IMPACT OF LOAD MANAGEMENT
ON THE RELIABILITY AND PRODUCTION COST

BY

MD. MAHBUBUR RAHMAN

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1. ______________________________ Chairman (Supervisor)
(Dr. Md. Quamrul Ahsan)
Associate Professor,
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Central Zone,
Bangladesh Power Development Board.

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Countersigned

M. Q. Ahsan

(DR. MD. QUAMRUL AHSAN)
SUPERVISOR

Signature of the Student

Md. Mahbubur Rahman.

(Md. Mahbubur Rahman)

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ABSTRACT

In the first decade the electric utility industry, motivated by the need to control spiralling production costs, has expended considerable effort on the assessment and analysis of load management (LM).With the increasing recognition that load management could be beneficial to the utility the planner has an added alternative in generation expansion planning in deciding whether to construct a new plant, purchase power from the neighbouring utility or implement a load management scheme. An investigation have been made to find out the impacts of the different load management strategies on the reliability as well as on production costs of a power system. In this study,'segmentation method' has been utilized for the evaluation of loss of load probability (LOLP) as well as the production cost.

In this research work two different utilities, Bangladesh power system and IEEE reliability test systems have been considered for the implementation of load management programs. The economic benefits as well as the benefits in terms of reliability of the systems are evaluated for different LM schemes and the comparisons of each scheme with the others are presented in this thesis.

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ABBREVIATIONS

AC	-	Available capacity
AEP	-	American Electric power
BPDB	-	Bangladesh Power Development Board
BPS	-	Bangladesh power system
CLC	-	Chronological load curve
CRR	-	Capacity Reserve Requirement
DLC	-	Direct Load Control
ECS	-	Economic Commitment Schedule
EFOR	-	Equivalent Forced outage rate
EPRI	-	Electric Power Research Institute
EWI	-	East West Interconnector
FAD	-	Frequency and Duration
FCR	-	Fixed charge rate
FOR	-	Forced outage rate
HR	-	Heat rate
IEEE	-	Institution of Electrical & Electronic Engineers.
IHR	-	Incremental Heat rate
LDC	-	Load duration curve
LM	-	Load management
LOEP	-	Loss of energy probability
LOLP	-	Loss of load probability
MCS	-	Monte carlo simulation
PDF	-	Probability distribution function
PURPA	-	Public utility regulatory policies act.
RTS	-	Reliability test system
RV	-	Randon variable
TOD	-	Time of day.

NOTATIONS

C_k	=	Capacity of the k-th generating unit
E_k	=	Expected energy generations of the k-th unit
EB	=	Energy balance
EC_k	=	Production cost for the k-th unit
F(L)	=	Load probability distribution
IC	=	Installed capacity
L	=	Random system load
Le	=	Equivalent load
Lo_i	=	Random outage load corresponding to the i-th unit
LOLP	=	Loss of load probability
p_k	=	Availability of capacity C_k of the k-th unit
PL	=	Peak load
q_k	=	FOR of the k-th unit
$UE_{\bar{k}}$	=	Unserved energy before convolving the k-th unit
UE_k	=	Unserved energy after convolving the k-th unit
ε(DNS)	=	Expected demand not served
ε(ENS)	=	Expected energy not served
ΔC	=	Segment size
λ	=	Generating unit failure rate
λ_k	=	Average incremental cost of the k-th unit
μ	=	Generating unit repair rate

CHAPTER ONE

INTRODUCTION

1.1 Introduction.

Electricity plays the vital role in the economic development of a nation in the modern world. Economists consider the per capita consumption of electricity as an indicator of the state of economic development of a nation. It is a common experience of the urban planners that with the enhancement of population and industrial growth,demand for electric power increases. Electric power companies are authorized to shoulder the responsibility of meeting the alarmingly high demand of the consumers. An integral part of any utility is the responsibility of planning for the future load growth.

The classic arrangement of base-load, intermediate and peaking units has long permitted utilities to meet the customer's electricity at a low cost. However,the use patterns have been changing in the recent years and electricity demand changing with them. Airconditioning, space and water heatings, once a luxury, have become common place and major contributors to peak load in the most of the utilities of the western world. Due to complex change in use patterns, the loading behavior of an utility system has resulted in a sharper peak demand in most of the cases necessiating construction of newer power plant to meet the peak demand of the shortest duration with an adverse effect on the economic operation of utility system.

Traditional solutions to deal with the growing peak loads are:

1. Construction of newer power plants.
2. Interconnection with other utilities.
3. Reducing system voltages (Brown out).

However, the construction cost of a new plant is increasing with time very rapidly. The interconnection with neighbouring utility may not always be a solution to meet the peak. Due to the sophistication in industrial use the reduction in system voltages causes a serious adverse effect on the equipment. Because of the unsatisfactory response from the traditional solutions to the problems of meeting the peak demand, the utility planners are considering the load management (LM) as the means for limiting the peak load growth and hence capacity addition. The different strategies, direct load control (DLC), time of day (TOD) pricing, pumped hydro storage, involved in the implementation of load management program have by now been well established among the electric power companies. An annual EPRI - DOE Survey (1,2) shows that over 100 utilities are involved in a variety of load management program.

1.2 Background and Motivation.

Load management (LM) has been an accepted practice for many years. Many utilities have used time clock control of electric water heaters[3] since 1950's and earlier. With the advent of the

Arab oil embargo[4] in the fall of 1973 and subsequent media coverage of the oil shortage, the concept of LM as a means of energy use was conceived by a large number of electric utilities in the United States. Load management activity has proliferated[5] since about 1978. The earliest analyses were directed toward the application of technology and equipment for the direct control of electric load. Further delineation was made between mandatory and voluntary consumer participation and in the application of price signals (rates and incentives) to either elicit customer co-operation or to align customer payments with cost of service. The public utility commission examines the potential benefits of load management and have asked utility companies under their jurisdiction to identify and quantify load management impacts on future utility plans. Load management has, therefore, become a significant aspect of system planning for many utilities. The electric utility rate design study conducted by the Electric Power Research Institute (EPRI) over a period of recent years included topics covering load shape analysis, cost determination, and rate design which have application to the study of load management.

In the last few years, a large group of papers has appeared[5] in the literature, in which mainly different arts of load management are discussed. However, there has appeared very few investigating the impacts of load management either on the reliability or on the production cost of the system. The impacts of load management on the reliability or on the production of the interconnected system are also not reported in the literature. Recently Schenk and Ahsan[6,7] reported the impacts of load management on the reliability as well as on the production costs of two interconnected systems. The authors have utilized the bivariate Gram Charlier series expansion in the simulation. Ahsan[8] and also Ahsan et al.[9] have investigated the impacts of load management on the reliability and production costs of two interconnected system utilizing the segmentation method. The evaluation of a single area system is altogether different from that of two area system. To the best of the author's knowledge the researchers have not yet attempted to investigate the impacts of different LM strategies on the reliability as well as on production cost of single area system.

1.3 Thesis Organization.

This thesis consists of six chapters. In an introductory approach in chapter one, an attempt has been made to unveil the rationale of LM and motivation to its implementation both from the economic and historical perspective. Different approaches to load management program along with the economic evaluation is presented in chapter two.'Pumped hydro' is a very attractive type of the energy storage scheme. Therefore, the physical features of a pumped hydro project along with a storage type of hydro electric project is briefly discussed in chapter three. Discussions in chapter four is devoted to the development of generation and load models based on the probabilistic simulation technique. In chapter Five the segmentation method is briefly discussed as this method is incorporated by the author to investigate the reliability and production cost of the system. Chapter six presents the results of the 'impact of load management on the reliability and production costs'. In chapter seven, an observation as well as discussion is made on the basis of the results of chapter six.

CHAPTER TWO

LOAD MANAGEMENT

2.1 Introduction.

Load management[10] is the deliberate control or influencing of customer load in order to shift the time of use of electric power and energy. Reducing the system load at the time of peak by load management techniques is an alternative to installing peaking type of generating unit. Any load that can be supplied as an off peak load instead of an on peak load will reduce[8] the need for an increment of generating, transmission and distribution capacity.

The terminology task committee of load management[11] sub-committee has defined LM as follows:

It is the actions initiated by the utility or one or more of its customers as a result of financial incentives to

i) control of load growth,

ii) alter the shape of the load curve and

iii) increase supply through non traditional sources.

Load management procedure involve changes to equipment and/or consumption pattern on the customer side of the meter. The customer may be a residential or commercial user of electricity or it may be a distribution utility receiving wholesale electricity for resale to end use customers. Load management (acting on the customer side of the meter) is complimentary to supply management (acting on the utility side of the meter). Both load and supply management have the same principal objectives.

In this chapter, a brief discussion on the various aspects including objectives, conditions and approaches to load management is presented. Various load management strategy are also brought to discussion in this chapter.

2.2 Reasons of Load Management.

The increasing peak demand is usually met by the utilities implementing one of the three following strategies.

1. Construction of new power plant.
2. Interconnection with other systems.
3. Reducing system voltage (brown out).

The construction of a new power plant requires a huge investment. The economics of power plant construction have been changing. New plant construction costs are more than ever before because of materials, labor and, specially, financing costs. Plant licensing is increasingly difficult because of regulatory road blocks. In the past, the installation of oil fired equipment was a low cost means of supplying peak loads.

Now the future prospects of availability and price of oil may inhibit the advisability of major investments in combustion turbines. There are considerable environmental and legal obstacles to power plant siting and construction.

The prospects of interconnection with the neighbouring utilities to meet the peak may not be feasible in all cases. Surplus energy of exporting system may be inadequate to meet the peak demand of the importing system. It may also happen that both of the systems experience loss of load or shortage of reserve at the same time. There are many other limitations like tie line capacity, geographical location, economic feasibility etc. for which interconnection may not be enough to meet the demand in crisis.

Although the major reason for voltage reduction is the transmission inadequacy, it is a practice employed by many utilities as a method of reducing system peak demand[12] during emergency conditions. Generally this reduction is for short duration after which voltage is returned to normal. But a voltage reduction[8] beyond certain percentage (maximum 8%) exceeds the tolerance built in many appliances. The major impact of brown outs is overheating and lower performance of electric motors, less light from light bulbs and similar inconvenience. The sophisticated industry, the computer industry for instance, can be seriously affected by voltage fluctuation. For example[12], with their experience the American Electric power service corporation (AEP system) had reached to the conclusion that voltage reduction as a means of reducing energy was not a viable approach for the AEP system due to the extensive capital investment required to implement the program and the minimum savings in energy.

That is, most of the traditional approaches to solve the problem of meeting the peak demand have been failed to prove it as economically viable as load management.

2.3 Objectives of Load Management.

The principal objective[13] of load management is to alter the real or apparent pattern of electricity use in order to

i) improve the efficiency as well as the utilization of generation, transmission and distribution system.

ii) shift fuel dependency from limited to abundant energy resource.

iii) lower the reserve requirements of generation and transmission capacity.

iv) improve the reliability of service to essential loads.

v) improve the load factor and reduce the cost/benefit ratio as well as the average cost of electricity.

vi) improve system efficiency by reducing the share of electric energy provided by the relatively inefficient units.

2.4 Conditions of Load Management (LM).

LM as an strategy may not work for every utility. Certain conditions are needed before LM can even be considered.

one required condition is the 'peakiness' of the utilicies load profile, i.e., a low power factor-the ratio of average demand to peak demand. Obviously, an utility with a flat load profile will not need load management because its power plants are fully utilized.

The second condition is the utility's generation mix. If an utility has a coal or nuclear base load, but burns oil or gas to meet sharp peaks, load management could spare some of that costly oil or gas. However, if an utility meets its peaks with less costly unit, such as pumped hydro, load management may not be necessary. If an utility burns oil or gas to meet both peak and off peak load, load management will not provide any economic benefits because there is no inexpensive base load energy to shift to. If an utility has new plants well under consideration, load management may not be attractive.

The third condition is the contractual limitation. If an utility has farm purchase contracts during the peak periods with the connected utilities, any load management scheme may not be beneficial.

The fourth condition for load management is the customers ability to reduce peak load or to shift peak load to off peak periods.This depends partly on the saturation level of devices such as water heaters and airconditioners, and partly on whether customers can use those devices at off peak periods.

The fifth condition is the customers acceptance of the program as a means of load reduction during the peak period. Achieving significant amount of load reductions[2] may not be realized if the customers are not motivated towards the acceptance of LM program.

Therefore, load management schemes are not applicable to all utilities. Careful consideration of such factors as load profile, generation mix, ability to shift load, and customer's attitude is necessary before an utility can adopt a load management program.

2.5 Economic Analysis of Load Management Program.

Load management (LM) can be looked upon as a source of generation and analyzed to determine its value in resource plans.

However, unlike a conventional generator, the effectiveness of LM program may vary throughout the day and year[14]. The problem is then, how the KW reductions resulting from LM programs be compared to the KW output of a conventional generator.

In the evaluation of load management program as an electric system resource, the two unique feature incorporated in the methodology is the reliability analysis and economic assessment involving a comparison between the program costs and the cost of adding the next generating unit. Reliability analysis based on probabilistic simulation technique is discussed in the subsequent chapters while the discussion in the following sections are devoted to economic analysis. The incremental cost of deferred generation has been defined for the industry by the Public Utility Regulatory Policies Act (PURPA), as the avoided capacity cost.

2.6 Cost Effectiveness of Load Management

In evaluating cost effectiveness, it is necessary to identify and quantify all the benefits and costs involved. Factors which can not be quantified are handled as intangibles (i.e., invironmental impacts) in the decission making process. A load managment program is cost effective, from the utility's perspective, when the costs of implementing the program are less than the incremental cost of possible supply of the electric service.

The specific parameters that are used in the calculation of the cost effectiveness of load management programs are:

i) Avoided cost of capacity

ii) Capacity response ratio

iii) Program costs

iv) Cost of capital

v) Interest in escalation rates

vi) Customer withdrawal rate.

These parameters are briefly discussed below.

i) Avoided cost of capacity.

The preparation of a balanced generation expansion plan to meet future loads requires the comparison between new conventional generation & load management program. That is, two plans for future are to be developed. One of the plans would serve the system load, assuming that all forecast load management programs are implemented. The second plan would serve the load if the utility does not implement these programs. The difference in the cost involvement of these two plans is the cost avoided by the load management program. (+ ve)

ii) Capacity response ratio.

A change in peak load does not necessarily equate to a change of the same magnitude in generation system capacity to maintain the same level of reliability. The capacity response ratio is defined as the ratio of a change in system capacity to a change in system load at a constant level of reliability.

iii) Program costs.

The program costs consist of the cost of the equipment, the cost of installation, the cost of removing the equipment after one normal life cycle, the operation and maintenance costs, the initial customer contact cost (one time only) and the incentives. It is assumed in these calculations that the equipment, installation and removal costs will be capitalized for the life of the equipment. The operation and maintenance costs escalate throughout the program. The customer contact costs occur only once during the program. The incentives are also considered an expense and escalate over the life of the program.

To estimate the cost for the load management program calculations, the average equipment lives are estimated for various types of equipment. The equipments with reliable components (e.g., electric meters and circuit breaker type switches) are assumed to have a life of approximately 30 years and the equipments with new technology and / or solid state boards along with microprocessor are assumed to have a life of approximately 15 years.

iv) Cost of capital

The cost of capital is based on the debt, equity, and other factors that are normally utilized in determining the rate of return. In addition, it considers income taxes, property taxes, and overhead and insurance values. The cost of capital (fixed charge rate) is a factor used to convert a capital expenditure to a levelized annual cost.

v) Present worth factor.

It is an important parameter in the economic assessment of any capital intensive project likely to remain in operation for a considerable period. Major factors influencing the present worth factor are depreciation, rate of return, taxes and insurances related to the projects or machineries under analysis.

vi) Customer withdrawal rate

The number of customers that would be removed annually as a percentage of the total number of customers is referred to as the customer withdrawal rate or drop out rate. This rate depends upon the type of the equipment being installed and the customer acceptance of that equipment. In many cases, the load management programs are very new and the drop out rates must be estimated in order to make the cost effectiveness calculation. The drop out rate is normally 5% for (14) new programs until sufficient information is gathered to make a formal estimate.

2.7 Costs and Benefits Analysis.

The cost effectiveness analysis compares the various cumulative costs and benefits. The benefits are calculated as (14)

$$B_o = B_d + B_e + B_{op} \quad \ldots \quad (2.1)$$

B_o = Total benefits of operation

B_d = program dollar savings directly attributable to the net demand benefits.

B_e = program dollar savings directly attributable to the net energy benefits.

B_{op} = program dollar savings directly attributable to the net operating benefits.

The total cost for the program is comprised of six separate costs. The total program cost may be expressed as

$$C_o = C_e + C_i + C_{om} + C_{con} + C_{inc} + C_{ris} \quad \ldots \quad (2.2)$$

C_o= Total program cost.

C_e = capital cost of LM equipment.

C_i = costs resulting from the initial installation and final removal of the equipment.

C_{om} = cost of maintenance of LM equipments and also of removal and reinstall of LM equipment.

C_{con} = costs for customer contact and training.

C_{inc} = the levelized money transferred from all the rate payers, or non-participants, to the participants (incentives).

C_{ris} = the utility's unrecovered fixed costs caused by either reductions in kwh sales and /·or kw billing demand of the participant customers prior to any rate relief adjustment.

After calculation the benefits and costs the benefit/cost ratio can be determined. Should this ratio be greater than one, the program is then considered to be cost beneficial. Should the program be marginally cost effective (meaning the costs excluding the incentive costs is cost effective, but the incentive costs raise the total cost to a point where the cost benefit ratio is less than one), further assessments must be made as to whether or not the program should be investigated. It should be noted that this method of determining the cost effectiveness relate to the utility perspective and not to the non participants, participants, or society perspectives. Societal benefits relating to clean air, less fuel oil usage, etc. have not been assumed due to the difficulty in quantifying such benefits.

2.8 Approaches to Load Management.

There are three basic approaches to load management.

1. Direct control.
2. Indirect control or customer incentives.
3. Energy storage.

2.8.1 Direct Load Control.

It is defined as the utility control, of customer loads during peak period or other operating periods to limit the amount of demand of related customers. The loads which are controlled by direct LM approach are of two types: interruptive customer load such as airconditioner and deferrable customer loads such as water heaters, space heating systems, and swimming pool pump. A unidirectional or bidirectional communication system is used to activate control devices at the customer locations during this period. Direct load control is attractive to utilities because they can plan for specific demand level. Over the years considerable interest has been shown by electric utilities in the direct load control (DLC) aspect of LM because, it can be used, within its capabilities, to achieve definite load reductions. The load reduction achievable through TOD pricing (Discussed later in this chapter) is uncertain and solely dependent on the customer. Although considerable work has been done on energy storage applications for LM and the use of TOD pricing, DLC remains as the most widely investigated method of load shaping. The conclusion pertaining to the effectiveness of a particular load management program is purely system dependent. The effectiveness of a DLC strategy [15] depends on several system characteristics-

i) generation mix

ii) load curve shape

iii) planned capacity addition mix

iv) types of loads controlled and

v) meteorological characteristics.

And the most commonly employed indicators of the effectiveness are:

i) load reductions

ii) production cost and fuel cost saving

iii) capacity deferral/reductions

iv) revenue requirements

v) load factor and

vi) system reliability.

Control of device or an appliance can be accomplished by interrupting its supply of power for a specified time period. Service can be interrupted for varying time intervals depending on the device being controlled. Many control strategies have been identified and tested by various utilities involved in load management program. However, the two most common types are the cycling and [10] pay back strategies. Cycling turns groups of loads off for specified short time periods (fractions of an hour) to reduce the overall diversified demand.

Pay back control strategies are accomplished by shutting off groups of devices for periods upto 6 hours in duration. The diversity of devices controlled in this fashion is usually low. As a result, when control is removed the group of devices present a demand to the system which can be significantly larger than normal and is called the pay back effect. Normally it consists of a unidirectional signal system operated by a company which upon command from a central control station provides switching signals to turn one or more selected customer appliances off or on. In what follows some control systems are briefly discussed.

Power line carrier:

A communication system where the utility power line is used as the predominant element in the communication link. Frequencies may range from under 6Hz to 200Hz and above. The system can be unidirectional or bidirectional and power levels are low, normally less than 500 watts.

Radio control:

Any load control procedure using unidirectional or bidirectional radio signals to initiate interruption of customer loads and obtain system data.

Telephone control:

Any load management procedure where the interruption of customers loads as well as the data accquisition for the purpose of metering or system security is achieved using telephone line as the predominant media of communication.

Ripple control:

A communication system[13] installed within an electric power network to superimpose on the power line a frequency/time coded message which is interpreted as command or data signals by remotely located receiver. Ripple control systems can be used to remotely control switches, capacitor banks, reclosers, customer loads, and meter registers.

Transponder:

A receiver transmitter or transreceiver equipment, the capability of which is to transmit signals automatically when a proper interrogation is received.

2.8.2 Indirect Control (Customer Incentives).

Indirect control or voluntary control strategy of customer's loads can be better realized through the concept of passive load management program. It is a concept relying on customer response to rate design, conservation ethic. Customer incentives, such as time of day rates, encourage customers to shift electricity demand to off peak periods, typically by charging less for off peak use of electricity. The customer decides which appliances should be used and when. Nonessential appliances may be used during off peak periods when rates are low, or the customer may choose to pay higher peak rates. However, customer incentives may not guarantee the utility a definite demand level, and the utility must plan accordingly.

If the different pricing of electricity is adopted as a tool to motivate the customers to shift their demands from on peak hours to off peak periods of the days then the rate designers should have to introduce some adjustment clauses[11] in its rate structure. In order to be certain that their objectives of diferent pricing of electricity use based on demand level and time of use is accomplished, the consumer appliances must also be monitored by special metering devices.

2.8.3 Energy Storage Scheme.

It is the processes for the storing energy in various form utilizing the electricity during off peak periods for future use at the time of systems peak load. Possible types of energy storage systems which are under consideration for future use or in the stages of research and development are; briefly discussed below.

1) Mechanical - such as spring, inclined plane, vertical lift and flywheel.
2) Hydraulic - such as pumped fluids, lifted or compressed, including change of stage.
3) Thermal - such as heated or cooled, insulated media, including change of state.
4) Chemical - such as electrolytic cell.

Of all the different types of energy storage system, the pumped hydro and electric thermal storage are widely practiced by the utility systems as the load management strategy because of their technoeconomic feasibility. However, the selection of a particular system as a load management strategy are dependent upon such constraints as systems load and generation characteristics, geographical and environmental factors.

2.9 Compressed Air-storage Plants.

Geological conditions do not always permit the installation of pump storage plants. Consequently in flat regions, the compressed air storage plant may be a suitable alternative. Instead of pumping the water to the upper reservoir, air is compressed to high pressure and stored in an air tight underground cavern. During peak period this air may be heated up and expanded in gas turbine plant where the gas turbine drives generator.

Presently, the peak power is generated using gas turbines, special steam turbines, water turbines and in a few places pump storage plants are also used to meet the peak demand. Among these plants, only pumped storage plant has the ability of storing off-peak power for peak load power. Air storage power plant equipped with a gas turbine can also be used to store energy during off peak hours and to utilize the energy during the peak hours.

2.9.1 Working Principle of the Plant.

The arrangement of the plant is shown in fig. 2.1. A unique feature of this arrangement is a combined generator motor unit (similar to pump turbine unit in pump storage plant) incorporated to work as a motor or generator. The outlet terminals of this generator-motor unit are connected to the main grid of the supply system.

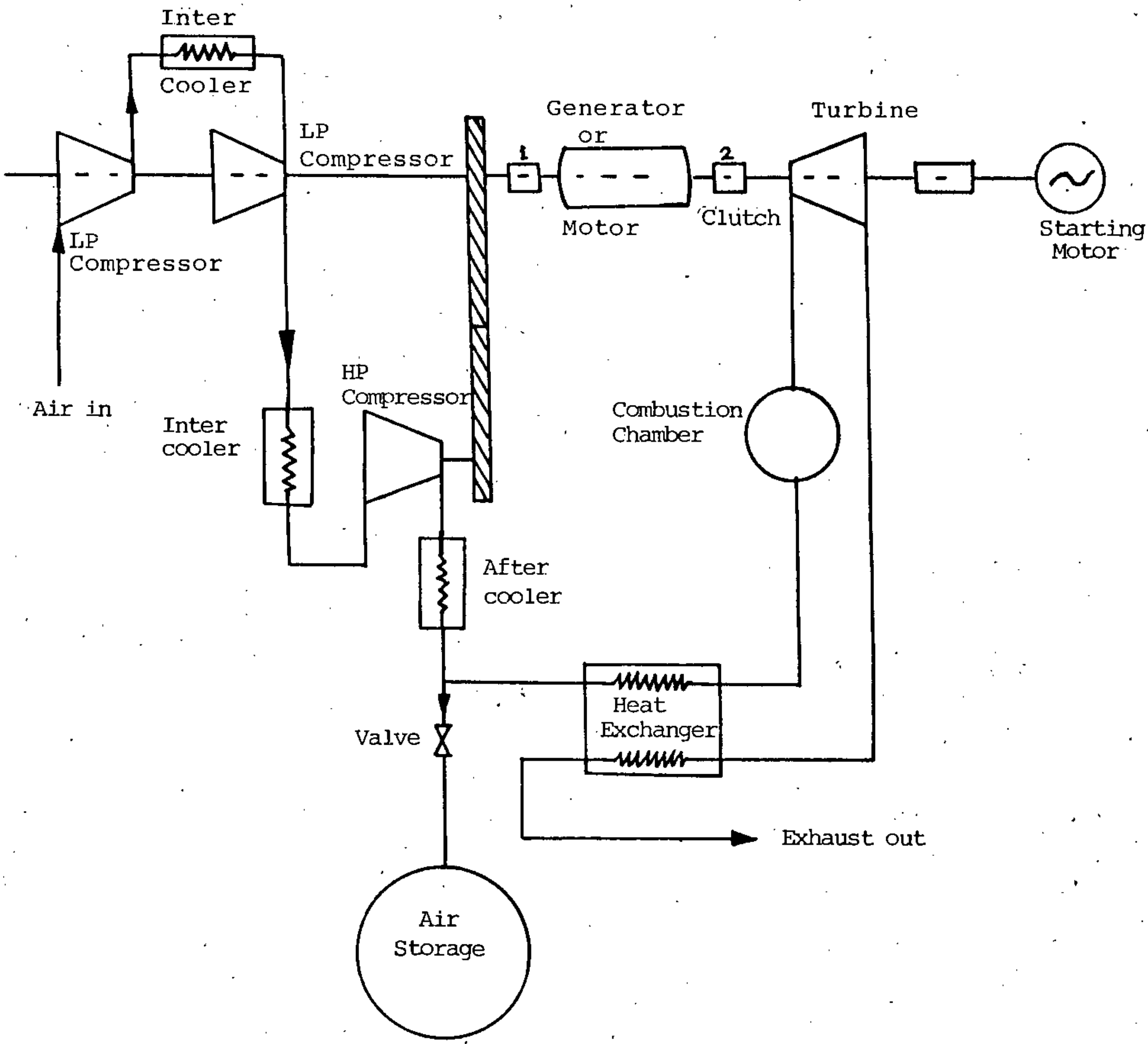


Fig. 2.1 General arrangement of air storage power plant.

During off peak periods, the turbine will be disconnected with the help of clutch (2) and the compressors are driven by the generator motor set which works as a motor taking its power from grid. The compressed air during this period is stored in a large cavern.

During the peak load periods, the compressor is disconnected from the system with the help of clutch (1) and the compressed air stored in cavern is supplied to the gas turbine through combustion chamber as shown in figure. The entire output of turbine will be used to generate the electricity. The generator motor unit during this period works as a generator and supplies the power to the main grid.

The same system may also be used as a conventional gas turbine plant generating power continuously and supplying to the main grid. During this mode of operation, the compressed air from the compressor is taken to the gas turbine without passing to the air storage cavern and the power generated will be supplied to the main grid.

2.10 Specific Studies for the Simulation of Load Management Program.

To investigate the effect of different load management schemes on the reliability and production costs of the system the following studies are performed in this thesis.

1) Direct load management is simulated in two different ways.

a) Loads of any one of the system are reduced by a certain amount during the peak hours of the day. The managed load of the system, may be expressed as

$$\tilde{L}(t) = L(t) - (a\,L(t))\,\lambda_{(t_1,t_2)}(t) \qquad (2.10.1)$$

$0 \leqslant a \leqslant 1$

where $\lambda_{(t_1,t_2)}(t) = \begin{cases} 1 & \text{if } t_1 \leqslant t \leqslant t_2 \\ 0 & \text{elsewhere.} \end{cases}$

and

$\tilde{L}(t)$ = The managed load of the system.

$L(t)$ = The demand of the system.

t_1 = The starting time of the load management scheme which lies during the 24 hours interval of the day.

t_2 = The final time of the load management scheme which lies during the 24 hours interval of the day.

b) The second direct load control approach is to reduce the demand whenever it exceeds a prefixed value. This load control technique may be referred to as constant peak technique. In this case the managed load of the system may be expressed as

$$\tilde{L}(t) = L(t) - (L(t) - cpk)\;\lambda\,(L(t)) \quad \ldots \qquad (2.10.2)$$

where

$$\lambda_{(L(t))} = \begin{cases} 1 & \text{if } L(t) > cpk \\ 0 & \text{otherwise} \end{cases}$$

and cpk is a prefixed constant peak demand.

2. Indirect load management is simulated by shifting the loads from the 'on peak' to 'off peak' period of the day. Loads are reduced during the peak hours through a certain percentage and the total amount of loads thereby reduced are met during the off peak periods through equal increment to the respective hourly loads. In this approach, the total amount of energy requirements for the day remains the same as before.

The managed load $(\tilde{\bar{L}}(t))$ of the system can be expressed as,

$$\tilde{\bar{L}}(t) = L(t) + \frac{1}{N} \sum_{t=t_m}^{t_n} (\quad a\, L(t) \quad) \lambda_{(t_p, t_q)}(t)$$

$$- a \;\; L(t)\; \mu_{(t_m, t_n)}(t) \qquad \ldots \quad (2.10.3)$$

$$0 \leqslant a \leqslant 1$$

where

$$\lambda_{(t_p, t_q)}(t) = \begin{cases} 1 & \text{if } t_p \leqslant t \leqslant t_q \\ 0 & \text{otherwise.} \end{cases}$$

$$\mu_{(t_m, t_n)}(t) = \begin{cases} 1 & \text{if } t_m \leqslant t \leqslant t_n \\ 0 & \text{otherwise.} \end{cases}$$

and

N = total no. of off peak hours at which load is increased.

t_m = starting time of load reduction

t_n = final time of load reduction

t_p = starting time of load increase

t_q = final time of load increase.

3. Energy storage approach is simulated using the pumped storage unit. The energy is stored by pumping water into the reservoir during the low demand period of the day and this water is utilized during the peak demand period of the day to generate electric power. The managed load of the system, can be expressed as,

$$\tilde{\tilde{L}}(t) = L(t) - (a\, L(t))\, \lambda_{(t_1,t_2)}(t) + (b\, L(t))\, \mathbb{1}_{(t_3,t_4)}(t) \qquad \ldots (2.10.4)$$

$$0 \leqslant a < 1$$

where
$$\lambda_{(t_1,t_2)}(t) = \begin{cases} 1 & \text{if } t_1 \leqslant t \leqslant t_2 \\ 0 & \text{otherwise.} \end{cases}$$

and
$$\mathbb{1}_{(t_3,t_4)}(t) = \begin{cases} 1 & \text{if } t_3 \leqslant t \leqslant t_4 \\ 0 & \text{otherwise.} \end{cases}$$

and

t_1 = Starting time of pumping the water.

t_2 = Final time of pumping the water.

t_3 = Starting time of the utilization of the pumped water.

t_4 = Final time of the utilization of the pumped water.

t_1, t_2, t_3, t_4 lie in the 24 hours interval of the day and the value of b depends on the capacity of the pump and the reservoir.

CHAPTER THREE

PUMPED HYDRO-AN ENERGY STORAGE SCHEME

3.1 Introduction.

Hydro electric plants utilize the energy of water to move turbines to which electric generators are mechanically coupled. The energy of water utilized for hydro power generation may be kinetic or potential. The kinetic energy of water is its energy in motion and is a function of mass and velocity, while the potential energy is a function of the difference in level of water between two points, called the head. In either case, availability of water is a basic necessity.

Among all the conventional type power plants, the operation and maintenance costs involved with a hydro electric plant is the lowest, and it generates least environmental pollution. It can be operated as either the base load or peak load plant depending on the nature of the availability of water.

Pumped hydro is a special type of hydro electric plant used for meeting the peak load of the system. Energy storage scheme is the most attractive approach to 'Indirect load management' programme and pumped hydro is a very suitable technique in the implementation of energy storage scheme.

This chapter presents the general concepts and technology involved with pumped hydro as a tool of the implementation of load management programme. This chapter also discusses briefly the general features involved with a conventional hydro electric power plant.

3.2 Selection of Sites for Hydro Electric Power Plant.

The essential characteristics for selecting the site of a hydro electric plant are (i) large catchment area (ii) steep gradient in the area (iii) high average rainfall, (iv) favourable sites for impounding reservoir. The important factors which have to be considered in this selection are:

1) Quantity of water available.
2) Quantity of water that can be economically stored
3) Head of water which can be utilized
4) Distance of power station site from power demand centre
5) Accessibility of the site.

Quantity of water available is estimated on the basis of measurements of stream flow over a long period, Rainfall records taken at various locations in the catchment area for many years serve as a source of data for availability of water. For dependable assessment of water potential, data recorded over a large number of years is desirable. Losses due to evaporation and percolation should be estimated to find the net volume of water available for power generation.

Storage of water is required to maintain its availability during all seasons of the year so that operation of the plant can be ensured at all times. Rainfall usually varies from year to year and also season to season resulting variable river flow. Storage of water helps to smoothen out this non uniformity of flow.

Availability of head of water has considerable effect on the cost of a scheme and economy of power generation. The availability of water heads depends upon the topography of the area. The every increase in head for given output reduces the quantity of water to be stored, and therefore, the capital cost. In order to find out the most effective and economical head, it is necessary to consider all possible factors which may affect it.

3.3 Classification of Hydro Electric Plants.

The Hydro electric plants [16] are generally classified according to

a) availability of head

b) according to the nature of load

c) according to the quantity of water available for generation.

3.3.1 Availability of Head

Again according to the availability of head of water the hydro-electric plants are classified as

1) Low head plants

i) <u>Low head plants</u>

When the available head of water is below 30 meters, the plant is known as the low head plant. In this case, a dam is built across the river to create the necessary head of water. The excess water is allowed to flow over the dam itself. In this case no surge tank is required as the power house is located near the dam itself. Francis, Kaplan or Propeller type turbines are generally used in such power plants.

ii) <u>Medium head power plants.</u>

If the operating head of water lies between 30 and 100 meters, the power plant is known as medium head power plant. The forebay provided at the beginning of penstock serves as water reservoir. In these plants, the water is generally carried in open canals from main reservoir to the forebay and then to the power house through the penstock. The forebay itself works as surge tank in these plants. The common types of prime movers used in these plants are Francis, Propeller and Kaplan.

iii) <u>High head plants</u>.

If the available head exceeds 100 meters, the plant is known as high head plant. The water from the main reservoir is first carried by a tunnel upto the surge tank and then it is carried through penstock (steelpipe) to the power house. The surge tank incorporated in the system reduces the water hammering effects on the penstock. The Francies turbine (upto 300 meters) and pelton wheels are the common prime movers used in high head plants.

3.3.2 Nature of Load

Depending on the nature of loading the hydro plant are classified as (i) Base load unit (ii) Peak load unit or peaking unit.

i) Base load plants.

This type of plants are loaded on the bottom portion of the load curve. The loading level remains more or less constant throughout the operation period. Base load plants are generally large in capacity. The run-off-river and storage type power plant are used as base load plants. The load factor of such a plants is usually high.

ii) Peak load or peaking unit.

The peak load plants are designed primarily for taking care of peak loads of the system. Runoff river plants with pondage and pumped storage plants are generally used as peak load plants. In case of runoff river hydro plants with pondage, a large pond is essential and extensive seasonal storage is usually provided. They store the water during off peak period and supply during peak periods on the top of the load curve. The load factor of peak load plants is considerably low compared to base load plants.

3.3.3 Quantity of Water Available.

Depending on the availability of amount of water the hydro-electric plants are classifed as,

i) Run-off river plant without pondage (16,17)

This type of plant does not store the water and uses the water as it comes. This type of plant has no control over the river flow. Therefore, water is wasted during low load and high flood conditions. During dry seasons, the capacity of the plant goes down due to the low flow rates of the water. Essentially, these plants lack the assurance of continuous constant supply.

ii) Run-off river plants with pondage. (18)

The usefulness of the run off river plant is increased by incorporating the pond in the plant. The pond permits to store water during off peak hours and uses during peak hours of the same day. Pondage increases the stream capacity for a short period, a hour or week depending on the capacity of the pond. The tail race condition should be such that the tail-race water level should not increase during floods because it reduces the effective head of the plant. This type of plant can be used as a base load or peak load plant.

iii) Storage reservoir plants. (19)

A storage type plant is one with a reservoir of sufficient size to permit carry-over storage from the wet season to the dry season and thus to supply firm flow substantially more than the minimum natural flow. This plant can be used as base load as well as peak load plant as sufficient water is available as required. The majority of the hydro-electric plants are of this type.

iv) Pump storage plants.

Pump storage plants (to be discussed in detail later) are generally used for peak load plants. If there is a storage of water at a particular location, then the water after passing through the turbine is pumped back from the tail race to the head race during the off-peak periods provided the ponds are constructed at head water and tail water locations. This type of plant generates power for peak load but during off-peak period, water is pumped from tail water pond to the head water pond for future use.

3.4 Design of Water Head

The principal factors involved in capacity calculations are: i) quantity of water and (ii) available head. The difference of elevation between the head water and tail water of a plant constitutes the gross head. The entire head is not effective in producing power as part of it is lost during passage of water from pond to the turbine runner. These losses are loss in penstocks and conduits, loss in the entry to scroll, and loss in tail race.

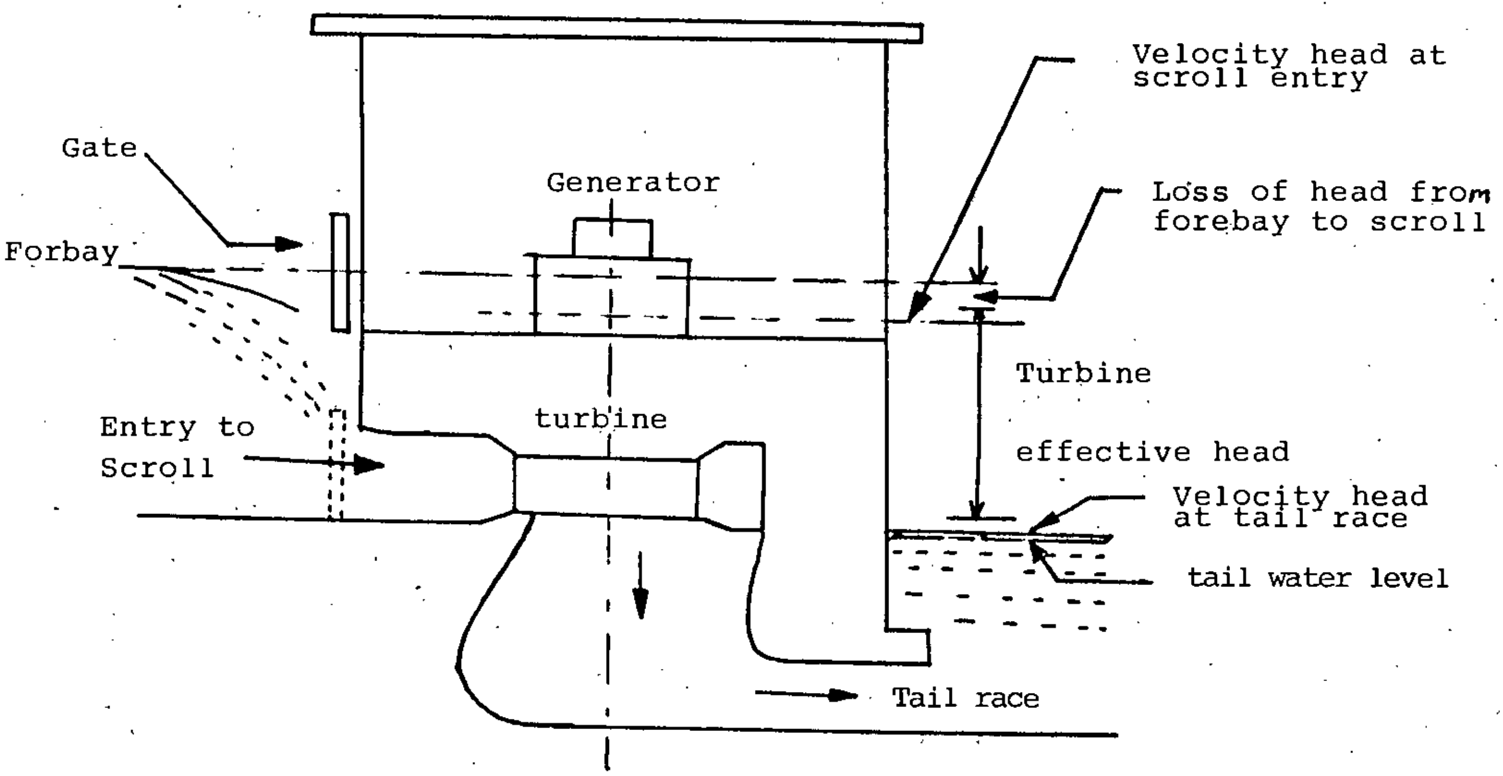


Fig.3.1: Schematic diagram of a power plant.

The difference between gross head and the sum of all losses gives the net or effective head. A schemic diagram showing different losses are shown in fig. 3.1.

The American Society of Mechanical Engineers has defined effective head for reaction turbines as "the difference between the total energy contained in the water immediately before its entrance into the turbine and its total energy immediately after discharge from the draft tube". Or this may be taken as the difference between the elevation corresponding to the pressure head in the penstock at the entrance to the turbine casing and the elevation of tail water, this difference being corrected by adding the velocity head in the penstock at the section of measurement and subtracting the residual velocity head at the section of measurement in the tail race.

3.4.1 Hydro Power Capacity.

Energy available from stored water can be calculated from the relation:

$$E = VW\,(H_g - h_f) \times \eta \qquad \ldots \qquad (3.1)$$

Where E is the energy

V is the volume of water flowing through the turbine

W is the unit weight of water

H_g is the gross head.

h_f is the head lost in the system above entrace to the scroll and below draft tube exit

η is the plant efficiency

3.5 General Arrangement of a Storage Type Hydro-electric Project and its Operation.

The storage type hydro electric projects have large contents of water and the water collected during heavy rain period is supplied during dry period of the year. The collection of water is done on seasonal basis (yearly),therefore, the capacity of reservoir required is extremely large compared with other types of hydraulic power plants.

Majority of the hydraulic power plants used now are storage type. The arrangement of the different components used in this type of plant is depicted in fig. 3.2.

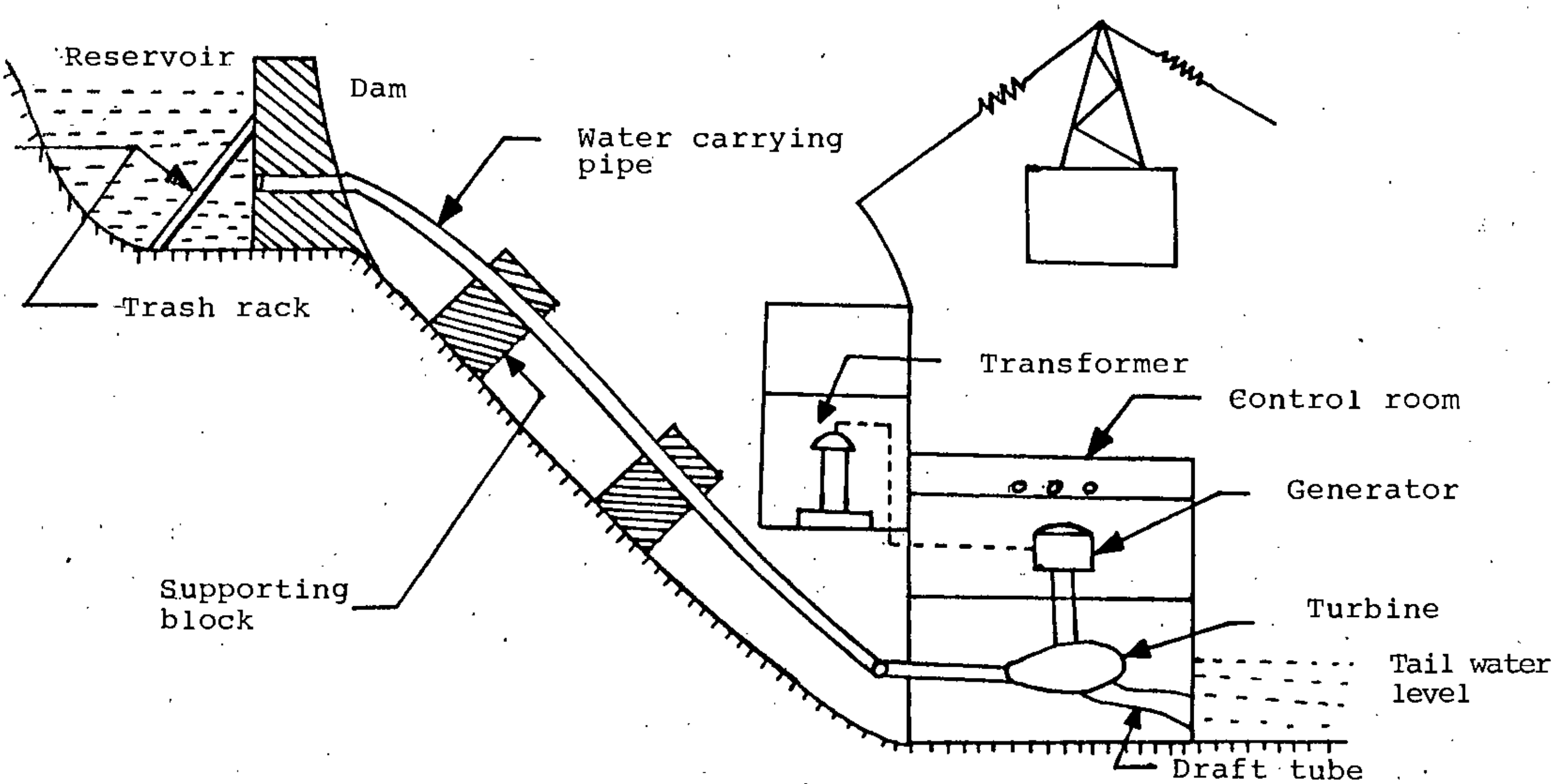


Fig. 3.2: General arrangement of a hydroelectric plant.

The basic requirement of a hydro electric power station is a reservoir where large quantity of water is stored during flood season and used during dry season. The reservoir is generally built by constructing a dam across a river. The water from the reservoir is drawn by the forebay through an open canal or tunnel. The water from the forebay is supplied to the turbine (prime mover) through the penstock which is located at much lower level than the height of the reservoir. The water entering the turbine rotates the turbine shaft to which the generator shaft is coupled.

The different components used in storage type hydraulic power plant along with their functions are briefly described below.

3.5.1 Reservoir.

The natural stream of water, used for hydro electric project, may be unable to satisfy the demands of its consumers, especially during the dry season. A huge amount of water flows during the rainy seasons while the flow rate is very low during the dry season. Therefore, it is required to store water when the rate of water flow is high. A storage used to retain such excess water from high flow periods to low flow period is commonly known as reservoir. The main function of the reservoir is to supply the water according to demand by regulating the quantity of water. The capacity of the reservoir on natural sites is determined with the help of topographic surveys as its shape is always irregular.

3.5.2 Dam

The function of the dam is to increase the height of water level which ultimately increases the reservoir capacity. The dam also helps to increase the working head of the power plant. Most of the times high dams are built only to provide the necessary head to the power plant.

3.5.3 Trash Rack.

The water intakes from the dam or from the forebay are provided with trash rack to prevent the entry of debris which might damage the wicket gates and turbine runners. If the winters are severe, special provision is made to prevent the trouble from ice. To prevent ice from clinging to the trash racks, they are often heated electrically. Sometimes an air bubbling system is provided in the vicinity of the trash rack which brings warmer water to the surface of trash rack.

3.5.4 Forebay

The forebay serves as a regulating reservoir. It stores water temporarily when the load on the plant is low and it provides water for initial increment of an increasing load while water in the canal is being accelerated. In many cases, the canal itself may be large enough to absorb the flow variations. If the canal is long, its end is sometimes enlarged to provide necessary temporary storage. In short, forebay is a naturally provided storage which is able to absorb the flow variations. The forebay is always provided with some type of outlet structure to direct water to the penstock depending upon local conditions.

3.5.5 Surge Tank.

There may be sudden increase of pressure in the penstock due to sudden closing of the gates admitting water to the turbines. This happens when the load on the generator decreases. This sudden rise of pressure in the penstock above normal due to reduced load on generation is known as'water hammer'.

If the turbine gates suddenly open to supply more water to the turbine to meet an increased demand, water has to rush through the penstock and there is a tendency to cause a vaccum in the system. The penstock must withstand the positive hammer caused by sudden opening of turbine gates and no vaccum should be produced in the system when the gates suddenly open. A surge tank is introduced in the system between the dam and the power house and close to the power house, preferably on the high ground to reduce the height of the tower to provide better regulation of water pressure in the system during variable load. It reduces the 'water hammering' effect.

A simple surge tank is a vertical standpipe connected to the penstock as shown in fig. 3.3.

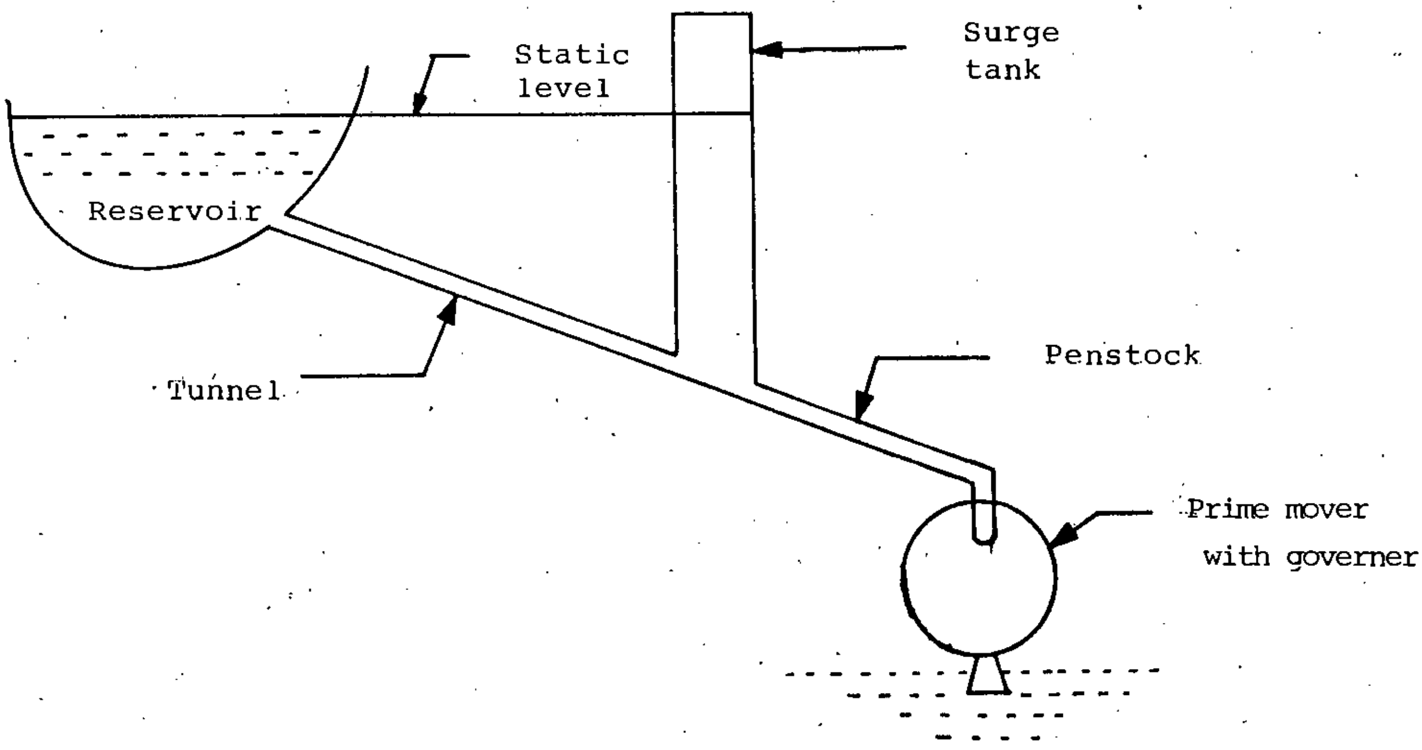


Fig. 3.3: Simple surge tank connected to a penstock.

When the turbine gates are partly closed, reduced water flows into the turbine and water rises in the surge tank. This produces retardation and decreases the velocity of water in the penstock. When the velocity of water in the penstock is reduced, the level of the water in the surge tank starts falling and fluctuates up and down till its motion is damped out by friction. When there is sudden rise in the load on the turbine, additional water is supplied from the surge tank. This lowers the water surface in the surge tank thus producing an accelerating head which increases the flow of water in the penstock. The surge tank thus helps in stabilising the velocity and pressure in penstock and reduces the water hammer effect.

3.5.6 Penstock.

A pipe between the surge tank and prime mover is known as the penstock. The structural design of the penstock is same as any other pipe. It is supposed to withstand very high pressure on inside surface during decreased load as well as onside surface during increased load. Penstocks are most commonly made of steel through reinforced concrete.

3.5.7 Spill Way.

Spill way is considered as a safety valve for a dam. It must have the capacity to discharge major amount of water without damaging the dam and at the same time keeps the reservoir level below some predetermined maximum level.

3.6 Pump Storage Power Plant.

These projects involve pumping of water into the reservoir during off-peak or low load periods, so that additional supply of water is available during high load periods. pumping may be for two categories of storage, (i) seasonal and (ii) periodical. Seasonal storage augments the reservoir capacity during low periods of the stream while the periodical storage builds up additional plant capacity for daily peak load supply. The energy for pumping water is obtained from the plant itself or from the grid.

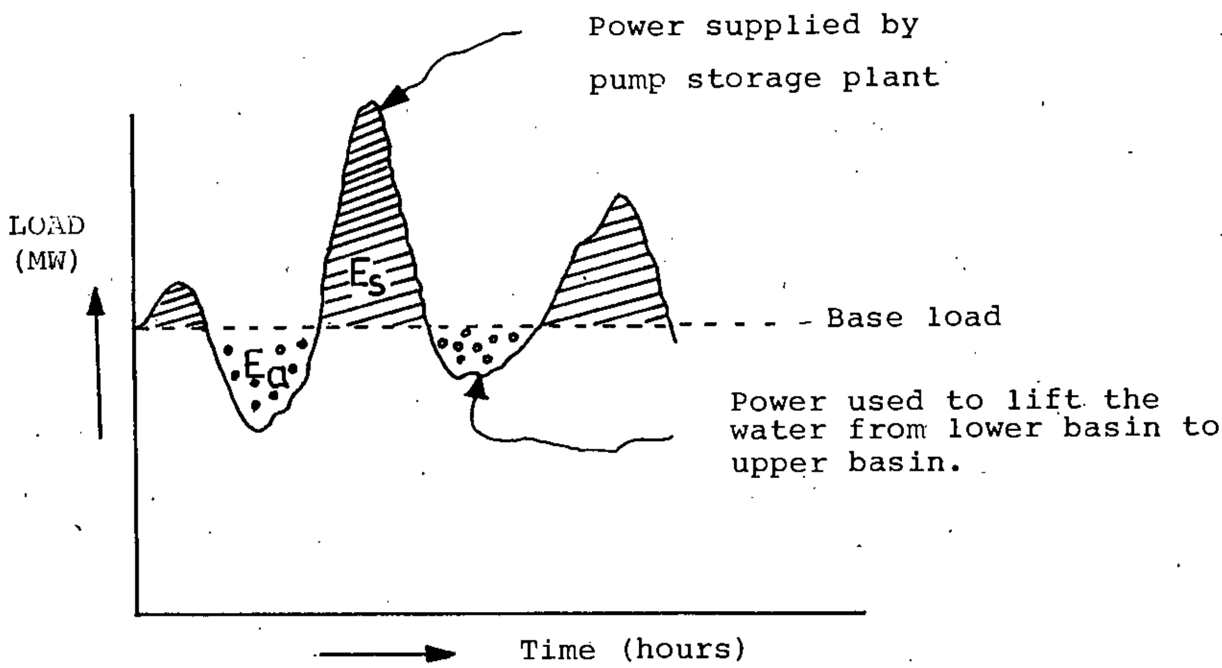


Fig. 3.4: Load curve

Fig. 3.4 shows a typical load curve. The hatched area represents the energy supplied by the pumped storage plant while the dotted area represents the energy required to pump water into the reservoir. The surplus available energy (Ea), during off peak period, is stored in the form of hydraulic potential energy by lifting the water from lower basin to higher basin. The same stored hydraulic energy is used during peak load period by supplying the water from the upper basin to the turbine. A typical pumped storage plant in conjunction with a thermal plant is shown in fig. 3.5. The quantity of water pumped back may be equal to the water passing through the water turbine during peak load period or part of that depending on the requirements.

The energy requirement for a pump storage plant may be expressed

$$E_p \eta = E_s \qquad (3.2)$$

where η = the efficiency of the pump storage plant.

E_s = Energy supplied by the pump storage plant

E_p = Energy required to pump water into the reservoir.

3.6.1 Physical Arrangement of a Pump Storage Plant.

The pump storage plants comprise normal turbogenerator with the addition of centrifugal pump. The centrifugal pump may be either coupled directly to the turbogenerator in which case, during pumping cycle, the generator is used as motor to drive the pump or it may be an independent unit driven by separate motor.

The early pump storage plants consisted of a synchronous generator set capable of serving also as a synchronous motor with the turbine and pump units mounted on a common shaft. Coupling were provided so as to enable the turbine to be disconnected and thereby eliminate turbine losses during pumping. Now, the turbine and pump units are combined in a single reversible machine. This arrangement allows the capital cost of the machine and power-house to be reduced substantially.

The reversible hydraulic machine operates as turbine when revolving in one direction and as a pump when rotates in the opposite direction. With reversible hydraulic machines, no continuous change- over from one operation to other is possible. The machine set must be brought to complete standstill for every change over.

3.6.2 Efficiency and Time Schedulling of the Pump Storage Plant.

The time available for pumping water is the time during which the demand is below the base load.

The time t_2 and t_4 as shown in fig. 3.6 is the time for pumping the water during off peak&the time t_1 and t_3 is the time during which the water is supplied for generating electricity.

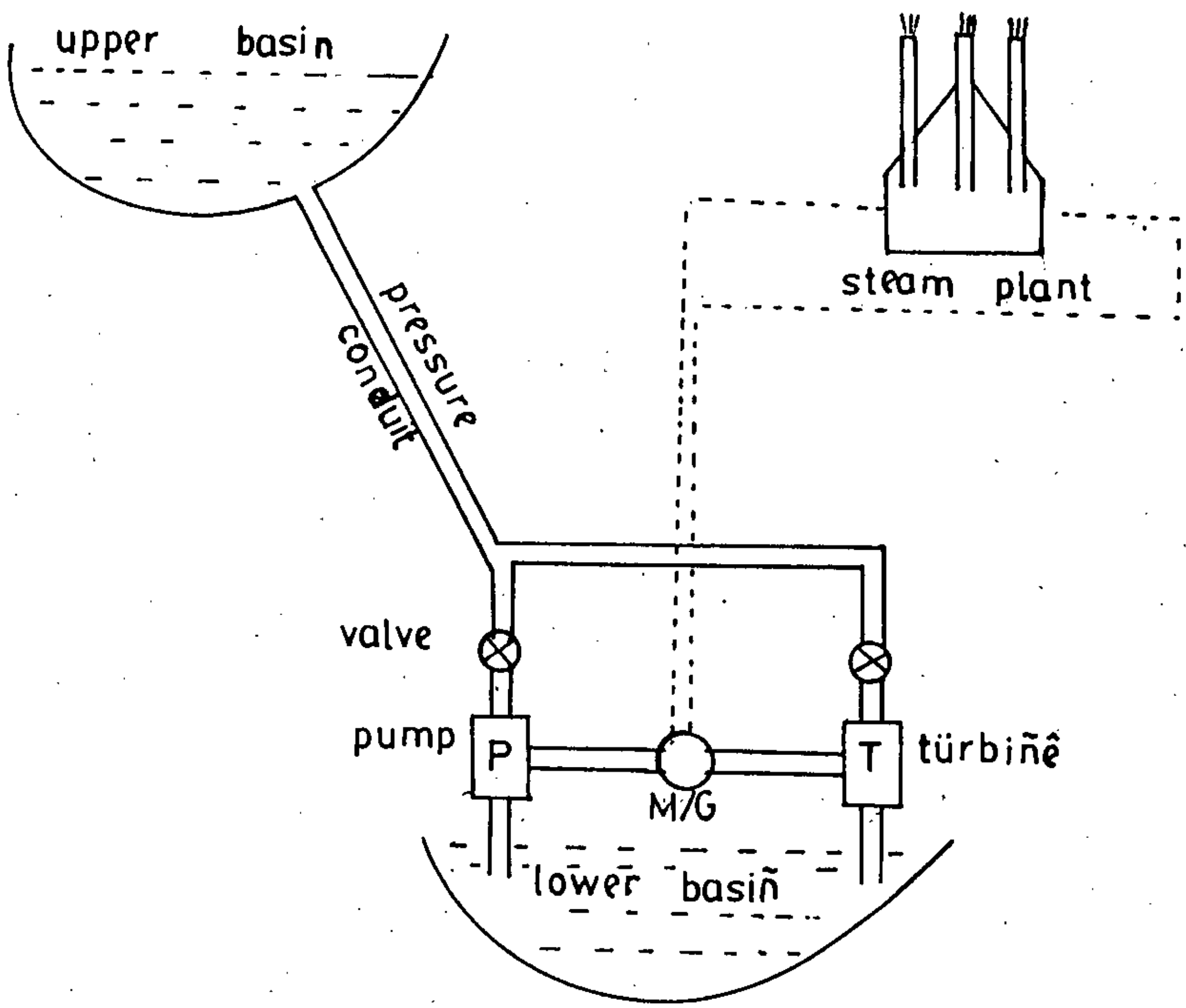


Fig. 3.5: Pumped storage power plant for peak load in conjunction with steam plant.

For ideal condition the efficiency of pumped storage plant may be expressed using equation (3.2) as:

$$\eta = \frac{E_s}{E_p} \tag{3.3}$$

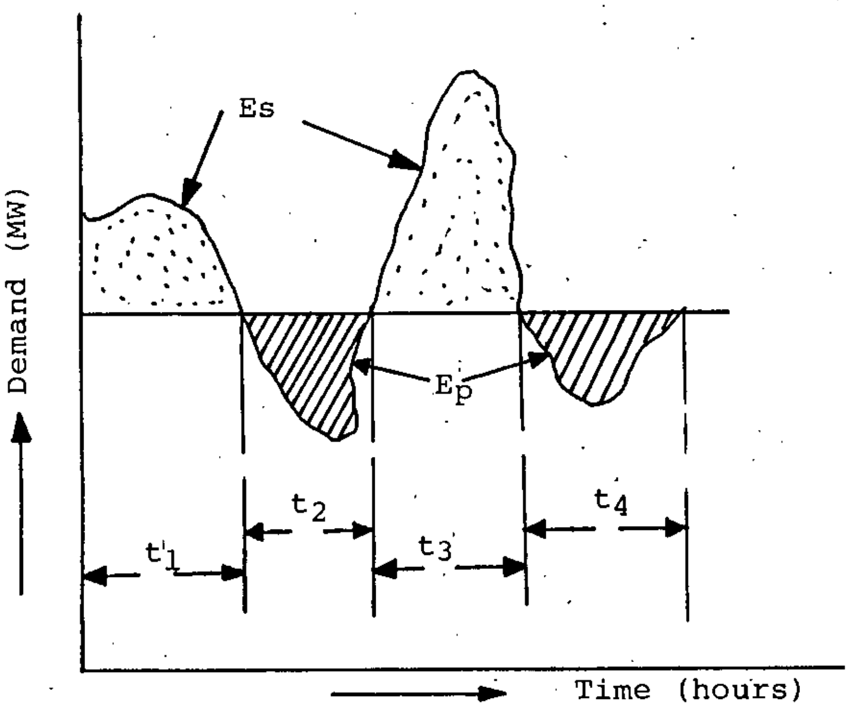


Fig. 3.6: Load curve

The total quantity of water pumped by the pump during off peak period and total quantity of water supplied to the turbine during peak period must be same to maintain equilibrium of the system. If Q_p is the total quantity of water pumped in time $(t_2 + t_4)$ hours and Q_p is the quantity of water passed through the turbine in time $(t_1 + t_3)$ hours, then E_p and E_s may be expressed in terms of quantity of water and water head as

$$E_p = \frac{Q_p}{(t_2 + t_4)} \cdot \frac{\rho . H}{75 \times 3600} \times \frac{1}{\eta_p} \times 0.736 \; (t_2 + t_4) \text{ kw - hrs.}$$

... (3.4)

and

$$E_s = \frac{Q_p}{(t_1 + t_3)} \cdot \frac{\rho . H}{75 \times 3600} \times \eta_t \times 0.736 \; (t_1 + t_3) \text{ kw hours.}$$

... (3.5)

where η_p = efficiency of the pump

η_t = efficiency of the turbogenerator system

Q is expressed in cum/sec

ρ is kg/cum and

H is in meter.

Note that 1 water H.p (metric) = 75 kgm/sec.

From (3.4) and (3.5)

$$\frac{E_p}{E_s} = \frac{1}{\eta_p . \eta_t} \tag{3.6}$$

The common value of η_p and η_t are 0.8 and 0.9

$$\frac{E_p}{E_s} = \left(\frac{1}{0.8 \times 0.9} \right) \approx 1.4 \tag{3.7}$$

Therefore, per kw-hr energy developed by the water turbine during peak period requires nearly 1.4 kw-hr energy to be supplied to the pump during off peak period.

Generally the pumping of water from the lower basin to an upper basin is done during the late hours of night and the same stored energy (hydraulic form) is used during peak periods. The time period allowed for pumping may vary from 4 to 10 hours according to the nature of the load curve. The reservoir capacity depends upon the total time base used for plant operation. The size of the reservoir on week basis would be greater than the size of the reservoir on day basis because the pumping will be done only at the week end (sunday) if the selected time base is a week.

3.6.3 Economic Assessment of Pump Storage Plant.

Usually 1.5 kw-hr energy is required in pumping water to get each kw-hour energy from the pump storage plant. However, the operation is economically justified because of the price of peaking power in contrast to the relatively lower price of power used in pumping. Further, the pump storage plant in conjunction with thermal power plant can substantially reduce the size of the thermal plant and increase the flexibility to meet emergency requirements. This is exemplified in what follows.

A) Consider the hourly load curve shown in Fig. 3.7. To meet the demand, a thermal plant of 100 MW capacity will generate

$= 100 \times 0.44t + 84 \times 0.16t + 60 \times 0.4t.$

$= 44t + 13.44t + 24t = 81.44t$ MW-hours.

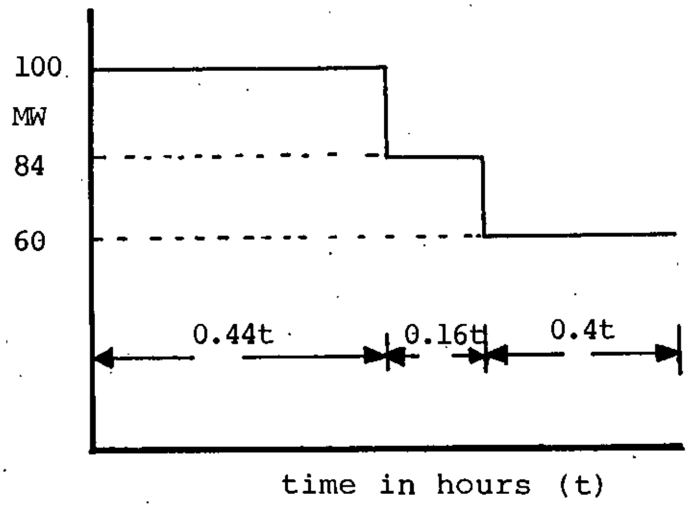


Fig. 3.7: Hourly load curve.

Also consider 40%, 35% and 30% thermal efficiencies of the thermal plant for 100%, 84% and 60% output respectively. Now to generate 81.44t MW hr of energy the thermal plant require

$$= \frac{100 \times 0.44t}{0.4} + \frac{84 \times .16t}{0.35} + \frac{60 \times 0.4t}{0.3}$$

$$= (110t + 38.4t + 80t)$$

$$= 228.4t \text{ MW hours of input}$$

Therefore, the overall efficiency of the plant

$$\text{is} = \frac{\text{Total output}}{\text{Total input}} = \left(\frac{81.44t}{228.4t}\right)$$

$$= 35.6\%$$

Instead of installing a thermal plant of 100 MW capacity, consider that thermal plant of 84 MW capacity connected with a pump storage system is installed. Also consider that the plant generates 84 MW all through the period. During the off peak period the extra thermal energy of the thermal plant can be used for pumping the water and the same water is used to generate the power during peak period. The total thermal input to the thermal plant in this case as it is working at full load throughout the period is

$$= \left(\frac{84 \times t}{0.4}\right) = 210t \text{ MW hours.}$$

where 40% is the full load efficiency of the thermal plant.

The total output = output of thermal + output of pump storage plant.

$$= 84 \times 0.6t + 60 \times 0.4t + (84-60) \times 0.4t \times 0.7$$

$$= 50.4t + 24t + 6.72t$$

$$= 81.12t \text{ MW hours.}$$

where 0.7 is the overall efficiency of the pump storage plant.

Overall efficiency of the combined plants (thermal + pump storage)

$$= \frac{\text{Total output}}{\text{Total input}} = \left(\frac{81.12t}{210t}\right) = 38.7\%$$

This numerical example reveals that thermal plant in conjunction with pump storage plant increases the overall efficiency and decreases the capacity of the thermal plant.

CHAPTER FOUR

PROBABILISTIC SIMULATION

4.1 Introduction.

The principal objective of an electric utility is to ensure an economic supply of electrical energy to consumers maintaining a desired level of reliability. In the generation expansion planning process, it is a complicated task to select a plan suitable for a particular utility. Utility planners evaluate the different alternative plans interms of the reliability and economic factors. The plan involving the lowest cost, which also satisfies the desired level of reliability and environmental regulations is finally selected.

The main theme of this chapter is concentrated on the 'probabilistic simulation' of generation and load models of an utility system as it would be followed in the reliability assessment. Different types of costs involved with the generation system are also briefly discussed in the chapter.

4.2 Power System Reliability.

Reliability[20] is the probability of a device or system performing its purpose adequately for the period of time intended under the operating conditions encountered. In order to quantify the reliability of power system a number of reliability indices have been deviced. Some of commonly used indices are described in what follows.

i) Loss of load probability (LOLP)

The loss of load probability (LOLP) is the probability that the available generating capacity of a system will be insufficient to meet its demand.

Thus,

$$LOLP = prob\,(AC < L) \qquad (4.1)$$

where, 'AC' and 'L' are the available capacity and system load respectively.

The evaluation of LOLP take into consideration of forced and scheduled outages of generating units as well as load forecast uncertainty and assistance due to interconnections. LOLP does not give an indication of the magnitude or duration of the generation deficiency. This reliability index only provides the probability of occurrence of the loss of load. The LOLP for a system is a realistic indication than the reliability figure for an individual machine operating in the system or even of a section of the power system. As LOLP is the simplest and most commonly used reliability [22,23] index especially for the whole of a power system, it will be used in this thesis for evaluating the impact of load management on the reliability of power system.

ii) Loss of energy probability (LOEP)

The ratio of the expected amount of energy not supplied during some long period to the total energy required during the same period is defined as the loss of energy probability. It reflects the frequency, magnitude and duration of the capacity outage.

iii) Frequency and duration (FAD) (24)

This gives the average number of times and average length of time during which available generation is inadequate to supply the load. This requires consideration of load cycle and data on the frequency and duration of unit outages. One problem with FAD technique is that it requres more detailed data than is usually available. In addition to failure rates of various components, repair times must also be available.

iv) Monte carlo simulation (MCS)

In MCS, the actual realization of the life process of a component or a system is simulated on the computer and, after having observed the simulated process for some time, estimates are made of the desired reliability indices. MCS is best suited to the problems in which reliability is significantly affected by system operating policies.

4.3 Generating Capacity Model.

Different types of generating units are in use today and all types of units are randomly forced off line because of technical problems during normal period of operation. To consider the random outages or availability of a unit, it is necessary to determine the probability density function(PDF) that describes the probability that a unit will be forced off line or will be available during its normal period of operation. It may be assumed on the basis of historical data that the availability of the generating capacity of a given unit may be graphically represented as shown in figure 4.1. This figure conveys the idea that random failure and repair of a unit can be defined as a two-state stochastic process. By the way a stochastic process is defined as a process that develops in time in a manner controlled by probabilistic laws.

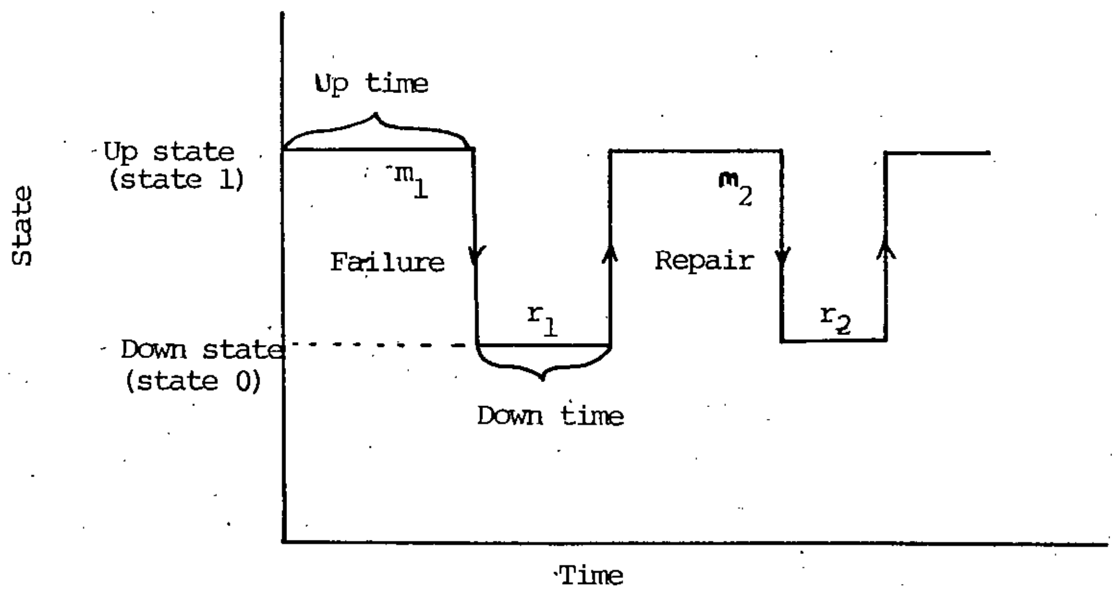


Fig. 4.1 : Run-fail repair-run cycle for a generating unit.

The figure 4.1 represents that the system alternates between an operating state, or, up state, followed by a failed state, or down state, in which repair is effected. For the i-th cycle, let

m_i = up time

r_i = down time

The average up time and an average down time may be expressed as,

$$m = \text{mean up time} = \frac{1}{N} \sum_i m_i$$

$$r = \text{mean down time} = \frac{1}{N} \sum_i r_i$$

where N is the total number of run-fail-repair-run cycles. Thus the unit failure rate λ and the repair rate μ may be expressed as

$$\lambda = \text{unit failure rate} = \frac{1}{m} \quad (4.2)$$

$$\mu = \text{unit repair rate} = \frac{1}{r} \quad (4.3)$$

With these two parameters the random failure and repair of a generating unit can be defined as a state-space diagram (two state) as shown in figure 4.2.

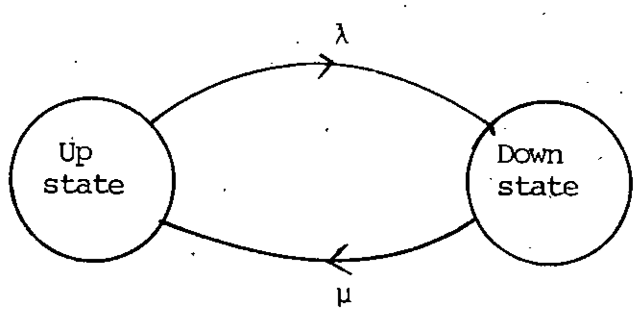


Fig. 4.2: Generating unit state-space diagram.

The traditional term for the unit unavailability is 'forced outage rate' (FOR), a misnomer in fact, since the concept is not a rate. An estimate for this important parameter may be given by

$$\text{FOR} = \frac{\text{Foreced outage hours}}{\text{Forced outage hours + service hours}}$$

or,
$$\text{FOR} = \frac{\text{FOH}}{\text{FOH + SH}}$$

From the two state model of figure 4.2 the probability density function of available and forced outage capacity of a generating unit may be depicted as in figure 4.3.

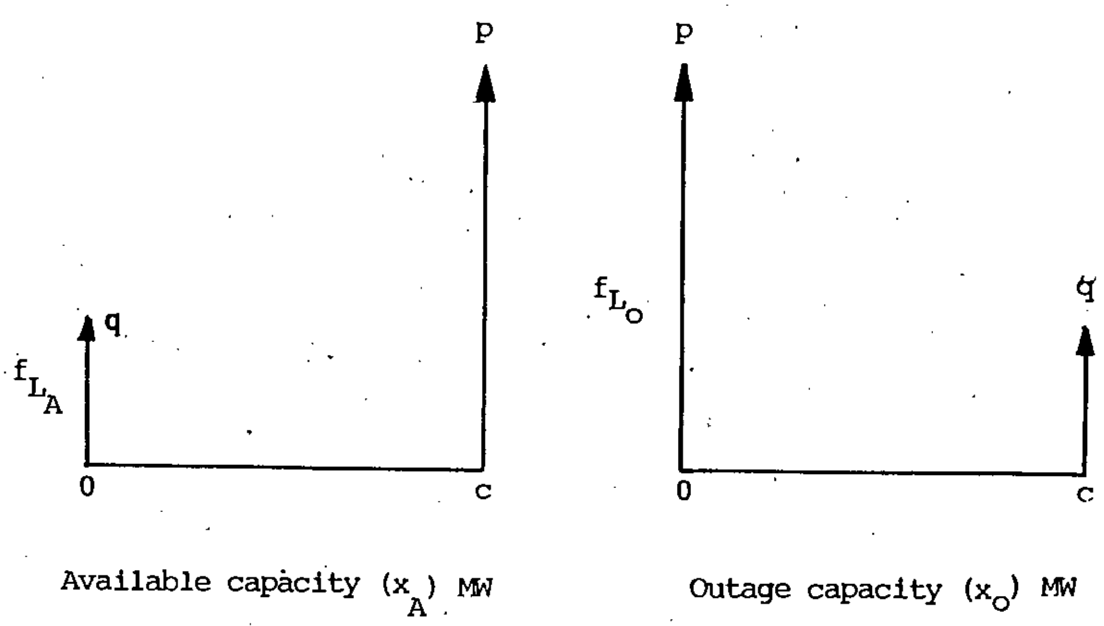


Fig. 4.3: PDFs of available and forced outage capacity

The PDF of forced outage capacity may be conventionally expressed as

$$f_{Lo}(x_o) = P\delta\ (x_o) + q\delta\ (x_o - c) \tag{4.4}$$

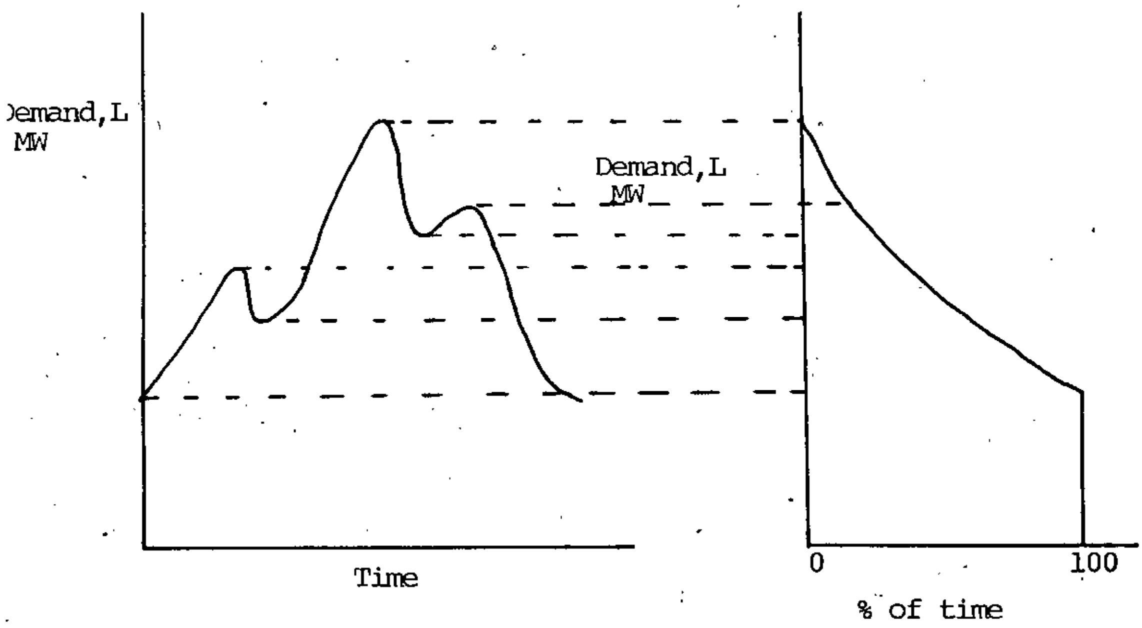
where

f_{Lo} = PDF of forced outage capacity

$\delta(.)$ = Dirac-delta function.

4.4 Probabilistic Load Models.

The proper modelling of load is an important factor in the probabilistic simulation. The data required to develop probabilistic load model are readily available, since continuous readings of system demand and energy are usually obtained on a routine basis by electric utilities. If a recording of instantaneous demands were plotted for a particular period of time, a curve such as depicted in Fig. 4.4(a) might result. This is known as the'chronological load curve' (CLC). From this curve the so called load duration curve in Fig. 4.4(b) is easily constructed. The load duration curve is created by determining what percentage of time the demand exceeded a particular level.



a) Instantaneous demand vs time   b) Load duration curve

Fig. 4.4 Chronological load curve and load duration curve.

4.4.1 Load Probability Distribution

For generation system studies it is necessary to interchange the axis parameters in figure 4.4(b) and normalize time, producing the load probability distribution in fig. 4.5 where the y-axis shows the probability that the load exceeds the corresponding x-axis megawatt value. This load distribution will be denoted generally by $F_k(L)$, where k indicates the time period for which the distribution is applicable.

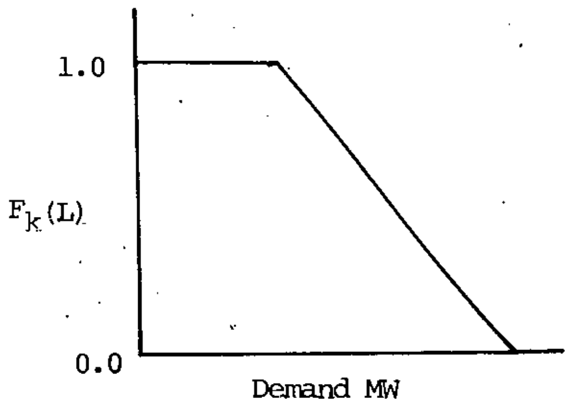


Fig. 4.5 Load probability distribution for week k.

4.4.2 Development of Hourly Load Model.

Hourly load model is often used in various probability methods for evaluating LOLP and production cost.

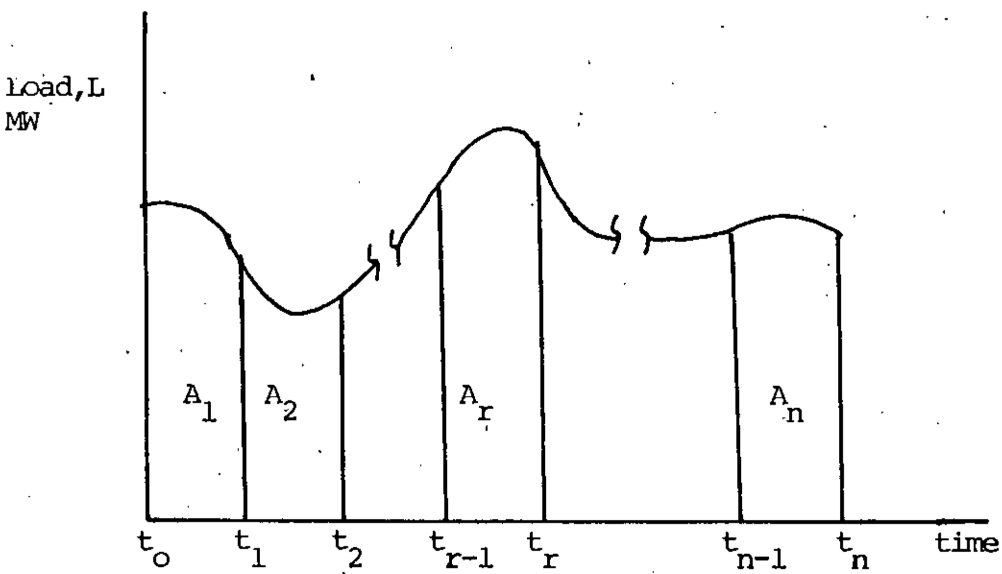


Fig. 4.6: CLC with time axis divided into n small intervals.

Figure 4.6 shows a chronological load curve (CLC) depicting the changes in instantaneous demand with respect to time. The time axis is divided into a number of small intervals between times t_o, t_1, t_2 ... t_{r-1}, t_r,..... t_{n-1}, t_n.

In the figure, the energy demand during the period between t_{r-1} and t_r is given by the area A_r under the CLC between t_{r-1} and t_r. Hence

$$A_r = \int_{t_{r-1}}^{t_r} L dt \qquad (4.5)$$

The average load during the period of time (t_r - t_{r-1}) can be obtained by dividing the area by the time period.

$$L^r_{avg.} = \frac{A_r}{t_r - t_{r-1}} \qquad (4.6)$$

In this way, the average load for all other time intervals can be calculated. If the average load for each time interval is assumed to remain constant for the corresponding interval, then a distribution of load as shown in fig. 4.7 will result. Note that by such construction of load curve, the energy demand for each interval assumed constant.

If the time intervals is equal to one hour then the resulting load curve is called hourly load curve.

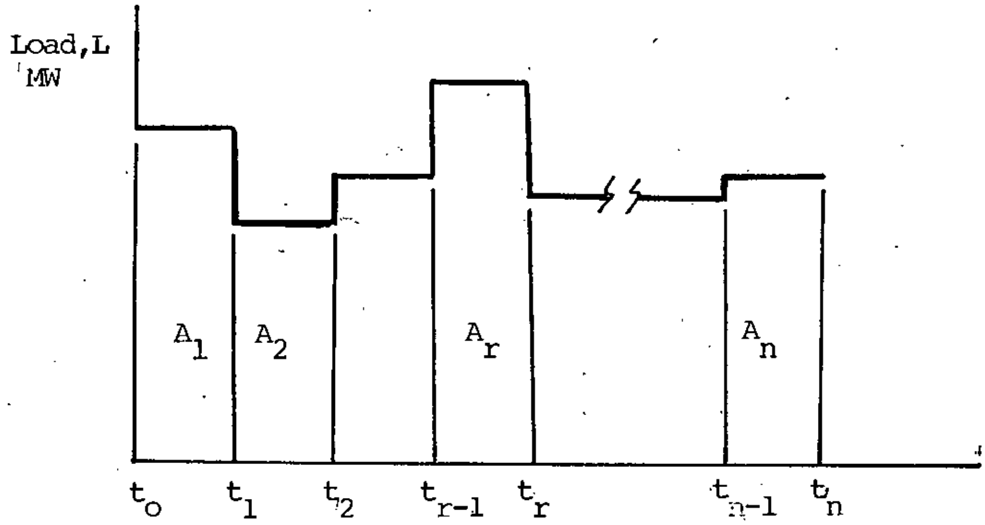


Fig. 4.7: Load distribution assuming constant load for each small interval.

4.4.3 Effective Load.

The randomness in the availability of generation capacity is taken into consideration by defining a fictitious load, known as 'effective load' (L_e)[25]. Figure 4.8 depict the relationship between the system load and generating units, where actual units have been replaced by fictitious random loads; whose probability density functions are the outage capacity density functions of the units.

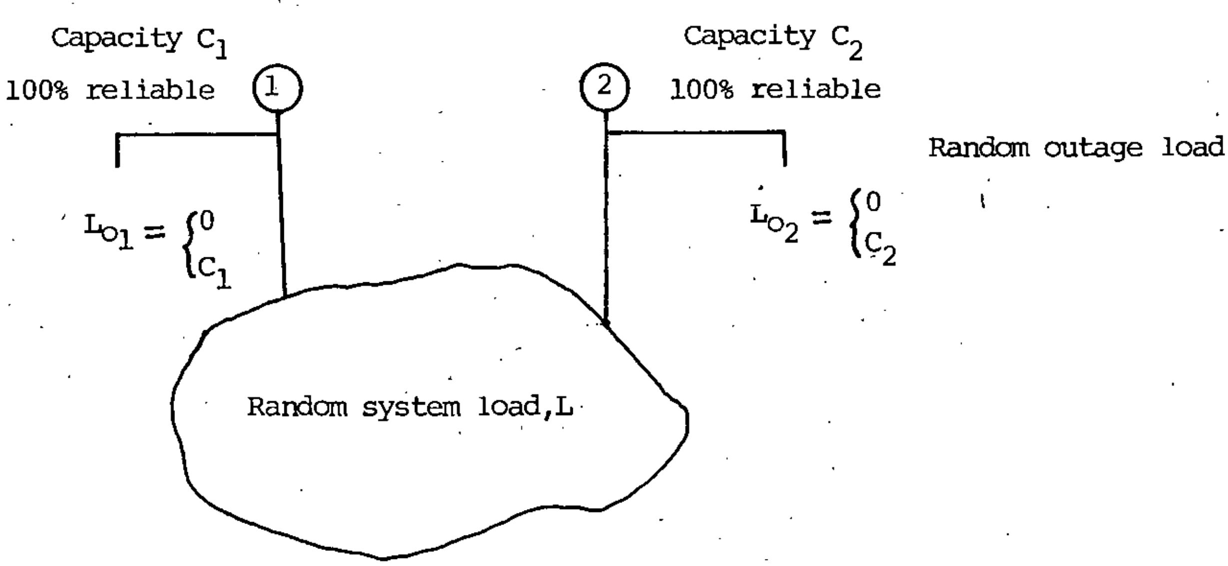


Fig. 4.8: Fictitious generating unit and system load model.

If Lo_i represents the randon outage load corresponding to the i-th unit, the equivalent load (L_e) may be expressed as

$$L_e = L + \sum_{i=1}^{n} Lo_i \tag{4.7}$$

where n is the total number of generating units. When $Lo_i = C_i$, the net demand injected into the system is zero for the i-th unit, just as it would be if the actual unit of capacity C_i were forced off line.

Note that the installed capacity of the system is given by

$$IC = \sum_{i=1}^{n} C_i \tag{4.8}$$

The outages of the generating units may be assumed independent of the system load. Then the distribution of the equivalent load will be the outcome of convolution of two distributions: f_{Lo} and f_L representing the PDFs of the outage capacity and the system load respectively. For the discrete case the PDFs, f_L and f_{Lo} respectively, may be written as

$$f_L\ (l) = \sum_i P_{L_i}\ \delta(l-l_i) \tag{4.9}$$

$$f_{Lo}\ (l_o) = \sum_j P_{Lo_j}\ \delta(l_o-l_{o_j}) \tag{4.10}$$

Then the PDF of equivalent load f_{Le} may be given as

$$f_{Le}\ (l_e) = f_L\ (l) * f_{Lo}\ (l_o)$$

$$= \sum_{i,j} P_{L_i}\ P_{Lo_j}\ \delta(l_e - (l_i + l_{o_j})) \tag{4.11}$$

where * indicates the convolution and P_L and P_{Lo} are the probabilities of load and outages of machine respectively. The small case letters within bracket of equation (5.30) are the values of the corresponding random variables (RV_s).

4.5 Cost Analysis

The main components which enter into the determination of revenue requirements for a generation expansion are;

i) capacity cost

ii) production cost

iii) operating and maintenance cost

Besides these three major factors, timing of unit additions is also important in cost analysis.

4.5.1 Capacity Cost.

Uitilities require a very high investment in plant and equipment in comparison to annual revenues and annual operating cost. The relative high plant investment is the most distinguishing characteristic of an electric ulity. Factors which affect capacity costs include type of generating unit, unit size, site, depreciation, taxes, labour costs, environmental requirements, capital and financing costs.

The capacity cost of unit i, denoted by CC_i, is usually expresses as

$$CC_i = FCR_i \; UC_i \; C_i \quad (\$) \tag{4.12}$$

where

FCR = Fixed charge rate,

UC = Unit capacity cost ($/MW)

C = Capacity of the unit (MW).

The fixed charge rate reflects the annual amount of revenue requirement to pay for the facility over its life time, and is designed to meet the annual costs associated with capital investment. In general, the FCR consists of depreciation, income taxes and annual return (interest on debt, dividends on preferred stock and earnings on common equity). Unit capacity cost is self explanatory. In order to convert the capacity cost into equivalent annual revenue requirements a carrying charge rate is used. The carrying charge reflects the levelized annual amount of revenue requred to pay for the facility over its life span. The carrying charge rate begins to flow once construction begins, which is not uniform over the period.

4.5.2 Production Costs.

Production costs, the second important component in evaluating the cost of a particular expansion plan, can be accurately determined only if

i) realistic load model for the future period under consideration can be developed.

ii) the commitment of the units to supply load can be realized in such a way that reflects the actual operating procedures and conditions.

The estimation of the energy production cost of an electric utility is by far the most complex part of cost analysis associated with a particular expansion plan. It depends on the loading order procedure, availability of units, and the demand for electric energy in the day to day operation of the system, which are highly variable and unpredictable, especially when the calculation extends far into the future. Production cost associated with unit i is given by

$$EC_i = FC_i + OM_i$$

where EC = production or energy cost in $\$$

FC = fuel cost in $\$$

OM = operation and maintenance in $\$$

Since for a particular type of generating unit, operation and maintenance cost are approximately fixed in nature, it is the cost of fuel which varies with amount of energy generation.

4.5.3 Operating and Maintenance Cost.

These costs include all fixed non-production costs such as labour, supplies and materials required to maintain and operate a plant, and in the case of a Nuclear plant also the heavy water up keep plus any additional security and insurance costs, etc. The operation and maintenance cost also include all variable costs associated with preparing the unit for daily operation. Essentially these cost do not depend on the amount of energy produced. Data regarding operating and maintenance cost are estimated on an annual basis in order to be integrated into the economic analysis.

4.6 Economic Commitment Schedule.

In reliability assessment, it is the number of units and their PDFs which account for the value of LOLP rather than the order in which the units are loaded. However, in cost analysis, to determine the minimum production the loading order of units is very important. The schedule for the commitment of units in the order of their increasing incremental cost for the economic operation of the system is called 'economic commitment schedule (ECS)' or merit order of loading.

The basic concept underlying the loading order procedure is that the generating units are loaded in the order of their average incremental costs. The most efficient generating unit is the one with the lowest incremental cost, this generating unit is loaded first. Next in line is the generating unit with again the lowest incremental cost among the set of the remaining units. The economics of the generating units are governed by performance parameters such as the heat rate and price of fuel used by the units. In actual operation, it is seldom economical to commit one generating unit fully before another unit is loaded. To simulate this fact the generating unit capacities are segmented into several capacity blocks. Generally, lower segments of large units are commited before committing any particular unit completely.

The reason for segmented commitments is the basic shape of the heat rate (HR) curve, a typical heat rate curve is shown in the fig. 4.9.

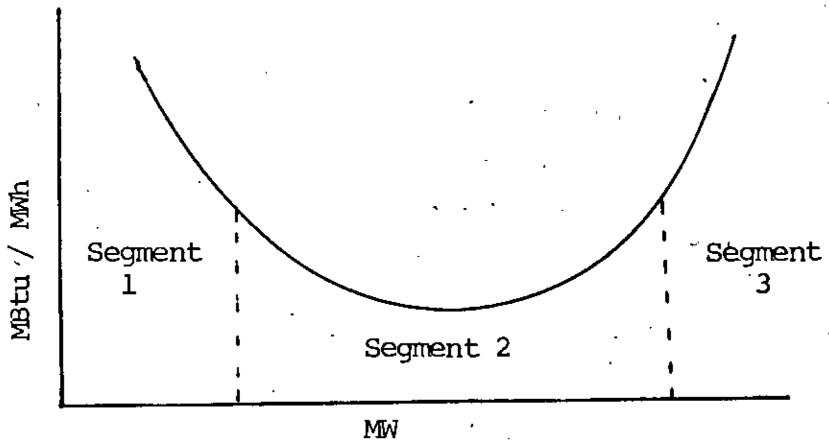


Fig. 4.9: Typical heat rate curve.

It is clear from the shape of the heat rate curve that the second segment corresponds to higher efficiency, since fewer Btus are required for each MWh of energy produced. From the basic HR curve the input/output, I/O, curve obtained by multiplying every y-axis value by its corresponding x-axis value. A typical I/O curve is depicted in fig. 4.10.

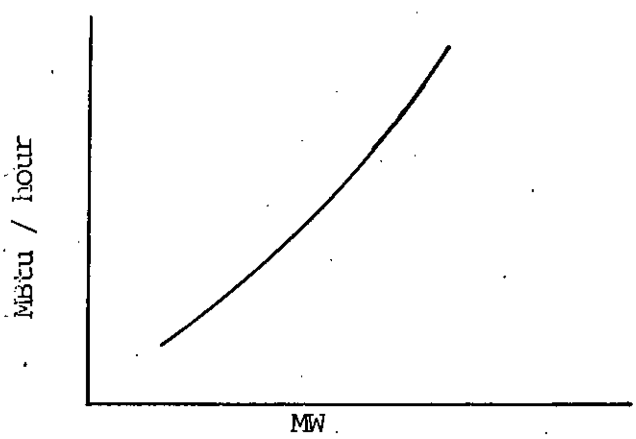


Fig. 4.10 : Typical input/output curve

By differntiating the I/O, curve with respect to load (L), the incremental heat rate (IHR) curve is obtained. A typical IHR curve is depicted in fig. 4.11.

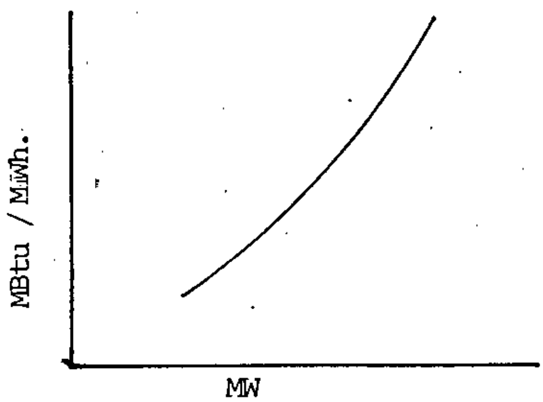


Fig. 4.11: Typical incremental heat rate curve.

To quantify these relationships, one has for unit i,

$$I/O_o = L_i \; HR_i \; (L_i) \tag{4.13}$$

and

$$IHR_i \; (L_i) = \frac{dI/O_i}{dL_i} \tag{4.14}$$

In a special case when HR curve is assumed to be constant then

$$IHR_i = HR_i \tag{4.15}$$

In the commitment of capacity blocks of a generating unit it is important to note that the lower capacity block should be committed before any higher capacity block is loaded, since physically it is not possible to commit any higher capacity blocks before committing all the lower capacity blocks of that unit.

CHAPTER FIVE

SEGMENTATION METHOD

5.1 Introduction.

Probability methods are used extensively at present for evaluating the reliability and production costs of power systems. Earliest researchers (7,8,9) in this field proposed the methods which with some modifications are now generally known as the 'loss of load approach', and the 'frequency and duration of outage approach'. The 'Recursive method' described in detail in a series of four publications (21,22,23,24) is the modification of the initial approach to the calculation of outage frequency and duration indices in generating capacity reliability evaluation. The most important development in the evaluation of LOLP and production cost by probabilistic simulation was suggested by Baleriaux[25] and Booth[26]. Raw, Toy and Schenk[28] proposed 'the method of cumulants' using the gram-charlier expansion to calculate the LOLP and expected energy generation. Recently Schenk et al.[29] proposed the 'segmentation method' for the evaluation of expected energy generation and LOLP of a single area system. This is computationally the most efficient and accurate[9] technique.

In this chapter the author has briefly presented 'segmentation method' as it is used for the evaluation of reliability and production cost in this thesis.

5.2 Segmentation Method.

The procedural steps which are required to be followed in the evaluation of LOLP as well as production costs in the segmentation method is presented in what follows.

The starting point of the segmentation method is the formation of segments of equal size by dividing the demand axis. The size of the segments depend upon the largest common factor of the generating unit capacities. To each segments a probability value is attached which is equal to the sum of the probabilities (zeroth moment) of load impulses lying in the range of a particular segments. One segment beyond the installed capacity is always considerred.

5.2.1 Evaluation of LOLP.

Recalling that the LOLP of a system is the probability that the equivalent load will exceed the installed capacity of the system it may be expressed as

$$\text{LOLP} = \text{prob.}\{Le > Ic\} \qquad (5.1)$$

In fact, in the segmentation method, LOLP is obtained from the knowledge of the zeroth moment of the equivalent demand after the convolution of all the generating units. In order to account for the random outages of units it is necessary to get a new distribution of segments incorporating the outages of all units. Considering the k-th segment and assuming a generating unit of capacity C MW and FOR = q , to be convolved, the probability of k-th segment, after the convolution may be expressed as

$$\tilde{P}_k = P_k (1-q) + \hat{P}_k q \tag{5.2}$$

where

$\tilde{P}_k$ = probability of the k th segment after the convolution.

$\hat{P}_k$ = probability of the k th segment after the shift.

P_k = probability of the k th segment before convolving the unit.

The procedure to be followed in convolving a generating unit may be described as follows.

i) Multiply the original distribution of segments by the availability of units (1-q).

ii) Shift the original distribution by the unit capacity and multiply by the FOR of the unit q.

iii) Add the value of the corresponding segments, obtained in (i) and (ii) above.

The formation of segments may be started from the base load, since the probability of occurrence of any load lower than the base load is zero. Note that the probability value attached to the last segment is the sum of the probabilities of all the segments exceeding the installed capacity. The zeroth moment of the equivalent demand of the last segment is the LOLP for the system. In section 5.3, a simple but revealing example will be presented to clarify the method.

5.2.2 Evaluation of Production Cost.

The evaluation of production cost of a system utilizing segmentation method requires the formation of segments in exactly the same way as described in section 5.2.1. A probability value is attached to each segment which is obtained from the probability values (zeroth moment) of the load impulses in the corresponding range of the segment. Unlike the reliability (LOLP) analysis, in the evaluation of production cost each segment is also filled up with the sum of the first order moments of the load impulses lying in the range of the particular segment in addition to the zeroth moment. The first moment is given by the expression

$$m_1 = \int_{-\alpha}^{\alpha} x f_x(x)\, dx \tag{5.3}$$

where x is the random variable and $f_x(x)$ is the probability density function of x. In discrete case,

$$m_1 = \sum_i x_i p_i \tag{5.4}$$

where x_i = value of the random variable.

p_i = probability of the distribution corresponding to x_i.

Sum of the first moments of all the segments gives the initial expected unserved demand. Generating units are then convolved one by one in the economic merit order of loading. Convolution of the units are carried out in a way similar to that described in section 5.2.1. The only difference is that in this case each segment contains two quantities, viz., the zeroth moment and the first moment of the load impulses. It is well known that [30] when segments are shifted all but the first moment remain unchanged. Therefore, the zeroth moments of all the segments remain the same. However, the first moment of any segments after the shift may be obtained using the following relationship.

$$m_1^{new} = m_1^{old} + \text{shift} \times m_o \qquad (5.5)$$

where m_o is the zeroth moment.

The zeroth and the first m oments after the convolution of a particular unit is obtained in a way similar to that described in section 5.2.1 (equation 5.2). Unserved demands are calculated before and after the convolution of each unit. The unserved demands multiplied by the period under study gives the expected unserved energies. The expected energy generation of a particular unit is the difference between unserved energies before and after the convolution of the machine. Thus for unit k, expected energy generation is given by

$$E_k = UE_{k^-} - UE_k \tag{5.6}$$

where E_k = Expected energy generated by the k-th unit

UE_{k^-} = Unserved energy before convolving the k-th unit,

UE_k = Unserved energy after convolving the k-th unit.

The fuel cost for the unit is obtained by multiplying the expected generation with the average incremental cost of the unit.

$$EC_k = \lambda_k E_k \tag{5.7}$$

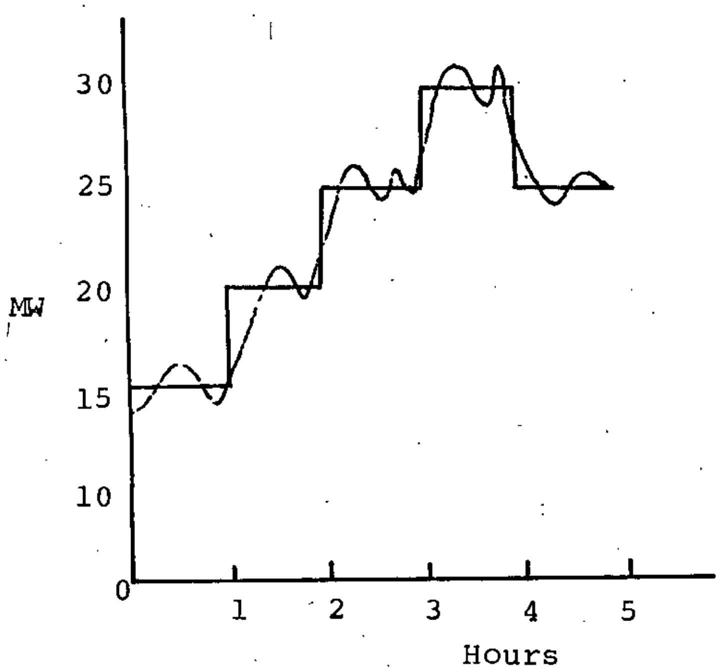
where EC_k = production cost for the k-th unit,

λ_k = Average incremental cost of k-th unit.

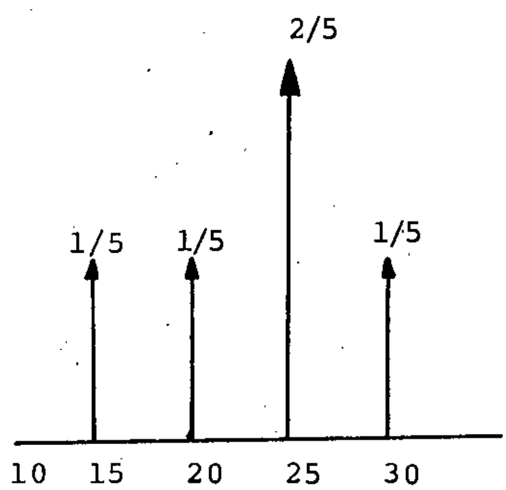
The segments below the already committed capacity are not required to be considered in calculating the unserved demand. Therefore, it is not necessary to keep track of these segments. Thus, as the convolution of units proceeds, the number of segments decreases. It should be noted that the moment of the last segment is the sum of the moments of all segments exceeding the limit. In the next section, an example is given for the clarification of the method.

5.3 An Example to Clarify the Method.

To examplify the segmentation method,consider the hourly load as shown in the figure 5.1. The dotted line represents the chronological load while the firm line represents the hourly load. The hourly load is obtained from the chronological load (secion 4.4.2) assuming an average value for an hour.



a) Chronological and hourly load profile



b) PDF of load

Fig. 5.1: Load representation

The hourly load of figure 5.1(a) is sampled at an interval of one hour (may be sampled at any equal interval) and by assigning to each sampled hourly load an equal probability i.e., $\frac{1}{5}$ in this case, the PDF of load shown in figure 5.1(b) is obtained. Also consider the generating system as shown in table 5.1.

Table 5.1

No, of units.	Capacity (MW)	FOR.	Avg. Incremental Fuel cost Tk/ MWh	Installed capacity.
2	10	0.2	300	45
1	25	0.1	500	

The segment size is choosen to be 5 MW using the largest common factor of the generating unit capacities of table 5.1. Thus the demand axis upto 45 MW is divided into 9 segments each of 5 MW size. Out of these nine (9) segments two initial segments are omitted since there is no impulse before 15 MW (base load) and one additional segment is considered at the end which is shown in figure 5.2(a). The probability value of each segment is the sum of the probabilities of the load impulse lying in the range of the particular segment. The numbers shown in the boxes of figure 5.2 should be divided by 5 to get the value of PDF, which is the zeroth moment.

The different steps of convolution of load and the generating units of table 5.1. are depicted in fig. 5.2. As the merit order of loading suggests, either of the two 10 MW units should be convolved first since the average incremental fuel costs of these two units are the lowest in the generating system. The convolution procedure is illustrated in figure 5.2. The upper number in each segment represents the zeroth moment of the load, and the other one represent the first moment. Note that the first moment of any segment is obtained by summing the product of load and its probability in the range of that segment. To convolve the first 10 MW unit the segments of figure 5.2(a) are shifted towards right in Fig. 5.2(b) by the unit capacity i.e. 10 MW. During the shift, the zeroth moment assigned to each

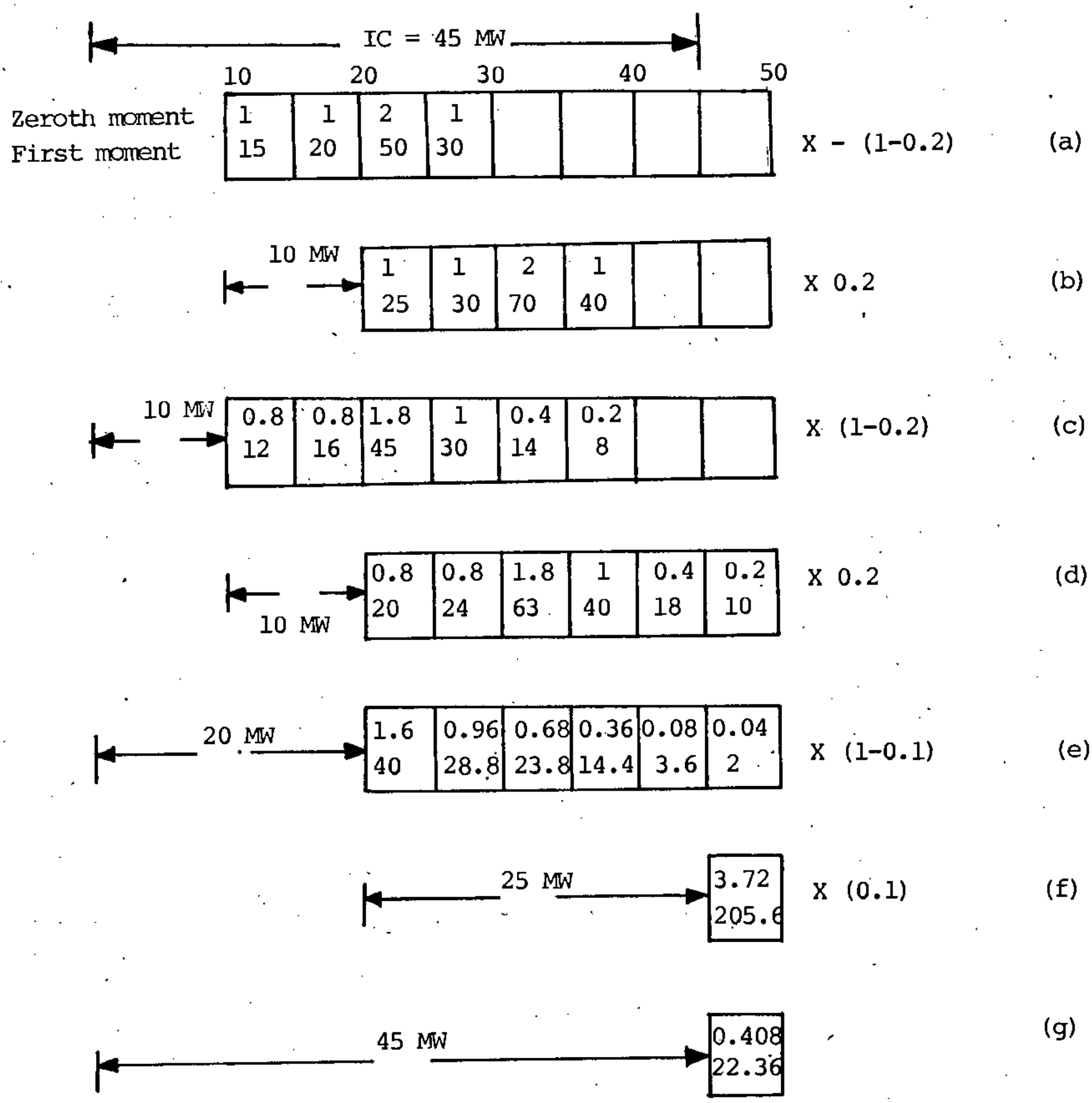


Fig. 5.2: Schematic of convolution procedure
(All number in the boxes to be divided by 5).

segment remain unchanged but the first moment is changed according to equation 5.5. The original distribution in fig.5.2(a) is multiplied by the availability of unit, 0.8 and the shifted distribution of figure 5.2(b) is multiplied by the FOR of the unit 0.2. The distribution after convolution is obtained by adding the probability values of the corresponding segments of figure 5.2(a) and figure 5.2(b). This is shown in fig. 5.2(c) and the same procedure is followed for the rest of the units. As segments are shifted the probability values and the first moment are accumulated in this special segment beyond the installed capacity. Thus, the last segment of figure 5.2(f) is the sum of the last six segments of 5.2(e). Now, since LOLP is obtained when the equivalent load is larger than the installed capacity it is the zeroth moment attached to the last segment of figure 5.2(g).

$$\text{Thus , } \quad \text{LOLP} = \frac{0.408}{5} = 0.0816$$

The unserved energy and the expected generation by each unit may be calculated as follows. Unserved energy before convolving the first 10 MW unit is

$$UE_1 = \text{Ist moment of all segments x time}$$

$$= 5 \times (15 + 20 + 50 + 30)/5 = 115 \text{ MWh.}$$

Unserved energy after convolving the Ist 10 MW unit

$$UE_1 = 5x\{(12 + 16 + 45 + 30 + 14 + 8) - 10 \times (.8+0.8+1.8+1 + 0.4 + 0.2)\}/5$$

$$= 75 \text{ MWh.}$$

Expected energy generation of Ist 10 MW unit

$$E_1 = (115 - 75) = 40 \text{ MWh.}$$

Cost of energy generated by Ist unit

$$EC_1 = (40 \times 300) = 12{,}000 \text{ Taka.}$$

Unserved energy after convolving the second 10 MW unit.

$$UE_2 = 5 \times \{(40 + 28.8 + 23.8 + 14.4 + 3.6 + 2) - 20\,(1.6 + .96 + .68 +.36+.08+.04)\}/5$$

$$= 38.2 \text{ MWh.}$$

Expected generation of the second unit

$$E_2 = (75 - 38.2) = 36.8 \text{ MWh}$$

Cost of energy generated by the second unit,

$$EC_2 = 36.8 \times 300 = 11{,}040 \text{ Taka.}$$

Similarly for the third unit (25 MW).

$$UE_3 = 5x\ (22.36 - 45 \times 0.408)/5 = 4 \text{ MWh.}$$

$$E_3 = (38.2-4) = 34.2 \text{ MWh.}$$

$$EC_3 = 34.2 \times 500 = 17{,}100 \text{ Taka}$$

Energy demand

$$ED = \text{Initial unserved energy} = 115 \text{ MWh.}$$

Total expected energy generation

$$EG = E_1 + E_2 + E_3 = 111 \text{ MWh.}$$

Expected energy not served

$$\varepsilon(ENS) = UE_3 = 4 \text{ MWh.}$$

Total energy production cost

$$EC = EC_1 + EC_2 + EC_3 = 40{,}140 \text{ Taka.}$$

For a given system and for the period under study the energy balance (EB) is the difference between the energy demand (ED) and the sum of the total expected energy generation (EG) and expected energy not served ϵ(ENS) as:

$$EB = \varepsilon(ED) - (\varepsilon(EG) + \varepsilon(ENS)) \qquad (5.8)$$

For the present problem energy balance is

$$EB = 115 - (111 + 4) = 0.0$$

It is important to note that there are no approximations made in the evaluations and hence the LOLP and unserved energies are exact.

CHAPTER SIX

NUMERICAL EVALUATION.

6.1 Introduction

With the development of the concept of load management and its subsequent acceptance as an alternative to conventional electric system power resources, utility planners are attaching utmost importance to the evaluation of impacts of LM in generation expansion. The models of LM strategis developed in chapter two have been applied to two power systems: (i) Bangladesh power system and (ii) IEEE reliability test system. In this chapter the LOLPs as well as production costs are computed for different LM strategies. These two parameters are also computed for different conditions of each LM strategy. The economic benefits as well as the benefits in terms of reliability of the systems are evaluated for different LM schemes and the comparisons of each scheme with the other are presented in this chapter. This chapter also determines the appropriate limit of each LM scheme.

In addition to the results, this chapter presents a brief discription of the two systems considered for the study. An analysis of the load profile is made in this chapter in order to select the time as well as the horizon of application of LM.

6.2 Bangladesh Electric Power Generation System[31].

The sole responsibility of generation, transmission and distribution of electrical energy in Bangladesh is with Bangladesh Power Development Board (BPDB). This power system may be divided into two zones: the East zone and the West zone seperated by the rivers Padma, Jamuna and Meghna. These two zones are interconnected by the East west interconnector (EWI) forming an integrated national grid.

There are a number of power stations in the East and the west zones. The geographical locations of different power stations of BPDB are shown on the map of Bangladesh in Figure 6.1. The simplified single line diagram of the integrated power system of Bangladesh is shown in fig. 6.2. The large power stations are Karnafuli Hydro-electric station, Ashuganj steam power station and combined cycle power station, Ghorashal thermal power station, Siddirganj thermal power station, Chittagong steam station, Khulna steam and Gas turbine, Shahjibazar gas turbine power station and Bheramara gas turbine. Besides these power plants, there are a number of small diesel stations which continue to play an important role in the northern areas of Bangladesh. Most of the thermal stations in the East zone use natural gas as fuel, while those in the west zone generate electricity by burning costly liquid fuel.

6.2.1 Generation Data.

Generation data of BPDB systems used for this research are given in Appendix A . The column showing 'capacity' actually

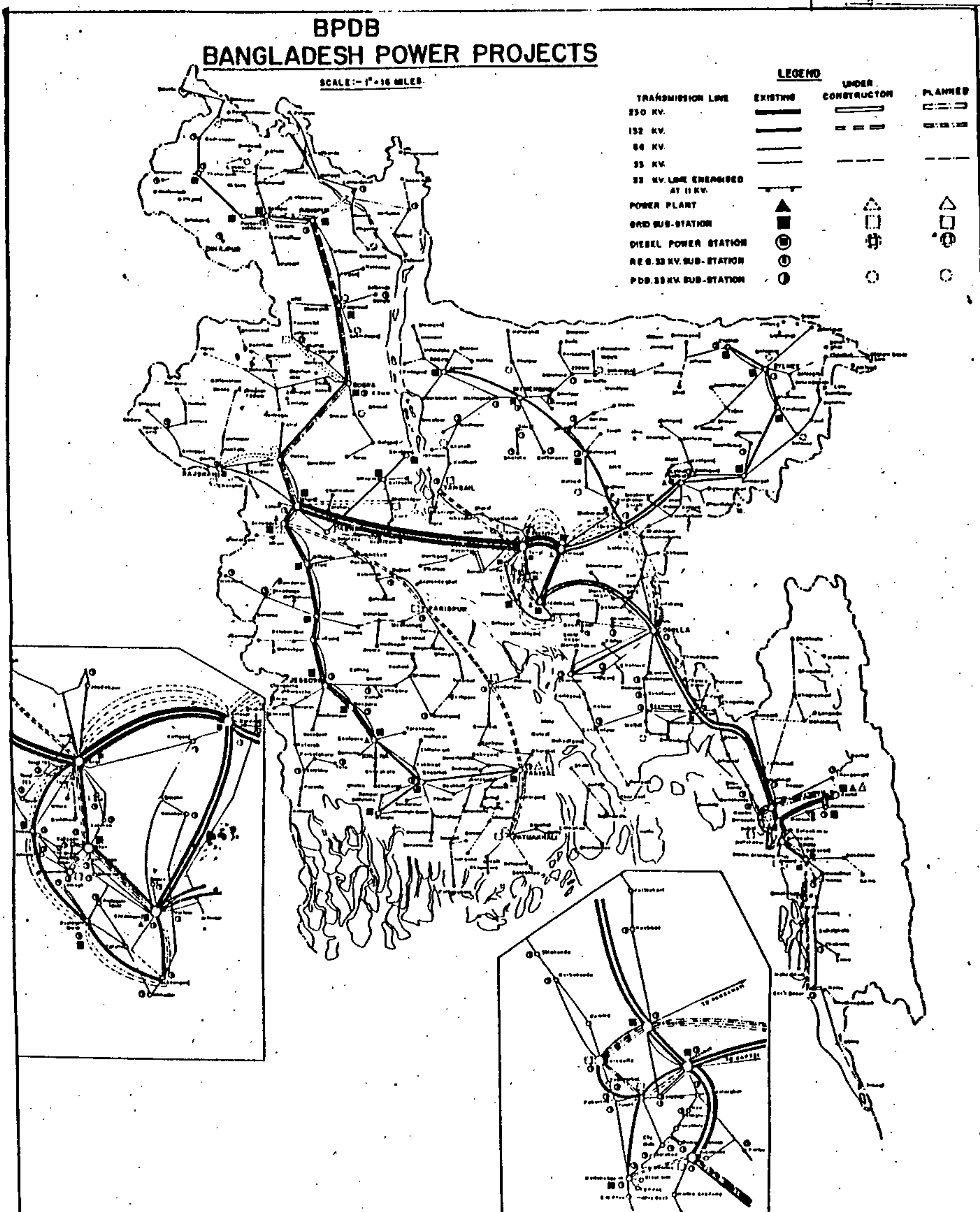


Figure: 6.1 : Geographical Locations of different power stations of BPDB shown on the map of Bangladesh.

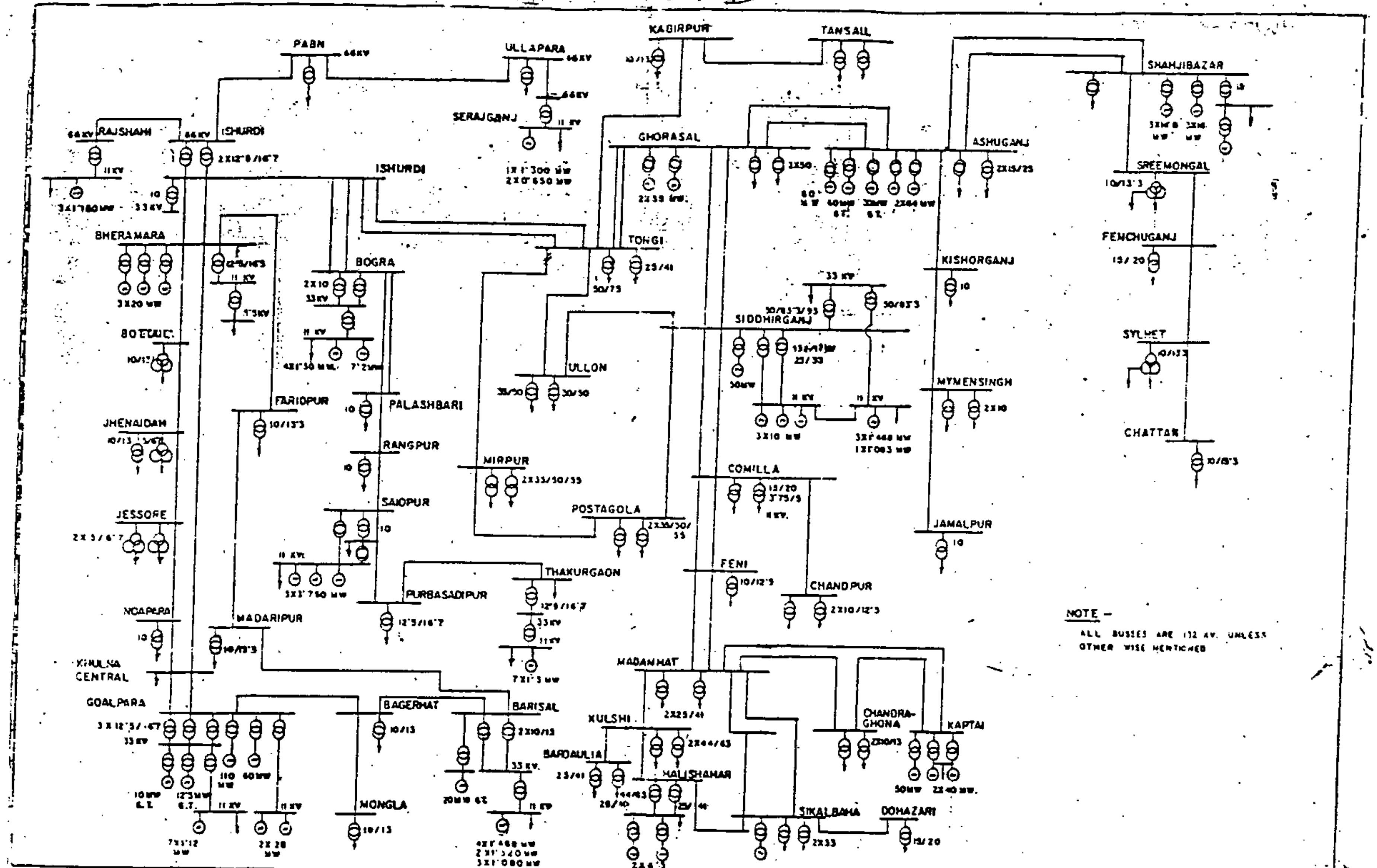


Figure: 6.2 : Single Line Diagram of the integrated power system of Bangladesh.

contains the maximum capabilities of different units. Also some of the unit capacities are rounded off. For example, the capacity of each of the two 64 MW steam units at Ashuganj are rounded off to 65 MW to avoid excess CPU time in the segmentation method. Also, in the West zone the small diesel units with capacities less than 5 MW are aggregated to form units of 5 MW capacity and are shown in the appendix in the name of 'small diesel stations'. The total generation capacity of the integrated system is 1010 MW.

6.2.2 Load Data.

Hourly load from August to December of 1985 are used in this research. The loads are analyzed in order to find the nature, time of occurence of peak loads as well as the time horizon at which load management program can be implemented successfully. The peak and base loads for the period of 3672 hours under study is 811.44 and 246.29 MW respectively.

6.3 IEEE - Reliability Test System[32]

Generation model of this system is presented in the appendix B. The system comprises nuclear, coal, oil and hydro generating units. Some of the unit capacities of this system are rounded off. Hydro units are loaded as base loaded units. Total installed capacity for the system is 3400 MW with 32 generating units of different capacities.

Load model

The first thirteen (1-13) weeks of IEEE- RTS[32] hourly loads are utilized in this research work as the demand data. Thus the time duration of the hourly loads considered in this thesis is 2184 hours. Peak and base loads for the systems are 2850 and 1102 MW respectively. The load pattern shows that the peak load of the day occurs within the period 17 to 21 hours.

6.4 Results.

In the numerical simulation for this study the segmentation method is used. In chapter five, the method is explained in detail. The impacts of the different strategies of LM on the reliability and production cost of the two earlier mentioned systems are presented in what follows for critical analysis & observations. The base case is referred to the condition where no load management scheme is applied to the system.

Period of load management.

Daily load factor for the whole period of 153 days are computed and graphically plotted (appendix C) to observe in case of BPS the variation of load factors. It is observed to vary from 60% to 84% which suggests the implementation of load management program for the overall improvement of systems load factor. For each week, the day of maximum peak load is found out and the hourly load curve for that day is plotted. Some of those hourly load curves are presented in appendix D . The load curves reveal the sharp peakiness of the systems load. It is also observed that in almost all the days of the period under study, peak load occurs from 17 to 23 hours of each day while the minimum load occurs during the period 1 to 6 hours. Therefore, the time horizon for the application of LM is choosen to be 17 to 23 or 18 to 22 hours each day. Similarly, for the IEEE reliability test system, the hourly loads are carefully analysed and it is observed that the patterns of the daily load curve is such that the maximum load occurs from 17 to 21 hours while the minimum from 1 to 6 hours of the day. Therefore, the period of load reduction for IEEE- RTS is considered to be 17 to 21 hours.

6.4.1 Direct Load Management Scheme.

a) Bangladesh Power System.

In the first scheme of direct load control, the load is reduced by 10,15,20,25 and 30 percent of the peak hour load during 18 to 22 hours of each day. That is in equation 2.10.1 'a' is considered to be 0.1,0.15,0.20, 0.25 and 0.30 and t_1 & t_2 are considered to be 18 and 22 hours of the day respectively. To investigate the impacts on the reliability, the 'LOLPs', 'peak loads' and 'percentage reduction in LOLP' are presented in table 6.1. This table also presents LOLP of the base case for comparison. The improvement of reliability in terms of percentage reduction in LOLP over that of the base case is depicted in Fig. 6.3. For comparison, Fig. 6.3 is also incorporated with the plottings for 'constant peak approach' of LM to be discussed later in this section.

Table - 1

Direct Load reduction scheme
(load reduced from 18 to 22 hours)

Percentage reduction of demand	Modified peak load (MW)	LOLP %	Percentage reduction in LOLP over base case.
base case (0)	811.44	0.062917	-
10	730.30	0.008479	86.5
15	689.72	0.003313	94.7
20	671.64	0.001786	97.2
25	671.64	0.001375	97.8
30	671.64	0.001279	97.9

The production cost is also evaluated when this LM scheme is applied. The production cost, the expected fuel cost in taka as well as the savings in fuel cost over the base case are presented in table 2. The expected savings in fuel cost over the base case is plotted in figure 6.4. The plottings for the impact of constant peak approach' on production cost is also made in fig. 6.4 to facilitate the comparison between different schemes of direct LM.

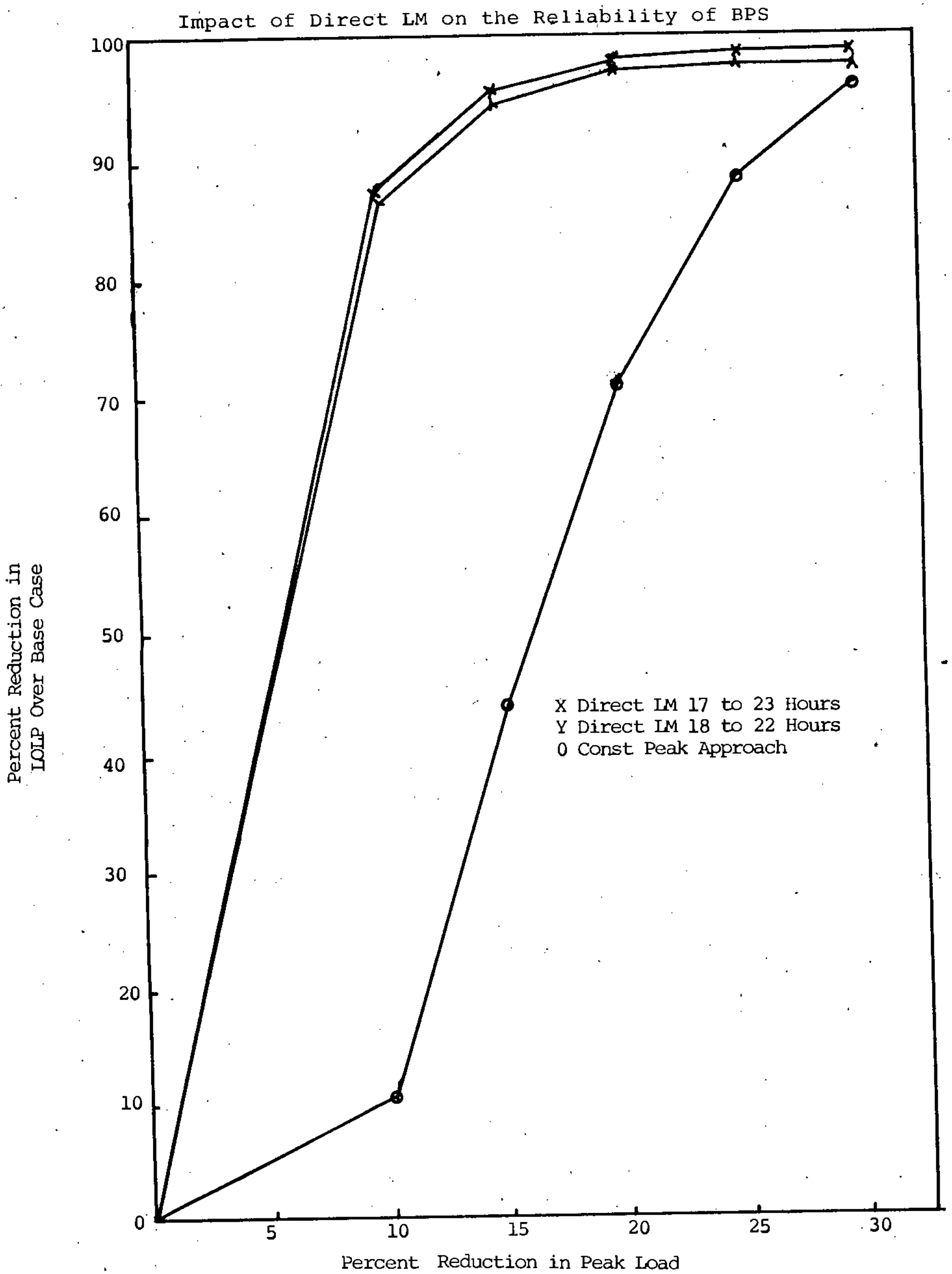

Impact of Direct LM on the Reliability of BPS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
Percent Reduction in LOLP Over Base Case
X Direct LM 17 to 23 Hours
Y Direct LM 18 to 22 Hours
0 Const Peak Approach
Percent Reduction in Peak Load

Fig.6.3

Table - 2

Direct load reduction scheme
(load reduced from 18 to 22 hours)

Percentage reduction of demand	Expected Fuel cost (MTK.)	Expected Savings in Fuel cost (MTK.)
Base case	260.1165836	-
10	219.7320580	40.3845256
15	207.4897008	52.6268828
20	198.9550843	61.1614993
25	192.8157870	67.3007966
30	187.9960370	72.1205460

The impacts on the reliability as well as the production cost are studied for the same percentages of load reduction but the period of load reduction is 17 to 23 hours of each day. The results are shown in table 3 and 4 respectively. The improvement in reliability and the production costs savings are graphically presented in fig. 6.3 and fig. 6.4 respectively.

Table - 3

Direct load reduction scheme
(load reduced from 17 to 23 hours)

Percentage reduction	Modified peak load (MW)	LOLP (%)	Percentage reduction in LOLP over base case.
Base case	811.44	0.062917	
10	730.30	0.008059	87.2
15	689.72	0.002863	95.4
20	658.97	0.001328	97.9
25	658.97	0.000915	98.5
30	658.97	0.000819	98.7

Impact of Direct LM on the Production Cost of BPS

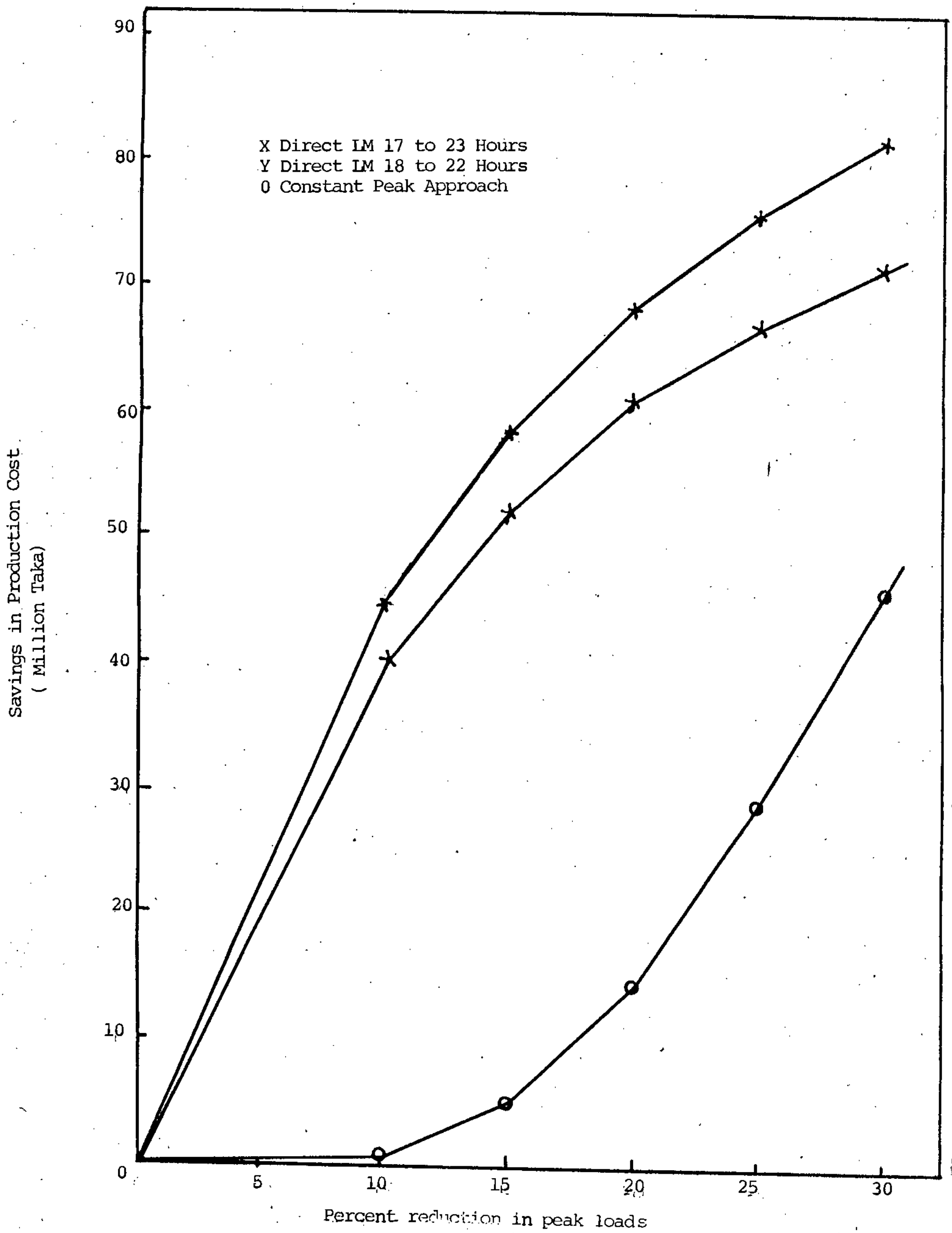


Fig. 6.4

Table - 4

Direct load reduction scheme
(load reduced from 17 to 23 hours).

Percentage reduction	Expected Fuel cost. (MTK)	Expected savings in fuel cost (MTK)
Base case	260.1165836	
10	215.2154693	44.9011143
15	201.3688716	58.7477120
20	191.4185887	68.6979949
25	183.9578321	76.1587515
30	177.8602734	82.2563102

b) <u>IEEE- Reliability test system</u>.

The load model of the system reveals that 17 to 21 hours of the day is the period of peak loads at which the application of LM is expected to have a favourable impact on the reliability as well as production cost. Therefore, like the BPDB system, in the first scheme of DLC, the loads are reduced by 5,10,15,20,25,30 percent during 17 to 21 hours of each day. The effects on the reliability as well as on the production costs are presented in tables 5 and 6 respectively. The improvement of reliability through the direct load reduction scheme is graphically shown in Fig. 6.5 by plotting the percentage reduction in LOLP over the base case against the percentage reduction of the loads of peak periods. Also expected savings in fuel costs are depicted in

Fig. 6.6 which also reflects the effects of 'constant peak approach' discussed later.

Table -5

Direct load reduction scheme
(Impact on the reliability of IEEE-RTS).

Percentage reduction	Modified peak load (MW)	LOLP %	Percentage reduction in LOLP over base case.
Base case	2850	0.064141	-
5	2736	0.031424	51.0
10	2736	0.024090	62.4
15	2736	0.023017	64.1
20	2736	0.022917	64.2
25	2736	0.022911	64.3

Table - 6

Direct load reduction scheme
(Impact on production cost of IEEE-RTS).

Percentage reduction	Expected Fuel cost (M$)	Expected savings in Fuel cost (M$)
Base case	37.5292466	-
5	36.9021202	0.6271264
10	36.3066230	1.2226236
15	35.7069350	1.8223116
20	35.0983269	2.4309197
25	34.4886105	3.0406361

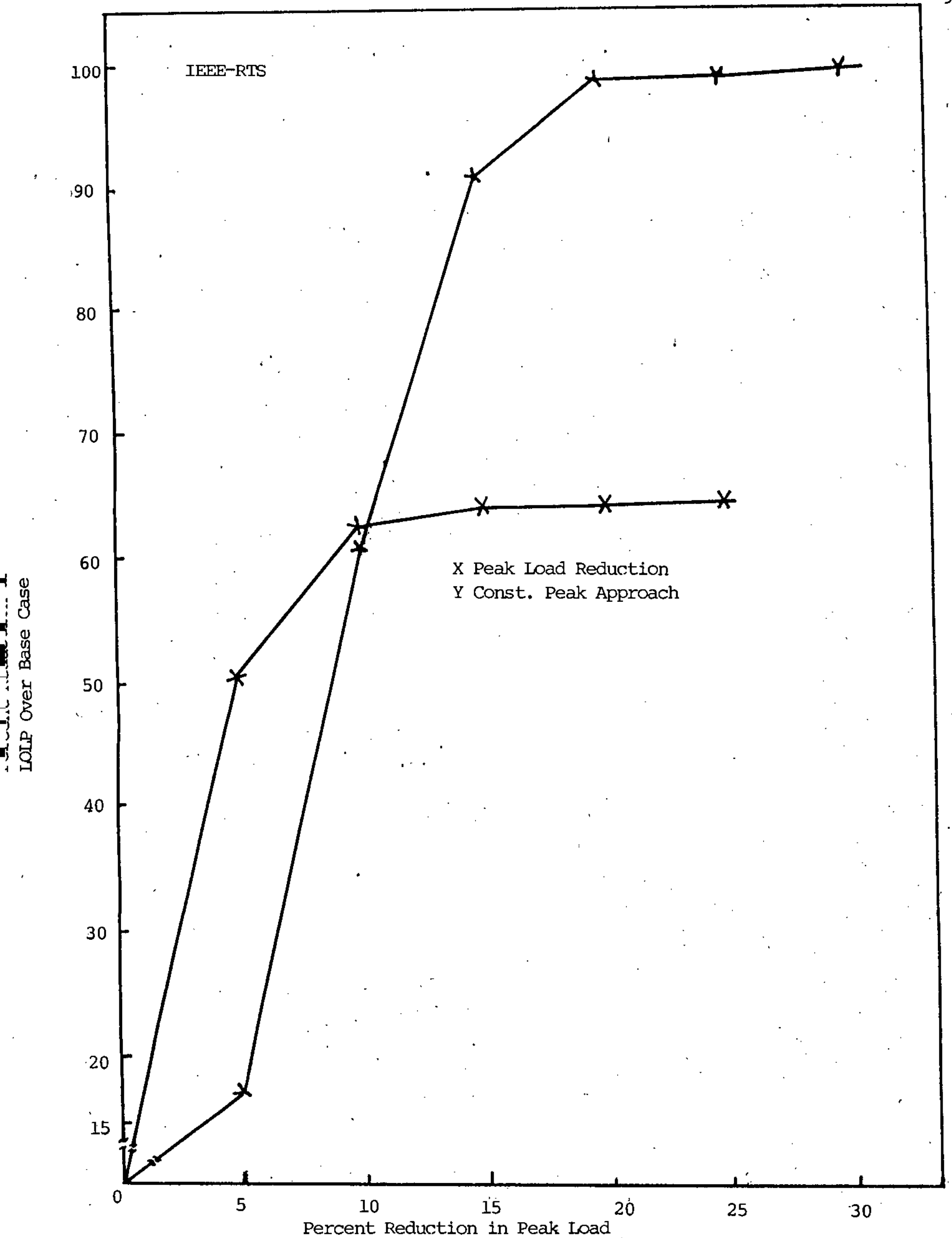


Fig.6.5: Impact of Direct LM on the reliability of IEEE-RTS.

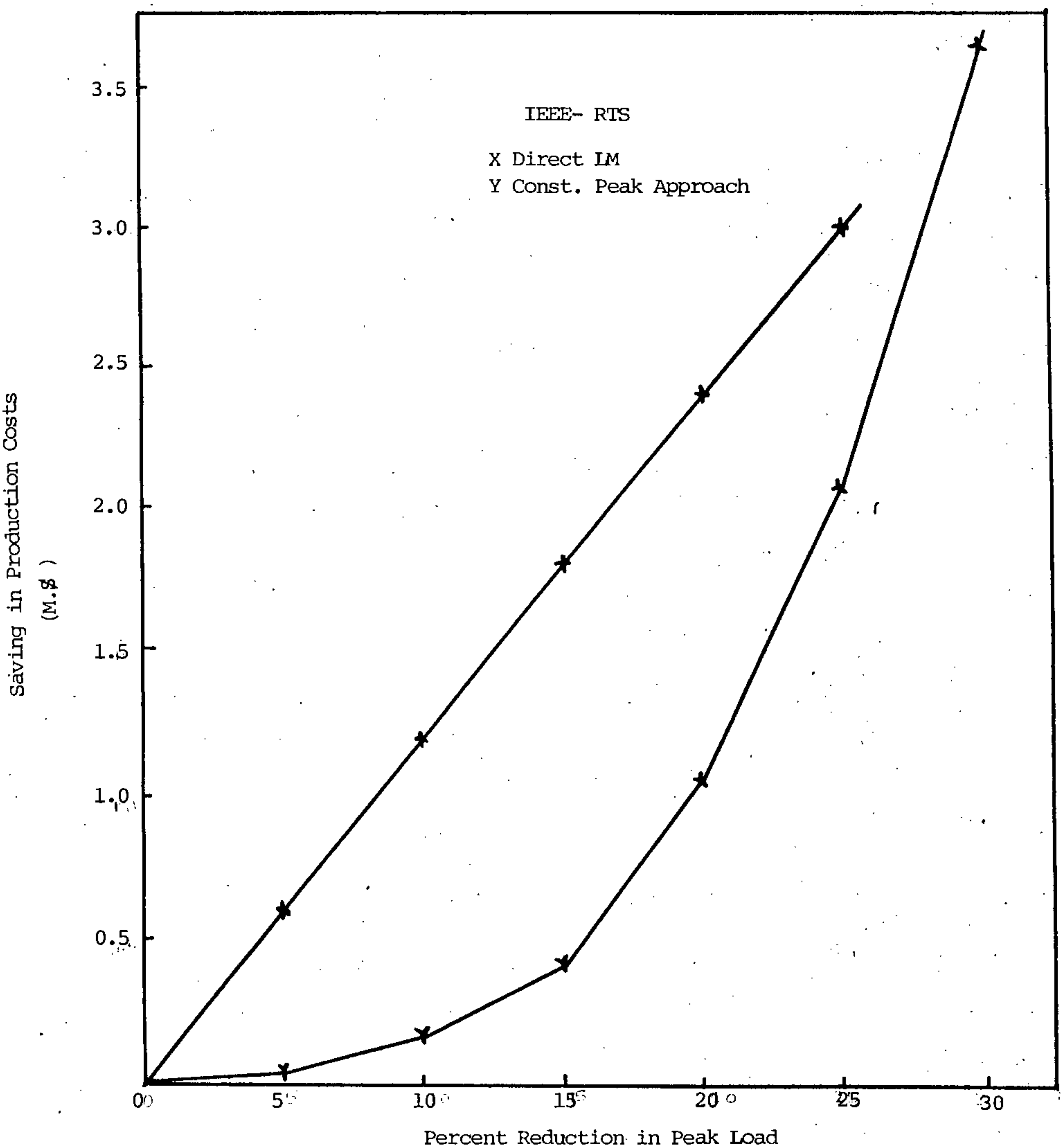


Fig. 6.6: Impact of Direct LM on the Production cost of IEEE-RTS.

Constant Peak Approach.

a) Bangladesh power system.

In the second scheme of direct load control called 'constant peak approach' the hourly loads are reduced whenever it exceeds the prefixed value. The prefixed value (CPK in equation 2.10.2) is set by reducing the highest amount of load (811.44 MW) of the 5 months period (Aug.'85 to Dec.'85) under study by 10,15,20, 25,30 percentages. The results illustrating the effects on reliability and production costs are presented in table 7 and 8 respectively. Graphical representations of reliability improvement and production cost savings are given in Fig. 6.3 and 6.4.

Table - 7

Constant peak approach

(Impact on reliability of BPDB system).

Percentage reduction	Modified peak load (MW)	LOLP (%)	Percentage reduction in LOLP over base case.
Base case	811.44	0.062917	-
10	730.30	0.056100	10.8
15	689.72	0.035457	43.6
20	649.15	0.018328	70.9
25	608.58	0.007518	88.1
30	568.01	0.002504	96.0

Table - 8

Constant peak approach

(Impact on the production cost of BPDB system).

Percentage reduction	Expected Fuel cost (MTK)	Expected savings in fuel cost (MTK)
Base case	260.1165836	
10	259.4092480	.7073356
15	255.0309394	5.0856442
20	245.2485886	14.8679950
25	230.5349976	29.5815860
30	214.0158696	46.1007140

b) <u>IEEE - Reliability test system.</u>

It may be recalled here that the peak load of thirteen weeks of the load model of this system is 2850 MW. Therefore, in the constant peak approach of direct load control the prefixed value is set by reducing 2850 MW through (5,10,15,20,25,30) percentages as in case of Bangladesh power system. The results illustrating the impacts on the reliability and production costs are shown in table 9 and 10. respectively. Graphical representations of the results are made in Figure 6.5 and 6.6.

Table - 9

Constant peak approach.

(Impacts on the reliability of IEEE-RTS).

Percentage reduction	Modified peak load (MW)	LOLP (%)	Percentage reduction in LOLP over base case.
Base case	2850	0.064141	-
5	2707.50	0.053133	17.2
10	2565.00	0.025023	61.0
15	2422.50	0.005670	91.2
20	2280.00	0.000661	98.9
25	2137.50	0.000029	99.95
30	1995.00	0.000001	99.998

Table 10

Constant peak approach.

(Impacts on the production cost of IEEE-RTS).

Percentage reduction	Expected Fuel cost(M$)	Expected savings in Fuel cost (M$)
Base case	37.5292466	-
5	37.5092184	0 .0200282
10	37.3667261	0 .1625205
15	37.1077620	0 .4214846
20	36.4888541	1.0403925
25	35.4515593	2.0776873
30	33.953333	3.5759135

6.4.2 Indirect Load Control.

The art of indirect load control through incentives to consumers or motivating them by some other means to make use of electricity during off peak hours thereby reducing loads during peak load periods are discussed in chapter two of this thesis. Essentially, in this approach, hourly loads are reduced by 5,10, 15,20,25,30 percent of the actual value during the peak periods extending from 18 to 22 hours of each day. The total amount of load reduced in each day during the peak hours is served during the off-peak periods extending from 1 to 6 hours of the day. This approach may be considerred as the shifting of loads from the 'on peak periods' to 'off peak periods' of the day. The results of this load shifting illustrating the impacts on the reliability as well as on the production costs are presented in table 11 and table 12 respectively. Also graphical presentation is made in fig. 6.7 and 6.8.

Table 11

Indirect load control
(Impact on reliability of BPS)

Percentage reduction	Modified peak load (MW)	LOLP (%)	Percentage reduction in LOLP over base case.
Base case	811.44	0.062917	-
5	770.87	0.023631	62.4
10	730.30	0.008525	86.5
15	689.72	0.003469	95.0
20	671.64	0.002284	96.4
25	681.97	0.002822	95.5
30	708.03	0.005235	91.7

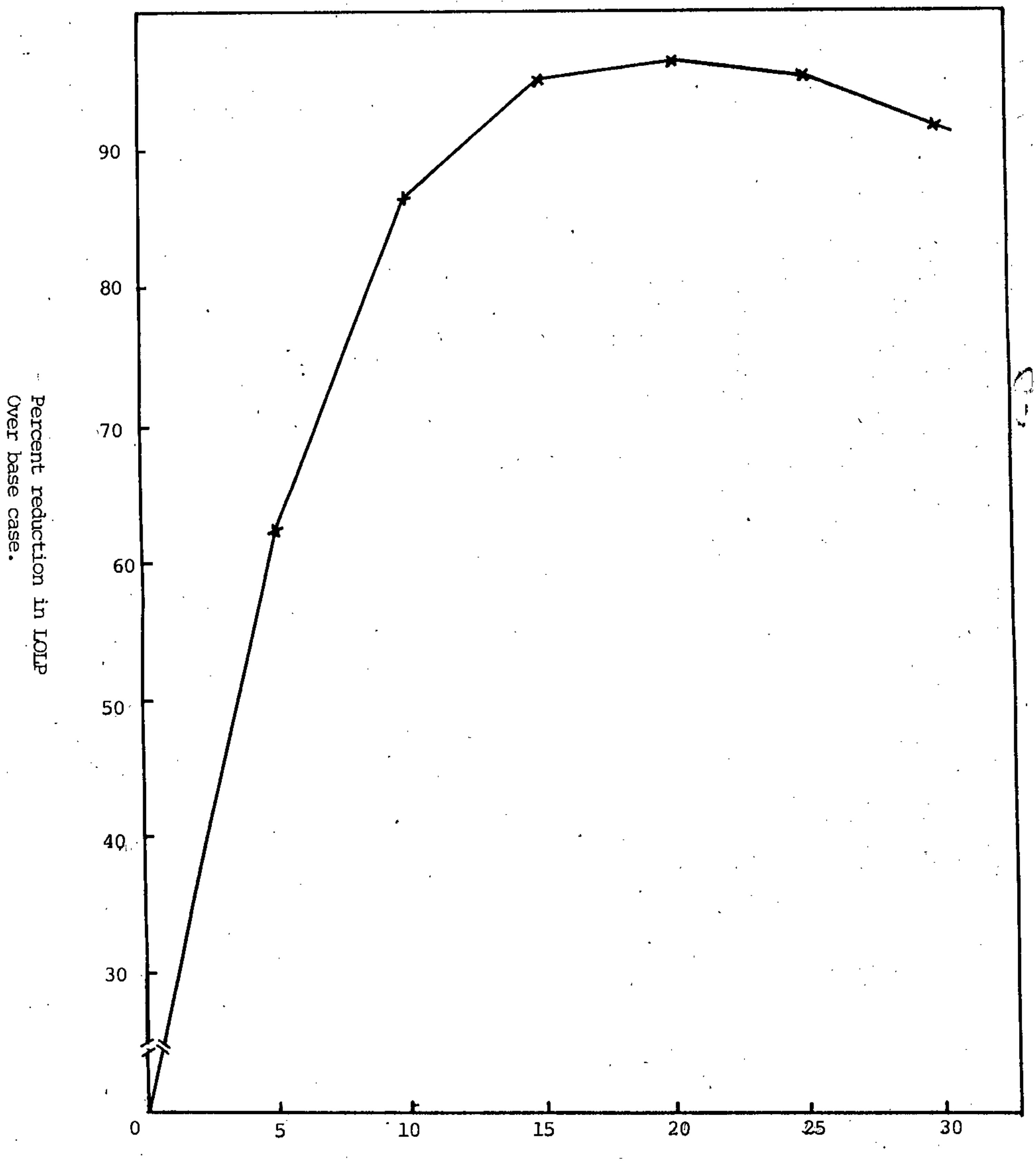


Fig. 6.7: Impact of Indirect load control on the reliability of BPS.

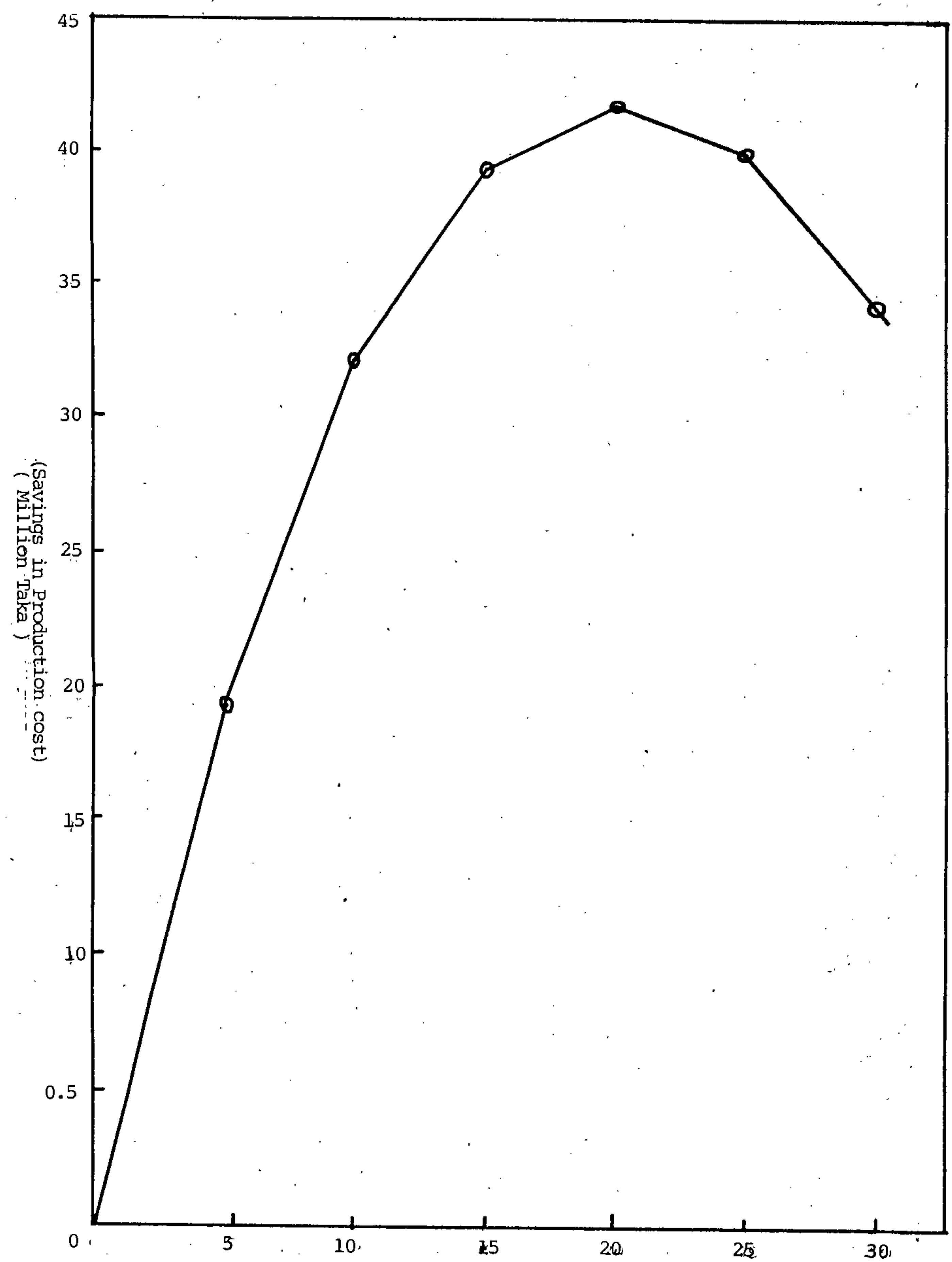


Fig. 6.8: Impact of Indirect load control on the production cost of BPS.

Table 12

Indirect load control

(Impact on production cost of BPS)

Perecentage reduction	Expected Fuel cost (MTK)	Expected savings in Fuel cost (MTK)
Base case	260.1165836	-
5	241.0582501	19.0583335
10	228.1212875	31.9952961
15	220.8366779	34.2799057
20	218.3586922	41.7578914
25	220.1013468	40.0152368
30	225.9455100	34.1710736

6.4.3 Energy Storage Scheme.

a) Bangladesh power system.

In the energy storage scheme the load of the system is reduced by 5,10,15,20,25 and 30 percent from 18 to 22 hours and the load is increased from 1 to 6 hour. That is, in equation (2.10.4) t_3, t_4, t_1, t_2 are 18,22, 1 and 6 hour respectively and a is 0.05, 0.1, 0.15, 0.20, 0.25, 0.3 . The value of 'b' is selected depending on the overall efficiency of the pump storage plant. In this study the pump efficiency is assumed to be 50%, 55% and 71.4%. In what follows, the impacts on the reliability as well as on production cost are presented in tabular form for the different pump efficiencies. The results are also graphically depicted in Fig. 6.9 and 6.10 respectively.

Table 13

Energy storage scheme - BPDB system
(Pump efficiency considered is 50%)

Percentage reduction	Modified peak load	LOLP (%)	Percentage reduction in LOLP over base case
Base case	811.44	0.062917	-
10	730.30	0.008978	85.7
15	708.03	0.007269	88.4
20	760.14	0.026745	57.5
25	812.25	0.126420	-100.9
30	864.36	0.492258	-682.4

Table 14

Energy storage scheme - BPDB system
(Pump efficiency considered 55%)

Percentage reduction	Modified peak load (MW)	LOLP (%)	Percentage reduction in LOLP over base case.
Base case	811.44	0.062917	-
10	730.30	0.008797	86%
15	692.40	0.005495	91.3
20	739.29	0.014111	77.6
25	786.19	0.058851	6.5
30	833.09	0.221909	-252.7%

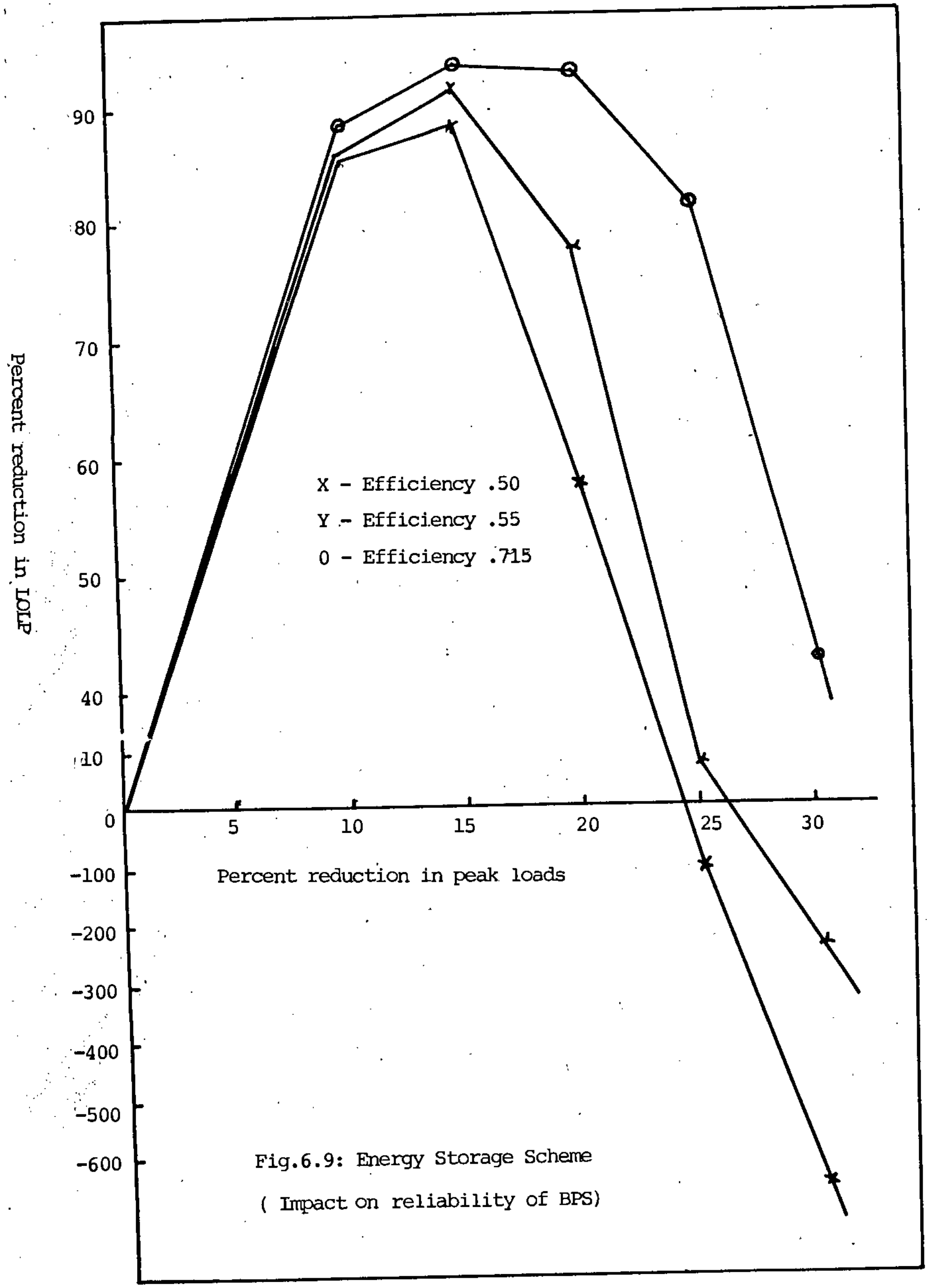


Fig.6.9: Energy Storage Scheme

(Impact on reliability of BPS)

Table 15

Energy storage scheme-BPDB system

(pump efficiency considerred is 71.5%)

(Impact on reliability)

Percentage reduction	Modified peak load (MW)	LOLP (%)	Percentage reduction in LOLP over base case
Base case	811.44	0.062917	-
5	770.87	0.023641	62.5
10	750.12	0.000705	88.9
15	689.72	0.003931	93.8
20	697.61	0.004454	92.9
25	734.08	0.011629	81.5
30	770.56	0.036398	42.1

The impacts of the energy storage scheme on the production cost of the system is shown in the following tables for the different value of pump efficiencies.

Table 16

Energy storage scheme - BPDB system

(Pump efficiency considerred is 50%)

(Impact on production cost)

Percentage reduction	Expected Fuel cost (MTK)	Expected savings in Fuel cost (MTK)
Base case	260.1165836	-
10	239.1356627	20.9809209
15	245.4391776	14.6774060
20	270.8024800	-10.6858964
25	319.8153582	-59.6987746
30	390.1222466	-130.0056630

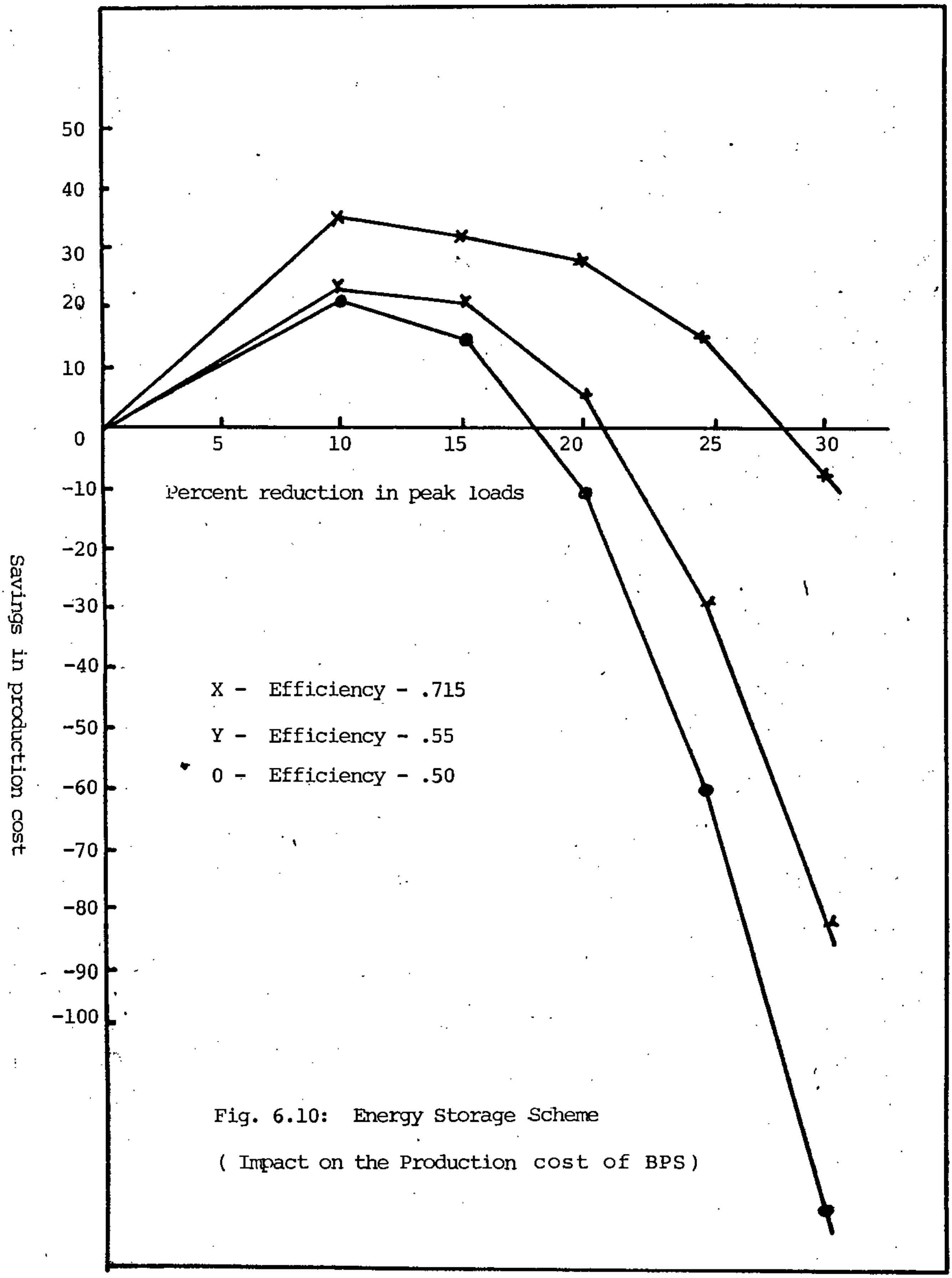


Fig. 6.10: Energy Storage Scheme

(Impact on the Production cost of BPS)

Table 17

Energy storage scheme BPDB system
(Pump efficiency considerred is 55%)

Percentage reduction	Expected Fuel cost (MTK)	Expected savings in Fuel cost (MTK)
Base case	260.1165836	-
10	236.5393504	23.5772332
15	238.6471378	21.4694458
20	254.9142127	5.2023709
25	289.5037602	-29.3871766
30	342.9011983	-82.7846147

Table 18

Energergy storage scheme BPDB system
(Pump efficiency is considerred 71.5%)

Percentage reduction	Expected Fuel cost (MTK)	Expected savings in Fuel cost (MTK)
Base case	260.1165836	-
5	242.7478262	17.3687574
10	224.9333143	35.1832693
15	228.2967864	31.8197972
20	232.2363002	27.8802834
25	245.3152270	14.8013566
30	269.0984913	-8.9819077

b) IEEE - Reliability Test System.

Keeping similarity to the 'energy storage scheme' applied to the BPDB system, the load of the IEEE-RTS is reduced by 5,10,15,20,25, percents during the peak periods extending from 17 to 21 hours. The total amount of energy thus curtailed during the peak periods is multiplied by a factor corresponding to the efficiency of the pump storage plant. This amount of energy is increased by increasing the hourly loads of the period extending from 1 to 5 hours. The results illustrating the impacts on the reliability and production costs are presented in table 19 and 20 respectively.

Table 19

Energy storage scheme IEEE -RTS
(Pump efficiency considered is 50%)

Percentage reduction	Modified peak load (MW)	LOLP (%)	Percentage reduction in LOLP over base case
Base case	2850	0.064141	-
5	2736	0.031424	51
10	2736	0.024182	62.3
15	2740.56	0.028942	54.9
20	3017.58	0.121842	-90.0
25	3294.60	0.687128	-971.3

Table 20

Energy storage scheme IEEE - RTS

Percentage reduction	Expected Fuel cost (M$)	Expected savings in Fuel cost (M$)
Base case	37.5292466	-
5	38.0890747	-.5598281
10	38.7243826	-1.1951360
15	39.3339360	-1.8046894
20	39.9840316	-2.4547850
25	40.8792216	-3.3499750

To clearly observe the impacts of energy storage scheme on the reliability as well as on the production cost of IEEE-RTS, the results of table 19 to 20 are also graphically depicted in fig. 6.11. From the results, it is observed that for the said system production cost increases over the base case although reliability improves with the implementation of energy storage scheme. It may be recalled here that negative savings in production cost indicates its increment over the base case.

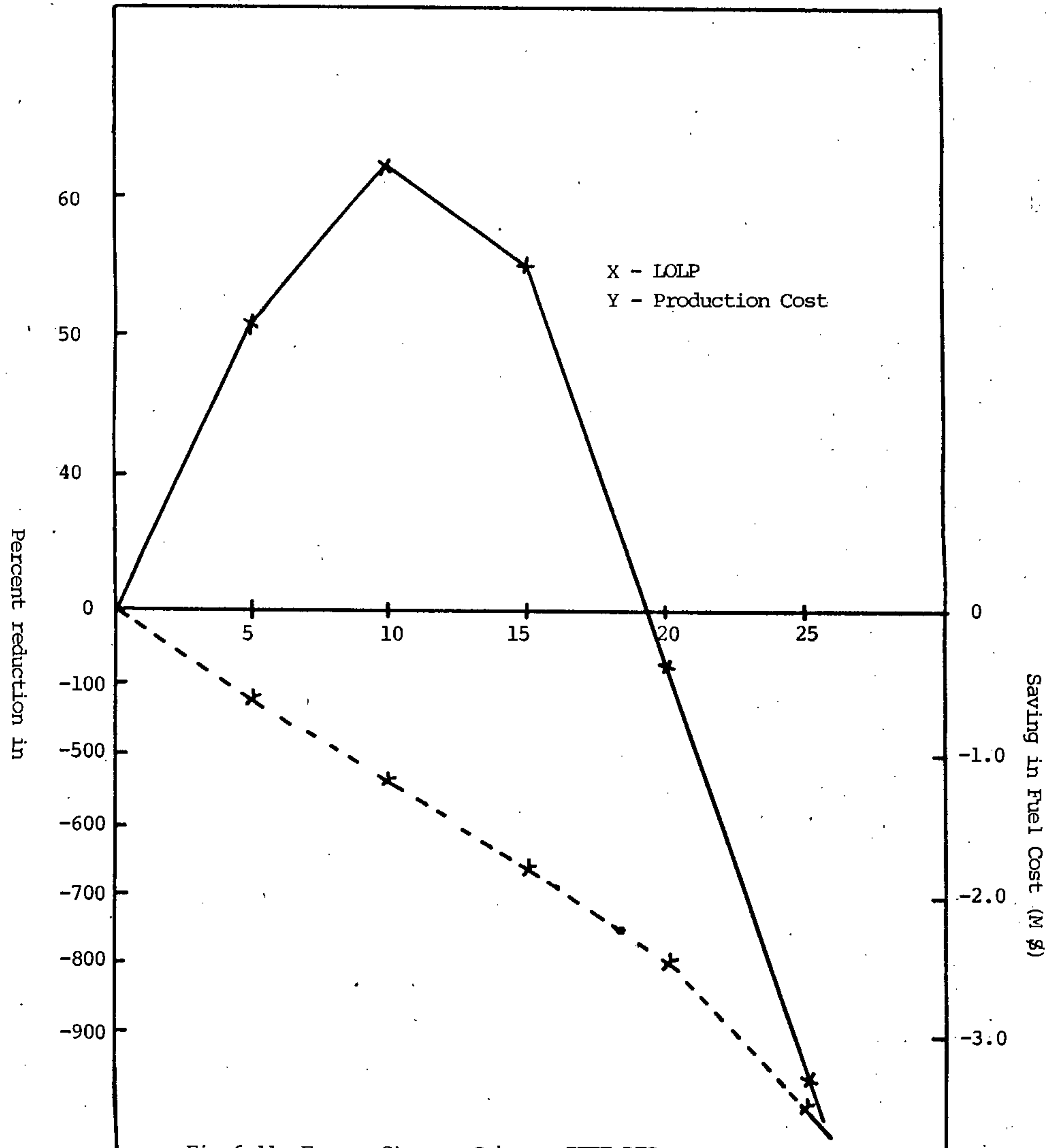


Fig.6.11: Energy Storage Scheme, IEEE-RTS

(Impact on the Reliability as well as Production Cost)

6.5 Impacts of Load Managment Incorporating Energy Limited Hydro Units.

a) Rated hydrostation capacity (130 MW) is replaced by the available generation (108 MW) of peak period.

In the generation model (Appendix - A) of BPS, a hydrostation capacity of (40 x 2+50 x 1) = 130MW is considerred. However, due to limitations in the availability of required quantity of water in the reservoir it is not possible to generate 130 MW of electricity at all the time. This type of hydro unit is known as energy limited units. To replace the hydro unit by an equivalent unit, an investigation has been made with the available hourly generation data of the hydrostation for five consecutive months extending from August'85 to December'85. In constructing the equivalent unit the generation data of peak periods, 17 to 23 hours, are only considered. The histogram of the hourly generation is depicted in fig. 6.12.

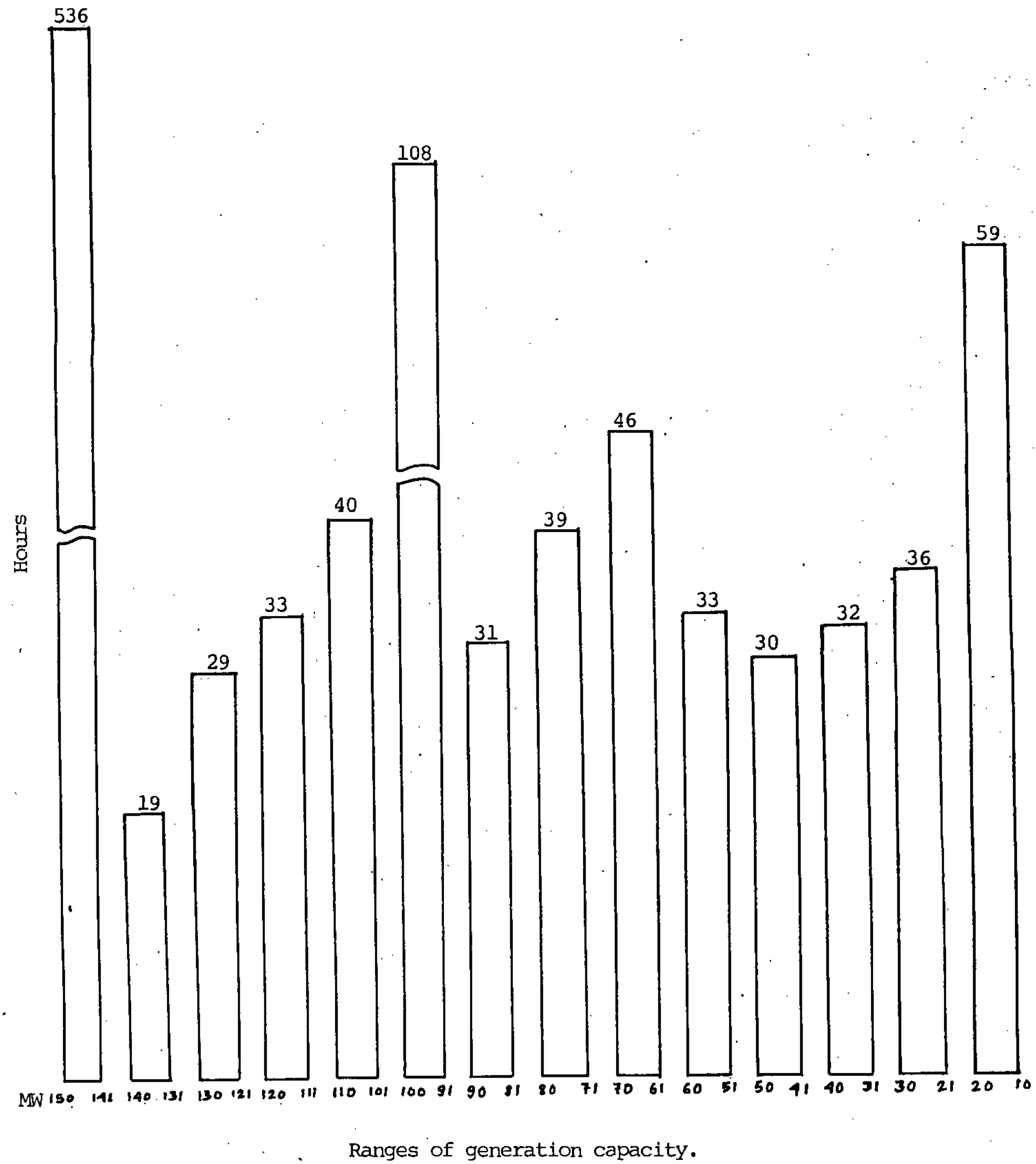


Fig. 6.12 : Histogram depicting the available hourly generation of hydrostation during the daily peak hours (17 to 23 hours) from Aug.'85 to Dec.'85.

From the histogram of fig. 6.12, the PDF of the hourly hydro generation is constructed which is shown in fig. 6.13.

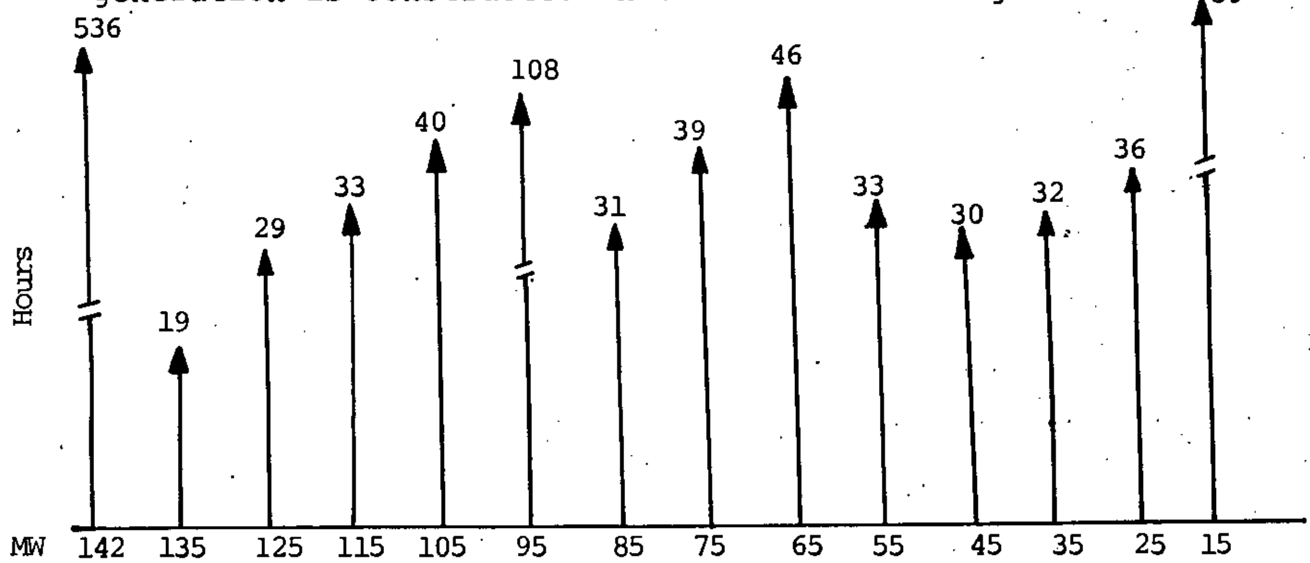


Fig. 6.13: PDF of hourly hydrogeneration during the peak periods of 153 days (August'85 to Dec.'85).
(all impulses to be divided by (153x7) = 1071).
(Vertical axis not to the scale).

The expected hydro capacity can be computed from the PDF using the basic formula of expected values. That is

$$\bar{X} = \sum_i X_i \, P_{x_i} \tag{6.1}$$

where, $\bar{X}$ is the mean of the random variable x.

P_{x_i} is the probability of occurrence of x_i.

Therefore, from fig. 6.13 the expected hydro capacity is

$= (142 \text{x} 536 + 135 \text{x} 19 + 125 \text{x} 29 + 115 \text{x} 33 + 105 \text{x} 40 + 95 \text{x} 108 + 85 \text{x} 31$

$+ 75 \text{x} 39 + 65 \text{x} 46 + 55 \text{x} 33 + 45 \text{x} 30 + 35 \text{x} 32 + 25 \text{x} 36 + 15 \text{x} 59)/1071$

$= 107.54 \simeq 108$ MW.

Now replacing the hydrostation capacity by a 108 MW hydro unit, the reliability as well as production cost is evaluated and compared with the base case. The results corresponding to reliability and production cost are shown in tables 21 and 22 respectively.

Table 21

(Hydrostation capacity 108 MW)

Peak Load	LOLP (%)	Comparison with LOLP of base case.
811.44	0.121127	LOLP is increased by 92.5% over the base case.

Table 22

Installed capacity	Expected Fuel cost (MTK)	Expected effect on the Fuel cost.
988	295.3530015	Fuel cost is expected to have increased over base case by 35·236417 9 MTk.

b) Energy storage for generating 142 MW by hydrostation during peak periods.

Although the total name plate ratings of the generating units of hydrostations are 130 MW (40x2 + 50x1), it can practically generate 142 MW of electricity if the conditions pertaining to the potentials of water heads and quantity of water flow are fulfilled.

For the present study the generation unit of 130 MW capacity is replaced by 142 MW unit. However, due to the shortage of hydro energy the hydrostation will fail to generate at the rate of 142 MW throughout the year or even throughout the day. The difference between the maximum capability (142 MW) and the average generation (108 MW) during the peak period is 34 MW. Therefore, the consideration of 142 MW hydrostation capacity will produce incorrect result.

It is assumed that this 34 MW difference in generation can be simulated by pumping water into the reservoir during the off peak period extending from 1 hour to 6 hour of each day. As the available generation capacity during the peak periods is 108 MW, then if it is made possible to run at the rate of 142 MW during the peak period of an assumed six hours, an additional (34 x6) = 204 MWh of energy will be generated. Therefore, in order to pump water to the reservoir, during the off peak period to generate at the rate of 142 MW during the peak loads, 204 MWh is multiplied by a factor of 1.4, 1.8 and 2 corresponding to the efficiencies of the pump storage plant. The results of the multiplication in terms of MWh, is equally distributed to the hourly loads extending from 1 to 6 hours.

The impacts on the reliability as well as the production costs are shown in table 23 and 24 respectively.

Table 23

(Energy storage scheme-Hydrostation generates 142 MW during peak periods)

Pump storage plant efficiency	Peak load (MW)	LOLP (%)	Percentage reduction in LOLP over base case
Base case	811.44	0.062917	
.50	811.44	0.047545	24.4%
.55	811.44	0.047540	24.4%
.715	811.44	0.047518	24.5%

Table 24

(Energy storage scheme - Hydro station generates 142 MW during peak periods).

Pump storage plant efficiency η (%)	Expected Fuel cost (MTK).	Expected savings in Fuel cost (MTK).
Base case	260.1165836	
50	253.1258387	6.9907449
55	251.9320471	8.1845365
71.5	249.6407730	10.478106

c) Rated hydrostation capacity 130 MW is replaced by the average generation (68 MW) of five months.

In this case, an analysis has been made with the hourly hydrogeneration for five consecutive months. Fig. 6.14 is the histogram depicting the ranges of available hydro power capacity in MW corresponding to the hours of five consecutive months (153 days or

3672 hours). Here, both the 'on peak' as well as the 'off peak' hours of generation are considered. From the histogram the PDF of the hydro power is constructed which is shown in Fig. 6.15.

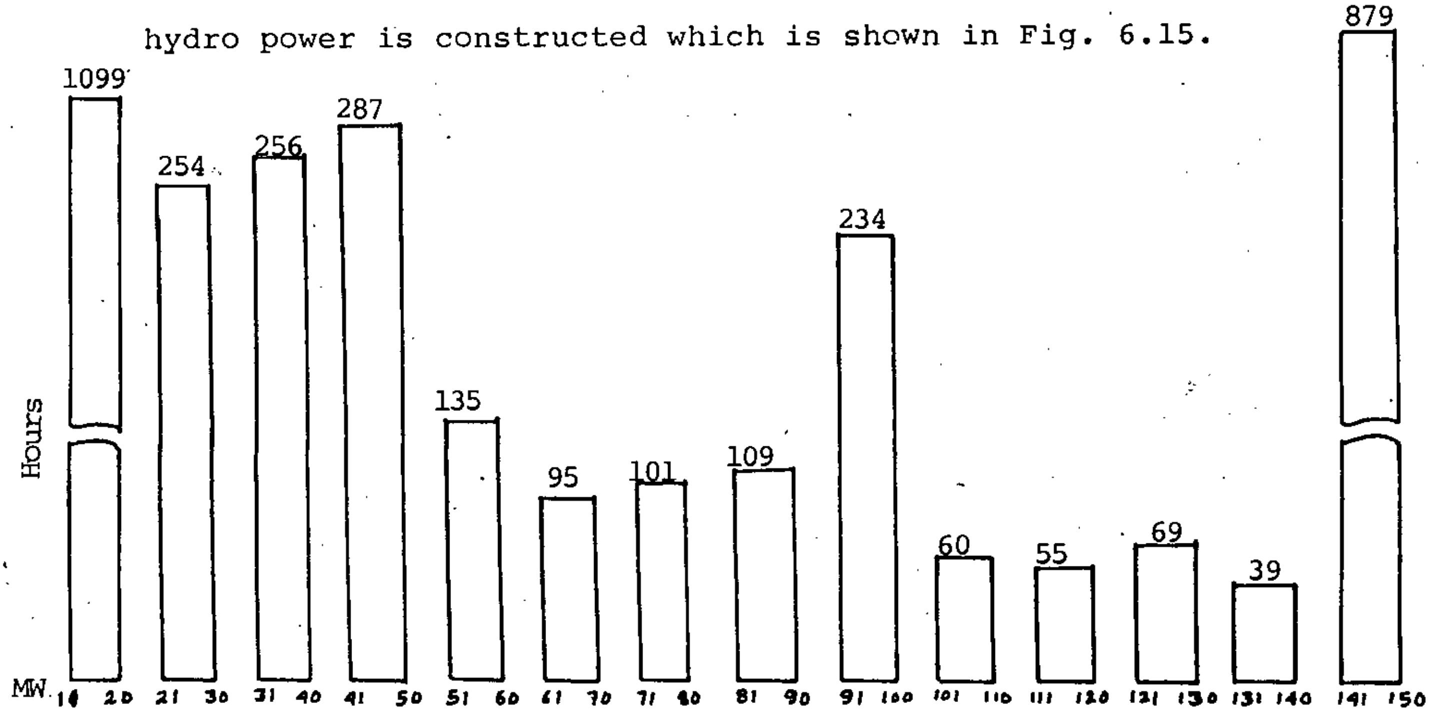


Fig. 6.14: Histogram of hourly generation by hydro station of BPS.
(From August'85 to December'85.
Total number of hours = 3672).

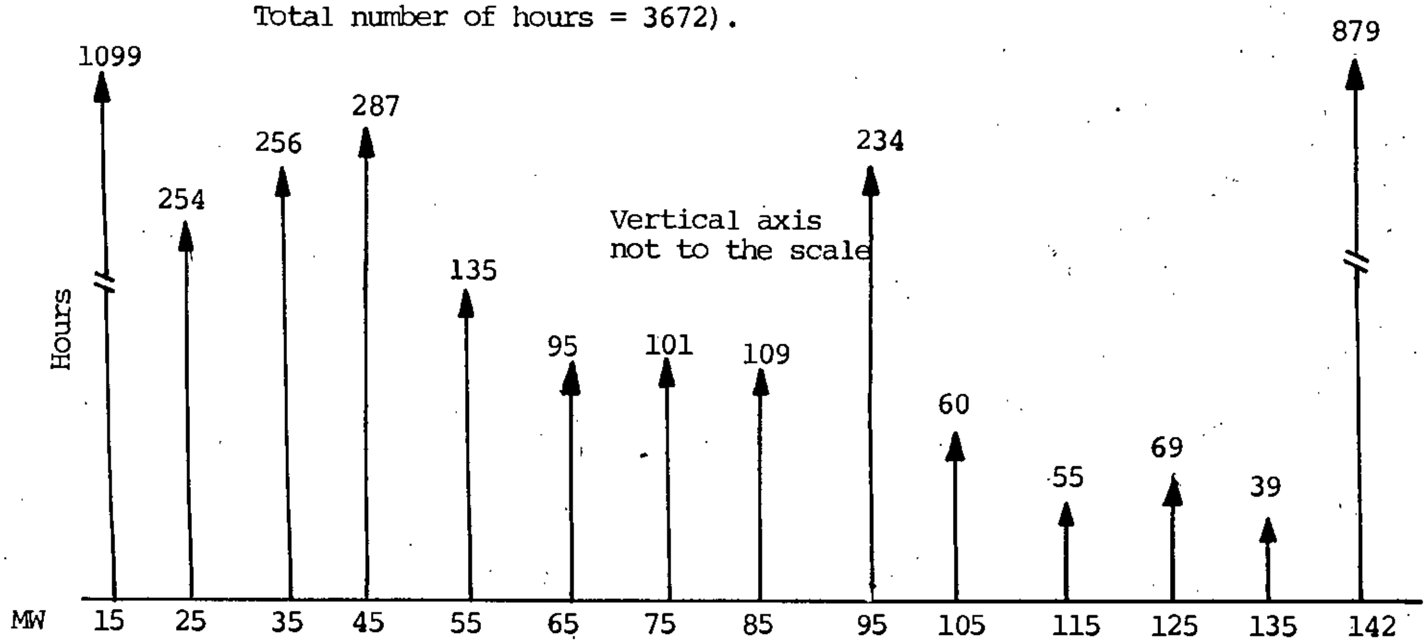


Fig. 6.15 PDF of hourly generation from Aug. to Dec.'85 of hydro power station of BPS.
(All impulses should be divided by 3672).

The expected hydro capacity may be computed from the PDF using the basic formula of expected values. That is, recalling equation (6.1).

$$\bar{X} = \sum_i x_i p_{x_i}$$

Therefore, expected hydro capacity

$$= (15x1099 + 25x254 + 35x256 + 45x287 + 55x135 + 65x95$$
$$+ 75x101 + 85x109 + 95x234 + 105x60 + 115x55 + 125x 69$$
$$+ 135x39 + 142x879)/3672 = 68.56 \simeq 68 \text{ MW}.$$

Generation model is again modified by replacing the hydrostation capacity with 68 MW. The impacts on the reliability as well as on the production costs are shown in table 25 and 26 respectively.

Table 25

(Hydro station capacity 68 MW.
Impact on reliability).

Peak load (MW)	LOLP (%)	Percentage reduction in LOLP over base case.
811.44	0.062917	Base case
811.44	0.323511	-414.2%

Table 26

(Hydrostation capacity 68 MW.
Impact on production cost).

Installed capacity	Expected Fuel cost (MTK.)	Expected savings in Fuel cost (MTK.)
1010	260.1165836	Base case
948	378.0575863	-117.9410027

d) Energy storage for generating 142 MW throughout the day

The hydrostation capacity is again considered as 142 MW in generation model and water is pumped during off peak periods corresponding to the capacity diff. of (142-68). = 74 MW. In this case, it is assumed that through the pumping of water during off peak periods only, the hydrostation will be capable of generating 142 MW for the whole 24 hours of the day The results showing the impacts on reliability and production cost are shown in table 27 and table 28 respectively.

Table 27

(Energy storage for generating 142 MW throughout the day, Impact on reliability).

Pump storage plant efficiency (η)	Modified peak load (MW)	LOLP (%)	Percentage reduction in LOLP over base case
Base case	811.44	0.062917	
.50	1143.70	18.010120	-285.3x100
.55	1084.50	14.871524	-235.4x100
.715	966.10	2.949747	- 45.88x100

Table 28

(Energy storage for generating 142 MW throughout the day. Impact on production cost).

Pump storage plant efficeincy η	Expected Fuel cost (MTK.)	Expected savings in fuel cost (MTK.)
Base case	260.1165836	-
.50	819.6793454	-559.5627618
.55	760.2608803	-500.1442967
.715	614.7482158	-354.6316322

CHAPTER SEVEN
OBSERVATIONS AND CONCLUSIONS

7.1 Observation and Discussions.

In what follows, the salient point observed in this study are mentioned along with probable explanation.

7.1.1 Reliability.

Regarding the impacts of load management on the reliability of the systems, the following observations are made.

Direct load management strategy.

1) It is observed from tables 1. 3 and 5 as well as from figures 6.3 and 6.5 that the reduction of the loads during the peak periods causes a reduction in LOLPs over that of base case. That is, every reduction in the value of peak loads provides a corresponding improvement in the reliability of the system. It is also evident from the results that the increase amount of load reduction decreases the LOLP. However, if the load reduction exceeds 20% in case of BPDB system and 15% in case of IEEE-RTS the rate of improvement in reliability becomes almost flat. A sharp rate of improvement is observed for the load reduction upto 10%.

2) For the constant peak approach of direct load management scheme it is observed from tables 7 and 9 as well as from fig. 6.3 and 6.5 that the application of this approach reduces the LOLP of the systems. It is also observed that the decrease in

LOLP increases with the lower amount of the prefixed peak demand.

In case of BPDB system, comparing the results of tables 1 and 7 and also the results of fig. 6.3 it is observed that the load reduction during the peak hours approach improves the systems reliability more than that due to constant peak approach. For example, for a 20% peak reduction the LOLP is 0.001786% while for 20% reduced prefixed peak demand the LOLP is 0.018328%.

In case of IEEE-RTS, it is observed from fig. 6.5 that the constant peak approach provides a better improvement in the system's reliability than the direct load reduction approach if the load reduction is more than 10%. However, if the load reduction is less than 10%, then the direct load reduction approach provides better improvement in the system's reliability. The comparison of the results of table 5 and 9 confirm this.

3) The results of table 1, 3 and 7 show that the constant peak approach have a better control on the peak load of the system than the direct LM scheme. That is with the constant peak approach the system will have the desired peak thereby it can easily reduce the reserve requirements.

Indirect load management strategy

Recall that in this approach only the loads are shifted from on peak period to off peak period. However, the total amount of energy requirements remains the same as the base case. It is observed from the results of fig. 6.7 and table 11 that with the application of indirect load management strategy the reliability of the system improves over the base case. It is also observed from the results that the shifting of load beyond 20% increases the LOLP. That is, the improvement in the reliability occurs upto 20% of the load shift, beyond which the systems reliability deteriorates.

Energy storage scheme.

1) From table 13 to 15 and table 19 as well as from figures 6.9 and 6.11, it is observed that the application of the energy storage scheme reduces the LOLP upto certain percentage of load reduction, beyond which the LOLP increases even exceeding the LOLP of the base case. For example, in case of BPDB system for the 50% pump efficiency, the improvement in reliability halts if the load reduction is more than 15% and the reliability deteriorates compared to the base case for the load reduction more than 20%. The limit of load reduction causing the improvement in reliability increases with the increase of the pump efficiency. This is confirmed in fig. 6.9 and 6.11.

2) The hydro unit of BPDB system with the rated capacity of 130 MW is replaced by a unit of average capacity 108 MW. This average capacity is obtained from the distribution of genera-

tion. It is expected that with the hydro unit of average capacity the LOLP will increase and the results of table 21 confirm this.

3) The results of table 23 show that the reliability of the system improves if the hydro unit with average capacity i.e., 108 MW, is available throughout the day except the peak hours and if the hydro unit during peak hours is available with its maximum capacity, i.e., 142 MW. Recall that the extra head of water during the peak hours is procured through pumping water during off peak hour.

7.1.2 Production Costing.

Regarding the impacts of load management schemes on production costs the following observations are made.

Direct load management scheme.

1) It is evident from table 2, 4 and 6 as well as from fig. 6.4 that the direct load reduction scheme decreases the production cost of the systems. A higher percentage reduction in the hourly loads results in the greater savings of the production cost which is expected.

2) Comparing the results of tables 2 and 4 and also the results of fig. 6.4 it is observed that a greater savings in production costs can be achieved if the period of load management is increased. This is also expected.

3) If a comparison is made between the fig. 6.4 and fig. 6.6 it becomes clearly evident that direct reduction in loads assures a higher savings in production cost than the constant peak approach.

Indirect load management scheme.

Table 12 and Fig. 6.8 show that if the load is shifted from the on peak to off peak period the savings in production cost can be achieved although the total amount of energy supplied remains the same as the base case. However as incase of reliability, the maximum savings in the production cost is realized at 20% reduction of the peak loads. If the load reduction is made beyond 20% the savings in production cost starts to decrease.

Energy storage scheme.

1) In case of BPDB system, it is observed from the table 16, table 17, table 18 and fig. 6.10 that the application of the energy storage scheme provides the savings in production cost of the system upto a certain percentage of reduction of the hourly loads of peak period depending upon the efficiency of the storage plant considered. It is noted that the greater the efficiency of the storage plant, the greater is the savings in production cost. From fig. 6.10, it is clearly observed that the savings in production cost over the base case increases with the percentage reduction of load, reaching at the maximum

savings at 10% and then begins to decrease ultimately becomes zero or negative depending upon the efficiency of the storage plant. It may be noted here that negative savings indicates that the production cost of the system has become higher than that of the base case as a result of the implementation of energy storage scheme.

2) Table 20 and fig. 6.11 indicate that the application of energy storage scheme is not suitable for the IEEE-RTS so far as the savings in production cost is concerned. Any percentage reduction in peak loads causes the production costs to become higher over the base case.

3) Table 22 and table 26 show that if the generation model of the BPDB system is modified with the replacement of 130 MW hydrostation capacity by 108 or 68 MW considering the limitations in generation capacity arising out of nonavailability of required water head then the production cost of the system increasesabove the base case.

4) It is observed from table 24 that if the energy storage scheme is applied in BPDB system with 142 MW hydro unit during the peak period the production cost decreases from the base case. That is, the savings in terms of production cost is achieved.

5) However, table 27 shows that if the energy storage scheme is applied in BPDB system with 142 MW hydro unit during the whole

day then the production costs of the system increases. That is, the utility looses in terms of production cost in this case.

7.2 Conclusions.

Pressed for funds and concerned about huge investment in constructing new power plants electric utilities are increasingly placing renewed emphasis on the load management program. In this thesis, investigation has been made to study the impacts on the reliability as well as on the production cost while different load management strategies are applied to the system.

On the basis of the results obtained in this research the following conclusions are put forward.

1) The load management strategies have better effect on improving the systems reliability and also on increasing the benefit interms of production cost savings.

2) The indirect load management approach improves the reliability as well as provides the savingsin the production cost upto certain percentage of load reduction beyond which the reliability deteriorates and the savings decreases. The limits of load reduction depends on the system.

3) Generally, the direct load reduction scheme has a better effect in improving the reliability and savings in production cost compared to constant peak approach. This is also system dependent.

4) The application of energy storage.scheme improves the reliability and saves production cost in general. However, the optimum amount of energy storage depends on the load pattern of the system.

7.3 Recommendation for further study.

Prior to the commissioning of East-west interconnector the power system of Bangladesh has been operated as two isolated systems separated by the river Jamuna. As the east west interconnector (EWI) came into operation with the subsequent augmentation of the whole of generation, transmission and distribution networks the power system is supposed to be operating as a single area system. However, inequality and nonuniformity still exists between the two interconnected areas in both generation and consumption due to resource limitations particularly in the western grids and inherent limitations in the tie line capacities of the interconnector.

In this thesis, the system is evaluated by studying the impact on reliability and production cost through the implementation of load management program assuming the power system of Bangladesh as a single area system. But it has already been established [33] that the evaluation of two interconnected systems with finite tie line capacity using a 'two area' approach is the most appropriate way of evaluation of such systems . So research works addressing the impacts of load management on the system may be carried out considering BPDB system as the two area system for different tie line capacities. In this research, the existing generation system and demand of BPDB has been used. But for a realistic long term generation expansion planning, the demand for the planning period must be forecasted. Also, the planned generating capacity additions for that period must be taken into consideration. And for a more realistic analysis, the multistate representation of generating units as well as multiblock loading of generating units may be taken into consideration.

Energy storage schemes deserve proven potentiality as the most important and pragmatic approach of load management strategy. Research works may be addressed to the techno-economic feasibility study of constructing another reservoir along with the existing one at the only hydroelectric project of the country. To meet the increasing load growth BPDB is planning for the construction of newer power plants. Construction of large gas turbine power plants are also included in its planning process and research work may be carried out to investigate the suitability of air storage plant to be incorporated with the gas turbine plants. In the generation expansion planning process, load management is considered as an alternative to installing conventional power plants for meeting the future demand or to improve the system reliability. The equivalent capacity addition to the percentage reduction of load in different LM strategies may be investigated in terms of reliability improvement and production cost savings.

APPENDIX-A

GENERATION DATA FOR BPDB SYSTEM

Name of power station	Type of fuel	No. of units	Capacity (MW)	FOR	Avg. inc. fuel cost Tk./KWh.
Karnafuli Hydro	Hydro	1 2	50 40	0.01 0.01	0.0 0.0
Ashuganj Steam Turbine	Gas	2	65	0.10	0.14
Siddhirganj Steam Turbine	Gas	1 3	50 10	0.10 0.15	0.15 0.23
Chittagong Steam Turbine	Gas	1	60	0.10	0.16
Ghorasal Steam Turbine	Gas	2	55	0.10	0.16
Ashuganj Combined Cycle	Gas	1(GT) 1(ST)	55 30	0.19 0.19	0.16 0.16
Shahjibazar Gas Turbine	Gas	7	10	0.18	0.27
Chittagong Gas Turbine	Gas	2	5	0.18	0.28

Appendix-A (Continued)

Name of power station	Type of fuel	No. of units	Capacity (MW)	FOR	Avg. inc. fuel cost Tk./KWh
Khulna Steam Turbine	F. oil	1	110	0.10	1.57
		1	60	0.10	1.79
		2	5	0.15	3.32
Khulna Gas Turbine (Barge)	SKO	2	25	0.18	2.62
Barisal Gas Turbine	HSD	1	20	0.15	3.01
Bheramara Gas Turbine	HSD	3	20	0.18	3.24
Small Diesel Stations*	LDO/ HSD	1	5	0.12	1.93
		1	5	0.12	2.00
		1	5	0.12	2.20
		1	5	0.12	2.35
		1	5	0.12	2.49

* These are small diesel stations located at Thakurgaon, Bogra, Goalpara, Barisal, Rajshahi and Serajganj. Several small diesel units of these stations have been aggregated to form 5 units of 5 MW size.

APPENDIX-B

GENERATION DATA FOR
IEEE RELIABILITY TEST SYSTEM.

Type of unit	Unit size (MW)	No. of units	FOR	Avg.λ ($/MWh)
Nuclear	400	2	0.12	5.45
Coal	350	1	0.08	10.883
Coal	150	4	0.04	10.704
Coal	80	4	0.02	13.494
Oil	200	3	0.05	20.730
Oil	100	3	0.04	20.853
Oil	20	4	0.10	37.500
Oil	10	5	0.02	25.875
Hydro	50	6	0.01	0

Total installed capacity	3400 MW.
Peak load	2850 MW.
Minimum load	1102 MW.
Time duration	2184 hours.

APPENDIX-C

DAILY LOAD FACTOR OF BANGLADESH POWER SYSTEM FOR THE PERIOD OF FIVE CONSECUTIVE MONTHS FROM AUGUST'85 TO DECEMBER'85.

In order to investigate the patterns of loads on Bangladesh power system an analysis have been made with the hourly demand data for a period of five consecutive months. To observe the variation in the hourly demand, daily load factors for the said periods of five months or 153 days are graphically depicted in what follows.

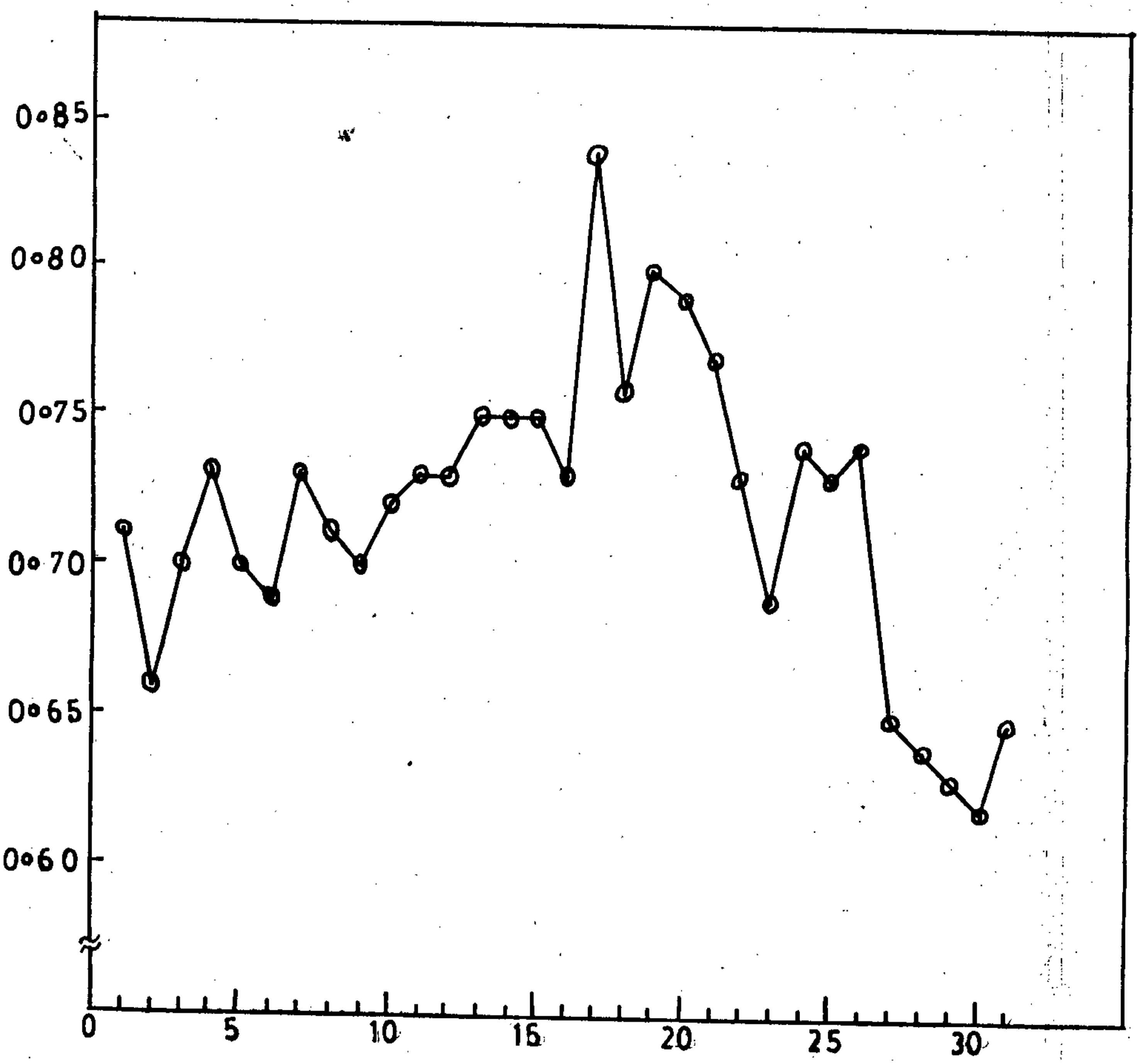


FIG. 1-DAILY LOAD FACTOR FOR THE MONTH OF AUGUST- 1985

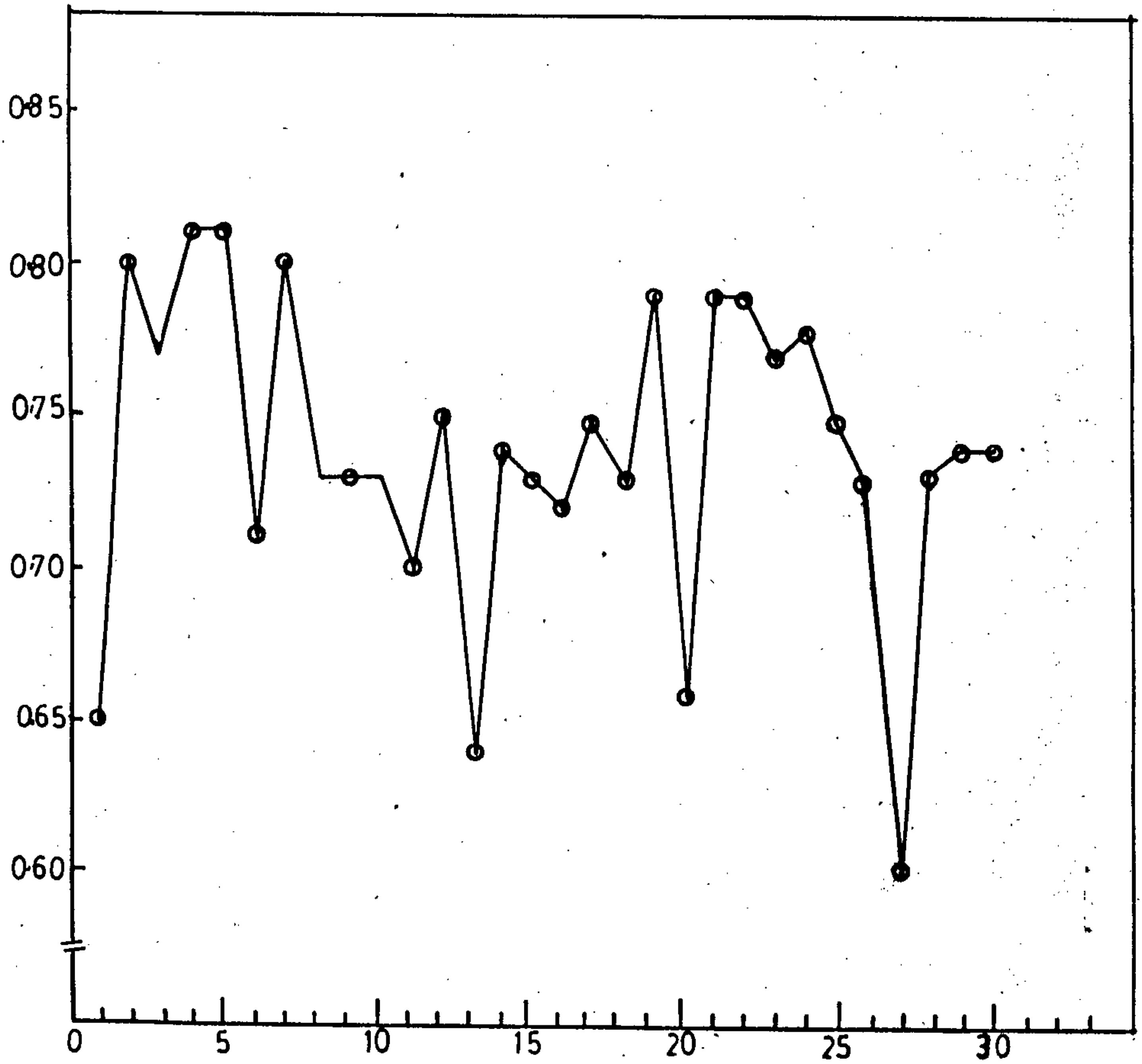


FIG. 2 : DAILY LOAD FACTOR FOR THE MONTH OF SEPTEMBER-1985.

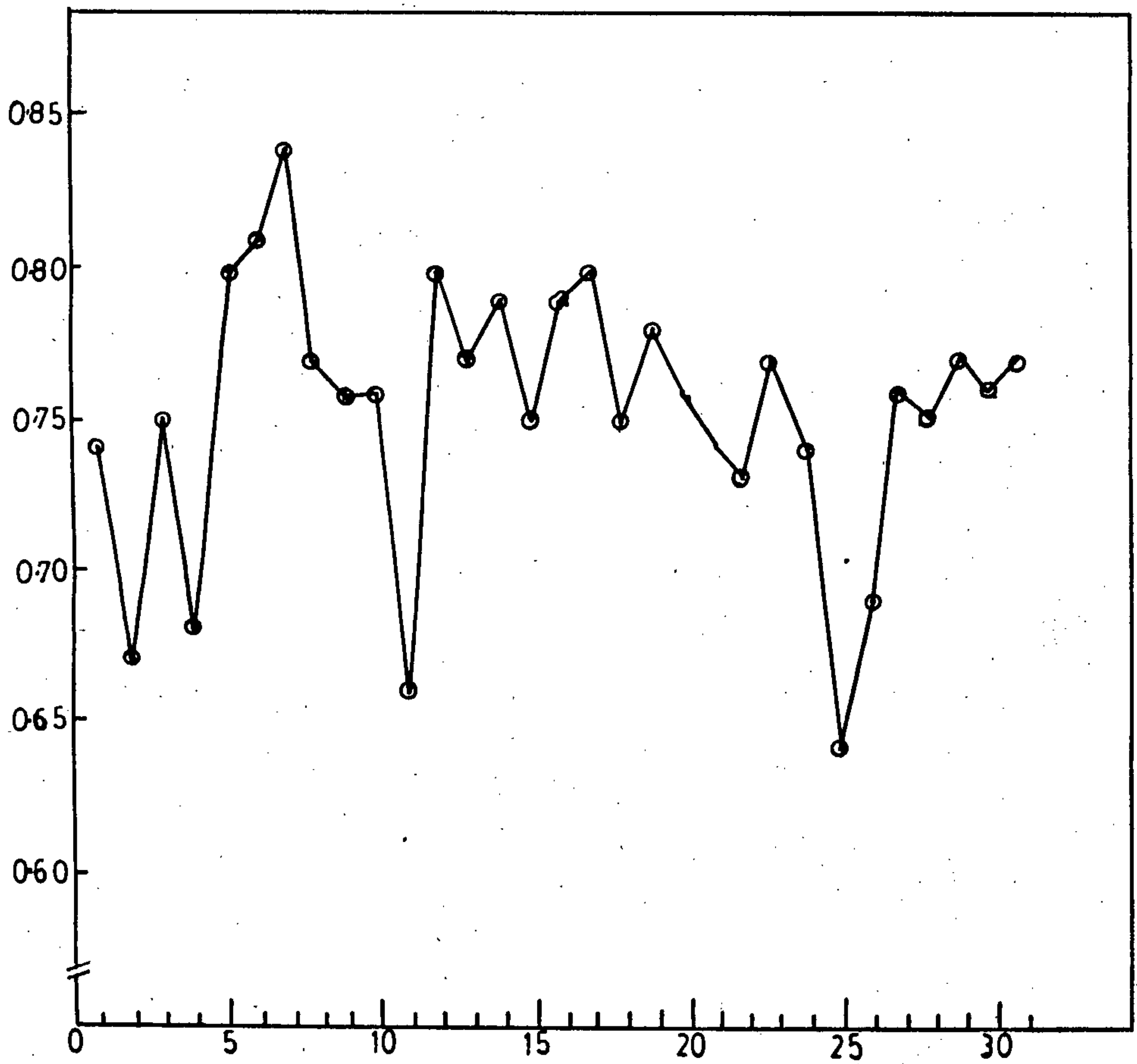


FIG. 3: DAILY LOAD FACTOR FOR THE MONTH OF OCTOBER-1985.

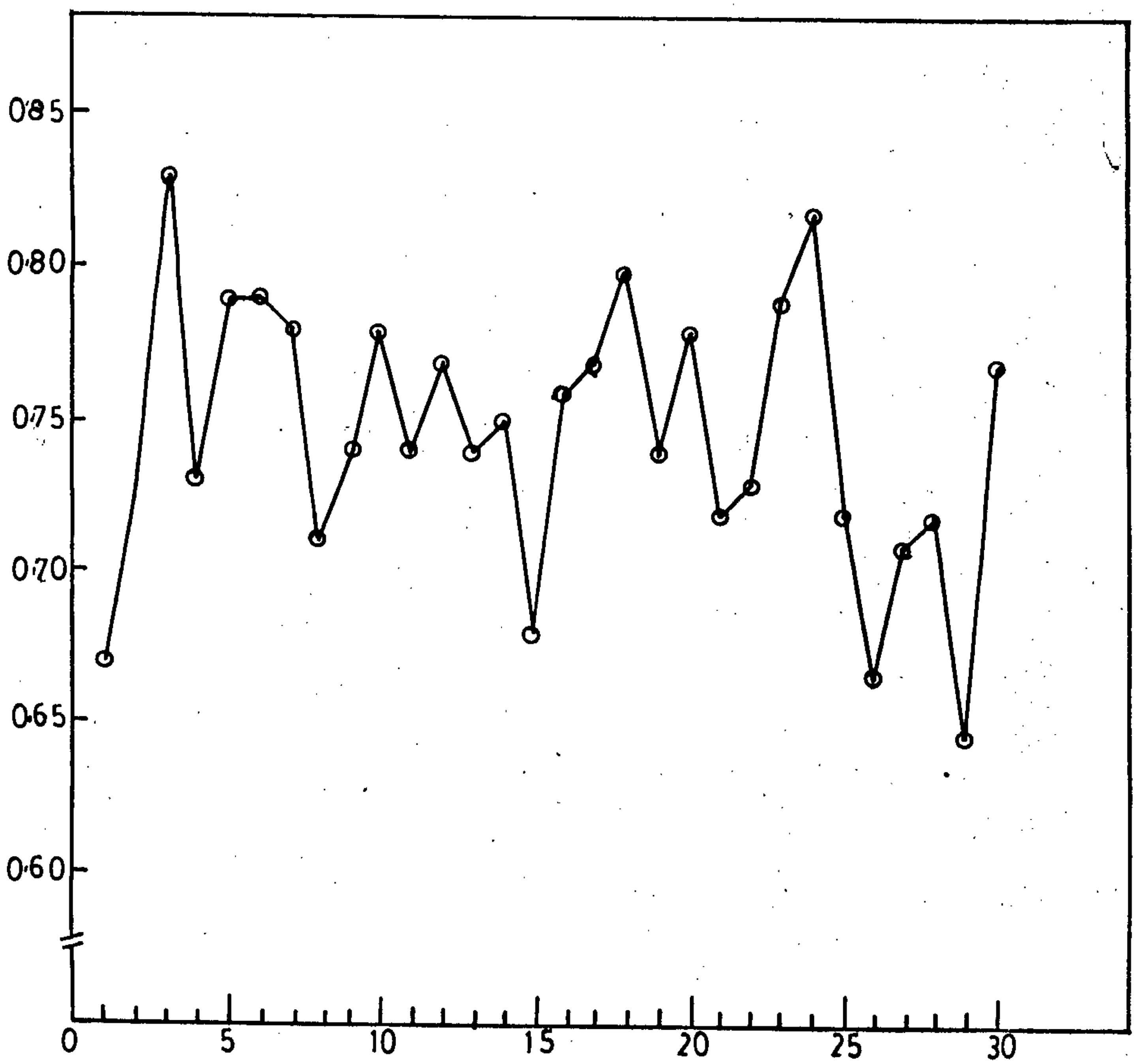


FIG. 4: DAILY LOAD FACTOR FOR THE MONTH OF NOVEMBER-1985.

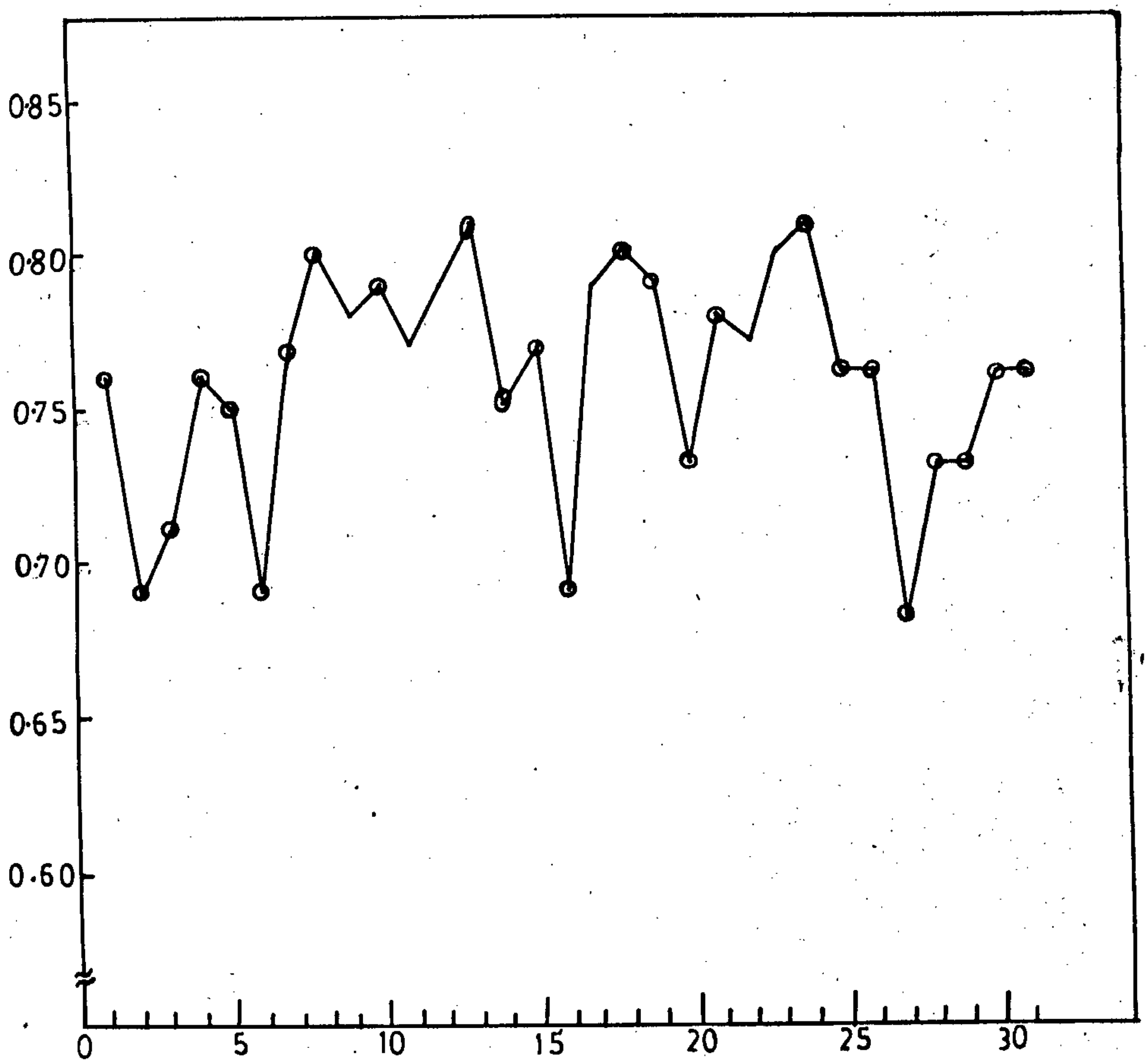
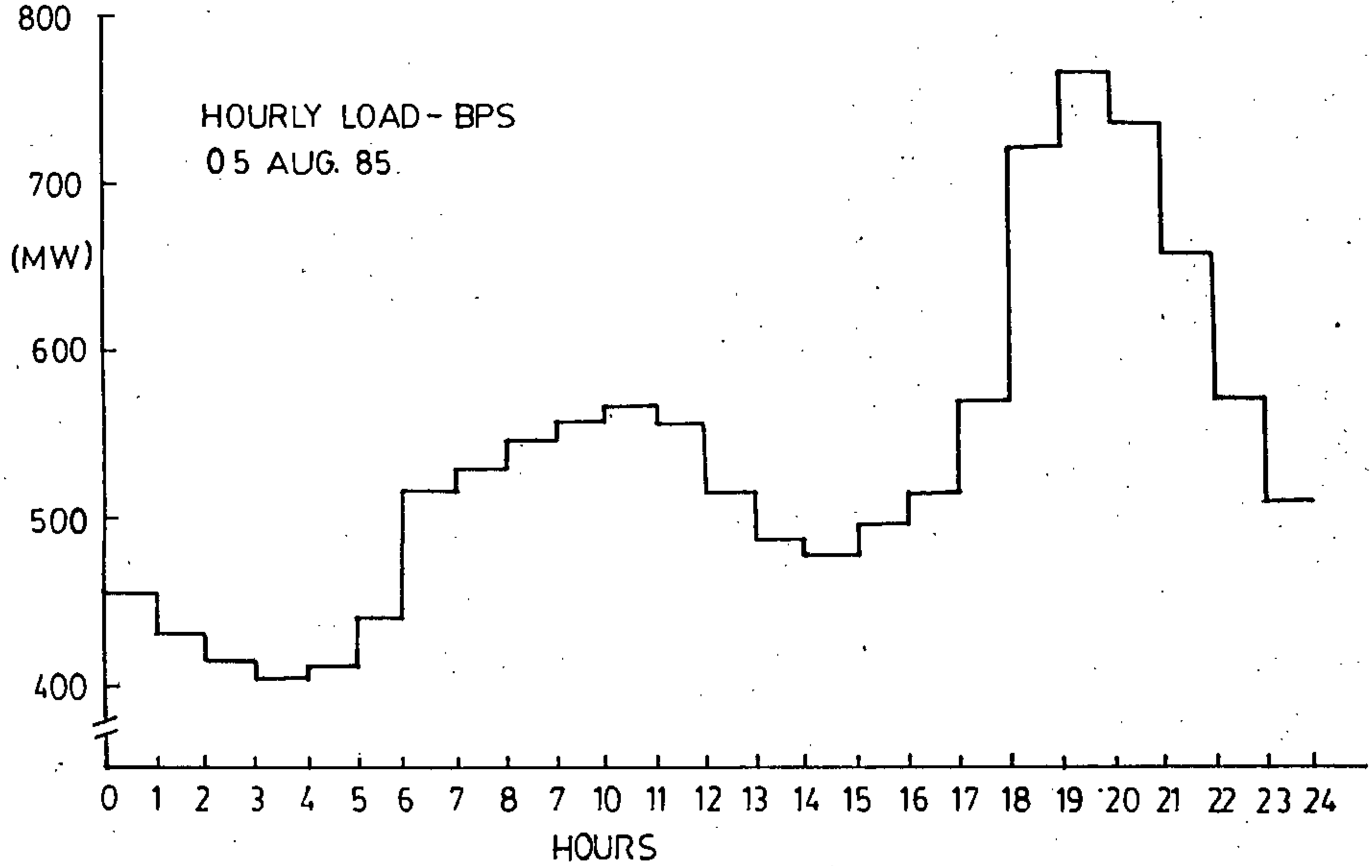


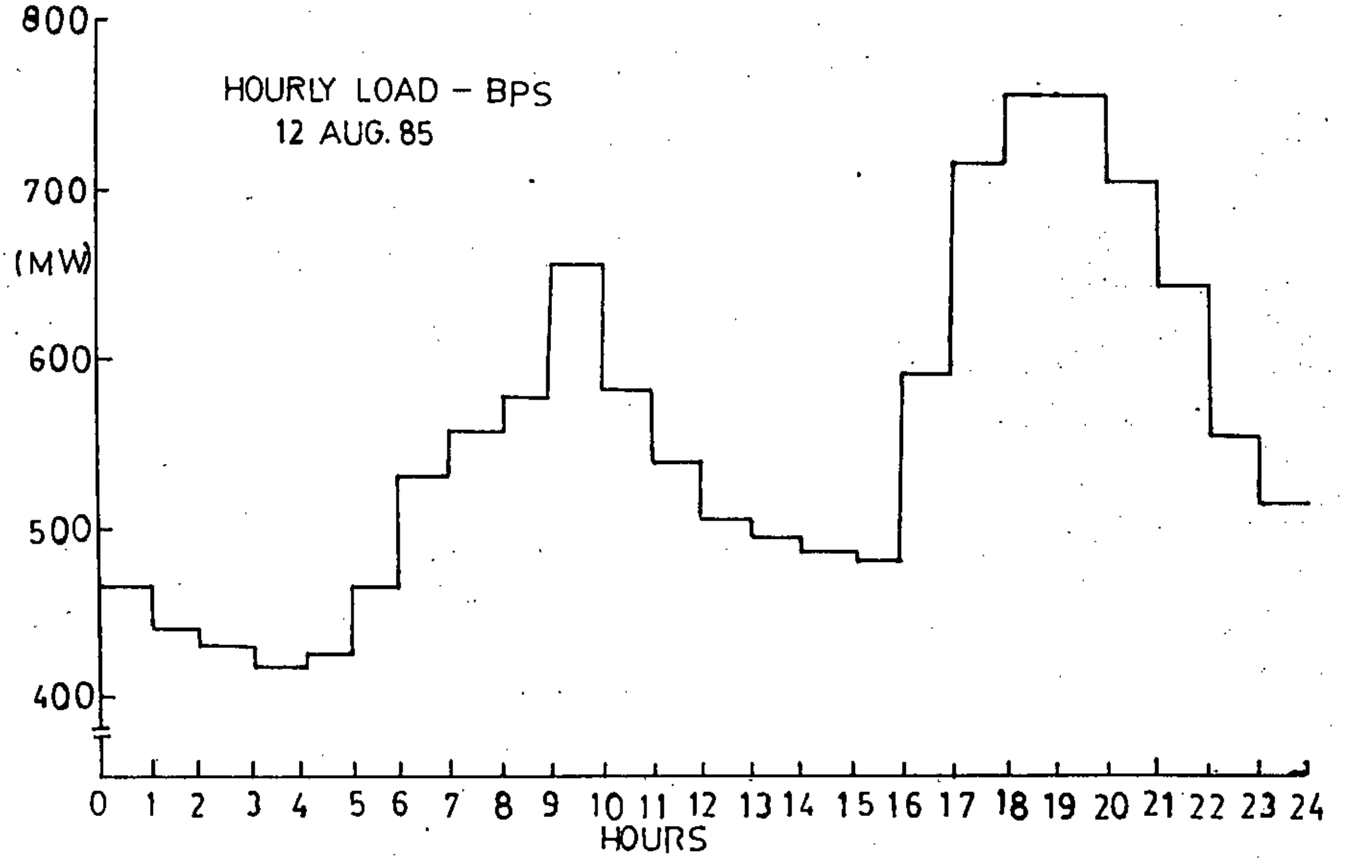
FIG. 5: DAILY LOAD FACTOR FOR THE MONTH OF DECEMBER-1985.

APPENDIX-D

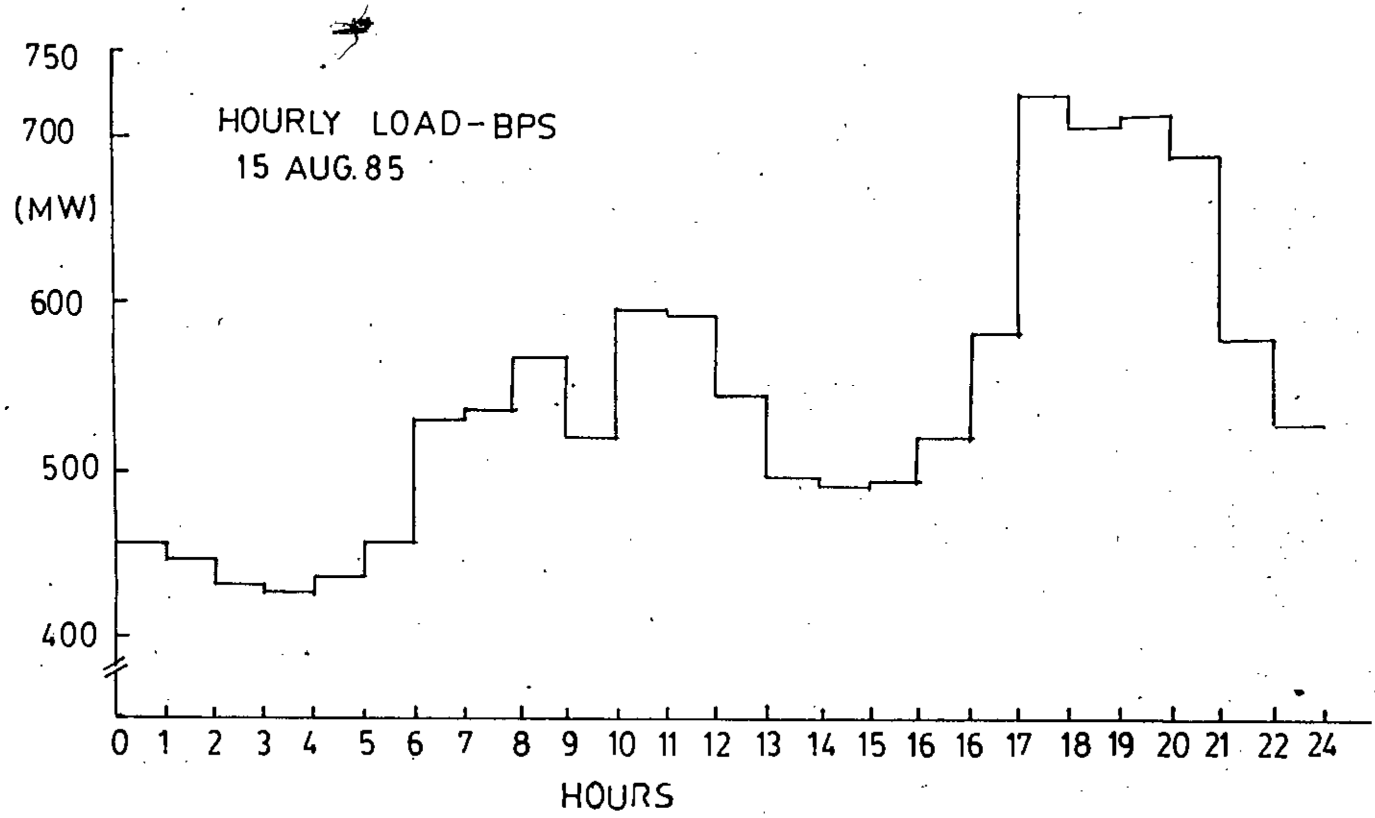
To investigate the most suitable period at which the implementation of load management strategy is expected to impact favourably on Bangladesh power system, an analysis have been made with the hourly load data of five consecutive months. For each week, the day at which the highest load of the week occurs is found out and hourly load curves for that day is plotted. Curves for twenty such consecutive weeks are presented in the next pages.

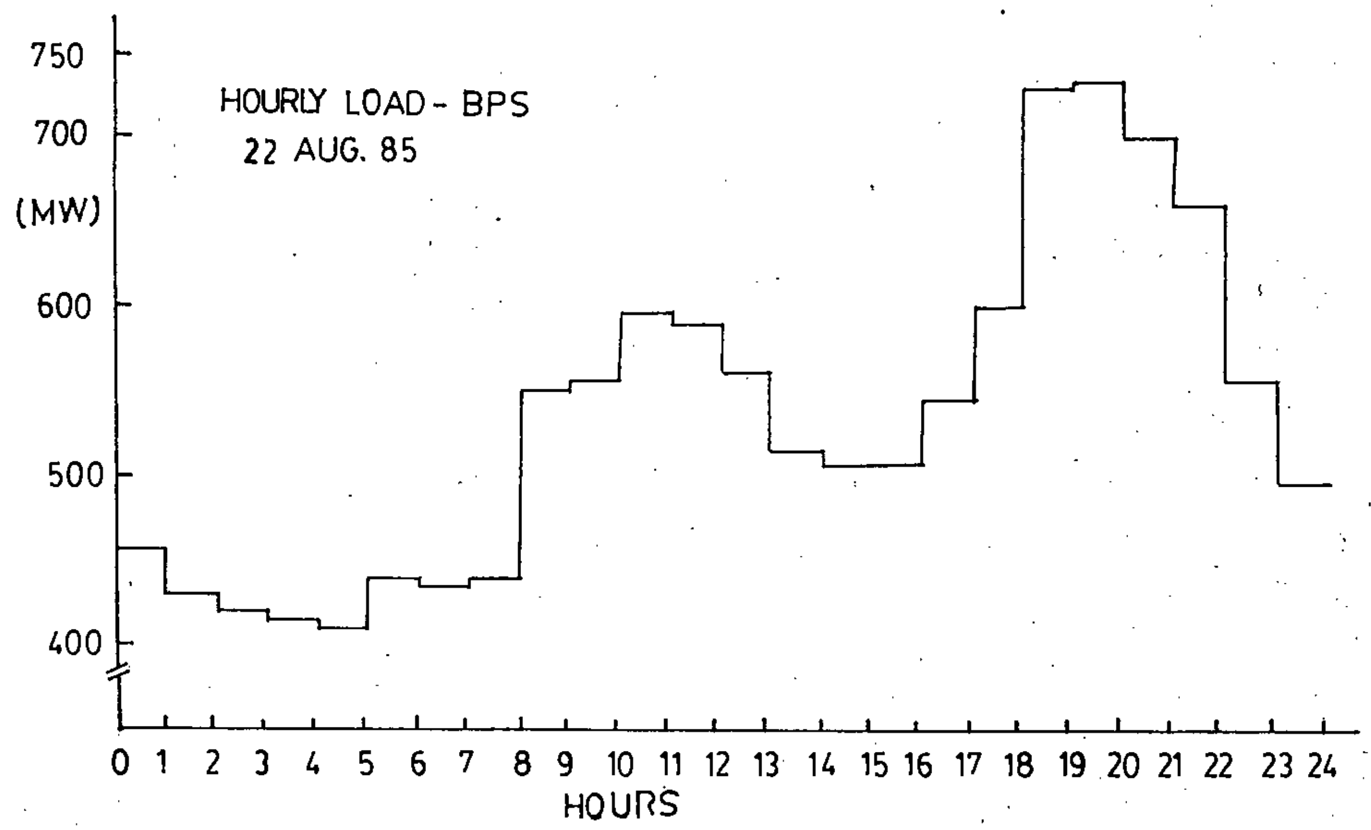


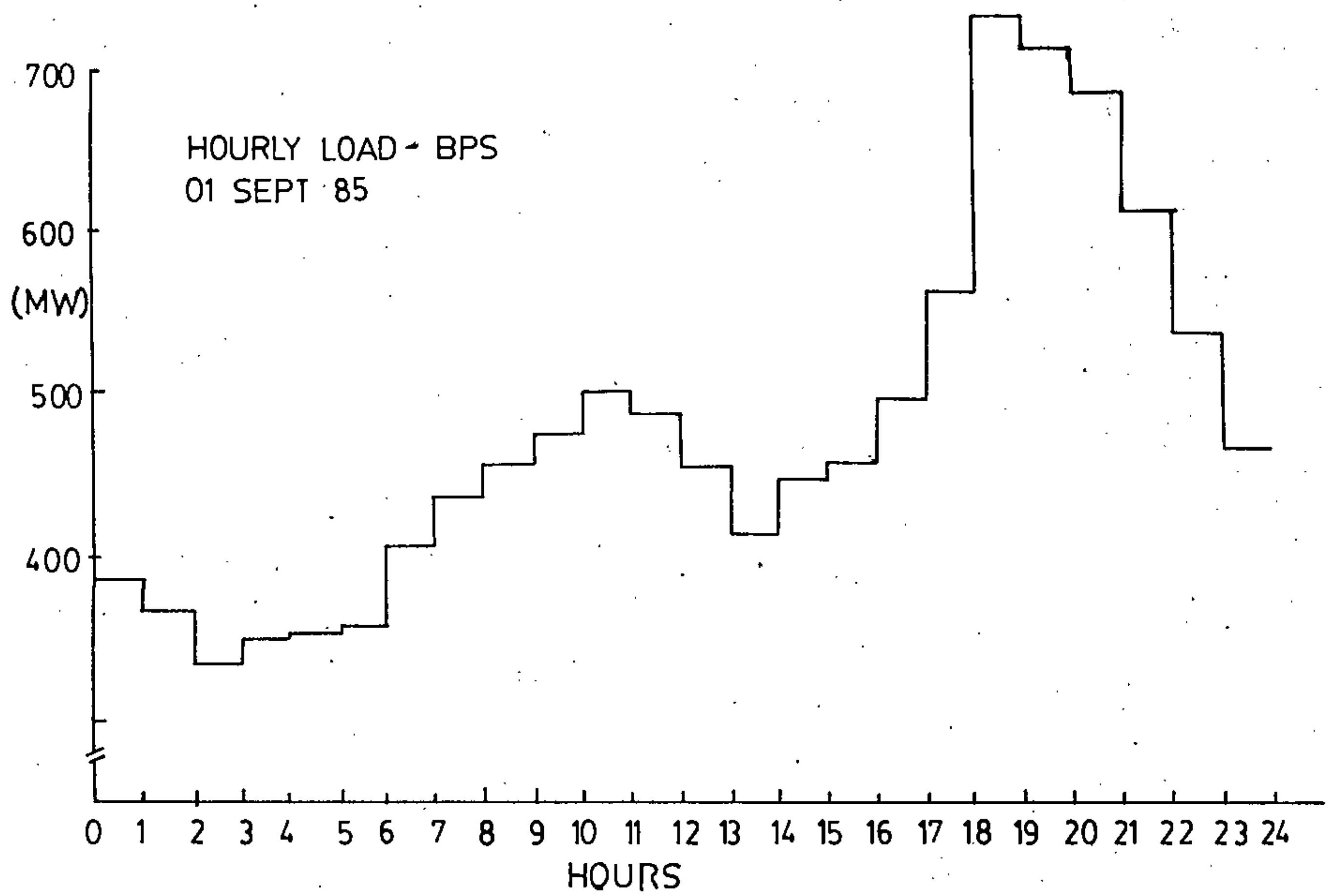
800
700
600
500
400
(MW)
HOURLY LOAD - BPS
05 AUG. 85
0 1 2 3 4 5 6 7 8 7 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOURS

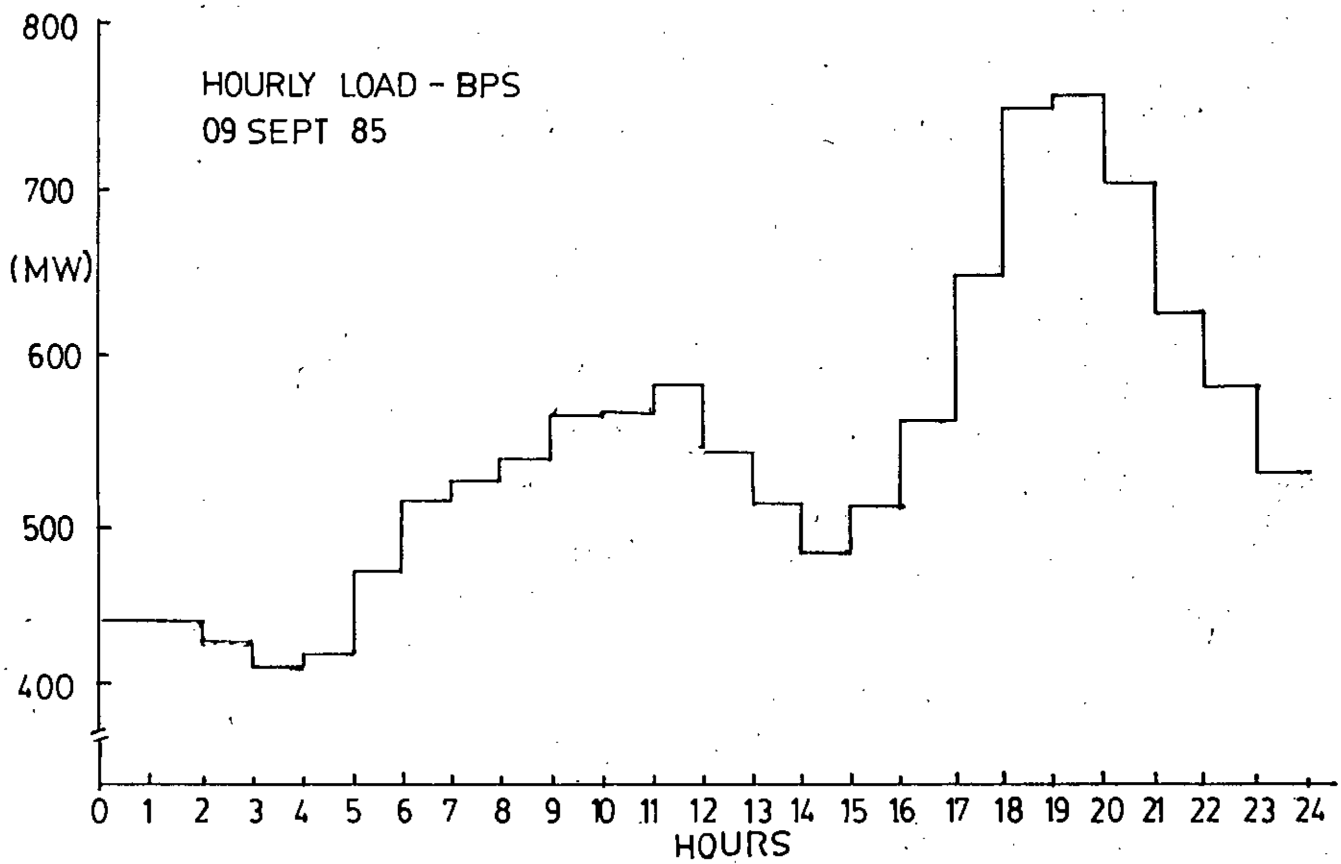


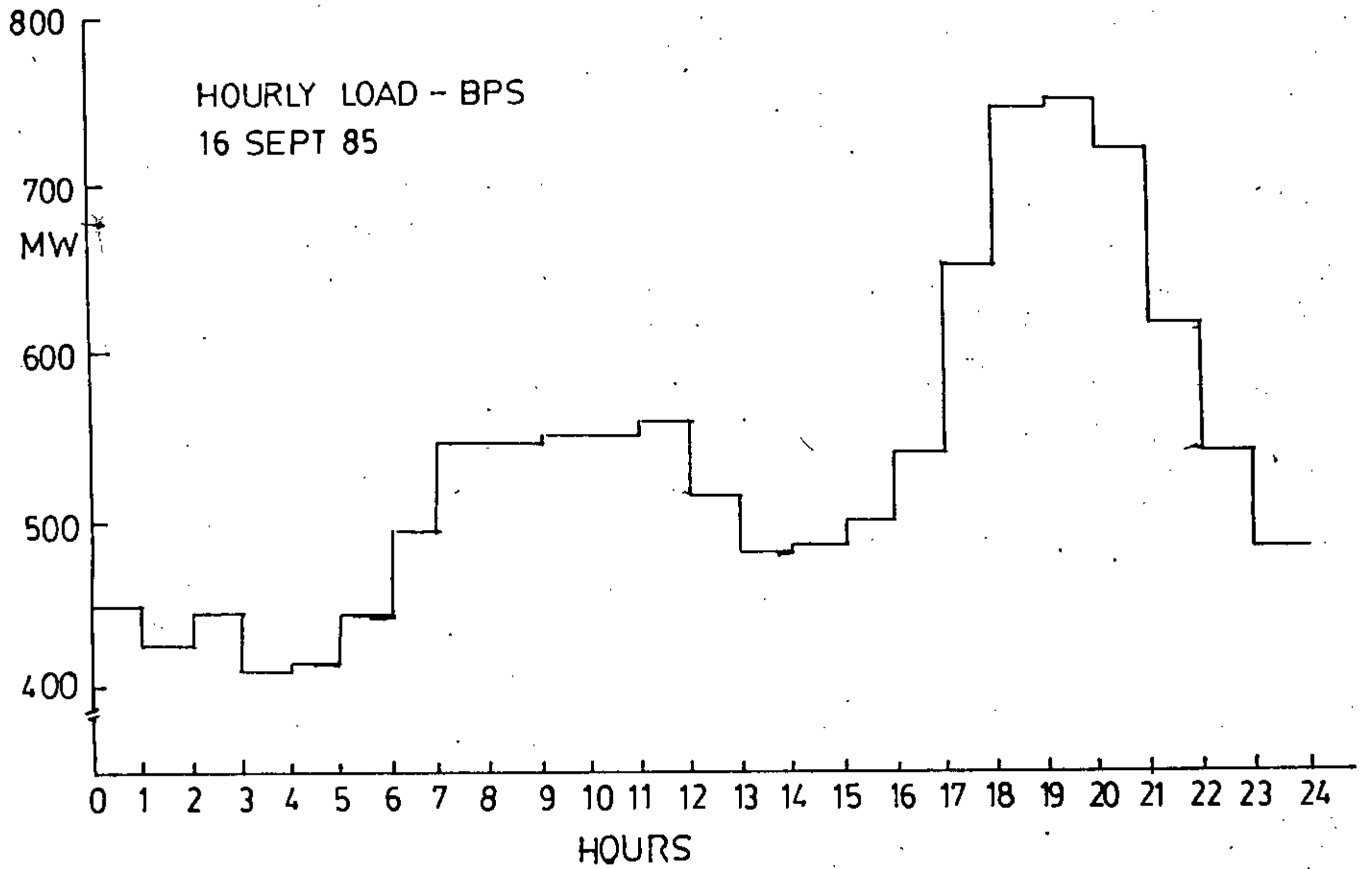
800
700
600
500
400
(MW)
HOURLY LOAD - BPS
12 AUG. 85
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOURS


750
HOURLY LOAD-BPS
15 AUG.85
700
(MW)
600
500
400
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 16 17 18 19 20 21 22 24
HOURS

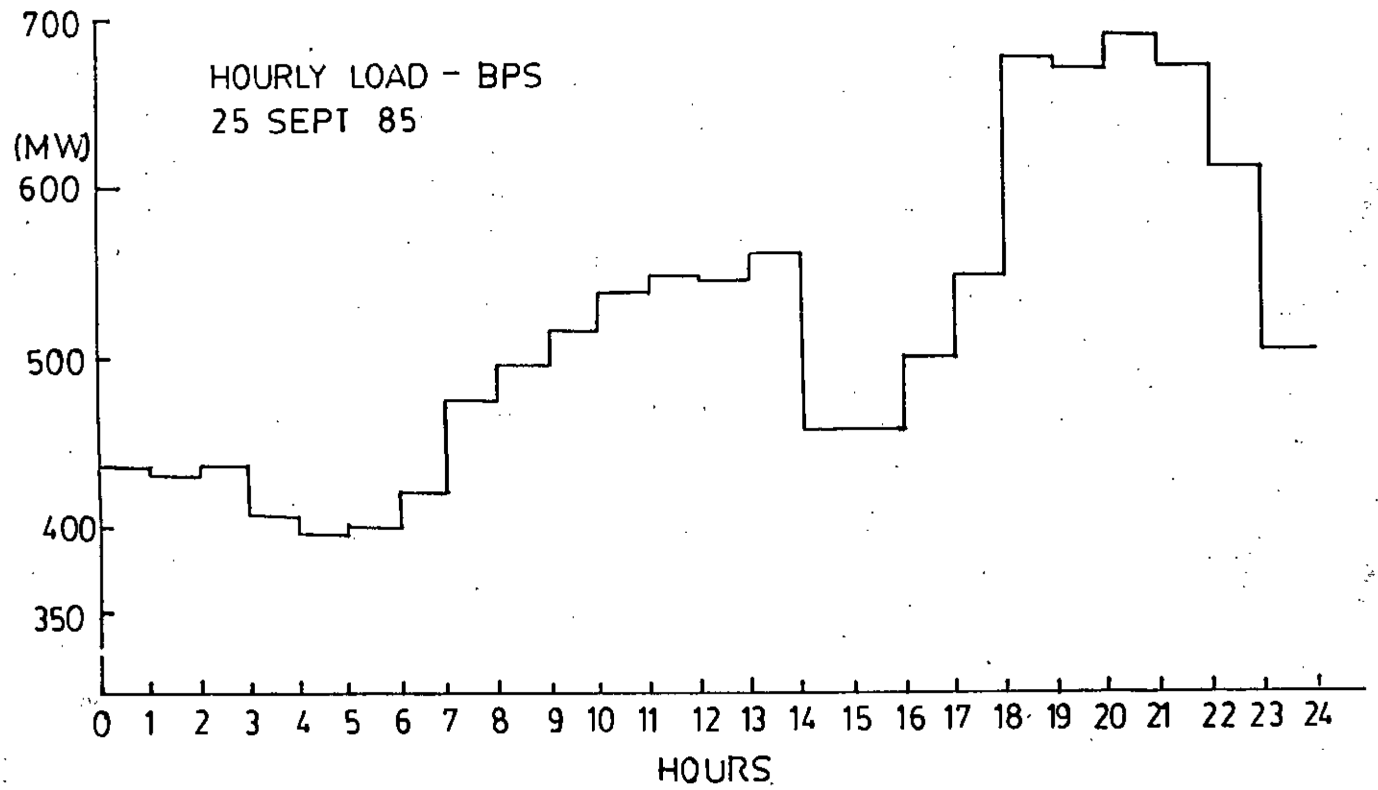

750
HOURLY LOAD-BPS
22 AUG. 85
700
(MW)
600
500
400
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOURS


HOURLY LOAD - BPS
01 SEPT 85
700
600
(MW)
500
400
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOURS

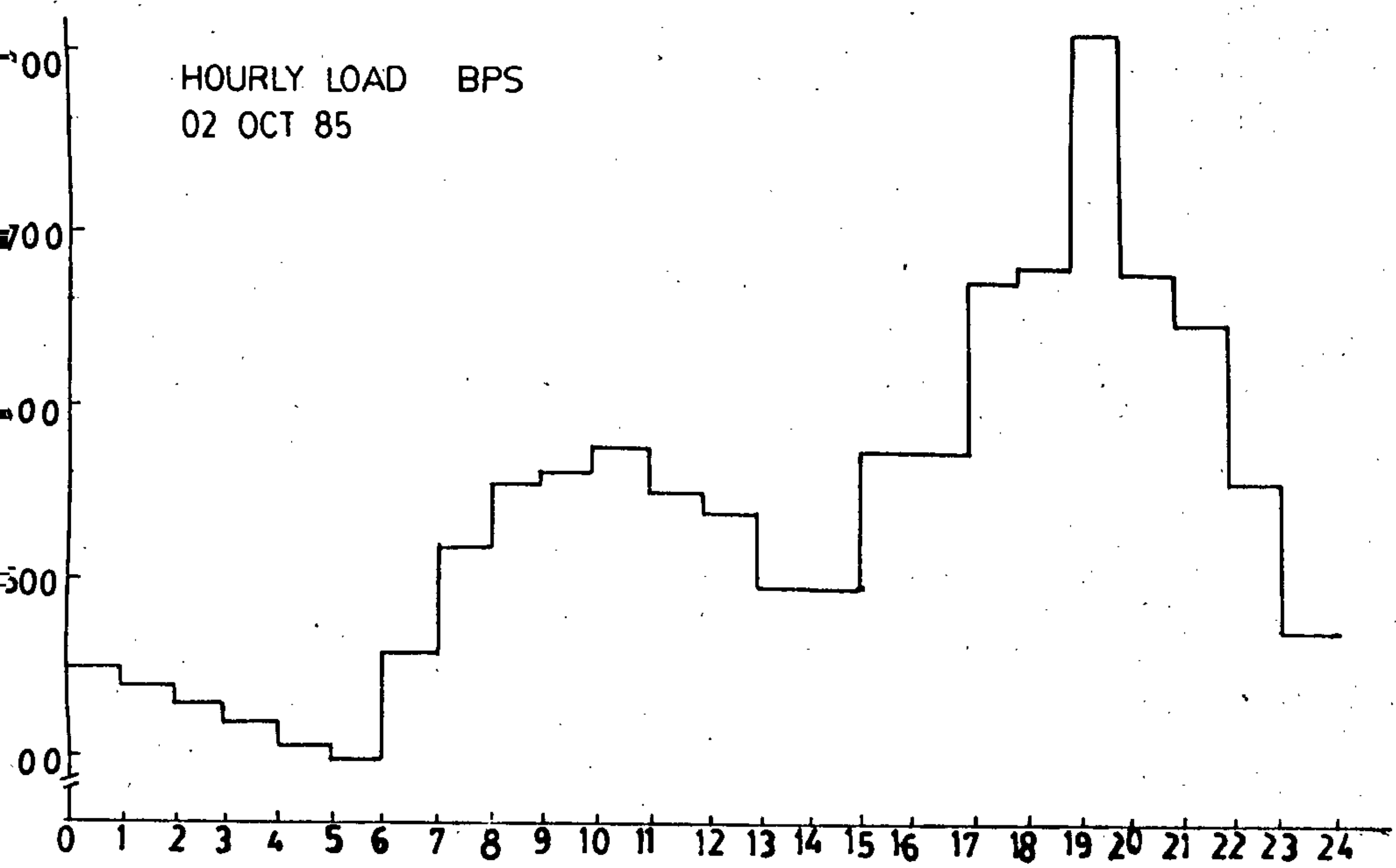

HOURLY LOAD - BPS
09 SEPT 85
800
700
(MW)
600
500
400
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOURS



HOURLY LOAD - BPS
16 SEPT 85
800
700
MW
600
500
400
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOURS



HOURLY LOAD - BPS
25 SEPT 85
700
(MW)
600
500
400
350
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOURS


HOURLY LOAD BPS
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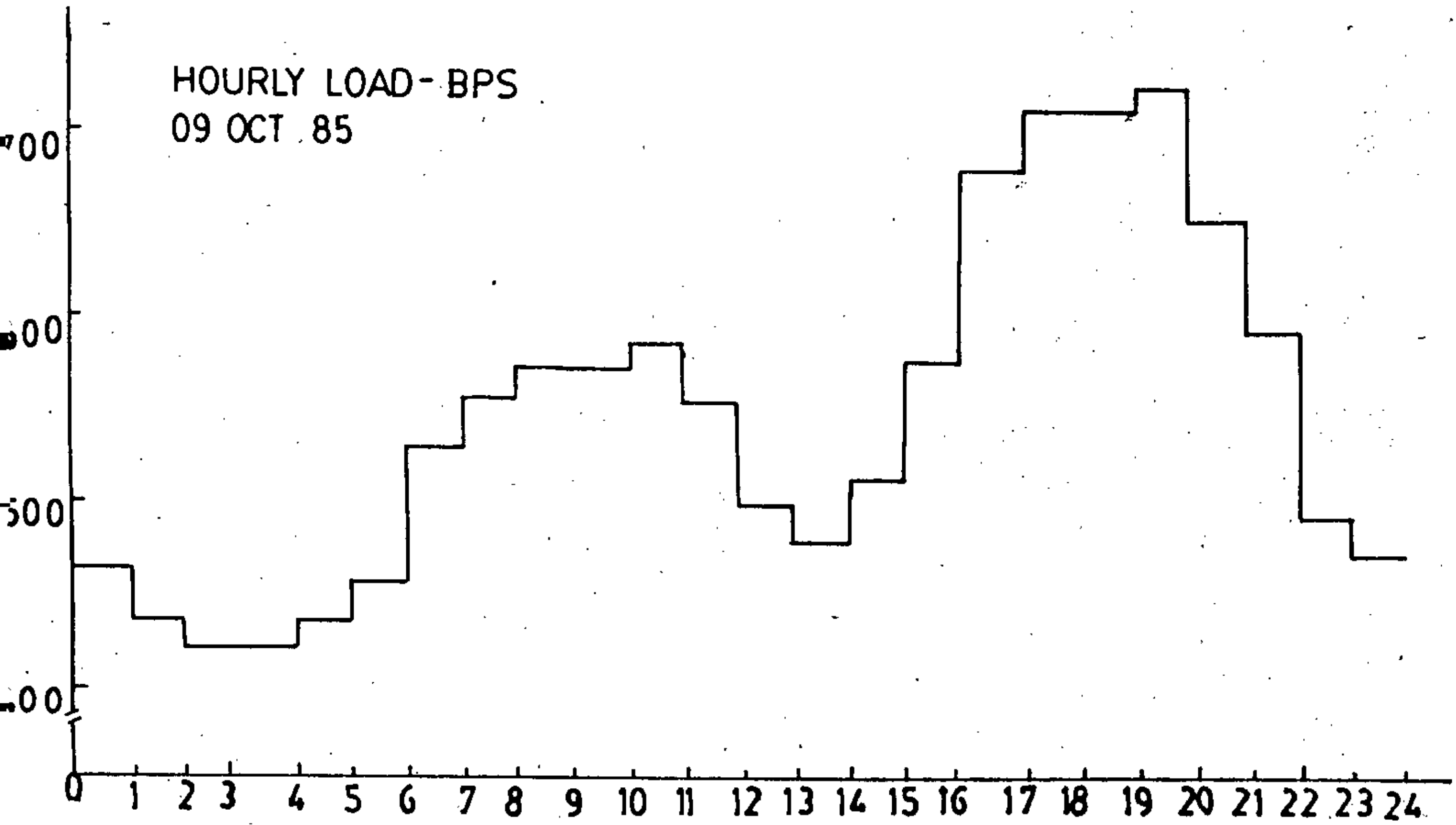
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09 OCT 85
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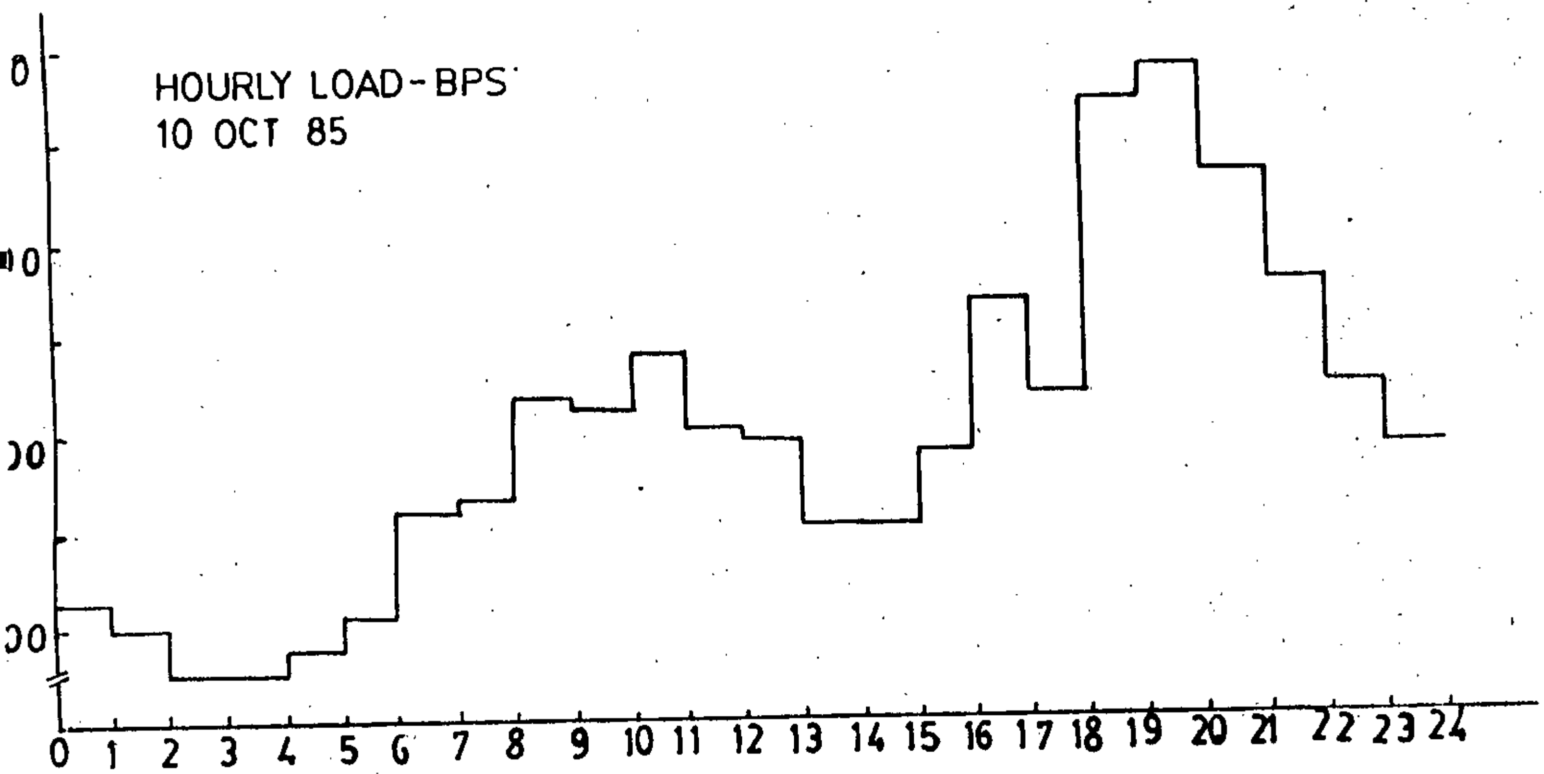
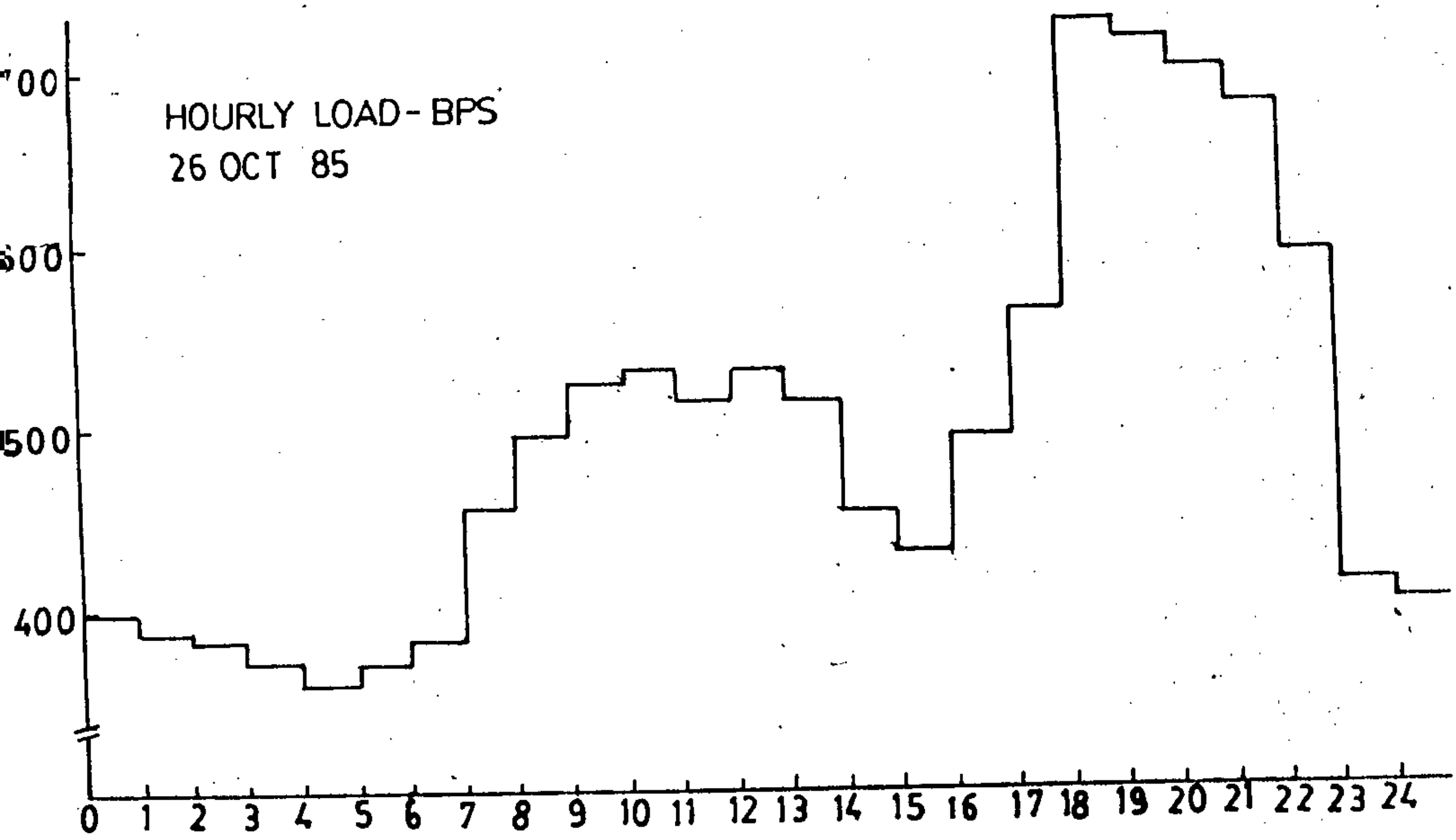
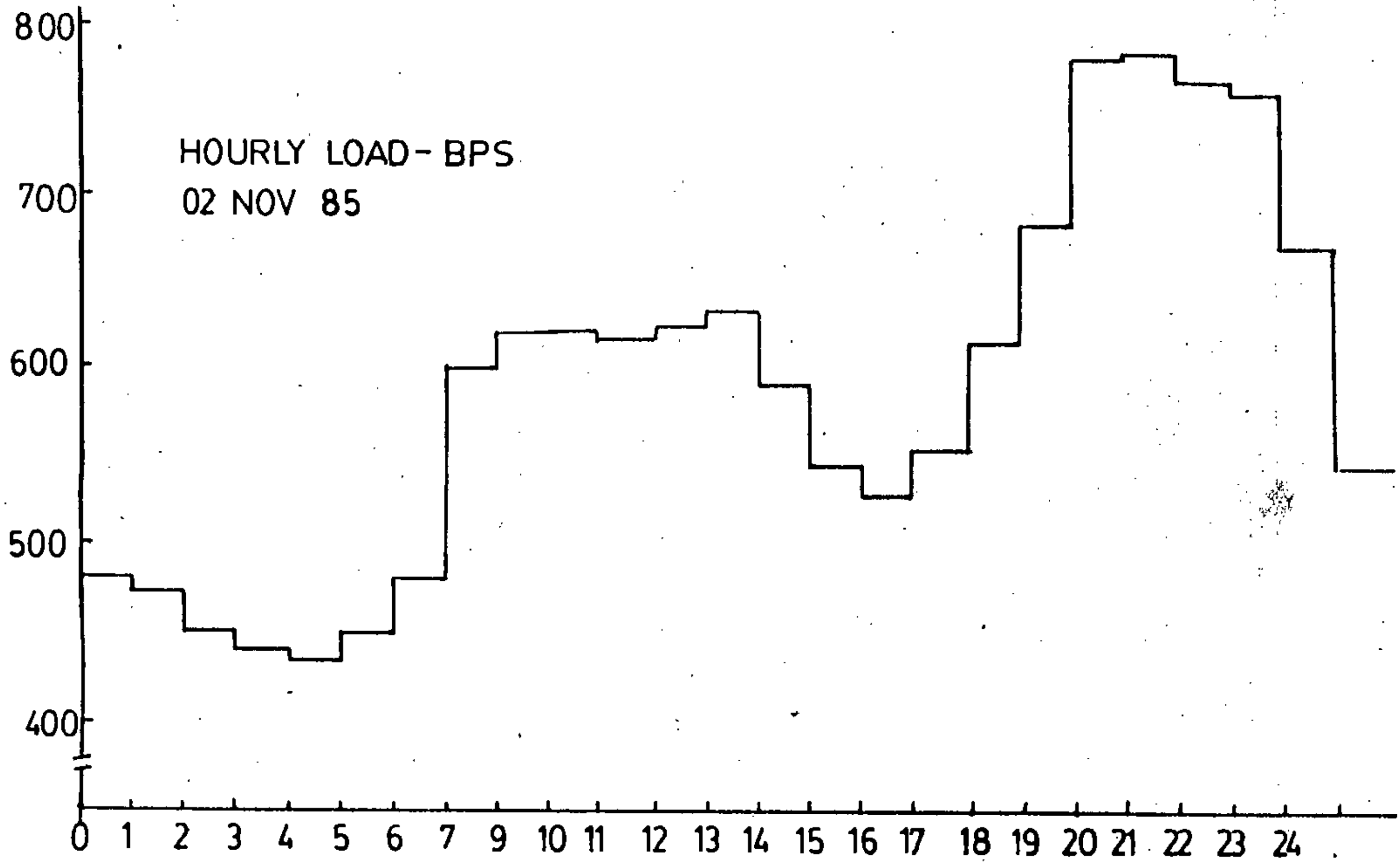


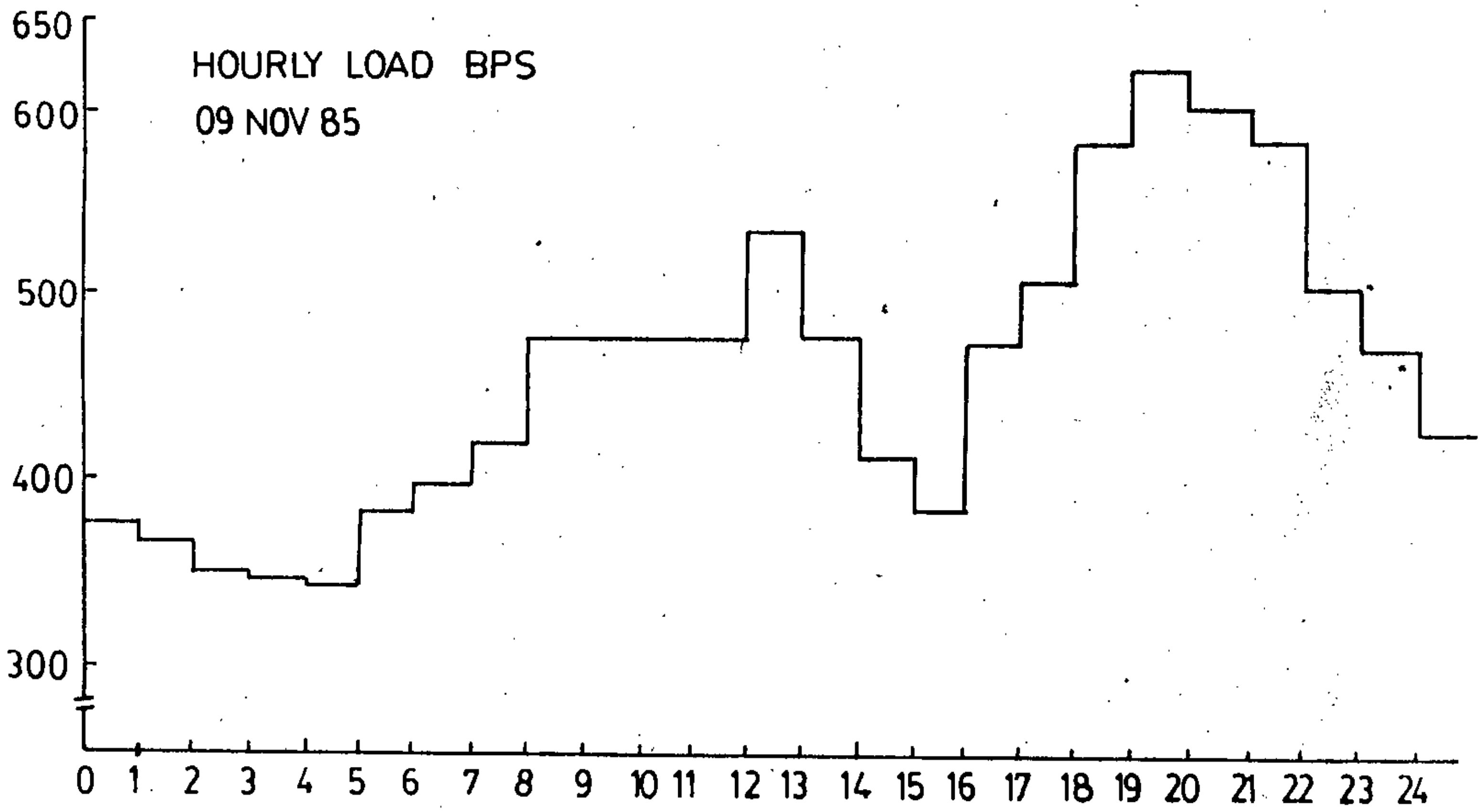
HOURLY LOAD-BPS
10 OCT 85
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24



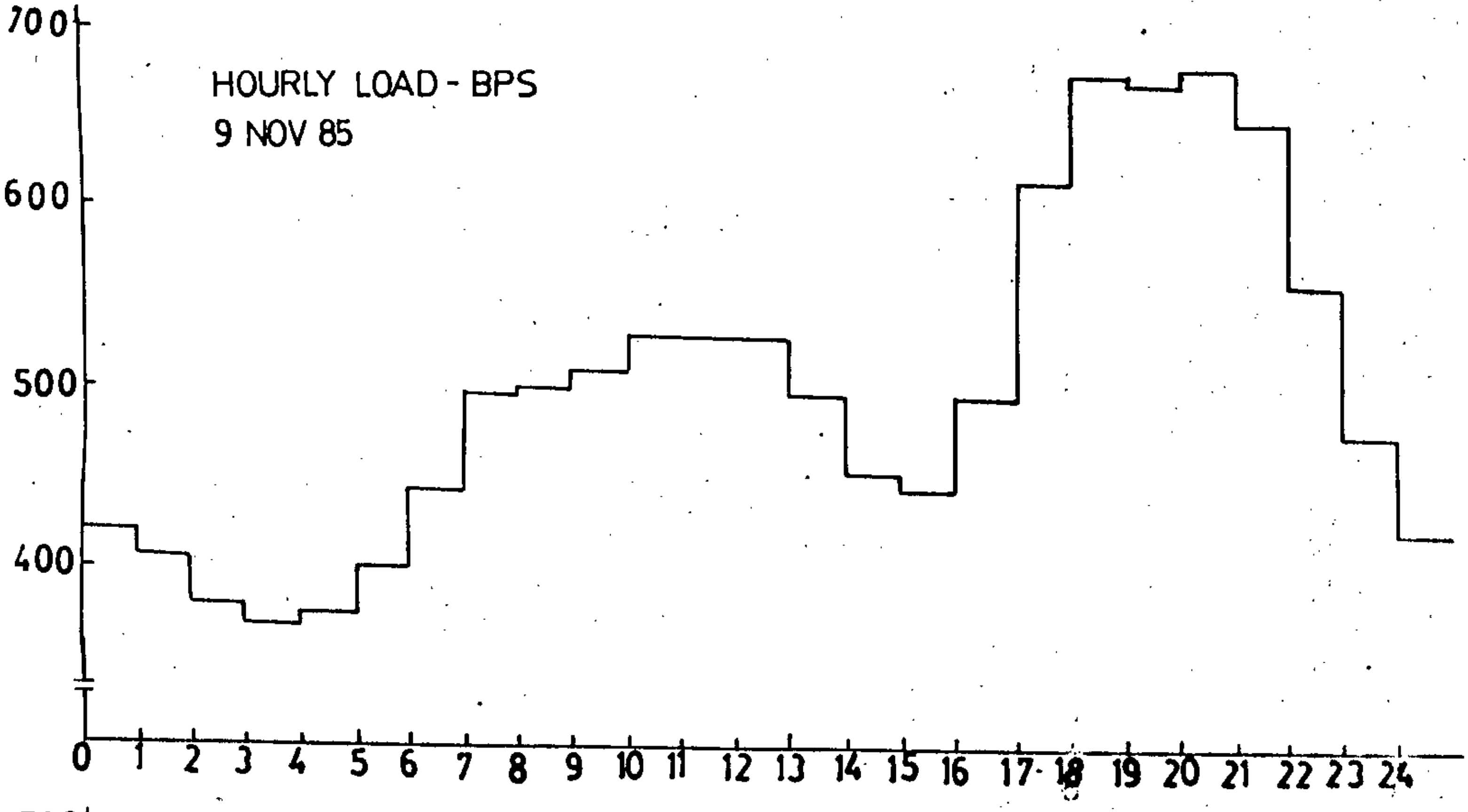
700
600
500
400
HOURLY LOAD-BPS
26 OCT 85
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

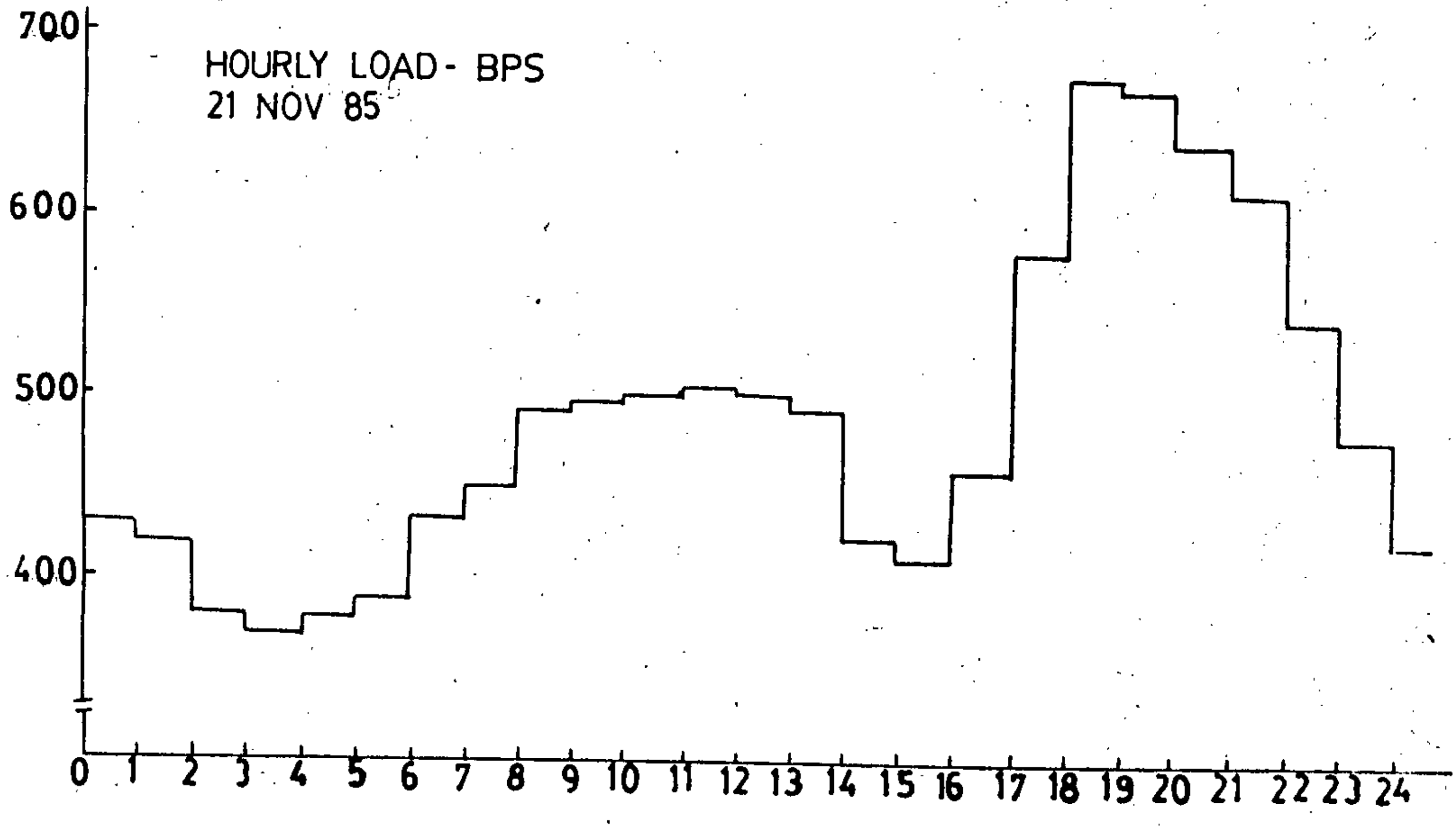


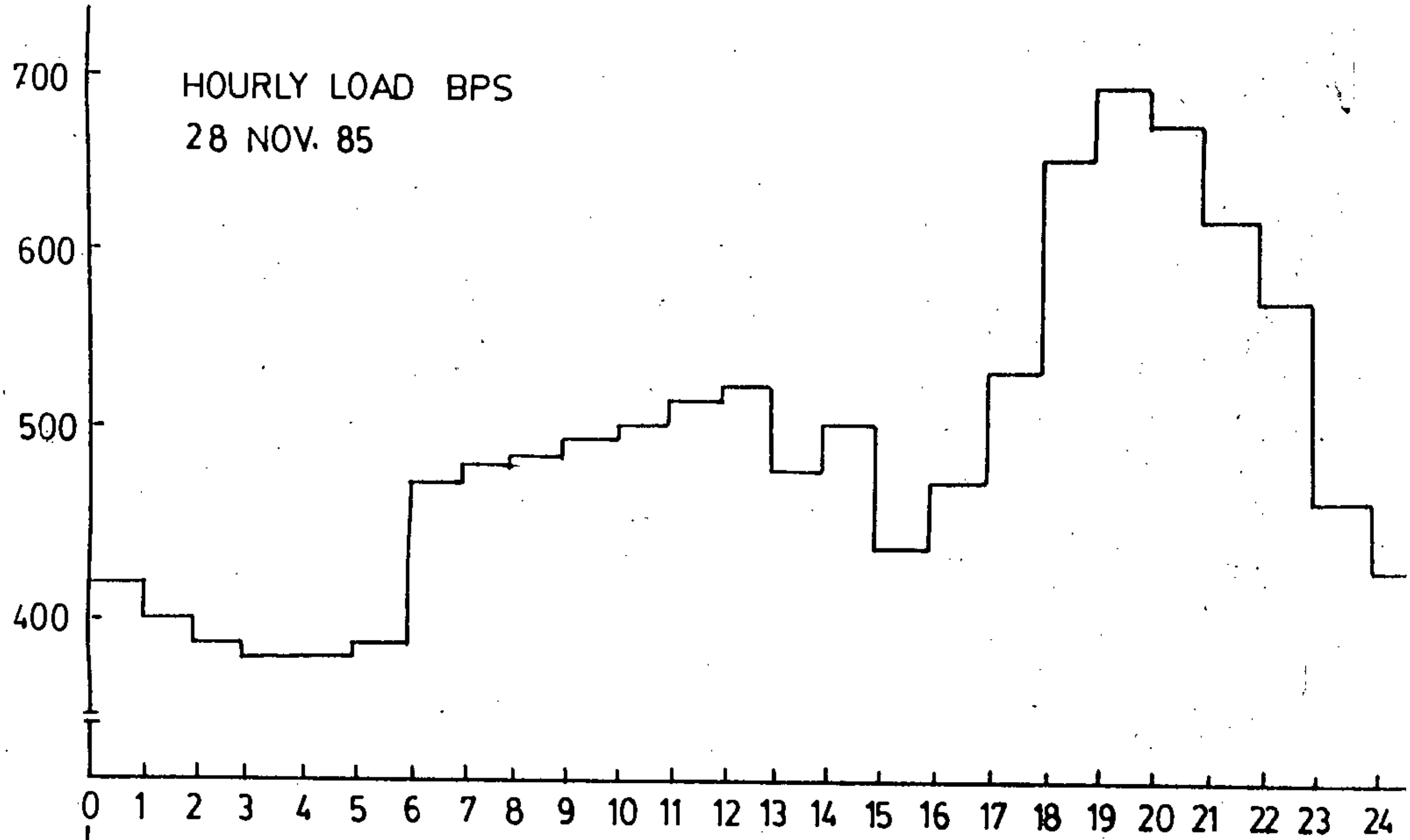
HOURLY LOAD - BPS
02 NOV 85
800
700
600
500
400
0 1 2 3 4 5 6 7 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

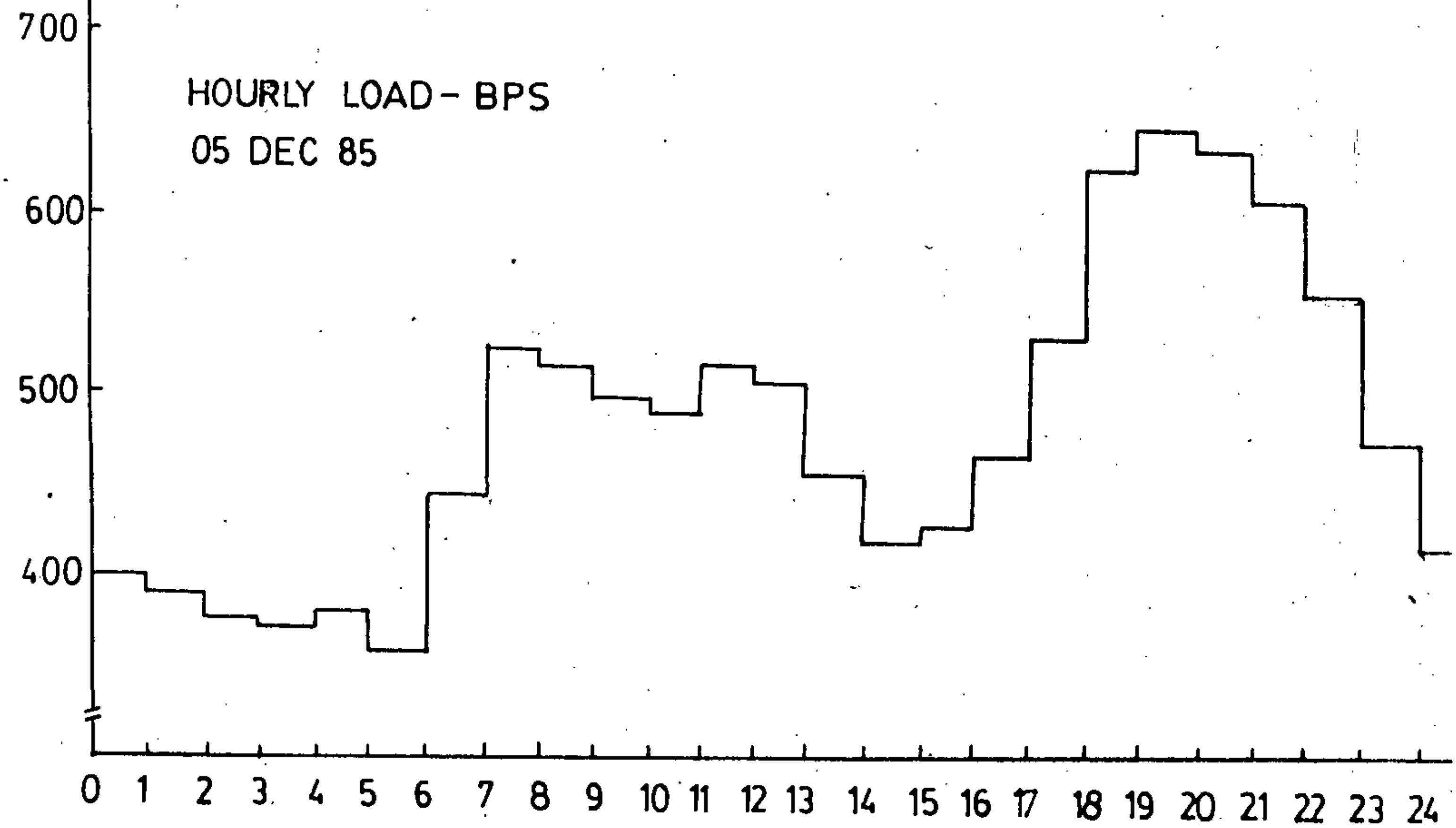


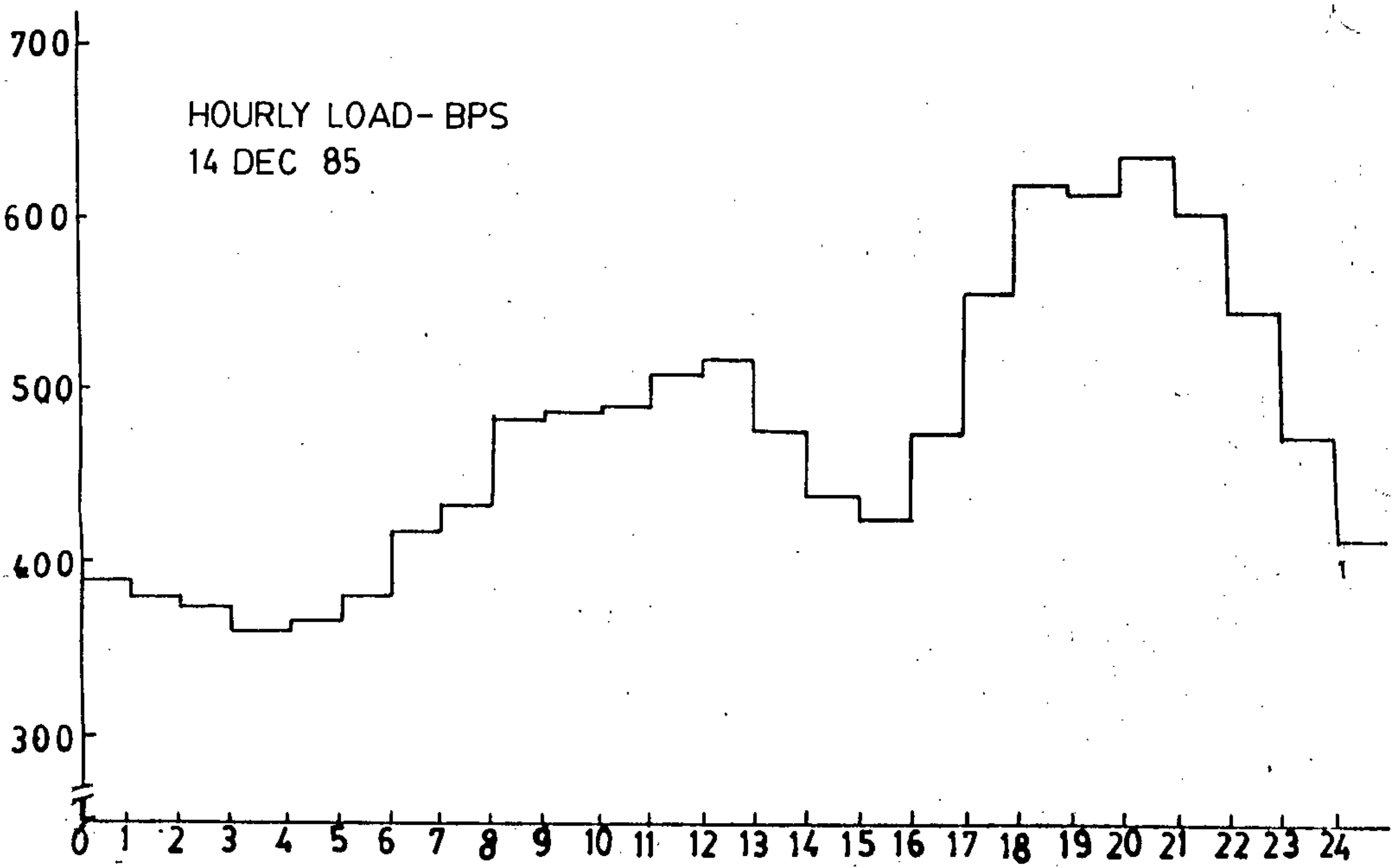
HOURLY LOAD BPS
09 NOV 85
650
600
500
400
300
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

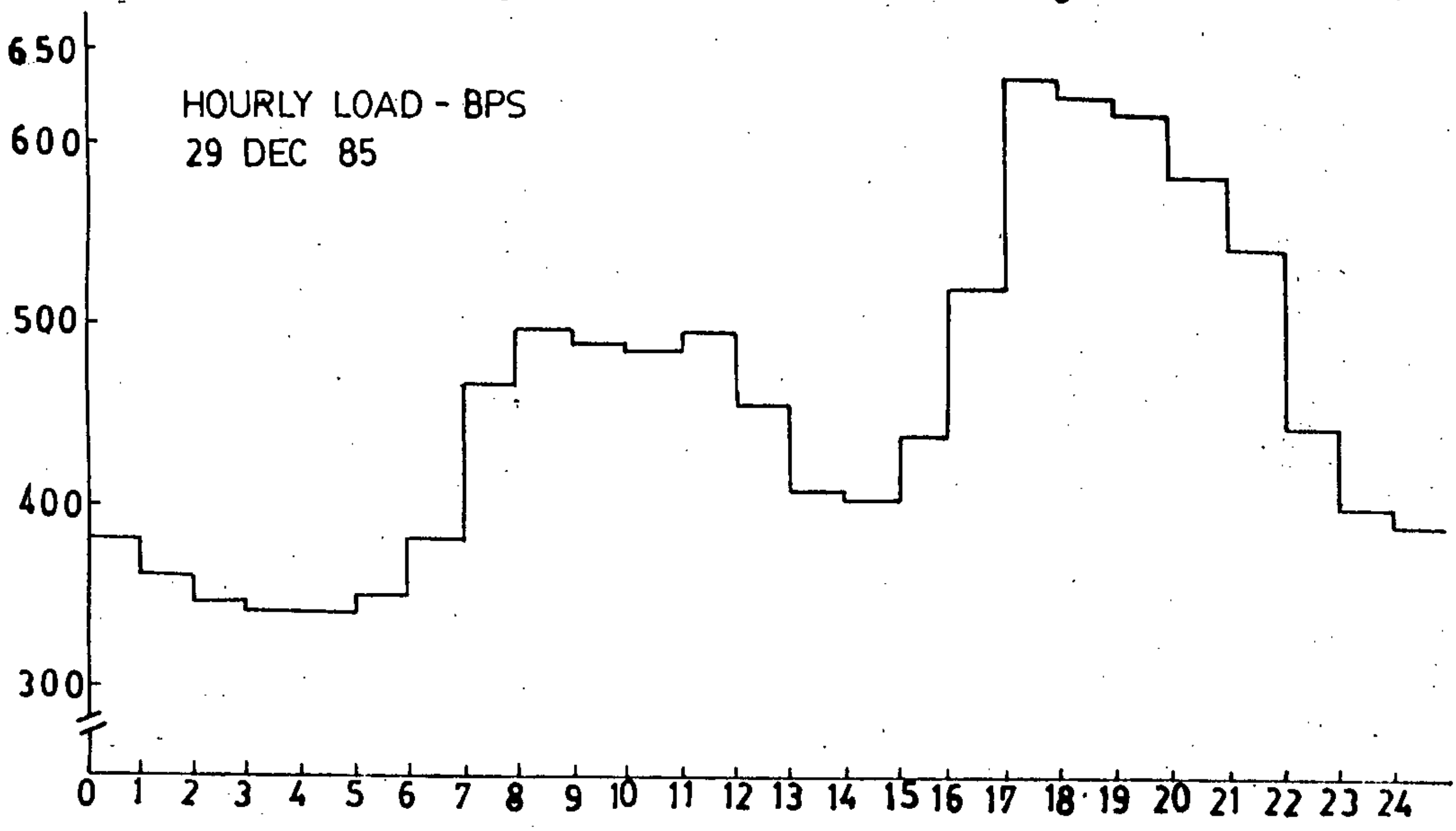

HOURLY LOAD - BPS
9 NOV 85
700
600
500
400
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24


HOURLY LOAD - BPS
21 NOV 85
700
600
500
400
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24


700
600
500
400
HOURLY LOAD BPS
28 NOV. 85
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24


700
600
500
400
HOURLY LOAD- BPS
05 DEC 85
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24


HOURLY LOAD- BPS
14 DEC 85
700
600
500
400
300
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24


HOURLY LOAD - BPS
29 DEC 85
650
600
500
400
300
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

APPENDIX- E

SEGMENTATION METHOD

Let X be the continuous random variable "mean load in an elementary time interval" (for example the "mean hourly load") and f(x) its p. d. f.

Let A > 0 be a real number, hereafter the "segment size", S(i) the interval (i-segment)

$$S(i) = [(i-1).A, i.A], \quad i=1,\ldots,M$$

and I(i, x) the indicator function of S(i) defined as

$$I(i, x) = 1 \text{ if } x \in S(i)$$
$$= 0 \text{ otherwise}$$

and let

$$P(i,X) = \mathrm{Prob}(X \in S(i)) = \int_{S(i)} f(x).dx$$

$$E(i,X) = E(X/X \in S(i)) = \int_{S(i)} x.f(x).dx / \int_{S(i)} f(x).dx$$

$$C(i,X) = E(i,X).P(i,X) = \int_{S(i)} x.f(x).dx$$

and

$$C(X) = \sum_{i=1}^{\infty} E(i,X).P(i,X) = \int_{0}^{\infty} x.f(x).dx = \sum_{i=1}^{\infty} \int_{S(i)} x.f(x).dx$$

Given N independent sample values (x(1),..., x(N)) of the r. v. X (for example the hourly load diagram for one year) the natural estimators for p(i,X), E(i,X), and C(i,X) are, respectively

$$P(i,X) = \sum_{j=1}^{N} I(i,x(j))/N = n(i) / N$$

$$E(i,X) = \sum_{j=1}^{N} I(i,x(j)).x(j) / n(i)$$

$$C(i,X) = \sum_{j=1}^{N} I(i,x(j)).x(j) / N$$

where

n(i)=number of observations in the interval S(i)

In this way we have obtained an estimate of the p. d. f. of the r. v. X, the system load.

If X is the mean hourly load, x(i) the observed mean load at hour i and N the number of hours in the period, then P(i,X).N is the number of hours the system load is in the interval S(i), and C(i,X). N is the observed total energy demand during N hours given that the load is in the load interval S(i).

The segment size must be a common factor of all generating units's capacities.

Recurrence relations for the segmentation method

Let Y be the discrete random variable "outaged capacity of the generating unit" with p. d. f. given by:

$$\begin{aligned}\text{Prob}(Y=0) &= p\\ \text{Prob}(Y=K) &= q = 1-p,\ K=n.A\end{aligned}$$

where n is a positive integer. Note that the capacity of the generating unit is an integer multiple of the segment size.

Let X be a r. v. with p. d. f. f(x) and

$$W = X + Y$$

$$\begin{aligned}P(i,W) &= \text{Prob}(W\ S(i))\\ &= \text{Prob}(X\ S(i)/Y=0).\text{Prob}(Y=0)\\ &\quad + \text{Prob}(X\ S(i-n)/Y=n.A).\text{Prob}(Y=n.A)\\ &= p.P(i,X) + q.P(i-n,X)\end{aligned}$$

$$\begin{aligned}C(i,W) &= \int_{S(i)} x[p.f(x)+q.f(x-n.A)].dx\\ &= p\int_{S(i)} x.f(x)dx + q\int_{S(i)} x.f(x-n.A)dx\\ &= p.C(i,X) + q\int_{S(i-n)} (z+n.A).f(z).dz\\ &= p.C(i,X) + q.C(i-n,X) + q.n.A.P(i-n,X)\end{aligned}$$

then the recurrence relations for the convolution of i-th segment are:

$$P(i,W)=p.P(i,X)+q.P(i-r,X) \tag{3a}$$
$$C(i,W)=p.C(i,X)+q.C(i-r,X)+q.n.A.P(i-n,X) \tag{3b}$$

After all convolutions, we get the equivalent load

$$W = X + Y$$

where:

X = system load
Y = outaged capacity of generating unit

Now letting Y be the system capacity, i. e., the r. v.

$$Y = Y(1) + ... + Y(J)$$

taking values in the discrete set

$$[0, A, 2A, ..., (n-1).A, n.A]$$

where:

n = some positive integer
J = number of generating units
Y(j) = outaged capacity for generating unit j

the expressions for LOLP and ENS (*) are, respectively:

$$LOLP = Prob(W>n.A) = \sum_{i>n} P(i,W) \tag{4}$$

$$ENS = E(W/W>n.A).Prob(W>n.A) - n.A.Prob(W>n.A)$$

$$= \sum_{i>n} C(i,W) - n.A.\sum_{i>n} P(i,W) \tag{5}$$

In the algorithm n depends on the total capacity (k) of the generating system and on the segment size A, k=n.A. For the calculation we need (n+1) segments and in the last segment we keep all the information obtained for w > n.A. So the last segment contains the information necessary to quantify the two commonly used reliability indices (LOLP and ENS, expressions (4) and (5)).

The expected energy generated by a particular unit is given by the difference between the ENS's before and after its commitment.

In this method the computational effort is increasing with total system capacity, when we keep the segment size constant.

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