CONTROL OF GENERATION RAMPING FOR POWER STSTEM SECURITY ASSESSMENT

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Abstract

The problem of control and adjustment of power system generation ramping capability is formulated as a non-linear multi-objective constrained dispatch recognizing generation cost, transmission losses, generator operating limits, line security limits, and load uncertainty.

The paper presents a novel method for economic dispatch employing Bender's Decomposition Principle coupled with a successive linearization technique to provide certain generation ramping capable to follow rapidly the unexpected load changes. In such iterative scheme, the non-linear functions may be accomodated in the linear programming using updated linearization about the base case solution.

The program used offers a sensitivity analysis which permits an answer to the "what if" question using about 20 % of computational time required to solve the base case. This property is attractive to power system operator. The proposed concept of power dispatch offers an efficient tool to make an economic-secure decision on whether to buy or sell regulating margin or whether to install new ramping capability.

INTRODUCTION

In operating an electric power system, it is required to provide a continuous and economical supply for the load in the near future time while satisfying system security constraints. At every instant of time, energy generation must equal the momentary load demand plus network transmission losses as well as the power interchanges with the neighboring systems. To achieve this, a sufficient reserve is necessary to be called upon immediately. This type of reserve can be supplied from either an emergency start-up expensive generating units with fast response or the full utilization of the existing generation ramping capabilities. The provision of ramping capabilities contributes directly to the overall system security. On the other hand, the control for higher ramping capabilities is associated with higher generation costs. Consequently a compromise between economy and security is necessary in the power system operation. This problem can no longer be solved intuitivly due to the growing complexity of power systems.

Recent methods of security constrained dispatch [1-3] provide generation policy to meet the load demand while providing certain amount of spinning reserve to be called upon for overload corrections. However, the propabilistic measure of load prediction [4] are not yet used to judge the provision of operating reserve. Ref. [5] presented a method to determine the minimum cost of providing a particular level of reserve or operating with a particular set of ramp rate capabilities. The spinning reserve and the ready reserve have been determined as function of both the largest unit in service and the peak load. However, the matching between the load uncertainty and the system reserve margin was not considered. Adler and Fischl [6] presented a method for adjusting regulating responsibility among designated generators to ensure a secure dispatch to the broadest variations in bus demands. Such adjustment is specified through the assignment of patcicipation factors which govern the fraction of the net change in total system demand that each generator will supply. This method aims to optimize the security function instead of operating cost function. Moreover, there is no guarantee that each generator can supply its participation to the assigned regulation in a reasonable time.

This paper presents a novel method for control and adjustment of generation ramping to improve the power system security. This method employs Bender's Decomposition Principle [7] coupled with asuccessive linearization technique to provide an economic generation dispatch with the ability to follow rapidly the unexpected overloads.

MATHEMATICAL FORMULATION

The minimization of the instantaneous operating cost of a power system is an objective of the power dispatch problem. The cost curve f_i of each generating unit is a non-linear function of the real power output PG_i and is commonly approximated by a quadratic function. The system operating cost F is the summation of the cost curves of all N committed generators.

$$F(PG) = \sum_{i=1}^{N} f_i(PG_i)$$

$$= \sum_{i=1}^{N} (a_i.PG_i^2 + b_i.PG_i + c_i) \qquad ....(1)$$

where a_i, b_i, and c_i are coefficients of the quadratic cost function of unit i.

The objective cost function can be written as;

$$\text{Minimize: } F\,(PG) \qquad ....(2)$$

The objective function can be linearized about certain operating point. Correspondingly, the incremental cost at each generation level can be approximated by constant values around each operating point.

Another objective of the power dispatch problem is to maximize the overall generation ramping to follow the predicted load variance. It is reasonable to assume that the system load generation imbalance can be restored to zero within ten minutes. Due to load uncertainty, generation ramping capability is required to be adjusted at each instant of time to satisfy the instantaneous load generation balance requirements. The system generation ramping (SGR) is the summation of the regulation each unit can add to the system in ten minutes.

$$SGR = \sum_{i=1}^{N} \text{Min}\,(\overline{PG}_i - PG_i\ ,\ R_i) \qquad ....(3)$$

where;

$\overline{PG}_i$ = the present capacity of unit i,

R_i = the maximum regulation allowed on unit i in ten minutes.

The conditional summation (3) may be replaced by direct summation and a set of inequality constraints [3];

$$SGR = \sum_{i=1}^{N} (\overline{PG}_i - PG_i - Y_i) \qquad ....(4)$$

and $$\overline{PG}_i - PG_i - Y_i \leqslant R_i \qquad ....(5)$$

wher Y_i is a non-negative variable representing the amount of spinning reserve on the unit i that is unavailable to contribute to SGR in order that the regulation adjusted on that unit is less than or equal to R_i. Maximization of SGR contributs directly to the system Security on the expense of operating cost incrementation. Hence, the second objective of the power dispatch problem can be written as;

$$\text{Maximize: } SGR = \sum_{i=1}^{N} (\overline{PG}_i - PG_i - Y_i) \qquad ....(6)$$

$$\text{Subject to : } \overline{PG}_i - PG_i - Y_i \leqslant R_i \qquad ....(7)$$

The objective (6) can be transformed to:

$$\text{Minimize: } \sum_{i=1}^{N} PG_i + Y_i - \overline{PG}_i \qquad ....(8)$$

The above two objectives are subjected to equality constraints imposed by physical characteristics governing the system and inequality constraints imposed by the equipments, generators and transmission network ratings. The equality constraint arises from the requirement that the total generation must equal to the total load demand (P_d) plus the respective transmission losses (P_L) as well as the net power interchange with the neighboring areas (P_{IN}), i.e;

$$\sum_{i=1}^{N} PG_i \pm P_{IN} = P_d + P_L \quad \text{....(9)}$$

Each generating unit must be operated at a level between upper and lower limits,

$$\underline{PG}_i \leqslant PG_i \leqslant \overline{PG}_i \quad \text{....(10)}$$

The response rate of each generating unit is a constraint that have to be met in following the load changes;

$$PG_i(t-1) - PD_i \leqslant PG_i(t) \leqslant PG_i(t-1) + PU_i \quad \text{....(11)}$$

where;

PD_i = response rate for unit i to meet a reduction in load demand,

PU_i = response rate for unit i to meet an increase in load demand,

$PG_i(t)$ = generation level for unit i at time t.

The active power flow (P_k) in transmission line k connecting bus l to bus j should be restricted by an upper security limit;

$$\underline{P}_k \leqslant P_k \leqslant \overline{P}_k \quad \text{....(12)}$$

where $\underline{P}_k$, and $\overline{P}_k$ are minimum and maximum limits on active power flow in line k respectively.

The power dispatch proplem recognizing generation cost, ramping capability, transmission losses, generator operating limits, line security limits, and the uncertainty in load forecast is formulated as a multi-objective non-linear optimization. The cost function, transmission losses, and load flow equations may be accomodated in a linear programming by successive linearizations about the recent operating point to have more accurate solution.

Linearized Loss Formula

The classical loss formula with P-coefficients [8] is simple but not accurate and introduces considerable error due to the large number of assumptions made. Another formula was proposed by Lee et.al. [9] assuming a 1.0 p.u. flat voltage over the transmission lines and considering the reactive power transmitted over the line to be zero. Another formula compensating the above assumptions is given as;

$$P_{LK} = B_{OK} + B_{1k} P_k + B_{2k} P_k^2 \quad \text{....(13)}$$

where;

P_{LK} = transmission line losses in line k,

B_{0k}, B_{1k}, and B_{2k} are coefficients of line k identified using least square fitting with data supplied from AC load flow analysis.

The total losses (P_L) in a network with NL transmission lines is given as;

$$P_L = \sum_{k=1}^{NL} P_{LK} \qquad \ldots.(14)$$

The incremental change of transmission losses w.r.t. generation output of unit i can be written as;

$$\Delta P_L = \sum_{k=1}^{NL} \frac{\partial P_{LK}}{\partial P_k} \, dP_k$$

$$= \sum_{k=1}^{NL} \frac{\partial P_{Lk}}{\partial P_k} \, \frac{\partial P_k}{\partial P_d} \, dP_d \qquad \ldots.(15)$$

Substituting the partial derivative of eqn. (13) in eqn.(15) with some algebraic simplifications we get;

$$\Delta P_L = \left[q + \sum_{i=1}^{N} V_i \cdot PG_i \right] \Delta P_d \qquad \ldots.(16)$$

where;

$$q = \sum_{k=1}^{NL} (B_{1k} / W_k) \,,$$

$$W_k = \sum_{i=1}^{N} (1 / D_{k,i}) \,,$$

$$V_i = \sum_{k=1}^{NL} (B_{2k} \cdot D_{k,i} / W_k) \,,$$

$$\Delta P_d = P_d(t) - P_d(t-1) \,, \text{ and}$$

$D_{k,i}$ = the contribution of one MW power generated at bus i to the active power flow in line k. This coefficient is calculated using the Generalized Generation Distribution Method [10].

SOLUTION ALGORITHM

The problem of economic dispatch of deterministic load can be formulated in a concise form as follows;

$$\text{Minimize: } a + b^T \cdot x \qquad \ldots.(17)$$

$$\text{Subject to: } A \cdot x = B \qquad \ldots.(18)$$

$$\underline{X} \leqslant x \leqslant \overline{X} \qquad \text{....(19)}$$

$$D \;.\; x \qquad T_m \qquad \text{....(20)}$$

where;

- x : a vector of decision variable whose components represent the generation level of the committed units for operation,
- $Ax=B$: the load demand constraint,
- $\underline{X} \leqslant x \leqslant \overline{X}$: constraint of the upper and lower limits on generation level of each generating unit including the ramp rate capability,
- $Dx \leqslant T_m$: the security constraint on active power flow in transmission network.

Introducing the necessary slack variables which transform the inequality constraints to equality ones, the problem can be written in the following form;

$$\text{Minimize:} \quad C\ x \qquad \text{....(21)}$$

$$\text{Subject to:} \quad A\,.x = B \qquad \text{....(22)}$$

Such a program with the above characteristics can be solved optimally using the Bender's Decomposition Principle [7].

By the use of the Bender's Decomposition Principle, the optimization procedure described above can provide an economic dispatch for uncertain loads by providing the maximum possibility of load following capacity limited by definite incrementation of the generation cost based on the uncertainty of the load demand. The provision of a suitable amount of generation ramping on the generating units to rapidly follow the load changes will ensure the system security requirements. Therefore, The obtained solution is a trade-off between the required two objectives: minimization of generation cost and maximization of the system load following capability which can match the unpredictable load changes.

APPLICATIONS

Test System

The test system given in Table.I is used as an application to the proposed technique. This system [1] contains 8 generators and 6 transmission lines. The uncertainty of load demand is represented by a normal distribution characterized by the predicted standard deviation [4]. The system unit committment is assumed to be made before the economic dispatch [11]. Table.I contains the operating data of each generator as the initial loading condition, the maximum and minimum power generating limits, the rate of change of output power per 10 minutes, and generation cost quadratic factors.

TABLE. I Data of generating system

Unit No.	Initial Condition (MW)	Maximum power (MW)	Minimum power (MW)	10-min Reserve (MW)	b_i \$/MW-hr	$a_i/2$ \$/MW/MW-hr
1	372	400	20	40	17.094	0.009
2	458	550	20	60	16.201	0.015
3	214	350	20	35	19.000	0.009
4	124	200	20	20	21.060	0.010
5	159	250	20	25	20.000	0.010
6	100	200	20	20	21.060	0.018
7	88	100	20	10	23.074	0.022
8	239	350	20	35	19.000	0.009

Results

Simulations of different operating conditions are used to analyze the cost of system operation with different levels of security. To achieve a higher system security margin in power system operation, one or more of the following procedures can be used:-

* Reducing the active power flow in the critically loaded transmission lines.
* Increasing the generation ramping capability of the existing units.
* Reducing the time required by the system to call and utilize the adjusted generation ramping.

Fig.1 shows the required generation ramping to cope with the standard deviation of predicted loads for system operation with different confidence in load generation balance. The generation ramping is expressed as percentage of the total available ramp in 10-minutes.

Fig. 2 shows the additional cost required to adjust system generation ramping for different loading levels at normal power flow limits.

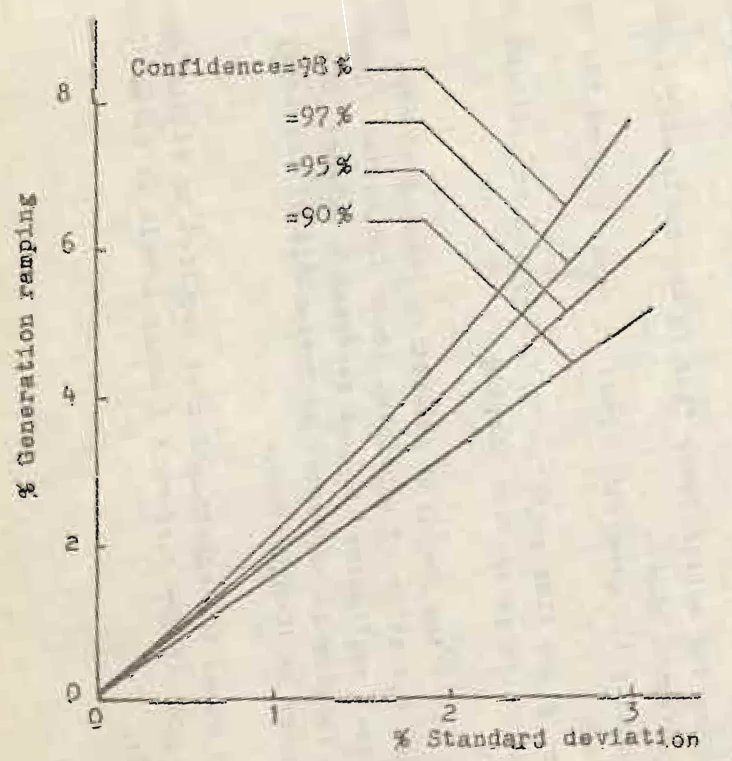

Fig.1 Generation ramping against standard deviation of predicted load for different confidence in load-generation balance.

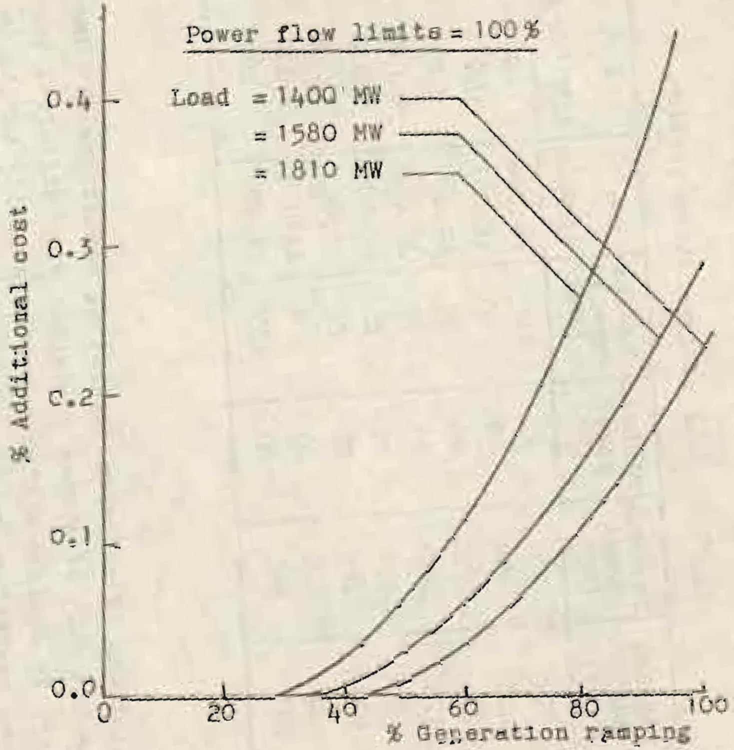

Fig.2 Cost of generation ramping at normal power flow limits for different loading levels.

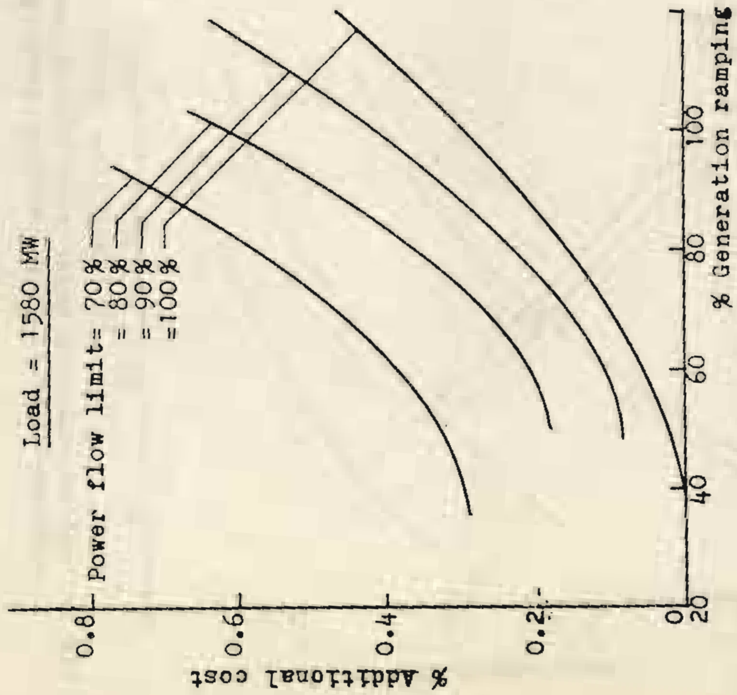

Fig.3 Cost of generation ramping for different power flow limits.

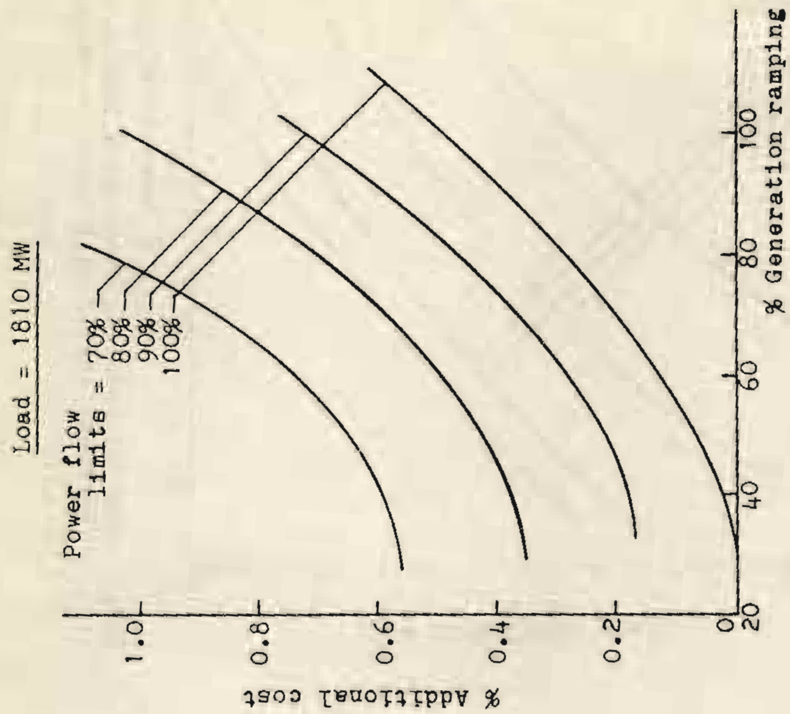

Fig.4 Cost of generation ramping for different power flow limits.

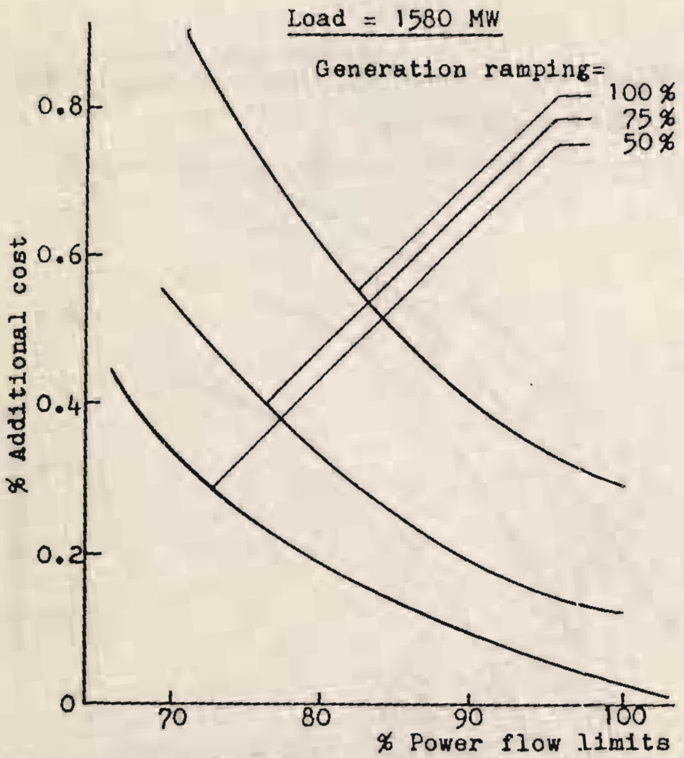

Fig.5 Cost of reducing power flow limits for different levels of generation ramping.

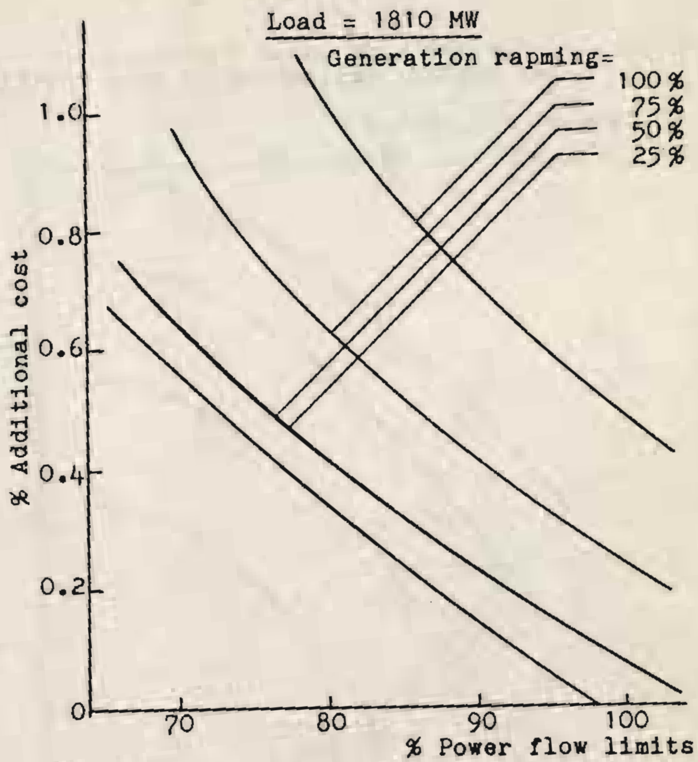

Fig.6 Cost of reducing power flow limits for different levels of generation ramping.

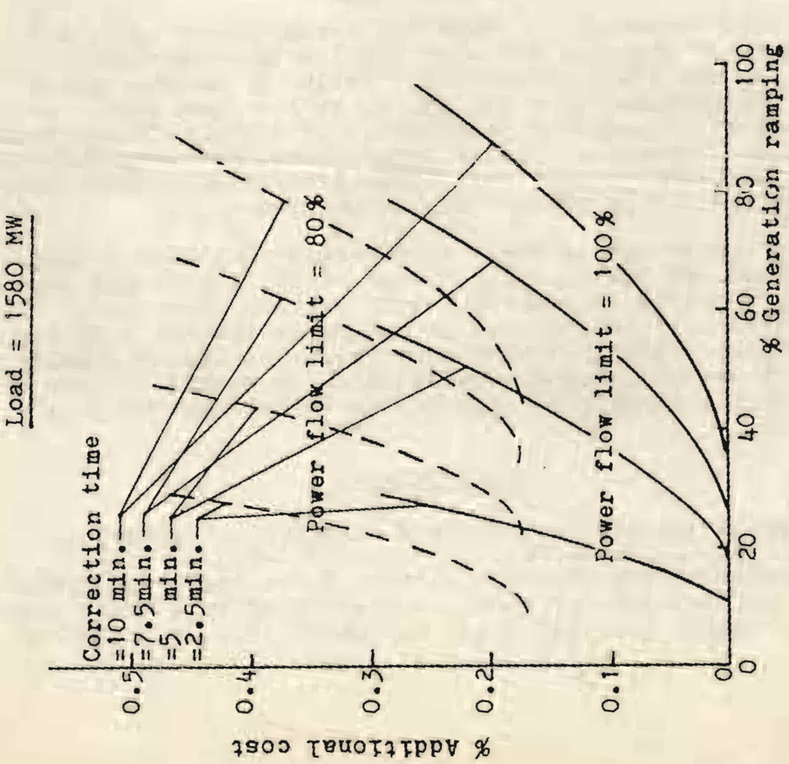

Fig.7 Cost of generation ramping for different values of correction time.

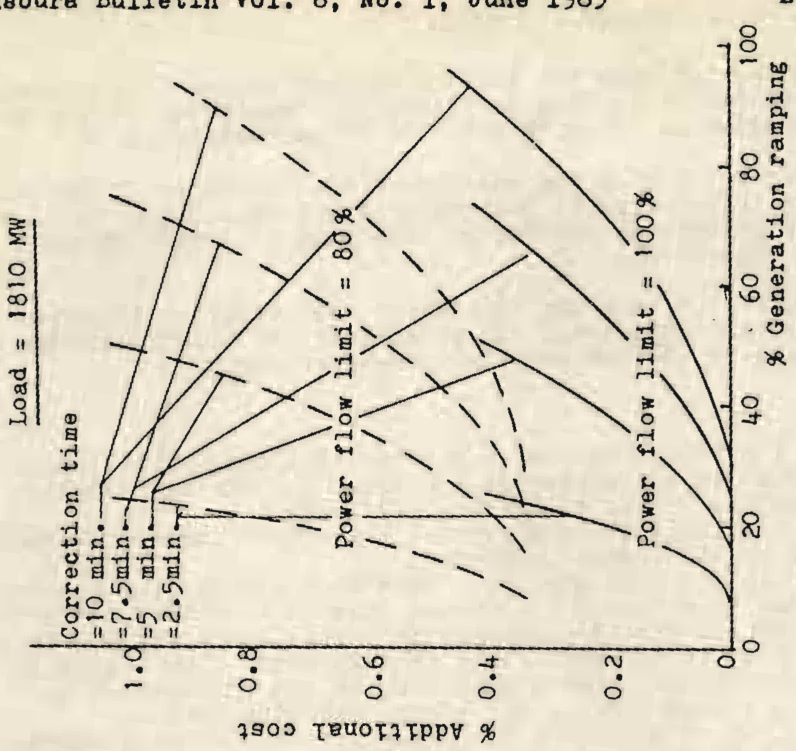

Fig.8 Cost of generation ramping for different values of correction time.

Figures 3,4 show the additional cost required to adjust system generation ramping for different line power flow limits at load demand of 1580 MW and 1810 MW respectively.

Figures 5,6 show the additional cost required to reduce the active power flow in the critically loaded lines for different generation ramping at load demand of 1580 MW and 1810 MW respectively.

Figures 7,8 show the additional cost required to adjust system generation ramping for different correction times at load demand of 1580 MW and 1810 MW respectively.

Comments

1- The confidence in the load generation balance increases as the genration ramping increases for certain standard deviation of the predicted load demand.
2- The cost of adjusting certain generation ramping increases as the load demand increases.
3- The cost of maintaining certain security margins increases as the load demand increases. This cost increases also as the margin itself increases for certain loading condition.
4- The cost of operating with certain power flow limits in the critically loaded transmission lines increases as these limits reduces for higher security margins.
5- The cost of adjusting certain generation ramping increases with the decrease in the time required to call and utilize this adjusted ramp.

CONCLUSIONS

The paper presents an iterative technique to solve the multi-objective economic dispatch problem by employing a mathematical model which accurately reflects the generation cost and security requirements while, at the same time, maintaining a successive linearization of the non-linear functions to facilitate the use of linear programming. The computational burden is highly dependent on the required accuracy when solving the linearized master program and subprograms.

The proposed method makes it possible to obtain a cost-benefit trade-off between economy and security in power system operation. The cost of operating with certain generation ramping capability can be used to determine whether addition of security margins would be cost effective. The system manager can make an economic and secure decision on whether to buy or sell regulating margins or whether to install new ramping capabilities.

REFERENCES

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[2] W.R.Barcelo et al, "Optimization of the real time dispatch with constraints for secure operation of bulk power systems", IEEE Trans., Vol. PAS - 96, May/June, 1977, pp. 741-750.