DYNAMIC OPTIMAL ECONOMIC DISPATCH UNDER SYSTEM AVAILABILITY CONSTRAINTS

by

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The University of Ottawa requires the signatures of all persons using or photocopying this thesis. Please sign below, and give address and date.

To

my wife Yeon-Hee

and

my parents Chang H. and Woo H.

ABSTRACT

In this thesis, a dynamic optimal economic dispatch policy has been developed on the basis of a stochastic availability model of large-scale power systems[6,7] and a piece-wise constant incremental fuel cost model[8].

Using these models the optimal economic dispatch under given system availability constraints is formulated as a dynamic nonlinear optimization problem. The random variation of demand, available generation capacities and availability of the tie lines are considered as constraints in the problem.

In order to solve the optimization problem an efficient algorithm based on the rule of merit-order loading has been developed. The algorithm allows large dimensionality of the system and randomness of the system parameters. The algorithm can also be easily implemented on a dispatch computer.

In order to illustrate the effect of the proposed method on system economy and availability, an example has been presented, giving detailed numerical results.

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Chapter I

INTRODUCTION

Electric power is one major industry that has shaped and contributed to the progress and the technological advances of mankind over the past century. The electric power system engineer is faced with the challenging task of planning and operating one of the most complex systems of today's civilization.

A main objective in the operation of any of today's complex power systems is to produce and transfer power to meet the system demand at the lowest possible cost, while maintaining safe and clean standards of environmental impact or with consideration of the effect on system security. Reliability (or availability) among those goals is the most essential one that the electrical power system engineer strives to meet at all times.

Economic dispatch ranks high among the major economy security functions in power system operation. This is a procedure for the distribution of thermal generation requirements among alternative sources for optimal system economy with due consideration of generating costs, transmission losses, and several recognized constraints imposed by the requirements of reliable service and equipment limitations. Because of the following trends in the growth of power systems, it becomes progressively important to give increasing attention to economic operation.

1. In many cases economic factors and the availability of primary resources, such as coal, water, etc., dictate that new generating plants be located at greater distances from the load centers.
2. The installation of larger blocks of power has resulted in the necessity of transmitting power out of a given area until the load in that area is equal to the new block of installed capacity.
3. Power systems are being interconnected for the purpose of economic interchange and reduction of reserve capacity.
4. In many countries the cost of fuel is rapidly increasing.

A fully interconnected system allows not only maximum possible savings in the total system running costs but also the effective improvement of the overall level of system reliability (availability). The savings in system fuel costs by incorporating all generating units into one merit order list with consideration on transmission losses with interconnection can be set against the capital and running costs for the interconnection. The installed capacity benefits due to interconnection depend mainly upon the operating reserves in the individual systems, the interconnection limitations and the type of agreement between the two systems regarding emergency help.

In the operation of a power pool consisting of several areas interconnected by tie lines, the basic question is therefore: how much power should be generated by each generator and how much power should be transferred through tie lines in order to meet the demands as economically as possible, while maintaining the reliability index at the highest possible level (under the given system environment).

The two important problems of dynamic economic dispatch and reliability (or availability) have been extensively studied but seperately in the past [1-7]. However, for real practical applications economic dispatch calculations for a power pool interconnected through tie lines must take into account the system availability as well as various types of constraints such as

i) demands of interconnected areas,

ii) available generation capacities in various areas,

iii) capacity limits of tie lines interconnecting areas,

iv) and finally the random variation of all these parameters.

To the kowledge of the author, a dynamic economic dispatch problem with the system availability constraint* has not been considered in the literature before[8].

---

* The requirement that system availability be maintained at the highest possible level is referred to as "(system) availability constraint" in the sequel.

In this research, the dynamic economic dispatch problem, taking into account the above constraints, is formulated as a dynamic optimization problem. The solution to the problem provides the optimal dispatch policy which minimizes the generation (fuel) cost under the availability constraint. Two main difficulties associated with the optimization problem are the system availability constraint and the nonlinearity. The system availability improvement under the random variation of the system parameters such as available generation capacities, area demands and available tie line capacities makes most of the conventional methods inapplicable. Recently a dynamic reliability model for large scale interconnected power systems has been developed [6,7] in order to consider the random variation of the system parameters. Using such a model, the system reliability can be considerably improved by solving a linear programming problem as demonstrated by the results of Ahmed and Dabbous. However, in the work [7], the system economy has not been considered. In this research the economic generation as well as system reliability improvement is considered.

Because of nonlinear constraints involved in the economic dispatch problem, direct application of the existing optimization algorithms [9,10] to the problem results in increased computation time and slow convergence. In order to overcome the difficulties an algorithm is proposed for solving the economic dispatch problem under the constraints described above. This algorithm can be easily implemented on a dispatch computer for real time applications without any problems in computation time and memory size increase which have been the main difficulties in linear programming approach [11,12].

In order to illustrate the usefulness of the proposed method on generation economy under the availability constraint, an example consisting of three areas interconnected through tie lines (Figure 5.1) is presented. It should be empasized that the algorithm developed here can be easily modified to take into account the system security constraints as well as any binding agreements between areas.

In the following, major contributions of this thesis will be presented, followed by the outline of the thesis.

Major Contributions Of The Thesis

(i) Development of a methodology for dynamic optimal economic dispatch under the availability constraint for large-scale interconnected power systems.

(ii) Development of an efficient algorithm for implementation on a dispatch computer.

Outline Of The Thesis

In chapter II a large - scale power pool consisting of several power systems interconnected by tie lines is considered. The power pool is completely described by the stochastic reliability models of the major components composing the individual areas or power systems.

In chapter III the production cost as an objective function of the economic dispatch problem is expressed as a function of the output of generators and corresponding incremental costs. The constraints that should be satisfied in the cost minimization problem are available generation capacities, available tie line capacities and the system availability requirement. After the constraints are described in terms of the output of the generating units, the economic dispatch problem is formulated as a nonlinear constrained minimization problem.

In chapter IV a data estimation problem associated with the minimization problem is briefly discussed. In order to avoid some limitations of the application of existing optimization algorithms to the problem, a new efficient algorithm based on the rule of merit order loading is developed for the problem.

In chapter V, in order to illustrate the usefulness of the proposed algorithm on the system economy and availability, numerical simulations for a power pool consisting of three interconnected areas are performed, giving detailed numerical results which are very encouraging.

In chapter VI conclusions of the research and proposals for further research are finally presented.

Chapter II

LARGE-SCALE INTERCONNECTED POWER SYSTEMS

2.1 INTRODUCTION

A good model of large scale interconnected power systems is essential in order to develop the plausible control policies for economy and availability. In this chapter, a stochastic model of reliability dynamics for interconnected power systems is presented. In the model, a power network consists of many individual subsystems, interconnected through tie lines and exchanges powers in order to minimize the generation cost under the system availability constraint.

There have been several approaches for dynamic modelling of power system components [7,13-17]. However, for real applications, a plausible model for reliability of power systems must take into account the following natural random environment:

Random failures and repairs of generators,

Random variation of demands,

Random availability of tie lines.

2

In order to take into consideration the above properties of system components, a very interesting model for reliability or availability of power systems has been developed recently by Ahmed and Dabbous[6,7]. It is a new complete time series model which considers the random variation of the system components.

The dynamic models for the components in the sequel in this chapter were taken from references [6,7]. Complete development of the models are also given in the references.

Before proceeding to the dyamics, the topology of power systems will first be outlined. The reliability dynamics of the system components is followed by the power pool description.

2.2 POWER POOL MODEL

A power pool consisting of N areas interconnected through tie lines is considered. Each area or subsystem has a number of generators of different sizes, a number of local transmission lines and a number of major load or demand centers. The system is controlled by a main central dispatch computer. If there is a shortage of power in an area, the area can import power from another area, provided there is a tie line interconnecting the two and there is available power after the lending area's local demand has been met. If required, more than one area can co-operate to meet the shortage.

Figure 2.1. presents the topology of the interconnected power system. Each area is denoted by a large circle indexed by an integer with an accompanying small circle denoting the area demand. The notations and their meanings are listed as follows:

Index for Areas : $\{i\}$, $i=1,2,\cdots,N$

Demand center in the i-th Area = D_i

No. of generators in the i-th Area = n_i

Total capacity of generation of the i-th Area = C_i.

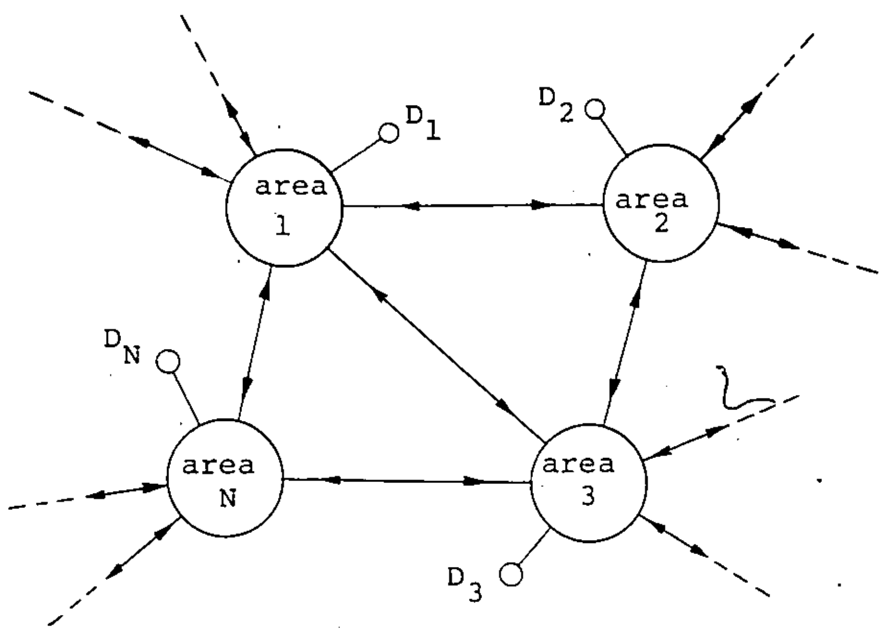


Figure 2.1. A large scale interconnected power pool.

2.3 STOCHASTIC DYNAMICS OF THE SYSTEM COMPONENTS

In this section, the dynamics of the power system is considered component by component. The complete mathematical model of interconnected power systems consists of

(1) A stochastic dynamic model of the failures and repairs of generators,

(2) A stochastic dynamic model of the power demand of each area,

(3) A stochastic model of the matrix of tie lines interconnecting the areas to form the power pool.

2.3.1 Stochastic generator models

Let $r_i = (r_{ki}(t);\ k=1,2,\ldots n_i; i=1,2,\ldots N)$ denote the generator vector for the area i with r_{ki} representing the state of the k-th generator in the area i at time t.
The elements of this vector are random processes $\{r_{ki}(t), t\geq 0\}$ taking values either zero or one depending on whether it is in the failed state or operating state as shown in Figure 2.2.

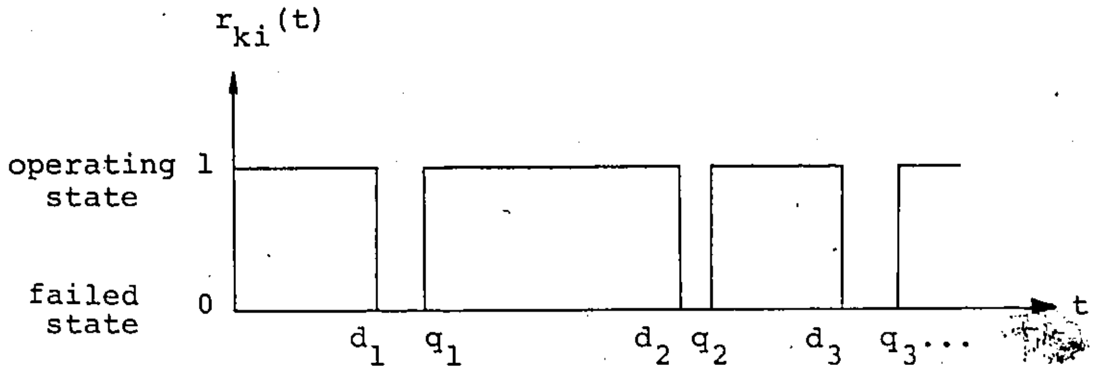


Figure 2.2. Random unit performance of a generator.

Consider any generator r_{ki} and let $\{d_1, d_2, d_3, \bullet\bullet\bullet\}$ denote the sequence of its random failure times and $\{q_1, q_2, q_3, \bullet\bullet\bullet\}$ the corresponding repair times. It is clear, from Figure 2.2, that with probability one, $d_m < d_{m+1}$, $q_m < q_{m+1}$ and $d_m < q_m < d_{m+1}$ for all integers $m \geq 1$. Note that

$$T_m(1) \triangleq d_{m+1} - q_m \qquad (2.1)$$
$$T_m(0) \triangleq q_m - d_m$$

denote the residence times in state 1 and 0, respectively. It is assumed that these random variables are exponentially distributed with parameters ξ_{ki} and μ_{ki} respectively independently of m. That is

$$\Pr\{T_m(1) \leq z\} = \int_o^z \xi_{ki} e^{-\xi_{ki} t} dt \qquad (2.2)$$
$$\Pr\{T_m(0) \leq z\} = \int_o^z \mu_{ki} e^{-\mu_{ki} t} dt$$

where $\Pr\{\bullet\} \equiv$ probability of $\{\bullet\}$.

Normally $\xi_{ki} << \mu_{ki}$ . . Under the above assumption the process $\{r_{ki}(t), t \geq 0\}$ is a homogeneous jump Markov process. Further, for Δ sufficiently small (>0),

$$\begin{aligned}
&Pr\{r_{ki}(t)=1 | r_{ki}(t-\Delta)=0\} = \mu_{ki}\Delta + o(\Delta) \\
&Pr\{r_{ki}(t)=0 | r_{ki}(t-\Delta)=0\} = (1-\mu_{ki}\Delta) + o(\Delta) \\
&Pr\{r_{ki}(t)=0 | r_{ki}(t-\Delta)=1\} = \xi_{ki}\Delta + o(\Delta) \qquad (2.3) \\
&Pr\{r_{ki}(t)=1 | r_{ki}(t-\Delta)=1\} = (1-\xi_{ki}\Delta) + o(\Delta)
\end{aligned}$$

From this, the following state transition diagram is obtained.

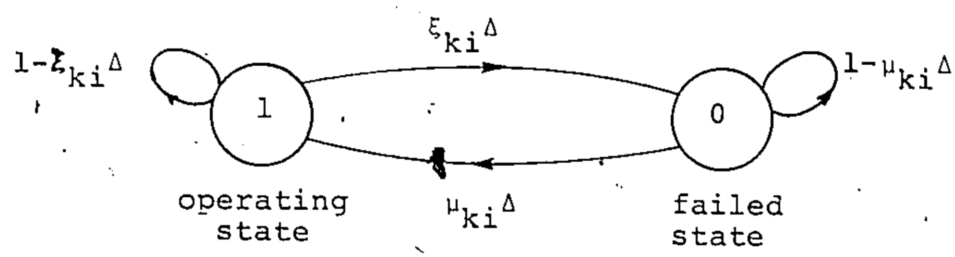


Figure 2.3. State transition diagram for generator r_{ki}.

Thus the elements of the generator vector r_i are independent random processes and each one is governed by a homogeneous jump Markov process with values 0 or 1. Introducing random Poisson counting measures $M^o_{ki}(dt)$ and $M^1_{ki}(dt)$ on the Borel sigma- field B(Ro) on Ro=[0,∞) with $E(M^o_{ki}(\Delta)) = \xi_{ki}\Delta$ and $E(M^1_{ki}(\Delta)) = \mu_{ki}\Delta$, stochastic differential equations for the generators are obtained as follows:

$$dr_{ki}(t) = 1\cdot(r_{ki}(t-)=0)M^1_{ki}(dt) - 1\cdot(r_{ki}(t-)=1)M^o_{ki}(dt)$$
$$k=1,2,\bullet\bullet\bullet,n_i;\ i=1,2,\bullet\bullet\bullet,N. \qquad (2.4)$$

where

$$1^{\cdot}(\bullet) = \begin{cases} 1 & \text{if } (\bullet) \text{ is true.} \\ 0 & \text{otherwise.} \end{cases} \tag{2.5}$$

Note that this is mathematically equivalent to the model discussed above. Using the process $\{r_{ki}(t), t\geq 0\}$, we can define the available generation capacity of the generator k in the area i at time t as

$$C_{k,i}(t) = c_{k,i}r_{ki}(t) \tag{2.6}$$

where $c_{k,i}$ denote generation capacity of the generator k in the area i.

Similarly, the available generation capacity of the area i is defined as

$$C_i(t) = \sum_{k=1}^{n_i} C_{k,i}(t) \tag{2.7}$$

2.3.2 Stochastic demand models

Let $D_i, i=1,2,\bullet\bullet\bullet N$ denote the demand for the area i at time t. Since the overall demand rate is given by a sum of two components, one representing the mean demand rate and the other representing a random fluctuation around the mean, the process $\{D_i(t), t\geq 0\}$ is obtained as the solution of

$$dD_i/dt = H_i(t) + S_i(t), \tag{2.8}$$

where $H_i(t)$ is the mean demand rate at time t and $S_i(t)$ its random variation. For a short term model, it suffices to take H_i as a deterministic function of time and S_i a suitable random process. For a generalized model, taking into account possible regional expansion, for example population and industrial growth, it is natural to consider $H_i(t)$ not only dependent on time but also on the level of demand at the time t. Thus it may be taken as

$$H_i(t) = g_i(t, D_i(t)) \tag{2.9}$$

for a suitable function g_i, a function of time and the demand D_i. Also the component S_i, representing random fluctuations around the mean, depends on the size of the population and density of industries in the area and consequently on the demand level. This can be modelled as

$$S_i(t) = \sigma_i(t, D_i(t))(dW_i/dt) \tag{2.10}$$

where dW_i/dt is the White noise and σ_i is a function of time and the demand $D_i(t)$. Thus the demand process for the area i is governed by the differential equations

$$dD_i(t)/dt = g_i(t, D_i(t)) + \sigma_i(t, D_i(t))(dW_i/dt). \tag{2.11}$$

Since White nose is defined as the derivative of the Wiener process $\{W_i(t), t \geq 0\}$ whereas the Wiener process is not differentiable in the classical sense, the equation (2.11) has no rigorous mathematical sense. For a rigorous mathematical interpretation, equation(2.11) is written as

$$dD_i(t) = g_i(t, D_i(t))dt + \sigma_i(t, D_i(t))dW_i \tag{2.12}$$

and dD_i is called the Ito differential of D_i. The equation (2.12) is known as the Ito differential equation.

The demand equation for the entire power pool is then given by a set of stochastic differential equations:

$$dD_i(t) = g_i(t,D_i(t))dt + \sigma_i(t,D_i(t))dW_i \tag{2.13}$$
$$D_i(0) = D_i^o, \qquad i=1,2,\bullet\bullet\bullet N.$$

The process $\{D_i(t),\ t\geq 0\}$ is a Markov process. Admitting g_i and σ_i as general functions of the demand D_i, the system demand(for the entire power pool) can be given by

$$D(t) = \sum_{i=1}^{N} D_i(t). \tag{2.14}$$

2.3.3 Model for the stochastic tie line matrix

As shown in Figure 2.4, the tie line matrix is given by $\{\tau_{ij}, i\neq j=1,2,\bullet\bullet\bullet N\}$. The elements of this vector are random processes $\{\tau_{ij}(t), t\geq 0\}$ taking values either zero or one depending on whether it is in the failed state or operating state as shown in Figure 2.4.

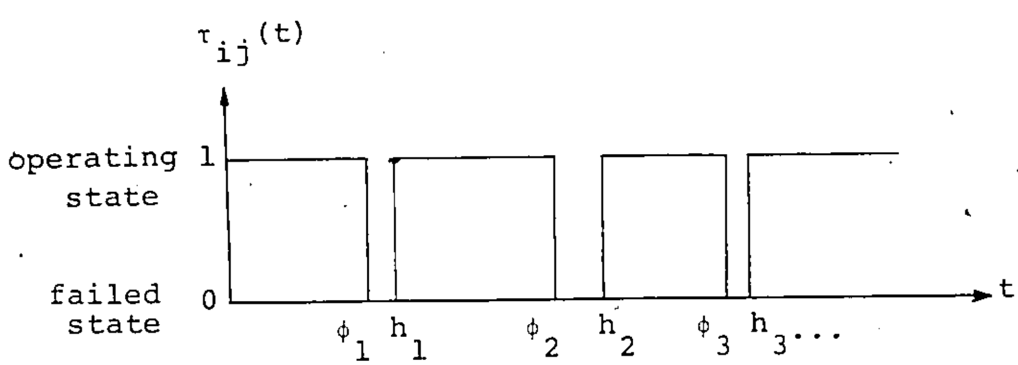


Figure 2.4. Random tie line performance.

Consider any tie line τ_{ij} and let $\{\phi_1,\phi_2,\phi_3,\bullet\bullet\bullet\}$ denote the sequence of its random failure times and $\{h_1,h_2,h_3,\bullet\bullet\bullet\}$ the corresponding repair times. It is clear, from Figure 2.4, that with probability one, $\phi_m<\phi_{m+1}$, $h_m<h_{m+1}$ and $\phi_m<h_m<\phi_{m+1}$ for all integers $m\geq 1$. Note that

$$T_m(1) \triangleq \phi_{m+1} - h_m \qquad (2.15)$$
$$T_m(0) \triangleq h_m - \phi_m$$

denote the residence times in state 1 and 0, respectively. It is assumed that these random variables are exponentially distributed with parameters ζ_{ij} and δ_{ij} respectively independently of m. That is

$$\Pr\{T_m(1)\leq z\} = \int_o^z \zeta_{ij} e^{-\zeta_{ij}t} dt \qquad (2.16)$$
$$\Pr\{T_m(0)\leq z\} = \int_o^z \delta_{ij} e^{-\delta_{ij}t} dt$$

Normally $\zeta_{ij} << \delta_{ij}$. Under the above assumption the process $\{\tau_{ij}(t),t\geq 0\}$ is a homogeneous jump Markov process. Further, for Δ sufficiently small (>0),

$$\Pr\{\tau_{ij}(t)=1|\tau_{ij}(t-\Delta)=0\}= \delta_{ij}\Delta + O(\Delta)$$
$$\Pr\{\tau_{ij}(t)=0|\tau_{ij}(t-\Delta)=0\}=(1-\delta_{ij}\Delta) + O(\Delta) \qquad (2.17)$$
$$\Pr\{\tau_{ij}(t)=0|\tau_{ij}(t-\Delta)=1\}= \zeta_{ij}\Delta + O(\Delta)$$
$$\Pr\{\tau_{ij}(t)=1|\tau_{ij}(t-\Delta)=1\}=(1-\zeta_{ij}\Delta) + O(\Delta)$$

From this, the following state transition diagram is obtained.

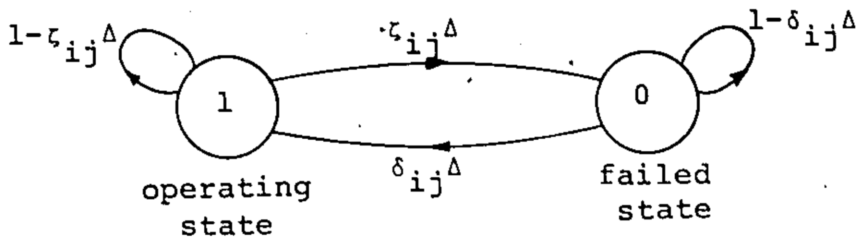


Figure 2.5. State transition diagram for tie line τ_{ij}.

Thus the elements of the tie line matrix $\tau=\{\tau_{ij}, i\neq j=1,2,\cdots N\}$ are independent random processes and each one is governed by a homogeneous jump Markov process with values 0 or 1. Introducing random Poisson counting measures $N^{o}_{ij}(dt)$ and $N^{1}_{ij}(dt)$ on the Borel sigma- field B(Ro) on Ro=$[0,\infty)$ with $E(N^{o}_{ij}(\Delta))=\zeta_{ij}\Delta$ and $E(N^{1}_{ij}(\Delta))=\delta_{ij}\Delta$, the stochastic differential equations for the tie lines are obtained as follows:

$$d\tau_{ij}(t)=1\cdot(\tau_{ij}(t-)=0)N^{1}_{ij}(dt)-1\cdot(\tau_{ij}(t-)=1)N^{o}_{ij}(dt) \qquad (2.18)$$

$i\neq j=1,2,\cdots,N.$

Note that this is mathematically equivalent to the model discussed above.

2.4 SUMMARY

In this chapter, a complete dynamic model of reliability dynamics for power systems interconnected through tie lines was presented. Using this model the system availability can also be introduced as given in [7]. When combined with the incremental production cost model, the economic dispatch under the system availability constraint can be formulated in terms of the power output and incremental fuel cost. The formulation of the problem is presented in the next chapter.

Chapter III

FORMULATION OF THE PROBLEM

3.1 INTRODUCTION

An important problem involved in the operation of large interconnected power systems is to determine dispatch policy for optimum system economy, including the effects of both incremental production costs and incremental transmission losses. Thus the objective is to determine the generation allocation of each generator in the system and power exchange between the areas so as to minimize the production cost while maintaining the system availability index at the highest possible level subject to several constraints. These constraints will be described later.

In this chapter, the objective function is described as the integral of fuel cost rate over the specified time period and transformed to subinterval optimization problem using Bellman's principle of optimality[18]. In order to express the objective function in terms of power outputs, in the next section, the fuel cost curves of thermal generating systems are briefly discussed. Using the given cost curve, the economic dispatch problem can be formulated. However, the direct use of the given cost curve to the problem results in a constrained nonlinear objective function which is difficult to solve. In order to avoid the difficulties associated with the cost curve, it can be approximated in several ways[19-21] without a large error in the production cost calculation. In this research, piece-wise linear approximation using several straight line segments was used. The corresponding incremental cost curve becomes a staircase function with several constant line-segments. The advantage of this approximation is that the piece-wise constant incremental cost function enables us to solve the minimization problem by using the rule of merit - order loading as shown in reference [8].

After the constraints (for the objective function) such as available generation capacities, available tie line capacities and system availability requirements are discussed, the optimization problem is finally formulated.

3.2 PRINCIPLE OF OPTIMALITY

The objective function may be written as:

$$J(0,T) = \int_0^T F(P(t))\,dt \tag{3.1}$$

where J(0,T)= Total generation cost of the power pool over the time interval [0,T].

$F(P)$= Hourly fuel cost(cost rate) of the power pool at the generation level P.

$P(t)$= Power generated in the power pool at time t.

Using Bellman's principle of optimality[18] we may write:

$$J^*(0,T) = \sum_{\ell=1}^{n_T} J^*(t_{\ell-1},t_\ell), \qquad \ell=1,2,\cdots,n_T. \tag{3.2}$$

with $t_0=0, t_{n_T}=T$, where $J^*(t_{\ell-1},t_\ell)$ is the minimum generation cost over the time interval $(t_{\ell-1},t_\ell]$. In other words, the minimum cost over the time interval $(0,T]$ is the sum of the minimum cost over the subintervals $(t_{\ell-1},t_\ell]$. For computation of the optimal dispatch policy for each interval $(t_{\ell-1},t_\ell]$, it is assumed that sufficiently accurate prediction of the system data like area demands, available generation capacities and the state of tie lines is available for the given time interval at time $t_{\ell-1}$. Several stochastic models are available for the prediction of demands, generation capacities and tie line availabilities [7,35-37]. However, in this research, these data were made available by use of the stochastic models[6,7] as summarized in chapter 1.

3.3 PRODUCTION COST MODELLING

This section begins with a description of some necessary definitions. Then the incremental production cost of a generator will be derived as a function of the output of individual segments corresponding to the generator.

3.3.1 Definitions

Frequently used type of simplified performance curves of thermal units are shown in Figures 3.1, 3.2 and 3.3. In Figure 3.1, the fuel(heat) input H, in Btu per hour, is plotted as a function of power output P, in megawatts.

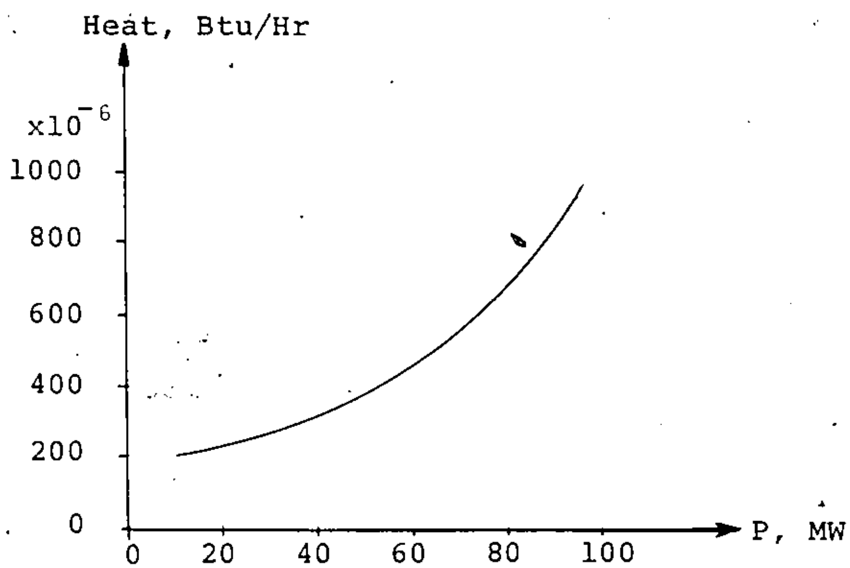


Figure 3.1. Heat input curve.

The corresponding heat (fuel) rate which is obtained by dividing the input by corresponding output, is given in Figure 3.2. It is to be noted that the units associated with heat rate are Btu per Kw-hr. The incremental fuel (heat) rate is given by the following definition:

$$\text{Incremental Fuel (heat) Rate} = \frac{dH}{dP} \tag{3.3}$$

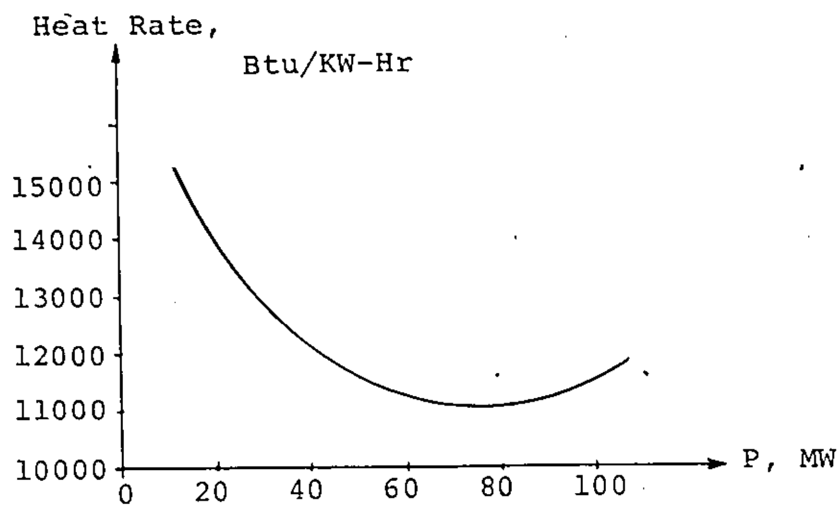


Figure 3.2. Heat rate curve.

In other words, the incremental fuel rate is equal to instantaneous change in the input divided by the corresponding instantaneous change in the output. The units associated with the incremental fuel rate are Btu per Kw-hr and are the same as the heat rate units. The incremental fuel rate is converted to incremental fuel cost by multiplying the incremental fuel rate in Btu per Kw-hr by the fuel cost in cents per million Btu.

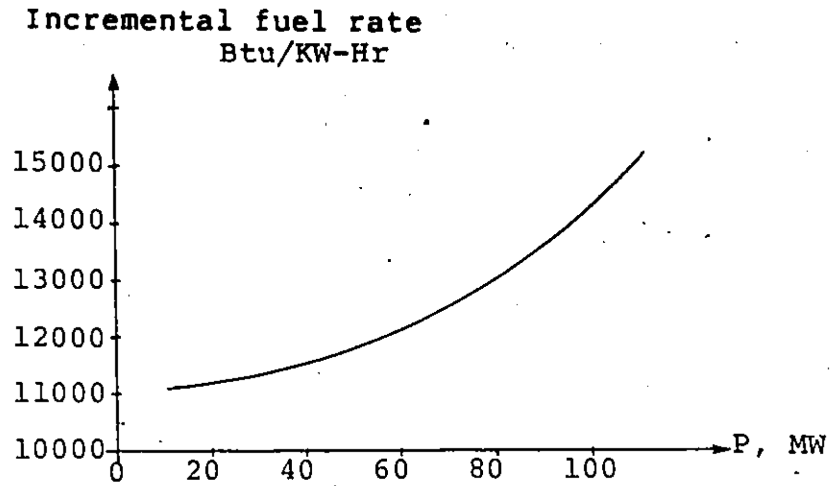


Figure 3.3. Incremental fuel rate curve.

The incremental fuel cost is usually expresssed in mills per Kw-hr or dollars per Mw-hr. That is,

$$\text{Incremental Fuel Cost} = \frac{dH}{dP} \bullet (\text{Fuel Cost}), \quad \text{in } [\$/\text{Mw-hr}]. \tag{3.4}$$

Incremental production cost of a given unit is made up of incremental fuel cost plus the incremental cost of such items as labors, supplies, maintenance, and water. It is necessary for a rigorous analysis to be able to express the costs of these production items as a function of instantaneous output. However, no methods are presently available for expressing the cost of labor, supplies, or maintenance accurately as a function of output. For the purpose of generation scheduling towards minimum generation fuel cost, incremental production cost can be assumed to be equal to the incremental fuel cost.

3.3.2 Incremental cost modelling

Economic dispatch makes sense only if reasonably accurate cost curves are available from the measurements, which are not always easy to obtain [22]. In this section an incremental fuel cost model for a given cost curve is suggested by segmentation of the generation of power output. Consider that a typical fuel cost function $f(p)$ for a thermal generating unit and its linear approximation as shown in Figure 3.4. In Figure 3.4, p^m is the maximum generation level of the generator. It is assumed that the cost curves are convex.

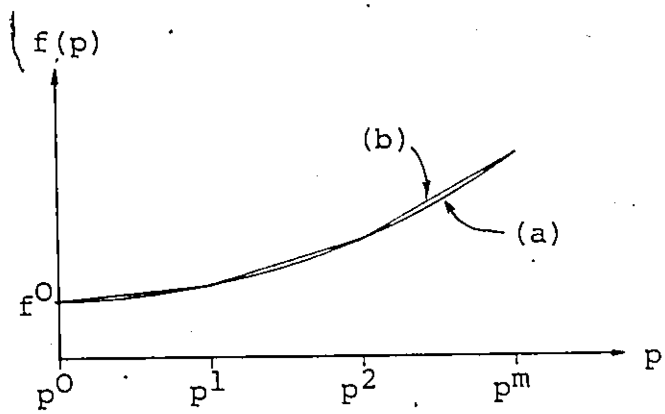


Figure 3.4. A fuel cost function for a generator (a) and its linear approximation (b).

The corresponding incremental fuel cost curves $\lambda(p)$ are shown in Figure 3.5.

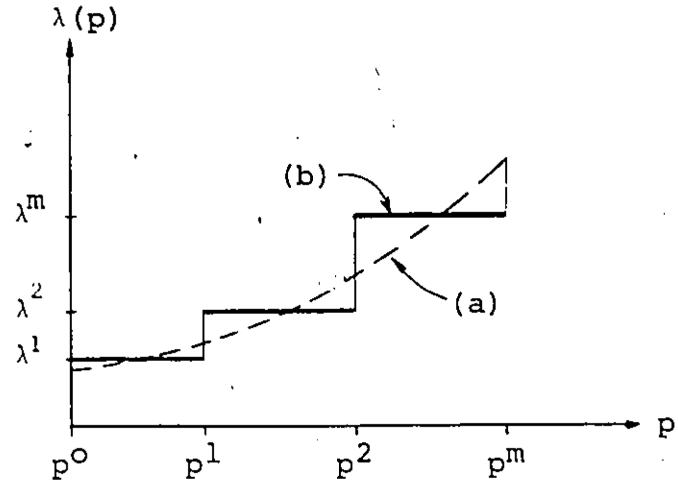


Figure 3.5. The incremental fuel cost corresponding to f(p).

Referring to Figures 3.4-3.5,

$$f(p) = \left(f^o + \sum_{s=1}^{m} \lambda^s x^s \right) \bullet \chi_{p^o} \tag{3.5}$$

and $$0 \le x^s \le p^s - p^{s-1} \tag{3.6}$$

$$\chi_{p^o} = \begin{cases} 1 & \text{if } p \ge p^o \text{ (operating state)} \\ 0 & \text{if } p < p^o \text{ (failed state)} \end{cases} \tag{3.7}$$

where m is the number of segments and p^m is the installed capacity of the generator. Now each generator may be regarded as several equivalent generating units whose outputs are $\{x^s, s=1,2,\bullet\bullet\bullet m\}$ with linear costs as shown in Figure 3.4. It is clear, from the equation (3.5), that this incremental fuel cost model can take into account the random failures and repairs of the generator by introducing the simple function χ_{po}. Furthermore, it should be noted that each segment may be considered as an independent unit, but any segment of generation for a generator can be loaded only after all the preceeding segments have been loaded to their full capacities. This is a consequence of the convexity assumption on f(p) which implies:

$$\lambda^1 < \lambda^2 < \bullet\bullet\bullet < \lambda^m . \qquad (3.8)$$

3.4 EFFECT OF TRANSMISSION LOSSES

Another problem encountered by a system operator for the interconnected power system is to determine whether it is economical to export power to (or import from) other areas. Whenever power is imported into an area, the power to be produced to carry the area load is reduced by the amount received from the other area. Conversely, whenever power is exported, the power production must equal the area load plus the amount of the export. In case of power exchange between areas, if transmission losses are unavoidable, their effects should be included in the evaluation of incremental fuel cost to compensate for the energy lost in transmission and to arrive at a true economic loading of the entire system.

Thus in this section the effect of transmission losses on the incremental fuel cost of the area exporting power is considered. Let us consider power transfer from the area i to the area j as shown in Figure 3.6.

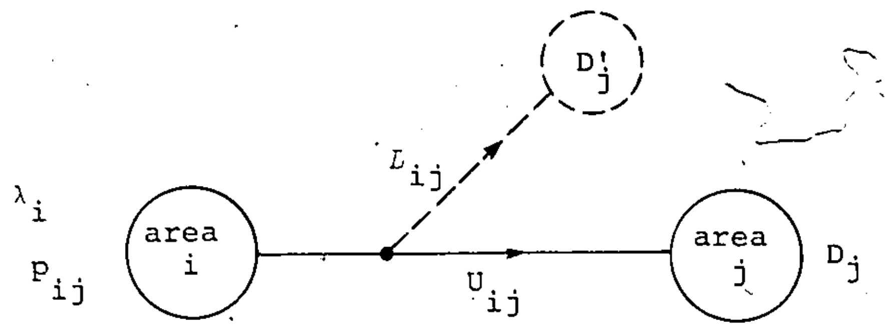


Figure 3.6. Power transfer from area i to area j.

In Figure 3.6,

λ_i = Incremental fuel cost at the level of power generation p_{ij} in the area i,

U_{ij} = Delivered power to the area j.

L_{ij} = The transmission loss for the power transfer U_{ij}. This can be computed by a formula for thermal loss (see Appendix A).

D'_j = Artificial demand to represent the loss L_{ij}.

In order for the area i to supply U_{ij} to area j, the required generation in the area i is

$$p_{ij} = U_{ij} + L_{ij}. \tag{3.9}$$

The corresponding generation cost in the area i is then $\lambda_i p_{ij}$, but the actual amount of power transferred to the area j is only U_{ij}. Thus the effective incremental cost at the receiving area corresponding to U_{ij} must be compensated in the following way.

$$\lambda_i \, p_{ij} = \lambda_i' U_{ij} \tag{3.10}$$

In other words, to export power U_{ij} to the area j at the new incremental cost λ_i' can be considered equivalent to generate p_{ij} at the cost λ_i. The factor λ_i' may be expressed in terms of the original incremental cost λ_i. Substituting equation (3.9) into equation (3.10) gives

$$\lambda_i' = \frac{p_{ij}}{p_{ij} - L_{ij}} \lambda_i$$

$$= \left(\frac{1}{1 - (L_{ij}/ p_{ij})} \right) \lambda_i \tag{3.11a}$$

$$= K_{ij} \lambda_i \tag{3.11b}$$

where

$$K_{ij} \triangleq \frac{1}{1 - (L_{ij}/ p_{ij})} . \tag{3.12a}$$

Substituting equation (3.9) into equation (3.12a) and using equation(A.4), we obtain

$$K_{ij} = p_{ij} \;/\; U_{ij} = (a_{ij} U_{ij}^2 + U_{ij}) \;/\; U_{ij} =$$

$$= a_{ij}U_{ij} + 1 \tag{3.12b}$$

The coefficient K_{ij} can be interpreted as the "penalty factor" for the transmission loss L_{ij} corresponding to the power transaction U_{ij}. Therefore the effect of transmission loss can be considered by the penalty factor in the economic scheduling of power systems. This will be discussed in the next section.

3.5 OBJECTIVE FUNCTION

Factors involved in the cost of producing electric energy can be divided into those that are for meeting local demands or loads and those for export of power to other areas. Within an area, the economic allocation of the generation for minimum fuel cost among several available units can be determined by the rule of merit order loading, on the basis of the incremental fuel cost function developed in the previous section. However, if the power exchange between areas is necessary for fuel economy or high system availability, the incremental fuel cost of the area exporting the energy should be compensated for the energy lost in transmission. In this section the objective function, which represents the generation cost to be minimized, is formulated in terms of incremental fuel cost and the penalty factor associated with transmission losses.

3.5.1 Production cost for an area

Consider a power pool consisting of N areas. Let n_i denote the number of generators in the area i, i=1,2,•••,N. Let

$m(k,i)$ = Maximum number of segments of the capacity of generator k in area i with the installed capacity denoted by $p_{k,i}^{m(k,i)}$.

$\lambda_{k,i}^{s}$ = Incremental fuel cost of the segment s of the generator k in the area i.

$X_{k,i}^{s}$ = Generation allocation of the segment s of the generator k in area i to meet local demand.

U_{ij} = The power delivered to area j from area i given by

$$U_{ij} = \sum_{k=1}^{n_i} \cdot \sum_{s=1}^{m(k,i)} U_{k,ij}^{s} \tag{3.13}$$

where $U_{k,ij}^{s}$ represents the same object corresponding to power segment s of the generator k in area i.

$P_{k,i}$ = Power output of the generator k in area i.

$$= P_{k,i}^{O} + \sum_{s=1}^{m(k,i)} X_{k,i}^{s} + \sum_{\substack{j=1 \\ j\neq i}}^{N} K_{ij} \left(\sum_{s=1}^{m(k,i)} U_{k,ij}^{s} \right) \tag{3.14}$$

$P_{k,i}^{O}$ = Minimum power output of the generator k in area i.

For a given area i, the hourly fuel cost function may be written as

$$\underbrace{f_i(\overline{P}_i)}_{\substack{\text{total cost} \\ \text{in area i}}} = \underbrace{f_i^{O}(\overline{P}_i^{O})}_{\substack{\text{fixed} \\ \text{cost}}} + \underbrace{f_i^{l}(\overline{X}_i)}_{\substack{\text{cost for} \\ \text{local demand}}} + \underbrace{\sum_{j\neq i}^{N} f_i^{e}(\overline{U}_{ij})}_{\substack{\text{cost for} \\ \text{power export}}} \tag{3.15}$$

where $$f_i^o(\overline{P}_i^o) = \sum_{k=1}^{n_i} f_{k,i}^o(P_{k,i}^o) \tag{3.16a}$$

$$f_i^l(\overline{X}_i) = \sum_{k=1}^{n_i} \sum_{s=1}^{m(k,i)} \lambda_{k,i}^s X_{k,i}^s \tag{3.16b}$$

$$f_i^e(\overline{U}_{ij}) = K_{ij}\left(\sum_{k=1}^{n_i} \sum_{s=1}^{m(k,i)} \lambda_{k,i}^s U_{k,ij}^s\right) \tag{3.16c}$$

with the variables defined as

$$\overline{X}_i \triangleq \{X_{k,i}^s;\ s=1,2,\bullet\bullet\bullet,m(k,i);\ k=1,2,\bullet\bullet\bullet,n_i\} \tag{3.17a}$$

$$\overline{U}_{ij} \triangleq \{U_{k,ij}^s;\ s=1,2,\bullet\bullet\bullet,m(k,i);\ k=1,2,\bullet\bullet\bullet,n_i\} \tag{3.17b}$$

$$\overline{P}_i \triangleq \{P_{k,i};\ k=1,2,\bullet\bullet\bullet,n_i\} \tag{3.17c}$$

$$\overline{P}_i^o \triangleq \{P_{k,i}^o;\ k=1,2,\bullet\bullet\bullet,n_i\} \tag{3.17d}$$

3.5.2 Production cost for a power pool

The hourly fuel cost function of the power pool is given by the sum of the corresponding cost functions of individual areas :

$$F(\overline{P}) = \sum_{i=1}^{N} f_i(\overline{P}_i) \tag{3.18}$$

where $\overline{P} = \{\ \overline{P}_i\ ;\ i=1,2,\bullet\bullet\bullet,N\ \}$

$F(\overline{P})$ = Hourly fuel cost function of the entire power pool at the generation level $\overline{P}$.

Using this hourly cost function, the objective function can be formulated in terms of the incremental fuel cost, the penalty factor and power output of generators. This will be described in the following subsection.

3.5.3 Objective function

Suppose that the generation level of a generator remains constant during each interval $(t_{\ell-1},t_\ell]$ of optimization. Since F of equation (3.18) is the hourly fuel cost function or fuel cost rate, the fuel cost over the time interval $(t_{\ell-1},t_\ell]$ is then given by multiplying $F(\overline{P})$ by $(t_\ell - t_{\ell-1})$. That is,

$$J(t_{\ell-1},t_\ell) = F(\overline{P})\bullet(t_\ell - t_{\ell-1}) \tag{3.19}$$

Substituting equations (3.15) & (3.18) into equation (3.19),

$$J(t_{\ell-1},t_\ell) = (t_\ell - t_{\ell-1})\bullet \sum_{i=1}^{N}\left(f_i^o(\overline{P}_i^o) + f_i^l(\overline{X}_i) + \sum_{\substack{j=1\\ j\neq i}}^{N} f_i^c(\overline{U}_{ij})\right) \tag{3.20}$$

Substituting equation (3.16) into equation (3.20) gives

$$J(t_{\ell-1},t_\ell) = (t_\ell - t_{\ell-1}) \sum_{i=1}^{N}\sum_{k=1}^{n_i} f_{k,i}^o(P_{k,i}^o) \tag{3.21a}$$

$$+ (t_\ell - t_{\ell-1}) \sum_{i=1}^{N}\sum_{k=1}^{n_i}\sum_{s=1}^{m(k,i)} \lambda_{k,i}^s X_{k,i}^s \tag{3.21b}$$

$$+ (t_\ell - t_{\ell-1}) \sum_{i=1}^{N}\sum_{\substack{j=1\\ j\neq i}}^{N} K_{ij} \sum_{k=1}^{n_i}\sum_{s=1}^{m(k,i)} \lambda_{k,i}^s U_{k,ij}^s \tag{3.21c}$$

Note that the expression (3.21a) does not depend on the power output X or U. However, since our objective is to minimize $J(t_{\ell-1},t_\ell)$ with respect to $\{\overline{X}_i\}$ and $\{\overline{U}_{ij}\}$, $i=1,2,\bullet\bullet\bullet,N$, the first term (3.21a) will be disregarded in the optimization. Therefore, the objective function to be minimized is as follows:

$$\tilde{J}(t_{\ell-1},t_\ell) = (t_\ell - t_{\ell-1})\bullet \sum_{i=1}^{N}\sum_{k=1}^{n_i}\sum_{s=1}^{m(k,i)} \lambda_{k,i}^s X_{k,i}^s \tag{3.22a}$$

$$+ (t_\ell - t_{\ell-1})\bullet \sum_{i=1}^{N}\sum_{\substack{j=1\\ j\neq i}}^{N} K_{ij} \sum_{k=1}^{n_i}\sum_{s=1}^{m(k,i)} \lambda_{k,i}^s U_{k,ij}^s \tag{3.22b}$$

From the convexity assumption, it should be noted that any segment $x^{s}_{k,i}$ of a generator k in the area i can be allocated only after all the preceeding segements (i.e., from $x^{1}_{k,i}$ to $x^{s-1}_{k,i}$) of the generator have been allocated to their full capacities in the optimization of $\tilde{J}$ of equation (3.22) as described in section 3.3. This implies that the variables $X^{s}_{k,i}$ and $U^{s}_{k,ij}$ should be governed by the same loading principle as for $x^{s}_{k,i}$ corresponding to the generator k in area i.

Let us define that

$$P_i \triangleq \sum_{k=1}^{n_i} P_{k,i} \tag{3.23}$$

$$P \triangleq \sum_{i=1}^{N} P_i \tag{3.24}$$

Then P_i denotes the total power output of the area i and P total power output of the power pool (entire system).

3.6 CONSTRAINTS

The constraints that should be satisfied in minimizing the objective function

$$\tilde{J} = \sum_{\ell=1}^{n_T} J(t_{\ell-1}, t_\ell) \tag{3.25}$$

are considered in the following subsections.

3.6.1 Available capacity limits of generators

It should be noted that the segmented capacities $\{x^s_{k,i}\}$ are limited according to equation (3.6) and they are given by

$$0 \le x^s_{k,i} \le p^s_{k,i} - p^{s-1}_{k,i} \tag{3.26}$$
$$s=1,2,\bullet\bullet\bullet,m(k,i);\ k=1,2,\bullet\bullet\bullet,n_i;\ i=1,2,\bullet\bullet\bullet,N.$$

This implies, from the equations (3.14) and (3.23), that $P_{k,i}$ and P_i cannot exceed corresponding available generation capacities $C_{k,i}$ and C_i respectively. That is,

$$P_{k,i} \le C_{k,i}, \qquad P_i \le C_i \tag{3.27}$$
$$k=1,2,\bullet\bullet\bullet,n_i;\ i=1,2,\bullet\bullet\bullet,N.$$

Where $C_{k,i}$ and C_i denote the available generation capacity of generator k in the area i and that of the area i as defined in equations (2.6) and (2.7).

3.6.2 Total generation requirement

If we include the transmission losses in the generation allocation, the total required generation P is given by

$$P = L + \sum_{i=1}^{N} \sum_{\substack{j=1 \\ j \ne i}}^{N} \mathcal{L}_{ij} \tag{3.28}$$

where L denotes the total load actually taken by the customers in the power pool.

However, the system load L can be different from the total system demand D due to the following reasons.

i) The total available generation capacity is less than the total system demand.

ii) Although the total capacity reserve is enough to meet the system demand, sometimes the available tie line capacities are not enough to transfer the required power in order to meet the loss of demand in the areas having negative reserves.

Hence the load is limited by the constraint

$$L \leq \text{minimum } \{D, C\} \tag{3.29}$$

where
$$D = \sum_{i=1}^{N} D_i , \tag{3.30}$$

$$C = \sum_{i=1}^{N} C_i , \tag{3.31}$$

and D_i denotes the total demand of the area i and C_i the total available generation capacity of area i at time t.

3.6.3 Limit on power flow through tie lines

Since tie lines have their own capacity limits, the amount of power that can be transferred through them is also limited. Let us consider the power U_{ij} delivered from the area i to area j through the tie line τ_{ij} having capacity ν_{ij}. Then, it is limited by

$$|U_{ij}| \leq \nu_{ij} , \qquad i \neq j = 1, 2, \cdots, N, \tag{3.32}$$

where ν_{ij} denotes the capacity of the tie line τ_{ij}.

3.7 SYSTEM AVAILABILITY AND POWER EXCHANGE MATRIX

Let R_i denote the operating (i.e., immediately dispatchable) reserve of area i, which is defined by

$$R_i = P_i - D_i, \qquad i=1,2,\bullet\bullet\bullet,N. \tag{3.33}$$

If $R_i>0$, the area i exports power to the other areas of the power system and if $R_i<0$, it can import power (from other areas) provided the corresponding tie lines are available. Thus, with the help of the tie lines, the operating reserve can be distributed over the power pool as desired. Hence after the distribution, the resulting operating reserve $\tilde{R}_i$ has the form

$$\tilde{R}_i = R_i + \sum_{\substack{j=1 \\ j\neq i}}^{N} \tau_{ji}\,(\beta_{ji}R_j - L_{ji}\,1^{+}(\beta_{ji}\neq 0, R_i>0)) \tag{3.34}$$

$$i=1,2,\bullet\bullet\bullet,N,$$

where $\beta=\{\beta_{ji}\}$ is defined as the power exchange (or transfer) matrix. Note that the upper limits of β_{ji}'s must be reduced to a fraction which is determined by the capacity of tie line and the operating reserves. These are discussed below:

(i) If there is no exchange of power between the areas i and j, then $\beta_{ij} = \beta_{ji} = 0$.

(ii) Since maximum power transfer from one area to another can not exceed the operating reserve,

$$0 \le \beta_{ji} \le 1 \quad \text{for all } i \ne j = 1,2,\bullet\bullet\bullet,N. \tag{3.35}$$

(iii) Since any area (say i) can at most export all its operating reserve to the rest of the system,

$$\sum_{\substack{j \ne i \\ j=1}}^{N} \beta_{ij} \le 1. \tag{3.36}$$

Remark 3.1. Since power export and import between two areas must be equal, it is necessary that

$$\beta_{ij} Q_i = -\beta_{ji} Q_j, \qquad j \ne i = 1,2,\bullet\bullet\bullet,N. \tag{3.37}$$

Thus the matrix β is not symmetric.

Remark 3.2. In order to include the capacity limits of tie lines, the upper values of β_{ji}'s must be reduced to a fraction. This is mainly determined by the capacity of the tie line and the operating reserves. For example, if the capacity of the tie line τ_{ij} is ν_{ij} and the operating reserves are R_j and R_i (allowing both positive and negative values) respectively, then the upper limits are given by

$$\max.\beta_{ij} = \text{minimum}\{1, |R_j|/|R_i|, \nu_{ij}/|R_i|\}, \tag{3.38a}$$

$$\max.\beta_{ji} = \text{minimum}\{1, |R_i|/|R_j|, \nu_{ji}/|R_j|\}, \tag{3.38b}$$

This can be summarized as

$$0 \le \beta_{ji} \le \text{minimum}\ \{1, |R_i|/|R_j|, \nu_{ji}/|R_j|\} \tag{3.39}$$

$j \ne i = 1,2,\bullet\bullet\bullet,N,$

at all times. The value of β_{ji} at any time indicates the fraction of operating reserve delivered from the area j to the area i.

One of the ideal goals of the interconnection is to achieve a high degree of reliability or availability of the system towards meeting the power demand of all its customers in the power pool. Clearly this objective is met if

$$\tilde{R}_i \geq 0, \qquad i=1,2,\bullet\bullet\bullet,N, \tag{3.40}$$

for all time. This, however, is impossible since the demands, the available generation capacities and the availability of tie lines are all random and hence the inequalities (3.40) may not always hold. Instead, the following relation holds for sufficiently large ε_i's.

$$\left.\begin{array}{l} \tilde{R}_i \geq -\varepsilon_i, \qquad \varepsilon_i \geq 0, \qquad i=1,2,\bullet\bullet\bullet,N \\ 0 \leq \beta_{ji} \leq \text{minimum}\{1,|R_i|/|R_j|,\nu_{ji}/|R_j|\} \\ j\neq i=1,2,\bullet\bullet\bullet,N. \end{array}\right\} \tag{3.41}$$

It is clear that in order to improve the system availability, the inequalities (3.41) should be satisfied with the smallest possible ε_i's. Thus after the distribution (or dispatch), the (potential) reserve margin, say Q_i, of the area i is given by

$$Q_i = (C_i-D_i) + \sum_{\substack{j=1\\ j\neq i}}^{N} \tau_{ji}(\beta_{ji}R_j-L_{ji}1(\beta_{ji}\neq 0,R_i>0)) \tag{3.42}$$
$$i=1,2,\bullet\bullet\bullet,N.$$

3.8 THE OPTIMIZATION PROBLEM

From the previous development, the economic dispatch problem can be described as:

For given cost functions (equations 3.15-3.17) and

and system data $\{C_i, D_i, \tau_{ij};\ i \neq j=1,2,\bullet\bullet\bullet,N\}$

for the time period $(t_{\ell-1}, t_\ell]$,

find (1) the optimal generation allocations

$\{X^{s\ *}_{k,i}, U^{s\ *}_{k,ij};\ s=1,2,\bullet\bullet\bullet,m(k,i)\}$ or $\{P_{k,i}{}^*\}$,

$k=1,2,\bullet\bullet\bullet,n_i;\ i\neq j=1,2,\bullet\bullet\bullet,N$

(2) and the power exchange matrix

$\{\beta_{ji}\},\quad i\neq j=1,2,\bullet\bullet\bullet,N$

for the same period $(t_{\ell-1}, t_\ell]$

such that the generation cost (equation 3.22) is minimum,

subject to the constraints

$$P_{k,i} \leq C_{k,i}, \qquad P_i \leq C_i \tag{3.27'}$$

$$L \leq \text{minimum}\ \{D, C\} \tag{3.29'}$$

$$|U_{ij}| \leq \nu_{ij} \tag{3.32'}$$

$$k=1,2,\bullet\bullet\bullet,n_i;\quad j\neq i=1,2,\bullet\bullet\bullet,N$$

and the inequalities (3.41):

$$\left\{\begin{array}{l} \tilde{R}_i \geq -\varepsilon_i, \qquad \varepsilon_i \geq 0 \qquad\qquad (3.41)' \\ 0 \leq \beta_{ji} \leq \text{minimum}\{1, |R_i|/|R_j|, \nu_{ji}/|R_j|\} \\ j\neq i=1,2,\bullet\bullet\bullet,N \\ \text{with the smallest possible } \varepsilon_i\text{'s.} \end{array}\right.$$

3.9 SUMMARY

In this chapter, the economic dispatch problem under the system availability constraint was formulated as a dynamic minimization problem. The objective function of the problem was derived as a function of the incremental fuel cost and output of the generators, by introducing the piece-wise constant incremental cost model. This incremental cost model results in a very simple and efficient minimization method which is called "merit- order loading"[8]. The solution to this problem, based on the rule of "merit- order loading", is presented in the next chapter.

Chapter IV

OPTIMIZATION ALGORITHM

4.1 INTRODUCTION

In chapter III, the economic dispatch problem was formulated as mathematical optimization problem. The problem can be solved by the algorithms based on modern mathematical optimization techniques such as nonlinear, quadratic, linear and dynamic programming and their many combinations and extensions [23-26]. However, slow convergence and long computation time have been the principal drawbacks of the algorithms when applied to large scale systems especially with nonlinear constraints. In order to overcome these limitations, considerable efforts have been made [1,2,27-29]. The large number of recent papers available is a measure of the necessity for an efficient algorithm in the field of economic dispatch.

The classical loss coefficient models[20,30] are simple but involve many assumptions. Optimal load flow methods[31,32] promise accurate dispatch solution but these methods are sensitive to load flow mismatches and many have convergence problems. Unfortunately these methods are inapplicable to the problem being considered here because of the system availability constraint as well as the other random environments. Thus it is essential to have a plausible method for the problem. In this chapter such an algorithm is developed on the basis of the rule of merit-order loading. Before describing the algorithm, the prediction of the system data, such as available generation capacities, area demands and the availability of tie lines, will be briefly discussed. Using these data the algorithm is then developed. For the sake of convenience for computer implementation, it is described in the form of a flow diagram.

4.2 PREDICTION OF THE DATA

For presentation of the prediction of the system data $\{D_i(t),\ C_i(t),\ \tau_{ij}(t);\ i\neq j=1,2,\bullet\bullet\bullet,N\}$, certain standard concepts and notations from probability theory [33] are required.

Let

(Ω, F, P) = The probability space,

where Ω = A sample space,

F = Sigma-algebra of events,

P = Probability measure on F.

All random variables and processes discussed in the sequel are assumed to be based on the probability space without mention. For any F measurable and integrable random variable X, its expectation $\int XdP$ is denoted by $E\{X\}$, and its conditional expectation for any sub-sigma-algebra $A\subset F$ and the X is denoted by $E\{X|A\}$.

Ideally our aim is to find the optimal generation and dispatch policy, i.e. $\{X^{s*}_{k,i}\}$, $\{U^{s*}_{k,ij}\}$ and $\{\beta_{ij}\}$; $s=1,2,\bullet\bullet\bullet\bullet,m(k,i)$; $k=1,2,\bullet\bullet\bullet,n_i$; $i\neq j=1,2,\bullet\bullet\bullet,N$ for each time interval $(t_{\ell-1},t_\ell]$, $\ell=1,2,\bullet\bullet\bullet,n_T$. However, the policy decision and the execution of dispatch of power according to the policy at the same time is practically impossible. In practice it requires a finite time to determine the dispatch policy and then execute it. Let this finite delay period be denoted by Δ. Thus if the decision is taken at time $(t_{\ell-1}-\Delta)$ and execution of the required dispatch takes place at a later time $t_{\ell-1}$ as shown in Figure 4.1, then the dispatch policy for the time period $(t_{\ell-1},t_\ell]$ must be estimated on the basis of the history of the system up to time $t_{\ell-1}-\Delta$.

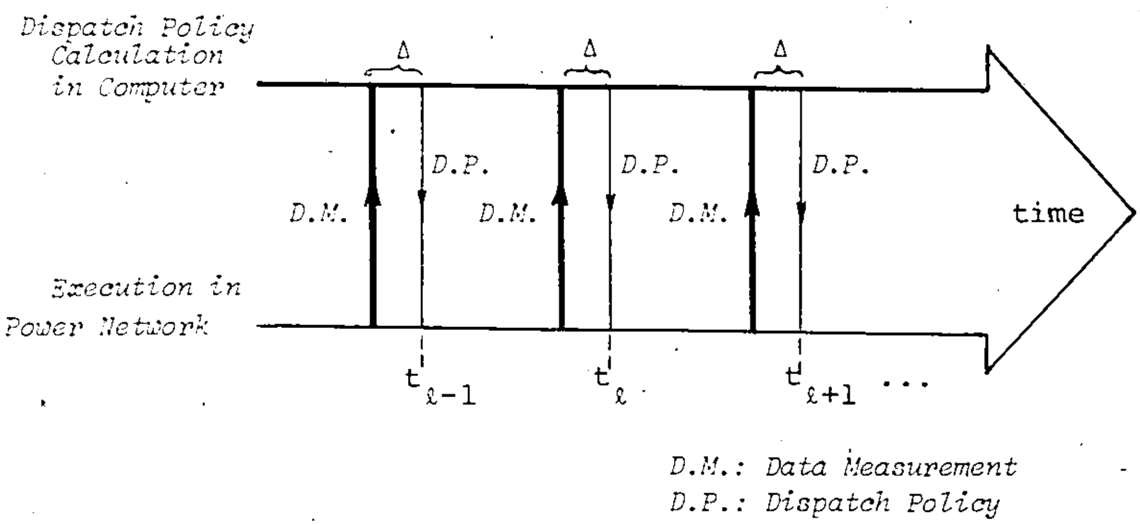


Figure 4.1. Signal flow between computer and power network.

This requires short term prediction of the system data like $\{D_i, C_i, \tau_{ij} ; \ i \neq j=1,2,\bullet\bullet\bullet,N\}$ for the period $(t_{\ell-1}, t_\ell]$ on or before the time $t_{\ell-1}$. The best estimate for these data, given the history up to the time $t_{\ell-1}-\Delta$, is determined by their conditional expectations as given in reference [6,7]. Therefore, instead of requiring that the objective function $\tilde{J}(t_{\ell-1}, t_\ell)$ be minimized on the basis of the data measured at time $(t_{\ell-1}-\Delta)$, it is preferable to do it on the basis of the estimated (predicted) data. For simplicity let the conditional expectations be denoted by the symbol $(\hat{\bullet})$, for example $\hat{D}$ for D. Then the problem can be described in terms of the predicted data (or conditional expectations) as follows.

Find the optimal generation allocations and power exchange matrix:

$\{X^{s\,*}_{k,i}\}, \{U^{s\,*}_{k,ij}\}$ and $\{\beta_{ij}\}$; $s=1,2,\bullet\bullet\bullet,m(k,i)$; $k=1,2,\bullet\bullet\bullet,n_i$; $j \neq i=1, 2,\bullet\bullet\bullet,N$, such that the generation cost (equation 3.22) is minimum, subject to the constraints

$$P_{k,i} \le \hat{C}_{k,i}, \quad P_i \le \hat{C}_i \tag{4.1}$$

$$L \le \text{minimum} \{ \hat{D}, \hat{C} \} \tag{4.2}$$

$$|U_{ij}| \le \nu_{ij} \tag{4.3}$$

and the inequalities

$$\left.\begin{array}{l} E\{\tilde{R}_i | F^z_{t-\Delta}\} \ge -\varepsilon_i, \qquad \varepsilon_i \ge 0 \\ 0 \le \beta_{ji} \le \text{minimum} \{ 1, |\hat{R}_i|/|\hat{R}_j|, \nu_{ji} / |\hat{R}_j| \} \\ \text{with smallest possible } \varepsilon_i\text{'s,} \end{array}\right\} \tag{4.4}$$

where,

$$\hat{C}_i = E\{C_i(t) \mid F^z_{t-\Delta}\} = \sum_{k=1}^{n_i} c_{k,i} E\{r_{ki}(t) \mid F^z_{t-\Delta}\} \tag{4.5}$$

$$\hat{D}_i = E\{D_i(t) \mid F^z_{t-\Delta}\} = D_i(t-\Delta) + g_i(t-\Delta, D_i(t-\Delta)) \bullet \Delta \tag{4.6}$$

$$\hat{\tau}_{ij} = E\{\tau_{ij}(t) \mid F^z_{t-\Delta}\} = 1^{\bullet}(\tau_{ij}(t-\Delta)=0) \bullet \delta_{ij}\Delta + 1^{\bullet}(\tau_{ij}(t-\Delta)=1) \bullet (1-\zeta_{ij}\Delta) \tag{4.7}$$

$$E\{r_{ki}(t) \mid F^z_{t-\Delta}\} = 1^{\bullet}(r_{ki}(t-\Delta)=0) \bullet \mu_{ki}\Delta + 1^{\bullet}(r_{ki}(t-\Delta)=1) \bullet (1-\xi_{ki}\Delta) \tag{4.8}$$

$$E\{\tilde{R}_i(t) \mid F^z_{t-\Delta}\} = E\{R_i(t) \mid F^z_{t-\Delta}\} + \sum_{j=1,\neq i}^{N} \hat{\tau}_{ji}(t)(\beta_{ji}(t)\hat{R}_j(t) - L_{ji} 1^{\bullet}(\beta_{ji}(t) \neq 0, \hat{R}_i(t) > 0)) \tag{4.9}$$

with following definitions

$z(t)$ = The state of the power pool at time t .

$\triangleq \{\tau_{ij}(t), D_i(t), r_{ki}(t);\ k=1,2,\bullet\bullet\bullet,n_i;\ i\neq j=1,2,\bullet\bullet\bullet,N\}$

= Sigma$\{z(\theta); \theta \leq t\}$: sigma-algebra generated by the process z associated with the probability space(Ω, F, P)

$F^z_{t-\Delta}$ = history of the process z up to time $t-\Delta$.

= Increasing family of completed sub-sigma algebras of the sigma algebra F measured on the probability space.

The solution to this problem is presented in the next section. For convenience of users it will be given in the form of an algorithm.

4.3 THE ALGORITHM

In this section, an efficient algorithm is developed on the basis of the heuristic principle of merit-order loading and using the data $\{\hat{D}_i, \hat{C}_i, \hat{\tau}_{ij};\ i\neq j=1,2,\bullet\bullet\bullet,N\}$ discussed in section 4.2. The algorithm can be easily implemented on a dispatch computer.

4.3.1 On the Merit-Order Loading

The simple optimization rule of equal incremental cost (Appendix B) will work only if all incremental cost curves are continuous and monotonically increasing and if the available power is not constrained [19]. For example, if the incremental cost functions are of staircase-type, clearly the equal incremental cost loading cannot be used for the optimal solution. Instead, the power demand must be allocated by the principle of merit-order loading, whereby the segments are loaded up in the order of their increasing incremental fuel costs, that is, the segment with smallest incremental cost must be loaded first up to its upper limit before the next efficient unit is loaded, untill the total load is met.

4.3.2 Flow chart of the algorithm

Figure 4.2 presents the flow chart of the algorithm. It is divided into five steps. After setting the time index to 1, in STEP 1, the fuel cost data are given from the power network. From these data the generation cost function equation (3.22) is formulated as given in section 3.5. In STEP 2, the system data $\{D_i, C_i, \tau_{ij}; i\neq j=1,2,\bullet\bullet\bullet,N\}$ are given at time $(t_{\ell-1}-\Delta)$ from the power network. In STEP 3, the conditional expectations $\{\hat{D}_i, \hat{C}_i, \hat{\tau}_{ij}; i\neq j=1,2,\bullet\bullet\bullet N\}$ for the time interval $(t_{\ell-1}, t_\ell]$ are computed based on the past information $\{D_i(t_{\ell-1}-\Delta), C_i(t_{\ell-1}-\Delta), \tau_{ij}(t_{\ell-1}-\Delta); i\neq j=1,2, \bullet\bullet\bullet N\}$ by the equations 4.5-4.7.

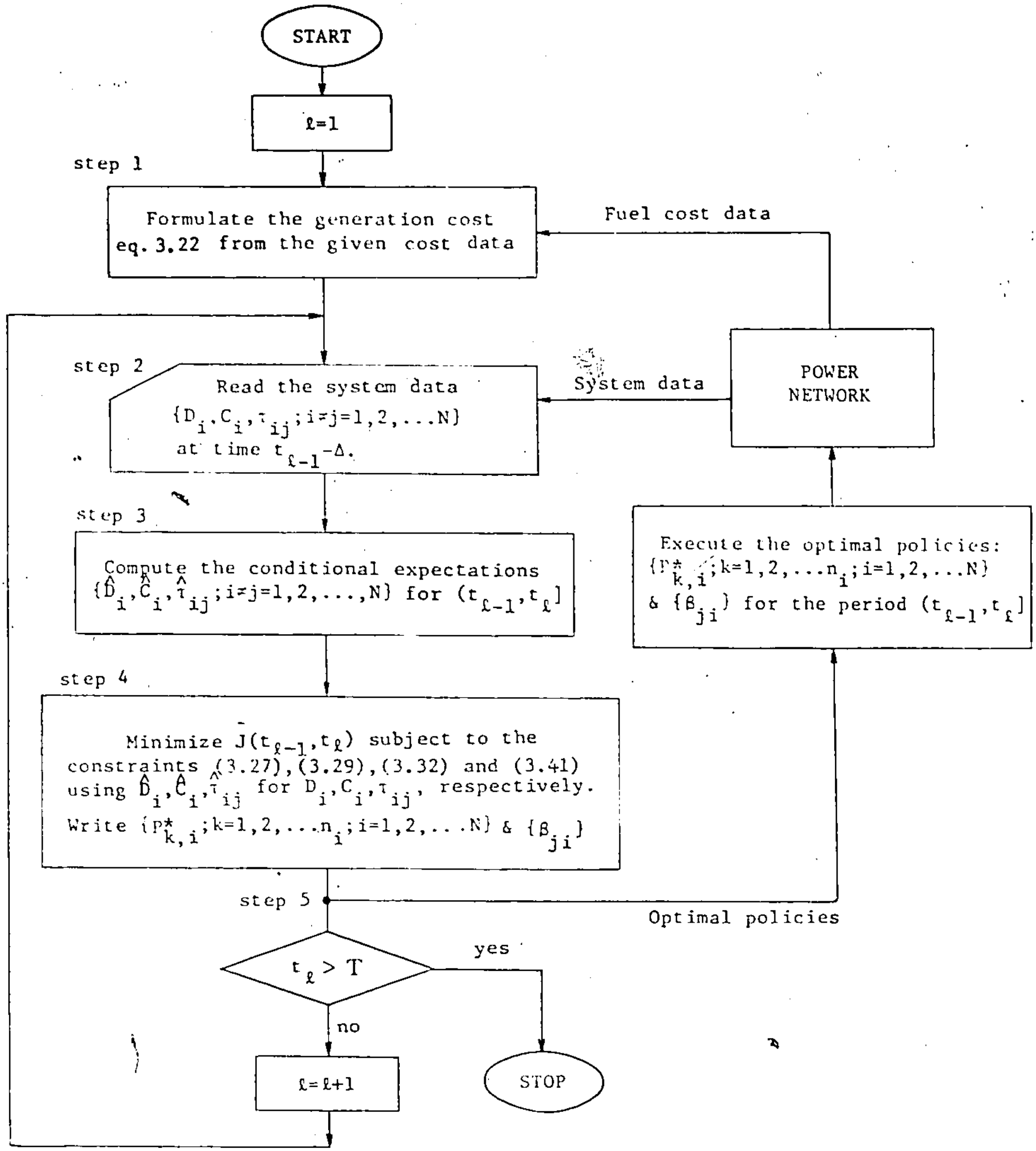


Figure 4.2. Flow chart of the algorithm.

Now at this point all necessary data for optimization are available and so, in STEP 4, the generation cost $\tilde{J}(t_{\ell-1}, t_\ell)$ is minimized on the basis of the predicted data $\{\hat{D}_i, \hat{C}_i, \hat{\tau}_{ij};\ i \neq j = 1,2,\cdots N\}$. This step can be described by the following sub-steps:

STEP 4.1: Find the loading order of $\{x^s_{k,i};\ s=1,2,\cdots,m(k,i);\ k=1,2,\cdots,n_i;\ i=1,2,\cdots,N\}$ by their corresponding incremental costs $\{\lambda^s_{k,i};\ s=1,2,\cdots,m(k,i);\ k=1,2,\cdots,n_i; i=1,2,\cdots,N\}$. Let the ordered $\{x^s_{k,i}\}$ be denoted by $\{x^s_{k,i}(e);\ e=1,2,\cdots,E\}$, $E = \sum_{i=1}^{N} \sum_{k=1}^{n_i} m(k,i)$.

STEP 4.2: Allocate the ordered segments $\{x^s_{k,i}(e);\ e=1,2,\cdots,E\}$ in the order of increasing e subject to the constraints (3.26), (3.27), (3.29), (3.32) and (3.41) with the smallest possible ε_i's. More details of this procedure is depicted in Figure 4.3. As a result, we have the optimal generation $\{X^{s*}_{k,i}, U^{s*}_{k,ij};\ s=1,2,\cdots,m(k,i);\ k=1,2,\cdots,n_i;\ i=1,2,\cdots,N\}$ and the exchange matrix $\{\beta_{ji};\ j \neq i = 1,2,\cdots,N\}$ for the time interval $(t_{\ell-1}, t_\ell]$.

STEP 4.3: Compute $P^*_{k,i}$ using $X^{s*}_{k,i}$ and $U^{s*}_{k,ij}$ for $X^s_{k,i}$ and $U^s_{k,ij}$ in equation (3.14) for the generators $k=1,2,\cdots,n_i$ in the area i; and P^*_i using $P^*_{k,i}$ in equation (3.23) for $i=1,2,\cdots,N$.

STEP 4.4: Compute the reserve margins $\{Q_i,\ i=1,2,\cdots,N\}$ by equation (3.42) at time $t_{\ell-1}$.

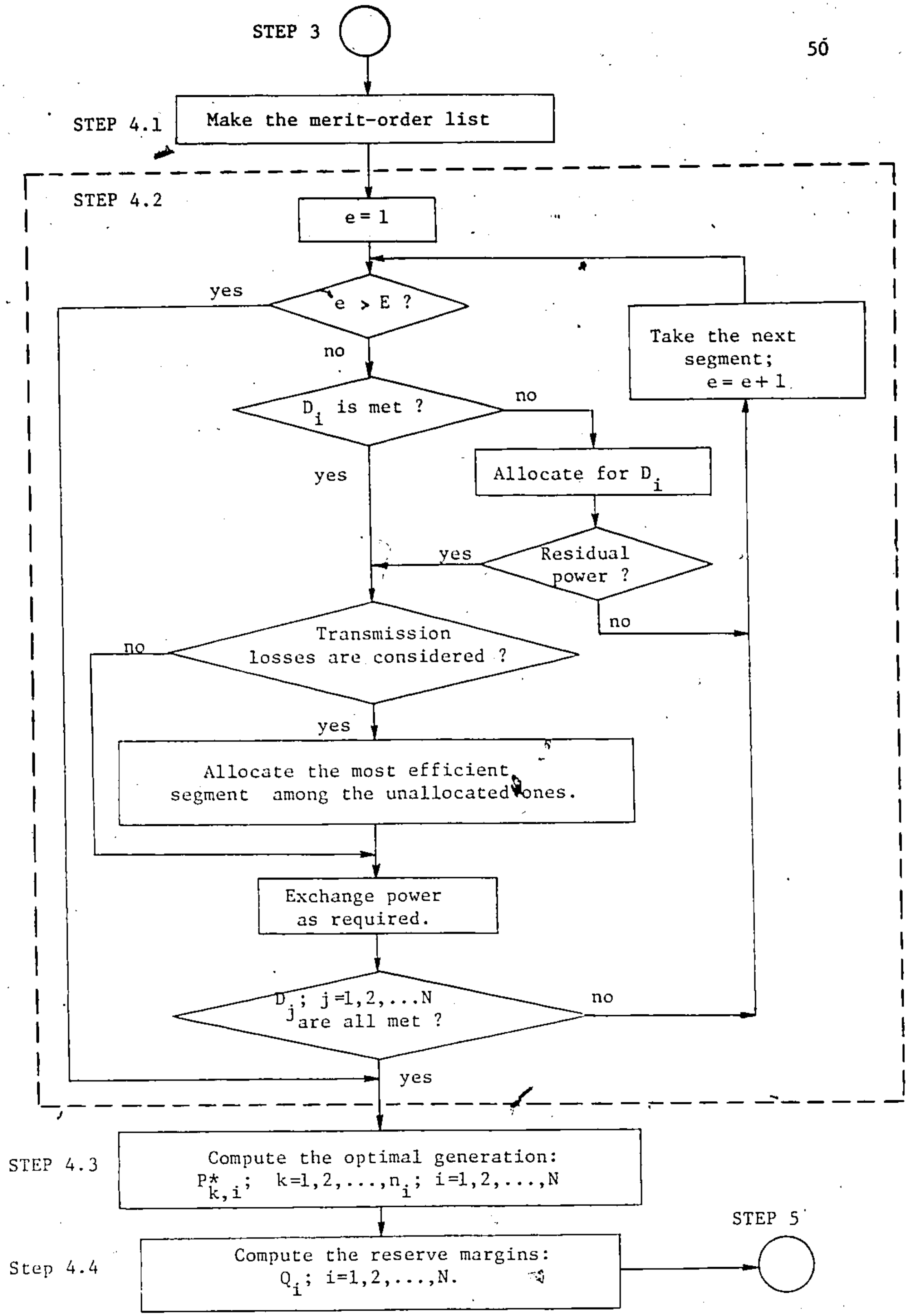


Figure 4.3. The flow chart of STEP 4.

Finally, the step 5 is to execute the optimal generation and dispatch policy determined in step 4 and at the same time to increase the time index ℓ by 1 for the next time interval. Then the steps 2 to 5 are repeated until the specified time T.

4.3.3 On the practical application of the algorithm

In this subsection, the problem associated with application of the algorithm to practical systems shall be addressed. In practice, being able to compute the optimum generation allocation policy of real power is only half of the problem of the optimum operation; the other half consists of implementing it in real time. This aspect of optimum control belongs to the topic of automatic generation control(AGC). The generator controls are divided into automatic load-frequency control(ALFC) and automatic voltage regulator(AVR).

Under normal operation the controllers keep the generator operating about a prescribed "nominal" state with minimal excursions. Thus in the normal state the frequency and bus voltages should be kept at the prescribed values. This frequency and voltage constancy results from a carefully maintained balance between power demand by the loads and those supplied by the power sources. It is a well known fact that the frequency is closely related to the real power generation, whereas the voltage level of a bus is strongly related to the reactive power injection at the bus (i.e., added reactive power translates into a rise in voltage). The reactive power generation has negligibly small influence on the generation cost because it is controlled by varying the field current. However, the generated real power accounts for the major influence on the generation cost since individual real power generation is raised by increasing the prime mover torques and this requires an increased expenditure of fuel.

Therefore, as the system load changes with time, it becomes necessary to adjust the generation in real time so that the power imbalance is continuously zeroed or at least minimized. This requirement can be effectively satisfied by the optimum control policy of real power generation computed at high speed by the algorithm which has fast demand tracking capability as demonstrated in reference [8]. Moreover, it should be noted that the algorithm does not require large computing resources (see section 5.6). This is another advantage of the algorithm in practical applications.

4.4 SUMMARY

In this chapter, the estimation of the system data like available generation capacities, area demands and the availability of tie lines was discussed. The estimation was carried out by taking the conditional expectations in the probability space as given in section 4.2. On the basis of the predicted data, an algorithm was developed in order to minimize the production cost under the constraints. The principle of merit-order loading was adopted efficiently in the algorithm[8] which was presented in the form of a flow diagram for convenient implementation on a dispatch computer. Brief discussions were also made on the practical application of the algorithm to automatic generation control systems.

Chapter V

NUMERICAL SIMULATION

5.1 INTRODUCTION

As an illustrative example, a power pool consisting of three interconnected areas (Figure 5.1) is considered. The details of the power pool are given in section 5.2. In order to study the effect of the proposed method on system economy and system availability, the simulations for the three different system environments have been carried out and compared with each other. For the purpose of clear presentation, the cases being considered are designated as follows:

CASE (A): The control policy is determined by the availability control method in reference[7] without considering transmission losses.

CASE (B): The control policy is determined by the economic dispatch algorithm developed here (chapter IV) without considering transmission losses[8].

CASE (C): The control policy is determined by the economic dispatch algorithm developed here (chapter IV) with consideration of transmission losses.

In section 5.3 (Case study 1), the results corresponding to the cases (A) and (B) are discussed in detail for demand curves shown in Figure 5.4. For the purpose of comparison of results, the same set of demand curves as given in reference [7] was taken in the simulation. These results correspond to mild fluctuations of demand (i.e., small standard deviation). The section 5.4 (Case study 2) presents similar results for large fluctuations (i.e., large standard deviation) as shown in Figure 5.10. The results corresponding to CASE (C) for the demands shown in Figure 5.4 are considered in section 5.5 (Case study 3). Finally the computational aspects associated with the proposed algorithm will be briefly discussed.

5.2 A POWER SYSTEM FOR THE CASE STUDIES

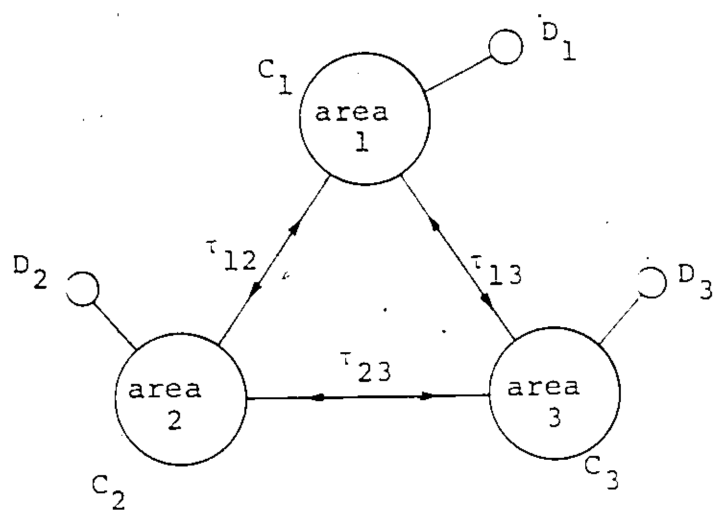
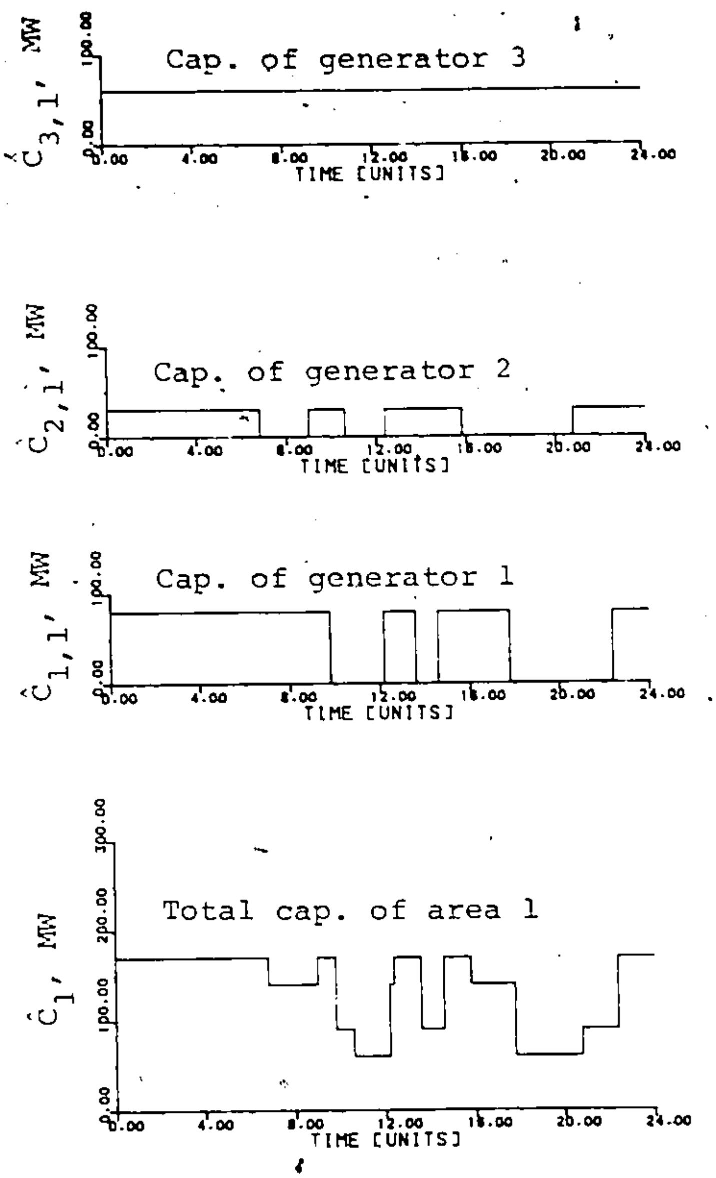


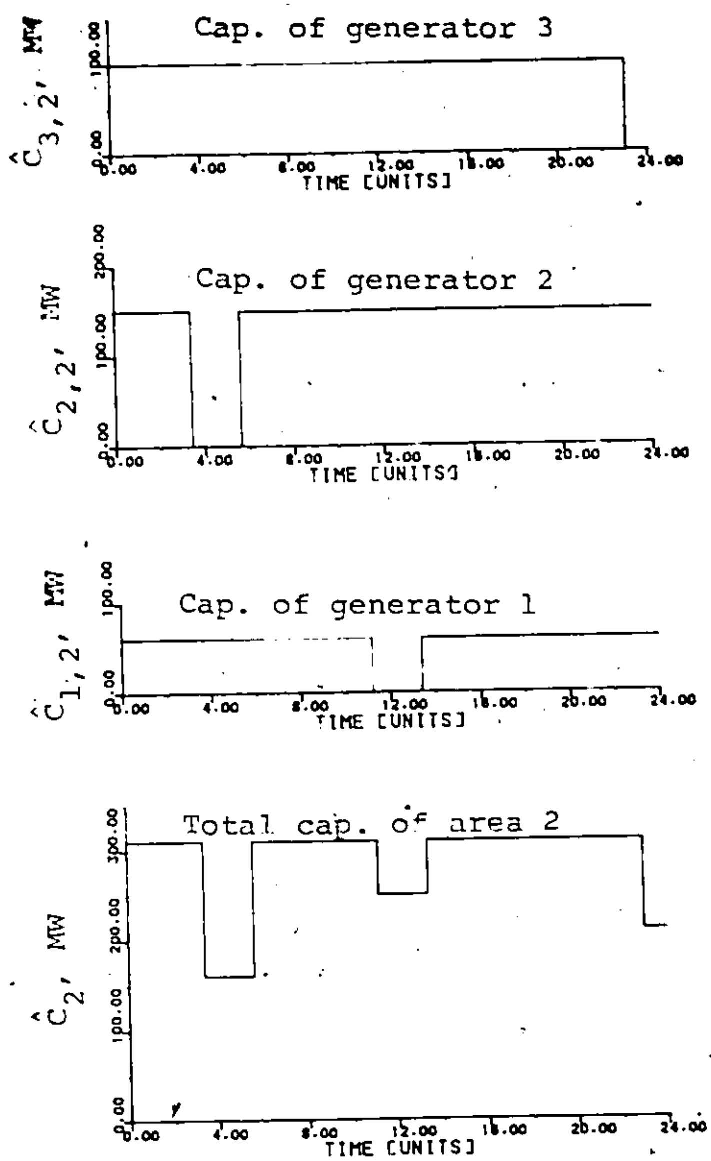
Figure 5.1. A power pool with three areas.

It is considered that in Figure 5.1, each area has three different (in capacities and cost characteristics) generators whose available generation capacities (expected value) are given in Figure 5.2. And the tie line capacities are ν_{12}=65 MW, ν_{13}=55 MW, ν_{23}=45 MW. It is also considered that the fuel costs of the generators are characterized by $\lambda^{s}_{k,i}$'s as shown in Figure 5.3. For simulation we take $p^{o}_{k,i}=0$ and $f^{o}_{k,i}=0$ for k,i=1,2,3. Further we consider that the area demands and the states of tie lines are given by Figures 5.4 & 5.10 and Figure 5.5, respectively. The effects of the dispatch policies on the generation (fuel) economy and the system availability, corresponding to the above system data, are discussed in the following sections. The FORTRAN code used to solve this problem is listed in Appendix C.



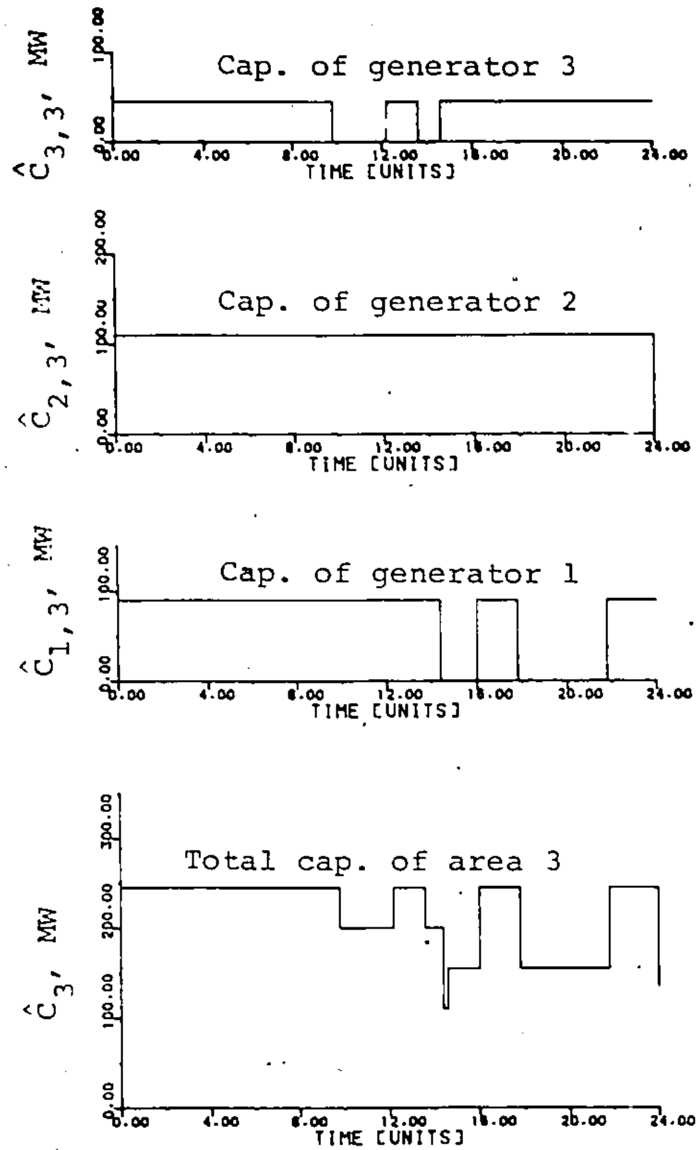
(a) Area 1

Figure 5.2.(a) Available generation capacities.



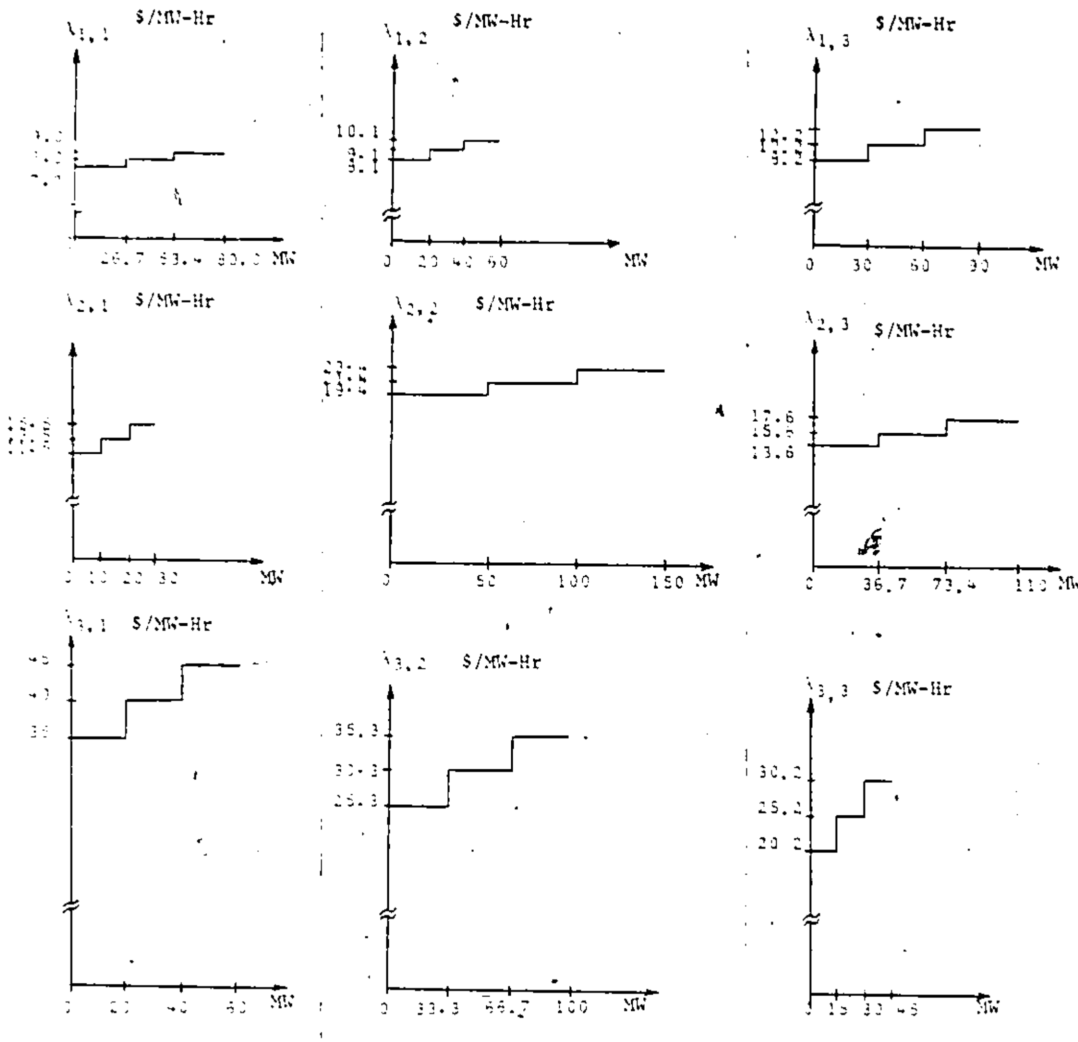
(b) Area 2

Figure 5.2.(b) Available generation capacities.



(c) Area 3

Figure 5.2.(c) Available generation capacities.



(a) Area 1 (b) Area 2 (c) Area 3

Figure 5.3. Incremental fuel cost functions.

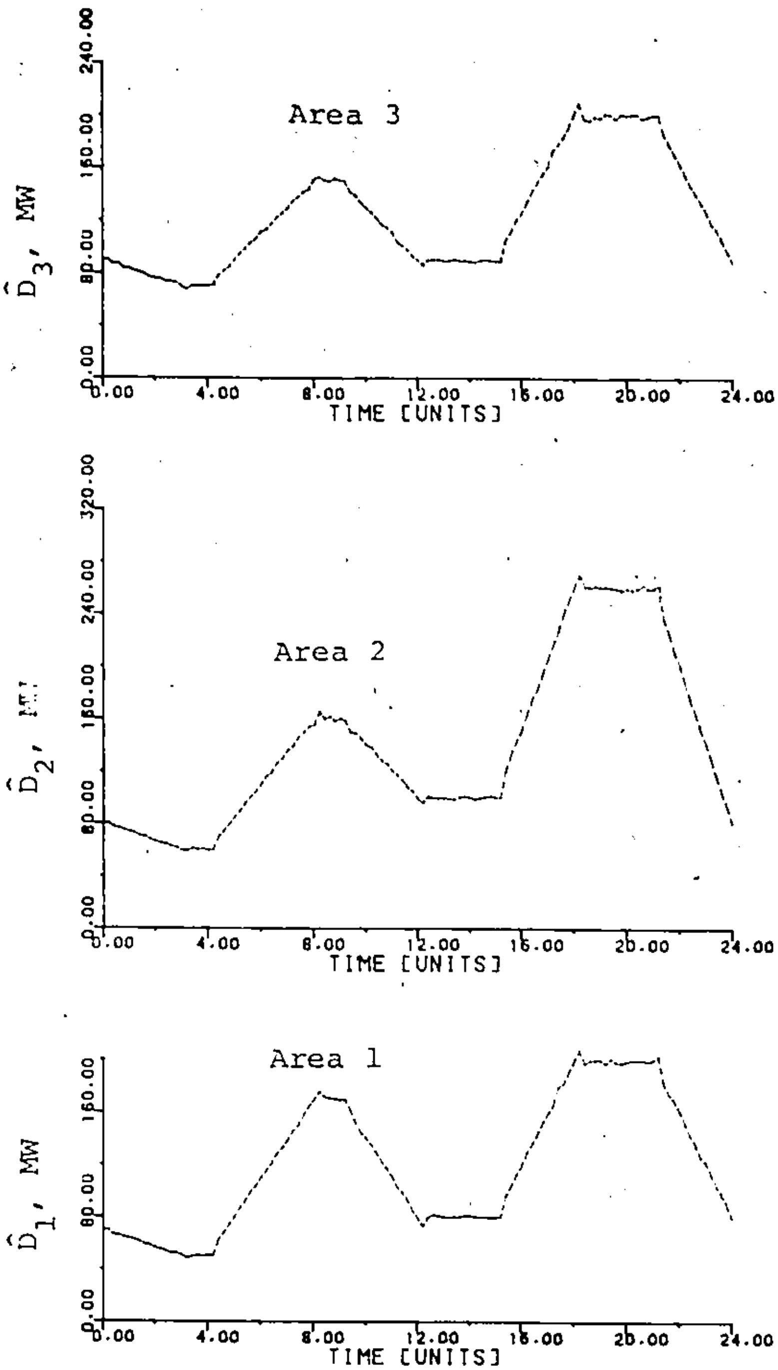


Figure 5.4. The area demands.

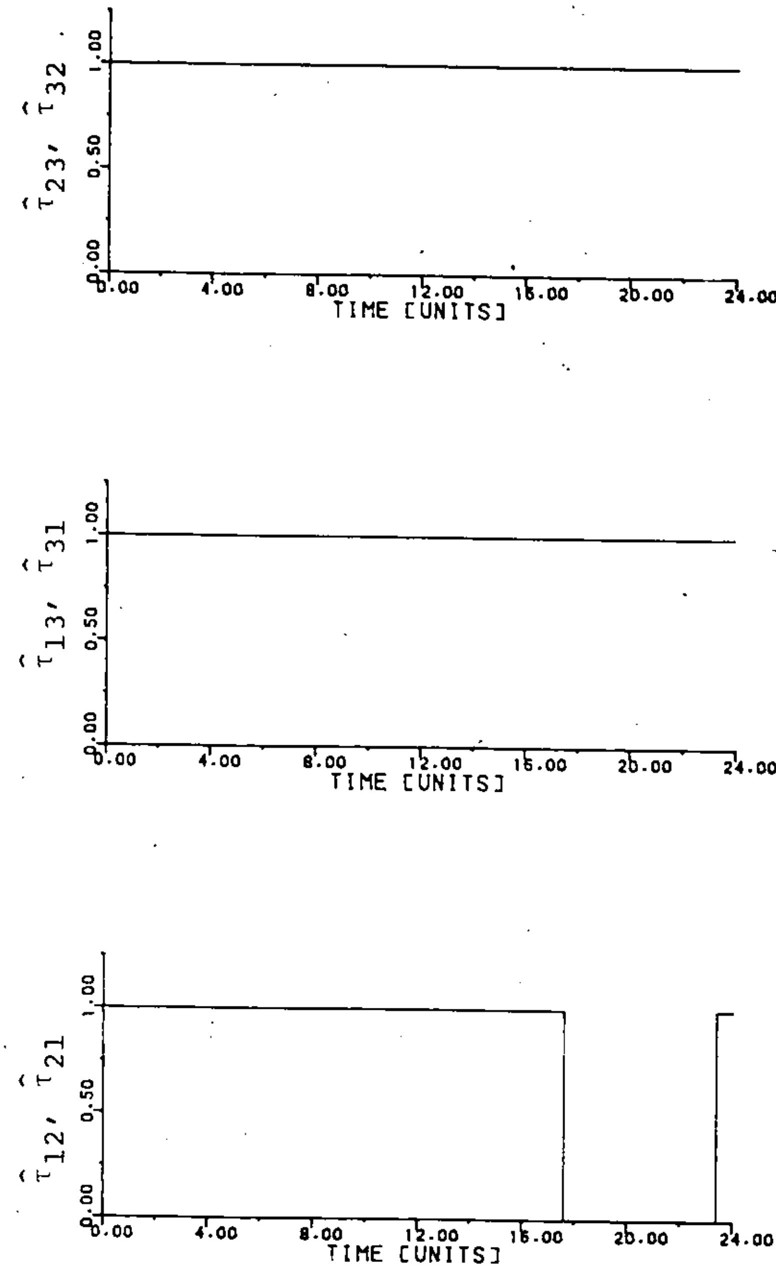


Figure 5.5. The states of tie lines.

5.3 CASE STUDY 1 (RESULTS CORRESPONDING TO MILD FLUTUATION OF DEMANDS)

The effects of the proposed control policy on the generation economy and system availability for the CASES (A) and (B) are discussed in this section. Figures 5.6-5.7 present the optimal control policies, i.e., optimal generation allocation $\{P_{k,i}^{*}(t)\ ,\ k=1,2,3;\ i=1,2,3\}$ and the power exchange matrix $\{\beta_{ji}(t),\ i\neq j=1,2,3\}$. The reserve margins (equation 3.42) and the minimum hourly generation (fuel) cost are presented in Figure 5.8 and Figure 5.9 respectively.

5.3.1 Effect of the control policies on system availability

For the two cases (A) and (B), the reserve margins after exchange between the areas are compared with those without exchange in Figure 5.8. It is clear, from Figure 5.8, that:

(i) Use of the control policies has improved the system availability considerably (compare the reserve margins before control with those after control for both cases (A) and (B)).

(ii) For some period of time [0,5], the reserve margins before dispatch of power are all positive in all areas. Thus for the case (A) the power exchange is not required at all and so the reserves after availability control remain at the same level as those before control. However, for the case (B), during the same period [0,5], in spite of positive reserves in all areas, the power exchange (between areas) is essential for minimum global generation cost. Therefore, the reserves after economic dispatch (control) are not identical to the original reserves; while the system availability index (see section 5.3.3) remains at the same level as those of case (A).

(iii) During the time interval [17.8,22.2], the reserve of area 1 remains negative (even after control) with some improvement. So does the reserve of area 3 for the time interval [18,21.2]. Indeed, this result is expected since the reserve power available from area 2, during the time interval [17.8,22.2], is not enough to meet the loss of load imposed by area 1 and area 3, and also since the area 2 can only supply areas 1 and 3 with power less than or equal to the available tie line capacities $\tau_{21}(t)\nu_{21}(t)$ and $\tau_{23}(t)\nu_{23}(t)$, respectively.

(iv) Note that throughout the entire dispatch horizon (of time), the improvement of system availability by the proposed method (case (B)) is the same as that of case (A).

For quantitative presentation, the system availability indices are introduced in the following. If the system availability is defined as the probability that the reserve margins are positive, then the indices can be defined as:

System Availability Index 1

During the time period [0,T] the total failure times of service or LOSS OF DEMAND in an area, say i, is computed by

$$(TLOD)_i = \int_o^T 1^{\cdot}(Q_i(t)<0)\ dt \qquad (5.1)$$

where $(TLOD)_i$ = Total Times of LOSS OF DEMAND in area i,

$Q_i(t)$ = Reserve margin of the area i at time t,

$$1^{\cdot}(\bullet) = \begin{cases} 1 & \text{if } (\bullet) \text{ is true.} \\ 0 & \text{otherwise.} \end{cases} \qquad (5.2)$$

The total time of LOSS OF DEMAND in the power pool having N areas is the sum of the times in each area. That is,

$$(TLOD) = \sum_{i=1}^{N} (TLOD)_i \qquad (5.3)$$

Thus the ratio of (TLOD) to total service time can be interpreted as the probability of LOSS OF DEMAND. Then the system availability is defined by

$$A1 \triangleq 1 - \frac{(TLOD)}{N \bullet T} \qquad (5.4)$$

where A1 is called as the system availability index 1 in the sequel.

System Availability Index 2

System availability can also be defined on the basis of LOSS OF ENERGY. The total ENERGY NOT SERVED corresponing to the LOSS OF DEMAND in area i during the time period [0,T] is computed as

$$(ENS)_i = -\int_o^T Q_i(t) \bullet 1^{+}(Q_i(t)<0)\ dt \qquad (5.5)$$

where $(ENS)_i$ = ENERGY NOT SERVED in area i. The total ENERGY NOT SERVED in the power pool having N areas is computed by

$$(ENS) = \sum_{i=1}^{N} (ENS)_i \qquad (5.6)$$

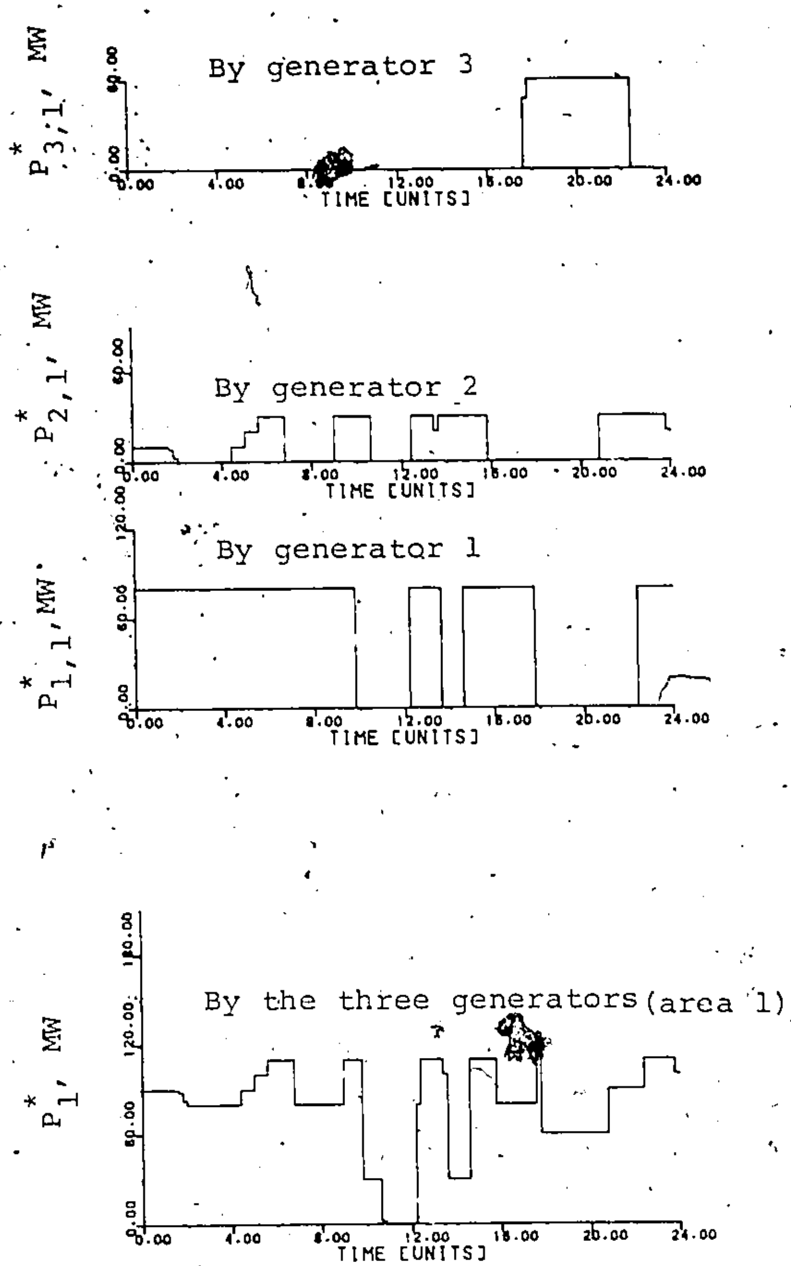
Thus the probability of ENERGY NOT SERVED can be computed by the ratio of (ENS) to total energy required during the period [0,T]. Then the system availability can be defined by

$$A2 \triangleq 1 - \text{Prob}\{ENS\} \qquad (5.7a)$$

$$= 1 - \frac{(ENS)}{(TRE)} \qquad (5.7b)$$

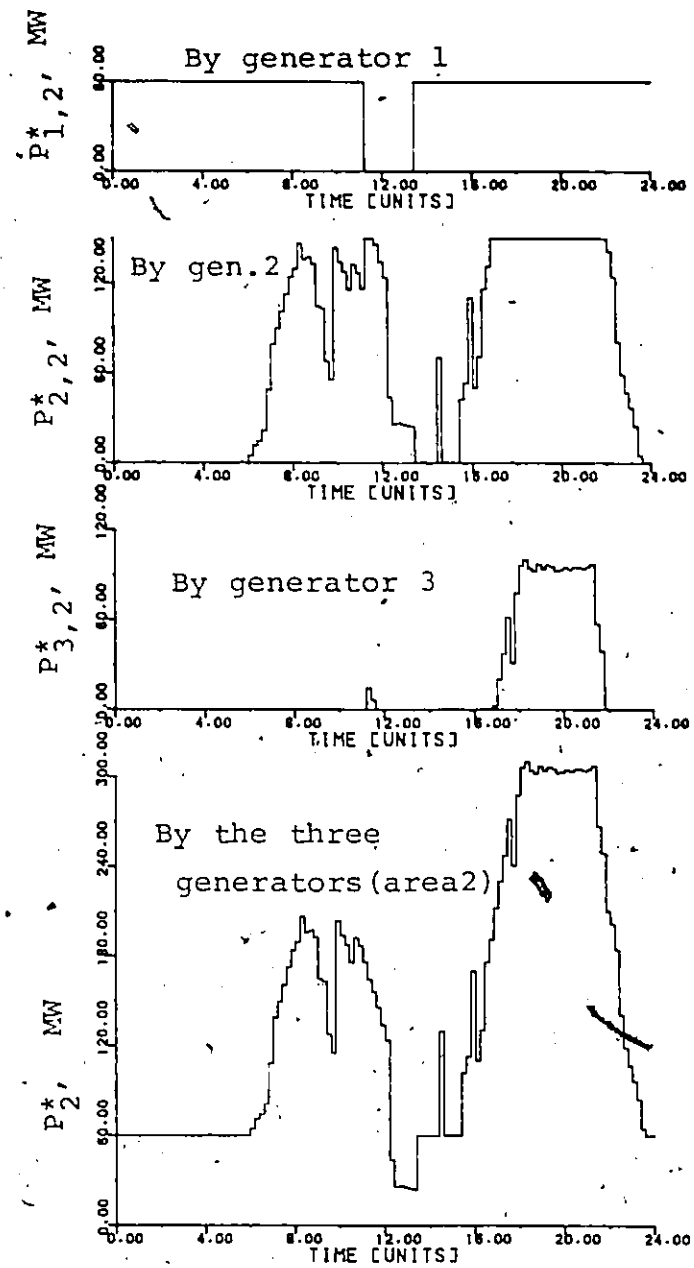
where (TRE) denotes the total required energy during the period [0,T] and A2 the system availability index 2.

Note that these indices A1 and A2 are slightly different from those computed by the methods of Loss Of Load Probability and Energy Index Of Reliability, but the concepts used are basically the same.



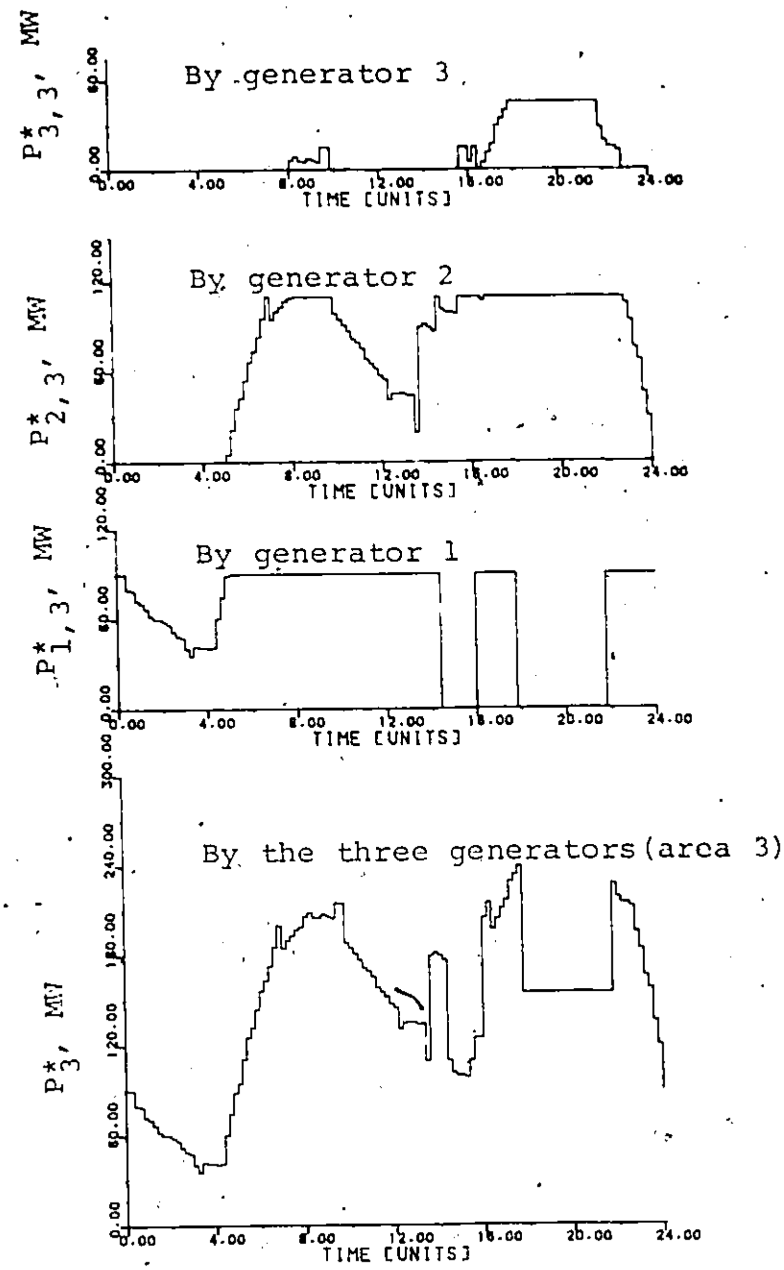
(a) Area 1

Figure 5.6.(a) Optimal generation.



(b) Area 2

Figure 5.6.(b) Optimal generation.



(c) Area 3

Figure 5.6.(c) Optimal generation.

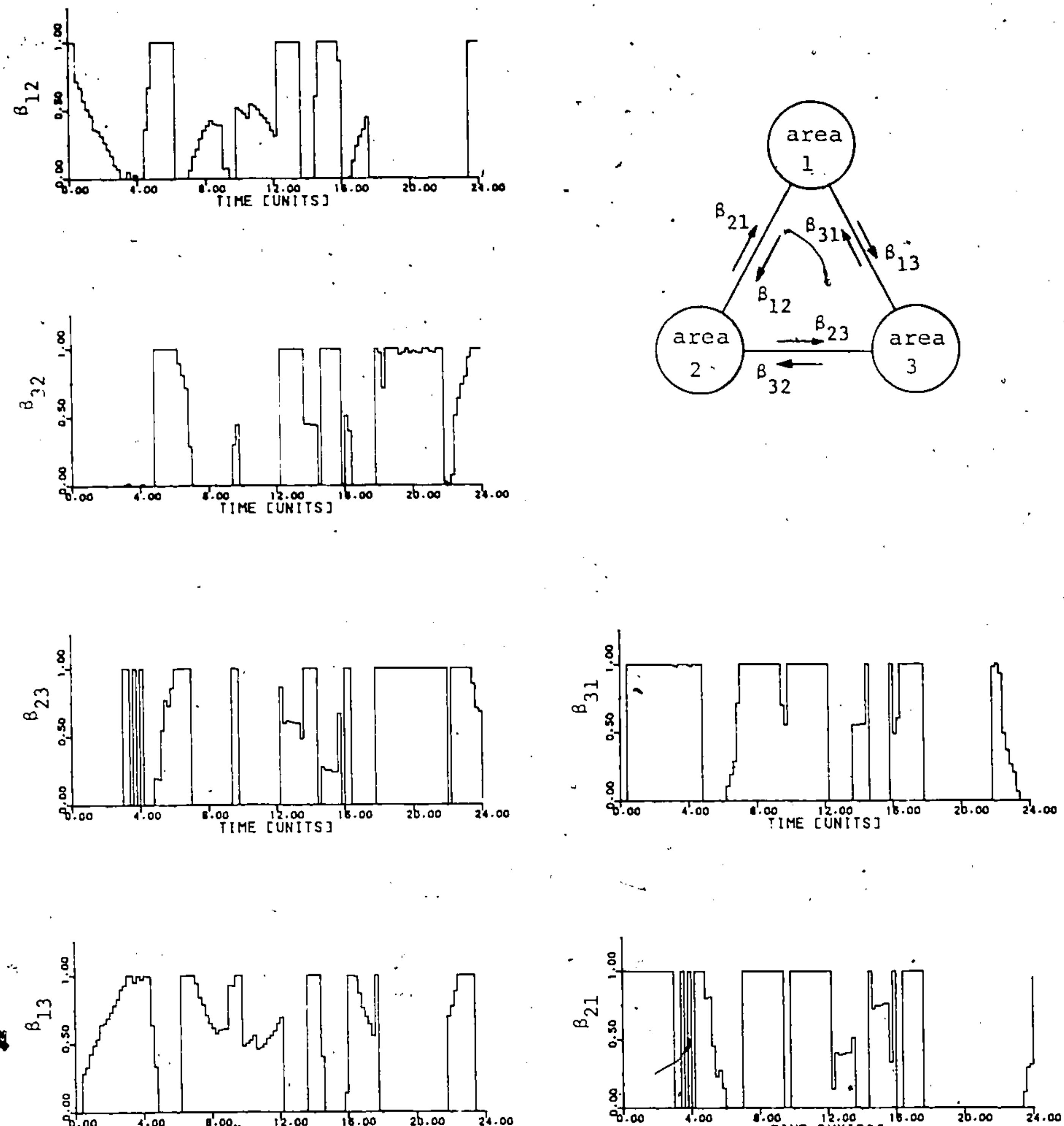


Figure 5.7. The power exchange matrix.

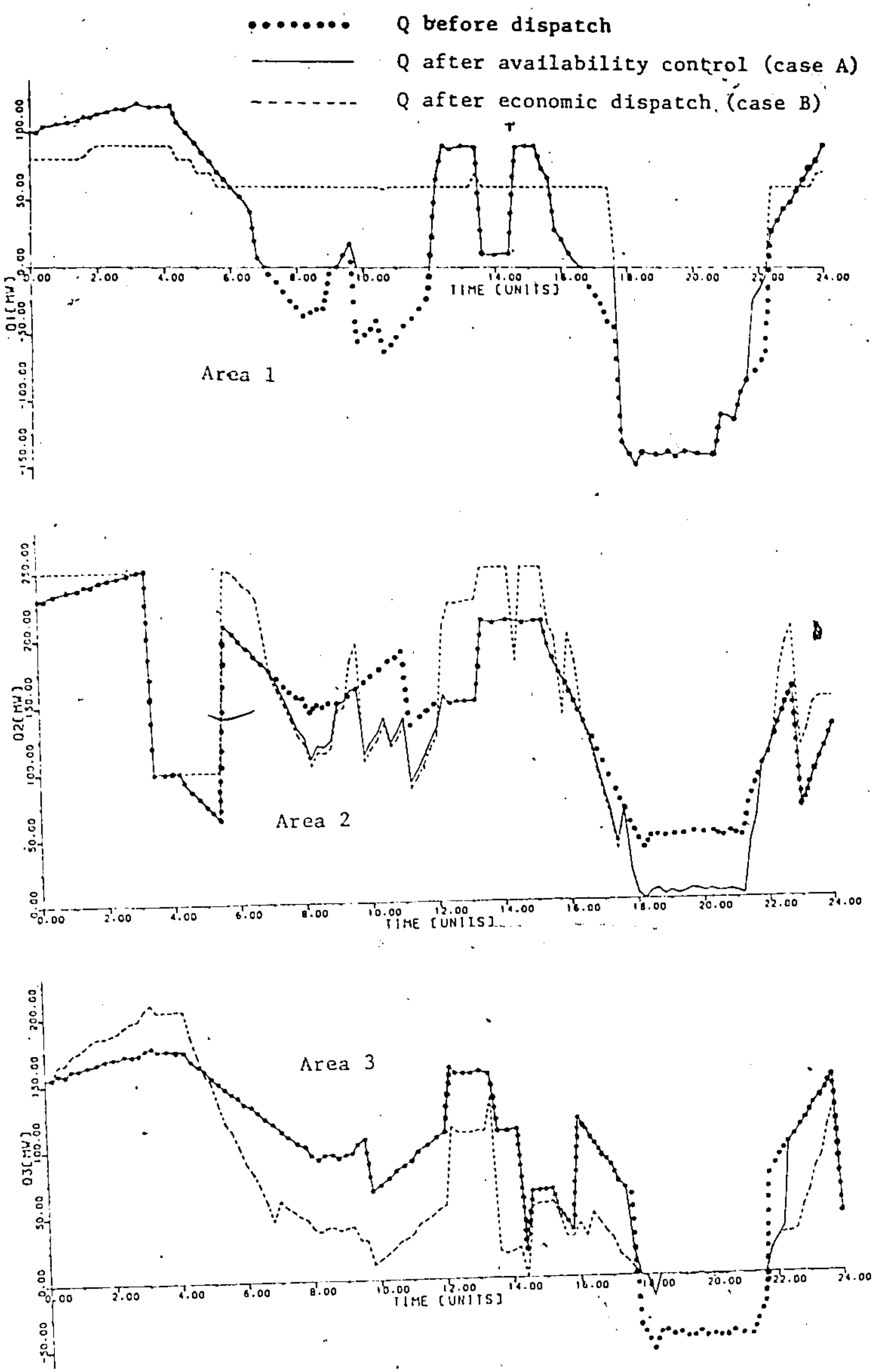


Figure 5.8. The reserve margins.

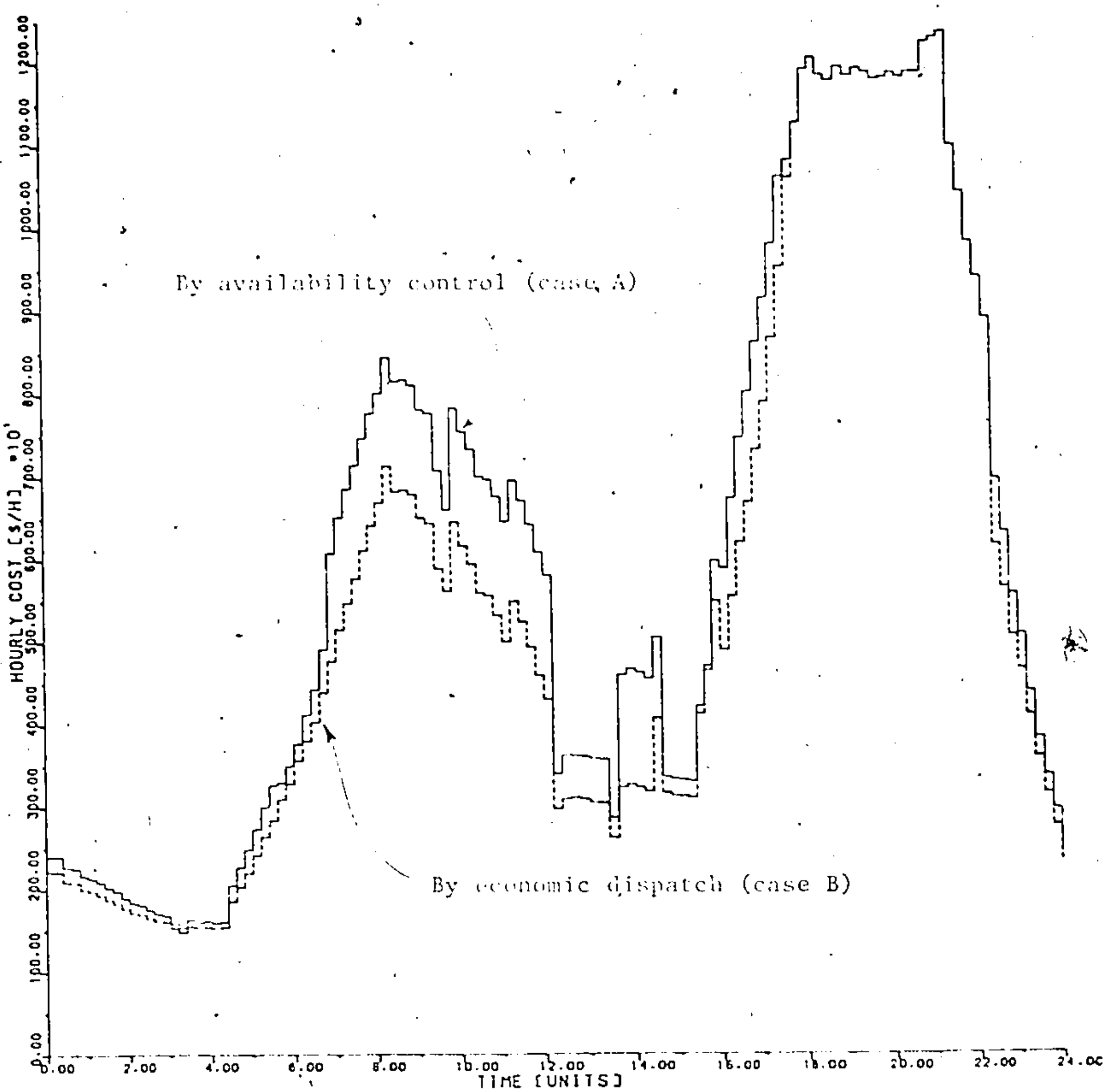


Figure 5.9. The minimal hourly generation cost.

5.3.2 Effect of the control policy on generation economy

In Figure 5.9, the minimum hourly generation costs are presented for the two cases (A) and (B). It is clear, from Figure 5.9, that:

(i) The minimum hourly generation cost in case (B), which is the minimal solution of equation 3.22, is considerably less than that in case (A), except for the time interval [17.8,21.6].

(ii) During the time period [17.8,21.6], the hourly cost curves for the two cases are identical. In fact, this result is expected since there is no room for improvement of the fuel cost due to the fact that the reserve of area 2, during the same period, is not large enough to meet the loss of load imposed by areas 1 and 3 and also the area 2 can only supply areas 1 and 3 with power less than or equal to the available tie line capacities.

(iii) The shapes of these cost curves have the same pattern as that of the demands. In fact, this is quite logical since more energy production corresponds to more demand.

5.3.3 Summary of the results (Case study 1)

The above observations may be summarized as follows.

CASE	Fuel Cost [$]		Loss of Energy (based on 24 Hrs.)	A1	A2
	per day	per year			
A	146,515.1	53,478,011.5	534.9 MW·Hr	0.91	0.94
B	133,030.18	48,556,015.7	534.9 MW·Hr	0.91	0.94

Table 5.1. Summary of the results (case study 1).

In this table, the fuel cost was computed on a day or year basis. The system availability indices A1 and A2 were computed by the definitions i.e., equations (5.4) and (5.7).

Comparing the two cases (A) and (B), it is clear, from Table 5.1, that the generation cost in case (B) (the proposed method) is remarkably less than that corresponding to case (A), retaining the same system availability indices.

Therefore, it is concluded that the proposed method (case (B)) provides the optimal control policy for the generation and power exchange at the least fuel cost with the highest possible availability index.

5.4 CASE STUDY 2 (RESULTS CORRESPONDING TO LARGE FLUCTUATION OF DEMANDS)

In this section, the effect of the control policies on system economy and availability under large fluctuation of demands (Figure 5.10) is considered for the same example system (Figure 5.1). The results are presented in Figures 5.11-5.14. The dispatch policies (i.e., optimal generation and power exchange matrix) are presented in Figures 5.11 and 5.12, respectively. Figures 5.13 and 5.14 present the effects of the control policies on system availability and economy, respectively. It is summarized in Table 5.2.

CASE	Fuel Cost [$]		Loss of Energy (based on 24 Hrs.)	A1	A2
	per day	per year			
A	145,898.46	53,252,937.9	566.1 MW·Hr	0.91	0.94
B	132,488.58	48,358,331.7	566.1 MW·Hr	0.91	0.94

Table 5.2. Summary of results (Case study 2).

Examining Figures 5.13 and 5.14 and Table 5.2, we arrive at the similar conclusions as obtained in the previous example (case study 1).

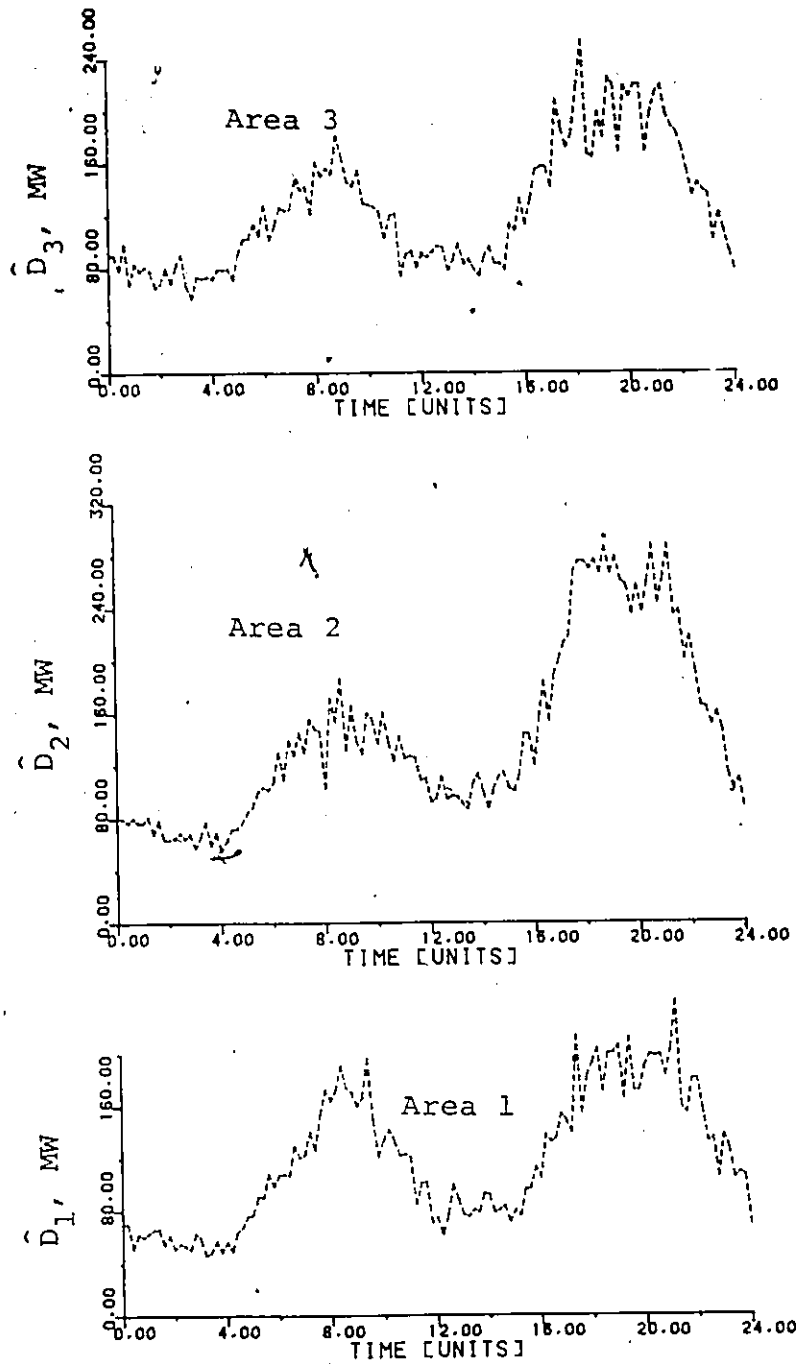
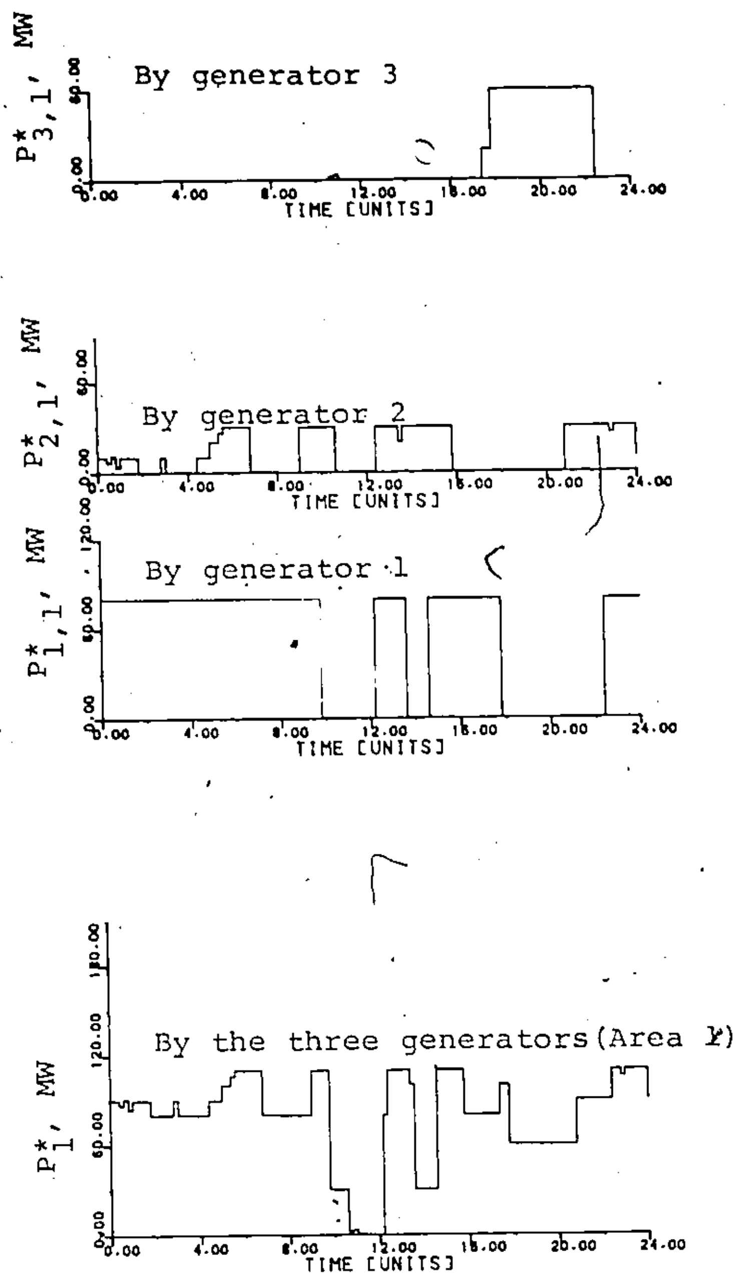
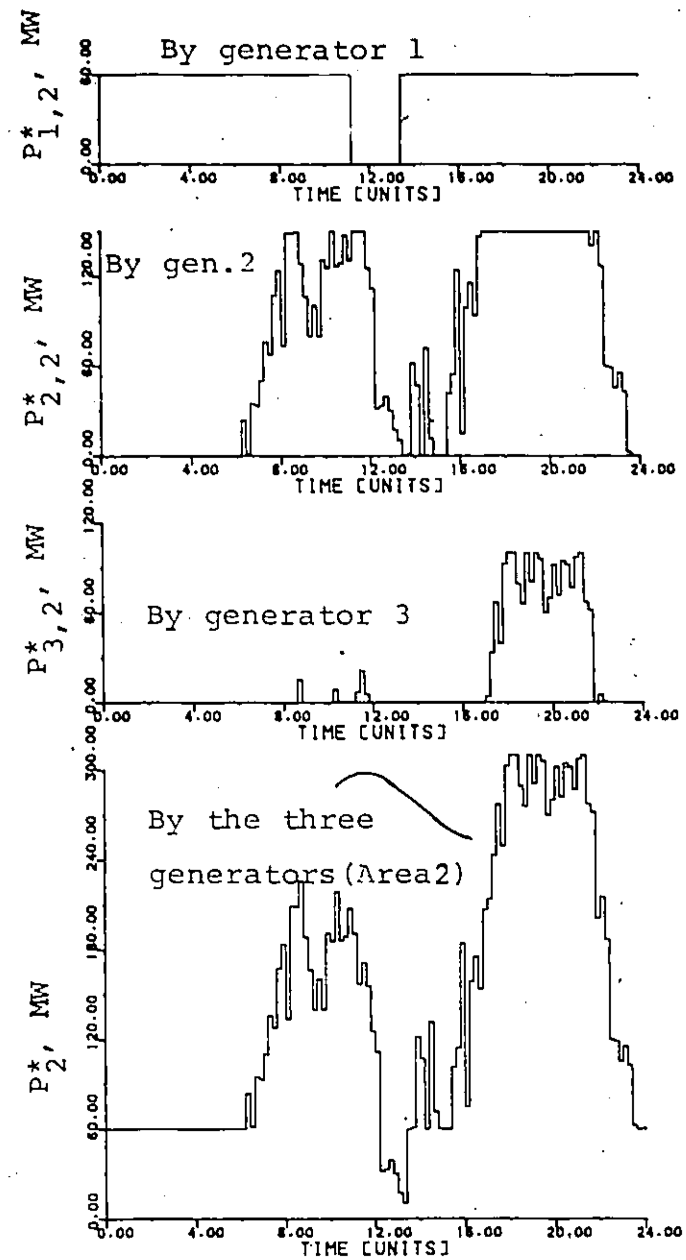


Figure 5.10. The area demands.



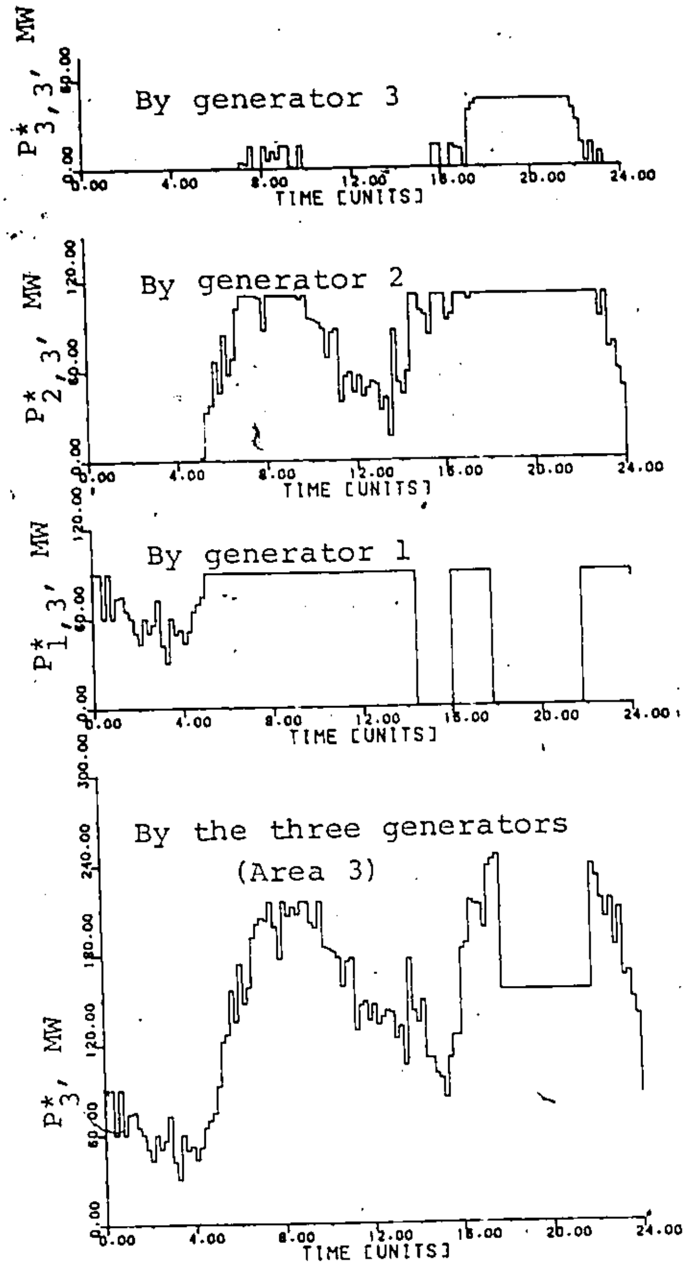
(a) Area 1

Figure 5.11(a) Optimal generation.



(b) Area 2

Figure 5.11(b) Optimal generation.



(c) Area 3

Figure 5.11(c) Optimal generation.

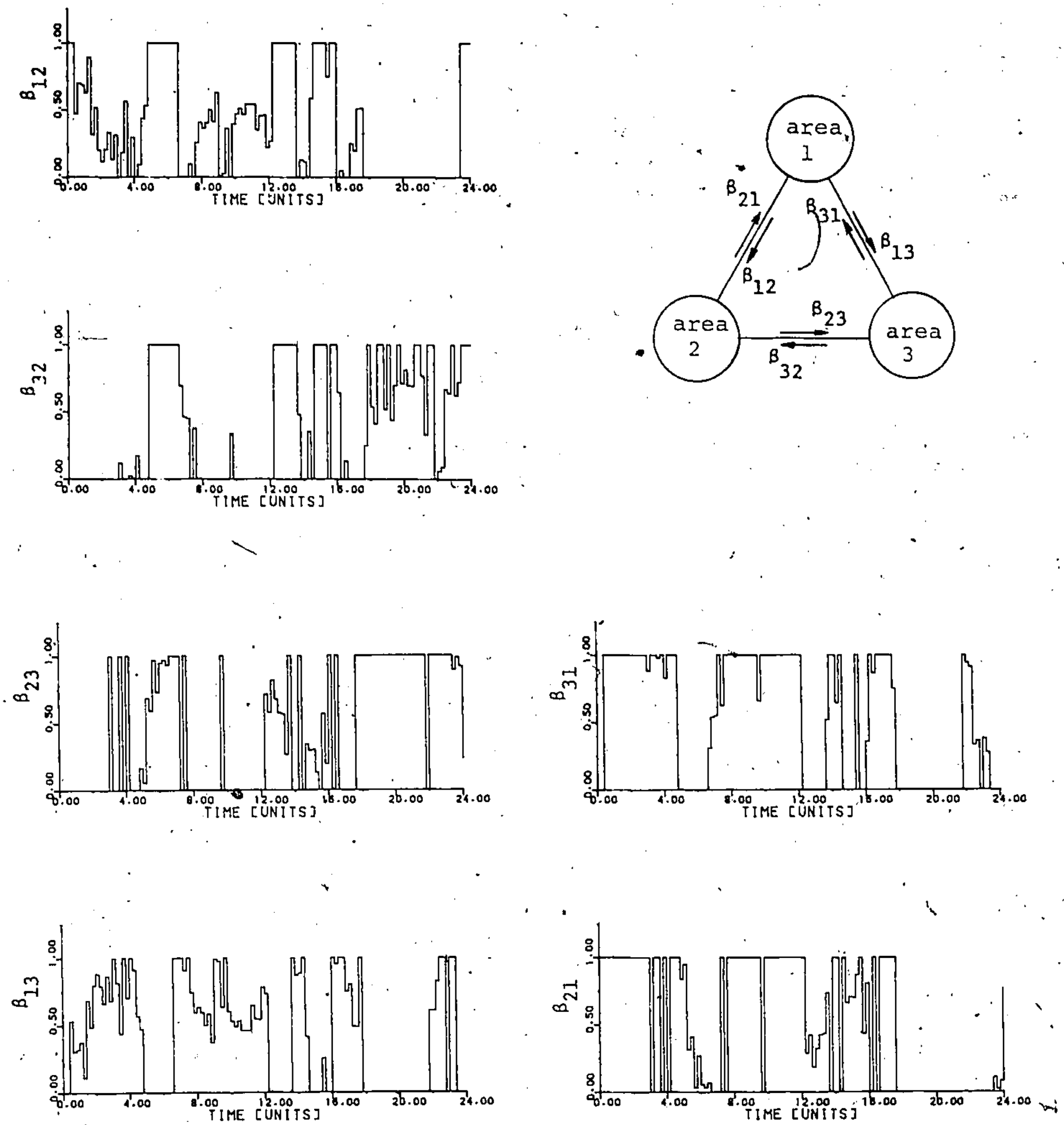


Figure 5.12. Power exchange matrix.

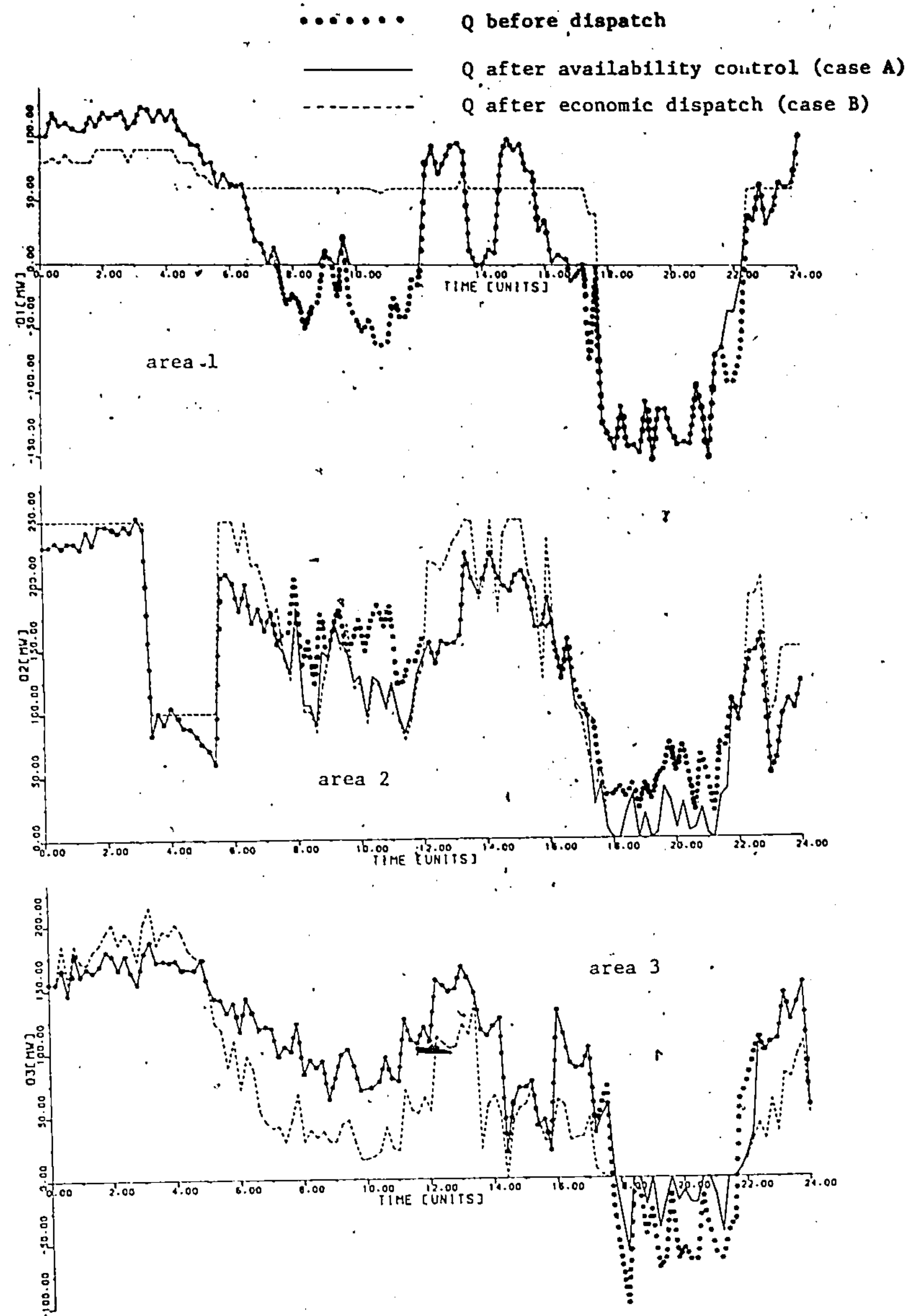


Figure 5.13. The reserve margins.

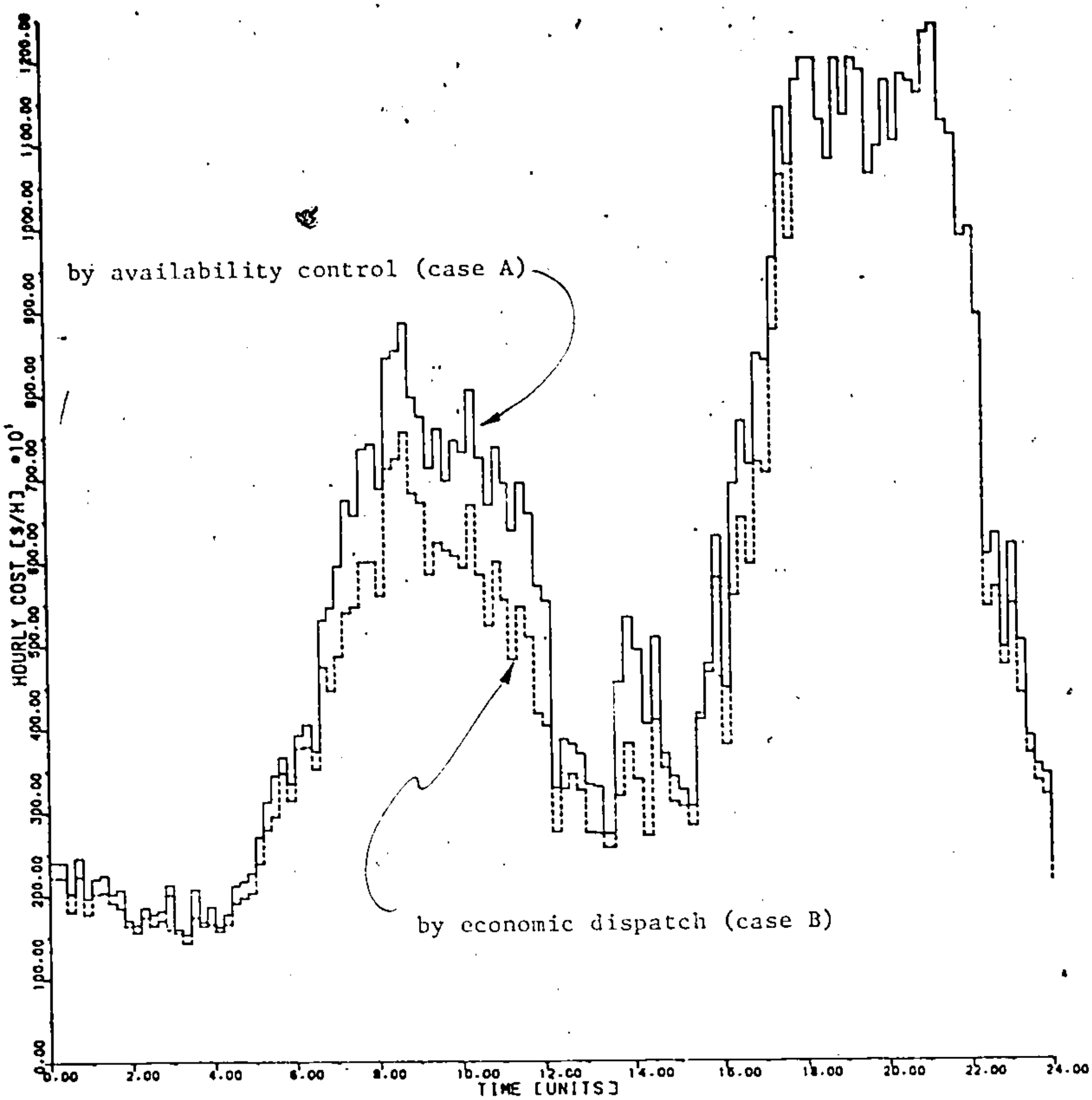


Figure 5.14. The minimal hourly generation cost.

5.5 CASE STUDY 3 (TRANSMISSION LOSSES CONSIDERED)

In order to show the effects of the proposed control policies on system economy and availability, in this section, the simulation results corresponding to CASE (C) are discussed. To examine the effect of transmission losses, the results of CASE (C) are compared with those of CASE (B) in which the losses were not considered. Figure 5.15 and Figure 5.16 present the optimal dispatch policies, (i.e., generation and exchange matrix) for the demand curves in Figure 5.4. The corresponding reserve margins and minimum hourly generation fuel costs are presented in Figure 5.17 and Figure 5.18, respectively.

5.5.1 Effect of the control policy on system availability

The reserve margins are presented in Figure 5.17 for the cases (B) and (C). It is clear, from Figure 5.17, that:

(i) Use of the control policies has improved the system availability considerably (compare the reserve margins before control with those after control for both cases (B) and (C)).

(ii) It is interesting to observe that the reserve margins corresponding to case (C) (i.e., including line losses) is always closer to the original reserve (without any control) than that corresponding to case (B). This is quite logical since there is a trade off between the losses (or gains) in availability and gains (or losses) in economy caused by reduced (or increased) transmission of power.

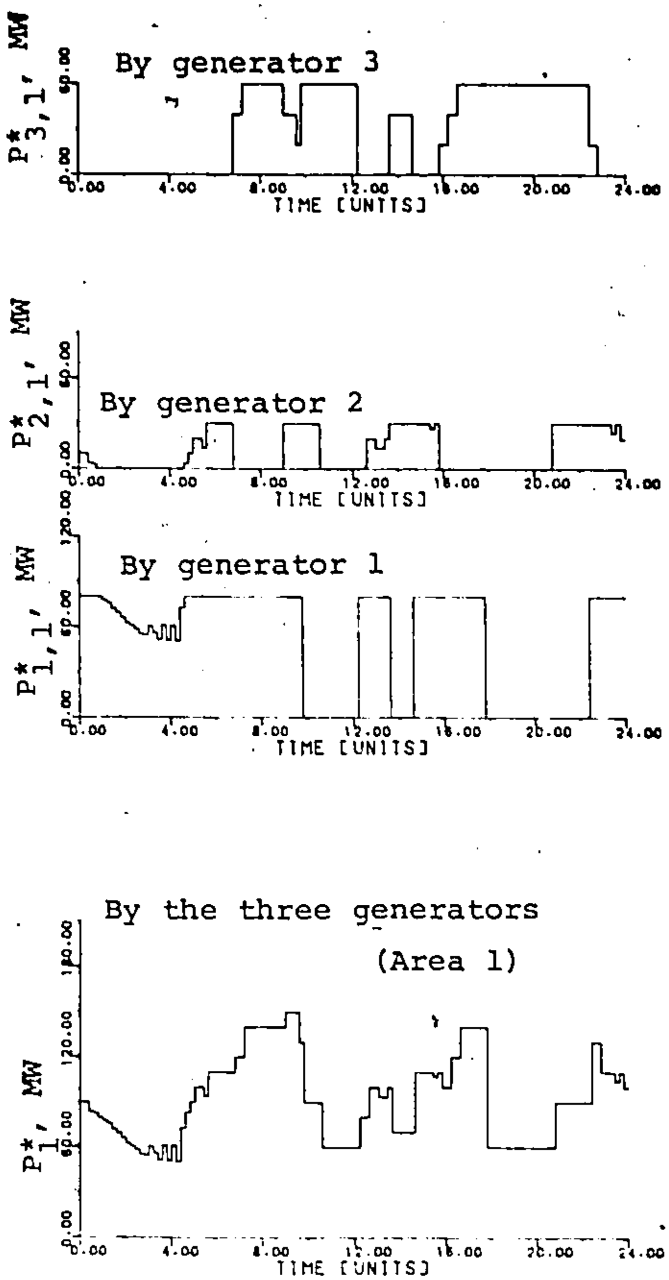
5.5.2 Effect of the control policy on system economy (CASE STUDY 3)

In Figure 5.18 the minimum hourly generation (fuel) cost for case (C) is compared with that for case (B) in order to show the effect of the losses on system economy. It is clear, from Figure 5.18, that:

(i) The results show clearly that the transmission losses increase the generation cost as expected.

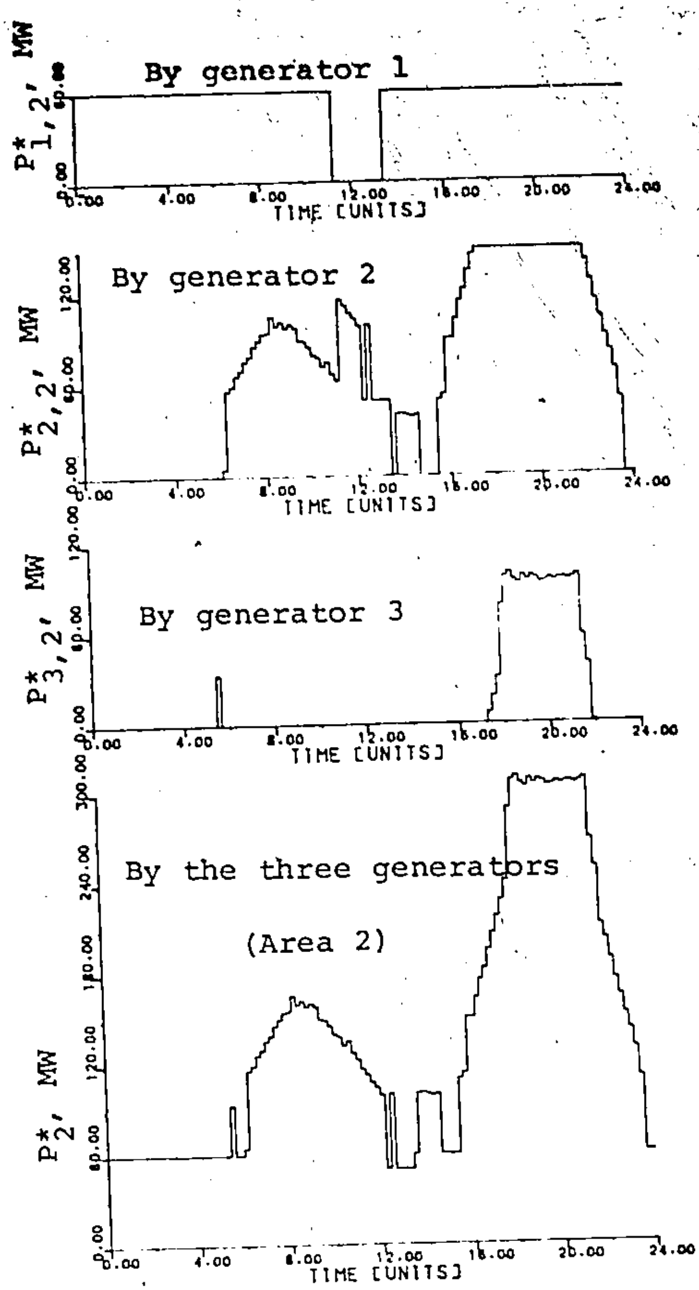
(ii) During the periods [6.8,14.6], [15.8,17.8], the minimum hourly generation cost in case (C) is substantially higher than that in case (B). This is expected, since during these periods, there has been substantial transaction of power between the areas thereby increasing the cost of transmission losses.

(iii) During the period [17.8,21.6], the hourly cost curves for the two cases are almost identical. In fact, this result is expected since there is no room for substantial improvement of generation cost in both cases due to the fact that the reserve of area 2, during the same period, is not large enough to meet the loss of load in area 1 and area 3 and also because area 2 can only supply areas 1 and 3 with power less than or equal to the available tie line capacities.



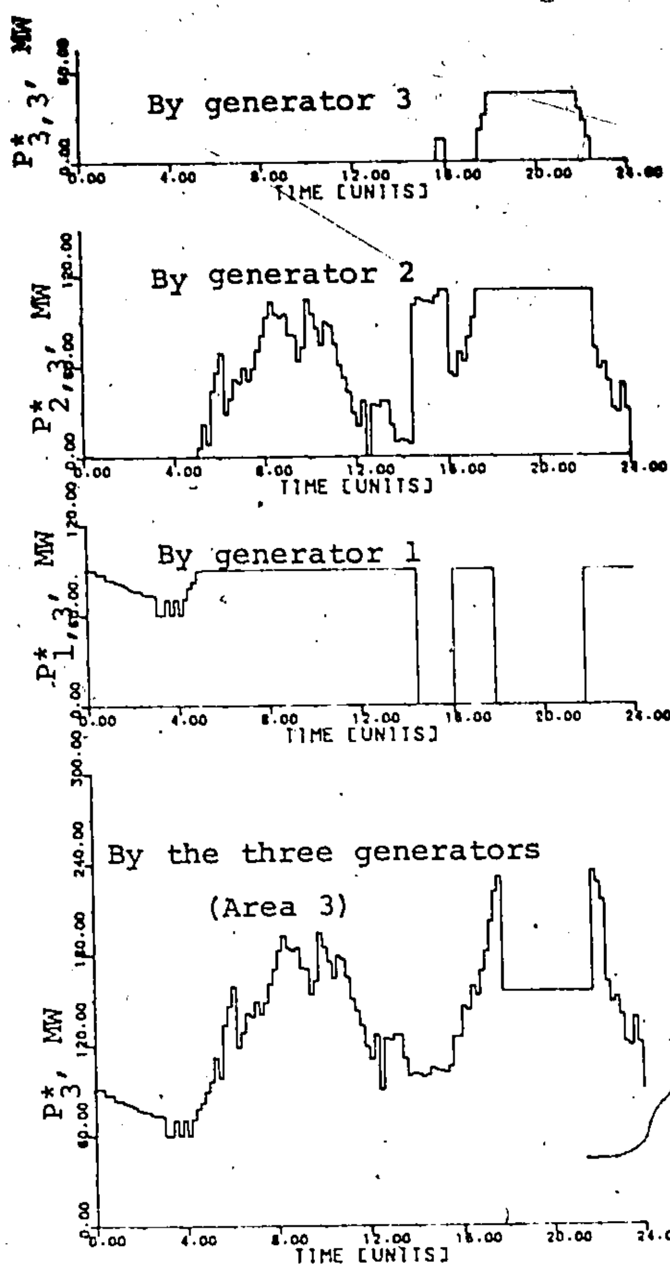
(a) Area 1

Figure 5.15(a) Optimal generation.



(b) Area 2

Figure 5.15(b) Optimal generation.



(c) Area 3

Figure 5.15(c) Optimal generation.

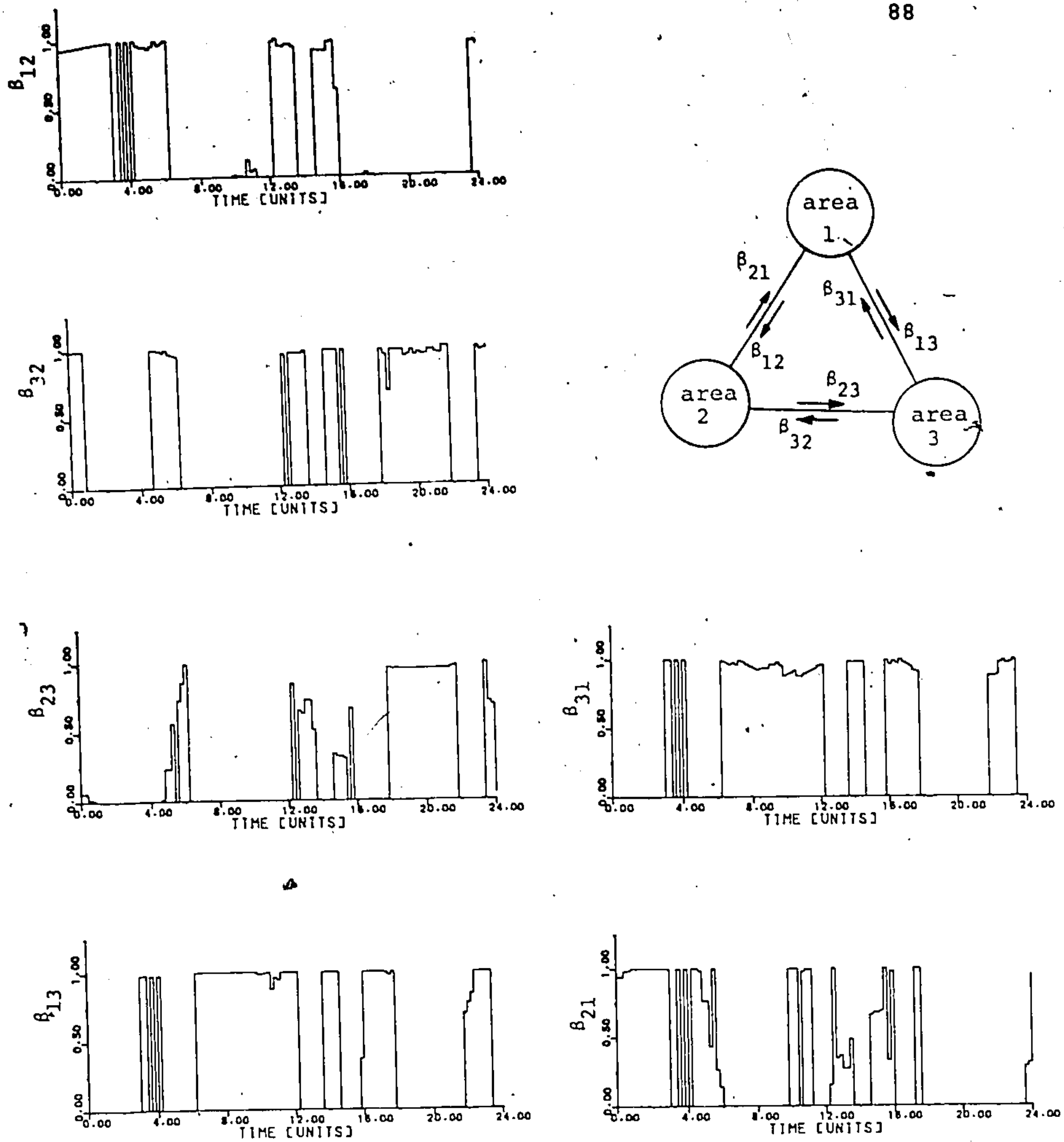


Figure 5.16. Power exchange matrix.

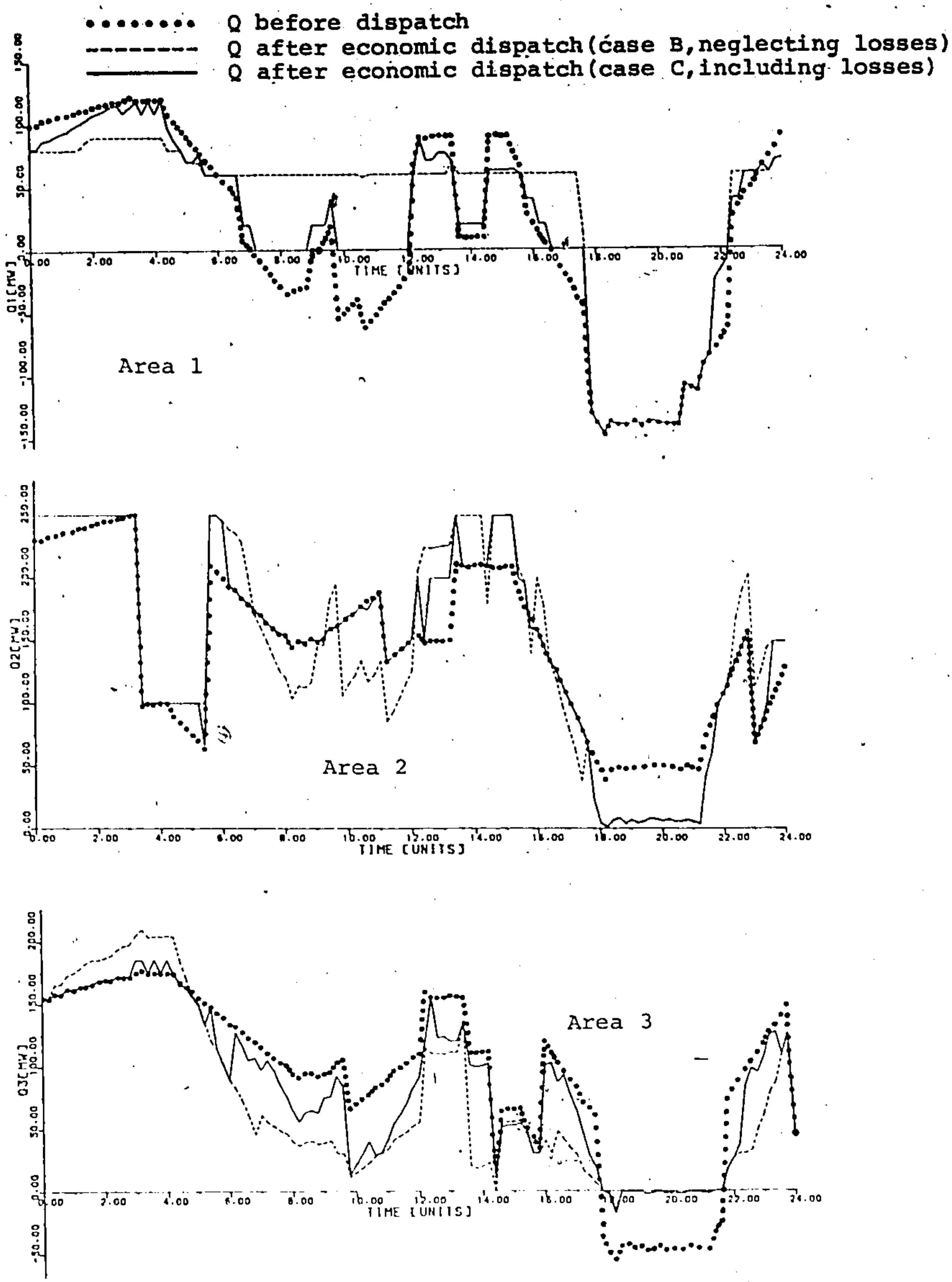


Figure 5.17. The reserve margins.

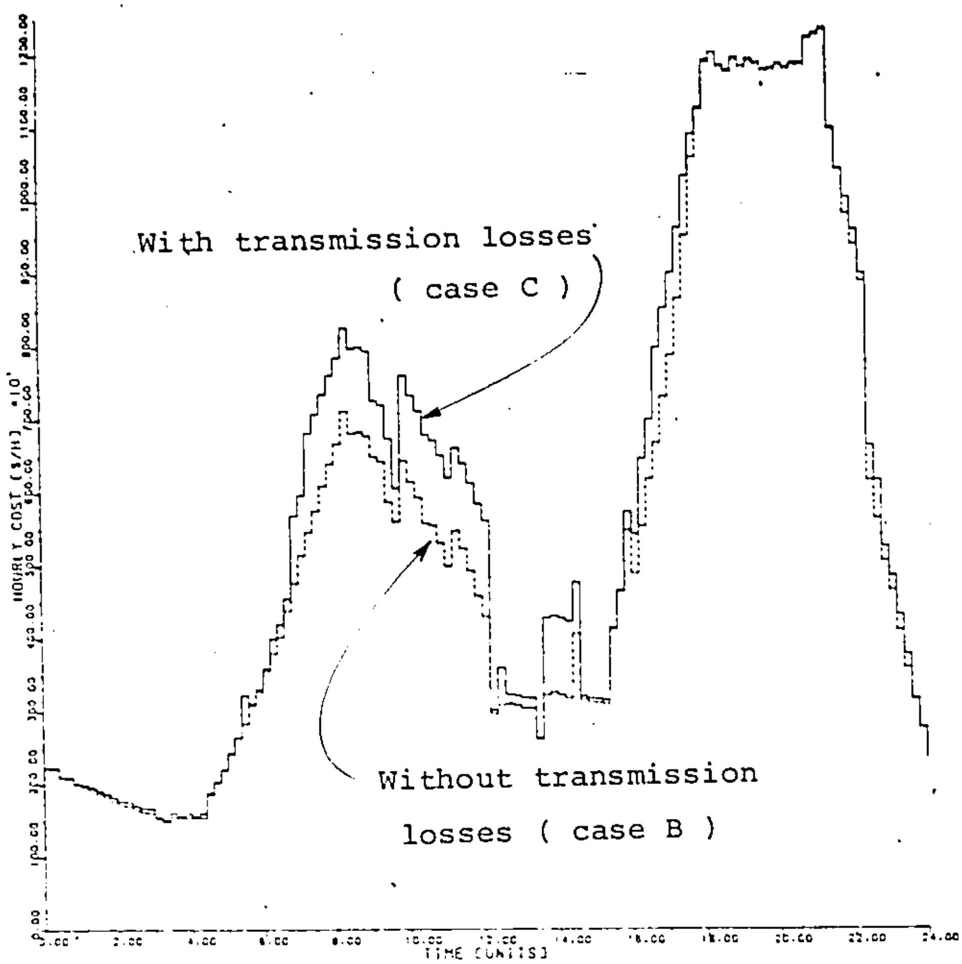


Figure 5.18. The minimal hourly generation cost.

5.5.3 Summary of the results (CASE STUDY 3)

The above observations may be summarized as follows:

CASE	Fuel Cost [$]		Loss of Energy (based on 24 Hrs.)	A1	A2
	per day	per year			
B	133,030.18	48,556,015.7	534.9 MW·Hr	0.91	0.94244
C	142,936.46	52,171,807.9	539.1 MW·Hr	0.87	0.94199

Table 5.3. Summary of the results (CASE STUDY 3).

In this table, the results for CASES (B) and (C) were compared in order to show the effect of transmission losses. Comparing the two cases, it is clear, from Table 5.3, that transmission losses considerably increase the generation (fuel) cost while slightly decreasing the system availability indices. This is again due to trade off between system economy and system availability.

Finally, it should be pointed out that the proposed method provides the optimal dispatch policy which gives minimum generation cost and maximum system availability under any given system environment.

5.6 ON THE COMPUTATION

It was observed, from the case studies, that the required time for computing an optimal control policy for generation and power exchange in the example was about 5 milli-sec, (in CPU time in IBM470) for each decision. This is due to the simple structure of the optimization algorithm which is based on the simple heuristic principle of Merit-Order Loading and hence does not require any complex optimization procedure for solving the problem. Furthermore, the proposed algorithm does not require any kind of large dimensional matrix manipulations or corresponding intermediate variables, and therefore it does not require large computing resources.

5.7 SUMMARY

In this chapter, three case studies for a power pool (Figure 5.1) were performed in order to illustrate the effectiveness of the proposed method on system economy and availability. It is clear, from the case studies, that the proposed method provides the optimal control policy for generation and power exchange at the least fuel cost with the highest possible system availability for any given system environment, while using modest computing resources.

Chapter VI

CONCLUSIONS

In this thesis, a methodology for constrained dynamic economic dispatch under the system availability constraint for large scale interconnected power systems has been presented.

In order to include the effects of the random variations of system data such as available generation capacities, area demands and availability of the tie lines, the model of reliability dynamics [7] was selected and briefly discussed in chapter 2 for the power pool model. A dynamic model for the incremental generation cost, taking into account the random failures and repairs of generating units, has been developed by segmenting original cost curves into several lines. It resulted in a piecewise constant stair-case function. The incremental cost model was extremely useful to solve the economic dispatch problem under the constraints as presented in section 3.6-3.7. Using such an incremental cost model,the economic dispatch problem has been formulated as a dynamic nonlinear minimization problem. The objective function of the problem was transformed into a cost function for the subintervals by Bellman's Principle of Optimality.

Examining the cost function, it is easy to find that the principle of Merit-Order Loading is very suitable to minimize the cost function (equation 3.22). Therefore, in chapter IV, an efficient algorithm has been developed by using the principle of Merit Order Loading on the basis of the predicted system data. For convenience (of users), the algorithm was described in the form of flow diagrams.

As an illustrative example to show the effectiveness of the proposed method, the following simulation studies were carried out for a power pool as shown in Figure 5.1.

(i) CASE STUDY 1: Two control methods were compared under mild fluctuation of demands and without considering transmission losses.

(ii) CASE STUDY 2: Two control methods were compared under large fluctuation of demands and without considering transmission losses.

(iii) CASE STUDY 3: With consideration on transmission losses, the results corresponding to mild demand fluctuations were discussed.

It is clear, from the case studies, that the proposed algorithm can be used to determine the optimal control policy for generation and power exchange (over the entire power network) <u>with the minimum generation cost and the highest possible system availability indices</u>. Therefore, when used together with proper short term load prediction techniques, the optimal dispatch policy obtained by the proposed algorithm can provide benefits of better load tracking and improved system availability as well as best generation economy.

In this research, only the thermal units were considered. However, the other type of generators can also be integrated into the economic operation in a similar way. For example, if a value can be placed on water (which is true in the case of pumped-storage hydro units), usually in dollars per cubic-meters, then these units can be operated incrementally along with thermal units for overall economic operation of the system. By the fast load-following capability of the algorithm intermittent generation which is quite different from conventional power plants operation can be included, too.

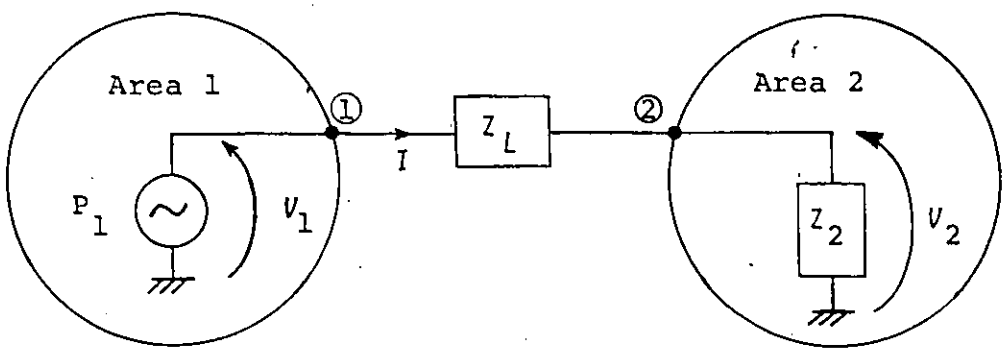
In defining thermal cost models in common use, the assumption of monotonically increasing cost curves is being employed. This assumption is not everywhere valid because of the throttling losses near valve points. In this case the valve point loading should be used for the economic operation [34]. However, it should be pointed out that the benefit of the valve point loading can be achieved in the proposed method (section 3.3) by taking the points of the lines at the valve points.

Furthermore, the method can be applied to the system with binding agreements between areas and allowing power exchange through composite tie lines. The power exchange matrix can be used for the interchange billing between areas. If the security constraints are taken into consideration, decoupled load flow methods may be combined with the algorithm. Finally the author feels that the flexible structure of the algorithm has high potential for applications to many relevent problems under different operational environments.

Appendix A

TRANSMISSION LOSSES

Consider the following network, in which area 1 generates the power required from the area 2.



$Z_L = R_L + jX_L =$ *Line Impedance*

$Z_2 = R_2 + jX_2 =$ *Load Impedance*

Figure A.1. A power network.

The active power generation in area 1 and the corresponding power delivered to area 2 are given by

$$P_1 = V_1 I \cdot \cos\theta_1 \qquad \text{(A.1a)}$$

$$P_2 = V_2 I \cdot \cos\theta_2 \qquad \text{(A.1b)}$$

where P_1 = Average power generated in area 1,

P_2 = Average power delivered to area 2,

V_1, V_2 = r.m.s. value of the voltages at nodes 1 and 2,

I = r.m.s. value of the current flowing from node 1 to node 2,

$\cos\Theta_1, \cos\Theta_2$ = Power factor in areas 1 and 2.

The thermal loss on the transmission line depends on the resistance R_L of the line. That is,

$$L_{12} = R_L I^2 \qquad (A.2)$$

Substituting equation (A.1b) into equation (A.2),

$$L_{12} = R_L\left(\frac{P_2}{V_2\cos\Theta_2}\right)^2 = \left(\frac{R_L}{V_2^2\cos^2\Theta_2}\right) P_2^2 \qquad (A.3)$$

Therefore, the active power loss in the line is directly proportional to the P_2^2 for given Z_1 and Z_2. That is,

$$L_{12} = a_{12}P_2^2 \qquad (A.4)$$

where

$$a_{12} = \frac{R_L}{V_2^2\cos^2\Theta_2} \qquad (A.5)$$

It is noted, from equations (A.4) and (A.5), that the transmission loss is a function of the delivered power P_2 and the coefficient can be assumed constant for the fixed power factor and voltage level at the receiving node.

Appendix B

EQUAL INCREMENTAL COST LOADING

The optimal allocation of power to n_i individual running units within an area i for a given total load L_i can be formulated as:

Minimize $f(\overline{P})$ with respect to $\overline{P}$

$$f(\overline{P}) = \sum_{k=1}^{n_i} f_k(P_k) \tag{B.1}$$

subject to the power balance equation

$$\sum_{k=1}^{n_i} P_k = L_i \tag{B.2}$$

where P_k = Power output of the generator k,

$\overline{P} = \{ P_k;\ k=1,2,\bullet\bullet\bullet,n_i\}$,

L_i = Total load to be supplied by the area i.

By application of the method of Lagrangian multipliers, the augmented function is obtained as

$$\Psi(\overline{P}) = f(\overline{P}) - \gamma\left(\sum_{k=1}^{n_i} P_k - L_i\right) \tag{B.3}$$

where γ=Lagrangian type of multiplier.

The necessary condition for optimal solution is that

$$\frac{\partial\Psi}{\partial P_k} = 0, \qquad k=1,2,\ldots,n_i \tag{B.4}$$

Then

$$\partial f(\bar{P})/\partial P_k - \gamma = 0, \quad k=1,2,\ldots,n_i. \tag{B.5}$$

Substituting equation (B.1) into equation (B.5) gives

$$\partial f_k(P_k)/\partial P_k - \gamma = 0, \quad k=1,2,\ldots,n_i. \tag{B.6}$$

$$df_k(P_k)/dP_k = \gamma, \quad k=1,2,\ldots,n_i. \tag{B.7}$$

Note that in equation (B.7), $df_k(P_k)/dP_k = \gamma$ is the incremental production cost of the generator k. In other words, the minimum hourly fuel cost in dollars per hour for a given load is obtained when all generating units are operated at the same incremental production cost. Therefore, if a chart of the incremental cost curves of all units is available, the optimal dispatch policy can be easily found. Station loading slide rules were based on this principle[20]. If the transmission losses must be taken into consideration, the well-known penalty factor method may be used in a similar way[20].

Appendix C

FORTRAN CODES

In the following the FORTRAN codes in chapter V are exhibited.

```
      DOUBLE PRECISION DSEED,DNE,DNE1
      REAL M(3),NU(3,3),LUM(3,3),ET(3,3),EX1(3),EX2(3),EX(3)
      REAL MU(3,3),LANDA(3,3),EXR(3,3),EXF(3,3),EXC(3,3),XCX(3,3)
      REAL*8 EO(3),A(14,6),B(14),C1(6),DSOL(14),DCC(3,3),DED(3),S4
      REAL*8 FE,FP,FA,TLC,A1,B1,A2,B2,A3,B3,A4,B4,A5,B5,
     X A6,B6,E,AB,SCOST,HCOST,TCOST,RCOST,QTIL,RINDX,PMOO,TCLL,QRT
      REAL*8 QS,TEIR,SUMC,ROET,PGC,PGG,DEXC,DEX,DEQ,RAM,REM,ETT,TT
      REAL*8 PM(3,9),RAMDA(3,10),RW(267),PSOL(12),ROE(3),EIR(3),DSUM(3)
      REAL*8 CAPP,GES,EGES,FAIL,REPA
      REAL*8 PE(27),DPE(15)
      INTEGER X(3),TX(3),XR(3),XF(3),IR1(60),IR2(60),T(3,3)
      INTEGER XC(3,3),KXF(3,3),TXC(3,3),KXR(3,3),EPA(3),PA(3)
      COMMON /GGGTT/ CAPP(3,3),GES(3,3),EGES(3,3),FAIL(3,3),REPA(3,3)
      COMMON /MMMM1/ M1(121),M2(121),M3(121),M4(121),M5(121),M6(121)
      COMMON /NNNN2/ N1(121),N2(121),N3(121),N4(121),N5(121),N6(121)
      COMMON /MMMM2/ M7(121),M8(121),M9(121),N7(121),N8(121),N9(121)
      COMMON /CCCTT/ SCOST,HCOST,PGC(3,3),PGG(3)
      COMMON /QQQTT/ QTIL(3),FA(3,3),QS(3),QRT(3),TLC(3,3)
      COMMON /DDDAA/ DEXC(3,3),DEX(3),DEQ(3),PMOC(9)
      COMMON /TTTLL/ ETT(3,3),TT(3,3),TCLL(3,3)
      DIMENSION NR(3),NF(3),IR(10),IJ(10),D(3),ED(3),W(3),V1(3),TF(3,3)
      DIMENSION CC(3,3),IW(42),RLOLP(3),RIN(3),ION(3),IQN2(3),QIN(3)
      DIMENSION Q(3),S(3),SUM(3,3),SUM1(3,3),S3(3),S31(3),S1(3),S11(3)
      DIMENSION GEN11(125),GEN12(125),GEN13(125),GEN21(125),GEN22(125
     X ),GEN23(125),GEN31(125),GEN32(125),GEN33(125),GENT1(125),GENT2(1
     X 25),GENT3(125),EGENT1(125),EGENT2(125),EGENT3(125),DEM1(125),DEM2
     X (125),DEM3(125),EDEM1(125),EDEM2(125),EDEM3(125),RM1(125),RM2(12
     X5),RM3(125),ERM1(125),ERM2(125),ERM3(125),ALF1(125),ALF2(125),ALF3
     X (125),ALF4(125),ALF5(125),ALF6(125),ALD1(125),ALD2(125),ALD3(125
     X ),EALD1(125),EALD2(125),EALD3(125),TIME(125),TIE1(125),TIE2(125),
     X TIE3(125),ETIE1(125),ETIE2(125),ETIE3(125)
      DIMENSION P11(125),P12(125),P13(125),P21(125),P22(125),P23(125)
      DIMENSION P31(125),P32(125),P33(125),QTI1(125),QTI2(125)
      DIMENSION QTI3(125),PGG1(125),PGG2(125),PGG3(125)
      DIMENSION COST1(125),COSTT(125),Q1(125),Q2(125),Q3(125)
      DIMENSION COST2(125),COST3(125)
      DIMENSION RAMD(3,10)
      DIMENSION PP1(125),PP2(125),PP3(125),PP4(125),PP5(125),PP6(125),
     1     PP7(125),PP8(125),PP9(125),TC12(125),TC13(125),TC23(125)
      DIMENSION QR1(125),QR2(125),QR3(125)
      DATA YOUT/24.0/,ITIE,NTC/2,1/
      DATA NAREA/3/,NTIE/3/,NC/3/,DY/0.2/
      DATA RAMD/7.0,8.1,8.2,8.0,9.1,10.2,9.0,10.1,12.2,
     1          11.5,19.4,13.6,13.5,21.4,15.6,15.5,23.4,17.6,
     2 35.0,25.3,20.2,40.0,30.3,25.2,45.0,35.3,30.2,3*1000.0/
        NA=1
        DSEED=12345.0D00
        DNE=DSEED
      TCOST=0.0D0
      RCOST=0.0D0
        DNE1=DSEED
C       DEFINE NUMBER OF AREAS AND NUMBER OF CLASSES OF GENS.
        E=1.00
        Y=0.0
      RINDX=-1.0D-6
C
      DO 1000 I=1,3
      ION(I)=0
      IQN2(I)=0
      DSUM(I)=0.0D0
      ROE(I)=0.0D0
```

```
 1000 CONTINUE
C      ENTER TOTAL NUMBER OF GENS. IN EACH AREA
       TX(1)=13
       TX(2)=10
       TX(3)=15
C      ENTER NO. OF GENS. IN EVERY CLASS
       TXC(1,1)=4
       TXC(1,2)=4
       TXC(1,3)=4
       TXC(2,1)=4
       TXC(2,2)=3
       TXC(2,3)=3
       TXC(3,1)=5
       TXC(3,2)=5
       TXC(3,3)=5
C   ENTER INITIAL NO. OF GENS. AVIALABLE FROM EVERY CLASS AT TIME=0.
       XC(1,1)=3
       XC(1,2)=3
       XC(1,3)=2
       XC(2,1)=4
       XC(2,2)=3
       XC(2,3)=3
       XC(3,1)=4
       XC(3,2)=4
       XC(3,3)=4
       EXC(1,1)=3.0
       EXC(1,2)=3.0
       EXC(1,3)=2.0
       EXC(2,1)=4.0
       EXC(2,2)=3.0
       EXC(2,3)=3.0
       EXC(3,1)=4.0
       EXC(3,2)=4.0
       EXC(3,3)=4.0
C ENTER THE CAPACITY OF EACH CLASS (IN EVERY AREA) IN MW.
       CC(1,1)=30.0
       CC(1,2)=20.0
       CC(1,3)=15.0
       CC(2,1)=15.0
       CC(2,2)=50.0
       CC(2,3)=40.0
       CC(3,1)=20.0
       CC(3,2)=30.0
       CC(3,3)=15.0
      CAPP(1,1)=80.0
      CAPP(1,2)=30.0
      CAPP(1,3)=60.0
      CAPP(2,1)=60.0
      CAPP(2,2)=150.0
      CAPP(2,3)=100.0
      CAPP(3,1)=90.0
      CAPP(3,2)=110.0
      CAPP(3,3)=45.0
      DO 423 I=1,3
      DO 423 K=1,10
      RAMDA(I,K)=RAMD(I,K)
  423 CONTINUE
      REPA(1,1)=0.085
      REPA(1,2)=0.105
      REPA(1,3)=0.1
      REPA(2,1)=0.102
      REPA(2,2)=0.095
      REPA(2,3)=0.09
      REPA(3,1)=0.095
      REPA(3,2)=0.088
      REPA(3,3)=0.101
```

```
      FAIL(1,1)=0.0085
      FAIL(1,2)=0.009
      FAIL(1,3)=0.0088
      FAIL(2,1)=0.0077
      FAIL(2,2)=0.0099
      FAIL(2,3)=0.0085
      FAIL(3,1)=0.0088
      FAIL(3,2)=0.0075
      FAIL(3,3)=0.0095
C
      DO 764 I=1,3
      DO 764 J=1,3
      EGES(I,J)=1.0D0
      FAIL(I,J)=FAIL(I,J)*1.0D0
      REPA(I,J)=REPA(I,J)*1.0D0
  764 CONTINUE
CCC   ------------------------------------------
      CALL POSCN
CCC   ------------------------------------------
C      ENTER THE CAPACITY OF THE TIE LINE IN MW.
        TLC(1,1)=100.
        TLC(1,2)=65.
        TLC(1,3)=55.
        TLC(2,1)=TLC(1,2)
        TLC(2,2)=TLC(1,1)
        TLC(2,3)=45.
        TLC(3,1)=TLC(1,3)
        TLC(3,2)=TLC(2,3)
        TLC(3,3)=TLC(1,1)
        DO 616 I=1,NTIE
        DO 616 J=1,NTIE
  616   FA(I,J)=1.0
        M(1)=0.0
        M(2)=0.0
        M(3)=0.0
        D(1)=70.0
        D(2)=80.
        D(3)=90.
        DO 45 I=1,NAREA
        XR(I)=0
        XF(I)=0
        V1(I)=0.0
        W(I)=0.0
   45   ED(I)=D(I)
C             CALCULATE THE SYSTEM INITIAL CONDITIONS
        DO 600 I=1,NAREA
        X(I)=0
        PA(I)=0
        DO 602 J=1,NC
        PA(I)=PA(I)+CC(I,J)*XC(I,J)
  602   X(I)=X(I)+XC(I,J)
        EPA(I)=PA(I)
        Q(I)=PA(I)-D(I)
        EQ(I)=EPA(I)-ED(I)
        EX1(I)=X(I)
        EX2(I)=0.0
  600   EX(I)=EX1(I)-EX2(I)
       DO 655 I=1,12
  655  PSOL(I)=0.0
       SO=0.2
       AM=0.0
       IX=11
  101  NTIE=3
       DO 201 I=1,NTIE
       DO 201 J=1,NTIE
       IF(I.NE.J) GO TO 201
       T(I,J)=1
       ET(I,J)=1.0
       NU(I,J)=0.0
       LUM(I,J)=0.0
  201  CONTINUE
```

```
      T(1,2)=1
      T(1,3)=1
      T(2,1)=T(1,2)
      T(2,3)=1
      T(3,1)=T(1,3)
      T(3,2)=T(2,3)
      ET(1,2)=T(1,2)
      ET(1,3)=T(1,3)
      ET(2,3)=T(2,3)
      ET(2,1)=T(2,1)
      ET(3,1)=T(3,1)
      ET(3,2)=T(3,2)
      NU(1,2)=0.1
      NU(1,3)=0.08
      NU(2,3)=0.07
      NU(3,2)=NU(2,3)
      NU(3,1)=NU(1,3)
      LUM(1,2)=0.05
      LUM(1,3)=0.01
      LUM(2,1)=LUM(1,2)
      LUM(2,3)=0.0018
      LUM(3,1)=LUM(1,3)
      LUM(3,2)=LUM(2,3)
      NR1=1
      MM=NTIE-1
       IF(Y.EQ.0.0) GO TO 102
C      CALCULATIONS OF NO. OF GENS. HAVE BEEN REPAIRED
21     I=1
      RAV=0.0
      QAV=0.0
5      EX1(I)=0.0
       XR(I)=0
       K=1
610    KR=TXC(I,K)-XC(I,K)
       KR1=TX(I)-X(I)
       IF(KR1.LE.0) GO TO  404
       IF(KR.LE.0) GO TO 404
       KXR(I,K)=0
       SUM(I,K)=0.0.
       DO 190 KK=1,KR
       S31(I)=KK**2*EXP(KK*1.0)
       MU(I,K)=0.10*I/S31(I)
190    SUM(I,K)=SUM(I,K)+KK*DY*MU(I,K)
       J=1
1      IJ(J)=0
       NL=1
       IF(NL.LE.0) GO TO 400
       S3(I)=J**2*EXP(J*1.0)
       AMU=0.10*I/S3(I)
       CALL  GGPOS(AMU,DNE,NL,IR,IER)
       KXR(I,K)=KXR(I,K)+IR(1)*J
       GO TO 401
400    IF(J.EQ.1) GO TO 404
       KXR(I,K)=KXR(I,K)
       GO TO 3
404    KXR(I,K)=0
       SUM(I,K)=0.0
       GO TO 3
401    J=J+1
       IF(J.LE.KR) GO TO 1
3      EXR(I,K)=XC(I,K)+SUM(I,K)
       K=K+1
       IF(K.LE.NC) GO TO 610
       DO 535 IK=1,NC
       EX1(I)= EX1(I)+EXR(I,IK)
535    XR(I)=XR(I)+KXR(I,IK)
```

```
      I=I+1
      IF(I.LE.NAREA) GO TO 5
C     CALCULATIONS OF NO. OF GENS. HAVE BEEN FAILED FROM EVERY CLASS.
 33   I=1
 15   EX2(I)=0.0
      XF(I)=0
      K=1
 630  KF=XC(I,K)
      IF(KF.LE.0) GO TO 504
      KF2=X(I)
      IF(KF2.LE.0) GO TO 504
      KXF(I,K)=0
      SUM1(I,K)=0.0
      DO 191 KK=1,KF
      S11(I)=KK*EXP(KK*1.0)
      LANDA(I,K)=0.04*I/S11(I)
 191  SUM1(I,K)=SUM1(I,K)+KK*DY*LANDA(I,K)
      J=1
 11   IJ(J)=0
      NM=1
      IF(NM.LE.0) GO TO 500
      S1(I)=J*EXP(J*1.0)
      ALANDA=0.04*I/S1(I)
      CALL GGPCS(ALANDA,DNE,NM,IR,IER)
      KXF(I,K)=KXF(I,K)+IR(1)*J
      GO TO 501
 500  IF(J.EQ.1) GO TO 504
      KXF(I,K)=KXF(I,K)
      GO TO 13
 504  KXF(I,K)=0
      SUM1(I,K)=0.0
      GO TO 13
 501  J=J+1
      IF(J.LE.KF) GO TO 11
 13   EXF(I,K)=SUM1(I,K)
      K=K+1
      IF(K.LE.NC) GO TO 630
      DO 635 IK=1,NC
      EX2(I)=EX2(I)+EXF(I,IK)
 635  XF(I)=XF(I)+KXF(I,IK)
      I=I+1
      IF(I.LE.NAREA) GO TO 15
 14   DO 16 I=1,NAREA
      PA(I)=0
      EPA(I)=0
      DO 17 J=1,NC
      XC(I,J)=XC(I,J)+KXR(I,J)-KXF(I,J)
      EXC(I,J)=EXR(I,J)-EXF(I,J)
      PA(I)=PA(I)+XC(I,J)*CC(I,J)
 17   EPA(I)=EPA(I)+EXC(I,J)*CC(I,J)
      EX(I)=EX1(I)-EX2(I)
 16   X(I)=X(I)+XR(I)-XF(I)
      DO 995 I=1,NAREA
995   ED(I)=D(I)+M(I)*DY
C
  100 IF(Y.GT.12.0) GO TO 715
      IF(Y.GT.8.0) GO TO 703
      IF(Y.GT.4.0) GO TO 702
      IF(Y.GT.3.0) GO TO 701
      M(1)=-20.0/3.0
      M(2)=M(1)
      M(3)=M(1)
      GO TO 777
  701 M(1)=0.0
      M(2)=0.0
      M(3)=0.0
      GO TO 777
```

```
702 M(1)=30.0
    M(2)=25.0
    M(3)=20.0
    GO TO 777
703 IF(Y.GT.9.0) GO TO 704
    M(1)=0.0
    M(2)=0.0
    M(3)=0.0
    GO TO 777
704 M(1)=-30.0
    M(2)=-20.0
    M(3)=-20.0
    GO TO 777
715 IF(Y.GT.18.0) GO TO 717
    IF(Y.GT.15.0) GO TO 716
    M(1)=0.0
    M(2)=0.0
    M(3)=0.0
    GO TO 777
716 M(1)=40.0
    M(2)=160.0/3.0
    M(3)=110.0/3.0
    GO TO 777
717 IF(Y.GT.21.0) GO TO 718
    M(1)=0.0
    M(2)=0.0
    M(3)=0.0
    GO TO 777
718 M(1)=-40.0
    M(2)=-60.0
    M(3)=-110.0/3.0
777 CONTINUE
     DO 130 I=1,NAREA
     CALL GAUSS(IX,S(I),AM,V1(I),K)
     D(I)=C(I)+(V1(I)-W(I))+M(I)*DY
     Q(I)=PA(I)-D(I)
130  EQ(I)=EPA(I)-ED(I)
    IF(ITIE.EQ.1) GO TO 102
200  I=1
208  J=I+1
203  NRP=0
     NF1=0
     R=NU(I,J)
     P=LUM(I,J)
     IF(T(I,J).EQ.0) GO TO 301
     CALL GGPOS(P,DNE1,NR1,IR1,IER)
     ET(I,J)=1-P*DY
     ET(J,I)=ET(I,J)
     T(I,J)=T(I,J)-IR1(1)
     T(J,I)=T(I,J)
     GO TO 302
301  CALL GGPOS(R,DNE1,NR1,IR2,IER)
     ET(I,J)=R*DY
     ET(J,I)=ET(I,J)
     T(I,J)=T(I,J)+IR2(1)
     T(J,I)=T(I,J)
302  J=J+1
     IF(J.LE.NTIE) GO TO 203
     I=I+1
     IF(I.LE.MM) GO TO 208
102 DO 393 I=1,3
    DO 393 J=1,3
    TF(I,J)=FLOAT(T(I,J))
    TT(I,J)=TF(I,J)
393 ETT(I,J)=ET(I,J)
      WRITE(6,103) Y
103   FORMAT(1H1,28X,'TIME=',F6.3)
      WRITE(6,132)
132   FORMAT('0',27X,'-------------')
```

```
      WRITE(6,138)
138   FORMAT('0',4X,'X(I)',3X,'EX(I)',3X,'PA(I)',7X,'D(I)',8X,'ED(I)'
     1 ,9X,'Q(I)',8X,'EQ(I)')
      DO 104 I=1,NAREA
104   WRITE(6,105) X(I),EX(I),PA(I),D(I),ED(I),Q(I),EQ(I),
     X (XC(I,J),J=1,NC)
105   FORMAT('0',5X,I2,3X,F8.4,3X,I3,3X,4(F10.4,3X),3(I2,2X))
      WRITE(6,149)
149   FORMAT('0',17X,'T(I,J)',18X,'ET(I,J)')
      DO 106 I=1,NTIE
106   WRITE(6,107) (TT(I,J),J=1,NTIE),(ETT(I,J),J=1,NTIE)
107   FORMAT('0',15X,3(F6.3,3X),5X,3(F6.3,3X))
C
 670 NZ=9
     M1Z=12
     M2Z=1
     IA=M1Z+M2Z+2
     M12Z=M1Z+M2Z
     MIW=(3*M1Z)+(2*M2Z)+4
     MRW=(IA*IA)+MIW
     IPE=MAX0(NZ,M12Z)
C
     DO 674 I=1,3
     DED(I)=DBLE(ED(I))
     DEX(I)=DBLE(EX(I))
C    DEQ(I)=EQ(I)
     IYY=Y*10.0
C   ------------------------------------------
     CALL GENCC(IYY)
C   ------------------------------------------
C
     DO 674 J=1,3
     XCX(I,J)=XC(I,J)
     DEXC(I,J)=GES(I,J)
 674 DCC(I,J)=CAPP(I,J)
C------------------------------------------------------------
     CALL COST(PE,DPE,RW,IW,IA,NZ,MRW,MIW,RAMDA,
    1             DCC,XC,DED,PM,3,3,M1Z,M2Z,IPE,S4,PSOL,ITIE,NTC)
C------------------------------------------------------------
       F1=EQ(1)+PSOL(1)*ET(1,2)*EQ(2)+PSOL(2)*ET(1,3)*EQ(3)
       F2=EQ(2)+PSOL(4)*ET(2,1)*EQ(1)+PSOL(3)*ET(2,3)*EQ(3)
       F3=EQ(3)+PSOL(5)*ET(3,1)*EQ(1)+PSOL(6)*ET(3,2)*EQ(2)
       F4=Q(1)+PSOL(1)*T(1,2)*Q(2)+PSOL(2)*T(1,3)*Q(3)
       F5=Q(2)+PSOL(4)*T(2,1)*Q(1)+PSOL(3)*T(2,3)*Q(3)
       F6=Q(3)+PSOL(5)*T(3,1)*Q(1)+PSOL(6)*T(3,2)*Q(2)
      ALF1(NA)=PSOL(1)
      ALF2(NA)=PSOL(2)
      ALF3(NA)=PSOL(3)
      ALF4(NA)=PSOL(4)
      ALF5(NA)=PSOL(5)
      ALF6(NA)=PSOL(6)
      GEN11(NA)=XC(1,1)
      GEN12(NA)=XC(1,2)
      GEN13(NA)=XC(1,3)
      GEN21(NA)=XC(2,1)
      GEN22(NA)=XC(2,2)
      GEN23(NA)=XC(2,3)
      GEN31(NA)=XC(3,1)
      GEN32(NA)=XC(3,2)
      GEN33(NA)=XC(3,3)
      GENT1(NA)=X(1)
      GENT2(NA)=X(2)
      GENT3(NA)=X(3)
      EGENT1(NA)=EX(1)
      EGENT2(NA)=EX(2)
      EGENT3(NA)=EX(3)
      DEM1(NA)=D(1)
```

```
      DEM2(NA)=D(2)
      DEM3(NA)=D(3)
      EDEM1(NA)=ED(1)
      EDEM2(NA)=ED(2)
      EDEM3(NA)=ED(3)
      RM1(NA)=Q(1)
      RM2(NA)=Q(2)
      RM3(NA)=Q(3)
      ERM1(NA)=DEQ(1)
      ERM2(NA)=DEQ(2)
      ERM3(NA)=DEQ(3)
      TIME(NA)=Y
      TIE1(NA)=T(1,2)
      TIE2(NA)=T(1,3)
      TIE3(NA)=T(2,3)
      ETIE1(NA)=ET(1,2)
      ETIE2(NA)=ET(1,3)
      ETIE3(NA)=ET(2,3)
      ALD1(NA)=F4
      ALD2(NA)=F5
      ALD3(NA)=F6
      EALD1(NA)=F1
      EALD2(NA)=F2
      EALD3(NA)=F3
      P11(NA)=PGC(1,1)
      P12(NA)=PGC(1,2)
      P13(NA)=PGC(1,3)
      P21(NA)=PGC(2,1)
      P22(NA)=PGC(2,2)
      P23(NA)=PGC(2,3)
      P31(NA)=PGC(3,1)
      P32(NA)=PGC(3,2)
      P33(NA)=PGC(3,3)
      PGG1(NA)=PGG(1)
      PGG2(NA)=PGG(2)
      PGG3(NA)=PGG(3)
      PP1(NA)=PMOO(1)
      PP2(NA)=PMOO(2)
      PP3(NA)=PMOO(3)
      PP4(NA)=PMOO(4)
      PP5(NA)=PMOO(5)
      PP6(NA)=PMOO(6)
      PP7(NA)=PMOO(7)
      PP8(NA)=PMOO(8)
      PP9(NA)=PMOO(9)
      TC12(NA)=TCLL(1,2)
      TC13(NA)=TCLL(1,3)
      TC23(NA)=TCLL(2,3)
      QTI1(NA)=QTIL(1)
      QTI2(NA)=QTIL(2)
      QTI3(NA)=QTIL(3)
      Q1(NA)=QS(1)
      Q2(NA)=QS(2)
      Q3(NA)=QS(3)
      QR1(NA)=QRT(1)
      QR2(NA)=QRT(2)
      QR3(NA)=QRT(3)
        Y=Y+DY
        DO 135 I=1,NAREA
        S(I)=SO+D(I)/150.
  135   W(I)=V1(I)
C
      TCOST=TCOST+SCOST
      RCOST=RCOST+HCOST
      COST1(NA)=SCOST
      COST2(NA)=HCOST
      COSTT(NA)=TCOST
      COST3(NA)=RCOST
      YDY=Y-DY
      IF(YDY.LT.0.0001) GO TO 673
```

```
C
      DO 695 I=1,NAREA
      IF(QS(I).GE.RINDX) GO TO 694
      IQN2(I)=IQN2(I)+1
  694 CONTINUE
      QIN(I)=1.0-(IQN2(I)*DY/YDY)
  695 QAV=QAV+QIN(I)
      QAV=QAV/NAREA
C
      DO 665 I=1,NAREA
      IF(QTIL(I).GE.RINDX) GO TO 665
      IQN(I)=IQN(I)+1
  665 CONTINUE
C
      DO 667 I=1,NAREA
      RLOLP(I)=IQN(I)*DY/YDY
      RIN(I)=1.0-RLOLP(I)
  667 RAV=RAV+RIN(I)
      RAV=RAV/NAREA
C
      ROET=0.0D0
      SUMD=0.0D0
      DO 657 I=1,NAREA
      IF(QTIL(I).GE.0.0D0) GO TO 656
      ROE(I)=ROE(I)+QTIL(I)
  656 DSUM(I)=DSUM(I)+ED(I)
      EIR(I)=1.0D0+(ROE(I)/DSUM(I))
      SUMD=SUMD+DSUM(I)
      ROET=ROET+ROE(I)
  657 CONTINUE
      TEIR=1.0D0+(ROET/SUMD)
      WRITE(6,669)RAV,(RIN(I),I=1,3),QAV,(QIN(I),I=1,3),TCOST
      ROET=-ROET
  669 FORMAT(/,10X,'RELIABILITY INDEX=',F5.2,5X,'R1,R2,R3 = ',
     13F5.2,/,10X,'REL BEFORE CONTROL=',F5.2,5X,'QR1,QR2,QR3=',3F6.2,
     2   /,10X,'TOTAL COST = ',F13.3,1H1)
      WRITE(6,672)TEIR,(EIR(I),I=1,3),ROET,SUMD
  672 FORMAT(10X,'ENERGY INDEX OF REL.=',F5.2,5X,'EIR(I)=',3F5.2,/,
     1   10X,'ROET=',F12.4,5X,'SUM OF D = ',F12.4)
C
  673 CONTINUE
      NA=NA+1
      IF(Y.LE.YOUT) GO TO 21
C
      DO 839 I=1,NA
      WRITE(6,831)TIME(I),COST1(I),COST2(I),COSTT(I),COST3(I),
     1    PGG1(I),PGG2(I),PGG3(I),ALF1(I),ALF2(I),ALF3(I),ALF4(I),
     2ALF5(I),ALF6(I),EDEM1(I),EDEM2(I),EDEM3(I),QR1(I),QR2(I),QR3(I)
      WRITE(6,833) QTI1(I),QTI2(I),QTI3(I),ERM1(I),ERM2(I),ERM3(I),
     1    Q1(I),Q2(I),Q3(I)
      WRITE(6,835) P11(I),P12(I),P13(I),P21(I),P22(I),P23(I),P31(I),
     1          P32(I),P33(I)
      WRITE(6,837)PP1(I),PP2(I),PP3(I),PP4(I),PP5(I),PP6(I),PP7(I),
     1 PP8(I),PP9(I),TC12(I),TC13(I),TC23(I),DEM1(I),DEM2(I),DEM3(I)
  839 CONTINUE
  831 FORMAT(2X,F4.1,4F10.2,3F8.3,/,2X,6F11.5,/,2X,3F12.4,3F11.4)
  833 FORMAT(2X,6F11.3,/,2X,3F10.3)
  835 FORMAT(9F8.3)
  837 FORMAT(2X,9F7.2,/,2X,3F8.3,3X,3F9.4)
         STOP
         END
```

```
C-----------------------------------------------------------------------I
C        ECONOMIC DISPATCH SUBROUTINE                                   I
C                                                                       I
      SUBROUTINE COST(PE,DPE,RW,IW,IA,NZ,MRW,MIW,RAMDA,
     1              CX,NX,D,PM,NAREA,NCLAS,M1Z,M2Z,IPF,SA,PSOL,ITIE,NTC)
C-----------------------------------------------------------------------I
      IMPLICIT REAL*8(A-H,O-Z)
      COMMON /DDDAA/ DEXC(3,3),DEX(3),DEQ(3),PMOO(9)
      COMMON /QQQTT/ QTIL(3),FA(3,3),QS(3),QFT(3),TLC(3,3)
      COMMON /TTTLL/ ETT(3,3),TT(3,3),TCLL(3,3)
      DIMENSION PE(27),DPE(IA),RW(MRW),IW(MIW)
      DIMENSION RAMDA(3,10),CX(NAREA,NCLAS),NX(NAREA,NCLAS)
      DIMENSION D(3),QED(3),PED(3),ORD(3),TCL(3,3),PM(3,9),GEST(3,9)
      DIMENSION PEI(3),RWD(230),EQ(3),ET(3,3),PF(3),QLP(3),QRR(3)
      DIMENSION AD(14,6),BD(14),CD(6),T(3,3),Q(3),QSS(3),PG(3)
      DIMENSION NCC(4),NC(3),NCF(3),NCL(3),LAR(27),LAC(27),LAG(30)
      DIMENSION PSOL(12),DSO(14),QE(3),TIE(3),QF(3),PMM(3),FOS(3)
      DIMENSION QTI(3),PC(3),TQE(3),TEXT(3),AAAI(30),AAI(30),PMO(27)
      DIMENSION FEX(3,3),BETA(3,3),TEX(3,3),TCT(3,3),DEXX(3,10),CXS(3,9)
      DIMENSION PPM(3,9),PGX(3,9),RAMA(3,10),PGXX(3,3),PLOS(3,3)
      DIMENSION PLOPO(27,3),XFER(27,3),PXFER(27,3)
      DIMENSION A1(3,3),A2(3,3),A3(3,3)
      DIMENSION LARR(30),LAS(27),LIM(3),LIN(3)
C
      DATA NC/9,9,9/,NA/3/,NARG,NCT/0,1/, NGEN,NSEG,LOSCO/3,3,1/
      DATA TLC1,TLC2,TLC3/60.0D0,50.0D0,30.0D0/
      DATA LAR/1,1,2,3,1,2,2,3,1,3,1,3,1,3,3,2,3,2,2,3,2,3,2,1,2,1,1/
      DATA LAC/1,2,10,19,3,11,12,20,4,21,5,22,6,23,24,13,25,14,
     1         15,26,16,27,17,7,18,8,9/
      DATA LAG/1,2,1,1,3,2,3,2,4,3,5,4,6,5,6,4,7,5,6,8,7,9,8,7,9,8,9,
     1         10,10,10/
      DATA LAS/1,2,3,4,5,6,7,8,9,1,2,3,4,5,6,7,8,9,1,2,3,4,5,6,7,8,9/
      DATA LARR/1,2,3,1,1,2,1,2,3,2,3,2,2,3,2,3,3,1,3,1,3,1,3,2,
     1          2,1,3,2,1,1/
      DATA A1/0.D0,3.00-3,2.D-3,3.D-3,0.D0,1.D-3,2.D-3,1.D-3,0.D0/
      DATA A2/9*0.D0/
      DATA A3/9*0.D0/
C     DATA A1/0.0D0,2.5D-3,1.6D-3,2.5D-3,0.0D0,8.6D-4,1.6D-3,
C    1        8.6D-4,0.0D0/
C     DATA A2/0.0D0,0.1D0,0.08D0,0.1D0,0.0D0,0.0D0,0.08D0,2*0.0D0/
C     DATA A3/0.D0,16.D0,21.D0,16.D0,0.D0,18.D0,21.D0,18.D0,0.D0/
C
C     IF LAR, LARR NEEDED, SET NARG>0 FOR LARGE SYSTEM,
C                              FROM SUBROUTINE PDIS
      IF(NARG.EQ.1) CALL PDIS(LLLLL)
C
C     DATA INITIALIZATION & INITIAL CLEAR OF ALL VARIABLES.
C
C

      NGT=NGEN*NSEG
      NUT=NGT*NA
      NUTA=NUT+NA
      NGT1=NGT+1
      NAR1=NA+1
C
C
      DO 33 I=1,NA
      DO 33 K=1,NGT
      L=(K-1)/3 +1
      GEST(I,K)=DEXC(I,L)
      CXS(I,K)=CX(I,L)/3.0D0
   33 CONTINUE
C
    5 PMT=0.0
      PMM(1)=0.0
      PMM(2)=0.0
      PMM(3)=0.0
      DO 90 I=1,NA
      DO 90 J=1,NGT
      PM(I,J)=CXS(I,J)*GEST(I,J)
      PMM(I)=PMM(I)+PM(I,J)
   90 PMT=PMT+PM(I,J)
```

```
      D(U)=0.0
      DO 150 I=1,NAREA
      DEQ(I)=PMM(I)-D(I)
      QR(I)=DEQ(I)
      Q(I)=QR(I)
      QTI(I)=0.0D0
      EQ(I)=QR(I)
      TQE(I)=0.0D0
  150 DTOT=DTOT+D(I)
      DO 594 I=1,NUTA
  594 AAI(I)=0.0D0
      DO 596 I=1,NA
      DO 596 J=1,NGT1
  596 DEXX(I,J)=0.0D0
C
C
      DO 667 I=1,NA
      DO 667 J=1,NA
      T(I,J)=TT(I,J)
      FEX(I,J)=0.0D0
      TEX(I,J)=0.0D0
      BETA(I,J)=0.0D0
      PLOS(I,J)=0.0D0
      PGXX(I,J)=0,0D0
      IF(ETT(I,J).LT.0.9) GO TO 647
      ETT(I,J)=1.0
      GO TO 658
  647 ETT(I,J)=0.0
  658 CONTINUE
      TCL(I,J)=ETT(I,J)*TLC(I,J)
      TCLL(I,J)=ETT(I,J)
  667 ET(I,J)=ETT(I,J)
C
C ------ PRE-DISPATCH FOR BEST SYSTEM AVAILABILITY --------
C
  601 IF(QR(1).GE.0.0D0.AND.QR(2).GE.0.0D0.AND.QR(3).GE.0.0D0) GO TO 451
  433 IF(QR(1).LT.0.0D0.AND.QR(2).LT.0.0D0.AND.QR(3).LT.0.0D0)GO TO 408
C
      IF(ITIE.NE.1.AND.NTC.EQ.1) GO TO 606
      DO 505 I=1,NA
      DO 505 J=1,NA
  505 TCL(I,J)=DTOT
  606 CONTINUE
C
C
  339 DO 341 I=1,NA
  341 QTI(I)=DEQ(I)
  345 CONTINUE
C
      CALL QQLP(NA,QTI,EPS1,EPS2,EPS3,TCL)
      CALL DISPE(QTI,ET,T,Q,S4,PSOL,EPS1,EPS2,EPS3,NTC,NA)
C
      DO 426 I=1,NA
      IF(DEQ(I).LE.0.0D0) GO TO 425
      PR(I)=D(I)+QTI(I)-QTIL(I)
      GO TO 426
  425 PR(I)=PMM(I)
  426 CONTINUE
      GO TO 455
C
  451 CONTINUE
      DO 457 I=1,NA
  457 PR(I)=D(I)
  455 CONTINUE
C
C ----  COMPUTE THE RESERVES BY REL. CONTROL-----------------
C
```

```
      DTOT2=0.0D0
      DO 135 I=1,NA
      PC(I)=0.0D0
  135 DTOT2=DTOT2+PR(I)
C
      QRT(1)=DEQ(1)+PSOL(1)*QTI(2)+PSOL(2)*QTI(3)
      QRT(2)=DEQ(2)+PSOL(3)*QTI(3)+PSOL(4)*QTI(1)
      QRT(3)=DEQ(3)+PSOL(5)*QTI(1)+PSOL(6)*QTI(2)
C     IF(ITIE.EQ.1.AND.NTC.NE.1) GO TO 139
C
      WRITE(6,783) (PM(1,J),J=1,NGT)
      WRITE(6,783)  (PM(2,J),J=1,NGT)
      WRITE(6,783)  (PM(3,J),J=1,NGT)
  783 FORMAT(3X,'AVA. PWR ',3X,9F6.1)
C-------------------------------------------------------------------
C     MERIT-ORDER LOADING
C-------------------------------------------------------------------
      WRITE(6,802)  (RAMDA(1,J),J=1,9)
      WRITE(6,802)  (RAMDA(2,J),J=1,9)
      WRITE(6,802)  (RAMDA(3,J),J=1,9)
  802 FORMAT(3X,'LAMDA=',9F9.3)
C
C
      PMOO(1)=PM(1,1)+PM(1,2)+PM(1,3)
      PMOO(2)=PM(2,1)+PM(2,2)+PM(2,3)
      PMOO(3)=PM(3,1)+PM(3,2)+PM(3,3)
      PMOO(4)=PM(1,4)+PM(1,5)+PM(1,6)
      PMOO(5)=PM(3,4)+PM(3,5)+PM(3,6)
      PMOO(6)=PM(2,4)+PM(2,5)+PM(2,6)
      PMOO(7)=PM(3,7)+PM(3,8)+PM(3,9)
      PMOO(8)=PM(2,7)+PM(2,8)+PM(2,9)
      PMOO(9)=PM(1,7)+PM(1,8)+PM(1,9)
C
      DO 55 L=1,NUT
      KAR=LAR(L)
      KAG=LAG(L)
      PMO(L)=PM(KAR,KAG)
   55 CONTINUE
C
      DO 916 I=1,NUT
      PE(I)=0.0D0
      DO 916 J=1,NA
  916 XFER(I,J)=0.0D0
C
      DEPP=DTOT
C
      DO 3300 I=1,NA
      NCCC=NC(I)
      DEXXX=PMM(I)
      IF(D(I).GE.DEXXX) GO TO 3150
      DEXXX=D(I)
      DO 3100 K=1,NCCC
      K99=9*(I-1) + K
      K88=LAS(K99)
      DEXX(I,K88)=PM(I,K88)
      DEXXX=DEXXX-DEXX(I,K88)
      IF(DEXXX.GE.0.0D0) GO TO 3100
      DEXX(I,K88)=PM(I,K88)+DEXXX
      GO TO 3300
 3100 CONTINUE
      GO TO 3300
 3150 DO 3200 K=1,NCCC
      DEXX(I,K)=PM(I,K)
 3200 CONTINUE
      NCCC1=NCCC+1
      DEXX(I,NCCC1)=D(I)-DEXXX
 3300 CONTINUE
C
```

```
C
      DO 66 I=1,NA
      IFIR=LARR(I)
   66 AAI(I)=DEXX(IFIR,NGT1)
C
      DO 77 K=NAR1,NUTA
      LVAR=NUTA+1-K
      LR1=LARR(K)
      LR2=LAG(LVAR)
   77 AAI(K)=DEXX(LR1,LR2)
C
      DO 88 K=1,NUTA
   88 AAAI(K)=AAI(K)
      DO 81 I=1,NA
      DO 81 K=1,NGT
   81 PPM(I,K)=PM(I,K)
C
C     WRITE(6,3400) ((DEXX(I,J),J=1,NGT1),I=1,3)
C3400 FORMAT(3X,'AAI=',30F7.2)
C
      NUTA1=NUTA+1
      KKK=1
      LEF=0
      JI=0
 3500 L=1
 4197 IL=LAR(L)
      LC=LAC(L)
      KSG=LAG(L)
      KML=NUTA1-L
      PCMM=PC(IL)
      PELC=PE(LC)
      PE(LC)=PMO(L)
      PC(IL)=PC(IL)+PMO(L)
C
 5000 IF(NCT.GE.2) GO TO 920
C
      IF(PC(IL).LE.D(IL)) GO TO 7100
      IF(LUSCO.EQ.1) GO TO 1001
C-----------------------------------------------------------------
C           COMPUTE  EXCHANGES WITHOUT LOSSES
C-----------------------------------------------------------------
 5090 TEXXX=0.0D0
      PCOO=PC(IL)-PMO(L)
      IF(PCOO.GE.D(IL)) GO TO 5900
      TTPP=PC(IL)-D(IL)
      GO TO 6005
 5900 TTPP=PMO(L)
 6005 CONTINUE
      DO 6600 K=1,NUTA
      ILL=LARR(K)
      IF(ILL.EQ.IL) GO TO 6600
      IF(PC(ILL).GE.D(ILL)) GO TO 6600
      IF(AAI(K).LE.0.0D0) GO TO 6600
      IF(TCL(IL,ILL).LE.0.0D0) GO TO 6600
      TTP=TTPP
      TTPP=TTP-AAI(K)
      IF(TTPP.GE.0.0D0) GO TO 6400
      IF(TTP.LT.TCL(IL,ILL)) GO TO 6300
 6100 TEX(IL,ILL)=TCL(IL,ILL)
      AAI(K)=AAI(K)-TCL(IL,ILL)
      PC(ILL)=PC(ILL)+TCL(IL,ILL)
      TTPP=TTP-TEX(IL,ILL)
      TCL(IL,ILL)=0.0D0
      TCL(ILL,IL)=0.0D0
      TEXXX=TEXXX+TEX(IL,ILL)
      FEX(IL,ILL)=FEX(IL,ILL)+TEX(IL,ILL)
      FEX(ILL,IL)=-FEX(IL,ILL)
      GO TO 6600
```

```
6200 IF(TTPP.LE.0.0D0) GO TO 6800
     GO TO 6600
6300 TEX(IL,ILL)=TTP
     AAI(K)=AAI(K)-TTP
     PC(ILL)=PC(ILL)+TTP
     TTPP=0.0D0
     TCL(IL,ILL)=TCL(IL,ILL)-TEX(IL,ILL)
     TCL(ILL,IL)=TCL(IL,ILL)
     TEXXX=TEXXX+TEX(IL,ILL)
     FEX(IL,ILL)=FEX(IL,ILL)+TEX(IL,ILL)
     FEX(ILL,IL)=-FEX(IL,ILL)
     GO TO 6800
6400 IF(AAI(K).LT.TCL(IL,ILL)) GO TO 6500
     GO TO 6100
6500 TEX(IL,ILL)=AAI(K)
     AAI(K)=0.0D0
     PC(ILL)=PC(ILL)+TEX(IL,ILL)
     TTPP=TTP-TEX(IL,ILL)
     TCL(IL,ILL)=TCL(IL,ILL)-TEX(IL,ILL)
     TCL(ILL,IL)=TCL(IL,ILL)
     TEXXX=TEXXX+TEX(IL,ILL)
     FEX(IL,ILL)=FEX(IL,ILL)+TEX(IL,ILL)
     FEX(ILL,IL)=-FEX(IL,ILL)
     GO TO 6200
6600 CONTINUE
C
6800 PC(IL)=PC(IL)-PMO(L)
     IF(PC(IL).GE.D(IL)) GO TO 6910
     PE(LC)=D(IL)-PC(IL)+TEXXX
6900 PC(IL)=PC(IL)+PE(LC)
     GO TC 6950
6910 PE(LC)=TEXXX
     GO TO 6900
6950 DEPP=DEPP-PE(LC)
     GO TO 7000
C---------------------------------------------------------------
C     EXCHANGE LOOP WITH TRANSMISSION LOSSES
C---------------------------------------------------------------
1001 IF(PCMM.GE.D(IL)) GC TO 1010
     DMPC=D(IL)-PCMM
     PE(LC)=DMPC
     PPM(IL,KSG)=PPM(IL,KSG)-DMPC
     PC(IL)=D(IL)
     AAI(KML)=AAI(KML)-DMPC
     DEPP=DEPP-DMPC
     GO TO 1011
1010 CONTINUE
     PC(IL)=PCMM
     PE(LC)=PELC
1011 IF(LEF.NE.0) GO TO 1020
     LEF=L
1020 CONTINUE
C
C----- SELECT IMPORT CANDIDATE AREAS ----------
     JJI=0
     JFIR=1
1021 DO 1050 K=JFIR,NUTA
     IF(AAI(K).LE.0.0D0) GO TO 1050
     JI=LARR(K)
     IF(JI.EQ.JJI) GO TO 1050
     JK=K
     K31=31-K
     JS=LAG(K31)
     GO TO 1055
1050 CONTINUE
1055 IF(JI.EQ.0) GO TO 7000
```

```
C----- CANDIDATES FOR EXPORT OF POWER --------
C
      DO 1200 I=1,NA
 1200 LIN(I)=0
      DO 1210 I=1,NA
 1210 LIM(I)=0
      IFAL=0
C
      DO 1300 I=1,NA
      IF(I.EQ.JI) GO TO 1300
      IF(PC(I).LT.D(I)) GO TO 1300
      DO 1280 KK=LEF,NUT
      IF(LAR(KK).EQ.I) GO TO 1230
      GO TO 1280
 1230 KKG=LAG(KK)
      IF(PPM(I,KKG).EC.0.0D0) GO TO 1280
      IF(TCL(I,JI).LE.0.0D0) GO TO 1290
      LIM(I)=LAC(KK)
      LIN(I)=KKG
      IFAL=1
      GO TO 1300
 1290 IFALS=1
      GO TO 1300
 1280 CONTINUE
 1300 CONTINUE
C
      IF(IFAL.EQ.0) GO TO 1303
      GO TO 1304
 1303 IF(IFALS.NE.1) GO TO 7000
      JFIR=JK+1
      IF(JFIR.GT.NUTA) GO TO 7000
      JJI=JI
      GO TO 1021
 1304 CONTINUE
C
C----- LOSSES & PENALTY FACTORS AND NEW LAMDA'S ---------
C
      DO 1305 I=1,NUT
      DO 1305 J=1,NA
      PXFER(I,J)=0.0D0
 1305 PLOPO(I,J)=0.0D0
      DO 1307 I=1,NA
      DO 1307 K=1,NGT1
 1307 RAMA(I,K)=1000.0D0
      DO 1310 I=1,NA
      DO 1310 K=1,NGT
 1310 PGX(I,K)=0.0D0
C
      DO 1400 I=1,NA
      K5=LIN(I)
      K55=LIM(I)
      IF(K5.EQ.0) GO TO 1400
      IF(TCL(I,JI).LE.0.D0) GO TO 1400
      IF(PPM(I,K5).LF.0.0D0) GO TO 1400
      IF(TCL(I,JI).GT.AAI(JK)) GO TO 1311
      PDJ=TCL(I,JI)
      GO TO 1320
 1311 PDJ=AAI(JK)
 1320 IF(PDJ.GE.PPM(I,K5)) GO TO 1330
      IF(A1(I,JI).EQ.0.D0) GO TO 1335
C     DISCC=A3(I,JI)+FEX(I,JI)+PDJ
C     DISC3=(A2(I,JI)-1.D0)*(A2(I,JI)-1.D0)
C     DISC4=4.D0*DISCC*A1(I,JI)
C     DISC=DISC3-DISC4
C     IF(DISC.LT.0.0D0) GO TO 1330
C     DISC=DSQRT(DISC)
C     PGXXX=(1.0D0-A2(I,JI)-DISC)*0.5D0/A1(I,JI)
      PGXXX=A1(I,JI)*PDJ*PDJ + A2(I,JI)*PDJ + A3(I,JI) + PDJ
      PGXXX=PGXXX + PGXX(I,JI)
      GO TO 1340
```

```
 1335 PGXXX=FEX(I,JI)+PDJ
      GO TO 1340
 1330 PGXXX=PPM(I,K5)+PGXX(I,JI)
 1340 CONTINUE
      PLOSS=(A1(I,JI)*PGXXX*PGXXX)+(A2(I,JI)*PGXXX)+A3(I,JI)
      PLOPO(K55,JI)=PLOSS - PLOS(I,JI)
      PGX(I,K5)=PGXXX-PGXX(I,JI)
      IF(PGX(I,K5).LE.0.D0) GO TO 1400
      PXFER(K55,JI)=PGX(I,K5)-PLOPO(K55,JI)
      PLPGX=PLOPO(K55,JI)/PGX(I,K5)
      PLPGM=1.0D0-PLPGX
      IF(PLPGM.LE.0.D0) GO TO 1400
      ROCO=1.0D0/PLPGM
      RAMA(I,K5)=RAMDA(I,K5)*ROCO
 1400 CONTINUE
C
C----- MINIMUM VALUE OUT OF THE NEW LAMDA'S -----------
C
 1410 MK=LIN(1)
      MI=1
      RAMM=2000.0D0
      DO 1430 I=1,NA
      K7=LIN(I)
      IF(K7.EQ.0) GO TO 1430
      IF(RAMM.LT.RAMA(I,K7)) GO TO 1430
      MK=K7
      MI=I
      RAMM=RAMA(I,K7)
 1430 CONTINUE
C
      MS=LIM(MI)
C     IF(RAMM.EQ.2000.0D0) GO TO 7000
      IF(RAMM.GE.RAMDA(JI,JS)) GO TO 1440
      GO TO 1470
 1440 IF(DEQ(JI).GE.0.0D0) GO TO 7000
      FEEX=0.0D0
      DO 1460 I=1,NA
      IF(I.EQ.JI) GO TO 1460
      FEEX=FEEX+FEX(I,JI)
 1460 CONTINUE
      FEXD=FEEX+PMM(JI)
      IF(FEXD.GE.D(JI)) GO TO 7000
 1470 CONTINUE
C
C----- DISPATCH WITH TRANS. LOSSES -----------
C
 1500 PLOS(MI,JI)=PLOS(MI,JI)+PLOPO(MS,JI)
      PGXX(MI,JI)=PGXX(MI,JI)+PGX(MI,MK)
 1510 PPM(MI,MK)=PPM(MI,MK)-PGX(MI,MK)
      PC(MI)=PC(MI)+PGX(MI,MK)
      PC(JI)=PC(JI)+PXFER(MS,JI)
      XFER(MS,JI)=XFER(MS,JI)-PXFER(MS,JI)
      TCL(MI,JI)=TCL(MI,JI)-PXFER(MS,JI)
      FEX(MI,JI)=FEX(MI,JI)+PXFER(MS,JI)
      AAI(JK)=AAI(JK)-PXFER(MS,JI)
      PE(MS)=PE(MS)+PGX(MI,MK)
      DEPP=DEPP-PXFER(MS,JI)
      TCL(JI,MI)=TCL(MI,JI)
      FEX(JI,MI)=-FEX(MI,JI)
C
C----- CHECK IF THE TOTAL DEMANDS ARE MET ---------------------
C
 7000 IF(DEPP.LE.1.0D-6) GO TO 4297
      IF(L.GE.NUT) GO TO 4297
      L=L+1
      GO TO 4197
```

```
 7100 DEPP=DEPP-PMO(L)
      PPM(IL,KSG)=PPM(IL,KSG)-PMO(L)
      AAI(KML)=AAI(KML)-PE(LC)
      GO TO 7000
  920 CONTINUE
 4297 CONTINUE
      WRITE(6,1234) ((FEX(I,J),J=1,3),I=1,3)
C
C      COMPOSITE TIE LINES ARE ALLOWED ? ----------------
C                                           IF YES, SET NCT > 2.
      IF(NCT.GE.2) GO TO 4298
C
 5500 LCON=2
      NCON=3
C
      DO 5810 I=1,NA
      DO 5810 J=1,NA
 5810 TCT(I,J)=ETT(I,J)*TLC(I,J)
C
      DO 5890 I=1,NA
      MCON=3
      IF(DEQ(I).GE.0.0D0) GO TO 5850
      DO 5840 J=1,NA
      IF(J.EQ.I) GO TO 5840
      IF(FEX(I,J).LT.0.0D0) GO TO 5835
      IF(FEX(I,J).EQ.0.0D0) GO TO 5840
      MCON=1
      LCON=1
      DO 5830 K=J,NA
 5830 TCT(I,K)=0.0D0
      GO TO 5890
 5835 MCON=2
 5840 CONTINUE
 5850 CONTINUE
      DO 5880 J=1,NA
      IF(J.EQ.I) GO TO 5880
      IF(FEX(I,J).GT.0.0D0) GO TO 5855
      IF(FEX(I,J).EQ.0.0D0) GO TO 5880
      IF(MCON.EQ.1) GO TO 5873
      MCON=2
      GO TO 5880
 5873 LCON=1
      MCON=2
      DO 5875 K=J,NA
 5875 TCT(K,I)=0.0D0
      GO TO 5890
 5855 IF(MCON.EQ.2) GO TO 5860
      MCON=1
      GO TO 5880
 5860 MCON=1
      LCON=1
      KK22=J-1
      DO 5870 K=1,KK22
 5870 TCT(K,I)=0.0D0
      GO TO 5890
 5880 CONTINUE
 5890 CONTINUE
C
      IF(LCON.EQ.2) GO TO 4298
C
C      RE-START --------------
C
      IF(KKK.GT.NA) GO TO 4298
C
      DEPP=DTOT
C
      DO 99 K=1,NUTA
   99 AAI(K)=AAAI(K)
```

```
      DO 5500 K=1,NUT
      PE(K)=0.0D0
      DO 5500 I=1,NA
 5500 XFER(K,I)=0.0D0
      DO 5700 I=1,NA
      PC(I)=0.0D0
      DO 5700 J=1,NA
      TCL(I,J)=TCT(I,J)
      PLOS(I,J)=0.0D0
      PGXX(I,J)=0.0D0
      FEX(I,J)=0.0D0
 5700 CONTINUE
      DO 5705 I=1,NA
      DO 5705 K=1,NGT
 5705 PPM(I,K)=PM(I,K)
      KKK=KKK+1
      GO TO 3500
C
C ------ COMPUTE POWER GENERATION & RESERVES FOR HELP ---------
C
 4298 KKK=1
      WRITE(6,1234) ((FEX(I,J),J=1,3),I=1,3)
 1234 FORMAT(3X,'EXCHANGES=',9F10.3)
      WRITE(6,4231) (PE(I),I=1,9)
      WRITE(6,4231) (PE(I),I=10,18)
      WRITE(6,4231) (PE(I),I=19,27)
 4231 FORMAT(3X,'PSEG=',3F6.2,2X,3F6.2,2X,3F6.2)
C
  994 CONTINUE
      NA1=NA+1
      NCC(1)=0
      DO 301 J=2,NA1
      J1=J-1
  301 NCC(J)=NCC(J1)+NC(J1)
C
      DO 303 K=1,NA
      NCF(K)=NCC(K)+1
      NCL(K)=NCF(K)+NC(K)-1
      PEI(K)=0.0
      NCFK=NCF(K)
      NCLK=NCL(K)
      DO 303 I=NCFK,NCLK
  303 PEI(K)=PEI(K)+PE(I)
C
  603 CONTINUE
      DO 605 I=1,NA
      QS(I)=PEI(I)-D(I)
      PG(I)=PEI(I)
      QSS(I)=QS(I)
  605 CONTINUE
      WRITE(6,973) (PEI(I),I=1,NA),(PR(I),I=1,NA)
      WRITE(6,975) (D(I),I=1,NA),(QS(I),I=1,NA)
  973 FORMAT(/,10X,'PEI(I)=',3F12.4,5X,3F12.4)
  975 FORMAT(10X,'D(I) = ',3F12.4,5X,'QS(I)=',3F12.4)
C
C       COMPUTE BETA'S  ---------------
C
      DO 7550 I=1,NA
      IF(QS(I).EQ.0.0D0) GO TO 7530
      DO 7520 J=1,NA
      IF(I.EQ.J) GO TO 7520
      BETA(J,I)=DABS(FEX(I,J))/DABS(QS(I))
 7520 CONTINUE
      GO TO 7550
 7530 DO 7540 J=1,NA
      IF(I.EQ.J) GO TO 7540
      BETA(J,I)=0.0D0
 7540 CONTINUE
 7550 CONTINUE
```

```
C
      PSOL(1)=BETA(1,2)
      PSOL(2)=BETA(1,3)
      PSOL(3)=BETA(2,3)
      PSOL(4)=BETA(2,1)
      PSOL(5)=BETA(3,1)
      PSOL(6)=BETA(3,2)
C
      WRITE(6,2651)  (PSOL(III),III=1,6)
 2651 FORMAT(10X,
     1 '   BETA(1,2)      BETA(1,3)      BETA(2,3)      BETA(2,1)   ',
     2 '   BETA(3,1)      BETA(3,2)   ',/,3X,'BETA=',6F9.5)
C
        F1=DEQ(1)+PSOL(1)*QS(2)+PSOL(2)*QS(3)
        F2=DEQ(2)+PSOL(4)*QS(1)+PSOL(3)*QS(3)
        F3=DEQ(3)+PSOL(5)*QS(1)+PSOL(6)*QS(2)
        F4=DEQ(1)
        F5=DEQ(2)
        F6=DEQ(3)
      QTIL(1)=F1
      QTIL(2)=F2
      QTIL(3)=F3
        WRITE(6,2671) F1,F2,F3
 2671    FORMAT(/,10X,'QT1,QT2,QT3=    ',3(F11.5,3X))
        WRITE(6,2681) F4,F5,F6
 2681    FORMAT(10X,'EQ1,EQ2,EQ3=    ',3(F11.5,3X),/)
      GO TO 995
C
  408 DO 482 I=1,3
      PG(I)=PMM(I)
      QS(I)=PG(I)-D(I)
      QTIL(I)=QS(I)
  482 CONTINUE
      WRITE(6,779) (PG(I),I=1,NA),(D(I),I=1,NA),(QS(I),I=1,NA)
  779 FORMAT(/,10X,'ALL NEG. RESERVE',/,10X,
     1    'P(I) MAX. =',3F12.4,/,10X,'D(I)=       ',3F12.4,/,10X,
     2   'QS(I)=      ',3F12.4)
      S4=QS(1)+QS(2)+QS(3)
      DO 438 I=1,6
  438 PSOL(I)=0.0D0
  995 CALL COSTM(RAMDA,PM,D,Q,PG,PR,3,9,NSEG,NGEN)
C     CALL LAMDA(PR,PM,RAMDA,3,3,PG)
      RETURN
      END
C-------------------------------------------------------------
      SUBROUTINE PDIS(LLLLL)
C-------------------------------------------------------------
      IMPLICIT REAL*8(A-H,O-Z)
      RETURN
      END
C
C-----------------------------------------------------------------
      SUBROUTINE COSTM(RAMDA,PM,D,Q,PG,PR,NA,NC,NS,NG)
C-----------------------------------------------------------------
      IMPLICIT REAL*8(A-H,O-Z)
      COMMON /CCCTT/ SCOST,HCOST,PGC(3,3),PGG(3)
      DIMENSION RAMDA(NA,10),PM(NA,NC),D(NA),Q(NA),PG(NA),P(3),PR(NA)
      DIMENSION PGS(3,9)
      ICON=1
      DO 110 I=1,NA
      P(I)=PR(I)
      DO 110 J=1,NC
  110 PGS(I,J)=0.0D0
  115 COST=0.0
      DO 223 I=1,NA
      PGI=P(I)
```

```
      DO 223 J=1,NC
      TEMP=PGI
      IF(TEMP.EQ.0.0D0) GO TO 223
      IF(TEMP.LT.PM(I,J)) GO TO 221
      TEMP=PM(I,J)
      PGS(I,J)=PM(I,J)
      GO TO 222
  221 TEMP=PGI
      PGS(I,J)=PGI
  222 CCC=RAMDA(I,J)*TEMP
      COST=COST+CCC
      PGI=PGI-TEMP
  223 CONTINUE
      IF(ICON.EQ.2) GO TO 447
      ICON=2
      HCOST=COST
      DO 441 I=1,NA
      DO 441 J=1,NC
  441 PGS(I,J)=0.0D0
      DO 444 I=1,NA
  444 P(I)=PG(I)
      GO TO 115
  447 SCOST=COST
      DO 555 I=1,NA
  555 PGG(I)=PG(I)
C
C
      DO 600 I=1,NA
      DO 600 J=1,NG
  600 PGC(I,J)=0.0D0
C
      DO 700 I=1,NA
      DO 700 K=1,NC
      K2=(K-1)/NS +1
      PGC(I,K2)=PGC(I,K2) + PGS(I,K)
  700 CONTINUE
C
      WRITE(6,333) SCOST,HCOST,(PG(I),I=1,NA),((PGC(J,I),I=1,NG),J=1,NA)
  333 FORMAT(/,10X,'COST=',F10.4,'HCOST=',F10.4,/,10X,'POWER GEN.=',
     1    3F12.4,/,10X,9F10.3)
C
      RETURN
      END
C-----------------------------------------------------------------
      SUBROUTINE DISPE(EQ,ET,T,Q,S4,PSOL,EPS1,EPS2,EPS3,NTC,NA)
C-----------------------------------------------------------------
      IMPLICIT REAL*8(A-H,O-Z)
C
      COMMON /QQGTT/ QTIL(3),FA(3,3),QS(3),QRT(3),TLC(3,3)
      DIMENSION EQ(NA),ET(NA,NA),T(NA,NA),Q(NA)
      DIMENSION A(14,6),B(14),C1(6),PSOL(12),DSOL(14),RW(233),IW(37)
      DATA E/1.0D0/
      IF(EQ(1).GE.0.0D0.AND.EQ(2).GE.0.0D0.AND.EQ(3).GE.0.0D0) GO TO 217
        IF(NTC.GE.1) GO TO 670
        A1=DABS(EQ(1))/DABS(EQ(2))
        B1=TLC(1,2)/DABS(EQ(2))
        FA(1,2)=DMIN1(E,B1,A1)
        A2=DABS(EQ(1))/DABS(EQ(3))
        B2=TLC(1,3)/DABS(EQ(3))
        FA(1,3)=DMIN1(E,B2,A2)
        A3=DABS(EQ(2))/DABS(EQ(3))
        B3=TLC(2,3)/DABS(EQ(3))
        FA(2,3)=DMIN1(E,B3,A3)
        A4=DABS(EQ(2))/DABS(EQ(1))
        B4=TLC(2,1)/DABS(EQ(1))
        FA(2,1)=DMIN1(E,B4,A4)
        A5=DABS(EQ(3))/DABS(EQ(1))
        B5=TLC(3,1)/DABS(EQ(1))
        FA(3,1)=DMIN1(E,B5,A5)
        A6=DABS(EQ(3))/DABS(EQ(2))
        B6=TLC(3,2)/DABS(EQ(2))
        FA(3,2)=DMIN1(E,B6,A6)
```

```
670     N1=6
        M1=9
        M2=3
        IA=M1+M2+2
        DO 305 I=1,IA
        DO 305 J=1,N1
305     A(I,J)=0.0
        C1(1)=EQ(2)
        C1(2)=EQ(3)
        C1(3)=EQ(3)
        C1(4)=EQ(1)
        C1(5)=EQ(1)
        C1(6)=EQ(2)
      DO 339 I=1,3
      DO 339 J=1,3
 339  ET(I,J)=1.0D0
215     A(1,1)=-ET(1,2)*EQ(2)
        A(1,2)=-ET(1,3)*EQ(3)
        A(2,3)=-ET(2,3)*EQ(3)
        A(2,4)=-ET(2,1)*EQ(1)
        A(3,5)=-ET(3,1)*EQ(1)
        A(3,6)=-ET(3,2)*EQ(2)
        A(4,1)=1.0
        A(5,2)=1.0
        A(6,3)=1.0
        A(7,4)=1.0
        A(8,5)=1.0
        A(9,6)=1.0
        A(10,1)=EQ(2)*ET(1,2)
        A(10,4)=EQ(1)*ET(1,2)
        A(11,2)=EQ(3)*ET(1,3)
        A(11,5)=EQ(1)*ET(1,3)
        A(12,3)=EQ(3)*ET(2,3)
        A(12,6)=EQ(2)*ET(2,3)
        B(1)=EQ(1)
        B(2)=EQ(2)
        B(3)=EQ(3)
        B(4)=FA(1,2)
        B(5)=FA(1,3)
        B(6)=FA(2,3)
        B(7)=FA(2,1)
        B(8)=FA(3,1)
        B(9)=FA(3,2)
        B(10)=0.0
        B(11)=0.0
        B(12)=0.0
        CALL ZX3LP(A,IA,B,C1,N1,M1,M2,S4,PSOL,DSOL,RW,IW,IER)
        GO TO 210
  217 DO 273 I=1,6
  273 PSOL(I)=0.0D0
      S4=0.0D0
  210 WRITE(6,555) S4, (PSOL(I),I=1,6)
  555 FORMAT(10X,'TOTAL DISPATCH = ',F10.3,/,10X,
     1 '   BETA(1,2)      BETA(1,3)      BETA(2,3)      BETA(2,1)    ',
     2 '   BETA(3,1)      BETA(3,2)    ',/,8X,6F13.7)
C
        F1=EQ(1)+PSOL(1)*ET(1,2)*EQ(2)+PSOL(2)*ET(1,3)*EQ(3)
        F2=EQ(2)+PSOL(4)*ET(2,1)*EQ(1)+PSOL(3)*ET(2,3)*EQ(3)
        F3=EQ(3)+PSOL(5)*ET(3,1)*EQ(1)+PSOL(6)*ET(3,2)*EQ(2)
        F4=Q(1)+PSOL(1)*T(1,2)*Q(2)+PSOL(2)*T(1,3)*Q(3)
        F5=Q(2)+PSOL(4)*T(2,1)*Q(1)+PSOL(3)*T(2,3)*Q(3)
        F6=Q(3)+PSOL(5)*T(3,1)*Q(1)+PSOL(6)*T(3,2)*Q(2)
      QTIL(1)=F1
      QTIL(2)=F2
      QTIL(3)=F3
        WRITE(6,283) QTIL(1),QTIL(2),QTIL(3)
 283    FORMAT('0',3X,'QTIL1,QTIL2 AND QTIL3=',3(F11.5,3X))
C       WRITE(6,287) F4,F5,F6
C287    FORMAT('0',3X,'D1,D2 AND D3=',3(F11.5,3X))
      RETURN
      END
```

```
C-----------------------------------------------------------
      SUBROUTINE QQLP(NA,Q,EPS1,EPS2,EPS3,TCL)
C-----------------------------------------------------------
      IMPLICIT REAL*8(A-H,O-Z)
      DIMENSION Q(3),QQ(3),QQQ(3),QLP(3),TCL(3,3)
C
      DO 500 I=1,NA
      TCLT=0.0D0
      QQ(I)=Q(I)
      IF(Q(I).LT.0.0D0) GO TO 150
      DO 100 J=1,NA
      IF(J.EQ.I) GO TO 100
      IF(Q(J).GE.0.0D0) GO TO 100
      TCLT=TCLT+TCL(J,I)
  100 CONTINUE
      IF(TCLT.GE.Q(I)) GO TO 500
      QQ(I)=TCLT
      GO TO 500
  150 DO 400 J=1,NA
      IF(J.EQ.I) GO TO 400
      IF(Q(J).LE.0.0D0) GO TO 400
      IF(Q(J).GE.TCL(I,J)) GO TO 200
      TCIJ=Q(J)
      GO TO 300
  200 TCIJ=TCL(I,J)
  300 TCLT=TCLT+TCIJ
  400 CONTINUE
      QMOD=-Q(I)
      IF(TCLT.GT.QMOD) GO TO 500
      QQ(I)=-TCLT
  500 CONTINUE
C
C
      QQS=0.0D0
      DO 600 I=1,NA
      QQQ(I)=QQ(I)
      QLP(I)=0.0D0
  600 QQS=QQS+QQ(I)
C
      IF(QQS.GE.0.0D0) GO TO 1000
      DO 900 I=1,NA
      IF(QQ(I).GE.0.0D0) GO TO 800
      IF(QQ(I).GE.QQS) GO TO 700
      QQQ(I)=QQ(I)-QQS
      QLP(I)=QQS
      GO TO 2000
  700 QQQ(I)=0.0D0
      QLP(I)=QQ(I)
      QQS=QQS-QQ(I)
      IF(QQS.GE.0.0D0) GO TO 2000
      GO TO 900
  800 QQQ(I)=QQ(I)
      QLP(I)=0.0D0
  900 CONTINUE
      GO TO 2000
C
 1000 DO 1500 I=1,NA
      QQQ(I)=QQ(I)
      QLP(I)=0.0D0
 1500 CONTINUE
C
 2000 EPS1=-QLP(1)
      EPS2=-QLP(2)
      EPS3=-QLP(3)
C
      DO 2200 I=1,NA
 2200 Q(I)=QQQ(I)
C
      WRITE(6,3000) (QQ(I),I=1,3),(Q(I),I=1,3),EPS1,EPS2,EPS3
 3000 FORMAT(3X,9F11.4)
C
C
      RETURN
      END
```

```
C-----------------------------------------------------------
      SUBROUTINE GENCC(IT)
C-----------------------------------------------------------
      IMPLICIT REAL*8(A-H,O-Z)
C
      COMMON /GGGTT/  CAPP(3,3),GES(3,3),EGES(3,3),FAIL(3,3),REPA(3,3)
      COMMON /MMMM1/  M1(121),M2(121),M3(121),M4(121),M5(121),M6(121)
      COMMON /NNNN2/  N1(121),N2(121),N3(121),N4(121),N5(121),N6(121)
      COMMON /MMMM2/  M7(121),M8(121),M9(121),N7(121),N8(121),N9(121)
      K=IT/2+1
C
      DO 100 I=1,3
      DO 100 J=1,3
      GES(I,J)=EGES(I,J)
  100 CONTINUE
C
      INDX=1
C
      DO 600 I=1,3
      DO 600 J=1,3
      IF(GES(I,J).EQ.0.0D0) GO TO 500
      GO TO (1,2,3,4,5,6,7,8,9),INDX
    1 IF(N1(K).LE.0) GO TO 400
      GO TO 300
    2 IF(N2(K).LE.0) GO TO 400
      GO TO 300
    3 IF(N3(K).LE.0) GO TO 400
      GO TO 300
    4 IF(N4(K).LE.0) GO TO 400
      GO TO 300
    5 IF(N5(K).LE.0) GO TO 400
      GO TO 300
    6 IF(N6(K).LE.0) GO TO 400
      GO TO 300
    7 IF(N7(K).LE.0) GO TO 400
      GO TO 300
    8 IF(N8(K).LE.0) GO TO 400
      GO TO 300
    9 IF(N9(K).LE.0) GO TO 400
  300 GES(I,J)=0.0D0
  400 INDX=INDX+1
      GO TO 600
  500 GO TO (11,22,33,44,55,66,77,88,99),INDX
   11 IF(M1(K).LE.0) GO TO 580
      GO TO 550
   22 IF(M2(K).LE.0) GO TO 580
      GO TO 550
   33 IF(M3(K).LE.0) GO TO 580
      GO TO 550
   44 IF(M4(K).LE.0) GO TO 580
      GO TO 550
   55 IF(M5(K).LE.0) GO TO 580
      GO TO 550
   66 IF(M6(K).LE.0) GO TO 580
      GO TO 550
   77 IF(M7(K).LE.0) GO TO 580
      GO TO 550
   88 IF(M8(K).LE.0) GO TO 580
      GO TO 550
   99 IF(M9(K).LE.0) GO TO 580
  550 GES(I,J)=1.0D0
  580 INDX=INDX+1
  600 CONTINUE
C
      DO 700 I=1,3
      DO 700 J=1,3
      EGES(I,J)=GES(I,J)
  700 CONTINUE
      RETURN
      END
```

```
C-----------------------------------------------------------------
      SUBROUTINE POSON
C-----------------------------------------------------------------
C
      REAL*8 CAPP,GES,EGES,FAIL,REPA,SEED(3,3),SEE2(3,3),DSEE2,DSEED
      COMMON /GGGTT/ CAPP(3,3),GES(3,3),EGES(3,3),FAIL(3,3),FEPA(3,3)
      COMMON /MMMM1/ M1(121),M2(121),M3(121),M4(121),M5(121),M6(121)
      COMMON /NNNN2/ N1(121),N2(121),N3(121),N4(121),N5(121),N6(121)
      COMMON /MMMM2/ M7(121),M8(121),M9(121),N7(121),N8(121),N9(121)
      DIMENSION IRRR(121),IRRF(121)
      DATA SEED/11.D0,12.D0,13.D0,21.D0,222.D0,23.D0,31.D0,32.D0,33.D0/
      DATA SEE2/44.D0,45.D0,47.D0,54.D0,55.D0,57.D0,74.D0,75.D0,77.D0/
C
C     GENERATE POISON RANDOM NUMBERS -------------
C
      INDX=1
      N121=121
C
      DO 500 I=1,3
      DO 300 J=1,3
      FF=FAIL(I,J)
      RR=REPA(I,J)
      DSEED=SEED(I,J)
      DSEE2=SEE2(I,J)
C
      CALL GGPOS(FF,DSEED,N121,IRRF,IER)
      CALL GGPOS(RR,DSEED,N121,IRRR,IER)
C
      GO TO (1,2,3,4,5,6,7,8,9),INDX
C
    1 DO 11 K=1,N121
      M1(K)=IRRR(K)
      N1(K)=IRRF(K)
   11 CONTINUE
      GO TO 200
    2 DO 22 K=1,N121
      M2(K)=IRRR(K)
      N2(K)=IRRF(K)
   22 CONTINUE
      GO TO 200
    3 DO 33 K=1,N121
      M3(K)=IRRR(K)
      N3(K)=IRRF(K)
   33 CONTINUE
      GO TO 200
    4 DO 44 K=1,N121
      M4(K)=IRRR(K)
      N4(K)=IRRF(K)
   44 CONTINUE
      GO TO 200
    5 DO 55 K=1,N121
      M5(K)=IRRR(K)
      N5(K)=IRRF(K)
   55 CONTINUE
      GO TO 200
    6 DO 66 K=1,N121
      M6(K)=IRRR(K)
      N6(K)=IRRF(K)
   66 CONTINUE
      GO TO 200
    7 DO 77 K=1,N121
      M7(K)=IRRR(K)
      N7(K)=IRRF(K)
   77 CONTINUE
      GO TO 200
    8 DO 88 K=1,N121
      M8(K)=IRRR(K)
      N8(K)=IRRF(K)
   88 CONTINUE
```

```
      GO TO 200
    9 DO 99 K=1,N121
      M9(K)=IRRR(K)
      N9(K)=IRRF(K)
   99 CONTINUE
  200 INDX=INDX+1
  300 CONTINUE
  500 CONTINUE
C
      DO 700 L=1,121
      WRITE(6,888) M1(L),M2(L),M3(L),M4(L),M5(L),M6(L),M7(L),M8(L),M9(L)
  700 CONTINUE
      DO 800 L=1,121
      WRITE(6,888) N1(L),N2(L),N3(L),N4(L),N5(L),N6(L),N7(L),N8(L),N9(L)
  800 CONTINUE
  888 FORMAT(2X,9I7)
C
      RETURN
      END

            SUBROUTINE GAUSS(IX,S,AM,V,K)
 1      A=0.0
        N=12
        DO 8 J=1,12
        CALL RANDU(IX,IY,YFL,L)
        IX=IY
 8      A=A+YFL
        V=(A-6.0)*S+AM
        RETURN
        END
                 SUBROUTINE RANDU(IX,IY,YFL,IFL)
        IY=IX*65539
 7      IF(IY) 5,6,6
 5      IY=IY+2147483647+1
 6      YFL=IY
        YFL=YFL*.4656613E-9
 2      IFL=YFL
        RETURN
        END
```

The IMSL Routines used in this program are as follows:

GGPOS, GGNML, GGUBS, MDNRIS, MERFI
UERTST, UGETIO, ZX3LP, ZX0LP

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