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A Sequential Method for Real and Reactive Power Allocation for Loss and Marginal Cost Reduction

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Abstract: - Pattern of load sharing / generation scheduling that results in heavy flows tend to incur greater losses, threaten security, and ultimately making certain generation patterns undesirable. Generation schedules mainly based on economic criteria may lead to lower reserve margins and therefore diminished security is a serious concern for the systems. In this paper, network sensitivity between load voltages and source voltages is used as the basis to evaluate optimal real power allocation for marginal cost reduction and a method for optimum allocation of reactive power in day –to-day operation of power system for loss reduction is presented The technique will try to utilize fully the reactive power sources in the system to improve the voltage profile and to minimize the real power losses besides meeting the optimal real power generation levels. The method involves successive solution of steady state power flows and optimization of reactive power control variables using linear programming techniques. The proposed method has been applied to few systems and the results obtained on a 96-bus Indian practical system are presented for illustration.
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Key-Words: - Optimal generation, real and reactive power dispatch, loss reduction, and marginal cost

1 Introduction

Increased economic benefit was the primary motivation for the introduction of deregulation. Thus transmission loss minimization is one aspect of power system operation that needs much attention. This has been done in traditional power systems for a long time now. With the advent of deregulation, it has been necessary to be able to assess the impact of power transaction on the system generation levels. A poorly scheduled generation levels can also reduce a system's ability to transfer power while maintaining its security and stability. With open access transmission in the deregulated environment, poorly scheduled generation patterns and load patterns from competitive bidding, will be seen more and more often. These patterns might cause many stability problems[1].

The ability to maintain stability in an interconnected power grid has become a growing concern in present day stressed power systems. Power system stability problems are caused by many factors. The generation pattern and load pattern, which represent generation and load at every bus, are among the leading factors. A poorly scheduled generation or load pattern can reduce a system’s ability to transfer power while maintaining its security and reliability. Intensive studies on the economic dispatch problem assume that the system can maintain its security and reliability. The optimal power flow (OPF) program does consider both economic dispatch and stability, but it requires heavy computations. With open access transmission in the future deregulated environment, poorly scheduled generation patterns and load patterns from competitive bidding, will be seen more and more often. These patterns might cause many stability problems.

A good generation direction (or pattern) should be maintained to supply the maximum power possible to the load before reaching the boundary of a system limit. The boundary of the limit can be a voltage collapse boundary (also called the point of collapse (PoC) boundary [1]), or a low voltage boundary (LVB) or a thermal limit boundary, etc. To form a good generation direction, sometimes a generator needs to reduce its power output so that other generators can transfer more power to the load. Much work has been done in a load space to control the load direction to avoid the system limits, while little work has been done in the generation space. In this paper, a new method for re-dispatching the generation based on network sensitivity between load voltages and source voltages is proposed to increase system loss reduction and security/stability margins.

The reactive power dispatch aspect also has received considerable attention in present day power system operation. The voltage magnitudes throughout a system are very important, as they must be high enough to support loads, and low enough to avoid equipment breakdown. Thus, we have to control, and if necessary to support or constrain the voltages at all key points of the power system. This control may be accomplished in large part by the supply or consumption of reactive power at these points. There are two basic types of reactive power flows of concern in a power system. One, reactive power consumed by loads, and two, reactive power consumed within the network. At heavy/light load periods, voltage control is provided by the controllable reactive sources. These reactive power controls, which are scattered throughout the transmission network, function in co-ordination.

Reactive power dispatch has been researched extensively as a static snapshot problem, and the objective of ORPD is to minimize the active power transmission loss by means of dispatching reactive power sources while satisfying a lot of constraints, such as reactive power generation limits of generators, voltage limits of load buses, tap ratio limits, reactive power compensation limits, and power flow balance [2]–[8]. Such an objective is considered as a classic model of ORPD, or, for the sake of enhancing voltage stability, a multi-objective model that minimizes real power loss and maximizes voltage stability margin is considered [9]. All of these models are based on the principle of income maximization.For many applications in optimal power flow (OPF), this kind of solution is not practical because the number of control actions would be too large to be executed in actual operation, and many of the actions would be trivial [10]. Although the number of controls has little effect on the CPU time in a Newton OPF [11], the operators cannot move so many control devices within a reasonable time. A curtailed number of control actions through selecting the most effective subset of controls has been investigated for a real time OPF [12]. Taylor *et al.* [13] present that ORPD should be seen as a time-based scheduling problem with the intention of avoiding unnecessary changes in status and output of a reactive control plant. They consider some transition constraints such as the number of control actions allowable within a time domain and the time interval required between actions performed.

In this paper, a sequential method for optimum allocation of real and reactive power in day –to-day operation of power systems is presented. The technique will try to utilize fully the reactive power sources in the system to improve the voltage profile and to minimize the real power losses. In this paper, network sensitivity between load voltages and source voltages is used as the basis to obtain optimal real power allocation and a method for optimum allocation of reactive power for loss and marginal cost reduction is presented. The proposed method gives the most desirable real and reactive power generation levels and the method involves successive solution of steady state power flows and optimization of reactive power control variables using linear programming techniques.

2 Optimal Real Power Dispatch

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 operating condition it can be written as

$$\begin{bmatrix} \boldsymbol{I_G} \\ \boldsymbol{I_L} \end{bmatrix} = \begin{bmatrix} \boldsymbol{Y_{GG}} & \boldsymbol{Y_{GL}} \\ \boldsymbol{Y_{LG}} & \boldsymbol{Y_{LL}} \end{bmatrix} \begin{bmatrix} \boldsymbol{V_G} \\ \boldsymbol{V_L} \end{bmatrix} \quad (1)$$

where I_G, I_L and V_G, V_L represent complex current and voltage vectors at the generator nodes and load nodes, $[Y_{GG}]$, $[Y_{GL}]$, $[Y_{LG}]$, and $[Y_{LL}]$ are the corresponding partitioned portions of network Y-bus matrix.

Rearranging the above equation (1) we get

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

Where $[F_{LG}] = -[Y_{LL}]^{-1}[Y_{LG}]$ and F_{ji} are the complex elements of $[F_{LG}]$ matrix. This matrix gives the relation between load bus voltages and source bus voltages, which is used as basis for the optimal generation scheduling/dispatch.

For a given load distribution in the system, it can have many possible combinations of generation schedules. Different possible combinations of real power generation schedules to meet a given load demand give different real power flows in the network and voltage angles which also influence system loss and stability. The optimal generation scheduling/load sharing is obtained by Optimal Generation Factors (OGF) and is obtained from the absolute value of the $[F_{LG}]$ matrix and are given by

$$Optimal\ Generation\ Factors(OGF) = \left| [F_{LG}] \right|$$

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The optimal generation levels/scheduling is obtained by multiplying the optimal generation factors with the real powers at load buses and are given by

$$P_{i \in n_G} = \sum_{j=1}^{n_L} (OGF)_{ji}^{norm} P_j$$

where P_i -represents the generation levels in at bus I

P_j - represents the load at bus j

2.1 Test System -1

The radial six-bus test system - 1 shown in Figure1 is considered for evaluating the optimal real power scheduling. In this system, it is assumed that the lines L1, L2 and L3 are of 200, 300 and 100kms length respectively and each of 400kV line. The generators considered are two units of 250 MVA with step up transformers of 250 MVA each at both buses 1 and 2. The 400 kV line parameters in p.u. per 100 kms are r=0.0166, x=0.0206 and b/2=0.2692. The $[F_{LG}]$ matrix corresponding to the load/generator bus for the network is as given below.

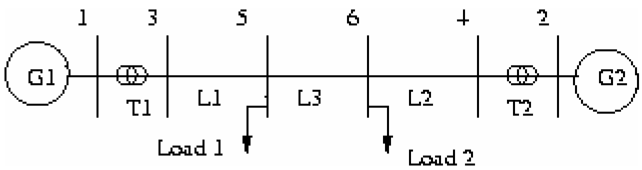

Fig.1 Test System-1

$$[F_{LG}] = \begin{bmatrix} 0.8999-0.0040i & 0.1343+0.0021i \\ 0.1343+0.0021i & 0.8997-0.0040i \\ 0.6717-0.0043i & 0.4106-0.0017i \\ 0.5464-0.0035i & 0.5419-0.0030i \end{bmatrix}$$

The optimal generation factors to meet each load demand for the given network are given in Table 1. The optimal generation levels are obtained by multiplying the OG Factors with the corresponding load at the lad buses and are given in Table 2. Power flow results are carried out with the optimal generation levels and the system grid totals for maximum power transfer are given in Table 3.

Table 1
OG Factors for the Test System-I

Load Bus No.	**Generators**	
	G1	**G1**
3	0.8999	0.1343
4	0.1343	0.8997
5	0.6717	0.4106
6	0.5464	0.5419

Table 2
Optimal Generation scheduling

Load Bus No.	**Generation levels at Bus**		**Load at the Bus(MW)**
	G1(MW)	**G2(MW)**	
3	0.8999x 0 =0.0	0.1343 x 0 =0.0	0
4	0.1343x 0 =0.0	0.8997 x 0 =0.0	0
5	0.6717x593 =398.3181	0.4106x593 =243.4858	593
6	0.5464x393 =214.7352	0.5419x393 =212.9667	393
Total Gen.	= 613.0533	=456.4525	

Table 3
Loss and Marginal cost

		Without OGF	**With OGF**
Load (MW)	Load at bus 5	593	593
	Load at bus 6	393	393
%Power Loss		3.57	2.73
Power Loss (MW)		64.33	60.85
Generation (MW)	G1	661	594
	G2	393	456
Marginal Cost	G1(3.34P_1\$/MWhr)	2207.7	1984.0
	G2(2.00P_2\$/MWhr)	786.0	912.0
Total Marginal Cost ($/MWhr)		2993.7	2896.0

From the Table 3, it can be seen that the percentage power loss, power loss in MW and marginal cost is less when the generation scheduling is according to the OGF and they are more if the generation scheduling to the OGF.

3 Optimal Reactive Power Dispatch

Minimization of real power losses in a system forms the basis for the reactive power optimization problem. The model uses linearized sensitivity relationships to define the problem. The constraints are, the linearized network performance equations relating to control and dependent variables and the limits on the control variables. The control variables are:

- The transformer tap settings (T)
- The generator excitation settings (V)
- The Switchable VAR compensator (SVC) settings (Q)

The dependent variables are:

- The reactive power outputs of the generators (Q)
- The voltage magnitudes of the buses other than the generator buses (V)

It is assumed that,

- 1,2…g are the generator buses,
- g+1,g+2,…,g+s are the SVC buses ,and
- g+s+1,g+s+2,…,n are the remaining buses.

The optimization problem can then be defined as,

Minimize $P_{loss} = C^T x$

Subject to

$b_{\min} \le b = S\,x \le b_{\max}$, and $x_{\min} \le x \le x_{\max}$

Where, C is the row matrix of linearized loss sensitivity coefficients and S is the linearized sensitivity matrix relating the dependent and control variables and are evaluated using the load flow sensitivity matrix and the results of the load flow analysis [14]. A linear programming technique is applied to the above problem to determine the optimum settings of the control variables

The control vector in incremental variables is defined as

$$X = \left[\Delta T_1,..,\Delta T_{2,}\Delta V_1,..,\Delta V_{g,}\Delta Q_{g+1},..,\Delta Q_{g+s}\right]^t$$

And the dependent vector in incremental variables as

$$b = \left[\Delta Q_1,..,\Delta Q_{g,}\Delta V_{g+1},..,\Delta V_{g+s},..,\Delta V_{n,}\right]^t$$

The upper and lower limits on both the control and dependent variables in linearized form are expressed as

$$b^{\max} = \left[\Delta Q_1^{\max},.....,\Delta Q_g^{\max},\Delta V_{g+1}^{\max},.... \right.$$
$$\left. ....,\Delta V_{g+s}^{\max},\Delta V_{g+s+1}^{\max},....,\Delta V_n^{\max}\right]^t$$

$$b^{\min} = \left[\Delta Q_1^{\min},.....,\Delta Q_g^{\min},\Delta V_{g+1}^{\min},.... \right.$$
$$\left. ....,\Delta V_{g+s}^{\min},\Delta V_{g+s+1}^{\min},....,\Delta V_n^{\min}\right]^t$$

$$x^{\max} = \left[\Delta T_1^{\max},.....,\Delta T_g^{\max},\Delta V_1^{\max},.... \right.$$
$$\left. ....,\Delta V_g^{\max},\Delta Q_{g+1}^{\max},....,\Delta Q_{n+s}^{\max}\right]^t$$

$$x^{\min} = \left[\Delta T_1^{\min},.....,\Delta T_g^{\min},\Delta V_1^{\min},.... \right.$$
$$\left. ....,\Delta V_g^{\min},\Delta Q_{g+1}^{\min},....,\Delta Q_{n+s}^{\min}\right]^t$$

Where

$$\Delta T_{\min} = T_{\min} - T_{actual}\,,\ \Delta T_{\max} = T_{\max} - T_{actual}$$

$$\Delta Q_{\min} = Q_{\min} - Q_{actual}\,,\Delta Q_{\max} = Q_{\max} - Q_{actual}$$

$$\Delta V_{\min} = V_{\min} - V_{actual}\,,\ \Delta V_{\max} = V_{\max} - V_{actual}$$

3.1 Computational Procedure

This section presents the computational steps followed in the program developed for the optimization of reactive power allocation in the day-to-day operation of the power systems for improvement of voltage profiles.

Step 1: Input -data relating to system

- Scheduled load and generation, upper and lower limits and step size for transformers tap settings
- Upper and lower generator excitation settings and SVC settings, the generator reactive powers and voltage magnitudes at buses other than the generator buses.

Step 2: Perform the power flow to obtain the values of voltage violations in the system and advance the VAR control iteration count.

Step 3: Check for the satisfactory voltage profiles in the AC system

Step 4: Compute the column matrices $b^{\max}$,and $b^{\min}$ of the dependent variables.

Step5: Compute the column matrices $x^{\max}$ and $x^{\min}$ of the control variables and modify them to reasonably small ranges.

Step 7: Compute the sensitivity matrix (S), relating the dependent variables and control variables.

Step 8: Compute the row matrix (C) of the objective function sensitivities wrt the control variables.

Step 9: Solve the optimization problem using the linear programming technique.

Step 10: Obtain the optimum settings of the control variables.

Step 11: Perform the load flow with the optimum settings of the control variables.

Step 12: Check for satisfactory limits on the dependent variables.

Step 13: Check for the significant change in the objective function, if yes go to step 4.

Step 14: Print the results.

4 Typical System Studies and Results

A system of 96 buses (typical of Indian grid equivalent system including the voltage levels of 220kV and 400kV) has been considered for studies. There are 20 numbers of generators in the system connected at buses 1-13, 15-19, 95 and 96. There are 20 numbers of generators, 18 tap regulating transformers and 95 transmission lines in the system. About 30 numbers of buses are considered as Switchable VAR compensator (SVC) buses. The system has about 12345.8MW, 6410.0MVAR peak load and 8631.07MW, 4289.67MVAR light load. Results obtained for the two cases, viz., peak load and light load are presented with and without generation scheduling obtained according to OGF.

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4.1 Peak load condition

The initial power flow results for this case show a low voltage profile in the system with the voltages of about 39 buses not being within acceptable limits (0.95-1.05 p. u.). There are 12 generators exceeding the maximum Q limits and no generator Q is exceeding the minimum limit. The proposed algorithm for reactive power optimization has been applied to improve the situation. The step size taken for both the regulating transformers and generators excitations is 0.0125 p.u. The compensation at the selected places initially it is assumed to be zero. After four iterations of the VAR optimization the voltages at all the buses have been brought within the satisfactory operable limits (0.95-1.05 p.u.) and all the generators reactive power outputs (Q) are brought within the limits. The summarized results initial and after optimization (final) for the system are presented in Tables 4 and 5. The load bus voltage profiles before and after optimization are shown in Figure 2.

Table 4
System-Grid Totals

	Initial	Final
Total P Gen. (MW)	12741.37	12670.77
Total Q Gen. (MVAR)	6133.22	3869.79
Total P Load (MW)	12345.80	12346.20
Total Q Load (MVAR)	6410.0	6430.30
Total comp. (MVAR)	1350.00	2475.00
Total P Loss	395.56	324.60
Total Q Loss	482.17	1817.55
% P loss	3.10%	2.56%
Marginal Cost($/MWhr)	8325.67	7294.36
Reduction in Loss (MW)	-	70.96

Table 5
Generators (MVAR) limits

Generator No.	Max. MVAR	Initial (MVAR)	Final (MVAR)
6	206.0	351.30	190.30
9	330.0	434.32	274.80
10	248.0	286.18	161.00
11	30.0	60.33	26.80
12	135.0	196.45	67.30
13	96.0	166.41	92.10
15	99.0	104.15	52.70
16	160.0	215.49	150.60
17	80.0	150.80	72.20
18	586.0	587.69	388.80
19	297.0	340.39	243.60
95	120.0	169.67	81.60

4.2 Light load condition

The initial power flow results for this case show an over voltage profile in the system. There are 2 generators exceeding the minimum Q limits and no generator Q is exceeding the maximum limit. The proposed algorithm is applied to improve the situation. The step size taken for both the regulating transformers and generators excitations is 0.0125 p.u. The total number of SVC buses selected for the compensation is about 30. The compensation at the selected places initially is assumed to be zero.

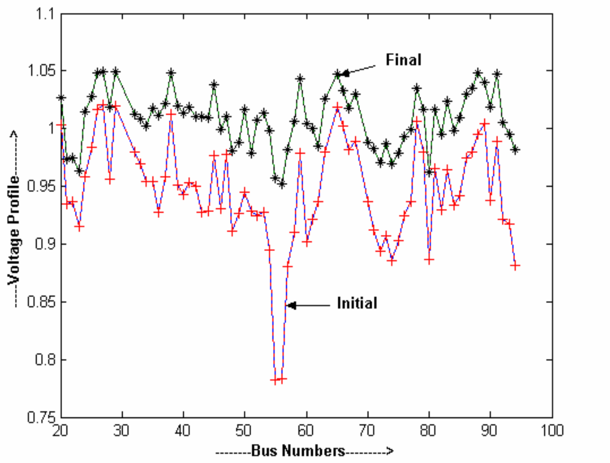

Fig.2 Bus Voltage profile before and after optimization (peak load condition)

After one iteration of the optimization, the voltages at all the buses have been brought within the satisfactory operable limits (0.95-1.05 p.u.). After the optimization all the generators reactive power outputs (Q) are brought within limits. The summarized results initial and after optimization (final), are given in Tables 6 and 7, and the load bus voltage profiles are shown in Figure 3.

Table 6
System-Grid Totals

	Initial	Final
Total P Gen. (MW)	8780.96	8784.35
Total Q Gen. (MVAR)	631.78	757.36
Total P Load (MW)	8631.00	8631.00
Total Q Load (MVAR)	4288.20	4289.67
Total comp. (MVAR)	1350.00	1390.00
Total P Loss	149.97	153.51
Total Q Loss	4111.85	3889.21
% P loss	1.71%	1.74%
Marginal Cost($/MWhr)	7285.76	6226.64
Reduction In Loss (MW)	-	-3.54

Table 7
Generators Q_{min} (MVAR) limits

Generator No.	Min. MVAR	Initial	Final
12	-50.0	-59.34	-33.20
15	-40.0	-53.33	-36.8

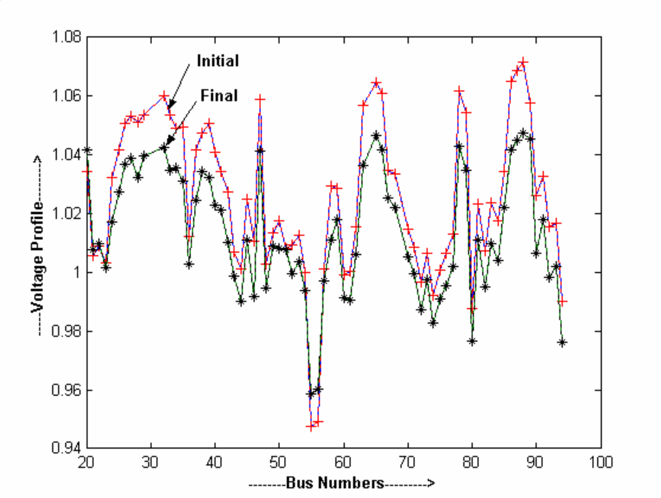

Fig.3 Bus Voltage profile before and after optimization light load condition)

4 Conclusion

A sequential algorithm for optimum allocation of real and reactive power in a practical system with an objective of improving the loss and marginal cost reduction has been presented. In this paper a new concept, called optimal generation factors is used to generation scheduling for improving voltage profiles. The proposed algorithm is demonstrated to give encouraging results for improving the operational conditions of the system under both peak load and light load conditions. The developed algorithm has been tested on typical sample systems and results for a practical real-life equivalent system of 96-bus are presented.

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