CONTROL OF POWER SYSTEMS

VIA

THE MULTI-LEVEL CONCEPT

by

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Submitted in partial fulfillment of the requirements

for the Degree of Doctor of Philosophy

School of Engineering

CASE WESTERN RESERVE UNIVERSITY

June 1968

CASE WESTERN RESERVE UNIVERSITY

GRADUATE STUDIES

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ABSTRACT

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THE MULTI-LEVEL CONCEPT

Tomás E. Dy-Liacco

The research described by this thesis marks a beginning in the systems engineering study of power systems for high-reliability operation.

The thesis starts with a presentation of the operating problem of power systems and introduces the idea of characterizing the nature of operation by means of three operating states -- preventive, emergency, restorative. The control for each operating state is then cast in the multi-layer hierarchy of direct, optimizing, and adaptive controls. The multi-layer structure permits the identification and the organization of various control functions for a complete control system for power system operation.

The thesis points out that the effectiveness of the control system in realizing its objective depends primarily on the effectiveness of control in the preventive operating state. This is referred to as "preventive control." Preventive control is designed not only to meet immediate, actual needs but also to anticipate possible emergencies and to take measures so as to avoid such emergencies. The

main contribution of this thesis is in the development of important aspects of preventive control, in the optimizing and adaptive layers.

A concept of system security is defined and with this as basis, the evaluation of system security is treated as a pattern classification problem. The thesis shows that this approach, which is new to power system control, will provide the system operator with a decision-making tool for taking preventive control action.

Other adaptive functions in the preventive state are identified as non-linear optimization problems with non-linear equality constraints. The results of using non-linear programming methods to solve power system problems are presented.

In considering interconnected power systems, a new approach to the decomposition of steady-state problems is described and demonstrated for the non-linear load flow problem. The treatment of large systems with small programs becomes practical.

On-line optimizing control in the preventive state is extended from a single area to a multi-area basis. The contribution made by this thesis is the incorporation, in this extension, of the network equality constraints without the simplifying assumptions of present methods. A two-level algorithm for multi-area optimizing control is developed.

Another contribution offered by this thesis is a method for on-line modelling of the interconnection so that the interaction of external systems with a power system under control may be approximated and the approximation kept current.

A flow chart is presented of a proposed control system which shows the interplay of the various functions developed in the research and others still to be developed.

This thesis concludes with a review of the significance of the research made and an indication of areas for future research.

PREFACE

This thesis is oriented to the control problems of a significantly large class of complex systems, namely, electric power systems.

The electric power utilities comprise the largest single industry in the United States.

The significance of the preceding statement lies not so much in the statistics of size, which are impressive, but in the fact that the electric power utilities, with very few and small exceptions, make up a single electrically contingnuous system covering the entire continental US and parts of Canada.

Thus, the electric power industry, in contrast to other industries, is truly a single industry operating as one physical system.

But first let us look at the statistics. The electric utility industry has doubled its energy output almost every decade since it was founded in 1882. The industry continues to grow and grow. "It is all but certain that its current annual output of 1.16 trillion kilowatt hours will have grown a decade from now to more than 2 trillion Kwh. By the year 2000, present output will have more than quadrupled" (1). A recent publication (2) of Edison Electric Institute, an organization of privately owned electric utilities, points out that "the investor-owned electric utilities with an estimated total investment of over $60 billion in electric plant and equipment at the end of 1965, comprise the largest single industry in the US, and their average annual investment for plant and equipment is greater than that of any other industry."

The average current expenditure for the period 1956-1965 for new plant and equipment of the major industries in the US are shown in Table A below, which is taken from Reference 2.

TABLE A

EXPENDITURES ON NEW PLANT AND EQUIPMENT*
1956-1965 AVERAGE
(BILLIONS OF DOLLARS)

Investor-Owned Electric Utilities	$3.44
Communication	3.40
Petroleum and Coal	2.99
Transportation (Except Rail)	2.00
Machinery Manufacture	1.92
Chemicals and Allied Products	1.67
Gas Utilities	1.64
Primary Iron and Steel	1.39
Mining	1.10

*Except Alaska and Hawaii.

We note from Table A that the electric utilities during the 1956-1965 period spent $40 million more annually for expansion than the communication industry, and $450 million more annually than the third-ranking group, petroleum and coal. Also, the expenditures by electric utilities were almost as much as the combined investments of the primary iron and steel, mining and railroad industries.

The growth of the electric utility industry is the natural outcome of the constant growth of demand for energy of a highly industrialized country with ever-rising material standards of living. Electricity, competing with other forms of fuel, has tended steadily to increase its share of the total energy market. Admittedly, this is partly due to the inherent advantages in the ease, versatility, efficiency, and aesthetics with which electricity can be applied. But, "at least as important has been the industry's achievement, almost alone among major US industries, of steadily reducing the price of its basic commodity despite steadily rising prices for practically everything else" (1). The power companies have steadily lowered the cost of production from about 5 mills per Kwh in 1950 to slightly less than 4 mills per Kwh in 1965. By 1975 the cost of production is expected to be down to almost 3 mills per Kwh. In marked contrast, the wholesale price for practically every other commodity increased by about 18% from 1950 to 1965 and is expected to increase another 13% by 1975 (1).

The constant reduction in production cost has been achieved by taking advantage of economies of scale in ever-larger, more efficient generating units. This has been accompanied by further economies of scale in higher and higher transmission voltages and in more and more interconnections. The pattern continues. The demand keeps growing. More and larger generating units are installed. More transmission is built. Transmission voltages are pushed higher. The entire country is already one vast interconnected system and more interconnections are being built to overlay the existing ones.

Interconnections have become vital to electric power systems for a number of very important reasons. Firstly, interconnections make feasible the installation of a large-capacity generating unit without having to provide an equal amount of capacity in spinning reserve.[1] Secondly, the interconnected companies can realize operating economies by trading energy in such amounts as to satisfy, as nearly as possible, optimality conditions for combined minimum operating cost. Lastly, the existence of interconnections yields a simple and effective means of automatic control by which each utility can adjust its generation to meet its constantly varying load.

Interconnections, however, increase the degree of complexity of power system operating problems arising from the complexity of the network topology and of the dynamic behavior of the disturbances occuring not only internally but also elsewhere in other systems in the interconnection.

The electric utilities have always been aware of the growing difficulties of decision-making associated with the reliable operation of a power system. The approach to this problem has generally been to design into the system a certain amount of reliability sufficient to maintain a predetermined standard of service. The standard of service used for design purposes is predicated on arbitrary assumptions concerning the state of the system and of the interconnections. This approach has been the best that power system engineers could use with the analytical techniques available. The drawbacks however are apparent. Present analytical techniques involve time-consuming

[1] "Spinning reserve" is the total amount of unused capacity in generating units which are running and connected to the power system.

studies which do not give assurance of yielding the best solutions. Relative reliabilities of alternate arrangements have not been quantified and the dollar cost has been the predominant decision-making factor. Generally, a less costly design is chosen as long as it appears adequate to maintain the minimum service requirement. Such decisions made in favor of the most economical design, if of dubious reliability, are usually rationalized by invoking the low probabilities of system or component failure or the low probability of a combination of circumstances which could lead to failure. It has always been assumed that as long as a system has been designed according to the prevailing standards, any abnormality in operation requiring control beyond that provided for by conventional automatic devices would have to be taken care of by the human operator. This philosophy may be the most practical from the viewpoint of building up the system to meet the load growth while keeping the cost of electricity down. The fallacy, however, lies in: firstly, the emphasis given to the low probability of occurrence of a failure which discounts the increasing seriousness of the consequences of a failure; and secondly, the dependence on the human operator to act quickly and correctly during abnormalities in operation. In the overall, electric service in the US has been extremely reliable. Ironically, it has been this very fact of reliability and that of low cost that have made electricity such an important part of US economy and way of living that a power failure, however rare, has become anathema. The assumption that the human operator can, in the nick of time, find the right solutions to operating problems not considered in the system design is somewhat tragi-comic. Possibly nobody really believes this. Certainly while there is recognition of the increasing difficulty of coping with complex emergency conditions promptly and correctly, there has been no commensurate modernization or improvement in the gathering and presentation of system information which could, at least, lessen the burden on the operator. The system information being brought in to the system operator's office is still pretty much the same type of data as was being monitored twenty or thirty years ago.

Thus, by way of the fallacy described, we see that the approach to the reliable operation of a power system is in need of improvement. Helping the human operator with better system information is only one aspect of the solution. The real need is for a total control system which would be effective under all operating conditions and whose reliance on human intervention would be minimized. Human control action would be relegated to situations where the problem would be compatible with the average operator's capability for decision-making.

It is this need of interconnected power systems for an integrated operating control system that motivates the work presented by this thesis. This motivation is a strong one indeed from the standpoint of the far-reaching social and economic implications involved in the operation of electric power systems. This need was dramatically demonstrated by the Northeast blackout of 1965 which affected 30 million people, over nine states and three Canadian provinces. In the words of New York Times: "Our society is such that there was not one area of life, physical life or mental life, that was not in some way touched by the fact that the power had failed." "The blackout," said

Chairman White of the Federal Power Commission, "was the best damn thing that ever happened to the industry. It focused public attention not only on electricity but on reliability."

The electric power industry today is just beginning to study ways of achieving improved methods of control for service reliability. Various study teams have been organized in several parts of the country. Goals have been set up within the next five to ten years for the installation of new operating control centers. For these efforts, however, to result successfully in an effective control system it is evident that concepts and methods should be developed from the systems engineering viewpoint. The need for this approach is real and the need is now.

This thesis is offered as a systems engineering contribution in concepts and methods to the design of a control system for the reliable operation of interconnected power systems.

The following paragraphs briefly outline the contents of this thesis.

Chapter I is a description of a power system and its operating problem. The problem of stability of a power system is briefly described. The equilibrium condition or the "load flow" problem is then considered in its most general formulation and conditions for the existence of a solution are identified. The requirements of a stable system and of certain steady-state limitations establish a set of operating constraints or "conditions for operation", in the sense of continuous operation.

In viewing the overall operating problem, I introduce the concept of three operating states, where each state is defined in terms of the "conditions for operation." This breaks up the complex operating problem into three operating sub-problems with different control objectives. The three operating states are called: preventive, emergency, and restorative.

Chapter II is a description of the multi-layer control hierarchies in each of the three operating states. The control hierarchy is patterned after the multi-layer concept advanced by I. Lefkowitz (7). The three layers of control which are discussed are the direct control, optimizing control, and adaptive control layers. I then propose the philosophy that the overall control objective should have its emphasis on preventive control, i.e., control in the preventive operating state. The main contribution of this thesis lies in the development of this idea.

Chapter III presents aspects of preventive control in the optimizing and adaptive layers. The key to an effective preventive control is in the adaptive layer where predictive approaches are used so that preventive action may be taken ahead of time. I base such preventive action on a procedure for evaluating system security. The concept of system security is defined in specific terms by referring to an arbitrary sub-set of the disturbance set. This sub-set is called the "next-contingency" set. If the system will not get into an emergency on the occurrence of any of the disturbances in the "next-contingency" set the system is said to be "secure." Otherwise, if there is a next-contingency which will cause the system to get into an emergency then the system is said to be "insecure." To develop an on-line procedure for the evaluation of system security, I view the problem as one of pattern recognition. If an existing pattern of system conditions can be recognized as being insecure then preventive measures may be taken to make the pattern secure. Considerations for choosing a pattern vector are discussed. The abstraction of a patter classifier, α, from sample patterns of known classification is an application of a stochastic approximation algorithm of Blaydon and Ho (14). The classifier, α, is then used to determine the probability, $P(S/z)$, that a given pattern, z, of unknown classification, belongs to the class, S, of secure patterns, by the equation $P(S/z) = \alpha^T z$.

The preventive optimizing control is next discussed from the point of view of a practical on-line application. This requires a simple optimizing model which is achieved by developing two functions at the adaptive layer. The first function is system voltage control whose purpose is to maintain voltage magnitudes at generating stations according to a pre-determined schedule. The second function is the calculation of penalty factors which are fed to the optimizing control so that the optimal solution will automatically incorporate the system network equality constraints. The evaluation of penalty factors considers actual real and reactive power loadings and is free of the assumptions required by present-day methods.

Also in Chapter III, decision-making problems at the adaptive layer which require optimization techniques are discussed. I describe two types of power system problems which I have solved using nonlinear programming techniques. These problems which are of realistic dimensions have highly non-linear objective functions and constraints.

In Chapter IV, some problems of interconnected systems are considered. A method of decomposition is presented which is based on the electrical separation of a system into independent areas when arbitrary voltage sources are applied at interconnection points. I develop a two-level algorithm for multi-area preventive optimizing control by extending the idea of penalty factors and by using the aggregate powers from the interconnection into each area as interconnection variables. The aggregate powers are related to individual interconnection power flows by means of an interconnection flow model. A method for developing the interconnection flow model on-line is described.

Chapter V presents an integrated picture of a possible control system for using functions developed in my research and others still to be developed.

Chapter VI is a summary of the thesis and points out areas for further research.

Finally, the Appendix presents generalized flow charts of various computer programs developed in conjunction with the investigation reported in this thesis.

With the completion of this thesis, and of this phase of my education, I say thanks to the Cleveland Electric Illuminating Company for making it possible for me to pursue formal studies beyond the M.S. level and for its direct support of this research work.

I thank all my colleagues at the Illuminating Company who have helped me, directly and indirectly, with various aspects of my research.

Special thanks to Ray Rabickas, Tom Kraynak, and K. Ramarao for their help in many details of analysis and computer programming. I thank Miss Mary Tate for her expert transformation of my scrawl into this final manuscript.

I thank Dr. S. K. Mitter and Dr. I. Lefkowitz for their help and advice during my study and research work at Case Western Reserve University.

And lastly, I thank the Blessed Sacrament Fathers for giving me a place to study and write parts of this thesis in the quiet of their seminary, two blocks away from home.

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CHAPTER I

THE OPERATING PROBLEM OF POWER SYSTEMS

1.1 Introduction

An electric power company is a complex enterprise whose primary goal may be expressed in terms of an operating objective: to furnish electrical energy as required by customers and for as long as required. Requisite to this objective is a quality of service characterized by stable electrical frequency and voltage and by continuity in time.

The operating objective admits of various interpretations by different decision-makers within the company organization. This thesis will concern itself only with the decision-making problems of the electrical system operator. The total system which functions to meet or to influence the stated objective encompasses the areas of load-building, engineering planning and design, construction, maintenance, operation, procurement, rate structures, personnel, research, and services. Thus it is recognized that looking into only one segment of this total system may not yield the best solutions. However, electrical operation is, as it were, closest to the customer, being the final step in the carrying out of the objective. The image of the power company as seen by the customer is most directly shaped by the outcome of decisions made in electrical operation.

What sets electrical operation decision-making apart from the other sub-systems is the fact that most of the decisions have to be made within very short periods of time. This property which evidently requires automatic control serves as a justification for studying the electrical operating problem in isolation.

We consider the electrical operating problem as the problem of controlling the generation-transmission system so as to meet the operating objective (as stated in the first paragraph of this section) under all system conditions.

The generation-transmission system is understood to include all generators, the transmission network, all transmission substations, and all interconnections to external systems. The system loads are assumed to be concentrated at the low-voltage busses of the transmission substations. Thus all networks beyond these busses to the low-voltage distribution points are in effect cut off from consideration. The prime movers themselves and their energy sources are not included although the mechanical powers they produce are included as inputs to the generation-transmission system.

In this thesis all subsequent references to the "power system" should be understood to refer to the generation-transmission system.

Before we discuss in Section 1.5 the control problem of a power system, we will first review, in the next three sections, some basic features of a power system in order to establish the necessary background.

1.2 The Power System Network Models

The functions describing the performance of a power system make use of suitable models of the electric network. Generally, the model used is a "node-to-neutral network" where it is assumed that the nodes of the power system are entry points for impressed currents which flow through the network and exit at the electrical neutral of the system. This model is also referred to as the "nodal voltage" network.

Let V_S = the vector of complex voltages from node to neutral in network S

I_S = the vector of complex currents impressed at the nodes in network S

V_S and I_S are related by:

$$I_S = Y_S V_S \tag{1.1}$$

where Y_S is a non-singular complex matrix known as the nodal admittance matrix of S.

In what follows we will show how Y_S is obtained using methods introduced by Gabriel Kron (3,4,5,6). Kron's approach or the method of piecewise analysis consists of three steps: tear the original network into several smaller subnetworks; solve each subnetwork in isolation; interconnect the individual solutions to obtain the overall solution to the original network.

Given an electrical network, let us tear it apart so that each subnetwork is a single branch element or else a group of branch elements which are mutually coupled to one another by magnetic induction. In either case all metallic connections between branches are disconnected. We will have what Kron calls a primitive network.

In general, each branch element may be represented as shown in Fig. 1.2.1.

We will define the electrical quantities shown in Fig. 1.2.1 as vectors in order to gain generality. Obviously a single branch is just a special case of a sub-network whose voltages and currents are 1-vectors.

E = the vector of voltages across the branches

i = the vector of currents through the branches

e = the vector of voltages impressed through the branches

I = the vector of currents impressed across the branches

V = the vector of voltages across the branch impedance

J = the vector of currents through the branch impedance

z = the matrix of branch impedances where z_{ii} = the impedance of the i-th branch and z_{ij} $(i \neq j)$ is the mutual impedance relating a voltage induced in the i-th branch by a current through the j-th branch.

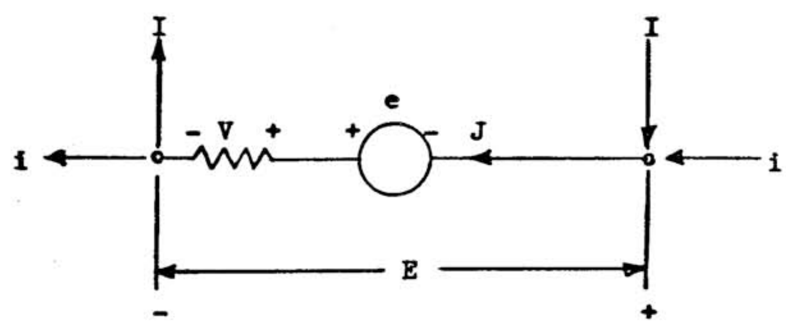

Fig. 1.2.1 The General Branch of an Electrical Network

The branch impedance matrix, z, will always have an inverse since for the determinant z to be zero implies that the branches are perfectly coupled, which is never true. The inverse, $y = (z)^{-1}$, will be called the branch admittance matrix.

The generalized Ohm's Law for a sub-network of coupled branches will be

$$V = zJ \quad (1.2a)$$

$$J = yV \quad (1.2b)$$

From Fig. 1.2.1 we see that

$$V = E + e \text{ and } J = I + i \quad (1.3a)$$

Thus $E + e = z(I + i)$

$$I + i = y(E + e) \quad (1.3b)$$

(1.2a), (1.2b) and (1.3a), (1.3b) can be extended to the entire primitive network, which we shall designate by B. We can write

$$V_B = z_B J_B \quad (1.4a)$$

$$J_B = y_B V_B \quad (1.4b)$$

$$E_B + e_B = z_B(I_B + i_B) \quad (1.5a)$$

$$I_B + i_B = y_B(E_B + e_B) \quad (1.5b)$$

z_B is the direct sum of the impedance matrices of the primitive sub-networks. Similarly, y_B is the direct sum of the admittance matrices of the primitive sub-networks. It is clear that $y_B = (z_B)^{-1}$. Since there is no interaction between sub-networks, (1.4a), (1.4b), and (1.5a), (1.5b) are just compact expressions for the voltage and current relationships of the torn network. These relationships are independent of the way the branches are interconnected in the original network.

In power system networks there are no active voltages in the branches, i.e., $e_B = 0$. Hence

$$V_B = E_B \quad (1.6)$$

Our next step is to consider the interconnection of the various subnetworks so as to obtain the original network in terms of the node-to-neutral voltage vector, E_S, of the interconnected network by:

$$E_B = A\ E_S \tag{1.7}$$

where A is the transformation matrix for expressing each branch voltage as a linear combination of node-to-neutral voltages. A is a matrix whose elements are +1, -1, and 0. The rows correspond to the branches and the columns to the nodes. Each row of A has a +1 and a -1 corresponding to the nodes at the + and - polarities, respectively, of the branch voltage.

Since $e_B = 0$,

$$V_S = E_S$$

and (1.7) can be written as

$$V_B = A\ V_S \tag{1.8}$$

Now the complex power consumed in any electrical network is defined as the inner-product $\langle V,J \rangle$. In the transformation of the primitive network, B, to the interconnected network, S, we require that the complex power be invariant.

Thus $\langle V_B, J_B \rangle = \langle V_S, I_S \rangle$ or

$$V_B^T\ J_B^* = V_S^T\ I_S^* \tag{1.9}$$

where the superscript T indicates transposition and the symbol * indicates the complex conjugate.

Substituting V_B from (1.8) in (1.9) we get

$$V_S^T\ A^T\ J_B^* = V_S^T\ I_S^* \text{ or} \tag{1.10}$$

$$A^T\ J_B^* = I_S^* \quad \text{hence}$$

$$I_S = A^T\ J_B \tag{1.11}$$

(Note: $A^{T*} = A^T$ since A is a real matrix)

$$I_S = A^T\ y_B V_B \tag{1.12}$$

Substituting V_B from (1.8) in (1.12) we get the Ohm's Law for the node-to-neutral network:

$$I_S = A^T y_B A V_S \tag{1.13}$$

(1.13) is the same as (1.1), $I_S = Y_S V_S$, where

$$Y_S = A^T y_B A \tag{1.14}$$

is the desired nodal admittance matrix.

In the nodal admittance matrix, Y_S, the diagonal terms are called self-admittances and the off-diagona- terms are called mutual admittances.

In the common case where there is no mutual impedance between branches or where the mutual impedance may be neglected, the primitive impedance matrix, z_B, is a diagonal matrix of branch impedances. Thus y_B would be a diagonal matrix of branch admittances or the reciprocals of the branch impedances. When such a y_B is substituted in (1.14) it will be found that each self-admittance term in Y_S is simply the sum of branch admittances which terminate at the designated node and the off-diagonal terms are the negatives of the branch admittances between nodes.

(1.1) will have a solution if $(Y_S)^{-1} = (A^T y_B A)^{-1}$ exists. Y_S will have an inverse if at least one node has an admittance to neutral.

The inverse of Y_S is called the nodal impedance matrix Z_S. That is, $Z_S = (Y_S)^{-1}$. We can write the dual form of (1.1) as

$$V_S = Z_S I_S \tag{1.15}$$

We have obtained two network models for the power system: a nodal admittance network and a nodal impedance network. Depending upon the system and the input-output condition being studied, either model may be used.

1.3 The Power System Stability Problem

Let I = {P,|E|,D,χ,A} be the set of input time functions and Ω = {θ,V,ω} be the set of output time functions of a power system, where

P = vector of mechanical power inputs to generators

|E| = vector of generator voltage magnitudes

θ = vector of generator voltage phase angles

D = vector of electrical loads in the system

V = vector of complex voltages at load points

ω = electrical frequency of the system

χ = inter-system power flows

A = electrical fault conditions

The input set, I, is made up of two disjunctive subsets, M and U, i.e., $I = M \cup U$ and $M \cap U = \phi$. M = {P,|E|,B} is the set of manipulated inputs. U = {D,χ,A} is the uncertainty set of disturbance inputs.

The operation of a power system may be characterized by a set, F, of functions.

$$F = P \times |E| \times D \times \chi \times A \rightarrow \theta \times V \times \omega \tag{1.16}$$

For the purposes of this section we will consider a simplified version of F.

If we consider short time intervals during a system disturbance we can neglect the effect of governor action and thus consider the vector of mechanical inputs, P, to the generators as constant. We will also assume that within this short time interval, the magnitudes, |E|, of generator voltages are constant, where the generator nodes are located behind the generator reactances.

Let G = the set of generator nodes

L = the set of load nodes

R = the set of passive nodes (i.e., with neither generation nor load)

Electrical loads of a power system behave as constant impedances, as constant current elements, or as constant power elements. In investigating the motion of power systems as indicated by (1.16), the most common assumption made is that the loads may be represented by constant impedances (11, 12). We will make this same assumption by connecting at the load entry points, i.e., the set L, impedances to neutral. Thus the set L can be combined with the set R of passive nodes. Let this combined set be called K. That is, $K = L \cup R$. The network nodal admittance, Y_S, can therefore be partitioned as shown:

$$Y_S = \left[\begin{array}{c|c} Y_G & Y_{GK} \\ \hline Y_{KG} & Y_K \end{array}\right]$$

The network model can further be reduced in dimension to the set of generator entry points by Kron's network reduction formula (3). Calling this new model, Y, we have:

$$Y = Y_G - Y_{GK}(Y_K)^{-1}Y_{KG} \tag{1.17}$$

The effect of the interconnection is given by the inter-system flow vector, χ. We will obtain this effect by developing an approximate network model. Such an equivalent we will assume to be obtainable by known methods (8,9,10) or by other means as yet to be developed. The interconnection network will have one or more fictitious generating sources capable of either positive or negative generation. We will include these sources in the set G of generator nodes.

In (1.16), A reflects the changes in network connections as brought about by fault conditions and circuit breaker operations because of a fault.

$$A(t) = \begin{cases} A_{\tau_0}, & 0 < t \leq \tau_1 \\ A_{\tau_1}, & \tau_1 < t \leq \tau_2 \\ \vdots & \vdots \\ A_{\tau_n}, & \tau_n \leq t \end{cases} \qquad (1.18)$$

where $A_{\tau i}$ is a transformation matrix such that

$$A_{\tau_0} Y = Y$$

$$A_{\tau_i} Y = Y_{\tau_i}$$

and $\tau_1, \tau_2, \ldots, \tau_n$ are the times at which either a fault or a circuit breaker operation occurs and τ_n is the last disturbance time.

For a generator at node "i" with inertial constant, M_i, we will have the differential equation:

$$\ddot{\theta}_i = \frac{1}{M_i}\left(P_i - Re\{|E_i| \, \varepsilon^{j\theta_i} \sum_{k \in G} (A(t) \, Y_{ik}{}^{*} \, |E_k| \, \varepsilon^{-j\theta k}\}\right) \qquad (1.19)$$

For the entire set, G, of generators, we can write

$$\ddot{\theta} = F(t, \theta, A) \qquad (1.20)$$

where each element of (1.20) is of the form of (1.19).

Since during the interval $\tau_i < t < \tau_{i+1}$ the matrix A_{τ_i} is fixed, we can re-write (1.20) as

$$\ddot{\theta} = F(\theta) \qquad (1.21)$$

or, in the normal form

$$\dot{X} = F(X) \qquad (1.22)$$

The state, X, is the vector of generator angles, θ, and their first-order derivatives, $\dot{\theta}$. If there are n generator nodes in G, the state variables would be

$$x_i = \theta_i \qquad\qquad i = 1,2, \ldots, n \tag{1.23}$$

$$x_{i+n} = \dot{\theta}_i \tag{1.24}$$

The differential equations in (1.22) are of the form

$$\dot{x}_i = x_{i+n} \tag{1.25}$$

$$\dot{x}_{i+n} = \frac{1}{M_i}(P_i - Re\{|E_i|\epsilon^{jx_i} \sum_{k \in G} Y^s{}_{ik}{}^* |E_k|\epsilon^{-jx_k}\}) \tag{1.26}$$

The limit point of X(t) at the end of one time interval is the initial state for the suceeding time interval. That is, $\lim_{t \to \tau_i} X(t) = X(\tau i)$. This condition holds true for a power system, i.e. $\dot{\theta}$ is continuous for all $t > t_o$.

When there is no fault (or breaker) disturbance, (1.20) becomes (1.21) directly and the same normal form, (1.22), applies.

Equilibrium conditions will hold when $F(X) = 0$, and the equilibrium state will be a constant, $a = (\theta_{a1}, \theta_{a2}, \ldots, \theta_{an}, 0, \ldots, 0)^T$, where n is the number of generator nodes.

Let $\theta(t) = \theta(t, t_o, \theta^o)$ denote the solution of (1.21) with initial values $t = t_o$, $\theta = \theta^o$, i.e., $\theta(t_o) = \theta^o$.

Assume that there is no disturbance to the system, that the system is in equilibrium. Let $S_d(a) = \{\theta | \|\theta - a\| \leq d\}$, where $\|\theta - a\|$ is the usual metric on E^n.

Definition 1.3.1 - A power system with an equilibrium state, a, is said to be steady-state stable if (1) there exists a positive number p such that if $\theta^o \in S_p(a)$, the solution $\theta(t)$ of (1.21) is defined for all values of $t > t_o$; (2) for any positive number ϵ there exists a positive number $\delta<p$ such that for $\theta^o \in S_\delta(a)$, $\theta(t) \in S_\varepsilon(a)$ for all $t>t_o$; and (3) there exists a small positive number $\sigma<p$ such that for $\theta^o \in S_\sigma(a)$ the $\lim_{t\to\infty} |\theta(t) - a| = 0$.

Steady-state stability when expressed in terms of an operating limit becomes one of the constraints in the set of "conditions for operation" which will be discussed in Section 1.5.

There is another, more stringent form of stability, associated with large disturbances. Let us first define

$$\|\theta\| = \max_{\substack{i,j \\ i\neq j}} |\theta_i - \theta_j|$$

That this is a norm can be readily verified.

<u>Definition 1.3.2</u> - A power system with an equilibrium state, a, is said to be <u>completely stable</u> if: (1) the system is steady-state stable; (2) for any fault condition, $A(t)$, $\|\theta(t)\|<\pi$ for all $t>t_o$; and (3) the $\lim_{t\to\infty} \theta(t) =$ a constant.

This type of stability, commonly called "transient stability" for short time intervals or "dynamic stability" for longer time intervals, can also be expressed in terms of an operating limit and becomes another constraint in the set of "conditions for operation" to be discussed in Section 1.5.

<u>1.4 Power System Load Flow Problem</u>

When the power system is in a state of equilibrium, (1.21) becomes the set of simultaneous algebraic equations

$$F(\theta) = 0 \qquad (1.27)$$

Each element of (1.27) is of the form

$$P_i - Re\{|E_i|\varepsilon^{j\theta_i} \sum_{k\in G} Y_{ik}^* |E_k| \varepsilon^{-j\theta_k}\} = 0 \qquad (1.28)$$

The solution, a, of (1.27) gives the angles at the generator nodes so that the complex vector, E_G, of generator voltages is completely specified. The voltages at the combined set of nodes, K, will be given by

$$V_K = -(Y_K)^{-1} Y_{KG} E_G \tag{1.29}$$

With all the voltages at the system nodes completely known the power flows in each circuit of the system can be calculated.

Thus, at node i, the power flow, S_{ij}, over the circuit to node j is

$$S_{ij} = V_i (V_i - V_j)^* y_{ij} \tag{1.30}$$

where y_{ij} = the admittance of the branch from node i to node j. The values of the voltages at all the system nodes and the power flows in all system branches for a given equilibrium constitute what is known as a "load flow" solution.

We realize that (1.27) is an approximate load flow problem since it was derived with the assumption that all the loads are equivalent to constant impedances. We made this assumption in order to simplify the description of the power system stability problem. In analyzing the load flow problem, however, we do not have to make this assumption. In fact, since we are interested in details of the steady-state, such as loadings of circuits and voltage magnitudes at certain locations, a more accurate and general modelling is necessary.

Suppose we have a network with N+1 nodes. At each node, i, there are four variables -- P_i, Q_i, $|V_i|$, θ_i. P_i is the real power into the node; Q_i is the reactive power into the node; $|V_i|$ is the node voltage magnitude; θ_i is the node voltage phase angle. For all the N+1 nodes the steady-state conditions are given by the implicit equation

$$g(P,\ Q,\ |V|,\ \theta) = 0 \tag{1.31}$$

where g is a 2(N+1)-vector; $P = (P_o,\ P_1,\ \ldots,\ P_N)^T$;

$$Q = (Q_o,\ Q_1,\ \ldots,\ Q_N)^T;\ |V| = (|V_o|,\ |V_1|),\ \ldots,\ |V_N|)^T$$

$$\theta = (\theta_o,\ \theta_1,\ \ldots,\ \theta_N)^T.$$

g consists of N+1 equations of the form

$$Pi - Re\{|V_i|\varepsilon^{j\theta i}\sum_{k=0}^{N+1} Y_{ik}^*|V_k|\varepsilon^{-j\theta k}\} = 0, \tag{1.32}$$

and N+1 equations of the form

$$Q_i - Im\{|V_i|\varepsilon^{j\theta i}\sum_{k=0}^{N+1} Y_{ik}^*|V_k|\varepsilon^{-j\theta k}\} = 0 \tag{1.33}$$

If for each node we specify any two variables then the load flow problem becomes one of solving the implicit equation

$$F((|V|,\ \theta)^T) = 0 \tag{1.34}$$

for $(|V|,\ \theta)^T$, where f and $(|V|,\ \theta)^T$ are both m-vectors. The dimension m is less than or equal to 2(N+1). $|V|$, a vector of unknown voltage magnitudes, and θ, a vector of unknown voltage angles are not necessarily of the same dimension.

An element of (1.34) is an equation of the form of (1.32) or (1.33), with P_i or Q_i known. We can easily verify that this is so. Regardless of what set of variables are given, provided there are two specified for each of the N+1 nodes, the load flow problem reduces to solving for an m-dimensional $(|V|,\ \theta)$ from m simultaneous equations, where m may be any number from 0 to 2(N+1).

There are six possible ways by which we can specify at a node two of the four variables, P_i, Q_i, $|V_i|$, and θ_i. These possible node specifications are: (P_i, θ_i), (Q_i, θ_i), $(|V_i|, P_i)$, $(|V_i|, Q_i)$, (P_i, Q_i), $(|V_i|, \theta_i)$. After the node specifications have been given for all the N+1 nodes, (1.34) will consist of m equations in the remaining unspecified $|V_i|$'s and θ_i's.

It is possible to establish certain requirements which have to be satisfied if the load flow problem is to have a solution.

Requirement A - Looking at (1.32) and (1.33) we see that the voltage phase angles are actually combined to form phase angle differences. Out of the N+1 angles we end up using N angular differences in each equation. This is equivalent to saying that one of the node phase angles should be specified in order to establish a reference angle.

We can show that if no angle is specified at all then the resulting load flow problem will have no solution. In this case (1.34) will be of dimension, $N+1 \leq m \leq 2(N+1)$. If there are r unknown voltage magnitudes then $m = N+L+r$. Let us rewrite (1.34) in the form

$$\begin{bmatrix} F_P\ (|V|,\theta)^T \\ \hline F_Q\ (|V|,\theta)^T \end{bmatrix} = 0 \tag{1.35}$$

where $F_P\ (|V|,\theta)^T$ is a p-vector of functions similar to the left-hand side of (1.32); $F_Q\ (|V|,\theta)^T$ is a q-vector of functions similar to the left-hand side of (1.33); and $p + q = m$. Let J be the Jacobian matrix of (1.34). From (1.35) we can write

$$J = \frac{\partial(F_P,\ F_Q)}{\partial(|V|,\theta)} = \left[\begin{array}{c:c} \dfrac{\partial F_P}{\partial|V|} & \dfrac{\partial F_P}{\partial\theta} \\ \hdashline \dfrac{\partial F_Q}{\partial|V|} & \dfrac{\partial F_Q}{\partial\theta} \end{array}\right] \tag{1.36}$$

$$\text{where } \frac{\partial F_P}{\partial|V|} \triangleq \begin{bmatrix} \frac{\partial F_{P1}}{\partial|V_a|} & \frac{\partial F_{P1}}{\partial|V_b|} & \cdots & \frac{\partial F_{P1}}{\partial|V_r|} \\ \frac{\partial F_{P2}}{\partial|V_a|} & \frac{\partial F_{P2}}{\partial|V_b|} & \cdots & \frac{\partial F_{P2}}{\partial|V_r|} \\ \vdots & \vdots & & \vdots \\ \frac{\partial F_{Pp}}{\partial|V_a|} & \frac{\partial F_{Pp}}{\partial|V_b|} & \cdots & \frac{\partial F_{Pp}}{\partial|V_r|} \end{bmatrix}$$

$$\frac{\partial F_P}{\partial|\theta|} \triangleq \begin{bmatrix} \frac{\partial F_{P1}}{\partial\theta_o} & \frac{\partial F_{P1}}{\partial\theta_1} & \cdots & \frac{\partial F_{P1}}{\partial\theta_N} \\ \frac{\partial F_{P2}}{\partial\theta_o} & \frac{\partial F_{P2}}{\partial\theta_1} & \cdots & \frac{\partial F_{P2}}{\partial\theta_N} \\ \vdots & \vdots & & \vdots \\ \frac{\partial F_{Pp}}{\partial\theta_o} & \frac{\partial F_{Pp}}{\partial\theta_1} & \cdots & \frac{\partial F_{Pp}}{\partial\theta_N} \end{bmatrix}$$

$$\frac{\partial F_Q}{\partial|V|} \triangleq \begin{bmatrix} \frac{\partial F_{Q1}}{\partial|V_a|} & \frac{\partial F_{Q1}}{\partial|V_b|} & \cdots & \frac{\partial F_{Q1}}{\partial|V_r|} \\ \frac{\partial F_{Q2}}{\partial|V_a|} & \frac{\partial F_{Q2}}{\partial|V_b|} & \cdots & \frac{\partial F_{Q2}}{\partial|V_r|} \\ \vdots & \vdots & & \vdots \\ \frac{\partial F_{Qq}}{\partial|V_a|} & \frac{\partial F_{Qq}}{\partial|V_b|} & \cdots & \frac{\partial F_{Qq}}{\partial|V_r|} \end{bmatrix}$$

$$\frac{\partial F_Q}{\partial \theta} \triangleq \begin{pmatrix} \frac{\partial F_{Q1}}{\partial \theta_o} & \frac{\partial F_{Q1}}{\partial \theta_1} & --- & \frac{\partial F_{Q1}}{\partial \theta_N} \\ \frac{\partial F_{Q2}}{\partial \theta_o} & \frac{\partial F_{Q2}}{\partial \theta_1} & --- & \frac{\partial F_{Q2}}{\partial \theta_N} \\ \vdots & \vdots & & \vdots \\ \frac{\partial F_{Qq}}{\partial \theta_o} & \frac{\partial F_{Qq}}{\partial \theta_1} & --- & \frac{\partial F_{Qq}}{\partial \theta_N} \end{pmatrix}$$

The indices for F_P and F_Q correspond to the ordinal positions of the functions in the respective vector arrays. a, b, . . . r are nodes with unspecified voltage magnitudes.

We will find by actual substitution that

$$\sum_{i=0}^{N} \frac{\partial F_{Pj}}{\partial \theta_i} = 0 \qquad j = 1, 2, \ldots, p$$

and

$$\sum_{i=0}^{N} \frac{\partial F_{Qj}}{\partial \theta_i} = 0 \qquad j = 1, 2, \ldots, q$$

Hence the N+1 columns of the right-hand side of the Jacobian are linearly dependent. That is, the Jacobian of $F((|V|,\theta)^T) = 0$ is singular and therefore the set of equations has no solution. If at least one angle is specified, the Jacobian becomes non-singular (32). In practice the node specifications for an ordinary[1] load flow are restricted to either (P_i, Q_i) or $(P_i, |V_i|)$ for load nodes. Hence the reference angle, θ_o, should be assigned to a generator node. Let us say that the reference node is node "0".

Requirement B - Another requirement for the load flow problem to have a solution can be readily seen from the physics of the

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[1]In Section 3.7 we will consider the so-called "optimal load flow."

electrical network. In a network the sum of all the real powers is equal to the system real losses; the sum of all the reactive powers is equal to the system reactive losses. Since all the load real powers are specified it will be impossible to specify all of the generator real powers. At least one generator node should have P_i unspecified. If again we say that this is node "0" then by specifying $(|V_0|, \theta_0)$ for node "0" we will be satisfying both requirements A and B.

Let us call the generator node at which we specify both the voltage magnitude and the angle the "swing bus." It is clear that it is possible to assign more than one swing bus in a load flow problem. Theoretically all of the generator nodes can be made swing busses. In Section 4.3 when we consider the decomposition of a load flow problem we will use the artifice of assigning more than one swing bus to a sub-system.

If we had specified (P_0, θ_0) for generator node "0" we could still satisfy requirement B by making another generator node the swing bus, i.e. with $(|V_i|, \theta_i)$ specifications.

In summary, for an ordinary load flow we will be dealing with three types of node specifications, namely: (P_i, Q_i), $(P_i, |V_i|)$, and $(|V_i|, \theta_i)$. The other possibilities are interesting but academic. As long as we observe both requirements A and B a solution is possible. Otherwise, no solution can be found.

There are several successful iterative methods (29,35) for solving (1.34). A method using mathematical programming is discussed in Section 3.7.

1.5 Characterization of System Operation by Operating States

Analysis of system stability and of load flow conditions yield certain "conditions for operation," i.e., in the sense of continuous operation. These conditions may all be expressed in the form of a set of constraints:

$$G(M,U) \geq 0$$

$$H(M,U) = 0$$

where M and U are as described in Section 1.3.

We will now describe the operation problem by introducing the concept of "operation states."

Definition 1.5.1 - A power system is said to be in normal operation when the conditions for operation, $G(M,U) \geq 0$ and $H(M,U) = 0$ are all satisfied.

A power system in normal operation will be referred to as being in the preventive operating state.

The designation "preventive" is chosen to stress the fact that during normal operation, control action should be taken, whenever feasible, to enhance system security. (A more formal treatment of system security is given in Chapter 3.) In the preventive operating state, the power system is being operated so that the demands of all customers are satisfied at standard frequency and voltage. The control problem in the preventive operating state is to continue indefinitely this satisfaction of customer demand without interruption and at minimum cost. Since continuity of service is required it follows that no electrical component of the system shall be operated beyond its safe thermal limit. It is also implied that the power system will be able to go through a disturbance from one preventive state to another. The control action is defensive or preventive in character. That is, the operating control should recognize electrical system and environmental changes, evaluate the effect of uncertainties, and take courses of action to prevent, as economically as possible, the impairment of satisfactory service.

Definition 1.5.2 - A power system is said to be in an emergency operation whenever, of the conditions for operation, the subset $G(M,U) \geq 0$ is not completely satisfied. That is, $\exists g_i(M,U) \in G(M,U)$ such that $g_i(M,U) < 0$.

A power system in emergency operation will be referred to as being in the emergency operating state.

The emergency operating state comes about when some component emergency ratings are exceeded or when the voltage at a customer cannot be maintained at a safe minimum or when the system frequency starts to decrease toward a value at which important motors will stall, or when the electrical system is in the process of losing synchronism. The control objective in the emergency state is to relieve the system distress and forestall further degradation while satisfying a maximum of customer demand. Economic considerations become secondary.

Definition 1.5.3 - A power system is said to be in partial load operation whenever, of the conditions for operation, the subset $H(M,U) = 0$ is not completely satisfied. That is, $\exists h_i(M,U) \in H(M,U)$ such that $h_i(M,U) \neq 0$.

A power system in partial load operation will be referred to as being in the restorative operating state.

The restorative operating state is that condition when service to some customer loads has been lost. Usually this is the aftermath of an emergency. The control objective in the restorative state is the safe transition from partial to 100 percent satisfaction of all customer demands in minimum time. From the standpoint of real customer satisfaction, restoration of interrupted supply in as short time as possible is of crucial importance.

The decision-making problems associated with system operation may now be studied within the framework of the three operating states: preventive, emergency, and restorative. In effect we have decomposed the total operating problem time-wise, corresponding essentially to "before, during, and after" a system emergency. As we shall see in Chapter 2 the structuring of the control system will be facilitated by this characterization of operating states.

CHAPTER II

A CONTROL STRUCTURE FOR POWER SYSTEM OPERATION

A very useful approach to control system design is the multilevel control concept and its extension by I. Lefkowitz into multilayers of control (7). As will be evident, this multi-layer concept is particularly effective in structuring a control system for power system operation.

2.1 Decomposition of Power System Networks into Areas

We can take the power system network and subdivide it into several areas. The need for subdivision into areas will depend on: the complexity and computational difficulty associated with a single control model; the geographical disposition of generating sources, heavy load centers, and interconnections; ownership or political boundaries; overall considerations of reliability. The natural decomposition induced by ownership boundaries generally asserts itself. That is, decomposition becomes necessary in this case, not so much for computational and control efficiency but by the fact that independently owned power systems have independent control systems. When we consider control of interconnected systems we will have to accept this manner of decomposition. In some other political environment one may have more freedom (at the expense of somebody else's) to consider other ways of subdividing the total network.

If a network area is very large, it may further be subdivided into sub-areas. In this case there are no ownership considerations and the problem reverts to the basic one in systems theory -- "What is a subsystem?" We will not address ourselves to this question. Rather, we will say that our motivation for further decomposition into sub-areas is either for computational efficiency in modelling or for overall reliability in control. The decomposition will be guided by the specific nature of the network. An attempt should be made so that each sub-area is as self sufficient as possible in generating capacity and in interconnection support. For modelling, this criterion is not really important. For control reliability this criterion would be a sound operating principle.

The decomposition method for the network itself is straightforward and is an extension of the piece-wise approach described in Section 1.2, where now the primitive networks are the several separate areas.

For each network area the operating problem may be decomposed into the three operating states defined in Section 1.5. Each area control would develop the first level solutions for all operating states and a second-level control would be required to coordinate these solutions.

2.2 Multi-Layer Hierarchy (13)

For each operating state we can structure the controls according to the multi-layer concept of: direct, optimizing, and adaptive control (7).

The first layer, or direct control, performs high-speed decisions using logic or a logical decision process and carries out directly the necessary control action. This layer of control will be predominantly located at local points within the system rather than at a control center. As much as possible the logic used at a given location would make use of local information and would be kept fairly simple. Although direct control decisions should have a minimum of dependence on central processing, there would be some decisions which would have to be done at the control center. Whether done locally or centrally, the distinguishing features of direct control are its high-speed and the use of logic programming. Direct control is also influenced by instructions from the upper layers.

Table I lists the automatic sub-system at the direct control layer for each of the three operating states.

In the preventive state, the direct control sub-systems are all found in present-day power systems. The functions of these existing controls would be extended and improved on a system basis by the addition of instructions from the higher control levels. The power industry already has an example of this in economic dispatch where optimal raise and lower models determined by an optimizing model are applied to the turbine governor control.

The emergency direct control functions, as listed in Table I, are intended to relieve an emergency immediately in cases where there is not enough time or when there is no means for finding the best solution at the optimizing layer. The cases are usually those involving instability, low or rapidly decreasing frequency or critically low voltage levels.

TABLE I

DIRECT CONTROL FUNCTIONS

Preventive

1. Load-frequency control
2. Turbine governor control
3. Generator voltage regulation
4. Transformer tap changing
5. Capacitor switching
6. Circuit reclosing

Emergency

1. Fault clearing
2. Load shedding
3. Generator switching
4. Automatic switching
5. System splitting

Restorative

1. Automatic feeder restoration
2. Automatic load transfer

The second layer, or optimizing control, solves for the "best" control decisions using a mathematical model of the operating state and an appropriate criterion for optimum performance. In contrast to the first layer, all second layer functions would be done on a central computer because of the mathematical calculations involved in arriving at optimal solutions. A further distinction is that second layer decisions take time. The mathematical model should be as simple an approximation as possible consistent with the quality of performance desired. Because the model is only an approximation and because of the time lag between the system conditions input and the decision output, the second level decisions are strictly speaking, sub-optimal.

Table II lists the optimizing control functions planned for each of the three operating states.

TABLE II

OPTIMIZING CONTROL FUNCTIONS

Preventive

1. Economy interchange determination
2. Economic generation dispatch

Emergency

1. Maximum load control

Restorative

1. Dynamic restoration procedure

For the optimization processes in all three operating states, there is a common set of decision variables, i.e., variables which may be manipulated for the best combination of values to meet the objective without breaking any constraints. The set of decision variables consists of:

(1) Units on line
(2) MW output of generators
(3) Interchange schedule
(4) System voltages
(5) System load connected

To put into effect a desired set of values, orders will be sent to the direct control sub-systems, to the system itself, or to the system operator. Some orders will be carried out automatically, and some manually. Orders sent out to the sytem itself will be for breaker operations, generally tripping operations. Thus to effect a desired load level so as to relieve an emergency, trip signals would be sent to various stations to drop prescribed amounts of load.

The third layer, or adaptive control, determines and adjusts the settings, parameters, and logic used in the first and second layers. Whereas both the first two layers are automatic, the decision-making process at the third level is a man-machine combination with the system control operator playing an active part. The third layer compensates for disturbances or environmental conditions not considered in the first two layers. Any adjustments done by the operator would as much as possible be aided by off-line computer calculations or by predetermined decision tables or both.

Table III lists the adaptive control functions for each of the three operating states.

Adaptive control has to anticipate, in some fashion, the disturbance inputs to the generation-transmission system. The disburbance set consists of: loads, tie-line flows, and faults. One method of dealing with the disturbance set is to reduce the uncertainty by prediction.

Loads for the day can be predicted with reasonable accuracy. The results of such load forecasts would be used in making direct and optimizing control decisions in the preventive state. Load forecasts would also be one of the factors considered in making adaptive decisions for near-future conditions of the system. Restorative procedures would also require estimates of loads in areas or at substations.

A method of prediction would also be of great value in representing the interconnection. Although it may be possible to develop a good network equivalent to represent the interconnection, the

TABLE III

ADAPTIVE CONTROL FUNCTIONS

Preventive

1. Regulator & relay setting changes
2. Unit committment
3. Constraint values
4. Lower-layer logic
5. Short-term load forecast
6. Tie-line flow model
7. System security evaluation
8. Penalty factor calculation
9. System voltage control
10. Fault location procedure
11. Switching operations
12. Manual intervention

Emergency

1. Constraint values
2. Lower-layer logic
3. Tie-line flow model

Restorative

1. Constraint values
2. Lower-layer logic
3. Tie-line flow model
4. Load forecast

adaptive problem is to keep this equivalent up-to-date under all system conditions. What is required is a fairly accurate estimate of what the flows would be as changes are made in the area generation, load, and network configuration.

System security evaluation in the preventive state will be discussed in Chapter III.

One of the functions of adaptive control is to supplement the optimizing layer with functions which result in the simplification of the optimizing control. Two such functions are the Penalty Factor culation will be discussed in Section 3.6.

2.3 Overall Control Strategy

The overall control objective is to keep the power system operating in the preventive state. The three control layers in the preventive state are all designed for this purpose. The key function is in the adaptive control where predictive approaches are used so that preventive action may be taken ahead of time.

Some preventive control actions may be too costly to implement and some set of events leading to an emergency may be completely unforeseen. It is thus expected that some emergencies can occur which cannot be avoided by preventive control. In this case the control system would switch over to the emergency control mode. The emergency control would try to take the power system back to preventive operation. Failing this, some customer demand would not be satisfied, deliberately, as a control solution; or unavoidably because of the severity of the emergency. In this situation the control system would switch to the restorative mode where restorative control would bring the system back to the preventive state as fast as possible.

In the remaining part of this thesis the discussion will be limited to the work I have accomplished in the areas having to do primarily with preventive control.

CHAPTER III

PREVENTIVE CONTROL

The continuity of electric power service will depend primarily on the effectiveness of control in the preventive operating state. In this chapter, we will consider in some detail important facets of the adaptive layer of preventive control which are, as of this writing, new to power system operation. While the idea of preventive control action is inherent in good system operation, the approach described in this chapter is a major departure from prevailing, subjective methods of decision-making.

We will also go through the optimizing layer and show how "penalty factors" may be used to reflect the full effect of network steady-state conditions on the optimizing problem.

Finally we will consider general optimization problems of power systems and how they may be solved by non-linear programming methods.

3.1 The Concept of System Security

Consider the uncertainty set, U, of disturbance inputs to the power system. As described in Section 1.3, $U = \{D, \chi, A\}$, where:

D = electrical loads in the system

χ = inter-system flows

A = electrical fault conditions

The set U may be partitioned into two subsets U_α and U_β, i.e., $U = U_\alpha \cup U_\beta$, where:

$U_\alpha = \{u_{\alpha i}: \ u_{\alpha i} = D_i(t), \ i \in L\}$

$U_\beta = \{u_\beta : \ u_\beta \in A \text{ or } u_\beta = \Delta X\}$

L = set of load nodes

Δx = large step change in inter-system flow

Each $u_{\alpha i} \in U_\alpha$ exhibits an approximately periodic variation with time so that it is feasible to predict $u_{\alpha i} = D_i(t)$, $t_o \le t \le T$ with good accuracy for some time period, $\tau = T - t_o$, in the near future. This prediction would be based on the continuous or regular monitoring of the aggregate, $\alpha = \sum_{i \in L} u_{\alpha i}$. Of course if cost of instrumentation and communication were not a problem, each individual $u_{\alpha i}$ may be monitored. We will call the load prediction routine the "Short-term Load Forecast." This is listed in Table III, Section 2.2, as one of the adaptive control functions in preventive operation.

Assuming that the Short-term Load Forecast is satisfactory to a desired degree of accuracy, then the uncertainty aspect of the disturbance set, U, would in effect be reduced to that of the subset, U_β.

When a normal operating system is perturbed by a disturbance from U_β, the system may settle down to a new normal state or may go into an emergency condition. If the system were stable (see Def. 1.3.2) the emergency condition might be due to a violation of a voltage constraint or of a circuit loading constraint. If the system were unstable, generating units would drop out of synchronism and the system network may break up into isolated areas. The end result would be the loss of customer load.

System security may be considered as the ability of a power system in normal operation to undergo a disturbance without getting into an emergency condition. A means of evaluating system security is necessary for an effective preventive control. The determination of system security resolves into the identification of whether or not a system would satisfy the conditions for operation under the occurrence of a disturbance from the set U_β. In order to come up with a practical way of making this determination we will define system security in specific terms.

We will first define an arbitrary set of disturbances which is a subset of U_β, and which we will call the "next-contingency set."

Definition 3.1.1 - The "next-contingency set" is the set of the following disturbances:

(a) any circuit out
(b) any generating unit out
(c) any 3-phase fault in the system
(d) Ax sudden change in inter-system flows

Definition 3.1.2 - A normal system is said to be secure if, assuming the occurrence of a disturbance in the next-contingency set, the resulting system would be normal, for any disturbance in the next-contingency set.

Definition 3.1.3 - A normal system is said to be insecure if there is at least one disturbance in the next-contingency set whose occurrence would result in the system getting into an emergency operating condition.

We note that by defining arbitrarily a next-contingency set we are in effect deciding that the evaluation of system security will be made only in terms of a specific subset of disturbances. No matter what the existing system conditions may be, security will always be considered for the next contingency. The next-contingency set is an arbitrary standard by which relative securities between different system conditions may be determined. If the next-contingency set were expanded such as, for example, to include any two circuits going out simultaneously or double 3-phase faults then the security standard would be stricter. This would mean more instances of insecure system conditions and consequently more requirements for preventive control action. The next-contingency set as defined in Definition 3.1.1 is a reasonable one, representing the minimum set of next-contingencies which would justify the initiation of preventive control.

3.2 System Security Evaluation Through Pattern Recognition

One approach to system security evaluation is through simulation, i.e., for a given system, to try out the various disturbances in the next-contingency set. The simulation approach would be quite inefficient for on-line evaluation of system security.

The approach that we will investigate is that of pattern recognition.

A system with a given operating condition can be completely characterized by a suitable state vector, Z. From Definitions 3.1.2 and 3.1.3, a system with a given state vector is either secure or insecure but not both. Hence if a system with state vector Z_A is secure and the same system with state vector Z_B is insecure, it follows that $Z_A \neq Z_B$. We can therefore view system security as an attribute of the state vector. Now it would be impractical to take measurements of the state vector of a large power system. Instead, is there a small subset, z of the state vector, Z, which can be used as a pattern for security? The choice of the set of system measurements or, that is to say, the choice of the pattern vector, is the so-called characterization problem in pattern classification (14).

In most of the literature on pattern classification, the characterization problem is assumed to be solved beforehand. This is accomplished by a selection of pattern variables by someone having intimate knowledge of the specific problem. In the case of system security of a power system, the pattern vector, z, may be selected according to the considerations discussed in Section 3.3.

Assuming that we have chosen a security vector, $z = (z_1, z_2, \ldots, z_m)^T$, we will then obtain a set of N sample vectors each of which is known to be either secure or insecure. We will designate the secure category by S and the insecure category by $\overline{S}$. The set of sample vectors will be called the training set. The training set will be obtained from data generated by load flow studies and stability studies. With the training set at hand the next step is to abstract the information contained in the samples into a function, f(z), which may then be used for classifying new vectors as belonging to S or $\overline{S}$. The determination of f(z) is known as the learning or the abstraction problem of pattern classification. The classification of new vectors is known as the recognition or generalization problem.

The appeal of the pattern recognition approach to system security evaluation lies in its power for on-line application as compared to simulation methods. This is due to the inherent characteristic of pattern recognition as an adaptation and learning process.

In the pattern recognition method, only a small number of system variables need be monitored. While simulation methods would still be required for obtaining the training set, these will be all off-line. After the function f(z) has been successfully abstracted, no further simulation will be required except occasionnally for checking purposes.

3.3 The Security Vector of a Power System

In a power system, an emergency condition (see Definition 1.5.2) is one where there are excessive power flows, low voltage magnitudes, or system instability. Power flows and voltage magnitudes are determined if the voltage vector of all active busses and the network description are known (see Section 1.4). Instability may be determined if in addition to the voltage vector and network model, the rotating inertias of the turbo-generators are known (see Section 1.3). Now the voltage vector is affected by the system load level, the network impedances, and the allocation of generation. The chief effect on the voltage vector by changes in load, network impedances, and generation is in the phase angles, more than in the magnitudes. In addition, we will assume that the automatic voltage regulating devices at all active busses are doing a perfect job of maintaining voltage magnitudes constant. Thus we will use the voltage phase angles as components of the pattern vector for security. Further, since we wish to make the dimension of the security vector as small as possible we will monitor the phase angles of the generating and interconnection nodes only. The justification for using phase angles at plants and interconnections only is that for approximating purposes, all loads may be considered as equivalent to either constant impedance or constant current devices. In either case, the voltages at all loads will be uniquely determined from the voltage information at generators and interconnections. To take into account the rotating inertias in the system we may use for the remaining components of the security vector, the values of the rotating capacities at all generating nodes. The values of the rotating capacities are readily available and are also needed for determining the amount of rotating generation reserve in the system.

3.4 Adaptation Algorithm for Pattern Classification

There are several algorithms available for the abstraction problem of pattern classification (14,15,16,17,18,19). For system security evaluation we will adopt the adaptation algorithm developed by C. C. Blaydon and Y. C. Ho (14). This algorithm is an extension of an earlier work by Aizerman, Braverman, and Rozonoer (17,18). Blaydon and Ho show that the new algorithm is more rapidly convergent than the earlier one.

We will assume first of all that the image compactness hypothesis (15), a concept introduced by E. M. Braverman, applies to our problem. By this hypothesis, we assume that the class of secure system patterns and the class of insecure system patterns possess the compactness property, i.e., the two classes are easily separable. The concept of compactness or compact groups implies that the area of overlap between the two classes is small compared to the combined space. We recall that if we use the complete state vector, the secure classes are completely separable. However, we are characterizing system security by only a small set of attributes, a subset of the state vector. Hence we would expect overlaps between the two classes. If we have chosen the security vector wisely the overlap would be small and the compactness hypothesis would be justified. This suggests that if we have difficulty with our algorithms in separating the two classes then we should go back and come up with a new pattern vector, with different or possibly more elements in it.

A well known deterministic method for pattern recognition is that of the linear discriminator or separating hyperplane. If the pattern vector is z, a linear function $f(z) = \alpha^T z$ is assumed to exist such that

$$f(z) \begin{cases} > 0 \text{ if } z \in S \\ < 0 \text{ if } z \in \overline{S} \end{cases} \tag{3.1}$$

An excellent algorithm for determining the unknown parameter α from a training set of N vectors is the method of solving N simultaneous linear inequalities due to Ho and Kashyap (16). If we let

$$z = \begin{cases} z \text{ if } z \in S \\ -z \text{ if } z \in \overline{S} \end{cases}$$

Then (3.1) becomes

$$f(z) > 0 \tag{3.2}$$

We then have N sets of inequalities of the form of (3.2) for the N vectors in the training set. If we let the training set be represented by the N x m matrix, A, the problem is to determine the solution, α, of the system of linear inequalities $A\,\alpha > 0$, assuming that one exists. Ho and Kashyap solve this problem by applying an approach from mathematical programming, of if one prefers, from control theory.

An eminently readable overview of the use of mathematical programming to adaptation and learning procedures is a recent paper by Tsypkin (20). A more thorough treatment of various algorithms on a unified control theory basis is given by Blaydon (21).

The criterion function $J = \|A\alpha - \beta\|^2$ is defined and the original problem of inequalities is transformed to the minimization problem:

$$\text{Find Min } J = \|A\alpha - \beta\|^2 \qquad (3.3)$$
$$\text{Subject to } \beta > 0$$

It is evident that the solution of (3.3) is the solution to $A\alpha > 0$. The algorithm for solving (3.3) is based on the steepest descent method. At each iteration the step size in the direction of the negative gradient is of such a value that the criterion function J is minimized. The power of this deterministic algorithm lies in the fact that it converges to a solution in a finite number of steps if indeed the pattern is separable; and terminates conclusively if the pattern is not separable.

I have written a computer program for pattern classification using the Ho-Kashyap algorithm just described. Sample patterns taken from a set of load flow studies were tried and, as anticipated, the algorithm terminates on non-separability of the two classes. We are not completely ruling out the potential value of a deterministic approach and there may exist ways of getting around this difficulty of overlap. Modification of the security vector is one approach. Development of more than one hyperplane is another. However, these approaches do not appear worthwhile pursuing for the present since there is so much more to be gained with the non-deterministic or stochastic approach.

The deterministic approach has no rationale for extending the results of classifying the training set to the ultimate purpose of generalization or the recognition of new patterns of unknown classifications. The recognition of new patterns is most appropriately expressed as a probability of correct classification.

The stochastic approach on the other hand can directly relate the results of the abstraction of information from the training set to the generalization problem. In effect, the stochastic approach considers the training set as an statistical sample of the entire population of security patterns.

When the S and $\overline{S}$ classes overlap, as we anticipate, the classification of a pattern vector becomes probabilistic. Thus we will have two probability functions:

$P(S/z)$, the conditional probability that $z \in S$

$P(\overline{S}/z) = 1 - P(S/z)$, the conditional probability that $z \in \overline{S}$

$P(S/z)$ serves the same purpose as the decision function, $f(z)$, in the deterministic approach.

Let us choose $f(z)$ as a linear combination of a certain known function vector, $\phi(z)$. That is, $f(z) = \alpha^T\phi(z)$. Our problem is to find α such that $f(z)$ is a good approximation of $P(S/z)$, in the sense that $f(z)$ would converge in the limit to the true $P(S/z)$.

The algorithm that we will adopt is a special case of the general class of recursive estimation schemes in the field of Stochastic Approximation (22,23).

For $\alpha^T\phi(z)$ to be a good approximation of the unknown $P(S/z)$ we can say that we want to find the value α^* which minimizes

$$\hat{J}(\alpha) = E_z\{(P(S/z) - \alpha^T\phi(z))^2\} \tag{3.4}$$

If we define the random variable $s(z)$ as

$$s(z) = \begin{cases} 1 \text{ if } z\epsilon S \\ 0 \text{ if } z\epsilon \overline{S} \end{cases} \tag{3.5}$$

then $E_s\{s(z)\} = P(S/z)$

By expanding (3.4), we can show that that minimizing $\hat{J}(\alpha)$ is equivalent to minimizing $J(\alpha)$ given by

$$J(\alpha) = E_{s,z}\{(s(z) - \alpha^T\phi(z))^2\} \tag{3.6}$$

We now want to develop a criterion function which in the limit will converge to $J(\alpha)$. Let us consider the popular procedure of curve fitting by the least squares method. Let there be j samples.

$$J(j) = \frac{1}{j}\sum_{i=1}^{j}\{s(z(i)) - \alpha^T\phi(z(i))^2\}$$

or in vector notation

$$S(j) = \begin{bmatrix} s(z(1)) \\ s(z(2)) \\ \cdot \\ \cdot \\ s(z(j)) \end{bmatrix}, \quad F(j) = \begin{bmatrix} \phi^T(z(1)) \\ \phi^T(z(2)) \\ \cdot \\ \cdot \\ \phi^T(z(j)) \end{bmatrix}, \quad J(j) = \frac{1}{j}\|S(j) - F(j)\|^2 \tag{3.7}$$

Clearly $\lim_{j\to\infty} J(j) = J(\alpha)$

If we minimize $J(j)$ at every stage, j, in the limit we should find α which minimizes $J(\alpha)$ with probability one. From the argument presented before, minimizing $J(\alpha)$ is the same as minimizing $\hat{J}(\alpha)$.

Let us see what the value of α^* should be which minimizes

$\hat{J}(\alpha)$. From (3.6)

$$\hat{J}(\alpha) = E_z\{(P(S/z) - \alpha^T\phi(z))^2\}$$

$$\nabla\hat{J}(\alpha) = -2\phi^T(z)E_z\{P(S/z) - \alpha^T\phi(z)\}$$

$$\nabla\hat{J}(\alpha^*) = E_z\{P(S/z)\phi(z)\} - E_z\{\phi(z)\phi^T(z)\}\alpha^* = 0$$

$$\alpha^* = (E_z\{\phi(z)\phi^T(z)\})^{-1} E_z\{P(S/z)\phi(z)\} \tag{3.8}$$

assuming that $E_z\{\phi(z)\phi^T(z)\}$ exists and > 0; and $E_z\{P(S/z)\phi(z)$ exists. Hence the value of α which minimizes the criterion function $J(j)$ should in the limit converge to the value of α^* given by (3.8).

To minimize $J(j)$, (3.7), we should find $\alpha(j)$ which solves the equation $\nabla J(j) = 0$.

$$\nabla J(j) = F^T(j)\ S(j) - F^T(j)\ F(j)\ \alpha(j) = 0 \tag{3.9}$$

$$\alpha(j) = (F^T(j)F(j))^{-1}\ F^T(j)\ S(j) \text{ or}$$

$$\alpha(j) = \left(\sum_{i=1}^{j} \phi(z(i))\phi^T(z(i))\right)^{-1} \sum_{i=1}^{j} \phi^T(z(i))s(z(i)) \tag{3.10}$$

Blaydon and Ho (14) show that for the algorithm given by (3.10)

$$\text{Prob}\ \{\lim_{j\to\infty} \alpha(j) = (E_z\{\phi(z)\phi^T(z)\})^{-1}E_z\{P(S/z)\phi(z)\}\} = 1$$

Rather than use (3.10) directly we would prefer its recursive form. From (3.9) we can write

$$\nabla J(j) = \sum_{i=1}^{j} \phi(z(i))\{s(z(i)) - \alpha^T(j)\phi(z(i))\} - \sum_{i=1}^{j} \phi(z(i)) \cdot \phi^T(z(i))\,\Delta\alpha = 0$$

$$\Delta\alpha = \left(\sum_{i=1}^{j} \phi(z(i))\phi^T(z(i))\right)^{-1} \sum_{i=1}^{j} \phi(z(i))\{s(z(i)) - \alpha^T(j)\phi(z(i))\}$$

This leads to the recursion formula (14)

$$\alpha(j+1) = \alpha(j) + D(j)\phi(z(j))\{s(z(j)) - \alpha^T(j)\phi(z(j))\} \tag{3.11}$$

where $(D(j))^{-1} = (D(j-1))^{-1} + \phi(z(j))\phi^T(z(j))$

$\alpha(0)$ arbitrary and $D(0) > 0$

I have written a computer program for system security evaluation using the stochastic pattern recognition approach described above. The flow chart for this program is given in Appendix I.

This program has been tried out on a training set consisting of 160 patterns obtained from load flow and stability studies of a large power system. The pattern vector, z, consists of the following components:

z_1 = voltage phase angle of station 1 with respect to the reference generator

z_2 = voltage phase angle of station 2 with respect to the reference generator

z_3 = voltage phase angle of station 3 with respect to the reference generator

z_4 = aggregate real power from the interconnection

z_5 = circulating power flow through the system

Applying the algorithm (3.11) yields the pattern classifier α which approximates $P(S/z)$ as follows:

$$P(S/z) = 0.947 + 0.022z_1 + 0.001z_2 - 0.015z_3 - 0.114z_4 + 0.118z_5$$

Trying out this approximation on the training set results in about 10% misclassification with equal number of false alarms and false dismissals. I consider this an acceptable performance. With a large training set, a better approximation would naturally be obtained.

Figure 3.4.1 shows the value of $\alpha(j)$ as a function of the iteration count, j.

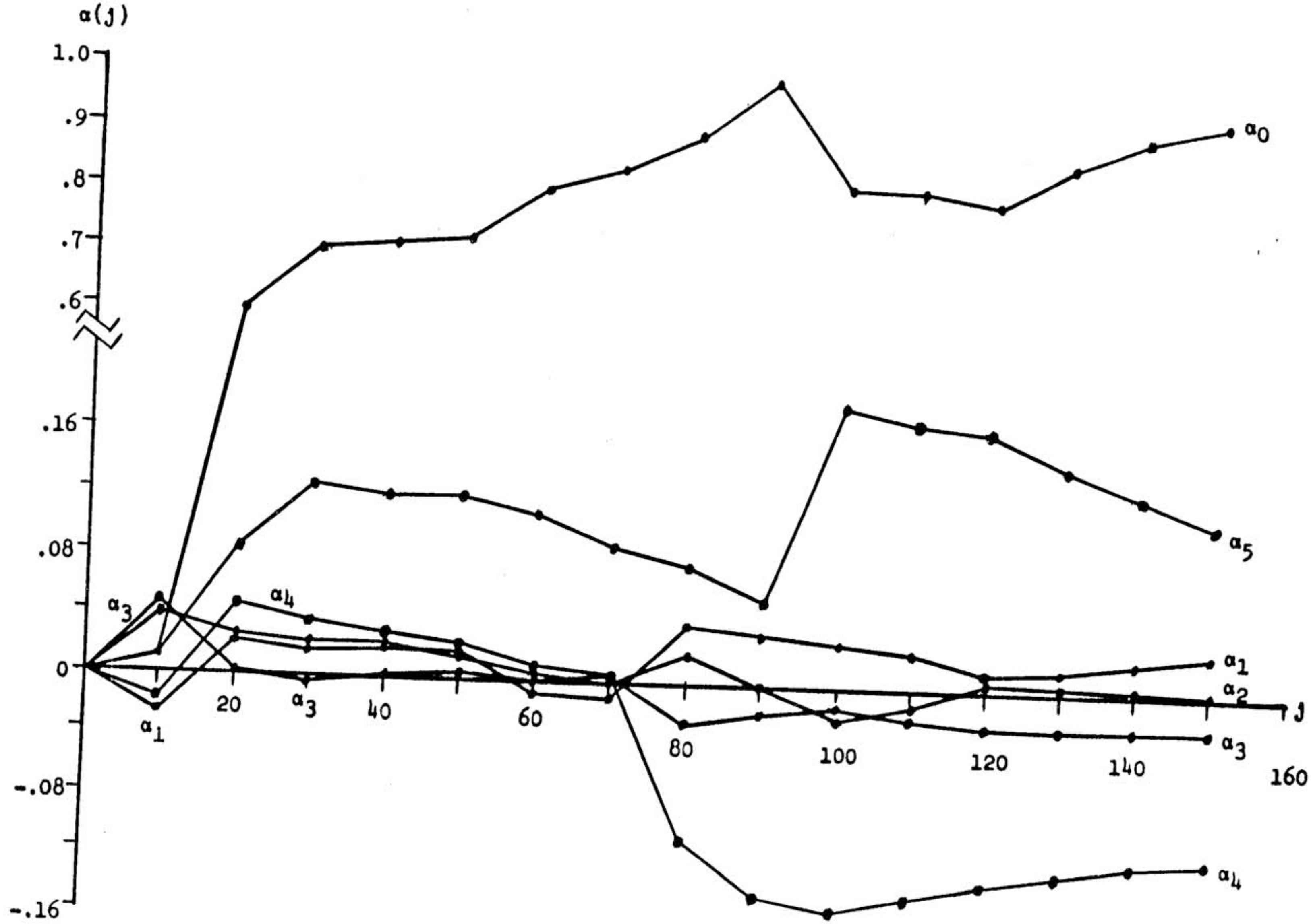

Fig. 3.4.1 Value of α(j) vs. Iteration Count, j

3.5 Role of Security Evaluation in Control

Let us assume that we have obtained the vector, α, such that $f(z) = \alpha^T\phi(z)$, from a sufficiently large training set. We can then use this α for recognizing new security patterns as obtained on-line from the system. If the security vector, z, is being periodically sampled, then for each set of readings we calculate the latest $f(z) = \alpha^T\phi(z)$, which, as we know, is an approximation of P(S/z). If $f(z) > \mu$, the system will be considered secure; and insecure if $f(z) \leq \mu$. The choice of the threshold, μ, will depend on the balance desired between false alarms and false dismissals.

The role of security evaluation in control is to give the system operator, at his request, an on-line assessment of system security. This assessment, in terms of probability of security, will serve as a guide by which he could base a decision for taking control action or not. We see that the decision-making process would be the same as that which a system operator now has to go through, except that instead of a purely subjective security evaluation which he himself has to make, he would have an evaluation made by the pattern classifier.

In spite of its obvious advantages as an operating tool, the pattern classifier approach has a problem which remains to be fully resolved. This is the problem of establishing procedures or guidelines for up-dating the classifier, α. Further work is required in this area. My present thinking on this is that a large training set will be obtained off-line using a "General Simulation" program (see Section 3.8) to study the power system conditions as projected for, say, the coming year. The classifier so obtained would then be used for security evaluation when the projected system is indeed in operation. As the next major system change is planned, either in new generation or in new transmission, additional samples would be obtained, added to the training set, and a new classifier would be derived. In developing the training set a wide variety of abnormal system conditions should be tried so that the classifier would be valid as much of the time as possible.

A second role of system security evaluation still in the adaptive layer is for off-line decision-making. The operator may wish to evaluate the security of a future system state or of the existing system but with certain changed parameters which he plans to make. In this case, using the Short Term Load Forecast and a "Fast Simulation" program (see Section 3.8) the new security vector may be calculated. This may then be tested for security by the pattern classifier.

3.6 Preventive Optimizing Control

In the preventive state, the two functions listed in Table II, Section 2.2, may be combined into one optimizing control problem which we call by the popular designation of "Economy Dispatch." We will reserve the use of this term to the actual on-line optimizing control where the generation and interchange with other companies are adjusted so that the load demand is met at minimum total operating cost. We will not use the term for a more general formulation of the minimum operating cost problem which may be justified for off-line use. This latter problem is discussed in Section 3.7.

The electric industry has a long history of economy dispatch operation — starting with manual loading based on "slide-rule" calculations of minimum cost allocation, through centralized automatic dispatch using analog computers, and recently using DDC. Economy dispatch is predicated on having a direct control layer to take care of the continuous variations in load demand. This is referred to in the utility industry as the "Load-Frequency Control." A thorough description of this two-layer control, load-frequency control and economy dispatch, may be found in reference 24.

As will be seen in Section 3.7 the minimum operating cost problem of a power system is very complex with a non-linear objective function and a substantial number of non-linear equality and inequality constraints.

Methods so far tried for solving this problem such as the conjugate gradient approach described in Section 3.7 and one which combines a fast algebraic solution of the network equations with the Kuhn-Tucker conditions (33) are too slow for on-line implementation.

In order to simplify the optimization problem for on-line control it is assumed that the magnitudes of voltages at generation nodes have been predetermined and are being maintained by automatic voltage regulators. We view this as an adaptive control function and we will call this "System Voltage Control." System voltage control will not be discussed in this thesis. However we will consider it as an integral part of our control system without which the optimizing layer may not be simplified. Conceptually, system voltage control will call for or initiate adjustments in the voltage regulator settings at all generators. Future work in this area should yield the proper adaptive algorithm which would determine the "best" voltage schedule. An extension of the pattern classification approach combined with optimization so that the best solution insures system security while minimizing a performance function, is worth considering.

With load-frequency control at the first layer and system voltage control at the third layer, the proolem of economy dispatch at the second layer becomes less complex and more tractable for on-line control. As we shall see later, another adaptive function called "Penalty Factor Calculation" will be used to take care of the equality constraints of the optimizing problem.

We want to develop the economy dispatch for an interconnected system but first, let us consider in this section the case of a single system. In Chapter IV we will develop the extension of economy dispatch to the multi-area case. For the single system, let us assume that external connections to other systems can be represented by some equivalent.

Let G = the set of generator nodes

L = the set of load nodes

P_i = the real power entering node i

$f_i(P_i)$ = the cost of generating one unit of power at node i

Q_i = the reactive power entering node i

$|V_i|$ = the magnitude of the voltage at node i

θ_i = the phase angle of the voltage at node i

Y_{ij} = the nodal admittance between node i and node j

$n + 1$ = the number of nodes in G

m = the number of nodes in L

$n + m = N$

The power system steady-state conditions are given by:

$$P_i = Re \{ \sum_{j \in G,L} |V_i| Y_{ij}^* |V_j| \varepsilon^{j(\theta_i - \theta_j)} \} \tag{3.12}$$

$$Q_i = Im \{ \sum_{j \in G,L} |V_i| Y_{ij}^* |V_j| \varepsilon^{j(\theta_i - \theta_j)} \} \tag{3.13}$$

In set G, let us assign node "r" as the reference node for phase angles, i.e., assume $\theta_r = \theta_o$. Number the remaining generator nodes consecutively from 1 to n. Number all the load nodes consecutively from n + 1 to N. Assume that the voltage magnitudes $|V_i|$ of all generators are given, as remarked earlier. We can write (3.12) and (3.13) in the compact form

$$P_i = g_i(|V|, \theta) \qquad i = 1, \ldots, N, r \tag{3.14}$$

$$Q_i = h_i(|V|, \theta) \qquad i = n+1, \ldots, N \tag{3.15}$$

where $|V| = (|V_{n+1}|, \ldots, |V_N|)^T$

$$\theta = (\theta_1, \ldots, \theta_n, \theta_{n+1}, \ldots, \theta_N)^T$$

Now assume that we can combine (3.14) and (3.15) so that we get an implicit function

$$H(P, Q, |V|, \theta) = 0 \tag{3.16}$$

where P represents the variables $P_1, \ldots, P_N, P_r$ and Q represents the variables $Q_{n+1}, \ldots, Q_N$.

We know, from Section 1.4, that there exist functions such that

$$|V_i| = \phi_i(P,Q) \qquad i = n+1, \ldots, N$$

$$\theta_j = \phi_j(P,Q) \qquad j = 1, \ldots, N$$

Hence we can rewrite (3.16) as

$$H(P,Q) = 0 \tag{3.17}$$

The economy dispatch problem can be formulated as:

$$\text{Find } \underset{P}{\text{Min}}\ F = \sum_{i\in G} f_i(P_i)$$

$$\text{subject to } H(P,Q) = 0 \tag{3.18}$$

Forming the Lagrangian function we get

$$L = F + H$$

and taking partial derivatives

$$\partial L/\partial P_i = \partial f_i/\partial P_i + \lambda \partial H/\partial P_i = 0 \qquad i \in G \tag{3.19}$$

Assuming that $\partial H/\partial P_i \neq 0$, for all i, (this assumption will be shown to be correct later), we can form the set of equations

$$\frac{\partial f_1}{\partial P_1} \Big/ \frac{\partial H}{\partial P_1} = .. = \frac{\partial f_n}{\partial P_n} \Big/ \frac{\partial H}{\partial P_n} = \frac{\partial f_r}{\partial P_r} \Big/ \frac{\partial H}{\partial P_r} \qquad \text{or}$$

$$(\partial f_1/\partial P_1)\pi_1 = \ . \ . \ . = (\partial f_n/\partial P_n)\pi_n = \partial f_r/\partial P_r \tag{3.20}$$

where $$\pi_i = \frac{\partial H}{\partial P_r} \Big/ \frac{\partial H}{\partial P_i} \qquad i = 1, \ . \ . \ ., n \tag{3.21}$$

We do not know the function H. But no matter what it may be it is true that the partial derivatives with respect to each $|V_i|$, $\forall i \in L$ and each θ_i, $\forall i \in G,L$ are all equal to zero. Thus

$$\partial H/\partial |V_i| = \sum_{j=1}^{N} (\partial H/\partial P_j)(\partial P_j/\partial |V_i|) = \sum_{j=n+1}^{N} (\partial H/\partial Q_j)(\partial Q_j/\partial |V_i|) + (\partial H/\partial P_r)(\partial P_r/\partial |V_i|) = 0$$

$$i = n+1, \ . \ . \ ., N \tag{3.22}$$

$$\partial H/\partial \theta_i = \sum_{j=1}^{N} (\partial H/\partial P_j)(\partial P_j/\partial \theta_i) + \sum_{j=n+1}^{N} (\partial H/\partial Q_j)(\partial Q_j/\partial \theta_i) + (\partial H/\partial P_r)(\partial P_r/\partial \theta_i) = 0$$

$$i = 1, \ . \ . \ ., N \tag{3.23}$$

Dividing through the set of equations (3.22) and (3.23) by $\partial H/\partial P_r$

and rearranging terms we get

$$(\alpha,\beta)\cdot J = -\nabla P_{r\,|V|,\theta}^{\ T} \qquad (3.24)$$

where $J = \dfrac{\partial(P',Q)}{\partial(|V|,\theta)}$ is the (n+2m)x(n+2m) Jacobian matrix of the form given by (1.36) in Chapter I

$P' = (P_1, \ldots, P_n)^T$

$Q = (Q_{n+1}; \ldots, Q_N)^T$

$\alpha = (1/\pi_1, \ldots, 1/\pi_n)$

$\nabla P_{r\,|V|,\theta} = (\partial P_r/\partial|V_{n+1}|, \ldots, \partial P_r/\partial|V_N|, \partial P_r/\partial\theta_1, \ldots, \partial P_r/\partial\theta_N)^T$

and β are the remaining terms.

We know from Section 1.4 that J is non-singular and can be calculated from (3.12) and (3.13). Similarly, $\nabla P_{r\,|V|,\theta}$ exists and can be calculated from (3.12). Hence the solution to (3.24) exists,

$$(\alpha,\beta) = (-\nabla P_{r\,|V|\theta}^{\ T})\,(J)^{-1} \qquad (3.25)$$

Actually, all we are interested in is the value of α since its components are the reciprocals of the penalty factors which we require for the economy dispatch condition, (3.21). The fact that we can solve for the π_i's validates our assumption that they exist.

The set of equations (3.21) are necessary conditions for economy dispatch. Sufficiency is difficult to establish because the function H is not known. However, we can interpret (3.21) as saying that the incremental cost of power at any generator node multiplied by a factor related to the flow through the network of the increment of power is equal, for all generators, to the incremental cost of power at the reference. In the case where the penalty factor is based on an approximate loss formula (34), this interpretation has been demonstrated to yield the minimum cost solution.

On an on-line basis, the penalty factors would be calculated as an adaptive function at relatively infrequent intervals as compared to the performance of economy dispatch control. The system data required for penalty factor calculations may be obtained either by direct instrumentation or else by making use of the Fast Simulation program.

In the formulation of the economy dispatch problem we did not consider any inequality constraints. On the assumption that in the preventive state we have a secure system, or that is, corrective action has been taken so that the system is secure, the only inequality constraints that have to be considered are of the type:

$$A_i \leq P_i \leq B_i \qquad i \in G \tag{3.26}$$

where A_i and B_i are minimum and maximum limits, respectively, on the power generated at node i. Other inequality constraints such as voltage magnitude limits and reactive power limits at generator nodes are taken care of by the System Voltage Control. The A_i and B_i limits may be due either to equipment operating limitations, spinning reserve requirements, or system security considerations. For economy dispatch the inequality constraints given by (3.26) are best handled, on-line, as limit settings. Thus when $P_i = B_i$, the generation at node i will not be made to participate any further in generation increases. Similarly when $P_i = A_i$, the particular generator at node i will not participate in any generation decreases.

3.7 Off-Line Optimization Problems

At the adaptive layer in preventive control are some decision-making problems which are actually optimization problems. These problems are more general in nature than the on-line economy dispatch control. Thus we can not make assumptions about the system being secure or about the voltage and reactive power inequality constraints being observed via System Voltage Control, as we did in the preceding section. Furthermore, since we have an off-line problem, we can not assume that we always have a set of decision variables which always satisfy the network equations. We will therefore have to consider a large number of equality and inequality constraints, almost all non-linear.

For the general optimization problem our decision variables will be the complex voltages at the active nodes. If there are N active nodes, let

$$V = (V_1, V_2, \ldots, V_2)^T$$

where $V_i = |V_i|\ ^{j\theta i}$

We may also write $V = \begin{bmatrix} |V| \\ \theta \end{bmatrix}$ where

$$|V| = (|V_1|, \ldots, |V_N|)^T$$

$$\theta = (\theta_1, \ldots, \theta_N)^T$$

The optimization problem may be expressed as follows:

Find V^* which minimizes $F(V)$

$$\text{subject to } g_i(V) \geq 0 \qquad i = 1, \ldots, m$$
$$h_i(V) = 0 \qquad i = 1, \ldots, p \tag{3.27}$$

where F is a functional of V.

The functional F represents the objective we want to optimize, such as minimum operating cost, minimum system losses, maximum load satisfied, maximum possible demand, maximum power import or export, etc.

Let us now consider the details of the inequality and equality constraints by enumerating all the possibilities, realizing that not all of them may necessarily be required for a particular objective function.

Let G = the set of generator nodes

L = the set of load nodes

M = the set of interconnection nodes to external systems

S_i = the complex power into node i

A_i = the volt-ampere limit at node i, $i \in G, M$

B_i = the real power upper limit at node i, $i \in G, M$

b_i = the real power lower limit at node i, $i \in G$

C_i = the voltage magnitude limit at node i, $i \in G, M$

c_i = the voltage magnitude limit at node i, $i \in L$

D_i = the complex demand at node i, $i \in L$

T_{ij} = loading limit of branch between i and j

X = system security parameter vector

μ = security recognition criterion

The set of constraints are:

a. Electrical network laws

$$S_k - V_k \sum_{j \in G,L,M} Y_{kj}^* V_j^* = 0 \qquad k \in G,L,M$$

b. Power supplied at each load should not exceed demand

$$D_k - S_k \geq 0 \qquad k \in L$$

c. Power factor of load satisfied should be constant (this is an approximation)

$$\frac{Im\{D_k\}}{Re\{D_k\}} - \frac{Im\{S_k\}}{Re\{S_k\}} = 0 \qquad k \in L$$

d. Volt-ampere limits at generator and interconnection nodes should not be exceeded

$A_k - S_k \geq 0$ $\qquad$ $k \in G, M$

e. Voltage limits at generator and interconnection nodes should not be exceeded

$C_k - V_k \geq 0$ $\qquad$ $k \in G, M$

f. Voltages at load nodes should not go below limits

$|V_k| - c_k \geq 0$ $\qquad$ $k \in L$

g. The real power at a generator should not exceed a given limit

$B_k - Re\{S_k\} \geq 0$ $\qquad$ $k \in G$

h. The real power at a generator should not go below a given limit

$Re\{S_k\} - b_k \geq 0$ $\qquad$ $k \in G$

i. Loading limits of specified circuits should not be exceeded

$T_{ij} - |V_i - V_j| \geq 0$ $\qquad$ i, j are the nodes of a given circuit

j. Security vector should be secure

$\alpha^T \phi(Z) - \mu \geq 0$

k. Algebraic signs of real and reactive power should be positive for generator nodes and negative for load nodes.

$Re\{S_k\} \geq 0$ $\qquad$ $k \in G$

$Im\{S_k\} \geq 0$ $\qquad$ $k \in G$

$-Re\{S_k\} \geq 0$ $\qquad$ $k \in L$

$-Im\{S_k\} \geq 0$ $\qquad$ $k \in L$

l. The flow at an interconnection point should vary with the aggregate interconnection power as:

$$Re\{S_k\} = \beta_k + m_k \sum_{k\epsilon M} Re\{S_k\} \qquad k\epsilon M$$

We can see that all of the constraints can be expressed as functions of $|V|$ and θ. We can readily appreciate that the dimension of the optimization problem, (3.27) is large and that the objective function and constraints are highly non-linear.

A computer program (26) for solving (3.27) has been written by R. Babickas, T. J. Kraynak[1], and myself using the Fiacco-McCormick "sequential unconstrained minimization technique", (SUMT) (27). The unconstrained minimization procedure adopted is that due to Fletcher and Powell (28). A flow chart of the program is given in Appendix II. We have applied the program to two optimization problems: the maximum load problem and the load flow problem.

The maximum load problem arises when it is desired to find the best allocation of generation and load supplied such that the total load supplied is a maximum and all the constraints are met. The problem is formulated as follows:

$$\text{Min } F = -\sum_{i\epsilon L} Re\{S_i\}$$

$$\begin{aligned} \text{Subject to } g_i(V) &\geq 0 \qquad i = 1, \ldots, m \\ h_i(V) &= 0 \qquad i = 1, \ldots, p \end{aligned} \qquad (3.28)$$

where $g_i(V)$ and $h_i(V)$ are the constraints a, b, c, d, e, f, k, l described above.

The ordinary load flow problem, as described in Section 1.4, is

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[1]Both of the Cleveland Electric Illuminating Company, Cleveland Ohio.

to find the solution vector $(|V|, \theta)^T$ to the equation

$$f((|V|, \theta)^T) = 0$$

This can be solved as a minimization problem:

$$\text{Min } \| f(|V|, \theta)^T \|^2 \tag{3.29}$$

Subject to $Q_{min} < Q_i < Q_{max}$ $\quad i \in G$.

For the maximum load problem we have tried the program on a network representing the Illuminating Company power system. This sample network consists of 24 active nodes and 56 passive nodes. The total number of constraints is 111. The maximum load solution was found in 80 iterations on the CDC 3600 computer in approximately 11 minutes running time. A plot of the convergence pattern for this sample problem of realistic dimensions is given in Figure 3.7.1.

For the ordinary load flow problem the same size Illuminating Company system was tried. In this problem there are only 10 constraints all of the type shown in (3.29). The objective function which we will call the "mismatch norm squared" should go to zero as the optimum solution. In the actual CDC 3600 run, the objective function was reduced to 0.000287 in 72 iterations from an initial value of 8.485072. The computer running time took slightly less than five minutes.

Figure 3.7.2 shows a plot of the convergence of the objective function.

The results of these two computer runs show that for off-line decision problems, non-linear programming techniques of the type described here may be successfully used. To my knowledge this is the first application of the Fiacco-McCormick and Fletcher-Powell methods

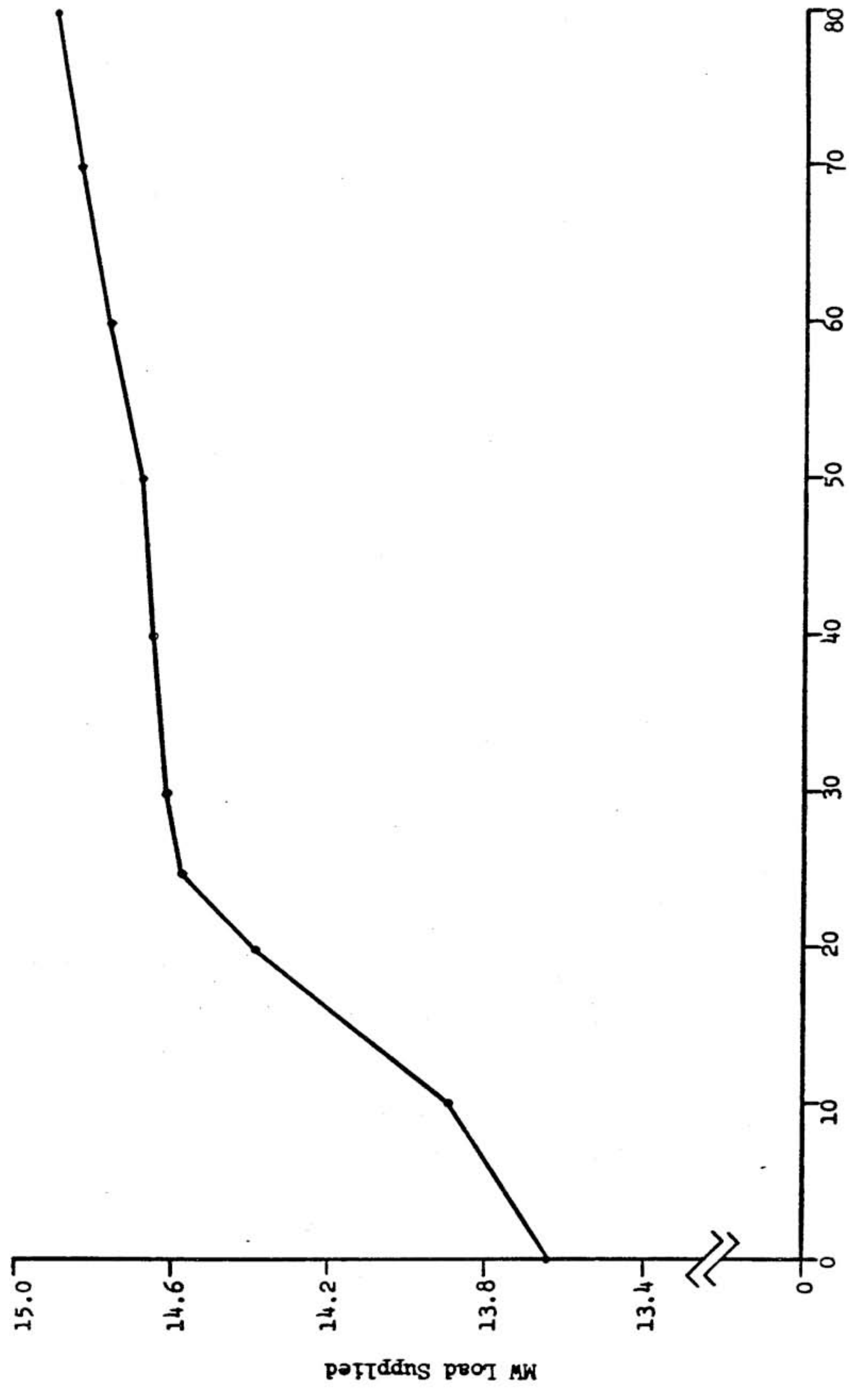

Fig. 3.7.1 Convergence of Maximum Load Solution

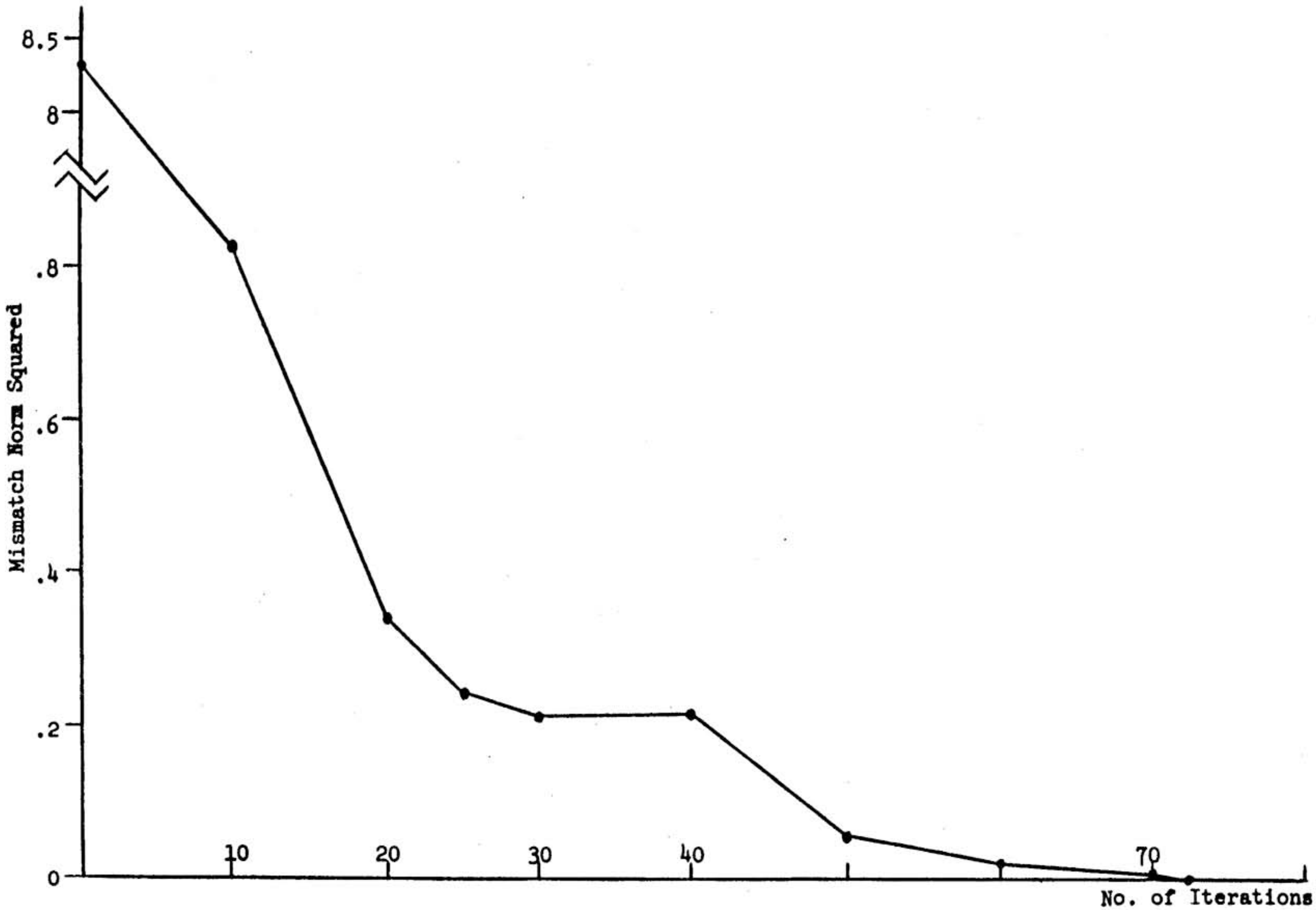

Fig. 3.7.2 Convergence of Load Flow Objective Function

to large power system problems involving highly non-linear objective functions and a large number of non-linear constraints. For the ordinary load flow problem however, other techniques (27,35) are more efficient computationally. The only reason for trying the optimization method was to gain experience for solving a more general class of problems which we shall call "optimal load flow." These problems are of the type where, given a set of fixed loads to be satisfied, find the solution vector V which minimizes a certain objective function subject to a set of inequality and equality constraints. For example, an optimal load flow can be used to find both the real and reactive power allocation for minimum operating cost. This procedure however is useful only for off-line problems since with the techniques described and present computer speeds the solution time would be too long for on-line control.

3.8 Other Prediction Procedures for Preventive Control

We will conclude this chapter on preventive control by calling attention to some functions which we consider necessary for our adaptive control strategy. These functions, which are also included in Table III, Section 2.2, are all prediction procedures. I have done no work in developing these procedures but it is important to identify them here as any future implementation of a control system such as that described in this thesis, will be predicated on having these procedures available.

Short Term Load Forecast: - We have alluded to this procedure in Section 3.1 as a necessary tool for the reduction of uncertainty in the disturbance set, U. Another use, which is for security evaluation of future systems, was mentioned in Section 3.5. The purpose of this procedure is to forecast load demand a day, or less, in advance, especially of the peak magnitude. Several factors have to be considered in load forecasting, such as -- day of the week, temperature and weather, business activity, community customs, the time of year, effects of heavy industries. Some work on this problem has been done in the industry (25).

Fast Simulation: - There is a need for a fast procedure for solving the load flow problem (see Section 1.4) for predicting future system conditions and also for estimating actual system data which are not or can not be measured. We use the word "simulation" so as to encompass approaches not only those based on deterministic models as discussed in Section 1.4 but also simulation techniques, less accurate perhaps but faster in performance.

General Simulation: - There is a need for a more general type of simulation, tailored for operating use, which could go through a predetermined sequence of load flow studies and stability analyses for a given set of system conditions. The chief use of the general simulation procedure is for confirming a specific result of the security evaluation routine. Vital to this simulation is the procedure for stability analysis. Existing methods of stability solve (1.21), Section 1.3, by step-by-step integration. New procedures are described which would perform the stability analysis faster with less requirements for operating data.

CHAPTER IV

DECOMPOSITION OF POWER SYSTEM PROBLEMS

The need for decomposition of a power system into areas or sub-systems was discussed in Section 2.1. It was pointed out that in most cases the decomposition would be dictated by the reality of ownership boundaries so that each sub-system would correspond to the generation-transmission system owned and operated by one utility company. In this chapter we will consider problems of an interconnected system made up of several sub-systems and how they may be solved by decomposition techniques.

4.1 Decomposition of a System at Interconnection Nodes

Assume that we have a large power system, S, made up of several interconnected sub-systems.

Definition 4.1.1 - An interconnection node is a node common to two or more sub-systems in S.

Definition 4.1.2 - The set of all interconnection nodes is called the "interconnection."

Let M designate the interconnection. Then

$M = \{m : m \text{ is an interconnection node in } S\}$

Our definition of an interconnection as a set of nodes is in contrast to the common view of an interconnection as the set of circuits which connect a node belonging to one system to a node belonging to another sub-system. Although the difference may appear trivial, the concept of the interconnection as the set of all interconnection nodes results in a decomposition which preserves ownerships. Thus if sub-systems, A, B, and C, have a common interconnection node, m, all circuits from any sub-system to node m remain a part of that sub-system. This is illustrated in Fig. 4.1.1.

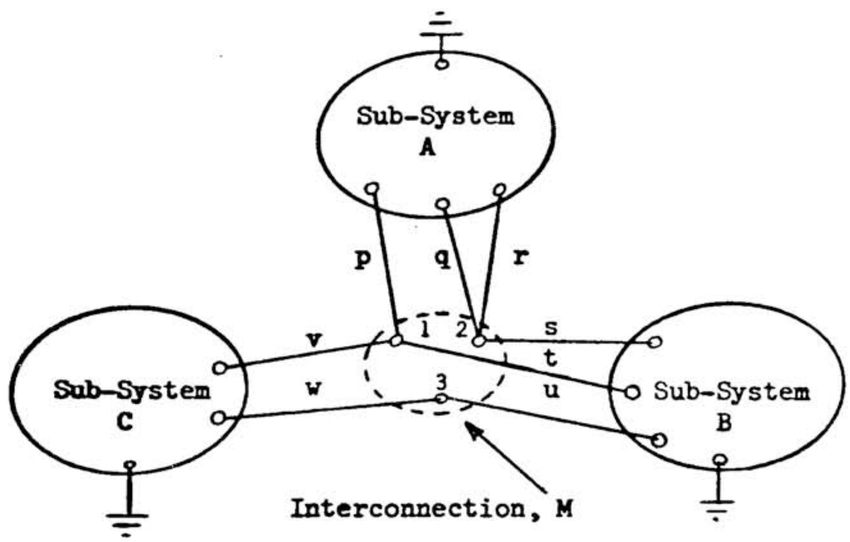

Fig. 4.1.1 An Interconnection of Three Sub-Systems

The interconnection consists of interconnection nodes 1, 2, and 3. The circuits p, q, r belong to A; s, t, u belong to B; and v, w, belong to C.

Each interconnection node may be conceived of as made of several parts, so that the system may be torn apart at the interconnection nodes with each sub-system retaining the part of node to which it is connected. This is shown in Fig. 4.1.2.

Let us indicate the segment of node 1 which belongs to sub-system A by A1, that which belongs to sub-system B by B1, and so on.

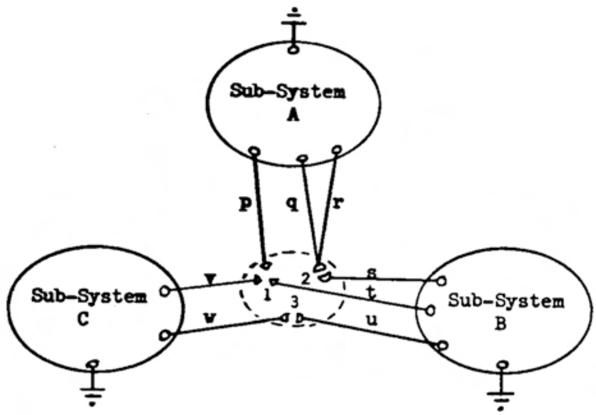

Fig. 4.1.2 Sample System Torn at Interconnection Nodes

Then, as in Kron's piece-wise methods (3,4,5,6) we can solve the network problem of each sub-system in isolation and later coordinate the individual solutions to obtain the overall solution. To solve each sub-system in isolation we will apply voltages at the segments of the torn nodes -- V_{A1}, V_{B1}, V_{C1}, V_{A2}, V_{B2}, V_{B3}, V_{C3} -- such that $V_{A1} = V_{B1} = V_{C1}$, $V_{A2} = V_{B2}$, and $V_{B3} = V_{C3}$. Each solution will produce currents at the segments of the torn nodes -- J_{A1}, J_{B1}, J_{C1}, J_{A2}, J_{B2}, J_{B3}, J_{C3}. The coordination solution will require that $J_{A1} + J_{B1} + J_{C1} = 0$, $J_{A2} + J_{B2} = 0$, and $J_{B3} + J_{C3} = 0$.

It is evident that it is not really necessary to "tear" the interconnection nodes so as to isolate each sub-system. Instead let us apply an arbitrary set of voltage sources V_1, V_2, and V_3 at the interconnection nodes as shown in Fig. 4.1.3. The currents from the sources are J_1, J_2, J_3, respectively.

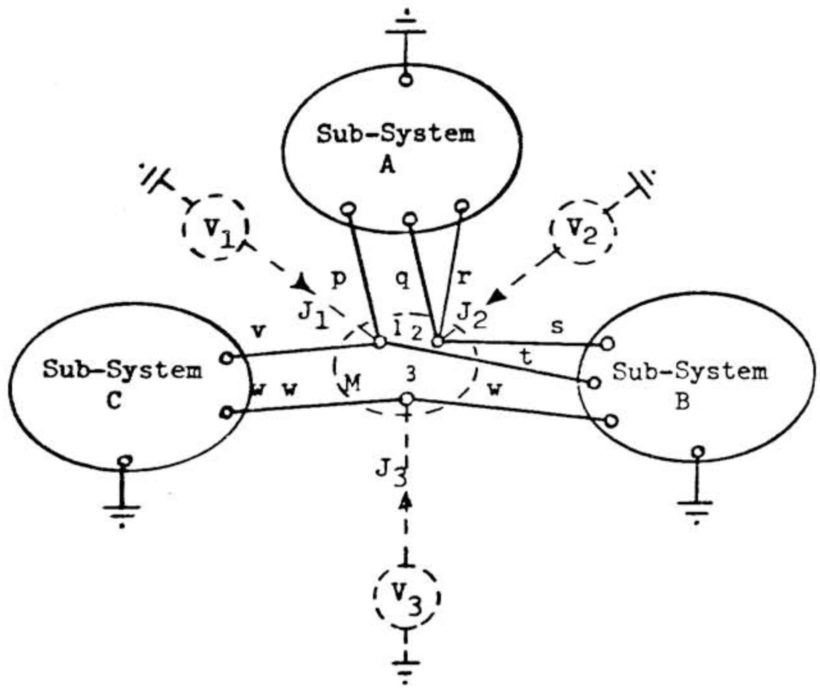

Fig. 4.1.3 Sample System Decomposed by Application of Voltage Sources at Interconnection

With these impressed voltages at the interconnection the system is automatically decomposed into electrically isolated sub-systems. The response of each sub-system is independent of the others. The coordination problem then is to adjust V_1, V_2, and V_3 such that $J_1 = J_2 = J_3 = 0$.

4.2 The Network Problem -- Linear Case

As shown in Section 1.2, in an electrical network conditions are adequately described by the set of linear equations:

$$J = YV \text{ or} \qquad (4.1)$$

$$V = ZJ$$

where V is the vector of node to neutral voltages, J is the vector of impressed currents, Y is the nodal admittance matrix, and Z is the nodal impedance matrix. The network problem is, given J find V, or given V find J.

Assume that the network S is made up of several sub-networks, S_i, i = A, B, . . ., N. $S = S_A \cup S_B \cup . . . \cup S_N$.

Let M designate the interconnection

V_i = vector of nodal voltages in sub-network, i

J_i = vector of nodal currents in sub-network, i

V_M = vector of nodal voltages in interconnection, M

J_M = vector of nodal currents in interconnection, M

V_{iM} = vector of nodal voltages of subset of M which is connected to sub-network, i

J_{iM} = vector of nodal currents entering i from M

For any sub-network i the following conditions hold:

$$\begin{pmatrix} J_i \\ \hline J_{iM} \end{pmatrix} = \begin{pmatrix} Y_i & Y_{i-iM} \\ \hline Y_{iM-i} & Y_{iM} \end{pmatrix} \cdot \begin{pmatrix} V_i \\ \hline V_{iM} \end{pmatrix} \qquad i \in S \qquad (4.2)$$

Let us now decompose the network by applying the arbitrary voltage $V_M{}^o$ at the interconnection nodes. With these impressed voltages the interconnection currents to each sub-network will not necessarily satisfy the condition

$$J_M = 0 \qquad (4.3)$$

Hence our problem is to correct $V_M{}^o$ by an amount v_M such that when $V_M = V_M{}^o + v_M$ is applied to the interconnection the currents J_M satisfy (4.3).

We can rewrite (4.2) as

$$\begin{pmatrix} J_i \\ \hline J_{iM} \end{pmatrix} = \begin{pmatrix} Y_i & Y_{i-iM} \\ \hline Y_{iM-i} & Y_{iM} \end{pmatrix} \cdot \begin{pmatrix} V_i \\ \hline V_{iM}^o + v_{iM} \end{pmatrix}$$

$$= \begin{pmatrix} Y_i & Y_{i-iM} \\ \hline Y_{iM-i} & Y_{iM} \end{pmatrix} \cdot \begin{pmatrix} V_i \\ \hline V_{iM}^o \end{pmatrix} + \begin{pmatrix} Y_{i-iM} \\ \hline Y_{iM} \end{pmatrix} \cdot v_{iM} \qquad (4.4)$$

$$\begin{pmatrix} J_i \\ \hline J_{iM} \end{pmatrix} = \begin{pmatrix} J_i^o \\ \hline J_{iM}^o \end{pmatrix} + \begin{pmatrix} j_i \\ \hline j_{iM} \end{pmatrix} \qquad (4.5)$$

where $\begin{pmatrix} J_i^o \\ \hline J_{iM}^o \end{pmatrix}$ is the current vector for sub-network i when it is electrically isolated

and $\begin{pmatrix} j_i \\ \hline j_{iM} \end{pmatrix}$ is the correction due to the correction voltage v_M.

The solution algorithm is as follows:

1. Isolate the sub-networks by imposing a set of arbitrary voltages, V_M^o, at the interconnection nodes.
2. For each sub-network, i, calculate the interconnection currents

   $$J_{iM}^o = (Y_{iM-i} \quad Y_{iM}) \begin{pmatrix} V_i \\ \hline V_{iM}^o \end{pmatrix} \qquad i = A, B, \ldots, N \quad (4.6)$$

3. Calculate the vector of interconnection currents J_M^o, whose element J_m^o, $m \in M$, is given by

   $$J_m^o = \sum_{i \in S} J_{im}^o \qquad m \in M \qquad (4.7)$$

   If $J_M^o = 0$ the network problem is solved. If $J_M^o \neq 0$, go to step 4.
4. Calculate the vector of correction voltages, v_M, such that $V_M = V_M^o + v_M$, will make $J_M = 0$.

   From (4.4) $J_M = J_M^o + j_M$

where j_M is the vector of correction currents whose element j_m, $m \in M$ is given by

$$j_m = \sum_{i \in S} Y_{im} \, v_m$$

$$j_M = Y_M \, v_M \text{ hence}$$

$$v_M = -\{Y_M\}^{-1} \cdot J_M^{\circ}$$

5. Set $V_M = V_M^{\circ} + v_M$

Then calculate

$$\left(\frac{J_i}{J_{iM}}\right) = \left(\begin{array}{c:c} Y_i & Y_{i-iM} \\ \hdashline Y_{iM-i} & Y_{iM} \end{array}\right) \cdot \left(\frac{V_i}{V_{iM}}\right) \quad i \in S$$

and the problem is solved.

A similar algorithm may be developed for the problem V = ZJ.

4.3 The Network Problem -- Non-Linear Case

In the preceding section we solved a large linear network problem by applying an arbitrary set of voltages at the interconnection nodes, determining the interconnection currents, and calculating the correction voltages. Using the corrected voltages the required currents were found. The problem was solved exactly without any iterations.

We will apply the same procedure to the non-linear case, which is the load flow problem. However, because of the non-linearity the correction voltages will not be obtained exactly and an iterative process will be required.

As in the linear case, we will start by connecting a set of arbitrary voltage sources at the interconnection nodes. As this automatically isolates each sub-network we can solve the load flow problem of each sub-network. We may use any convenient method of load flow solution with the condition that all interconnection nodes are to be treated as swing busses. Just like any swing bus, the voltage (magnitude and angle) at an interconnection node is fixed at the arbitrary value chosen.

The solution algorithm for the load-flow problem is as follows:

1. Isolate the sub-networks by imposing a set of arbitrary voltages, V_M^o, at the interconnection nodes.
2. By any convenient method, solve the load-flow problem for each sub-network, i, treating its interconnection nodes as swing busses. The swing bus for the entire system will be retained in whatever sub-network it belongs.
3. Calculate the vector of interconnection currents, J_M^o, whose element J_m^o, $m \in M$ is given by

   $$J_m^o = \sum_{i \in S} J_{im}^o \qquad m \in M$$

   If $J_M^o \cong 0$ the total load flow problem is solved. If $J_M^o \neq 0$, go to step 4.
4. Calculate the vector of correction voltages v_M by

   $$v_M = -(Y_M)^{-1} \cdot J_M^o$$

5. Set $V_M = V_M^o + v_M$ and go back to step 2.

Reference 30, presented at the IEEE 1968 Winter Power Conference, is possibly the first paper to appear on the solution of the load flow problem of a large system by tearing. The approach used was developed by H. H. Happ of General Electric Company and is an application of the orthogonal network concept originated by G. Kron (6,31). In view of the importance of decomposition techniques for solving load flows of large systems and for solving other non-linear network problems it would be well worth the time of one working on such problems to study Happ's method and related work. We will not discuss the details of reference 30 but we should remark that in Happ's approach the system is torn into sub-divisions by the removal of the interconnection circuits. The identity of the interconnection circuits is preserved by creating a new auxiliary matrix called the "inter-subdivision matrix." By the method I propose in this thesis, the decomposition is induced by the application of voltage sources at the interconnection nodes. No auxiliary matrix is required. The decomposition at interconnection nodes is neater in that the sub-division matrices (admittance or impedance) and the first-level computations are truly independent. This independence is preserved in the calculations by the fact that we treat all the interconnection nodes as swing busses. As we converge to a solution all the corrections are automatically taken up by the system swing bus. In reference 30, although the sub-division matrices can be calculated independently, it is still necessary to establish relationships between each sub-division and the one containing the swing bus by calculating the swing bus vector for the entire interconnected system.[1] Although this calculation may be readily accomplished, the necessity to have such information based on the entire untorn system for doing computations at the first level blurs slightly the idea of the "tearing" or decomposition approach.

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[1]Dr. Happ told me recently that this requirement was dictated by the nature of the algorithm used in reference 30 and that there are ways of getting around it.

Another feature of the decomposition-at-interconnection-nodes method is that a sub-system need not have any generation. Thus a wholly owned system may be decomposed into areas for computational reasons and one of the areas may have nothing but load nodes. The decomposition method would still work since the sources at the interconnection nodes of this load area would serve as the generation.

I have tried out my decomposition approach to the non-linear load flow problem successfully on both a network analyzer and a digital computer. The computer program follows the algorithm described in this section. The actual load flow solution for each sub-network is done by Newton's method (35). To test out the decomposition method I took the small sample system of Ward and Hale (36) as shown in Fig. 4.3.1.

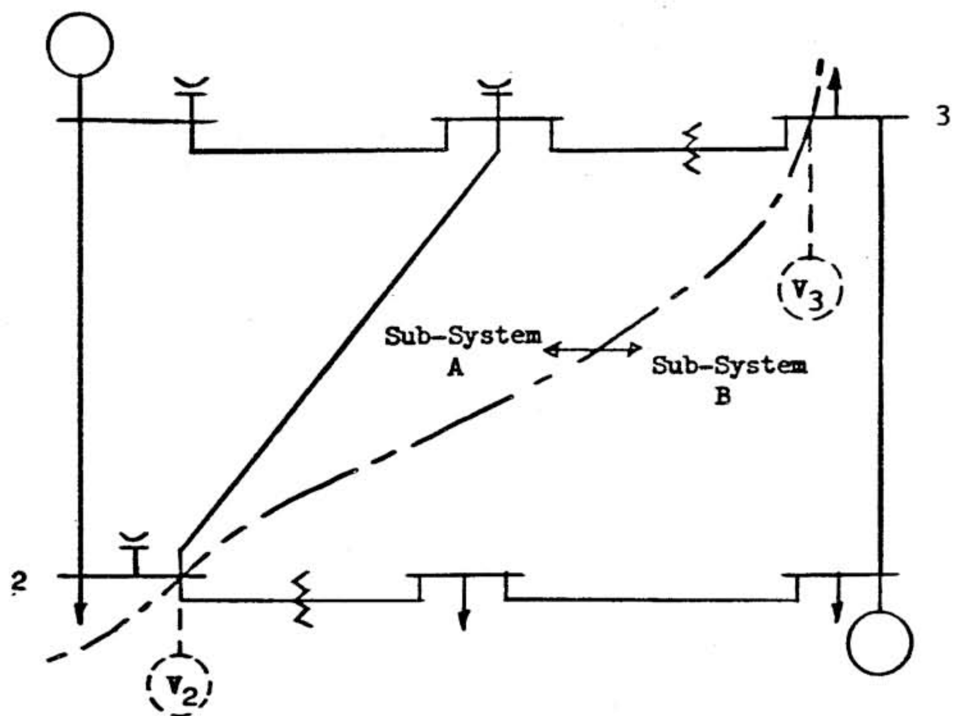


Fig. 4.3.1 Decomposition of Sample System

Taking nodes (2) and (3) as the interconnection points, voltage sources V_2 and V_3 were applied to separate the system into two areas. The convergence of the real and reactive powers, P_2, Q_2 of the source at node (2), and P_3, Q_3 of the source at node (3), is shown in Fig. 4.3.2. We see that for this sample system it took approximately 20 iterations of the second-level algorithm to solve the load flow problem of the whole system. The results of this sample problem demonstrate that it is possible to solve the load flow problems of very large networks with an under-sized load flow program.

4.4 Multi-Area Economy Dispatch

In Section 3.6 we developed the preventive optimizing control (economy dispatch) of a single system. The key feature was the use of penalty factors which are calculated exactly for actual network conditions. We will extend this approach to the overall economy dispatch problem of an interconnected power system S made up of several areas, A, . . ., N, each of which has its own three-layer (load-frequency, economy dispatch, system voltage and penalty factor) control. This would be the typical situation in an interconnected power system where there is either a contractual arrangement to trade power or else an agreement for pooled operation. In the extension to the multi-area economy dispatch problem we will make one assumption — that the voltage magnitudes at the interconnection points are being held at certain scheduled values. This assumption is a reasonable representation of actual operating practices.

Let G_j = the set of generating nodes in area j

M = the interconnection

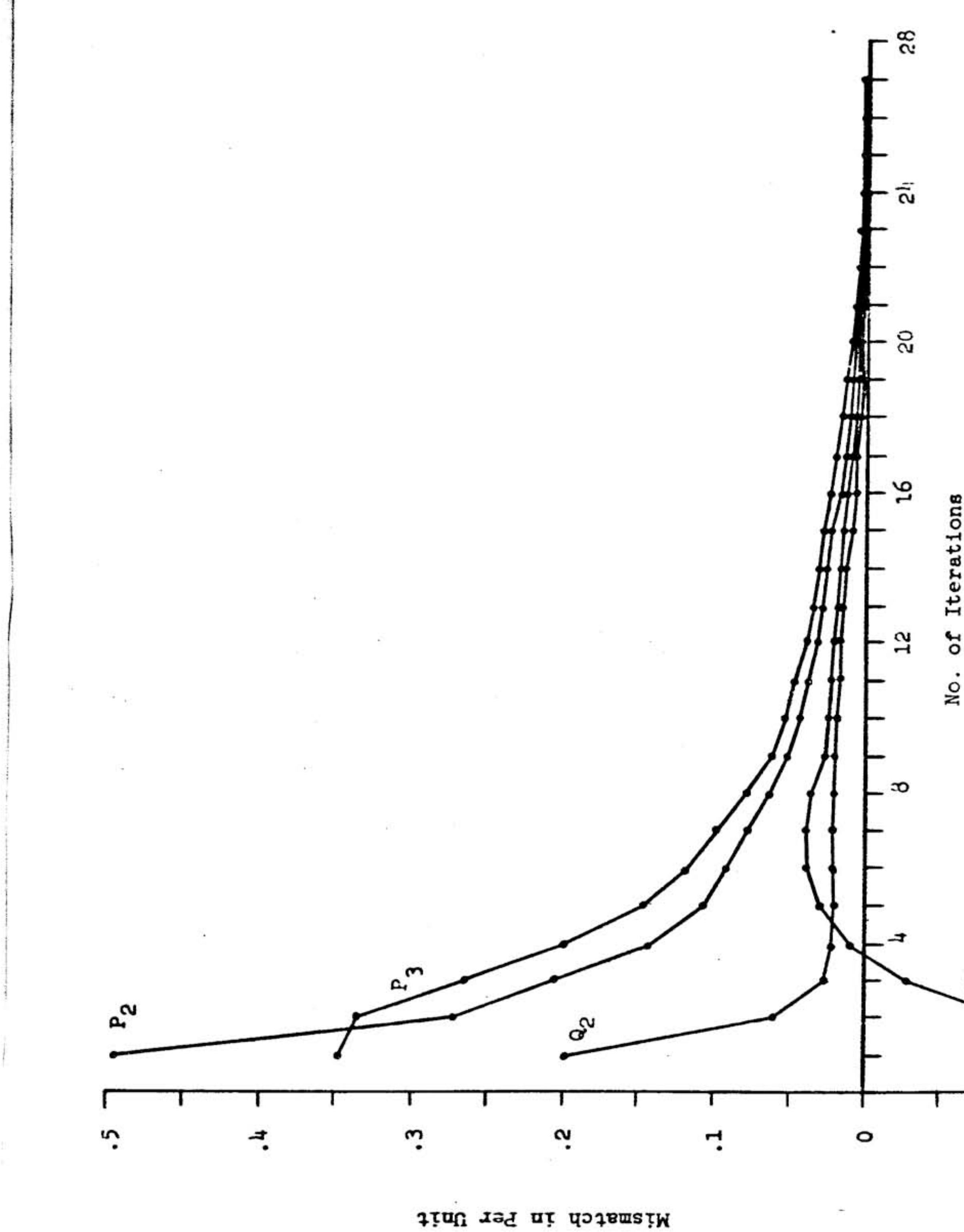


Fig. 4.3.2 Convergence of Two-Level Load Flow Solution

P_{ji} = the real power entering node i, i is in area j

$f_{ji}(P_{ji})$ = the cost of generating one unit of power at node i, $i \in G_j$

P_j = the vector of real powers entering the nodes of area j

Q_j = the vector of imaginary powers entering the load nodes of area j

Q_{ji} = the reactive power entering node i, i is in area j

jM = the set of interconnection nodes connected to area j i.e., $jM = \{m : m \in M \text{ and } m \text{ is connected to area } j\}$

$P_{jM} = \sum_{m \in jM} P_{jm}$, the aggregate power entering area A from the interconnection M

$H_j(P_j, P_{jM}, Q_j)$ = the implicit network function for area j (see Section 3.6)

The multi-area economy dispatch problem is to find the generation allocation for each area and the aggregate power which each area should get from the interconnection. This problem can be formulated as:

$$\text{Find min } F = \sum_{j=A}^{N} \sum_{i \in G_j} f_{ji}(P_{ji}) \tag{4.8}$$

$$\text{Subject to } H_j(P_j, P_{jM}, Q_j) = 0 \qquad j = A, \ldots, N \tag{4.9}$$

$$\text{and} \quad \sum_{j=A}^{N} P_{jM} = 0. \tag{4.10}$$

Forming the Lagrangian we get

$$L = F + \lambda^T H + \mu \sum_{j=A}^{N} P_{jM} \tag{4.11}$$

where $\lambda^T = (\lambda_A, \ldots, \lambda_N)$

$H = (H_A, \ldots, H_N)^T$

Taking partial derivatives with respect to the generator powers and the interconnection aggregates we form the conditions for the optimum:

$$\partial L/\partial P_{ji} = \partial f_{ji}/\partial P_{ji} + \lambda_j\ \partial H_j/\partial P_{ji} = 0 \qquad i \in G_j \qquad (4.12)$$

$$j = A, \ldots, N$$

$$\partial L/\partial P_{jM} = \lambda_j\ \partial H_j/\partial P_{jM} + \mu = 0 \qquad j = A, \ldots, N \qquad (4.13)$$

We see from (4.12) and (4.13) that the multi-area economy dispatch problem may be decomposed into two levels. The first level would consist of the independent controllers performing economy dispatch in each area. For each area, j, the problem would be:

$$\text{Find Min } F_j = \sum_{i \in G_j} f_{ji}(P_{ji})$$

$$\text{subject to } H_j(P_j, P_{jM}^{o}, Q_j) = 0$$

for a fixed value $P_{jM} = P_{jM}^{o}$.

The assigned values of P_{jM}^{o}, while arbitrary, should satisfy (4.10). This assignment will be done by the second-level controller. The second level also has the function of coordinating the first-level solutions so that (4.13) is satisfied. (4.13) however, is not in a directly usable form. Let us transform it in terms of available or known parameters.

Let jr be the reference node, $jr \in G_j$, in area j, j = A, . . . , N. From (4.12) we obtain

$$\lambda_j = -(\partial f_{jr}/\partial P_{jr}) \ / \ (\partial H_j/\partial P_{jr})$$

Multiplying by $\partial H_j/\partial P_{jM}$,

$$\lambda_j\ \partial H_j/\partial P_{jM} = -(\partial f_{jr}/\partial P_{jr})\ (\partial H_j/\partial P_{jM}) \ / \ (\partial H_j/\partial P_{jr})$$

From (4.13) we get

$$\mu = (\partial f_{jr}/\partial P_{jr}) \ / \pi_{jM} \qquad (4.14)$$

where π_{jM} is the penalty factor of the "combined" interconnection node of area j and is given by

$$\pi_{jM} = (\partial H_j/\partial P_{jr}) \;/\; (\partial H_j/\partial P_{jM})$$

But $$\partial H_j/\partial P_{jM} = \sum_{m\in jM} (\partial H_j/\partial P_{jm})\;(\partial P_{jm}/\partial P_{jM}) \qquad (4.15)$$

Dividing (4.15) through by $\partial H_j/\partial P_{jr}$, we get

$$(\partial H_j/\partial P_{jM}) \;/\; (\partial H_j/\partial P_{jr}) = \sum_{m\in jM} (\partial P_{jm}/\partial P_{jM})\;(\partial H_j/\partial P_{jm}) \;/\; (\partial H_j/\partial P_{jr})$$

which can be written as

$$1/\pi_{jM} = \sum_{m\in jM} \sigma_{jm}\;(1/\pi_{jm}) \qquad (4.16)$$

$\sigma_{jm} = \partial P_{jm}/\partial P_{jM}$, which relates the flow at each individual interconnection point, jm, of area j, to the aggregate interconnection power, P_{jM}, is obtainable by methods which are described in Section 4.5.

Substituting the value of $1/\pi_{jM}$ from (4.16) into (4.14) we get the second-level coordination equation:

$$\mu = (\partial f_{jr}/\partial P_{jr})/\pi_{jM} = (\partial f_{jr}/\partial P_{jr}) \sum_{m\in jM} \sigma_{jm}\;(1/\pi_{jm}) \qquad (4.17)$$

The values of $1/\pi_{jm}$, which are the reciprocals of the penalty factors at the interconnection nodes of area j, are calculated directly from (3.24), Section 3.6. The row vector β of (3.24) contains the set of $1/\pi_{jm}$, $m\in jM$.

(4.17) can be interpreted as saying that for the entire interconnected system to be operating at minimum cost, the incremental cost of power at the interconnection should be the same for all areas.

A two-level algorithm for the multi-area economy dispatch can proceed as follows:

1. At the second level, assign values of aggregate interconnection powers, P_{jM}^{o}, such that $\sum_{j=A}^{N} P_{jM}^{o} = 0$. Send the assigned powers to the first-level or area controllers.

2. At the first level, with the assigned interconnection powers perform the economy dispatch operation. Calculate

$$\mu_j = (\partial f_{jr}/\partial P_{jr}) \;/\; \pi_{jM} \quad j = A, \ldots, N$$

Send the values of μ_j to the second level.

3. At the second level, find the average incremental cost of power at the interconnection.

$$\mu = \frac{1}{N} \sum_{j=A}^{N} \mu_j \tag{4.18}$$

Calculate new values of aggregate interconnection powers by the following:

$$P_{jM}(n+1) = P_{jM}(n) + k\,(\mu_j - \mu) \tag{4.19}$$

$$\sum_{j=A}^{N} P_{jM}(n+1) = 0 \tag{4.20}$$

where n is the iteration count.

Send the new values of P_{jM} to the first level.

4. Repeat steps 2-4 until $\mu_j \cong \mu$, $j = A, \ldots, N$

The algorithm given by (4.19) is obtained from the fact that the decomposition is feasible, i.e., (4.9) and (4.10) are always satisfied for any set of values of P_{jM}. We can therefore say from (4.11) that $L = F$. Thus $\partial L/\partial P_{jM} = \partial F/\partial P_{jM}$. But $\partial F/\partial P_{jM}$ is the first-order partial derivative of F, the function we want to minimize, with respect to P_{jM}, the interconnection variable. Hence the change in P_{jM} so as to minimize F should be in the direction of $-\partial L/\partial P_{jM}$, i.e.,

$$\begin{aligned} P_{jM}(n+1) &= P_{jM}(n) - k\,\partial L/\partial P_{jM} \\ &= P_{jM}(n) - k\,(\lambda_j\,(\partial H_j/\partial P_{jM}) + \mu) \end{aligned}$$

And we get (4.19)

$$P_{jM}(n+1) = P_{jM}(n) + k\,(\mu_j - \mu)$$

4.5 The Interconnection Flow Model

A good approximation of the power flows at the interconnection nodes of a system or sub-system is needed for some of the decision-making processes so far discussed. In the multi-area economy dispatch problem, the rate of change of the real power flows at each interconnection node with respect to the aggregate interconnection flow is required for the calculation of penalty factors. In the emergency optimizing control, in off-line optimization problems, and in simulation procedures, changes in interconnection flows as changes in decision variables are made have to be taken into account.

The power flows at the interconnection nodes depend upon the generation, loads, and the network conditions of the system of interest and of all the other systems connected to the interconnection. As conditions change so do the interconnection flows. Although there are ways of approximating a part of a system by equivalents (8,9,10), such equivalents are not very useful for operating decision problems such as those mentioned above. Equivalents are generally based on certain assumed conditions and cannot reflect the effect on interconnection flows of an ever-changing electrical system. The desired interconnection model should be able to recognize changes in interconnection flow distribution as soon as they are brought about by changes in the interconnected system.

The key to an up-to-date interconnection representation lies in the interconnection flows themselves. Given a power system over which we have control, we can view the external systems beyond the interconnection boundaries of our system as an uncertainty whose structure at any given time is not adequately known. However, this uncertainty is in constant communication with our system. Information is continuously being sent to us in the form of the actual interconnections with our system, i.e., in the magnitude and direction of the flows into our interconnection nodes. This communication is instantaneous and therefore provides the most up-to-date information concerning the state of the external systems and how our system reacts with it.

The most important thing that we want to know about the state of external systems is not what it is, but how it affects the flows into our system. Thus it is not essential that we know what transmission circuit in somebody else's system has suddenly been taken out of service or what large generating unit has suddenly failed. What we need to know is that suddenly the distribution of interconnection flows has changed significantly and that for the immediate future we should expect flows at each interconnection node to change according to this new distribution.

The interconnection flow variables which are most sensitive to changes in system conditions are the real power flows. A sudden deficiency or excess of a large block of real power at one location will cause abnormal flows through many systems as the entire interconnected network responds to correct the unbalance. Thus the loss of a large generator in New York will cause a substantial increment of flow from West to East through the utilities in Ohio and Pennsylvania. The removal or addition of a transmission circuit at the right place will alter the distribution of real power flows in the surrounding systems. Thus, in 1965 the sudden removal of transmission circuits from a Canadian generating station caused the large amount of generated power to surge through systems in the United States seeking new paths to the various load centers which had been dependent on this power. Real power can flow over very long distances; reactive power cannot. In this section we will develop a model for the real power interconnection flows. The problem of reactive power flow at the interconnection does not have the degree of uncertainty associated with real power flows. The reactive power flows, except during emergencies, may be kept within predictable bounds by voltage control in our system and in our immediately adjacent neighboring systems.

Power system engineers have long recognized, from evidence of load flow studies and actual operating data, that the real power flow at each interconnection point is, to a high degree of approximation, linearly related to the aggregate real power import from the interconnection. This approach which makes use of the information content of the flows themselves was part of my contribution to the work reported in reference 37.

No new instrumentation will be required as all the interconnection real power flows are continuously monitored for load-frequency control and economy dispatch. Since the interconnected system is always changing the interconnection flows are hardly constant. Therefore if we measure the changes in the individual interconnection flows and compare them with the net change, we will be able to estimate the linear relationships. Theoretically, any two sets of interconnection flow readings moments apart should yield the constants of the linear functions. Practically, an approximation routine could be developed based on the last sequence of n readings, where n is arbitrary.

Let P_{jm} be the real power flow into the interconnection node $jm \in jM$. $jM = \{m{:}m$ is an interconnection node of system $j\}$.

The net or aggregate real power flow into the system j will be

$$P_{jM} = \sum_{jm \in jM} P_{jm} \tag{4.21}$$

We now assume that each interconnection flow is a linear function of the aggregate flow. That is,

$$P_{jm} = a_{jm} + \sigma_{jm} P_{jM} \qquad jm \in jM \tag{4.22}$$

It is readily seen that the following relationships are true:

$$\sum_{jm \in jM} a_{jm} = 0; \qquad \sum_{jm \in jM} \sigma_{jm} = 1 \tag{4.23}$$

Since we are continuously monitoring the interconnection points, we can take readings at fixed time intervals. Our approximation procedure, as in reference 37, can fit straight lines to the latest sequence of readings by the method of least squares.

As changes take place in the interconnected system the values of a_{jm} and σ_{jm} will change. We will therefore be able to identify the the effects on interconnection flows by changes anywhere in the system without having to know what all the changes are.

From (4.22) we see that

$$\frac{\partial P_{jM}}{\partial P_{jM}} = \sigma_{jm} \qquad jm \in jM \tag{4.24}$$

which are the quantities required for determining interconnection penalty factors in multi-area economy dispatch, see Section 4.4.

CHAPTER V

A PROPOSED DEVELOPMENT OF THE CONTROL SYSTEM

In this chapter we will summarize the ideas for the control of an interconnected power system which have been discussed in the preceding chapters. We will perform this summary by way of presenting a general flow chart depicting a proposed development of the control system. To make the picture complete we will include functions which we have identified in Chapter II in our description of the multi-layer hierarchy but which have not, as yet, been adequately investigated. These functions are discussed briefly in Section 5.1. We will also discuss in Section 5.2 the information system which plays an integral part in the control system development.

5.1 Apropos of Emergency and Restorative Controls

In this thesis we have gone through the development of the multi-layer control in the preventive operating state. The overall strategy gives emphasis to preventive control as the best means for insuring service reliability. However, as outlined in Chapter II, the total control system that we envision should provide for emergencies and service outages which cannot be avoided by preventive control. Suggested control functions for the direct control layers of the emergency and restorative states are given in Table I, Section 2.2; suggested functions for the optimizing control layers are given in Table II of the same section.

Very little work has been done as yet in these areas of power system control. I have participated in a preliminary investigation of the emergency optimizing control and restorative optimizing control problems conducted as a joint study by the Operations Research Group of Case Institute of Technology and the Cleveland Electric Illuminating Company in 1965 (37). This study was the first attempt ever reported to solve the emergency optimizing problem as the maximum load problem described in Section 3.7. The solution procedure used the Fletcher-Powell unconstrained minimization algorithm. The objective function and constraints were expressed in a penalty function formulation called the Fox-Schmidt draw-down technique (38). The procedures developed in this joint study had been tried out on an elementary three-bus network but not on a bigger system representation.

The work that I have done in connection with this thesis work on the emergency optimizing control problem was described in Section 3.7 in the discussion of the maximum load problem. The results indicate that the direct non-linear programming approach to emergency optimizing control using the Fiacco-McCormick method is not suitable for on-line control. The problems encountered with the Fiacco-McCormick procedure are the following:

a. Difficulty in choosing the initial value of the coefficient r of the penalty function term

b. Difficulty in handling equality constraints

c. Convergence problems when pushing against the constraint surface.

d. Relatively long computer running time.

The Fiacco-McCormick method when applied to the highly non-linear power system equations is evidently acceptable for off-line operating decisions or for engineering planning as was indicated in Section 3.7. For on-line optimizing control we need a technique which would take well under 5 minutes to run on a scientific computer such as the CDC 3600 or the Sigma 5.

The problem of restorative optimizing control is practically unexamined. The only work so far is that reported in reference 37 where an approach is suggested for a dynamic restoration procedure based on the same non-linear programming technique used for the emergency problem.

The direct control layers of the emergency and restorative operating states are more straightforward in that most of the desired control functions are known and existing in some form in many power systems. The problems that remain are those which involve the participation of a central computer in the logic processes which are based on local information. The most difficult problem that remains to be analyzed is that of direct control for maintaining system stability.

To make the proposed development of the control system computer, we will include in the flow chart to be presented in Section 5.3 a box labelled "emergency direct control" and another box labelled "emergency optimizing control." We do this realizing that more work remains to be done, especially in the second area.

5.2 The Information System

The principal role of the information system is to determine the operating conditions of the power system and to provide the necessary inputs to the various control functions. In addition, the information system will provide the link between the power system and the human operator giving him pertinent information via a display system.

A tabulation is given in Table IV of system data, measured directly or indirectly, and the control functions which require the data.

TABLE IV

INFORMATION INPUTS TO VARIOUS CONTROL FUNCTIONS

("X" INDICATES THAT THE DATA IS NEEDED FOR THE CONTROL FUNCTION)

System Data	Control Function								
	A	B	C	D	E	F	G	H	I
Frequency	X					X			
Interconnection Flows	X	X	X			X	X		X
Generator Voltage Magnitudes			X	X					
Generator Voltage Phase Angles			X		X				
Other Voltage Phase Angles					X				
Load Real & Reactive Power			X			X	X	X	
Network Status			X	X			X	X	
Generator Outputs & Status	X	X		X	X	X	X	X	
Interconnection Status		X	X				X	X	X

A - Load-frequency control
B - Economy dispatch
C - Penalty factor calculation
D - System voltage control
E - Security evaluation

F - Emergency direct control
G - Emergency optimizing control
H - Short-term load forecast
I - Interconnection flow model

Frequency and interconnection flows are standard items which are being measured directly in all interconnected utility systems for load-frequency control. Smoothing and filtering of the interconnection flow measurements will be required for DDC type of control and also for inputs to the interconnection flow model.

The telemetry of generator voltage phase angles still has to be developed. The problem is not in the measurement of each angle but in the establishment of a common reference. However if a phase angle telemetry is not available the data may be calculated by the Fast Simulation procedure. This will make the measurement of the next item, real and reactive powers at all loads, mandatory.

The real and reactive powers should be measured at all loads. If there are communication or cost difficulties to gather the data from all load nodes, measurements by load areas may be made and the individual station loads may be estimated. The load areas should be chosen so that the loads are approximately homogeneous.

The network status is derived from direct indications of circuit breaker positions and protective relay operation (13). The procedure for processing these indications is based on propositional logic. The procedure not only derives an up-to-date picture of the power system network but also makes a realistic diagnosis of a case of system trouble. The logic used is simple and is independent of the actual sequence of events attending a system disturbance. The procedure which we will call "Automatic System Trouble Analysis" (ASTA) is fully described in reference 39.

Direct measurements and the ASTA logic provide the information on generator outputs and status along with transmission network status.

Information on interconnection status is obtained by verbal communication with operators of other systems in the interconnection.

5.3 Control System Flow Chart

Fig. 5.3.1 is a flow chart representing a proposed development of the control system for a power system. In the chart and in the sequel the following symbols are used freely:

D - information display and reports

E - environmental data

G - operating constraints

M - economy interchange schedule

P - penalty factors

T - system data obtained from general simulation

X - network status, output of ASTA

Y - interconnection flow model

Z - load forecast

α - system security parameter set, obtained from pattern classifier

The chart is divided into the three control layers -- direct, optimizing, and adaptive control.

The direct control layer includes local control systems and

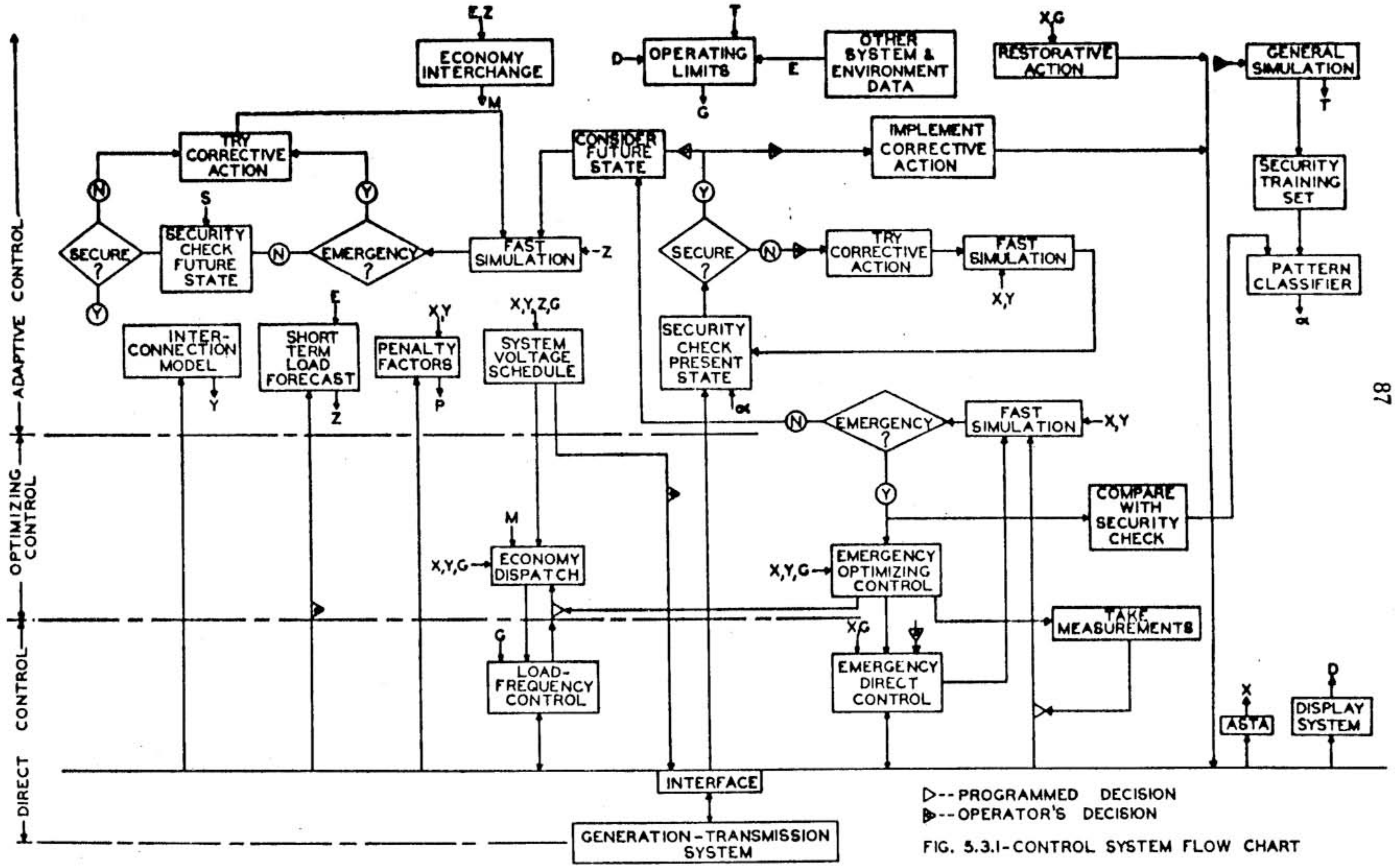


FIG. 5.3.1-CONTROL SYSTEM FLOW CHART

devices scattered throughout the generation-transmission system. These local control systems consist of: regulatory equipment for preventive control; protective relay systems for emergency control; and automatic switching systems for restorative control.

During normal operation the information being sent from the system to the control center is a steady stream of measurements of: frequency, interconnection flows, and generator outputs. These inputs are used by the load-frequency control. The control cycle of the load-frequency control will be τ_A, which is of the order of a few seconds. The load-frequency control has three more inputs which come from the higher layers. One is the economy dispatch signal which has a control cycle, $\tau_B > \tau_A$, of the order of a few minutes provided the change in generation requirement is greater than a prescribed amount. The other inputs to the load-frequency control are "M" the economy interchange schedule and "G" which is a set of operating constraints. G may also include an interchange schedule which is required from considerations other than that used for M.

The economy dispatch has the inputs: "P", the set of penalty factors for the generator nodes; "M", the economy interchange; and "G" a set of operating constraints. During an emergency the economic dispatch may be temporarily suspended.

The set of penalty factors is calculated every τ_C minutes where $\tau_C > \tau_B > \tau_A$ or when the loading has changed by a prescribed amount or when there has been a network change. The inputs to the penalty factor calculation are the generator voltages (magnitudes and angles), the interconnection flows, the loads (real and reactive power), and the network status, X.

The economy interchange is calculated as part of the economy dispatch in case the system is part of a pooled operation. If not, the economy interchange is calculated every τ_D minutes where $\tau_D > \tau_C > \tau_B > A$.

At the same sampling times, every τ_C minutes, as the penalty factor calculation, the generator voltage phase angles are processed by the security evaluation which classifies the state of the system as being secure or insecure. If the system is considered insecure and the classification is accepted by the operator, he has the option of trying out certain corrective action. For each corrective action, the fast simulation procedure will come up with a new security pattern which again will be classified by the security evaluation. If the system is secure after corrective action is taken, the operator may decide to implement the corrective action.

At every half-hour or at the option of the operator, readings of load real and reactive powers are taken for use in the short-term load forecast. Other inputs to the forecast routine are X and "E", a set of environmental data.

Every few hours or as infrequently as two times a day, a system voltage schedule will be generated using for inputs, X, Y, Z, and G. The new voltage regulator settings will be transmitted to the generating stations and other points in the system by the operator.

In the foregoing discussion we have confined ourselves to the normal or preventive operating state. We now consider the train of events when there is a large disturbance in the system. If there are any sudden changes in the system because of fault disturbances any changes of status of circuit breakers and all attendant relay operations are reported automatically to the control center. These are fed to the ASTA logic which determines the new network status, X. At the same time other information such as change in frequency, changes in interconnection flows, loss of generation are also collected. The emergency direct control takes the necessary control action if the prescribed decision logic based on X and the other system data mentioned are satisfied. The emergency direct control also calls the fast simulation to determine if there is any emergency (overload or undervoltage) or not. If there is an emergency, the emergency optimizing control determines the best arrangement of generation, interchange, and load distribution so that the maximum load is supplied. The solution is implemented via the load-frequency control to alter generation and via the emergency direct control to drop load at the chosen locations. Measurements following the control action are fed back and again a fast simulation is made to verify if the emergency has been corrected.

If the large disturbance does not cause an emergency or if the emergency has been corrected by the two-layer emergency control, the operator should consider the future state especially if the system peak load is still to come. The fast simulation is used to determine if the future state would get into an emergency with the new network status, X. The short-term load forecast provides the information Z on the future state. If the future state will get into an emergency, corrective actions are tried using the fast simulation.

If no corrective action is successful and the network failure cannot be restored in time, the off-line optimization program will be called to determine the best way for meeting the future load so that a maximum load may be supplied.

If the future state will not be in an emergency, it should be checked for security using the security pattern vector obtained from the fast simulation.

The control system flow chart presented is just one of many possible ways of developing a control system for poer system reliability. Our purpose in presenting this particular flow chart was to show how the various control functions, either developed or simply referred to in this thesis, are used to accomplish the overall objective stated in Section 2.3, via the multi-layer control structure.

We also realize from the seemingly labyrinthine flow of information and decision-making and the interplay of various procedures that the matter of programming language is another important problem to be resolved.

CHAPTER VI

CONCLUSION

6.1 The Significance of This Research

In the electric power industry, the need for meeting an ever-increasing demand for electric energy at a continued low cost and reliability of service has led to installations of high-capacity generation and extra-high-voltage transmission, plus large-scale interconnections between power systems. Interconnections link vast geographical areas together into one huge super-system. As demand for power grows, the super-system also grows in size and in complexity of its network and of its dynamic behavior.

In the operation of power systems, the decision problems have become much more complex than those which existing automatic control devices, let alone human operators, can cope with successfully. There is a vital need for an improvement in the control of power systems consonant with the full meaning of continuity of service to modern society. This thesis has been motivated by that need.

With this thesis, I have embarked on a systems engineering study of the total problem of control of interconnected power systems. I have, first of all, identified the operating problem via three operating states. Next, I have cast the control problem in each operating state in the multi-layer structure (7) and have made a comprehensive identification of the various control functions which fit in the structure. This overall plan of the control system permitted me to direct my research on one general area without losing sight of its role with respect to the other areas. This general area is what I call "preventive control" or control in the preventive operating state. I claim that this is where initial research efforts should be made because of the importance of preventive control in the overall strategy. Also because of realizable pay-offs in improved day-to-day operation.

In the area of preventive control, I have defined "system security" and have investigated with good results the use of pattern recognition as an approach to security evaluation. The method used, which is one of adaptation, would be an invaluable aid in the making of control decisions for the maintenance of system security against emergencies.

I have also considered the optimizing control layer of preventive control and have developed so-called "penalty factors" for multi-area control. The penalty factors, which would be calculated as an adaptive layer algorithm, would reflect at all times actual network and loading conditions into the optimization algorithm.

For the calculation of penalty factors, I have developed an on-line approach for modelling the interconnection. This on-line modelling is a new idea and would be needed not only for penalty factor calculations but also for other control functions requiring an interconnection representation.

I have also looked into other adaptive functions in the preventive state which are capable of being formulated through non-linear programming. My results in the application of unconstrained minimization techniques to large-scale non-linear objective functions with highly non-linear penalty terms provided useful insight and experience on just how amenable power system problems are to mathematical programming procedures.

I have introduced a new technique for decomposition of power system networks and have successfully tried it out on a non-linear problem. This technique would also be of value in the adaptive layer where there is a need for simulation of very large networks.

In this thesis, I have demonstrated the value of the multi-level concept as an analysis and design tool and as a basis for an actual control system. I have shown by means of an organizational flow chart how a possible control system might be set up using functions developed in the thesis and other functions still to be developed.

My work to date is only a beginning. More research still remains to be done.

6.2 Areas for Future Research

From Chapter II and from occasional remarks made throughout the text, we can identify several areas for future research. Among these are:

Analysis of stability of power systems.- Techniques for analyzing stability within an actual operating environment need to be developed.

Generalization problem of security evaluation.-In this thesis, the abstraction problem was investigated. In the generalization problem, a procedure is needed for determining when and how the training set should be up-dated.

Non-linear optimization techniques for power system problems.- Highly efficient optimization methods are needed for the special types of functions and constraints which arise from power system problems. The handling of equality constraints merits special study.

Programming languages for power system operation.- The development of a real-time programming language best suited for power system operation and for man-computer communication needs investigation.

Emergency control.- A study of the feasibility of optimal control for directly steering the power system from a state of emergency to a safe steady-state operation is needed.

Restorative control.- A study of the feasibility of direct or optimizing control for steering the power system from a partial or complete shut-down to a full load steady-state operation is needed.

Decomposition methods for interconnected system problems.- Decomposition techniques are needed for problems of control and analysis of interconnected power systems. The problems to be considered include multi-area computer control, optimization, stability analysis, simulation methods, etc.

The above list is but a representative sampling of appealing areas for research. The power system control problem when viewed in its real dimensions of size, complexity, and impact on society, is readily seen to be replete with challenges and opportunities for the systems researcher and engineer.

APPENDIX I

FLOW CHART OF SECURITY EVALUATION PROGRAM

The program represented by this flow chart is a stochastic approximation procedure for a 2-category pattern classification problem.

Let z = a pattern vector in the training set

m = the number of components in z

j = sample count

α = the pattern classifier, α_o, α_1, α_2, . . . , α_m

s = the classification of z: $s = 1$ if secure; $z = 0$ if insecure

Psec = the conditional probability that the given pattern is secure

The program approximates the conditional probability of security, Psec, by the equation

$$Psec = \alpha_o + \sum_{i=1}^{m} \alpha_i z_i$$

α is up-dated with each sample according to the algorithm

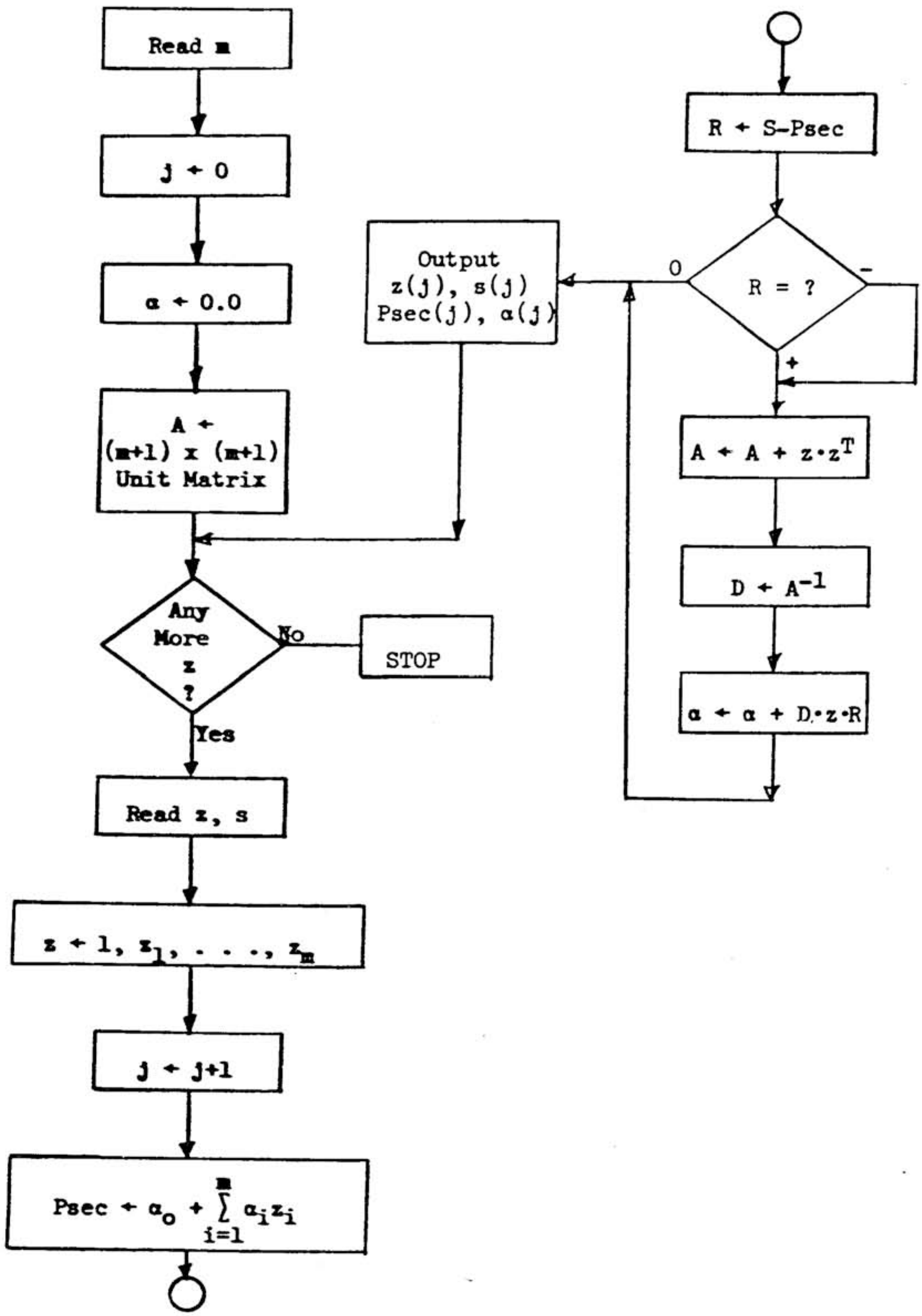
$$\alpha(j+1) = \alpha(j) + D(j)\ z(j)\{s(j) - Psec\}$$

where z is augmented by an initial component $z_o = 1.0$.

$$D(j) = (A(j) + z(j)^T)^{-1}$$

$$A(0) = \text{the unit matrix}$$

The flow chart is presented on the following page.


Read m
j ← 0
α ← 0.0
A ←
(m+1) x (m+1)
Unit Matrix
Any
More
z
?
No
STOP
Yes
Read z, s
z ← 1, z1, . . ., zm
j ← j+1
Psec ← αo + ∑ αi zi
i=1
m
R ← S-Psec
R = ?
0
−
+
Output
z(j), s(j)
Psec(j), α(j)
A ← A + z·zT
D ← A-1
α ← α + D·z·R

APPENDIX II

GENERALIZED FLOW CHART FOR OPTIMIZATION PROGRAM

The program represented by this flow chart finds the vector of complex voltages of a power system which minimizes a non-linear objective function subject to a set of non-linear inequality constraints. These constraints are generally as enumerated in Section 3.7. It is assumed that the equality constraints may be satisfied to within a specified tolerance. Hence the equality constraints are replaced by inequalities.

The problem is transformed into an unconstrained minimization by using the Fiacco-McCormick formulation (27). The unconstrained minimization is done by the Fletcher-Powell method (28) with a quadratic interpolation for the unimodal search.

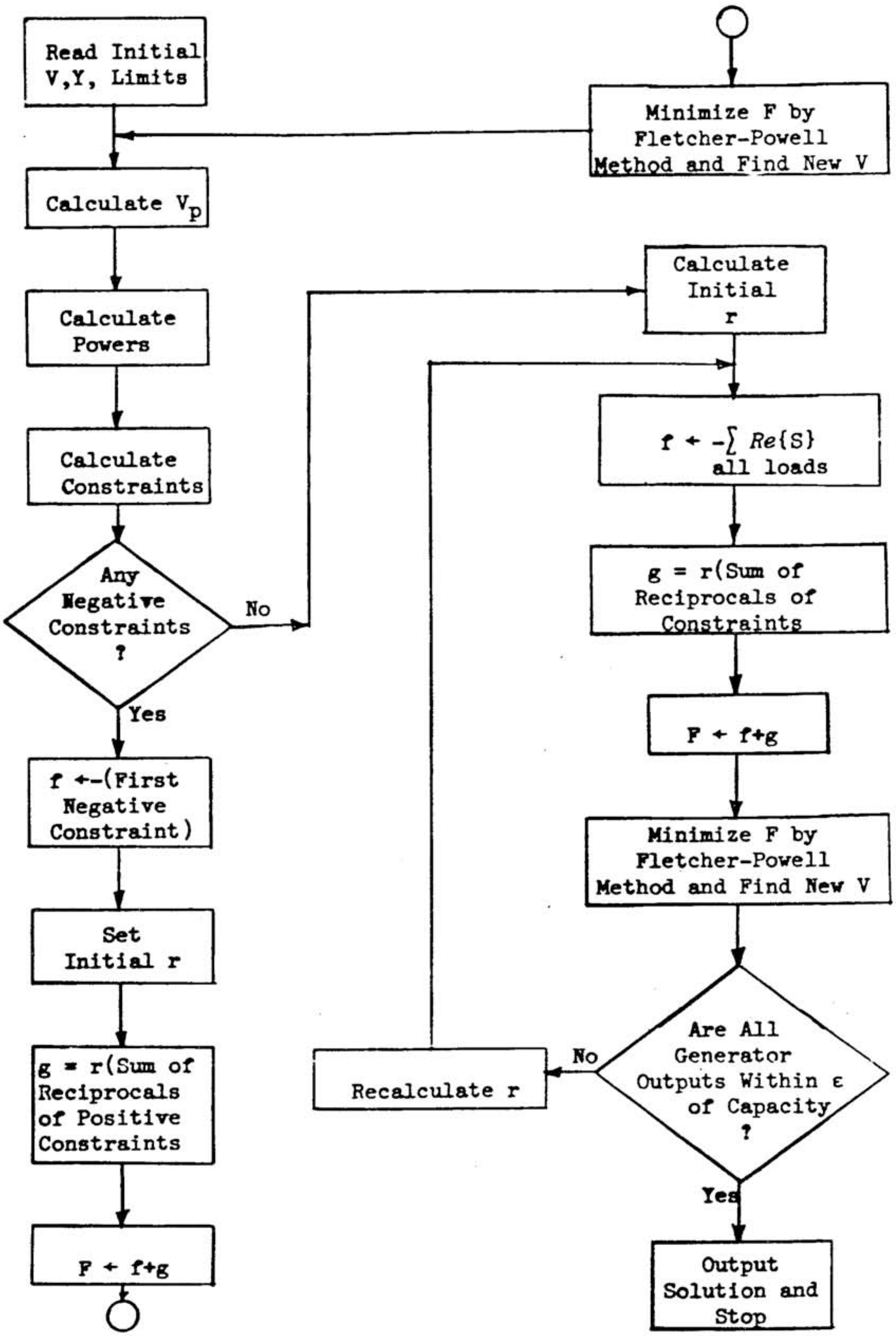
This program has been used for both the maximum load problem and the load flow problem as described in Section 3.7. The objective function shown in the flow chart is for the maximum load problem. For this problem the overall stopping criterion is the availability of power from the generating sources.

Let V = vector of complex voltages at active nodes

V_p = vector of complex voltages at passive nodes

S = complex power at a node

Y = nodal admittance matrix of network


Read Initial V,Y, Limits
Calculate Vp
Calculate Powers
Calculate Constraints
Any Negative Constraints ?
No
Yes
f ←-(First Negative Constraint)
Set Initial r
g = r(Sum of Reciprocals of Positive Constraints
F ← f+g
Minimize F by Fletcher-Powell Method and Find New V
Calculate Initial r
f ← -∑ Re{S} all loads
g = r(Sum of Reciprocals of Constraints
F ← f+g
Minimize F by Fletcher-Powell Method and Find New V
Are All Generator Outputs Within ε of Capacity ?
No
Recalculate r
Yes
Output Solution and Stop

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