Comparative studies of congestion management in deregulated electricity market

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Abstract—One of the main issues that threaten the system security in deregulated electricity market is congestion and its management. Congestion Management is one of the most challenging tasks System Operator. It may not be always 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. This paper presents a comparison of the Cluster/Zone based approach and Relative Electrical Distance approach. In Cluster/Zone based approach congestion management is carried out by using congestion relief and based on associated pricing. In congestion relief process, rescheduling the generation using Transmission Congestion Distribution Factors is done so as to minimize the rescheduling cost by Particle Swarm Optimization. Further load curtailment based on sensitivity index is also carried out if necessary. Congestion cost consists of rescheduling cost. Rescheduling cost is determined from bids supplied by GENCOs. In Relative Electrical Distance approach, the control used for overload alleviation is real power generation rescheduling based on relative electrical distance concept. The method estimates the relative location of load nodes with respect to the generator nodes, so that the system will have minimum transmission losses and more stability margins with respect to voltage profiles, bus angles and better transmission tariff. Power flow tracing is used to determine the Contribution of Generators.

Index Terms—congestion management, transmission congestion distribution factors (TCDFs), relative electrical distance, power flow tracing, voltage stability.

I. INTRODUCTION

Deregulation, a new paradigm in the electric supply industry, uses the transmission network as a common carrier. The open access causes congestion which occurs frequently in deregulated systems where it is somewhat complex to manage. Congestion Management remains as a main issue to System Operator. In deregulated systems, careful intervention to CM is necessary to make the dreams of deregulated systems true [1]. The methods generally adopted to manage congestion include rescheduling generator outputs, supplying reactive power support or physically curtail transactions. Several techniques of congestion management have been reported in literature [2]. Different models to deal with the different transactions, interactions between properties and limitations of the transmission system and the economic efficiency of the energy market have been mentioned in [3]. Congestion management techniques applied to various kinds of electricity markets are presented in [4]. Prioritization of electricity transactions and related curtailment strategies in a system where pool and bilateral/multilateral dispatches coexist is proposed in [5]. In [6], Congestion management ensuring voltage stability is addressed. An optimal topological configuration of a power system as a tool of congestion management is presented in [7]. Literature on optimal power flow (OPF) based congestion management schemes for multiple transaction systems and service cost has been proposed. A coordination mechanism between generating companies and system operator for congestion management using Benders cuts has been discussed in [9]. In [10], a technique has been proposed for alleviating congestions due to voltage instability and thermal overloads. This also uses OPF which is solved by standard solvers. In [11], a congestion clusters based method has been presented that groups the system users having similar effects on the transmission constraints of interest. Here, clusters of type 1, 2 and higher based on congestion distribution factors have been demarcated, with type 1 cluster consisting of those with strongest and non-uniform effects on the transmission constraints of interest. The clusters based on dc load flow form an effective congestion management market where readjustments of transactions in the type 1 cluster help to eliminate congestion. A zonal model based on ac load flow was proposed in [12] and [13]. Zones have been identified based on sensitivity values in these works also. However, in both [11] and [12], it is necessary to compute the sensitivity values for all the buses in the system which, given a practical power system, calls for a large amount of computational effort. Sensitivities of line flow to changes in generation have been used in [14] to alleviate congestion but no effort has been made to reduce the number of participating generators. In [15], a technique has been proposed for selection of participating generators based on sensitivity to current flow on congested line as well as the generation bids. However an optimal selection of the design variables is essential for regulating the number of participating generators. A method of overload alleviation by real power generation rescheduling...
based on relative electrical distance (RED) concept has been introduced in [16]. This technique claims to minimize the system losses and maintain a better voltage profile and hence more stability margin. However, the bids of individual generation units and costs of rescheduling are not taken into account. Generators having same RED but different price bids must reschedule their outputs in such a way that the total cost rescheduling is minimum. This problem has not been addressed in [16].

Therefore the main intent of the present work is 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. In a congested power system, the incremental or decremented power outputs of all the generators do not affect the system losses and maintain a better voltage profile and hence more stability margin. However, the bids of individual generation units and costs of rescheduling are not taken into account. Generators having same RED but different price bids must reschedule their outputs in such a way that the total cost rescheduling is minimum. This problem has not been addressed in [16].

Therefore the main intent of the present work is 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. In a congested power system, the incremental or decremented change in power outputs of all the generators do not affect the power transmitted on the congested line to the same extent. As such, there is no need to reschedule the outputs of generators whose generations are less critical to the congested line flow. Therefore, the sensitivities of the generators to the congested lines are used.

II. CONGESTION RELIEF

Though congestion is a condition during which the system constraints are violated, more often it is related to exceeding the power flow limit of lines. So congestion relief must be an action of removing this overload. Among the basic ways for congestion relief, the priority is given in the following manner:

1. Carry out rescheduling in the non-firm contract without disturbing firm contract.
2. If not enough, introduce new contracts or curtail some of the loads, which is possible.
3. If it is still not enough, reschedule the firm contracts.

The method of rescheduling of available resources based on minimum cost is an effective approach for CM in real time operation. During real time operation, it can be practiced more efficiently, if the knowledge of system users is gained. The system users in deregulated market are the GENCOs and the loads. The knowledge represents the GENCOs/loads that have similar & more contribution in transmission congestion. This knowledge is gained by Transmission Congestion Distribution Factors (TCDFs).

A. Cluster / zone based approach

A congestion cluster based method identifies the group of system users that have a similar effect on a transmission constraint of interest. These clusters/zones are obtained using Transmission Congestion Distribution Factors (TCDFs). These clusters are termed as of type 1, 2 and higher, where type 1 cluster represents users with strongest and non-uniform effects on transmission constraint on interest. The congestion cluster /zone of type 1 (zone-1) has been defined as zone having large and non-uniform TCDFs, and the congestion zones of type 2 (zone-2) and higher have been defined as those having small and similar TCDFs. Therefore the transactions in the congestion zone 1 have critical and unequal impact on the line flow. The congestion zones of types 2, 3 and higher are farther from the congested line of interest.

B. Transmission Congestion Distribution Factors (TCDFs)

Transmission congestion distribution factors (TCDFs) are defined as the change in real power flow ($\Delta P_i$) in a transmission line-k, connected between bus-i and bus-j, due to unit change in the power injection ($\Delta P_j$) at bus-j. Mathematically, the TCDF for line-k can be written as

$$TCDF_{ij}^k = \Delta P_n / \Delta P_i$$

(1)

TCDF$_{ij}^k$ denotes how much active power flow over a transmission line connecting bus-i and bus-j would change due to active power injection at bus-n. The method of obtaining this TCDF using DC load flow & AC load flow are discussed [4]. This work considers only real power rescheduling and uses DCTCDF & ACTCDF.

DC method:

$$TCDF_{ij}^u = D_{ij}^u + \beta_{ij}$$

(2)

Where,

$$[D_{ij}^u] = [B_{n-x}]^{-1} \begin{bmatrix} 0 \\ 0 \\ 0 \end{bmatrix}$$

Where, $[D_{ij}^u]$ is the distribution factor with bus-n, $[B]$ is the susceptance matrix, $(.)_n$ represents a vector without n$^{th}$ row and column or a matrix with corresponding n$^{th}$ row and column eliminated. $[L_{ij}]$ is a sensitivity vector of the line power flow with respect to bus voltage phase angle.

To obtain the fairness in the competitive environment, the line flow sensitivity at the slack bus should not be zero corresponding to the injections at the slack bus. To attain this, a shift factor has been defined as:

$$[\beta_{ij}] = - \frac{1}{2} \begin{bmatrix} D_{ij}(i) + D_{ij}(j) \end{bmatrix}$$

(4)

AC method:

The TCDFs have been derived utilizing the sensitivity properties of the Newton-Raphson load flow (NRLF) Jacobian (considering J11 only) as given below:

$$\Delta P_j = a_j \sum_{i=1}^{N} m_{ij} \Delta P_i + b_j \sum_{i=1}^{N} m_{ji} \Delta P_i$$

(5)

Where

$$a_j = \frac{\partial P_j}{\partial \delta_i} = V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i)$$

$$b_j = \frac{\partial P_j}{\partial \delta_j} = -V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i)$$

$$\Delta \delta = [J_{11}]^{-1} [\Delta P] = [M][\Delta P]$$

$$\Delta \delta_i = \sum_{j=1}^{N} m_{ij} \Delta P_i \quad i = 1, 2, \ldots, N, i \neq s$$

$$TCDF_{ij}^s = a_j m_{is} + b_j m_{js}$$

(6)

Where, TCDF$_{ij}^k$ are the transmission congestion distribution factors corresponding to bus-n and line-k, connecting buses i and j.
C. Re-dispatch
Rescheduling is done on the buses in the sensitive zones i.e., zone-1 and zone-2 so as to minimize the cost for re-dispatch. The objective is to minimize the total costs for rescheduling.

\[
\text{Minimize } \sum_{i=1}^{N_g} C_i (\Delta P_i) \Delta P_i
\]

The solution of above equation i.e., rescheduling amount at each GENCO are be obtained so that the following constraints are satisfied.

TCDF constraint:

\[
\sum_{i=1}^{N_g} \left( (ACTCDF_i^k) \Delta P_i + F_0^k \right) \leq F_{k}^{\max} \quad k = 1, 2, \ldots, N_i
\]

Where, \( F_0^k \) is the power flow caused by all contracts previously settled on line-k. \( F_{k}^{\max} \) is the line flow limit of line-k connecting buses i and j.

Ramp limit:

\[
\Delta P_{i}^{\min} \leq \Delta P_i \leq \Delta P_{i}^{\max} \quad i = 1, 2, \ldots, N_G, i \neq s
\]

Power limit of generation:

\[
P_{i}^{\min} \leq P_i + \Delta P_i \leq P_{i}^{\max} \quad i = 1, 2, \ldots, N_G, i \neq s
\]

Power balance:

\[
P_{Gm} - P_{Gn} = 0
\]

\[
\sum_{n} P_{Gm}^{i} - \sum_{n} P_{Dn}^{i} = 0 \quad t = 1, 2, \ldots, N_i
\]

\( P_{Gm}^{i}, P_{Dn}^{t} \) are power flow equations for bilateral and multilateral contracts, respectively. This work uses PSO algorithm to solve the above mentioned optimization problem.

The fitness function for this problem is

\[
\sum_{i=1}^{N_g} C_i (\Delta P_i) \Delta P_i + \text{penalty} \left[ \sum_{i=1}^{N_g} ((ACTCDF_i^k) \Delta P_i) + F_0^k - F_{k}^{\max} \right] + \\
\left( \sum_{n} P_{Gm}^{i} - \sum_{n} P_{Dn}^{i} + \sum_{i=1}^{N_g} \Delta P_i \right)
\]

D. Relative Electrical Distance (RED) method

The generators are classified into two groups based on the generators direction of contribution to the congested lines. Generators which are contributing (in the direction of overloading) to all the congested lines are identified as GD group (where generation decrease is recommended), and the generators which are not contributing (in opposite direction) to all the congested and fully loaded network elements are categorized under GI group (where generation increase is recommended). For a given operating condition the total generation change in GI group must be same as the total generation change in the GD group.

D.1. Approach for load sharing/generation scheduling

Consider a system where \( n \) is the total number of buses with 1, 2…, \( g \) number of generator buses, and \( g+1, \ldots, n \), remaining \( (n-g) \) buses. For a given system we can write,

\[
\begin{bmatrix}
I_G \\
I_L
\end{bmatrix} = \begin{bmatrix}
Y_{GG} & Y_{GL} \\
Y_{LG} & Y_{LL}
\end{bmatrix} \begin{bmatrix}
V_G \\
V_L
\end{bmatrix}
\]

Where \( I_G, I_L, V_G \) and \( V_L \) represents complex current and voltage vectors at the generator nodes and load nodes. \( Y_{GG}, Y_{GL}, Y_{LL}, \) and \( Y_{LG} \) are corresponding partitioned portions of network Y-bus matrix.

Approach for load sharing/generation scheduling as defined in (8) gives the information, for each load bus, about the amount of power that should be taken from each generator under normal and network contingencies, as far as the system performance is considered with respect to the voltage profiles, bus angles and voltage stability index.

\[
F_{LG} = -\left[Y_{Ll}\right]^T [Y_{Ll}]
\]

This matrix is used as the basis for the desired load sharing/generation scheduling. If each consumer takes the power from each generator according to the \([ F_{LG} ]\) matrix the system will have minimum transmission loss, minimum angle separation between generator buses and minimum L-indices. The elements of \([ F_{LG} ]\) matrix are complex and its columns correspond to the generator bus numbers and rows correspond to the load bus numbers. This matrix gives the relation between load bus voltages and source bus voltages. It also gives information about the location of load nodes with respect to generator nodes that is termed as relative electrical distance between load nodes and generator nodes.

The relative electrical distances, i.e., the relative locations of load nodes with respect to the generator nodes are obtained from the \([ F_{LG} ]\) matrix as,

\[
R_{LG} = \text{abs} \left( [ F_{LG} ] \right)
\]

The desired proportions of generation for the desired load sharing/generation scheduling is also obtained from the \([ F_{LG} ]\) matrix and is given by,

\[
D_{LG} = [A] - \text{abs} \left( [ F_{LG} ] \right)
\]

Where, \( A \) is identity matrix.

E. Domain of Generator

The domain of a generator is defined as the set of buses which are reached by power produced by this generator. For this it is necessary to trace the line flow for each GENCO and load. Therefore the power flow tracing is used in this work.

E.1 Power Flow Tracing

The power flow tracing algorithm is a mechanism for tracing the contribution of each user on a line flow and for allocating charges for the use of transmission line. The algorithm is in fact an electricity auditing procedure and answers all questions relating to individual user’s contribution in the transmission network. For a specific GENCO it results in downstream tracing and for a load results in upstream tracing. In general, tracing algorithm uses the concepts of dominion and proportional sharing principle.

Dominion concept

In down-stream tracing, it starts with a specific GENCO and traces the information where the electric power of each
GENCO goes. In case of upstream tracing, starting point is load with minimum load angle and it traces over all lines to know from where the electric power of each load comes. Steps for source dominion determination are as follows:
1. Run the base case ac load flow.
2. Form branch-bus incidence matrix.
3. The branches corresponding to the +1 entry in the specific GENCO’s row are included as the dominion of that GENCO.
4. The receiving end row of those branches is also traced for -1 entry. All those branches are also included in dominion.
   For up-stream tracing the reverse procedure is followed i.e. tracing starts with -1 entry and ends with +1 entry.

Proportional sharing principle:
This concept of tracing answers the question: How much is the contribution? For that, the contribution factor is determined at each end of the line. In downstream tracing it is a fraction of inflow to that bus and in upstream tracing it is a fraction of outflow at that bus. The contribution of each dominion to the branch power and load power is determined using the proportional sharing principle. The power flow at the sending end of line ‘m’ is made up of contribution of ‘n’ inflows and the generator. Similarly ‘n’ inflows and the generator also feed the load P_l as shown in fig.1.

At the sending end:

\[ C'_P_m = \frac{P_{mk}'}{P_{D1} + P_{D2} + \ldots + P_{Dn} + P_G} \]

\[ P_{mk}' = P_{D1}' + P_{D2}' + \ldots + P_{Dn}' + P_G' \]

\[ P_G' = P_G' * C'_P_m \]

Where i=1, 2, ..., n, and single primes indicate the sending end.

Fig.1. The real power contribution on line mk

Similar equations are obtained for receiving end and load points [9]. The equations are derived for upstream tracing also. Thus the contribution in various transmission lines and hence change in transmission tariff for the users participating in congestion are determined.

F. Load curtailment
In this work rescheduling the non-firm transactions is carried out first. If the optimum rescheduling is not enough to relieve the congestion, the load curtailment is carried based on some index at the load buses in the sensitive zone. The index is derived from three simple indices [7]. Among these this work considers two indices.

The indices considered are:
1. The sensitivity of a particular load to a congested branch – it confines the number of loads to be considered.
2. The consumer’s willingness to curtail the load – it indicates the adjustment amount. The index based on the sensitivity factor

\[ \Delta P_k = S_k \Delta P_j \]

Where,

\[ S_k = \left( \frac{x_{mj} - x_{nj}}{x_{mn}} \right) k = \text{line joining m & n} \]

To scale the effect of physical change in the power flow, the sensitivity factors of different locations (j) of the system are measured by the following index.

\[ \mu_{sj} = \frac{S_k - S_{\min}}{S_{\max} - S_{\min}} \]

Where \( S_{\max} \) and \( S_{\min} \) are respectively maximum and minimum values of S to the particular target branch. With the highest sensitivity, the index \( \mu_k \) is highest at 1, and if sensitivity is below \( S_{\min} \), the index is zero, meaning no effect on congestion relief. If the minimum reduction of power flow on the congested branch is given by \( \Delta P_d \), the required amount of adjustment at bus j will be given by:

\[ \mu_{lj} = \frac{\Delta P_j}{S_{kj}} \]

The possibility of above determined adjustment value is obtained by fixing the acceptable range for load curtailment by \( \mu_{\max} \) and \( \mu_{\min} \).

\[ \mu_{lj} = \begin{cases} 1 & \mu_{\max} \\
\frac{\mu_{\max} - \mu_{lj}}{\mu_{\max} - \mu_{\min}} & \mu_{\min} \leq \mu_{lj} \leq \mu_{\max} \\
0 & \mu_{lj} \geq \mu_{\min} \end{cases} \]

Generally, the higher the sensitivity, the smaller the amount of curtailment needed. The overall index for a possible load curtailment is then given by:

\[ \omega_{lj} = \mu_{lj} \cdot \mu_{lj} \]

Since load curtailment is done on the sensitivity zone it doesn’t consider the price of the load point.

G. System Performance Parameters
Here the system Performance is considered with respect to the voltage profiles, bus angles and voltage stability index.

Voltage stability index L:
Consider a system where \( n \) is the total number of buses with 1, 2..., \( g \) number of generator buses, and \( g+1 \ldots n \), remaining \( (n-g) \) buses. For a given system operating condition, using the operational load flow (state estimation) results, the static voltage stability L-index is computed as,

\[ L_j = \left| 1 - \sum_{i=1}^{\zeta} F_{ji} \frac{V_i}{V_j} \right| \]
Where, \( j = g+1, \ldots, n \) and \( F_{ji} \) are the complex elements of \( F_L \) matrix. An \( L \) index value away from 1 and close to zero indicates an improved system security.

### H. Rescheduling Cost

The cost of rescheduling is determined from the bids of each GENCO. This work assumes that the bid for increment and decrement are same and it is incremental cost function. i.e. the bid of GENCO-\( i \). \[
\frac{dC_i}{dP_i} = a_i \cdot P_i + b_i \quad \text{$/\text{MW-hr}$}
\] (16)

### III. RESULTS AND DISCUSSION

To illustrate the efficiency of the proposed idea for congestion management, IEEE 6 bus and IEEE 30 bus system are used as test systems. The numerical data for IEEE 6 bus system and IEEE 30 bus system are taken from [11] and [12] respectively.

#### Case 1: IEEE-6 bus system:

**Cluster / zone based approach:**

The above explained procedure is tested with IEEE-6 bus system [11] modified with firm transaction between bus-3 and bus-6 shown in Fig 2. Repeated AC load flow shows that transaction of 7.5MW results in safer operation. In most cases congestion is created either by unexpected rise in load or by outage of some elements. In this case the unexpected increase of load at bus-4 & bus-5 by 2MW causes congestion on lines 1-2 and 3-5.

- 1-2 Line flow: 30.123 > 30MW
- 3-5 Line flow: 20.222 > 20MW

Fig 2. IEEE-6 bus system with firm transaction of 7.5MW between bus-3 and bus-6

The ACTCDF values and clusters/zones are listed in Table I.

### TABLE I: CONGESTION CLUSTERS

<table>
<thead>
<tr>
<th>Congestion of line 1-2</th>
<th>Congestion of line 3-5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone -1</td>
<td>Zone -2</td>
</tr>
<tr>
<td>Bus</td>
<td>ACTCDF</td>
</tr>
<tr>
<td>1</td>
<td>0.2396</td>
</tr>
<tr>
<td>2</td>
<td>-0.2396</td>
</tr>
<tr>
<td>3</td>
<td>-0.1778</td>
</tr>
<tr>
<td>6</td>
<td>-0.1872</td>
</tr>
</tbody>
</table>

**RESCHEDULING:**

Rescheduling is carried in zone 1 (superimposing of two zone-1s) i.e. at GENCO-2 and GENCO-3. At bus-3 the firm transaction is not disturbed. Rescheduling amount is obtained using eq (7)–(11). For solving this optimization problem PSO algorithm is used. The PSO parameters are as follows:
- Number of particles: 70
- Number of iterations: 100
- Weight maximum: 0.9, minimum: 0.2
- Acceleration factors: \( C_1 = C_2 = 1.4 \)

Rescheduling cost is calculated using eq.(16)

Rescheduling results are listed in Table II.

### TABLE II: RESCHEDULING RESULTS

<table>
<thead>
<tr>
<th>GENCO</th>
<th>Generation during congestion ((P_i)) (MW)</th>
<th>Rescheduling amount ((\Delta P_i)) (MW)</th>
<th>Generation after congestion relief ((P_i)) (MW)</th>
<th>Rescheduling cost (($/\text{hr}))</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>50</td>
<td>1.6697</td>
<td>51.6697</td>
<td>18.7374</td>
</tr>
<tr>
<td>3</td>
<td>60</td>
<td>-1.6576</td>
<td>58.3424</td>
<td>19.4307</td>
</tr>
</tbody>
</table>

From the above table it is clear that, increasing the generation at generator-2 with 1.6697MW and decreasing the generation at generator-3 with 1.6576MW congestion has been relieved.

**LINE FLOWS:** 1-2: 30.00MW, 3-5:19.892MW.

**RELATIVE ELECTRICAL DISTANCE (RED):**

Based on the \( F_L \) matrix the contribution of each generator to each load has been calculated and mentioned in the Table III.

### TABLE III: DESIRED LOAD SHARING/ GENERATION SCHEDULING (MW)

<table>
<thead>
<tr>
<th>Load bus</th>
<th>Power taken from Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>G1 (MW)</td>
<td>G1 (%)</td>
</tr>
<tr>
<td>----------</td>
<td>--------</td>
</tr>
<tr>
<td>4</td>
<td>24.7449</td>
</tr>
<tr>
<td>5</td>
<td>19.7647</td>
</tr>
<tr>
<td>6</td>
<td>3.8256</td>
</tr>
<tr>
<td>sum</td>
<td>48.3353</td>
</tr>
</tbody>
</table>
Based on the contribution of generators, Generator 2 is not contributing to the congested lines so it will be in GI group and generator 3 is in GD group since it is contributing to the congested lines, as shown in Table IV.

<table>
<thead>
<tr>
<th>Lin e</th>
<th>Flow (MW)</th>
<th>Contribution of G1 %</th>
<th>Contribution of G2 %</th>
<th>Contribution of G3 %</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-2</td>
<td>30.123</td>
<td>100</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1-4</td>
<td>45.332</td>
<td>100</td>
<td>45.332</td>
<td>0</td>
</tr>
<tr>
<td>1-5</td>
<td>36.902</td>
<td>100</td>
<td>36.902</td>
<td>0</td>
</tr>
<tr>
<td>2-3</td>
<td>1.978</td>
<td>0</td>
<td>100</td>
<td>1.978</td>
</tr>
<tr>
<td>2-4</td>
<td>33.553</td>
<td>0</td>
<td>0</td>
<td>100</td>
</tr>
<tr>
<td>2-5</td>
<td>15.810</td>
<td>0</td>
<td>100</td>
<td>15.810</td>
</tr>
<tr>
<td>2-6</td>
<td>27.786</td>
<td>0</td>
<td>0</td>
<td>100</td>
</tr>
<tr>
<td>3-5</td>
<td>20.222</td>
<td>0</td>
<td>0</td>
<td>20.222</td>
</tr>
<tr>
<td>3-6</td>
<td>49.219</td>
<td>0</td>
<td>0</td>
<td>100</td>
</tr>
<tr>
<td>4-5</td>
<td>4.191</td>
<td>58.14</td>
<td>2.436</td>
<td>41.78</td>
</tr>
<tr>
<td>5-6</td>
<td>2.932</td>
<td>50.86</td>
<td>1.1662</td>
<td>21.28</td>
</tr>
</tbody>
</table>

From the above table it is clear that, increasing the generation at generator-2 by 2.4581MW and decreasing the generation at generator-3 by 1.6319MW congestion has been relieved. So, Line flows: 1-2: 29.63 < 30 MW, 3-5: 19.95 < 20MW
Case2: IEEE-30 Bus System:
Cluster / zone based approach:
Congestion due to outage of some elements is explained with IEEE30 bus system [12]. Here the outage of line 4-6 causes congestion on lines 1-2 and 2-6.
Line flows: 1-2: 132.887 >130MW 2-6: 69.531 > 65MW
According to ACTCDF values congestion clusters are formed as shown in Figs 3a and 3b.

RESCHEDULING:
Rescheduling is carried out in zone-1 buses i.e. at GENCOs 2, 5 and 8 except 1 which is considered as slack. Slack bus value is changed so as to meet the change in loss. For rescheduling, PSO parameters are same as in case1. The rescheduling results are listed in Table VI.

<table>
<thead>
<tr>
<th>GENCO</th>
<th>Generation during congestion (P) (MW)</th>
<th>Rescheduling amount (ΔP) (MW)</th>
<th>Generation after Congestion relief (MW)</th>
<th>Rescheduling cost ($/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>50</td>
<td>2.4581</td>
<td>52.5481</td>
<td>19.0233</td>
</tr>
<tr>
<td>3</td>
<td>60</td>
<td>-1.6319</td>
<td>58.3681</td>
<td>21.166</td>
</tr>
</tbody>
</table>

Here congestion has been relieved by reducing the generation at Genco-2 with an amount of 10MW and increasing the generation at Genco-5 and Genco-8 with an amount of 7.2809MW and 3.7527MW respectively.

RESCHEDULING RESULTS

RESCHEDULING VALUES

<table>
<thead>
<tr>
<th>GENCO</th>
<th>Generation during congestion (P) (MW)</th>
<th>Rescheduling amount (ΔP) (MW)</th>
<th>Generation after congestion relief (MW)</th>
<th>Rescheduling cost ($/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>48.79</td>
<td>-10.00</td>
<td>38.79</td>
<td>26.04</td>
</tr>
<tr>
<td>5</td>
<td>21.5</td>
<td>7.2809</td>
<td>28.781</td>
<td>17.06</td>
</tr>
<tr>
<td>8</td>
<td>22.12</td>
<td>3.7527</td>
<td>25.873</td>
<td>12.89</td>
</tr>
<tr>
<td>1</td>
<td>177.742</td>
<td>4.546</td>
<td>173.196</td>
<td>12.12</td>
</tr>
</tbody>
</table>
Line flows: 1-2: 131.713 > 130MW  
3-5: 64.994 < 65MW  
Still congestion is not relieved on line 1-2. So the load curtailment is carried out as per the priority rule.

**Load curtailment:**  
Here load buses in zone-1 of line 1-2 congestion are considered i.e. 2, 3, 4, 5, 7 and 30. Minimum load curtailment is 5% and maximum is 20%. 1.5% of congestion line flows are considered i.e. 2, 3, 4, 5, 7 and 30. Minimum load curtailment is 0.004 hense voltage stability has been improved.

**Table shows that curtailment of load at bus 5 relieves congestion efficiently. The curtailment value is given by μL* i.e., 2.3623MW. Now congestion on line 1-2 is relieved.**  
Line flow: 1-2: 128.712 < 130MW.

**Relative Electrical Distance (RED):**  
From the contributions of generators, Congested lines are completely contributed by G1& G2 only. There is no contribution from the generator G5, G8, G11, G13 (G5 is not Contributing to any line) hence generator G1& G2 belongs to GD group and the remaining generators belongs to GI group. So generation decrease is recommended at G2 (G1 is slack bus) and the equal amount of generation increase is recommended from GI group. Before suggesting the Rescheduling, check for margin available on the line lines. Flow margin available on line = Flow suggested as per DLG – Actual flow.  
Based on this sufficient margin is available in GI group is G8 & G11. The rescheduling amount of GI and GD group generators are as shown in Table VIII

**Table shows that curtailment of load at bus 5 relieves congestion efficiently. The curtailment value is given by μL* i.e., 2.3623MW. Now congestion on line 1-2 is relieved.**  
Line flow: 1-2: 128.712 < 130MW.

Comparison of the two methods, Cluster/Zone based method and RED method has been mentioned in table X and table XI.
From the above results in Cluster/Zone based approach after rescheduling, power loss has been decreased by an amount of 1.190 MW and the system cost has been reduced by an amount of 1.53 $/MW-hr. In Relative Electrical Distance approach the L-index value has been reduced with an amount of 0.0223 and voltage deviation is reduced by 0.0012 volts, hence voltage stability has been improved. So, it is useful for improving the voltage stability margin.

IV. CONCLUSION

To have efficient operation in deregulated power system, it is necessary to know the possible ways of congestion and its relief. In this paper, first method made an attempt to relieve congestion by cluster/zone based approach using Transmission Congestion Distribution Factors (TCDFs) and to evaluate the congestion cost. This is effective for lowering the system Power loss and system cost. In second method, control used for over load alleviation is real power generation rescheduling based on the contribution of generators to the overloaded line and the relative electrical distance concept. This will improve the Voltage Stability Margin. These methods encourage users not to cause congestion. Thus the present work paves a way for an efficient congestion management in a restructured power system.

REFERENCES


BIographies

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