DECENTRALIZED AUTOMATIC GENERATION CONTROL

BASED ON OPTIMAL LINEAR REGULATOR THEORY

by

SHEAU-WEI FU

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Approved by:

Lloyd W. Harris

Major Professor

mpb

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NOMENCLATURE

f^*	nominal system frequency in Hertz
H_i	inertial constant in second
$P_{tie\ i}$	tie-line power in MW, positive means flowing out of the i-th area
$\Delta P_{tie\ i}$	incremental change in tie-line power in MW
Δf_i	incremental frequency deviation in Hertz
D_i	load frequency constant in pu MW/Hz
ΔP_{di}	incremental load demand change in pu MW
ΔP_{gi}	incremental generation change in pu MW
ΔX_{gvi}	incremental change in an equivalent area governor valve position in pu MW
ΔP_{ci}	incremental change in speed changer position in pu MW
$T^*_{i\nu}$	tie-line power flow constant in pu MW
T_{ti}	turbine time constant in second
T_{gvi}	speed governor time constant in second
R_i	area equivalent self regulation of generation in Hz/pu MW
P_{ri}	rated megawatts of area i in MW

CHAPTER I

INTRODUCTION

An electric energy system must be maintained at a nominal state characterized by nominal frequency, voltage profile, and a load flow configuration through megawatt-frequency control and megavar-voltage control. In the interconnected power system in North America, the megawatt-frequency control is obtained by conventional automatic generation control - the incremental speed-changer position is established by control action that is proportional to the integral of area control error (ACE). Typically the ACE is a linear combination of the frequency deviation from scheduled frequency and tie-line flow deviation from scheduled flow. In order to minimize the frequency and tie-line flow deviations and the control effort, Elgerd and Fosha [1] developed a mathematical model for interconnected power systems in state variable form. Optimal linear regulator theory was then applied to the model to design an optimal feedback controller. The resulting control variable is a linear combination of all the state variables in the whole interconnected system. Elgerd and Fosha showed that the response of the system with such a controller is better damped when subjected to a step disturbance than that which is obtained when a conventional automatic generation control strategy is utilized. But when implementation is considered, the Elgerd and Fosher controller seems to be impractical because the real interconnected system may have several thousand state variables. As the dimension of the system becomes as great as several thousand, it is very difficult, if not impossible, to obtain the optimal controller parameters by solving the matrix Riccati equation. Also, it is impractical for the controller in a control area to obtain information concerning the state variables in all other control areas. So an approximate decoupled model of the interconnected system is developed and used as a basis for the design of a suboptimal controller. The incremental speed changer position of each area then depends only on the state variables in that area. The only coupling between areas in the interconnected system model appears in the tie line flow terms, which depend on the difference in the integrals of the respective frequency deviations of the interconnected areas. An approximate model can be obtained by assuming that these integrals of frequency deviations are scalar multiples of one another. This allows the tie line flow deviation in a given area to be approximated in terms of its own state variables. The system matrix, A, is altered slightly and each area can be regarded as a single area control system in a mathematical sense. This approximate model is valid only for the transient state and so the optimal feedback controller (speed-changer position) is designed to reduce swings of frequency and tie line deviations during transient state. It is shown, by example, that the steady state performance is comparable to that of other controllers that have appeared in the literature. The performance of the suboptimal controller was simulated using the customary system model of a two-area two-source system. This strategy is referred to as decentralized optimal automatic generation control.

Compared with advanced automatic generation control [1], the response of decentralized automatic generation control subjected to a step disturbance is almost as good as that of advanced automatic generation control but less information about the state variables is needed. Besides, it is much easier to solve the matrix Riccati equation for the decentralized automatic generation control strategy than for the advanced automatic generation control strategy; the dimension of the model is reduced many times. In this manner it becomes practical to apply optimal control theory to the automatic generation control for a large interconnected system.

The response requirements which an interconnected system must satisfy are as follows [1, 9]:

1. The static frequency deviation following a step-load change must be zero.
2. The static change in tie-line flow must be zero.
3. The transient frequency deviations should not exceed ± 0.02 Hz under normal conditions.
4. The time deviation represented by the integral of frequency deviation should not exceed ± 3 seconds.

Requirement 1 holds only if the area in which the step-load change occurs has adequate generation capacity to fully accommodate this change. If it does not, the system operation objective will be altered to allow the static frequency error to persist to a degree sufficient to permit other areas to provide assistance to the area in need, for the full duration of the need.

Requirement 3 holds only if the area in which the step-load change occurs can adjust its own generation to meet the change in demand. If it cannot, the operational specifications are altered to permit the static error to persist so that other areas can provide sustained assistance to the area in need, for the full duration of the need.

Because of limitations on machine dynamics, the commanded power generation and rate of generation change may exceed certain machine limitations. A detailed analysis of system response under these "abnormal conditions" will be discussed later in this thesis in order to show the validity of the strategy that has been developed.

A discussion of optimal linear regulator theory and related numerical solution techniques are presented in Appendices A, B, and C.

CHAPTER II

CONVENTIONAL AND ADVANCED AUTOMATIC GENERATION CONTROL

— THE STATE OF THE ART —

Automatic generation control, which was formerly named load frequency control of electric power systems, is concerned with the regulation of the power output of the electric generators within a prescribed area in response to changes in system frequency, tie-line loading or the relation of these quantities to each other, so as to maintain the scheduled system frequency and/or the established interchange with other areas within predetermined limits. The basic feature of the conventional automatic generation control strategy is that each area acts to reduce its own area control error (ACE) to zero after an imbalance between generation and load occurs somewhere in the interconnected system. In the steady state both frequency and tie-line flow deviations are zero provided that each area can regulate its own load fluctuations and is properly controlled.

SYSTEM DYNAMIC MODEL

Two assumptions have to be made in developing a mathematical model suitable for studying the automatic generation control of electric power systems. The first one is that for an incremental change in demanded power, the magawatt-frequency control, or "P-f control", and the megavar-voltage control, or "Q-V control", can be decoupled and considered separately. The second one concerns the coherency of an area, i.e., it is assumed that the individual electrical connections within an area are so strong, at least in comparison to the ties between adjoining areas, that each area may be characterized by a single frequency.

In the i-th area of an interconnected electric power system the system equations, which consist of the equations for power equilibrium, the incremental tie line flow, the change in generation, and the incremental valve position of speed governor, as developed by Elgerd and Fosha [1, 3] in the state variable form are shown as follows:

$$\frac{2H_i}{f^*}\frac{d}{dt}\Delta f_i + D_i\Delta f_i + \sum_{\nu} T^*_{i\nu}\left(\int\Delta f_i dt - \int\Delta f_\nu dt\right) = \Delta P_{gi} - \Delta P_{di} \qquad (1)$$

$$\frac{d}{dt}\Delta P_{gi} = -\frac{1}{T_{ti}}\Delta P_{gi} + \frac{1}{T_{ti}}\Delta X_{gvi} \qquad (2)$$

$$\frac{d}{dt}\Delta X_{gvi} = -\frac{1}{T_{gvi}}\Delta X_{gvi} - \frac{1}{T_{gvi}R_i}\Delta f_i + \frac{1}{T_{gvi}}\Delta P_{ci} \qquad (3)$$

The definitions of these variables and parameters are listed in the nomenclature. T_{gvi} is a measure of the reaction speed of the speed-control mechanism. Its normal value is less than 100 ms. T_{ti} is the turbine time constant for a nonreheat turbine generator. Its typical value lies in the range of 0.2 to 2 seconds. R_i is the frequency change for per unit MW generation change, a parameter of the speed governor system.

The state and control variables in the i-th area are defined as follows:

$$\begin{aligned} X_{i1} &\triangleq \int\Delta P_{tie_i} dt \\ X_{i2} &\triangleq \int\Delta f_i\, dt \\ X_{i3} &\triangleq \Delta f_i \\ X_{i4} &\triangleq \Delta P_{gi} \\ X_{i5} &\triangleq \Delta X_{gvi} \\ u_i &\triangleq \Delta P_{ci} \end{aligned} \qquad (4)$$

The model of a general multiple-input-multiple-output control system is shown in Figure 1. The interconnected control areas are shown in block diagram form in Figure 2. Figure 3 shows a simplified scheme of a typical mechanism for output power control of a steam driven generator. Figure 4 displays the system dynamic equations in block-diagram form. Only the i-th area is shown in Figure 4.

In the following, a two-area, two-source system is considered, which will be used as a typical model for simulation purposes later in this thesis. The tie-line flow deviation in the first area is proportional to that in the second area, i.e.

$$\Delta P_{tie2} = a_{12}\ \Delta P_{tie1}$$

where

$$a_{12} \triangleq -P_{r1}/P_{r2}$$

The state variables and control variables are defined according to equation (4) as follows:

$$x_1 \triangleq \int \Delta P_{tie} dt$$

$$x_2 \triangleq \int \Delta f_1 dt$$

$$x_3 \triangleq \Delta f_1$$

$$x_4 \triangleq \Delta P_{g1}$$

$$x_5 \triangleq \Delta X_{gv1}$$

$$x_6 \triangleq \int \Delta f_2 dt$$

$$x_7 \triangleq \Delta f_2$$

$$x_8 \triangleq \Delta P_{g2}$$

$$x_9 \triangleq \Delta X_{gv2}$$

$$u_1 \triangleq \Delta P_{c1}$$

$$u_2 \triangleq \Delta P_{c2}$$

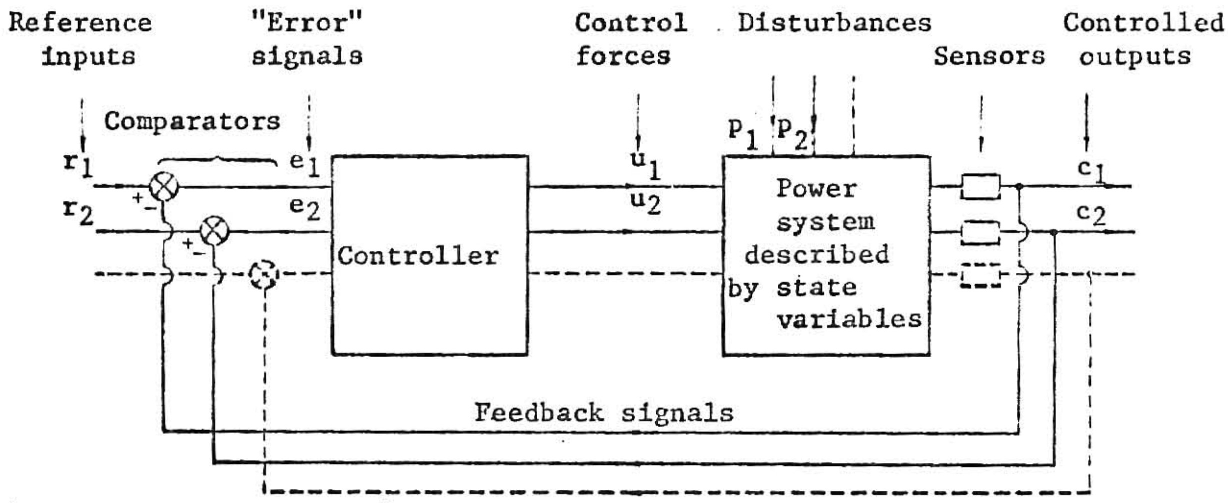

Fig. 1. Multiple-input-multiple-output control system.

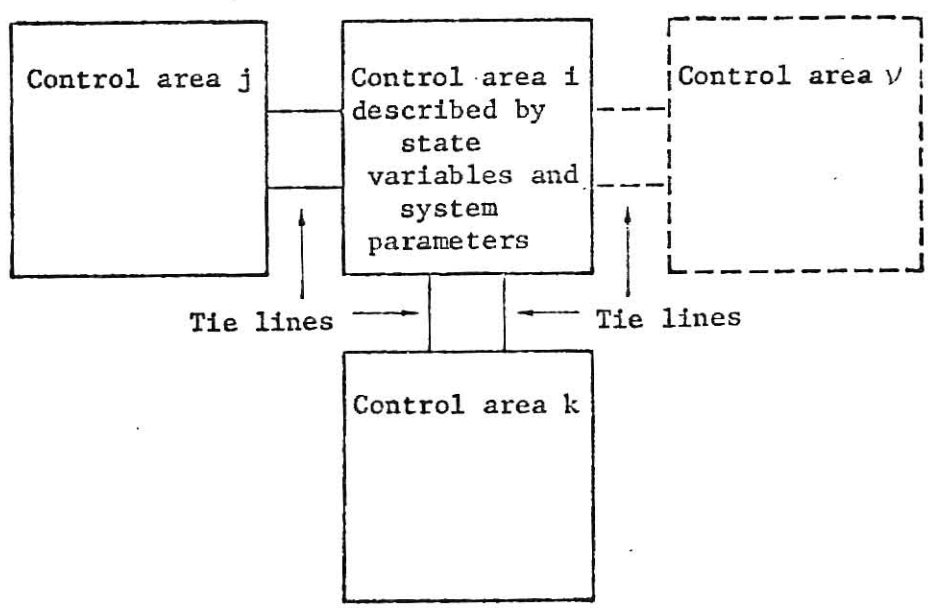

Fig. 2. Interconnected"control areas."

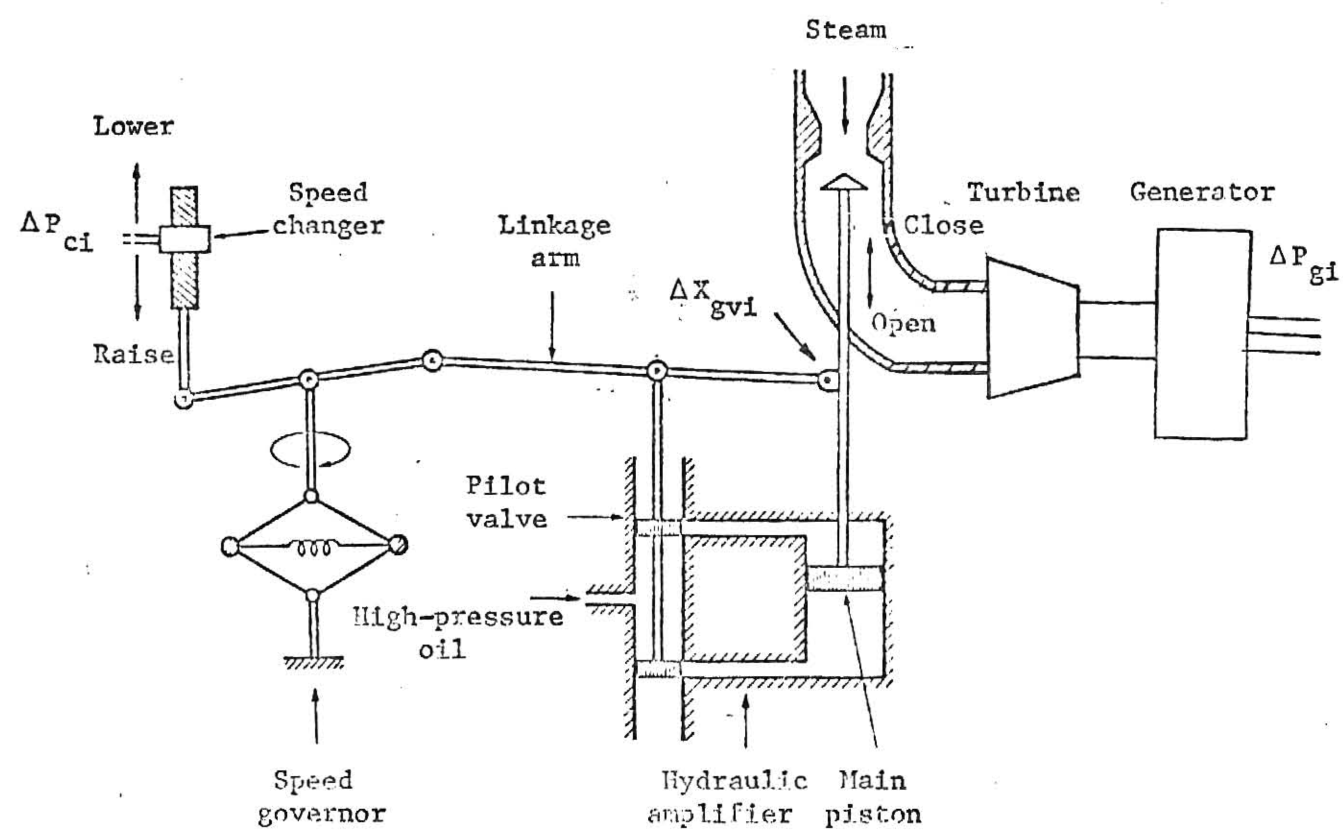

Fig. 3. Typical turbine control arrangement.

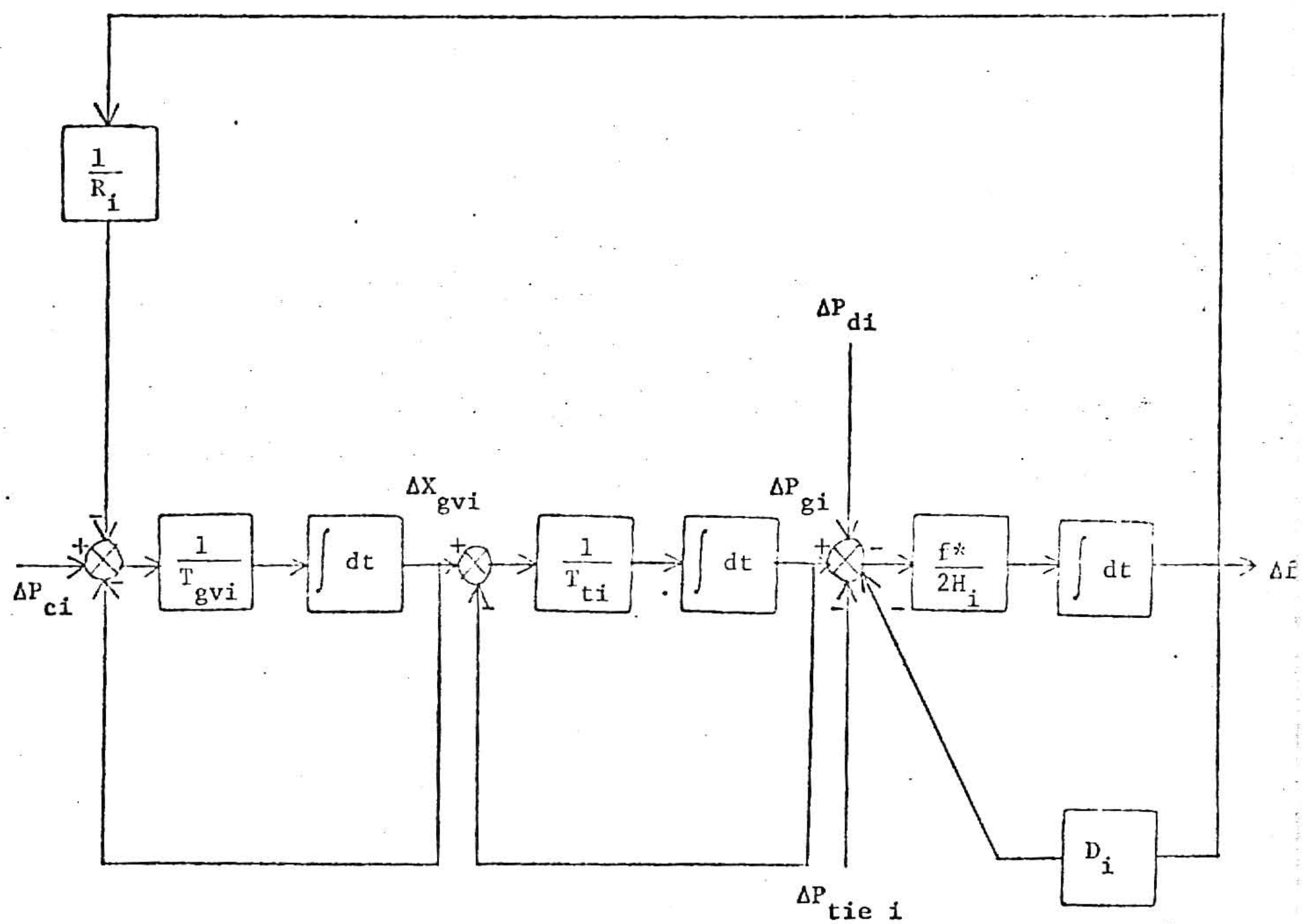

Fig. 4. Block diagram of one area of an interconnected electric power system.

After substituting the definitions of the state and control variables in equations (1) through (3), we obtain the state equation for the two area dynamic system as follows:

$$\dot{X} = AX + Bu + \Gamma \Delta P_d$$

where

$$A = \begin{bmatrix} 0 & T_{12}^{*} & 0 & 0 & 0 & -T_{12}^{*} & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & \frac{-f^{*}T_{12}^{*}}{2H_1} & \frac{-f^{*}D_1}{2H_1} & \frac{f^{*}}{2H_1} & 0 & \frac{f^{*}T_{12}^{*}}{2H_1} & 0 & 0 & 0 \\ 0 & 0 & 0 & -\frac{1}{T_{t1}} & \frac{1}{T_{t1}} & 0 & 0 & 0 & 0 \\ 0 & 0 & -\frac{1}{T_{gv1}R_1} & 0 & -\frac{1}{T_{gv1}} & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 \\ 0 & -\frac{a_{12}f^{*}T_{12}^{*}}{2H_2} & 0 & 0 & 0 & \frac{a_{12}f^{*}T_{12}^{*}}{2H_2} & -\frac{f^{*}D}{2H_2} & \frac{f^{*}}{2H_2} & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{T_{t2}} & \frac{1}{T_{t2}} \\ 0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{T_{gv2}R_2} & 0 & -\frac{1}{T_{gv2}} \end{bmatrix},$$

$$B = \begin{bmatrix} 0 & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \\ \frac{1}{T_{gv1}} & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & \frac{1}{T_{gv2}} \end{bmatrix},$$

$$\Gamma = \begin{bmatrix} 0 & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \\ -\frac{f^*}{2H_1} & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & -\frac{f^*}{2H_2} \end{bmatrix},$$

and

$$\Delta P_d = \begin{bmatrix} \Delta Pd_1 \\ \Delta Pd_2 \end{bmatrix}.$$

The matrix Γ is called the disturbance distribution matrix while the matrix A is referred to as the system dynamics matrix and B as the input distribution matirx. Optimal linear regulator theory requires that the term

$\Gamma \Delta P_d$ disappear and that the state variables be driven to zero. This in turn requires that the following change of variables be made.

$$x_i' \triangleq x_i - x_{iss} \qquad i = 1,2, \ldots n$$

which shifts the reference position of the system and puts the system equations in the form

$$X' = AX + Bu' \qquad (5)$$

$$X'(0) = -X_{ss}$$

where X_{ss} is the static state vector. For the two-area, two-source system under normal conditions, the components of X_{ss} are as follows:

$$x_{1ss} = \int_0^\infty \Delta P_{tie} dt$$

$$x_{2ss} = \int_0^\infty \Delta f_1 dt$$

$$x_{3ss} = 0$$

$$x_{4ss} = \Delta Pg_{1ss} = \Delta Pd_1$$

$$x_{5ss} = \Delta x_{4ss} = \Delta Pd_1$$

$$x_{6ss} = \int_0^\infty \Delta f_2 dt$$

$$x_{7ss} = 0$$

$$x_{8ss} = \Delta Pg_{2ss} = \Delta Pd_2$$

$$x_{9ss} = x_{8ss} = \Delta Pd_2$$

CONVENTIONAL AUTOMATIC GENERATION CONTROL

The control strategy being used in the electric power industry today is referred to as conventional automatic generation control. In this conventional control strategy, the incremental change in speed-changer position, ΔPci, is proportional to the integral of the area control error (ACE). ACE is usually defined as a linear combination of tie-line flow deviation and frequency deviation, that is

$$ACE_i(t) = \Delta P_{tie\ i}(t) + B_i \Delta f_i(t) \tag{6}$$

$$\Delta P_{ci}(t) = -K_i \int_0^t ACEi(t)dt \tag{7}$$

where $\Delta P_{tie\ i}(t)$ is the net deviation of tie-line flow out of the i-th area; $\Delta f_i(t)$ is the deviation of the i-th area frequency and B_i is a frequency bias coefficient, which is usually selected to be equal to the area frequency response characteristic (AFRC) of that area.

$$B_i = AFRCi$$

$$\Delta D_i + \frac{1}{R_i}$$

K_i is the integral gain in the i-th area.

For a two-area, two source system, $i = 1$ or 2 and so

$$\Delta P_{c1}(t) = K_1 \int (\Delta P_{tie1}(t) + B_1 \Delta f_1(t))dt$$

$$\Delta P_{c2}(t) = K_2 \int (\Delta P_{tie2}(t) + B_2 \Delta f_2(t)dt$$

<u>Static System Response</u>

Under normal conditions, following a step load change in either area, a new static equilibrium, if it exists, can be achieved only after incremental changes in speed-changer positions, ΔP_{c1} and ΔP_{c2}, have reached constant values, i.e.

$$\Delta P_{tie1,stat} + B_1 \Delta f_{stat} = 0$$

$$\Delta P_{tie2,stat} + B_2 \Delta f_{stat} = 0$$

where the subscript stat means static values. Evidently these conditions can be met only if

$$\Delta f_{stat} = 0$$

and

$$\Delta P_{tie1,stat} = \Delta P_{tie2,stat} = 0$$

The steady state frequency and tie-line flow deviations are thus eliminated. This is the result of integral feedback control.

Simulation - Two-Area, Two-Source System

The following system parameters are used throughout this thesis.

$$P_{r1} = P_{r2} = 2000 \text{ MW}$$

$$H_1 = H_2 = 5 \text{ seconds}$$

$$D_1 = D_2 = 8.33 \times 10^{-3} \text{PuMW/Hz}$$

$$T_{t1} = T_{t2} = 0.3 \text{ second}$$

$$P_{tie\ max} = 200 \text{ MW}$$

$$T_{12}^* = 0.545 \text{ PuMW}$$

$$T_{gv1} = T_{gv2} = 0.08 \text{ second}$$

$$R_2 = R_2 = 2.4 \text{ Hz/PuMW}$$

$$\Delta P_{d1} = \Delta P_{d2} = 0.01 \text{ PuMW}$$

The case in which $K_1 = K_2 = 1$, $B_1 = B_2 = 0.425$ is simulated by solving the system state equation using subroutine RKGS in IBM Scientific Subroutine Package and plotted by using CalComp Model 663 digital incremental drum plotter (Appendix C). The system data and response of Δf_1, Δf_2 and ΔP_{tie} are shown in Figures 5, 6, and 7. Apparently, the frequency and tie-line flow deviations are highly oscillatory and poorly damped when conventional control strategy is used.

$$A = \begin{pmatrix} 0 & 0.545 & 0 & 0 & 0 & -0.545 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & -3.27 & -0.05 & 6 & 0 & 3.27 & 0 & 0 & 0 \\ 0 & 0 & 0 & -3.333 & 3.333 & 0 & 0 & 0 & 0 \\ 0 & 0 & -5.208 & 0 & -12.5 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 \\ 0 & -3.27 & 0 & 0 & 0 & 3.27 & -0.05 & 6 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & -3.333 & 3.333 \\ 0 & 0 & 0 & 0 & 0 & 0 & -5.208 & 0 & -12.5 \end{pmatrix}$$

$$B^T = \begin{pmatrix} 0 & 0 & 0 & 0 & 12.5 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 12.5 \end{pmatrix}$$

Feedback gains

$$F = \begin{pmatrix} 1 & 0.425 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ -1 & 0 & 0 & 0 & 0 & 0.425 & 0 & 0 & 0 \end{pmatrix}$$

Net interchange = -0.0052 pu MW

Time deviation in area 1 = -0.00019 sec

Time deviation in area 2 = -0.00020 sec

Fig. 5. System data for conventional automatic generation control.

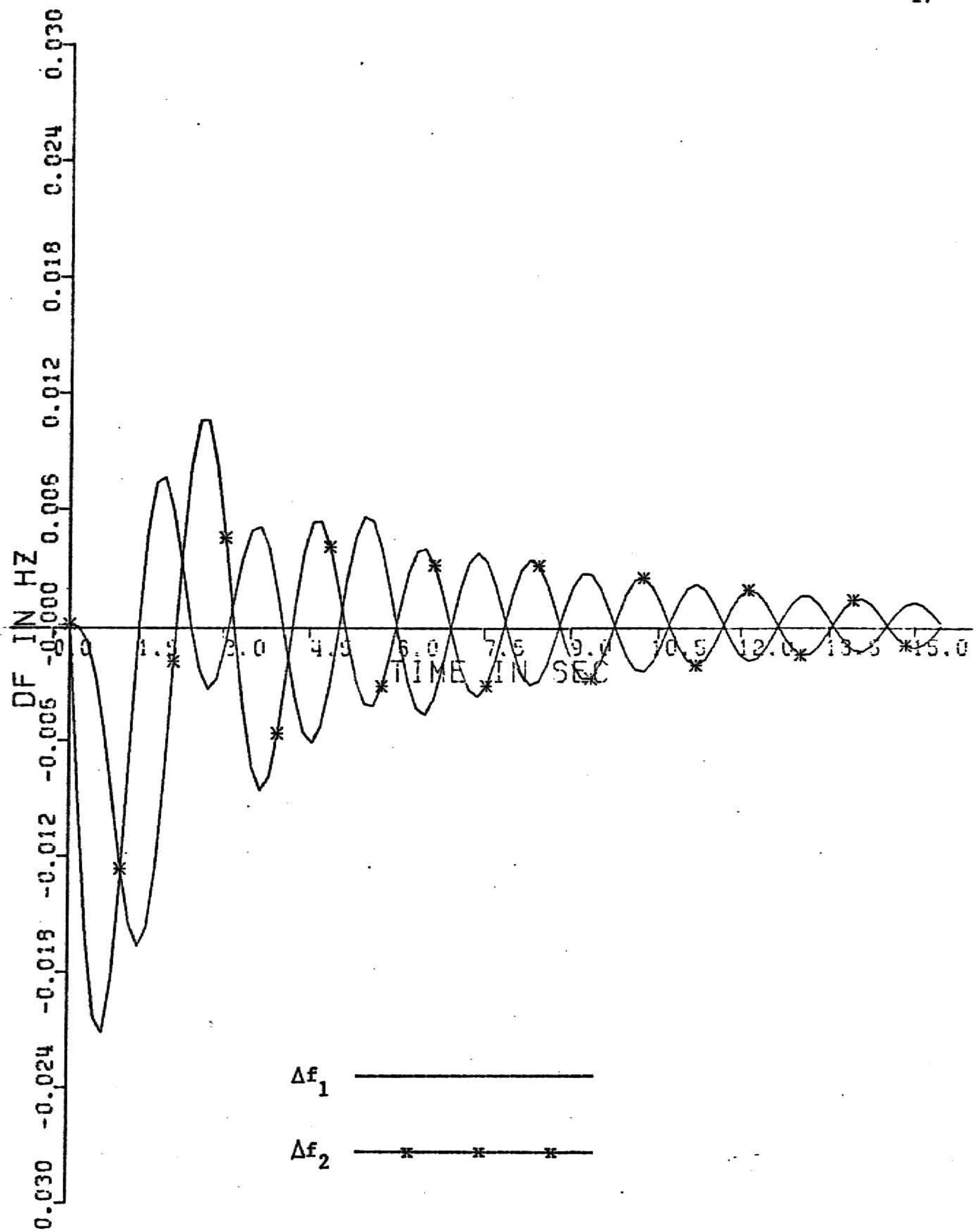

Fig. 6. Frequency deviations of conventional AGC.

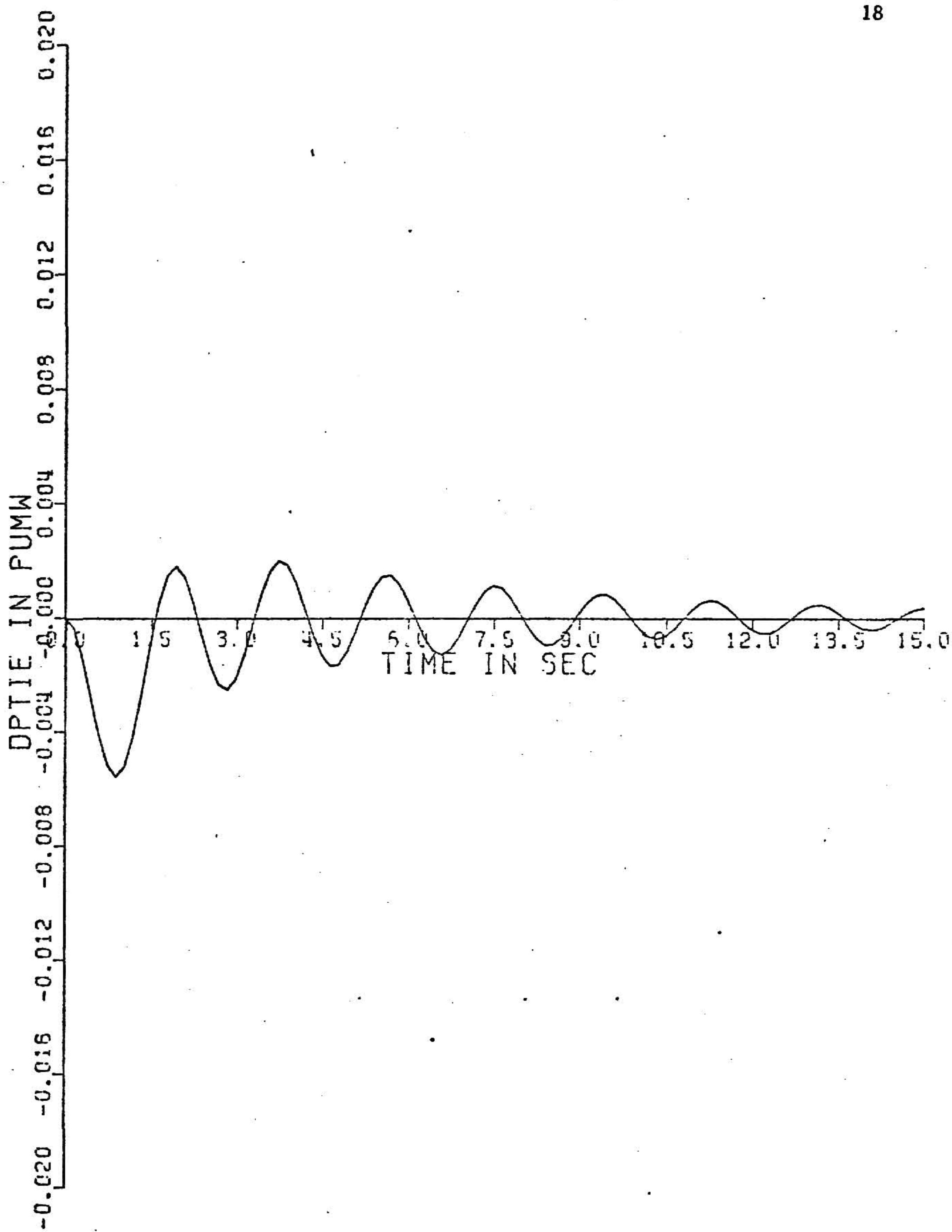

Fig. 7. Tie line deviation of conventional AGC.

Since any type of deterministic disturbance can be expressed as a superposition of step functions, and the system is assumed to be linear, the response following any disturbance will also be a superposition of the response to step disturbances. This fact justifies studying system behavior in terms of the system response to a step disturbance.

Comments on the Choice of Frequency Bias

As recommended by NAPSIC and presently used in electric utility industry, frequency bias is chosen to be equal to AFRC [9].

If the integral of squared error (ISE) criterion is chosen as a measure for the quality of transient response, the objective is then to look for the optimum value of K_i and B_i to minimize the function value C defined by

$$
\begin{aligned}
C &= C\,(K_i,\ B_i) \\
&= \int_0^\infty (\Delta P_{tie}^2 + \alpha \Delta f_i^2)dt
\end{aligned}
\tag{8}
$$

where the parameter α in (8) is a weighting factor which determines the relative penalty attached to the tie-line power error and frequency error respectively. It was shown [17] that the optimum value of B_i is less than AFRC.

System equation (5) can be further expressed as

$$
\dot{X} = AX \tag{9}
$$

since u' is the linear combination of the state variables. From the Liapunov theorem for linear systems, the equilibrium state X(0) of the system (9) is asymptotically stable if and only if given any symmetric, positive-definite matrix Q, there exists a symmetric, positive definite matrix P which is the unique solution of the set of $n(n+1)/2$ linear equations

$$A^tP + PA = -Q \tag{10}$$

Taking Q in equation (10) to be a unit matrix and differentiating with respect to any control variable ν, then

$$A^t\frac{\partial P}{\partial \nu} + \frac{\partial P}{\partial \nu} A = -D$$

where

$$D = \frac{\partial A^t}{\partial \nu} P + P\frac{\partial A}{\partial \nu}$$

The sensitivity of T with respect to the control variable ν is given by [18]

$$S_\nu^T = \frac{\partial T}{\partial \nu}$$

$$= Y^T\frac{\partial P}{\partial \nu}Y$$

where Y is the eigenvector of P corresponding to the eigenvalue T and T is the largest eigenvalue of P. According to this sensitivity analysis [15], it was shown that frequency biases should be chosen to be less than their AFRC so as to correspond to the zero-crossing of the sensitivity measures, i.e., $S_{B_i}^T \simeq 0$. However, B_i can be chosen equal to $AFRC_i$ without significant deterioration in system transient response. This is due to the fact that the dynamic response measure is not overly sensitive in the vicinity of near-zero crossing. But selection of B_i much in excess of $AFRC_i$ leads to oscillatory transient response.

ADVANCED AUTOMATIC GENERATION CONTROL

In the advanced automatic generation control strategy [1], the controller, ΔP_{ci}, is the linear combination of all the state variables in the interconnected system rather than being the integral of ACE only.

$$U = \begin{pmatrix} \Delta P_{c1} \\ \vdots \\ \Delta P_{ci} \\ \vdots \\ \Delta P_{cn} \end{pmatrix} = KX$$

where X is the state vector and K is the feedback gain matrix obtained by optimal linear regulator theory to minimize the performance index. For the two-area, two-source system, in order to meet the requirements stated in Chapter I, the performance index is defined as

$$J = \int_0^\infty [(\Delta f_1)^2 + (\Delta f_2)^2 + (\Delta P_{tie1})^2 + (\int \Delta f_1 dt)^2 + (\int \Delta f_2 dt)^2 + (\Delta P_{c1})^2 + (\Delta P_{c2})^2]\, dt$$

According to the model used in this thesis, the matrices Q and R are defined as

$$Q = \begin{pmatrix} 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & T_{12}{*}^2+1 & 0 & 0 & -T_{12}{*}^2 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & -T_{12}{*}^2 & 0 & 0 & T_{12}{*}^2+1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \end{pmatrix}$$

$$R = \begin{pmatrix} 1 & 0 \\ 0 & 1 \end{pmatrix}$$

A discussion of optimal linear regulator theory and related numerical solution techniques are given in Appendices A, B, and C.

Some features of advanced automatic generation control are as follows:

1. The control law is defined to be a linear combination of the state variables. The constituents of this linear combination are independent of the disturbance.
2. Each area regulates its own load fluctuation (if possible).
3. Each area contributes to the control of system frequency.
4. In the steady state, frequency and tie-line power are returned to schedule in all areas.
5. The transient frequency oscillations (swings) are reduced without a large increase in magnitude and speed of control.
6. The number of AGC signals sent to the plants is reduced without compromising other AGC objectives.

Simulation - Two-Area, Two-Source System

For the given Q and R, the feedback gain matrix is obtained by solving the matrix Riccati equation. The system data and response when subjected to a 0.01 puMW disturbance in demand in area 1 are shown in Figures 8, 9, and 10. Compared with Figures 6 and 7, the following improvements in performances are observed:

1. The maximum peaks of frequency deviations are reduced.
2. The frequency deviations are less oscillatory.
3. The tie-line power oscillation decays to zero at a faster rate.

But the mechanical power is required to develop at a faster rate. This fact may become a disadvantage of the strategy if the rate of generation change exceeds the machine limits. This circumstance will be discussed later on and

A, B are the same as those in figure 2-a

$$Q = \begin{pmatrix} 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 1.297 & 0 & 0 & 0 & -0.297 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & -0.297 & 0 & 0 & 0 & 1.297 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \end{pmatrix}$$

$$R = \begin{pmatrix} 1 & 0 \\ 0 & 1 \end{pmatrix}$$

Feedback Gains

$$F = \begin{bmatrix} 0.707 & 0.300 & 0.932 & 1.28 & 0.296 & 0.701 & 0.064 & 0.03 & 0.006 \\ -0.707 & 0.701 & 0.064 & 0.03 & 0.006 & 0.300 & 0.932 & 1.28 & 0.296 \end{bmatrix}$$

Net interchange = -0.01794 pu Mw

Time deviation in area 1 = 0.00022 sec

Time deviation in area 2 = 0.00022 sec

Maximum rate of change of generation in area 1 = 0.022 pu MW/sec

Fig. 8. System data for advanced automatic generation control.

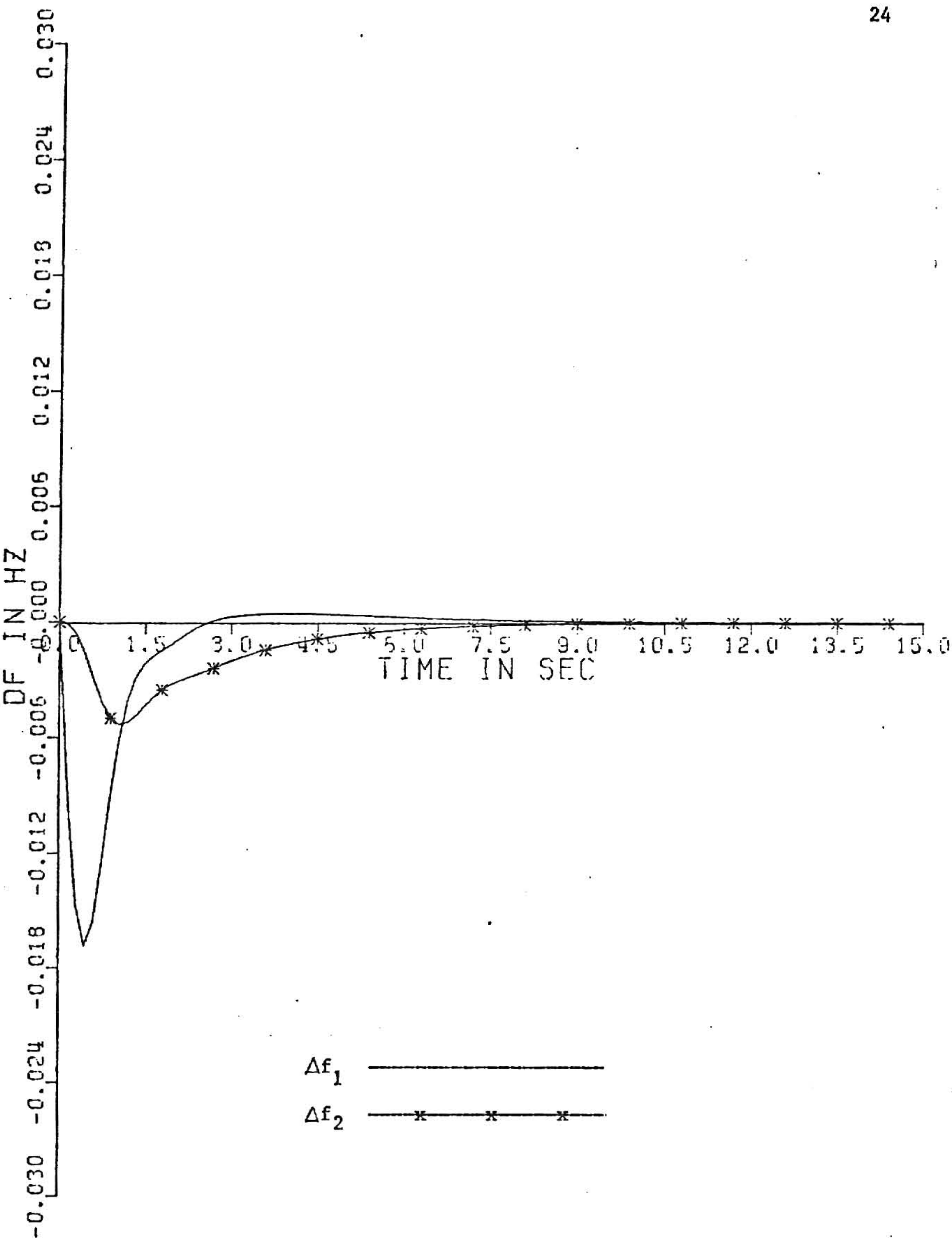

Fig. 9. Frequency deviations of advanced AGC.

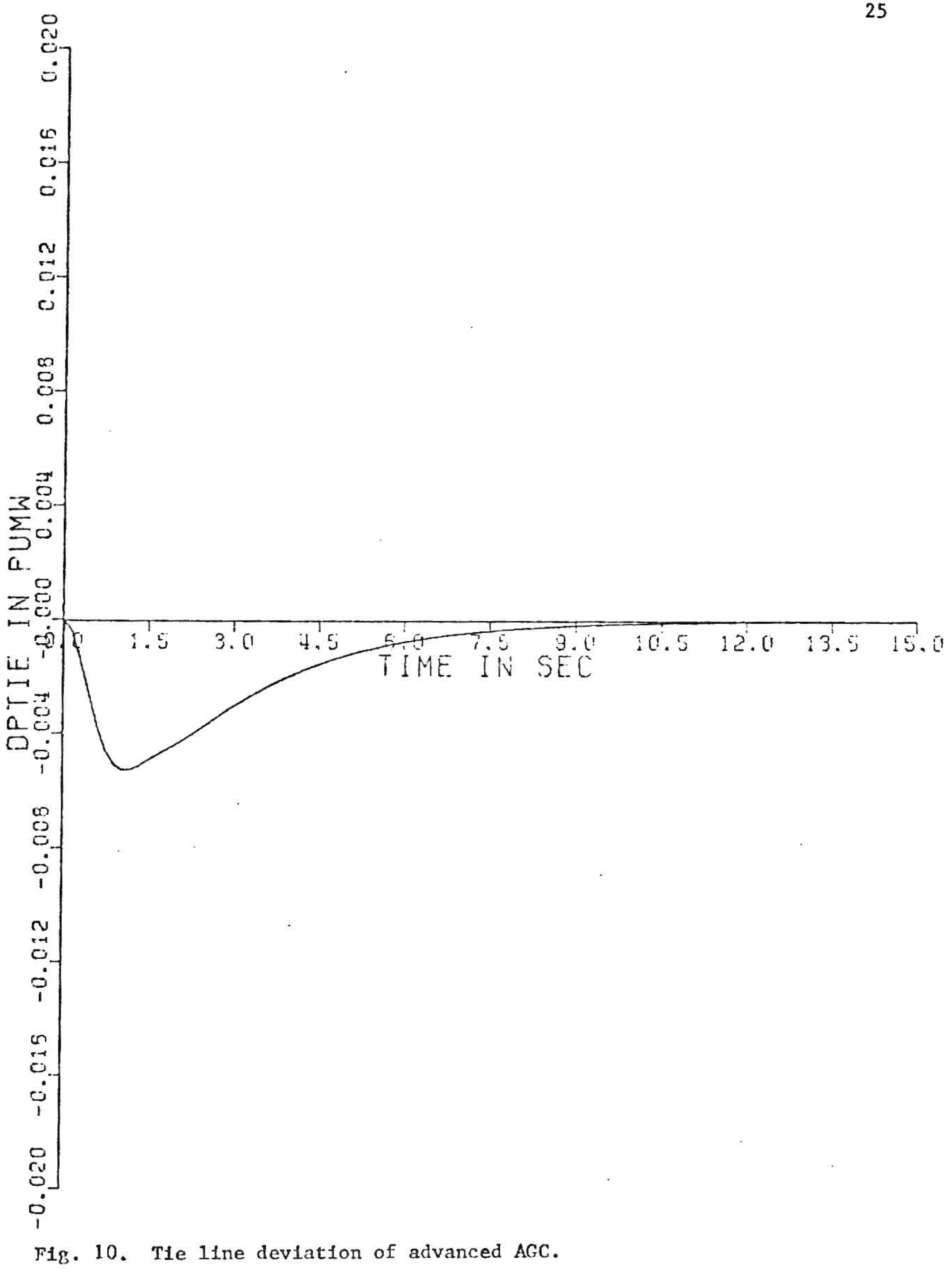

Fig. 10. Tie line deviation of advanced AGC.

referred to as a kind of abnormal condition. Also, the advanced controller requires information about total state of the system, and when an actual interconnected power system such as the coast-to-coast network that encompasses most of the United States and part of Canada, is considered, the dimension of the system is so great that it becomes practically impossible to obtain the optimal feedback controller by solving the matrix Riccati equation. Also, one is required to design very complicated and expensive communication systems for information transmission. The applicability of this scheme is thus severely limited by its complexity and cost.

Selected State Variable Feedback Controller

Since not all the state variables are measurable, the practicality of the advanced controller is questionable with respect to physical implementation, and thus a more practical realization including only selected state variables has been explored.

For a linear system characterized by the set of state equations and output equations

$$\dot{X}(t) = AX(t) + Bu(t)$$

$$Y(t) = CX(t)$$

where the output vector Y(t) is a r x 1 vector (r is less than or equal to the dimension n of the system) consisting of measurable state variables. It is then desired to select u(t) to minimize the infinite time quadratic performance index

$$J = \int_0^\infty (X^T(t)QX(t) + u^T(t)Ru^T(t))dt \qquad (11)$$

The process involves finding a matrix F which satisfies

$$u(t) = - FY(t)$$
$$= - FCX(t) \tag{12}$$

and minimizes J [19, 20].

One proposed controller of this sort is a configuration using the frequency, the net power interchange, and the integral of the ACE (IACE) [4]. In that case the system dynamic model is slightly different from that described before, that is

$$\frac{2H_i}{f^*} \frac{d}{dt} \Delta f_i + D_i \Delta f_i + \Delta P_{tie\ i} = \Delta P_{gi} - \Delta P_{di}$$

$$\frac{d}{dt} \Delta P_{gi} = - \frac{1}{T_{ti}} \Delta P_{gi} + \frac{1}{T_{ti}} \Delta X_{gvi}$$

$$\frac{d}{dt} \Delta X_{gvi} = - \frac{1}{T_{gvi}} - \frac{1}{T_{gvi} R_i} \Delta f_i + \frac{1}{T_{gvi}} \Delta P_{ci} \tag{13}$$

$$\frac{d}{dt} \Delta P_{tie\ i} = \sum_{\nu} T_{i\nu}^* (\int \Delta f_i dt - \int \Delta f_\nu dt)$$

$$\frac{d}{dt} IACE_i = B_i \Delta f_i + \Delta P_{tie\ i}$$

Consdiering a single area to an infinite bus system, the performance index is chosen as

$$J = \int_0^\infty (aACE_i^2 + bIACE_i^2 + c(\Delta X_{gvi} - \Delta P_{gi})^2 + \Delta P_{ci}^2) dt$$

where the term $c(\Delta X_{gvi} - \Delta P_{gi})^2$ is the penalty term that penalizes large rates of generation changes.

In the notation of equation (12), we have

$$Q = \begin{pmatrix} ab^2 & 0 & 0 & -ab^2 & 0 \\ 0 & \frac{c}{T_{ti}} & -\frac{c}{T_{ti}} & 0 & 0 \\ 0 & -\frac{c}{T_{ti}} & \frac{c}{T_{ti}} & 0 & 0 \\ 0 & 0 & 0 & a & 0 \\ 0 & 0 & 0 & 0 & b \end{pmatrix}$$

$R = [1]$

$X = [\Delta f_i \ \Delta X_{gvi} \ \Delta P_{gi} \ \Delta P_{tie} \ IACE_i]$

Relative weighting of the state variables is obtained by chaning the parameters a, b, and c.

Comparing the area control error with that of all state variable feedback controller, the simulation study [4] has shown that selected state variable feedback controller only slightly degrades the response, but it reduces the complexity of state estimation problem.

As implementation is considered for a real interconnected system, the dimension of which is so great that the numerical computation of the feedback gain matrix F in equation (12) may become impossible [20], and thus the difficulty in obtaining the feedback gains still exists as was the case for the all state feedback control strategy.

All the simulations in this chapter are based on a continuous-time system model and optimization techniques. This can also be done for discrete-time models [11, 13]. A single source was assumed for each area. This source can be regarded as an equivalent energy source because a real power system has more than one source. These responses can also be obtained by simulating more complicated system dynamics which includes more than one source and reheat turbine generator [11, 12, 13].

CHAPTER III

DECENTRALIZED OPTIMAL AUTOMATIC GENERATION CONTROL

In the previous discussion of the all state variable feedback controller, the optimal controller (incremental change in speed-changer position) is a linear combination of all the state variables in the entire interconnected system. It is impractical for the controller in each area to obtain information about the state variables in all other areas in the system. Furthermore, there may be as many as several thousand state variables in a large interconnected power system and the resulting model becomes so complicated that it is presently not numerically possible to obtain the optimal feedback controller parameters based on optimal linear regulator theory by solving the matrix Riccati equation. Its application in system design is thus severely limited by the capacity of computers being used during the design process. Even for the selected state variable feedback controller, the difficulty arising from the numerical solution of matrix Riccati equation still exists. Thus it is desirable to search for some kind of suboptimal control strategy in which only the local state variables are fedback in each area and it is only necessary to solve the linear regulator problem based on an approximate model of one area. The effect of the tie-line interconnections must be approximated in this model if such a method is to be used. One of these methods is described as follows:

Let each control area of an interconnected power system be a subsystem indexed by $i = 1,2,\ldots,n$. The coupled dynamics of each area (subsystem) is described by the following equations, [2]:

$$\dot{X}_1 = A_{11}X_1 + \sum_{k=2}^{n} A_{1k}X_k + B_1u_1$$

$$\dot{X}_2 = A_{22}X_2 + \sum_{\substack{k=1 \\ k\neq 2}}^{n} A_{2k}X_k + B_2u_2$$

$$\vdots$$

$$\dot{X}_i = A_{ii}X_i + \sum_{\substack{k=1 \\ k\neq i}}^{n} A_{ik}X_k + B_iu_i$$

$$\vdots$$

$$\dot{X}_n = A_{nn}X_n + \sum_{k=1}^{n-1} A_{nk}X_k + B_nu_n$$

where the second terms on the right side are the terms which express the dependence of the subsystem on the other subsystems of the whole interconnected system due to coupling; X_i is the state vector consisting of state variables of the i-th area; u_i is a scalar input in the i-th area.

The decentralized control strategy is obtained by modifying the matrix A_{ii} so as to include the coupling effect in it, i.e.,

$$\dot{X}_i = A'_{ii}X_i + B_iu_i$$

where the terms $\sum_{\substack{k=1 \\ k\neq i}}^{n} A_{ik}X_i$ are approximated in A'_{ii}. In this way, the optimal feedback control, u_i, depends only on the state variables of the i-th subsystem itself. The performance index in area i is

$$J_i = \int_0^\infty (X_i^T Q X_i + a u_i^2)dt$$

where a is a real positive constant and Q is a positive semidefinite matrix.

The system dynamic response in area i is described by equations (1), (2), (3) and (4). The coupling between control areas in the interconnected system appears in the tie line flow deviation terms which are expressed as

$$\Delta P_{tie\ i} = \sum_{\substack{\nu \\ \nu \neq i}}^{n} T^*_{i\nu} \left(\int \Delta f_i dt - \int \Delta f_\nu dt\right)$$

One basic property of interconnected power systems is the coherence of their frequency, i.e., the frequencies in all the areas are nearly the same, so we define a function $\psi_\nu(t)$ for area ν such that

$$\int \Delta f_\nu dt = \psi_\nu(t) \int \Delta f_i dt$$

$\psi_\nu(t)$ is a time varying function whose form depends upon the disturbance, however it is known that $\psi_\nu(t) = 1$ in the steady state when all control areas have adequate generation to meet their own demand deviations (referred to as the normal case in this paper).

Substituting the expression for $\int \Delta f_\nu dt$ into the expression for $\Delta P_{tie\ i}$

$$\begin{aligned} \Delta P_{tie\ i} &= \sum_\nu T^*_{i\nu} \left(\int \Delta f_i dt - \psi_\nu(t) \int \Delta f_i dt\right) \\ &= \sum_\nu (1 - \psi_\nu(t))\, T^*_{i\nu} \left(\int \Delta f_i dt\right) \\ &= \sum_\nu \alpha_\nu(t)\, T^*_{i\nu} \int \Delta f_i dt \end{aligned}$$

$\alpha_\nu(t) = 1 - \psi_\nu(t)$ is also a time varying function. By this approximation, each area is then decoupled from the rest of the system. In order to apply conventional optimal linear regulator theory, we have to assume $\alpha_\nu(t)$ to be a non-zero constant, α_ν. This approximation is reasonably accurate only in the transient state. In the steady state, α_ν is a zero for the normal case. The optimal controller thus obtained, which is a linear combination of the state variables of the local area, can reduce transient frequency and tie line flow deviations. The state equation for area i becomes

$$\dot{X}_i = A_{ii}X_i + B_i u_i + \Gamma_i \Delta P_{di}$$

where

$$A_{ii} = \begin{pmatrix} 0 & \sum_\nu \alpha_\nu T^*_{i\nu} & 0 & 0 \\ 0 & 0 & 1 & 0 \\ 0 & -\sum_\nu \frac{\alpha_\nu f^* T^*_{i\nu}}{2H_i} & -\frac{f^* D_i}{2H_i} & 0 \\ 0 & 0 & -\frac{1}{T_{ti}} & \frac{1}{T_{ti}} \\ 0 & 0 & 0 & -\frac{1}{T_{gvi}} \end{pmatrix}$$

$$B_i = \begin{pmatrix} 0 \\ 0 \\ 0 \\ 0 \\ \frac{1}{T_{gvi}} \end{pmatrix}$$

$$\Gamma_i = \begin{pmatrix} 0 \\ 0 \\ -\frac{f^*}{2H_i} \\ 0 \\ 0 \end{pmatrix}$$

The design of the optimal feedback controller follows the same argument as that for the advanced automatic generation control strategy [1].

SIMULATION - TWO-AREA, TWO-SOURCE SYSTEM

The dynamic responses and system data of the two-area system previously discussed when subjected to a step disturbance in area 1 are shown in Figures 11, 12, 13 ($\alpha_1 = \alpha_2 = 0.3$) and Figures 15, 16, 17 ($\alpha_1 = \alpha_2 = 1$). A comparison of actual and assumed tie line flow is shown in Figure 14 ($\alpha_1 = \alpha_2 = 0.3$). As we can see, the approximation is not accurate in the steady state, but in the transient state, it is quite acceptable for design purposes. Comparing Figures 12 and 13 with Figures 9 and 10 we have shown that there is no substantial difference between advanced automatic generation control and the suboptimal strategy proposed, but the decentralized optimal automatic generation control has the advantage that only information about the state variables in one area is required for the implementation of each controller. Besides, the dimension of the subsystem is much less than that of the whole system and so less computational effort is needed to solve the linear regulator problem.

Comparing Figures 6 and 7 with Figures 13 and 14 shows that the suboptimal controller has a better damped transient response than the conventional controller. Both controllers will eliminate steady state errors in the normal case, as an integral feedback controller does.

Another advantage observed is that the frequency deviations in both areas return to the same value very fast before steady state is reached. In other words, the coherency of the frequency for the whole interconnected system is improved. This fact will be more obvious when one observes the system response under abnormal condition of generation deficiency. Under these circumstances, frequency deviations reach the same steady state errors much faster than those for other control strategies (See Chapter IV).

$$A = \begin{bmatrix} 0 & 0.164 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 & 0 \\ 0 & -0.981 & -0.05 & 6 & 0 \\ 0 & 0 & 0 & -3.333 & 3.333 \\ 0 & 0 & -5.208 & 0 & -12.5 \end{bmatrix}$$

$$B^T = \begin{pmatrix} 0 & 0 & 0 & 0 & 12.5 \end{pmatrix}$$

$$Q = \begin{bmatrix} 1 & 0 & 0 & 0 & 0 \\ 0 & 1 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix}$$

$$R = [1]$$

Feedback gains

$$F = [1 \quad 0.806 \quad 0.983 \quad 1.303 \quad 0.302]$$

Net interchange = -0.01296 pu MW

Time deviation in area 1 = 0.00027 sec

Time deviation in area 2 = 0.00027 sec

Maximum rate of change of generation in area 1 = 0.024 pu MW/sec

Fig. 11. System data for decentralized optimal automatic generation control when $\alpha_1 = \alpha_2 = 0.3$.

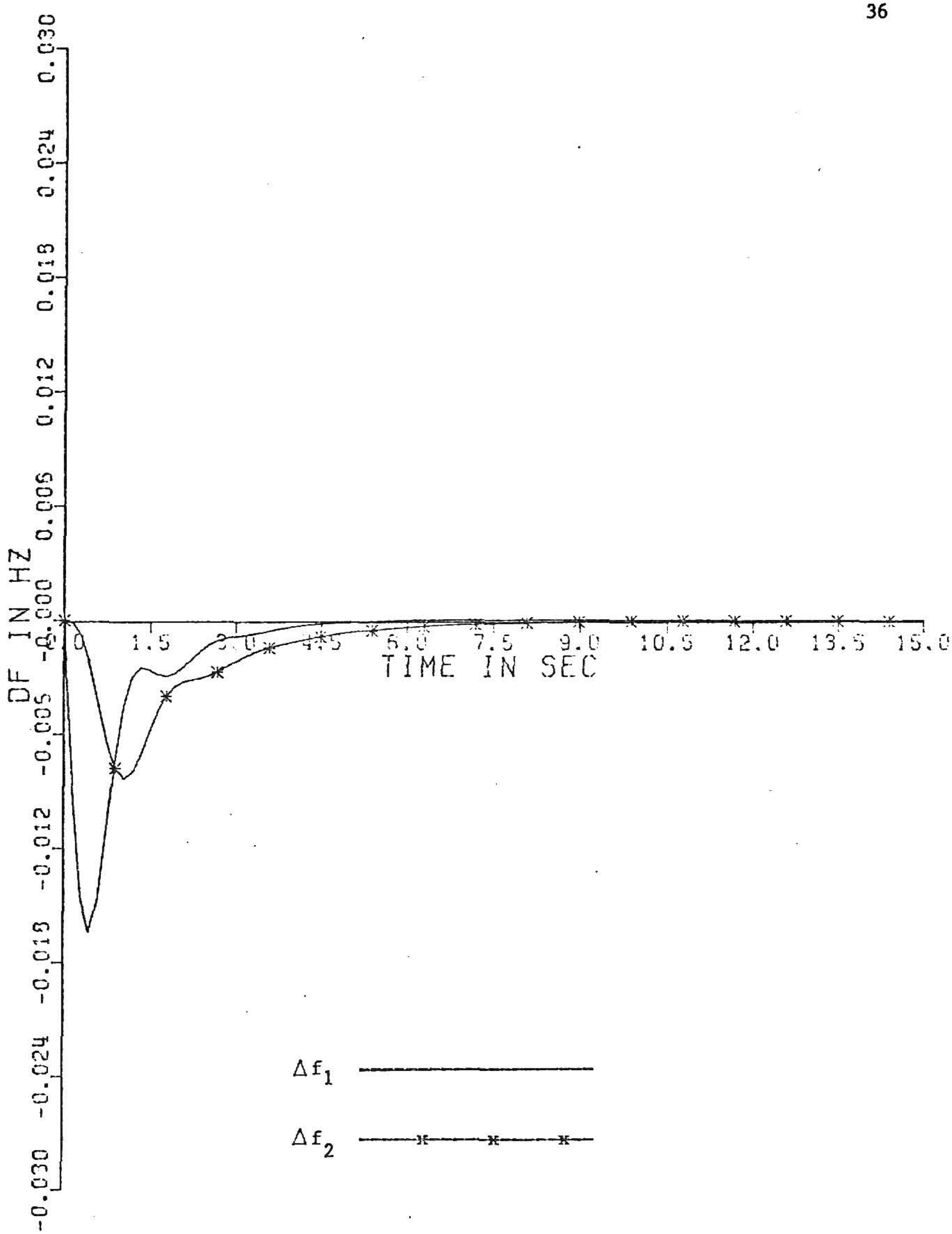

Fig. 12. Frequency deviations of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$.

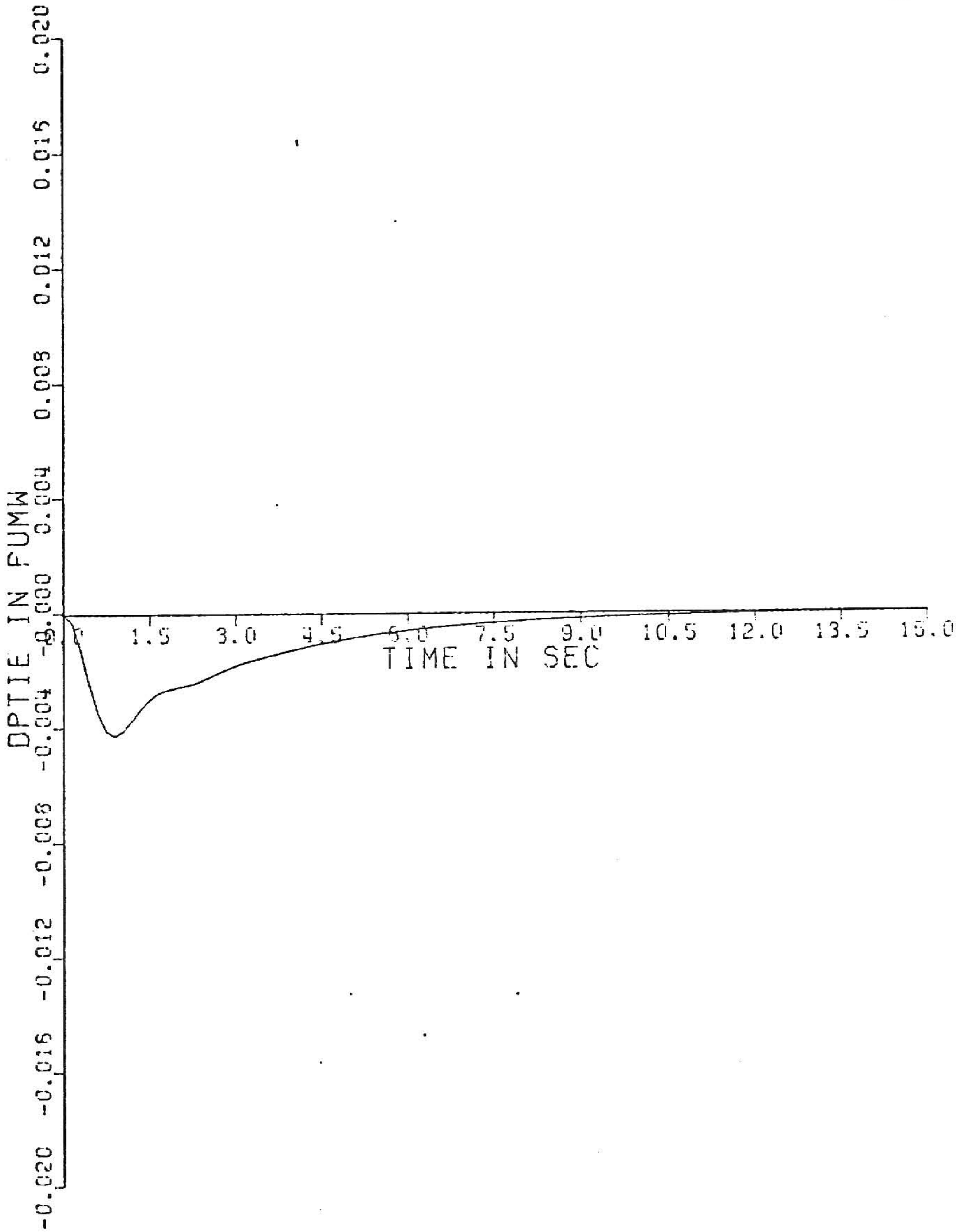

Fig. 13. Tie line deviation of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$.

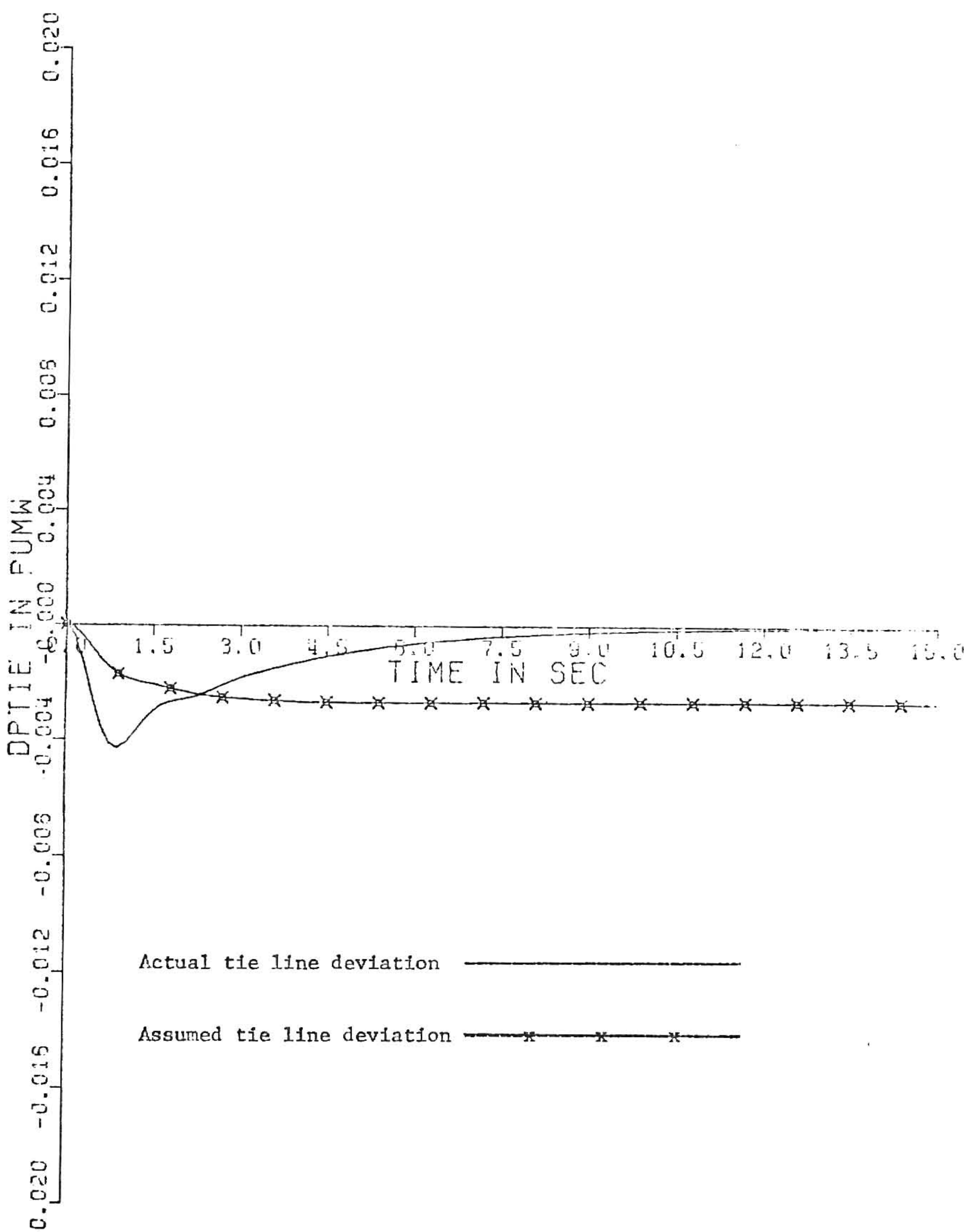

Fig.14. Comparison of actual and assumed tie line deviation for decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$.

$$A = \begin{bmatrix} 0 & 0.545 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 & 0 \\ 0 & -3.27 & -0.05 & 6 & 0 \\ 0 & 0 & 0 & -3.333 & 3.333 \\ 0 & 0 & -5.208 & 0 & -12.5 \end{bmatrix}$$

B, Q, R are the same as those in figure 4-a.

Feedback Gains

$$F = [1.000 \quad 0.346 \quad 0.945 \quad 1.288 \quad 0.299]$$

Net interchange = -0.01292 pu MW

Time deviation in area 1 = -0.00061 sec

Time deviation in area 2 = -0.00061 sec

Fig. 15. System data for decentralized optimal automatic generation control when $\alpha_1 = \alpha_2 = 1$.

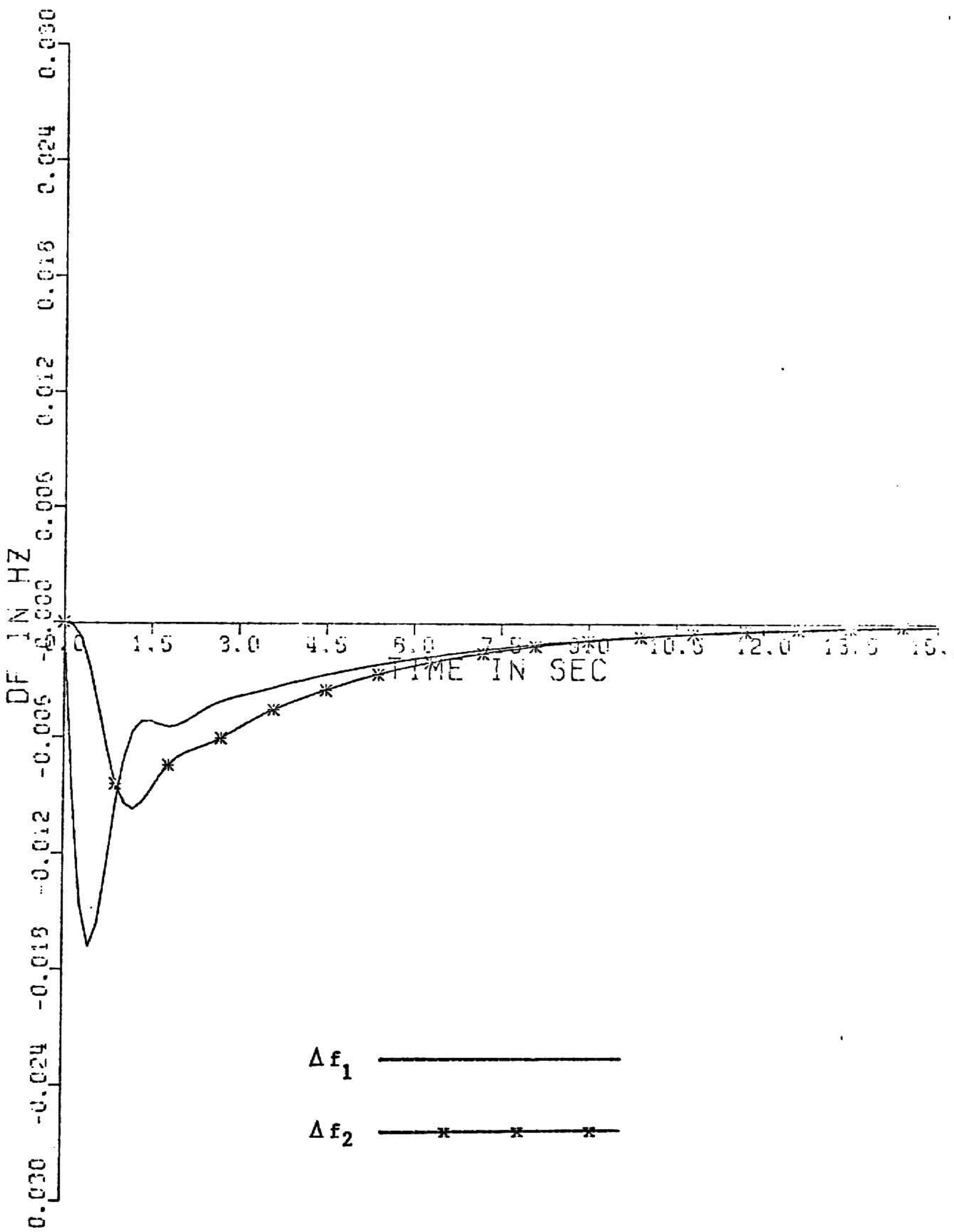

Fig. 16. Frequency deviations of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 1$.

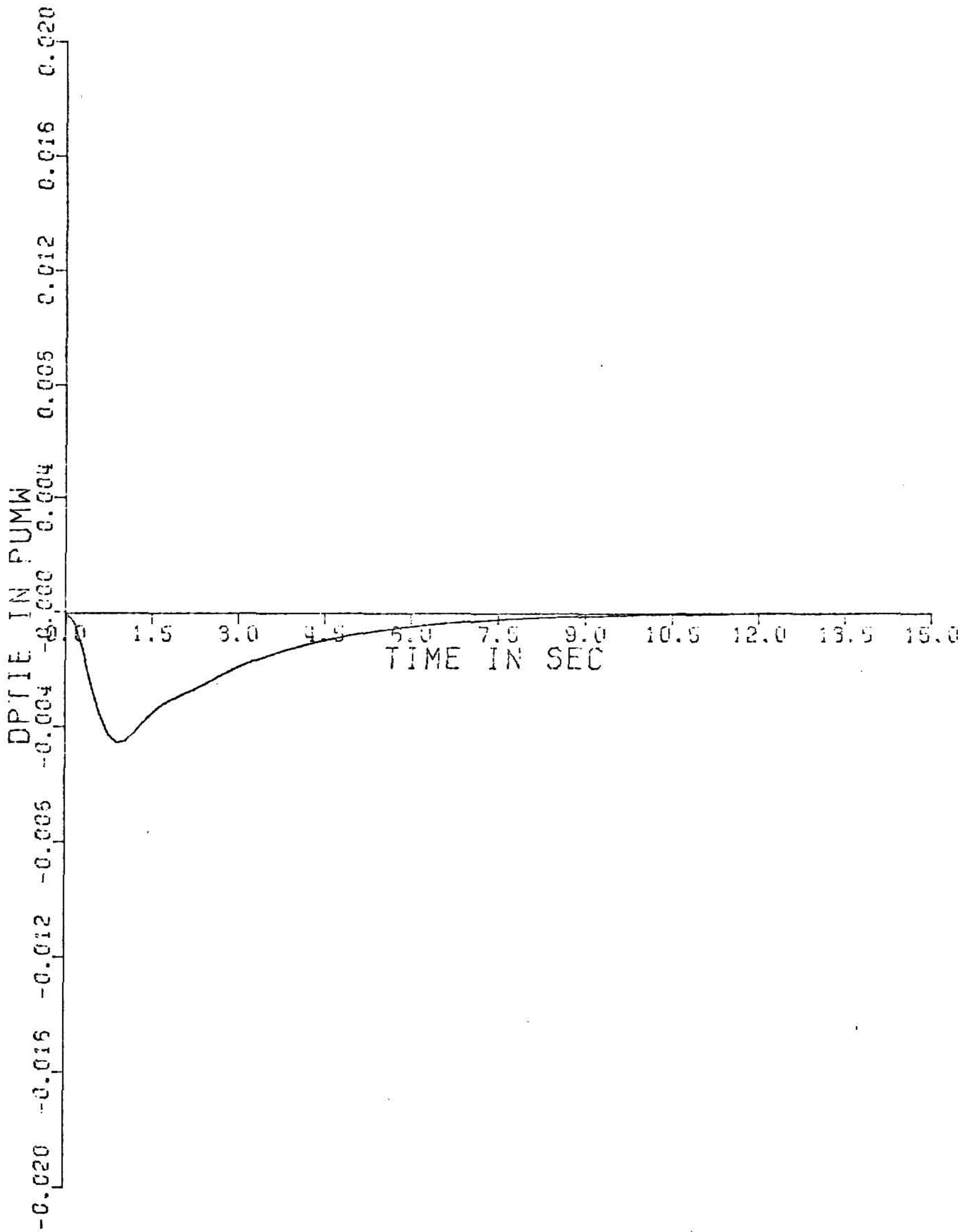

Fig. 17. Tie line deviation of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 1$.

CHAPTER IV

ANALYSIS OF SYSTEM RESPONSE UNDER ABNORMAL CONDITIONS

DEFICIENCY IN POWER GENERATION

When the area in which the load change occurs cannot adjust its generation fully to accomodate this change, i.e., the change of demand in that area exceeds its available generation capacity, the system operating objective is to permit the static frequency error to persist so that other areas can assist the area in need. The performance of the control strategy under this circumstance must be observed before its validity is confirmed.

The simulations of different controllers under this circumstance are shown in Figures 18, 19, 20, 21, 22, 23, 24, 25, and 26. Comparing these with Figures 6, 7, 9, 10, 12, and 13, we see that the static errors in both frequency and tie line flow deviation exist, and the generation change in area 1 can attain is 0.01 PuMW while a demand change of 0.015 PuMW occurs in area 1.

It is shown in these figures that the rate of change of frequency and tie line flow deviations of the decentralized controller is slower than that of conventional and advanced controller and the static errors in frequency deviations of the decentralized controller are greater than those of advanced controller but less than those of conventional controller. One is also interested in looking for some other control strategies which will minimize the static frequency errors, or even eliminate them, but permit static tie line flow errors to exist within certain limit under this abnormal condition.

HIGH RATE OF GENERATION CHANGE

Since the rate of generation change for advanced controller is usually

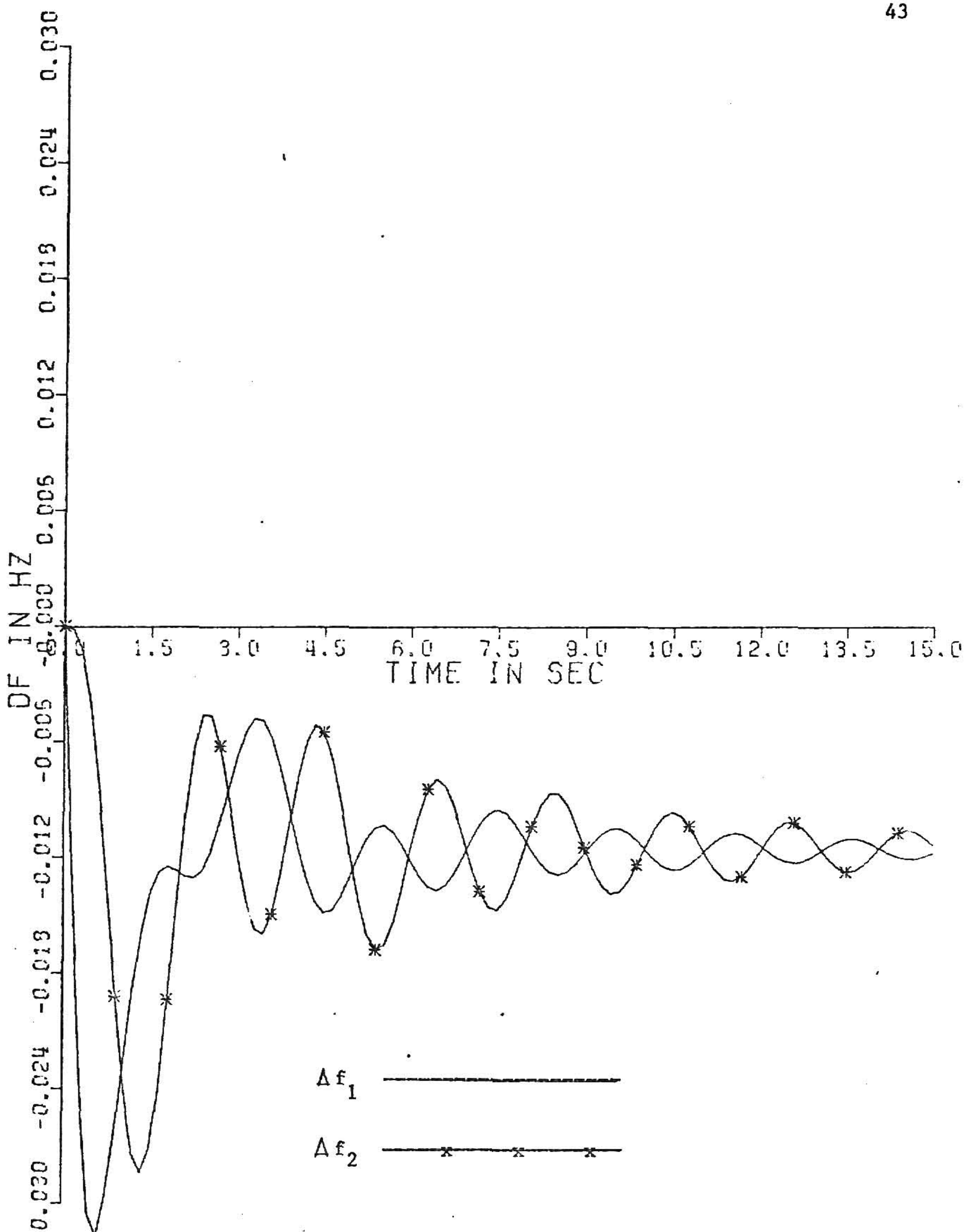

Fig. 18. Frequency deviations of conventional AGC under abnormal condition.

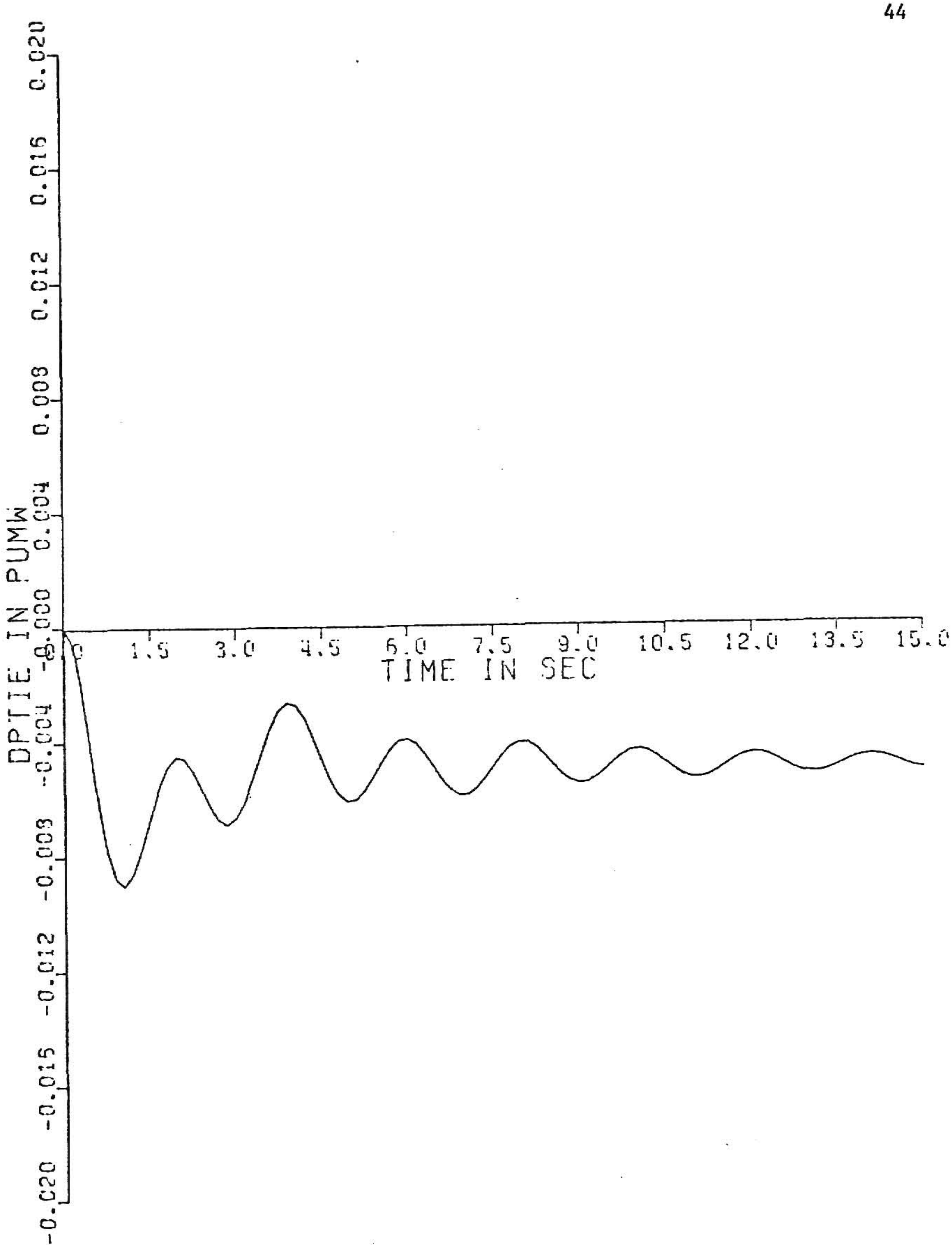

Fig. 19. Tie line deviation of conventional AGC under abnormal condition.

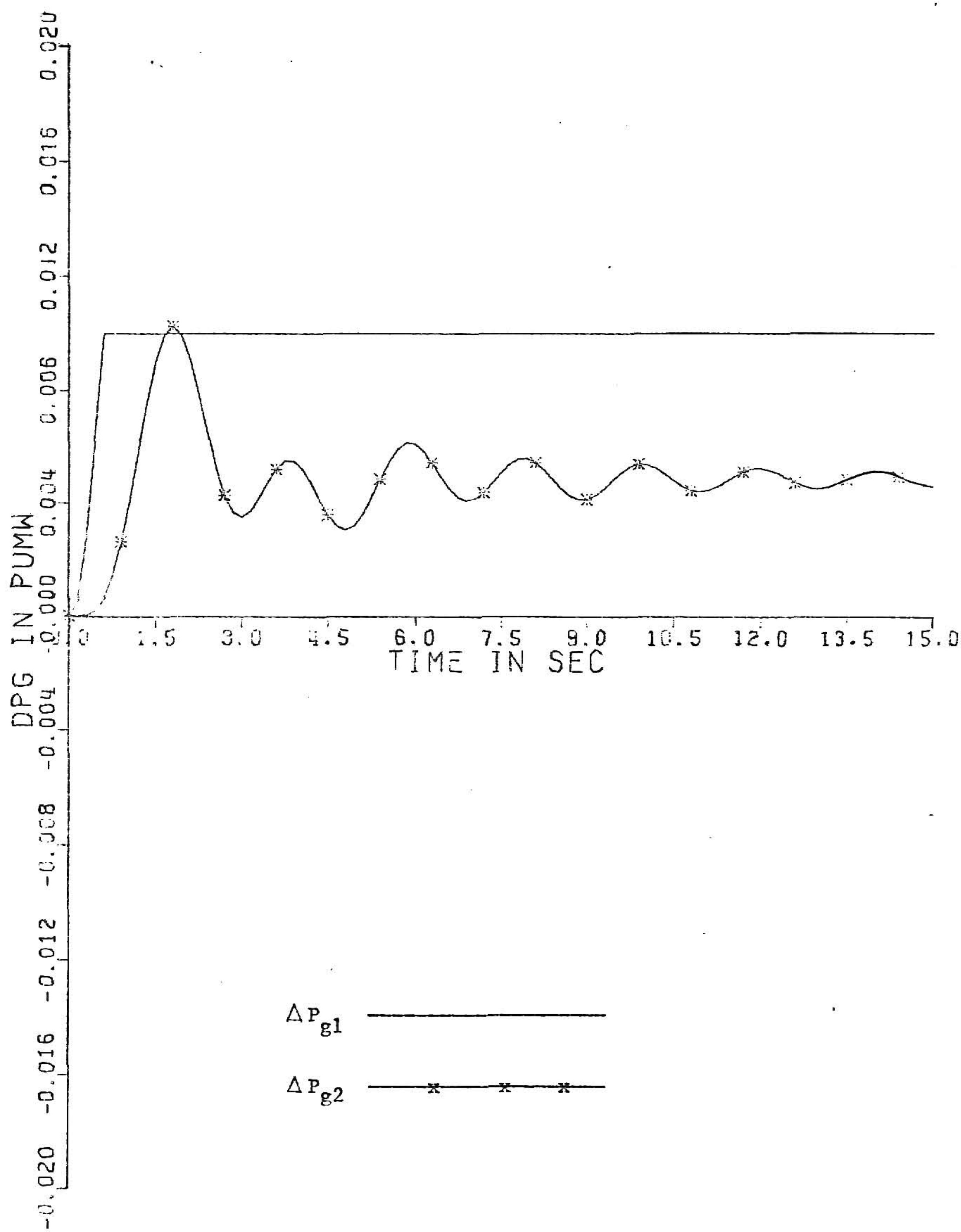

Fig. 20. Incremental generation change of conventional AGC under abnormal condition.

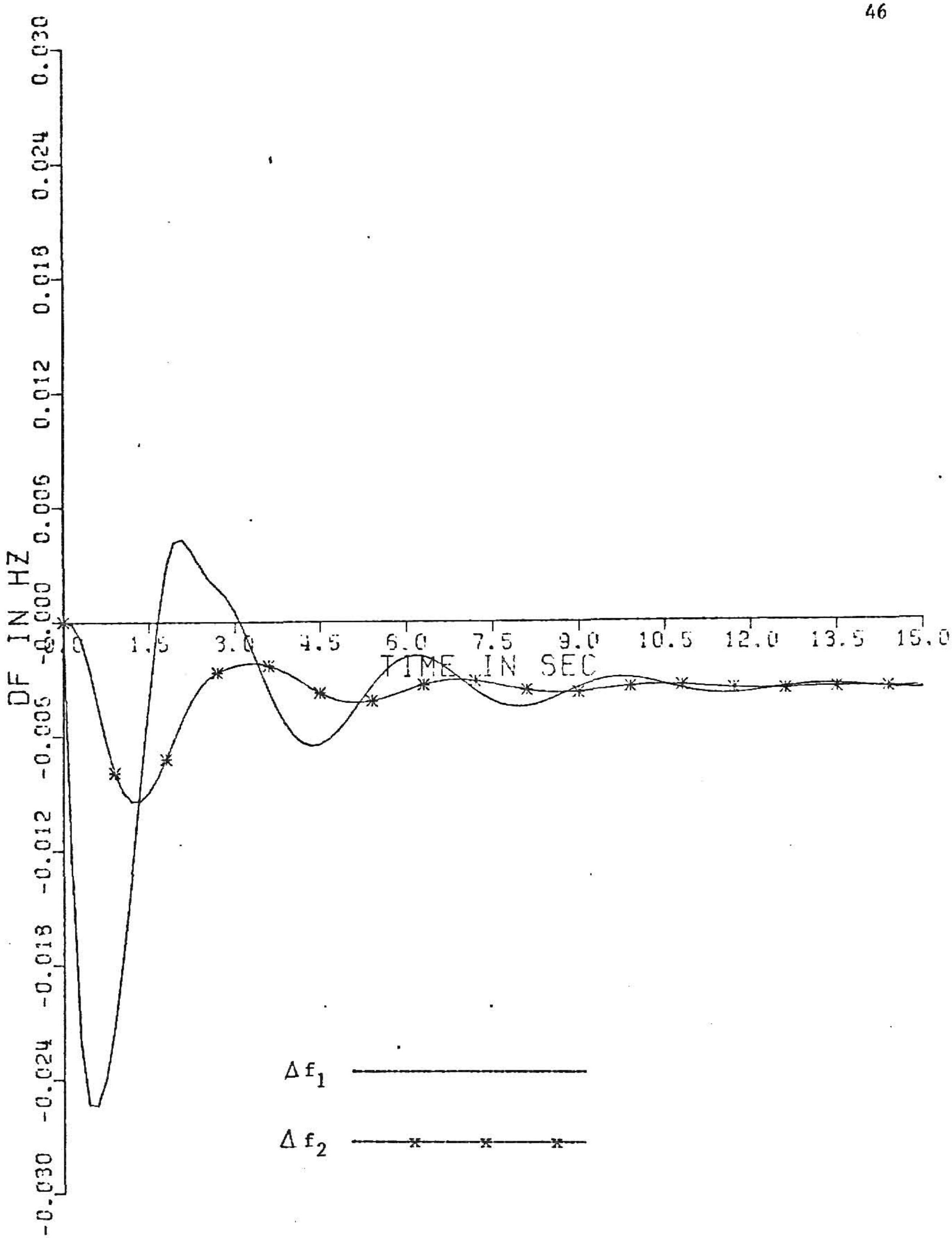

Fig. 21. Frequency deviations of advanced AGC under abnormal condition.

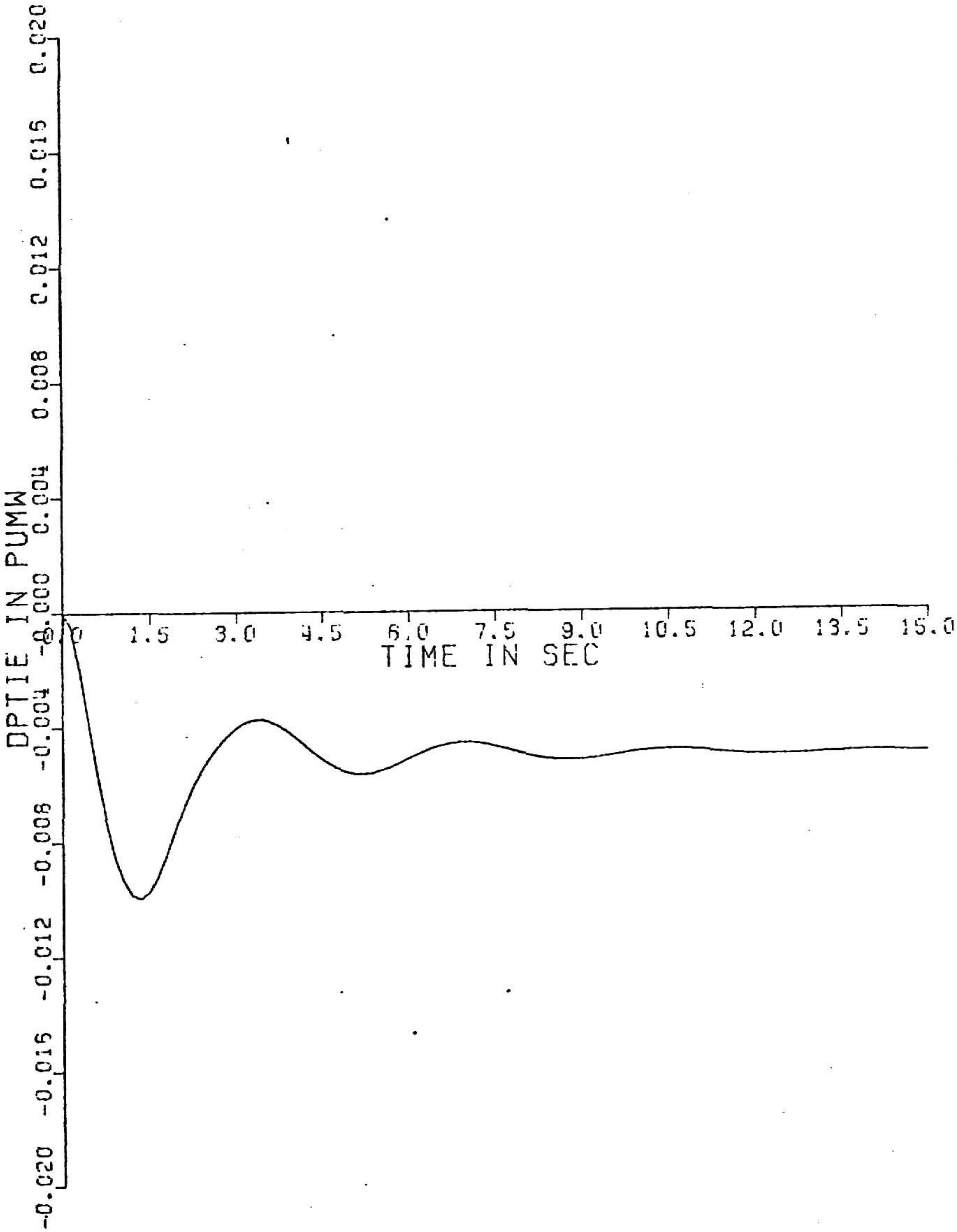

Fig. 22. Tie line deviation of advanced AGC under abnormal condition.

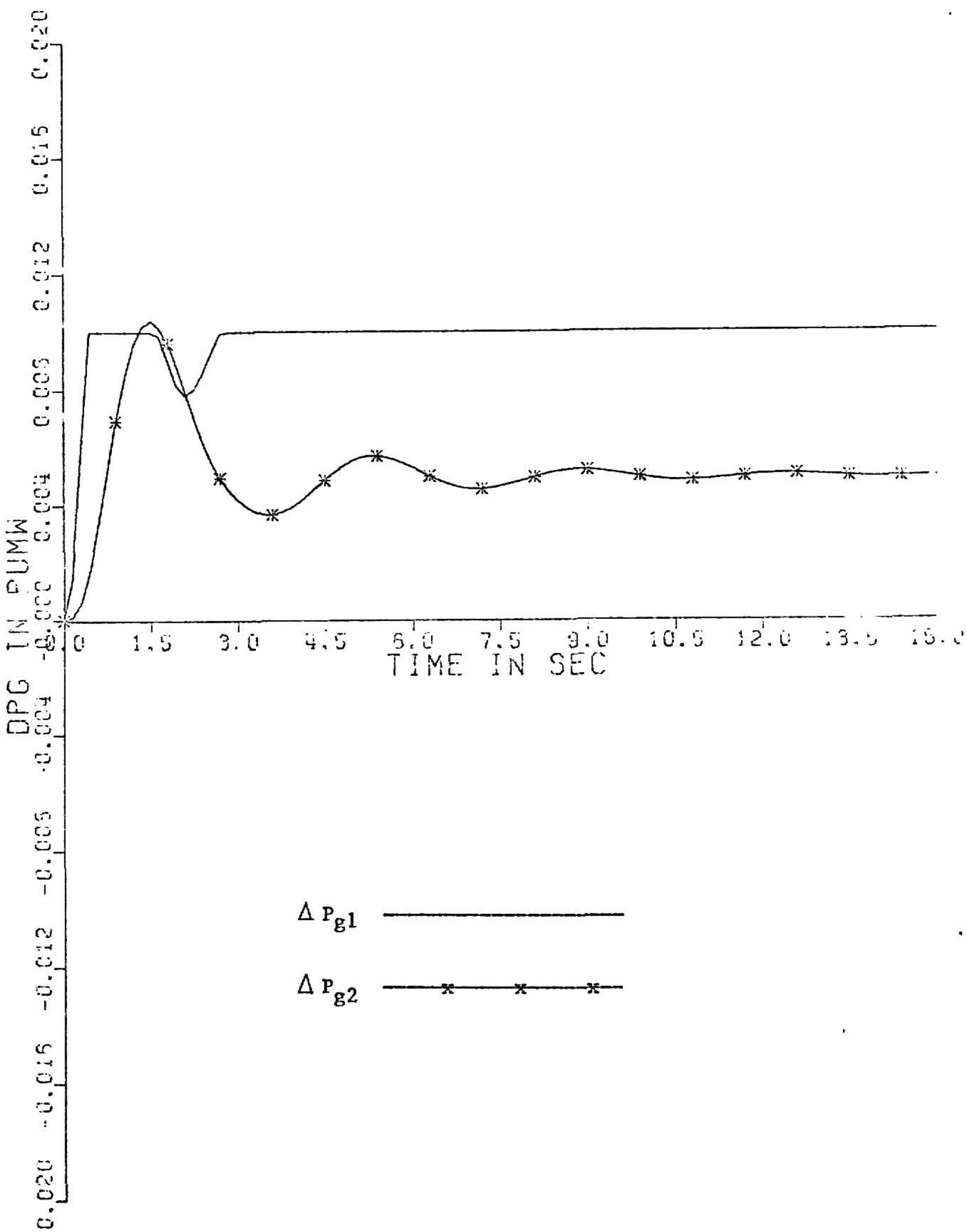

Fig. 23. Incremental generation change of advanced AGC under abnormal condition.

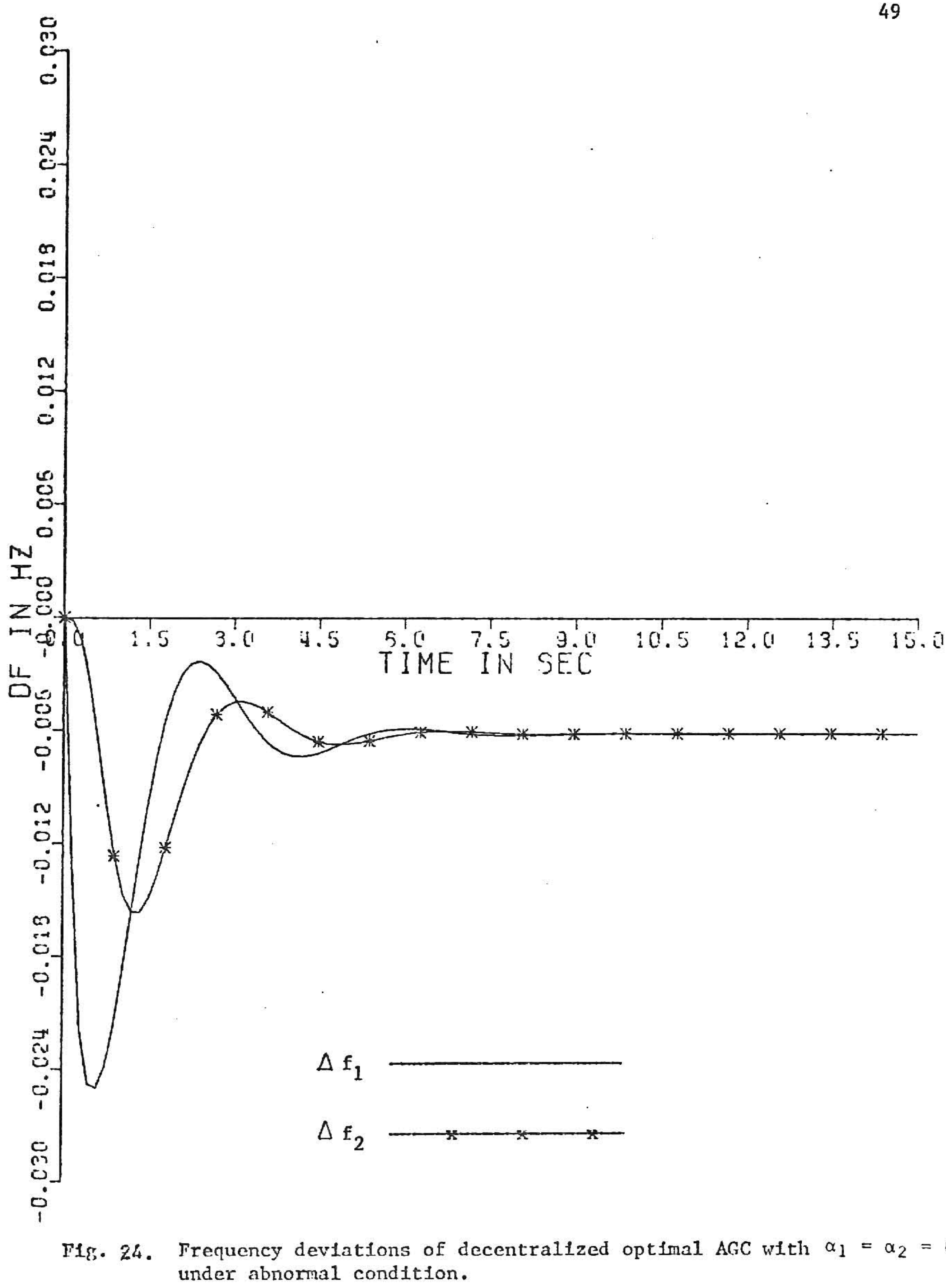

Fig. 24. Frequency deviations of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$. under abnormal condition.

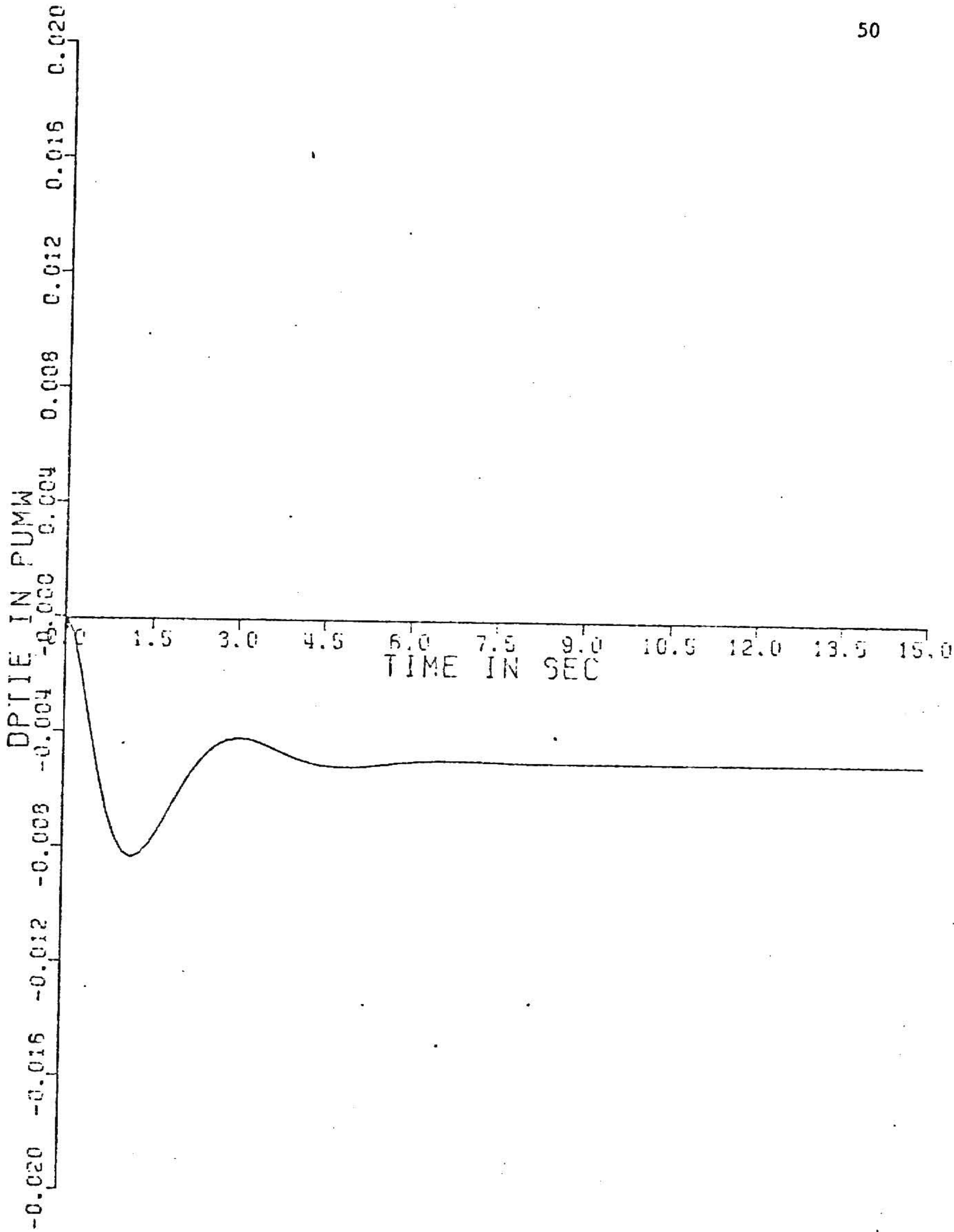

Fig. 25. Tie line deviation of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$. under abnormal condition.

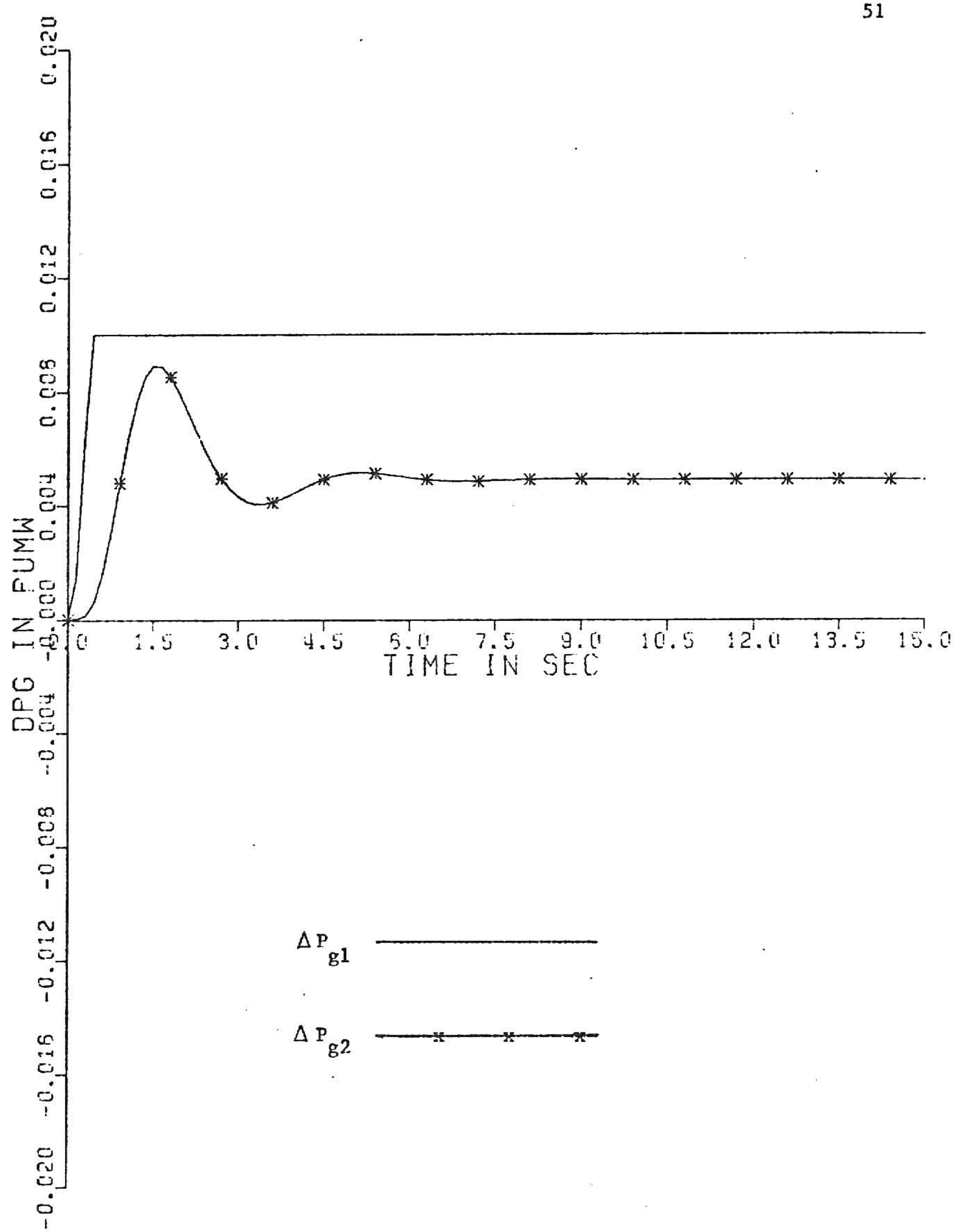

Fig. 26. Incremental generation change of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$ under abnormal condition.

greater than that of conventional controller as shown in Chapter II, the rate of generation change may exceed the limitations of the machine. In this case, the system cannot function properly. This is another kind of abnormal condition. The response of frequency and tie line flow deviations and incremental generation change are shown in Figures 27, 28, 29. In this simulation the maximum rate of generation change is limited to 0.02 PuMW/sec while the commanded rate of generation change reaches 0.024 PUMW/sec. Some authors have criticized the advanced controller for the fast rate of generation change [1], but it is shown here that even if it is limited by machine dynamics, the system response is still satisfactory.

One may also design another controller which has smaller commanded rate of generation change by including the minimization of rate of generation change in the performance index [4]. The maximum rate of generation change obtained by this strategy is reduced and the system data and response are as shown in Figures 30, 31, 32. It was pointed out that this result can also be achieved by decreasing the relative weighting between the states and the control [4].

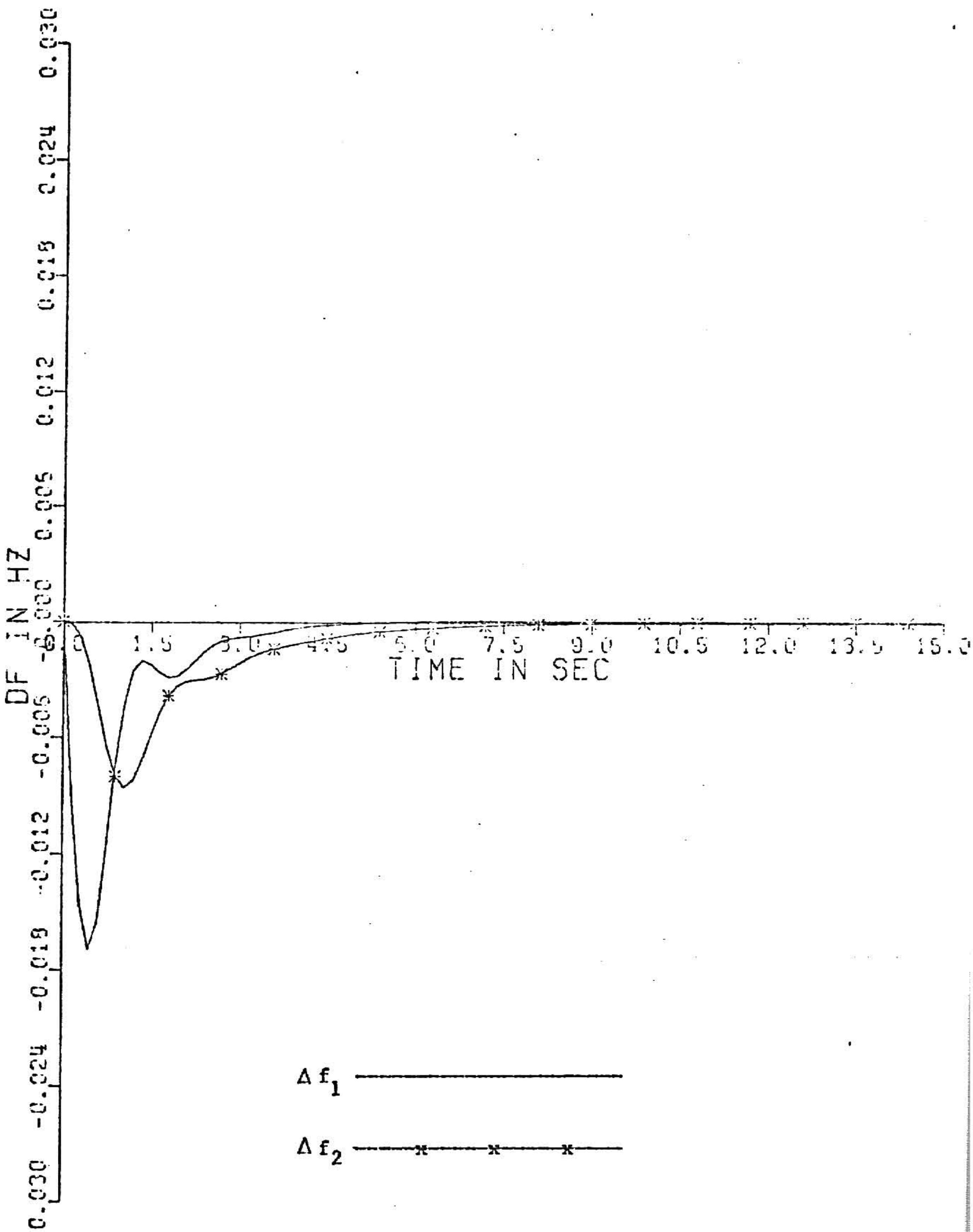

Fig. 27. Frequency deviations of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$ when commanded rate of generation change exceeds the machine limit.

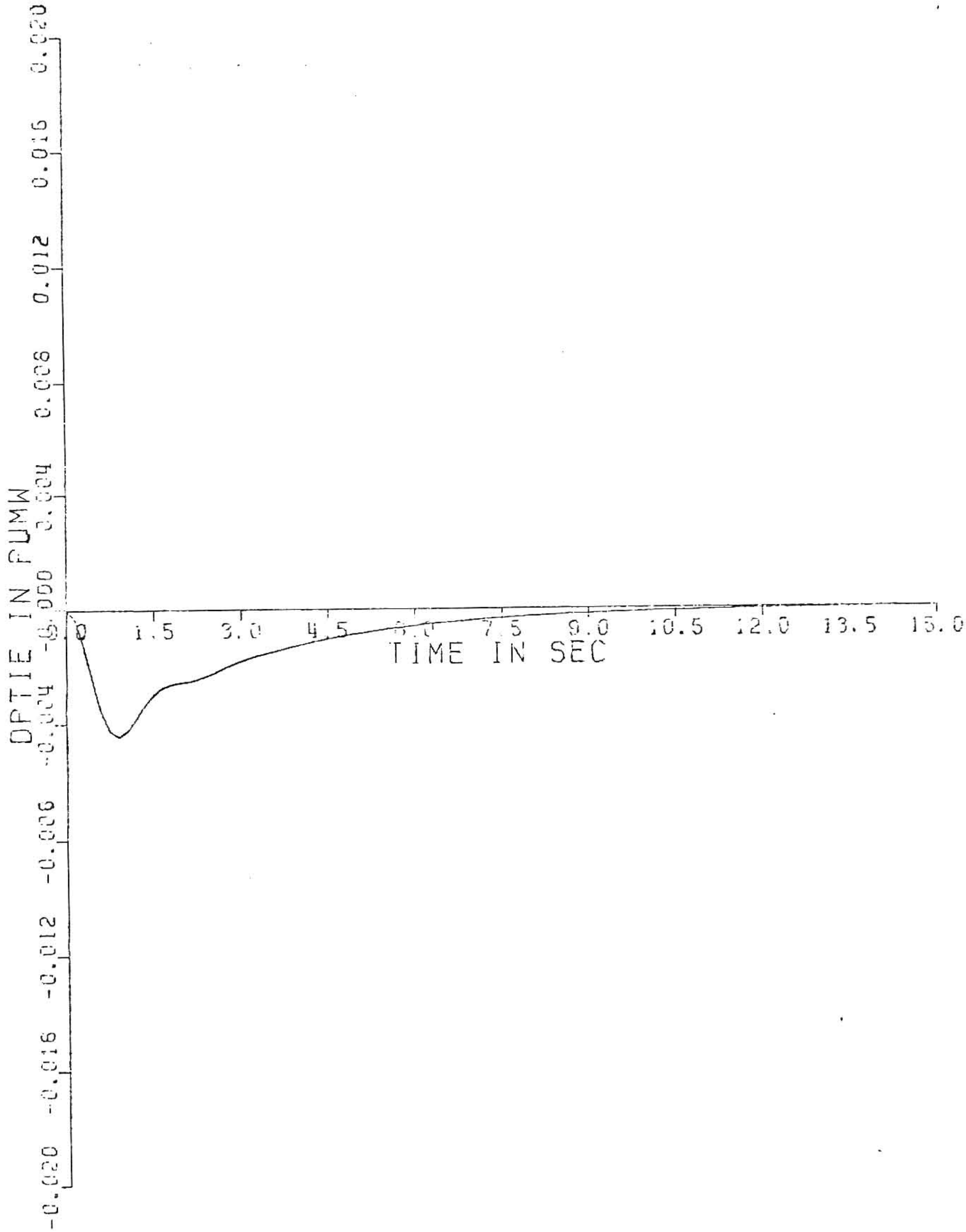

Fig. 28. Tie line deviation of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$ when commanded rate of generation change exceeds the machine limit.

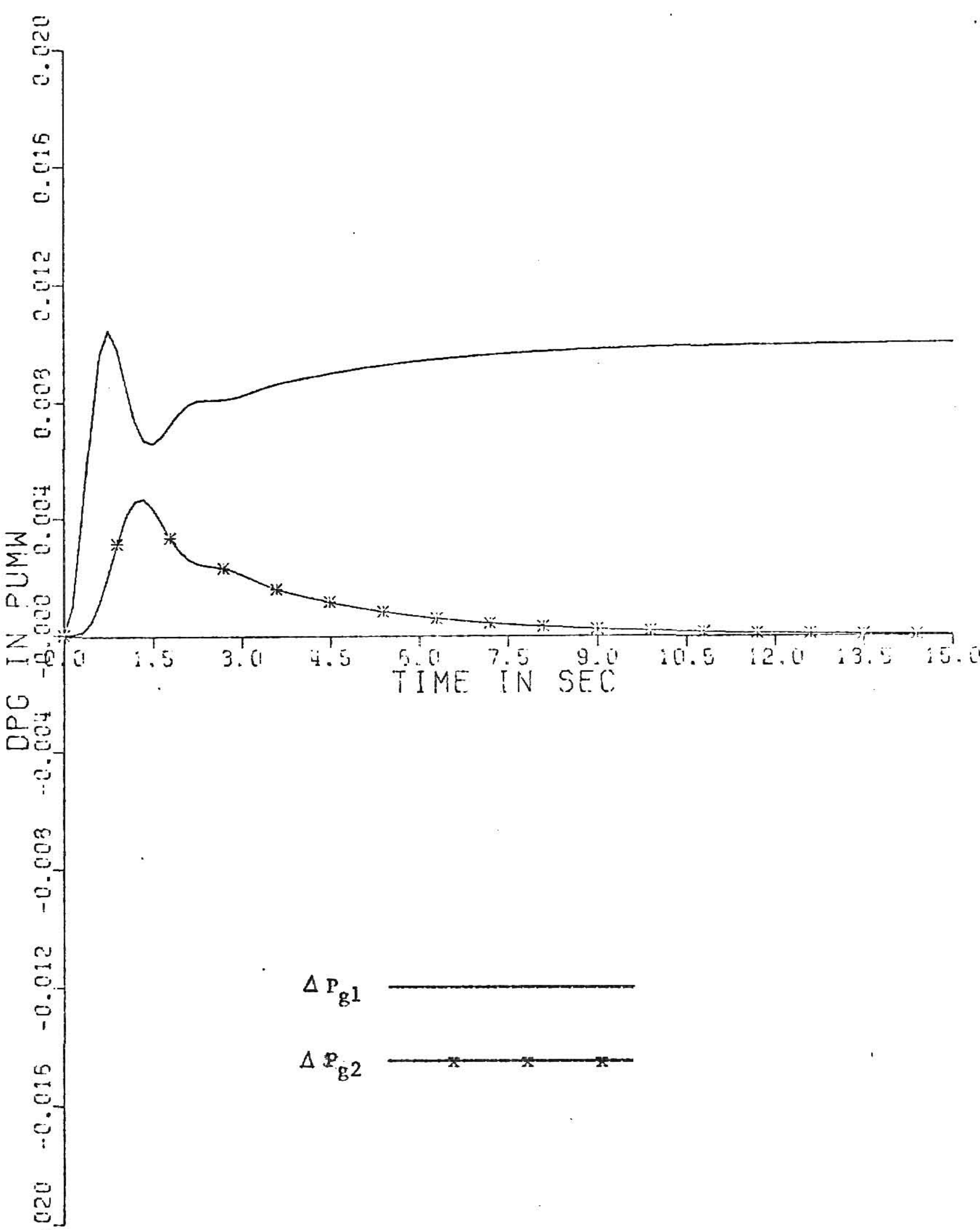

Fig. 29. Incremental generation change of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$ when commanded rate of generation change exceeds the machine limit.

A, B, R are the same as those in figure 5-a.

$$Q = \begin{bmatrix} 1 & 0 & 0 & 0 & 0 \\ 0 & 1 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 & 0 \\ 0 & 0 & 0 & 2.8 & -2.8 \\ 0 & 0 & 0 & -2.8 & 2.8 \end{bmatrix}$$

Feedback Gains

$$F = [1.000 \quad 0.693 \quad 1.044 \quad 1.267 \quad 1.116]$$

Net interchange = -0.01667 pu MW

Time deviation in area 1 = 0.00041 sec

Time deviation in area 2 = 0.00041 sec

Maximum rate of change of generation in area 1 = 0.018 pu MW/sec

Fig. 30. System data for decentralized optimal automatic generation control in which great rate of change of generation is penalized when $\alpha_1 = \alpha_2 = 0.3$.

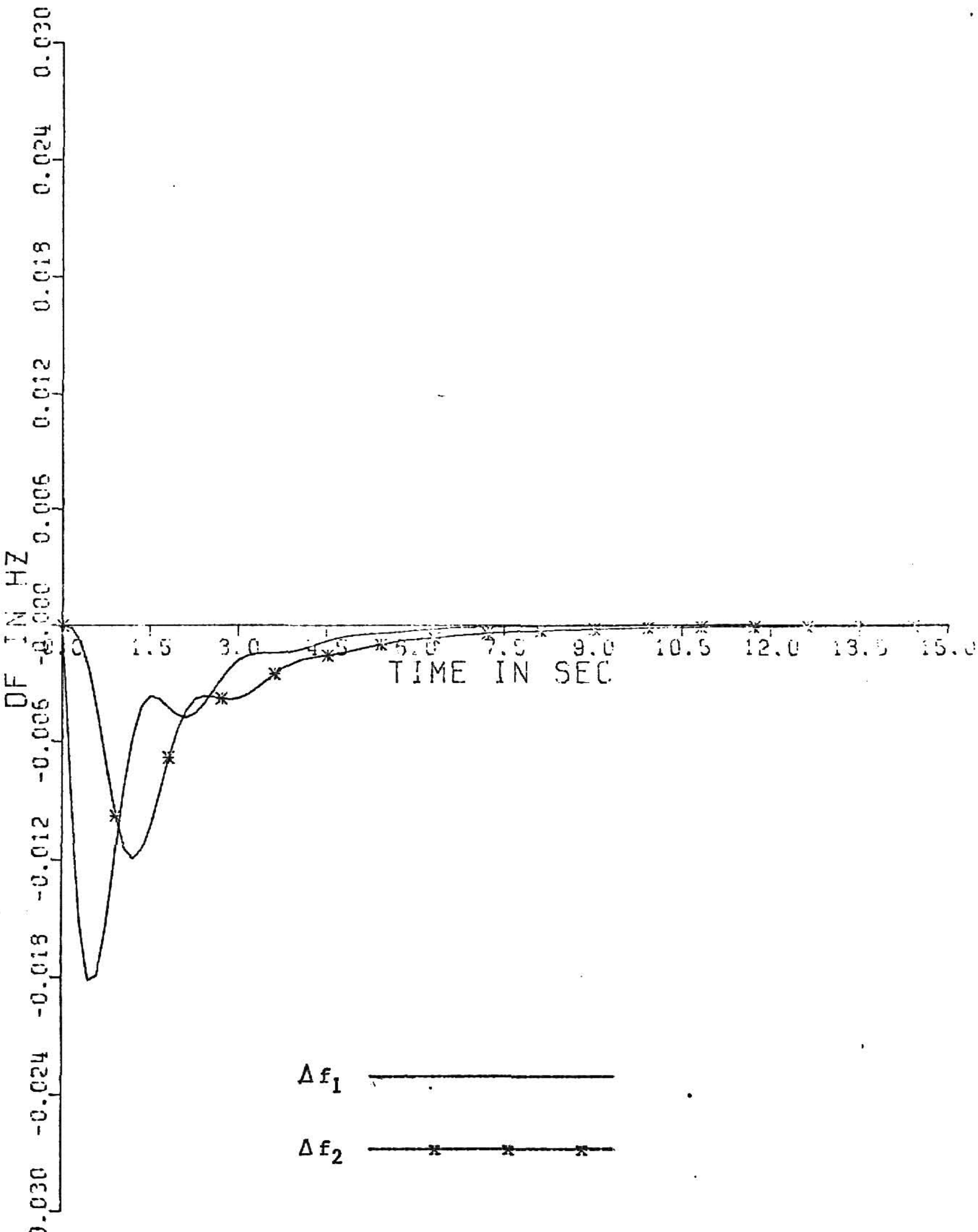

Fig. 31. Frequency deviations of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$ when great rate of generation change is penalized in the design of the controller.

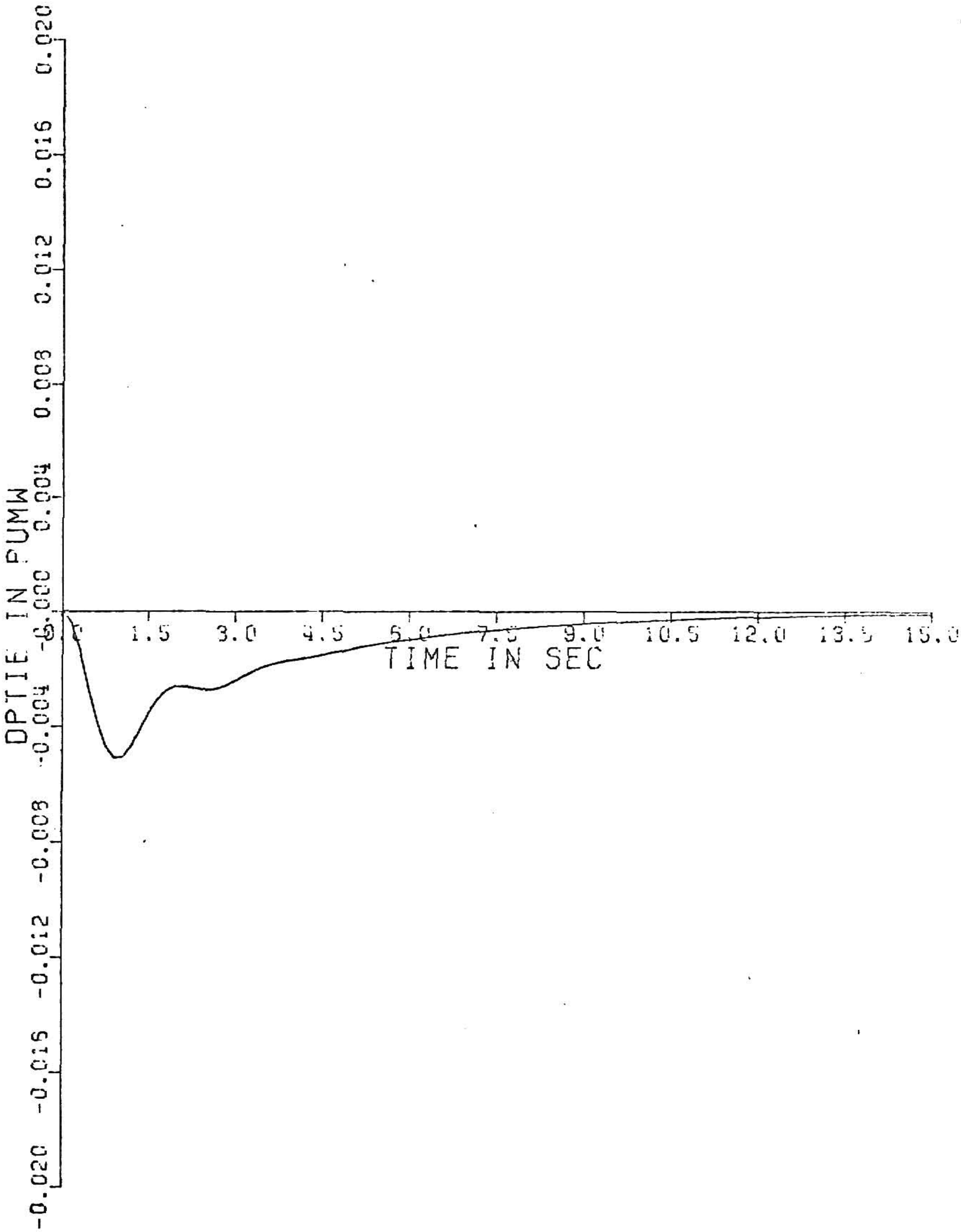

Fig. 37. Tie line deviation of decentralized optimal AGC with $\alpha_1 = \alpha_2 = 0.3$ when great rate of generation change is penalized in the design of the controller.

CHAPTER V

IMPLEMENTATION CONSIDERATION

The realization of the control strategy is obtained through the three level control concept [22] which consists of direct, optimizing, and adaptive control as shown in Figure 33. The direct or first level control is applied as a local option with the characteristic of fast action. The optimizing or second level control applies an optimal strategy based on a chosen performance criterion and a best mathematical system model. The adaptive or third level control makes adjustments in various parameters in the first two levels based on data from various system operating conditions.

A refinement of the automatic generation control strategy is to add an "Error Adaptive Control Computer" (EACC) [23]. In conventional control strategy, EACC analyzes the ACE with regard to the type of disturbance. The first type is an actual imbalance between generation and load which needs to be corrected. The second type is a random disturbance which may be attenuated by the inherent damping of the power system. These are recognized using knowledge of the natural periods of oscillation of the system frequency. Only control commands resulting from the first type are used. Those resulting from the second type are blocked. In this way, the wear on control and communication equipment and the inefficiency resulting from following the load fluctuations are reduced. The control law with EACC is described as

$$u(t) = \begin{cases} -K[IACE(ie)] & \text{if} \quad ACE(ie) \text{ is of the first type} \\ u(ie-e) & \text{if} \quad ACE(ie) \text{ is of the second type} \end{cases}$$

where $ie \le t < (i+1)e$.

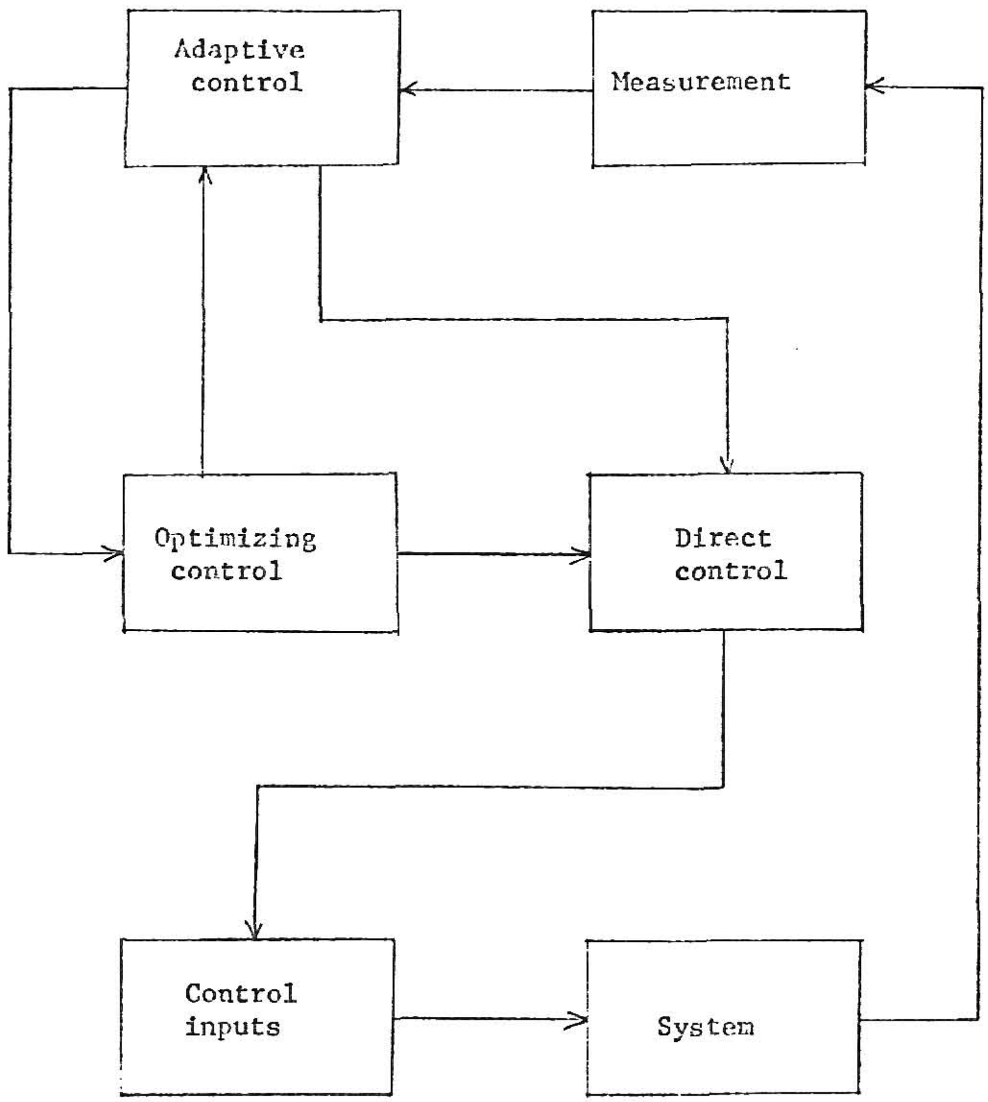

Fig. 33. Three level control concept.

For the advanced controller, one can analyze ΔP_{ci}, which is a linear combination of certain state variables, instead of ACE and design the control law similar to that of conventional control strategy.

In each area, ΔP_{ci} is allocated among various power generators according to a specified schedule. More commands from economic dispatch are sent to the power generators in order to achieve optimum operating conditions. The governor control is the first level control, the automatic generation control is the second level control and the economic dispatch is the third level control.

The simplified diagram of the controller based on Leeds & Northrup concept is shown in Figure 34. Control action is motivated effectively in three different ways. First, a sufficient large or sustained deviation in ΔP_{ci} will trigger the master controller or emergency by-pass. Secondly, scheduled changes in generation or tie-line commitments are accommodated separately. Thirdly, an economic dispatch update will change allocation of generation among the units of the area.

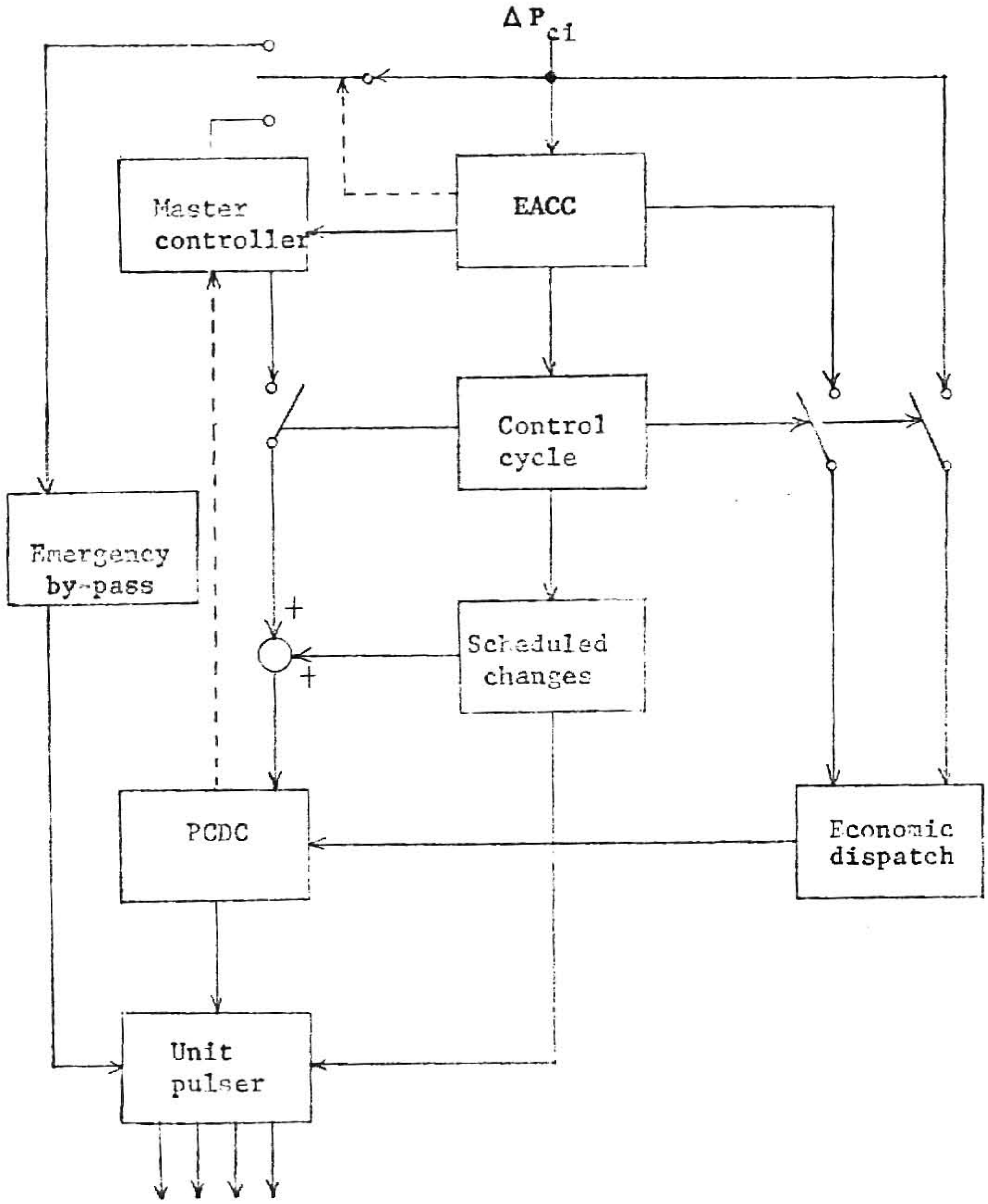

Fig. 34. Implementation of automatic generation control.

CHAPTER VI

CONCLUSION

The decentralized automatic generation control strategy proposed in this thesis makes it practical to apply optimal linear regulator theory to the automatic generation control problem. First, only state variables in a local area are needed for the design and implementation of the optimal feedback controller in that area. Secondly, the reduction in system dimension by decentralization makes it much easier to solve the matrix Riccati equation numerically.

The analysis of system response under normal condition has shown that the strategy makes the system function well. In the abnormal case the steady state errors in both frequency and tie line flow deviations exist as is also the case with conventional and advanced controller.

Although the simulation in this thesis is based on a much simplified model and a step disturbance, the same strategy can be applied to a more complicated model and for other kinds of disturbances such as a ramp or a random disturbance [21].

Appendix A

Optimal Linear Regulator Theory

A plant described by the linear state equation

$$\dot{X}(t) = A(t)X(t) + B(t)u(t) \tag{A-1}$$

and subject to the performance index

$$J = \frac{1}{2} X^T(t_f)HX(t_f) + \frac{1}{2}\int_{t_o}^{t_f} [X^T(t)Q(t)X(t) + u^T(t)R(t)u(t)]dt$$

where t_f is the fixed final time, H and Q are real symmetric positive semi-definite matrices, and R is a real symmetric positive definite matrix. The states and controls are assumed to be unbounded and the final state $X(t_f)$ is free. The performance index can be physically interpreted as a means of maintaining the state vector as close to the origin as possible without an excessive expenditure of control effort. The optimal control is found [5,6,7] to be

$$\begin{aligned} u^*(t) &= -R^{-1}(t)B^T(t)K(t)X(t) \\ &= F(t)X(t) \end{aligned} \tag{A-2}$$

where

$$K(t) \triangleq [\phi_{22}(t_f,t) - H\phi_{12}(t_f,t)]^{-1}[H\phi_{11}(t_f,t) - \phi_{21}(t_f,t)]$$

and

$$\phi(t_f,t) = \left[\begin{array}{c|c} \phi_{11}(t_f,t) & \phi_{12}(t_f,t) \\ \hline \phi_{21}(t_f,t) & \phi_{22}(t_f,t) \end{array}\right]$$

is the solution of the vector equation

$$\begin{bmatrix} \dot{X}^*(t) \\ \hline \dot{P}^*(t) \end{bmatrix} = \left[\begin{array}{c|c} A(t) & -B(t)R^{-1}(t)B^T(t) \\ \hline -Q(t) & -A^T(t) \end{array}\right] \begin{bmatrix} X^*(t) \\ \hline P^*(t) \end{bmatrix} .$$

where P(t) is the co-state vector.

It is shown [6] that K(t) also satisfies the matrix Riccati equation

$$\dot{K}(t) = -K(t)A(t) - A^T(t)K(t) - Q(t) + K(t)B(t)R^{-1}(t)B^T(t)K(t) \qquad \text{(A-3)}$$

with the boundary condition $K(t_f) = H$

In the case that

(1) the plant is completely controllable

(2) $H = 0$

(3) A, B, R, and Q are constant matrices.

Kalman [7] has shown that as $t_f \to \infty$, $K(t) \to K$ (a constant matrix). This means the optimal control law for an infinite duration process is stationary. From a practical point of view, it may be feasible to use the fixed control law even for a process of finite duration.

To determine K, we either integrate the matrix Riccati equation backward in time until a steady-state solution is obtained or solve the nonlinear algebraic equation

$$0 = -KA - A^TK - Q + KBR^{-1}B^TK$$

obtained by setting $\dot{K}(t) = 0$ in equation (A-3).

It is shown [6] that K is a symmetric positive-definite matrix.

Appendix B

Modified Linear Regulator Theory

A linear system is described by the state equation

$$\dot{X}(t) = A(t)X(t) + B(t)u(t) \tag{B-1}$$

Suppose the swings of both the state X and the rate of change of state $\dot{X}$ are to be minimized, the performance index is then chosen as:

$$\begin{aligned} J &= \frac{1}{2}\int_{t_o}^{t_f} (X^TQX + \dot{X}^T T\dot{X} + u^TRu)dt \\ &= \frac{1}{2}\int_{t_o}^{t_f} (X^TQX + (AX + Bu)^T T(AX + Bu) + u^TRu)dt \\ &= \frac{1}{2}\int_{t_o}^{t_f} (X^T(Q + A^TTA)X + 2X^T(A^TTB)u + u^T(R + B^TTB)u)dt \end{aligned} \tag{B-2}$$

where Q(t) and T(t) are positive semi-definite weighting matrices and R(t) is a positive definite weighting matrix. By defining

$$\begin{aligned} Q'(t) &= Q(t) + A^T(t)T(t)A(t) \\ R'(t) &= R(t) + B^T(t)T(t)B(t) \\ S\,(t) &= A^T(t)T(t)B(t) \end{aligned}$$

the performance index can be further expressed as

$$J = \frac{1}{2}\int_{t_o}^{t_f} (X^T(t)Q'(t)X(t) + 2X^T(t)S(t)u(t) + u^T(t)R'(t)u(t))dt$$

which contains the interacting terms between the states and the inputs. The optimal controller is determined as follows:

The integrand of the performance index can be expressed as

$$X^T(t)Q'(t)X(t) + 2X^T(t)S(t)u(t) + u^T(t)R'(t)u(t)$$
$$= (u(t) + R'^{-1}(t)S^T(t)X(t))^T R'(t)(u(t) + R'^{-1}(t)S^T(t)X(t)) +$$
$$X^T(t)(Q'(t) - S(t)R'^{-1}(t)S^T(t))X(t)$$

$R'^{-1}(t)$ exists because $R'(t)$ is positive definite.

By defining $u_1(t) = u(t) + R'^{-1}(t)S^T(t)X(t)$, the original system (B-1) becomes equivalent to

$$\dot{X}(t) = (A(t) - B(t)R'^{-1}(t)S(t))X(t) + B(t)u_1(t)$$

and the original performance index becomes

$$J = \frac{1}{2}\int_{t_o}^{t_f} (X^T(t)(Q'(t) - S(t)R'^{-1}(t)S^T(t))X(t) + u^T(t)R'(t)u(t))dt$$

The optimal controller is found to be (Appendix A):

$$u_1^*(t) = R'^{-1}(t)B^T(t)K(t)X(t)$$

where $K(t)$ satisfies the matrix differential equation

$$\dot{K}(t) = -K(t)(A(t) - B(t)R'^{-1}(t)S^T(t)) - (A^T(t) - S(t)R'^{-1}(t)B^T(t))\cdot$$
$$K(t) + K(t)B(t)R'^{-1}(t)B^T(t)K(t) - Q'(t) + S(t)R'^{-1}(t)S^T(t)$$

and $Q'(t) - S(t)R'^{-1}(t)S^T(t)$ must be positive semi-definite, i.e.,

$$Q'(t) - S(t)R'^{-1}(t)S^T(t)$$
$$= Q(t) + A^T(t)T(t)A(t) - (A^T(t)T(t)B(t))(R(t) + B^T(t)T(t)B(t))^{-1}\cdot$$
$$(A^T(t)T(t)B(t))^T$$
$$= Q(t) + A^T(t)(I - T(t)B(t)(R(t) + B^T(t)T(t)B(t))^{-1}B^T(t))T(t)A(t)$$

must be a positive semi-definite matrix in order that the optimal control exists. I denotes an identity matrix.

The optimal controller for the original system is

$$u^*(t) = u_1^*(t) - R'^{-1}(t)S^T(t)X(t)$$

$$= - R'^{-1}(t)(B^T(t)K(t) + S^T(t))X(t)$$

In case that (1) The plant is completely controllable, (2) A, B, R, Q and T are constant matrices, as t_f approaches infinite, K(t) approaches a constant matrix K which satisfies the matrix equation

$$0 = - K(A - BR'^{-1}S^T) - (A^T - SR'^{-1}B^T)K + KBR'^{-1}B^TK - Q' + SR'^{-1}S^T$$

Appendix C

Computer Programs used in This Thesis

A computer program MODRIC is developed to solve the steady state matrix Riccati equation that is described in Appendices A and B. From a starting matrix K, $\dot{K}$ is computed from matrix Riccati equation. By intergrating K backwards in time, K is obtained when $\dot{K}$ is close enough to a zero matrix. The input format for MODRIC program in shown in table C-1. A complete list of MODRIC is shown in Program 1. T is set to be a zero matrix when the solution in Appendix A is needed.

The program output consists of the input data (matrices A, B, R, Q, and T) and matrices K and $\dot{K}$ when steady state is reached. The stopping criterion is defined such that $\dot{K}$ is as close to a zero matrix as possible.

Program 2 is used to solve the state equation

$$\dot{X} = AX + Bu + \Gamma \Delta P_d$$

and Program 3 is used to plot all the responses in this thesis.

Table C-1. Input format for MODRIC program

Card Number	Column Number	Description	Format
1	1-20	problem identification	5A4
	21-22	N=dimension of A($\leq$10)	I2
	23-24	M=number of controls($\leq$10)	I2
2	1-10	A_{11} (system matrix A)	8F10.3
	11-20	A_{12}	
	etc.	....	
3	1-10	A_{21}	8f10.3
	11-20	A_{22}	
	etc.	....	
N + 1	1-10	B_{11} (control matrix B)	8F10.3
	11-20	B_{21}	
	etc.	....	
N + 2	1-10	B_{12}	8F10.3
	11-20	B_{22}	
	etc.	....	
N + M + 1	1-10	R_{11} (control weighting matrix R)	8F10.3
	11-20	R_{12}	
	etc.	....	
N + M +2	1-10	R_{21}	8F10.3
	11-20	R_{22}	
	etc.	....	
N + 2M + 1	1-10	Q_{11} (state weighting matrix Q)	8F10.3
	11-20	Q_{12}	
	etc.	....	
N + 2M + 2	1-10	Q_{21}	8F 10.3
	11-20	Q_{22}	
	etc.	....	
2N + 2M + 1	1-10	T_{11} (rate weighting matrix T)	8F10.3
	11-20	T_{12}	
	etc.	....	
2N + 2M + 2	1-10	T_{21}	8F10.3
	11-20	T_{22}	
	etc.	....	

Program 1. Matrix Riccati equation solution program.

```
C     MODIFIED RICCATI EQUATION PROGRAM (MODRIC)
C     SUBROUTINES USED MATINV
      DIMENSION A(10,10),B(10,10),C(10,10),R(10,10),Q(10,10),
     * K(10,10),D(10,10),NAME(5),F(10,10),E(10,10),T(10,10),
     *  G(10,10),H(10,10),S(10,10),W(10,10)
      REAL K
 1000 FORMAT (1H1,5X,23HOPTIMAL CONTROL PROGRAM/)
 1001 FORMAT (5A4,2I2)
 1002 FORMAT (6X,25HPROBLEM IDENTIFICATION - ,5A4)
 1003 FORMAT (1H0,5X,13H THE A MATRIX/)
 1004 FORMAT (1H0,5X,23H THE B TRANSPOSE MATRIX/)
 1005 FORMAT (1H0,5X,13H THE T MATRIX/)
 1006 FORMAT (8F10.3)
 1008 FORMAT (1H0,45(1H*))
 1011 FORMAT (10(F8.3,2X))
 1012 FORMAT (1H0,5X,13H THE R MATRIX/)
 1013 FORMAT (1H0,5X,13H THE Q MATRIX/)
 1016 FORMAT (1H0,5X,21HSTEADY STATE SOLUTION//6X,6H GAINS/)
  100 READ 1001,(NAME(I),I=1,5),N,M
      PRINT 1000
      PRINT 1002,(NAME(I),I=1,5)
      PRINT 1008
      PRINT 1003
      DO 110 I=1,N
      READ 1006,(A(I,J),J=1,N)
  110 PRINT 1011,(A(I,J),J=1,N)
      PRINT 1004
      DO 120 I=1,M
      READ 1006,(B(J,I),J=1,N)
  120 PRINT 1011,(B(J,I),J=1,N)
      PRINT 1008
      NR=M
      NQ=N
      NT=N
  400 PRINT 1012
      DO 410 I=1,NR
      READ 1006,(R(I,J),J=1,NR)
  410 PRINT 1011,(R(I,J),J=1,NR)
      PRINT 1013
      DO 420 I=1,NQ
      READ 1006,(Q(I,J),J=1,NQ)
  420 PRINT 1011,(Q(I,J),J=1,NQ)
      PRINT 1005
      DO 710 I=1,NT
      READ 1006,(T(I,J),J=1,NT)
  710 PRINT 1011,(T(I,J),J=1,NT)
      DO 720 I=1,N
      DO 720 J=1,N
      W(I,J)=0.0
      DO 720 II=1,N
  720 W(I,J)=W(I,J)+T(I,II)*A(II,J)
      DO 730 I=1,N
      DO 730 J=1,N
      DO 730 II=1,N
  730 Q(I,J)=Q(I,J)+A(II,I)*W(II,J)
      DO 740 I=1,N
      DO 740 J=1,NR
      W(I,J)=0.
```

```
      DO 740 II=1,N
740   W(I,J)=W(I,J)+T(I,II)*B(II,J)
      DO 750 I=1,NR
      DO 750 J=1,NR
      DO 750 II=1,N
750   R(I,J)=R(I,J)+B(II,J)*W(II,J)
      DO 760 I=1,N
      DO 760 J=1,NR
      T(I,J)=0.
      DO 760 II=1,N
760   T(I,J)=T(I,J)+A(II,I)*W(II,J)
      CALL MATINV(R,NR,H)
      DO 440 I=1,NR
      DO 440 J=1,N
      R(I,J)=0.0
      C(I,J)=0.0
      DO 440 II=1,NR
      C(I,J)=C(I,J)+H(I,II)*T(J,II)
440   R(I,J)=R(I,J)+H(I,II)*B(J,II)
      DO 770 I=1,N
      DO 770 J=1,N
      DO 770 II=1,NR
      A(I,J)=A(I,J)-B(I,II)*C(II,J)
770   Q(I,J)=Q(I,J)-T(I,II)*C(II,J)
      DO 330 I=1,N
      DO 310 J=1,M
310   E(I,J)=B(I,J)
      DO 330 J=1,N
330   F(I,J)=A(J,I)
      DO 520 I=1,N
      DO 510 J=1,N
510   G(I,J)=0.0
520   G(I,I)=0.05
      EPS=0.005
      SO=0.
574   IST=0
575   DO 580 I=1,NR
      DO 580 J=1,N
      K(I,J)=0.0
      DO 580 II=1,N
580   K(I,J)=K(I,J)+R(I,II)*G(II,J)
      DO 590 I=1,N
      DO 590 J=1,N
      H(I,J)=0.0
      DO 590 II=1,NR
590   H(I,J)=H(I,J)+E(I,II)*K(II,J)
      DO 610 I=1,N
      DO 610 J=1,I
      D(I,J)=Q(I,J)
      DO 600 II=1,N
600   D(I,J)=D(I,J)+F(I,II)*G(II,J)+G(I,II)*F(J,II)-G(I,II)*H(II,J)
      S(I,J)=G(I,J)+D(I,J)*EPS
      D(J,I)=D(I,J)
      G(I,J)=S(I,J)
610   G(J,I)=S(I,J)
640   SUM=0.0
      DO 650 I=1,N
      DO 650 J=1,N
```

```
 650 SUM=SUM+ABS(D(I,J))
 649 FORMAT (2X,'SUM=',F10.6)
     IF (SUM .LE. 0.0001) GO TO 651
     SD=SUM-SO
     SO=SUM
     ST=ABS(SD)
     IF (ST.GE.0.000001) GO TO 574
     IST=IST+1
     IF (IST.LE.10) GO TO 575
 651 CONTINUE
1019 FORMAT(2X,10(F9.6,2X))
     DO 656 I=1,NR
     DO 656 J=1,N
 656 K(I,J)=K(I,J)+C(I,J)
     PRINT 1016
 655 DO 660 I=1,NR
 660 PRINT 1011,(K(I,J),J=1,N)
     DO 661 I=1,NR
 661 WRITE (7,1006) (K(I,J),J=1,N)
     PRINT 662
 662 FORMAT (1H0,5X,13H THE G MATRIX/)
     DO 663 I=1,N
 663 PRINT 1019,(G(I,J),J=1,N)
     PRINT 1018
1018 FORMAT (1H0,5X,13H THE D MATRIX/)
     DO 665 I=1,N
 665 PRINT 1019,(D(I,J),J=1,N)
     STOP
     END
```

Program 2. State equation solution program.

```
C     AGC STATE EQUATION SOLUTION PROGRAM (AGC-SESP)
      REAL K
      EXTERNAL FCT,OUTP
      DIMENSION AA(10,10),GAM(10,10),DPD(10),FF(10),DERY(10),PRMT(5),
     *  Y(10),ZV(10),B(10,10),K(10,10),AD(10,10)
      COMMON NDIM,AA,FF
   10 FORMAT (2I3,5F10.5)
   20 FORMAT(8F10.3)
   22 FORMAT (10F10.4)
      READ (5,10) NDIM,ND,(PRMT(I),I=1,4)
   30 FORMAT ('NDIM=',I2,2X,'ND=',I2)
      WRITE (6,30) NDIM,ND
      READ (5,20) (Y(I),I=1,NDIM)
      DO 100 I=1,NDIM
  100 READ (5,20) (AD(I,J),J=1,NDIM)
      DO 200 I=1,NDIM
  200 READ (5,20) (B(I,J),J=1,ND)
      DO 210 I=1,ND
  210 READ (5,20) (K(I,J),J=1,NDIM)
      DO 220 I=1,NDIM
      DO 220 J=1,NDIM
      DO 215 II=1,ND
  215 AD(I,J)=AD(I,J)-B(I,II)*K(II,J)
  220 AA(I,J)=AD(I,J)
  510 FORMAT (2X,14H THE AA MATRIX/)
      PRINT 510
      DO 500 I=1,NDIM
  500 WRITE (6,22) (AA(I,J),J=1,NDIM)
      DO 410 I=1,NDIM
  410 DERY(I)=1.0/FLOAT(NDIM)
      DO 300 I=1,NDIM
  300 READ (5,20) (GAM(I,J),J=1,ND)
      READ (5,20) (DPD(I),I=1,ND)
      DO 400 I=1,NDIM
      ZV(I)=0.
      DO 405 J=1,ND
  405 ZV(I)=ZV(I)+GAM(I,J)*DPD(J)
  400 FF(I)=ZV(I)
  310 FORMAT (14H THE FF VECTOR/)
      PRINT 310
      WRITE (6,20) (FF(I),I=1,NDIM)
  600 FORMAT(2X,4HTIME,9X,3HTD1,5X,3HTD2,8X,5HDPTIE/)
      PRINT 600
      CALL RKGS (PRMT,Y,DERY,NDIM,IHLF,FCT,OUTP,AUX)
   50 FORMAT (2X,'IHLF=',I2)
      WRITE (6,50) IHLF
  601 FORMAT (2X,'NET INTERCHANGE=',F10.5)
  602 FORMAT (2X,'TIME DEVIATION1=',F10.5)
  603 FORMAT (2X,'TIME DEVIATION2=',F10.5)
      WRITE (6,601) Y(1)
      WRITE (6,602) Y(2)
      WRITE (6,603) Y(6)
      STOP
      END
```

```
      SUBROUTINE MATINV(AA,N,AINV)
      DIMENSION AA(10,10),AINV(10,10),A(10,20),ID(10)
      NN=N+1
      N2=2*N
      DO 100 I=1,N
      ID(I)=I
      DO 100 J=1,N
  100 A(I,J)=AA(I,J)
      DO 200 I=1,N
      DO 200 J=NN,N2
  200 A(I,J)=0.
      DO 300 I=1,N
  300 A(I,N+I)=1.
      K=1
    1 CALL EXCH(A,N,N2,K,ID)
    2 IF(A(K,K))3,999,3
    3 KK=K+1
      DO 4 J=KK,N2
      A(K,J)=A(K,J)/A(K,K)
      DO 4 I=1,N
      IF(K-I)41,4,41
   41 W=A(I,K)*A(K,J)
      A(I,J)=A(I,J)-W
      IF(ABS(A(I,J))-.0001*ABS(W))42,4,4
   42 A(I,J)=0.
    4 CONTINUE
      K=KK
      IF(K-N)1,2,5
    5 DO 10 I=1,N
      DO 10 J=1,N
      IF(ID(J)-I)10,8,10
    8 DO 12 K=1,N
   12 AINV(I,K)=A(J,N+K)
   10 CONTINUE
      RETURN
  999 PRINT 1000
      RETURN
 1000 FORMAT(19H MATRIX IS SINGULAR)
      END
```

```
      SUBROUTINE EXCH(A,N,NN,K,ID)
      DIMENSION A(10,20),ID(10)
      NROW=K
      NCOL=K
      B=ABS(A(K,K))
      DO 2 I=1,N
      DO 2 J=1,N
      IF(ABS(A(I,J))-B)2,2,21
   21 NROW=I
      NCOL=J
      B=ABS(A(I,J))
    2 CONTINUE
      IF(NROW-K)3,3,31
   31 DO 32 J=K,NN
      C=A(NROW,J)
      A(NROW,J)=A(K,J)
   32 A(K,J)=C
    3 CONTINUE
      IF(NCOL-K)4,4,41
   41 DO 42 I=1,N
      C=A(I,NCOL)
      A(I,NCOL)=A(I,K)
   42 A(I,K)=C
      I=ID(NCOL)
      ID(NCOL)=ID(K)
      ID(K)=I
    4 CONTINUE
      RETURN
      END
```

```
      SUBROUTINE FCT (X,Y,DERY)
      DIMENSION F(10),FF(10),AA(10,10),DERY(10),Y(10)
      COMMON N,AA,FF
      DO 210 I=1,N
      DERY(I)=FF(I)
      DO 210 J=1,N
  210 DERY(I)=DERY(I)+AA(I,J)*Y(J)
      RETURN
      END
```

```
      SUBROUTINE OUTP (X,Y,DERY,IHLF,NDIM,PRMT)
      DIMENSION Y(10),DERY(10),Z(100),PRMT(5)
      DO 600 I=1,100
      Z(I)=PRMT(1)+PRMT(3)*FLOAT(I)
      D=ABS(Z(I)-X)
      IF (D.LE.0.01) GO TO 700
  600 CONTINUE
      GO TO 400
  700 CONTINUE
    1 FORMAT (8F10.5)
      WRITE (6,1) X,Y(2),Y(6),DERY(1)
      Y(2)=0.1*0.545*Y(2)
      WRITE (7,1) X,Y(2),Y(6),DERY(1)
  400 RETURN
      END
```

Program 3. Plotting program.

```
      DIMENSION IBUF(4000),X(303),Y(303),Z(303),DP(303)
C     ESTABLISH KNOWN ORIGIN
      CALL PLOTS (IBUF,4000)
      CALL PLOT (0.0,-11.0,23)
      CALL PLOT (0.0,2.0,23)
C     READ DATA
    1 FORMAT (4F10.5)
      DO 100 I=1,101
  100 READ (5,1) X(I),Y(I),Z(I),DP(I)
C     DRAW THE X AXIS
      CALL DAXIS (0.0,4.0,6.0,0.0,0.6,-1)
      X(102)=0.0
      X(103)=1.5
      CALL SAXIS (X(102),X(103),1,1,-1,'TIME IN SEC',11)
C     DRAW THE Y AXIS
      CALL DAXIS (0.0,0.0,8.0,90.0,0.8,1)
      Y(102)=-0.03
      Y(103)=0.006
      CALL SAXIS (Y(102),Y(103),3,2,1,'DF IN HZ',8)
C     PLOT A SMOOTH CURVE
      X(103)=X(103)/0.6
      Y(103)=Y(103)/0.8
      Z(102)=Y(102)
      Z(103)=Y(103)
      CALL FLINE (X,Y,101,1,0,0)
      CALL FLINE (X,Z,101,1,6,11)
      CALL PLOT (8.5,0.0,-3)
C     DRAW THE X AXIS
      CALL DAXIS (0.0,4.0,6.0,0.0,0.6,-1)
      X(102)=0.0
      X(103)=1.5
      CALL SAXIS (X(102),X(103),1,1,-1,'TIME IN SEC',11)
C     DRAW THE Y AXIS
      CALL DAXIS (0.0,0.0,8.0,90.0,0.8,1)
      DP(102)=-0.02
      DP(103)=0.004
      CALL SAXIS (DP(102),DP(103),3,2,1,'OPTIE IN PUMW',13)
C     PLOT A SMOOTH CURVE
      X(103)=X(103)/0.6
      DP(103)=DP(103)/0.8
      CALL FLINE (X,DP,101,1,0,0)
C     FINISH PLOTS
      CALL PLOT(0.0,0.0,999)
      STOP
      END
```

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by

SHEAU-WEI FU

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ABSTRACT

This thesis reviews different strategies used in electric utility industry and appearing in literature for automatic generation control in interconnected networks. A method is proposed that makes it practical to apply optimal control theory to this problem. An approximate decoupled dynamic system model is developed. This model is based on simplified state variable model of the megawatt-frequency control dynamics of a multiarea electric energy system such that each area in the interconnected system can be regarded as as a single control area while approximating the effect of coupling between areas (subsystems). In this way, the optimal linear regulator theory can be applied to each "single control area" for the design of optimal feedback controller which depends only on the state variables in that one area, thus making implementation practical. The summary of this thesis was presented at 1976 Midwest Power Symposium.