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Overload Alleviation And Determination of Cost of Rescheduling In An Open Acess Power System

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Abstract - This paper presents an approach for alleviation of network over loads in the day-to-day operation of power systems. The method used for over load alleviation is real power generation rescheduling based on relative electrical distance (RED) concept. The method estimates the relative location of load nodes with respect to the generator nodes. First congestion is observed, and then each generator's contribution to the congested line is found out. Based on RED method desired generation rescheduling is obtained to relieve overloaded line. Cost is also a key factor which has to be considered in real power rescheduling. A case studied is carried out for modified IEEE 39-bus New England system, where power flow is found by Newton Rapson's method and compared with operational load flow method.

I. INTRODUCTION

Transmission lines are often driven close to or even beyond their thermal limits in order to satisfy the increased electric power consumption. If the exchanges were not controlled, some lines located on particular paths may become overloaded, this phenomenon is called congestion. Overloading of a transmission network in a power system can occur due to various reasons including line outage. The network overloading may lead to tripping of overloaded lines, consequential tripping of other lines.

Different technical solution has been developed to relieve congestion, such as

- Real power generation rescheduling;
- phase shifting transformers;
- flow control through HVDC link(s);
- line switching;
- load shedding.

Real power generation rescheduling is considered for alleviation of network overloads [1]. A basic mathematical model to describe the problem of line overload alleviation has been developed. Algorithms for solving the model and suitable for incorporation in the Newton-Raphson and decoupled load flow programs are also described [2].One of the most practiced and obvious technique is rescheduling of generators in the system. However all generators in the system is not taking part in congestion. **A** technique for optimum selection of participating generators has been introduced using generator sensitivities to the power flow on congested lines. Based on particle swarm optimization (PSO) which minimizes the deviations of rescheduled values of generator power outputs from scheduled levels[3].

Now days it is important to find out, in day to day operation of power system, contribution of generators to the load and line flows [4]. By which alleviation of network overload and allocate transmission charges.

This paper allocates the desired generation changeover of participant based on the relative electrical distance, i.e., the relative locations of load points with respect to the generator points in open access[5].This method is computationally fast and well suited for on line implementation. However RED method[1] minimize the system losses and have a better voltage profile . But bids of individual generation units and costs of rescheduling are not taken in concern in this work.

Improved load flow algorithm operational load flow (OLF)[6] was introduced. Which eliminates the slack bus concept while calculating power flow. Congestion found by Newton Rapson algorithm and cost of rescheduling according to the bids of individual generator is calculated in this paper.

II. APPROACH FOR GENERATION SCHEDULING

2.1. Relative electrical distances (RED)

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

$$\begin{bmatrix} I_G \\ I_L \end{bmatrix} = \begin{bmatrix} Y_{GG} & Y_{GL} \\ Y_{LG} & Y_{LL} \end{bmatrix} \begin{bmatrix} V_G \\ V_L \end{bmatrix} \tag{1}$$

Where $\boldsymbol{I}_G$, $\boldsymbol{I}_L$, and $\boldsymbol{V}_G$, $\boldsymbol{V}_L$ represent complex current and voltage vectors at the generator nodes and load nodes.[$\boldsymbol{Y}_{GG}$],[$\boldsymbol{Y}_{GL}$],[$\boldsymbol{Y}_{LL}$] and [$\boldsymbol{Y}_{LG}$] are corresponding partitioned portions of network

$\boldsymbol{Y}$-bus matrix.

Rearranging (1) we get

$$\begin{bmatrix} V_L \\ I_G \end{bmatrix} = \begin{bmatrix} Z_{LL} & F_{LG} \\ K_{GL} & Y_{GG} \end{bmatrix} \begin{bmatrix} I_L \\ V_G \end{bmatrix} \tag{2}$$

where FLG =$-$[YLL]$^{-1}$[YLG].

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 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 [FLG] gives the information, for each load bus, about the amount of power that should be taken from each generator under normal and network contingencies. This matrix is used as the basis for the desired load sharing/generation scheduling and is explained with a sample system in this section. If each consumer takes the power from each generator according to the [FLG] matrix the system will have minimum transmission loss. This matrix can also be used as the basis for evaluating transmission costs for each transaction in open access environment.

2.2. RED and desired generation schedule

2.2.1. Sample system

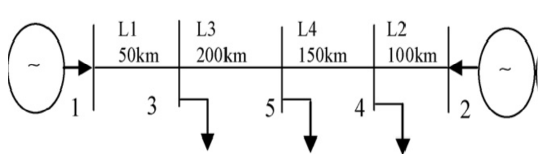

Fig. 1 : Sample system 1

The sample system 1 is considered for explaining relative electrical distance and desired generation of generators for load sharing.

The sample system 1 is shown in fig.1. It has two sources and five bus system. Two sources are at bus 1 and 2, rest 3,4and 5 are load buses. It is assumed that the lines L1, L2, L3 and L4 are of 50 km, 100 km, 200 km and 150 km length, respectively. The line parameters in per unit per 100 km are

$R = 0.00165$, $X = 0.02059$.

The [FLG] matrix corresponding to the load/generator buses for the network is given by

$$[F_{LG}] = \begin{bmatrix} 0.9000 + 0.0000i & 0.1000 + 0.0000i \\ 0.2000 + 0.000i & 0.8000 + 0.0000i \\ 0.5000 + 0.0000i & 0.5000 + 0.0000i \end{bmatrix}$$

The elements of [FLG] matrix are complex and its columns correspond to the generator bus numbers 1, 2 and rows correspond to the load bus numbers 3–5. It can be observed that the sums of the each row elements of the [FLG] matrix are close to (1.0, 0.0).

The relative electrical distances, i.e., the relative locations of load nodes with respect to the generator nodes are obtained from the [FLG] matrix and is given by

$$[RLG] = [A] - \text{abs}\{[FLG]\} \tag{4}$$

Where [A] is the matrix with ($n-g$) rows and g number of columns of all elements equal to '1'.

For the sample system 1 the relative electrical distance matrix is given by

$$[R_{LG}] = \begin{bmatrix} 0.1 & 0.9 \\ 0.2 & 0.8 \\ 0.5 & 0.5 \end{bmatrix}$$

Since the load bus 3 is at a distance of 50 km from the generator 1 and 450 km from the generator 2, which is nine times of 50 km, the corresponding elements of [RLG] matrix are 0.10 and 0.90. The load bus 4 is at a distance of 100 km from the generator 2 and 400 km from the generator 1 the corresponding elements of [RLG] matrix are 0.80 and 0.20. Similarly, the load bus 5 is at a distance of 250 km from the generator 1 and 250 km from the generator 2, the corresponding elements of [RLG] matrix are 0.50 and 0.50. These values, which are taken as relative electrical distances, can also be used for the evaluation of transmission charges in open access.

The desired proportions of generation for the desired load sharing/generation scheduling is also obtained from the [FLG] matrix and is given by,

[DLG] = abs {[FLG]} (5)

For the sample system 1 the desired proportions of generation, for the desired load sharing/generation scheduling, are given by

$$[D_{LG}] = \begin{bmatrix} 0.9 & 0.1 \\ 0.2 & 0.8 \\ 0.5 & 0.5 \end{bmatrix}$$

For example, the load at bus 3 is 200MWthen it should take 0.90×200=180MW of load from generator 1and the partial remaining load of 0.10×200 = 20MW from generator 2. Similarly the load at other buses also should take according to the corresponding elements of the [DLG] matrix. If the load sharing/generation scheduling is according to the [DLG] matrix, then the system will have minimum transmission losses.

2.3. *Contribution of generators towards load and line flows*

Finding out power flow solution by Newton Rapshon method, active and reactive power flow in each branch can be obtained. From this actual contribution of generators towards load and line flows can be estimated [4]. This method organizes the buses and branches in a group which describes below.

2.3.1 Domain of a Generator

The domain of a generator is defined as the set of busses which are reaches by power produced by this generator. Power from a generator reaches a particular bus if it is possible to find a path through the network from the generator to the bus for which the direction of travel is always consistent with the direction of the flow as computed by a power flow program.

2.3.2. Commons

A common is defined as a set of contiguous buses supplied by the same generators. Unconnected sets of buses supplied by the same generators are treated as separate commons. A bus therefore belongs to one and only one common. The rank of a common is defined as the number of generators supplying power to the buses comprising this common.

2.3.3. Links

Having divided the buses into commons, each branch is either internal to a common (i.e., it connects two buses which are part of the same common) or external (i.e., it connects two buses which are part of different commons). One or more external branches connecting the same commons form what will be called a link. It is very important to note that the actual flows in all the branches of a link are all in the same direction. Furthermore, this flow in a link is always from a common of lower rank to a common of higher rank.

2.3.4 State Graph

Given the direction of the flows in all the branches of the network, it produces unique sets of commons and links. If the commons are represented as nodes and the links as branches, the state of the system can be represented by a directed, acyclic graph. This graph is directed because the direction of the power in a link is specified. It is acyclic because links can only go from a common supplied by fewer generators to a common supplied by more generators. Typically, the root nodes of such a graph correspond to a common of rank one while the leaves consist of highest ranked commons.

2.3.5 Contribution to individual loads and line flows

As power tracing is concerned, all the buses within a common are indistinguishable to each other. But each bus load and branch flows within a common are taken individually. If $\mathbf{x_i}$, is the contribution of generator **i** to common **j**, it is also the contribution of generator **i** to every bus load and to every branch flow within common **j** and to every branch flow in the outward links of common **j**. Knowing the common to which a bus belongs and the contributions of each generator to each common therefore gives the ability to compute how much power each generator contributes to each load.

2.3.6 Computational algorithm

Step 1: Perform the initial load flow by Newton Rapson and check for any overload present. If any over load presents go to next step otherwise stop.

Step2: Find out D_{LG} and F_{LG} matrix as described in section 2.

Step3: For a given operating condition find out over loaded and fully loaded line and then find out contribution of each generator for all these lines.

Step 4: Divide the generators to two groups. One generation increase (GI) and other generation decrease (GD) group. Then find out the actual contribution values to the congested line as given section 2.3.

Step 5: From the steps 2 and 4, estimate the margin available on each generator of both the generator groups GD and GI.

Step 6: Estimate the change in generation ΔP to relieve congestion of mostly congested line using actual contribution of generators to the congested line.

Step 7: Distribute the required generation change among the generators of GD and GI group based on the margins available from step 5.

Step 8: Perform the Newton Rapson's load flow with new generation scheduling. If congestion still occurs in any line then go to step 2, otherwise stop.

III. SYSTEM STUDIES

This method has been explained on IEEE 39 bus New England System as shown in fig 1. In this system there are 29 load bus and 10 generator bus as shown in fig 2.

We make line 4 and 14($L_{4\text{-}14}$) outage, as a consequence line 5 and 6 is overloaded; flow through the line is 633MVA whereas line limit given is 500MVA. As described in section 2.3 it is observed that generator G_2 and G_3 is contributing to the congested line. The percentage of contribution is 53.29 and 46.77respctively. Hence these two generators are under GD group and rest 8 generators are GI group.

Table 1

Contribution to over loaded line (%)as per D_{LG} matrix

G_1	G_2	G_3	G_4	G_5	G_6	G_7	G_8	G_9	G_{10}
17.17	34.83	24.79	3.72	1.67	4.08	2.29	3.81	2.38	6.56

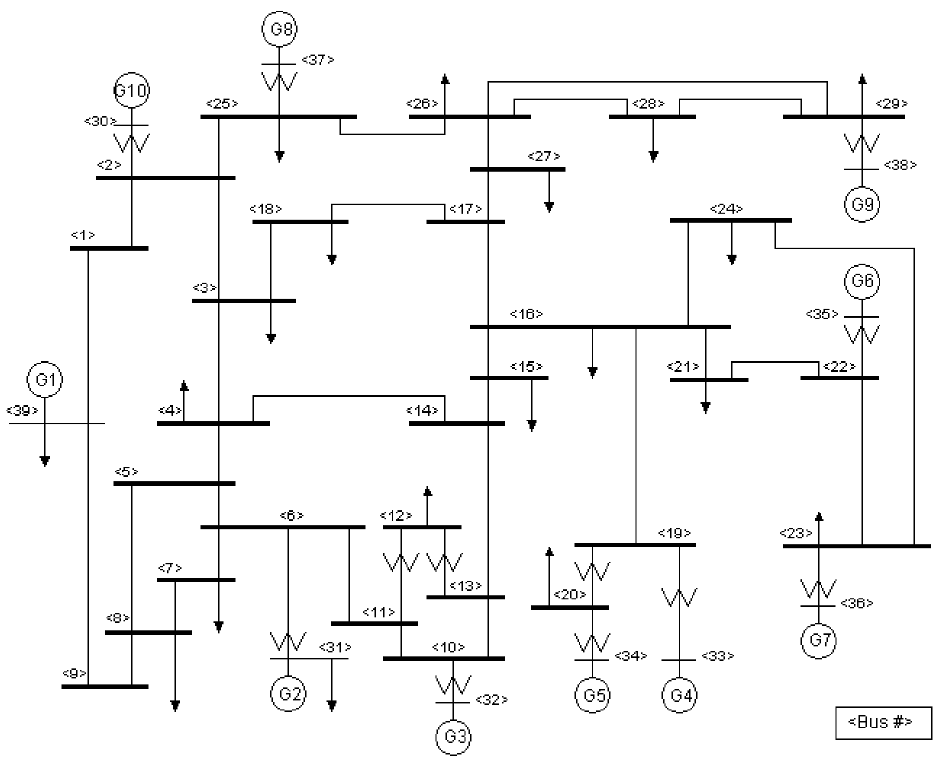

Fig. 2 : IEEE New England 39-bus system

From the D_{LG} matrix, the desired generation scheduled is given in table 1. From the table contribution of G_2 and G_3 are 34.83% and 24.79% respectively.

Margin available at G_2 is 34.83-53.29= -18.46%

Margin available at G_3 is 24.79-46.7= -21.91%

For G_2 =18.46/40.36*133=60.816MVA

For G_3 =21.19/40.37*133=72.183MVA

But actual contribution of generators to the overloaded line is 53.29% and 46.7%.

So the amount of generation decrease suggested is

ΔP_2^- = 60.816/.5329=114.12MW

ΔP_3^- = 72.183/.467=154.56MW

Therefore total generation decrease by GD group is 114.12+154.56 =268.68MW. This has to be met by GI group to avoid load shedding. Actual contribution of GI group to the congested line is zero. So the margin available for GI group is as per the D_{LG} matrix as given in table 1. Now individually fining out each generation increase in GI group is given in table 2.

Table 2 : Generation rescheduling for GI group

Generator no.	MW value
ΔP_1^+	15.33
ΔP_4^+	674.26
ΔP_5^+	531.96
ΔP_6^+	660.76
ΔP_7^+	586.29
ΔP_8^+	554.755
ΔP_9^+	854.55
ΔP_{10}^+	110.76

After this rescheduling of generators the line flow for congested line (5-6) is reduced to 510.12MW from 633MW without causing overloaded to any other line. The overloading factor reduces from 1.266 to 1.02, where as other lines overload factor increases but within the limit.

The generator cost curves have been assumed to be quadratic such that cost of rescheduling is proportional to the square of the change in active power output[3].

Table-3: *Generator Price Bids for IEEE 39-Bus System (Rs/MW^2 -DAY)*

Gen. No	G_1	G_2	G_3	G_4	G_5	G_6	G_7	G_8	G_9	G_{10}
bids	20	15	17	16	12	17	13	14	19	11

Table-4

Comparison of Results of 39-Bus System

	Present method	Method in [1]
ΔP_1^+	15.33MW	98.75MW
ΔP_4^+	42.26MW	24.69MW
ΔP_5^+	23.96MW	12.34MW
ΔP_6^+	10.76MW	24.69MW
ΔP_7^+	26.29MW	12.34MW
ΔP_8^+	14.755MW	24.69MW
ΔP_9^+	24.55MW	12.34MW
ΔP_{10}^+	110.76MW	49.38MW
ΔP_2^-	114.12MW	99.59MW
ΔP_3^-	154.56MW	159.64MW
Total rescheduling	537.34MW	518.45MW
App. Cost of rescheduling (Rs/day)	802021.3	839220.93

Generator bid price is given in table-3(approx.).

As shown in table 4, cost rescheduling is less for present method, although total rescheduling in MW is more.

IV. CONCLUSION

In this paper network over load is alleviated by real power rescheduling by Relative electrical distance method. Here congestion is found by Newton Rapson algorithm. In operational load flow algorithm slack bus concept is not taken, which is quite advantageous. But, as shown in this paper, the cost of rescheduling is found to be much lesser compared to the operational load flow algorithm based method.

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