POWER SYSTEM INTERCONNECTION IN SOUTH EAST ASIAN COUNTRIES

by

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To

my wife

Norulhuda

and sons

Azlan and Zulkifli

ABSTRACT

The benefits of interconnection of power systems include savings from reserve generation capacity, equilibration of marginal costs, bulk transportation of energy and the exploitations of economies of scales. This thesis investigates the benefits from reserve capacity sharing and the equilibration of marginal costs that would be experienced on a small and medium electricity grids. For this purpose, two computer programmes have been developed.

The first programme evaluates the reliability of the two interconnected systems using the reliability index HLOLE (Hourly Loss of Load Expectation). The benefits by capacity savings are through the HLOLE and the EENS (Expected Energy Not Supplied) before and after the interconnection. The second programme calculates the benefits from equilibration of the marginal costs. For each system, the marginal costs are determined at different levels of demands and the operating savings are then computed. The production cost routine for the evaluation of the marginal costs is based on probabilistic simulation.

In both programmes, the importance of system load diversity in the analysis is taken into account. The load model is represented by a two dimensional load probability density matrix. The capacity model is generated taking

into consideration the forced and planned outages of each plant. Data also include the capacity and the generation cost of each unit, and the energy capacity in GWh for the hydro unit if any.

The performances of the programmes have been tested by using data from two systems in the South East Asian Countries namely, the LLN of Malaysia and the PUB of Singapore. Results have indicated that both systems gain appreciably through having the interconnection. The PUB benefits more from the reserve requirements while the LLN gains from the energy interchange. An economic assessment was finally made for the combined benefits. The thesis concludes that interconnection is an economically efficient means of reducing production cost and increasing reliability on both systems.

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CHAPTER 1

INTRODUCTION

1.1 THE BENEFITS OF INTERCONNECTION

The electric utility industry is a capital intensive industry. Its shares about 5 to 20% of all public sector investments in most countries (1). The rates of growth of the demands for electricity are expected to grow especially in the developing countries, and this will have to be met by investments. Therefore any forms of savings in such investments should be critically assessed and judged fairly.

Choosing a generation system expansion plan among the many available to an electric utility is complicated. The uncertainties involved in planning are the forecasting future load requirements, fuel costs, unit reliability and maintenance schedules, construction costs, regulatory requirements and availability and cost of capital.

A common procedure in most utilities is to have several expansion plans that satisfy the reliability criterion. This criterion may be set arbitrarily and based on historical performances. From these, an economic assessments are being done to finally select the best option. The choices of new plants are normally a combinations of hydro, coal, oil or nuclear plants depending on the policy currently adopted.

For most developing countries representatives of the small and medium electricity grids, the interconnection of power system between neighboring countries is rarely given a status as an option candidate. Normally there is lack of commitment and goodwill of the utilities to cooperate fully on such venture. Until recently only the more industrialized developing countries have the desires to investigate further the benefits that could be derived from having such interconnection. The making of interconnection as an option has now becomes inevitable simply because of the immense economy and improved reliability that it can render.

The benefits of power system interconnection are well known and amply documented (2) to (6). The benefits will result in cost savings, either savings in installed cost or savings in the operating cost. Savings in the installed costs can be derived from lower installed reserve requirements and the ability to install larger generating units. Savings in the operating costs are due from the ability to interchange economy energy and from lower spinning requirements.

The lower installed reserve requirements for interconnected systems arise from generator unit outage diversity and load diversity. The full coordination of a system also permits the installation of larger units without excess reserve requirements and reduction in reliability.

The operational savings are through the equilibration of the marginal costs of generation and reduction in spinning reserve requirements. Savings due to economy energy interchange are in large offset by the ability to postpone new efficient generator units because of reduced capacity requirements.

1.2 THE NEED FOR RESEARCH

For the present moment, there is an urgent need to assess the benefits from interconnection for small and medium electricity grids. The ranges of interests are primarily on the savings in the installed reserve requirements and the savings in the energy interchange permitted. Other areas of research are in the interaction of unit sizes, optimal pool size and timing of the interconnection. Before further commitments are to be taken however studies have to be done on the increased transmission requirements and other technical and operational aspects like, load flow, transient stability, frequency stability and mode of operation.

This thesis investigates on the benefits of interconnection for two countries in the South East Asian Countries. The utilities represented are the Lembaga Letrik Negara (LLN) of Malaysia and the Public Utilities Board (PUB) of Singapore. They are typical of the countries where the potential benefits are necessary to be assessed for medium and long term planning. These two countries are members of the Association of the South East Asian Nations (ASEAN), other members being Thailand, Indonesia and the Philippines. Another country Brunei is to be the sixth member after gaining independence from Great Britain in January 1984. This association is set up for regional cooperation in the areas of political, trades, cultural, social, scientific and technical aspects.

One of their long term cooperations is the vizualisation of the ASEAN Power Grid whereby the member countries are interconnected by power lines to share the benefits to be attained from interconnection. This long term plan is justified based on the abundant of hydro potential not fully utilized and the possible gradual introduction of larger generating units like coal and nuclear power plants in these regions. The potential savings from interconnection may then prove to be vital for such economy and reliability enhancements in these regions.

1.3 ORIGINAL CONTRIBUTIONS AND REVIEW OF THESIS.

The benefits that are investigated are specifically on savings in reserve margins and equilibration of marginal costs. The savings in reserve margins mean that the two systems can share reserves depending on the circumstances regulated by the availability of plants due to forced and planned outages.

The savings through equilibration of marginal costs are directly related to the nature of power generation of both systems. By virtue of the differences in plant types, sizes, generation costs, forced outage rates and planned maintenances, there exist a difference in the system marginal cost. This difference results in the savings in the operating cost. The above two savings constitute the bulk of the benefits to be obtained from having the interconnection and are considered sufficient for the present analysis to provide some conclusions to the study.

For the above assessments, two computer programmes have been developed. Each programme can be run independently because of the different nature of the assessments and to save computer time. They are however linked by almost the similar data that are necessary to run the programme.

The first programme evaluates the benefits of interconnection through savings in the reserve margin through the reliability indices Hourly Lost of Load Expectation (HLOLE) and the Expected Energy Not Supplied (EENS). The analysis used the theory of interconnection developed in America during the course of the interconnection of the American Power System.

The second programme calculates the benefits from equilibration of the marginal costs. For each system the marginal costs are determined at different levels of demands, and finally the operating savings are then computed for different sizes of the interconnection. The production cost routine for the evaluation of the marginal cost is based on probablistic simulation.

In both programmes, the importance of system load diversity in the analysis is taken into account. The load model is represented by a two dimensional load probability function. The capacity model is generated taking into consideration of the forced and planned outages of each plant. The other data also include the capacity and the generation cost of each unit, and the energy capacity in GWh for the hydro unit if any.

The methodology and the construction of the computer programmes form an original contributions toward the assessments. The concept of using a two dimensional load probability density function allows the simulation of hour by hour load model which is essential in interconnection studies. The introduction of diversity in the load model in the form of a two dimensional density function provides a first of its kind in interconnection studies. The inclusions of the generator unit outage diversity and its maintenance schedules also provide important contributions toward a more realistic assessments.

The other benefits of the programmes are that, they are able to assess various sizes of interconnection in one computer run. They have the flexibility to investigate the influences of economies of scales, effects of pool maintenances and optimisation of the pool sizes. Generally most other models use large amount of computer time and often require simulations of the entire system even when small parameter changes are made. Using these programmes need however only to change the necessary data and the comparisons are easily done with economy on computer time. The results from these programmes are valuable in the rapid formation of possible plans of expansion which may then be studied in greater details by more sophisticated simulation techniques.

The case study that has been done is based on the available data that have been provided and some assumptions are made to complete the required input data. From results obtained the LLN and the PUB systems gain appreciably from having the interconnection. In general the PUB system gains more from the reserve margin whereas the LLN from the equilibration of marginal costs. This study concludes that interconnection is an economically efficient means of reducing production cost and increasing reliability on both systems.

In order to facilitate the presentation of the analysis, this thesis is divided into seven chapters. Chapter 1 describes the benefits of interconnection, the need for research and also states some original contributions toward the subject. Chapter 2 presents some aspects of the present interconnection studies done so far in the South East Asian Countries. It also defines the purpose and scope of the present research and finally describes the proposed methodology. Chapter 3 focuses on the fundamentals of reliability in general and describes some important reliability indices commonly used in generation studies.

Chapter 4 extends the reliability assessments for two interconnected systems, the concepts of the two dimensional load and capacity models are explained for the determinations of the HLOLE and EENS before and after interconnection. The computer programme developed is also outlined. Chapter 5 presents the methodology for the assessment of the benefits through equilibration of marginal costs. The evaluations of the marginal costs for thermal and mixed hydro thermal systems are explained. The computer programme developed related to this is also outlined. Chapter 6 presents the results of the case study and it follows by a detailed discussion and some further developments in related subjects. Finally, Chapter 7 ends the presentation by producing some conclusions as a result of the analysis. In addition to the main chapters, Appendix A describes the principles behind the application of probabilistic simulation for a mixed thermal hydro system. Appendices B and C present the system and load data for the LLN and the PUB systems respectively.

CHAPTER 2

POWER SYSTEM INTERCONNECTION

2.1 INTRODUCTION

This Chapter describes the present studies on interconnection in the ASEAN region. It shows the potential of interconnection in the overall planning of the power system in the region. The studies that have been carried out by some of the ASEAN utilities are also presented. This Chapter finally, defines the purpose and scope of the research and briefly explains the methodology to evaluate the benefits.

2.2 PRESENT INTERCONNECTION STUDIES

The interconnection studies in the ASEAN region evolved within the activities of the ASEAN Computer Application Committee. This committee was set up to provide a platform for closer cooperation and mutual exchange of experience and expertise in the field of computer applications among fellow utilities in the region. The present committee comprises members of the major utilities, namely, the Electricity Generating Authority of Thailand (EGAT), the Lembage Letrik Negara (LLN) of Malaysia, the Public Utility Board (PUB) of Singapore, the Perusahaan Umum Listrik Negara (PLN) of Indonesia, and the National Power Corporation (NPC) of the Philippines.

The future electric power demand in the ASEAN region is given in Table 2.1 [7]. As can be seen, by 1990 the expected total installed capacity in the region is about 40 GW. For comparison, this is almost equivalent to the combined generation of the eastern network of the United States of America, including the interconnected portion of the Canadian provinces in 1977 [8]. The utilities in this region are continuously synchronised with each other, power is dispatched among the various power systems composing each of the network in order to achieve both economy and reliability.

The power system interconnection in the South East Asian Countries is relatively a new subject. The only one ASEAN related power system interconnection is the weak link between Southern Thailand and West Malaysia. In the

TABLE 2.1

Forecast Electric Power Demand in ASEAN

Countries	1979		1985		1990	
	MW	GWh	MW	GWh	MW	GWh
Indonesia	4400	9800	10900	27000	20100	56000
Malaysia	1300	7500	2700	16000	4800	28000
Philippines	2300	14000	4400	27000	6400	40000
Singapore	1100	6500	1900	11000	2900	17000
Thailand	2400	14000	4800	27000	7100	41000
ASEAN	11500	51800	24700	108000	41300	182000

inaugural meeting of the ASEAN Power Interconnection Project [9], the possible projects within the regions are identified. Fig. 2.1 shows the geographical locations of the countries where the major utilities are involved. Table 2.2 indicates the ranking in order of realization dates of the projects and these have been taken into account of the project lead times.

A study group under the committee was formed in 1979 to investigate the various aspects of EHV (Extra High Voltage) Interconnection between EGAT/LLN/PUB system [10]. Common to all the three utilities was the use of Wein Automatic System Planning (WASP) suite of computer programmes of the IAEA for system expansion studies. With some limitations and constraints, WASP was used exclusively for the proposed interconnection studies.

There were two phases of the study. The first was to determine the economics of sharing reserves through the interconnection and ultimately to reach an optimal capacity and timing. For this purpose, the interconnection was treated as a candidate for system expansion programme, acting as a pseudo generating plant. The major assumptions taken were; i) the pseudo generating plant was loaded above the gas turbines in the economic loading order, it was to be considered as having no energy capacity; and ii) the pseudo generating plant was assumed to have a forced outage of 50% and zero maintenance outages.

This part of the study was done independently by each utility. The difference in the cost functions through optimisation of the generation expansion with and without

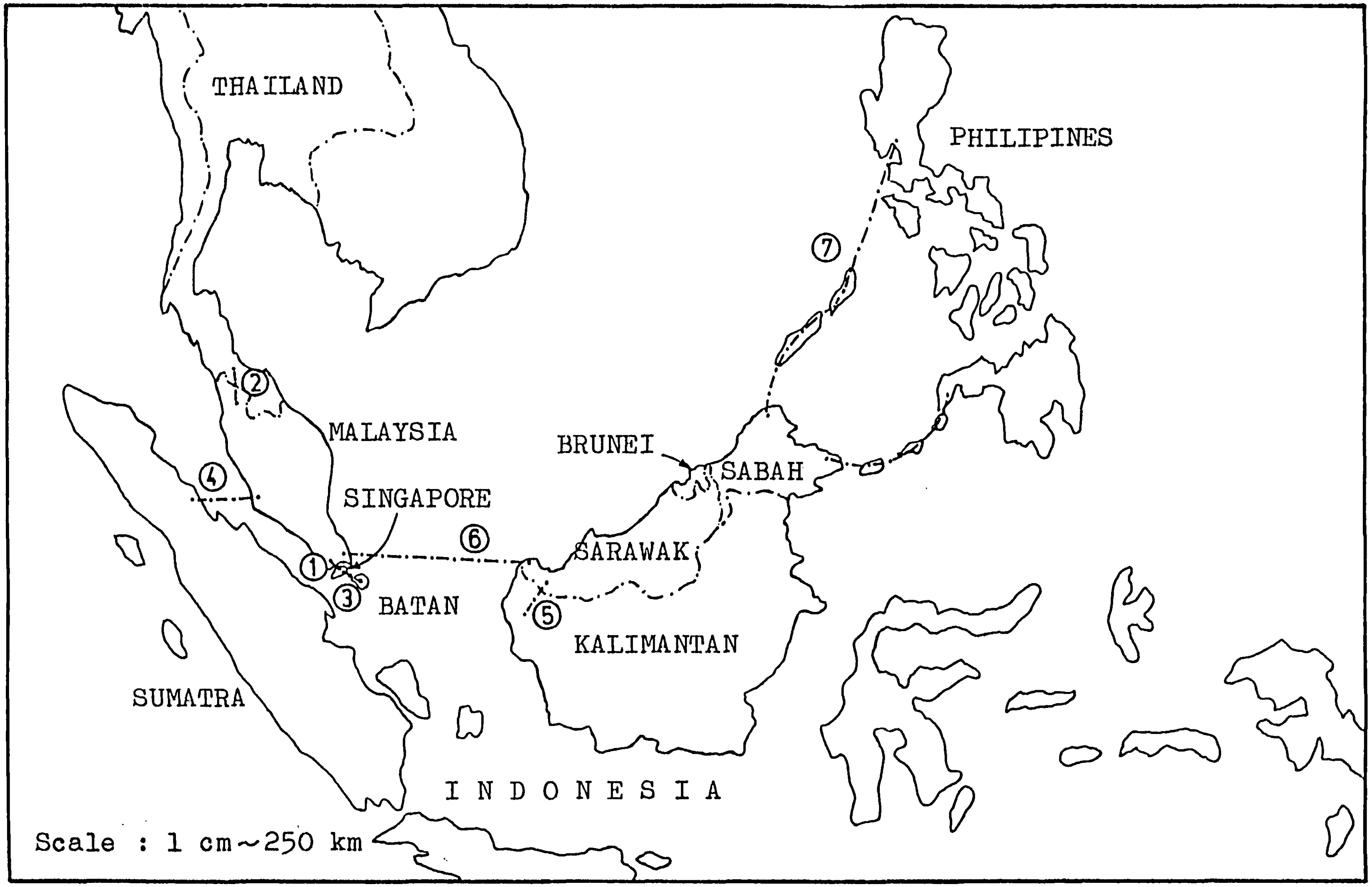

FIG. 2.1 Locations of the ASEAN Power Grid

TABLE 2.2

Realization of Interconnection Projects in ASEAN

No	Projects	< 5 years short	5-10 years medium	> 10 years long	Utilities involved
1	West Malaysia - Singapore	X			LLN*/PUB
2	West Malaysia - Thailand (South Thailand)	X	X		EGAT*/LLN
3	Singapore - Indonesia (Batan)		X		PUB/PLN*
4	West Malaysia - Indonesia (Sumatra)		X		LLN/PLN*
5	East Malaysia (Sarawak) - Indonesia (West Kalimantan)			X	SESCO*/PLN
6	East Malaysia (Sarawak) - West Malaysia			X	LLN/SESCO*
7	East Malaysia (Sabah) - Philippines			X	SESCO*/SEB/NPC

* Coordinating Utility

Note 1. SESCO - Sarawak Electricity Supply Corporation

2. SEB - Sabah Electricity Board

interconnection provided some measure of the benefits. For the periods of study from 1979 to 1992, the findings were that the optimal sizes and the dates for the interconnections were to be 100 MW from 1987/90 for the EGAT/LLN tie, and 200 MW from 1984/86 for the LLN/PUB tie. The above savings were obtained through optimisation of future plants capital investments and their operating costs.

The second part of the study assessed the benefits through energy interchange by combined operations of the three systems. The economic benefits would arise out of the combined system when compared to the independent individual system. The benefit was the difference in the aggregated costs of operation of the three systems operating individually without interconnection and the operating cost for the integrated combined system, assumed then to be interconnected.

The simulation of the system operation was carried out from 1985 to 1992. The equivalent load duration curve was obtained from the individual load duration curve for each system. Energy transfers within the interconnected systems were constrained to not more than 400 GWh/year, representing a load factor of 25% on the 200 MW tie line. In the simulation this was in effect the difference between the energy generated and required for the individual system. Any violations of these values were corrected by changing the loading order of the combined system. The adjustments were made so that the individual loading order for each system remained the same, while the relatively loading positions between the system were varied. The savings through operation of such nature over the 8 year period were approximately US$ 260 million (1977 US$)[1].

The report concluded that the savings evaluated were conservatives due to the constraints and limitations imposed on the simulation of the interconnection. In both the analysis, no account was taken of the diversity in chronological load curves that existed between the LLN/PUB and LLN/EGAT systems. This diversity would give a lower peak demand for the equivalent interconnected system even though the total energy required would remain the same.

2.3 PURPOSE AND SCOPE OF RESEARCH

The purpose of this research is to assess the benefits of power system interconnection with reference to the South East Asian Countries. The outcome of this research is to provide alternative methods of assessing the benefits of interconnection which are to provide quick assessment and economy in computer time for different sizes of the interconnection. The aim is to assess the value of interconnection through capacity savings and to determine the benefits through equilibration of the marginal costs for two interconnected systems. The two utilities selected for the case study are the LLN of Malaysia and the PUB of Singapore. The case study not only provides some realistic assessments of the benefits accrued but it also gives typical sample data and method of analysis for any two systems.

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[1] All costs in the text are in US$.

There are several factors which have been included in the assessments of the interconnection, and they include the effects of load diversity, outage diversity and the maintenance of major plants. These factors are fundamental for interconnection studies and can be very significant in the final assessments. Two programmes have been developed to include these important parameters in the studies. The first programme is able to assess the capacity savings through the measurements of reliability indices Hourly Loss of Load Expectation, HLOLE and Expected Energy Not Served, EENS. The second programme accounts for the benefits from equilibration of the marginal costs.

In the case study, actual system and load data are being used as much as being made available from the two systems. These include the forced and planned outages, system size, generation costs, historical hourly load performances, expansion plans and the corresponding growth rates. The evaluations are based on the hour by hour simulation over the period considered.

For the present analysis, the load management policy has been based on the no load loss policy. This means that the system is able to share reserves up to the limit of the interconnection without reducing the reliability of the individual system.

2.4 PROPOSED METHODOLOGY

The assessments are based on the following methodology. Both systems are required to provide the expansion plans up to the year of study. The year of study is defined as the year whereby interconnection is operational. The standards of security based on some reliability measurements are assumed to be acceptable for that year. The future hour by hour load profile is projected from the historical hourly peak chronology using the expected growth rates. From the expansion plans, the units in the systems are known and any maintenances for the period are reflected by adjustments of the forced outages.

The effects of the interconnection are then investigated on the reliability and the operational aspects of the two systems. The savings through reserve margin can then be estimated by measurements of the improved reliability after the interconnection using the first programme. The operating savings through equilibration of marginal costs can be done using the second programme. The total benefits in monetary terms will be the sum of the two values. The present value method of analysis on the benefits is used to provide a common basis of comparison for an operating period of 25 years.

For the case study undertaken, two years of interconnections are selected to provide comparisons, the years being 1990 and 2000. Each year has been divided into four periods. Using the data from the two systems, the benefits are calculated for different sizes of the interconnection for each period. The sizes of interconnection are 100 MW, 300 MW, and 500 MW. The sum of the benefits for the four periods provides the yearly benefits.

For reliability measurements, the HLOLE is determined using probability mathematics. A two dimensional capacity model and a two dimensional load model are generated and upon integration provides the HLOLE before and after interconnection. For the equilibration of the marginal costs analysis, the programme generates the marginal cost at each demand level, the production cost being obtained from probalistic simulation. The benefits through equilibration of the marginal costs are evaluated for each combination of demands for the two systems and on integration over the combined load probability density function, provides the savings. All the above have been incorporated in the computer programmes developed which are used exclusively for the case study undertaken.

CHAPTER 3

FUNDAMENTALS OF RELIABILITY

3.1 INTRODUCTION

This Chapter explains the concept of reliability, the derivations of the reliability indices and the differences in magnitudes as viewed by the systems and the customers. It also describes how economic evaluations can be incorporated into reliability measurements to balance cost and reliability. Finally, an overview of the common industry reliability indices for generation studies is presented.

3.2 CONCEPT OF RELIABILITY

There are many conditions of uncertainties that surround the electric power system industry. If everything is certain than there will not exist a question of reliability but, as always there are uncertainties associated with demand and supply. The underlying objective of reliability criteria is therefore to provide a basis for balancing cost and reliability. Alternatively, the primary purpose of reliability indices is to serve as basis for system planning.

In the operation and planning of power systems, there are several important criterion that may aid in the process of decision makings. Reliability based on the number of times there is a loss of load in a month or a year, the magnitude of the hours of load not supplied, the accumulation of the megawatts hours of unserved energy or the number of customers unserved would help the planners. If an index can lead towards some conclusions, and if computation of the index is economically practical, then application by planners can be expected.

A good account of the definitions and formulations of the reliability indices is given by an EPRI report [11] of which the followings are some of the important issues presented. The source for any measure of reliability is the reliability indicator. The reliability indicator can be visualized as an on/off type of indicator. For example, the Loss of Load (LOL) indicator will be on when there is a loss of load in the system or vice versa. It can also be a magnitude indicator, for example the Load Not Supplied

(LNS) will provide the amount of load not supplied in MW to the customer. The general concept of the reliability indicator is an observable characteristic which is central to describing the reliability of a system. The indicator may be further classified as a point, interval and duration indicators depending on the nature of the observation being made.

Point indicators merely lead to reliability indices which are not useful for economic studies and generation planning. It is often convenient to select probability indices to a certain period for example a year or a season, and this leads to the interval indicators. The third indicator, the duration indicators however give the interval between events, generally the duration of the loss of load or the duration between successive loss of loads.

The interval indices are the most practical use in generation planning, but computation methods are based on point and duration indices. From these, the interval indices can be computed. Thus, the point and duration indices are used primarily as a means for computing the interval indices. The observation times used to define the interval indicator are often chosen to be the times of system peak demands. The derived index is widely known as the Loss of Load Probability, LOLP even though it is not a probability. It is the expected value of many measurements depending on the number of system peaks in the interval. Conveniently it is usually quoted in days per year, so an LOLP of 1 day per year could mean that on average one should expect a loss of load at system peak about 1 time a year. An appropriate name would be the expected loss of system peaks. This index has little economic significant.

A slightly better index is the expectation value of the cumulative length of loss of load at the end of the period, normally expressed as the expected loss of load hours. However, the index that is of direct economic significant is the expectation value of the cumulative energy not supplied, at the end of the year expressed as the expected energy not supplied. For approximation, the product of the cost of not supplying the energy in $/MWh and the expected energy not supplied, MWh gives a measure of the economic consequences of the outage. It is a function of system size and does not permit comparison with the same index calculated on other system of different size.

A summary of the reliability indicators and indices are given in Table 3.1. The source of the reliability index from the reliability indicator, and the uniform terminology and the name which is commonly used in industry are shown. As can be seen the two point reliability indicators, load not supplied and loss of load, form the basis for all the remaining reliability indices.

By definitions there exist serveral reliability indices for different purposes. Each has its merits and demerits. The indices cover a wide range of contingencies, like a measure of the probability of system failure, the expected magnitude of the load lost, average duration of an outage, the size of the failure and the number of customers affected. Each index is not able to individually provide a

TABLE 3.1

Common Reliability Indices

Reliability Indicator	Reliability Index	
	Uniform Terminology	Industry Terminology
Point measure		
1) Load not supplied	Expected load not supplied	None
2) Loss of load	Probability of loss of load	Loss of load probability
Interval measure		
1) Loss of load points	Expected loss of load points	Loss of load expectation
2) Loss of load hours	Expected loss of load hours	Hourly loss of load expectation
3) Loss of load occurrences	Expected loss of load occurrences	Frequency of loss of load
4) Energy not supplied	Expected energy not supplied	Expected energy not supplied
Duration measure		
1) Loss of load duration	Expected loss of load duration	Duration of loss of load
2) Cycle duration	Expected cycle duration	None

(Taken from EPRI EL-1773 [11])

complete description of the outages.

The reliability indices however have to be quoted with specific relationship either for the utility system as a whole or for the customers, since both are viewed differently. For the system it is even divided into four subsystems; the generation, the bulk supply, area supply and distribution. Similarly, the customers indices vary from customer to customer depending on domestic, industrial or commercial sectors for examples. It is therefore necessary to state which of the area the reliability indices are being referred to as seen from the following examples.

Table 3.2 shows the differences in magnitudes of several reliability indices as viewed by the system and the customers. Tables 3.3a, b and c show the detailed breakdowns of the magnitudes of reliability indices Frequency of Loss of Load, Expected Energy Not Supplied and Hourly Loss of Load Expectation respectively. It can be observed that there are varied expectations and that the generation side contributes the least of the expectations.

There are two different but related concepts when assessing power system security and the use of system reliability measures. The first has an essentially short term objectives of guiding system operations on an hourly or daily basis; the second involves reliability evaluation for the long range expansion planning of power system. In the short run, it involves the use of preventive measures and on line decisions to maintain or to improve the security level of a power system in operation. The long run system reliability measurement however corresponds to

TABLE 3.2

Reliability Indices Yearly System and Customer Viewpoints

Reliability Index	Yearly System Viewpoint	Yearly Customer Viewpoint
Frequency of loss of load	350 occurrences	0.26 occurrence
Expected energy not supplied	1,677 MWh	3.13 KWh
Expected loss of load hours	1,068 hours	0.92 hour
Expected customers not supplied	66,600 customers	0.26 occurrence

Illustration from EPRI EL-1773 (11)

TABLE 3.3

Reliability Indices for Different Sectors of Electricity Supply

3.3a Frequency of Loss of Load

Cause	Yearly System Viewpoint	Yearly Customer Viewpoint
Distribution	345.0 occurrences	0.20 occurrences
Area Supply	5.0 "	0.02 "
Bulk Power	0.3 "	0.02 "
Generation	0.1 "	0.02 "
Total	350.0 "	0.26 "

Illustration from EPRI EL-1773 [11]

3.3b Expected Energy Not Supplied

Cause	Yearly System Viewpoint	Yearly Customer Viewpoint
Distribution	207 MWh	2.04 KWh
Area Supply	600 MWh	0.41 KWh
Bulk Power	720 MWh	0.54 KWh
Generation	150 MWh	0.14 KWh
Total	1677 MWh	3.13 KWh

Illustration from EPRI EL-1773 (11)

3.3c Hourly Loss of Load Expectation

Cause	Yearly System Viewpoint	Yearly Customer Viewpoint
Distribution	1035.0 Hours	0.60 Hours
Area Supply	30.0 Hours	0.12 hours
Bulk Power	2.4 Hours	0.16 Hours
Generation	1.0 Hours	0.04 Hours
Total	1068.0 Hours	0.92 Hours

Illustration from EPRI EL-1773 [11]

steady state probabilities.

Once reliability conditions have been accomplished, an economic assessment has to be made to balance the supply and demand of electricity, and this leads to the economic evaluation of reliability. The economic evaluation provides the equilibrium between cost and reliability whereby optimisation of both are to be reached.

3.3 ECONOMIC EVALUATION

One general requirement implicit in all methods for economic quantification of reliability performance is that the reliability indices utilized can be computed accurately and bear close relationship to actual historical reliability performance. This is necessary because the computed cost of interruptions is usually treated in an absolute way and traded off against other system costs such as operating costs to determine an optimal system or level of reliability performance.

The procedure is to establish socially with optimal reliability levels at the point where the marginal benefits of future improvements in reliability are equal to the marginal cost of supply. This leads to the reliability index being not only characterizes future system performance in the way that is helpful for traditional system planning, but also meaningful at the consumer level. It is ideal to have consumer related and physically measurable indices which have been verified against historical experience.

In the context of long range system expansion planning, it is required to establish target reliability levels and to achieve the future reliability levels for different system designs options. There are always several expansion plans that satisfy the reliability standards. From the imposition of the reliability standards, there will always be the cost which is related to the electricity not supplied, the outage cost. The expansion plan whereby the sum of the system costs and the outage costs is the minimum will be the optimal expansion plan. The system costs may not be difficult to evaluate but due to the varied nature of the customers, the outage costs may prove to be difficult to quantify. The applications of the economic evaluations including the outage costs have been shown for several case studies (12), (13).

Among the many forms of the reliability indices, the generation indices are the easiest to compute. Normally, the indices can be calculated without many failure states as compared to the other subsystems. The use of the generation reliability indices has been proven to be adequate in most expansion planning. The section below describes some of the more important reliability indices that are commonly referred by utilities in their expansion planning mechanism.

3.4 OVERVIEW OF RELIABILITY INDICES

When setting the generation reserve requirements for a utility, the basic question to be answered is; by how much generation reserve is required to provide a desired level of service given an uncertain future level of demand for electricity, to be supplied by generating units that are subject to planned and forced outages.

There are two deterministic indices commonly used. They are percent reserve and the number of largest units. Percent reserve is the earliest and the simplest method of fixing generation system reserve. Percent reserve can be calculated in two ways; as a percent of peak load or as a percent of installed capacity. The figure as a percent of peak load is most common. The system reserve may be based on any of the followings as examples; the capacity of the largest unit, the capacity of the largest two units, the capacity of the largest unit plus a fixed megawatts value. Such rules are arbitrary and do not consider any factors relating to load other than the annual peak.

Generation reliability based on a probablistic approach is sensitive to unit size, maintenance requirements, uncertainties, load magnitude and annual load shape. There are possibly five important reliability indices for generation studies that are of relevance.

i) Loss of Load Expectation (LOLE).

The loss of load probability using 365 days per year (or an approximation such as 250 or 260 days per year) results in the LOLE expressed in days/year (2), (14). When daily peaks loads are examined, the LOLE are daily peaks. However this has been traditionally shortened to just "days" and dividing by the interval, the common expression of days/period. If hourly load is used then it is HLOLE and the units are hours/period as described below.

ii) Hourly Loss of Load Expectation (HLOLE)

The loss of load probability method when computed over the 8760 hours calculates the expected number of hours with generation capacity less than load in a year. The reliability index has dimension of hours per year. This hour calculation is a calculation byproduct of stochastic production costing methods based on the Baleriaux - Booth method (15).

iii) Expected Energy Not Supplied (EENS)

The Expected Energy Not Supplied is computed by summing all the probabilities of outages times the megawatt amounts of shortage to arrive at megawatts hours. The same input data is used as was required for the HLOLE for 8760 hours.

iv) Frequency of Loss of Load (FLOL)

The frequency calculations require that the average repair time for each generating unit and a duration for each load be specified. With this additional input data it is possible to calculate the number of generation shortage occurrences in a year (16). The frequency calculation method using 8760 hours per year (17) requires the input of all hourly load forecasts for a year and the average repair time for each generator unit.

v) Duration of Loss of Load (DLOL)

The duration or the average duration of loss of load is the ratio of Hourly Expected Loss of Load Expectation

(HLOLE) and Frequency of Loss of Load (FLOL) [17]. The result is the conditional expected number of loss duration of a shortage of generation, given there is a shortage.

The generation conditions can be extended to include operation and interconnection considerations. For example the influence of emergency procedures [18], operating considerations such as spinning reserve, units with quick start abilities, the spinning reserve of pumped storage hydro units, and maintaining a spinning reserve capacity among the operating generating units [19] and finally the interconnection considered in loss of load probability calculation [20], [21].

An ample bibliography of the application of the probability methods in power system reliability evaluations is available [22]. The studies are on various forms ranging from the determination of reserve requirements and on the evaluation of unit additions [23] to [28]. Applications on economic evaluations are later investigated [29] to [32], and the techniques are also extended to interconnection studies [33] to [41].

Using the reliability indices can give a relative indicator of improving or deteriorating generation system. By using calculations and approximations, the indices not only tell what the relative reliability of the generating system is, they also indicate how much capacity is required to improve the reliability to a desired level. The above examples are the most basic reliability indices to the electric utility industry and they have been identified and been given firm mathematical definitions.

In general, from the utility point of view, reliability indices should accurately reflect the influence on system reliability performance of system and load characteristics. The indices should be able to display sensitivity of system reliability performance with respect to planning parameters and this helps to guide in the choice of alternatives in the planning process. The indices should be physically significant and measurable from historical informations and also should be meaningful to the public and utility agencies. From the regulatory point of view, the reliability indices apart from being physically meaningful and measurable, they should be significant in an absolute sense and accurately measure average customer reliability experience and be able to assess economic impact on interruptions.

CHAPTER 4

CAPACITY SAVINGS THROUGH INTERCONNECTION

4.1 INTRODUCTION

This Chapter describes the methods for the calculations of the generation reliability indices HLOLE (Hourly Lost of Load Expectation) and the EENS (Expected Energy Not Supplied). The concept of capacity and the load models is used to generate the reliability model. The analytical and computational equations are explained first for an independent system and later the formulations are extended to an interconnected systems. The evaluation of the savings in reserve margin through the HLOLE is shown. Finally, a computer programme is explained for the determination of the HLOLE and EENS before and after the interconnection.

4.2 METHODOLOGY

4.2.1 CAPACITY MODEL

Although there are many types of units being used today, all the units are randomly forced off-line because of technical problems during a normal period of operation. Hence, to account for the random outage or availability of the unit, it is necessary to determine the probability density function that describes the probability that the unit will be forced off-line or will be available during its normal period of operation.

The simplest stochastic method for treating reliability is to define two possible states for each unit. The unit is either available and capable of full power generation, or the unit is not available to deliver any power. This is not entirely accurate since there are many forms of defects which reduce output and not making the unit totally unavailable. However, for most power system planning, it is adequate to have the state definitions of the on/off model mentioned above.

Associated with each state is the probability of a unit being available, a_n and the probability of a unit being unavailable, q_n. Since the unit must be in one of the two states, it follows;

$$a_n + q_n = 1.0 \tag{4.1}$$

The probability q_n is normally called the expected forced outage rate.

The capacity model for the actual system is developed by considering every possible combination of unit availability using the forced outage rate characteristics of each unit in each combination. This results in a table of total available system generation and associated probability of occurrence. This table may be generated as outlined by several documented methods [(2), (25), (42), (43), (44)].

By assuming that the units are totally independent of one another, a forced outage distribution function, can be calculated using a recursive relationship similar to that used for a binomial distribution. If all the generating units have the same capacity and forced outage rate, the forced outage distribution would be a binomial distribution.

However, since the generating units have various capacities and different forced outage rates, the forced outage distribution is built up sequentially by considering one unit at a time.

A general form of the recursive equation that can be used to generate the table by adding one unit at a time is as follows;

$$P_n(y) = P_{n-1}(y).a_n + P_{n-1}(z).q_n \text{ for } z > 0 \qquad (4.2)$$

$$P_{n-1}(z) = 1.0 \text{ for } z \leq 0 \qquad (4.3)$$

where y = MW out of service

x = capacity of the nth plant

$z = y - x$

$P_n(y)$ = the probability of having y MW out of service in a n plant system

$P_{n-1}(y)$ = the probability of having y MW out of service in a n-1 plant system

a_n = availability of unit n

q_n = forced outage of unit n

Since the generation units on a system are in discrete MW sizes, and since the available outage data on generation units consists of discrete MW on outage at some discrete probability, then it follows that the probability of various system capacity outage is itself a discrete function.

The capacity model should be revised to reflect any change in the capacity configuration resulting from scheduled maintenance outage or changes in unit capabilities. The effect of scheduled maintenance outages is normally included by deterministically scheduling unit forced outage on the basis of a constant reserve margin as a preliminary computation before the simulation is carried out. One way is to modify the f.o.r. to include the scheduled maintenance outage and this can be approximated as follows;

$$q_n' = \frac{P_M}{P_T} + q_n \left(\frac{P_T - P_M}{P_T}\right) \qquad (4.4)$$

where q_n' = modified f.o.r.

q_n = f.o.r when no maintenance

P_M = period of maintenance

P_T = total period under consideration

So the capacity model is basically a table of capacity of outage and either the exact probability on outage or the cumulative probability on outage. A typical cumulative probability distribution of outage is as shown in fig. 4.1.

4.2.2 LOAD MODEL

A measure of the distribution of the load has to be expressed in terms of probability. The data required to develop such model are readily available, since continuous recordings of system demands are usually obtained on a routine basis by electric utilities. The future system demands may be projected using the expected growth rates.

If the values of the system demands are rearranged in decreasing order of magnitude, the resulting curve is called the Load Duration Curve (LDC). The LDC is created by determining what percentage of the time the demand exceeded a particular level, where percent time is shown on the X-axis and the demand level on the Y-axis. However, by doing this the chronological sequence of the loads has been lost.

For generation system studies, it is necessary to interchange the axis parameters of the LDC and to normalise the time. By normalising the time variable, the value at any point on the Y-axis now becomes the probability for the entire period for which a particular value of the system load equals or exceeds the associated power. This then is the load probability distribution and is one form of a load model, see fig. 4.2.

One other form to represent the load model is the load probability density function. It gives the probability of occurrence of a particular level of system load. The load probability density function can be derived from the LDC using the following equation;

$$f(L) = -\frac{dF(L)}{dL} \tag{4.5}$$

where f(L) = load probability density function, Fig. 4.3

F(L) = cumulative load distribution function

L = load, MW

In whatever form the load model is represented, the load model is developed to show the variability of the load for the period concerned. In general the load model can be represented as a probability distribution or as a probability density function.

4.2.3 RELIABILITY MODEL

Combining the appropriate capacity model and the load model can give the probability that the load exceeds the available capacity generation for a specific period. The representation of the load model plays a significant role in the terms used for the reliability index.

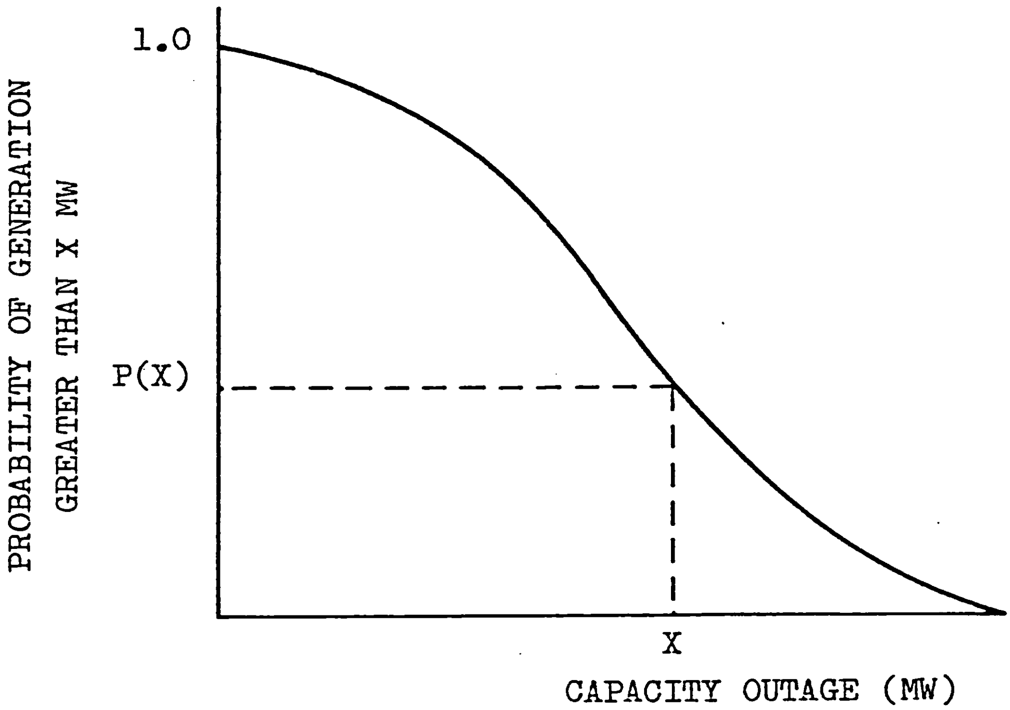


FIG. 4.1 Capacity Outage Probability Distribution

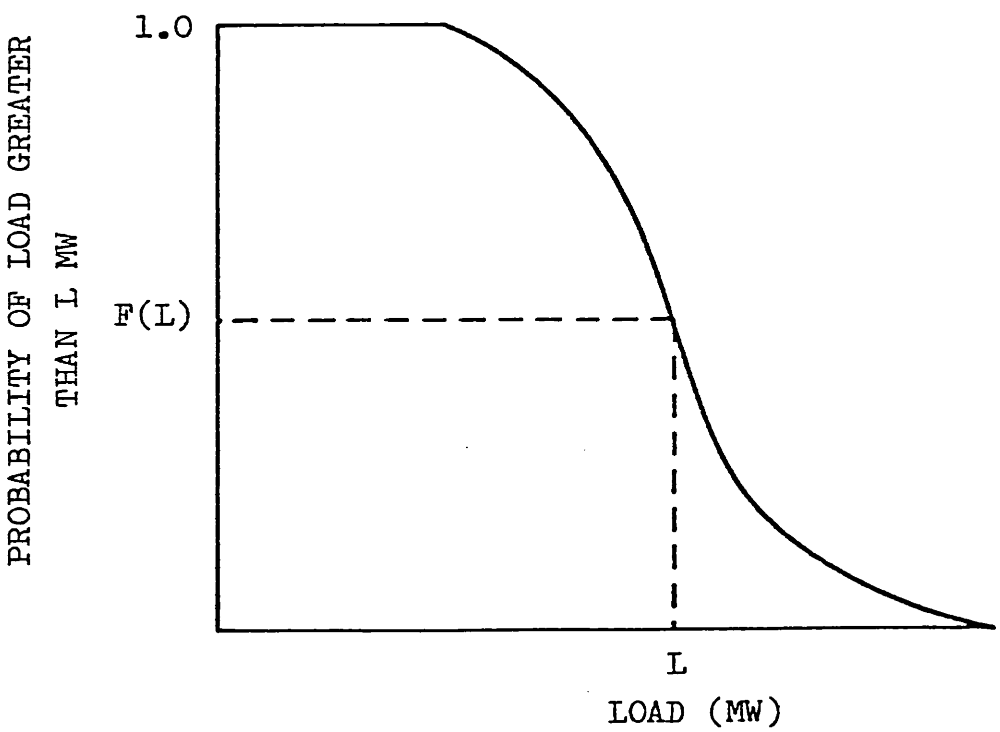


FIG. 4.2 Load Probability Distribution

Two types of commonly used load models are daily peak loads and hourly peak loads. When daily peak loads are used the resulting LOLE is expressed in days per period; when hourly peak loads are used the result is HLOLE and is expressed in hours per period.

In order to avoid confusion, for the present purpose LOLE will be the expected number of days with insufficient capacity at time of daily peak and HLOLE to refer to the expected number of hours of insufficient capacity. It is quite common to see in literature the terms LOLE and HLOLE are used interchangeably to denote either the expected number of days or hours per year of capacity shortage. Under no circumstance that it is correct to convert between LOLE in days/period and HLOLE in hours/year by using a factor of 24 hours/day. Using daily peaks give an estimate of the number of outages per year. Using hourly peak determines the total duration of outages within a year.

Lets assume for the moment the load model is simply in a form of hourly peaks for a certain period. The first step is to calculate the HLOLE for one load and the hourly probabilities in each period are summed to give the HLOLE for one period. The HLOLE for one year will be the sum of the HLOLE for the different periods assumed to be equal. If p(x) is the probability of exactly x MW on outage;

$$\mathrm{HLOLE}(1\ \mathrm{load}) = \sum_{x=C-L}^{C} p(x) \tag{4.6}$$

where C = Total installed capacity

L = Hourly peak load

If the cumulative probability of x MW or more on outage is represented by

$$P(x) = \sum_{X = x}^{C} p(X) \qquad (4.7)$$

then combining equations (4.6) and (4.7) gives the HLOLE for one load and is given by

$$\text{HLOLE(1 load)} = P\,(C-L) \qquad (4.8)$$

If the HLOLE is calculated over a period of time then equations (4.6) and (4.7) can be expanded to;

$$\text{HLOLE(period)} = \sum_{j=1}^{h} \sum_{x = C-L_j}^{C} p(x) \ \text{hours/period} \qquad (4.9)$$

$$= \sum_{j=1}^{h} P(C-L_j) \qquad (4.10)$$

where h = number of hours in the period

L_j = peak load on hour j

The period values of the HLOLE can be summed over all periods in a year to give HLOLE (annual).

Instead of the load model in the form of hourly peak loads throughout the period, the load model can be represented as a load probability density function as described in section (4.2.2), then equations (4.9) and (4.10) will have the following form;

$$\text{HLOLE(period)} = \sum_{j=1}^{n} \sum_{x=C-L_j}^{C} p(x) \,.\, f(L_j) \,.\, D \tag{4.11}$$

$$= \sum_{j=1}^{n} P(C-L_j) \,.\, f(L_j) \,.\, D \tag{4.12}$$

where n = range of hourly peak loads in the period

$f(L_j)$ = probability density of the hourly load in the period

D = period in hours

It can be seen that the capacity model is almost standard but the form of the load model defines the index of reliability being referred to. For the present analysis the reliability index in the form of HLOLE is being used and the load model used is represented by the probability density function. The above equations are for the determination of the HLOLE for a single independent system. A modified representations for a two systems will be described later and ultimately the HLOLE before and after interconnection can be evaluated.

4.2.4 LOAD MANAGEMENT POLICY

The rationale for interconnecting systems is based primarily on the fact that interconnected systems can help one another in times of emergency and hence improve reliability. The interconnected systems can share reserves without investing on additional electrical plant.

The reliability calculations for two interconnected systems depend to some extent on the policy of the operation of the power pool. If the power pool operates on the basis of sharing reserves up to the limit of the tie capabilities or to the point where the donating areas individually have a zero margin, then this type of event is not a failure for the self sufficient areas. On the other hand, if the pool's operating policy is such that generation reserves are to be shared up to the limits of the tie lines, even to the point of curtailing an individual area load, then this sort of event must be classified as a failure for a previously self sufficient area.

For the present purpose, the no load loss sharing policy is investigated. This implies that the reserves are transferred only up to the limit of the tie lines or available reserves, whichever is limiting. This policy seems to be reasonable for any small and medium size grid systems to assess interconnection in the initial stages.

The reliability calculations for a single independent system have been shown using the capacity model and the load model. An extension of the methodology can be applied to a two interconnected systems. For such calculations, the capacity model and the load model are better represented in a two dimensional forms representing the two areas. The followings sections describe the formation of a two dimensional probability distribution for the capacity model and a two dimensional probability density function for the load model.

A schematic representation of the two interconnected systems is shown in Fig. 4.4. Lets assume for the moment that the instantaneous loads at systems A and B are L_a and L_b respectively. For system A the probability of occurrence of L_a is given by $f(L_a)$ and the probability of outage is $p(x_a)$. Similar case applies to system B. Some of the principles involved in the development for the analysis for the two interconnected systems are available in published papers [(5), (45)].

4.3 INTERCONNECTED SYSTEM

4.3.1 CAPACITY MODEL FOR TWO AREAS

The two dimensional capacity model is simply an extension of the single system to a two area situation. The diagram in Fig. 4.5 gives a better picture of how this can be explained.

In relevance to the diagram and with reference to Fig.4.4 the following terms are defined for the calculation of the HLOLE;

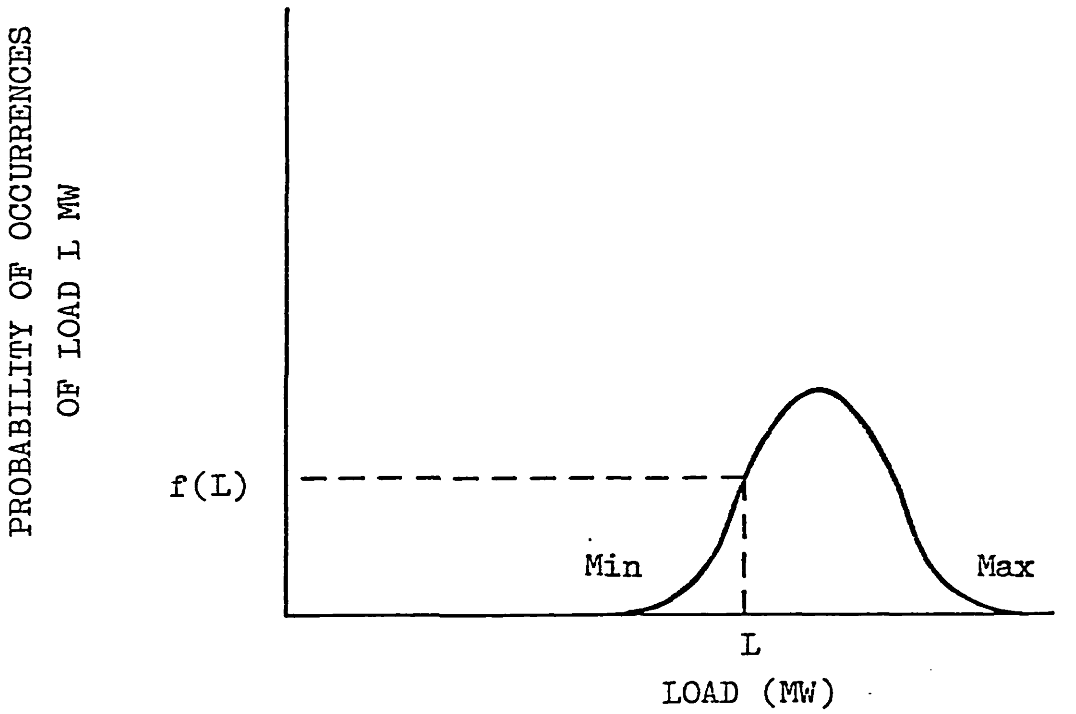


FIG. 4.3 Load Probability Density Function

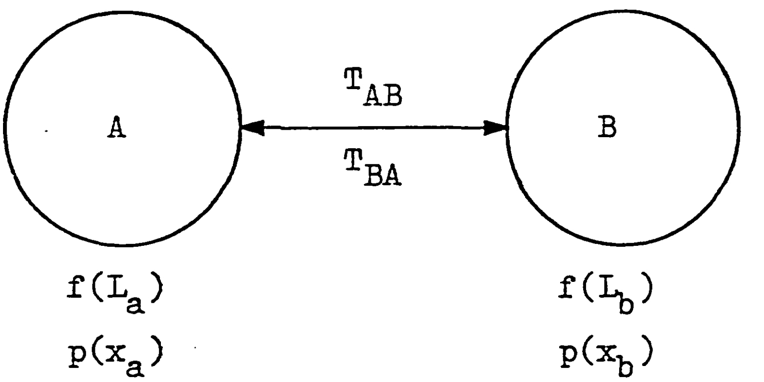


FIG. 4.4 A Group of Two Interconnected Systems

x_a, x_b = capacity outage MW in system A or B

$p(x_a), p(x_b)$ = probability of existence in A or B of the forced outage of exactly x_a or x_b

L_a, L_b = systems load for system A or B for an instant, MW

r_a, r_b = available reserve capacity in systems A or B, MW

$f(L_a), f(L_b)$ = load probability density function for system A or B

T_{AB}, T_{BA} = interconnection capacity between A to B, or vice versa, MW

The probability listings for each of the system contain all possible outage conditions with the corresponding exact probability of occurrence. The large matrix like probability array in the centre contains an enumeration of all possible forced outage conditions which could occur simultaneously in both areas. All possible events are represented in this area with the probability of simultaneous outages of $(x_a)_j$ in system A and $(x_b)_k$ in system B being given by $p(x_a)_j p(x_b)_k$. The sum of all the probabilities in the array is 1.0.

$$\sum_{\text{all } j,k} p(x_a)_j p(x_b)_k = 1.0 \tag{4.13}$$

For illustration, lets consider the hourly loads of L_a and L_b for systems A and B respectively. The probability array in the diagram can be divided into several areas where, by definition the loss of load probability can be determined depending on the nature of the interconnection. It is noted the stepped boundary in the diagram satisfies the relationship of the reserve and the outage conditions, i.e.

$$x_a + x_b = r_a + r_b \qquad (4.14)$$

With reference to Fig. 4.5 denoting the numbers for the areas, Table 4.1 gives a summary of all the possible states of the probability of loss of load for systems A and B for zero, finite and infinite interconnections. For example Area 1 means the summation of all probabilities $p(x_a)_j . p(x_b)_k$ within the boundaries defined. For system loads L_a and L_b and a finite interconnection of size T_{BA},

For system A;

HLOLE(1 load) before interconnection $= \Sigma\, p(x_a)_j\, p(x_b)_k$ Areas 1,2,3,4, for j,k (4.15)

HLOLE(1 load) after interconnection $= \Sigma\, p(x_a)_j\, p(x_b)_k$ Areas 1,2,3 for j,k (4.16)

The reduction in HLOLE(1 load) $= \Sigma\, p(x_a)_j\, p(x_b)_k$ Area 4 for j,k (4.17)

This is the basic formulation for the reliability analysis for the interconnection for the present studies.

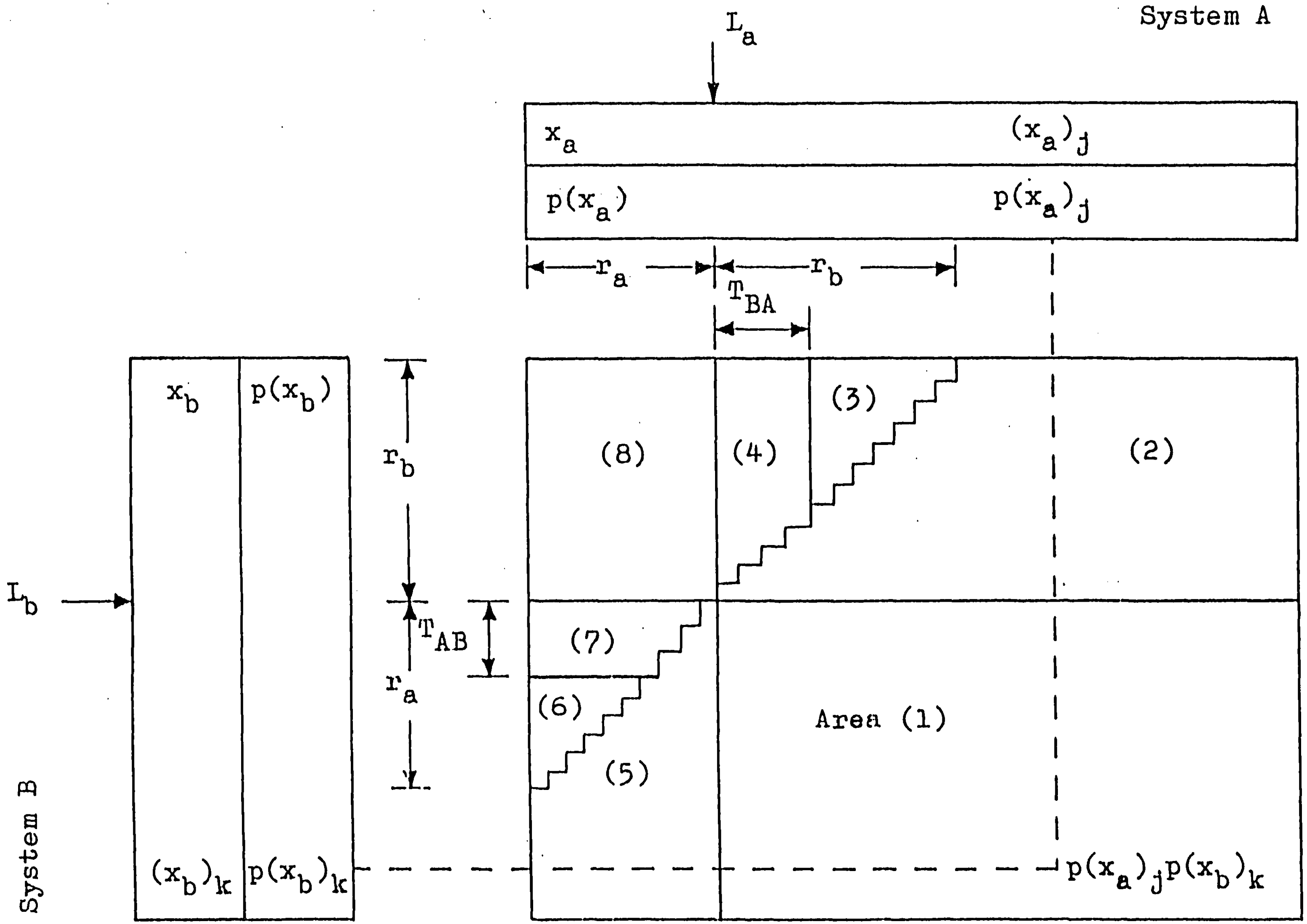


FIG. 4.5 Two Area Capacity Model

TABLE 4.1

Enumeration of Probabilities for Interconnected Systems

Probability of Loss of Load (PLOL) is Σ Area (ref Fig. 4.5)	Before Interconnection	After Interconnection			
		Finite Size		Infinite Size	
		PLOL	Less by	PLOL	Less by
System A	(1) + (2) + (3) + (4)	(1) + (2) + (3)	(4)	(1) + (2)	(3) + (4)
System B	(1) + (5) + (6) + (7)	(1) + (5) + (6)	(7)	(1) + (5)	(6) + (7)

On intergration over the two dimensional load probability density function, the period HLOLE before and after interconnection can be evaluated. The setting up of the two dimensional load probability density matrix for the reliability measurement is described below.

4.3.2 LOAD MODEL FOR TWO AREAS

So far no consideration has been given to the effect of diversity in the load demands between the two systems. Load diversity is an important factor in interconnection studies because interconnected systems often have non coincident peak demands; thus reserve available for sharing may not coincide with the timing of need. If load diversity is not taken into account, then it would be possible that for the period under investigation, the reserves in one system in the beginning of the period may supply the deficits of the other system in the later part of the period, an obviously unrealistic situation.

The load model as described earlier in section (4.2.2) will have to be modified to represent this diversity. Fig. 4.6 is an example of system daily load cycles for two interconnected areas and the cycle for the pool. In this particular example, system A has a load cycle which peaks during the morning while system B has its peak load early in the evening. For the pool, it occurs at neither of these times. Therefore, the maximum risks of loss of load for A, B and the pool may occur at different hours of the day.

The load model for the two interconnected systems can be represented by the two dimensional load probability density function $f(L_a,L_b)$. The summation of all the values in the two dimensional load probability density matrix is equal to 1.0. An additional information that can be derived from the table is the load probability density distribution for the each independent system. This can be done by adding the columns or rows for systems A and B respectively, resulting in $f(L_a)$ and $f(L_b)$.

A simplified two dimensional load probability density matrix is as shown in Fig. 4.7. The contours represent the values of the combined probability of occurrences of loads L_a and L_b. The outer contour represents higher diversity of loads than the inner contour. In terms of probability values, the inner contour has higher value than the outer contour. From the simplified diagram it can be seen clearly however that for the two systems, there exists a lower diversity in the low load regions than the high load regions. The reliability measurements depend a great deal on the extent of the diversity of the high load regions whereas for the equilibration of marginal costs the influence is more from the low load regions.

4.3.3 HLOLE CALCULATIONS

The combination of the two dimensional representations of the capacity and the load models can lead to the calculations of the HLOLE. From the capacity model, the probability of loss of load for system loads L_a and L_b can be determined, whereas, from the load model the probability

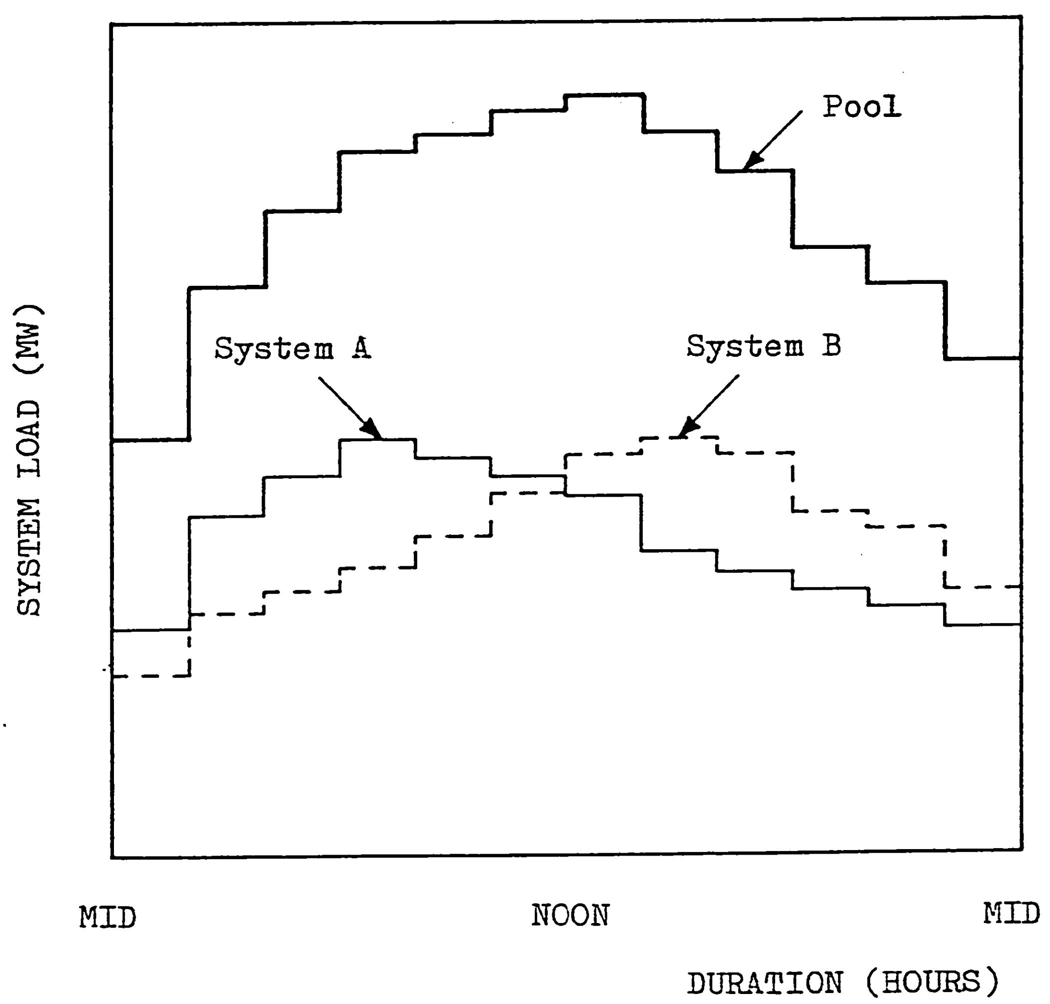


FIG. 4.6 Load Demands Diversity for Two Systems

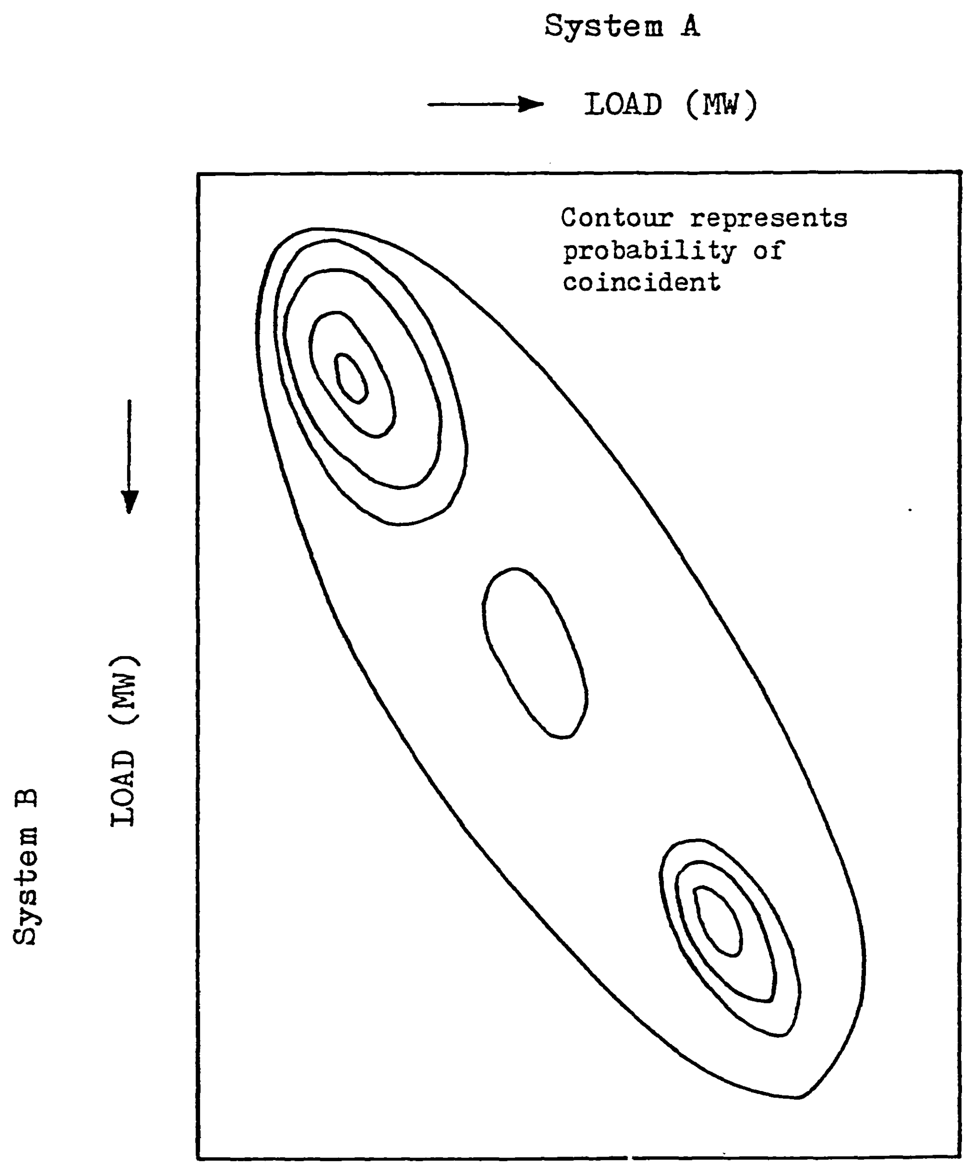


FIG. 4.7 Simplified Two Dimensional Load Model

of occurrence of these loads can be obtained. Therefore, the intergrations of the two models for all possible combinations of system loads give the desired HLOLE.

With reference to Table 4.1 and Fig. 4.5 and the equations (4.15), (4.16) and (4.17), the HLOLE of system A can now be defined;

$$\text{HLOLE(period) before interconnection} = \sum_{\substack{\text{Areas } 1,2,3,4 \text{ for } j,k \\ \text{All } L_a,\, L_b}} \sum p(x_a)_j \; p(x_b)_k \cdot f(L_a, L_b) \cdot D \quad (4.18)$$

$$\text{HLOLE(period) after interconnection} = \sum_{\substack{\text{Areas } 1,2,3 \text{ for } j,k \\ \text{All } L_a,\, L_b}} \sum p(x_a)_j \; p(x_b)_k \cdot f(L_a, L_b) \cdot D \quad (4.19)$$

$$\text{Reduction in HLOLE (period)} = \sum_{\substack{\text{Area } 4 \text{ for } j,k \\ \text{All } L_a,\, L_b}} \sum p(x_a)_j \; p(x_b)_k \cdot f(L_a, L_b) \cdot D \quad (4.20)$$

It is noted that for the same period, equation (4.18) will give the same result as equations (4.11) and (4.12) since they are both the values of HLOLE before interconnection. Similar equations can easily be derived for system B, the summation of the probabilities must obey however the enumeration of the probabilities in the areas that as stated in Table 4.1.

4.3.4 EENS CALCULATIONS

EENS (Expected Energy Not Supplied) can be defined as the expected amount of energy not supplied due to outages. As explained in section (3.4) Chapter 3, the two reliability indices give a two different dimensions on the measurement of reliability. The HLOLE only indicates that there is a probability of loss of load but the EENS gives the measurement in terms of the amount of the deficiency. For the present interconnection studies the interest is on the energy not supplied which is reduced due to the interconnection as another mean of measure of the benefits.

With reference to Fig. 4.5, for any point associated with a probability of loss of load, there is an amount of capacity in MW which is deficient. Fig. 4.8 gives a better representation of the deficiency for a particular loads L_a and L_b. This figure is derived in conjunction with Fig. 4.5 and as can be seen there are some similarities. Consider the case for system A when there is no interconnection, for a given capacity outage state, the unserved energy is the capacity deficiency times the probability of being in that state;

i) For system A (without interconnection)

Unserved Energy (1 point) $= (x_a - (C_a-L_a))p(x_a)p(x_b)$ (4.21)

$$\text{if } (x_a - (C_a-L_a) < 0$$

$$\text{set } (x_a - (C_a-L_a) = 0$$

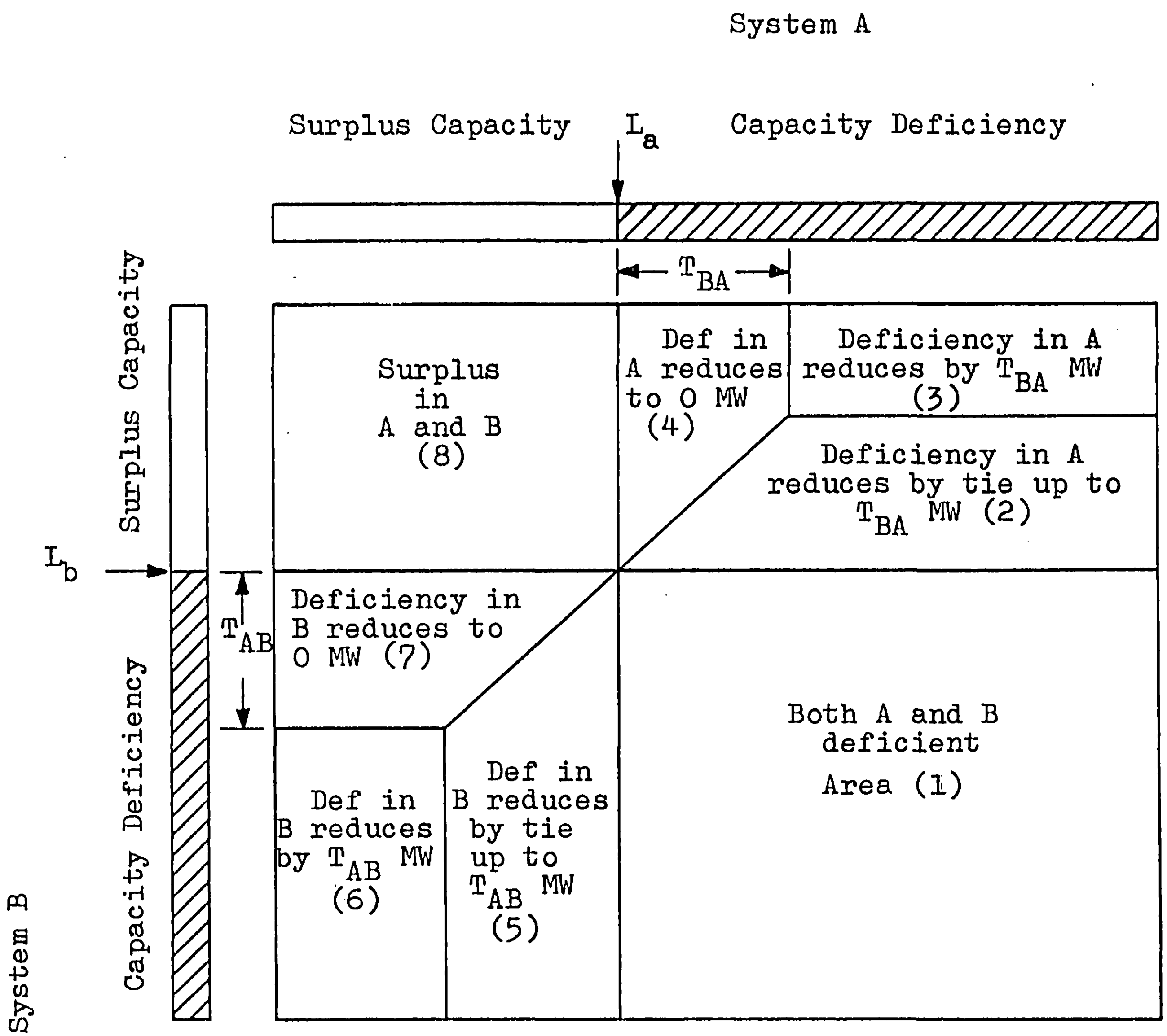


FIG. 4.8 Two Area Representation of Capacity Margin

where x_a = MW on outage

C_a = installed capacity

L_a = load

$p(x_a)$ = exact probability of x_a MW on outage

$p(x_b)$ = exact probability of x_b MW on outage

For a single hourly load of L_a and L_b, the unserved energy is then summed over all of the capacity states which result in a capacity deficiency:

$$\text{Unserved Energy (1 load)} = \sum_{\substack{x_a = C_a - L_a \\ \text{Areas } 1,2,3,4 \text{ for } j,k}}^{C_a} (x_a - (C_a - L_a))\, p(x_a)_j\, p(x_b)_k \text{ MWh} \tag{4.22}$$

For a series of hourly loads for the two systems, if the load model can be of a two dimensional load probability density function $f(L_a, L_b)$, then the above equation becomes;

$$\text{Unserved Energy (1 period)} = \sum \sum_{\substack{x_a = C_a - L_a \\ f(L_a, L_b) > 0 \\ \text{Areas } 1,2,3,4 \text{ for } j,k}}^{C_a} (x_a - (C_a - L_a))\, p(x_a)_j\, p(x_b)_k . f(L_a, L_b) . D \tag{4.23}$$

The unserved energy summed over 1 year gives the EENS for system A before interconnection.

The presence of the tie lines of capacities T_{AB} and T_{BA} MW each reduces the capacity of outage by the available tie line capability. The tie line provides the spare reserve margin from the neighbouring system thus reducing the deficiency. Thus equation (4.23) becomes;

ii) For System A (with interconnection)

$$\begin{aligned}
&\text{Unserved Energy (MWh/period)} = \sum_{C_a}\sum ((x_a-(C_a-L_a))-t)p(x_a)_j p(x_b)_k . f(L_a,L_b).D \\
&\quad x_a = C_a - L_a \\
&\quad t = 0 \text{ to } T_{BA}, \text{ depends on area} \qquad (4.24) \\
&\quad f(L_a,L_b) > 0 \\
&\quad \text{Areas } 1,2,3,4 \text{ for } j,k
\end{aligned}$$

The unserved energy for 1 year will then give the EENS (annual) after the interconnection. The reduction in EENS due to the interconnection is the difference in the values from equations (4.23) and (4.24). The magnitude of the reduction will depend on the size of the interconnection.

iii) Similarly, for system B (with interconnection)

$$\begin{aligned}
&\text{Unserved Energy (MWh/period)} = \sum_{C_b}\sum ((x_b-(C_b-L_b))-t)p(x_a)_j p(x_b)_k . f(L_a,L_b).D \\
&\quad x_b = C_b - L_b \\
&\quad t = 0 \text{ to } T_{AB}, \text{ depends on area} \qquad (4.25) \\
&\quad f(L_a,L_b) > 0 \\
&\quad \text{Areas } 1,5,6,7 \text{ for } j,k
\end{aligned}$$

4.4 BENEFITS FROM RESERVE MARGIN

The measure of the benefits from reserve margin is through the reliability indices HLOLE and EENS. Let's assume for the moment that the reliability standard for a particular system has been achieved prior to having any interconnection. With the advent of the interconnection, the HLOLE is reduced. This reduction in the value of the HLOLE indicates that there is an excess capacity. For the system to attain the same standard of reliability as before, this excess capacity will have to be removed. In an expansion plan, this excess capacity is in the form of the reserve margin and it can be from the projected plants which are to be added into the system. These plants can therefore be postponed or plants which are already committed can be delayed.

Interconnection leads to an improvement in reliability and simultaneous reduction in the EENS. The benefits of interconnection may therefore be thought of as the costs of advancement of new plants that otherwise are required. The product of the reduction of the EENS and the outage cost provides some measure of the advancement costs of the new plants. In a well balanced system, the cost of increment that is the marginal cost, is the same. One way to measure is by the value of its outage cost but because measurement of costs is unreliable, it may be difficult to quantify.

An indirect way of looking at it is by how much plant to advance to bring the same benefits. Naturally this may come about by more plants of different types, but in general as stated earlier, the plants are the same in a well balanced system. The easiest way is therefore to use the peaking units normally taken as the gas turbines so that the operation of the system is not disorderly and made complicated. This approach simplifies the assessment of the benefits on capital costs.

The benefit from this is directly on the capital cost involved. One way to assess this benefit is to compare the capital cost of peaking plants which are necessary to give the same improvement as the interconnection. A possible method would be to compare interconnection of size X MW is equivalent to the peaking unit of size Y MW to give the same standard of reliability. The capital cost involved provides some measure of the benefits in monetary values. This approach is to be applied in the case study which has been conducted.

4.5 COMPUTER PROGRAMME

A computer programme (HLOLENS) has been developed to determine the two generation reliability indices, HLOLE and EENS for two interconnected systems. The formulations for such evaluations have been described in earlier sections (4.3.3) and (4.3.4). The HLOLE and EENS calculated are for a period. The period is defined as an input, and it can be in days, weeks or year given in hours.

The simulation programme is made up of a main routine and several subroutines. There are six important steps in the calculations as described below;

1) Data Manipulation

The main routine reads in the input and prints it out. It also prints some of the more important results depending on the option provided. The important data that are necessary include ;

i) The period and the year of study. The historical load profile must be representative of the demands envisaged. The projected load profile is obtained using the expected growth rates from the year of the historical load profile up to the year of study.

ii) The number of generation units, sizes in MW, forced outage rates and plants under maintenance. The maintenance schedule is given in hours for that period. The planned outage is done as a prerequisite before computation to levelize capacity reserve. The modified f.o.r. is calculated from equation (4.4).

iii) Sizes of interconnection are given as minimum and maximum values under investigation included the increment step size.

This routine thus defines the load profile of the year of study, the range of the sizes of interconnection to be investigated and it makes corrections for the f.o.r. of the plants under maintenance. It also checks for any values that are beyond the storage limitations of the programme.

2) The Capacity Model Routine

From system data characteristics for that period, like the number of plants, sizes, forced and planned outage rates, the capacity outage probability distribution is constructed, see equations (4.2) and (4.3). Both the exact and the cumulative outage tables are constructed. Finally, the two dimensional capacity model is formed.

3) The Load Model Routine

For each system the load model is generated from the hourly peak loads for that period. The two dimensional load density matrix $f(L_a, L_b)$ is constructed following the outlines in section (4.3.2).

4) The HLOLE Calculations Routine

For each combination of loads of L_a and L_b, the probability of loss of load before and after interconnection is calculated, see section (4.3.3). The routine is entered only for $f(L_a, L_b) > 0$ to save computation time.

5) The EENS Calculations Routine

For similar loads L_a, L_b the EENS before and after interconnection is calculated based on that described in section (4.3.4). Also to save computer time this routine is entered for $f(L_a, L_b) > 0$ only.

6) Final Routine

This routine determines the product of the values from 4) and 5) above and the respective load probability density value $f(L_a, L_b)$. The summation is also done here to ultimately give the cumulative values of the HLOLE (period) and EENS (period) before and after interconnection.

The summary of the flow diagram for the programme is as shown in Fig. 4.9 and it also shows the important subroutines associated in each step. The programme is written in Fortran IV and is compatible to the CDC 6600 and the IBM 370.

There is no limit to the number of data input to run the programme if some minor changes can be made to the storage requirements. Presently, the limits are; the number of plants for each system is 100, the period is up to 2200 hours and the two dimensional load probability density matrix has an array of (170,170). These limitations are selected for optimum present utilization.

Other important data which can reduce the computer times and storage area are; peak and base loads are specified to define the range of the load probability density function, and the step size to be a multiple of the units and interconnection sizes. The step size provides the level of accuracy that is required in the computation. The smaller the step size results in a greater accuracy but the penalty is on larger storage requirements and longer computer time. Results from this programme have been obtained and will be discussed later in Chapter 6.

4.6 SUMMARY

This Chapter has explained the basic concepts in the evaluation of the reliability indices HLOLE and EENS. It shows how the calculations can be done for a single area and later extends to a two interconnected systems. The formations of the capacity model in the exact and cumulative outage tables are derived using the recursive formula. The load model is developed from the hourly peak demands.

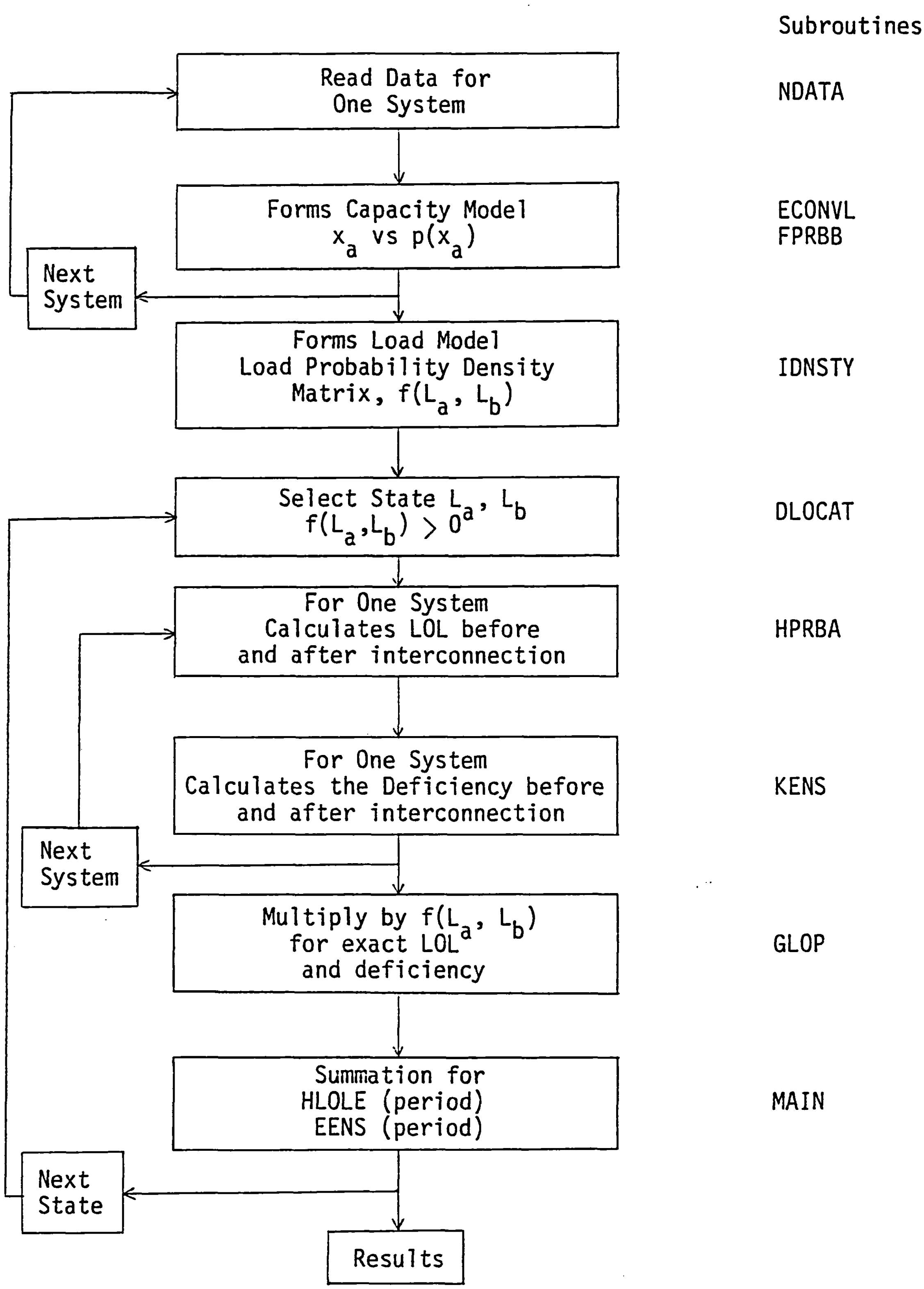


Fig. 4.9 Summary of the Flow Chart of Computer Programme HLOLENS

For purpose of interconnection studies, both these models are represented as a two dimensional capacity model and a two dimensional load model. The effects of the interconnection of finite and infinite sizes are shown on the values of the HLOLE and EENS of each system. The benefits derived through these measurements lead to capital cost savings. A method has been shown to assess these benefits in monetary terms. Finally, the computer programme developed has been explained.

CHAPTER 5

EQUILIBRATION OF MARGINAL COSTS

5.1 INTRODUCTION

This chapter explains the methodology to evaluate the benefits of interconnection through equilibration of the marginal costs. The system cost and the marginal cost at each demand level are calculated for an all thermal system and for a mixed hydro thermal system. The influences of the hydro units on these evaluations are explained. The production cost routine is based on probabilistic simulation. The method to evaluate the benefits through equilibration of the marginal costs is also explained. Finally, the outlines of the computer programme developed that can do the analysis are presented.

5.2 SYSTEM COST

For the present interconnection studies, the system costs at different demand levels are necessary for the evaluation of the marginal costs. In the system cost analysis, it is required to know the expected energy generation of each unit and its associated generation cost. The production cost calculations use the well known probabilistic simulation technique [(15),(46) to (49)]. This technique has been used by the IAEA in the development of the computer programmes for power system planning, WASP which are used by most developing countries [(50),(51)].

The principles underlying the concept of probabilistic simulation are elaborated in part one of Appendix A. Basically this technique is able to portray actual operating conditions like forecast uncertainty, unit outages and maintenance schedules. Its main advantage is the ability to estimate the cost of operation of a utility system by estimation of the expected energy generation of each unit showing the effects of unit forced outages. The characteristics of the unit with reference to being a two state model apply as explained in section (4.2.1), chapter 4.

5.2.1 ALL THERMAL SYSTEM

In the context of power system planning, a thermal power plant is able to generate electricity without any limitations up to its availability. It is normally assumed that there is no fuel shortage and that it is able to generate at any time as demanded. Therefore, for an all thermal system, the dispatching rule will be to operate the cheapest plant first, this is the merit order concept. For a given duration of demands, the operations of the units in the merit order configurations to meet demands and outages will result in the cheapest system cost.

For a given LDC, these plants can be arranged in ascending order of generation costs as shown in Fig. 5.1. For the present analysis, it is required to estimate the system costs to meet demands ranging for example, from the base load, L_1 to the peak load, L_M. The increment of load will depend on the accuracy of the analysis required. Complying with the probabilistic simulation technique, it means that for each unit, it is required to determine the expected energy generation for each demand level.

For each unit and demand level, there is a unique load equivalent curve (LEC), see Appendix A, that is required to be formed to determine the expected energy generated. The normal application of probabilistic simulation is to convolve one unit at a time. This procedure assists in the rapid calculations of the energy generated since the form or the shape of the LEC for each unit is unchanged for the different demand levels.

Fig. 5.2 illustrates this more clearly. Consider for the moment unit n, with respect to table 5.1 the LEC $F_{n-1}(x)$ has to be developed by convolving units 1 to n-1. If the calculations begin with the demand level L_1, then the LEC $F_{n-1}(x)$ is used to determine the expected energy generation of unit n, giving $E_{n,1}$ for the demand level L_1. If $F_{n-1}(x)$ is shifted to the right by a step size to L_2,

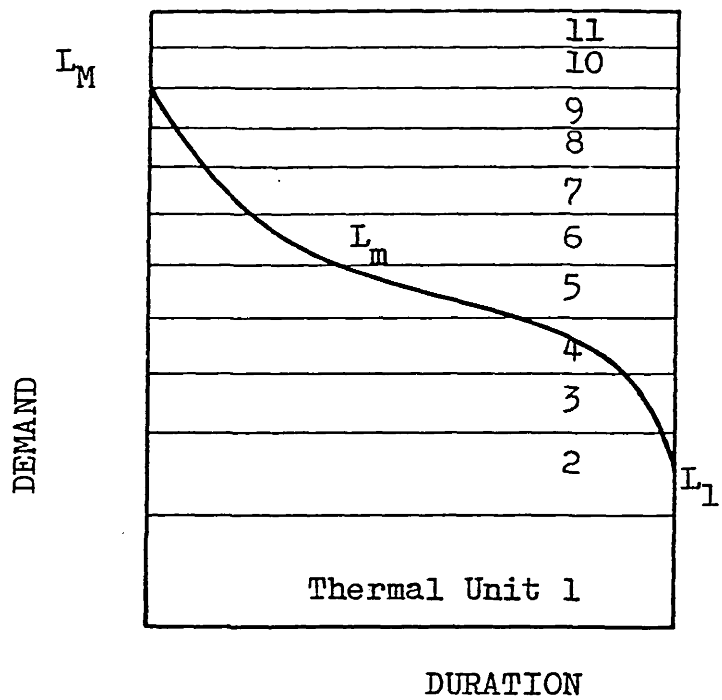


FIG. 5.1 Merit Order Configurations

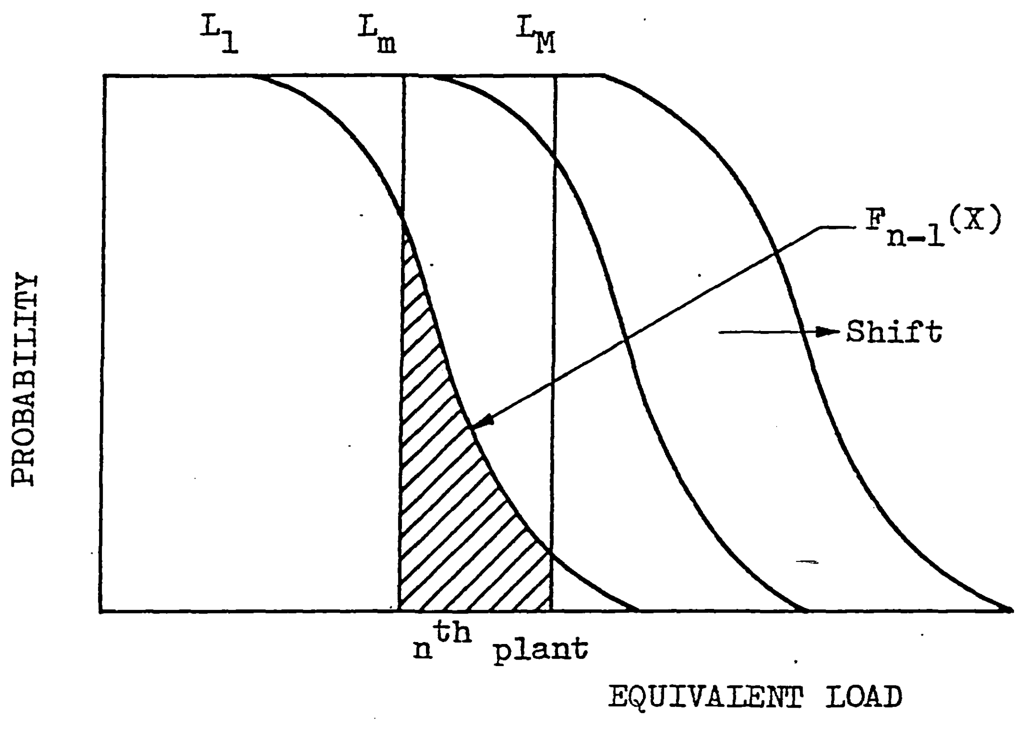


FIG. 5.2 Expected Energy Generation of a Thermal Unit for Different Demands

TABLE 5.1

System Costs for Different Demand Levels

Unit No.	Concolve unit No.	Load Equivalent Curve	Demand		
			L_1	... L_m ...	L_M
1	--	$F_0(x)$	$E_{1,1}$	...$E_{1,m}$ ...	$E_{1,M}$
2	1	$F_1(x)$	$E_{2,1}$	...$E_{2,m}$ ...	$E_{2,M}$
.	.	.			
.	.	.			
.	.	.			
n	n-1	$F_{n-1}(x)$	$E_{n,1}$	...$E_{n,m}$ ...	$E_{n,M}$
.	.	.			
.	.	.			
.	.	.			
N	N-1	$F_{N-1}(x)$	$E_{N,1}$	...$E_{N,m}$...	$E_{N,M}$
System Cost = $\sum_{n}^{N} E_{n,m} \times GC_n$			$C(L_1)$	...$C(L_m)$...	$C(L_M)$

then the expected energy generation of unit n at demand level L_2, $E_{n,2}$ can be calculated. This shifting of the LEC can be done in stages, and at each shift the expected energy generation can be calculated. This is repeated until the final demand L_M has been reached.

For the next unit n+1, the LEC $F_n(x)$ has to be formed by convolving unit n into the LEC $F_{n-1}(x)$. Similar calculations can then be done following the above steps for demand levels L_1 to L_M. This iteration has to be done for all the plants, see Table 5.1.

Finally, the summation of the product of the expected energy generation of each unit with the associated generation cost at each demand level will provide the system cost at that demand level. These values of the system costs are necessary for the evaluation of the marginal cost to be described later. If GC_n is the expected cost of generation of unit n, then the system cost $C(L_m)$ at demand level L_m is given by;

$$C(L_m) = \sum_{n}^{N} E_{n,m} \times GC_n \tag{5.1}$$

5.2.2 MIXED THERMAL HYDRO SYSTEM

For the system comprising hydro units, the basic characteristics of the hydro units have to be included in the production cost analysis to obtain an accurate cost results. The hydro plant has a rigid fuel cycle depending on the availability of water in the reservoir. The optimum operating strategy would be the full utilization of its capacity in MW and its energy capacity in MWh for the period under study.

A method for the simulation of the hydro unit is explained in part two of Appendix A using probablistic simulation. The basis of the formulation requires the hydro unit to be located in the merit order so that if it were a thermal plant, the expected energy generation will be equal to the energy capacity of the hydro unit. For this calculation , the thermal unit may have to be dispatched in two blocks, the first block to be dispatched ahead of the hydro unit and the second block to be dispatched after the hydro unit. Part two of Appendix A also describes these representations in more details.

Once the hydro unit has been strategically located in the merit order, it may then be treated as a thermal plant for the evaluation of the system costs for different demands. The method presented for the all thermal system therefore applies, section (5.2.1). In most instances the generation cost of the hydro unit is almost equal to zero for the system cost calculations. This procedure of locating the hydro unit in the merit order can be done for multiple hydro units without loss in generality. For the multiple hydro units, the first step is to locate all the hydro units in the merit order as described above. The second step is to treat the hydro units as thermal units for the system cost calculations at the different demand levels.

5.3 MARGINAL COST

In power generation, marginal cost may be defined as a cost of extra output of electricity. The value of the marginal cost is important to the utility especially in the tariffs adjustments. Also with relations to the future demands, reliability can be optimised at the instance whereby the marginal costs of increasing reliability are equal to the marginal costs of outages that are avoided because of the improved reliability.

For the present context, the equilibration of marginal cost approach, provides some basis of the measure of the operational benefits through interconnection. In using probabilistic simulation, the marginal cost is derived from the system costs and is thus not an optimisation routine but however provides a very close approximation. The alternative is to use linear programming formulation. The main disadvantages however it requires large number of constraints and high processing time. The marginal cost referred from now on is directed to the generation marginal cost that is the average fuel costs of the various sets.

If the system cost to meet demand L_m is $C(L_m)\$$, then for increment in demand of dL MW requires a new system cost $C(L_m+dL)\$$. By definition the marginal cost $MC(L_m)$ can be approximated by;

$$MC(L_m) = \frac{C(L_m+dL) - C(L_m)}{dL \times D} \ \$/MWh \qquad (5.2)$$

where D is the duration in hours.

So, for every demand level there are two values of the system costs that are necessary for the marginal cost evaluation. The sections below describe the methods for the determinations of the two values for an all thermal system and a mixed thermal hydro system. The increment of energy demand requires extra thermal capacity assuming the hydro units are fully committed. The cheapest way to obtain the extra thermal energy will be to keep the extra thermal capacity down to a minimum and to use it fully by spreading the extra thermal output over all the hours in the period under study.

5.3.1 ALL THERMAL SYSTEM

For an all thermal system, the cost of extra generation at a particular demand level poses no difficulty. Since there is no restriction on its fuel cycle and its duration of operation, the extra generation will have to be met by the thermal plants.

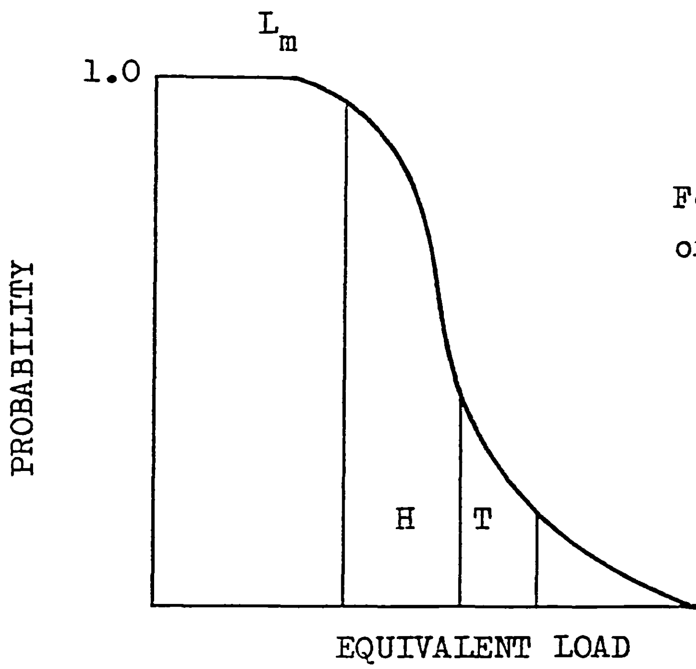
Referring to the entries in Table 5.1, for a demand L_m, the system cost is $C(L_m)$, but for an increment in demand dL, then $C(L_m+dL)$ is equal to $C(L_{m+1})$ if dL represents the increment step size. In other words, for an all thermal system the same system cost curve can be used to determine the system cost for the incremental in demand. The marginal cost is then derived using equation (5.2).

5.3.2 MIXED THERMAL HYDRO SYSTEM

Section (5.2.2) shows the methods for the evaluation of the system cost for a mixed thermal hydro system. For the marginal cost evaluations, it is required to establish the system cost for small increase in demand at a particular demand level. For the mixed thermal hydro system, the system cost derived previously is not applicable because of the hydro constraint on its energy capacity. The hydro energy capacity has been committed to meet the given LDC, no more and no less. Using the same cost curve would mean that the hydro load factor at the incremental demand be different. What is required is to determine the system cost at demand L_m+dL for the same hydro load factor as L_m so that the operational strategy of the hydro unit is not violated.

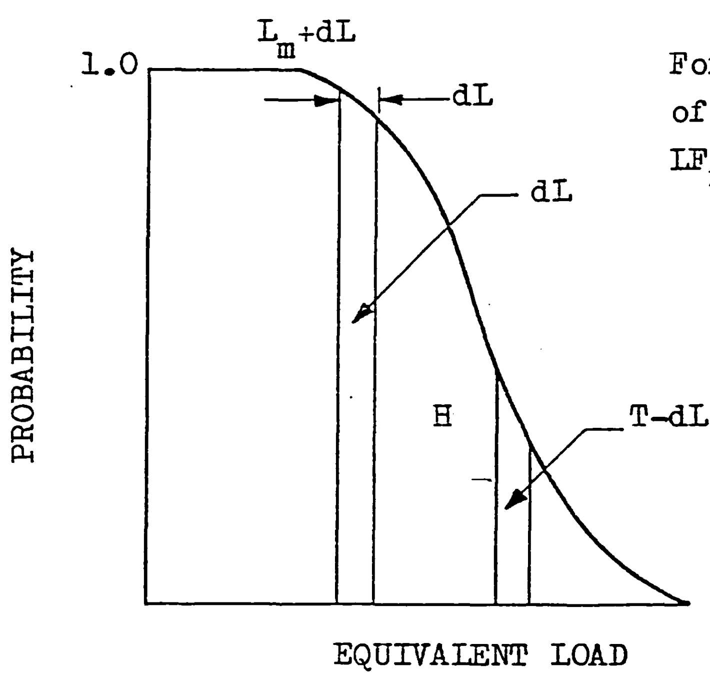
In using probabilistic simulation, this can be estimated as follows; to achieve the same load factor, the hydro unit is dispatch later by the amount dL. In other words, in the merit order configurations the dispatch of the hydro unit is moved down and instead is replaced by a thermal unit of size dL, Figs. 5.3a and 5.3b explain how this can be made possible.

Once this has been done, the simulation is repeated. A second set of system cost curve is developed for the different level in demands. This method provides a first approximation to the system cost evaluation for the same or fixed hydro load factor and some interpolation will have to be done to get the exact load factor. The common feature of these two curves is that at the demand level L_m on the



For demand L_m, load factor of hydro unit is LF_m

a) Hydro Unit Located in Merit Order



For demand L_m+dL, Load factor of hydro unit is approximately LF_m

b) Hydro Unit is Moved Down in Merit Order

<u>FIG. 5.3</u> Dispatch of Hydro Unit for Constant Load Factor

first curve the hydro load factor is expected to be the same as that at the demand level L_{m+1} on the second curve. The marginal cost is then obtained using equation (5.2).

Fig. 5.4 shows typical system cost curves for an all thermal system and for a mixed thermal hydro system. The two circles on the curves for each system show the values of the system costs required for the marginal cost calculation for demand L_m. Typical marginal cost curves for two systems are also shown in Fig. 5.5. There is a characteristic monotonic increase in the values of the marginal costs as the demand increases. It has to be noted however the application of probabilistic simulation for the evaluation of the marginal cost is not a natural part of the formulation and so the values are close approximation.

5.4 BENEFITS FROM EQUILIBRATION OF MARGINAL COSTS

The formulation to evaluate the benefits from equilibration of the marginal costs is described below. For a given demands of L_a and L_b, the respective marginal costs, $MC(L_a)$ and $MC(L_b)$ can be established from Fig. 5.5. The difference in the marginal costs provides some savings in the operations of both systems through the interconnection. These savings are limited by two factors; the first is the extent of the difference of the marginal costs, and the second is the capability of the tie line which is normally finite.

For purpose of illustration, refer to Fig. 5.6a, whereby it is assumed that $MC(L_b)$ is less than $MC(L_a)$. This implies that system B is able to supply energy to system A. If the tie capacity from B to A is T_{BA}, the process of estimating the benefits is as shown in the diagram. As can be seen the benefit is limited by the extent of the marginal cost being equilibrated. Fig. 5.6b however shows that the benefit is limited by the tie line capability even though there is still marginal cost difference between the two systems. In this case the transfer is from system A to system B. The hatched areas represent the benefits acquired.

If the demands for the duration D, are represented in the form of the combined load probability density function $f(L_a,L_b)$, see section (4.2.2), and if the computation of the benefit is done in a step size of dM, then;

i) Benefits B_{AB} from system A to system B,

$$B_{AB} = \Sigma\,\Sigma \quad MC(L_b-L_a)\ dM\ .\ f(L_a,L_b)\ .\ D \qquad (5.3)$$

$$\text{for } MC(L_a) < MC(L_b)$$
$$f(L_a,L_b) > 0$$

ii) Benefits B_{BA} from system B to system A,

$$B_{BA} = \Sigma\,\Sigma \quad MC(L_a-L_b)\ dM\ .\ f(L_a,L_b)\ .\ D \qquad (5.4)$$

$$\text{for } MC(L_a) > MC(L_b)$$
$$f(L_a,L_b) > 0$$

The total benefits through equilibration of the

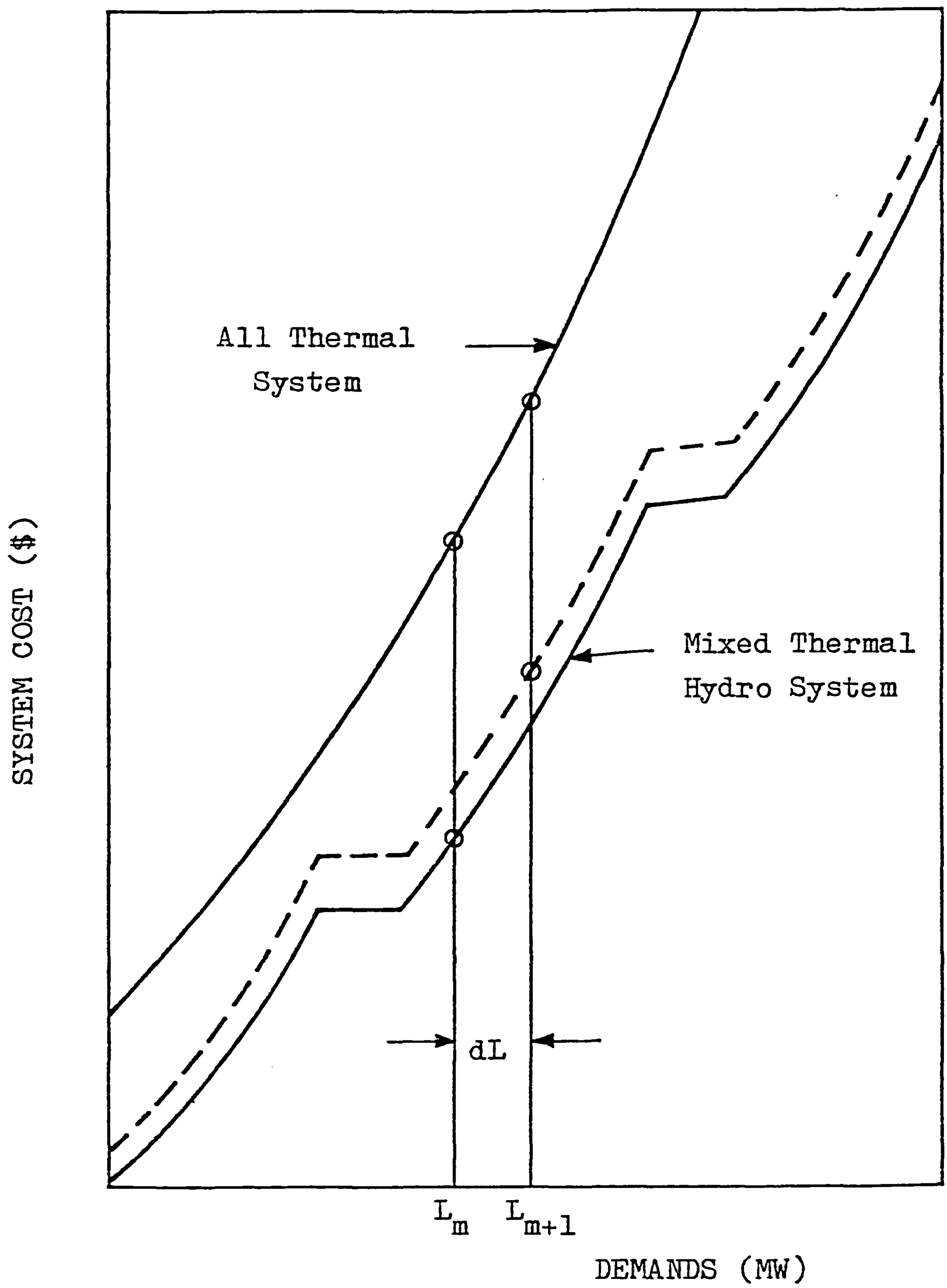


FIG. 5.4 Typical System Cost Curves

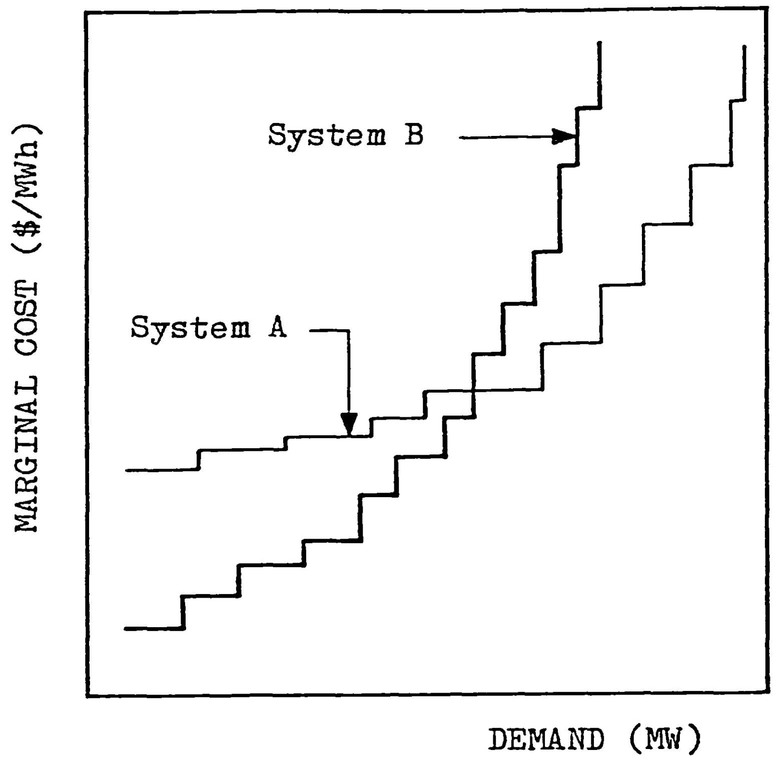


FIG. 5.5 Typical Marginal Cost Curves for Two Systems

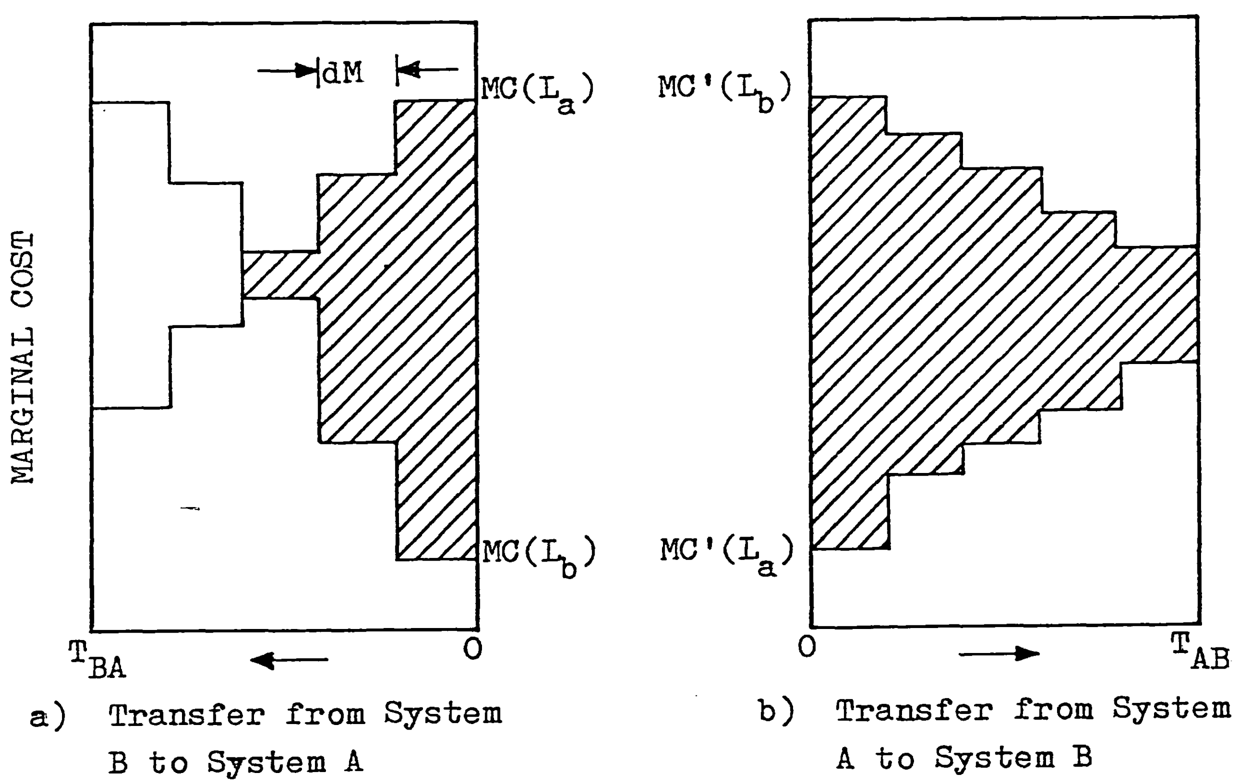


FIG. 5.6 Benefits from Equilibration of Marginal Costs

marginal costs will then be the sum of the two benefits derived from the equations (5.3) and (5.4). If the marginal cost is in \$/MWh, and the step increment dM, is in MW, then the benefit will be in \$ if the period is given in hours. Thus for a given size of the interconnection, the benefits through equilibration of marginal costs can be evaluated for the period under investigation.

5.5 COMPUTER PROGRAMME

A computer programme (EOMC) has been developed based on the above formulation for the evaluation of the benefits through equilibration of the marginal costs. The period is defined as an input in hours and can be in days, weeks or year.

The simulation programme is made up of a main routine and several subroutines. There are seven important steps in the calculations and they are described below,

1) Data Manipulation

The main routine reads in the input and prints its output. It also prints some of the more important results depending on the option chosen. The data are almost similar to that described for the computer programme (HLOLENS) in section (4.5), chapter 4, except for the following additional data; the generation cost of each unit and the energy capacity of the hydro unit given in GWh/period. The thermal units are arranged in the merit order. The effects of maintenances of the plants are corrected and the rest of the computation in this routine are similar to that for the programme (HLOLENS).

2) The Hydro Simulation Routine

In this routine the hydro unit is located within the merit order. The hydro unit is first placed at the last position in the merit order next to the most expensive plant. By trial and error the hydro unit is moved up in succession until the expected energy generation is equal to the energy capacity of the hydro unit. This routine uses the process of deconvolution to determine the expected energy generation. A two block representation of the thermal unit is incorporated to utilize the full energy capacity of the hydro. The step size chosen for the calculations will determine the accuracy of the utilization of the hydro unit.

3) The Load Model Routine

In this routine the two dimensional load density matrix $f(L_a,L_b)$ is constructed from the hourly peak chronology from the two systems as is described in section (4.3.2).

4) The System Cost Routine

This routine evaluates the system costs for different levels of demands. This routine is entered for system with or without hydro units since in essence the units are all treated as thermal units. The expected energy generation of each unit is calculated during convolution. The computation is done based on the methodology describes in section (5.2.1).

5) The Marginal Cost Routine

The marginal cost at different demand is evaluated in this routine. For an all thermal system the calculations are as described in section (5.3.2). For a mixed thermal hydro system the calculations follow that described in section (5.3.3) whereby a second cost curve has to be evaluated before the marginal cost can be determined. The marginal cost is calculated using equation (5.2).

6) The Equilibration of Marginal Costs Routine

The benefits through the equibibration of marginal costs are computed for all demands L_a and L_b. The integration is done for all $f(L_a,L_b) > 0$. The summation of the benefits for the period under consideration is also done in this routine. The amounts of transfers from system A to B and from system B to A are also accumulated.

7) The Final Routine

This routine establishes for each interconnection size, the benefits obtained and also the energy transfers in either directions. It also evaluates the tie line load factor and the average difference in the marginal cost for the period under investigation.

The summary of the flow diagram for the programme is as shown in Fig. 5.7 and it also shows the importance subroutines associated in each step. The flexibility of the programme applies similarly to that already explained for

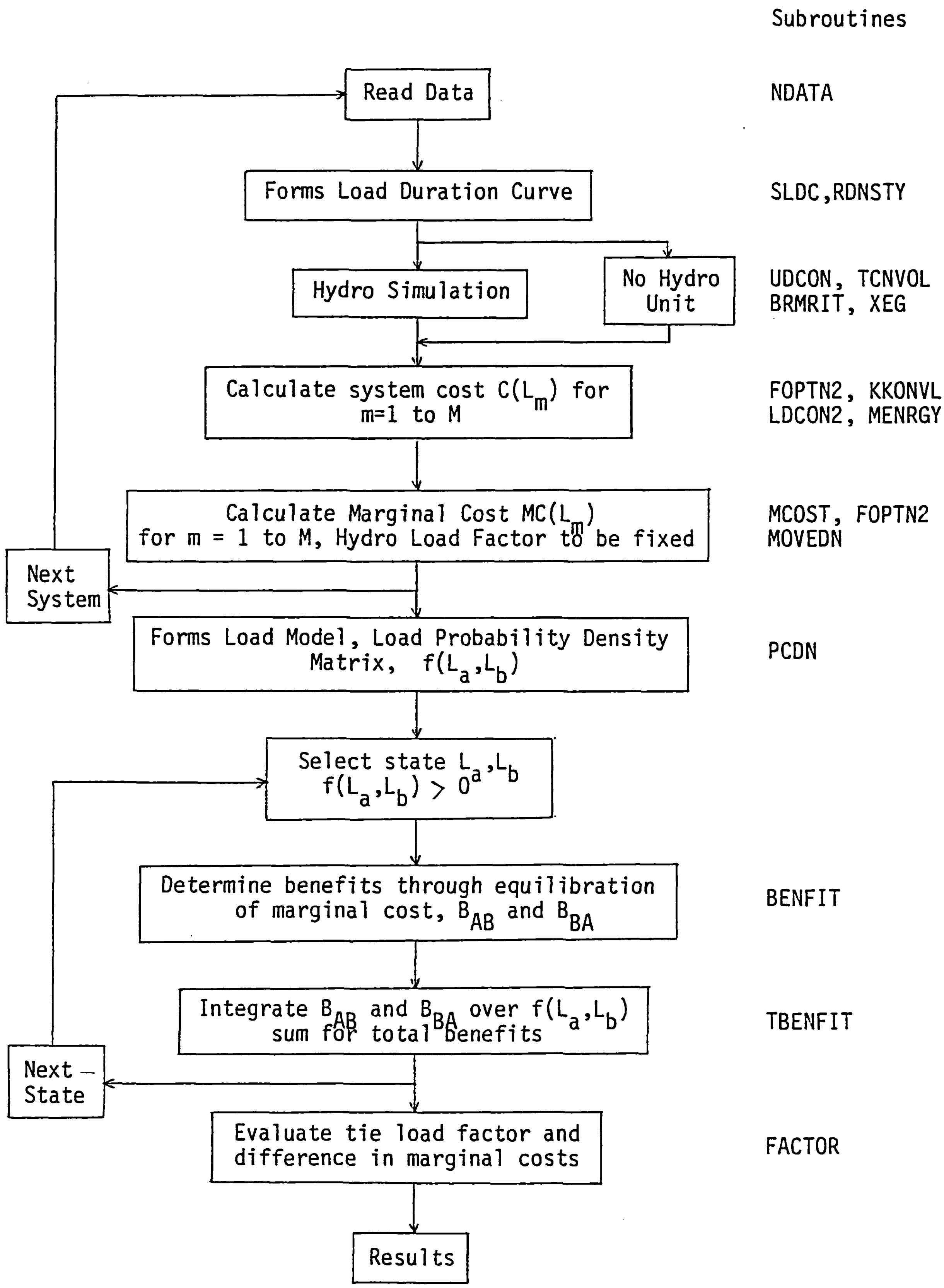


Fig. 5.7 Summary of the Flow Chart of Computer Programme EOMC

the computer programme (HLOLENS). The main advantage of this programme is the ability to evaluate the benefits through the varied configurations of the hydro units and the generation costs of the thermal units. The assessments of the benefits for different sizes of the interconnection can be done in one computer run. Results of this programme have been obtained and will be described in the next chapter.

5.6 SUMMARY

This chapter explains the methodology on the evaluations of the benefits of interconnection through equilibration of the marginal costs. The methodology to obtain the marginal cost using probabilistic simulation has been explained. The influence of the hydro units in the evaluation is also elaborated. The determination of the benefits has been described for a given period of study. Finally, the summary of the computer programme developed to do the assessment has been presented.

CHAPTER 6

CASE STUDY

6.1 INTRODUCTION

This Chapter presents the case study that was undertaken for the interconnection between the LLN system and the PUB system. The years of assessments are 1990 and 2000. The benefits evaluated are the capacity savings through the interconnection and the operating savings through equilibration of the marginal costs. The results are discussed and an economic assessment is done on the basis of the benefits derived. Comparisons of the results are made and finally some further developments are discussed.

6.2 SYSTEM AND LOAD DATA

The years of assessment for the interconnection are 1990 and 2000. The sizes of the interconnection introduced are from 100 MW to 500 MW. Each year is divided into four periods. The periods are defined to represent the hydrological conditions for the hydro simulation. Separate computer runs are made for each period. The periods are as follows;

Period 1 : January, February, March

Period 2 : April, May, June

Period 3 : July, August, September

Period 4 : October, November, December

The following data are necessary for the assessments

i) Load data : Hourly maximum demands throughout one year and the expected growth ratesup to 2000 AD. These are to represent the historical load data from which the future load demands for the years 1990 and 2000 can be projected using the expected growth rates.

ii) Existing System data : These include the number of units and types, unit capacity, forced outage rate, generation cost, planned maintenance for each unit. For system comprising hydro units, the energy capacities for the four periods are needed.

iii) A similar set of system data for the expansion plan up to the year 2000.

6.2.1 LLN SYSTEM

Three statutory bodies are entrusted with the duty to generate, transmit and distribute electrical energy in Malaysia namely; the LLN for West Malaysia (Peninsular Malaysia), the SESCO for the state of Sarawak and SEB for the state of Sabah. The total installed capacity of the intergrated system operated by the LLN as per August 1981 was of the order of 2150 MW, with percentage breakdown in terms of capacity of 65% thermal, 30% hydro and 5% gas turbine with the remaining consisting of small diesel stations.

In terms of energy generation, the total energy sent out by LLN from 1st. September 1980 to 31st. August 1981 was about 9100 GWh, of this 15% was generated by hydro stations, the remainder from petrol based fuels. The average growth rate of about 10% is expected to be maintained over the next two decades leading to a peak demand of around 9100 MW and energy generation of about 55500 GWh in the year 2000 [(9), (52), (53)].

The LLN has provided most of the required data [(54)]. The historical load data of the hourly maximum demands are given for 48 weeks from 1 June 1981 to 2 May 1982. The expansion plan is given from 1983 to 1987 and includes the system data for the year 1990. The generation costs for most of the major units and some informations on the maintenance schedules are given. The overall forecasts up to the year 2000 are also provided.

The information given for each existing hydro unit is the ratio of the expected generation bimonthly to its annual potential. The annual potential energy in GWh for each unit is not given. Estimates of these values are then made from the Statistical Bulletin [55]. For the present analysis, the energy capacity in GWh for each unit is divided into the 4 periods using the ratio provided. Appendix B shows the summary of some of the data gathered. The hourly demands for one week in January 1982 are included for reference. The remaining 4 weeks of the hourly peak demands which are not given, representing the month of July, are taken from the month of June. For the purpose of the present analysis the maintenance of the plants are scheduled on an annual basis.

The expansion plan for the LLN is provided including the timings of the new plants up to the year 1987. Also the system data for the year 1990 are given. The expansion plan is based on the reliability index of LOLE (commonly called LOLP) of 1 day/year [54]. The sizes of the units after 1985 have been decided but not some of the types. The options are for either oil, coal or gas generation. The other important factor in the LLN expansion plan is the utilization of the hydro potentials. There are already several sites that have been identified and proven to be feasible.

For the present moment, the years of assessments are 1990 and 2000. The expansion plan up to the year 1987 is taken from the data received. Due to the uncertainty to use either oil, coal or gas, it was decided that for the present analysis the expansion plan utilized oil and gas up to the year 1990, and that coal generation to be introduced only after 1990. Recent developments in the LLN however have introduced a 2x300 MW of coal power plants before 1990.

The expansion plan up to the year 2000 has been prepared as shown in table B.4 in Appendix B. The expansion plan is developed based on the early utilization of natural gas and the hydro potentials that are feasible. The size and the energy capacity for each potential hydro unit are obtained from the ASEAN Study on interconnection[10]. Coal units are introduced after 1990 and the sizes considered are 300 MW and 600 MW. The LLN has provided the system data for 1990. The HLOLE calculated for that year is about 4.58 hours/year and the EENS is about 1545 MWh. These are expected to be equivalent to the requirement of the LOLP of 1 day/year. For the expansion programme developed for the year 2000, the HLOLE calculated is 5.78 hours/year and the EENS is about 1547 MWh, see tables 6.3 and 6.5. By comparison to the year 1990, the expansion plan therefore closely satisfies the reliability standard. It is noted that the timings of the additions of the units are not relevant for the present analysis but the reliability criterion must be satisfied in the years 1990 and 2000. However, there are included for completion of the data.

6.2.2 PUB SYSTEM

The generation, transmission and distribution of electrical energy in Singapore is undertaken by the PUB. In 1982, the PUB operated three power stations with a total capacity of 2010 MW. The maximum demand was about 1250 MW, and it is expected to increase at the rate of 8 to 10% per annum for the rest of the decades. Singapore has no indigenous sources of energy and the generation of electricity depends solely on imported fuel oil (9),(53), (56).

The PUB has provided most of the data necessary(57). The historical data of hourly peaks are given for a complete year of 1982, from 27 December 1981 to 1 January 1983. The expansion plan is also provided up to the year 2000. The forced and planned outage rates are also given. The PUB system is almost reliable on imported oil and there is no hydro unit in the system.

The PUB is unable to provide the generation costs for their units (57), so estimates are made from the LLN thermal generating units (54). The data for the PUB system are as shown in Appendix C. For purpose of comparison, the hourly peaks for one week in January 1982 are also included. For compatibility of data, the maintenances of the units are given in an annual basis.

6.3 RESULTS AND DISCUSSIONS

For sample system data to run the programmes, tables 6.1 and 6.2 show the data preparation sheets for the LLN and the PUB systems for the year 1990. Similar data sheet can be prepared for the year 2000. It should be noted that the maintenance schedules were based on levelising the reserve margins for the whole year. These maintenance schedules were done as a prerequisite as part of the preparation of the data.

TABLE 6.1

System Data Sheet for LLN in 1990

No	Size (MW)	Avai	Types	Period 1	Period 2	Period 3	Period 4	Gen cost ($/MWh)	Planned outage (Hours)
1	300	0.820	Nat Gas	300				31.6	504
2	300	0.820	Nat Gas		300			31.6	504
3	300	0.820	Nat Gas			300		31.6	504
4	300	0.950	Oil				300	52.5	1920
5	300	0.950	Oil	300				52.5	1920
6	300	0.950	Oil		300			52.5	1920
7	300	0.950	Oil			300		52.5	1920
8	120	0.991	Oil				120	54.8	1080
9	120	0.991	Oil				120	54.8	1080
10	120	0.991	Oil			120		54.8	1080
11	120	0.991	Oil				120	54.8	1080
12	120	0.991	Oil	120				54.8	1080
13	120	0.991	Oil		120			54.8	1080
14	120	0.991	Oil			120		54.8	1080
15	120	0.991	Oil				120	54.8	1080
16	60	0.988	Oil				60	57.1	840
17	60	0.988	Oil	60				57.1	840
18	60	0.988	Oil	60				57.1	840
19	60	0.988	Oil		60			57.1	840
20	80	0.936	Oil	80				57.6	840
21	80	0.936	Oil		80			57.6	840
22	30	0.984	Oil		30			62.6	840
23	30	0.984	Oil		30			62.6	840
24	30	0.984	Oil			30		62.6	840
25	30	0.984	Oil			30		62.6	840
26	30	0.984	Oil				30	62.6	840
27	30	0.984	Oil				30	62.6	840
28	10	0.962	Oil				10	74.6	840
29	20	0.940	GT			20		104.8	360
30	20	0.940	GT				20	104.8	360
31	20	0.940	GT	20				104.8	360
32	20	0.940	GT		20			104.8	360
33	20	0.940	GT			20		104.8	360
Total under maintenance				940	940	940	930	MW	
34	1750	0.999	Hydro	1530	1160	1096	1814	GWh per period	
Total installed capacity	5500 MW								

TABLE 6.2

System Data Sheet for PUB in 1990

No	Size (MW)	Avai	Types	Period 1	Period 2	Period 3	Period 4	Gen cost ($/MWh)	Planned outage (Hours)
1	250	0.96	Oil	250				53.5	1800
2	250	0.96	Oil		250			53.5	1800
3	250	0.96	Oil			250		53.5	1800
4	250	0.96	Oil				250	53.5	1800
5	250	0.96	Oil	250				53.5	1800
6	250	0.96	Oil		250			53.5	1800
7	250	0.96	Oil			250		53.5	1800
8	250	0.96	Oil				250	53.5	1800
9	250	0.96	Oil	250				53.5	1800
10	250	0.96	Oil		250			53.5	1800
11	120	0.97	Oil			120		54.8	1080
12	120	0.97	Oil			120		54.8	1080
13	120	0.97	Oil				120	54.8	1080
14	120	0.97	Oil				120	54.8	1080
15	120	0.97	Oil	120				54.8	1080
16	120	0.97	Oil		120			54.8	1080
17	60	0.98	Oil			60		57.1	840
18	60	0.98	Oil			60		57.1	840
19	60	0.98	Oil				60	57.1	840
20	60	0.98	Oil				60	57.1	840
21	60	0.97	Oil	60				57.1	840
22	60	0.97	Oil		60			57.1	840
23	60	0.97	Oil			60		57.1	840
24	60	0.97	Oil				60	57.1	840
25	96	0.98	GT			96		104.8	504
26	96	0.98	GT				96	104.8	504
27	20	0.99	GT	20				104.8	360
28	20	0.99	GT		20			104.8	360
Total under maintenance				950	950	1016	1016	MW	

Total installed capacity 3932 MW

Fig. 6.1 shows the chronology of hourly peaks for a typical day for the LLN and the PUB systems. The load model is a vital component in the evaluation of both the benefits. The two dimensional load model is constructed as described in Chapter 4. A sample output of the two dimensional load model is as shown in Fig. 6.2 for the LLN/PUB systems for period 1 in year 1990. The numbers in the matrix represent the numbers of coincident of hourly peaks. Since the period considered is 2184 hours, therefore the probability of occurrence of load L_a and L_b will be the number of hours of coincident divided by 2184 hours. For example if L_a = 1250 MW, and L_b = 2000 MW, then the probability of occurrence $f(L_a,L_b)$ = 0.01419.

It is observed from the two dimensional load model, two distinct characteristics of the loads. For the LLN/PUB systems there exists little diversity in the low loads whereas there is high diversity in the high loads. The significant of these features is that the reliability analysis is expected to be influenced by the diversity in the high loads and the equilibration of marginal costs influenced most from the diversity in the low load regions.

Another version of the two dimensional load model is through a contour representing the probability of occurrence. Fig. 6.3 is an attempt to do it and as shown it is not an easy task because the surface is very irregular. But the attempt illustrates clearly the extent of the diversities in the loads. The surface for the intermediate loads if it is possible to draw is rather 'choppy'. Similar illustrations are given for the year 2000, see

Figs. 6.4 and 6.5.

The cost benefit analysis was done in two parts. The first part computed the reliability indices HLOLE and EENS before and after interconnection. For each period, these values were obtained for interconnection sizes of 100, 300 and 500 MW. The second part calculated the benefits derived through equilibration of the marginal costs for interconnection sizes of 100, 300 and 500 MW.

The step size of 50 MW was used for the year 1990 and 100 MW was used for the year 2000. For the computer programme HLOLENS, the computer CPU times for typical runs using the IBM 370 were about 420 seconds and 480 seconds for period 1 for the years 1990 and 2000 respectively for interconnection sizes of 100, 300 and 500 MW. For similar interconnection sizes and period, the programme EOMC required about 36 seconds and 47 seconds for the years 1990 and 2000 respectively.

6.3.1 CAPACITY SAVINGS THROUGH INTERCONNECTION

The results for the measurements of the reliability indices HLOLE and EENS before and after interconnection for the years 1990 and 2000 are shown in tables 6.3 to 6.6. Each of the table gives for one period, the values of the HLOLE and EENS before and after interconnection for the different sizes of the interconnection.

The graphical outputs are as shown in Figs. 6.6 to 6.13. The dotted lines in the figures are extensions of the expected behaviour of the curves. These extrapolations were done to complete some of the entries in the tables

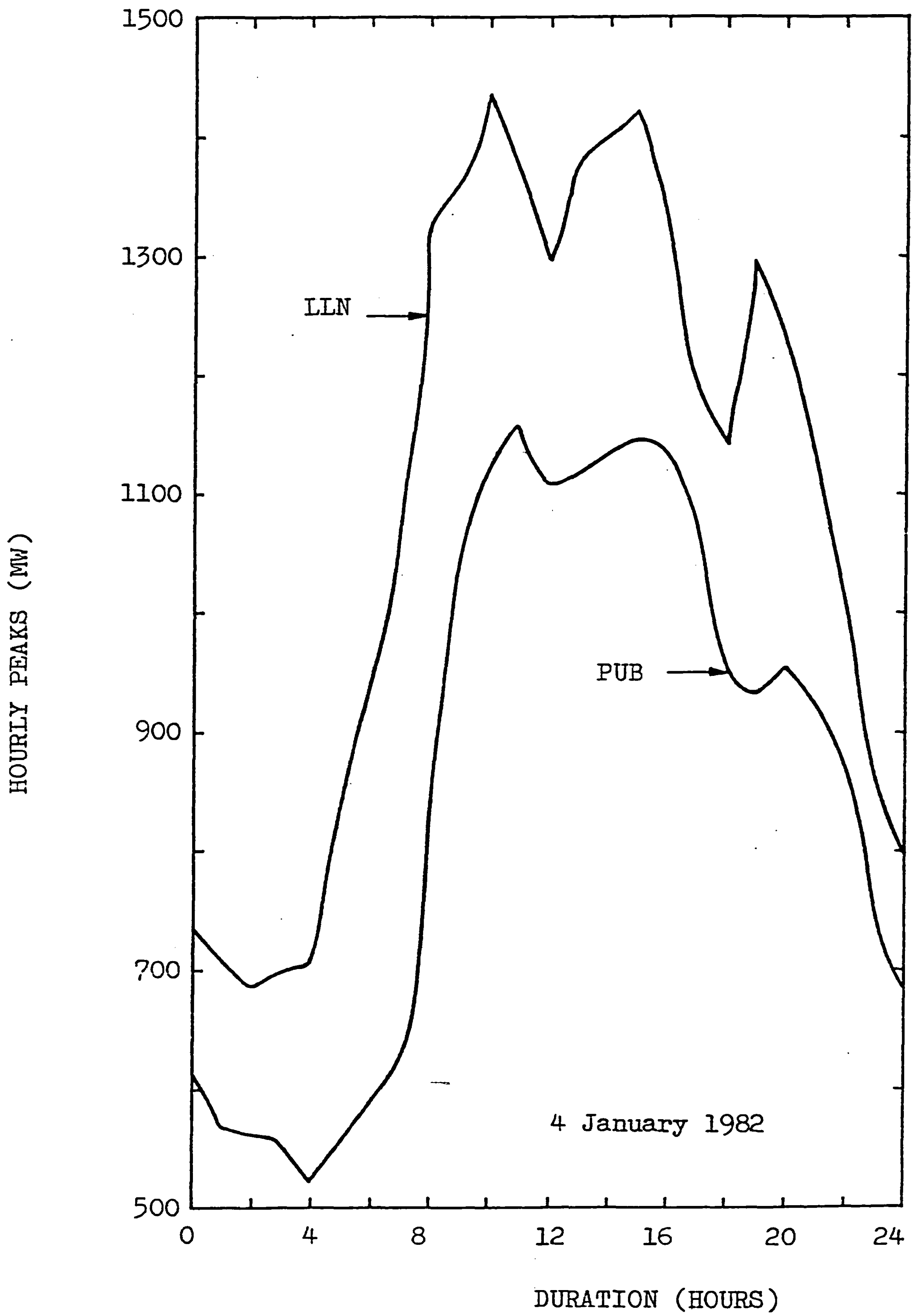


FIG. 6.1 Hourly Peak Demands for a Day for LLN and PUB Systems

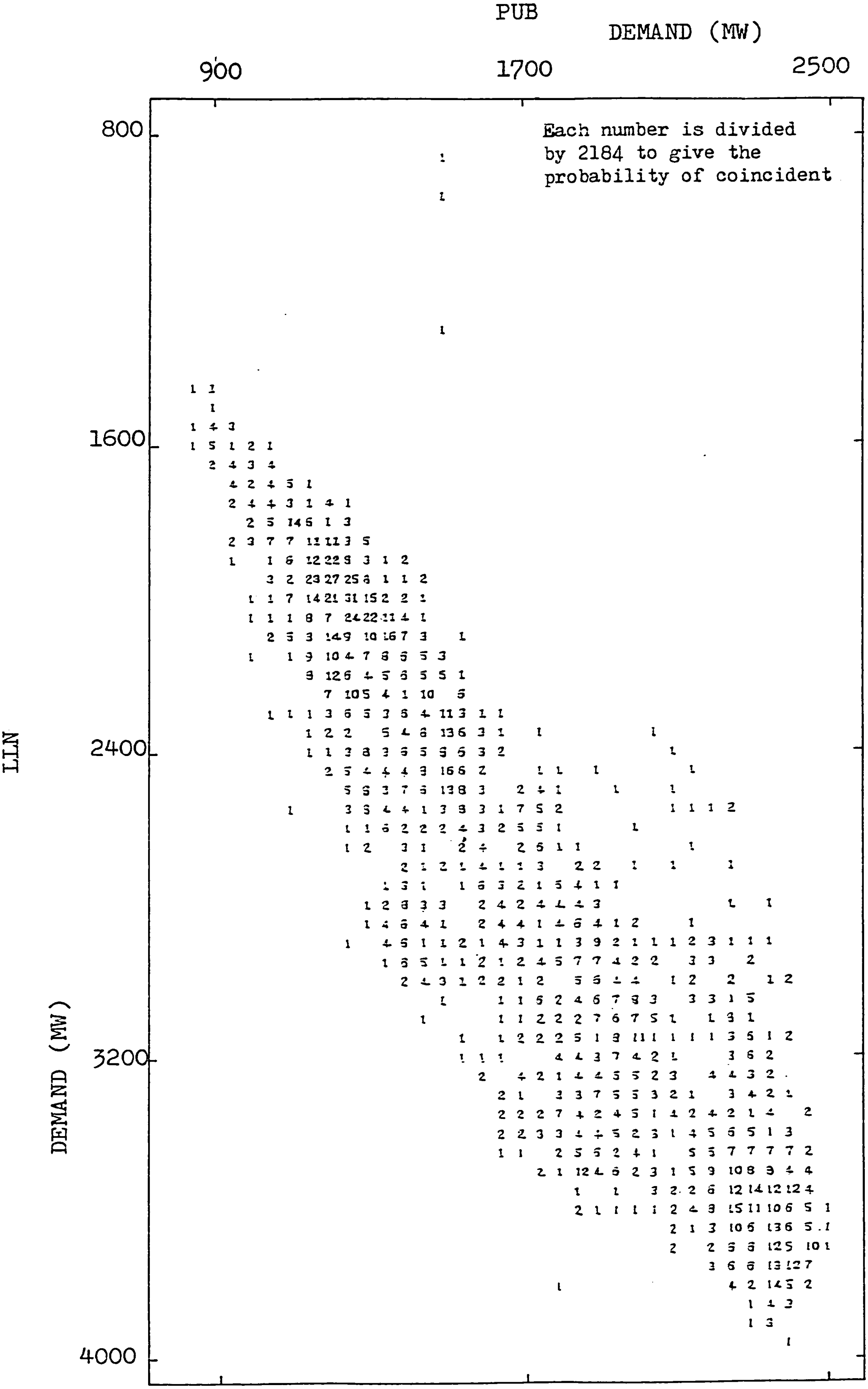


FIG. 6.2 Load Probability Density Matrix for LLN/PUB Systems for Period 1 in 1990

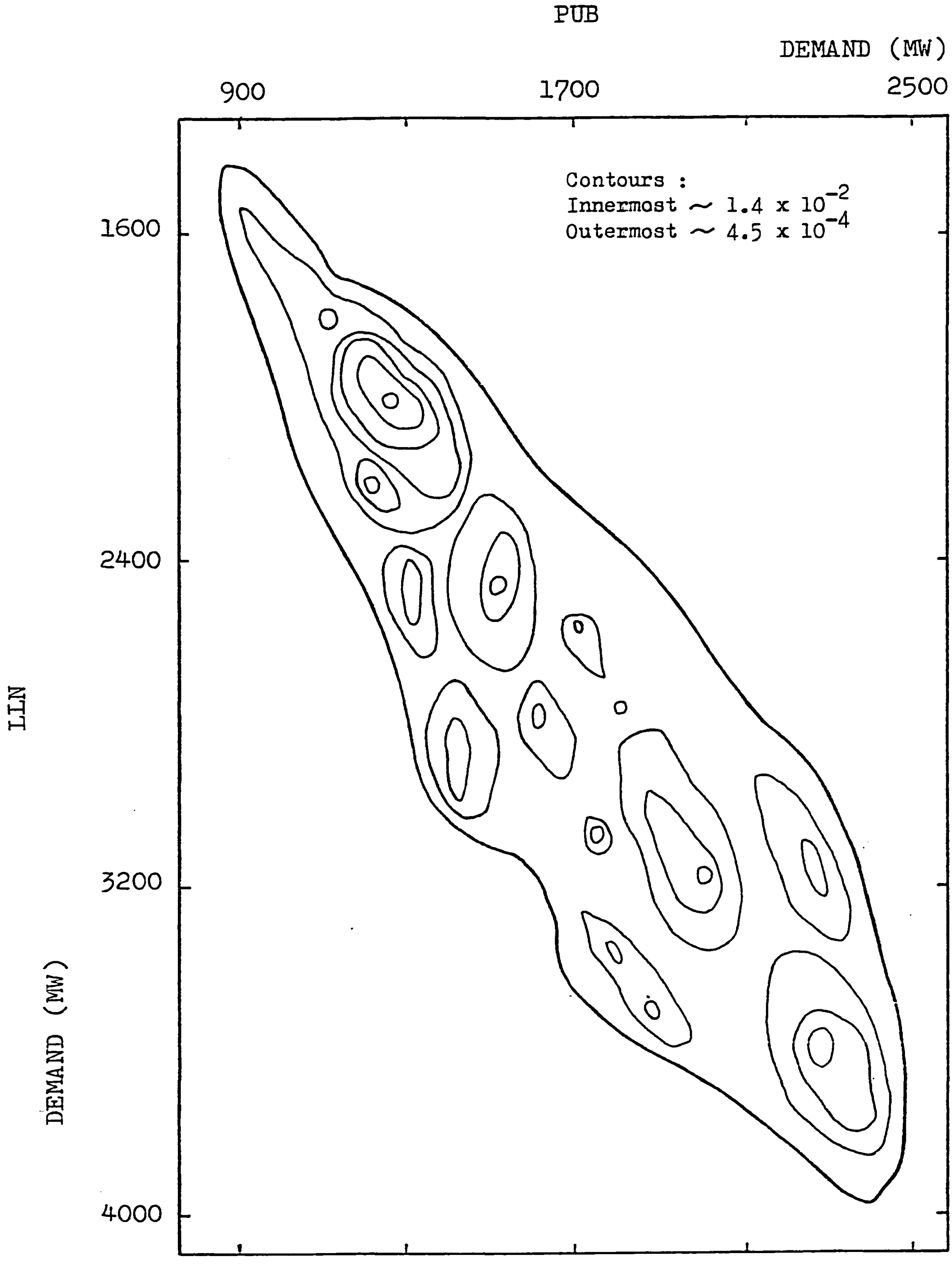


FIG. 6.3 Load Probability Density Contours for Period 1 in 1990

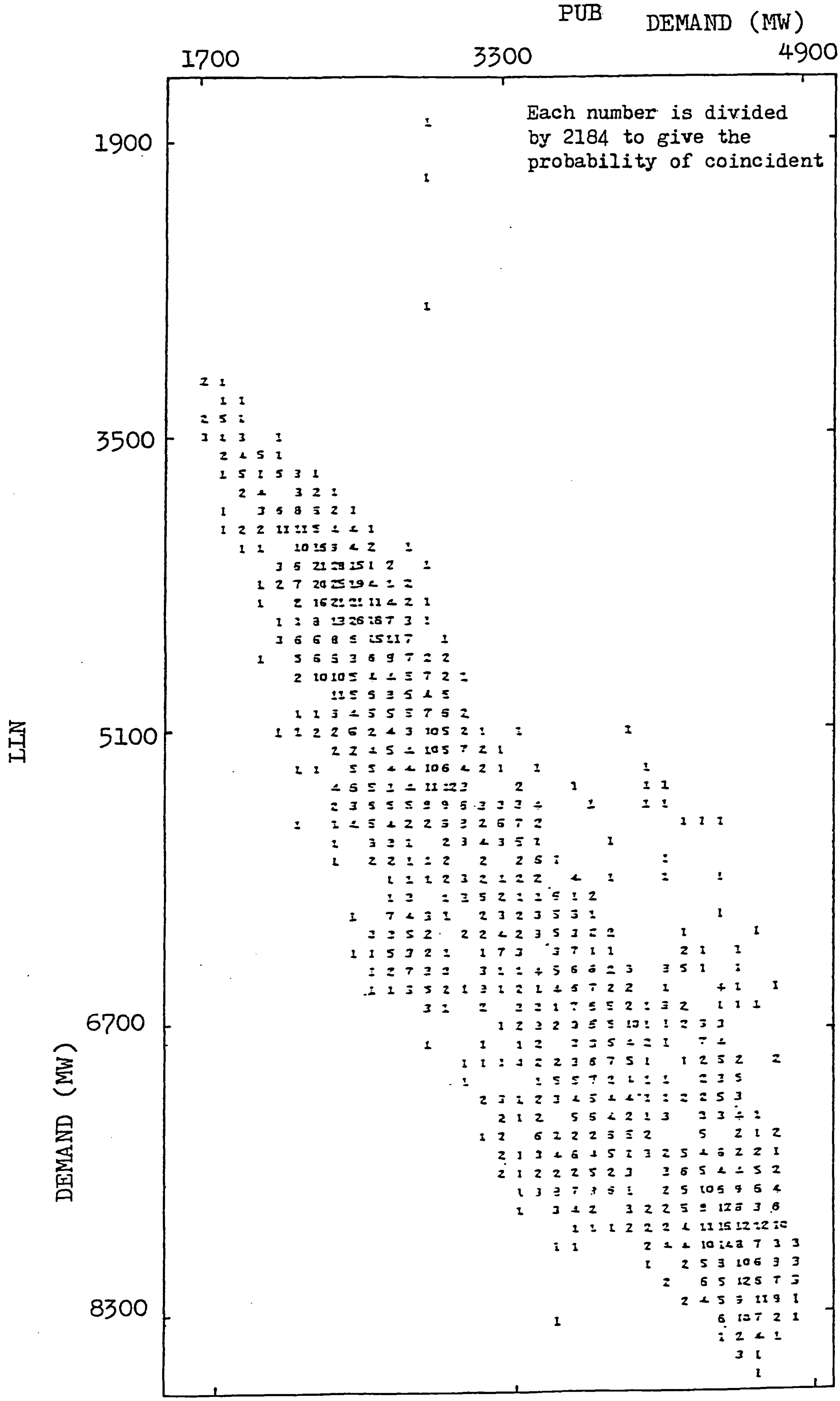


FIG. 6.4 Load Probability Density Matrix for LLN/PUB Systems for Period 1 in 2000

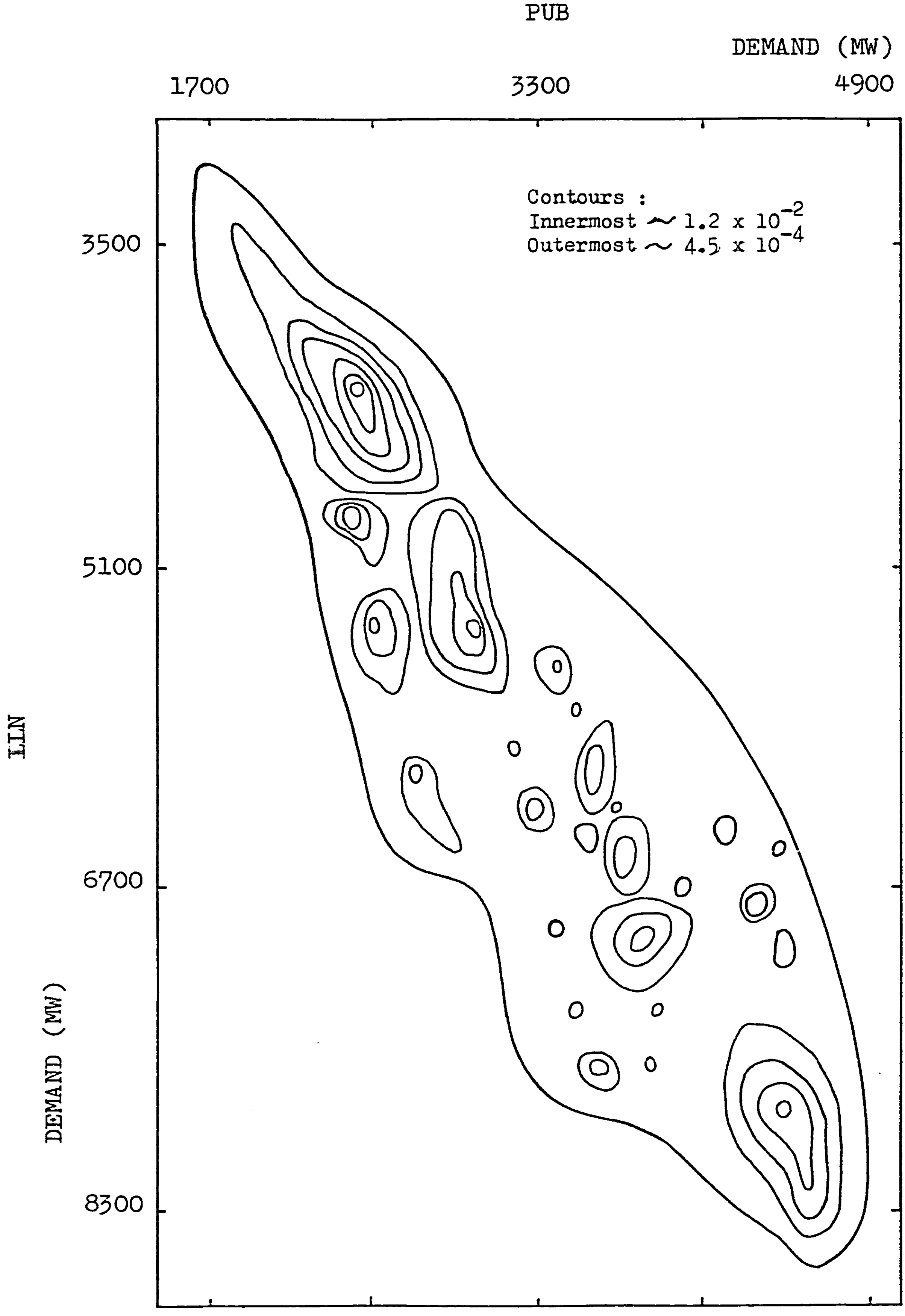


FIG. 6.5 Load Probability Density Contours for Period 1 in 2000

TABLE 6.3

HLOLE and EENS Before and After Interconnection for LLN in 1990

SYSTEM:LLN	Period	Before	After Interconnection			
YEAR:1990			100 MW	200 MW	300 MW	500 MW
HLOLE (Hours/Period) (Each entry x 2184)	1	0.2855×10^{-3}	0.2348×10^{-3}	0.1881×10^{-3}	0.1449×10^{-3}	0.10×10^{-3}*
	2	0.4053×10^{-3}	0.3322×10^{-3}	0.2764×10^{-3}	0.2266×10^{-3}	0.15×10^{-3}*
	3	0.5118×10^{-3}	0.3974×10^{-3}	0.3268×10^{-3}	0.2722×10^{-3}	0.1789×10^{-3}
	4	0.8858×10^{-3}	0.5971×10^{-3}	0.4390×10^{-3}	0.3514×10^{-3}	0.26×10^{-3}*
EENS (MWh)	1	0.20388×10^{3}	0.14998×10^{3}	0.10663×10^{3}	0.73172×10^{2}	0.35×10^{2}*
	2	0.33156×10^{3}	0.25567×10^{3}	0.19303×10^{3}	0.14225×10^{3}	0.65×10^{2}*
	3	0.41604×10^{3}	0.32406×10^{3}	0.24971×10^{3}	0.18841×10^{3}	0.1007×10^{3}
	4	0.59393×10^{3}	0.45174×10^{3}	0.34958×10^{3}	0.26997×10^{3}	0.150×10^{3}*
	Total	1.54541×10^{3}	1.18145×10^{3}	0.89895×10^{3}	0.67380×10^{3}	0.3507×10^{3}
	Difference	-	0.36396×10^{3}	0.64646×10^{3}	0.87160×10^{3}	1.1947×10^{3}

* Interpolation

TABLE 6.4

HLOLE and EENS Before and After Interconnection for PUB in 1990

SYSTEM:PUB YEAR:1990	Period	Before	After Interconnection 100 MW	200 MW	300 MW	500 MW
HLOLE (Hours/Period) (Each entry x 2184)	1	0.3531×10^{-3}	0.1201×10^{-3}	0.3793×10^{-4}	0.1075×10^{-4}	0.25×10^{-5}*
	2	0.8976×10^{-3}	0.3095×10^{-3}	0.1043×10^{-3}	0.3151×10^{-4}	0.27×10^{-5}*
	3	0.5939×10^{-3}	0.2123×10^{-3}	0.7231×10^{-4}	0.2323×10^{-4}	0.2761×10^{-5}
	4	0.4768×10^{-3}	0.1699×10^{-3}	0.5770×10^{-4}	0.1930×10^{-4}	0.26×10^{-5}*
ENS (MWh)	1	0.51601×10^{2}	0.16191×10^{2}	0.45986×10^{1}	0.13072×10^{1}	0.34×10^{0}*
	2	0.13536×10^{3}	0.44475×10^{2}	0.13422×10^{2}	0.39355×10^{1}	0.37×10^{0}*
	3	0.93049×10^{2}	0.31113×10^{2}	0.97888×10^{1}	0.30251×10^{1}	0.3615×10^{0}
	4	0.73911×10^{2}	0.24511×10^{2}	0.77554×10^{1}	0.25227×10^{1}	0.35×10^{0}*
	Total	3.53921×10^{2}	1.1629×10^{2}	0.35564×10^{2}	0.10790×10^{2}	1.4215×10^{0}
	Difference	-	2.37631×10^{2}	3.18356×10^{2}	3.43130×10^{2}	3.5250×10^{0}

* Interpolation

TABLE 6.5

HLOLE and EENS Before and After Interconnection for LLN in 2000

SYSTEM:LLN YEAR:2000	Period	Before	After Interconnection 100 MW	200 MW	300 MW	500 MW
HLOLE (Hours/Period) (Each entry x 2184)	1	0.8934×10^{-4}	0.6406×10^{-4}	0.4600×10^{-4}	0.3302×10^{-4}	0.3×10^{-4}*
	2	0.3818×10^{-3}	0.2760×10^{-3}	0.1993×10^{-3}	0.1438×10^{-3}	0.70×10^{-4}*
	3	0.9247×10^{-3}	0.6774×10^{-3}	0.4945×10^{-3}	0.3601×10^{-3}	0.1636×10^{-3}
	4	0.1252×10^{-2}	0.9269×10^{-3}	0.6814×10^{-3}	0.5020×10^{-3}	0.2675×10^{-3}
ENS (MWh)	1	0.49510×10^{2}	0.35531×10^{2}	0.25506×10^{2}	0.18327×10^{2}	0.15×10^{2}*
	2	0.21466×10^{3}	0.15445×10^{3}	0.11104×10^{3}	0.79827×10^{2}	0.35×10^{2}*
	3	0.53597×10^{3}	0.38822×10^{3}	0.28058×10^{3}	0.20245×10^{3}	0.9102×10^{2}
	4	0.74722×10^{3}	0.54508×10^{3}	0.39673×10^{3}	0.28781×10^{3}	0.1516×10^{3}
	Total	1.54736×10^{3}	1.12328×10^{3}	0.81385×10^{3}	0.58841×10^{3}	1.29262×10^{3}
	Difference	–	0.42407×10^{3}	0.73350×10^{3}	3.95894×10^{3}	1.15474×10^{3}

* Interpolation

TABLE 6.6

HLOLE and EENS Before and After Interconnection for PUB in 2000

SYSTEM:PUB	Period	Before	After Interconnection			
YEAR:2000			100 MW	200 MW	300 MW	500 MW
HLOLE	1	0.1239×10^{-3}	0.6059×10^{-4}	0.2910×10^{-4}	0.1351×10^{-4}	0.20×10^{-5}*
(Hours/Period)	2	0.2546×10^{-3}	0.1290×10^{-3}	0.6380×10^{-4}	0.3104×10^{-4}	0.82×10^{-5}*
(Each entry	3	0.2679×10^{-3}	0.1375×10^{-3}	0.6920×10^{-4}	0.3423×10^{-4}	0.8349×10^{-5}
x 2184)	4	0.2448×10^{-3}	0.1251×10^{-3}	0.6279×10^{-4}	0.3115×10^{-4}	0.8059×10^{-5}
	1	0.24844×10^{2}	0.11622×10^{2}	0.52814×10^{1}	0.23454×10^{1}	0.50×10^{0}*
ENS	2	0.54348×10^{2}	0.26246×10^{2}	0.12409×10^{2}	0.57360×10^{1}	0.1490×10^{1}*
(MWh)	3	0.58400×10^{2}	0.28565×10^{2}	0.13694×10^{2}	0.64864×10^{1}	0.1492×10^{1}
	4	0.52767×10^{2}	0.25702×10^{2}	0.12308×10^{2}	0.58548×10^{1}	0.1451×10^{1}
	Total	19.0359×10^{1}	9.12355×10^{1}	4.36924×10^{1}	2.04226×10^{1}	0.4933×10^{1}
	Difference	—	9.82235×10^{1}	14.66666×10^{1}	16.99364×10^{1}	18.5426×10^{1}

* Interpolation

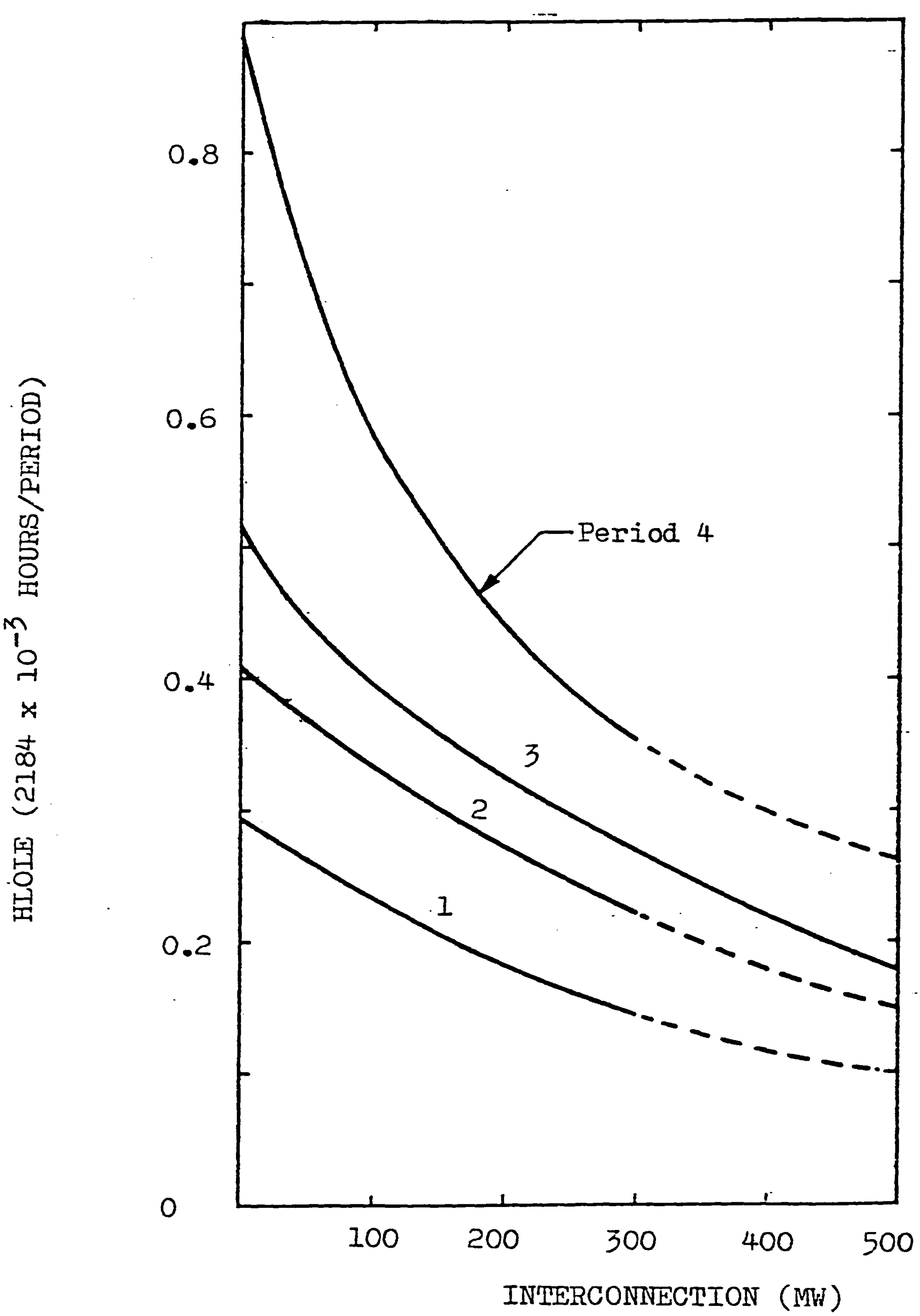


FIG. 6.6 HLOLE Before and After Interconnection for the LLN System for Periods in 1990

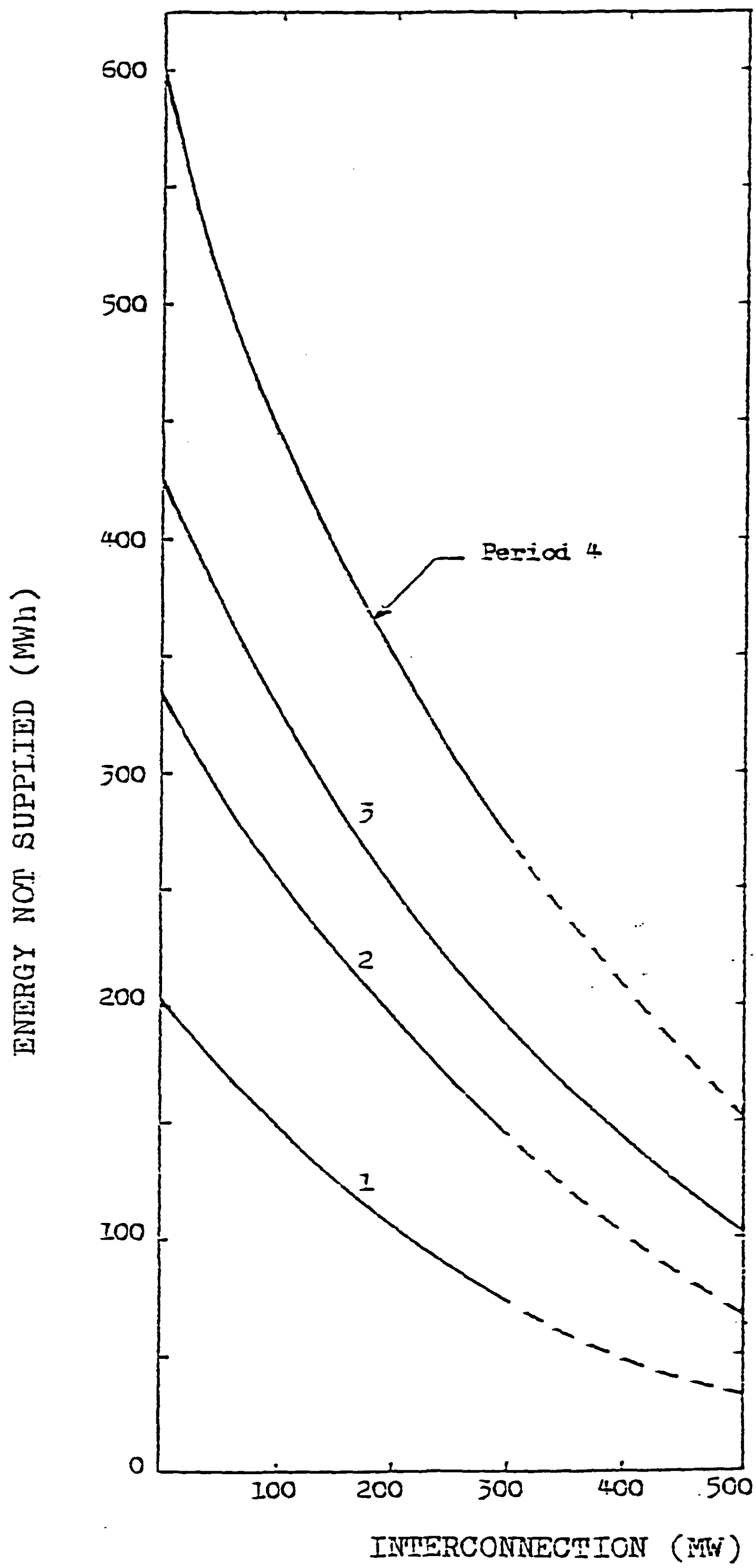


FIG. 6.7 EENS Before and After Interconnection for the LLN System for Periods in 1990

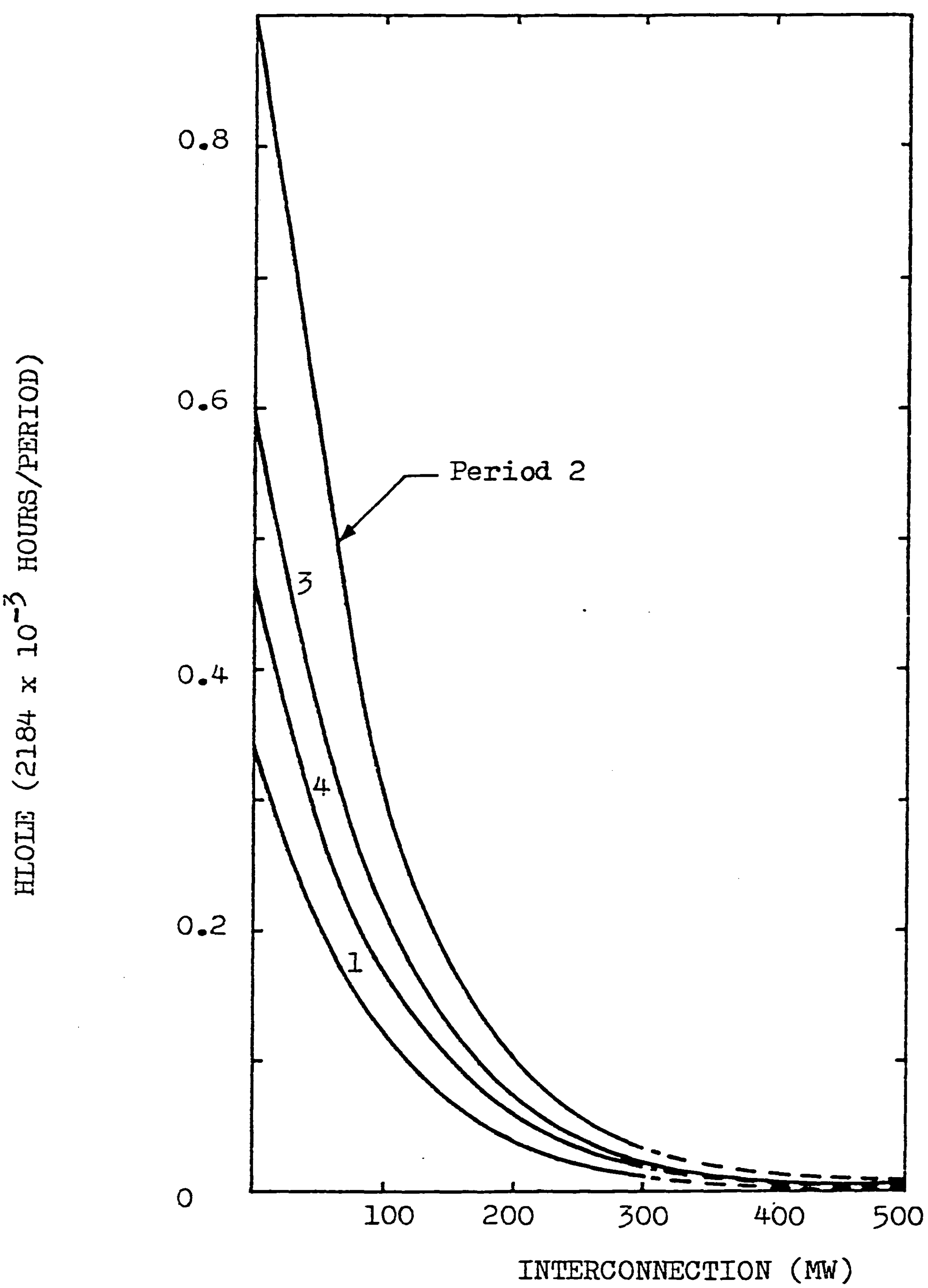


FIG. 6.8 HLOLE Before and After Interconnection for the PUB System for Periods in 1990

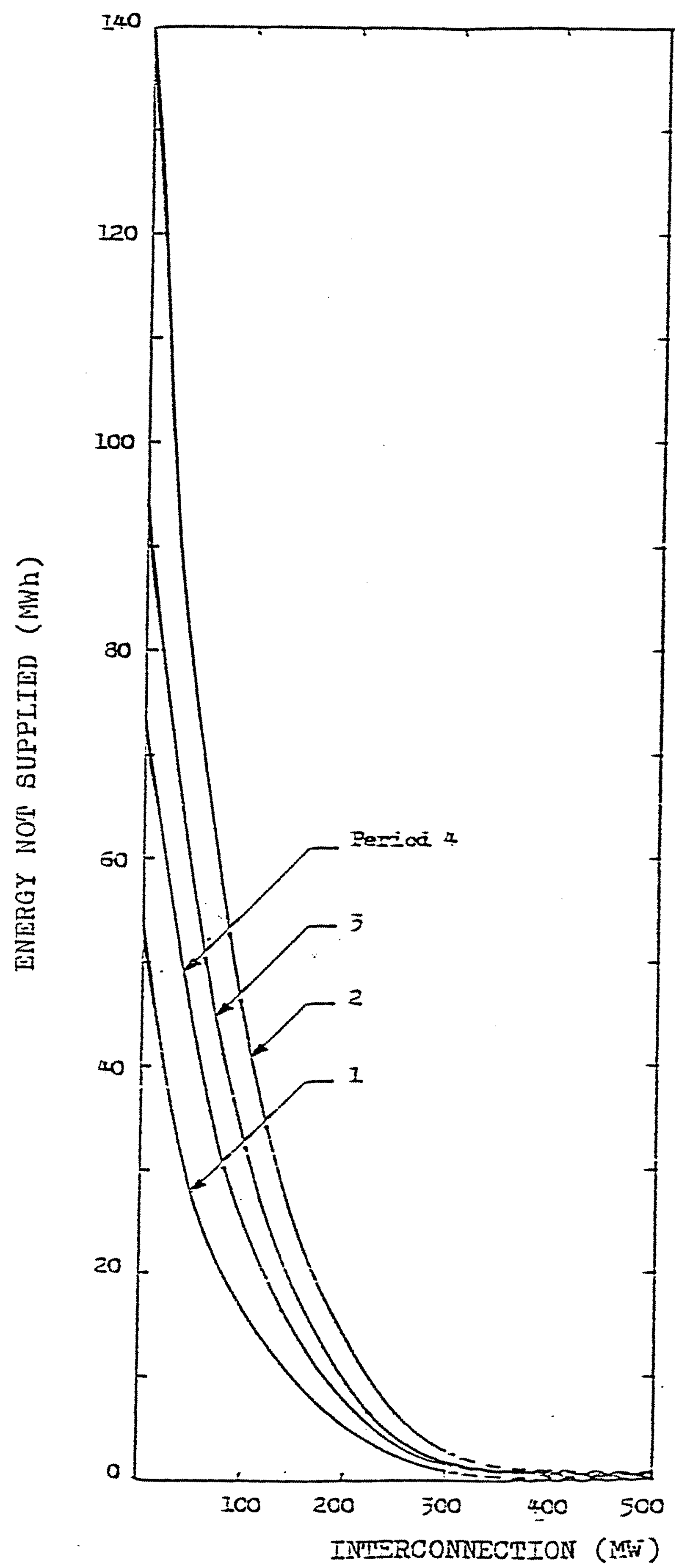


FIG. 6.9 EENS Before and After Interconnection for the PUB System for Periods in 1990

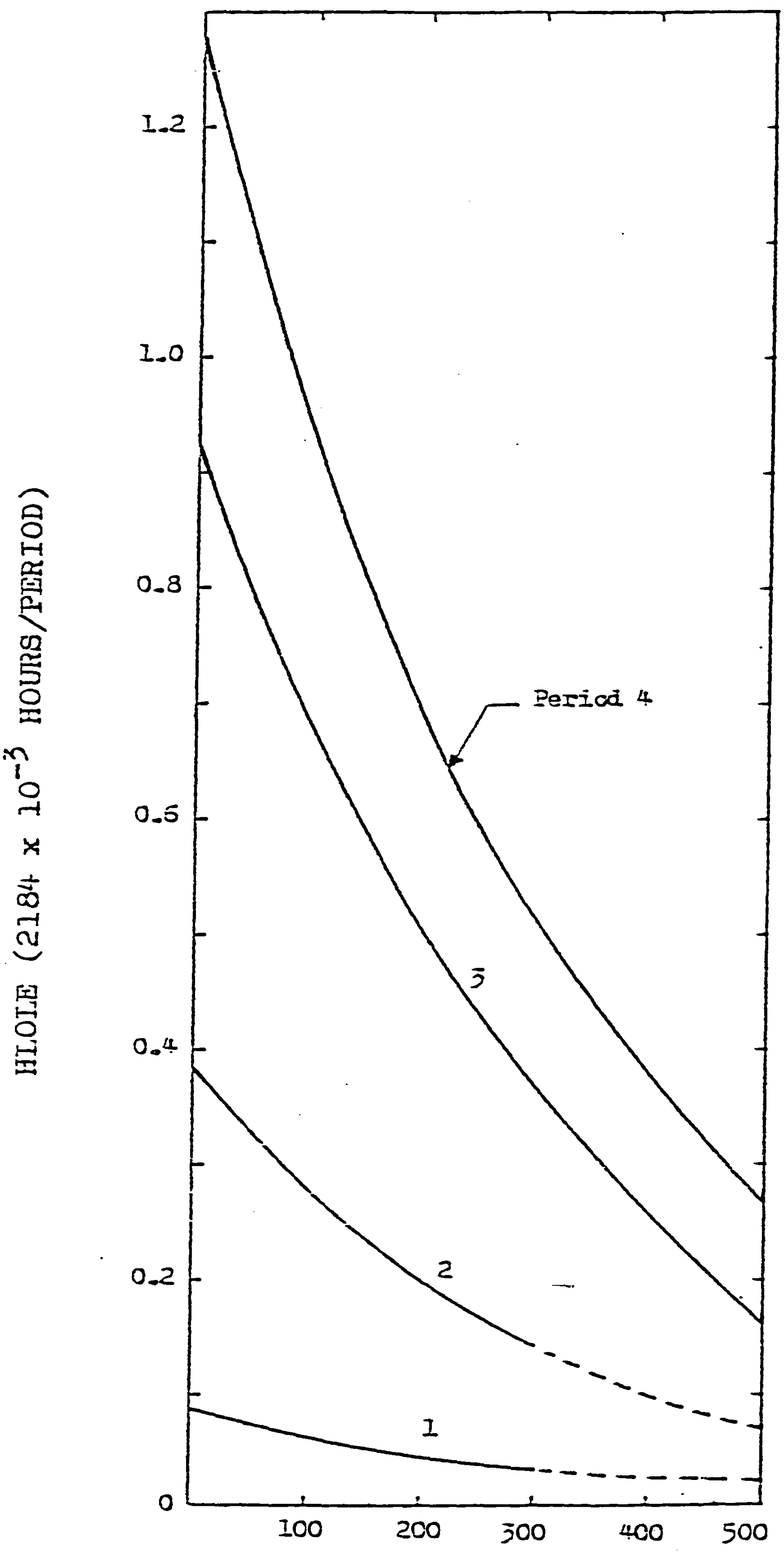


FIG. 6.10 HLOLE Before and After Interconnection for the LLN System for Periods in 2000

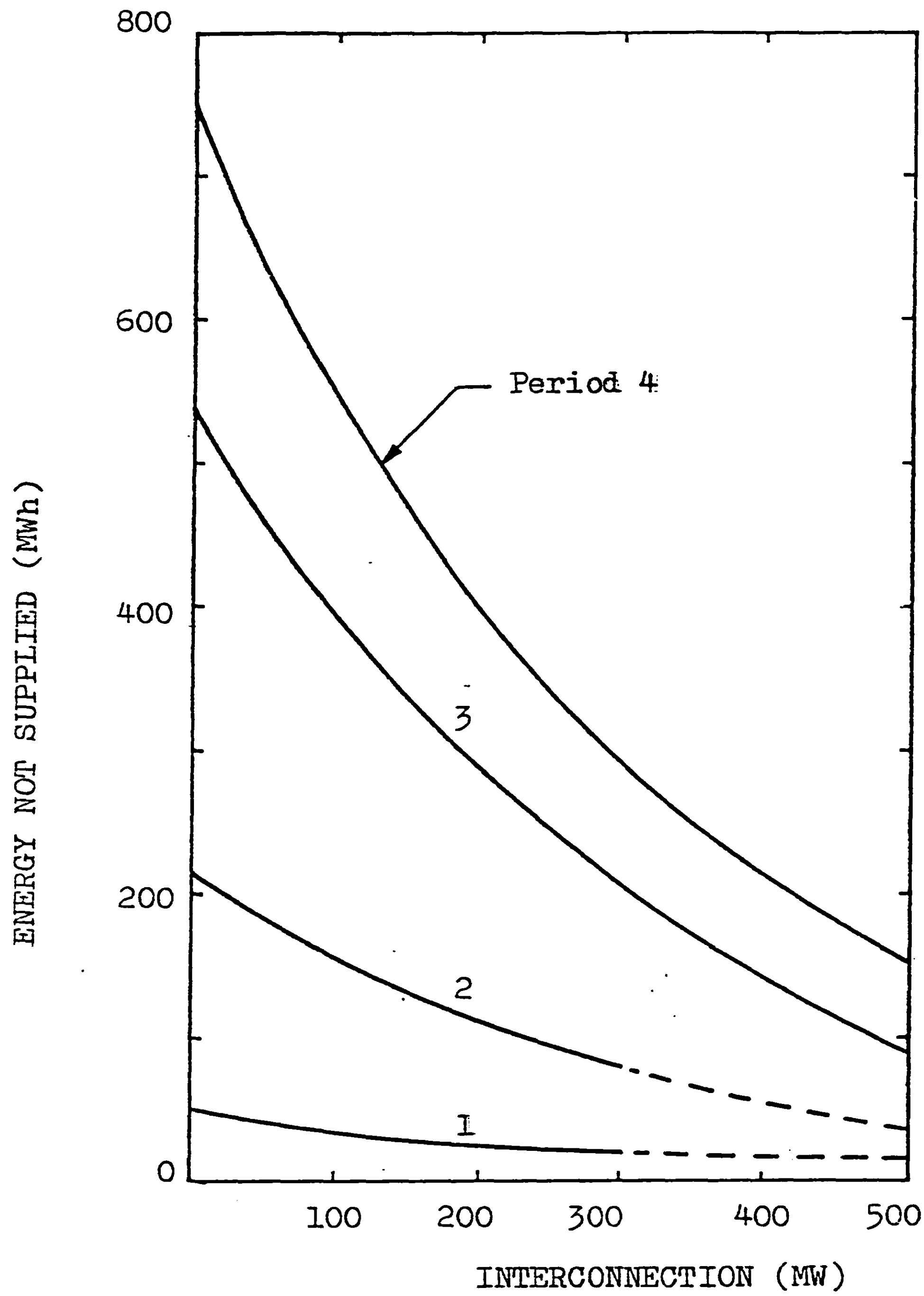


FIG. 6.11 EENS Before and After Interconnection for the LLN System for Periods in 2000

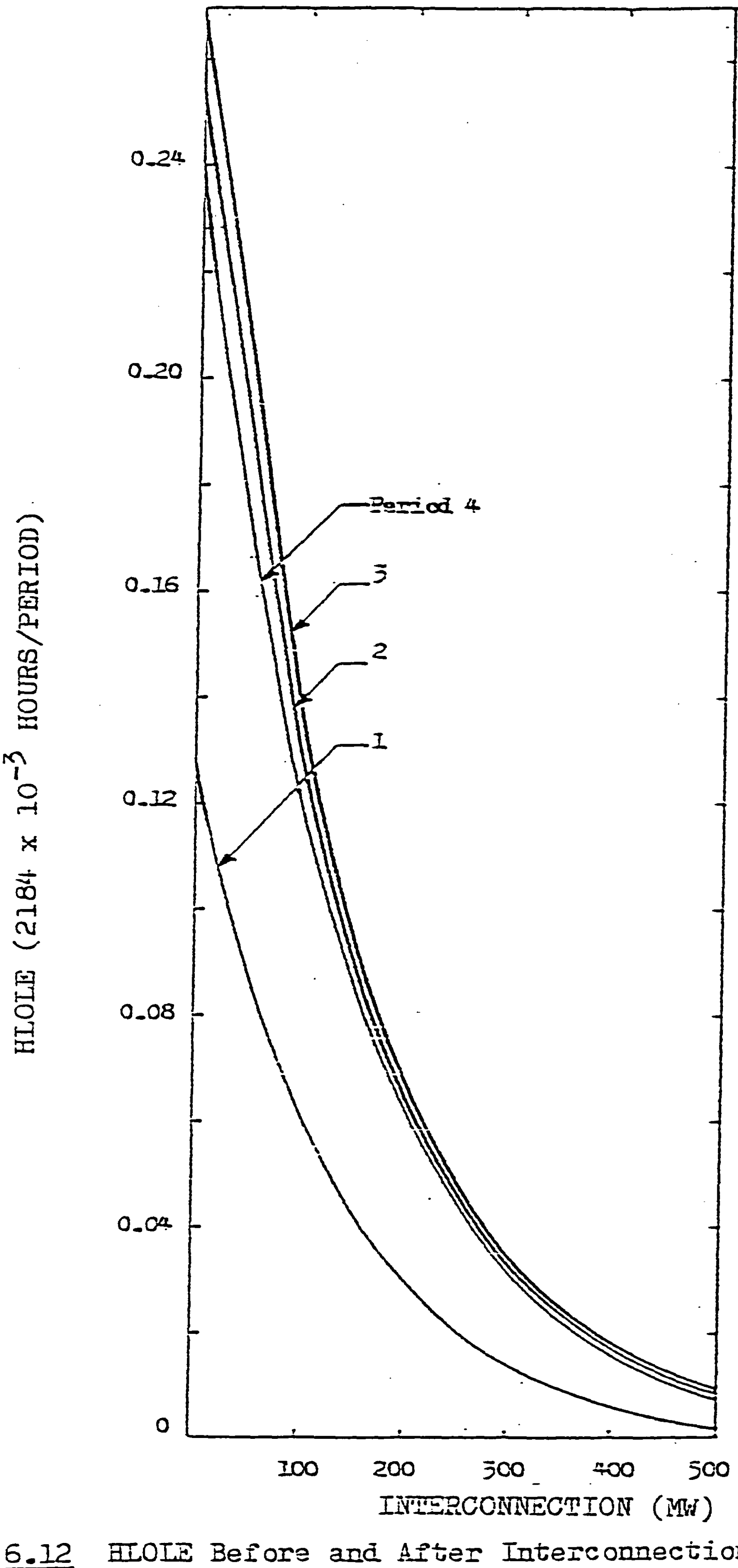


FIG. 6.12 HLOLE Before and After Interconnection for the PUB System for Periods in 2000

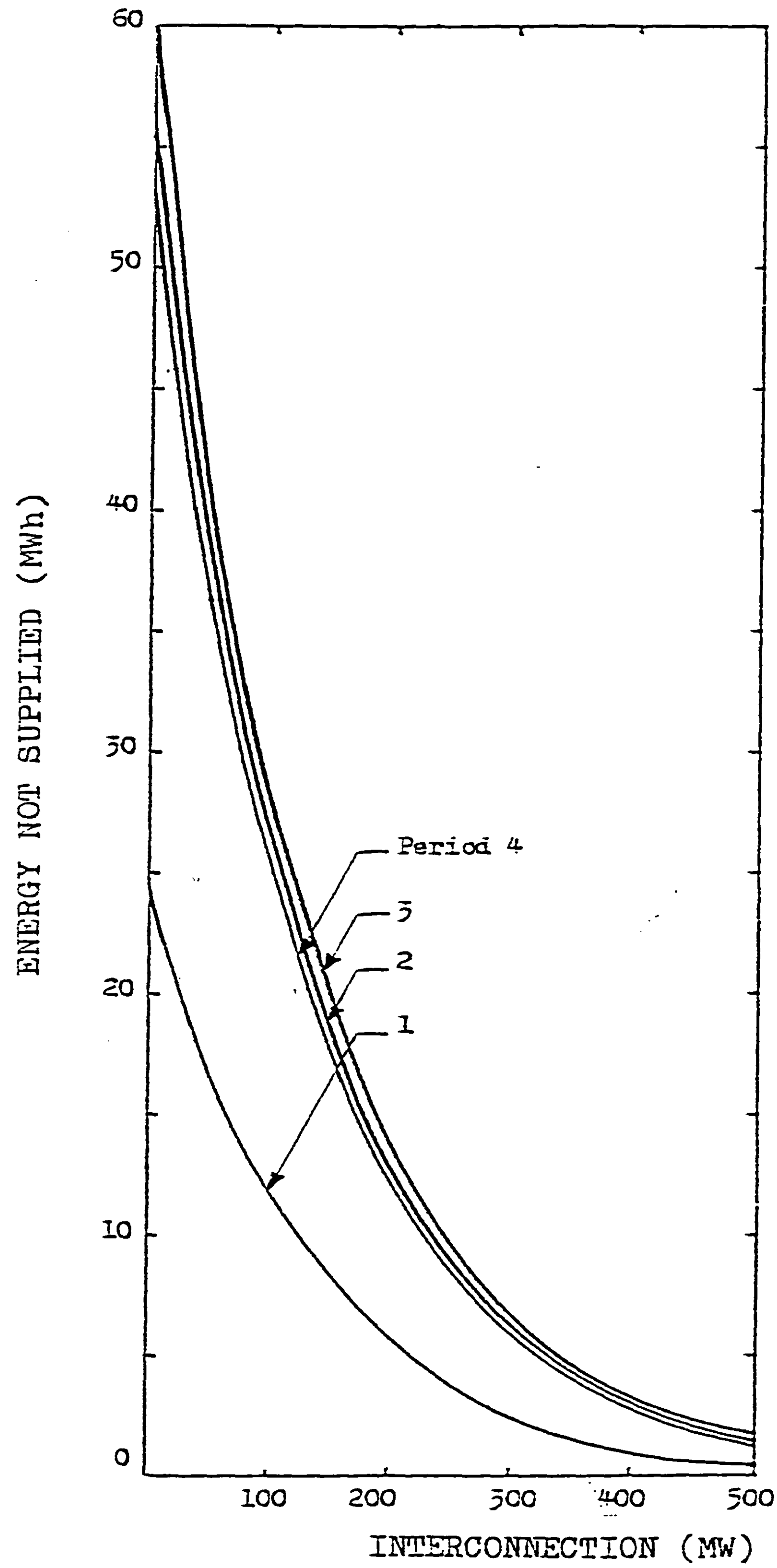


FIG. 6.13 EENS Before and After Interconnection for the PUB System for Periods in 2000

provided earlier and due to the availability of the computer time allocations.

As can be seen from the graphs, the improvement in reliability is substantial as the size of interconnection increases for both the systems. The rates of improvements however vary. For the first few megawatts of interconnection, the PUB system has a higher rate of improvement in reliability than the LLN system. For example, for the year 1990 for period 1, the PUB system has an improvement in reliability measurement (HLOLE) of about 65% whereas the LLN system has about 20% for a 100 MW interconnection.

The PUB system gains more from the sharing of reserve margins. The PUB system is a slightly smaller system than the LLN, and the gain is largely due to the diversity of outages in both the systems. The report by the ASEAN studies [10] did not however indicate any of this phenomenon since the formulations were different. The rates of the improvement for both systems however decrease as the interconnection sizes increase. For the PUB system the gain reduces substantially after 300 MW of interconnection. The LLN system being the larger system has a steady, though still decreasing values in the gains at interconnection of 500 MW.

The method which has been adopted to make some assessments on the benefits in monetary terms is to compare the gain in reliability with that of a peaking unit. The approach is to determine the value of the equivalent peaking unit that could provide a similar gain in reliability as the interconnection. A peaking unit is considered because of the simplicity and convenient as explained in Section 4.4, Chapter 4. Therefore a separate computer run was made, each by adding a peaking unit of different size and the reliability measurement was recorded. The same computer programme was used but instead of any interconnection, a peaking unit having 100% availability was added to the system data.

Fig. 6.14 shows the graphical representation of the results and the table 6.7 provides the differences in numerical values. As can be seen from the graphs and the tables, the interconnection is almost equivalent to having a peaking unit of the same size. For each instant the peaking unit however gives a slightly more reliable system than the interconnection of the same size. This means therefore that for the interconnection of the LLN/PUB systems, the capacity savings are nearly equivalent to the capital costs of the same size of peaking unit. This approach of assessment in monetary terms is adopted in the economic evaluations to be described in the later section.

6.3.2 EQUILIBRATION OF MARGINAL COSTS

Fig. 6.15 shows the system costs for the LLN and the PUB systems for period 1 in the year 1990. The PUB system being an all thermal system shows a steady increase in the system costs, whereas for the LLN, the system cost is influenced by the hydro contribution which has a generation cost of almost zero.

Sample calculations for the equilibration of marginal costs for two coincident loads for the LLN and PUB systems are described below;

i) Year : 1990

ii) Period 1 : 2184 hours

iii) Interconnection size : 500 MW.

iv) Load at PUB system L_a : 1250 MW.

Load at LLN system L_b : 2000 MW.

v) Probability of occurrence $f(L_a,L_b)$: 0.01419

First the loads L_a and L_b are located for the determination of the marginal costs. The actual values are however taken from the computer outputs in the followings examples. With reference to Fig. 6.16,

Savings due to equilibration	=	250 (55.6 - 53.5) +
of marginal costs		250 (54.4 - 53.8) \$/hour
Actual savings intergrated over the load probability density function and period considered	=	675 x 0.01419 x 2184
	=	20918.8 \$

The benefit is proportional to the hatched area in the figure. Similar calculations are repeated in the computations for all $f(L_a,L_b) > 0$, and the savings are then cumulated for the period under study.

In the evaluation of the marginal cost for a mixed thermal hydro system, it is shown in Section 5.3.2 in Chapter 5, that the hydro load factor has to be constant for a particular demand. In using probabilistic simulation

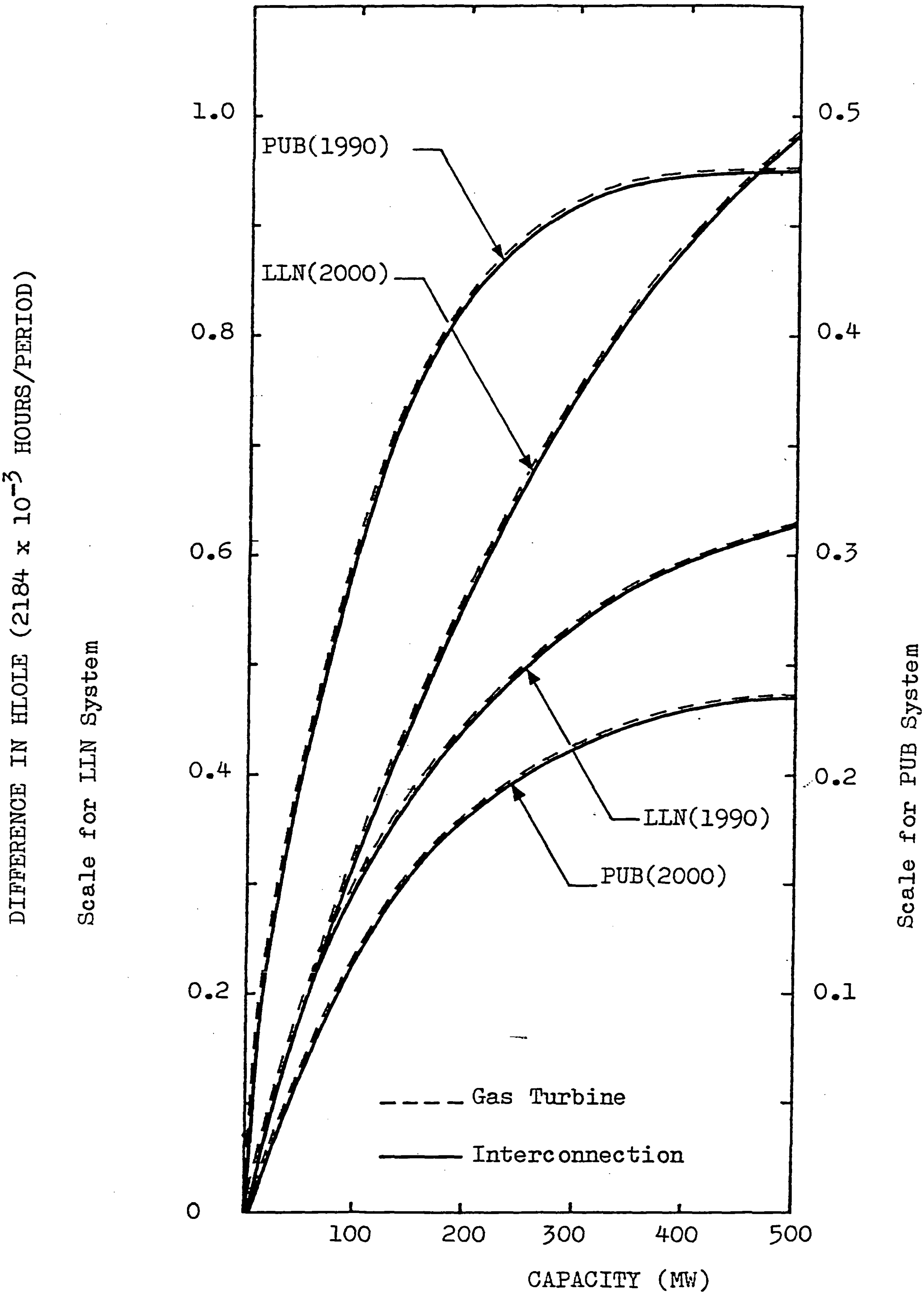


FIG. 6.14 Comparison of Interconnection and Peaking Unit on HLOLE

TABLE 6.7

Comparison of Interconnection and Peaking Unit on HLOLE and EENS

Period 4			Before	100 MW		300 MW		500 MW	
				Link	Peaking Unit	Link	Peaking Unit	Link	Peaking Unit
1990	LLN	HLOLE(Hrs)*	0.8858×10^{-3}	0.5917×10^{-3}	0.5910×10^{-3}	0.3514×10^{-3}	0.3489×10^{-3}	-	-
		EENS (MWh)	0.59393×10^{3}	0.45174×10^{3}	0.45143×10^{3}	0.26997×10^{3}	0.26828×10^{3}	-	-
	PUB	HLOLE(Hrs)	0.4768×10^{-3}	0.1699×10^{-3}	0.1689×10^{-3}	0.1930×10^{-4}	0.1721×10^{-4}	-	-
		EENS (MWh)	0.73911×10^{2}	0.24511×10^{2}	0.24344×10^{2}	0.25227×10^{1}	0.21949×10^{1}	-	-
2000	LLN	HLOLE(Hrs)	0.1252×10^{-2}	0.9269×10^{-3}	0.9267×10^{-3}	0.5020×10^{-3}	0.5006×10^{-3}	0.2675×10^{-3}	0.2641×10^{-3}
		EENS (MWh)	0.74722×10^{3}	0.54508×10^{3}	0.54482×10^{3}	0.28781×10^{3}	0.28683×10^{3}	0.1516×10^{3}	0.1494×10^{3}
	PUB	HLOLE(Hrs)	0.2448×10^{-3}	0.1251×10^{-3}	0.1245×10^{-3}	0.3115×10^{-4}	0.2982×10^{-4}	0.8059×10^{-5}	0.6419×10^{-5}
		EENS (MWh)	0.52767×10^{2}	0.25702×10^{2}	0.25559×10^{2}	0.58548×10^{1}	0.55567×10^{1}	0.1451×10^{1}	0.1094×10^{1}

* Each entry multiplies by 2184

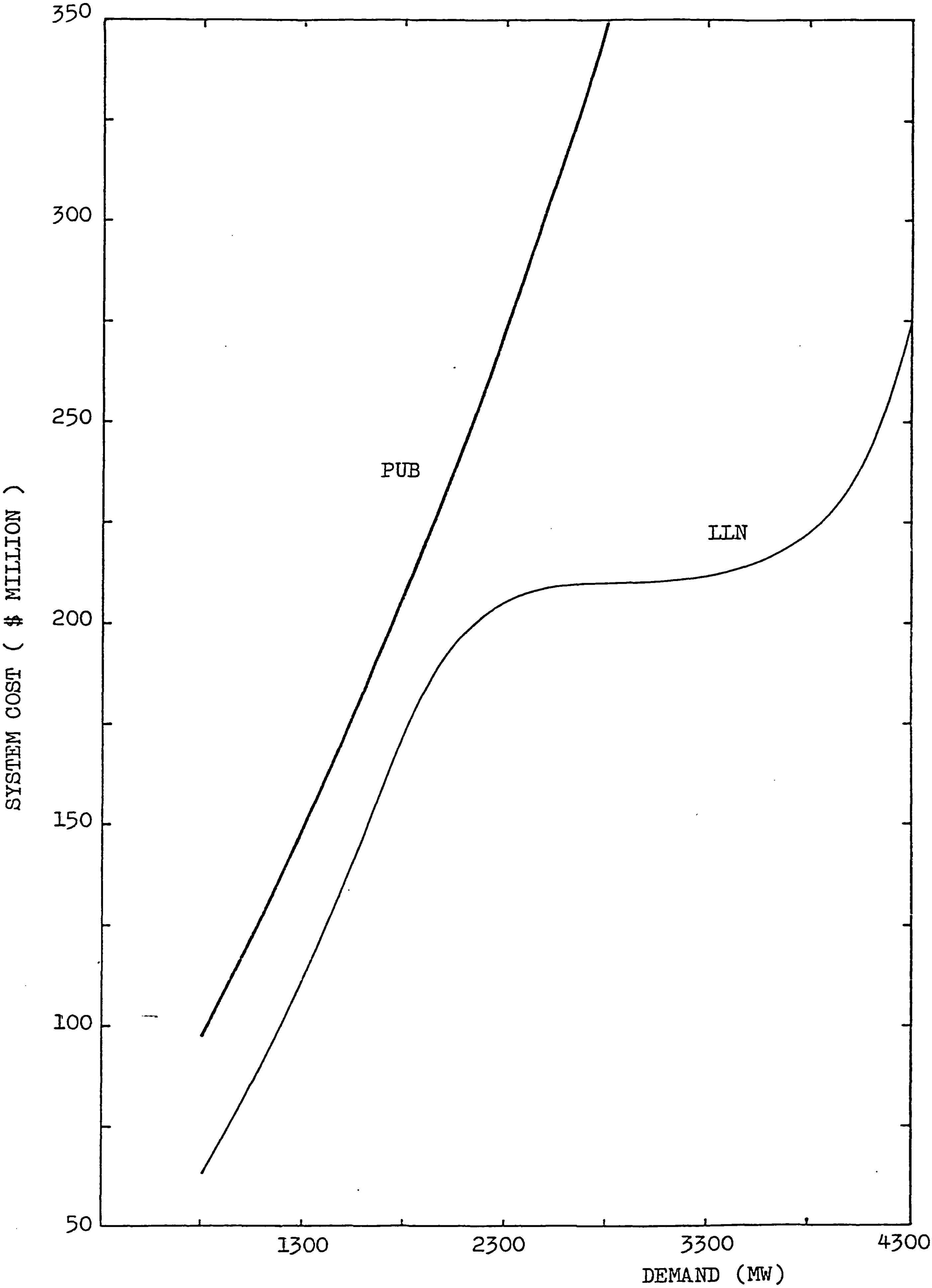


FIG. 6.15 System Costs for LLN and PUB for Period 1 in 1990

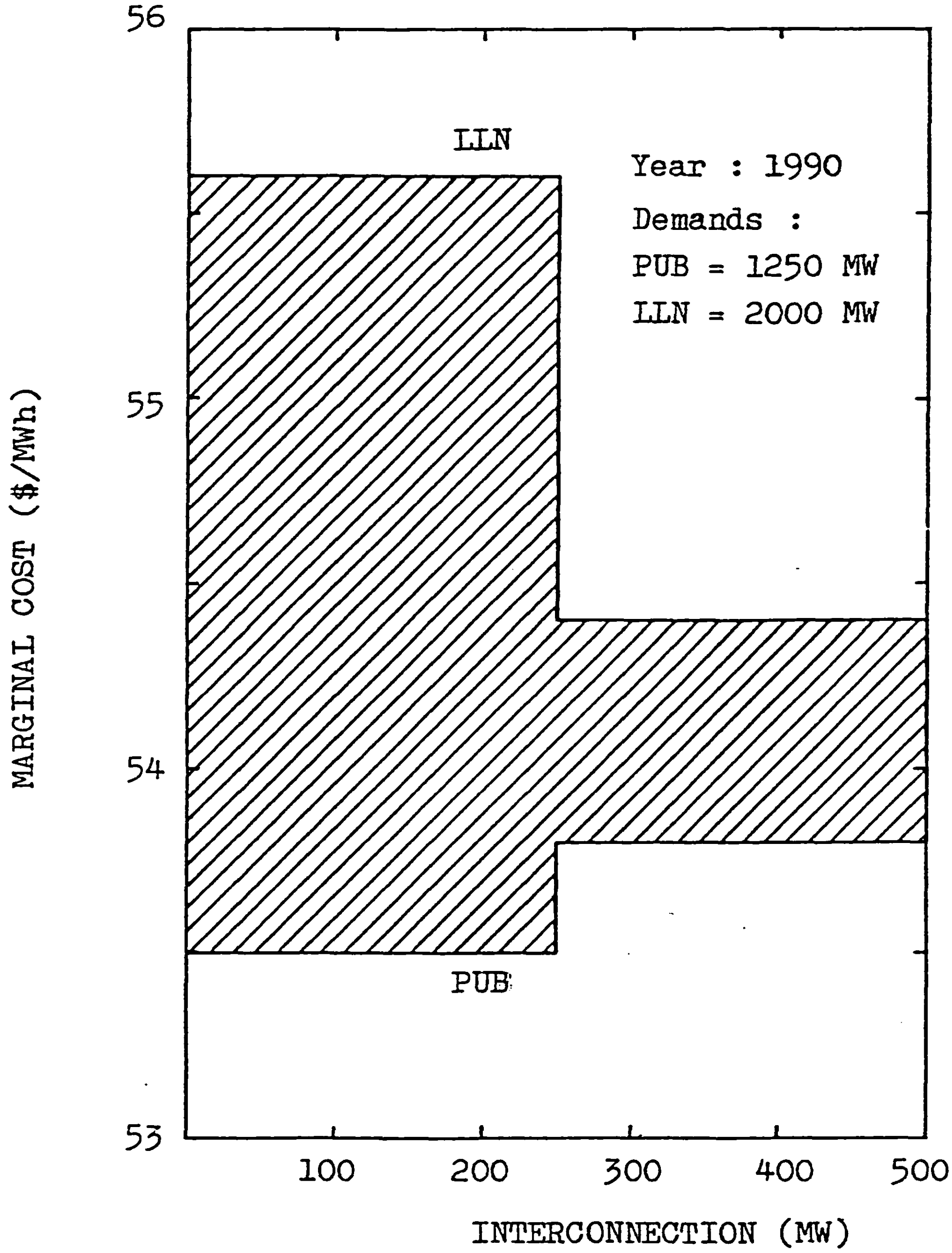


FIG. 6.16 Energy Transfer from PUB to LLN due to Equilibration of Marginal Costs

some interpolations have to be done. Table 6.8 shows a sample result of the interpolation that has been done to determine the system cost for an incremental in demand for the LLN system. As can be seen the interpolations are reasonably accurate for the present purpose. Samples of the marginal costs for the two systems computed for periods 1 and 3 for each year 1990 and 2000 are shown in Figs. 6.17 to 6.20.

The results for the equilibration of marginal costs are presented in tables 6.9 to 6.16. Each table gives informations on the amount of transfer between the two systems and associated with each transfer there is the savings in generation costs. Also for each interconnection, the tie line load factor and the average difference in marginal cost of the two systems are given for the period concerned.

For example, with reference to table 6.9, for a 100 MW interconnection, PUB transferred to LLN electrical energy of amount 0.141 x 10^6 MWh and at a cost of 0.252 x 10^6 \$. In the same period LLN also transferred to the PUB about 0.560 x ^{5} MWh and at a cost of 0.147 x 10^6 \$. The percentage transfers from the PUB to LLN and from the LLN to PUB were about 71.6% and 28.4% respectively. In 1990, the PUB transferred more energy to the LLN system, indicating that at that period the PUB had a more efficient generating plants. In the year 2000 however, the transfer from equilibration of the marginal costs was equally divided. The values of the tie line load factors in all the computation range from about 45% to 93%.

For each year, the cumulative benefits can be derived from the four periods accordingly. Tables 6.17 and 6.18 show the benefits for the years 1990 and 2000. The tie lines capacity factors tend to decrease as the interconnection size increases. In 1990, the tie line capacity factor is about 90% for 100 MW of interconnection and decreases to about 65% for interconnection of 500 MW. This clearly indicates that as the tie line increases the load factor decreases. By interpolation, at 200 MW tie line, the load factors are about 83% and 76% in 1990 and 2000. The report from the studies by the ASEAN utilities [10] had used a tie line of 200 MW load factor of 25%, and this was rightly stated in the report to be conservative.

In the simulation of the hydro plant, it is expected to utilize its full capacity and the energy capacity for minimum system cost. Due to constraint on the step size, the hydro utilization for the present analysis is as shown in table 6.19. As can be seen the percentages utilization vary from 95.8% to 99.3%. In general the smaller the step size the more accurate is the simulation of the hydro units. This variation would be reflected in the system costs for the LLN system of which the calculated values are on the high side.

6.3.3 ECONOMIC EVALUATIONS

For economic evaluations, the reference year present worth calculation was considered to be 1990. The two costs that constitute the savings can be classified as the capital and operating costs. The evaluation in the savings

TABLE 6.8

System Costs for a Fixed Hydro Load Factor

System : LLN Period : 1 Year : 1990

Demand (MW) P_A ($\times 10^4$)	Hydro Capacity Factor % at P_A ($\times 10^2$)	System Cost in \$ $C(P_A)$ ($\times 10^9$)	Hydro Capacity Factor % at P_A+dP ($\times 10^2$)	System Cost in \$ $C(P_A+dP)$ ($\times 10^9$)
0.2500	0.2502	0.2089	0.2228	0.2147
0.2550	0.2776	0.2092	0.2502	0.2150
0.2600	0.3050	0.2094	0.2776	0.2153
0.2650	0.3356	0.2094	0.3050	0.2155
0.2700	0.3621	0.2094	0.3356	0.2155
0.2750	0.3907	0.2094	0.3621	0.2155
0.2800	0.4193	0.2094	0.3907	0.2155
0.2850	0.4478	0.2094	0.4193	0.2155
0.2900	0.4763	0.2095	0.4478	0.2155
0.2950	0.5048	0.2095	0.4763	0.2156
0.3000	0.5333	0.2095	0.5048	0.2156
0.3050	0.5618	0.2095	0.5333	0.2156
0.3100	0.5903	0.2096	0.5618	0.2156
0.3150	0.6188	0.2096	0.5903	0.2157
0.3200	0.6465	0.2096	0.6188	0.2157
0.3250	0.6742	0.2100	0.6465	0.2159
0.3300	0.7019	0.2102	0.6742	0.2161
0.3350	0.7295	0.2104	0.7019	0.2163
0.3400	0.7846	0.2106	0.7295	0.2165
0.3450	0.8079	0.2108	0.7846	0.2167

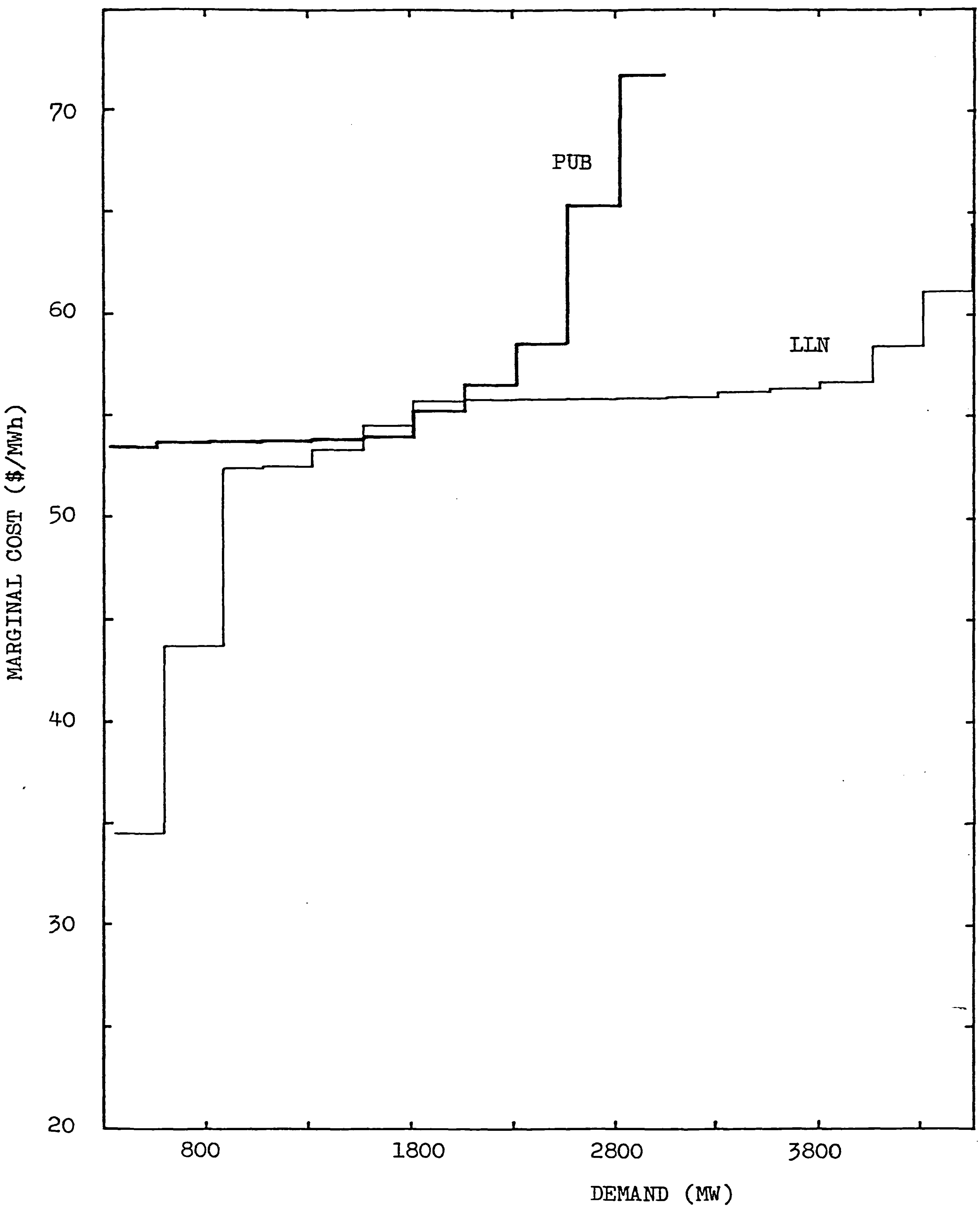


FIG. 6.17 Marginal Cost Curves for LLN and PUB Systems for Period 1 in 1990

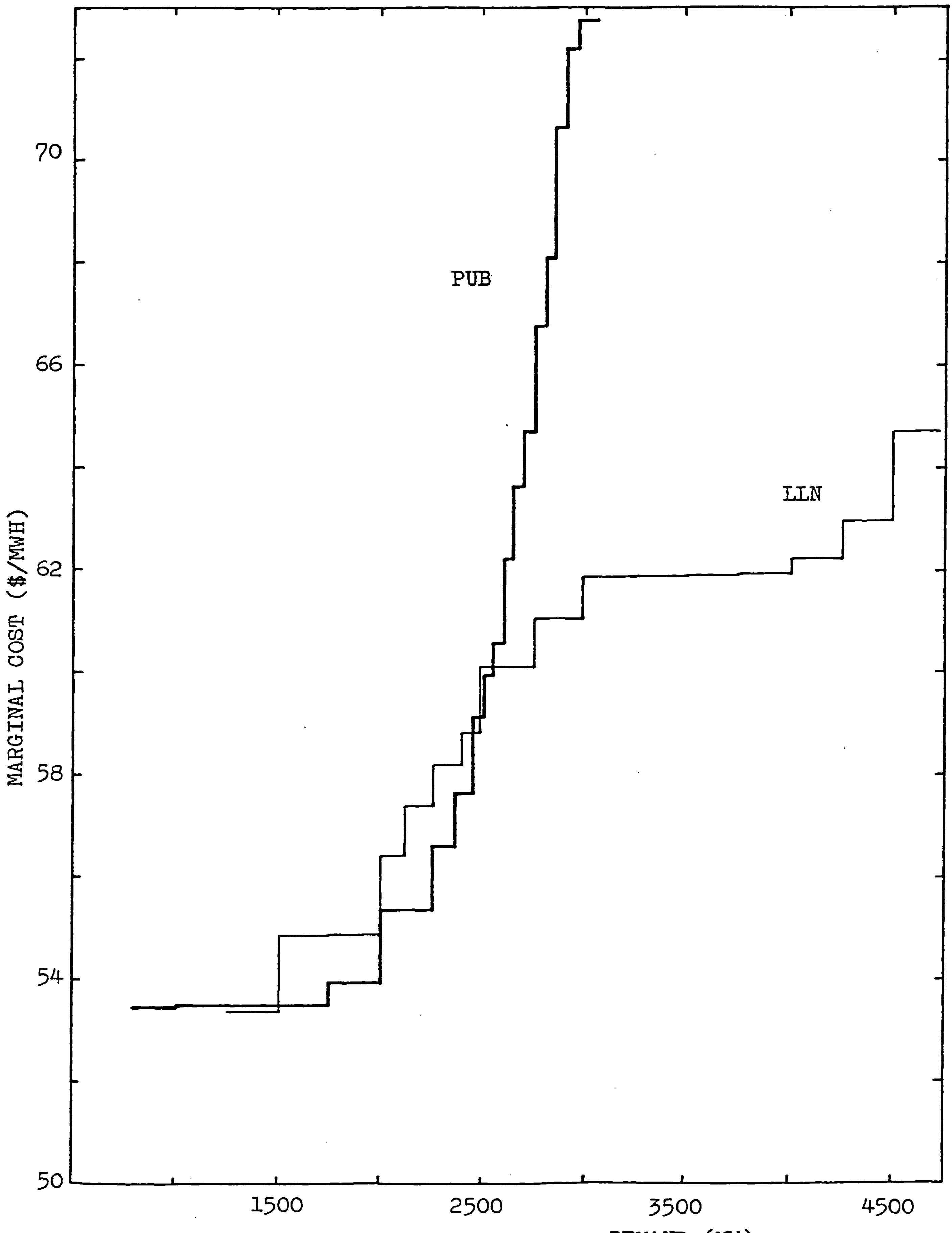


FIG. 6.18 Marginal Cost Curves for LLN and PUB Systems for Period 3 in 1990

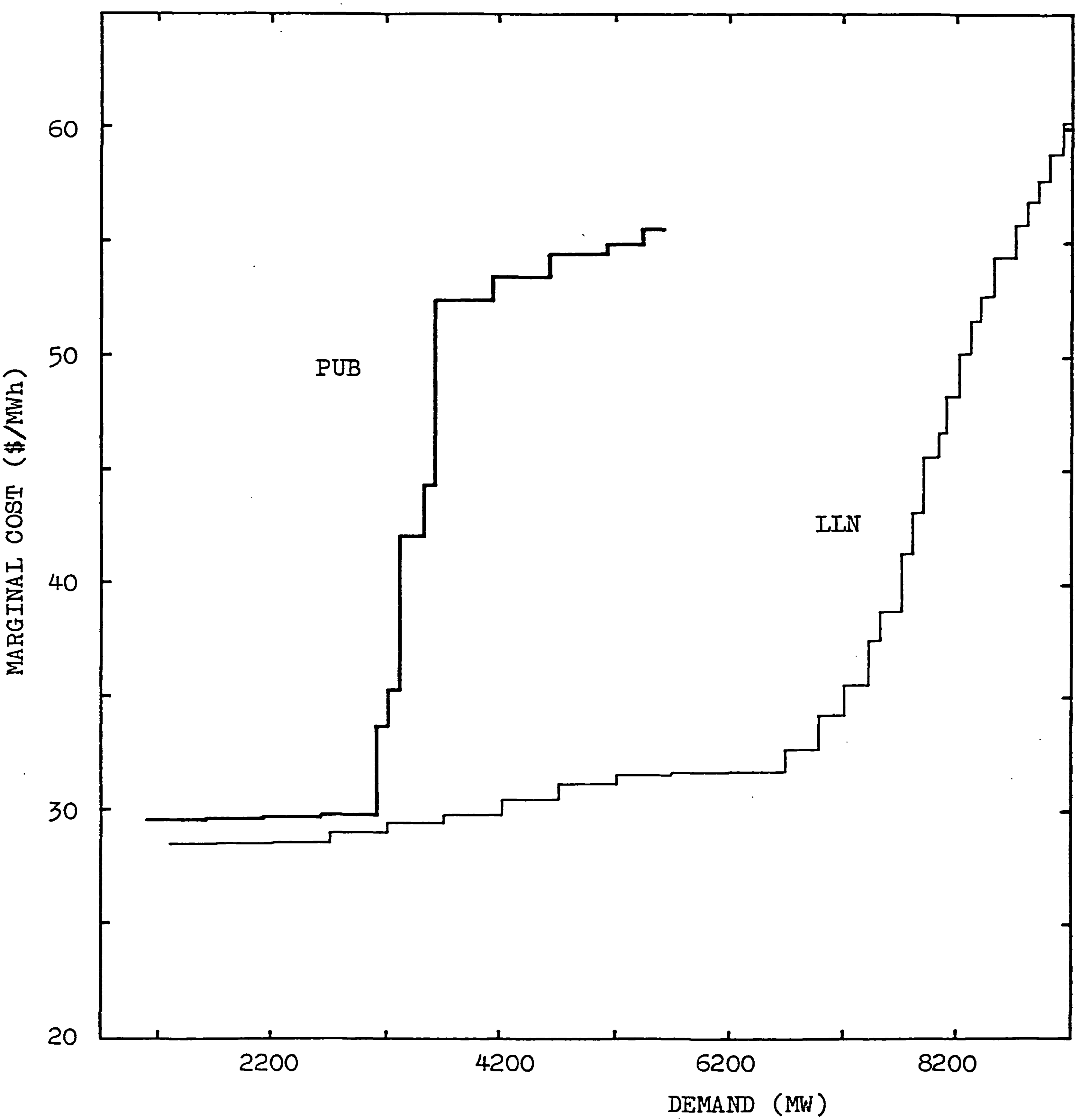


FIG. 6.19 Marginal Cost Curves for LLN and PUB Systems for Period 1 in 2000

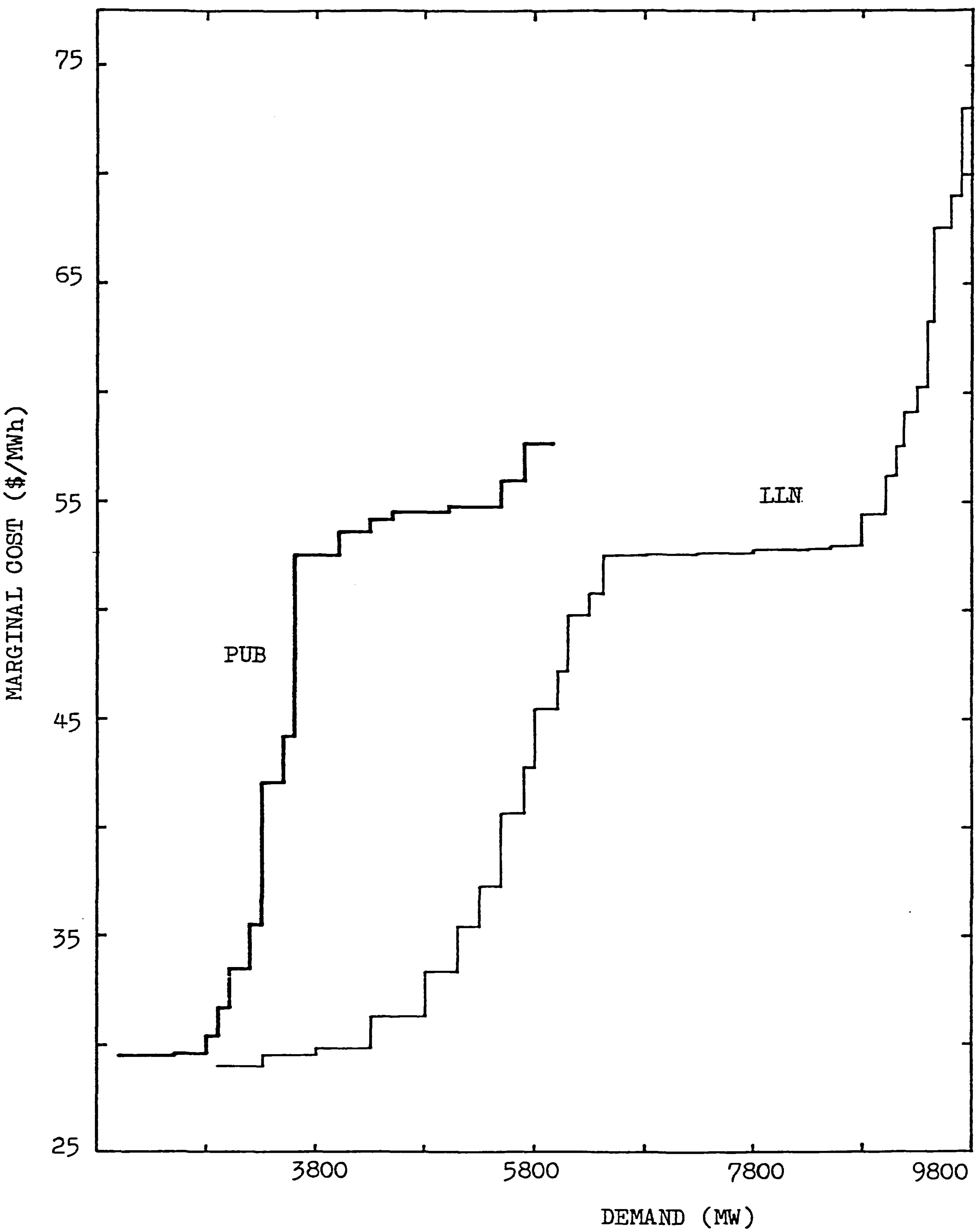


FIG. 6.20 Marginal Cost Curves for LLN and PUB Systems for Period 3 in 2000

TABLE 6.9

Equilibration of Marginal Costs for Period 1

in 1990

Year 1990	Period 1		A : PUB	B : LLN
Interconnection		100 MW	300 MW	500 MW
Benefits	A to B	0.2528E+06	0.6192E+06	0.7491E+06
	B to A	0.1475E+06	0.2185E+06	0.2196E+06
($)	Total	0.4003E+06	0.8377E+06	0.9687E+06
Transfer	A to B	0.1411E+06	0.3757E+06	0.5171E+06
	%	0.7157E+02	0.7769E+02	0.8250E+02
	B to A	0.5604E+05	0.1078E+06	0.1096E+06
	%	0.2843E+02	0.2231E+02	0.1750E+02
(MWh)	Total	0.1971E+06	0.4835E+06	0.6267E+06
Tie line capacity factor		90.2	73.6	57.3
Average difference in Marginal Cost ($/MWh)		2.03	1.73	1.54

TABLE 6.10

Equilibration of Marginal Costs for Period 2

in 1990

Year 1990 Period 2			A : PUB	B : LLN
Interconnection		100 MW	300 MW	500 MW
Benefits	A to B	0.4194E+06	0.1016E+07	0.1234E+07
	B to A	0.1322E+06	0.1607E+06	0.1607E+06
($)	Total	0.5516E+06	0.1177E+07	0.1395E+07
Transfer	A to B	0.1562E+06	0.4292E+06	0.5770E+06
	%	0.7668E+02	0.8659E+02	0.8967E+02
	B to A	0.4749E+05	0.6644E+05	0.6644E+05
	%	0.2332E+02	0.1341E+02	0.1033E+02
(MWh)	Total	0.2037E+06	0.4957E+06	0.6435E+06
Tie line capacity factor		93.2	75.6	58.9
Average difference in Marginal Cost ($/MWh)		2.70	2.37	2.16

TABLE 6.11

Equilibration of Marginal Costs for Period 3

in 1990

Year 1990	Period 3		A : PUB	B : LLN
Interconnection		100 MW	300 MW	500 MW
Benefits	A to B	0.1052E+07	0.2635E+07	0.3627E+07
	B to A	0.3887E+04	0.4161E+04	0.4161E+04
($)	Total	0.1055E+07	0.2639E+07	0.3631E+07
Transfer	A to B	0.2003E+06	0.5374E+06	0.8327E+06
	%	0.9914E+02	0.9963E+02	0.9976E+02
	B to A	0.1749E+04	0.1999E+04	0.1999E+04
	%	0.8600E+00	0.3700E+00	0.2400E+00
(MWh)	Total	0.2020E+06	0.5393E+06	0.8346E+06
Tie Line Capacity Factor		92.4	82.3	76.4
Average difference in Marginal Cost ($/MWh)		5.22	4.89	4.35

TABLE 6.12

Equilibration of Marginal Costs for Period 4

in 1990

Year 1990	Period 4		A : PUB	B : LLN
Interconnection		100 MW	300 MW	500 MW
Benefits	A to B	0.5476E+06	0.1420E+07	0.1931E+07
	B to A	0.2176E+05	0.2341E+05	0.2341E+05
($)	Total	0.5694E+06	0.1433E+07	0.1954E+07
Transfer	A to B	0.1699E+06	0.4758E+06	0.7210E+06
	%	0.9368E+02	0.9730E+02	0.9820E+02
	B to A	0.1144E+05	0.1319E+05	0.1319E+05
	%	0.6320E+01	0.2700E+01	0.1800E+01
(MWh)	Total	0.1814E+06	0.4890E+06	0.7342E+06
Tie Line Capacity Factor		83.0	74.6	67.2
Average difference in Marginal Cost ($/MWh)		3.13	2.95	2.66

TABLE 6.13

Equilibration of Marginal Costs for Period 1

in 2000

Year 2000	Period 1		A : PUB	B : LLN
Interconnection		100 MW	300 MW	500 MW
Benefits	A to B	0.8790E+05	0.1758E+06	0.1912E+06
	B to A	0.1487E+07	0.3757E+07	0.5094E+07
($)	Total	0.1574E+07	0.3933E+07	0.5285E+07
Transfer	A to B	0.8299E+05	0.1932E+06	0.2180E+06
	%	0.4262E+02	0.3884E+02	0.3287E+02
	B to A	0.1116E+06	0.3042E+06	0.4453E+06
	%	0.5737E+02	0.6116E+02	0.6713E+02
(MWh)	Total	0.1946E+06	0.4975E+06	0.6634E+06
Tie Line Capacity Factor		89.1	75.9	60.7
Average difference in Marginal Cost ($/MWh)		8.08	7.90	7.96

TABLE 6.14

Equilibration of Marginal Costs in Period 2

in 2000

Year 2000	Period 2		A : PUB	B : LLN
Interconnection		100 MW	300 MW	500 MW
Benefits	A to B	0.6518E+06	0.1408E+07	0.1685E+07
	B to A	0.1421E+06	0.3168E+06	0.4254E+06
($)	Total	0.7940E+06	0.1725E+07	0.2111E+07
Transfer	A to B	0.1201E+06	0.2686E+06	0.3151E+06
	%	0.6707E+02	0.6647E+02	0.6485E+02
	B to A	0.5899E+05	0.1354E+06	0.1707E+06
	%	0.3293E+02	0.3353E+02	0.3515E+02
	Total	0.1791E+06	0.4041E+06	0.4859E+06
Tie Line Capacity Factor		82.0	61.6	44.5
Average difference in Marginal Cost ($/MWh)		4.43	4.26	4.34

TABLE 6.15

Equilibration of Marginal Costs in Period 3

in 2000

Year 2000	Period 3		A : PUB	B : LLN
Interconnection		100 MW	300 MW	500 MW
Benefits	A to B	0.7596E+06	0.1775E+07	0.2238E+07
	B to A	0.2433E+06	0.6014E+06	0.8432E+06
($)	Total	0.1002E+07	0.2376E+07	0.3082E+07
Transfer	A to B	0.9689E+05	0.2409E+06	0.3042E+06
	%	0.5081E+02	0.4964E+02	0.4738E+02
	B to A	0.9379E+05	0.2443E+06	0.3384E+06
	%	0.4919E+02	0.5036E+02	0.5262E+02
	Total	0.1906E+06	0.4853E+06	0.6432E+06
Tie Line Capacity Factor		87.2	74.0	58.9
Average difference in Marginal Cost ($/MWh)		5.25	4.89	4.79

TABLE 6.16

Equilibration of Marginal Costs in Period 4

in 2000

Year 2000	Period 4		A : PUB	B : LLN
Interconnection		100 MW	300 MW	500 MW
Benefits	A to B	0.1842E+06	0.3764E+06	0.4326E+06
	B to A	0.9894E+06	0.2434E+07	0.3289E+07
($)	Total	0.1173E+07	0.2810E+07	0.3722E+07
Transfer	A to B	0.9009E+05	0.2006E+06	0.2295E+06
	%	0.5090E+02	0.4772E+02	0.4305E+02
	B to A	0.8689E+05	0.2197E+06	0.3036E+06
	%	0.4910E+02	0.5228E+02	0.5695E+02
	Total	0.1769E+06	0.4204E+06	0.5332E+06
Tie Line Capacity Factor		80.9	64.1	48.8
Average difference in Marginal Cost ($/MWh)		6.63	6.68	6.98

TABLE 6.17

Equilibration of Marginal Costs for the Year 1990

Year 1990	Periods 1,2,3 and 4	A : PUB		B : LLN
Interconnection		100 MW	300 MW	500 MW
Benefits	A to B	0.2271E+07	0.5690E+07	0.7541E+07
	B to A	0.3053E+06	0.4067E+06	0.4078E+06
($)	Total	0.2576E+07	0.6096E+07	0.7948E+07
Transfer	A to B	0.6675E+06	0.1818E+07	0.2647E+07
	%	0.8511E+02	0.9058E+02	0.9326E+02
	B to A	0.1167E+06	0.1894E+06	0.1912E+06
	%	0.1489E+02	0.9420E+01	0.6740E+01
(MWh)	Total	0.7842E+06	0.2007E+07	0.2838E+07
Tie line capacity factor		89.7	76.5	64.9
Average difference in Marginal Cost ($/MWh)		3.28	3.03	2.80

TABLE 6.18

Equilibration of Marginal Costs for the Year 2000

Year 2000	Periods 1,2,3 and 4		A : PUB	B : LLN
Interconnection		100 MW	300 MW	500 MW
Benefits	A to B	0.1683E+07	0.3735E+07	0.4546E+07
	B to A	0.2861E+07	0.7109E+07	0.9651E+07
($)	Total	0.4544E+07	0.1084E+08	0.1419E+08
Transfer	A to B	0.3900E+06	0.9033E+06	0.1066E+07
	%	0.5261E+02	0.4999E+02	0.4586E+02
	B to A	0.3512E+06	0.9036E+06	0.1258E+07
	%	0.4739E+02	0.5001E+02	0.5414E+02
(MWh)	Total	0.7412E+06	0.1806E+07	0.2324E+07
Tie Line Capacity Factor		84.8	68.9	53.2
Average difference in Marginal Cost ($/MWh)		6.13	6.00	6.10

TABLE 6.19

Percentages of Hydro Utilization in the

Simulation for the LLN System

Year	1990	2000
Step size	50 MW	100 MW
Period 1	99.3 %	97.5 %
Period 2	99.4 %	95.9 %
Period 3	98.1 %	95.8 %
Period 4	98.2 %	97.5 %

in capital costs has been described in section (6.3.1) and it was concluded that the savings were equivalent to the cost of the peaking unit of the same size as the interconnection. Therefore for interconnection of say 100 MW, the savings will the sum of the cost of 100 MW of peaking unit for the LLN system and the cost for 100 MW of peaking unit for the PUB system.

For purpose of present economic evaluation, the peaking units for both systems are assumed as gas turbines and that the capital cost is 222.0 \$/KW, plant life of 20 years and a discount rate on capital of 10% [10]. Table 6.20 shows the enumeration for the costs for the years 1990 and 2000 for interconnection sizes of 100, 300, and 500 MW, the costs are given in present worth \$ 1990[1]. It is noted that capital savings constitute from the capital costs of two gas turbines each from the LLN and the PUB. The inter-

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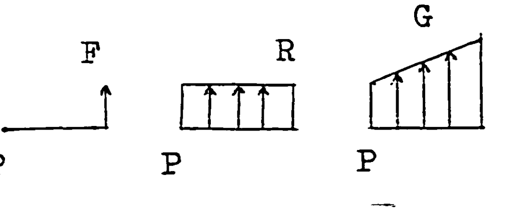
[1] The followings equations are used ;

i) $$P = F \frac{1}{(1+i)^n}$$

ii) $$P = R \frac{(1+i)^n - 1}{i(1+i)^n}$$



iii) $$P = R \frac{(1+i)^n - 1}{i(1+i)^n} + G \left[\frac{1}{i} \left\{ \frac{(1+i)^n - 1}{i(1+i)^n} - \frac{n}{(1+i)^n} \right\} \right]$$

where P = Present Worth

F = Future Worth

R = Uniform Amount

G = Gradient Amount

connection provides simultaneous improvements for both the systems. Even though the improvement in the reliability differs in magnitude, results have indicated that for both the systems the savings are almost equivalent to having the peaking units.

The other savings are the operating costs due to equilibration of the marginal costs. The annual operating savings are summed and are shown in table 6.21. Also for illustration, the followings are assumed for the economic evaluation; the discount rate on operation cost is 10% and the years of operation are for 25 years. For interconnection in the year 1990 the savings are assumed linear from 1990 to 2000 and from 2000 to 2015 the savings are assumed constant and equal to the savings calculated in the year 2000. For interconnection in the year 2000, the savings are assumed constant from 2000 to 2025.

Based on the above assumptions, table 6.22 provides the combined benefits in monetary values on capital and operating costs of different sizes of interconnection in present value 1990 $. As can be seen, there are substantial savings for both the systems. For example, in the year 1990 for a 100 MW interconnection, the total benefit would be 80.9 $ million, of which about 60% is from capital cost and 40% from operating cost. For the same year the total savings are about four times if the size of the interconnection is also increased to 500 MW. This phenomenon is repeated in the year 2000, where the savings for a 500 MW interconnection are also about four times that for a 100 MW. In general, if the size of interconnection is increased from 100 MW to 500 MW, the capital savings increase about four times and the operating savings about three times. Fig. 6.21 shows the savings graphically, and it shows clearly that for the two systems the interconnection greater than 500 MW can still be advantages.

The values illustrate that interconnection is an economic way of reducing operation costs and improving reliability for the LLN and the PUB systems. The economic evaluations are the most basic that could have been done from the results available. The present results only indicate the magnitude of the savings involved if interconnection of a certain size has been implemented. For the moment it is not possible to indicate the optimum size and timing for the interconnection. If several years of interconnection have been done between 1985 to 2000, maybe further economic analysis could have provided some informations to these problems. The present study is not definitive but it provides a starting point for a thorough analysis of interconnection for economy and flexibility in the assessments. The computer programmes developed can be utilized to provide some answers on the assessments of the benefits. For a given information that can truly represents any two systems, the benefits from savings in reserve margin and savings from equilibration of marginal costs can be quantified, analysed and critically judged.

6.3.4 COMPARISON OF RESULTS

The only comparison that can be made are from the results obtained by the ASEAN study group[10]. Even though

TABLE 6.20

Capital Savings in Present Value 1990 for Each System

Gas Turbine (MW)	Capital Cost $ million	Annuity Factor (1/X) X =	Annual Payment $ million	Year 1990	Year 2000
				Present Value 1990 $ million (25 years)	Present Value 1990 $ million (25 years)
100	22.2	8.51356	2.607	23.663	9.123
300	66.6	8.51356	7.822	71.007	27.373
500	111.0	8.51356	13.038	118.346	45.622

TABLE 6.21

Operating Savings for Years 1990 and 2000

Operating Benefits	Size of Interconnection		
$ million	100 MW	300 MW	500 MW
1990	2.576	6.096	7.948
2000	4.544	10.840	14.190

TABLE 6.22

Combined Savings in Present Value 1990

Benefits		Size of Interconnection		
$ million		100 MW	300 MW	500 MW
1990 - 2015	Capital	47.326	142.014	236.692
	Operating	33.600	80.100	104.700
	Total	80.926	222.114	341.392
2000 - 2025	Capital	18.246	54.746	91.244
	Operating	15.900	37.900	49.600
	Total	34.146	92.646	140.844

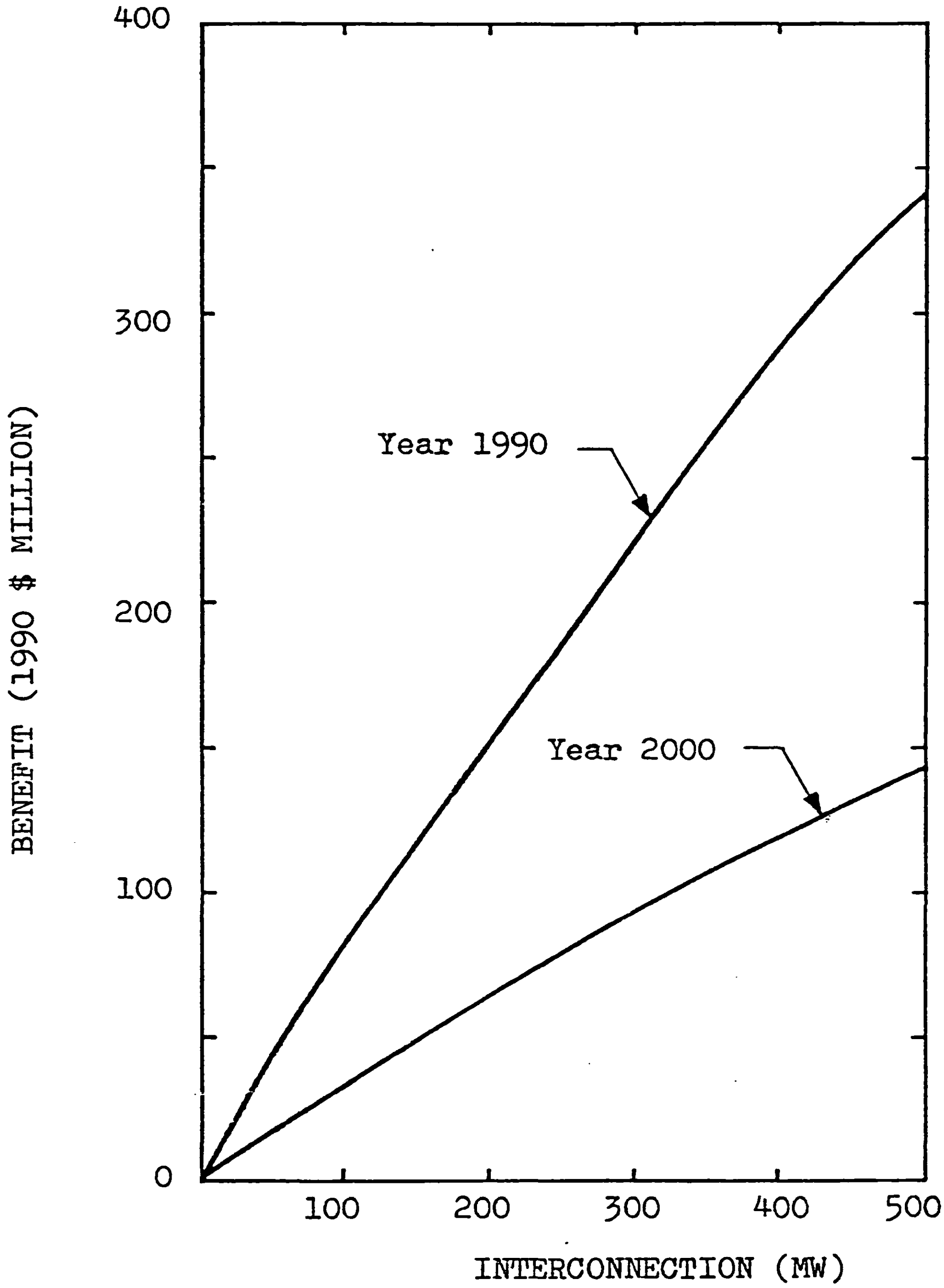


FIG. 6.21 Total Benefits from Interconnection for Years 1990 and 2000

the overall values were different in their derivations, some relative comparison can be made. The studies as explained in Chapter 2 were in two parts. The first involved generation optimisation with and without interconnection as development options and the second, an assessment of combined operation with limited inter system energy transfer.

The first phase evaluated the advantages to be gained from capacity sharing. The difference in their objective functions with and without interconnection gave an assessment of the economic advantage of the interconnection. The objective function was defined as the minimization in the cost in the expansion plan of both capital costs of the added plants and the system operation of the various alternatives. The benefits arising from inter system energy transfers were not quantified at that stage. The study was conducted separately by each utility.

Table 6.23 shows the interconnection benefits (US 1979 $ million) obtained through capacity sharing through the year 2000. The combined net benefits from the LLN, EGAT and the PUB systems were about 70 US $ million based on the studies by the LLN and the PUB. These included the benefits due to the interconnection of the EGAT/LLN as observed by the LLN. From these results it was not possible to determine the benefits specifically for the LLN/PUB interconnection alone since in each study the timing and the size were different.

The second phase assessed the economic benefits arised from the combined operation of the three systems namely LLN/PUB/EGAT for the period 1985 to 1992. Inter system energy transfers were constrained to not more than 400 GWh per annum, representing a load factor of 25% on the 200 MW tie line. Table 6.24 shows the summary of the benefits acquired of which the present worth to 1979 $ for the period 1985 to 1992 was about 262 US $ million. Table 6.25 shows the amount of transfers of energy as obtained from the combined systems operations. Also from these two tables, the benefits and the exchanges of energy between the LLN and the PUB were not able to be separated since the analysis was done for the combined systems of the 3 systems LLN/PUB/EGAT.

The comparison of the results has to take into account of the several differences between the two approaches; the fundamental differences are as outlined in table 6.26. On the onset the timings of the interconnection for both the studies were different. Since the capital savings were done independently by each utility, the LLN studies concluded that the interconnection for the LLN/PUB systems were optimal in 1984 and 1985, depending on the voltages, see table 6.23. The PUB studies revealed the optimal year being 1986. The present studies however assessed the benefits for the years 1990 and 2000.

The computer programme used by the ASEAN study group was WASP [50], and for its applications on interconnection studies, certain assumptions were imposed as explained in Section 2.2, Chapter 2. In the assessments for the capital and operating savings, the load models were in the forms of the load duration curves. The use of the LDC in inter-

TABLE 6.23 (10)

Interconnection Benefits (1979 US$ million) obtained through Capacity Sharing

Utility	Inter-connection	Location	Voltage kV	Capacity MW	Year	Estimated Capital Cost of Inter-Connection US$ million	Net Benefits through Year 2000* US$ million
EGAT	EGAT/LLN	Hat Yai	230/275	100	1990	5.95	5.5
LLN	(LLN/EGAT	Alor Star	275/230	100	1987	13.1	)
Case (1B)	(						)
	(						)
	LLN/PUB	Pasir	275/230	100	1984	)	) 59.9
		Gudang	or			) 5.5	)
			132/230	+100	1985	)	
PUB	PUB/LLN	Senoko	230/275	200	1986	12.78	10.0

Note : * Net benefits take into account the capital cost of the interconnection

TABLE 6.24 (10)

Comparison of Operating Costs between Combined and Individual Operation (US$ Million)

Year	Cost of Combined Operation (A)	Aggregated Cost of Individual System Operation (B)	Difference (B-A)
1985	887.932	885.940	-1.992
1986	926.415	924.386	-2.029
1987	927.170	992.925	20.755
1988	1000.655	1075.650	74.995
1989	1024.843	1165.089	140.246
1990	1100.754	1267.445	166.691
1991	1179.776	1357.679	177.903
1992	1251.580	1480.449	228.869

Present worth total to 1992 (base on 1979) : 262.010

Present worth total to lifetime Operation (50 years) : 882.205

TABLE 6.25 (10)

Transfer of Energy from Combined System Operation

Year	EGAT	LLN	PUB
1985	24.7	-80.2	51.4
1986	-79.4	23.7	49.8
1987	-139.9	300.0	-164.2
1988	8.5	201.9	-214.5
1989	-74.9	38.7	31.7
1990	6.3	354.0	-267.4
1991	-198.0	26.9	165.2
1992	-232.0	8.1	217.3

(200 MW interconnection at 0.25 load factor transfers 438 GWh of energy per year, excess (+) or import (-) of energy (GWh) generated by individual utilities as obtained from simulation of the combined system)

Table 6.26

Comparison of Methodology

	ASEAN Approach	Thesis
1.	Diversity of loads not considered. Load duration curve was used.	Diversity of loads is considered. Hourly peaks are used.
2.	Savings from capacity derived from difference in objective function with and without interconnection for each system. The objective function involved capital investment costs of the added plants and system operation costs of the various alternatives. The interconnection was assessed as a pseudo generating plant with a forced outage of 50% and zero maintenance outages. It was placed next to the gas turbines.	Savings from capacity is measured in relation to the capital cost of peaking units to provide the same improvement in realiability.
3.	Operation benefits evaluated from combined operation of the 3 systems namely, LLN/PUB/EGAT. Constraints on the tie were 200 MW and 25% annual load factor. Years of assessments were 1985 to 1992. The benefits were the difference in the aggregated cost of the individual system operation and the cost of the combined operation.	Operation benefits was through equilibration of marginal costs. No constraint on the tie line capacity factor. Years of assessments were 1990 to 2015.
4.	Generation costs data used 1977 values. The capital cost of gas turbine was $222/KW.	Generation costs data used the 1982 values. Same capital cost for gas turbine.

connection studies implies that in the assessments, the diversity in the loads and outages for the interconnected systems is not considered. This diversity can be significant in the final assessments on the benefits of interconnection.

In the operating savings assessments, the equivalent load duration curve was a composite of the three load duration curves. This approach is expected to raise some errors since correlations of the loads are not taken into account. It is noted that diversity of the loads in the operating costs is important, more so for the LLN/PUB systems whereby the diversity in the middle merit order provides the most opportunity for exchanges rather than at the peak loads, see the two dimensional load density matrix, Fig. 6.3 as an example. In the ASEAN study the constraint imposed on the interconnection was a load factor of 25% for a 200 MW size and this was low compared to the equivalent of about 83% obtained from the present studies. A direct comparison proved more difficult since the exchange included the EGAT system.

A summary of the results for comparisons are shown in Tables 6.27 and 6.28 for capital and operating savings respectively. The tables also indicate some of the differences that exist between the two studies. As can be seen it was not possible to separate the benefits specifically for the LLN/PUB interconnection from the ASEAN studies. Considering the differences that have been accounted for, the results obtained in the capital savings are almost similar. However, the operating savings are higher from the ASEAN studies. The operating savings evaluations are sensitive to the system and load data used in the analysis. It is noted that in the thesis the generation costs data for the PUB have been estimated from the LLN system as explained in section 6.2.2. Another difference is the gradual increase in the benefits from 1987 to 1992 in the ASEAN studies, whereas for the thesis it is assumed that the benefits increase linearly from 1990 to 2000, and than constantly up to 2015, this is because the assessments are made only for the years 1990 and 2000.

The benefits of energy transfers from the ASEAN studies on the combined operation of LLN/EGAT/PUB systems are about 380 \$/MWh and 520 \$/MWh in 1990 and 1992 respectively. These values are obtained by dividing the benefits acquired and divided by the limited energy transfer of 438 GWh. These values are suspected to be too high. The benefit of transfer from the thesis for the year 1990 is about 3.15 \$/MWh for interconnection of 200 MW. The combined cost of unit generated for the two systems is about 43.1 \$/MWh, whereby the aggregate cost of the individual system is about 1.75×10^3 \$ million.

Generally the results from the ASEAN studies revealed greater benefits from the operating costs rather than from the capital costs. The present analysis however shows the benefits are more from the capital costs rather than the operating costs. Although it is not possible to decide what origins of discrepancies of the two studies, it would appear that the present studies are more precise in

Table 6.27

Comparison on Capital Savings

	Years of Operations	Size of Interconnection	Interconnection	Net Benefits (US$ million)
ASEAN Studies	LLN Studies			
(PV to the	1987-2000	100 MW	LLN/EGAT)	
year 1979)	1984-2000 or	100 MW or	LLN/PUB)	59.9 (1979 $)
	1985-2000	100 MW	LLN/PUB)	
	PUB Studies			
	1986-2000	200 MW	LLN/PUB	10.0 (1979 $)
				Benefits
Thesis	1990-2015	100 MW	LLN/PUB	47.3 (1990 $)
(PV to the		200 MW	LLN/PUB	94.6 *
year 1990)		300 MW	LLN/PUB	142.0

* Interpolation

Table 6.28

Comparison on Operating Savings

	Years of Operations	Size of Interconnection	Interconnection	Benefits (US$ million)
ASEAN Studies (PV to the year 1985)	1985-1992	200 MW 25% Load Factor	LLN/PUB/EGAT	262.01 (1979 $)
Thesis (PV to the year 1990)	1990-2015	100 MW 89.7% Load Factor	LLN/PUB	33.6 (1990 $)
		200 MW 83.1% Load Factor	LLN/PUB	56.8 *
		300 MW 76.5% Load Factor	LLN/PUB	80.1

* Interpolation

principle. One study on the relationship between the pool size and unit size [4] however states that generally savings from the operating savings are usually relatively small in comparison with savings in capital costs. The present programmes are more specific toward the analysis of interconnection and the advantages include; no constraint on the interconnection, diversity on the load and outages is considered and the effects of maintenances of major plants are easily incorporated. All these have not been taken into account in the previous studies.

6.4 FURTHER DEVELOPMENTS

The methodology and the computer programmes presented so far are sound and accurate. The values obtained should be regarded as no more than economic indices pointing to the merits and demerits of interconnection. There are however certain developments that may improve the analysis to provide a more firm understanding of the influences of the interconnection.

In the context of future developments there are two parts that are of relevance; the computer programmes and the input data for the programmes. Both are complementary to one another, that is, a more refined and complicated the programme the more accurate the data necessary.

In the present computer programme, the future load model is developed from projection of historical load data using the annual growth rates. A historical load data for more than one year may give a more accurate descriptions of the pattern of the demands. A method to incorporate some forms of uncertainty into the demand forecasts should provide a better representation of the load model. In the simulation of the generation size, a multi hydro representation should be made possible. The effects of spinning reserves should also be included on the analysis of the interconnection.

The programmes developed have been designed for the analysis for a two interconnected systems. For real analysis of the benefits of interconnection for more than two areas, some extensions have to be incorporated for multiple area situations. The concepts of a multiple load and capacity models are possible developments.

In terms of the input data, the requirements for the analysis for the capacity savings through interconnection are adequate. The methodology adopted in the computer programme is sound and a possible future development will be to improve on the rapid computation of the calculations. The same programme also evaluates the reliability index EENS before and after interconnection. These values in conjunction with the cost associated with the energy not supplied could provide another mean of assessments on the benefits of the interconnection.

In the equilibration of the marginal costs analysis, the present programme has included the possibility of representing a thermal unit as a two capacity blocks. The two capacity blocks are to be placed in nonadjacent positions in the loading order and in a realistic operation will have a different generation cost for each capacity block. The data for such configurations are not readily available and therefore provide future applications.

Other areas of interest that are possible using these programmes are to study the influences of interconnection on economics of scales and the power pool maintenances of large power plants. These are important because the introduction of larger units are inevitable and obviously maximum utilization of these large plants are necessary. These programmes when used in conjunction with other expansion programmes allow the benefits to be assessed, determine the optimum size and the timing for interconnection of any two systems.

6.5 SUMMARY

This Chapter assessed the benefits of interconnection for two systems in the South East Asian Countries namely the LLN of Malaysia and the PUB of Singapore. The years of assessments were 1990 and 2000 and the size of interconnection were 100, 300 and 500 MW. The benefits investigated were savings in reserve margin through the measurements of HLOLE and the equilibration of the marginal costs. From the results it is evident that interconnection is an economically efficient means of reducing production cost and increasing reliability on both the systems. It is also concluded that interconnection of size larger than 500 MW can still be of benefits to both systems.

CHAPTER 7

CONCLUSIONS

Assessments on interconnection for two South East Asian Countries were made namely, Malaysia and Singapore represented by the LLN and the PUB respectively. The assessments were done in two parts; the capital cost savings through the measurements of the reliability index HLOLE and the operating savings through the equilibration of the marginal costs. The years of assessments were 1990 and 2000 and the sizes of interconnection were 100 MW, 300 MW and 500 MW.

In the reliability measurements, both systems have shown appreciable gains in the reliability after the interconnection. The PUB being the smaller of the two systems shows greater gain than the LLN. In 1990, it was established that the PUB reached it saturation at interconnection size of about 300 MW whereas th LLN, the size can still be greater than 500 MW. In the year 2000, both systems still have substantial gain at interconnection of size 500 MW. From results on the reliability measurements, it is concluded that for both systems, interconnection of size 500 MW or greater is still possible.

For assessments in monetary values, the improvement in the reliability measurements HLOLE before and after interconnection was compared to that of the peaking units. The results obtained have indicated that for both systems, the improvements in reliability due to interconnection were almost equivalent to that of the peaking units of the same size. For both systems therefore, it is concluded that the capital cost savings are directly related to the capital costs of the peaking units.

In the operating savings, results have indicated that in 1990 the PUB has more efficient plants since the transfer accounted for about 90% to the LLN system. However, in the year 2000, the transfers were equally divided indicating that the plants in both systems were equally efficient and the exchange was due to the diversity in the loads and outages of plants. Generally in the transfer of energy the LLN system gains more benefits from the transfer from the PUB system. The tie line capacity factor in 1990 for 100 MW interconnection was about 90% and this reduced to about 60% if the interconnection was increased to 500 MW. Similar capacity factors were obtained for the year 2000. It is concluded that the capacity factor for the interconnection is high and that it decreases as the interconnection increases, indicating that the first few megawatts of interconnection are very significant.

An economic assessment was being made for both the savings in the capital and operating costs for operating period of 25 years using the present value method discounted to the year 1990. From the results obtained, the savings in 1990 are 80 $ million for a 100 MW interconnection and about 340 $ million if the interconnection is increased to 500 MW. In the year 200, the savings are 34 $ million and 140 $ million for a 100 MW and 500 MW interconnection respectively. There is clear evidence that the benefits are appreciable and that it is concluded that there is still substantial benefits to be acquired for interconnection size greater than 500 MW. The present implementation of the 200 MW interconnection for the LLN/PUB systems may prove to be small considering the benefits that may be acquired by having larger size of the interconnection.

Comparisons of the results obtained from the ASEAN study on interconnection have revealed some shortcomings of the methodology in using the WASP computer programmes. The constraints which were imposed have led to conservative results as stated by the report. The results obtained from the present analysis proved that the constraint imposed on the 200 MW interconnection capacity factor of 25% was too low in the operating assessments. Also the use of the combined load duration curve from the individual load duration curves was not adequate for a proper interconnection analysis. It is concluded that the present methodology which has taken into accounts of the diversity in the loads and outages and the influences of maintenances of major plants of both systems is more precise in principle. These factors are fundamentals for accurate representation in any interconnection studies.

The case study undertaken has provided sufficient information that interconnection in the South East Asian Countries is plausible and of great benefits to these regions. The values obtained from the capital and operating costs savings show that interconnection size of greater than 500 MW is still of great benefits for the LLN/PUB systems. The thesis concludes that interconnection is an economically efficient means of reducing production costs and increasing reliability on both systems.

The sample data and the computer runs provide an insight to the methods of assessments. The computer programme developed can be used for any two systems for interconnection studies. For further applications, the programmes can be used to study in more depths the inter-relationships of interconnection on economies of scales and pool maintenances. With some minor modifications these programmes in combination with other investment programmes are sufficient to provide the basis for the final analysis on the optimum size, timing and economic evaluation on the important issue of interconnection in the South East Asian Countries.

APPENDIX A

PROBABILISTIC SIMULATION FOR MIXED THERMAL HYDRO SYSTEM

This appendix is in two parts. The first part explains the basic principles underlying probabilistic simulation. An all thermal system has been used for illustration. The second part describes the extension in the simulation for a mixed thermal hydro system.

A.1 PRINCIPLES OF PROBABILISTIC SIMULATION

The methods of simulation based on probabilistic approach have been described in many publications [(47) to (50)]. In essence, the simulation procedure involves the formulation of the probability density functions, describing the loads to be met and the capacity on outages, convolves the two distributions and in a systematic manner provides some means of measuring reliability and expectation of the total generation cost for the period.

The basic model for this technique requires the following information; (i) generation unit characteristics, (ii) system load duration curve, (iii) loading order of units and (iv) the energy supplied of energy limited units such as hydro electric plants. The first and the second items will be discussed below. The loading order for full implication of the probabilistic simulation will be the merit order configurations whereby the cheapest plant of the thermal units is dispatched first. The simulation for hydro electric plant will be described in part two.

During the normal period of operation, all units are forced off-line because of technical problems. This can be taken into account as a probability density function that describes the probability that a unit will be forced off-line or will be available. The simplest model and adequate for most applications is a two state model. This defines a generating unit is in the up state denoting that it is available or it is in the down state denoting that it is forced off-line. Two important quantities arise; the unit availability p, describing the long term probability that the generating capacity of a unit will be available and the forced outage rate (f.o.r.), q describing the long term probability that the generating capacity of a unit will be unavailable or forced off-line.

For example, if a unit of capacity 100 MW has a forced outage rate of $q = 0.02$ and availability of $p = 0.98$, then its forced outage capacity density function will be as shown in Fig. A.1. On proper interpretation, the probability of an outage of 0 MW is 0.98 (where a 0 MW outage is identical to having a 100 MW available) and that the probability of 100 MW outage is 0.02.

For the demand side, the load duration curve (LDC) provides an interpretation of the load probability density function. The X axis represents the number of hours during which the system load equals or exceeds the value of the associated power in the Y axis. By normalising the time variable, the value at any point on the abscissa P, becomes the fraction of the entire period for which the load equals or exceeds the associated power X. In generation system studies it is necessary to interchange the axis parameters, see Fig. A.2.

When the load duration curve refers to some historical performances of the load, it is a convenient way of representing a completely determined situation. However, when the load duration curve refers to future load pattern than it has some genuine probabilistic meanings.

Probabilistic simulation involves the combined effects of the two sets of stochastic events the load and the outage distribution functions. An equivalent load distribution function can be generated by convolving the load density function with the forced outage density function. An equivalent load is formed whereby system load is added to the load caused by forced outages. To facilitate this, a unit with capacity C_n MW that is randomly available may be modelled as a fictitious unit of capacity C_n MW that is a 100% reliable and a fictitious load of C_n MW whose availability is equal to the forced outage rate of the actual unit. These two representations are identical, since when the fictitious load is available, the net injected demand into the system is zero, just as it is when the actual unit is forced off-line.

Consider a system comprising of N thermal units and the units are totally independent of one another, we can convolve the load duration curve and the random outages of the generating units using recursive formula;

$$F_n(X) = F_{n-1}(X) . a_n + F_{n-1}(X-C_n) . q_n \qquad (A.1)$$

where $F_{n-1}(X-C_n) = 1.0$ for $X-C_n \leq 0.0$

$F_{n-1}(X)$: Cumulative distribution function of equivalent load X with n-1 plants in the system

$F_n(X)$: Cumulative distribution function of equivalent load X when the n th plant is added to the system

$F_0(X)$: Load duration curve, inverted and normalized on the time axis

C_n : Equivalent capacity of unit n

a_n : Availability of unit n

q_n : Forced outage rate of unit n

where $a_n + q_n = 1.0$

The convolution is done sequentially for each unit for discrete step size depending on the accuracy required. The cumulative distribution function of load X is commonly called the load equivalent curve (LEC). There will be several unique load equivalent curves depending on the number of the units in the system.

With reference to Fig. A.3, some important parameters can be extracted from the LEC generated. $F_N(X)$ is the LEC after the last plant has been convolved. If the total installed capacity X_N is located at the equivalent

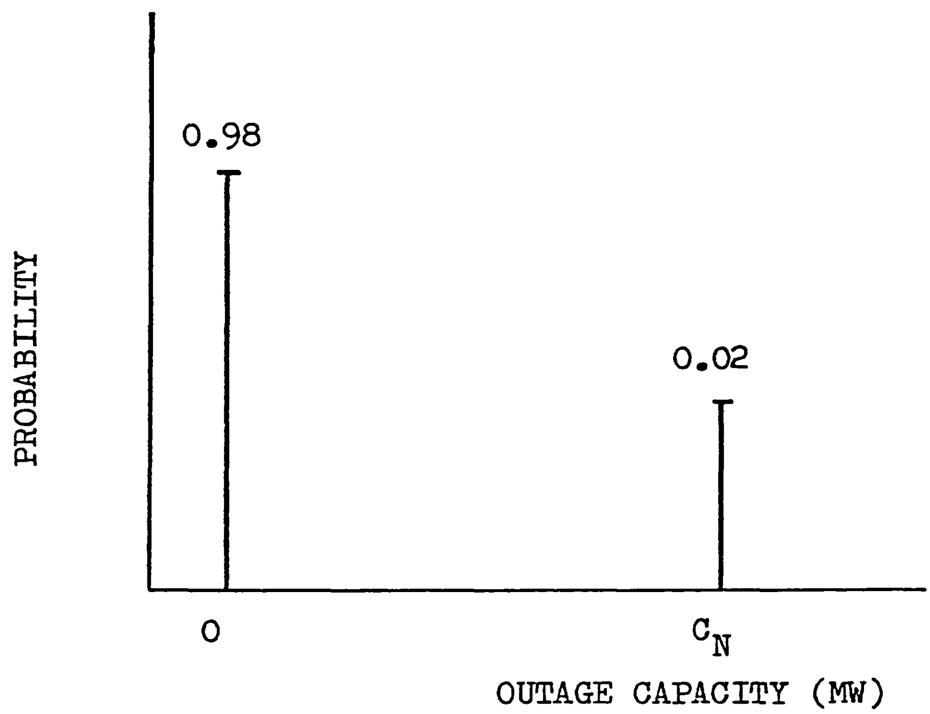


FIG. A.1 Forced Outage Capacity Probability Density Function

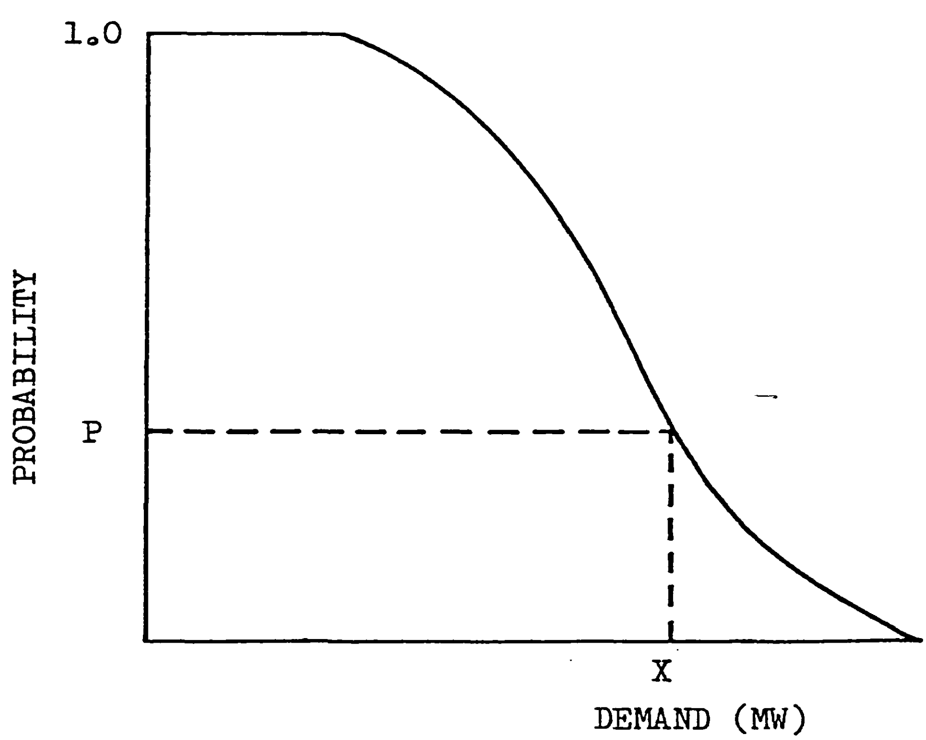


FIG. A.2 Load Duration Curve

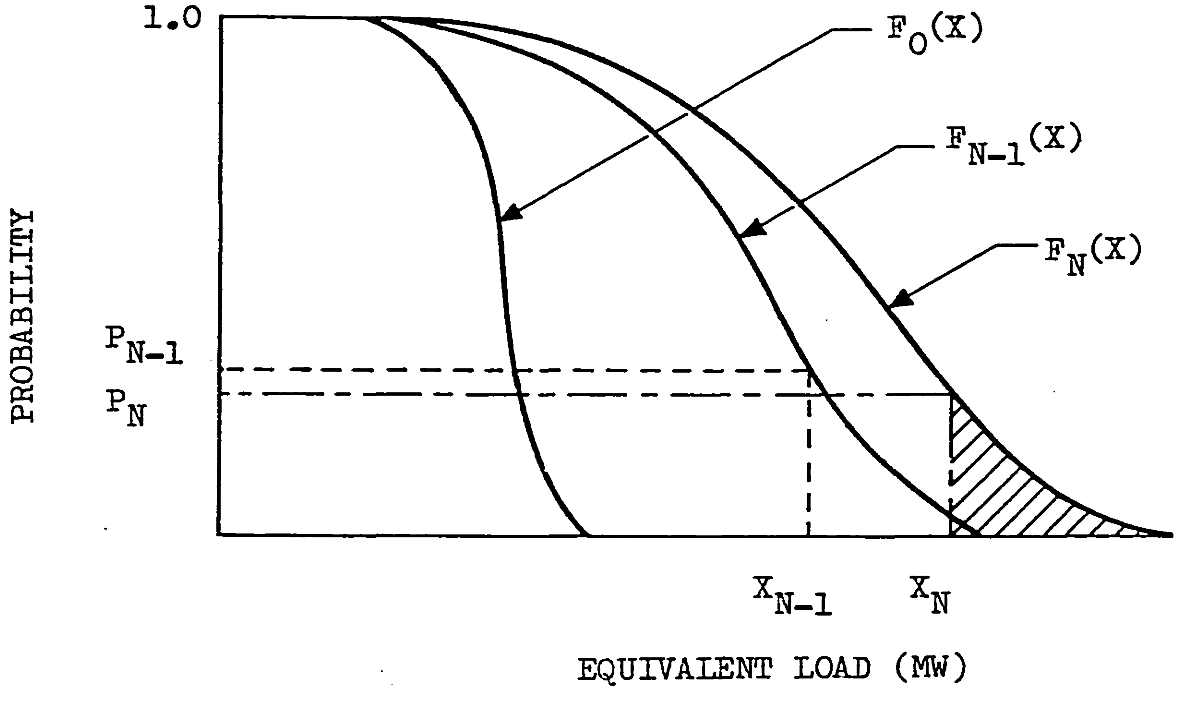


FIG. A.3 Equivalent Load Curves

load axis, the value which intercepts the probability axis is some measure of system failure, that is the equivalent load will exceed the installed capacity. If this probability is multiplied by the duration, D it gives the reliability index, Hourly Loss of Load Expectation (HLOLE) assuming that the LDC is developed from the hourly peak demands;

$$\text{HLOLE} = P_N \cdot D \tag{A.2}$$

The hatched area to the right of X_N is proportional to the expected energy demand that could not be served. For the duration considered, then the expected energy not supplied (EENS) when N plants are in the system equals;

$$\text{EENS}_N = D \int_{X_N}^{\infty} F_N(X)\, dX \tag{A.3}$$

If the last unit N is removed from the system, a new LEC $F_{N-1}(X)$, can be generated, for the system with N-1 units. The new LEC can be calculated by a process of deconvolution using the following formula, derived from equation (A.1).

$$F_{N-1}(X) = \frac{F_N(X) - F_{N-1}(X-C_N).q_N}{a_N} \tag{A.4}$$

The area under the $F_{N-1}(X)$ to the right of X_{N-1} is proportional to the expected EENS when N-1 plants are in the system.

Thus,

$$EENS_{N-1} = D \int_{X_{N-1}}^{\infty} F_{N-1}(X)\, dX \qquad (A.5)$$

Therefore, the expected energy of unit N, EEG_N is equal to the expected energy not served under N-1 units within the loads X_N and X_{N-1},

$$EEG_N = D \cdot a_N \int_{X_{N-1}}^{X_N} F_{N-1}(X)\, dX \qquad (A.6)$$

and the expected generation cost of unit N, GC_N is

$$GC_N = EEG_N \cdot UC_N$$

$$= D \cdot a_N \cdot UC_N \int_{X_{N-1}}^{X_N} F_{N-1}(X)\, dX \qquad (A.7)$$

where UC_N = unit cost of electric generated for unit N

The hours of operation of unit N are;

$$H_N = P_{N-1} (D \cdot \bar{a}_N) \qquad (A.8)$$

If the next unit in the merit order is removed from the system, i.e., N-2, the operating characteristics of unit N-1 can be calculated and so on for the succeeding units. When all units have been removed, the total energy produced, TE, and the total generating cost TGC, can be calculated;

$$TE = \sum_{n=1}^{N} EEG_n = D \sum_{n=1}^{N} a_n \int_{X_{n-1}}^{X_n} F_{n-1}(X)\, dX \quad (A.9)$$

$$TGC = D \sum_{n=1}^{N} a_n \cdot UC_n \int_{X_{n-1}}^{X_n} F_{n-1}(X)\, dX \quad (A.10)$$

The probabilistic simulation of all thermal systems operated in merit order gives the minimum of all possible dispatching strategies. The technique with its modifications has been used widely for estimating operating costs in conjunction with optimisation techniques for studying utility planning problems.

A.2 SIMULATION OF MIXED THERMAL HYDRO SYSTEM

For thermal plants, it is clear that the optimum operation leads to dispatching the next cheapest plant. This dispatching rule is not applicable to hydro plant because of its rigid constraint on its fuel cycle and almost all hydro plants have nearly zero operating costs. The generation of the hydro plant is not probabilistic and its generation cannot be more than the energy capacity of the reservoir.

The nature of the fuel cycles of the conventional hydro units must be operated along outflow trajectories and satisfying rather rigid constraints on reservoir storage levels which are determined by outflow from the reservoir as well as by highly variable inflows. The major fuel cycle constraint is that the equivalent energy of the reservoir or level must be returned to its original value at the end of the water cycle. The hydro unit is an energy limited plant for the period concerned.

In the simplest model, the hydro unit is inserted into the merit order at the point whereby for a given period, if it were a thermal unit, the expected energy generation equals to the energy capacity of the hydro unit. The hydro unit is located in the merit order by "trial and error" until the above constraint is satisfied. With reference to the optimal location, if the hydro unit is placed higher in the merit order, it would have to run below capacity to satisfy the energy constraint. This would essentially leads to increase in the loss of load expectation and in effect more expensive since the deficiency will have to be supplemented by the more expensive plants like the gas turbines. On the other hand, if it were to be placed lower, then it will have excess energy capacity which is not utilised, and the result also leading to a more expensive total operating cost.

In the simulation, the hydro is then treated as a thermal unit, and the introduction of the hydro unit into the merit order can be done in stages. This procedure also allows the hydro unit to cover the outages of the plants that are dispatched before it and also ensures that the capacity and energy capacity are fully utilised.

Initially the hydro unit is assigned at the lowest position in the merit order next to the most expensive thermal plant. The expected energy generation of the hydro unit can be calculated as a thermal unit as described in part one of the Appendix. This value can be considered as the minimum energy requirement from the hydro unit. If the minimum energy requirement is greater than the energy capacity for that period, then the system is deficient in energy and this has to be added to the expected unserved energy. However, if the energy capacity of the hydro unit is greater than the minimum energy requirement than the excess energy is available for reducing the expected energy requirements of the thermal units which are assigned below the hydro unit.

One method is to displace in an iterative manner the next thermal plant. In each instance, compare the expected energy generation of the hydro unit to its energy capacity. This will involve several convolutions and deconvolutions during the process of determination of the optimal position of the hydro unit. One method is described in the flow diagram as shown in Fig. A.4.

Obviously due to the discrete nature of the calculations, the two values of the expected energy generation and the energy capacity of the hydro unit are not exactly the same in the off loading of a complete thermal unit. This may result in the hydro unit off loading part of a thermal unit resulting in a two block representation of the thermal unit. In practice it means that the first block of the thermal unit is dispatched before the hydro unit and the second remaining block is to be dispatched after the hydro unit. The accuracy of this analysis greatly depends on the step size chosen for the calculations. The flow diagram mentioned above also describes this stage of the calculations.

If there are multiple hydro units, the hydro unit with the highest load factor has to move up the merit order first, followed by the next highest and so on. In the process of the calculations, a situation may arise whereby the hydro units are coalesced if they are both combined and not able to off load any further block of thermal unit. This may result in several composite hydro units representing several hydro units in the merit order, see Fig. A.5. In general the simulation of hydro unit involves more calculations and therefore requires more computer time but the methodology is appropriate and correct.

Theoretically if the hydro units are to be removed from the merit order after being strategically located, the modified load duration curve can be obtained so that it is to be served by the thermal units. Fig. A.6 shows the shape of the modified LDC for the thermal plants as an illustration after removing the hydro constributions from Fig. A.5.

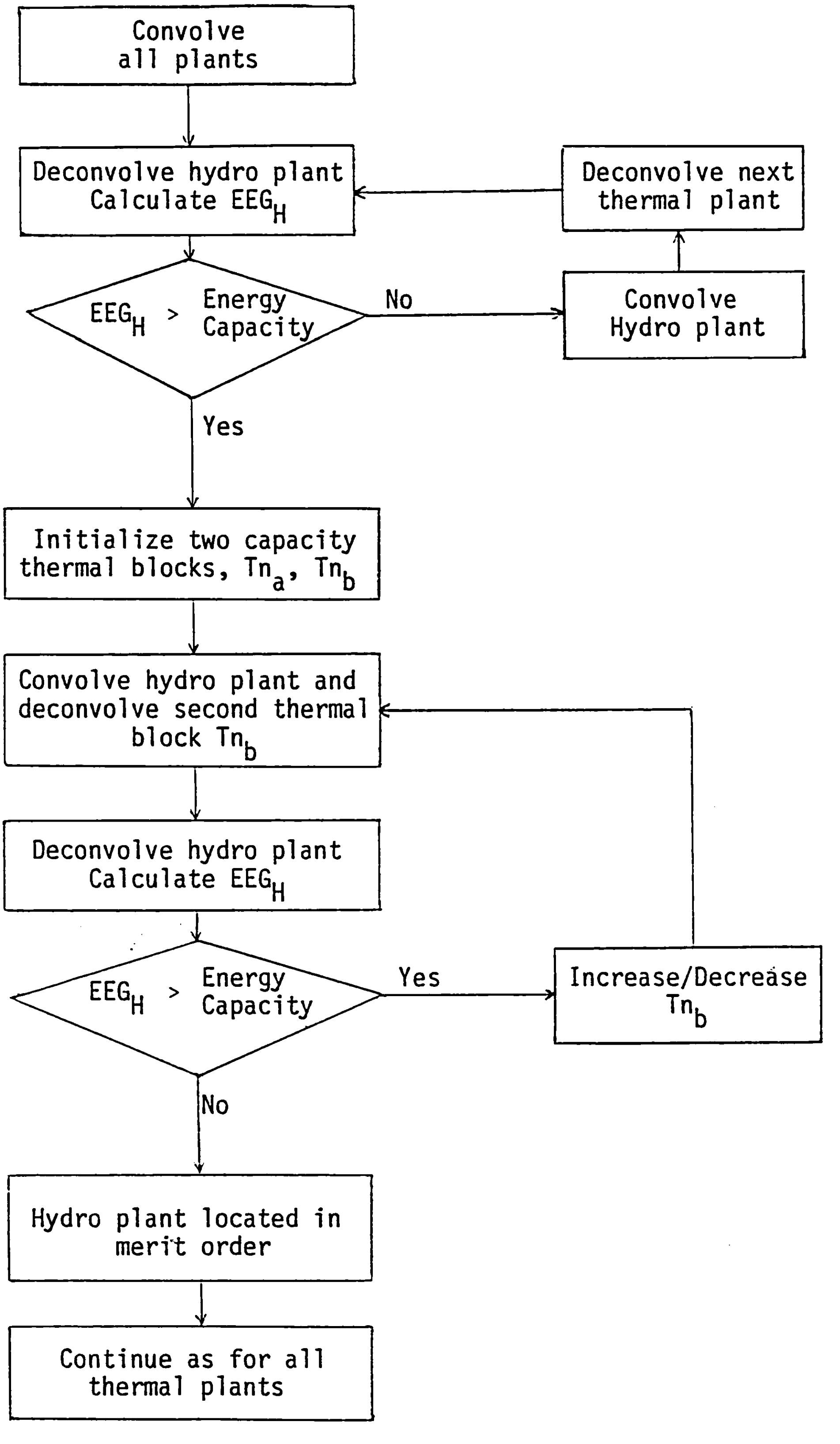


Fig. A.4 Flow Chart for Location of Hydro Unit in Merit Order

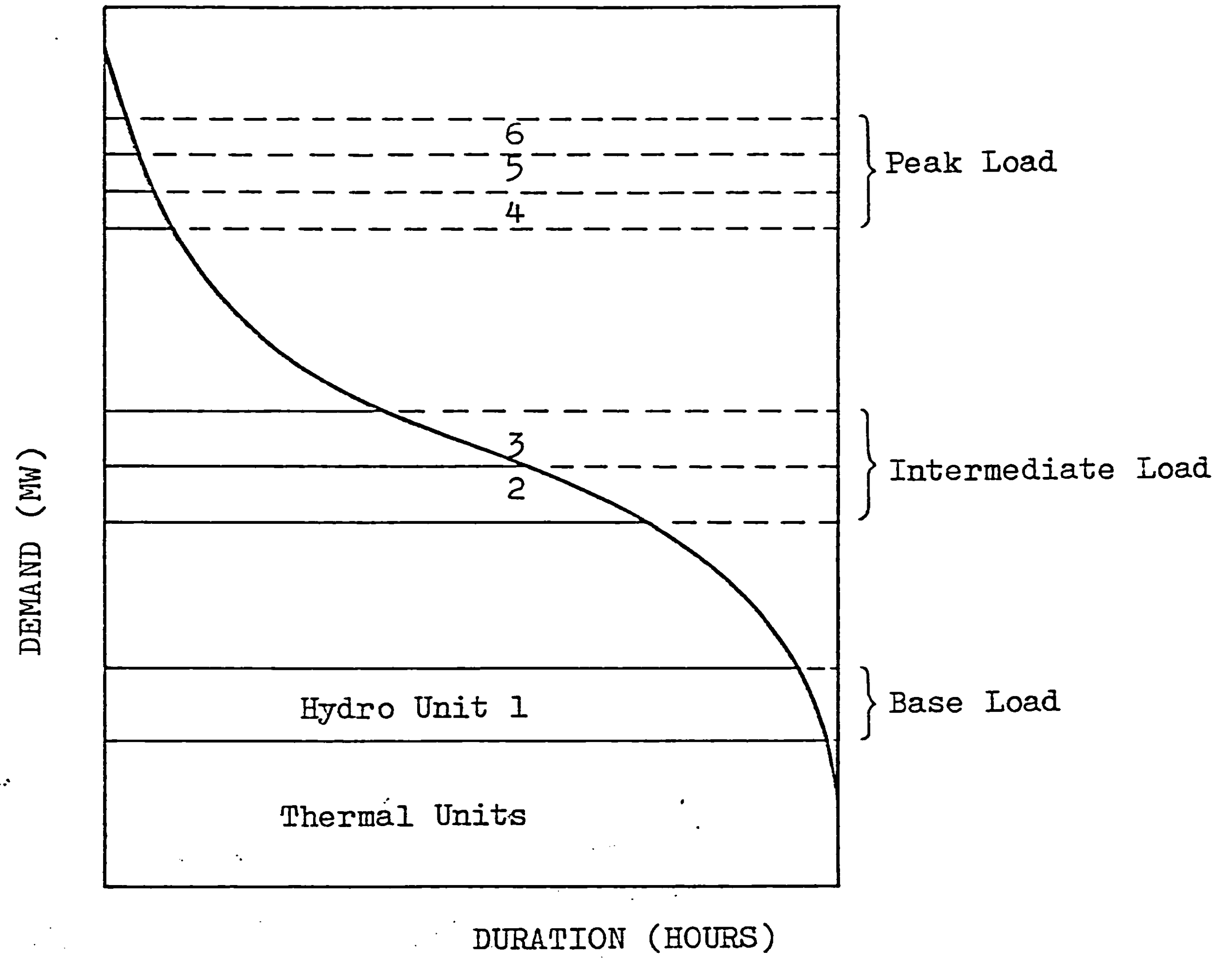


FIG. A.5 Typical Locations of Hydro Units in the Merit Order

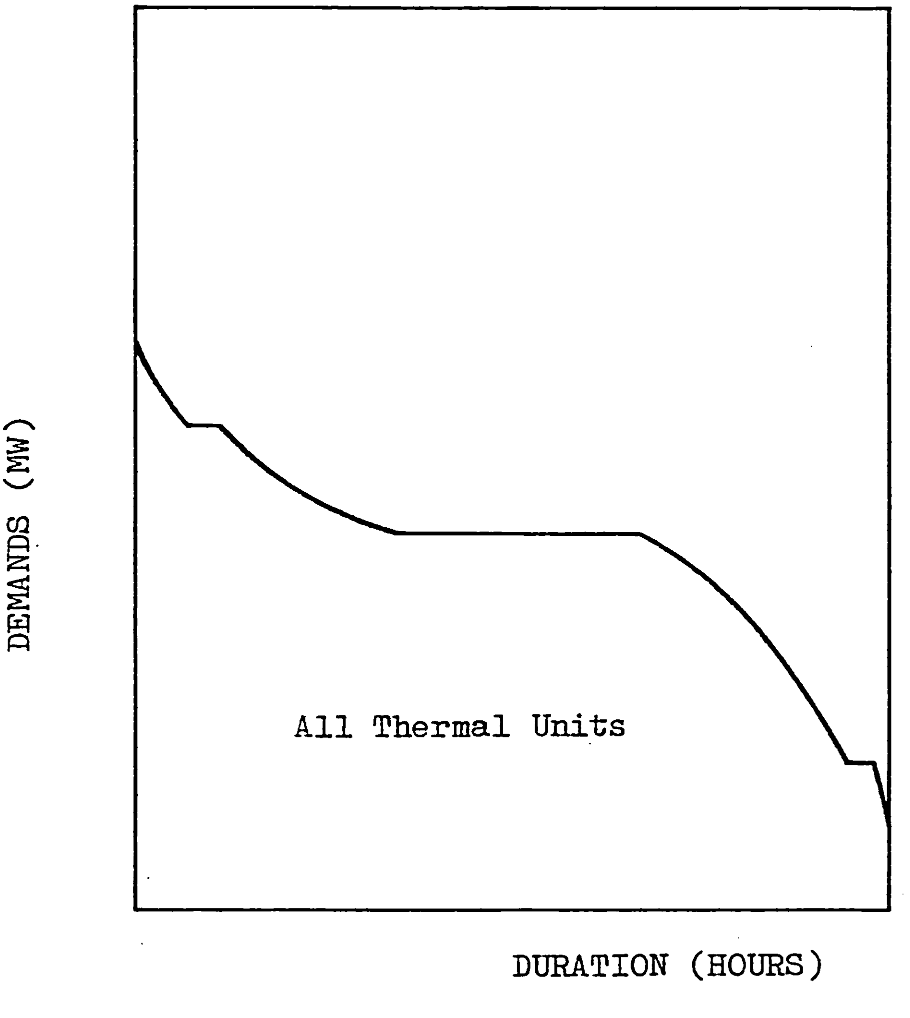


FIG. A.6 Modified Load Duration Curve for All Thermal Units

APPENDIX B

SYSTEM AND LOAD DATA FOR LLN

TABLE B.1

System Data for LLN in Year 1990

Number of units	Unit Capacity (MW)	Plant Type	Forced Outage Rate %	Generation Cost ($/MWh)	Planned Outage (days/year)
3	300	Com Cycle	18.0	31.6	21
4	300	Oil Fired	5.0	52.5	80
8	120	Oil Fired	0.9	54.8	45
4	60	Oil Fired	1.2	57.1	35
2	80	Oil Fired	6.4	57.6	35
6	30	Oil Fired	1.6	62.6	35
1	10	Oil Fired	3.8	74.6	35
5	20	Gas Turbine	6.0	104.8	15

Composite Hydro Data

Total Hydro Capacity (MW)	GWh per Period 1	2	3	4
1750	1530	1160	1096	1814
Load Factor %	40.0	30.3	28.6	47.4

TABLE B.2

System Data for LLN in Year 2000

Number of units	Unit Capacity (MW)	Plant Type	Forced Outage Rate %	Generation Cost ($/MWh)	Planned Outage (days/year)
7	600	Coal Fired	12.0	28.5	85
6	300	Coal Fired	7.0	29.6	80
6	300	Com Cycle	18.0	31.6	21
4	300	Oil Fired	5.0	52.5	80
8	120	Oil Fired	0.9	54.8	45
4	60	Oil Fired	1.2	57.1	35
2	80	Oil Fired	6.4	57.6	35
6	30	Oil Fired	1.6	62.6	35
1	10	Oil Fired	3.8	74.6	35
5	20	Gas Turbine	6.0	104.8	15

Composite Hydro Data

Total Hydro Capacity (MW)	GWh per Period 1	2	3	4
2150	2031	1667	1597	2315
Load Factor %	43.2	35.5	34.0	49.3

TABLE B.3

Expected Growth Rates of Power Demands from 1982 to 2000 for the LLN System

Year	Expected growth rates of power demands in %
1982	10.58
1983	12.03
1984	19.07
1985	15.79
1986	12.73
1987	10.48
1988	9.30
1989	9.27
1990	9.22
1991	8.16
1992	8.11
1993	8.12
1994	8.07
1995	8.08
1996	8.08
1997	8.13
1998	8.14
1999	8.18
2000	8.20

TABLE B.4

Expansion Plan for the LLN System from 1985 to 2000

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Peak (MW)	2632	2967	3278	3583	3915	4276	4625	5000	5406	5842	6314
Load Growth %	15.79	12.73	10.48	9.30	9.27	9.22	8.16	8.11	8.12	8.07	8.08
Unit addition (MW)	300(C) 300(O) 300(H)	300(C) 300(O) 300(O) 100(H)	300(O)	100(H)	100(H) 100(H)	50(H) 150(H)	300(CC) 300(CC) 100(H)	300(CC) 50(H) 300(C)	300(C) 100(H) 100(H)	300(C) 300(C) 50(H)	300(C) 300(C)
Total addition	900	1000	300	100.	200	200	700	650	500	650	600
Installed capacity	3700	4700	5000	5100	5300	5500	6200	6850	7350	8000	8600

Year	1996	1997	1998	1999	2000
Peak (MW)	6824	7379	7980	8633	9341
Load growth %	8.08	8.13	8.14	8.18	8.20
Unit addition (MW)	600(C) 600(C)	600(C)	600(C) 600(C)	600(C)	600(C)
Total addition	1200	600	1200	600	600
Installed capacity	9800	10400	11600	12200	12800

Notes : CC = Combined Cycle
O = Oil
C = Coal
H = Hydro

TABLE B.5

System Load Data for LLN in January 1982

Hourly peaks in MW from 4 to 10 January 1982 for

LLN system

728.4	708.4	685.4	700.4	705.4	834.4	929.4
1054.7	1325.6	1354.4	1435.2	1380.2	1300.2	1380.2
1400.2	1420.2	1320.3	1184.2	1144.2	1299.2	1239.1
1125.2	1008.2	874.9				
785.0	765.0	750.0	750.0	770.4	849.0	949.0
1085.1	1401.3	1435.7	1464.0	1424.0	1377.0	1448.0
1502.9	1471.6	1371.0	1245.6	1186.4	1332.1	1262.5
1170.7	994.5	899.4				
800.0	770.8	745.8	750.8	782.8	881.3	987.3
1139.3	1348.6	1399.4	1477.3	1413.6	1361.6	1418.6
1428.6	1450.6	1320.4	1207.8	1179.0	1360.3	1285.3
1171.3	1012.5	913.4				
835.4	815.4	789.4	789.4	784.4	881.4	974.4
1153.4	1365.0	1428.9	1453.5	1399.8	1384.5	1424.6
1426.5	1436.5	1352.0	1158.9	1133.9	1313.5	1229.9
1123.0	1009.0	878.4				
821.5	743.5	733.5	713.0	718.0	747.0	804.0
848.0	953.0	939.0	1009.0	1014.0	958.0	1008.0
983.0	1063.0	1019.1	992.5	982.5	1160.4	1079.4
1020.9	922.6	801.6				
721.5	711.5	696.5	681.5	705.0	758.7	872.7
1043.7	1249.8	1321.6	1370.6	1340.6	1230.5	1211.5
1175.9	1220.9	1210.9	1121.7	1068.2	1208.7	1148.4
1077.9	969.3	867.3				
782.3	744.2	719.2	715.2	730.2	773.2	818.2
850.9	910.0	933.0	1006.0	995.0	970.0	970.0
960.5	952.5	933.5	930.4	979.4	1136.4	1079.4
1001.9	884.9	779.9				

APPENDIX C

SYSTEM AND LOAD DATA FOR PUB

TABLE C.1

System Data for PUB in Year 1990

Number of units	Unit Capacity (MW)	Plant Type	Forced Outage Rate %	Generation Cost ($/MWh)	Planned Outage (days/year)
10	250	Oil Fired	4.0	53.5	75
6	120	Oil Fired	3.0	54.8	45
4	60	Oil Fired	2.0	57.1	35
4	60	Oil Fired	3.0	57.1	35
2	96	Gas Turbine	2.0	104.8	21
2	20	Gas Turbine	1.0	104.8	15

TABLE C.2

System Data for PUB in Year 2000

Number of units	Unit Capacity (MW)	Plant Type	Forced Outage Rate %	Generation Cost ($/MWh)	Planned Outage (days/year)
12	350	Coal Fired	7.0	29.0	85
10	250	Oil Fired	4.0	53.5	75
6	120	Oil Fired	3.0	54.8	35
4	60	Oil Fired	2.0	57.1	35
4	60	Oil Fired	3.0	57.1	35
2	96	Gas Turbine	2.0	104.8	21
2	20	Gas Turbine	1.0	104.8	15

TABLE C.3

Expected Growth Rates of Power Demands from

1982 to 2000 for the PUB System

Year	Expected growth rates of power demands in %
1982	7.60
1983	8.40
1984	8.90
1985	9.90
1986	9.40
1987	9.10
1988	8.80
1989	8.60
1990	8.40
1991	8.10
1992	7.90
1993	7.70
1994	7.40
1995	6.60
1996	7.00
1997	6.70
1998	6.50
1999	6.30
2000	6.10

TABLE C.4

Expansion Plan for the PUB System from 1985 to 2000

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Peak (MW)	1730	1893	2065	2247	2440	2645	2860	3085	3323	3569	3805	4071	4344	4626	4918	5218
Load Growth %	9.9	9.4	9.1	8.8	8.6	8.4	8.1	7.9	7.7	7.4	6.6	7.0	6.7	6.5	6.3	6.1
Unit addition (MW)	-	-	250(O) 250(O)	250(O)	-	250(O) 250(O)	350(C)	350(C)	350(C)	350(C)	350(C)	350(C)	350(C) 350(C)	350(C)	350(C) 350(C)	350(C)
Total addition	-	-	500	250	-	500	350	350	350	350	350	350	700	350	700	350
Installed capacity	2682	2682	3182	3432	3432	3932	4282	4632	4982	5332	5682	6032	6732	7082	7782	8132

Notes : O = Oil
C = Coal

TABLE C.5

System Load Data for PUB in January 1982

Hourly peaks in MW from 4 to 10 January 1982 for

PUB system

616.0	568.0	563.0	556.0	524.0	553.0	598.0
621.0	849.0	1042.0	1127.0	1157.0	1105.0	1115.0
1134.0	1145.0	1137.0	1078.0	943.0	939.0	954.0
925.0	864.0	746.0				
686.0	622.0	598.0	586.0	576.0	569.0	625.0
696.0	872.0	1085.0	1118.0	1151.0	1097.0	1097.0
1134.0	1113.0	1131.0	1080.0	960.0	945.0	973.0
929.0	855.0	730.0				
659.0	628.0	608.0	583.0	570.0	614.0	650.0
693.0	895.0	1106.0	1127.0	1152.0	1108.0	1072.0
1113.0	1089.0	1134.0	1085.0	957.0	944.0	958.0
904.0	812.0	704.0				
615.0	613.0	588.0	559.0	565.0	568.0	600.0
642.0	841.0	1015.0	1048.0	1083.0	1020.0	1022.0
1061.0	1042.0	1067.0	1007.0	903.0	896.0	908.0
863.0	795.0	686.0				
627.0	581.0	575.0	564.0	542.0	566.0	625.0
664.0	840.0	1032.0	1074.0	1127.0	1057.0	1053.0
1082.0	1073.0	1102.0	1057.0	948.0	914.0	935.0
896.0	821.0	730.0				
639.0	603.0	595.0	562.0	554.0	571.0	593.0
621.0	791.0	967.0	999.0	1024.0	982.0	941.0
914.0	870.0	829.0	814.0	767.0	763.0	832.0
804.0	738.0	690.0				
618.0	585.0	546.0	527.0	528.0	530.0	531.0
512.0	569.0	639.0	689.0	730.0	696.0	688.0
687.0	718.0	699.0	700.0	705.0	711.0	757.0
736.0	696.0	659.0				

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