A HYBRID COMPUTER PARAMETER OPTIMIZATION STUDY OF

THE TWO-AREA LOAD FREQUENCY CONTROL PROBLEM

by

Robert Paul Broadwater

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APPROVED:

L. L. Grigsby, Chairman

N. A. Demerdash

G. R. Powley

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I. INTRODUCTION

1.1 Statement of the Problem

The load frequency control problem is a very important problem in electric power systems operation. Unfortunately, it is also a very complex problem. In its realistic form, the problem is concerned with controlling the power output of several thousand generating units that are interconnected via transmission lines so that three requirements are met (6). First, the power generated must equal the power demanded. Second, the system frequency must be maintained at approximately 60 Hertz. Third, the power flows over certain transmission lines in the system must be maintained at approximately constant levels. These transmission lines are referred to as "tie lines."

A group of generating units that act together to accomplish load frequency control is referred to as a "control area." The control action within each control area may be considered to originate from one central process controller. In all, there are over one hundred control areas that are interconnected via hundreds of tie lines in the United States. The load frequency control problem is most definitely concerned with one of the largest man made systems in existence.

1.2 Scope of Investigation

This study is concerned with a system composed of two areas connected together by one tie line. Each area is represented by a very simplified mathematical model (1,2,3). The model for each area includes representation for speed governor dynamics, non-reheat turbine-generator dynamics, and the dynamics of the "area's real power system." The model for each area neglects such considerations as boiler dynamics, speed governor deadband, generator rate limitation, and the interaction between the control of reactive power and voltage and the control of real power and frequency. The control scheme that is studied is one that is currently used in practice in many areas today.

The purpose of this study is to determine control settings that are optimum relative to a cost function for several different area sizes and for several different static tie line capacities. The static tie line capacity is defined as the maximum power the tie line can carry when it is operating under steady state conditions. There are a total of four parameters to be optimized, and optimum settings are found for two different cost functions. Search techniques employing a hybrid computer are used to find the optimum settings.

2. THE LOAD FREQUENCY CONTROL PROBLEM

2.1 Some Concepts in Electric Power Systems

Under normal operating conditions, the instantaneous power demand P_D in an electric power system varies slowly with time. For short periods of time the power demand may be considered to be composed of a nominal state P_D° plus small incremental changes W about the nominal state, so that

$$P_D = P_D^\circ + W \,. \tag{2.1.1}$$

When a power system experiences an increased power demand, there will exist a momentary power imbalance P_I between the instantaneous generated power P_G and the instantaneous power demand P_D. The generated power may also be represented by a nominal state P_G° plus a small incremental change ΔP_G, so that

$$P_G = P_G^\circ + \Delta P_G \,. \tag{2.1.2}$$

At the nominal operating point the power generated equals the power demanded

$$P_G^\circ = P_D^\circ \,. \tag{2.1.3}$$

Hence, the momentary power imbalance due to an increase in power demand is

$$P_I = \Delta P_G - W \,. \tag{2.1.4}$$

During the first few instants of time following an increased power demand (these few instants of time correspond to a time period during which the turbine-generator control systems have not had time to react) a time rate of decrease of the mechanical kinetic energy stored in the rotating masses of the turbine-generator systems acts to supply the power imbalance P_I. By this action, the total instantaneous power demand is satisfied. A time rate of decrease of the mechanical kinetic energy corresponds to a decrease in the angular velocity of the synchronous generators. As the angular velocities of the synchronous generators decrease, the power system frequency also decreases. The instantaneous power system frequency f may also be denoted by a nominal state f° plus an incremental change Δf, so that

$$f = f^\circ + \Delta f \ . \tag{2.1.5}$$

Therefore, during the first few instants of time following an increased power demand, there is a droop in power system frequency.

If there is a decrease in power demand,during the first few instants of time following the decrease, the excess power generation appears as a time rate of increase of the mechanical kinetic energy stored in the rotating masses of the turbine-generator systems. In this case, the system frequency will increase.

2.2 Areas and Tie Lines

The generators and busses within a control area are assumed to be tied together by "strong electrical connections." This assumption implies that when the total power system, which is assumed to contain more than one control area, experiences a load change, then all of the generators belonging to the i^{th} control area experience the same incremental change in angular velocity. This means that the system frequency in area i is changing at the same rate throughout area i. The tie lines that connect areas together are assumed to be "weak electrical connections."

To illustrate the above, suppose we have a power system that is composed of two control areas which are connected by one tie line, as shown in Figure 2.2.1. Let the tie line connect to bus 1 in area 1 and to bus 2 in area 2, and let the impedance of the tie line be represented by $Z = jX$. Assume that the power system is operating at a nominal operating point with

$$P^{\circ}_{G1} + P^{\circ}_{G2} = P^{\circ}_{D1} + P^{\circ}_{D2} \tag{2.2.1}$$

where

P°_{Gi} = nominal power generation in area i

P°_{Di} = nominal power demand in area i.

Now assume that area 1 experiences an increase in power demand W_1. During the first few instants of time following the increased power demand, both areas will experience a droop in frequency. However, the changing angular velocity of the generators in area 1 will be different from that of the generators in area 2. This difference in generator responses is what distinguishes areas 1 and 2 as separate control areas. Therefore, until the system reaches a new steady state operating point where the generation equals the demand, the instantaneous frequency of area 1, represented by

$$f_1 = f^{\circ} + \Delta f_1, \tag{2.2.2}$$

will differ from the instantaneous frequency of area 2, represented by

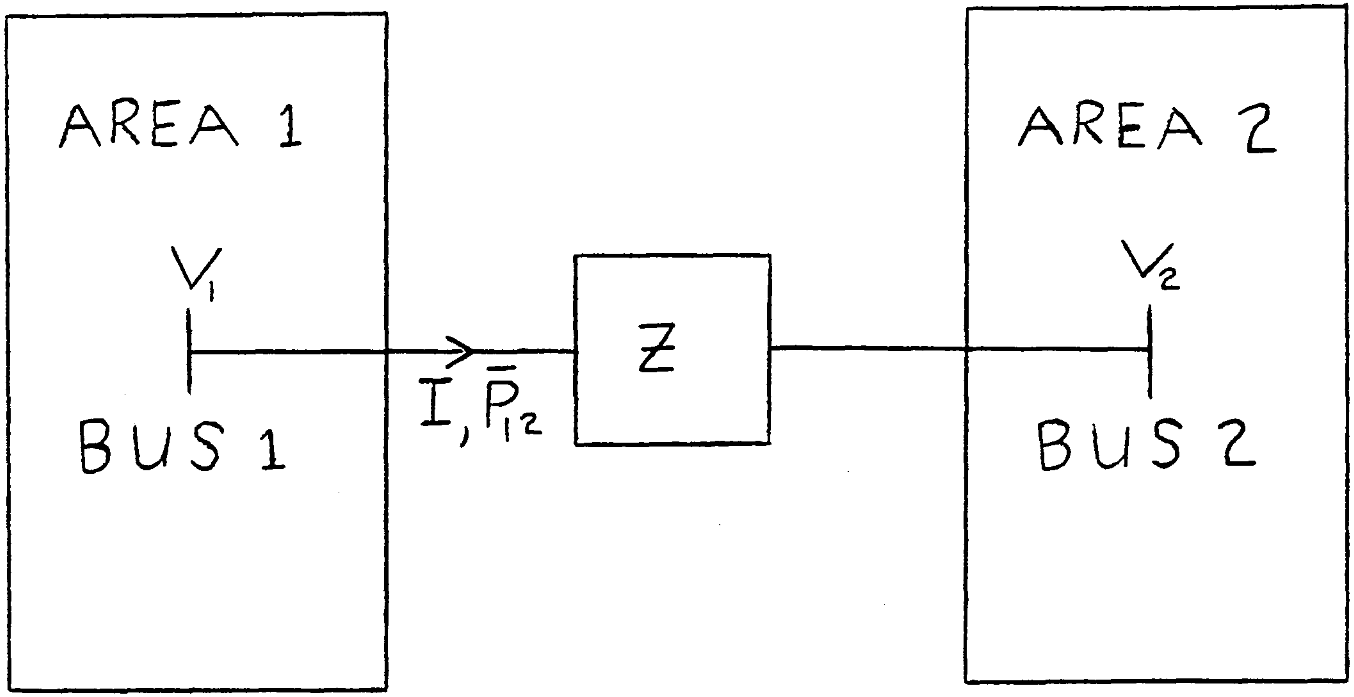

Figure 2.2.1. Two Area Power System.

$$f_2 = f^\circ + \Delta f_2 \ . \qquad (2.2.3)$$

The angles of the bus voltages in area 1 will vary with time as the frequency of area 1 varies with time. Assume that the power system is operating at a nominal operating point with the voltage at bus 1 given by

$$V_1 = |V_1^\circ| \sin (\omega^\circ t + \delta_1^\circ) \ . \qquad (2.2.4)$$

Following a change in real power demand, the voltage at bus 1 may be represented as

$$V_1 = |V_1^\circ| \sin (\omega^\circ t + \delta_1^\circ + \Delta\delta_1) \ . \qquad (2.2.5)$$

$\Delta\delta_1$ accounts for the change in the voltage reference angle at bus 1 due to the frequency change in area 1. The angular velocity ω_1 of bus 1 is given by

$$\omega_1 = \omega^\circ + \Delta\omega_1 \ . \qquad (2.2.6)$$

Since ω_1 is by definition the time rate of change of the sine argument in Equation (2.2.5), we have

$$\omega^\circ + \Delta\omega_1 = \frac{d}{dt} (\omega^\circ t + \delta_1^\circ + \Delta\delta_1) \ . \qquad (2.2.7)$$

This gives

$$\Delta\omega_1 = \frac{d}{dt} (\Delta\delta_1) \ . \qquad (2.2.8)$$

Therefore, the frequency change in area 1 is related to the change in bus voltage reference angle at bus 1 by

$$\Delta f_1 = \frac{1}{2\pi} \frac{d}{dt} (\Delta\delta_1) \ . \tag{2.2.9}$$

Likewise, the frequency change in area 2 is related to the change in bus voltage reference angle at bus 2 by

$$\Delta f_2 = \frac{1}{2\pi} \frac{d}{dt} (\Delta\delta_2) \ . \tag{2.2.10}$$

Note that since area 1 is characterized by a single incremental change in frequency Δf_1, then all of the bus voltages in area 1 will be characterized by a single incremental change in bus voltage reference angle $\Delta\delta_1$. Busses or generators belonging to the same area are said to swing coherently.

The boundaries of control areas may correspond to the boundaries of individual power companies. Power companies contract the amounts of power that are to flow over the tie lines that interconnect them together. Therefore, they wish to maintain the power flows over the tie lines at the agreed upon levels. However, the power flows in the tie lines vary with the power demand on the system. The load frequency control problem is concerned with controlling the system frequency and the power flows in the tie lines as the power system demand varies. This control action is achieved by changing the power generation as the power demand changes.

2.3 Mathematical Modeling of Areas and Tie Lines

In this section a mathematical model (1) which represents the load frequency control problem for the two-area system pictured in Figure

2.2.1 will be developed. The model will be developed for area 1, and the results will easily be extended to develop the model for area 2. The model to be developed applies only for small changes in the system variables about nominal operating points.

The real power generation of a synchronous generator is controlled by means of the turbine controllers. Incremental analysis studies of generator-turbine-governor systems, where a non-reheat turbine is used, reveal that the following differential equations characterize their operation:

$$\frac{d}{dt}(\Delta P_{G1}) = -\frac{1}{T_{T1}}(\Delta P_{G1}) + \frac{1}{T_{T1}}(\Delta X_1) \tag{2.3.1}$$

$$\frac{d}{dt}(\Delta X_1) = -\frac{1}{T_{G1}}(\Delta X_1) - \frac{1}{T_{G1}R_1}(\Delta f_1) - \frac{1}{T_{G1}}(\Delta P_{C1}) \tag{2.3.2}$$

where the subscript 1 refers to control area 1 and where

ΔP_{G1} = incremental change in real power generation in MW

ΔX_1 = incremental change in prime mover value setting in MW

Δf_1 = increment change in area frequency in Hz

ΔP_{C1} = incremental change in speed changer position setting in MW

R_1 = speed regulation due to governor action in Hz/MW

T_{G1} = time constant of the speed governor in sec

T_{T1} = time constant of the turbine in sec

Equations (2.3.1) and (2.3.2) are used to describe the combined response of all the generator-turbine-governor systems within control area 1. Therefore, the parameters in the equations represent average values for control area 1. In the development of Equations (2.3.1) and (2.3.2), the generator response is considered to be instantaneous in comparison with the time constants of the turbine and speed governor.

An equation that describes the power balance in area 1 will now be developed. Suppose area 1 is resting at a nominal operating point when it suddenly experiences a decrease in power demand W_1. The resulting difference in the incremental power generation and the incremental power demand, represented by

$$P_I = \Delta P_{G1} - W_1 \ , \tag{2.3.3}$$

may be absorbed in three ways:

1) Part of P_I appears as a rate of change of the kinetic energy stored in the synchronous generator systems of area 1. Area kinetic energy S_1 varies as the square of the area frequency as given by

$$S_1 = (\frac{f_1}{f^\circ})^2 \ S_1^\circ \tag{2.3.4}$$

where S_1° = kinetic energy of area 1 measured at nominal in MW sec. Letting $f_1 = f^\circ + \Delta f_1$ in Equation (2.3.4) gives

$$S_1 = (\frac{f^\circ + \Delta f_1}{f^\circ})^2 \ S_1^\circ \ . \tag{2.3.5}$$

Neglecting the term involving $(\Delta f_1)^2$ in Equation (2.3.5) gives

$$S_1 = 1 + 2 \ (\frac{\Delta f_1}{f^\circ}) \ S_1^\circ \ . \tag{2.3.6}$$

Therefore, the rate of change of the kinetic energy in area 1 may be expressed as

$$\frac{d}{dt}(S_1) = \left(\frac{2\,S_1^\circ}{f^\circ}\right)\frac{d}{dt}(\Delta f_1) \;. \tag{2.3.7}$$

2) Part of P_I appears as a change in the tie line power flow. In the two area system shown in Figure 2.2.1, the complex tie line power flow $\bar{P}_{12}$ from area 1 to area 2 may be expressed as

$$\bar{P}_{12} = V_1\, I^* \tag{2.3.8}$$

where $\bar{P}_{12}$ = complex power flowing out of area 1 toward area 2

V_1 = complex voltage of bus 1

I = complex tie line current with reference direction from area 1 to area 2

$*$ denotes complex conjugate.

The tie line current I may be written as

$$I = \frac{V_1 - V_2}{jX} \tag{2.3.9}$$

where V_2 = complex voltage of bus 2

X = reactance of the tie line.

Note that the resistance of the tie line is neglected. Substituting Equation (2.3.9) into Equation (2.3.8) gives

$$\bar{P}_{12} = V_1\left(\frac{V_1^* - V_2^*}{-\,j\,X}\right) . \tag{2.3.10}$$

Letting $V_1 = |V_1|\, e^{j\delta_1}$ and $V_2 = |V_2|\, e^{j\delta_2}$ in Equation (2.3.10) gives

$$\bar{P}_{12} = \frac{|V_1|^2 - |V_1||V_2|\, e^{j(\delta_1 - \delta_2)}}{-\,j\,X} \;. \tag{2.3.11}$$

The real power P_{tie} flowing out of area 1 may be expressed as

$$P_{tie} = \text{Real } (\bar{P}_{12}) \ . \tag{2.3.12}$$

Extracting the real part of $\bar{P}_{12}$ gives

$$P_{tie} = \frac{|V_1||V_2|}{X} \sin (\delta_1 - \delta_2) \ . \tag{2.3.13}$$

The static transmission capacity of the tie line is defined as

$$P_m = \frac{|V_1||V_2|}{X} \ . \tag{2.3.14}$$

Letting $\delta = \delta_1 - \delta_2$ and substituting Equation (2.3.14) into Equation (2.3.13) gives

$$P_{tie} = P_m \sin \delta \ . \tag{2.3.15}$$

An incremental change in P_{tie} due to an incremental change in δ may be expressed as

$$\Delta P_{tie} = \Delta\delta \frac{d}{d\delta} (P_{tie}) \ . \tag{2.3.16}$$

Using Equation (2.3.15) and performing the indicated differentiation in Equation (2.3.16) gives

$$\Delta P_{tie} = (P_m \cos \delta) \ \Delta\delta \ . \tag{2.3.17}$$

The synchronizing coefficient T° of the tie line is defined as

$$T^\circ = P_m \cos \delta^\circ \ . \tag{2.3.18}$$

Letting $\Delta\delta = \Delta\delta_1 - \Delta\delta_2$ and substituting Equation (2.3.18) into Equation

(2.3.17) gives

$$\Delta P_{tie} = T^{\circ}(\Delta\delta_1 - \Delta\delta_2) \ . \tag{2.3.19}$$

Solving Equations (2.2.9) and (2.2.10) for $\Delta\delta_1$ and $\Delta\delta_2$ gives

$$\Delta\delta_1 = 2\pi \int \Delta f_1 \, dt \tag{2.3.20}$$

$$\Delta\delta_2 = 2\pi \int \Delta f_2 \, dt \ . \tag{2.3.21}$$

Using Equations (2.3.20) and (2.3.21), Equation (2.3.19) may be re-written as

$$\Delta P_{tie} = 2\pi \, T^{\circ}\left(\int \Delta f_1 \, dt - \int \Delta f_2 \, dt\right) \ . \tag{2.3.22}$$

3) The power system demand is a function of the system frequency because of the heavy motor load experienced by power systems. Hence, part of P_I appears as a change in the power demand. This functional relationship for area 1 may be expressed as

$$P_{D1} = P_{D1}(f_1) \ . \tag{2.3.23}$$

Hence, an incremental change in P_{D1} due to an incremental change in f_1 may be expressed as

$$\Delta P_{D1} = \Delta f_1 \frac{d}{df_1}(P_{D1}) \ . \tag{2.3.24}$$

The load frequency characteristic of area 1 is defined as

$$D_1 = \frac{d}{df_1}(P_{D1}) \ . \tag{2.3.25}$$

D_1 is an empirically determined parameter. Substituting Equation (2.3.25) into Equation (2.3.24) gives

$$\Delta P_{D1} = D_1 \, \Delta f_1 \ . \tag{2.3.26}$$

Substituting the sum of Equations (2.3.7), (2.3.22) and (2.3.26) into Equation (2.3.3) for the term P_I gives

$$\Delta P_{G1} - W_1 = \frac{2\, S_1^{\circ}}{f^{\circ}} \frac{d}{dt} (\Delta f_1)$$

$$+ 2\pi \, T^{\circ} \left(\int \Delta f_1 \, dt - \int \Delta f_2 \, dt \right) + D_1 \, \Delta f_1 \ . \tag{2.3.27}$$

Let P_{r1} equal the total megawatt rating of area 1. The per unit inertia constant of area 1 is defined as

$$H_1 = \frac{S_1^{\circ}}{P_{r1}} \ . \tag{2.3.28}$$

Dividing Equations (2.3.1), (2.3.2) and (2.3.27) by P_{r1} gives

$$\frac{d}{dt} (\Delta P_{G1}) = - \frac{1}{T_{T1}} \Delta P_{G1} + \frac{1}{T_{T1}} \Delta X_1 \tag{2.3.29}$$

$$\frac{d}{dt} (\Delta X_1) = - \frac{1}{T_{G1}} \Delta X_1 - \frac{1}{T_{G1} R_1} \Delta f_1 - \frac{1}{T_{G1}} \Delta P_{C1} \tag{2.3.30}$$

$$\Delta P_{G1} - W_1 = \frac{2H_1}{f^{\circ}} \frac{d}{dt} (\Delta f_1) + 2\pi \, T^{\circ} \left(\int \Delta f_1 \, dt \right.$$

$$\left. - \int \Delta f_2 \, dt \right) + D_1 \, \Delta f_1 \tag{2.3.31}$$

where the variables ΔP_{G1}, ΔX_1, ΔP_{c1}, W_1, and the parameters R_1, H_1, T°, and D_1 are now expressed in per unit of P_{r1}. Equations (2.3.29), (2.3.30) and (2.3.31) form the incremental dynamic model of area 1.

The incremental tie line power $\Delta P'_{tie}$ flowing out of area 2, expressed in MW, must equal the negative of the incremental tie line power ΔP_{tie} flowing out of area 1, expressed in MW. Let $\Delta P'_{tie}$ represent the incremental tie line power flow out of area 2, expressed in per unit of P_{r2}, and let ΔP_{tie} represent the incremental tie line power flow out of area 1, expressed in per unit of P_{r1}. Therefore, the relationship between ΔP_{tie} and $\Delta P'_{tie}$ may be expressed as

$$P_{r1}\,\Delta P_{tie} = -\,P_{r2}\,\Delta P'_{tie}\;. \qquad (2.3.32)$$

Letting

$$A = -\frac{P_{r1}}{P_{r2}}\;, \qquad (2.3.33)$$

Equation (2.3.32) may be rewritten as

$$\Delta P'_{tie} = A\,\Delta P_{tie}\;. \qquad (2.3.34)$$

Using Equations (2.3.22) and (2.3.34), $\Delta P'_{tie}$ may be expressed as

$$\Delta P'_{tie} = 2\pi\,A\,T^{\circ}\left(\int \Delta f_1\,dt - \int \Delta f_2\,dt\right)\;. \qquad (2.3.35)$$

To develop a model for area 2, we need modify only the term in Equation (2.3.31) representing the tie line power flow and change the 1 subscripts to 2's in the model of area 1. The needed modification in the tie line power flow is given by Equation (2.3.35). Hence, the incremental dynamic model of area 2 is

$$\frac{d}{dt}(\Delta P_{G2}) = -\frac{1}{T_{T2}}\Delta P_{G2} + \frac{1}{T_{T2}}\Delta X_2 \tag{2.3.36}$$

$$\frac{d}{dt}(\Delta X_2) = -\frac{1}{T_{G2}}\Delta X_2 - \frac{1}{T_{G2}R_2}\Delta f_2 - \frac{1}{T_{G2}}\Delta P_{C2} \tag{2.3.37}$$

$$\Delta P_{G2} - W_2 = \frac{2H_2}{f^{\circ}}\frac{d}{dt}(\Delta f_2) + 2\pi\, A\, T^{\circ}\left(\int \Delta f_1\, dt - \int \Delta f_2\, dt\right) + D_2\,\Delta f_2 \tag{2.3.39}$$

where the variables ΔP_{G2}, ΔX_2, ΔP_{C2}, W_2 and the parameters R_2, H_2, (AT°) and D_2 are expressed in per unit of P_{r2}.

2.4 Description of the Control Strategy to be Investigated

An imbalance between the power generation and the power demand of an electric power system will cause the system frequency to deviate from its nominal value. This deviation in system frequency is used by the electric power industry as an error signal in controlling the power generation. When a power imbalance exists in a multi-area system, the tie line power flows deviate from their nominal values. This deviation in tie line power flows is also used by the power industry as an error signal in controlling the power generation.

Power generation is controlled by varying the speed changers of the turbines. Hence, the speed changer position for the i^{th} area is the control signal for the i^{th} area. The power industry uses a linear, integral control strategy to generate the incremental change in the speed changer position ΔP_{Ci} of the form

$$\Delta P_{Ci} = K_i \int (\Delta P_{tie} + B_i \Delta f_i)\, dt \tag{2.4.1}$$

where ΔP_{tie} = net deviation from nominal of the tie line power flows of area i

K_i = integrator gain

B_i = frequency bias parameter.

The term $\Delta P_{tie} + B_i\ \Delta f_i$ in Equation (2.4.1) is referred to as the area control error. Investigation of the performance of the above control strategy relative to specified cost functions is the topic of this thesis.

3. HYBRID COMPUTER SIMULATION OF THE LOAD FREQUENCY CONTROL OPTIMIZATION PROBLEM

3.1 Hybrid Computer Facilities at V.P.I. and S.U.

The Computer Engineering Laboratory at V.P.I. and S.U. designed and built a hybrid interface which couples a GE-4020 process control digital computer to an EAI-580 analog computer. A few of the functions that the hybrid computer system is capable of performing are:

1) The digital computer can control the mode of the analog computer.

2) The digital computer can set the servo-set potentiometers on the analog computer. The digital computer can also set digitally controlled attenuators, which serve as inverting potentiometers for analog operation. The digitally controlled attenuators are active devices which can be set in approximately three micro-seconds.

3) The digital computer can sense logic signals on and output logic signals to the digital patch panel of the analog computer.

4) By means of an analog to digital converter and a multiplexer, the digital computer can sample analog signals.

3.2 Formulation of the Optimization Problem to be Studied

From Equation (2.4.1) areas 1 and 2 shown in Figure 2.2.1 would have control strategies of the form

$$\Delta P_{C1} = K_1 \int (\Delta P_{tie} + B_1\ \Delta f_1)\ dt \tag{3.2.1}$$

$$\Delta P_{C2} = K_2 \int (\Delta P'_{tie} + B_2\ \Delta f_2)\ dt \tag{3.2.2}$$

where ΔP_{tie} = tie line power flow out of area 1 toward area 2, expressed in per unit of P_{r1}

$\Delta P'_{tie}$ = tie line power flow out of area 2 toward area 1 expressed in per unit of P_{r2}.

This research project is concerned with finding the values of K_1, B_1, K_2 and B_2 such that two different scalar cost criteria are minimized for various values of P_{r2}, P_m, W_1 and W_2,

where P_{r2} = total megawatt rating of area 2

P_m = static tie line capacity

W_i = incremental change in power demand in area i, i = 1, 2.

The total megawatt rating P_{r1} of area 1 will be maintained constant throughout the study. Therefore, the cost criteria C_i are functions of six parameters and two variables. This functional relationship for the cost criteria may be expressed as

$$C_i = C_i(K_1, B_1, K_2, B_2, P_{r2}, P_m, W_1, W_2)$$

$$i = 1, 2. \tag{3.2.3}$$

The two scalar cost criteria used to evaluate the system performance are

$$C_1 = \partial_1 \int_0^T (\Delta P_{tie})^2 \, dt \tag{3.2.4}$$

$$C_2 = \partial_2 \int_0^T |\Delta P_{tie}| \, dt \tag{3.2.5}$$

where ∂_1 and ∂_2 are scaling factors chosen to give reasonable analog voltages.

C_1 is the integral squared error criteria which is often used in evaluating the dynamic performance of a system. C_2, which will be referred to as the integral absolute value error criteria, gives a measure of the absolute value of the "inadvertent interchange of energy" between areas 1 and 2.

The minimum of C_1 will be found for twenty-seven different cases, and the minimum of C_2 will also be found for the same twenty-seven different cases. For any given case the values of P_{r2}, P_m, W_1 and W_2 are held constant. Therefore, for any given case the optimization problem reduces to finding the minimum of C_i as a function of K_1, B_1, K_2 and B_2, which may be expressed as

$$\text{Minimize} \quad C_i = C_i(K_1, B_1, K_2, B_2) \tag{3.2.6}$$

$$i = 1, 2$$

where P_{r2}, P_m, W_1 and W_2 are held constant. The 27 cases to be considered are shown in Table 3.2.1.

Assuming step type changes in power demand and using the mathematical models developed for areas 1 and 2 in Section 2.3, the mathematical model for the two area system may be represented by the following equations:

Table 3.2.1

Twenty-seven Cases to be Considered

Case	P_{r2}(MW)	P_m(MW)	W_1(P.U. of P_{r1})	W_2(P.U. of P_{r2})
1	2000	200	.01	0
2	2000	300	.01	0
3	2000	400	.01	0
4	3000	200	.01	0
5	3000	300	.01	0
6	3000	400	.01	0
7	4000	200	.01	0
8	4000	300	.01	0
9	4000	400	.01	0
10	2000	200	0	.01
11	2000	300	0	.01
12	2000	400	0	.01
13	3000	200	0	.01
14	3000	300	0	.01
15	3000	400	0	.01
16	4000	200	0	.01
17	4000	300	0	.01
18	4000	400	0	.01
19	2000	200	.01	-.01
20	2000	300	.01	-.01
21	2000	400	.01	-.01
22	3000	200	.01	-.01
23	3000	300	.01	-.01
24	3000	400	.01	-.01
25	4000	200	.01	-.01
26	4000	300	.01	-.01
27	4000	400	.01	-.01

$$\frac{d}{dt}(\Delta P_{tie}) = 2\pi\ T^{\circ}(\Delta f_1 - \Delta f_2) \tag{3.2.7}$$

$$\frac{d}{dt}(W_1) = 0\ ,\ W_1(t{=}0) = \text{constant} \tag{3.2.8}$$

$$\frac{d}{dt}(W_2) = 0\ ,\ W_2(t{=}0) = \text{constant} \tag{3.2.9}$$

$$\frac{d}{dt}(\Delta P_{C1}) = K_1(\Delta P_{tie} + B_1\ \Delta f_1) \tag{3.2.10}$$

$$\frac{d}{dt}(\Delta P_{C2}) = K_2(A\Delta P_{tie} + B_2\ \Delta f_2) \tag{3.2.11}$$

$$\frac{d}{dt}(\Delta X_1) = -\frac{1}{T_{G1}}(\Delta X_1 + \frac{1}{R_1}\Delta f_1 + \Delta P_{C1}) \tag{3.2.12}$$

$$\frac{d}{dt}(\Delta X_2) = -\frac{1}{T_{G2}}(\Delta X_2 + \frac{1}{R_2}\Delta f_2 + \Delta P_{C2}) \tag{3.2.13}$$

$$\frac{d}{dt}(\Delta P_{G1}) = -\frac{1}{T_{T1}}(\Delta P_{G1} - \Delta X_1) \tag{3.2.14}$$

$$\frac{d}{dt}(\Delta P_{G2}) = -\frac{1}{T_{T2}}(\Delta P_{G2} - \Delta X_2) \tag{3.2.15}$$

$$\frac{d}{dt}(\Delta f_1) = -\frac{f^{\circ}}{2H_1}(D_1\Delta f_1 + \Delta P_{tie} - \Delta P_{G1} + W_1) \tag{3.2.16}$$

$$\frac{d}{dt}(\Delta f_2) = -\frac{f^{\circ}}{2H_2}(D_2\Delta f_2 + A\Delta P_{tie} - \Delta P_{G2} + W_2) \tag{3.2.17}$$

where all terms for area 1 are expressed in per unit of P_{r1} and all terms for area 2 are expressed in per unit of P_{r2}.

For any given case, the problem of finding the minimum of C_1 may be stated as:

$$\text{Minimize } C_1 = \partial_1 \int_o^T (\Delta P_{tie})^2 \, dt$$

Subject to Equations 3.2.7 through 3.2.17, where the parameters K_1, B_1, K_2 and B_2 are to be varied and all other parameters are fixed. A similar statement may be made for the problem of finding the minimum of C_2.

3.3 Division of the Problem Between the Analog and Digital Computers

Two different search techniques employing a hybrid computer will be used in attempting to solve the optimization problem formulated in Section 3.2. In this section the division of the problem between the analog computer and the digital computer will be discussed.

The mathematical model of the two area system is programmed on the analog computer. The analog computer is also programmed to calculate the values of the cost functions. The analog computer program is shown in Figure 3.3.1. The logic circuitry associated with the calculation of C_2 is depicted in Figure 3.3.1, where as the logic circuitry associated with the calculation of C_1 is omitted. Digitally controlled attenuators are used to represent the values of K_1, B_1, K_2, B_2 and $2\pi T^{\circ}$.

The simulation is controlled by the digital computer. The digital computer controls the mode of the analog computer, causes the potentiometers and digitally controlled attenuators to be set to their corresponding parameter values, senses logic signals on the digital patch panel of the analog computer and samples analog voltages representing the

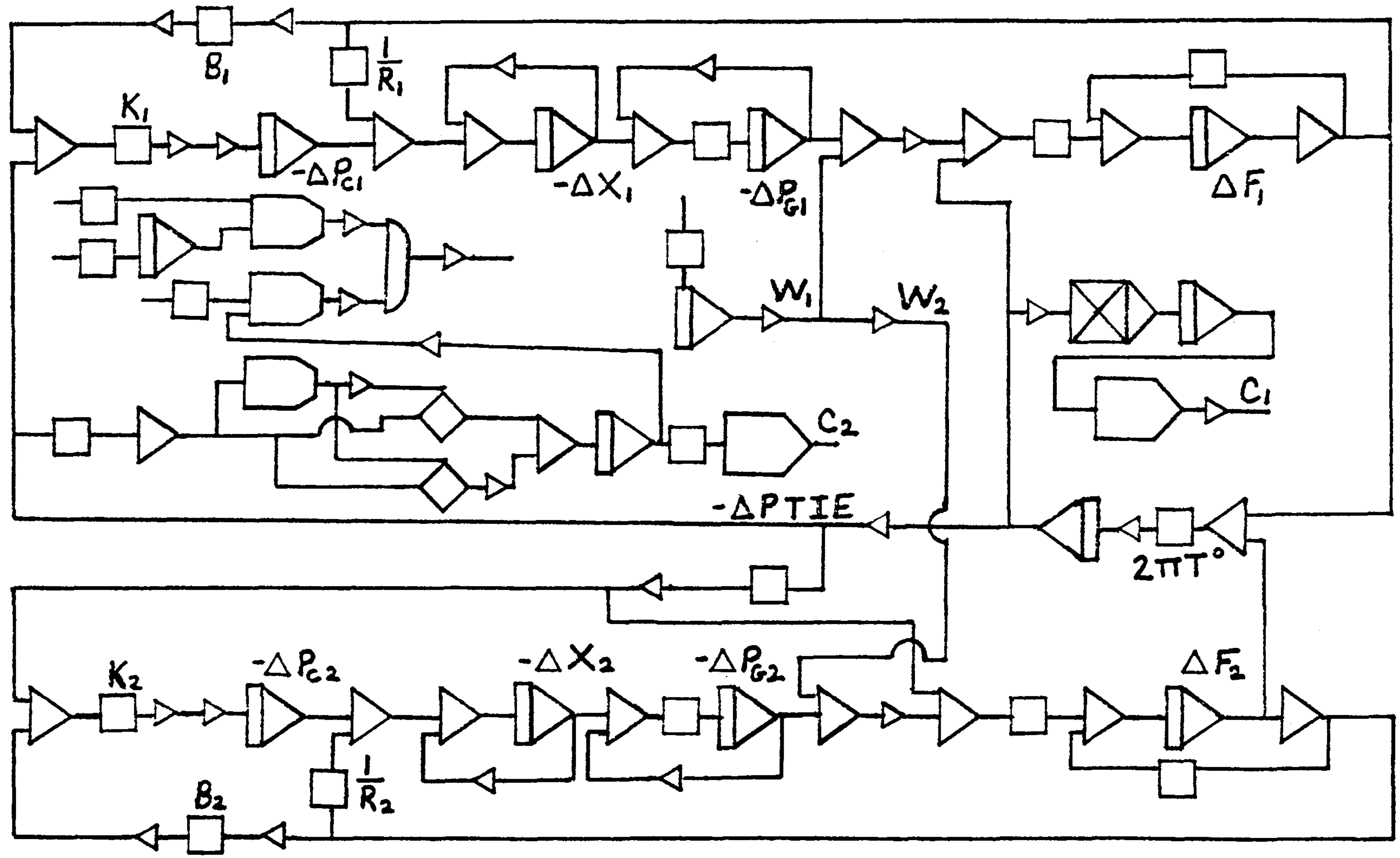

Figure 3.3.1. Analog Computer Simulation of Two-Area Load Frequency Control Problem.

values of the cost functions. The two search procedures employed are programmed on the digital computer. The digital program is written to run through nine case studies, where during each run all nine case studies correspond to the same values of W_1 and W_2. A listing of the digital program which employs the direct search technique is given in the Appendix.

3.4 Calculation of $C_1(T)$ and $C_2(T)$

The procedure that is used to solve for $C_2(T)$ will now be described. A similar procedure applies to $C_1(T)$.

Assume that all pots representing fixed parameter values have been set and that the analog computer is resting in the initial condition mode. Also assume that the digital computer is programmed to obtain the value of $C_2(T)$ corresponding to a set of given values of P_{r2}, P_m, K_1, B_1, K_2 and B_2. The sequence of events that occur in the calculation of $C_2(T)$ are as follows:

1) The digital program will cause the pot representing the parameter $A = \frac{P_{r1}}{P_{r2}}$ and the digitally controlled attenuators representing the parameters $2\pi T^{\circ} = 2\pi\ P_m \cos \delta^{\circ}$, K_1, B_1, K_2 and B_2 to be set to their corresponding values.

2) Next the digital program will cause the analog computer to be placed in the operate mode.

3) The analog computer simulates the response of the two area system to a given W_1 and W_2 and at the same time calculates the value of $C_2(t)$. The analog computer operates until either $C_2(t)$ exceeds a certain given value represented by C_{2max} or until time exceeds the value T. When

either of these conditions occur, a comparator switches states.

4) The switching of the comparator causes a track-store component to store the value of C_2 and at the same time it signals the digital computer to sample C_2. When the digital program has obtained the sampled value of C_2, it causes the analog computer to be placed in the initial condition mode.

The method that the digital program employs to process C_2 depends on the search technique used.

3.5 Fibonnaci Search Method

The Fibonnaci search method provides a logical sequence of steps for locating the extremum of a unimodal function of a single variable. The cost functions C_1 and C_2 are not functions of a single variable. However, from the nature of C_1 (see reference 1) and C_2 it appears reasonable to assume that the cost surfaces defined by them are "bowl shaped." Therefore, it could be the case that starting at a point on the side of the bowl, the Fibonnaci search method would move down the side of the bowl to the minimum of C_i.

The parameters to be varied are K_1, B_1, K_2 and B_2. Values of these parameters recommended by the power industry and values determined according to an integral squared error criteria found in reference 1 all fall in the range of 0.05 to 1.0. Therefore, the region over which the search will be performed is chosen to be

$$0.05 \le K_1 \le 1.0 \;, \quad 0.05 \le B_1 \le 1.0 \;.$$

$$0.05 \le K_2 \le 1.0 \;, \quad 0.05 \le B_2 \le 1.0 \;.$$

In using the Fibonnaci search method to locate the minimum of C_i, three of the parameters are held constant at fixed values and only one of the parameters is varied. For example, consider B_1, K_2 and B_2 to be held at constant values, say $B_1^{(0)}$, $K_2^{(0)}$ and $B_2^{(0)}$, and vary the parameter K_1 until the minimum of

$$C_i \; (K_1, \; B_1^{(0)}, \; K_2^{(0)}, \; B_2^{(0)}) \quad i = 1, \; 2$$

is found. Let this minimum be located at $K_1^{(1)}$, $B_1^{(0)}$, $K_2^{(0)}$ and $B_2^{(0)}$. Now repeat the process, except this time let K_1, K_2 and B_2 be held at the constant values of $K_1^{(1)}$, $K_2^{(0)}$ and $B_2^{(0)}$ and vary B_1. Continue this process until a point is reached such that in searching about this point no lower value of C_i can be found.

The way in which K_1, B_1, K_2 and B_2 are varied in searching for the minimum of C_i will now be described. The following discussion applies to all four parameters. The interval [0.05, 1.0] is divided into eight different sets shown in Table 3.5.1. The twelve points in each set are labeled from 1 to 12, as indicated in the table. It is assumed that C_i is a unimodal function of the particular parameter being varied over each individual set of twelve points. A Fibonnaci search is performed over each set of twelve points. Thus, eight Fibonnaci searches are performed - one for each set. Also, eight cost functions, each corresponding to the optimum of a particular set, are arrived at. The numerical value of the parameter presently being searched corresponding to the minimum of these eight cost functions determines the next iterate for the parameter presently being searched.

The Fibonnaci search that is performed over each set is pictured in

Table 3.5.1

Sets for Fibonnaci Search

Point	1	2	3	4	5	6	7	8	9	10	11	12
Set 1	.05	.06	.07	.08	.09	.10	.11	.12	.13	.14	.15	.16
Set 2	.17	.18	.19	.20	.21	.22	.23	.24	.25	.26	.27	.28
Set 3	.29	.30	.31	.32	.33	.34	.35	.36	.37	.38	.39	.40
Set 4	.41	.42	.43	.44	.45	.46	.47	.48	.49	.50	.51	.52
Set 5	.53	.54	.55	.56	.57	.58	.59	.60	.61	.62	.63	.64
Set 6	.65	.66	.67	.68	.69	.70	.71	.72	.73	.74	.75	.76
Set 7	.77	.78	.79	.80	.81	.82	.83	.84	.85	.86	.87	.88
Set 8	.89	.90	.91	.92	.93	.94	.95	.96	.97	.98	.99	1.0

Figure 3.5.1. To begin to search a particular set of twelve points in Table 3.5.1, the values of C_i corresponding to the fifth and eighth points of that set are calculated, as indicated in Figure 3.5.1. Let these values be represented by $C(5) = C_5$ and $C(8) = C_8$. If $C_5 < C_8$, then the value of C_i corresponding to the third point in the set is calculated next. If $C_8 \leqq C_5$, then the value of C_i corresponding to the tenth point in the set is calculated. The search continues in the manner indicated by Figure 3.5.1 until an optimum value of C_i, located at the bottom of the figure, is found.

Over each set of twelve points, the Fibonnaci search method requires five functional evaluations. For eight sets, this results in a total of forty functional evaluations. Therefore, for any given parameter, forty functional evaluations are required to determine the optimal numerical value for that parameter out of a set of ninety-five possible values.

3.6 Direct Search Procedure

The direct search method is a very straightforward method of determining a local minimum of C_i. The region over which the search will be performed is again chosen to be

$$0.05 \leq K_1 \leq 1.0 \quad , \quad 0.05 \leq B_1 \leq 1.0$$

$$0.05 \leq K_2 \leq 1.0 \quad , \quad 0.05 \leq B_2 \leq 1.0.$$

To begin the direct search method, a point is chosen in the space of feasible solutions, say $K_1^{(0)}$, $B_1^{(0)}$, $K_2^{(0)}$ and $B_2^{(0)}$. Then C_i is evaluated for all possible combinations of the form

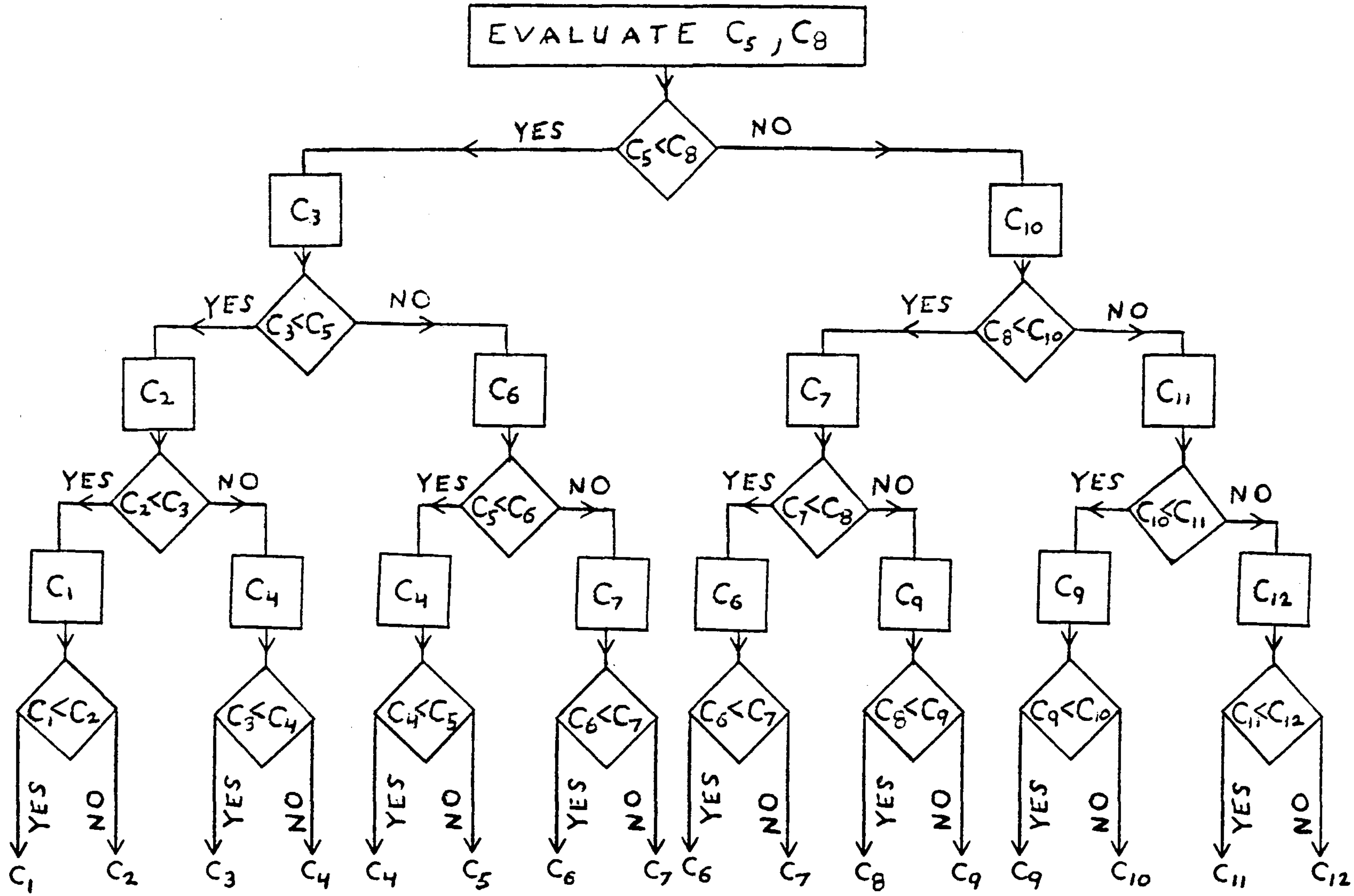

Figure 3.5.1. Fibonnaci Search Procedure.

$$(X_1^{(0)}, X_2^{(0)}, X_3^{(0)}, X_4^{(0)})$$

where $X_1^{(0)} \in (K_1^{(0)} - E_o, K_1^{(0)}, K_1^{(0)} + E_o)$

$X_2^{(0)} \in (B_1^{(0)} - E_o, B_1^{(0)}, B_1^{(0)} + E_o)$

$X_3^{(0)} \in (K_2^{(0)} - E_o, K_2^{(0)}, K_2^{(0)} + E_o)$

$X_4^{(0)} \in (B_2^{(0)} - E_o, B_2^{(0)}, B_2^{(0)} + E_o)$

E_o = small positive number.

Since there are three possible choices for each $X_i^{(0)}$, $i = 1,2,3,4$, the total number of distinct combinations is equal to 81. Hence, 81 values of C_i are calculated. The minimum of those 81 values of C_i is determined. Let $K_1^{(1)}$, $B_1^{(1)}$, $K_2^{(1)}$ and $B_2^{(1)}$ correspond to this minimum. C_i is then again evaluated for all possible combinations of the form

$$(X_1^{(1)}, X_2^{(1)}, X_3^{(1)}, X_4^{(1)})$$

where $X_1^{(1)} \in (K_1^{(1)} - E_1, K_1^{(1)}, K_1^{(1)} + E_1)$

$X_2^{(1)} \in (B_1^{(1)} - E_1, B_1^{(1)}, B_1^{(1)} + E_1)$

$X_3^{(1)} \in (K_2^{(1)} - E_1, K_2^{(1)}, K_2^{(1)} + E_1)$

$X_4^{(1)} \in (B_2^{(1)} - E_1, B_2^{(1)}, B_2^{(1)} + E_1)$

E_1 = small positive number.

The process is repeated until a point is found, say $K_1^{(n)}$, $B_1^{(n)}$, $K_2^{(n)}$ and $B_2^{(n)}$ such that

$$C_i(K_1^{(n)}, B_1^{(n)}, K_2^{(n)}, B_2^{(n)}) \leqq C_i(X_1^{(n)}, X_2^{(n)}, X_3^{(n)}, X_4^{(n)})$$

where $X_1^{(n)} \varepsilon (K_1^{(n)} - E_n, K_1^{(n)}, K_1^{(n)} + E_n)$

$X_2^{(n)} \varepsilon (B_1^{(n)} - E_n, B_1^{(n)}, B_1^{(n)} + E_n)$

$X_3^{(n)} \varepsilon (K_2^{(n)} - E_n, K_2^{(n)}, K_2^{(n)} + E_n)$

$X_4^{(n)} \varepsilon (B_2^{(n)} - E_n, B_2^{(n)}, B_2^{(n)} + E_n)$

E_n = small positive number.

$K_1^{(n)}$, $B_1^{(n)}$, $K_2^{(n)}$ and $B_2^{(n)}$ is then a local minimum of C_i.

4. RESULTS AND COMPARISON WITH INDUSTRY STANDARDS

4.1 Simulation Data

The final time of integration for the evaluation of the cost functions C_1 and C_2 is chosen to be

$$T = 8 \text{ seconds.}$$

This value of T may be seen to be reasonable by observing that in the vicinity of the optimum settings, the integrators representing C_1 and C_2 have for all practical purposes reached steady state by 8 seconds.

In this study the following system data will be used:

$$f^\circ = 60 \text{ Hz}$$

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

$$\text{Base MVA} = 2000 \text{ MVA}$$

$$P^\circ_{D1} = 1000 \text{ MW}$$

$$P^\circ_{D2} = 0.5\, P_{r2} \text{ MW}$$

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

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

$$T_{T1} = T_{T2} = 0.3 \text{ sec}$$

$$T_{G1} = T_{G2} = 0.1 \text{ sec}$$

$$R_1 = R_2 = 2.4 \text{ Hz/pu MW}$$

$$\delta_1^\circ - \delta_2^\circ = 30 \text{ degrees}$$

P_m, and therefore $T^\circ = P_m \cos \delta^\circ$, depends upon the case being considered. P_{r2}, and therefore $A = P_{r1}/P_{r2}$, also depends upon the case being considered.

$P_{D1}{}^\circ$ and $P_{D2}{}^\circ$ represent the nominal operating loads of areas 1 and 2, respectively, before the step change in power demand occurs. It is assumed that the load frequency characteristic D_i is a linear function of the power demand at the nominal operating point of area i. The load frequency characteristic D_i is expressed as

$$D_i = \frac{P_{Di}^\circ}{f^\circ} \quad , \quad i = 1,2 \ .$$

4.2 Results of Fibonnaci Search

The Fibonnaci search method did not prove effective in locating the minima of C_1 and C_2. The method did converge to an answer in all cases. However, in a few cases it converged to values of K_1, B_1, K_2 and B_2 that corresponded to a higher value of the cost function than the starting point had. Therefore, it appears that the assumption that C_1 and C_2 are unimodal functions of the particular parameter being varied over each interval of length 0.12 is false.

4.3 Results of Direct Search

The direct search method did prove effective in locating the minima of C_1 and C_2. The results for the fifty-four cases studied are listed in Tables 4.3.1 through 4.3.6. The incremental tie line power ΔP_{tie} flowing out of area 1 is plotted in Figures 4.3.1 through 4.3.18 for the cases where W_1 = .01 pu MW and W_2 = -.01 pu MW.

The values of K_1, B_1, K_2 and B_2 listed in Tables 4.3.1 through 4.3.6 correspond to the solutions of the optimization problems. The values listed in the columns labeled "Minimum Cost" and "Industry's Cost" in Tables 4.3.1 through 4.3.6 are octal numbers which represent analog voltages. In the column labeled "Minimum Cost", each cost corresponds to the minimum of C_1 or C_2 for a particular case. In the column labeled "Industry's Cost", each cost corresponds to a value of C_1 or C_2 evaluated at settings of K_1, B_1, K_2 and B_2 that the power industry might recommend for areas with characteristics corresponding to those given in Section 4.1. In most areas today, the value of K that is chosen by the power industry falls in the range of 0.05 to 0.25. The power industry recommends setting B equal to $D + \frac{1}{R}$. Using the values of D_1, R_1, D_2 and R_2 given in Section 4.1, the values of B_1 and B_2 are found to be

$$B_1 = B_2 = 0.425 .$$

Therefore, for the calculation of the industry's cost corresponding to control settings that the power industry might conceivably use in practice, the values of

$$K_1 = K_2 = 0.1 \quad \text{and} \quad B_1 = B_2 = 0.425$$

were chosen.

The columns labeled "Iterations" in Tables 4.3.1 through 4.3.6 represent the number of times C_1 or C_2 was evaluated for each case before the minimum was found. With the analog computer speeded up by a factor of ten, each evaluation of C_1 or C_2 required approximately one second. The hybrid program required between one and two hours to run through any set of nine cases listed in Tables 4.3.1 through 4.3.6.

The "cost surfaces" of C_1 and C_2 were found to be very "flat" in the vicinity of the minimum. In other words, for any particular case listed in Tables 4.3.1 through 4.3.6, there are many different combinations of settings of K_1, B_1, K_2 and B_2 that will give approximately the same minimum cost. The values of K_1, B_1, K_2 and B_2 listed in Tables 4.3.1 through 4.3.6 are the values that the hybrid program converged to. Due to the flatness of the cost functions, step sizes in the neighborhood of 0.01 did not prove as effective in obtaining convergence to the minimum as did step sizes in the neighborhood of 0.05.

The flatness of the cost function C_1 may be demonstrated by comparing the first three cases in Table 4.3.1 to the first three cases in Table 4.3.3. In Table 4.3.1 the system disturbance was

$$W_1 = 0.01 \text{ pu MW} \quad \text{and} \quad W_2 = 0 \text{ pu MW} ,$$

which was just the opposite of the system disturbance used in Table 4.3.3, which was

$$W_1 = 0 \text{ pu MW} \quad \text{and} \quad W_2 = 0.01 \text{ pu MW}$$

Therefore, since areas 1 and 2 are the same size in the first three cases of both Tables 4.3.1 and 4.3.3, it would be expected that the minimum cost would be the same for corresponding cases. As shown in the tables, the minimum cost is the same for corresponding cases. It also might be expected that the values of K_1 and B_1 in the first three cases of Table 4.3.1 would be equal to the corresponding values of K_2 and B_2 in the first three cases of Table 4.3.3. Likewise, it also might be expected that the values of K_2 and B_2 in the first three cases of Table 4.3.1 would be equal to the corresponding values of K_1 and B_1 in the first three cases of Table 4.3.3. However, this proves true only in the case for which P_m = 300 MW. The flatness of the cost function C_2 may be demonstrated by comparing the first three cases of Table 4.3.2 with the first three cases of Table 4.3.4.

An interesting result of the simulations is that the cost function C_2 evaluated at the industry's settings is insensitive to a change in P_m for a fixed value of P_{r2}. For instance, consider the following entries from Table 4.3.2.

P_{r2}(MW)	P_m(MW)	Industry's Cost(C_2)
2000	200	654
2000	300	660
2000	400	660
3000	200	763
3000	300	774
3000	400	770

For P_{r2} equal either 2000 or 3000 MW, note the small variation in C_2 as P_m increases.

The results listed in Tables 4.3.5 and 4.3.6 correspond to a load increase in area 1 and a load decrease in area 2. This situation may be considered to be a "worst case" analysis. The solutions given in Tables 4.3.5 and 4.3.6 indicate that the settings of B_1 and B_2 should be fairly low and the settings of K_1 and K_2 should be fairly high to minimize the inadvertent interchange of energy. $\Delta P_{tie} \equiv$ PTIE is plotted in Figures 4.3.1 through 4.3.18 for the results given in Tables 4.3.5 and 4.3.6. For a fixed P_{r2}, note the increase in the strength of the oscillations as P_m increases.

Table 4.3.1

Integral Squared Error Criteria C_1

W_1 = 0.01 pu MW W_2 = 0 pu MW

P_{r2} (MW)	P_M (MW)	K_1	B_1	K_2	B_2	Minimum Cost	Industry's Cost	Iterations
2000	200	.65	.65	.15	.15	313	777	324
2000	300	.8	.4	.2	.2	417	1064	243
2000	400	.95	.25	.1	.1	517	1153	324
3000	200	1.0	.4	.2	.2	401	1330	162
3000	300	1.0	.25	.15	.15	540	1434	243
3000	400	1.0	.15	.15	.05	654	1532	405
4000	200	1.0	.4	.2	.2	453	1560	162
4000	300	1.0	.25	.05	.05	630	1700	324
4000	400	1.0	.15	.15	.15	760	2007	243

Table 4.3.2

Integral Absolute Value Error Criteria C_2

$W_1 = 0.01$ pu MW $\qquad W_2 = 0$ pu MW

P_{r2} (MW)	P_M (MW)	K_1	B_1	K_2	B_2	Minimum Cost	Industry's Cost	Iterations
2000	200	1.0	.2	.2	.3	254	654	567
2000	300	.6	.35	.2	.2	340	660	891
2000	400	.65	.2	.2	.2	423	660	891
3000	200	.95	.2	.3	.3	277	763	405
3000	300	.8	.2	.2	.2	360	774	567
3000	400	.7	.2	.15	.15	447	770	1053
4000	200	.9	.25	.25	.25	305	1045	324
4000	300	.85	.15	.1	.1	377	1054	486
4000	400	.8	.1	.15	.05	477	1060	648

Table 4.3.3

Integral Squared Error Criteria C_1

W_1 = 0 pu MW W_2 = 0.01 pu MW

P_{r2} (MW)	P_M (MW)	K_1	B_1	K_2	B_2	Minimum Cost	Industry's Cost	Iterations
2000	200	.25	.25	.8	.5	313	777	405
2000	300	.2	.2	.8	.4	417	1064	486
2000	400	.1	.1	.8	.35	517	1153	648
3000	200	.35	.35	.85	.45	377	1301	243
3000	300	.15	.2	.7	.6	517	1407	507
3000	400	.05	.05	.75	.55	626	1507	891
4000	200	.35	.35	.85	.45	437	1534	243
4000	300	.25	.25	.75	.5	600	1654	405
4000	400	.05	.05	.65	.65	703	1760	891

Table 4.3.4

Integral Absolute Value Error Criteria C_2

W_1 = 0 pu MW W_2 = 0.01 pu MW

P_{r2} (MW)	P_M (MW)	K_1	B_1	K_2	B_2	Minimum Cost	Industry's Cost	Iterations
2000	200	.15	.25	1.0	.2	254	654	405
2000	300	.15	.15	.8	.2	340	660	405
2000	400	.2	.15	.75	.15	417	660	405
3000	200	.25	.35	.95	.3	207	776	405
3000	300	.1	.1	1.0	.2	351	1000	486
3000	400	.2	.2	.85	.2	437	777	324
4000	200	.3	.3	.5	.65	177	1060	324
4000	300	.2	.2	1.0	.25	370	1066	324
4000	400	.15	.15	.8	.3	437	1072	405

Table 4.3.5

Integral Squared Error Criteria C_1

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

P_{r2} (MW)	P_M (MW)	K_1	B_1	K_2	B_2	Minimum Cost	Industry's Cost	Iterations
2000	200	.95	.15	1.0	.15	437	1300	567
2000	300	.65	.05	1.0	.05	570	1413	567
2000	400	.75	.05	.8	.05	707	1460	567
3000	200	.95	.25	.95	.3	560	Saturation	567
3000	300	.75	.05	1.0	.15	745	Saturation	567
3000	400	.65	.05	1.0	.05	1077	Saturation	567
4000	200	.95	.25	.95	.35	637	Saturation	567
4000	300	.85	.05	1.0	.25	1054	Saturation	567
4000	400	.8	.05	1.0	.05	1227	Saturation	567

Table 4.3.6

Integral Absolute Value Error Criteria C_2

$W_1 = 0.01$ pu MW $W_2 = -0.01$ pu MW

P_{r2} (MW)	P_M (MW)	K_1	B_1	K_2	B_2	Minimum Cost	Industry's Cost	Iterations
2000	200	.65	.05	.95	.05	517	1476	486
2000	300	.7	.05	.7	.05	664	1507	567
2000	400	.5	.05	.8	.05	1017	1503	567
3000	200	.85	.05	1.0	.05	547	1740	243
3000	300	.7	.05	.8	.05	721	1760	567
3000	400	.6	.05	.8	.05	1060	1760	567
4000	200	.85	.1	1.0	.15	605	2103	243
4000	300	.65	.05	1.0	.05	747	2107	567
4000	400	.65	.05	.85	.05	1100	2107	567

Figure 4.3.1

Integral Squared Error Criteria C_1

Plot of ΔP_{tie} = PTIE

P_{r2} = 2000 MW P_M = 200 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.95$ $B_1 = 0.15$ $K_2 = 1.0$ $B_2 = 0.15$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

Figure 4.3.2

Integral Absolute Value Error Criteria C_2

Plot of ΔP_{tie} = PTIE

P_{r2} = 2000 MW P_M = 200 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.65$ $B_1 = 0.05$ $K_2 = 0.95$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

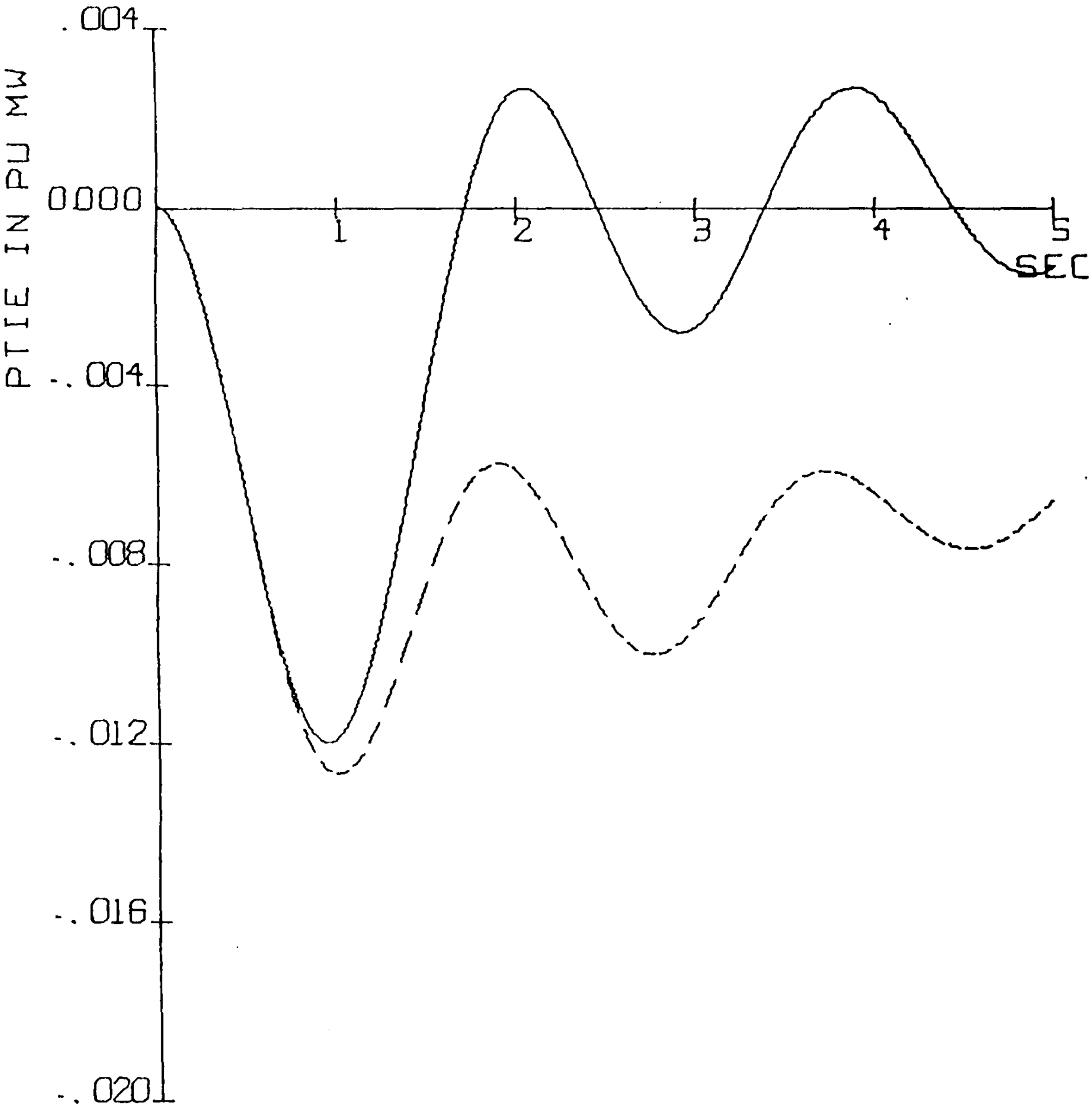

FIGURE 431

INTEGRAL SQUARED ERROR CRITERIA
BASE MVA=2000
PR1=1 PR2=1 PM=1 W1=01 W2=-01 PU MW
SOLID LINE K1=95 B1=15 K2=10 B2=15
DASHED LINE K1=1 B1=425 K2=1 B2=425

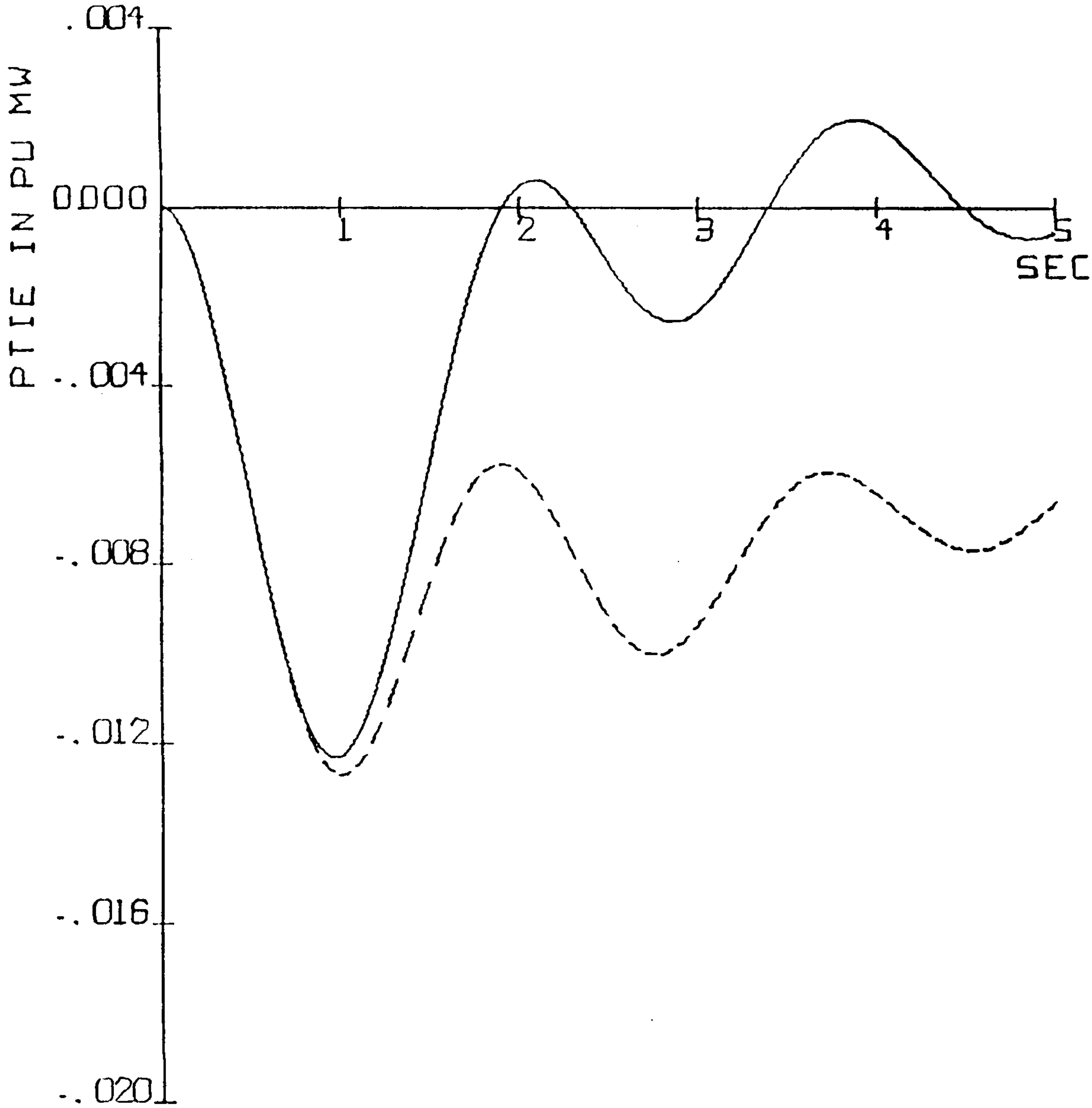

FIGURE 432

INTEGRAL ABSOLUTE VALUE ERROR CRITERIA
BASE MVA-2000
PR1-1 PR2-1 PM-1 W1-01 W2--01 PU MW
SOLID LINE K1-65 B1-05 K2-95 B2-05
DASHED LINE K1-1 B1-425 K2-1 B2-425

Figure 4.3.3

Integral Squared Error Criteria C_1

Plot of ΔP_{tie} = PTIE

P_{r2} = 2000 MW P_M = 300 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.65$ $B_1 = 0.05$ $K_2 = 1.0$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

Figure 4.3.4

Integral Absolute Value Error Criteria C_2

Plot of ΔP_{tie} = PTIE

P_{r2} = 2000 MW P_M = 300 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.7$ $B_1 = 0.05$ $K_2 = 0.7$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

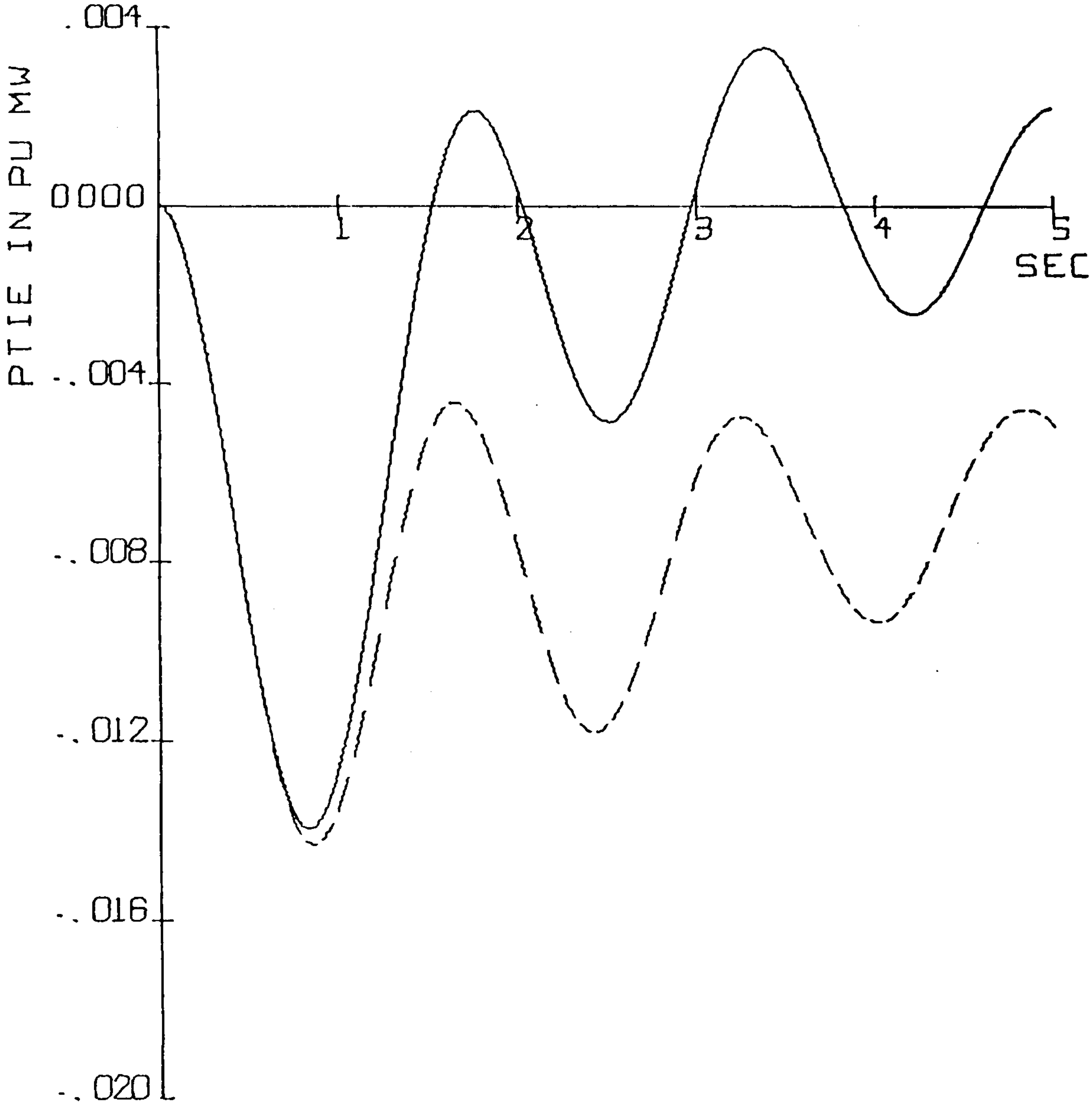

FIGURE 433

INTEGRAL SQUARED ERROR CRITERIA
BASE MVA-2000
PR1-1 PR2-1 PM-.15 W1-.01 W2-.01 PU MW
SOLID LINE K1-.65 B1-.05 K2-.10 B2-.05
DASHED LINE K1-.1 B1-.425 K2-.1 B2-.425

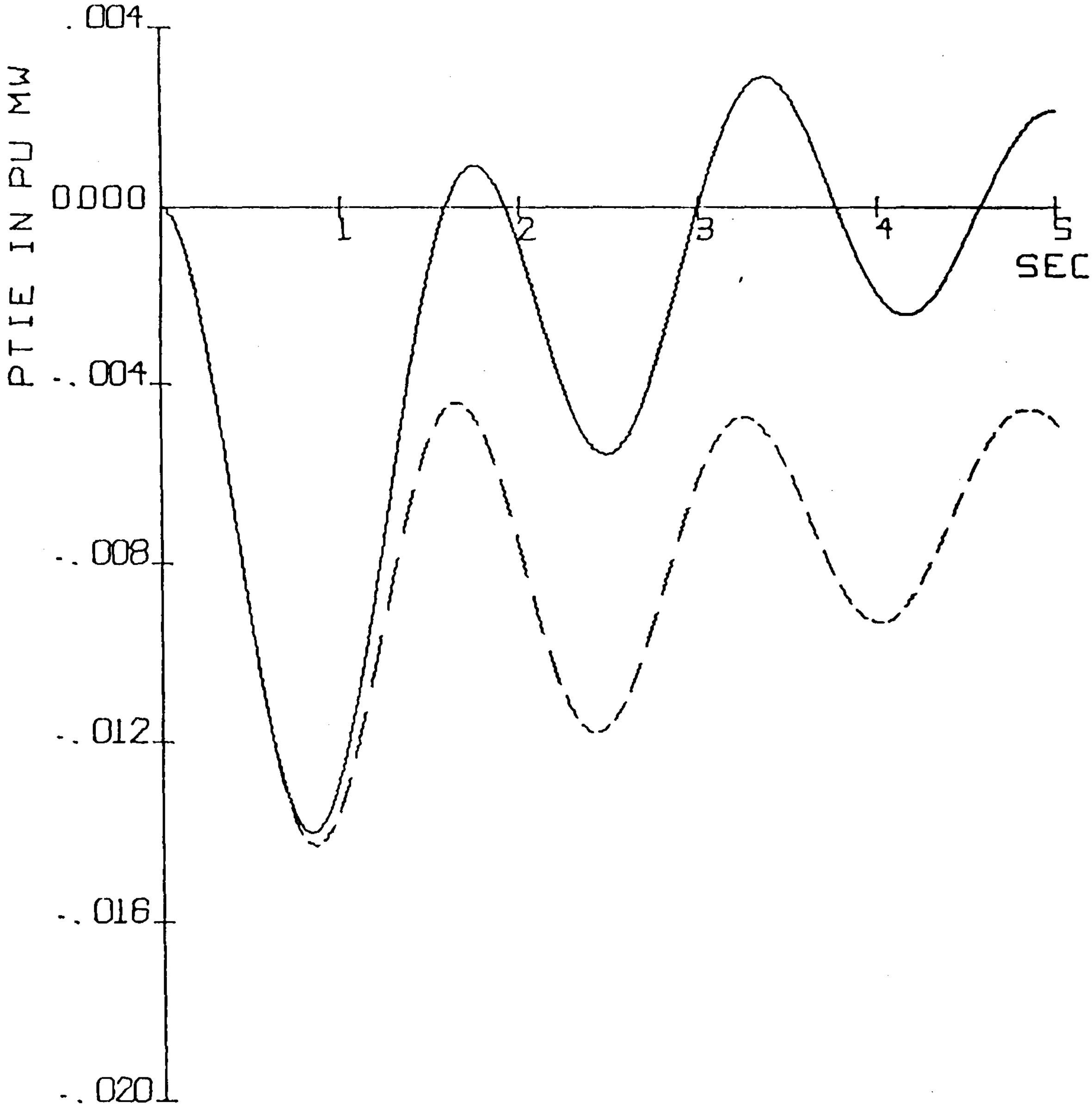

FIGURE 4.3.4

INTEGRAL ABSOLUTE VALUE ERROR CRITERIA
BASE MVA=2000
PR1=1 PR2=1 PM=.15 W1=.01 W2=-.01 PU MW
SOLID LINE K1=.7 B1=.05 K2=.7 B2=.05
DASHED LINE K1=.1 B1=.425 K2=.1 B2=.425

Figure 4.3.5

Integral Squared Error Criteria C_1

Plot of ΔP_{tie} = PTIE

P_{r2} = 2000 MW P_M = 400 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.75$ $B_1 = 0.05$ $K_2 = 0.8$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

Figure 4.3.6

Integral Absolute Value Error Criteria C_2

Plot of ΔP_{tie} = PTIE

P_{r2} = 2000 MW P_M = 400 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.5$ $B_1 = 0.05$ $K_2 = 0.8$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

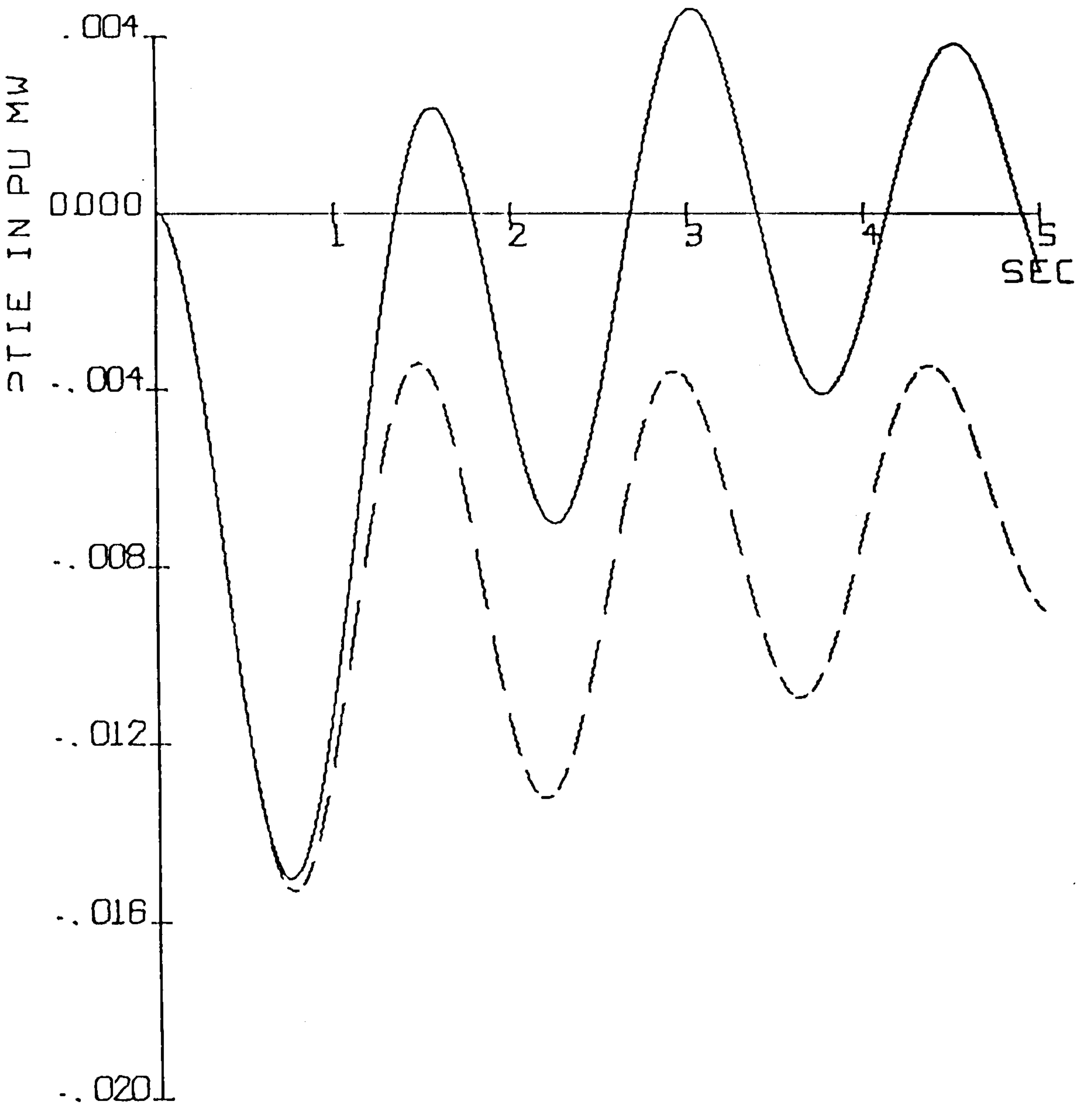

FIGURE 435

INTEGRAL SQUARED ERROR CRITERIA
BASE MVA-2000
PR1-1 PR2-1 PM-2 W1-01 W2--01 PU MW
SOLID LINE K1-.75 B1-05 K2-.8 B2-05
DASHED LINE K1-1 B1-.425 K2-1 B2-.425

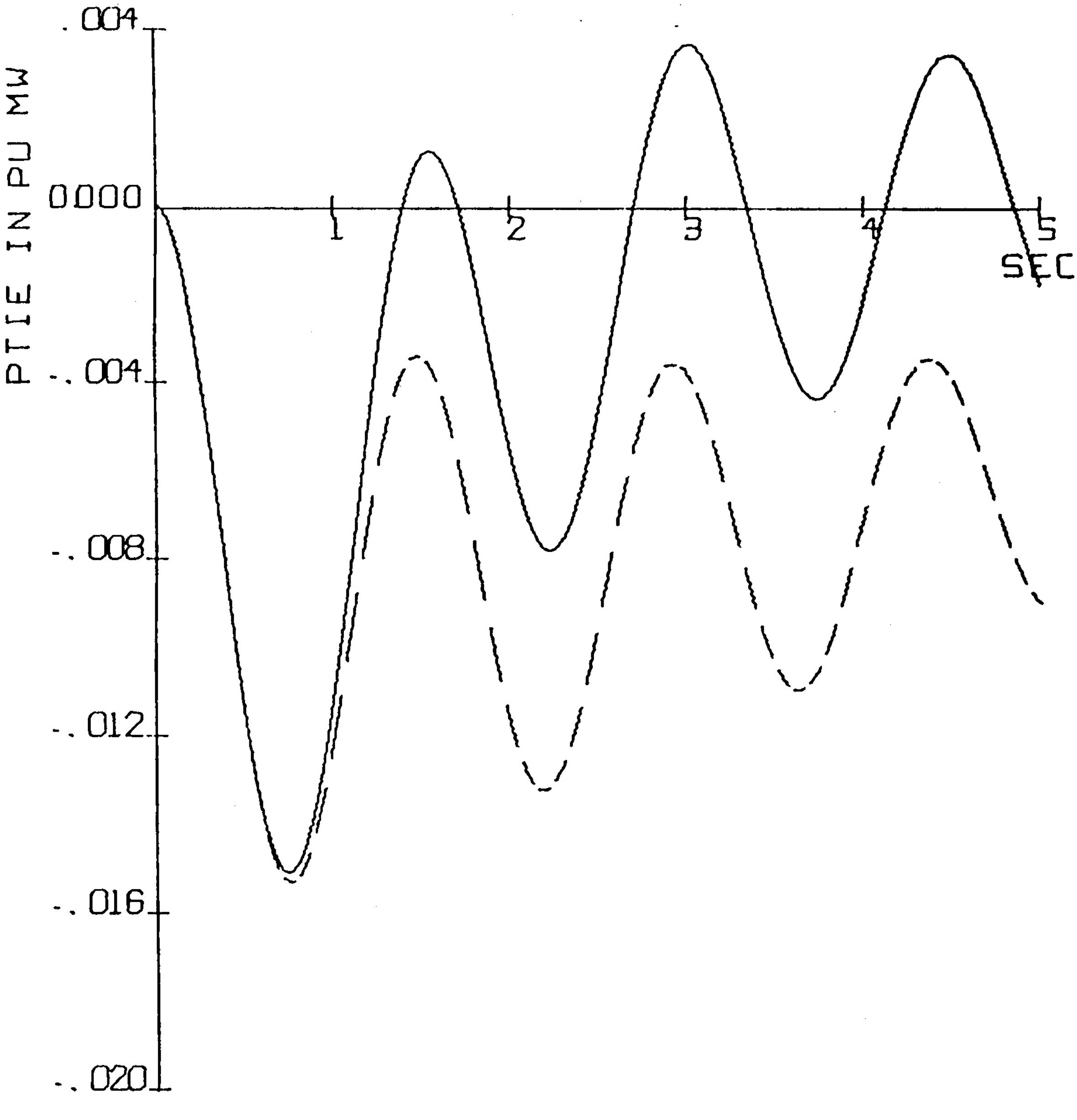

FIGURE 436

INTEGRAL ABSOLUTE VALUE ERROR CRITERIA
BASE MVA=2000
PR1=1 PR2=1 PM=2 W1=01 W2=-01 PU MW
SOLID LINE K1=5 B1=05 K2=8 B2=05
DASHED LINE K1=1 B1=.425 K2=1 B2=.425

Figure 4.3.7

Integral Squared Error Criteria C_1

Plot of ΔP_{tie} = PTIE

P_{r2} = 3000 MW P_M = 200 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.95$ $B_1 = 0.25$ $K_2 = 0.95$ $B_2 = 0.3$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

Figure 4.3.8

Integral Absolute Value Error Criteria C_2

Plot of ΔP_{tie} = PTIE

P_{r2} = 3000 MW P_M = 200 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.85$ $B_1 = 0.05$ $K_2 = 1.0$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

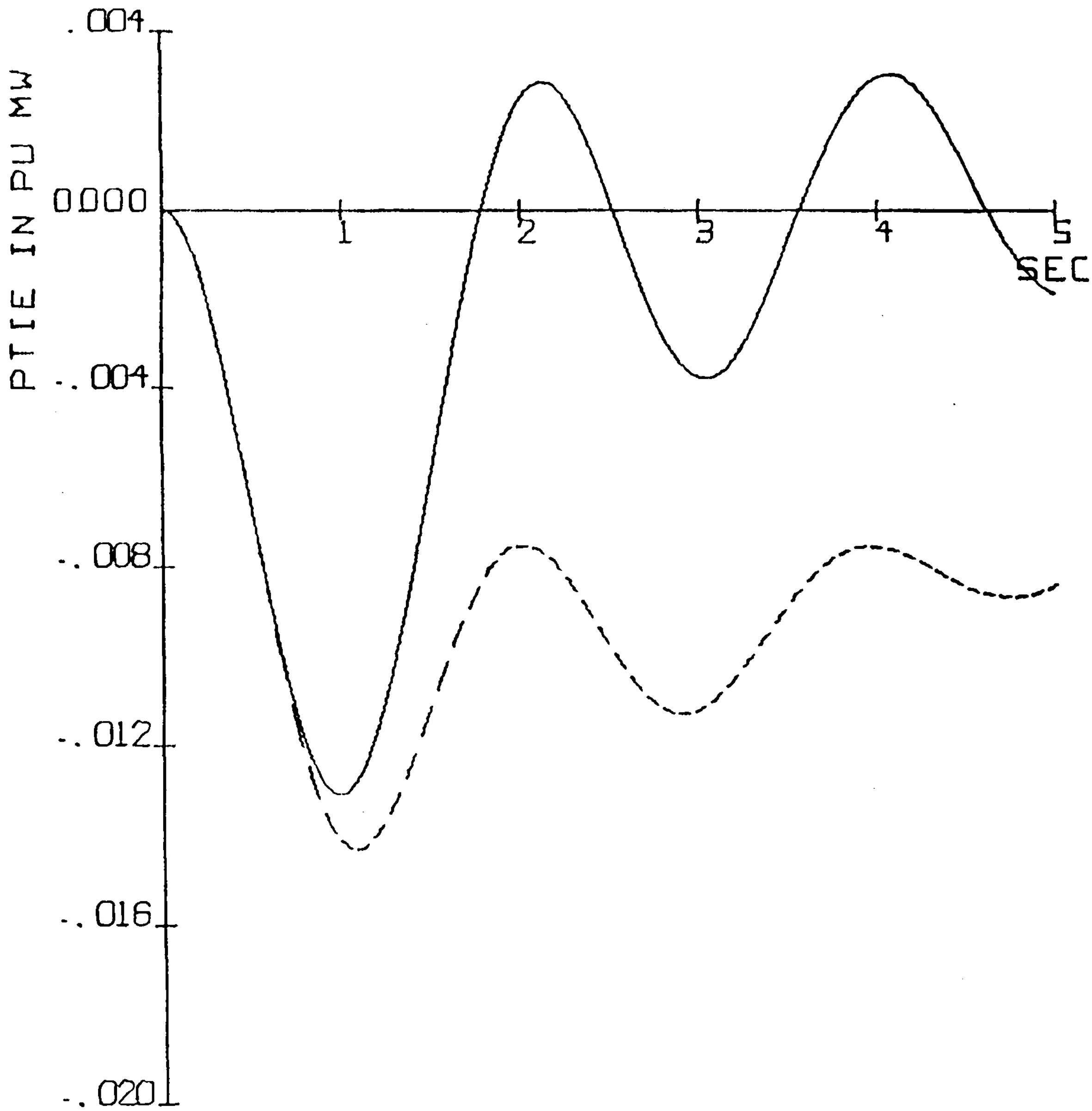

FIGURE 437

INTEGRAL SQUARED ERROR CRITERIA
BASE MVA-2000
PR1-1 PR2-15 PM-1 W1-01 W2--01 PU MW
SOLID LINE K1-95 B1-25 K2-95 B2-3
DASHED LINE K1-1 B1-425 K2-1 B2-425

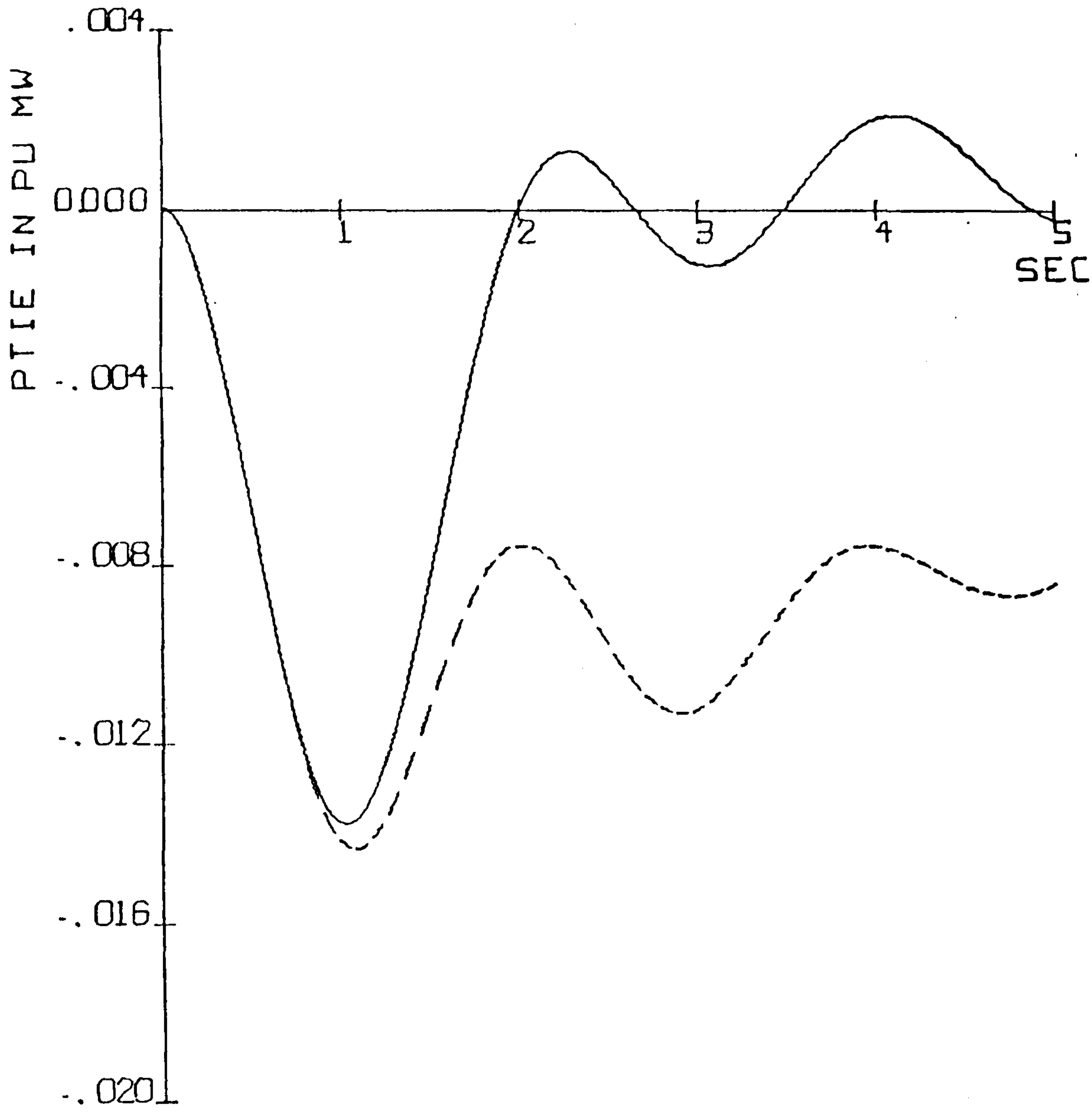

FIGURE 43B

INTEGRAL ABSOLUTE VALUE ERROR CRITERIA
BASE MVA=2000
PR1=.1 PR2=.15 PM=.1 W1=.01 W2=-.01 PU MW
SOLID LINE K1=.85 B1=.05 K2=.10 B2=.05
DASHED LINE K1=.1 B1=.425 K2=.1 B2=.425

Figure 4.3.9

Integral Squared Error Criteria C_1

Plot of ΔP_{tie} = PTIE

P_{r2} = 3000 MW P_M = 300 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.75$ $B_1 = 0.05$ $K_2 = 1.0$ $B_2 = 0.15$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

Figure 4.3.10

Integral Absolute Value Error Criteria C_2

Plot of ΔP_{tie} = PTIE

P_{r2} = 3000 MW P_M = 300 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.7$ $B_1 = 0.05$ $K_2 = 0.8$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

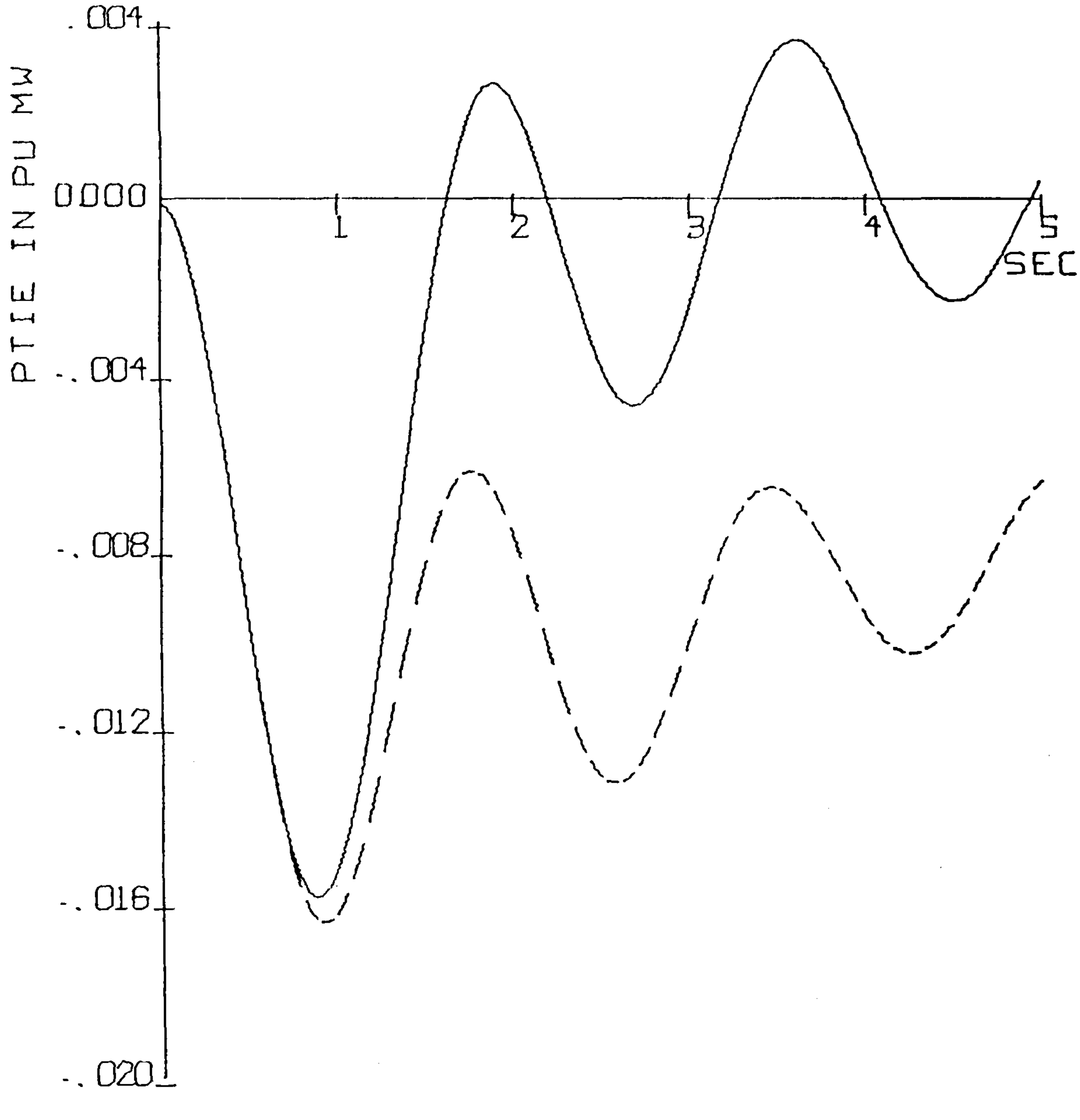

FIGURE 439

INTEGRAL SQUARED ERROR CRITERIA
BASE MVA=2000
PR1=1 PR2=15 PM=15 W1=01 W2=-01 PU MW
SOLID LINE K1=75 B1=05 K2=10 B2=15
DASHED LINE K1=1 B1=425 K2=1 B2=425

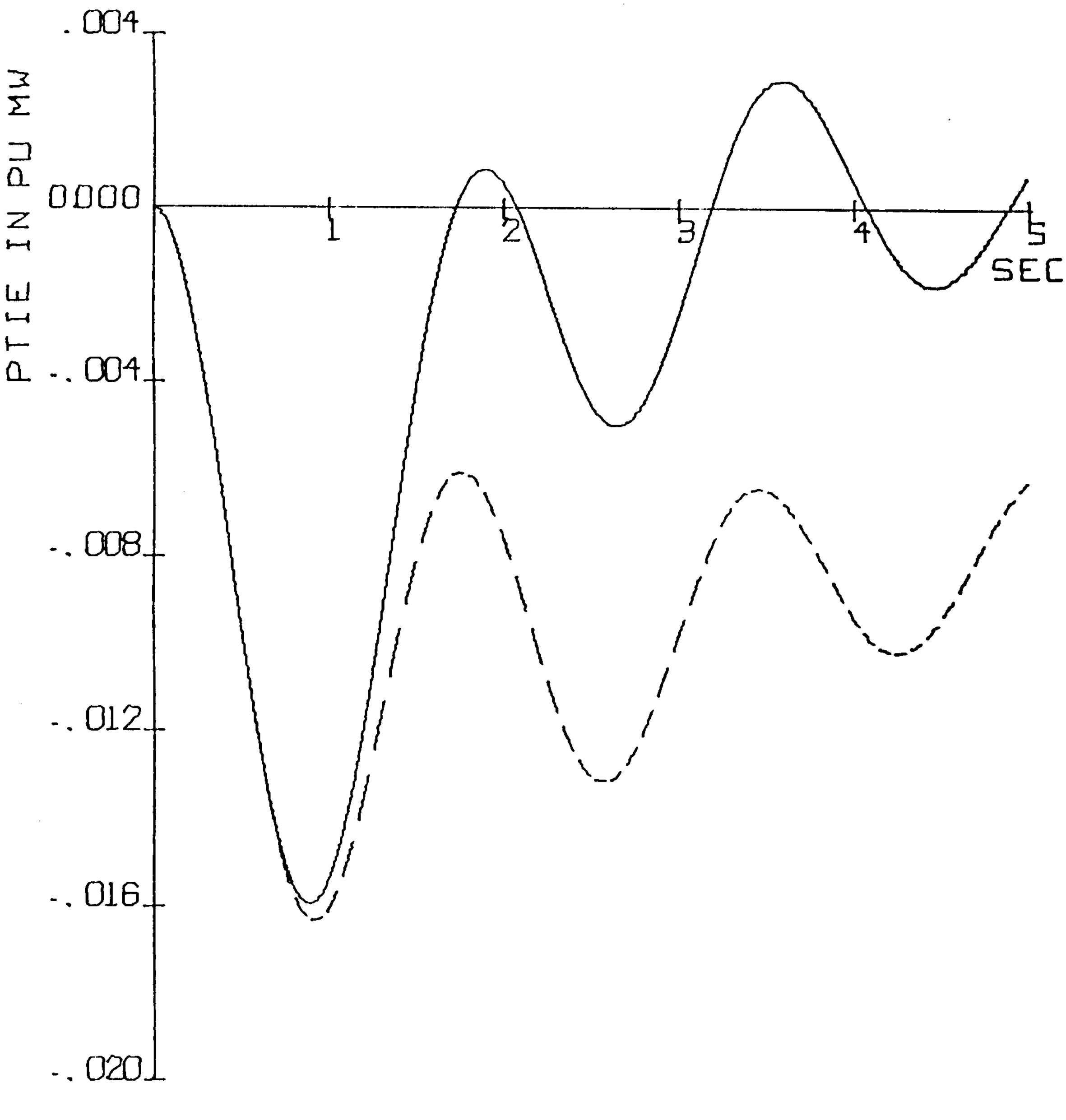

FIGURE 4310

INTEGRAL ABSOLUTE VALUE ERROR CRITERIA
BASE MVA-2000
PR1-.1 PR2-.15 PM-.15 W1-.01 WI--.01 PU MW
SOLID LINE K1-.7 B1-.05 K2-.8 B2-.05
DASHED LINE K1-.1 B1-.425 K2-.1 B2-.425

Figure 4.3.11

Integral Squared Error Criteria C_1

Plot of ΔP_{tie} = PTIE

P_{r2} = 3000 MW P_M = 400 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.65$ $B_1 = 0.05$ $K_2 = 1.0$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

Figure 4.3.12

Integral Absolute Value Error Criteria C_2

Plot of ΔP_{tie} = PTIE

P_{r2} = 3000 MW P_M = 400 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.6$ $B_1 = 0.05$ $K_2 = 0.8$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

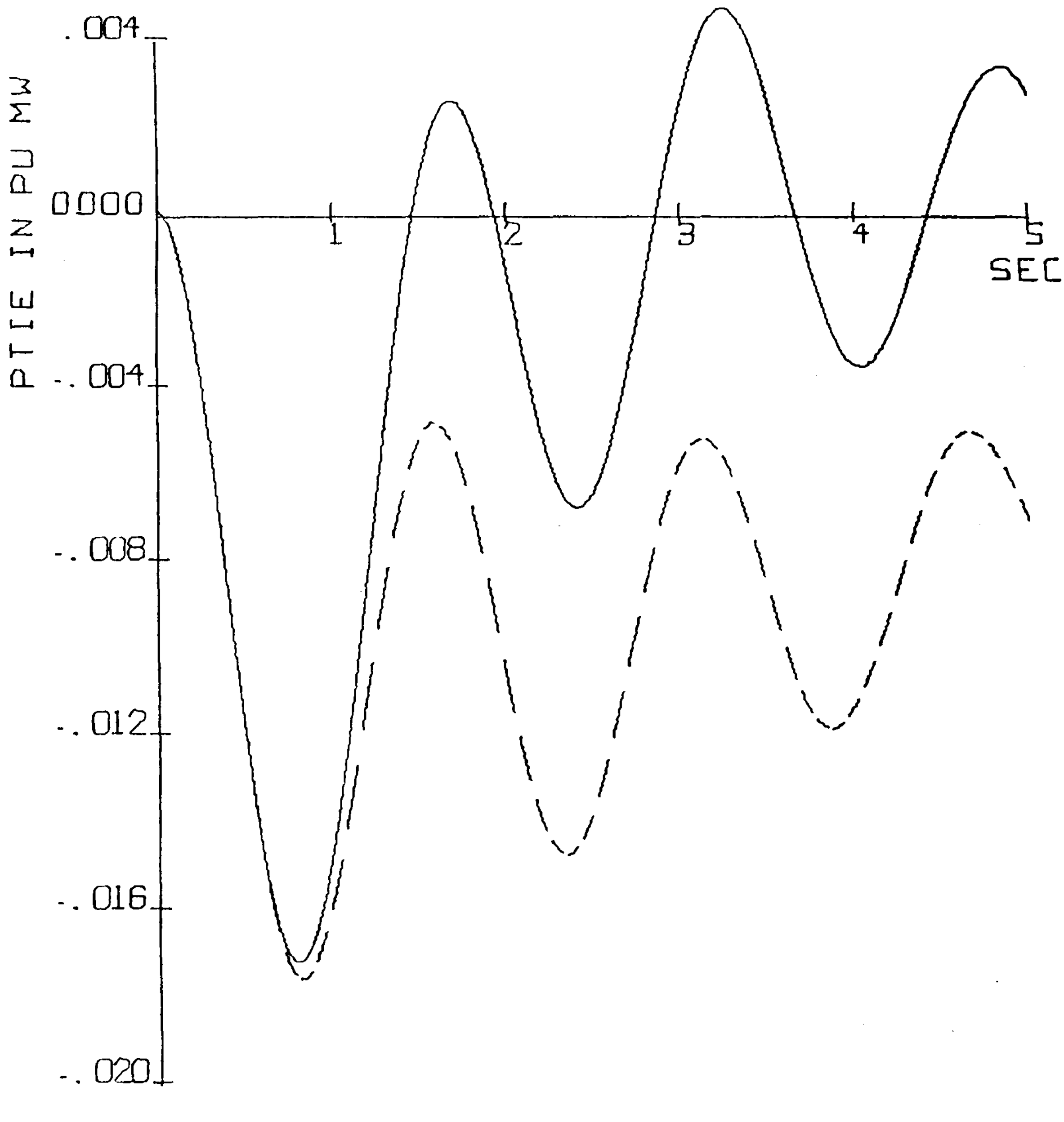

FIGURE 4311

INTEGRAL SQUARED ERROR CRITERIA
BASE MVA-2000
PR1-1 PR2-15 PM-2 W1-01 W2--01 PU MW
SOLID LINE K1-65 B1-05 K2-10 B2-05
DASHED LINE K1-1 B1-425 K2-1 B2-425

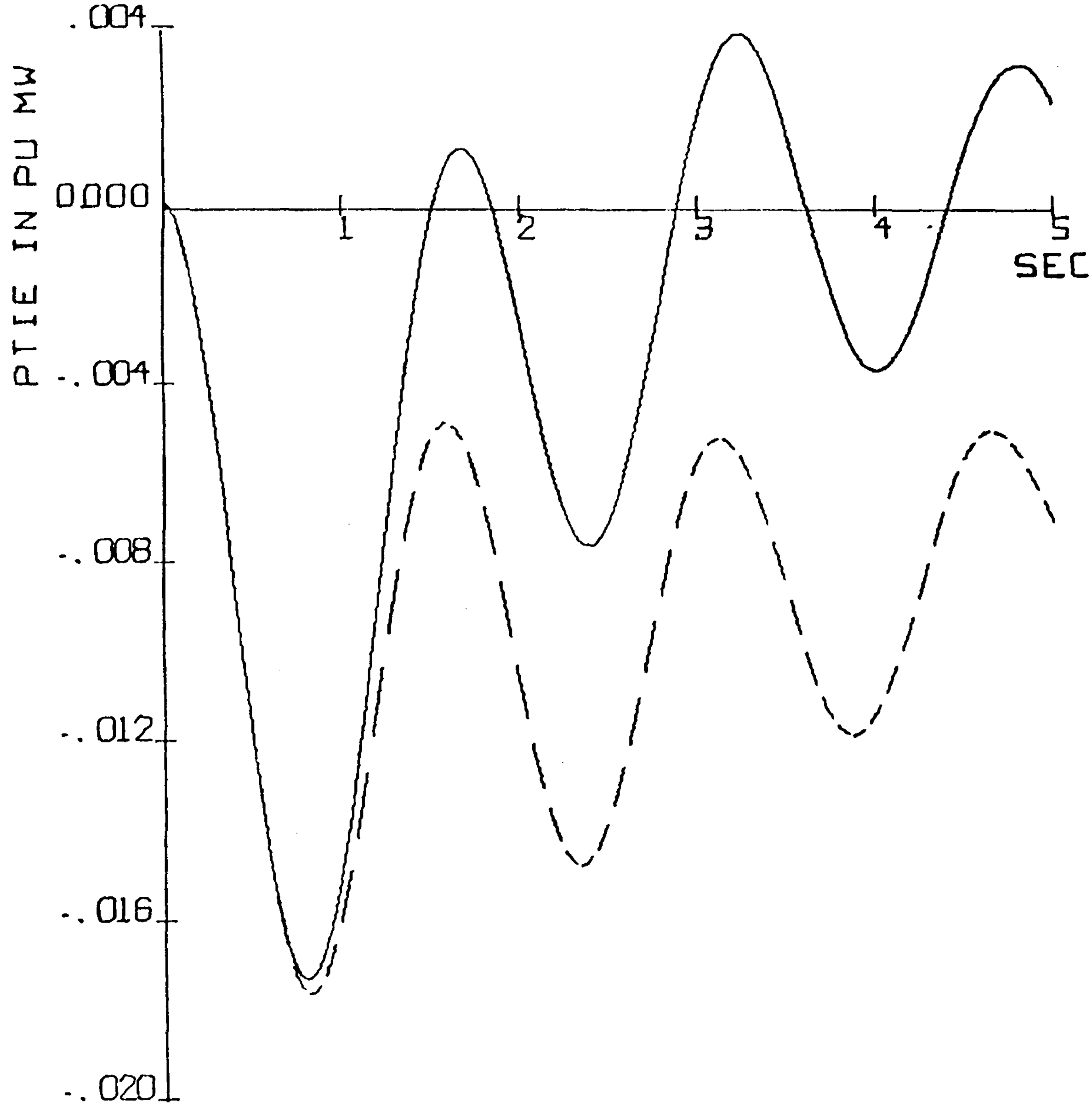

FIGURE 4312

INTEGRAL ABSOLUTE VALUE ERROR CRITERIA
BASE MVA=2000
PR1=1 PR2=15 PM=2 W1=01 W2=-01 PU MW
SOLID LINE K1=6 B1=05 K2=8 B2=05
DASHED LINE K1=1 B1=425 K2=1 B2=425

Figure 4.3.13

Integral Squared Error Criteria C_1

Plot of ΔP_{tie} = PTIE

P_{r2} = 4000 MW P_M = 200 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.95$ $B_1 = 0.25$ $K_2 = 0.95$ $B_2 = 0.35$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

Figure 4.3.14

Integral Absolute Value Error Criteria C_2

Plot of ΔP_{tie} = PTIE

P_{r2} = 4000 MW P_M = 200 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.85$ $B_1 = 0.1$ $K_2 = 1.0$ $B_2 = 0.15$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

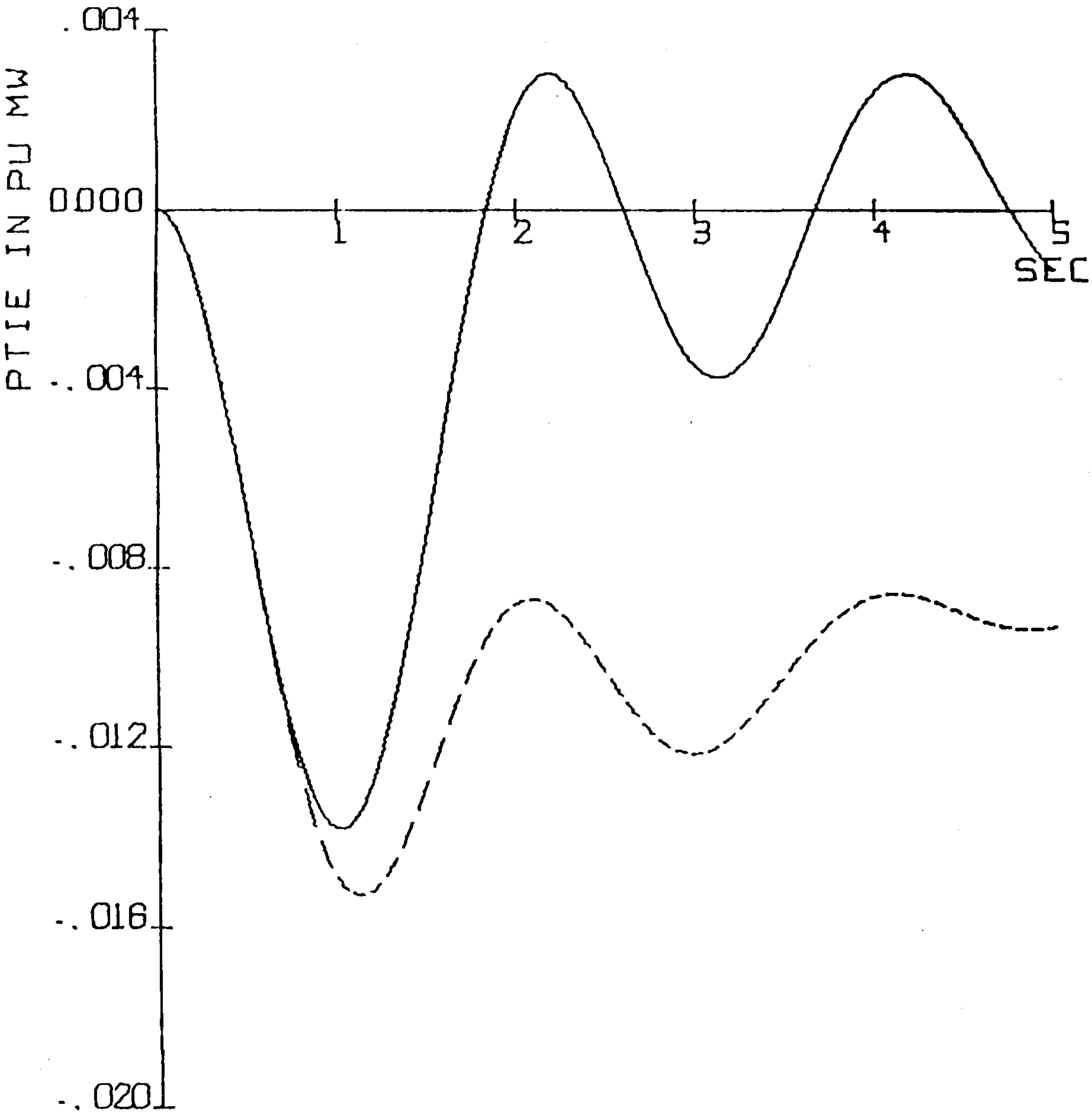

FIGURE 4313

INTEGRAL SQUARED ERROR CRITERIA
BASE MVA=2000
PR1=.1 PR2=.2 PM=.1 W1=.01 W2=-.01 PU MW
SOLID LINE K1=.95 B1=.25 K2=.95 B2=.35
DASHED LINE K1=.1 B1=.425 K2=.1 B2=.425

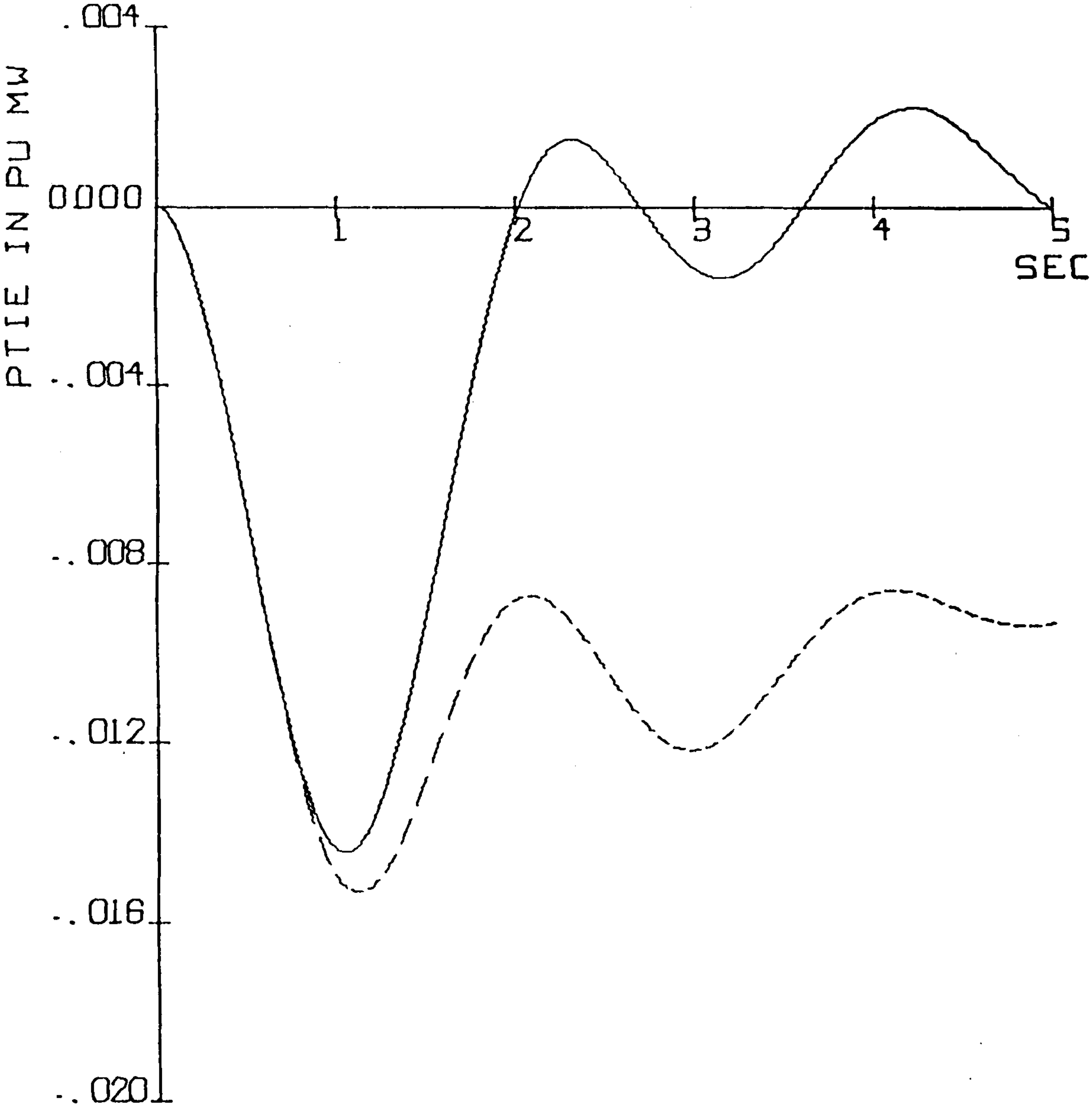

FIGURE 4314

INTEGRAL ABSOLUTE VALUE ERROR CRITERIA
BASE MVA=2000
PR1=1 PR2=2 PM=1 W1=.01 W2=-.01 PU MW
SOLID LINE K1=.85 B1=1 K2=10 B2=15
DASHED LINE K1=1 B1=.425 K2=1 B2=.425

Figure 4.3.15

Integral Squared Error Criteria C_1

Plot of ΔP_{tie} = PTIE

P_{r2} = 4000 MW P_M = 300 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.85$ $B_1 = 0.05$ $K_2 = 1.0$ $B_2 = 0.25$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

Figure 4.3.16

Integral Absolute Value Error Criteria C_2

Plot of ΔP_{tie} = PTIE

P_{r2} = 4000 MW P_M = 300 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.65$ $B_1 = 0.05$ $K_2 = 1.0$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

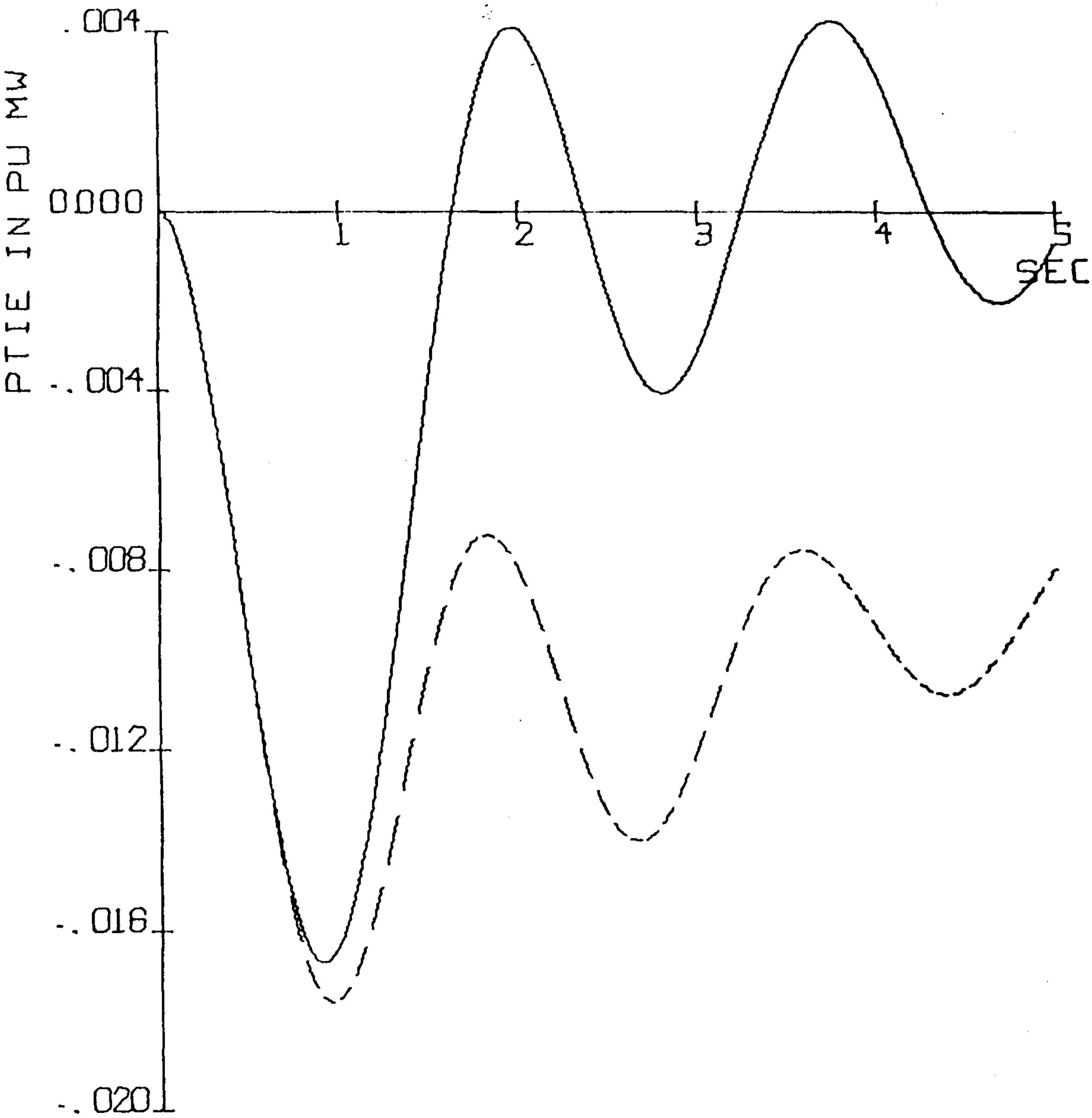

FIGURE 4315

INTEGRAL SQUARED ERROR CRITERIA
BASE MVA-2000
PR1-1 PR2-2 PM-15 W1-01 W2--01 PU MW
SOLID LINE K1-85 B1-05 K2-10 B2-25
DASHED LINE K1-1 B1-425 K2-1 B2-425

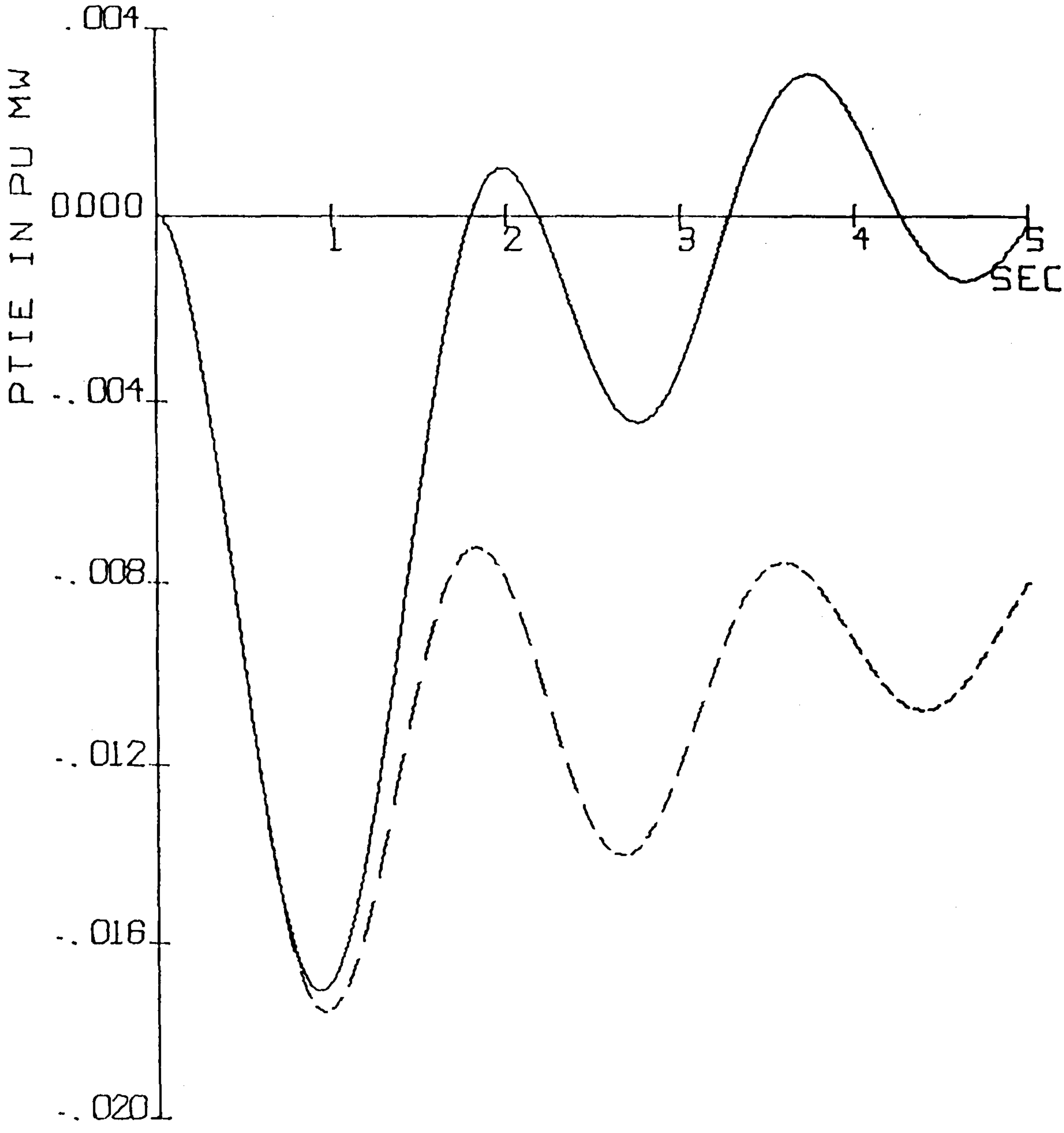

FIGURE 4316

INTEGRAL ABSOLUTE VALUE ERROR CRITERIA
BASE MVA-2000
PR1-1 PR2-2 PM-15 W1-01 W2--01 PU MW
SOLID LINE K1-65 B1-05 K2-10 B2-05
DASHED LINE K1-1 B1-425 K2-1 B2-425

<u>Figure 4.3.17</u>

Integral Squared Error Criteria C_1

Plot of ΔP_{tie} = PTIE

P_{r2} = 4000 MW P_M = 400 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.8$ $B_1 = 0.05$ $K_2 = 1.0$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

<u>Figure 4.3.18</u>

Integral Absolute Value Error Criteria C_2

Plot of ΔP_{tie} = PTIE

P_{r2} = 4000 MW P_M = 400 MW

W_1 = 0.01 pu MW W_2 = -0.01 pu MW

Solid Line $K_1 = 0.65$ $B_1 = 0.05$ $K_2 = 0.85$ $B_2 = 0.05$

Dashed Line $K_1 = 0.1$ $B_1 = 0.425$ $K_2 = 0.1$ $B_2 = 0.425$

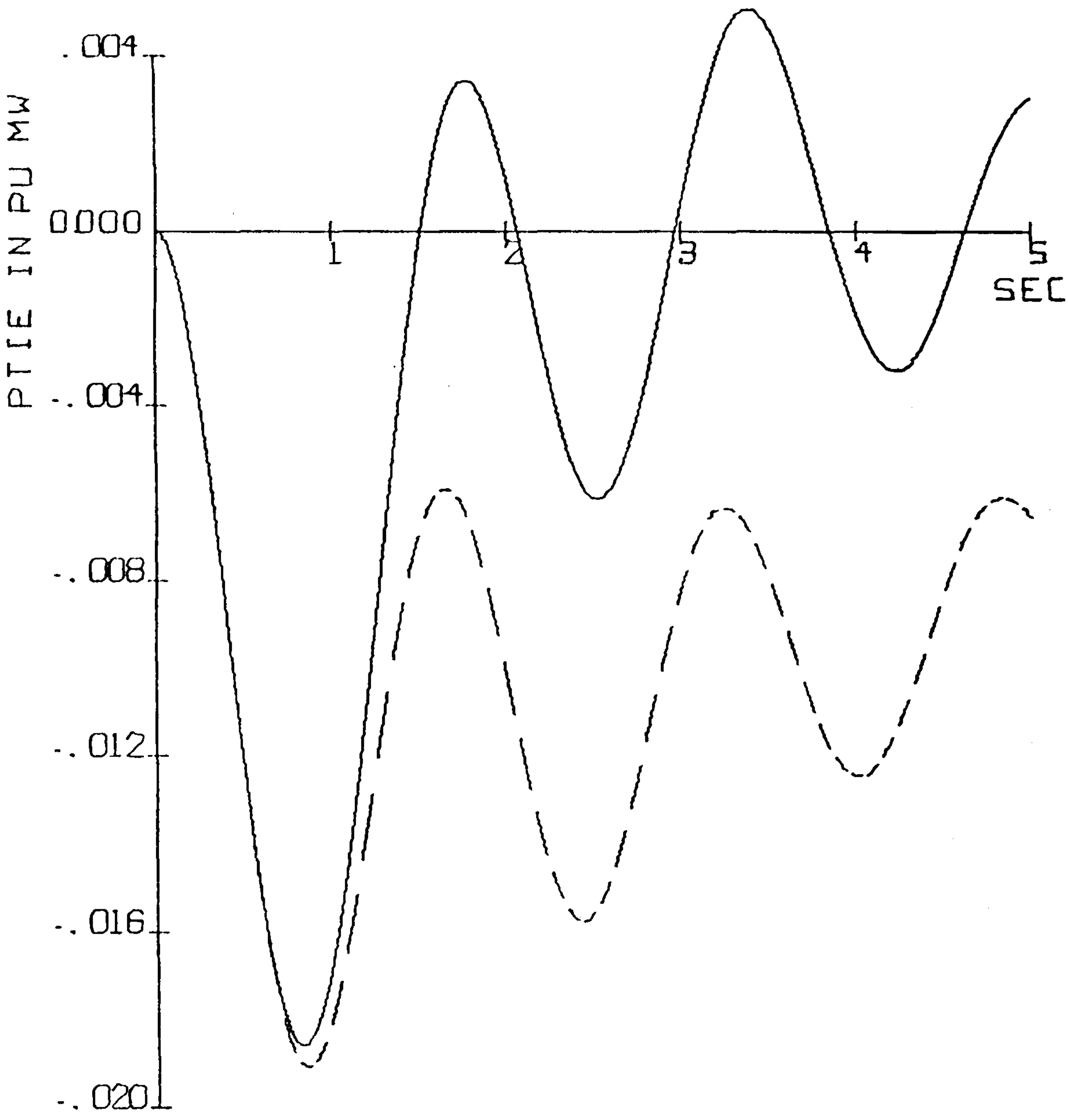

FIGURE 4317

INTEGRAL SQUARED ERROR CRITERIA
BASE MVA-2000
PR1-1 PR2-2 PM-2 W1-01 W2--01 PU MW
SOLID LINE K1-8 B1-05 K2-10 B2-05
DASHED LINE K1-1 B1-.425 K2-1 B2-.425

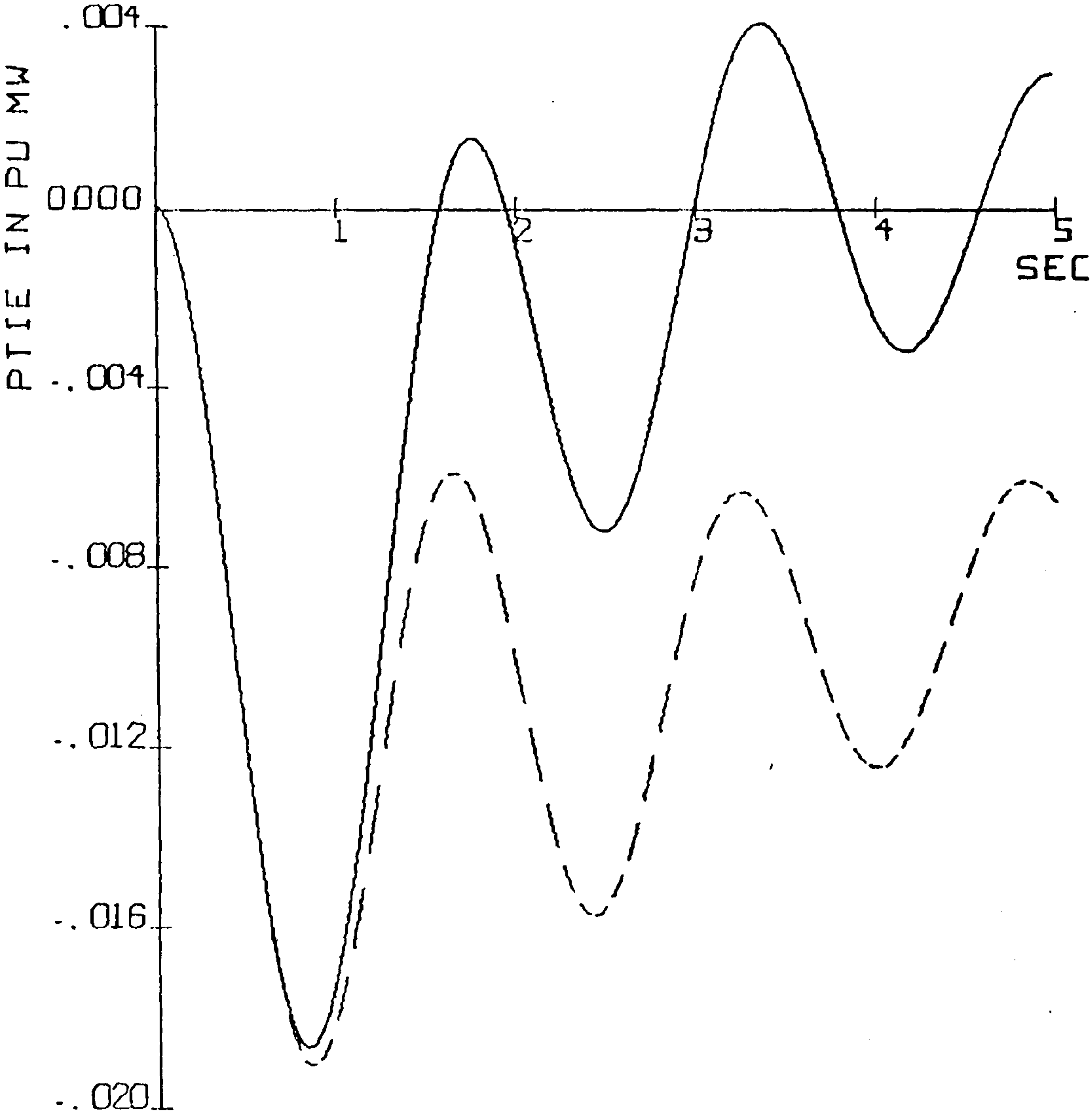

FIGURE 4318

INTEGRAL ABSOLUTE VALUE ERROR CRITERIA
BASE MVA-2000
PR1-1 PR2-2 PM-2 W1-.01 W2-.01 PU MW
SOLID LINE K1-.65 B1-.05 K2-.85 B2-.05
DASHED LINE K1-.1 B1-.425 K2-.1 B2-.425

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4. Chen, S. T., "Optimal Load Frequency Control of Power Systems," Ph.D. Dissertation, Electrical Engineering Department, Virginia Polytechnic Institute and State University, Blacksburg, Virginia.

5. Cohn, N., "A Step-By-Step Analysis of Load-Frequency Control Showing the System Regulating Response Associated with Frequency Bias;" presented before the 1956 Meeting of the Interconnected Systems Committee, Des Moines, Iowa, March 1956.

6. Cohn, N., "Power-System Interconnections Control of Generation and Power Flow," Standard Handbook for Electrical Engineers: 10th Edition, New York: McGraw-Hill.

7. Cohn, N., "Bias Revisited;" presented before the East Central Systems Group of the North American Power Systems Interconnection Committee, at its Spring meeting in St. Joseph, Michigan, April 1970.

8. Cohn, N., "Considerations in the Regulation of Interconnected Areas," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-86, No. 12, December 1967.

APPENDIX

```
*Program Performs Direct Search for Finding Optimum Control Settings for
*Two-Area Load Frequency Control Problem.
*
          ORG 0'2ØØØØ'
          Title Erg Load Frequency Control
          Bru Enter
*
*Counters That Must Be Initialized
*
 CINS     DC  5
 COPS     DC  5
*
*Parameters That Must Be Initialized
*
 INCINS   DC 0'144ØØ'      Ø.2
 INCOPS   DC 0'12ØØ'       Ø.Ø2
 UV       DC 0'74ØØØ'      Ø.96
 LV       DC 0'36ØØ'       Ø.Ø6
 KUV      DC 0'7Ø2ØØ'      Ø.9Ø
 KLV      DC 0'24ØØ'       Ø.Ø4
 SV       DC 0'36ØØ'       Ø.Ø6
*
*Constants For Set Pot Coefficients
*
 PTØ1     DC 0'5ØØ'        Ø.Ø1
 PT02     DC 0'12ØØ'       Ø.Ø2
 PT06     DC 0'36ØØ'       Ø.Ø6
 PT1      DC 0'62ØØ'       Ø.1
 PT2      DC 0'144ØØ'      Ø.2
 PT25     DC 0'175ØØ'      Ø.25
 PT3      DC 0'226ØØ'      Ø.3
 PT4      DC 0'31ØØØ'      Ø.4
 PT5      DC 0'372ØØ'      Ø.5
 PT6      DC 0'454ØØ'      Ø.6
 PT7      DC 0'536ØØ'      Ø.7
 PT8      DC 0'62ØØØ'      Ø.8
 PT9      DC 0'7Ø2ØØ'      Ø.9
 PVEQ1    DC 0'764ØØ'      1.Ø
*
*Integer Constants
*
 ONE      DC  1
 TWO      DC  2
*
*Constant Parameter Pot Addresses and Values
*
```

```
 P11V       DC 0'2464Ø'      Ø.333
 P11AD      DC 0'21'
 P23V       DC 0'31ØØØ'      Ø.4
 P23AD      DC 0'43'
 P24V       DC 0'31ØØ'       Ø.Ø5
 P24AD      DC 0'44
 P26V       DC 0'32Ø4Ø'      Ø.4165
 P26AD      DC 0'46'
 P27V       DC 0'31ØØ'       Ø.Ø5
 P27AD      DC 0'47'
 P29V       DC 0'62ØØ'       Ø.1
 P29AD      DC 0'51'
 P33V       DC 0'454ØØ'      Ø.6
 P33AD      DC 0'63'
 P61V       DC 0'62ØØØ'      Ø.8
 P61AD      DC 0'141'
 P63V       DC 0'62ØØ'       Ø.1
 P63AD      DC 0'143'
 P66V       DC 0'32Ø4Ø'      Ø.4165
 P66AD      DC 0'146'
 P67V       DC 0'454ØØ'      Ø.6
 P67AD      DC 0'147'
 P68V       DC 0'31ØØ'       Ø.Ø5
 P68AD      DC 0'15Ø'
 P69V       DC 0'2464Ø'      Ø.333
 P69AD      DC 0'151'
*
*Analog Computer Modes
*
 PPMODE     DC 0'41Ø1'       PP 1SEC RUN
 ICMODE     DC 0'11Ø2'       IC 1SEC CLEAR
 SPMODE     DC 0'1Ø12Ø'      SP 1SEC 10E6
 HOLDMODE   DC 0'21Ø4'       HD 1SEC STOP
*
*Pot Addresses for Variable Parameters
*
 POTADK1    DC Ø             POT 4Ø
 POTADK2    DC 1             POT 41
 POTADB1    DC 2             POT 42
 POTADB2    DC 3             POT 43
 POTADPR    DC 0'14Ø'        POT 6Ø
 POTADPM    DC 4             POT 44
*
*Values for Area Sizes and Tie Line Capacities
*
 PR1        DC 0'764ØØ'      PR2 = 2ØØØ      1.Ø
 PR2        DC 0'5154Ø'      PR2 = 3ØØØ      Ø.667
 PR3        DC 0'372ØØ'      PR2 = 4ØØØ      Ø.5
 PM1        DC 0'33ØØ'       PM = 2ØØ        Ø.Ø544
 PM2        DC 0'51ØØ'       PM = 3ØØ        Ø.Ø816
 PM3        DC 0'664Ø        PM = 4ØØ        Ø.1Ø88
```

```
*
*Constants Recommended and Used by the Industry
*
 INDK       DC O'144ØØ'     Ø.2
 INDB       DC O'32440'     0.425
*
*Counters, Decision Variables and Place Holders
*
 CPR1       DC Ø
 CPR2       DC Ø
 CPR3       DC Ø
 CPM1       DC Ø
 CPM2       DC Ø
 CPM3       DC Ø
 CK1        DC Ø
 CK2        DC Ø
 CB1        DC Ø
 CB2        DC Ø
 C          DC Ø
 CSP        DC Ø
 ITER       DC Ø
 FIRST      DC Ø
 TEMPS      DC Ø
 TEMPOP     DC Ø
 TEMPDCA    DC Ø
 TEMPSSP    DC Ø
*
*Miscellaneous Constants
*
 BIGNO      DC O'174ØØØØØ'
*
*Working Variables
*
 INC        DC Ø
 PR         DC Ø
 PM         DC Ø
 POTV       DC Ø
 POTADD     DC Ø
 K1         DC Ø
 K2         DC Ø
 B1         DC Ø
 B2         DC Ø
 SVK1       DC Ø
 SVK2       DC Ø
 SVB1       DC Ø
 SVB2       DC Ø
 OPK1       DC Ø
 OPK2       DC Ø
 OPB1       DC Ø
 OPB2       DC Ø
 OLDOPK1    DC Ø
 OLDOPK2    DC Ø
```

```
 OLDOPB1     DC Ø
 OLDOPB2     DC Ø
 F           DC Ø
 OPF         DC Ø
 OLDOPF      DC Ø
*
*End of Tables and Beginning of Program
*
 ENTER       NOP
*
*Initialize Index Register 3 to Ø
*
             LDZ
             STA 3
*
*Set Analog in to Trunk 1ØØ
*
             LDZ
             OUT O'12ØØ'
*
*Initialize Counters for Area Size Loops
*
             LDA ONE
             STA CPR1
             STA CPR2
             STA CPR3
 LPR1        DMT CPR1
             BTR LPR2
             LDA PR1
             STA PR
             BRU SETCPM
 LPR2        LDZ
             STA CPR1
             DMT CPR2
             BTR LPR3
             LDA PR2
             STA PR
             BRU SETCPM
 LPR3        LDZ
             STA CPR2
             DMT CPR3
             BTR ENDPROG
             LDA PR3
             STA PR
*
*Initialize Counters for Tie Line Capacity Loops
*
 SETCPM      LDA ONE
             STA CPM1
             STA CPM2
             STA CPM3
```

```
 LPM1       DMT  CPM1
            BTR  LPM2
            LDA  PM1
            STA  PM
            BRU  SETPOT
 LPM2       LDZ
            STA  CPM1
            DMT  CPM2
            BTR  LPM3
            LDA  PM2
            STA  PM
            BRU  SETPOT
 LPM3       LDZ
            STA  CPM2
            DMT  CPM3
            BTR  LPR1
            LDA  PM3
            STA  PM
*
*Set Pots for PR and PM
*
 SETPOT     LDA  PR
            STA  POTV
            LDA  POTADPR
            STA  POTADD
            SPB  SUBSSP
            LDA  PM
            STA  POTV
            LDA  POTADPM
            STA  POTADD
            SPB  SUBDCA
*
*Set Pots for All of the Constant Parameters
*
            LDA  P11V
            STA  POTV
            LDA  P11AD
            STA  POTADD
            SPB  SUBSSP
            LDA  P23V
            STA  POTV
            LDA  P23AD
            STA  POTADD
            SPB  SUBSSP
            LDA  P24V
            STA  POTV
            LDA  P24AD
            STA  POTADD
            SPB  SUBSSP
            LDA  P26V
            STA  POTV
            LDA  P26AD
```

```
          STA POTADD
          SPB SUBSSP
          LDA P27V
          STA POTV
          LDA P27AD
          STA POTADD
          SPB SUBSSP
          LDA P29V
          STA POTV
          LDA P29AD
          STA POTADD
          SPB SUBSSP
          LDA P33V
          STA POTV
          LDA P33AD
          STA POTADD
          SPB SUBSSP
          LDA P61V
          STA POTV
          LDA P61AD
          STA POTADD
          SPB SUBSSP
          LDA P63V
          STA POTV
          LDA P63AD
          STA POTADD
          SPB SUBSSP
          LDA P66V
          STA POTV
          LDA P66AD
          STA POTADD
          SPB SUBSSP
          LDA P67V
          STA POTV
          LDA P67AD
          STA POTADD
          SPB SUBSSP
          LDA P68V
          STA POTV
          LDA P68AD
          STA POTADD
          SPB SUBSSP
          LDA P69V
          STA POTV
          LDA P69AD
          STA POTADD
          SPB SUBSSP
*
*Initialize INC for Initial Search
*
```

```
            LDA INCINS
            STA INC
*
*Initialize C for Initial Search
*
            LDA CINS
            STA C
*
*Initialize Starting Values for Initial Search
*
            LDZ
            STA SVK1
            STA SVK2
            STA SVB1
            STA SVB2
*
*Perform Initial Search
*
            SPB SEARCH
*
*Store Optimum Initial Values
*
            LDA OPK1
            STA (3) O'3ØØØØ'
            INX (3) 1
            LDA OPK2
            STA (3) O'3ØØØØ'
            INX (3) 1
            LDA OPB1
            STA (3) O'3ØØØØ'
            INX (3) 1
            LDA OPB2
            STA (3) O'3ØØØØ'
            INX (3) 1
            LDA OPF
            STA (3) O'3ØØØØ'
            INX (3) 1
            LDZ
            STA (3) O'3ØØØØ'
            INX (3) 1
            LDZ
            STA (3) O'3ØØØØ'
            INX (3) 1
            LDZ
            STA (3) O'3ØØØØ'
            INX (3) 1
*
*Initialize Iter to Ø
*
            LDZ
            STA ITER
```

```
*
*Initialize Inc for Optimum Search
*
            LDA INCOPS
            STA INC
*
*Initialize C for Optimum Search
*
            LDA COPS
            STA C
*
*Save Last Set of Optimum Values That Were Found
*
 LS         LDA OPK1
            STA OLDOPK1
            LDA OPK2
            STA OLDOPK2
            LDA OPB1
            STA OLDOPB1
            LDA OPB2
            STA OLDOPB2
            LDA OPF
            STA OLDOPF
*
*Initialize Starting Values for Optimum Search
*
            LDA UV
            SUB OPK1
            TOD 23
            BTR TK1LTLV
            LDA KUV
            STA SVK1
            BRU TK2GTUV
 TK1LTLV    LDA OPK1
            SUB LV
            TEV 23
            BTS CSVK1
            LDA KLV
            STA SVK1
            BRU TK2GTUV
 CSVK1      LDA OPK1
            SUB SV
            STA SVK1
 TK2GTUV    LDA UV
            SUB OPK2
            TOD 23
            BTR TK2LTLV
            LDA KUV
            STA SVK2
            BRU TB1GTUV
```

```
TK2LTLV     LDA OPK2
            SUB LV
            TEV 23
            BTS CSVK2
            LDA KLV
            STA SVK2
            BRU TB1GTUV
CSVK2       LDA OPK2
            SUB SV
            STA SVK2
            LDA UV
            SUB OPB1
            TOD 23
            BTR TB1LTLV
            LDA KUV
            STA SVB1
            BRU TB2GTUV
TB1LTLV     LDA OPB1
            SUB LV
            TEV 23
            BTS CSVB1
            LDA KLV
            STA SVB1
            BRU TB2GTUV
CSVB1       LDA OPB1
            SUB SV
            STA SVB1
TB2GTUV     LDA UV
            SUB OPB2
            TOD 23
            BTR TB2LTLV
            LDA KUV
            STA SVB2
            BRU ONWARD
TB2LTLV     LDA OPB2
            SUB LV
            TEV 23
            BTS CSVB2
            LDA KLV
            STA SVB2
            BRU ONWARD
CSVB2       LDA OPB2
            SUB SV
            STA SVB2
ONWARD      NOP
*
*Perform Optimum Search
*
            SPB SEARCH
```

```
*
*Increment Iter
*
            LDA ITER
            ADD ONE
            STA ITER
*
*Test if New OPF is Less Than OLDOPF
*
            LDA OPF
            SUB OLDOPF
            TOD 23
            BTS LS
*
*Store Optimum Values
*
            LDA OLDOPK1
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDA OLDOPK2
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDA OLDOPB1
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDA OLDOPB2
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDA OLDOPF
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDA ITER
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDZ
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDZ
            STA (3) 0'3ØØØØ'
            INX (3) 1
*
*Find Cost Function for Industry's Settings
*
            LDA INDK
            STA POTV
            LDA POTADK1
            STA POTADD
            SPB SUBDCA
            LDA POTADK2
            STA POTADD
            SPB SUBDCA
```

```
            LDA INDB
            STA POTV
            LDA POTADB1
            STA POTADD
            SPB SUBDCA
            LDA POTADB2
            STA POTADD
            SPB SUBDCA
            SPB OP
            LDA F
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDZ
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDZ
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDZ
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDZ
            STA (3) 0'3ØØØØ'
            INX (3) 1
            LDZ
            STA (3) 0'3ØØØØ'
            INX (3) 1
            BRU LPM1
*
*Subroutine Search
*
 SEARCH     STX (1) TEMPS
            LDA ONE
            STA FIRST
            LDA SVK1
            STA K1
            LDA C
            STA CK1
 LK1        DMT CK1
            BTR ENDS
            LDA K1
            ADD INC
            STA K1
            STA POTV
            LDA POTADK1
            STA POTADD
            SPB SUBDCA
            LDA SVK2
            STA K2
            LDA C
            STA CK2
```

```
LK1     DMT CK1
        BTR ENDS
        LDA K1
        ADD INC
        STA K1
        STA POTV
        LDA POTADK1
        STA POTADD
        SPB SUBDCA
        LDA SVK2
        STA K2
        LDA C
        STA CK2
LK2     DMT CK2
        BTR LK1
        LDA K2
        ADD INC
        STA K2
        STA POTV
        LDA POTADK2
        STA POTADD
        SPB SUBDCA
        LDA SVB1
        STA B1
        LDA C
        STA CB1
LB1     DMT CB1
        BTR LK2
        LDA B1
        ADD INC
        STA B1
        STA POTV
        LDA POTADB1
        STA POTADD
        SPB SUBDCA
        LDA SVB2
        STA B2
        LDA C
        STA CB2
LB2     DMT CB2
        BTR LB1
        LDA B2
        ADD INC
        STA B2
        STA POTV
        LDA POTADB2
        STA POTADD
        SPB SUBDCA
        SPB OP
        LDA FIRST
        TZE
```

```
             BTS COMPARE
             LDZ
             STA FIRST
             LDA F
             STA OPF
             LDA K1
             STA OPK1
             LDA K2
             STA OPK2
             LDA B1
             STA OPB1
             LDA B2
             STA OPB2
             BRU LB2
 COMPARE     LDA F
             SUB OPF
             TOD 23
             BTR LB2
             LDA F
             STA OPF
             LDA K1
             STA OPK1
             LDA K2
             STA OPK2
             LDA B1
             STA OPB1
             LDA B2
             STA OPB2
             BRU LB2
 ENDS        LPR TEMPS
*
*Subroutine for Analog Computer Control
*
 OP          STX (1) TEMPOP
*
*Place in PPMODE
*
             LDA PPMODE
             OPR O'14ØØ'
             JNR O'147Ø'
             BRU *+2
             BRU *-2
*
*Test for Signal to End Operate Mode
*
             LDZ
 ANOPLO      IN O'11Ø1'
             TOD 23
             BTR ANOPLO
```

```
*
*Start A to D Converstion
*
              OPR O'12ØØ
              JNR O'12ØØ'
              BRU *+2
              BRU *-2
*
*Place in ICMODE
*
              LDA ICMODE
              OPR O'14ØØ'
*
*Test for Overflow
*
              JNE O'12ØØ'
              BRU OVERFLOW
*
*Bring Converted Value into A Register
*
              IN O'12ØØ
              STA F
              BRU ENDOP
 OVERFLOW     LDA BIGNO
              STA F
 ENDOP        NOP
*
*Test for ICMODE Condition
*
              JNR O'141Ø'
              BRU *+2
              BRU *-2
              LPR TEMPOP
*
*Subroutine for Setting Digitally Controlled Attenuators
*
 SUBDCA       STX (1) TEMPDCA
              LDA POTADD
              OPR O'14Ø1'
              LDA POTV
              OUT O'14Ø1'
              NOP
              NOP
              NOP
              NOP
              NOP
              NOP
              NOP
              LPR TEMPDCA
*
*Subroutine for Setting Servo Set Pots
*
```

```
SUBSSP      STX (1) TEMPSSP
            LDA TWO
            STA CSP
            LDA SPMODE
            OPR O'14ØØ'
            JNR O'145Ø'
            BRU *+2
            BRU *-2
LSUBSSP     DMT CSP
            BTR ENDSSP
            LDA POTV
            OUT O'11ØØ'
            LDA POTADD
            OUT O'14ØØ'
            JNR O'14ØØ'
            BRU *+2
            BRU *-2
            BRU LSUBSSP
ENDSSP      LDA ICMODE
            OPR O'14ØØ'
            JNR O'141Ø'
            BRU *+2
            BRU *-2
            LPR TEMPSSP
ENDPROG     BRU *
            END
```

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A HYBRID COMPUTER PARAMETER OPTIMIZATION

STUDY OF THE TWO-AREA LOAD FREQUENCY CONTROL PROBLEM

by

Robert Paul Broadwater

(ABSTRACT)

This thesis is concerned with finding optimum control system settings for the two-area load frequency control problem. The control system settings are optimized relative to two different cost criteria, both of which penalize the inadvertent interchange of energy between the two areas. The problem is studied for several different total megawatt ratings of area two and for several different static tie line transmission capacities.

Search techniques employing a hybrid computer are used to solve the optimization problem. Two different search techniques are used. One is based upon the Fibonacci search method, and the other is a direct search method.

The optimum control settings are compared with industry recommended standards.