International Journal on Electrical Engineering and Informatics - Volume 4, Number 2, July 2012

Power Flow Tracing Based Congestion Management Using Differential Evolution in Deregulated Electricity Market

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Abstract: In a restructured electricity market environment, the competition in the production and consumption of electric energy leads to the transmission network operating at or beyond one or more transfer limits. Then the system gets congested, resulting in an increase in the cost of electricity and the system security as well as reliability are said to be in danger. The selection of generators to reschedule their output for effective management of congestion is a crucial task for the system operator. This paper presents a differential evolution algorithm based on power flow tracing approach for selection and rescheduling of active power output. The proposed method is demonstrated on IEEE 30 bus and Indian utility 62 bus systems.

Key words: Generator contribution factor, differential evolution, optimal power flow, congestion management, deregulated environment.

1. Introduction

In a competitive electricity market, sufficient freedom is provided to the market participants to interact among themselves. Here, both the buyers and sellers try to buy and sell electric power so as to maximize their profit. In such a situation, to meet the desired transactions, power flow in the transmission network violates some of the physical limits of the transmission system. This condition is called the congestion of the transmission network. The undesirable effects of the congestion include volatility and increase of the electricity cost, jeopardizing the system security and reliability. Hence, to maintain the market efficiency, it is very important that the congestion be relieved in a fast, systematic and efficient manner.

The phenomenon of congestion is observed in both regulated and deregulated power systems. In regulated power market, since generation, transmission and distribution are managed by single entity, congestion management is relatively simple. But, in competitive power market, the situation is more complex.

Congestion can be relieved by using available resources like rescheduling of generators, on-load tap changers etc. System operators usually prefer these methods to relieve congestion. Further, congestion can also be relieved by providing the information of a particular line getting congested and financial incentives to the consumers so as to adjust the load within the system constraints. In extreme situations, the transactions may be physically curtailed to relieve the congestion. But the system operators keep this as the last option due to its inconvenience to the system users.

Ashwani Kumar et al [1] reported a bibliographical survey on congestion management schemes. Bombard et al [2] reviewed various congestion management schemes and developed a unified framework for mathematical representation of the market dispatch and redispatch problems. Many researchers [3–9] have proposed congestion management using FACTS controllers in deregulated environment. Scheweppe et al [10] laid the foundation of optimal spot pricing on the basis of optimal power flow (OPF). Hogan [11] proposed the contract path and nodal pricing approach for the pool type market structure which provides a mechanism to control the financial risk of congestion induced price variations. Christie et al [12] described three methods of relieving transmission congestion which includes available transfer capability (ATC) based method, price area based method and optimal power flow based method. Among these, optimal power flow based method is being widely used in deregulated market all over the world. Several OPF based congestion management schemes with generation redispatch and curtailment of load have been proposed in the literature [13]. Fang and David [14] proposed a new method as an extension of spot pricing theory in a pool, bilateral and multilateral transactions model. Redispatch of generator output to relieve congestion is also carried out by zonal cluster method [15, 16], relative electrical distance method [17] and generation distribution factor method [18]. In the above methods, generators are redispatched based on their sensitivity factor. Hence the selection of generator is less optimal and it is essential to determine the contribution of each generator to the congested line accurately. Bialek et al [19–21] have proposed power

Received: January 12th, 2012. Accepted: August 12th, 2012

flow tracing approach to determine the contribution of different generators to each transmission line and load in the given network. This method has been used for the transmission pricing in the deregulated market so far. Further, various optimization techniques like genetic algorithm [22], evolutionary programming [23] and particle swarm optimization [18, 24] have been applied to the problem of optimal power flow based congestion management. In this paper, we propose two methods for congestion management using Differential Evolution (DE) technique. The first method (method – 1) uses power flow tracing algorithm to identify the generators contributing to the congested line along with their contribution factors and only these generators are rescheduled. In the second method (method – 2), all generators are considered for rescheduling. Both the methods employ DE to optimally redispatch the generators so as to relieve congestion at minimum cost.

2. Problem Formulation

The power flow tracing algorithm is a mechanism for tracing the contribution of each user on a transmission system to allocate charges for using the transmission line. It works based on the concepts of Kirchhoff's current law and proportional sharing principle. Two methods are proposed for tracing the power flow namely upstream and downstream algorithms [19–21].

Upstream tracing gives the information about the contribution of each generator to each transmission line and the load, whereas downstream tracing provides the information about the amount of load power shared by the transmission line and the generator. Hence our work employs the upstream tracing algorithm to find the contribution of each individual generator to the flow of power in the transmission line.

The total inflow P_i through node i can be expressed as

$$P_i = \sum_{j \in \alpha_i^{(u)}} \left| P_{i-j} \right| + P_{Gi} = \sum_{j \in \alpha_i^{(u)}} c_{ji} P_j + P_{Gi} \tag{1}$$

where $i = 1, 2, 3 \ldots n$ and $\alpha_i^{(u)}$ is the set of nodes supplying the power directly to the node i. P_{i-j} is the power flowing from node i to node j, P_{Gi} is the generation power at bus i and $c_{ji} = \left| P_{j-i} \right| / P_j$. This equation can be rewritten as

$$P_i - \sum_{j \in \alpha_i^{(u)}} c_{ji} P_j = P_{Gi} \tag{2}$$

or

$$A_u P = P_G \tag{3}$$

where A_u is a $(n \times n)$ upstream distribution matrix . P is the vector of nodal through flows and P_G is the vector of nodal generations. The $(i, j)^{th}$ element of A_u is given by

$$\left[A_u \right]_{ij} = \begin{cases} 1 & \text{for } i = j \\ -c_{ji} = -\left| P_{i-j} \right| / P_j & \text{for } j \in \alpha_i^{(u)} \\ 0 & \text{otherwise} \end{cases} \tag{4}$$

If A_u^{-1} exists, then $P = A_u^{-1} P_G$ and its i^{th} element is equal to

$$P_i = \sum_{k=1}^{n} \left[A_u^{-1} \right]_{ik} P_{Gk} \quad \text{for} \quad i = 1, 2, 3, \ldots n \tag{5}$$

which shows the contribution of the k^{th} generator to i^{th} nodal power.

A line outflow in the line $i - j$ from node i can be calculated using the proportional sharing principle, as

$$\left| P_{i-j} \right| = \frac{\left| P_{i-j} \right|}{P_i} P_i = \frac{\left| P_{i-j} \right|}{P_i} \sum_{k=1}^{n} \left[A_u^{-1} \right]_{ik} P_{Gk}$$

$$= \sum_{k=1}^{n} D_{i-j,k}^{G} P_{Gk} \quad \text{for all } j \in \alpha_i^{(d)} \tag{6}$$

and $D^{G}_{i-j,k} = \left|P_{i-j}\right|\left[A_u^{-1}\right]_{ik} / P_i$ is the generation contribution factor, which is the flow in the line $i-j$ due to the k^{th} generator and $\alpha_i^{(d)}$ is the set of nodes supplied directly from node i. Based on the generation contribution factor, the generators are selected for the process of rescheduling. The amount of rescheduling required is computed by solving the following optimization problem:
Minimize

$$CC = \sum_{k}^{N_c} C_g \times \Delta P_{Gk} \tag{7}$$

subject to,

$$\sum_{k}^{N_c}\left(P_{Gk}^0 + \Delta P_{Gk}\right) + \sum_{l,l\neq k}^{N_g} P_{Gk}^0 = \sum_{m}^{N_d} P_{dm}^0 + P_L \tag{8}$$

$$\sum_{k}^{N_c} P_{Gk}^f + \sum_{l,l\neq k}^{N_g} P_{Gk}^0 = \sum_{m}^{N_d} P_{dm}^0 + P_L \tag{9}$$

$$P_{Gk}^0 - P_{Gk}^{\min} = \Delta P_{Gk}^{\min} \le \Delta P_{Gk} \le \Delta P_{Gk}^{\max} = P_{Gk}^{\max} - P_{Gk}^0 \tag{10}$$

$$S_{i,j} \le S_{i,j}^{\max} \tag{11}$$

$$V_i^{\min} \le V_i \le V_i^{\max} \tag{12}$$

$$\delta_i^{\min} \le \delta_i \le \delta_i^{\max} \tag{13}$$

where

$CC =$ total congestion cost to relieve congestion

$N_g =$ total number of generators.

$N_c =$ total number of participating generators in the process of rescheduling ($N_c \subset N_g$).

$k =$ participating generator.

$l =$ non participating generator.

$N_s =$ number of transmission line in the system.

$N_d =$ total number of loads in the system

$m =$ individual load at each bus

$P_L =$ total transmission losses

$P_{Gk}^0 =$ active power generated by the k^{th} generator as determined by the system operator.

$P_{Gk}^f =$ active power generated by the k^{th} generator after the process of rescheduling.

$P_{dm}^0 =$ active power consumed by the m^{th} load as determined by the system operator.

$P_{Gk}^{\min}$, $P_{Gk}^{\max} =$ minimum and maximum limits of the k^{th} generator.

$\Delta P_{Gk} =$ change in real power adjustment at bus k.

$\Delta P_{Gk}^{\min}$, $\Delta P_{Gk}^{\max} =$ minimum and maximum limits of the change in real power adjustment of the k^{th} generator.

$C_g =$ incremental and decremental price bids submitted by generators at which the generators
are willing to adjust their real power outputs to relieve congestion.

$S_{ij} =$ MVA power flow in the line $i-j$.

$S_{ij}^{\max} =$ maximum MVA limit of the line $i-j$.

V_i, $\delta_i =$ voltage and angle at bus i.

During the process of optimization the power balance and system losses are taken care by the slack bus generator.

3. Differential Evolution

Differential Evolution is an optimization algorithm developed by Storn and Price, which solves real-valued problems based on the principles of natural evolution [25, 26]. DE uses a population P of size N_p, composed of floating point encoded individuals that evolve over G generations to reach an optimal solution. Each individual X_i is a vector that contains as many parameters as the problem decision variables D. The population size N_p is an algorithm control parameter selected by the user which remains constant throughout the optimization process.

$$P^{(G)} = [X_i^{(G)}, \ldots\ldots, X_{N_P}^{(G)}]$$
$$X_i^{(G)} = [X_{1,i}^{(G)}, \ldots, X_{D,i}^{(G)}]^T, i = 1, \ldots, N_p \tag{14}$$

Here $X_i^{(G)}$ refers to i^{th} individual vector in the G^{th} generation.

The ^{i} optimization process in differential evolution is carried out with three basic operations viz, mutation, crossover and selection. This algorithm starts by creating an initial population of N_p vectors. Random values are assigned to each decision parameter in every vector according to

$$X_{j,i}^{(0)} = X_j^{\min} + \eta_j (X_j^{\max} - X_j^{\min}) \tag{15}$$

where $i = 1, \ldots, N_p$ and $j = 1, \ldots.D$; $X_j^{\min}$ and $X_j^{\max}$ are the lower and upper bounds of the j^{th} decision parameter; and η_j is an uniformly distributed random number within [0,1] generated a new for each value of j. $X_{j,i}^{(0)}$ is the j^{th} parameter of the i^{th} individual of the initial population.

The mutation operator creates mutant vectors $(X_i^{'})$ by perturbing a randomly selected vector (X_a) with the difference of two other randomly selected vectors (X_b and X_c).

$$X_i^{'(G)} = X_a^{(G)} + F(X_b^{(G)} - X_c^{(G)}), \quad i = 1, \ldots, N_p \tag{16}$$

where X_a, X_b and X_c, are randomly chosen vectors $\in \{1, \ldots, N_p\}$ and $a \neq b \neq c \neq i$. X_a, X_b and X_c are selected a new for each parent vector. The scaling constant (F) is an algorithm control parameter used to control the perturbation size in the mutation operator and improve algorithm convergence.

The crossover operation generates trial vectors $(X_i^{''})$ by mixing the parameters of the mutant vectors with the target vectors (X_i), according to a selected probability distribution.

$$X_{j,i}^{''(G)} = \begin{cases} X_{j,i}^{'(G)}, \text{ if } \eta_j^{'} \leq C_R \text{ or } j = q \\ X_{j,i}^{(G)}, \text{otherwise} \end{cases} \tag{17}$$

where $i = 1, \ldots, N_p$ and $j = 1, \ldots.D$; q is a randomly chosen index $\in \{1, \ldots, N_p\}$ that guarantees that the trial vector gets at least one parameter from the mutant vector; $\eta_j^{'}$ is a uniformly distributed random number within [0,1] generated newly for each value of j. $X_{j,i}^{(G)}$, $X_{j,i}^{'(G)}$ and $X_{j,i}^{''(G)}$ are the j^{th} parameter of the i^{th} target vector, mutant vector, and trial vector at generation G, respectively. Finally, the selection operator determines the population by choosing between the trial vectors and their predecessors (target vectors) those individuals that present a better fitness or are more optimal.

$$X_i^{(G+1)} = \begin{cases} X_i^{''(G)}, \text{ if } f(X_i^{''(G)}) \le f(X_i^{(G)}), i = 1, \ldots.., N_p \\ X_i^{(G)}, \text{otherwise} \end{cases} \tag{18}$$

The optimization process is repeated for several generations, allowing individuals to improve their fitness as they explore the solution space in the search for optimal values.

DE has three essential control parameters: scaling factor (F), crossover constant (C_R) and population size (N_P). The scaling factor is a value in the range (0, 2) that controls the amount of perturbation in the mutation process. The crossover constant is a value in the range (0, 1) that controls the diversity of the population. The population size determines the number of individuals in the population and provides the algorithm enough diversity to search the solution space.

DE offers several variants or strategies for optimization. These can be denoted by $DE/x/y/z$, where x refers to the vector used to generate mutant vectors, y the number of difference vectors used in the mutations process and z the crossover scheme used in the crossover operation. There are ten different working strategies proposed by Price and Storn [25, 26]. The working algorithm used in this paper is the seventh strategy of DE (i.e.) $DE/rand/1/bin$ in which DE represents differential evolution, $rand$ is any randomly chosen vector for perturbations, 1 represents the number of difference vectors to be perturbed and bin is the binomial type of crossover used. The DE simulation parameters employed in the present study are: population size $(N_p) = 40$, scaling factor $(F) = 0.6$, crossover constant $(C_R) = 0.8$, maximum iteration $(it_{\max}) = 100$.

4. Proposed Algorithm

Generators for the congestion management are selected based on generator contribution factor and rescheduled using DE as outlined in figure (1).

5. Case Studies and Results

A. 3 bus system

A sample 3 bus system [27] is considered for explaining the power flow tracing algorithm. The system shown in figure 2 has two generators at buses 1 and 3, one load at bus 2, and three transmission lines. The active and reactive power flows obtained through AC power flow program is shown in figure 3. Figure 4 shows the lossless real power flow obtained from lossy flow of figure 3. Using equation (4), the upstream matrix (A_u) for the above system is found to be:

$$A_u = \begin{pmatrix} 1 & 0 & 0 \\ \dfrac{-175.165}{214.135} & 1 & \dfrac{-233.955}{233.955} \\ \dfrac{-38.9615}{214.135} & 0 & 1 \end{pmatrix}$$

Inverting the above matrix, we get

$$A_u^{-1} = \begin{pmatrix} 1 & 0 & 0 \\ 1 & 1 & 1 \\ 0.1819 & 0 & 1 \end{pmatrix}$$

Equation (6) helps to determine the way in which the line flows are supplied by the individual generators. The flow in line say, from bus 3→2, can be calculated as

$$\left(\frac{233.955}{233.955}\right) \times 0.1819 \times 214.135 = 38.9512\text{MW}$$

from G_1 and

$$\left(\frac{233.955}{233.955}\right)\times 1\times 194.985 = 194.985\text{MW}$$

from G_3. Similarly, the flows in all other lines are calculated and given in Table 1.

Table 1. Actual contributions of generators to the transmission lines of a 3 bus system

Lines connected between the buses	Actual Power flows (MW)	Contribution of Generator G_1 (MW)	Contribution of Generator G_3 (MW)	Contribution Factor (D)	
				G_1	G_3
1 – 2	175.16	175.16	0.0000	0.8180	0.0000
1 – 3	38.9695	38.9695	0.0000	0.1819	0.0000
3 – 2	233.955	38.9512	194.985	0.1819	1.0000

B. IEEE 30 bus system

The test system shown in figure 5 has three areas with two generators in each area. It has 41 transmission lines, 23 load buses with a load demand of 189.2 MW. Price bids submitted by the independent power producers are given in Table 2. Incremental and decremental cost is assumed to be same and it is taken slightly more than the marginal cost [13]. The proposed method is applied to this test system as discussed below.

Table 2. Price bids submitted by the independent power producers

Generator number	Incremental / decremental bid ($/MWh)
G_1	35
G_2	40
G_3	42
G_4	44
G_5	48
G_6	36

Table 3. Active power flow contribution factor of generators to the transmission lines single line contingency

Line number	From bus	To bus	Contribution factor (D)					
			G_1	G_2	G_3	G_4	G_5	G_6
1	1	2	0.559	0.000	0.000	0.000	0.000	0.000
2	1	3	0.441	0.000	0.000	0.000	0.000	0.000
3	2	4	0.109	0.194	0.000	0.000	0.000	0.000
4	2	5	0.165	0.294	0.000	0.000	0.000	0.000
5	2	6	0.141	0.253	0.000	0.000	0.000	0.000
6	3	4	0.384	0.000	0.000	0.000	0.000	0.000
7	4	6	0.333	0.132	0.000	0.000	0.000	0.000
8	4	12	0.043	0.017	0.000	0.000	0.000	0.000
9	5	7	0.165	0.294	0.000	0.000	0.000	0.000
10	7	6	0.010	0.017	0.000	0.000	0.000	0.000

Continued on next page

Table 3. Continued from previous page

Line number	From bus	To bus	Contribution factor (D)					
			G_1	G_2	G_3	G_4	G_5	G_6
11	**6**	**8**	**0.251**	**0.209**	**0.000**	**0.000**	**0.000**	**0.000**
12	6	9	0.103	0.085	0.000	0.000	0.000	0.000
13	6	10	0.059	0.049	0.000	0.000	0.000	0.000
14	6	28	0.031	0.026	0.000	0.000	0.000	0.000
15	28	8	0.031	0.026	0.000	0.000	0.000	0.023
16	9	11	0.000	0.000	0.000	0.000	0.000	0.000
17	9	10	0.103	0.085	0.000	0.000	0.000	0.000
18	10	20	0.037	0.031	0.000	0.105	0.000	0.000
19	10	17	0.003	0.002	0.000	0.008	0.000	0.000
20	10	21	0.077	0.064	0.000	0.218	0.000	0.000
21	22	10	0.000	0.000	0.000	0.459	0.000	0.000
22	13	12	0.000	0.000	1.000	0.000	0.000	0.000
23	12	14	0.007	0.003	0.157	0.000	0.000	0.000
24	12	15	0.011	0.004	0.256	0.000	0.000	0.000
25	12	16	0.013	0.005	0.306	0.000	0.000	0.000
26	15	18	0.006	0.002	0.137	0.000	0.213	0.000
27	23	15	0.000	0.0 00	0.000	0.000	0.398	0.000
28	16	17	0.009	0.004	0.217	0.000	0.000	0.000
29	18	19	0.004	0.002	0.090	0.000	0.140	0.000
30	20	19	0.022	0.018	0.000	0.063	0.000	0.000
31	22	21	0.000	0.000	0.000	0.365	0.000	0.000
32	22	24	0.000	0.000	0.000	0.176	0.000	0.000
33	23	24	0.000	0.000	0.000	0.000	0.434	0.000
34	25	24	0.000	0.000	0.000	0.000	0.000	0.094
35	25	26	0.000	0.000	0.000	0.0 00	0.000	0.195
36	27	25	0.000	0.000	0.000	0.000	0.000	0.289
37	27	29	0.000	0.000	0.000	0.000	0.000	0.321
38	27	30	0.000	0.000	0.000	0.000	0.000	0.368
39	27	28	0.000	0.000	0.000	0.000	0.000	0.023
40	29	30	0.000	0.000	0.000	0.000	0.000	0.206
The values given in **bold** are contribution factors for the congested line								

B.1. Single line contingency

The line connecting buses 14 and 15 (line 24) in area 2 is considered to be out of service due to which the line connecting buses 6 and 8 (line 11) gets congested. Using power flow tracing method we located the generators contributing to the congested line 11 as G_1 and G_2 (figure 6). The contribution factor of generators G_1 and G_2 to the line 11 are found to be 0.251 and 0.209 respectively (Table 3). The output of the generators G_1 and G_2 is rescheduled by employing a differential evolution based optimal power flow algorithm shown in figure 1.

The amount of power flowing in each line during and after congestion is shown in figure 7. After relieving congestion, the power flow through line 11 lies well within the maximum limit. The contribution factor of G_1 and G_2 to the line 11 is changed to 0.239 and 0.234 respectively.

Figure 8 shows the rescheduled powers of different generators by method – 1 and method – 2. In method – 2, all the six generators (G_1, G_2, G_3, G_4, G_5 and G_6) need to be rescheduled to relieve the congestion. But, by applying the first method, it was possible to relieve the congestion by rescheduling only two generators (G_1 and G_2).

The convergence graph in figure 9 shows that the first method gives lesser congestion cost (225.8991 \$/h) than the second (305.4972 \$/h), thereby benefiting the consumers. Figure 10 shows the voltage magnitude and phase angle for each bus after relieving congestion. It can be seen that they are within the permissible limits ensuring system security and stability.

C. Indian utility 62 bus system

The system has 19 generators, 89 (220 kV) transmission lines, 11 tap changing transformers with a power demand of 3304 MW. The system is divided into 3 areas with six generators in area 1 and area 3 respectively, whereas area 2 has seven generators as shown in figure 11. The line data and bus data for the present system are taken from [28]. Price bids submitted by the independent power producers are given in Table 4.

C.1. Multiline contingency

We have considered the line connecting buses 61 and 62 between area 1 and area 2 (line 88) to be out of service due to which the lines connecting buses 31–32 (line 43), 39–42 (line 58) and 55–58 (line 78) get congested.

Using power flow tracing method, we located the generators contributing to the congested lines 43, 58 and 78 as G_9, G_{10}, G_{11}, G_{12}, G_{13} and G_{14} as shown in figure 12. The contribution factor of the generators to the congested lines 43, 58 and 78 is given in Table 5. From Table 5, it is found that the generators G_{12}, G_{13} and G_{14} are contributing more effectively than the other generators. Hence these generators are selected by the system operator for the process of rescheduling to relieve the congestion efficiently.

The amount of power flowing in each line during and after congestion is shown in figure 13. After relieving congestion, the power flow through the congested lines 43, 58 and 78 lies well within the maximum limit.

Figure 14 shows the rescheduled powers of different generators by method – 1 and method – 2. It is inferred from figure 14 that in method – 2, seven generators (G_{10}, G_{11}, G_{12}, G_{13}, G_{14}, G_{15} and G_{16}) are rescheduled to relieve the congestion. But, by applying the first method, it was possible to relieve the congestion by rescheduling only three generators – G_{12}, G_{13} and G_{14}.

The convergence graph in figure 15 shows that the first method gives lesser congestion cost (6805.1103 `/h, where ` is the symbol for Indian currency rupee and h represents *hour*) than the second (7114.0459 `/h), thereby benefiting the consumers. Figure 16 shows the voltage magnitude and phase angle for each bus after relieving congestion. It can be seen that they are within the permissible limits ensuring system security and stability.

6. Conclusions

This paper presents an OPF based method for congestion management. The generators to be rescheduled are identified based on active power flow contribution factor using power flow tracing algorithm. The congestion cost is minimized using differential evolution optimization technique. It is found that the power flow tracing method directly provides the contribution of each generator to the congested line. This results in lesser number of generators participating in the process of rescheduling thereby reducing the congestion cost to a larger extent. The proposed algorithm is illustrated on IEEE 30 bus and Indian utility 62 bus system. It is found that differential evolution gives better optimal solutions when used with power flow tracing algorithm.

Table 4. Price bids submitted by the independent power producers

Generator number	G_1	G_2	G_3	G_4	G_5	G_6	G_7	G_8	G_9	G_{10}
Incremental/ decremental bid (`/MWh)	1410	1645	2115	1450	1570	1555	1622	1370	1550	2100
Generator number	G_{11}	G_{12}	G_{13}	G_{14}	G_{15}	G_{16}	G_{17}	G_{18}	G_{19}	—
Incremental/ decremental bid (`/MWh)	2170	2200	1850	1680	1540	1720	1600	1680	1745	—

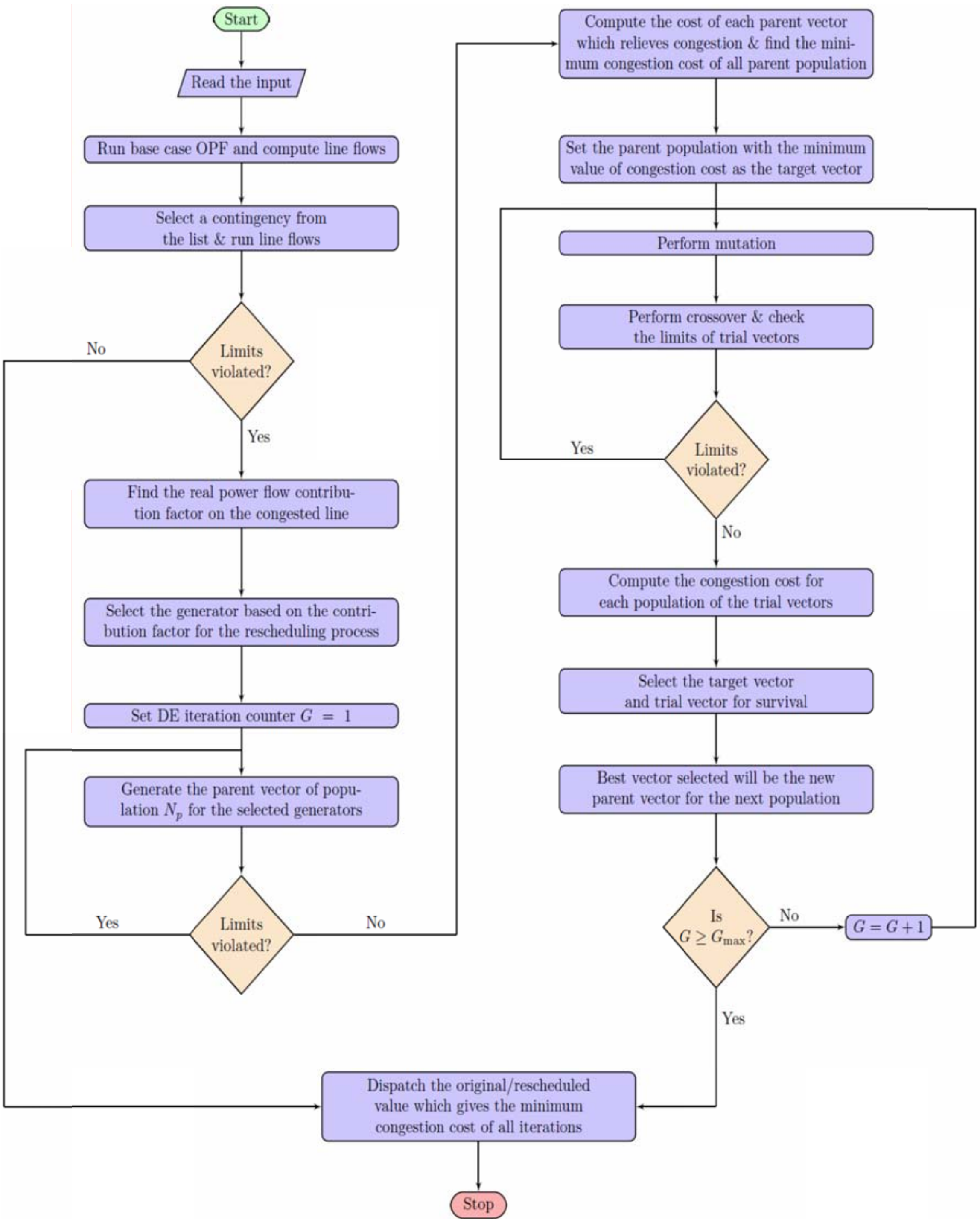

Figure 1. Flow chart of the proposed algorithm

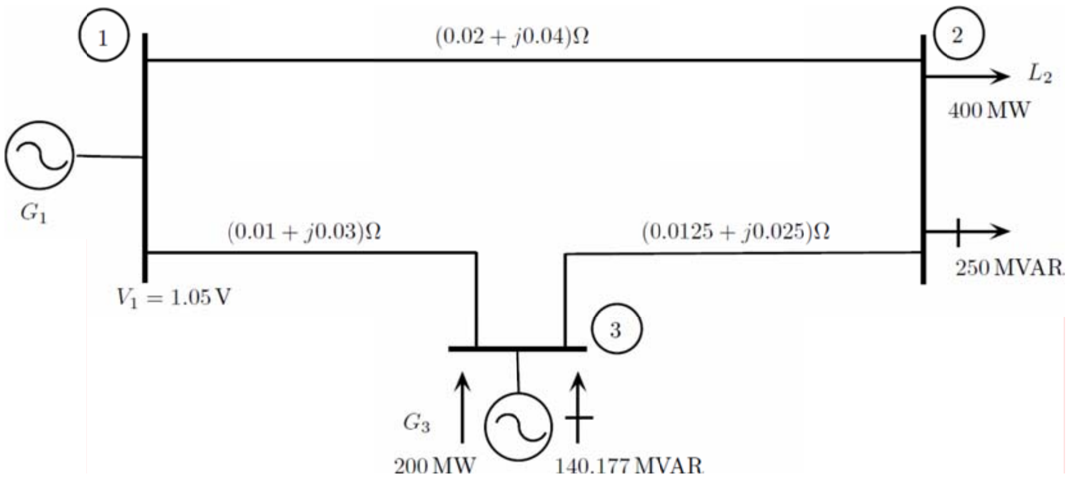

Figure 2. One line diagram of 3 bus system

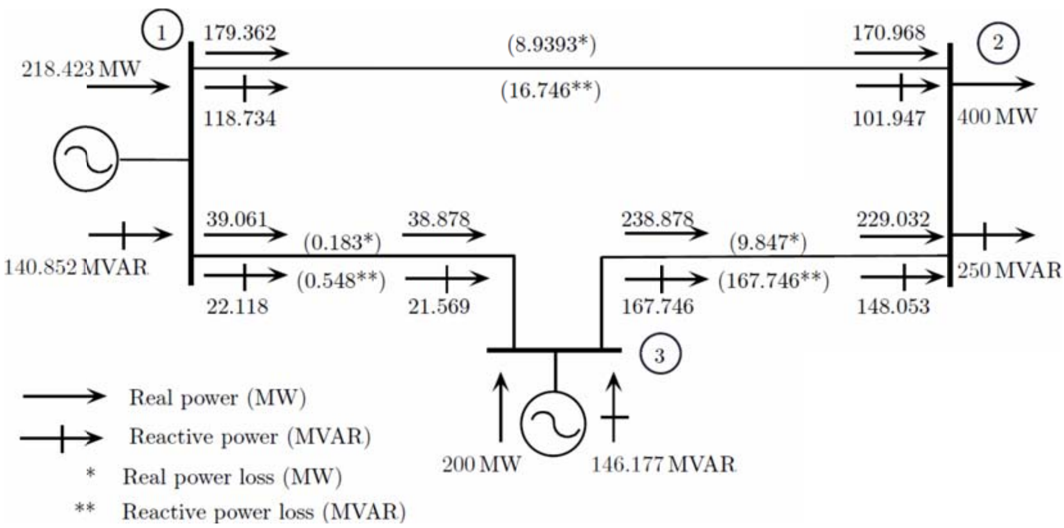

Figure 3. Power flow diagram of 3 bus system

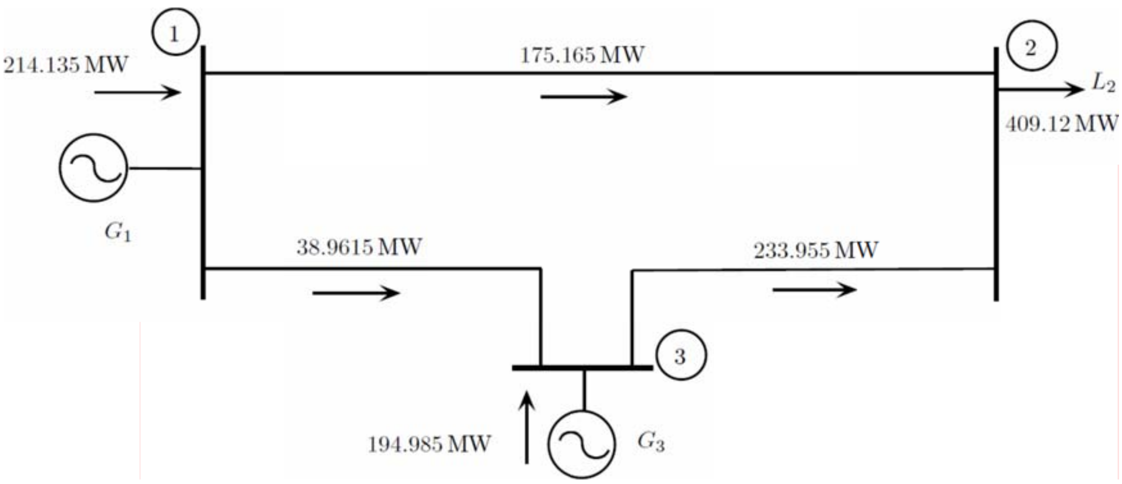

Figure 4. Lossless network of 3 bus system

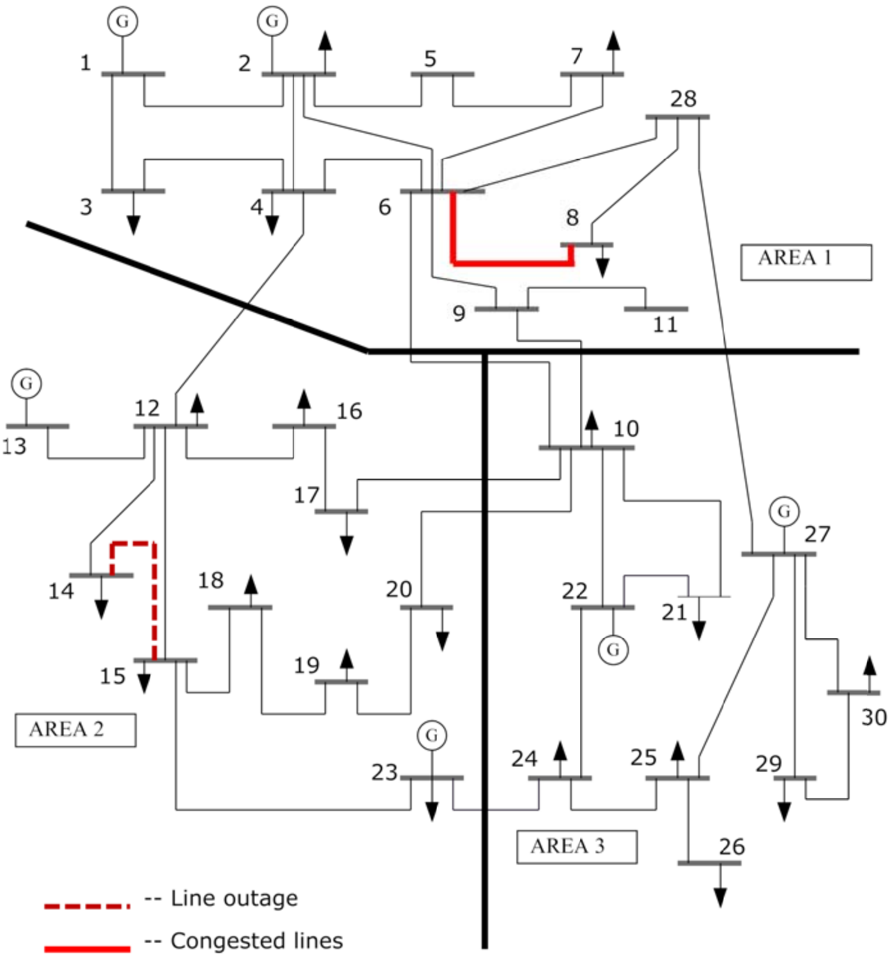

Figure 5. One line diagram of IEEE 30 bus system showing line outages and congested lines

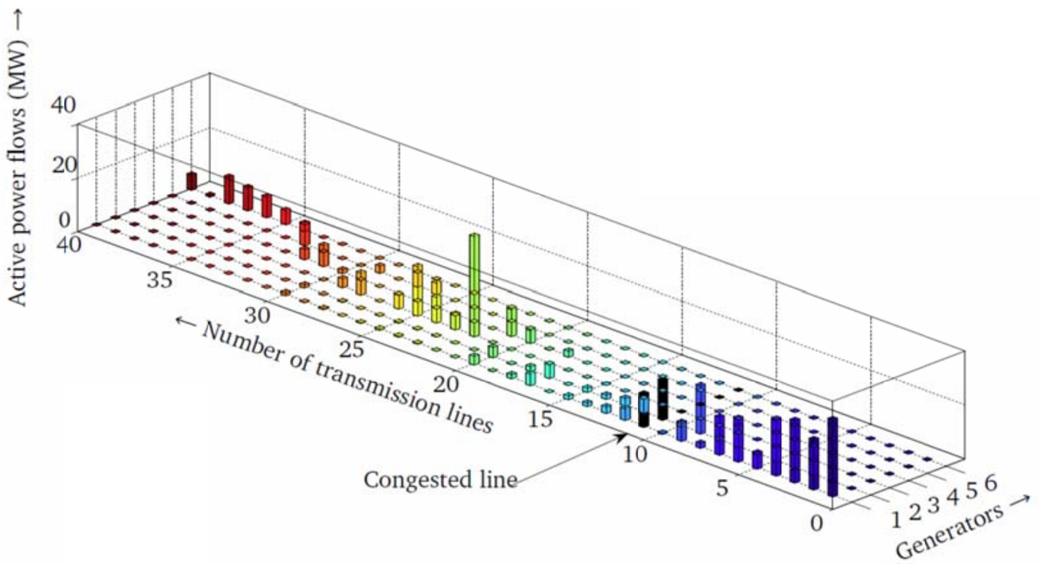

Figure 6. Contribution of generators to each transmission line

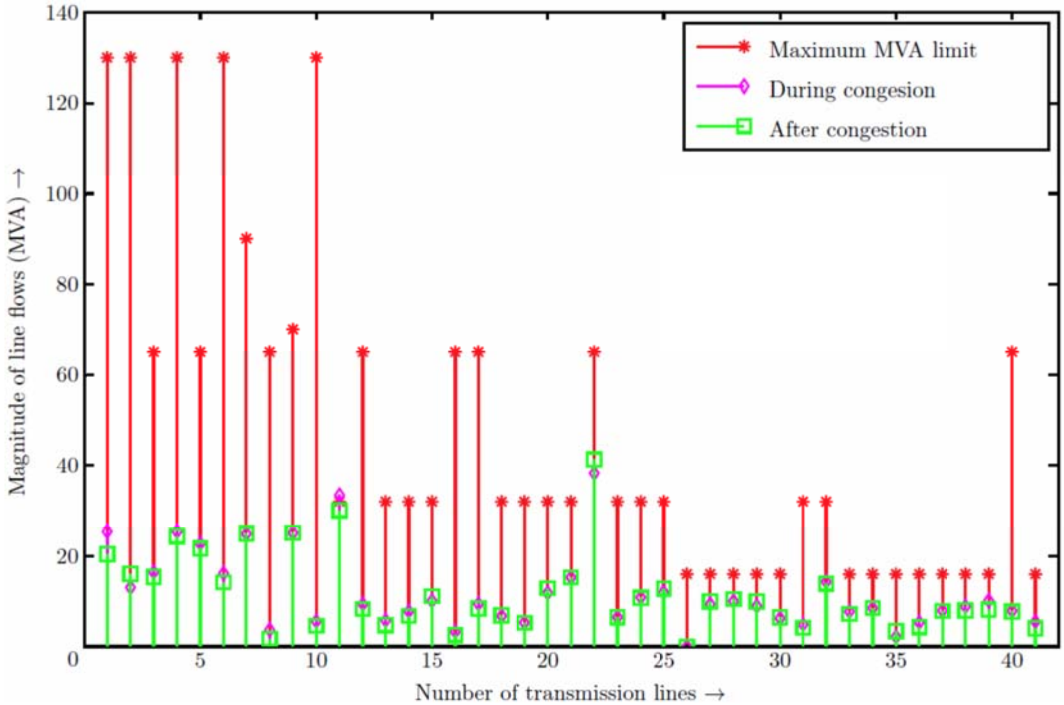

Figure 7. Power flows in each transmission line

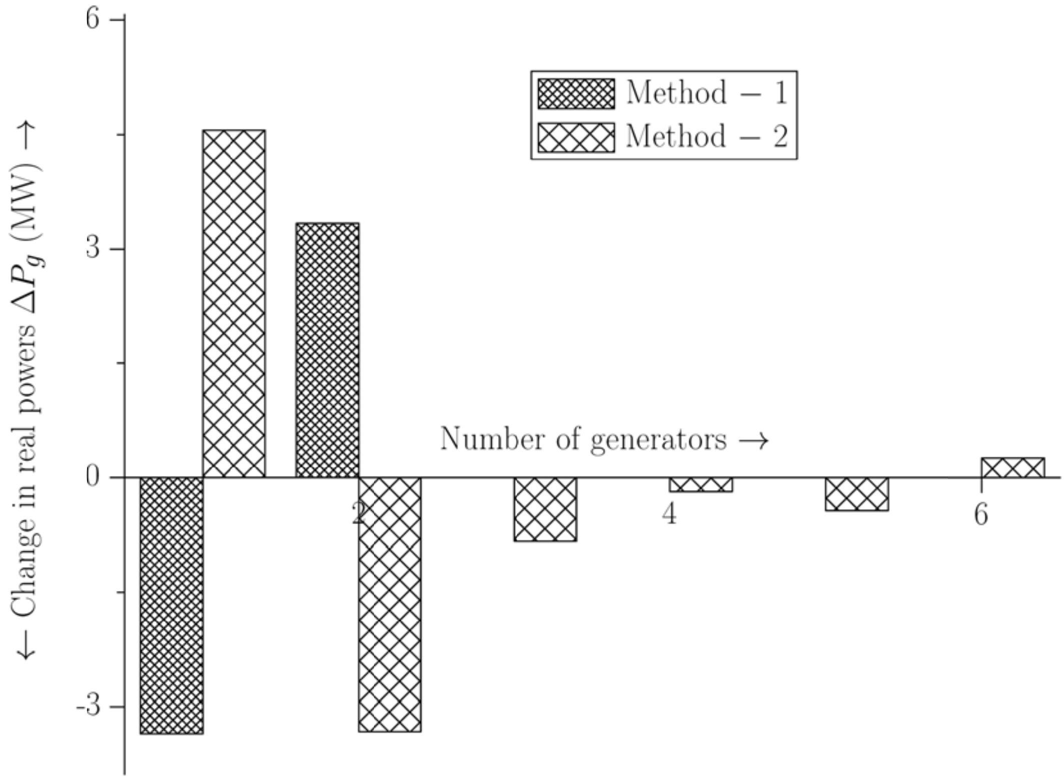

Figure 8. Rescheduled powers of participating generators

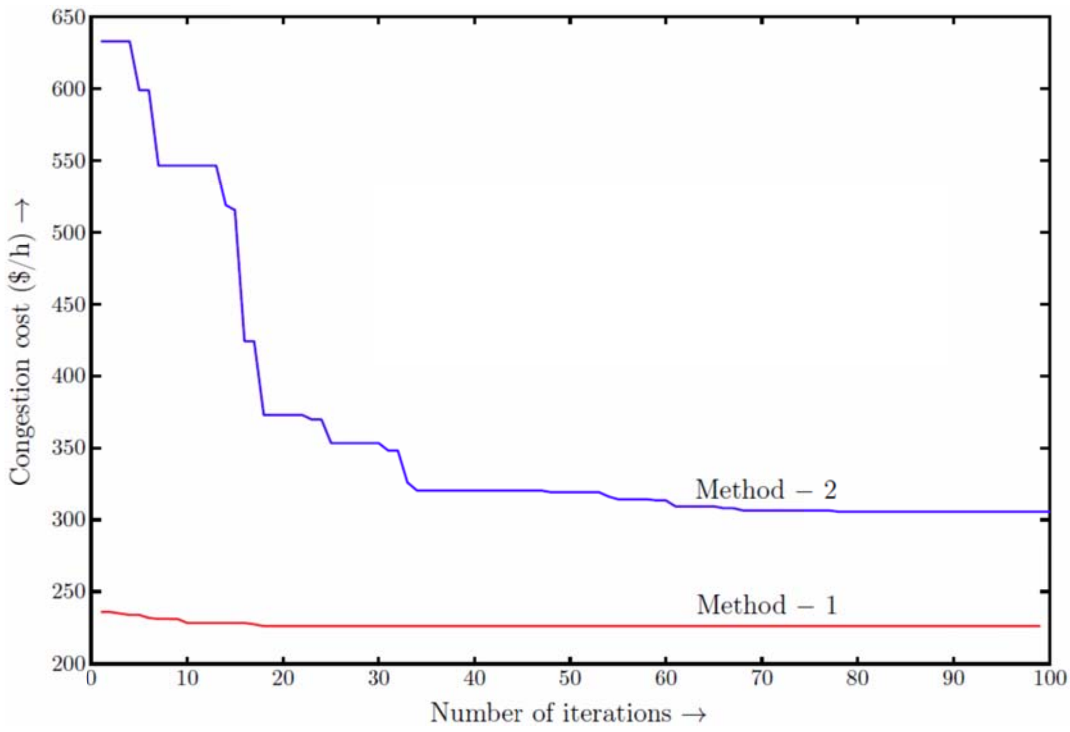

Figure 9. Convergence characteristics of intra zonal congestion

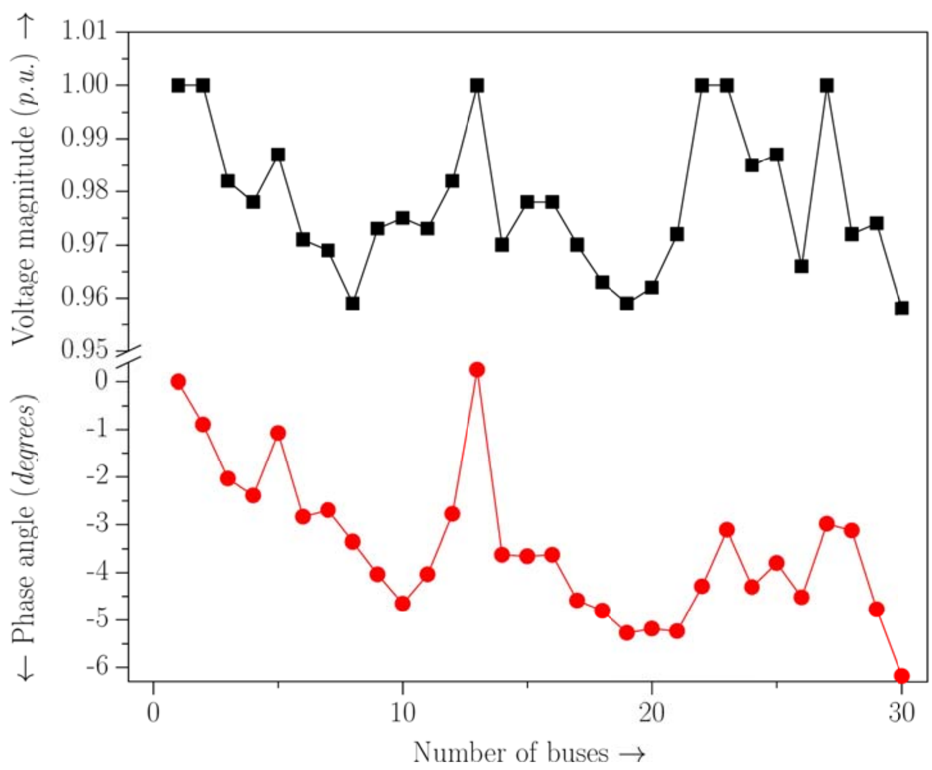

Figure 10. Phase angle and voltage magnitude of each bus

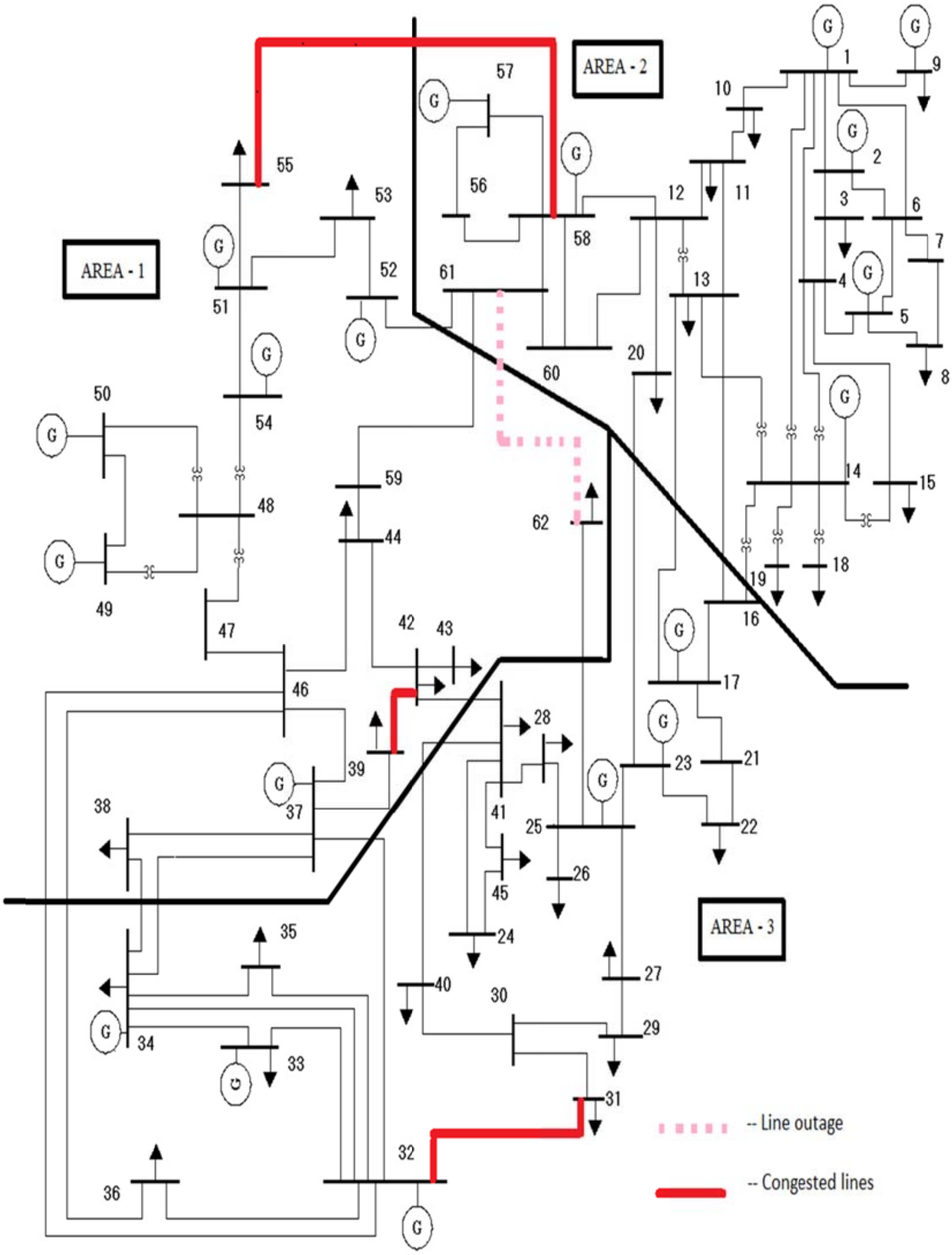

Figure 11. One line diagram of Indian utility 62 bus system showing line outages and congested lines

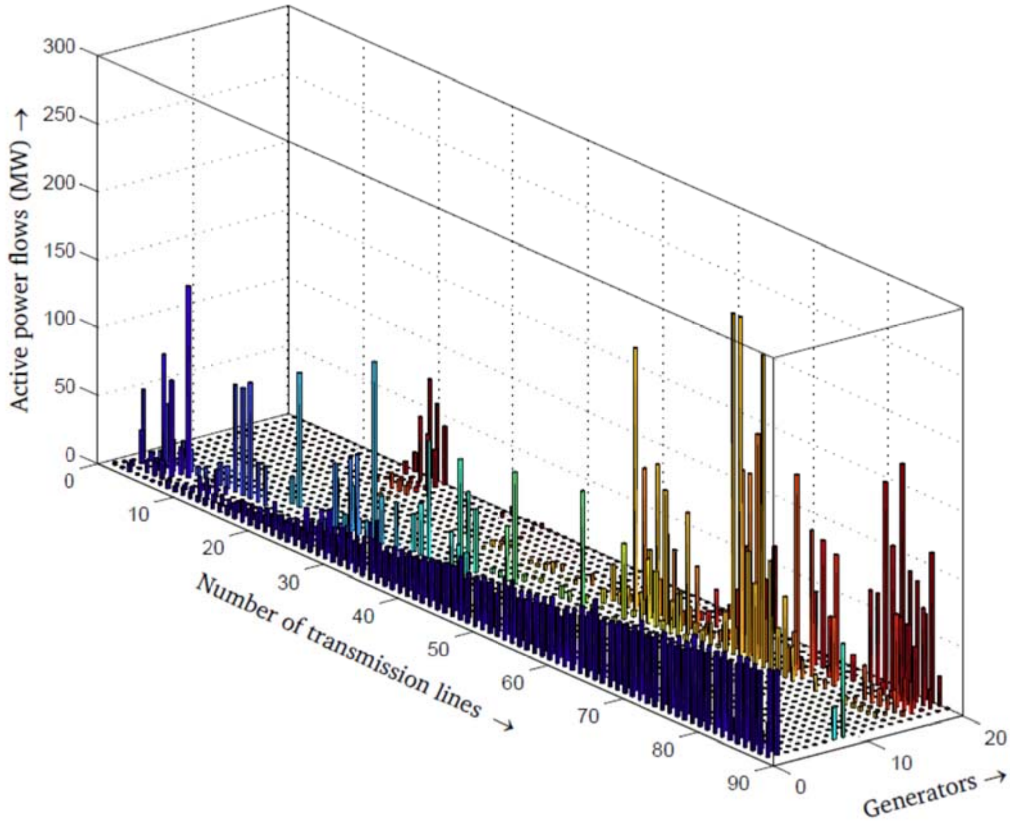

Figure 12. Contribution of generators to each transmission line

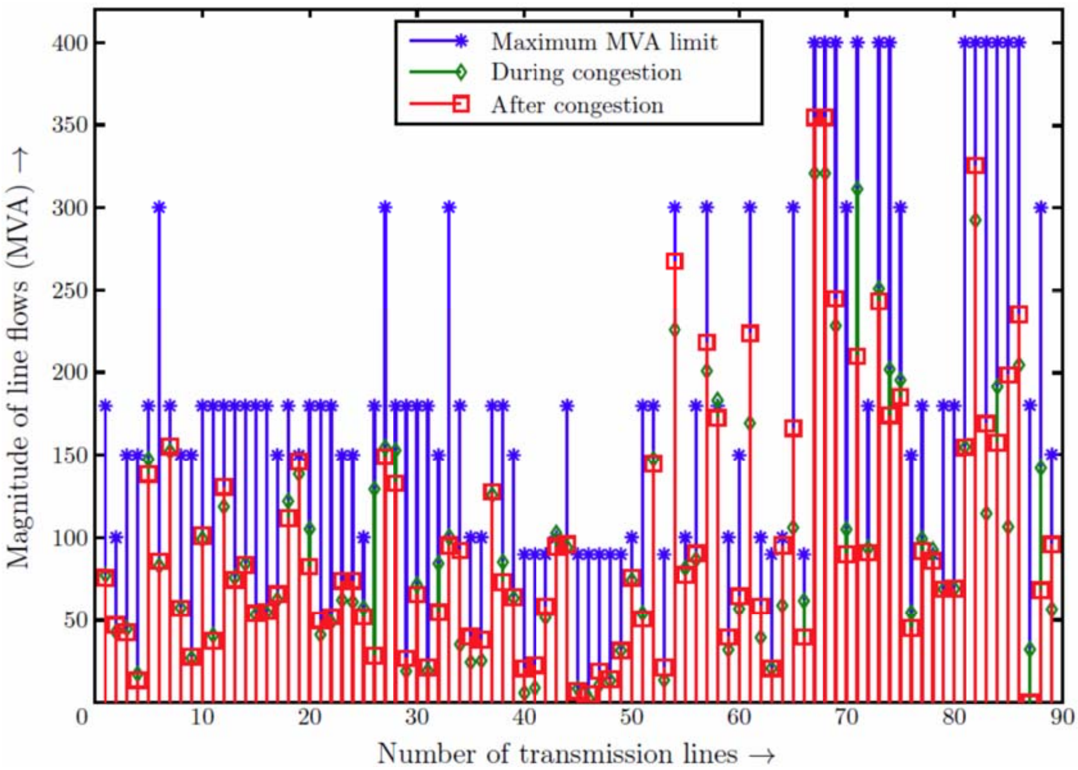

Figure 13. Power flows in each transmission line

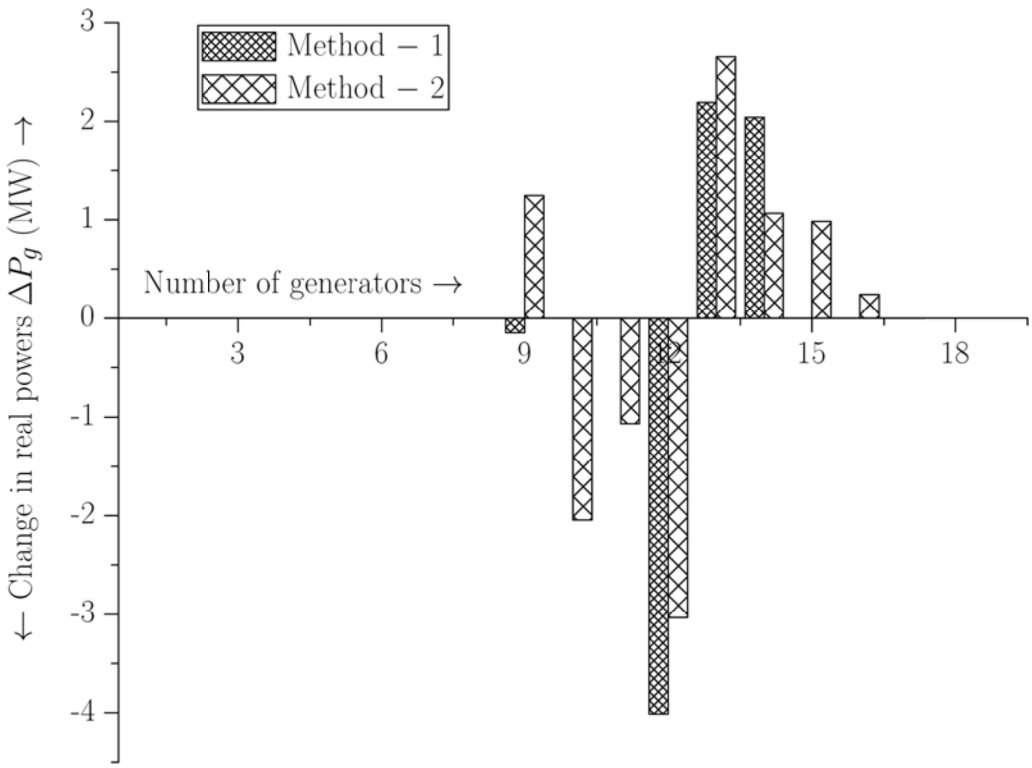

Figure 14. Rescheduled powers of participating generators

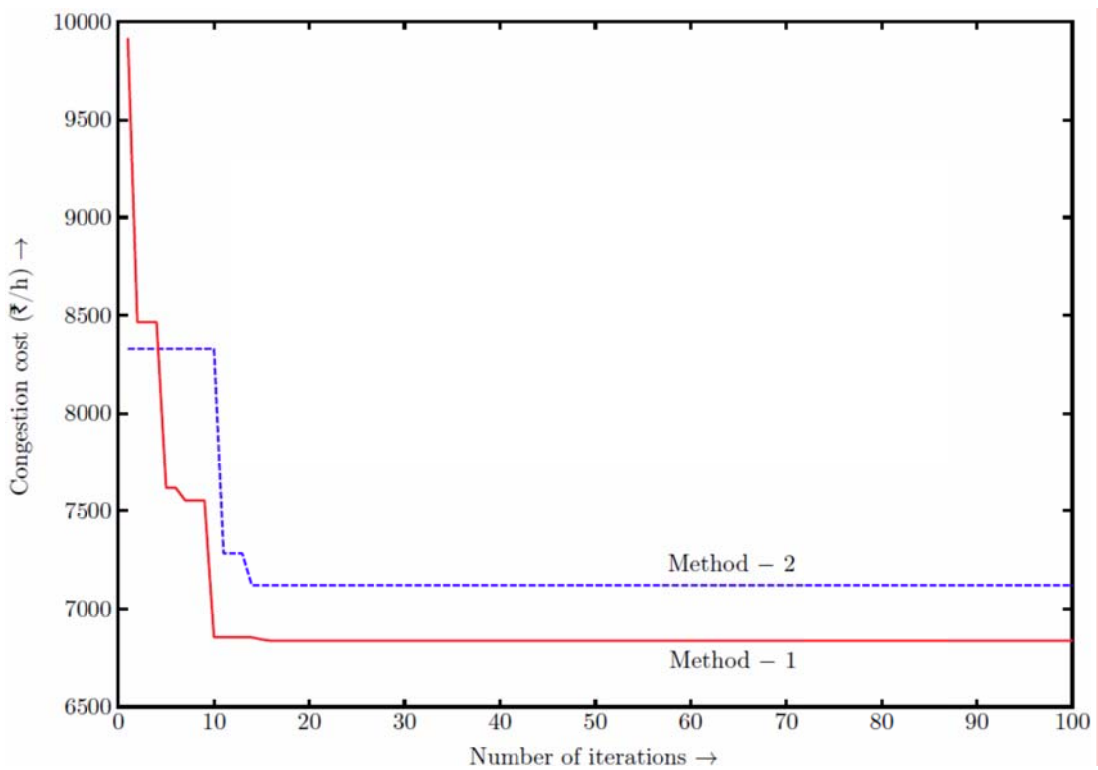

Figure 15. Convergence characteristics

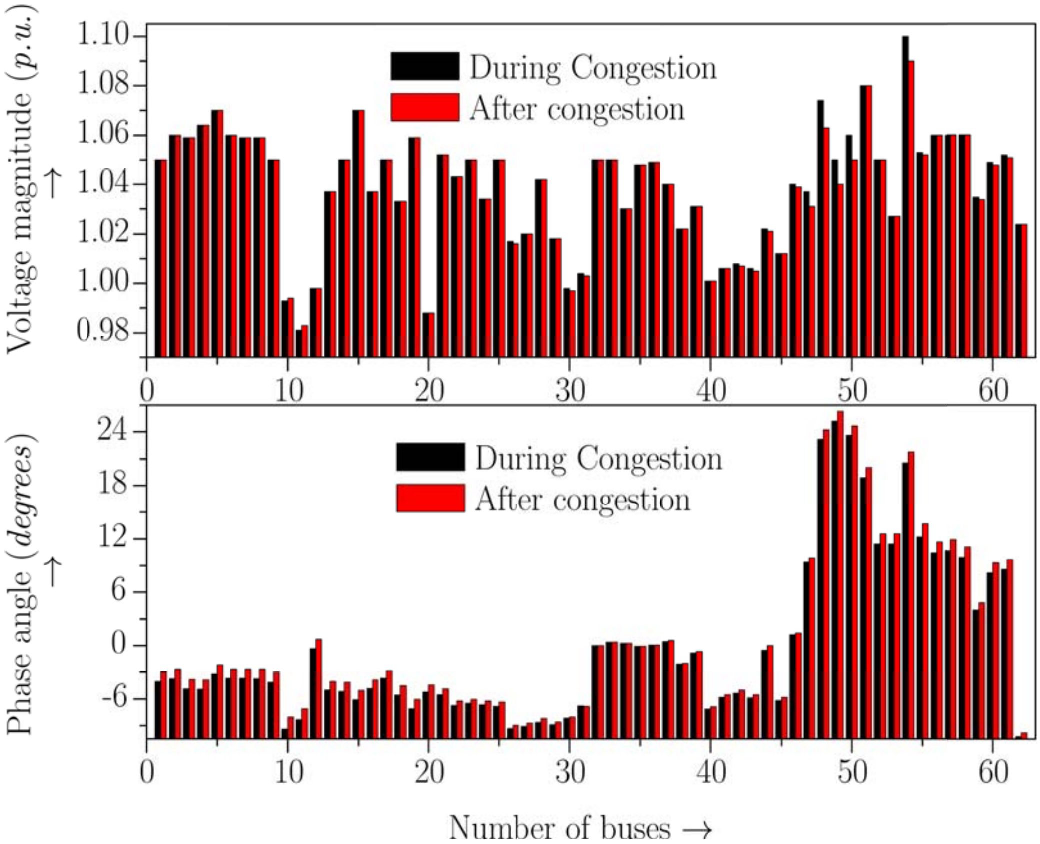

Figure 16. Phase angle and voltage magnitude of each bus

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Line no.	Bus	Contribution factor (D)																		
		G_1	G_2	G_3	G_4	G_5	G_6	G_7	G_8	G_9	G_{10}	G_{11}	G_{12}	G_{13}	G_{14}	G_{15}	G_{16}	G_{17}	G_{18}	G_{19}
1	2→1	0	0.260	0.009	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	1→4	0.127	0.033	0.022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	6→1	0	0	0.164	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	1→9	0.045	0.012	0.008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	1→10	0.458	0.119	0.079	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	1→14	0.37	0.096	0.064	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	2→3	0	0.74	0.024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	6→2	0	0	0.033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	4→3	0.002	0	0.005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	5→4	0.022	0.006	0.065	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	4→14	0.022	0.006	0.065	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	4→15	0.104	0.027	0.309	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	5→6	0	0	0.309	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	5→8	0	0	0.334	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	6→7	0	0	0.113	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	7→8	0	0	0.113	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	11→10	0	0	0	0	0	0.094	0	0	0	0	0	0	0.002	0.002	0.008	0.012	0.008	0.041	0.041
18	16→11	0	0	0	0	0	0.493	0	0	0	0	0	0	0	0	0	0	0	0	0
19	12→11	0	0	0	0	0	0	0	0	0	0	0	0	0.008	0.008	0.043	0.062	0.043	0.213	0.213
20	12→13	0	0	0	0	0	0	0	0	0	0	0	0	0.007	0.007	0.034	0.048	0.034	0.166	0.166
21	12→20	0	0	0	0	0	0	0	0	0	0	0	0	0.005	0.005	0.026	0.036	0.026	0.126	0.126
22	14→13	0.004	0.001	0.001	0	0.01	0.002	0	0	0	0	0	0	0	0	0	0	0	0	0
23	17→13	0	0	0	0	0	0.167	0	0	0	0	0	0	0	0	0	0	0	0	0
24	14→15	0.111	0.029	0.036	0	0.284	0.047	0	0	0	0	0	0	0	0	0	0	0	0	0
25	16→14	0	0	0	0	0	0.165	0	0	0	0	0	0	0	0	0	0	0	0	0
26	14→18	0.133	0.035	0.043	0	0.338	0.056	0	0	0	0	0	0	0	0	0	0	0	0	0
27	14→19	0.144	0.037	0.047	0	0.367	0.061	0	0	0	0	0	0	0	0	0	0	0	0	0
28	17→16	0	0	0	0	0	0.657	0	0	0	0	0	0	0	0	0	0	0	0	0
29	17→21	0	0	0	0	0	0.176	0	0	0	0	0	0	0	0	0	0	0	0	0
30	20→23	0	0	0	0	0	0	0	0	0	0	0	0	0.001	0.001	0.003	0.005	0.003	0.016	0.016
31	21→22	0	0	0	0	0	0.176	0	0	0	0	0	0	0	0	0	0	0	0	0
32	23→22	0	0	0	0	0	0	0.181	0	0	0	0	0	0	0	0.001	0.001	0.001	0.003	0.003

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Table 5. Active power flow contribution factor of generators to the transmission lines – multiline contingency

Table 5. Continued from previous page

Line no.	Bus	Contribution factor (D)																		
		G_1	G_2	G_3	G_4	G_5	G_6	G_7	G_8	G_9	G_{10}	G_{11}	G_{12}	G_{13}	G_{14}	G_{15}	G_{16}	G_{17}	G_{18}	G_{19}
33	23→24	0	0	0	0	0	0	0.249	0	0	0	0	0	0	0	0.001	0.001	0.001	0.004	0.004
34	23→25	0	0	0	0	0	0	0.57	.0	0	0	0	0	0	0	0.002	0.003	0.002	0.009	0.009
35	41→24	0	0	0	0	0	0	0	0	0	0	0	0.02	0.015	0.015	0.001	0.014	0.001	0.004	0.004
36	45→24	0	0	0	0	0	0	0	0	0	0	0	0.012	0.009	0.009	0	0.008	0	0.002	0.002
37	25→26	0	0	0	0	0	0	0.179	0.313	0	0	0	0	0	0	0.001	0.001	0.001	0.003	0.003
38	25→27	0	0	0	0	0	0	0.129	0.226	0	0	0	0	0	0	0	0.001	0	0.002	0.002
39	25→28	0	0	0	0	0	0	0.106	0.186	0	0	0	0	0	0	0	0	0	0.002	0.002
40	29→27	0	0	0	0	0	0	0	0	0.02	0.003	0	0.008	0.007	0.007	0	0.005	0	0.001	0.001
41	30→29	0	0	0	0	0	0	0	0	0.02	0.003	0	0.008	0.007	0.007	0	0.005	0	0.001	0.001
42	31→30	0	0	0	0	0	0	0	0	0.23	0.033	0.005	0.004	0.013	0.013	0	0	0	0	0
43	**32→30**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.483**	**0.068**	**0.002**	**0.200**	**0.025**	**0.040**	**0**	**0**	**0**	**0**	**0**
44	34→31	0	0	0	0	0	0	0	0	0.476	0.069	0.009	0.008	0.027	0.027	0	0	0	0	0
45	36→32	0	0	0	0	0	0	0	0	0	0.002	0.02	0.003	0.002	0.002	0	0	0	0	0
46	37→32	0	0	0	0	0	0	0	0	0	0	0	0	0.003	0.003	0	0	0	0	0
47	46→32	0	0	0	0	0	0	0	0	0	0	0	0.014	0.009	0.009	0	0	0	0	0
48	33→32	0	0	0	0	0	0	0	0	0	0	0	0	0.043	0.043	0	0	0	0	0
49	33→32	0	0	0	0	0	0	0	0	0	0.142	0	0	0	0	0	0	0	0	0
50	34→34	0	0	0	0	0	0	0	0	0	0.12	0	0	0	0	0	0	0	0	0
51	37→35	0	0	0	0	0	0	0	0	0	0.005	0.04	0.005	0.003	0.003	0	0	0	0	0
52	32→35	0	0	0	0	0	0	0	0	0.524	0.075	0.01	0.009	0.03	0.03	0	0	0	0	0
53	46→36	0	0	0	0	0	0	0	0	0	0	0	0	0.049	0.049	0	0	0	0	0
54	46→37	0	0	0	0	0	0	0	0	0	0	0	0	0.622	0.622	0	0	0	0	0
55	34→38	0	0	0	0	0	0	0	0	0	0.049	0.41	0.055	0.034	0.034	0	0	0	0	0
56	37→38	0	0	0	0	0	0	0	0	0	0	0	0.255	0.159	0.159	0	0	0	0	0
57	37→39	0	0	0	0	0	0	0	0	0	0	0	0.595	0.37	0.37	0	0	0	0	0
58	**39→42**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.511**	**0.316**	**0.332**	**0**	**0**	**0**	**0**	**0**
59	40→30	0	0	0	0	0	0	0	0	0	0	0	0.086	0.062	0.062	0.003	0.059	0.003	0.016	0.016
60	41→40	0	0	0	0	0	0	0	0	0	0	0	0.131	0.094	0.094	0.005	0.089	0.005	0.024	0.024
61	42→41	0	0	0	0	0	0	0	0	0	0	0	0.399	0.288	0.288	0.015	0.271	0.015	0.073	0.073
62	41→45	0	0	0	0	0	0	0	0	0	0	0	0.048	0.035	0.035	0.002	0.033	0.002	0.009	0.009
63	42→43	0	0	0	0	0	0	0	0	0	0	0	0.036	0.026	0.026	0.001	0.024	0.001	0.007	0.007
64	44→42	0	0	0	0	0	0	0	0	0	0	0	0	0.051	0.051	0.019	0.346	0.019	0.094	0.094
65	59→44	0	0	0	0	0	0	0	0	0	0	0	0	0.007	0.007	0.038	0.685	0.038	0.185	0.185

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Table 5. Continued from previous page

Line no.	Bus	Contribution factor (D)																		
		G_1	G_2	G_3	G_4	G_5	G_6	G_7	G_8	G_9	G_{10}	G_{11}	G_{12}	G_{13}	G_{14}	G_{15}	G_{16}	G_{17}	G_{18}	G_{19}
66	46→44	0	0	0	0	0	0	0	0	0	0	0	0	0.093	0.093	0	0	0	0	0
67	47→46	0	0	0	0	0	0	0	0	0	0	0	0	0.807	0.807	0	0	0	0	0
68	48→47	0	0	0	0	0	0	0	0	0	0	0	0	0.807	0.807	0	0	0	0	0
69	50→48	0	0	0	0	0	0	0	0	0	0	0	0	0.259	1	0	0	0	0	0
70	48→54	0	0	0	0	0	0	0	0	0	0	0	0	0.193	0.193	0	0	0	0	0
71	49→48	0	0	0	0	0	0	0	0	0	0	0	0	0.741	0	0	0	0	0	0
72	49→50	0	0	0	0	0	0	0	0	0	0	0	0	0.259	0	0	0	0	0	0
73	51→53	0	0	0	0	0	0	0	0	0	0	0	0	0.11	0.11	0.572	0	0.572	0	0
74	54→51	0	0	0	0	0	0	0	0	0	0	0	0	0.193	0.193	0	0	1	0	0
75	51→55	0	0	0	0	0	0	0	0	0	0	0	0	0.082	0.082	0.428	0	0.428	0	0
76	52→53	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.08	0	0	0
77	52→61	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.92	0	0	0
78	**55→58**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.040**	**0.040**	**0.022**	**0.027**	**0**	**0**	**0**	**0**	**0**
79	56→58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.308	0
80	57→56	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.308	0
81	57→58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.692	0
82	58→12	0	0	0	0	0	0	0	0	0	0	0	0	0.019	0.019	0.1	0	0.1	0.489	0.489
83	58→60	0	0	0	0	0	0	0	0	0	0	0	0	0.01	0.01	0.053	0	0.053	0.262	0.262
84	58→61	0	0	0	0	0	0	0	0	0	0	0	0	0.01	0.01	0.051	0	0.051	0.249	0.249
85	61→59	0	0	0	0	0	0	0	0	0	0	0	0	0.007	0.007	0.038	0.685	0.038	0.185	0.185
86	60→12	0	0	0	0	0	0	0	0	0	0	0	0	0.013	0.013	0.066	0.236	0.066	0.326	0.326
87	61→60	0	0	0	0	0	0	0	0	0	0	0	0	0.003	0.003	0.013	0.236	0.013	0.064	0.064
88	25→62	0	0	0	0	0	0	0.157	0.275	0	0	0	0	0	0	0.001	0.001	0.001	0.002	0.002

The values given in **bold** are contribution factors for the congested lines

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