constants, constriction factor, inertia weight and velocity of particles) on the convergence of the algorithm was studied for 50 different trials. Finally, those values of parameters were selected which gave the best rescheduling costs and they are given in Table 6.6.

As PSO is a stochastic optimization method, it randomly generates population of particles in each new simulation. So, different results may obtain in each simulation. Thus, simulations were carried out for 50 times and statistical results namely- the worst, average and the best rescheduling costs were obtained and are written in Table 6.7

Fig. 6.2 shows the graph of convergence characteristic of PSO for 30-bus system. From the graph, it is observed that total active power rescheduling costs gradually decrease with number of iterations and finally obtain their minimum values. The nature of graph also indicates that the selected parameters of PSO are proper. It is also seen that PSO based algorithm can remove congestion from the overloaded lines within 120 iterations which justifies the fact that it is a fast method. An average simulation time required by the proposed method was approximately 4.5 minutes.

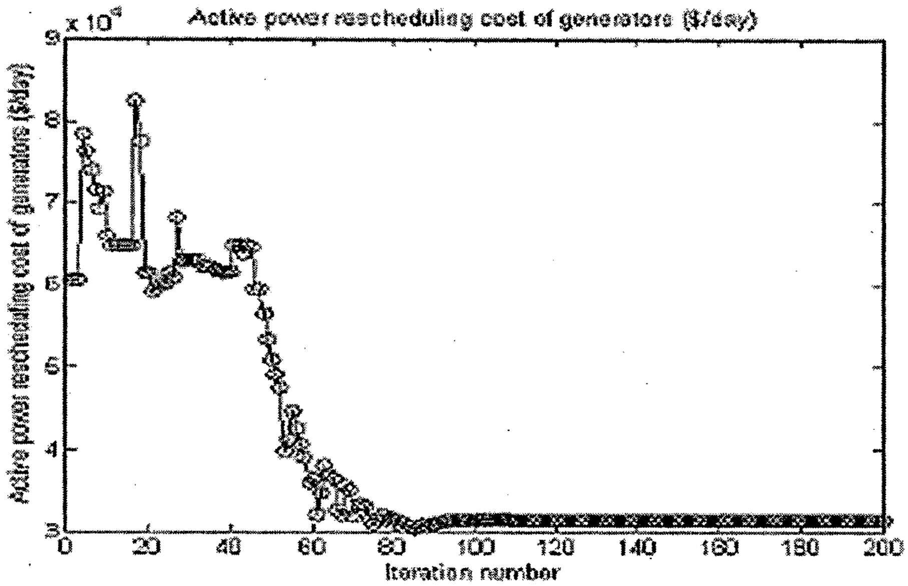

Figure 6.2: Convergence characteristic of PSO for active power rescheduling cost of 30 bus system

6.3.2 UPSEB 75-bus test system

The UPSEB 75-bus system has been also used to test effectiveness of the proposed algorithm. This system consists of 15 generator buses, 60 load buses and 98 transmission lines. Slack bus generator is assigned number 1. Remaining generators are assigned numbers from 2 to 15. Load buses are numbered from 16 to 75. Here, two lines i.e. line no. 13 (between buses 4 and 28) and line no. 59 (between buses 35 and 36) are found to be congested. Details of power flow of congested lines are given in table 6.8.

Table 6.8: Details of power flow of the congested lines of 75-bus system

Line	Power flow (MW)	Power flow limit (MW)
Line 13(bus 4-28)	303	110
Line 59 (bus 35-36)	138.49	120

Active power sensitivity factors and reactive power sensitivity factors of the congested line no.13 and 59 are given in Figs. 6.3 and 6.4 respectively. For this case, to select number of participating generators, the sensitivity factors of both lines have to be considered. Generally the generators with negative sensitivity factors are selected for congestion management and their active and reactive power output are rescheduled to manage congestion. So out of total 15 generators, only generators 1,2,4,5,6,7,8 and 10 are selected for managing congestion. Remaining generators will not take part in managing congestion.

Table 6.9 shows results of active power and reactive power rescheduling costs. As shown, in Case A, all generators have been selected for managing congestion. So active and reactive power output of all generators have been rescheduled to remove congestion. Whereas in Case B, only a few generators have been selected based upon their sensitivity factors for managing congestion. It is clearly seen that the active power rescheduling cost, reactive power rescheduling cost, total rescheduled active power and total rescheduled reactive power of Case B are much less than that of Case A.

Table 6.10 shows some other results in post-rescheduling state. It can be shown that results of Case B are superior than those of Case A. i.e. only a few generators are sufficient to remove congestion from the congested lines. Also, losses obtained by Case B are smaller than that of Case A. The L index value of Case B is lesser than Case A, which indicates that voltage stability is improved by the proposed method.

Figs. 6.5 and 6.6 show convergence characteristic of the proposed algorithm. It is seen that the graph of rescheduling cost gradually decreases as the number of iterations increases and then it obtaines its minimum (optimum) value. It converged within 50 iterations which justifies the fact that PSO is a fast algorithm.

The selected PSO parameters were same as indicated in Table 6.6.

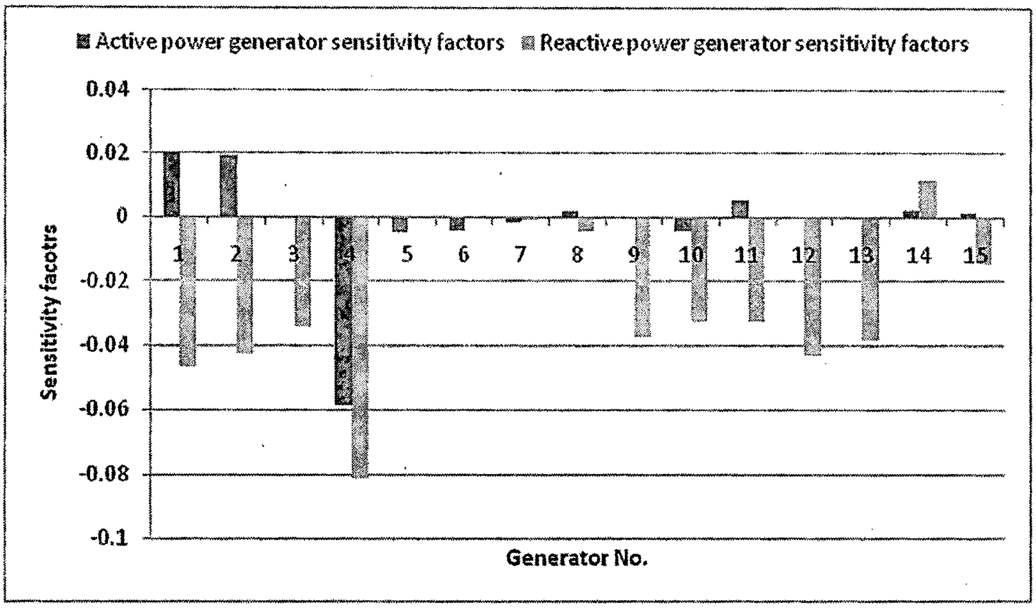

Figure 6.3: Senstivity factors of congested line no.13

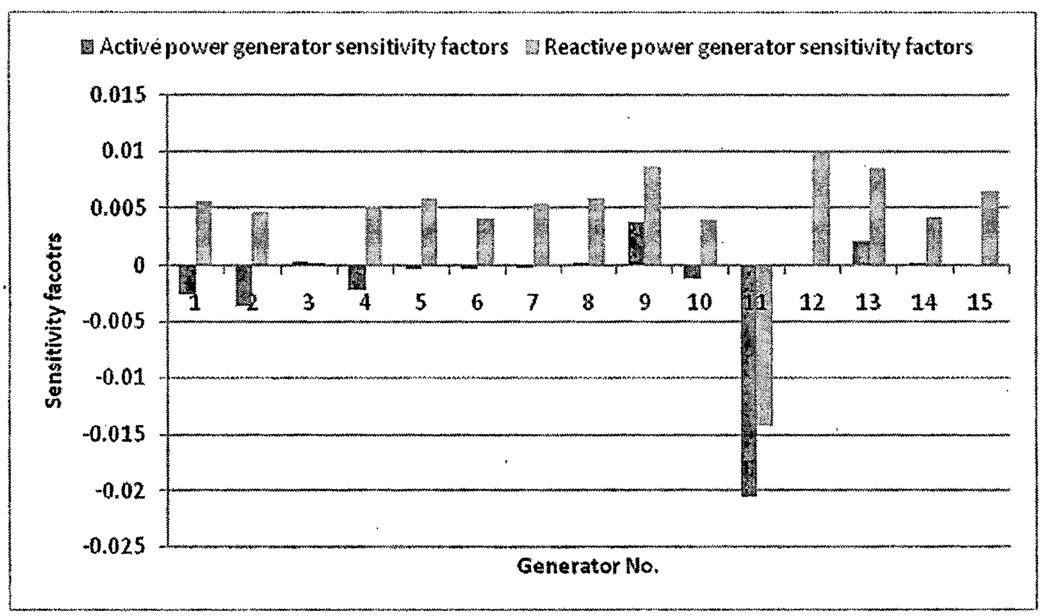

Figure 6.4: Sensitivity factors of congested line no. 59

Table 6.9: Resultant Rescheduling costs of 75-bus system

	Proposed PSO based method	
	Rescheduled O/P of all generators (Case A)	Rescheduled O/P of selected generators (Case B)
Active power rescheduling cost ($/day)	54,683.41	21,918.27
Reactive power rescheduling cost ($/day)	31,999.81	17,480.30
$\triangle P_1$(MW)	2925.50	1904.87
$\triangle P_2$	201.24	174.21
$\triangle P_3$	38.16	Not participated
$\triangle P_4$	196.47	274.52
$\triangle P_5$	493.34	402.53
$\triangle P_6$	380.58	337.28
$\triangle P_7$	190.96	205.66
$\triangle P_8$	139.52	64.16
$\triangle P_9$	298.57	Not participated
$\triangle P_{10}$	172.95	55.99
$\triangle P_{11}$	81.85	Not participated
$\triangle P_{12}$	492.88	Not participated
$\triangle P_{13}$	421.17	Not participated
$\triangle P_{14}$	121.39	Not participated
$\triangle P_{15}$	207.61	Not participated
Total active power rescheduled (MW)	6,362.19	3,419.22
$\triangle Q_1$(MVAR)	-1033.51	65.29
$\triangle Q_2$	-28.50	437.89
$\triangle Q_3$	-243.99	Not participated
$\triangle Q_4$	143.51	114.26
$\triangle Q_5$	-67.68	173.57
$\triangle Q_6$	126.02	620.21
$\triangle Q_7$	-151.04	-205.73
$\triangle Q_8$	-1.01	-0.14
$\triangle Q_9$	-359.42	Not participated
$\triangle Q_{10}$	-218.42	-496.14
$\triangle Q_{11}$	-24.23	Not participated
$\triangle Q_{12}$	-86.02	Not participated
$\triangle Q_{13}$	58.66	Not participated
$\triangle Q_{14}$	-564.68	Not participated
$\triangle Q_{15}$	-149.88	Not participated
Total reactive power rescheduled (MVAR)	-2600.19	709.21

Table 6.10: Some results in post-rescheduling state of 75-bus system

System component	System parameter	Post-rescheduling state	
		Rescheduled O/P of all gen.(Case A)	Rescheduled O/P of selected gen.(Case B)
Line 13	Active power flow (MW)	107.46	72.87
Line 59	Active power flow (MW)	107.10	74.94
	Total active power losses (MW)	743.12	637.23
	L_{max}	0.181	0.127

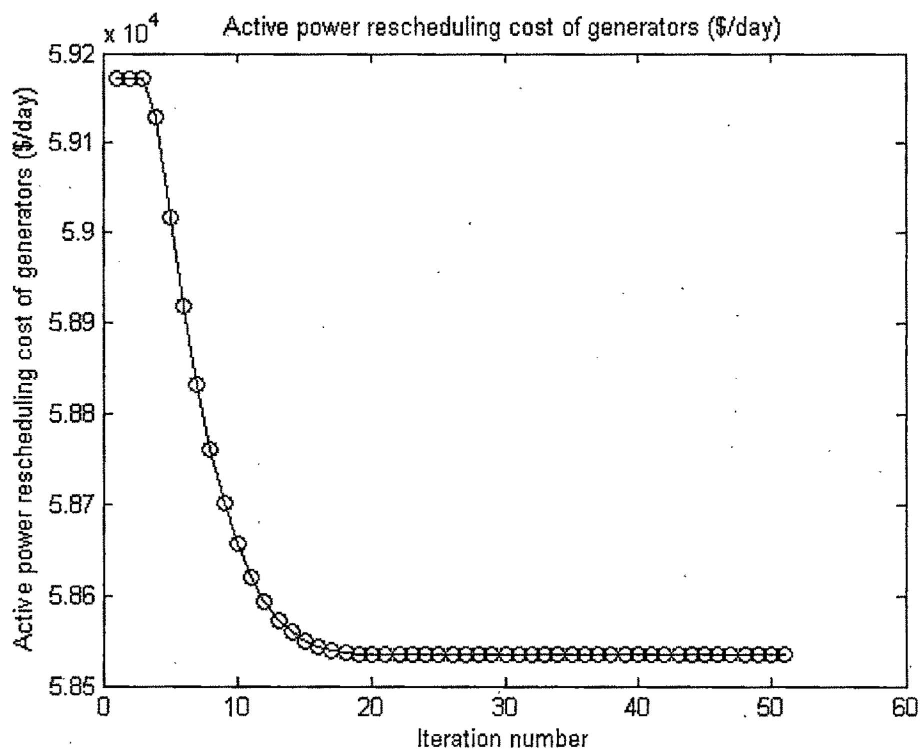

Figure 6.5: Convergence characteristic of PSO for active power rescheduling cost of 75-bus system(Output of all generators are rescheduled)

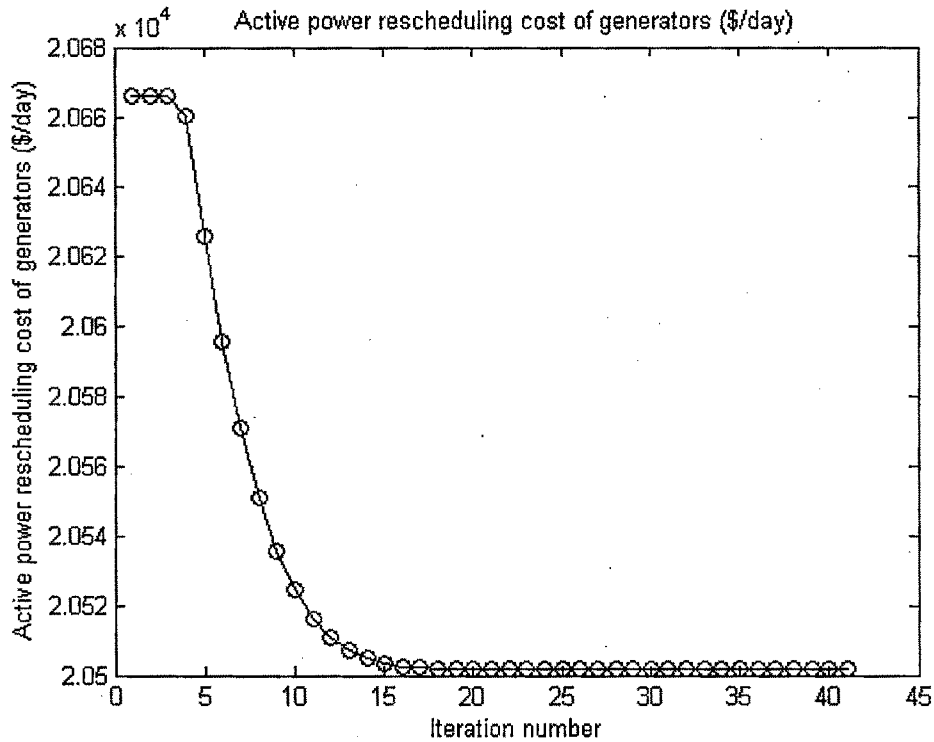

Figure 6.6: Convergence characteristic of PSO for active power rescheduling cost of 75-bus system(Output of only selected generators are rescheduled)

6.4 Conclusions

In this paper, PSO based algorithm has been suggested for minimizing active power rescheduling cost and reactive power rescheduling cost of generators to alleviate congestion in IEEE 30-bus and UPSEB 75-bus test systems. The contribution of this chapter to the available literature can be concluded as follows:

1. Instead of using all generators for managing congestion, only a few generators may be used to manage congestion and the generators which take part in congestion management may be selected based upon their sensitivities to the congested lines.

2. The effect of reactive power of generators should be considered in managing congestion. Rescheduling of reactive power of generators along with their active power rescheduling reduced overall rescheduling cost to manage congestion.

3. Reactive power rescheduling helped in improving voltage profile of the load buses and it enhanced voltage stability of the system in the post-rescheduling state.

4. Losses obtained by the proposed method were significantly lower than those of other reported methods.

Hence, the proposed algorithm improved performance of the system in the post-rescheduling state. Thus, experiment showed encouraging results, suggesting that the proposed approach was capable of efficiently determining higher quality solutions addressing congestion management.