Active and Reactive Power Rescheduling for Congestion Management Using Descent Gradient Method

V. Srinivasarao, S. P. Singh and G. S. Raju

Abstract— In deregulated environment of power sector, the transmission congestion management and pricing is one of the important tasks of system operator. In this paper, the number of generators participating in congestion management has been selected based on the sensitivities to power flow on the congested line. The generators are selected for real and reactive powers rescheduling based on their real and reactive sensitivity factors respectively. The descent gradient method has been used to alleviate congestion. The descent gradient method handles the binding constraints using penalty function method. The effect of reactive power support on the rescheduling of the generation has been studied. The reactive support is obtained from generators, capacitor and combination of both. The effectiveness of the proposed methodology has been analyzed on 39-bus New England system. The results obtained by the proposed method are compared with the available reported methods.

Index Terms— Deregulation, Descent Gradient, Congestion, Sensitivity Analysis, Rescheduling, Optimization, Newton’s Method, Jacobian.

I. INTRODUCTION

As restructuring and deregulation deepen in the electric power industry open access is gaining greater attention. Open access implies that the opportunity to use the transmission system must be equally available to all buyers and sellers. This is an important step to promote the deregulation of the electricity supply system. Transmission networks are one of the main sources of difficulties on fair implementation of electricity restructuring. The limitations of a power transmission network arising from environmental, right-of-way and cost problems are fundamental to both bundled and unbundled power systems. Power flow in lines and transformers should not be allowed to increase to a level where a random event could cause the network collapse because of angular instability, voltage instability or cascaded outages. Transmission congestion may be defined as the condition where more power is scheduled or flows across transmission lines and transformers than the physical limits of those lines. Transmission congestion may prevent the existence of new contracts, lead to additional outages, increase the electricity prices in some regions of the electricity markets, and can threaten system security and reliability [1-4]. The objective of congestion management is to take actions or control measures to relieve the congestion of transmission networks.

Reactive power plays an important role in supporting the real power transfer across a large-scale transmission system [5]. Reactive support is generally provided by the switching of shunt capacitors, the positioning of transformer taps and the reactive power outputs of generators. Thus, the Var support requirement from generators and capacitors to manage congestion along with real power rescheduling poses a great challenge to SO in an open-access electricity market.

Various congestion management schemes suitable for different electricity market structure have been reported in literature. In [6], congestion relief by the coordination between different FACTS devices via implementation of intelligent real genetic algorithm technique to increase the capacity of power transfer has been proposed. Alvarado [7] proposed power system application data dictionary to implement efficient codes in MATLAB used for congestion management. In [8], congestion management by optimal location of TCSC which is determined based on real power performance index and reduction of total system reactive power loss has been proposed. The multi-area congestion management is achieved through crossborder coordinated redispatching by regional transmission system operators [9]. In [10], a simple and efficient model for optimal location of FACTS devices that can be used for congestion management by controlling their parameters optimally has been proposed. Huang and Yan examined the impact of FACTS devices in congestion management by reducing transaction curtailment and total transfer capability (TTC) improvement issues [11]. A. Oudalove [12], proposed the coordinated emergency control system for overload limitations in a transmission system using load shedding combined with multiple FACTS devices. In [13], transmission congestion distribution factors (TCDFs) based on ac power flow Jacobian sensitivity has been proposed. In [14], a sensitivity based approach for the optimal location of unified power flow controller (UPFC) was proposed for the congestion management. In [15], hybrid model for congestion management with real and reactive power transaction using gradient method has been proposed. In [16], a new method based on the relative electrical distance (RED) has been proposed for the alleviation of congestion management. The RED is the relative location of load buses with respect to generator buses.

The present paper deals with alleviation of congestion
through rescheduling of real and reactive powers. The capability of descent gradient technique is exploited to achieve this objective such that the cost of rescheduling is minimum. The generators participating in congestion alleviation are selected based on the generator real and reactive powers sensitivities in order to reduce the number of participating generators. Based on the generator sensitivities appropriate generators are selected which participate in rescheduling of their real and reactive powers according to bid prices. The reactive power support is obtained from the generators, capacitor/s and combination of both. The effectiveness of proposed method has been demonstrated on 39-bus New England system. The effect of the reactive power rescheduling on the real power rescheduling for congestion management has also been studied.

II. CONGESTION MANAGEMENT PROBLEM FORMULATION

In the congestion management problem formulation, first it is required to find the optimal number of generators participating in the congestion alleviation process and then the application of one of available optimal power flow method to find minimum rescheduling cost to alleviate congestion. The effect of the generator and capacitor reactive support on the generator rescheduling has to be formulated. Thus the congestion management problem formulation consists of two parts which are as follows:

1) Sensitivity Analysis
2) Optimization Problem

The optimal number of the participating generators will be taken care by sensitivity calculations. The congestion alleviation process will be taken care by the optimal power flow.

A. Sensitivity Analysis

The generators in the system under consideration have different sensitivities to the power flow on the congested line. Real power sensitivity factor \( S_{p_{ij}}^k \) is defined as the change in real power flow in transmission line-\( k \) connected between bus-\( i \) and bus- \( j \) due to unit change in the real power injection (\( \Delta P_n \)) at bus- \( n \). Mathematically, for line- \( k \) it can be written as

\[
S_{p_{ij}}^k = \frac{\Delta P_{ij}}{\Delta P_n}
\]

(1)

where,

\( \Delta P_{ij} \) - change in real power flow in line- \( k \)

Similarly,

\[
S_{q_{ij}}^k = \frac{\Delta Q_{ij}}{\Delta Q_n}
\]

(2)

where,

\( \Delta Q_{ij} \) - change in reactive power flow in line- \( k \) connected between bus- \( i \) and bus- \( j \)

\( \Delta P_n \) - change in reactive power injection at bus- \( n \).

\( S_{p_{ij}}^k \) and \( S_{q_{ij}}^k \) denotes that how much real and reactive power flow over a transmission line- \( k \) connected between bus- \( i \) and bus- \( j \) would change due to change in real and reactive power injections respectively at bus- \( n \).

The real and reactive power sensitivity factors have been calculated as follows [13]:

\[
S_{p_{ij}}^k = \frac{\Delta P_{ij}}{\Delta P_n} = ((\Delta P_{ij}/\Delta \delta) (\Delta P_n/\Delta \delta)) (\Delta P_n/\Delta P_n)
\]

(3)

\[
S_{q_{ij}}^k = (a_{ij} m_{in} + b_{ij} n_{in})
\]

(4)

where,

\[
\Delta P_{ij}/\Delta \delta = a_{ij} = V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i)
\]

\[
\Delta P_{ij}/\Delta \delta = b_{ij} = -V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i)
\]

\[
\Delta Q_{ij}/\Delta V_i = a'_{ij} = -V_i V_j \sin(\theta_{ij} + \delta_j - \delta_i) + 2V_j Y_{ij} \cos \theta_{ij} - Y_{sh}
\]

\[
\Delta Q_{ij}/\Delta V_j = b'_{ij} = -V_i V_j \sin(\theta_{ij} + \delta_j - \delta_i)
\]

\[
m_{in} = \Delta \delta_{i}/\Delta P_n \quad n_{in} = \Delta \delta_{j}/\Delta P_n
\]

\[
n_{in} = \Delta V_i/\Delta Q_n \quad n_{in} = \Delta V_j/\Delta Q_n
\]

where,

\( Y_{ij} \) - Admittance of the line connected between bus- \( i \) and bus- \( j \)

\( Y_{sh} \) - Shunt Admittance

B. Selection of Generators and Capacitors for Reactive Power Support

Reactive power and voltage control plays an important role in supporting the real power transfer across a large-scale transmission system. In this paper, the reactive support is obtained from the generators, capacitor and combination of both. Based on the reactive power sensitivity factors, the generators having the highest and unevenly distributed sensitivity factor are selected for reactive support. However, the optimal placement of capacitor is selected, in case there is no or insufficient capacitive support in the system, at a bus which having most negative reactive power sensitivity factor with respect to congested line.

C. Optimization Problem

The cost of rescheduled active and reactive powers are \( f_1 \) and \( f_2 \), the objective function is formulated as optimization problem which has to be minimized is as follows:

Minimize \( Z = f_1 + f_2 \) (5)

Subjected to

\[
[g(x, u, p)] = 0
\]

(6)

\[
P_{ij} - P_{ij}^{\min} \leq P_{ij} \leq P_{ij}^{\max} = P_{ij}^{\max} - P_i
\]

(7)

\[
\Delta Q_{ij}^{\min} \leq \Delta Q_{ij} \leq \Delta Q_{ij}^{\max}
\]

(8)

\[
C_{ij}^{\min} \leq C_{ij} \leq C_{ij}^{\max}
\]

(9)

\[
F_k \leq F_k^{\max}
\]

(10)

where,

\[
f_1 = \sum_{i=1}^{N_g} C_{pi} (\Delta P_i) \Delta P_i
\]

(11)

\[
f_2 = \sum_{i=1}^{N_g} C_{qi} (\Delta Q_i) \Delta Q_i + \sum_{j=1}^{N_c} C_{cj} (\Delta Q_{cj}) \Delta Q_{cj}
\]

(12)
\( \Delta P_i \) and \( \Delta Q_i \) are the real and reactive power adjustment of the generator at bus \( i \).

\( \Delta Q_j \) is the change in the reactive support of the capacitor at bus \( j \). \( F_{\text{sec}} \) is the power flow caused by all contracts requesting the transmission service. \( F_{\text{max}}^{\text{sec}} \) is the line flow limit of the line connecting bus \( i \) and bus \( j \). \( N_g \) is the number of participating generators, \( n_l \) is the number of transmission lines in the system. \( P_i^{\text{min}} \) and \( P_i^{\text{max}} \) denote respectively the minimum and maximum limits of the generator real power outputs. \( \Delta Q_i^{\text{min}} \) and \( \Delta Q_i^{\text{max}} \) are the minimum and maximum limits of the change in generator reactive power outputs respectively. \( Q_j \) is the capacitor reactive support, \( Q_j^{\text{min}} \) and \( Q_j^{\text{max}} \) are the minimum and maximum limits of reactive power output of the capacitor at bus \( j \).

\[
C_{pi}(\Delta P_i) = a_i(\Delta P_i)^2 + b_i(\Delta P_i) + c_i
\]

(13)

\( C_{pi} \) is the cost of the active power rescheduling according to the bid functions submitted by the generators participating in congestion management. \( a_i, b_i \) and \( c_i \) are the predetermined cost coefficients of the \( i^{\text{th}} \) generator. Here \( c_i \) taken as zero for all the generators.

Similarly, \( C_{qi}(\Delta Q_i) \) is the cost of the reactive power rescheduling according to the bid functions submitted by the generators participating in congestion management which is taken as [17]:

\[
C_{qi}(\Delta Q_i) = \left[ C_{pi}\left(S_{Gi}^{\text{max}}\right) - C_{pi}\left(S_{Gi}^{\text{max}} - \Delta Q_i^2\right)\right] k_i
\]

(14)

where, \( C_{qi} \) is the active power generation cost. \( S_{Gi}^{\text{max}} \) is the apparent nominal power of the generator and \( k_i \) is an assumed profit rate of the active power generation at bus \( i \). Here \( k_i \) taken as 5\%. Here \( S_{Gi}^{\text{min}} = P_{Gi}^{\text{min}} \).

\( C_j \) is the equivalent cost for returns on the capital investment of the capacitors which is taken as follows:

\[
C_j(\Delta Q_j) = r_j \Delta Q_j
\]

(15)

where \( r_j \) and \( Q_j \) are the reactive cost and amount of reactive power purchased, respectively, at location \( j \).

The cost or depreciation rate of the capacitor can be calculated as:

\[
r_j = \frac{\text{Investment cost}}{\text{Operating hours}} = \frac{($11600 / MVArh)}{(15 \times 365 \times 24 \times 2 / 3h)} = $13.24 / MVAr
\]

Therefore

\[
C_j(\Delta Q_j) = $13.24 \Delta Q_j
\]

III. CONGESTION MANAGEMENT PROBLEM

SOLUTION

The Descent gradient method for optimal power flow was first introduced by Dommel and Tinney [18]. The main features of this method are gradient procedure for finding the optimum value of the function. The gradient method has been used as the optimization technique for above said problem.

A. Solution by descent gradient method

In the gradient method the equality constraints are handled by the lagrangian multiplier and the functional inequality constraints are handled by the penalty function.

Applying lagrangian multiplier for equality constraint and penalty term for inequality constraints to convert the above constrained problem (5) into an unconstrained problem, the resulting problem would be to minimize

\[
Z = f_1 + f_2 + \lambda (g(x, u, p)) + \alpha \sum_i W_i
\]

(16)

where,

\( \lambda \) is Lagrange multiplier\n
\( \alpha \) is a constant\n
\( W_i \) is the penalty function which is given by

\[
W_i = \eta_i (F_i - F_i^{\text{max}})^2 , \text{whenever} \ F_i > F_i^{\text{max}}
\]

(17)

where, \( \eta_i \) is penalty factor for each violated inequality constraint \( i \).

The value of penalty factor should be selected such that in case of congestion, the cost of rescheduling should not be optimum. So the penalty factor is selected as 100 for each violated inequality constraint.

Here the unknown or state vector \( [x] \) is taken as

\[
[x] = \begin{bmatrix} V \text{ on each } PQ \text{ - bus} \\ \delta \text{ on each } PV \text{ - bus} \end{bmatrix}
\]

(18)

where, \( V \) and \( \delta \) are the voltage magnitude and angle at each bus respectively.

For the present study following combinations of control variable \( [u] \) have been assumed. However, only one of the above mentioned combinations would exist.

\[
[u] = \begin{bmatrix} \Delta P_i \text{ Active power reschedule } d \text{ at generator bus } i \text{ without reactive sup port} \\ \Delta P_i \text{ Active and reactive powers reschedule } d \text{ at generator bus } i \\ \Delta Q_j \text{ Reactive power reschedule } d \text{ at bus } j \\ \Delta Q_j \text{ Reactive power reschedule } d \text{ at bus } j \end{bmatrix}
\]

(19)

The vector of all specified variables \( [y] \) taken as

\[
[y] = \begin{bmatrix} v_1 \text{ on slack bus} \\ \delta_1 \text{ on slack bus} \\ \text{P}^{\text{net}} \text{ on each } PQ \text{ - bus} \\ \text{Q}^{\text{net}} \text{ on each } PQ \text{ - bus} \\ \text{P}^{\text{net}} \text{ on each } PV \text{ - bus} \\ \text{Q}^{\text{net}} \text{ on each } PV \text{ - bus} \end{bmatrix}
\]

(20)
where, $P^\text{new}$ and $Q^\text{new}$ are respectively specified real and reactive power for each $PQ$ bus and $P^\text{net}$ specified real power for each $PV$ bus.

The LHS of the power flow equation of the network expressed by (6) are

$$g(V, \delta) = \begin{cases} 
    P_i(V, \delta) - P^\text{new}, & \text{for each } PQ \text{ bus } - i \\
    Q_i(V, \delta) - Q^\text{new}, & \text{for each } PV \text{ bus } - m \\
    P_m(V, \delta) - P^\text{net}, & \text{not including slackbus}
\end{cases}$$

(21)

where, $P_i$ and $Q_i$ are respectively the calculated real and reactive power for $PQ$ bus-$i$

$P_m$ and $P_m^\text{net}$ are respectively the calculated and specified real power for $PV$ bus-$m$

**B. Computational Steps**

The algorithm for the descent gradient method proposed in the above sections can be implemented using following steps:

Step1: Run base case load flow program. Find the initial values for $P_i$ and $Q_i$.

Step2: If there is any reactive support available for rescheduling then go to next step. Otherwise go to step 11.

Step3: Assume the suitable control parameters from above specified set of control parameters $[u]$ expressed by equation (19). Initially it is assumed as 2% of their initial value.

Step4: Update the control parameters

$q^\text{new} = q^\text{old} + u$

Step5: Find a feasible power flow solution by Newton’s method. This yields a Jacobian matrix for the solution point $x$.

Step6: Solve the following equation for $[\lambda_f]$,

$$\begin{bmatrix} \frac{\partial f_1}{\partial x} + \frac{\partial g}{\partial x} \end{bmatrix} \begin{bmatrix} \lambda_f \end{bmatrix} + \alpha \sum_i \frac{\partial W_i}{\partial x} = 0$$

which is obtained by differentiating the equation (16) with respect to $x$.

$$[\lambda_f] = -\left( \begin{bmatrix} \frac{\partial g}{\partial x} \end{bmatrix}^T \right)^{-1} \left( \begin{bmatrix} \frac{\partial f_1}{\partial x} \end{bmatrix} + \alpha \sum_i \frac{\partial W_i}{\partial x} \right)$$

(22)

Step7: Substitute $[\lambda_f]$ from (22) into the following equation and compute gradient

$$[\nabla L] = \begin{bmatrix} \frac{\partial f_1}{\partial u} + \frac{\partial g}{\partial u} \end{bmatrix} \begin{bmatrix} \lambda_f \end{bmatrix} + \alpha \sum_i \frac{\partial W_i}{\partial u}$$

(23)

Step8: If $[\nabla L]$ is less or equal to predefined tolerance then minimum has been reached and go to step 10. Otherwise go to step 9.

Step9: Find a new set of control parameters from

$$\Delta u = -c \cdot [\nabla L], \quad u^\text{new} = u^\text{old} + \Delta u$$

(24)

Check the limit of control variable. If it is within limit, then

$$Q_i^\text{new} = Q_i^\text{old} + u^\text{new}$$

Otherwise, set its value at its limiting value and

$$Q_i^\text{new} = Q_i^\text{old} + u^\text{new}$$

Go to step 5.

Step10: Check whether all the line flows are within the limit. If any line is congested, go to next step otherwise stop.

Step11: Select the suitable value of control variable $\Delta P_i$. Initially it is assumed as 2% of their generation.

Step12: Update the control parameters

$$P_i^\text{new} = P_i^\text{old} + u$$

(26)

Step13: Find a feasible power flow solution by Newton’s method. This yields a Jacobian matrix for the solution point $x$.

Step14: Solve the following equation for $[\lambda_p]$,

$$\begin{bmatrix} \frac{\partial f_1}{\partial x} + \frac{\partial g}{\partial x} \end{bmatrix} \begin{bmatrix} \lambda_p \end{bmatrix} + \alpha \sum_i \frac{\partial W_i}{\partial x} = 0$$

which is obtained by differentiating the equation (10) with respect to $x$.

$$[\lambda_p] = \left( \begin{bmatrix} \frac{\partial g}{\partial x} \end{bmatrix}^T \right)^{-1} \left( \begin{bmatrix} \frac{\partial f_1}{\partial x} \end{bmatrix} + \alpha \sum_i \frac{\partial W_i}{\partial x} \right)$$

(27)

Step15: Substitute $[\lambda]$ from (27) into the following equation and compute gradient

$$[\nabla L] = \begin{bmatrix} \frac{\partial f_1}{\partial u} + \frac{\partial g}{\partial u} \end{bmatrix} \begin{bmatrix} \lambda_p \end{bmatrix} + \alpha \sum_i \frac{\partial W_i}{\partial u}$$

(28)

Step16: If $[\nabla L]$ is less or equal to predefined tolerance then minimum has been reached and print $u^\text{new}$ and stop. Otherwise go to next step.

Step17: Find a new set of control parameters from

$$\Delta u = -c \cdot \left[ \nabla L \right], \quad u^\text{new} = u^\text{old} + \Delta u$$

(29)

Check the limit of control variable. If it is within limit, then

$$P_i^\text{new} = P_i^\text{old} + u^\text{new}$$

(30)

Otherwise, set its value at its limiting value and

$$P_i^\text{new} = P_i^\text{old} + u^\text{new}$$

Go to step 13.

**IV. RESULTS AND DISCUSSIONS**

The descent gradient method for congestion management has been implemented using Visual C++ programming language. The performance of the method has been tested on 39-bus New England system. This system consists of 10 generator buses and 29 load buses. The slack bus is numbered as 1 followed by the generating buses and load buses. The congested line, power flow and the line limit are shown in the TABLE-I.

The participating generators for congestion management have been selected based on the sensitivity analysis. The real and reactive power sensitivities for the congested line are shown in TABLE-II and TABLE-III respectively. The generators connected to buses 3, 8 and 10 are selected for the real and reactive power rescheduling. The price bids for
different generators are shown in TABLE-IV.

The following different cases are taken for the study for rescheduling the generators to alleviate congestion management.

Case 1: without reactive support from generators and capacitor.
Case 2: with generator reactive support.
Case 3: with capacitor reactive support.
Case 4: with generators and capacitor reactive support.

The capacitor is located at bus 14. The real and reactive powers rescheduling are tabulated for all the cases from TABLE-V to TABLE-VIII. The base case real power loss is 49.89MW. These tables also contain the results reported in [13] for said conditions. From the results it is concluded that the proposed method suggests less rescheduling cost, less losses i.e., 48.73MW compared to 49.74MW by the method.

Further, for comparing the performance of the proposed method with the method reported in [13], an outage of line connecting between the buses 14 and 34 resulting in congestion of the line connected between 15 and 16 as congested. The actual power flow in this line is 628.6 MW whereas the power flow limit of the line is 500 MW. The real and reactive power sensitivities for this congested line are shown in TABLE-IX. Based on the sensitivities, only six generators are participating in the congestion management by the proposed method compared to all the 10 generators participating in reported method in [13]. The cost of rescheduling is less in the proposed method i.e., $ 8520 per
day than the method reported in [13] i.e., $8631.6 per day in case 1 as shown in TABLE-X. The real and reactive powers rescheduling for congestion alleviation for different cases stated above are tabulated in TABLE-X and TABLE-XI.

### TABLE X
RESCHEDULING OF GENERATION FOR 39-BUS SYSTEM

<table>
<thead>
<tr>
<th>Cost ($/day)</th>
<th>Case 2</th>
<th>Case 3</th>
<th>Case 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed Method</td>
<td>8251.74</td>
<td>7729.77</td>
<td>7637.02</td>
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</table>

<table>
<thead>
<tr>
<th>ΔP (MW)</th>
<th>ΔQ (MVAR)</th>
<th>ΔP (MW)</th>
<th>ΔQ (MVAR)</th>
<th>ΔP (MW)</th>
<th>ΔQ (MVAR)</th>
</tr>
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<tbody>
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<td>-203.80</td>
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<td>Pmin (MW)</td>
<td>58.00</td>
<td>58.55</td>
<td>57.55</td>
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### TABLE XI
RESCHEDULING OF GENERATION FOR 39-BUS SYSTEM

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<th>Gen. No.</th>
<th>ΔP (MW)</th>
<th>ΔQ (MVAR)</th>
<th>ΔP (MW)</th>
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</table>

V. CONCLUSION

In this paper a new method for the minimization of the rescheduling cost to alleviate congestion in pool dispatch has been analyzed and applied to 39-bus New England system. The generators, which are participating in congestion alleviation, are selected based on their sensitivities to the power flow of the congested line and then the descent gradient method has been used for corrective rescheduling to alleviate congestion. The reactive power rescheduling cause lower cost of rescheduling and the better voltage profile. It has been observed that the cost of rescheduling is minimum when the generator and capacitor both provide reactive support. In case the amount of reactive power supplied by the capacitor is less when compared to the only capacitor reactive support. Proposed method is derived by the extension of basic load flow program, thus it is free from complex mathematical formulations. Proposed method gives the better results compared to the methods reported in [13] and [16].

### REFERENCES


