SOLUTION OF THE ECONOMIC DISPATCH PROBLEM OF HYDROTHERMAL POWER SYSTEMS

BY

A. K. M. DILDER HOSSAIN CHOWDHURY

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BOARD OF EXAMINERS:

i) ______ 25/5/88 — Chairman and supervisor.
(Dr. Syed Fazl-i Rahman)
Professor and Dean,
Faculty of Electrical and
Electronic Engineering.
B U E T, Dhaka.

ii) ______ 25/5/88 — Member. (Ex - Officio)
(Dr. Md. Mujibur Rahman)
Professor and Head,
Department of Electrical
and Electronic Engineering.
B U E T, Dhaka.

iii) ______ 25/5/88 — Member.
(Dr. Quamrul Ahsan)
Associate Professor,
Department of Electrical
and Electronic Engineering.
B U E T, Dhaka.

iv) ______ 25/5/88 — Member.
(Dr. Enamul Basher)
Associate Professor,
Department of Electrical
and Electronic Engineering.
B U E T, Dhaka.

v) ______ — Member (External)
(Dr. Nazrul Islam)
Chairman,
Bangladesh Tea Board.

CERTIFICATE

This is to certify that this work was done by me and it has not been submitted elsewhere for the award of any degree or diploma.

Countersigned

(PROFESSOR S. F. RAHMAN)

Supervisor

Signature of the candidate

7.5.88

(A. K. M. DILDER HOSSAIN CHOWDHURY)

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Abstract

With the rapid expansion of the integrated hydro-thermal grid system of BPDB (Bangladesh Power Development Board), it has become indispensable to operate the system in the most economic way, particularly because of the high fuel cost. This work presents the mathematical modeling of the hydro-thermal power system, the development of solution criteria and a computer program for the economic solution of the dispatch problem of a hydro-thermal power system.

The effect of a number of equality and inequality constraints together with transmission loss have been incorporated in the mathematical formulation of the hydro-thermal power system. The LaGrangian method has been combined with Kuhn-Tucker's condition in developing the solution criteria. The effects of the constraints on the solution have been evaluated in some detail.

The incremental cost curves are based on the data of BPDB power generating units. Least square curve fitting method has been used to fit the BPDB discrete data of input output characteristics. Z_{BUS} matrix has been used along with the Gauss Seidal method of load flow analysis for calculating the coefficients of the incremental transmission losses.

Optimization study has been carried out using the recent load curves of the BPDB system. A total of 33 buses out which 10 are thermal generating bus and one hydro generating bus have been considered in the study. The effect of the hydro unit generation on the total cost of generation has been considered in some details along with the effects of the constraints using the solution criteria developed here.

Optimum scheduling within the power limit and within the water volume constraints have been studied. In the optimization study only the production cost of generation is considered as the cost. Results indicate that a considerable amount of saving in production cost of the BPDB generation system is possible for an increased hydro generation capacity (installation cost is not considered) and if it is loaded at the time of system peak load at its maximum capacity. The justification of this saving considering the installation cost of new hydro electric units has not been investigated. The impact of increased hydro capacity in the present demand as well as the future demand has been presented here.

List of Symbols and Abbreviations

BPDB	=	Bangladesh Power Development Board
BUET	=	Bangladesh University of Engineering and Technology
SIKG	=	Sikalbaha Grid
SIDG	=	Siddhirganj Grid
SHAG	=	Shahjibazar Grid
ASHG	=	Ashuganj High voltage Grid
ASMG	=	Ashuganj Main Grid
GHHG	=	Ghorasal High voltage Grid
GHMG	=	Ghorasal Main Grid
BHEG	=	Bheramara Grid
BOGG	=	Bogra Grid
GOAG	=	Goalpara Grid
KAPG	=	Kaptai Grid
MCFT	=	Million Cubic Feet
MW	=	Mega watts
MWhr	=	Mega watt hour
Kwhr	=	Kilo Watt hour
H_g	=	Heat value (Million of British thermal unit/hour)
P_g	=	Total Thermal power generation (megawatts)
P_{gi}	=	Thermal power generation for ith unit (megawatts)
H_i	=	Heating value for ith thermal unit
F	=	cost of fuel
λ	=	Incremental cost of received power
λ_{min}	=	Minimum value of λ
λ_{max}	=	Maximum value of λ
F_T	=	Total cost of generation (Tk)
P_R	=	Total received power
$P_{gi,min}$	=	Minimum amount of power generation
$P_{gi,max}$	=	Maximum amount of power generation
μ_i^-	=	Multiplier to include minimum value of thermal generation for ith unit

μ_i^+ = Multiplier to include maximum value of thermal generation for ith unit

$(ID)_i$ = Incremental discharge for ith Hydro unit

$(IC)_i$ = Incremental cost of generation for ith unit

$(ITL)_i$ = Incremental transmission loss for ith bus

P_H = Hydro unit output (Megawatts)

q = Hydro discharge (Acre-Ft/hr.)

$q_{hi,min}$ = Minimum value of Hydro discharge

$q_{hi,max}$ = Maximum value of Hydro discharge

μ_H^- = Multiplier to include hydro minimum power

μ_H^+ = Multiplier to include hydro maximum power

σ_q^- = Multiplier to include hydro minimum discharge

σ_q^+ = Multiplier to include hydro maximum discharge

V_j = Water volume in the reservoir at a particular interval

V_{min} = Minimum allowable water volume in the reservoir at any interval

V_{max} = Maximum allowable water volume in the reservoir at any interval

$\mathcal{L}$ = Lagrangian equation (when objective function is augmented with a number of constraint equation)

σ_v^+ = Multiplier to include the effect of maximum value of water volume

σ_v^- = Multiplier to include the effect of minimum value of water volume

n_j = Number of hours in a particular interval (jth interval) of the study

γ_j = Water conversion factor at particular jth interval

$\alpha_i, \beta_i, \gamma_{ci}$ = coefficients of thermal unit characteristics

P_L = total system loss (real)

q_L = total system reactive loss

J_{bus} = injected bus current matrix

Z_{bus} = bus impedance matrix

R_{bus} = real part matrix of the bus impedance matrix

α_{jk}, β_{jk} = loss coefficients

h_w = water head

$h_{wi,min}$ = Allowable minimum value of water head for ith unit

$h_{wi,max}$ = allowable maximum value of water head for ith unit

P_D = total system demand

P_{di} = power demand at each bus

NB = number of buses

CONTENTS

CHAPTER 1 INTRODUCTION

1.1 Economic operation of power system:

The word "Optimal" is far from being a mere synonym to best. It implies that a certain object(process) meets particular requirements, which are the optimality criteria, better than other objects (processes). Thus the notion of optimality is relative and involves a comparison of objects or processes with respect to some aspects (characteristics) [4].

The comparison of the processes is confined to such problems the solution of which should manifest, quantitatively as a rule, to what a degree or by how many times one process is more favourable than the other or others regarded in the light of optimization. The ultimate goal of solving such problems is to maximize the economical feasibility for the country as a whole or to ensure in particular applications the minimum or maximum values of some parameters of the process, e.g. decrease the fuel consumption to the lowest possible degree in the energy generation process without cutting power supplies. On some locations the quantitative terms of the optimization prove insufficient so that certain general qualitative characteristics have to be resorted to. An example is the optimization of the ecological effect of the energy generating unit, when the system is designed or operated with a view to minimizing pollution.

The power system processes are usually described by a set of ordinary differential and algebraic equations. The same equations may be successfully used for describing with a reasonable realism some economical processes in the so called macroeconomical models which represent the economy of the country.

When considering the processes within the economic system, account must be taken of the disturbances both external and internal. The disturbances necessitate the on-line control of the system, e.g. of the energy generation system. The object of such a control is to fulfill the production program in view of the particular situation with the aid of the operations research.

The energy production optimization problems may relate either to transient conditions when sets of differential equations are to be necessarily used, or to the steady state conditions, when it is possible to confine to the sets of algebraic equations. Optimization may be applied to the operation of the existing power systems including plants, substations, transmission lines, networks and consumers, and to the stage of designing, planning and prediction of the systems being constructed.

1.2 Literature Survey:

When optimization problems became urgent for the power industries in the 1920s, they were solved on the basis of the mathematical methods of determining the extrema of functions and functionals by the analytical study of the connections between separate parameters (variables) characterizing the process.

A transmission loss formula as a function of source powers (so called B-coefficient method) was first presented by E.E. George [11] in 1943 and it was a longhand procedure then. Later in 1950 Network analyzer was first used to determine B-coefficients by Ward et.al.

In 1947 E.S.Loane & C.W.Watchorn [12] applied the probabilistic methods for solving the Generating capacity problems of a combined Hydro and Steam power system.

In 1951 G.kron, G.W.Stagg and L.K.Kirchmayer [13] introduced an improved method for finding total transmission loss using Network analyzer. A.F.Glimn and R.Habermann, Jr., L.K. Kirchmayer [14] presented the way of utilizing digital computer in 1953 for calculating line losses. Utilizing generator voltages, angles and the X/R ratios of transmission circuits W.R.Brownlee expressed another method of transmission system losses. In the economic operation analysis of Hydro-thermal power system W.G.Chandler et.al.[15] first reported the progress in 1953.

For a Hydrothermal Electric system a Computer search was carried out for Economical Operation using gradient concept in 1954 by R.J. Cypser [16]. In 1954 A.F.Glimn, R. Habermann et.al. [17] developed an iterative method of calculating generation schedule using digital computer. For a given total load the computer calculates and tabulates incremental cost of received power, total transmission losses, total fuel input, penalty factors and received load along with the allocation and summation of generation. The American Gas and Electric service successfully utilized this method in 1955.

In 1960 a digital computer method for direct calculation of loss formula coefficients was presented by L.K.kirchmayer, H.Hopp, G.W.Stagg and J.F.Hohenstein, which offered significant improvements over previous methods with respect to cost and data handling. Improved accuracy of the solution was also assured. P.L.Dandeno [18] in 1961 presented a paper regarding Hydrothermal scheduling with approximated method of transmission losses. A direct method for construction of loss formulae for systems containing off-nominal auto-transformers was presented by them in 1964.This method needed less computer time.

In 1966 E.B.Dahlin and D.W.C.shen [19] applied the maximum principle by Pontryagin to the problem of determining the operation of a hydro-steam generating system for the minimum generating costs. The techniques they had showed, greatly simplified the computer solutions for fixed and varying head operation. An improved method of determining loss formulae Coefficients and hence the incremental transmission loss factor from power system admittance and voltages developed by E.F.Hill and W.D.Stevensíon Jr. in 1968.This method utilized second-partial derivative of system losses with respect to plant outputs to determine transmission-line-loss-Coefficients.

In 1969 A.M. Sasson proposed a unified approach to load flow,minimum-loss,and economic dispatching problems. A load flow solution had been shown to coincide with the minimum of a function of the power system equations. An unconstrained minimization method developed by Fletcher-Powel was used to solve load-flow problem. This method always finds a solution or indicates non-existance of a solution. Its performance was highly independent of the reference slack bus position and required no acceleration factors.

J.S.Luo, E.P.Hill, and T.H.Lee [20] in their paper published in February 1986 utilized bus incremental costs as the key variable to Economic dispatch. They tried to show this method offering the possibility to get an insight into the Economic dispatch mechanism. Employing the Bender's method for decomposition H.Habibullahzadeh and J.A.Bubenko [21] in their paper published in 1986 developed a realistic model for Short term operation planning of Hydrothermal power system.

M.E El-Hawary and M. Kumar [22] presented a very good paper in IEEE transaction on power Systems Vol. PWRS-1 No.4 November 1986 with the heading "Optimal Parameter Estimation for Hydro-Plant performance models in Economic Operation Studies." which described the various way of representing Hydro models with relative analysis.

1.3 Objective of the Thesis:

With the increasing growth rate of BPDB (Bangladesh Power Development Board) power network it has become inevitable to run the system most economically. With the increasing load demand on the BPDB power network, the generation capacity of the BPDB power system has also been increasing from year to year. The hydro generation capacity will be 230 Mega Watt very soon. Therefore, the economic study of a hydrothermal power system is of considerable importance. This is for the first time a study of hydro thermal optimum scheduling has been carried out in B U E T. According to the recent survey report the average inflow of water per year in Kaptai lake is a significant amount. It is necessary to dispatch the water in such a way that the thermal generation cost become minimum. The BPDB hydro station (hydro reservoir) at Kaptai is subject to water volume constraint - it can not operate at its maximum capacity throughout the period of study, it can operate only for a part of the period with maximum generation. So it is very important that water scheduling must be the proper amount for the right period.

The objectives of the thesis are:

i) Mathematical formulation of the hydro thermal system co-ordination including a number of constraints.

ii) Development of the solution criteria for a thermal power system and for a hydro thermal power system.

iii) To use the economic solution criteria of hydro thermal power system for the economic scheduling of generation.

iv) To calculate the cost benefit of optimum hydro thermal scheduling.

CHAPTER 2

ECONOMIC SCHEDULING OF HYDRO-THERMAL GENERATING UNITS NEGLECTING TRANSMISSION LOSSES

2.1 Power Generation Unit Characteristics:

Thermal or Steam Units

Out of a number of different parameters fundamental to the economic operation problem is the set of input output characteristics of a thermal power generation unit. In a boiler turbine generating unit a typical steam turbine unit may require 2 to 6% of the gross output of the unit for the auxiliary power requirements necessary to drive boiler feed pumps, fans, condenser circulating water pumps and so on. In defining the unit characteristics, we will take gross input versus net output. The net output of the plant is the electrical power output available to the electrical utility system. And the gross input to the plant represents the total input whether measured in terms of taka per hour or gallons of diesel per hour or millions of cubic ft.of gas per hour or any other units. If data are specified in gross output they should be converted to net output to be more useful in scheduling the generation.

In defining the characteristics of steam turbine units, the following terms will be used.

H: Btu per hour heat input to the unit (MBtu/h) or MCft/Hr of gas or gallons of diesel per hour.

F: Fuel cost times H is the Tk. per hour (Tk./h) input to the unit for fuel.

P: The output of the generating unit (Mega Watts).

The characteristic shown in figure 2.1 is idealized in that it is presented as a smooth convex curve. In this chapter it will be shown that the curve for our study must be convex single valued function having a monotonically increasing slope or at best a constant positive slope.

Data for obtaining the required Characteristic curve may be found from design calculation or from heat rate tests. Steam turbine generating units have several critical operating constraints. Generally, most of the thermal units of this type cannot operate below 30% of design capability.

The incremental heat rate Characteristic is the slope of the input-Output Characteristic. This Characteristic is widely used in economic load dispatching. It is converted to an incremental fuel cost Characteristic by multiplying the incremental heat rate (fuel rate) in Btu per Kwhr (MCFT or gallon/KWHr) by the equivalent fuel cost in terms of Taka per Btu (Taka per MCFT or gallon).

The last important Characteristic of a steam unit is the unit (net) heat rate Characteristic. This Characteristic is H/P versus P. It is the reciprocal of the usual efficiency Characteristic for a machine.

Data obtained from heat rate (fuel rate) tests or from the plant design engineers may be fitted by a polynomial curve. In many cases quadratic Characteristic have been fitted to these data. If the input versus output Characteristic is a quadratic smooth convex function the incremental heat rate (fuel rate) will be a straight line. This incremental heat rate (fuel rate) Characteristic is monotonically increasing as a function of the power output of the unit.

Hydroelectric Units:

The input-output characteristic of Hydroelectric units are similar to steam turbine units. The input is in terms of volume of water per unit time; the output is in terms of electrical power. Figure 2.2 shows a typical input-output curve for a hydroelectric plant where the net hydraulic head is constant. The characteristic shows an almost linear curve of input water volume requirement per unit time as a function of power output as the power output increases from minimum to rated load. Above this point the volume requirements increases as the

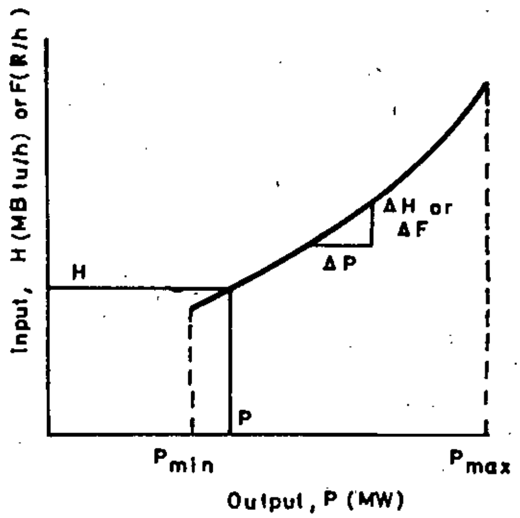

Fig. 2.1 Input-output curve(thermal power generator)

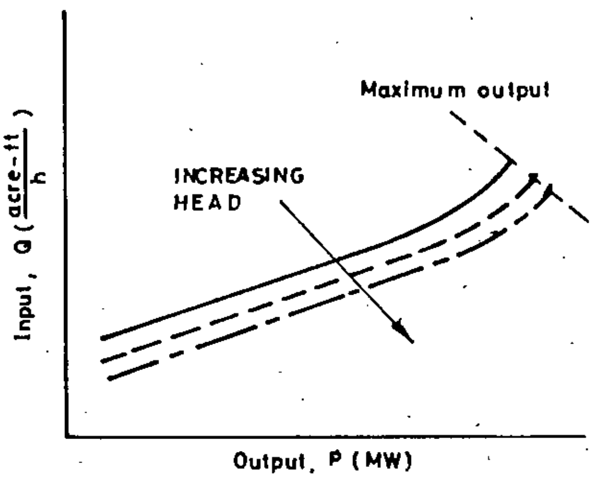

Fig. 2.2 Input-output curve for hydroelectric plant with a variable head..

efficiency of the unit falls off. Scheduling hydroelectric plants with variable head characteristics is more difficult than hydroelectric plants with fixed head. Maximum plant capacity varies with the hydraulic head. In our short range study we will assume hydraulic head fixed for the period. This assumption is true when the reservoir size is large enough compared to the period of study.

2.2 Intra Station economic dispatch:

The intra station optimization provides for saving the resources (fuel or water) by selecting the best availabilities, as well as active power of the units. It is assumed that the plant operates with load demand of the power system and that all the system constraints are satisfied.

It is unwise from the computer time point of view as well as from the computation complexity point of view to include all the units of all the generating station in the calculation. Of course, all the units must be included somehow but not during the total system optimization study. At first the units within the same station have to be loaded optimally by developing a composite cost curve including all the units of the station. Then for the total system evaluation this optimized composite curve for each station will be used for optimization study.

Composite Generation Production Cost Function:

A useful technique is to develop a composite generation production cost curve for all the generating units at the same station. For example, suppose there are n units to be scheduled at a generating station as shown in the figure. The procedure to obtain the composite cost curve for units 1,2,3,.....n is given below:

Let the fuel inputs be,

$$H_g(P_g)=H_1(P_{g1})+H_2(P_{g2})+.............. +H_n(P_{gn}) \tag{2.1}$$

then the composite cost curve,

$$F_g(P_g)=F_1(P_{g1})+F_2(P_{g2})+.............. +F_n(P_{gn}) \tag{2.2}$$

where,

H (Heat value or fuel value) is in MBtu/hr or MCft./hr or gallon/hr

$$F \text{ is in Tk./hr} = \text{Fuel rate} * H \tag{2.3}$$

and the total generation,

$$P_g=P_{g1}+P_{g2}+................+P_{gn} \tag{2.4}$$

And therefore the incremental costs are such that,

$$\frac{dF_1}{dP_{g1}} = \frac{dF_2}{dP_{g2}} = \frac{dF_3}{dP_{g3}} = \ldots = \frac{dF_n}{dP_{gn}} = \lambda \tag{2.5}$$

If one of the units hits a limit, its output is held constant.

A simple procedure to allow one to generate $F_g(P_g)$ consists of adjusting from λ_{min} to λ_{max} in specified increments, where,

$$\lambda_{min}=\min[dF_i/dP_{gi}\big|_{P_{gi}=P_{gi,min}}, \quad i=1,2,3,...n] \text{ and,} \tag{2.6}$$

$$\lambda_{max}=\max[dF_i/dP_{gi}\big|_{P_{gi}=P_{gi,max}}, \quad i=1,2,3,...n] \tag{2.7}$$

At each increment, calculate the total fuel consumption and the total power output for all the units. These points represents points on the $F_g(P_g)$ curve.

A smooth curve may be fitted to the points using a least-square curve fitting program. Care must always be taken so that the composite curve does not lose its convexity property. In that case different curve convex segments have to be taken.

Flow chart for obtaining the composite cost curve is given in figure A.6

2.3 Interstation economic dispatch (Transmission losses neglected)

Economic dispatch for thermal power system:

Let us consider a system of N thermal generating stations connected to a single bus bar serving an electrical load of P_R MW. This is so considered because transmission losses are neglected.

Now the objective function, that is the cost function to be minimized is,

$$F_T = F_1 + F_2 + \text{--------} + F_N = \sum_{i=1}^{N} F_i(P_{gi}) \qquad (2.8)$$

Where, $F_i(P_{gi})$ = The composite cost curve of the ith thermal generating plant.

P_{gi} = Power generated at the ith plant.

And the constraint equations are,

the power balance equation given by

$$P_R - \sum_{i=1}^{N} P_{gi} = 0 \quad \text{; equality constraint.} \qquad (2.9)$$

and the power limit equation given by

$$P_{gi,min} \le P_{gi} \le P_{gi,max} \text{ ; inequality constraint.} \quad (2.10)$$

Now dividing the each inequality constraint into two equality constraint along with one multiplier for each part such that the equation

$$P_{gi,min} \le P_{gi} \le P_{gi,max} \quad \text{becomes}$$

$$\mu_i^- \left(P_{gi,min} - P_{gi} \right) = 0 \quad ; \text{Where } \mu_i^- > 0 \quad (2.11)$$

$$\mu_i^+ \left(P_{gi} - P_{gi,max} \right) = 0 \quad ; \text{Where } \mu_i^+ > 0 \quad (2.12)$$

Where $i=1,2,3..............N$

Now the resulting LaGrangian function is

$$\mathcal{L} = \sum_{i=1}^{N} F_i(P_{gi}) + \lambda\left(P_R - \sum_{i=1}^{N} P_{gi}\right) + \sum_{i=1}^{N} \mu_i^- \left(P_{gi,min} - P_{gi}\right) + \sum_{i=1}^{N} \mu_i^+ \left(P_g - P_{gi,max}\right) = 0 \quad (2.13)$$

To solve the above equation for a minimum value partial derivatives of the function with respect to each variable has to be taken and then equate each resulting equation to zero. And then the equations evolved are the required criteria which will be used for getting the value of the variables at the minimum value of the function under the influence of the constraints.

Hence the equations to be solved becomes

$$\frac{dF_i}{dP_{gi}} - \lambda - \mu_i^- + \mu_i^+ = 0 \quad (2.14)$$

$$P_R - \sum_{i=1}^{N} P_{gi} = 0 \quad (2.15)$$

$$\left(P_{gi,min} - P_{gi} \right) = 0 \quad ; \text{If the lower limit is hit.} \quad (2.16)$$

$(P_{gi} - P_{gi,max}) = 0$; If the upper limit is hit (2.17)

Where i=1,2,3..............N

* For the same unit the above two condition can never occur simultaneously (conditions given by equations 2.16 and 2.17)

Case I

If P_{gi} where i=1,2,3.........N are such that none of the station hits the limits (neither upper nor lower limit).

In that case,

$$\mu_i^- = \mu_i^+ = 0 \qquad (2.18)$$

The equations to be solved becomes

$$\frac{dF_i}{dP_{gi}} - \lambda = 0, \text{ or } (IC)_i = \lambda \qquad (2.19)$$

and, $$P_R - \sum_{i=1}^{N} P_{gi} = 0 \qquad (2.20)$$

Case II

If P_{gi} (where i=1,2,3,.........N) such that some of the units hit there upper limit,

Say first M number of units hit upper limit.

So for these M number of units,

$$\mu_i^- = 0 \quad \text{for } i=1,2,3,.....M \qquad (2.21)$$

For all other units,

$$\mu_i^- = \mu_i^+ = 0 \quad \text{for } i=M+1,M+2,M+3,.....N \qquad (2.22)$$

Therefore, equations to be solved are

$$(IC)_i - \lambda + \mu_i^+ = 0 \quad ; \text{ for } i=1,2,.....M \qquad (2.23)$$

$$(IC)_i - \lambda = 0 \quad ; \text{ for } i=M+1, M+2, M+3, \ldots N \tag{2.24}$$

and

$$P_R - \sum_{i=1}^{N} P_{gi} = 0 \tag{2.25}$$

$$\mu_i^+ (P_{gi} - P_{gi,max}) = 0 \tag{2.26}$$

Where $i=1,2,3 \ldots\ldots\ldots\ldots M$

that is for those units hit upper limit, and $\left.\frac{dF_i}{dP_{gi}}\right|_{P_{gi}=P_{gi,max}} \leq \lambda$.

Summary: Equations to be solved,

$$(IC)_i \leq \lambda , i=1,2,3,\ldots, M \tag{2.27}$$

$$(IC)_i = \lambda , i=M+1, M+2, \ldots, N \tag{2.28}$$

$$P_R - \sum_{i=1}^{N} P_{gi} = 0 \tag{2.29}$$

$$\text{and, } P_{gi} = P_{gi,max}, \quad (\text{ if } i \leq M \text{ and } (IC)_i \leq \lambda) \tag{2.30}$$

Case III

If a number of units (say first M) hit lower limits.

then,

$$\mu_i^+ = 0 \quad ; \quad i \leq M \tag{2.31}$$

and

$$\mu_i^- = \mu_i^+ = 0 \quad ; \quad i > M$$

$$P_R - \sum_{i=1}^{N} P_{gi} = 0 \tag{2.32}$$

$$P_{gi,min} - P_{gi} = 0 \quad (\text{ if } i<M \text{ and } (IC)_i \geq \lambda) \tag{2.33}$$

Summary: Equations to be used,

$$(IC)_i \geq \lambda \quad ; \quad i = 1,2,3,\ldots\ldots\ldots M \tag{2.34}$$

$$P_R - \sum_{i=1}^{N} P_{gi} = 0 \qquad (2.35)$$

$$(IC)_i = \lambda \quad ; \quad i = M+1, M+2, \ldots\ldots N \qquad (2.36)$$

$$P_{gi} = P_{gi,max} \quad ; \ (\text{if } i \leq M \text{ and } (IC)_i \geq \lambda) \qquad (2.37)$$

Case IV .

If some of the units hit upper limit and some others hit lower limit in that case the conditions become

$$\mu_i^- = 0 \quad ; \text{ for those hits upper limit} \qquad (2.38)$$

$$\mu_i^+ = 0 \quad ; \text{ for those hits lower limit.} \qquad (2.39)$$

$$(IC)_i \leq \lambda \quad ; \text{ for those hits upper limit} \qquad (2.40)$$

$$(IC)_i \geq \lambda \quad ; \text{ for those hits lower limit} \qquad (2.41)$$

$$(IC)_i = 0 \quad ; \text{ for those not violating any constraints.} \qquad (2.42)$$

$$P_D = \sum_{i=1}^{N} P_{gi} \quad ; \text{ Power balance equation.} \qquad (2.43)$$

$$P_{gi} = P_{gi,max} \quad (\text{for those units hit upper limit and } (IC) \leq \lambda\ ) \qquad (2.44)$$

$$P_{gi} = P_{gi,min} \quad (\text{for those units hit lower limit and } (IC) \geq \lambda\ ) \qquad (2.45)$$

2.4 Hydro Thermal Co-ordination neglecting Transmission losses:

For a power system of N thermal and M hydro units and K number of buses, the objective function of the system is exactly same as for the thermal system and is given by

$$F_T(P_g) = \sum_{i=1}^{N} F_i(P_{gi}) \tag{2.46}$$

The equality constraints are

$$\sum_{i=1}^{K} P_{di} - \sum_{i=1}^{N} P_{gi} - \sum_{i=1}^{M} P_{Hi} = 0 \tag{2.47}$$

________ Power balance equation.

$$\sum_{j=1}^{j_{max}} \sum_{i=1}^{M} \{q_{i,j}(P_{Hij})\} n_j = q_{tot} \tag{2.48}$$

________ Discharge balance equation.

The inequality constraint equations are ,

i) for thermal generating units,

$$P_{gi,min} \leq P_{gi} \leq P_{gi,max} \tag{2.49}$$

which can be further written as

$$\mu_{ij}^{-} (P_{gi,min} - P_{gi}) = 0 \quad ; \quad \mu_{ij}^{-} \geq 0$$

$$\mu_{ij}^{+} (P_{gi} - P_{gi,max}) = 0 \quad ; \quad \mu_{ij}^{+} \geq 0 \tag{2.50}$$

ii) for hydroelectric generating units,

$$P_{Hi,min} \leq P_{Hi} \leq P_{Hi,max} \tag{2.51}$$

which can be further written as

$$\mu_{Hij}^{-} (P_{Hi,min} - P_{Hi}) = 0 \quad ; \quad \mu_{Hij}^{-} \geq 0$$

$$\mu_{Hij}^{+} (P_{Hi,min} - P_{Hi}) = 0 \quad ; \quad \mu_{Hij}^{+} \geq 0 \tag{2.52}$$

and the water discharge rate limit,

$$q_{hi,min} \leq q_{hi} \leq q_{hi,max} \tag{2.53}$$

can be written as,

$$\sigma_{qij}^{+} (q_{hi} - q_{hi,max}) = 0 \quad ; \quad \sigma_{qij}^{+} \geq 0$$

$$\sigma_{qij}^{-} (q_{hi,min} - q_{hi}) = 0 \quad ; \quad \sigma_{qij}^{-} \geq 0 \tag{2.54}$$

iv) For the whole period ,

the water volume constraints are

$$V_{min} \le V_j \le V_{max} \tag{2.55}$$

where V = reservoir volume.

And

J_j is the inflow rate to the reservoir for the particular interval (j).

Considering no spillage, the augmented LaGrangian equation becomes:

$$\mathcal{L} = \sum_{j=1}^{j_{max}} \Big\{ \Big(n_j \sum_{i=1}^{N} F_{ij}(P_{ij})\Big) - \lambda_j \Big(\sum_{i=1}^{K} P_{di} - \sum_{i=1}^{N} P_{gij} - \sum_{i=1}^{M} P_{Hij} \Big)$$

$$+ \gamma_j \Big(-V_{j-1} - n_j J_j + n_j \sum_{i=1}^{M} q_{ij}(P_{Hij}) + V_j \Big) + \mu_{ij}^{-} \big(P_{gi,min} - P_{gij}\big)$$

$$+ \mu_{ij}^{+} \big(P_{gij} - P_{gi,max}\big) + \sigma_{vj}^{-} \big(V_{min} - V_j\big) + \sigma_{vj}^{+} \big(V_j - V_{max}\big)$$

$$+ \sigma_{Hj}^{-} \big(H_{min} - H_j\big) + \sigma_{Hj}^{+} \big(H_j - H_{max}\big) + \mu_{Hij}^{-} \big(P_{Hi,min} - P_{Hij}\big)$$

$$+ \mu_{Hij}^{+} \big(P_{Hij} - P_{Hi,max}\big) + \sigma_{qij}^{-} \big(q_{i,min} - q_{ij}\big) + \sigma_{qij}^{+} \big(q_{ij} - q_{i,max}\big)\Big\} = 0 \tag{2.56}$$

Now for short term hydro thermal scheduling some of the constraints may be ignored e.g, head constraint. And considering the discharge constraint within power generation constraints the LaGrangian function can be written as

$$\mathcal{L} = \sum_{j=1}^{j_{max}} \Big\{ \Big[n_j \sum_{i=1}^{N} F_{ij}(P_{gij}) \Big] - \lambda_j \Big(P_D - \sum_{i=1}^{N} P_{gij} - \sum_{i=1}^{M} P_{Hij} \Big)$$

$$+ \gamma_j \Big(V_{j-1} - n_j J_j + n_j \sum_{i=1}^{M} q_{ij}(P_{Hij}) + V_j \Big) + \mu_{ij}^{-} \big(P_{gi,min} - P_{gij} \big)$$

$$+ \mu_{ij}^{+} \big(P_{gij} - P_{gi,max}\big) + \mu_{Hij}^{-} \big(P_{Hi,min} - P_{Hij}\big) + \mu_{Hij}^{+} \big(P_{Hij} - P_{Hi,max}\big)$$

$$+ \sigma_{vj}^{-} \big(V_{min} - V_j\big) + \sigma_{vj}^{+} \big(V_j - V_{max}\big) = 0 \tag{2.57}$$

Assuming only one hydro unit, the equation further reduces to

$$\mathcal{L} = \sum_{j=1}^{j_{max}} \Big\{ n_j \sum_{i=1}^{N} F_{ij}(P_{ij}) - \lambda_j \Big(P_D - \sum_{i=1}^{N} P_{gij} - P_{Hij} \Big)$$
$$+ \gamma_j \left(-V_{j-1} - n_j J_j + n_j q(P_{Hj}) + V_j \right) + \mu_{ij}^{-} \left(P_{gi,min} - P_{gij} \right)$$
$$+ \mu_{ij}^{+} \left(P_{gij} - P_{gi,max} \right) + \mu_{Hj}^{-} \left(P_{Hi,min} - P_{Hj} \right)$$
$$+ \mu_{Hj}^{+} \left(P_{Hj} - P_{H,max} \right) + \sigma_{vj}^{-} \left(V_{min} - V_j \right) + \sigma_{vj}^{+} \left(V_j - V_{max} \right) = 0 \qquad (2.58)$$

Then the equations to be used for solution are:

$$n_j \frac{dF_{ij}(P_{gij})}{dP_{gij}} - \lambda_j - \mu_{ij}^{-} + \mu_{ij}^{+} = 0 \; ; \; \begin{matrix} i = 1, 2, \cdots N \\ j = 1, 2 \cdots j_{max} \end{matrix} \qquad (2.59)$$

$$-\lambda_j + \gamma_j n_j \frac{dq(P_{Hj})}{dP_{Hj}} - \mu_{Hj}^{-} + \mu_{Hj}^{+} = 0 \; ; \; j = 1, 2, \cdots j_{max} \qquad (2.60)$$

$$\gamma_j - \gamma_{j+1} - \sigma_{vj}^{-} + \sigma_{vj}^{+} = 0 \; ; \; j = 1, 2 \cdots j_{max} \qquad (2.61)$$

and the equality and inequality constraint equations.

When some of the thermal units hit upper limits and some others hit lower limit and some of them are within the constraint, Then

$$n_j \frac{dF_{ij}(P_{gij})}{dP_{gij}} \leq \lambda_j$$; for those hits upper limit (2.62)

$$n_j \frac{dF_{ij}(P_{gij})}{dP_{gij}} \geq \lambda_j$$; for those hits lower limit (2.63)

$$n_j \frac{dF_{ij}(P_{gij})}{dP_{gij}} = \lambda_j$$; for those within the constraint (2.64)

$$\eta_j \gamma_j \frac{d\varphi(P_{Hij})}{dP_{Hj}} = \lambda_j$$; for the only hydro plant (when no generation limits are violated (2.65)

$$\eta_j \gamma_j \frac{d\varphi(P_{Hj})}{dP_{Hj}} \leq \lambda_j$$; when the hydro unit hits the upper limit of its generation capacity (2.66)

$$\eta_j \gamma_j \frac{d\varphi(P_{Hj})}{dP_{Hj}} \geq \lambda_j$$; when the hydro unit hits the lower limit of its generation capacity (2.67)

$$\gamma_j - \gamma_{j+1} \geq 0$$; when the water volume hits minimum value of the volume constraint ($V = V_{min}$) (2.68)

$$\gamma_j - \gamma_{j+1} \leq 0$$; when the water volume hits maximum value of the volume constraint ($V = V_{max}$) (2.69)

$$\gamma_j = \gamma_{j+1}$$; when within the constraint limit of volume (2.70)

along with the original equality and inequality constraints.

Now if only hydro unit hits the limit of power generation then equations to be solved becomes:

$$\eta_j \frac{dF_{ij}(P_{gij})}{dP_{gij}} = \lambda_j$$; when all the thermal units are within the constraints (2.71)

$$\eta_j \gamma_j \frac{d\varphi(P_{Hj})}{dP_{Hj}} \leq \lambda_j$$; when the hydro unit hits upper limit. (2.72)

$$\eta_j \gamma_j \frac{d\varphi(P_{Hj})}{dP_{Hj}} \geq \lambda_j$$; when hydro unit hits lower limit. (2.73)

$$\gamma_j = \gamma_{j+1}$$; when no volume constraints are violated. (2.74)

violated

Now if hydro unit hits volume constraints then governing equations become:

$$n_j \frac{dF_{ij}(P_{gij})}{dP_{gij}} = \lambda_j$$; when no thermal constraints are violated. (2.75)

$$n_j \gamma_j \frac{dq(P_{Hj})}{dP_{Hj}} = \lambda_j$$; when no hydro generation limits are violated. (2.76)

$$\gamma_j - \gamma_{j+1} = -\sigma_{vj}^{+} \leq 0$$; when the upper limit of the volume constraint is reached. (2.77)

$$\gamma_j - \gamma_{j+1} = \sigma_{vj}^{-} \geq 0$$

$$\gamma_j - \gamma_{j+1} = \sigma_{vj}^{-} \geq 0$$; when the lower limit of the volume constraint is reached. (2.78)

Therefore, the water conversion factor for the effectiveness of the water utilization remain constant during the period of study unless a storage volume constraint is hit.

2.5 Production cost:

The system lambda is the incremental cost in Taka/MWhr. to produce the last Megawatt for 1 hour. The total cost per hour is termed production cost, F_T

$$F_T = \int_0^{P_T} \lambda(P)\, dP \qquad (2.79)$$

where F_T is in Taka/Hour.

The production cost is readily evaluated numerically using the trapizoidal rule when (P) versus P is available in tabular form. Economic dispatch programs are commonly known as production costing programs.

2.6 Necessity of convexity of the cost function:

For a thermal power system, the objective function is,

$$F_T = \sum_{i=1}^{N} F_i\,(P_{gi}) \qquad (2.80)$$

where,

$$F_i\,(P_{gi} = \alpha_i + \beta_i\, P_{gi} + \gamma_{ci}\, P_{gi}^2 \qquad (2.81)$$

Now for F_T to be minimum,

$$\frac{\partial F_T}{\partial P_{gi}} = \frac{\partial F_i(P_{gi})}{\partial P_{gi}} = \frac{dF_i}{dP_{gi}} = 0\ ;\ i = 1,2,3,\cdots M \qquad (2.82)$$

That is,

$$\beta_i + 2\,\gamma_{ci}\, P_{gi} = 0 \qquad (2.83)$$

That is the optimum value of the power generation is,

$$P_{gi}^{opt} = -\,\frac{\beta_i}{2\,\gamma_{ci}} \qquad (2.84)$$

Now if second partial derivative is positive in that case this will assure minimum value of F_T.

Therefore, for F_T to be minimum, $\dfrac{\partial^2 F_T}{\partial P_{gi}^2} = \dfrac{d^2 F_i}{d P_{gi}^2} > 0$

$$\text{i.e.}\quad \gamma_{ci} > 0\ ;\ \&\ \frac{dF_i}{dP_{gi}} = 0 \qquad (2.85)$$

along with

$$\frac{\partial F_T}{\partial P_{gi}} = \frac{dF_i}{dP_{gi}} = 0 \qquad (2.86)$$

Again equation 2.88 must be modified to some equation with the inclusion of another constraint equation called power balance equation.

$$P_D = \sum_{i=1}^{NB} P_{di} = \sum_{i=1}^{N} P_{gi} \qquad (2.87)$$

Introducing Lagrangian multiplier, the augmented Langrangian equation become,

$$\mathcal{L} = F_T + \lambda\left(P_D - \sum_{i=1}^{N} P_{gi}\right) \qquad (2.88)$$

where,

$$F_T = \sum_{i=1}^{N} F_i\,(P_{gi}) \qquad (2.89)$$

For optimality,

$$\frac{\partial \mathcal{L}}{\partial P_{gi}} = 0\ ;\quad P_{gi} = \frac{\lambda - \beta_i}{2\,\gamma_{ci}} \qquad (2.90)$$

And
$$P_D = \sum_{i=1}^{NG} P_{gi} \qquad (2.91)$$

$$\lambda = \left\{ 2P_D + \sum_{i=1}^{N} \beta_i / \gamma_{ci} \right\} \Big/ \sum_{i=1}^{N} (1/\gamma_{ci}) \qquad (2.92)$$

From equation 2.85 it is clear that γ_{ci} must always be positive. β_i may be positive or negative depending on the generation constraints.

Now to have λ the incremental cost of received power always positive β_i has to be positive because otherwise for some value of P_D, λ will be negative. Physically it is never possible to have power output without input or negative input that is why β_i is to be positive. α_i, β_i may be positive or negative depending on the minimum generation limit. (β_i may be negative under the generation constraints).

So it is clear that the cost function must be such that β_i and γ_{ci} must be positive, i.e. the cost function must be strictly convex. And because $F_T = F_i$, and the summation of a number of strictly convex functions is strictly convex. So the objective function is also convex. It can be proved by evaluating the eigen value of the Hessian matrix of the total cost function.

Now for the whole system to check the convexity property of the objective function, the objective function can be used. The objective function is given by,

$$F_T = F_1(P_{g1}) + F_2(P_{g2}) + \ldots\ldots. + F_N(P_{gN}) \qquad (2.93)$$

Therefore, $$\frac{\partial F_T}{\partial P_{gi}} = \frac{dF_i}{dP_{gi}} = \beta_i + 2\gamma_{ci} P_{gi} \qquad (2.92)$$

$$\Rightarrow \frac{\partial^2 F_T}{\partial P_{gi}^2} = \frac{d^2 F_i}{dP_{gi}^2} = 2\gamma_{ci} \qquad (2.93)$$

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

And $$\frac{\partial^2 F_T}{\partial P_{gi} \partial P_{gj}} = 0 \quad \text{for } i \neq j \qquad (2.94)$$

So, the Hessian matrix becomes; $$H = \begin{bmatrix} 2\gamma_1 & 0 & 0 & 0 & 0 \\ \cdots & 2\gamma_2 & 0 & 0 & \\ \cdot & \cdot & \cdot & \cdots & \\ \cdot & - & \cdot & \cdot & 0 \\ \cdot & - & & - & 2\gamma_{cN} \end{bmatrix} \qquad (2.95)$$

2.7 Convexity of a Function:

In real world problem, if the objective function or the constraints are not concave or convex, the problem is usually mathematically intractable. A function is strictly convex if a line connecting any two points on the function lies completely above the function. The following is a mathematical statement and illustration of this definition for a function of one variable.

$$f[\alpha x_1 - (1-\alpha)x_2] < \alpha f(x_1) + (1-\alpha) f(x_2), \qquad (2.96)$$

where, $0 \leq \alpha \leq 1$

If "<" is replaced by "$\leq$" the expression will define convex functions. The above relationship is illustrated in figure

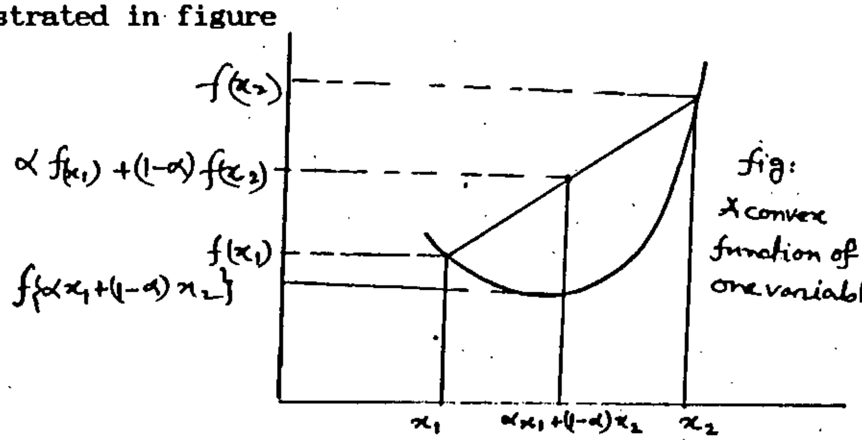

fig: A convex function of one variable.

A function is strictly convex if its slope is continually increasing, or

$$\frac{d^2 F}{dx^2} > 0 \qquad (2.97)$$

It is convex if its slope is nonincreasing or $\frac{d^2f}{dx^2} \geq 0$. (2.98)

A function of two variables, f(x) where, $[x]=[x_1, x_2]$, is strictly convex if $f[\alpha x_1+(1-\alpha)x_2] < \alpha f(x_1)+(1-\alpha)f(x_2)$ (2.99)

where, x_1 and x_2 are points located by the coordinates given in their respective vectors.

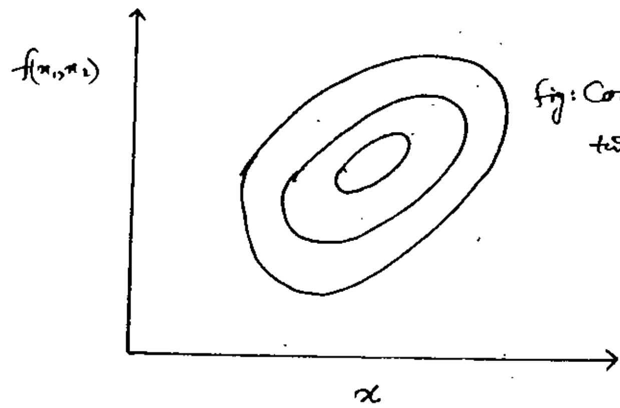

fig: Convex function of two variables.

Hessian Matrix:

Hessian matrix of a function of multiple variables, f(x), where, $x=[x_1, x_2, x_3, \ldots x_n]$, is a matrix of second partial derivative.

$$H_{f(x)} = \begin{bmatrix} \frac{\partial^2 f}{\partial x_1^2} & \frac{\partial^2 f}{\partial x_1 \partial x_2} & \cdots & \frac{\partial^2 f}{\partial x_1 \partial x_n} \\ \vdots & & & \vdots \\ \frac{\partial^2 f}{\partial x_n \partial x_1} & \cdots & \cdots & \frac{\partial^2 f}{\partial x_n^2} \end{bmatrix}$$

$|H_{f(x)}| > 0$; Convex function

$|H_{f(x)}| < 0$; Concave function

(2.100)

To determine convexity and concavity of a function of multiple variables, the eigenvalues and its Hessian matrix should be examined.

(a) If all eigen values of the Hessian are negative the function is strictly concave.

(b) If all eigen values of the Hessian are positive the function is strictly convex.

(c) If some eigen values are positive and some are negative, or if some are zero, the function is neither strictly concave nor strictly convex.

The following brief statements are some properties of concave and convex functions.

1. Local minimum of a convex function is also the global minimum and a local maximum of a concave function is also a global maximum.

2. A straight line is both concave and convex.

3. The sum of (strictly) convex functions are (strictly) convex, and the sum of (strictly) concave functions are (strictly) concave.

4. If f(x) is a convex function and k is a constant, then,

(a) kf(x) is convex if $k>0$

(b) kf(x) is concave if $k<0$.

CHAPTER 3

Transmission losses:

3.1 Introduction

Load flow solution gives currents, voltages and power flows at every bus in the system. In the load flow problem a set of non lilear relationship between voltage and current at each bus must be solved. The nonlinear relationship involve, the real and reactive power consumption at a bus, or the generated real and scheduled voltage magnitude at a generator bus. The load flow solution gives the electrical response of the transmission system to a particular set of loads and generator unit outputs.

One of the quantities available from a load flow solution is the electrical losses of the network. This result plays an important role in the optimum dispatch of generation. However, it is not simply the value of the losses but the derivatives of losses with respect to generator outputs (incremental transmission losses) that are important.

3.2 Incremental transmission loss :

The total network loss formula is given by,

$$P_L + jQ_L = \sum_{i=1}^{N} S_i = \sum_{i=1}^{N} V_i \; J_i^{*}$$
$$= V_{bus}^{T} \; J_{bus}^{*}$$

Therefore, $P_L + jQ_L \; = J_{bus}^{T} \; Z_{bus} \; J_{bus}^{*}$ (3.1)

Where,

P_L = real power, Q_L = reactive power,

J_{bus} = injected bus current matrix,

Z_{bus} = bus impedance matrix,

R_{bus} = matrix containing elements r_{jk} .

The total loss P_L is readily identified as being the total active power injected into the network

$$P_L = \mathrm{Re}\,(\, J_{bus}^{T}\; Z_{bus}\; J_{bus}^{*} \,)$$

$$= [\mathrm{Re}(J_{bus})]^{T} R_{bus}\; [\mathrm{Re}(J_{bus})] + [\mathrm{Im}(J_{bus})]^{T} R_{bus}\; [\mathrm{Im}(J_{bus})] \qquad (3.2)$$

because P_L is due only to the resistive part of Z_{bus} namely R_{bus}.

The required incremental transmission loss is the derivative of equation 3.2. The incremental transmission loss [9] is given by,

$$(ITL)_j = \frac{\partial P_L}{\partial P_j} = 2\sum_{K=1}^{N} (P_k\, \alpha_{jk} - Q_k\, \beta_{jk}) \qquad (3.3)$$

_________ for jth bus.

Where,

$$\alpha_{jk} = \frac{r_{jK}}{|V_j||V_K|} \mathrm{Cos}\,(\,\delta_j - \delta_k\,) \qquad (3.4)$$

$$\beta_{jk} = \frac{r_{jK}}{|V_j||V_K|} \mathrm{Sin}\,(\,\delta_j - \delta_k\,) \qquad (3.5)$$

This incremental transmission loss formula involves only line resistance, bus injection and load flow data.

CHAPTER 4

HYDRO THERMAL ECONOMIC DISPATCH

4.1 Introduction:

It is usually more complex in scheduling a hydro thermal electrical power generating system than a system that constitutes only thermal units. The one single aspect of hydroelectric power plants is that differentiates the coordination of their operation more than any other is the many, and highly varied constraints. In many cases, care must be taken in the release of water volume for control of flood of water or regular scheduled release of water for irrigation. Water head must be maintained carefully all the time. To keep the river navigable all the time, water release in a river have to be controlled. Again high volume of sudden water release may also create problem in the downstream.

The coordination of the operation of hydro electric plants involves, of course, the scheduling of water release. The long range hydro scheduling problem involves the long range forecasting of water availability and the scheduling of reservoir water release for an interval of time that depends on the reservoir capacity. Typical long range scheduling may be from one week to one year or several years. And it involves metrological and statistical analysis.

But for short range hydro scheduling which may be for few hours or one day or one week that involves the hour by hour scheduling of all the generating units to achieve the minimum production cost for the given period of time. In such scheduling problem, the hydraulic inflows, load, volume and head of the reservoir, unit availabilities are assumed to be known. In hydro thermal scheduling we must be aware that hydro generations are cost free and thermal generations are fuel cost dependent. So hydro scheduling along with the thermal scheduling must be such that the cost becomes minimum for a fixed amount of water volume discharge.

There are several constraints involved with the thermal and hydro generation. For an efficient scheduling this constraints must be carefully taken into amount. Improper involvement may cause loss of economy.

4.2 Inequality Constraints of Thermal Units:

A typical thermal unit is usually bounded by several constraints. Out of a number of constraints the inequality constraints to be considered here will be the generation constraint. That is generation limits. It is usually not economic to run any unit at less than 30% of the rated load. It is one of the major considerations involved in the optimization study. Although ignoring this constraint the optimization problem become very straight forward and simple. But excluding this consideration the ultimate result will fail to show highest economy. So its impact in the study is inevitable.

The inequality constraint of a thermal unit is,

$$P_{gi,min} \leq P_{gi} \leq P_{gi,max} \qquad \text{..................} \qquad (4.1)$$

where, $P_{gi,min}$ = Minimum possible generation from the ith unit when the unit is at running condition.

P_{gi} = Thermal generation at any interval.

$P_{gi,max}$ = Maximum possible generation from the ith unit when running

And another constraint of thermal units that can be taken into account is given by,

$$H_{gi,min} \leq H_{gi} \leq H_{gi,max} \qquad \text{...............} \qquad (4.2)$$

$H_{gi,min}$ = Minimum fuel input limit (MBtu/hr.) or MCFT./hr. or gallons/hr.

H_{gi} = Instanteneous fuel input

$H_{gi,max}$ = Maximum value of fuel input that is possible

where, $H_{gi}(P_{gi}) = a_i + b_i * P_{gi} + C_i P_{gi}^2$

and a_i, b_i and c_i are constants.

4.3 Inequality Constraints in Hydro Units:

There are a number of constraints for a hydro unit. Some of them can be taken into acount using mathematics i.e. quantitavely. Some others are metrological and statistical in nature, which can not be easily accounted for.

The constraints are;

(i) Discharge Constraint: This is the constraint offered by the water turbine, given by

$$q_{hi,min} \leq q_{hi} \leq q_{hi,max} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (4.3)$$

where, q_{hi} = Instanteneous discharge rate of the unit i

$q_{hi,min}$ = Minimum amount of discharge rate that must be maintained

$q_{hi,max}$ = Maximum amount of discharge rate that must not be violated for unit i

(ii) Head Constraint:

$$h_{wi,min} \leq h_{wi} \leq h_{wi,max} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (4.4)$$

Water head constraint must be maintained. Below certain head level it is not possible to create useful torque in the machine to produce electrical energy and above some level reservoir may cause flood.

(iii) Power Generation Constraints: This is the constraint offered by the alternator, given by,

$$P_{Hi,min} \leq P_{Hi} \leq P_{Hi,max} \qquad \ldots\ldots\ldots\ldots\ldots \qquad (4.5)$$

where, $P_{Hi,min}$ = Instanteneous hydro generation

P_{Hi} = Minimum generation for particular unit i

$P_{Hi,max}$ = Maximum generation for particular unit i

(iv) Total Amount of Discharge Constraint Including Inflow Rate of Water: The minimum water volume constraint must not be violated at any instant of the study period.

Volume of the reservoir water constraint:

$$V_{min} \leq V_j \leq V_{max} \qquad \ldots\ldots\ldots\ldots\ldots \qquad (4.6)$$

where, V =reservoir volume.

and, J_j =Inflow rate during the interval j

S_j = Spillage discharge rate during interval j

4.4 Equality Constraints:

(i) Active Power Balance Constraint:

$$P_D + P_L - \sum_{i=1}^{N} P_{Hi} - \sum_{K=1}^{M} P_{gk} = 0 \qquad \ldots\ldots\ldots\ldots\ldots \qquad (4.7)$$

where, for a particular interval,

$$P_D = \sum_{i=1}^{K=NB} P_{di} \quad = \text{Total demand. NB=Number of buses}$$

$$P_L = P_L\ (P_{g1}, P_{g2}, \ldots, P_{gN},\ P_{H1}, P_{H2}, \ldots, P_{HM}) \qquad (4.8)$$

---- System loss function

P_{Hi} = Hydro generation for the ith unit.

P_{gk} = Thermal generation for the kth unit.

M = Number of hydro units within the system

N = Number of thermal units within the system

4.5 OPTIMIZATION WITHIN CONSTRAINTS (ALL THERMAL):

The objective is to maximize the profit i.e. to minimize the cost of generation of several units. The cost is the function of generation. It is relatively straight forward to find the maximum or minimum using the rules of calculus. Of course, at first we must find a set of values for the variables where the first derivatives of the total cost function with respect to each variable (Each generating unit's generation) is zero. In addition, the second derivatives should be used to determine whether solution found is a maximum or minimum, or a saddle point.

Here, the objective function is the summation of the cost functions of the generating units and the constraints may be classified in the following category;

(a) For individual generating units;

$$P_{gi,min.} \leq P_{gi} \leq P_{gi,max} \quad ; \text{Generator power limit.} \qquad (4.9)$$

i=1,2,3,...,No. of generating units(N)

(b)

$$\sum_{i=1}^{N} P_{gi} - \sum_{i=1}^{NB} P_{di} - P_L = 0 \qquad ; \text{ Active power balance.} \qquad (4.10)$$

The objective function is

$$F_T = \sum_{i=1}^{N} F_i(P_{gi}) \tag{4.11}$$

And here each cost function must be concave upward (convex) and single valued .

That is,

$$F_i(P_{gi}) = \alpha_i + \beta_i * P_{gi} + \gamma_{ci} * P_{gi}^2 \tag{4.12}$$

where β_i and γ_{ci} must be positive constant.

We see that the problem is subject to both equality and inequality constraints. This is, in fact it is a optimization problem of general type.

Detail of the optimization rules for this type of problem has been reached in the following part.

Minimize:

$$F_T = H_i(P_{gi}) = F_i(P_{g1}, P_{g2}, P_{g3}, \ldots\ldots, P_{gN}) \tag{4.13}$$

Subject to:

$$\sum_{i=1}^{N} P_{gi} - P_D - P_L = 0 \tag{4.14}$$

where, $P_D = \sum_{i=1}^{NB} P_{di}$, and P_L is the transmission loss and is a function of $P_{g1}, P_{g2}, P_{g3}, \ldots\ldots, P_{gN}$

and, $P_{gi,min} \le P_{gi} \le P_{gi,max}$

for i=1,2,3,....n.

At first let us consider all the units are thermal i.e. no hydro units are present. Then the problem definition will be as follows;

Objective function (the function to maximize or minimize):

$$F_T = F_i(P_{gi}) = F_1(P_{g1}) + F_2(P_{g2}) + \ldots\ldots\ldots + F_N(P_{gN}) \tag{4.15}$$

Subject to:

Equality constraint,

$$h(P_{g1},P_{g2},\ \ldots\ldots\ ,P_N)=\sum_{i=1}^{N} P_{gi} - P_D - P_L \qquad (4.16)$$

where the total demand, $P_D = \sum_{i=1}^{NB} P_{di}$

and inequality constraints:

$$P_{gi,min} \leq P_{gi} \leq P_{gi,max} \qquad \text{for } i=1,2,3,\ldots\ldots\ldots N \qquad (4.17)$$

i,e $\qquad g_i(P_{gi}) \leq 0$

such that,

$$g_i^+(P_{gi})=P_{gi}-P_{gi,max} \leq 0 \qquad (4.18)$$

and

$$g_i^-(P_{gi})=P_{gi,min}-P_{gi} \leq 0 \qquad (4.19)$$

after introducing a multiplier eqns become

$$\mu_{i+}\, g_i^+ = 0 \qquad ; \qquad \mu_i^+ \geq 0 \qquad (4.20)$$

$$\mu_{i^-}\, g_i^- = 0 \qquad ; \qquad \mu_i^- \geq 0 \qquad (4.21)$$

Then the LaGrangian function become,

$$\mathcal{L} = F_T - h(P_{g1},P_{g2},P_{g3},\ldots,P_{gN}) + \mu_i^+ g_i^-(P_{gi}) + \mu_i^- g_i(P_{gi}) = 0 \qquad (4.22)$$

Now taking the derivatives with respect to different variables we have,

$$(IC)_i - \lambda(1 - (ITL)_i) + \mu_i^{+} \;\; \mu_i^{-} = 0 \quad ; \text{ for } i=1,2,3,\ldots.N \tag{4.23}$$

where,

$$\text{Incremental cost} = \frac{dF_i}{dP_{gi}} = (IC)_i$$

$$\text{Incremental transmission loss} = \frac{dP_L}{dP_{gi}} = (ITL)_i$$

from equality constraints,

$$\sum_{i=1}^{N} P_{gi} - P_D - P_L = 0 \tag{4.24}$$

from inequality constraints,

$$\mu_i^{-} (P_{gi,min} - P_{gi}) = 0 \quad ; \mu_i^{-} \geq 0 \tag{4.25}$$

and

$$\mu_i^{+} (P_{gi} - P_{gi,max}) = 0 \quad ; \mu_i^{+} \geq 0 \tag{4.26}$$

There are several cases depending upon the position or value of the control variable (P_{gi}) for optimum solution.

<u>Case 1</u>

if the values of P_{gi}'s are such that they are not at either generation limits. Then all μ multipliers are zero and

the coordination equation becomes

$$\frac{(IC)_i}{1. - (ITL)_i} = \lambda \quad ; \text{ for } i = 1, 2, \cdots N \tag{4.27}$$

or can be written as

$$(PF)_i * (IC)_i = \lambda \tag{4.28}$$

$$\text{where , Penalty factor, } (PF)_i = \frac{1.0}{1.0 - (ITL)_i} \tag{4.29}$$

Case II

Now suppose that optimum solution requires P_{gi} (i=1,2,..K; K<N) to be at there upper limit of generation ($P_{gi} = P_{gi,max}$; i=1,2,...K) and that P_{gi} (i= K+1,K+2,....,N) within its limits. Then

$$\mu_i^+ > 0 \quad ; \quad \text{for } i = 1,2,.....K$$

$$\mu_i^- = 0 \quad ; \quad \text{for } i = 1,2,.....K$$

$$\text{and } \mu_i^- = \mu_i^+ = 0 \quad ; \quad \text{for } i = K+1,K+2,....N \tag{4.30}$$

therefore,

$$(IC)_i - \lambda(1.0 - (ITL)_i) + \mu_i^+ = 0 \quad ; \; i < K$$

$$(IC)_i - \lambda(1.0 - (ITL)_i) = 0 \quad ; \; i > K \tag{4.31}$$

Hence the coordination equations become

$$\frac{(IC)_i}{1-(ITL)_i} \leq \lambda \quad ; \; i < k \tag{4.32}$$

$$\frac{(IC)_i}{1-(ITL)_i} = \lambda \quad ; \; i > k \tag{4.33}$$

Case III

Let the optimum solution requires P_{gi} (i= 1,2,...J ; J < N) to be at there lower limit ($P_{gi} = P_{gi,min}$) and the other units within there limits (i > J), Then

$$\mu_i^- \geq 0 \quad ; \quad i \leq J$$
$$\mu_i^+ = 0 \quad ; \quad i \leq J$$
$$\text{and } \mu_i^- = \mu_i^+ = 0 \quad ; \quad i > J \tag{4.34}$$

Hence

$$(IC)_i - \lambda(1.0 - (ITL)_i) - \mu_i^- = 0 \quad ; \text{ for } i \leq J$$
$$(IC)_i - \lambda(1.0 - (ITL)_i) = 0 \quad ; \text{ for } i > J \tag{4.35}$$

Therefore the coordination equations become,

$$\frac{(IC)_i}{1.0 - (ITL)_i} \geq \lambda \quad ; \quad i \leq J \tag{4.36}$$

$$\frac{(IC)_i}{1.0 - (ITL)_i} = \lambda \quad ; \quad i > J \tag{4.37}$$

Case IV

If the optimum solution requires that all the units are at there limits and the equality constraint can be met. Then and nonzero 's are indeterminate.

Then cordination equations become:

$$\frac{(IC)_i}{1 - (ITL)_i} \leq \lambda \quad ; \text{ for those thermal units hits upper limit.} \tag{4.38}$$

$$\frac{(IC)_i}{1 - (ITL)_i} \geq \lambda \quad ; \text{ for those thermal units hits lower limit.} \tag{4.39}$$

4.6 Hydro thermal generating system:

Short term scheduling

It is usually assumed that hydro generations are free of cost and that a given amount of water be used in such a way that the cost of thermal generation be minimized.

Here in the study a number of thermal unit and one hydro unit is used. So in the mathematical modeling will include a number of thermal generating unit and only one hydro unit. The assumption with the hydro plant is that it is not sufficient to supply all the load demands during any period and that there is a maximum total volume of water that may be used during the total period, say T_{max} hours.

The objective function:

$$F_T = \sum_{j=1}^{j_{max}} n_j \{ F_{1j}(P_{g1}) + F_{2j}(P_{g2}) + \ldots\ldots + F_{Nj}(P_{gN}) \} \qquad (4.40)$$

subject to

equality constraints:

$$\sum_{j=1}^{j_{max}} n_j q_j = q_{tot} \quad ; \text{Discharge balance} \qquad (4.41)$$

where q_{tot} = Total allowable water volume volume to be discharged .

$$\sum_{i=1}^{NB} P_{dij} + P_{Lj} - P_{Hj} - \sum_{k=1}^{N} P_{gkj} = 0 \quad ; \text{Active power balance} \qquad (4.42)$$

where $j = 1,2,\ldots,j_{max}$

$$\sum_{j=1}^{j_{max}} n_j = T_{max} \qquad (4.43)$$

Loads are assumed to be constant during each interval (j).

Other constraints are :

$V_j|_{j=0} = V_S$ = Water volume of the reservoir at the beggining of the study or starting volume

$V_j|_{j=j_{max}} = V_E$ = Water volume of the reservoir at the beggining of the study or starting volume

$q_j = Q_j$ = Amount of water discharge for the particular period j.

J_j = Water inflow during the jth period. (4.44)

Inequality constraints:

For thermal units:

$$P_{gi,min} \leq P_{gi} \leq P_{gi,max} \quad ; \text{Generation limit} \tag{4.45}$$

for i=1,2,3,.........N for all j

i,e $g_i(P_{gi}) \leq 0$

such that,

$$g_i^+(P_{gi}) = P_{gi} - P_{gi,max} \leq 0$$

and

$$g_i^-(P_{gi}) = P_{gi,min} - P_{gi} \leq 0 \tag{4.46}$$

after introducing a multiplier eqns become

$$\mu_i^+ \, g_i^+ = 0 \quad ; \quad \mu_i^+ > 0$$

$$\mu_i^- \, g_i^- = 0 \quad ; \quad \mu_i^- > 0 \tag{4.47}$$

For Hydro unit:

$$q_{min} \leq q_j \leq q_{max} \quad ; \text{Water discharge rate limit} \tag{4.48}$$

for $j = 1,2,....,j_{max}$.

Splitting the equation 4.48 into two parts:

$$\sigma_{qj}^{+} (q_j - q_{max}) = 0 ; \quad \sigma_{qj}^{+} \geq 0 \qquad (4.49)$$

$$\sigma_{qj}^{-} (q_{min} - q_j) = 0 ; \quad \sigma_{qj}^{-} \geq 0 \qquad (4.50)$$

Hydro equality constraints:

$V_S = V_0$ = Volume of water at the beginning.

$V_E = V_{jmax}$ = Volume of water at the end.

Then, volume of the reservoir for each time interval becomes,

$$V_{j-1} + n_j J_j = q_j (P_{Hj}) n_j + V_j \qquad (4.51)$$

; for $j = 1,2,3,\ldots\ldots\ldots\ldots j_{max}$

The total study period is divided into three intervals :

BL (base load)

IL (intermediate load)

PL (Peak load)

so, $J_{max} = 3$ (4.52)

And hydro inequality constraints are

$$V_{min} \leq V_j \leq V_{max} \qquad (4.53)$$

$$P_{H,min} \leq P_{Hj} \leq P_{H,max} \qquad (4.54)$$

So the augmented LaGrangian equation becomes:

$$L = \sum_{j=1}^{j_{max}} \{ n_j \sum_{i=1}^{N} F_{ij}(P_{gij}) \} + \sum_{j=1}^{j_{max}} (P_{Dj} + P_{Lj} - P_{Hj} - \sum_{k=1}^{N} P_{gkj})$$

$$+ \sum_{j=1}^{j_{max}} \gamma_j \{ -V_{j-1} - n_j (J_j - q(P_{Hj})) + V_j \} + \sum_{j=1}^{j_{max}} \sum_{k=1}^{N} \mu_{kj}^{-} (P_{gk,min} - P_{gkj})$$

$$+ \sum_{j=1}^{j_{max}} \sum_{k=1}^{N} \mu_{kj}^{+} (P_{gkj} - P_{gk,max}) \quad + \sum_{j=1}^{j_{max}} \sigma_{vj}^{-} \{ V_{min} - V_j \}$$

$$+ \sum_{j=1}^{j_{max}} \sigma_{vj}^{+} \{ V_j - V_{max} \} + \sum_{j=1}^{j_{max}} \mu_{Hj}^{-} (P_{H,min} - P_{Hj}) + \sum_{j=1}^{j_{max}} \mu_{Hj}^{+} (P_{Hj} - P_{H,max})$$

$$+ \sum_{j=1}^{j_{max}} \sigma_{qj}^{-} (q_{min} - q(P_{Hj})) + \sum_{j=1}^{j_{max}} \sigma_{qj}^{+} (q(P_{Hj}) - q_{max}) = 0 \qquad (4.55)$$

The hydro unit characteristics:

$$q = q(P_H) \quad ; \text{assuming constant head for a particular study period.} \qquad (4.56)$$

Here the unknowns are

P_{gi} = thermal generation for each plant

for $j = 1,2,\ldots\ldots,j_{max}$

and $i = 1,2,\ldots\ldots,N$ (Number of thermal plant)

λ = lagrangian multiplier that includes the effect of load balance equality constraints for each interval (BL,IL etc.).

γ_j = another lagrangian multiplier that includes the effect of the hydro constraints (effect of hydro volume , inflow rate and discharge of water constraints).

μ_{kj}^{-} = Multiplier take into account the effect of minimum amount of allowable generation for each unit at each interval.

μ_{kj}^{+} = Multiplier to take into account the effect of maximum amount of allowable generation for each unit at each interval.

σ_{vj}^-= Multiplier to represent the effect of minimum amount of water volume that must not be violated at each interval.

σ_{vj}^+= Multiplier to represent the effect of maximum amount of water volume of the reservoir so that there is no spillage at each interval.

μ_{Hj}^+= Maximum allowable amount of hydro generation at each interval is included with this multiplier.

μ_{Hj}^-= Minimum allowable amount of hydro generation at each interval is included with this multiplier.

σ_{qj}^-=To include the minimum allowable amount of hydro discharge rate at each interval to produce hydro power.

σ_{qj}^+=To include the maximum allowable amount of hydro discharge rate at each interval to produce useful hydro power.

and

$q(P_H)$= Hydro discharge rate as a function of hydro power generation and so it is implicit that for maximum discharge rate there will be a maximum power generation. That is indirectly the maximum hydro power generation is made limited. Similarly for minimum generation. Therefore it is clear that only one constraint out of these two is enough.

It may be mentioned that for the same amount of discharge rate power generation may be different for seasonal variation of water head at the water reservoir. So, if we take the power generation limits as the constraint, in that case care must be taken about the variation of this limit for different seasonal calculation. For short range operation it can be taken as a constant say, for a particular day of of a season. Similar is the case for discharge rate.

In the development of the mathematical model maximum possible number of constraints have been used both equality and inequality constraints. Thus, it is a nonlinear optimization problem with a number of equality and inequality constraints.

From the knowledge of calculus, to minimize a function of multiple variable partial derivative of the function with respect to each variable has to be taken and then equate it to zero. Then the set of equations evolved will be enough to find out the optimum setting of the variables to minimize the function under constraint condition. The function of multiple variable is the augmented LaGrangian function or the augmented objective function.

Now we can set up the conditions for an optimum solution of hydro thermal generation scheduling.

Taking the derivative of the LaGrangian function with respect to the variables thermal and hydro generation and with respect to another variable V(volume) we get the first set of conditions given by

$$n_j \frac{dF_{ij}(P_{gij})}{dP_{gij}} - \lambda_j\left(1 - \frac{\partial P_{Lj}}{\partial P_{gij}}\right) - \mu^-_{ij} + \mu^+_{ij} = 0 \text{ ; for } i=1,2,3,\ldots N \quad (4.57)$$

$$\text{for } j=1,2,3,\ldots j_{max}$$

$$-\lambda_j\left(1 - \frac{\partial P_{Lj}}{\partial P_{Hj}}\right) + n_j \gamma_j \frac{d\varphi(P_{Hj})}{dP_{Hj}} - \mu^-_{Hj} + \mu^+_{Hj} = 0 \text{ ; for } j=1,2,3,\ldots j_{max} \quad (4.58)$$

$$\text{and } \gamma_j - \gamma_{j+1} - \sigma^-_{vj} + \sigma^+_{vj} = 0 \text{ ; for } j=1,2,3,\ldots j_{max} \quad (4.59)$$

Let us assume that discharge limit is always such that it will never lead to violat the power generation constraints. That is, if the power generation limits are satisfied the discharge is automatically satisfied. considering this fact it can be written that

$$\sigma^-_{qj} = \sigma^+_{qj} = 0 \text{ , } j=1,2,3,\ldots,j_{max} \quad (4.60)$$

Next set can be obtained from the equality and inequality constraints as follows:

1. From equality constraints:

$$P_{Dj} + P_{Lj} - P_{Hj} - \sum_{K=1}^{N} P_{gkj} = 0 \text{ , } j=1,2,3 \ldots\ldots j_{max} \quad (4.61)$$

$$- V_{j-1} - n_j \ (J_j - q(P_{Hj})) + V_j = 0 \ , \ j=1,2,3, \ \ldots . \ j_{max} \tag{4.62}$$

2. From inequality constraints:

$$\mu^-_{ij} \ (P_{gi,min} - P_{gij}) = 0 \ ; \ \mu^-_{ij} \geq 0 \tag{4.63}$$

$$\mu^+_{ij} \ (P_{gij} - P_{gi,max}) = 0 \ ; \ \mu^+_{ij} \geq 0 \tag{4.64}$$

$$\sigma^-_{vj} \ (V_{min} - V_j) = 0 \ ; \ \sigma^-_{vj} \geq 0 \tag{4.65}$$

$$\sigma^+_{vj} \ (V_j - V_{max}) = 0 \ ; \ \sigma^+_{vj} \geq 0 \tag{4.66}$$

$$\mu^-_{Hj} \ (P_{H,min} - P_{Hj}) = 0 \ ; \ \mu^-_{Hj} \geq 0 \tag{4.67}$$

$$\mu^+_{Hj} \ (P_{Hj} - P_{H,max}) = 0 \ ; \ \mu^+_{Hj} \geq 0 \tag{4.68}$$

Case I

If the condition is such that all the constraints are satisfied then the equations for optimum solution becomes,

$$\frac{n_j \dfrac{dF_{ij}(P_{gij})}{dP_{gij}}}{1 - \dfrac{P_{Lj}}{P_{gij}}} = \lambda_j \ ; \ \text{for } j = 1,2,3, \ \ldots . \ j_{max}, \quad i = 1,2,3, \ \ldots .. \ N \tag{4.69}$$

$$\frac{n_j \ \ _j \ \dfrac{dq \ (P_{Hj})}{dP_{Hj}}}{1 - \dfrac{P_{Lj}}{P_{Hj}}} = \lambda_j \ ; \ \text{for } j = 1,2,3, \ \ldots . \ j_{max} \tag{4.70}$$

and, $\gamma_j = \gamma_{j+1}$; for $j = 1,2,3,\ldots . \ j_{max}$ (4.71)

OR,

$$n_j \frac{(IC)_{ij}}{1 - (ITL)_{ij}} = \;_j \quad ; \text{ for } i = 1,2,3,\ldots.\ N \quad j = 1,2,3,\ \ldots\ j_{max} \tag{4.72}$$

$$n_j\ \gamma_j \frac{(ID)_{ij}}{1 - (ITL)_{ij}} = \;_j \quad ; \text{ for } j = 1,2,3,\ldots.\ j_{max} \tag{4.73}$$

$$\gamma_j = \gamma_{j+1} \quad ; \text{ for } j = 1,2,3,\ \ldots j_{max} \tag{4.74}$$

Where,

$$(IC)_{ij} = \frac{dF_{ij}(P_{gij})}{dP_{gij}} \quad ; \text{ Incremental cost of ith thermal unit at jth interval.} \tag{4.75}$$

$$(ID)_j = \frac{dq(P_{Hj})}{dP_{Hj}} \quad ; \text{ Incremental dischrge rate of hydro unit at jth interval.} \tag{4.76}$$

$$(ITL)_{ij} = \frac{\partial P_{Lj}}{\partial P_{gij}} \quad ; \text{ Incremental transmission loss for the ith thermal unit at jth interval.} \tag{4.77}$$

$$(ITL)_{Hj} = \frac{\partial P_{Lj}}{\partial P_{Hj}} \quad ; \text{ Incremental transmission loss for the hydro unit at jth interval.} \tag{4.78}$$

Case II

Assuming some thermal units hitting the upper limit and some others hitting the lower limits and the rests are within the constraint limits. considering all other constraints are satisfied the solution criteria becomes:

For those thermal units which hit upper limits,

$$n_j \frac{(IC)_{ij}}{1 - (ITL)_{ij}} \leq \lambda_j \quad ; \text{ for } i = 1,2,3,\ldots.\ N \quad j = 1,2,3,\ \ldots\ j_{max} \tag{4.79}$$

For those thermal units which hit lower limits,

$$n_j \frac{(IC)_{ij}}{1 - (ITL)_{ij}} \geq \lambda_j \quad ; \text{ for } i = 1,2,3,\ldots.\ N \quad j = 1,2,3,\ \ldots.\ j_{max} \tag{4.80}$$

For those thermal units within the constraint limits,

$$n_j \frac{(IC)_{ij}}{1-(ITL)_{ij}} = \;_j \;;\; \text{for } i = 1,2,3,\ldots\ N \quad j = 1,2,3,\ \ldots\ j_{max} \tag{4.81}$$

$$n_j\ \gamma_j \frac{(ID)_j}{1-(ITL)_{Hj}} = \;_j \;;\; \text{for } j = 1,2,3,\ldots\ j_{max} \tag{4.82}$$

$$\gamma_j = \gamma_{j+1} \;;\; \text{for } j = 1,2,3,\ \ldots j_{max} \tag{4.83}$$

Case III

If it is so happens that the volume constraints are hit and all other constraints are satisfied then,

$$n_j \frac{(IC)_{ij}}{1-(ITL)_{ij}} = \;_j \;;\; \text{for } i = 1,2,3,\ldots\ N \quad j = 1,2,3,\ \ldots\ j_{max} \tag{4.85}$$

$$n_j\ \gamma_j \frac{(ID)_j}{1-(ITL)_{Hj}} = \;_j \;;\; \text{for } j = 1,2,3,\ldots\ j_{max} \tag{4.86}$$

$$\gamma_j - \gamma_{j+1} = \sigma_{vj}^{-} - \sigma_{vj}^{+} \;;\; \text{for } j = 1,2,3,\ \ldots j_{max} \tag{4.87}$$

$$\geq 0 \;;\; \text{if the lower limit of the volume of water is hit} \tag{4.88}$$

$$\leq 0 \;;\; \text{if the upper limit of the volume of water is hit} \tag{4.89}$$

Summary of the solution criteria of a hydrothermal power system having one hydro unit and N numbers of thermal units, subject to constraints are given below:

1. $$n_j \frac{(IC)_{ij}}{1-(ITL)_{ij}} = \lambda_j \;;\; \text{When the ith thermal unit generation is within the limit at jth interval.} \tag{4.90}$$

2. $$n_j \frac{(IC)_{ij}}{1-(ITL)_{ij}} \leq \lambda_j \;;\; \text{When the ith thermal unit hits upper limit at jth interval.} \tag{4.91}$$

3. $$n_j \frac{(IC)_{ij}}{1-(ITL)_{ij}} \geq \lambda_j \;;\; \text{When the ith thermal unit hits lower limit at jth interval.} \tag{4.92}$$

4. $$n_j\ \gamma_j \frac{(ID)_j}{1-(ITL)_{Hj}} = \lambda_j \;;\; \text{When the hydro unit generation is within the limit at jth interval.} \tag{4.93}$$

5. $n_j \gamma_j \dfrac{(ID)_j}{1 - (ITL)_{Hj}} \geq \lambda_j$; When the hydro unit generation hits lower limit at jth interval. (4.94)

6. $n_j \gamma_j \dfrac{(ID)_j}{1 - (ITL)_{Hj}} \leq \lambda_j$; When the hydro unit generation hits upper limit at jth interval. (4.95)

7. $\gamma_j = \gamma_{j+1}$; When volume constraint limits are not violated (4.96)

8. $\gamma_j - \gamma_{j+1} \geq 0$; When the volume of the water hits the lower limit of the volume constraint. (4.97)

9. $\gamma_j - \gamma_{j+1} \leq 0$; When the volume of the water hits the upper limit of the volume constraint. (4.98)

4.7 Hydrothermal optimization problem.

The flow diagram for solution of hydrothermal dispatch problem is given in appendix A and the program for computation is given in appendix B.

UNIT COMMITMENT

5.1 INTRODUCTION:

In the case of an electric power system, the total load on the system will generally be higher during the day time and early evening when industrial loads are high, lights are on, and so forth and lower during the late evening and early morning when most of the population are asleep. In addition, the load being lower over the weekend days than week days. So it is unnecessary to run more than enough unit and have them running all the time. It is also expensive to run too many generating units. To "commit" a generating unit is to "turn it on", that is to bring the unit upto speed, synchronize it to the system and connect it so that it can deliver power to the network.

5.2 CONSTRAINTS IN THE UNIT COMMITMENT:

Number of constraints is never fixed. Many constraints can be placed on the unit commitment problem. Any rule or condition imposed on a scheduling problem is one constraint. Here some of them (considered important) are given below.

SPINNING RESERVE:

The total amount of generation available from all the units synchronized on the system minus the present load plus losses being supplied. Spinning must be carried so that the loss of one or more units does not cause too far a drop in the system frequency. Simply, if one unit is lost, there must be ample reserve on the other units to make up for the loss in a specified time period. Typical rules specify that reserve must be a given percentage of forecasted peak demand, so that reserve must be capable of making up the loss of the most heavily loaded unit in a given period of time (Reliability requirement).

THERMAL UNIT CONSTRAINTS:

In the operation of a thermal power plant, various constraints arises, such as:

Minimum up time: Once the unit is running, it should not be turned off immediately.

Minimum down time: Once the unit is disconnected, there is a minimum time before it can be recommited.

Crew constraints: If a plant consists of two or more units, they can not both be turned on at the same time.

A certain amount of energy must be expended to bring the unit on line called start-up cost, because this energy does not result in any Megawatt generation from the unit. finally, the capacity limits of thermal units may change frequently due to maintenance or unscheduled outages of various equipments in the plant. This must also be taken into account in unit commitment.

HYDRO CONSTRAINTS:

Unit commitment can not be completely separated from the scheduling of hydro units.

5.3 UNIT COMMITMENT:

The priority list of unit commitment method has been used here.

PRIORITY LIST METHOD:

The method consists of creating a priority list of units. The priority list can be obtained using the full load average production cost of each unit, where the full load average production cost is simply the net fuel rate at full load times the fuel cost. Priority list schemes are built around a simple shut down algorithm that might operate as follows;

At each hour when load is dropping, determine whether dropping the next unit on the priority list will leave sufficient generation to supply the load plus spinning reserve requirements. If not, continue operating as is, if yes, go on to the next step.

Determine the number of hours, H, before the unit will be needed again. That is assuming that the load is dropping and will then go back up some hours later.

If H is less then the minimum shut down time for the unit, keep commitment as is, if not go to the next step.

Calculate two costs. The first is the sum of hourly production cost from the next H hours with the unit up. Then recalculate the same sum for the unit down and add in the start-up cost for either cooling the unit or banking it, whichever is less expensive. If there is sufficient savings from shutting down the unit, it should be shut down, otherwise, keep it on.

Repeat this entire procedure for the next unit on the priority list. If it is also dropped, go to the next and so forth.

To ensure that various constraints are met various enhancements can be made by grouping of units.

CHAPTER 6

RESULTS OF THE OPTIMIZATION STUDY OF HYDRO THERMAL GENERATION

6.1 Description of the sample system

The sample system considered here for optimization study contains the following :

1. 33 bus system
2. 11 Generating bus
3. Out of 11 Generating buses (corresponds 11 generating plant) there is only 1 Hydro plant and 10 Thermal plants.
4. Most of the data from BPDB integrated Hydrothermal power network
5. The sample system single line diagram is given at the fig 6.1.

Generator data description of the sample system I

The generator input-output characteristics is given by the equation

$$H(P_{Gi}) = Alp_i + Bet_i * P_{Gi} + Gam_i * P_{Gi} * P_{Gi}$$

where, H is expressed in MBtu/Hr or MCft/Hr or Gallon/Hr

P_{Gi} is in Megawatts

and Alp, Bet and Gam are the coefficients of the polynomial of input output characteristics of the generating unit when least square method of curve fit is utilized to the generator discrete input output data.

Bus No. i	Name of the Generating station	Minimum capacity $P_{Gi,min.}$ MW	Maximum capacity $P_{Gi,max.}$ MW	Alp_i	Bet_i	Gam_i	Fuel cost rate Tk/MCft
2	Sikalbaha	18.00	60.00	0.1917	0.0040	$5.056*10^{-5}$	$12.*10^3$
3	Siddhirganj	24.00	80.00	0.2142	0.0058	$4.868*10^{-5}$	$12.*10^3$
4	Shahjibazar	18.00	60.00	0.0274	0.0139	$4.519*10^{-6}$	$12.*10^3$
5	Ashuganj	90.00	300.00	0.2601	0.0069	$3.812*10^{-6}$	$12.*10^3$
6	Ashuganj	72.00	230.00	0.2400	0.0078	$5.490*10^{-5}$	$12.*10^3$
7	Ghorasal	33.00	110.00	0.1852	0.0077	$1.143*10^{-5}$	$12.*10^3$
8	Ghorasal	63.00	210.00	0.2000	0.0060	$5.000*10^{-6}$	$12.*10^3$
9	*Bheramara	18.00	60.00	248.714	60.027	1.0069	5.00
10	*Bogra	24.00	80.00	120.600	68.230	1.0340	5.00
11	*Goalpara	40.00	200.00	550.00	60.161	0.0800	5.00

* for deisel unit & cost rate is in Tk./gallon.

The input output characteristics of a hydro plant is given by the following equation :

$$q(P_H) = a + b * P_H + c * P_H^2$$

Where, (assuming constant head of water)

$q(P_H)$ is in acre ft per hour

P_H is in M W (power output)

a,b and c are the coefficient of polynomial.

6.1.1 *KAPTAI HYDROELECTRIC POWER PLANT*

In the year 1982 BPDB had 857 MW of installed capacity in hydro,steam,gas turbine and diesel Power station. The only Hydro Station located at Kaptai has 130 MW of installed capacity in three units. Although the installed capacity was 857 MW, the maximum capability was only 678 MW and the maximum demand was 600 MW. Demand was forecast to reach 1823 MW by 1990 MW. Generation capability was tentatively planned to reach 2210 MW by the same year. Kaptai Hydro power station Extension project (4th & 5th Unit) was a part of the plan and suppose to be completed by this year(1988).

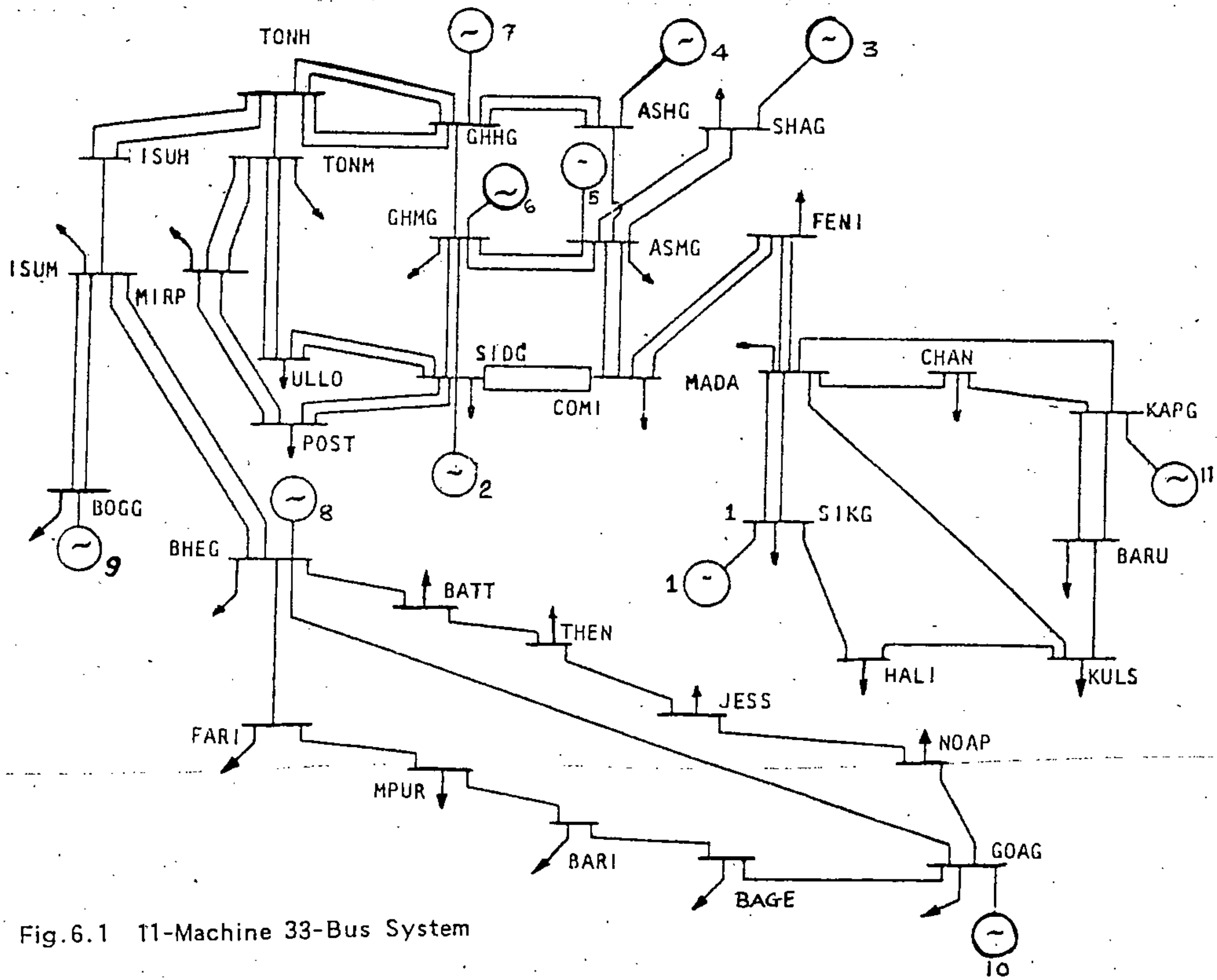

Fig.6.1 11-Machine 33-Bus System

The initial development of Hydro power at Kaptai was based on 18 years hydrological data since 1936. The records of the recent operating data (7 years: 1973 to 1979) showed an average in flow (run-off) of 16.05 million acre-feet. A recent survey revealed that the reservoir created by the dam has a capacity of 5.44 million acre-feet of water at a potential difference of 119 ft. Out of the three units, two units having capacity of 40 Mw each were installed in 1962 and the third unit having capacity of 50 MW was installed in September 1982.

REVISED RULE CURVE FOR RESERVOIR OPERATION OF KAPTAI HYDRO ELECTRIC POWER STATION (WATER YEAR NOVEMBER-NOVEMBER

Year 1985-1986-1987

Date / Month	1 HWH(ft)	1 TWH(ft)	1 Discg	8 HWH(ft)	8 TWH(ft)	8 Discg	15 HWH(ft)	15 TWH(ft)	15 Discg	22 HWH(ft)	22 TWH(ft)	22 Discg	MWHR
Year 1885-86													
November	91.61	8.0	5185	90.97	1.6	6246	90.25	9.2	5984	90.29	3.2	8396	32702
December	89.28	7.0	10118	88.46	3.0	9567	87.34	7.5	7936	86.33	1.5	9518	35008
January	85.41	4.5	8030	84.43	3.0	7115	83.32	4.5	9148	82.14	2.2	9151	33553
February	80.57	4.0	9825	78.95	5.0	9950	77.56	2.0	7666	75.88	2.5	5186	28925
March	74.61	4.0	4088	73.47	3.0	4412	72.13	5.3	3692	70.87	3.0	5202	18828
April	68.78	2.0	2107	67.63	5.2	3599	66.17	4.0	1087	66.38	4.5	5964	12745
May	65.73	1.0	2022	65.75	4.5	3206	64.73	3.5	1625	64.72	4.5	2231	7362
June	64.00	1.0	1973	63.28	5.3	2311	63.59	2.0	2865	63.64	6.5	3428	8143
July	67.48	3.0	4258	72.05	7.0	7966	74.01	1.8	7525	73.53	8.5	9771	31137
August	81.92	2.8	8354	83.12	10.0	15663	83.97	2.0	8089	86.18	8.5	6445	37171
September	91.39	4.3	9485	94.26	11.0	18418	96.87	3.0	8904	97.20	8.5	12674	53505
October	97.84	4.0	10049	100.59	9.0	8233	102.53	3.0	3845	102.71	6.5	7425	36029
Year 1986-87													
November	102.37	4.5	3826	102.21	3.0	6947	103.66	3.5	9844	103.66	6.6	9301	42488
December	103.17	5.5	14336	102.04	5.5	15524	101.11	6.0	16477	100.00	6.0	13989	73499
January	98.79	7.0	10244	95.41	3.9	15409	92.38	7.0	15003	89.87	5.0	17612	65654
February	88.85	8.7	18041	88.08	5.5	16330	85.73	8.0	15468	83.88	1.6	19574	58338
March	82.36	6.5	10453	81.15	1.0	8054	80.13	8.3	11333	79.18	6.0	8105	37597
April	75.66	12.0	15720	73.14	8.2	8459	76.23	10.5	13211	74.58	0.5	5712	36130
May	74.12	4.3	7408	73.47	3.0	10479	72.24	4.8	5551	70.94	0.4	2526	17106
June	70.09	4.0	3129	72.63	3.5	7073	75.24	8.5	8590	78.46	3.5	6054	20759
July	77.78	7.5	5726	77.68	5.0	6078	78.26	9.0	8159	79.98	5.0	5620	25452
August	94.59	10.5	12661	103.73	6.0	6311	104.66	10.0	13227	105.03	11.5	13079	57737

6.2 Optimum scheduling of units :

Unit commitment:

This is usually done one day in advance considering the predicted load of the following day. There are many ways of load prediction. Usual practice of committing generating units is to put the most efficient one first and then the next most efficient one. But this does not offer maximum economy. Strictly priority order unit commitment method is used here. The priority order is set using the full load average production cost of generation. Top priority is given to the generator having minimum full load average cost of generation. Next priority is given to the unit having minimum full load average production cost of generation among the rest and so on. After the priority order list is made commitment is done considering a load demand equal to the predicted load plus reliability requirement. Reliability requirement impose some extra unit to run to backup the system load when any of the running unit fails. Depending upon the reliability requirement reserve amount varies (i,e, number of extra units). Here reserve is taken in such a way that even if the largest running unit fails reserve will be sufficient to provide the necessary power to the system.

The optimum scheduling of units is done using the recent load curves of BPDB system. It is found that there is a distinct variation of load from season to season, and consequently, optimum dispatch studies for summer, winter and rainy season have been made. The daily load curves have been divided into three periods- base load, intermediate load and peak load periods. The available water for hydro generation can be used in any period or throughout a day. Consequently, twenty four studies have been made using recent load curves assuming maximum hydro generation of 130 MW as detailed in case studies- set A, no. 1-6. The studies have been repeated for a maximum hydro generation of 230 MW resulting in a further 24 studies as detailed in case studies- set B, no. 1-6.

Considering the general pattern of load growth 8 studies of future system demand have also been made as detailed in case studies- set A, no. 7 and set B, no.7.

Three sets of case studies have been made here as detailed in the following sections.

6.2.1 Case study - Set A.

Using the recent load curves, the following cases have been studied. It is considered that the hydro station can generate 130 MW maximum.

1. Winter weekend:
   BL = 540 MW ; Duration = 16 hours.
   IL = 650 MW ; Duration = 04 hours.
   PL = 950 MW ; Duration = 04 hours.

   1a. For maximum hydro generation at BL,
   The generation cost for the day = Tk. 318740.90
   1b. For maximum hydro generation at IL,
   The generation cost for the day = Tk. 306425.60
   1c. For maximum hydro generation at PL,
   The generation cost for the day = Tk. 304084.50
   1d. For fixed hydro generation throughout the day,
   The generation cost for the day = Tk. 307390.00

2. Winter weekday:
   BL = 550 MW ; Duration = 12 hours
   IL = 750 MW ; Duration = 8 hours
   PL = 1025 MW; Duration = 4 hours

   2a. For maximum hydro generation at BL,
   The generation cost for the day = Tk. 343076.30
   2b. For maximum hydro generation at IL,
   The generation cost for the day = Tk. 336449.60
   2c. For maximum hydro generation at PL,
   The generation cost for the day = Tk. 323912.60
   2d. For fixed hydro generation throughout the day,
   The generation cost for the day = Tk. 326503.50

3. Summer weekend: BL = 570 MW ; Duration = 12 hours
IL = 630 MW ; Duration = 08 hours
PL = 905 MW ; Duration = 04 hours

3a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 318079.70
3b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 310472.10
3c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 305269.80
3d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 309923.70

4. Summer weekday: BL = 575 MW ; Duration = 8 hours
IL = 690 MW ; Duration = 10 hours
PL = 1090 MW ; Duration = 6 hours

4a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 362852.10
4b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 349559.90
4c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 339048.60
4d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 343571.81

5. Rainy/weekend: season BL = 590 MW ; Duration = 7 hours
IL = 645 MW ; Duration = 12 hours
PL = 1015 MW ; Duration = 5 hours

5a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 338526.40
5b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 337647.40
5c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 326919.40
5d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 328685.70

6. Rainy/ weekday : season BL = 670 MW ; Duration = 9 hours
IL = 837 MW ; Duration = 12 hours
PL = 1153 MW ; Duration = 3 hours

6a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 410911.90
6b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 382933.90
6c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 376169.80
6d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 387452.40

7. Typical predicted weekday :
BL = 705.4 MW ; Duration = 12 hours
IL =1015.0 MW ; Duration = 8 hours
PL =1370.0 MW ; Duration = 4 hours

7a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 410911.90
7b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 382933.90
7c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 376169.80
7d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 387452.40

Discussion:

The above set of study is carried out with the existing recent system data and system load curves of BPDB power network. The results reveal that cost of generation become minimum in all the cases when the hydro plant is run at its maximum capacity at the system peak load and surplus energy at the intermediate load. The details of scheduling along with the information of incremental cost of received power, conversion factor for hydro unit (effectiveness of water utilization), water used during each period and total generation cost of power of each period is given in the following computer printout set-A on pages 6.8 - 6.23 . Least cost of generation among the other condition varies between the constant loading , base loading and intermediate loading of the hydro at its full capacity. Consequently, it can be said that loading of the hydro plant should be at its maximum capacity at the period of system peak load to get maximum cost benefit. In all the cases this gives maximum economy.

Set A : Case study 2

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 550.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	27.18	4053.8710
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	75.31	8162.6680
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	128.5	

INCREMENTAL COST OF RECEIVED POWER = 81.037280
WATER USED = 933.46 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 10.9440
TOTAL GENERATION COST = TK 85009.63

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 750.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	39.88	5181.0410
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	149.5	16519.550
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	204.0	19580.900
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	127.7	

INCREMENTAL COST OF RECEIVED POWER = 96.474950
WATER USED = 927.39 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.0390
TOTAL GENERATION COST = TK 103130.8

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1025.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	119.2	23400.160
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	3.791	

INCREMENTAL COST OF RECEIVED POWER = 250.67050
WATER USED = 64.689 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 38.4070
TOTAL GENERATION COST = TK 154935.8

GRAND TOTAL OF GENERATION COST = TK 343076.3

SET A: Case Study 2 IL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 550.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	33.17	4561.4990
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	136.0	13304.930
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	61.79	

INCREMENTAL COST OF RECEIVED POWER = 88.324310
WATER USED = 455.09 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 12.7360
TOTAL GENERATION COST = TK 90659.52

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 750.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	39.82	5175.0460
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	148.6	16439.900
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	203.3	19520.170
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	129.2	

INCREMENTAL COST OF RECEIVED POWER = 96.399380
WATER USED = 938.63 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.0100
TOTAL GENERATION COST = TK 102984.5

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1025.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	49.79	8767.5270
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	61.21	

INCREMENTAL COST OF RECEIVED POWER = 172.19960
WATER USED = 451.08 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 24.8450
TOTAL GENERATION COST = TK 142805.6

GRAND TOTAL OF GENERATION COST = TK 336449.6

SET A : Case Study 2 PL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 550.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	30.98	4371.0210
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	113.9	11375.390
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	86.16	

INCREMENTAL COST OF RECEIVED POWER = 85.662670
WATER USED = 626.18 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 12.0540
TOTAL GENERATION COST = TK 88539.50

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 750.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	39.82	5175.0460
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	148.6	16439.900
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	203.3	19520.170
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	129.2	

INCREMENTAL COST OF RECEIVED POWER = 96.399380
WATER USED = 938.63 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.0100
TOTAL GENERATION COST = TK 102984.5

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1025.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	45.27	6918.0870
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	109.7	14006.780
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	128.1	

INCREMENTAL COST OF RECEIVED POWER = 122.48730
WATER USED = 930.06 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 16.5490
TOTAL GENERATION COST = TK 132388.6

GRAND TOTAL OF GENERATION COST = TK 323912.6

CL

SETA: Case Study 2

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 550.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	28.88	4193.7710
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	92.58	9579.8520
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	109.5	

INCREMENTAL COST OF RECEIVED POWER = 83.109350
WATER USED = 794.25 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.4300
TOTAL GENERATION COST = TK 86566.70

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 750.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	40.88	5278.8440
02	S I D G	24.05	4582.2770
03	S H A G	18.00	3348.7700
04	A S H G	162.9	17819.050
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	107.2	

INCREMENTAL COST OF RECEIVED POWER = 97.699500
WATER USED = 777.30 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.4670
TOTAL GENERATION COST = TK 105118.3

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1025.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	63.24	9308.7900
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	109.8	

INCREMENTAL COST OF RECEIVED POWER = 143.48990
WATER USED = 795.81 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 19.7300
TOTAL GENERATION COST = TK 134818.6

GRAND TOTAL OF GENERATION COST = TK 326503.5

SET A : Case Study 4 BL

STUDY FOR BASE LOAD PERIOD, DURATION = 8 HOUR

1 DEMAND = 575.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	29.43	4239.3320
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	98.11	10041.390
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	128.5	

INCREMENTAL COST OF RECEIVED POWER = 83.773100
WATER USED = 933.10 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.3140
TOTAL GENERATION COST = TK 87073.81

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 10 HR

2 DEMAND = 690.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	38.65	5063.1630
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	133.1	14953.290
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	191.5	18386.790
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	97.76	

INCREMENTAL COST OF RECEIVED POWER = 94.978040
WATER USED = 709.08 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.2130
TOTAL GENERATION COST = TK 100252.6

STUDY FOR PEAK LOAD PERIOD, DURATION = 6 HR

3 DEMAND = 1090.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	184.3	42494.240
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	44.47	16917.980
11	K A P G	.7308	

INCREMENTAL COST OF RECEIVED POWER = 336.38130
WATER USED = 45.251 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 51.7920
TOTAL GENERATION COST = TK 175525.7

GRAND TOTAL OF GENERATION COST = TK 362852.1

SET A: Case Study 4

JL

STUDY FOR BASE LOAD PERIOD, DURATION = 8 HOUR

1 DEMAND = 575.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	35.71	4789.5810
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	94.11	11318.220
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	161.7	15615.400
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	54.44	

INCREMENTAL COST OF RECEIVED POWER = 91.409500
WATER USED = 404.28 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.2800
TOTAL GENERATION COST = TK 93572.56

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 10 HR

2 DEMAND = 690.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	37.26	4932.2280
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	114.6	13213.570
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	177.4	17060.420
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	131.7	

INCREMENTAL COST OF RECEIVED POWER = 93.287190
WATER USED = 957.27 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 12.5600
TOTAL GENERATION COST = TK 97055.58

STUDY FOR PEAK LOAD PERIOD, DURATION = 6 HR

3 DEMAND = 1090.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	134.5	27396.160
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	53.47	

INCREMENTAL COST OF RECEIVED POWER = 270.86150
WATER USED = 397.59 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 39.3900
TOTAL GENERATION COST = TK 158931.8

GRAND TOTAL OF GENERATION COST = TK 349559.9

SET A : Case Study 4 PL

STUDY FOR BASE LOAD PERIOD, DURATION = 8 HOUR

1 DEMAND = 575.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	37.92	4994.7570
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	123.5	14044.390
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	184.2	17693.840
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	.4268	

INCREMENTAL COST OF RECEIVED POWER = 94.098460
WATER USED = 42.775 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.4700
TOTAL GENERATION COST = TK 98582.34

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 10 HR

2 DEMAND = 690.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	37.68	4972.1840
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	120.3	13744.470
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	181.7	17465.180
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	121.3	

INCREMENTAL COST OF RECEIVED POWER = 93.806410
WATER USED = 880.19 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 12.7560
TOTAL GENERATION COST = TK 98031.20

STUDY FOR PEAK LOAD PERIOD, DURATION = 6 HR

3 DEMAND = 1090.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	47.63	8396.9620
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	128.4	

INCREMENTAL COST OF RECEIVED POWER = 171.96600
WATER USED = 932.39 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 23.2270
TOTAL GENERATION COST = TK 142435.0

GRAND TOTAL OF GENERATION COST = TK 339048.6

SETA: Case Study 4 *CL*

STUDY FOR BASE LOAD PERIOD, DURATION = 8 HOUR

1 DEMAND = 575.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	33.37	4579.0520
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	138.0	13482.750
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	84.58	

INCREMENTAL COST OF RECEIVED POWER = 88.565570
WATER USED = 614.97 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 12.4820
TOTAL GENERATION COST = TK 90854.89

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 10 HR

2 DEMAND = 690.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	39.16	5112.4420
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	140.0	15608.080
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	196.7	18885.990
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	85.13	

INCREMENTAL COST OF RECEIVED POWER = 95.606680
WATER USED = 618.87 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.4670
TOTAL GENERATION COST = TK 101455.9

STUDY FOR PEAK LOAD PERIOD, DURATION = 6 HR

3 DEMAND = 1090.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	103.9	19725.450
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	84.06	

INCREMENTAL COST OF RECEIVED POWER = 230.54740
WATER USED = 611.28 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 32.5090
TOTAL GENERATION COST = TK 151261.1

GRAND TOTAL OF GENERATION COST = TK 343571.8

6.15

SET A: Case Study 6 BL

STUDY FOR BASE LOAD PERIOD, DURATION = 9 HOUR

1 DEMAND = 670.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	36.56	4867.6660
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	105.4	12355.740
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	170.4	16406.410
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	128.7	

INCREMENTAL COST OF RECEIVED POWER = 92.442080
WATER USED = 934.84 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 12.4820
TOTAL GENERATION COST = TK 95479.17

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 12 HR

2 DEMAND = 837.1000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	48.44	6051.9860
02	S I D G	31.92	5386.7070
03	S H A G	18.00	3348.7700
04	A S H G	263.3	28091.780
05	A S M G	72.00	13034.420
06	G H M G	52.81	7484.6760
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	58.65	

INCREMENTAL COST OF RECEIVED POWER = 106.88710
WATER USED = 433.33 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 15.4620
TOTAL GENERATION COST = TK 119032.3

STUDY FOR PEAK LOAD PERIOD, DURATION = 3 HR

3 DEMAND = 1153.5000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	206.7	50380.470
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	81.46	29906.600
11	K A P G	3.327	

INCREMENTAL COST OF RECEIVED POWER = 365.97020
WATER USED = 61.661 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 56.1010
TOTAL GENERATION COST = TK 196400.5

GRAND TOTAL OF GENERATION COST = TK 410911.9

SET A: Case Study 6 IL

STUDY FOR BASE LOAD PERIOD, DURATION = 9 HOUR

1 DEMAND = 670.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	42.71	5458.9980
02	S I D G	25.95	4769.7220
03	S H A G	18.00	3348.7700
04	A S H G	187.1	20212.750
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	.7396	

INCREMENTAL COST OF RECEIVED POWER = 99.915880
WATER USED = 45.195 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 15.3840
TOTAL GENERATION COST = TK 107879.5

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 12 HR

2 DEMAND = 837.1000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	44.93	5684.4240
02	S I D G	28.26	5004.2710
03	S H A G	18.00	3348.7700
04	A S H G	216.7	23207.990
05	A S M G	72.00	13034.420
06	G H M G	37.26	5855.8920
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	128.0	

INCREMENTAL COST OF RECEIVED POWER = 102.62180
WATER USED = 929.51 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.8660
TOTAL GENERATION COST = TK 111769.7

STUDY FOR PEAK LOAD PERIOD, DURATION = 3 HR

3 DEMAND = 1153.5000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	150.0	31749.070
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	101.5	

INCREMENTAL COST OF RECEIVED POWER = 291.26750
WATER USED = 735.86 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 40.3730
TOTAL GENERATION COST = TK 163284.7

GRAND TOTAL OF GENERATION COST = TK 382933.9

SET A : Case Study 6 PL

STUDY FOR BASE LOAD PERIOD, DURATION = 9 HOUR

1 DEMAND = 670.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	42.71	5458.9980
02	S I D G	25.95	4769.7220
03	S H A G	18.00	3348.7700
04	A S H G	187.1	20212.750
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	.7396	

INCREMENTAL COST OF RECEIVED POWER = 99.915880
WATER USED = 4H5.195 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 15.3840
TOTAL GENERATION COST = TK 107879.5

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 12 HR

2 DEMAND = 837.1000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	45.27	5719.2940
02	S I D G	28.62	5040.5520
03	S H A G	18.00	3348.7700
04	A S H G	221.2	23671.310
05	A S M G	72.00	13034.420
06	G H M G	38.77	6010.4130
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	121.3	

INCREMENTAL COST OF RECEIVED POWER = 103.03400
WATER USED = 880.08 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.0110
TOTAL GENERATION COST = TK 112458.7

STUDY FOR PEAK LOAD PERIOD, DURATION = 3 HR

3 DEMAND = 1153.5000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	122.8	24295.940
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	128.7	

INCREMENTAL COST OF RECEIVED POWER = 255.33550
WATER USED = 935.22 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 34.4750
TOTAL GENERATION COST = TK 155831.6

GRAND TOTAL OF GENERATION COST = TK 376169.8

SET A: Case Study 6

CL

STUDY FOR BASE LOAD PERIOD, DURATION = 9 HOUR

1 DEMAND = 670.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	38.62	5060.3220
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	132.7	14915.550
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	191.2	18358.010
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	78.49	

INCREMENTAL COST OF RECEIVED POWER = 94.941680

WATER USED = 571.87 ACRE-FT PER HOUR

CONVERSION FACTOR FOR HYDRO UNIT = 13.4620

TOTAL GENERATION COST = TK 100183.3

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 12 HR

2 DEMAND = 837.1000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	47.42	5943.7570
02	S I D G	30.86	5274.0980
03	S H A G	18.00	3348.7700
04	A S H G	249.7	26653.740
05	A S M G	72.00	13034.420
06	G H M G	48.30	7005.0790
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	78.77	

INCREMENTAL COST OF RECEIVED POWER = 105.64910

WATER USED = 573.86 ACRE-FT PER HOUR

CONVERSION FACTOR FOR HYDRO UNIT = 14.9760

TOTAL GENERATION COST = TK 116893.8

STUDY FOR PEAK LOAD PERIOD, DURATION = 3 HR

3 DEMAND = 1153.5000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	173.2	38839.760
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	78.35	

INCREMENTAL COST OF RECEIVED POWER = 321.74850

WATER USED = 570.85 ACRE-FT PER HOUR

CONVERSION FACTOR FOR HYDRO UNIT = 45.6280

TOTAL GENERATION COST = TK 170375.4

GRAND TOTAL OF GENERATION COST = TK 387452.4

SETA : Case Study 7 BL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	37.98	5000.3070
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	124.3	14118.140
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	184.8	17750.060
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	129.4	

INCREMENTAL COST OF RECEIVED POWER = 94.170140
WATER USED = 939.95 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 12.7070
TOTAL GENERATION COST = TK 98717.86

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	59.52	7310.9360
02	S I D G	43.44	6696.6050
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	101.9	13063.490
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	128.1	

INCREMENTAL COST OF RECEIVED POWER = 120.35620
WATER USED = 930.58 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 16.2600
TOTAL GENERATION COST = TK 131166.3

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	43.57	23879.760
09	B O G G	38.46	21374.090
10	G O A G	200.0	78911.000
11	K A P G	37.96	

INCREMENTAL COST OF RECEIVED POWER = 738.87040
WATER USED = 291.83 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 109.183
TOTAL GENERATION COST = TK 279491.1

GRAND TOTAL OF GENERATION COST = TK 509375.3

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	38.95	5092.5710
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	137.2	15344.050
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	194.6	18684.700
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	105.6	

INCREMENTAL COST OF RECEIVED POWER = 95.353700
WATER USED = 765.75 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.1640
TOTAL GENERATION COST = TK 100970.7

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	59.52	7310.9340
02	S I D G	43.44	6696.6040
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	101.9	13063.480
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	128.1	

INCREMENTAL COST OF RECEIVED POWER = 120.35620
WATER USED = 930.58 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 16.2600
TOTAL GENERATION COST = TK 131166.3

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	169.2	65109.020
11	K A P G	108.8	

INCREMENTAL COST OF RECEIVED POWER = 436.18580
WATER USED = 788.68 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 60.0330
TOTAL GENERATION COST = TK 240481.0

GRAND TOTAL OF GENERATION COST = TK 472617.9

SET A : Case Study 7 *PL*

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	39.20	5115.5090
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	140.4	15648.820
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	197.0	18917.060
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	99.75	

INCREMENTAL COST OF RECEIVED POWER = 95.645670
WATER USED = 723.39 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.2800
TOTAL GENERATION COST = TK 101530.8

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	59.52	7310.9340
02	S I D G	43.44	6696.6040
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	101.9	13063.480
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	128.1	

INCREMENTAL COST OF RECEIVED POWER = 120.35620
WATER USED = 930.58 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 16.2600
TOTAL GENERATION COST = TK 131166.3

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	150.0	56857.910
11	K A P G	128.0	

INCREMENTAL COST OF RECEIVED POWER = 420.78060
WATER USED = 929.90 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 56.8520
TOTAL GENERATION COST = TK 232229.9

GRAND TOTAL OF GENERATION COST = TK 464926.9

Set A: Case Study 7 *CL*

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	38.61	5059.4120
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	132.6	14903.460
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	191.1	18348.790
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	114.1	

INCREMENTAL COST OF RECEIVED POWER = 94.930020
WATER USED = 827.65 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 12.9980
TOTAL GENERATION COST = TK 100161.0

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	46.90	7119.6310
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	116.1	

INCREMENTAL COST OF RECEIVED POWER = 124.39480
WATER USED = 842.09 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 17.0000
TOTAL GENERATION COST = TK 132629.4

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	165.0	63291.850
11	K A P G	113.0	

INCREMENTAL COST OF RECEIVED POWER = 432.84010
WATER USED = 819.13 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 59.3320
TOTAL GENERATION COST = TK 238663.8

GRAND TOTAL OF GENERATION COST = TK 471454.3

So the suggestion for BPDB hydro plant is to run the plant at the system peak load and its vicinity, instead of usual practice of loading it at the base load for all the season, to get the maximum cost benefit from the only hydro plant in Bangladesh.

6.2.2 Case study - Set B.

The recent load curves of BPDB system have been used in these studies, with a maximum generation of 230 MW.

1. Winter weekend: season — BL = 540 MW ; Duration = 16 hours.
IL = 650 MW ; Duration = 04 hours.
PL = 950 MW ; Duration = 04 hours.

1a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 321677.90
1b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 301966.90
1c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 289432.30
1d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 307390.00

2. Winter weekday: season — BL = 550 MW ; Duration = 12 hours
IL = 750 MW ; Duration = 8 hours
PL = 1025 MW; Duration = 4 hours

2a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 344205.00
2b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 332356.80
2c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 313967.90
2d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 326503.50

3. Summer weekend: — BL = 570 MW ; Duration = 12 hours
IL = 630 MW ; Duration = 08 hours
PL = 905 MW ; Duration = 04 hours

3a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 320736.00

3b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 313740.60

3c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 298301.80

3d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 309923.70

4. <u>Summer weekday:</u>

BL = 575 MW ; Duration = 8 hours
IL = 690 MW ; Duration = 10 hours
PL = 1090 MW ; Duration = 6 hours

4a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 362945.50

4b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 365662.60

4c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 330875.00

4d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 343571.81

5. <u>Rainy/weekend: season</u>

BL = 590 MW ; Duration = 7 hours
IL = 645 MW ; Duration = 12 hours
PL = 1015 MW ; Duration = 5 hours

5a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 337087.20

5b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 343723.80

5c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 319847.20

5d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 328685.70

6. <u>Rainy/weekday : season</u>

BL = 670 MW ; Duration = 9 hours
IL = 837 MW ; Duration = 12 hours
PL = 1153 MW ; Duration = 3 hours

6a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 411789.60

6b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 413385.00

6c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 359013.40

6d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 387452.40

7. Typical weekday : (predicted future)

BL = 705.4 MW ; Duration = 12 hours
IL =1015.0 MW ; Duration = 8 hours
PL =1370.0 MW ; Duration = 4 hours

7a. For maximum hydro generation at BL,
The generation cost for the day = Tk. 551160.50

7b. For maximum hydro generation at IL,
The generation cost for the day = Tk. 494224.50

7c. For maximum hydro generation at PL,
The generation cost for the day = Tk. 431374.70

7d. For fixed hydro generation throughout the day,
The generation cost for the day = Tk. 471454.30

Discussion

The above set of study is carried out considering the fact that within a very short period BPDB utility service is going to generate 230 MW of maximum hydro power. Its effect on the total future economy of generation is more important than to see what actually happened in the previous years with a maximum generation of 130 MW from the hydro plant. It has been found from the above study that benefit is more for this case when 230 MW hydro loading is at the peak load period of the same load curves. Details of the economic scheduling along with the other important factors are given in the computer printout set-B on pages 6.27 - 6.42. For the same load curve as the load increases the cost benefit also increases. It is found from the study for the future predicted load that when the hydro plant is loaded at its maximum capacity at the peak load period, maximum economy results.

Due to the continuous variation of water energy reserve from season to season, the quantity of water to be used at different season is different. But the energy of water for each of the above two studies was kept same, but the maximum hydro generation capacity was different.

SET B: Case Study 2 BL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 550.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	18.00	3361.3270
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	63.00	7174.1400
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	150.0	

INCREMENTAL COST OF RECEIVED POWER = 61.203600
WATER USED = 1094.2 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 8.10000
TOTAL GENERATION COST = TK 83328.56

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 750.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	41.43	5332.5000
02	S I D G	24.62	4638.1040
03	S H A G	18.00	3348.7700
04	A S H G	170.1	18531.980
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	98.82	

INCREMENTAL COST OF RECEIVED POWER = 98.364840
WATER USED = 716.68 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.6700
TOTAL GENERATION COST = TK 105940.7

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR.

3 DEMAND = 1025.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	119.2	23400.140
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	3.791	

INCREMENTAL COST OF RECEIVED POWER = 250.67040
WATER USED = 64.689 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 38.4070
TOTAL GENERATION COST = TK 154935.8

GRAND TOTAL OF GENERATION COST = TK 344205.0

SET B : Case study 2 IL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 550.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	34.84	4710.8900
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	153.0	14818.270
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	43.18	

INCREMENTAL COST OF RECEIVED POWER = 90.356990
WATER USED = 327.24 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.2800
TOTAL GENERATION COST = TK 92322.25

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 750.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	35.74	4792.4230
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	94.52	11355.980
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	162.1	15644.190
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	228.7	

INCREMENTAL COST OF RECEIVED POWER = 91.447290
WATER USED = 1710.5 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.2760
TOTAL GENERATION COST = TK 93641.95

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1025.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	81.36	14856.900
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	41.64	

INCREMENTAL COST OF RECEIVED POWER = 200.80460
WATER USED = 316.74 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 29.5600
TOTAL GENERATION COST = TK 146392.5

GRAND TOTAL OF GENERATION COST = TK 332356.8

SET B: Case Study 2 PL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 550.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	36.94	4903.0590
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	110.5	12826.000
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	174.2	16764.940
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	-.6272	

INCREMENTAL COST OF RECEIVED POWER = 92.906330
WATER USED = 35.924 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.3030
TOTAL GENERATION COST = TK 96343.36

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 750.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	37.10	4917.7790
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	112.6	13021.600
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	175.8	16914.060
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	195.5	

INCREMENTAL COST OF RECEIVED POWER = 93.098730
WATER USED = 1445.3 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.8200
TOTAL GENERATION COST = TK 96702.80

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1025.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	49.33	6147.6120
02	S I D G	32.84	5486.2030
03	S H A G	18.00	3348.7700
04	A S H G	275.1	29362.360
05	A S M G	72.00	13034.420
06	G H M G	56.76	7908.4260
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	229.0	

INCREMENTAL COST OF RECEIVED POWER = 107.96920
WATER USED = 1712.8 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.3100
TOTAL GENERATION COST = TK 120921.7

GRAND TOTAL OF GENERATION COST = TK 313967.9

SET B: Case Study 2 CL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 550.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	28.88	4193.7710
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	92.58	9579.8520
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	109.5	

INCREMENTAL COST OF RECEIVED POWER = 83.109350
WATER USED = 794.25 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.4300
TOTAL GENERATION COST = TK 86566.70

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 750.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	40.88	5278.8440
02	S I D G	24.05	4582.2770
03	S H A G	18.00	3348.7700
04	A S H G	162.9	17819.050
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	107.2	

INCREMENTAL COST OF RECEIVED POWER = 97.699500
WATER USED = 777.30 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.4670
TOTAL GENERATION COST = TK 105118.3

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1025.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	63.24	9308.7900
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	109.8	

INCREMENTAL COST OF RECEIVED POWER = 143.48990
WATER USED = 795.81 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 19.7300
TOTAL GENERATION COST = TK 134818.6

GRAND TOTAL OF GENERATION COST = TK 326503.5

SET B: Case Study 4 BL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 575.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	18.00	3361.3270
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	63.00	7174.1400
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	175.0	

INCREMENTAL COST OF RECEIVED POWER = 62.629200
WATER USED = 1285.3 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 8.10000
TOTAL GENERATION COST = TK 83328.56

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 690.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	40.28	5220.3760
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	154.9	17042.190
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	208.1	19979.360
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	57.76	

INCREMENTAL COST OF RECEIVED POWER = 96.969310
WATER USED = 427.20 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.0400
TOTAL GENERATION COST = TK 104091.3

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1090.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF .GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	184.3	42494.240
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	44.47	16917.980
11	K A P G	-.7308	

INCREMENTAL COST OF RECEIVED POWER = 336.38130
WATER USED = 35.251 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 51.7920
TOTAL GENERATION COST = TK 175525.7

GRAND TOTAL OF GENERATION COST = TK 362945.5

SET B : Case Study 4 IL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 575.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	37.92	4994.7570
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	123.5	14044.390
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	184.2	17693.840
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	.4268	

INCREMENTAL COST OF RECEIVED POWER = 94.098460
WATER USED = 42.775 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.4700
TOTAL GENERATION COST = TK 98582.34

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 690.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	34.08	4641.9040
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	145.2	14119.440
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	191.7	

INCREMENTAL COST OF RECEIVED POWER = 89.424080
WATER USED = 1415.6 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.3920
TOTAL GENERATION COST = TK 91554.44

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1090.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	184.3	42494.320
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	44.47	16918.110
11	K A P G	-.7314	

INCREMENTAL COST OF RECEIVED POWER = 336.38170
WATER USED = 35.248 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 51.7920
TOTAL GENERATION COST = TK 175525.9

GRAND TOTAL OF GENERATION COST = TK 365662.6

SET B : Case study 4 PL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 575.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	37.92	4994.7570
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	123.5	14044.390
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	184.2	17693.840
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	.4268	

INCREMENTAL COST OF RECEIVED POWER = 94.098460
WATER USED = 42.775 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.4700
TOTAL GENERATION COST = TK 98582.34

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 690.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	40.28	5220.3760
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	154.9	17042.200
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	208.1	19979.370
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	57.76	

INCREMENTAL COST OF RECEIVED POWER = 96.969310
WATER USED = 427.20 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.0400
TOTAL GENERATION COST = TK 104091.3

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1090.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	55.64	6852.8010
02	S I D G	39.40	6219.9300
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	84.71	11033.350
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	228.2	

INCREMENTAL COST OF RECEIVED POWER = 115.63650
WATER USED = 1707.0 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.2640
TOTAL GENERATION COST = TK 128201.3

GRAND TOTAL OF GENERATION COST = TK 330875.0

SET B: Case Study 4 CL

STUDY FOR BASE LOAD PERIOD, DURATION = 8 HOUR

1 DEMAND = 575.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	33.37	4579.0520
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	138.0	13482.750
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	84.58	

INCREMENTAL COST OF RECEIVED POWER = 88.565570
WATER USED = 614.97 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 12.4820
TOTAL GENERATION COST = TK 90854.89

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 10 HR

2 DEMAND = 690.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	39.16	5112.4420
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	140.0	15608.080
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	196.7	18885.990
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	85.13	

INCREMENTAL COST OF RECEIVED POWER = 95.606680
WATER USED = 618.87 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.4670
TOTAL GENERATION COST = TK 101455.9

STUDY FOR PEAK LOAD PERIOD, DURATION = 6 HR

3 DEMAND = 1090.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	103.9	19725.450
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	84.06	

INCREMENTAL COST OF RECEIVED POWER = 230.54740
WATER USED = 611.28 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 32.5090
TOTAL GENERATION COST = TK 151261.1

GRAND TOTAL OF GENERATION COST = TK 343571.8

SET B: Case Study 6

BL

STUDY FOR BASE LOAD PERIOD, DURATION = 9 HOUR

1 DEMAND = 670.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	31.73	4435.2690
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	121.4	12026.220
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	197.9	

INCREMENTAL COST OF RECEIVED POWER = 86.569590
WATER USED = 1463.9 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 10.9680
TOTAL GENERATION COST = TK 89254.58

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 12 HR

2 DEMAND = 837.1000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	51.58	6392.9870
02	S I D G	35.18	5741.5080
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	66.70	8995.7630
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	1.646	

INCREMENTAL COST OF RECEIVED POWER = 110.69730
WATER USED = 50.706 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 17.0000
TOTAL GENERATION COST = TK 125225.5

STUDY FOR PEAK LOAD PERIOD, DURATION = 3 HR

3 DEMAND = 1153.5000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	207.7	50723.860
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	83.00	30472.180
11	K A P G	.8471	

INCREMENTAL COST OF RECEIVED POWER = 367.20450
WATER USED = 45.509 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 56.4410
TOTAL GENERATION COST = TK 197309.5

GRAND TOTAL OF GENERATION COST = TK 411789.6

SET B: Case Study 6 IL

STUDY FOR BASE LOAD PERIOD, DURATION = 9 HOUR

1 DEMAND = 670.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	42.71	5458.9980
02	S I D G	25.95	4769.7220
03	S H A G	18.00	3348.7700
04	A S H G	187.1	20212.750
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	-.7396	

INCREMENTAL COST OF RECEIVED POWER = 99.915880
WATER USED = 35.195 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 15.3840
TOTAL GENERATION COST = TK 107879.5

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 12 HR

2 DEMAND = 837.1000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	43.50	5538.9440
02	S I D G	26.78	4852.9040
03	S H A G	18.00	3348.7700
04	A S H G	197.7	21275.010
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	154.2	

INCREMENTAL COST OF RECEIVED POWER = 100.88380
WATER USED = 1125.7 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.3000
TOTAL GENERATION COST = TK 109104.9

STUDY FOR PEAK LOAD PERIOD, DURATION = 3 HR

3 DEMAND = 1153.5000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	206.7	50380.470
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	81.46	29906.600
11	K A P G	3.327	

INCREMENTAL COST OF RECEIVED POWER = 365.97020
WATER USED = 61.661 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 56.1010
TOTAL GENERATION COST = TK 196400.5

GRAND TOTAL OF GENERATION COST = TK 413385.0

SET B: Case Study 6 PL

STUDY FOR BASE LOAD PERIOD, DURATION = 9 HOUR

1 DEMAND = 670.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	42.69	5457.4180
02	S I D G	25.93	4768.0780
03	S H A G	18.00	3348.7700
04	A S H G	186.9	20191.760
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	-.4974	

INCREMENTAL COST OF RECEIVED POWER = 99.896660
WATER USED = 36.768 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 15.3770
TOTAL GENERATION COST = TK 107855.3

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 12 HR

2 DEMAND = 837.1000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	46.62	5859.2280
02	S I D G	30.02	5186.1490
03	S H A G	18.00	3348.7700
04	A S H G	239.1	25530.610
05	A S M G	72.00	13034.420
06	G H M G	44.74	6630.5060
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	94.65	

INCREMENTAL COST OF RECEIVED POWER = 104.67200
WATER USED = 686.79 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.6060
TOTAL GENERATION COST = TK 115223.6

STUDY FOR PEAK LOAD PERIOD, DURATION = 3 HR

3 DEMAND = 1153.5000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	70.79	10424.620
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	230.7	

INCREMENTAL COST OF RECEIVED POWER = 152.30450
WATER USED = 1727.0 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 18.7470
TOTAL GENERATION COST = TK 135934.4

GRAND TOTAL OF GENERATION COST = TK 359013.4

SET B: Case Study 6

CL

STUDY FOR BASE LOAD PERIOD, DURATION = 9 HOUR

1 DEMAND = 670.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	38.62	5060.3220
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	132.7	14915.550
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	191.2	18358.010
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	78.49	

INCREMENTAL COST OF RECEIVED POWER = 94.941680
WATER USED = 571.87 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.4620
TOTAL GENERATION COST = TK 100183.3

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 12 HR

2 DEMAND = 837.1000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	47.42	5943.7570
02	S I D G	30.86	5274.0980
03	S H A G	18.00	3348.7700
04	A S H G	249.7	26653.740
05	A S M G	72.00	13034.420
06	G H M G	48.30	7005.0790
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	78.77	

INCREMENTAL COST OF RECEIVED POWER = 105.64910
WATER USED = 573.86 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.9760
TOTAL GENERATION COST = TK 116893.8

STUDY FOR PEAK LOAD PERIOD, DURATION = 3 HR

3 DEMAND = 1153.5000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	173.2	38839.760
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	78.35	

INCREMENTAL COST OF RECEIVED POWER = 321.74850
WATER USED = 570.85 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 45.6280
TOTAL GENERATION COST = TK 170375.4

GRAND TOTAL OF GENERATION COST = TK 387452.4

SET B: Case Study 7

BL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	33.27	4570.1610
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	137.0	13392.680
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	216.1	

INCREMENTAL COST OF RECEIVED POWER = 88.443450
WATER USED = 1609.0 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.0260
TOTAL GENERATION COST = TK 90755.94

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	110.1	21178.250
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	2.871	

INCREMENTAL COST OF RECEIVED POWER = 238.70590
WATER USED = 58.691 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 36.6100
TOTAL GENERATION COST = TK 152713.9

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	60.00	37375.960
09	B O G G	56.17	36077.520
10	G O A G	200.0	78911.000
11	K A P G	3.830	

INCREMENTAL COST OF RECEIVED POWER = 921.95250
WATER USED = 64.944 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 141.253
TOTAL GENERATION COST = TK 307690.7

GRAND TOTAL OF GENERATION COST = TK 551160.5

SET B: Case Study 7 TL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	41.65	5354.3710
02	S I D G	24.85	4660.8610
03	S H A G	18.00	3348.7700
04	A S H G	173.1	18822.580
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	50.81	

INCREMENTAL COST OF RECEIVED POWER = 98.634750
WATER USED = 379.38 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.3830
TOTAL GENERATION COST = TK 106275.9

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	48.85	6095.3590
02	S I D G	32.34	5431.8360
03	S H A G	18.00	3348.7700
04	A S H G	268.7	28668.080
05	A S M G	72.00	13034.420
06	G H M G	54.61	7676.8770
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	228.5	

INCREMENTAL COST OF RECEIVED POWER = 107.37930
WATER USED = 1709.4 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.2420
TOTAL GENERATION COST = TK 119889.3

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	35.26	18088.010
09	B O G G	30.37	15734.140
10	G O A G	200.0	78911.000
11	K A P G	54.36	

INCREMENTAL COST OF RECEIVED POWER = 655.20630
WATER USED = 403.76 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 95.1960
TOTAL GENERATION COST = TK 268059.4

GRAND TOTAL OF GENERATION COST = TK 494224.5

SET B : Case Study 7 PL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	39.63	5156.7430
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	146.1	16196.710
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	201.4	19334.760
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	89.25	

INCREMENTAL COST OF RECEIVED POWER = 96.168300
WATER USED = 648.17 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.4910
TOTAL GENERATION COST = TK 102537.6

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	71.53	10537.350
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	91.47	

INCREMENTAL COST OF RECEIVED POWER = 153.16680
WATER USED = 664.03 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 21.4400
TOTAL GENERATION COST = TK 136047.1

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	203.0	49016.460
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	75.28	27660.080
11	K A P G	229.8	

INCREMENTAL COST OF RECEIVED POWER = 361.02600
WATER USED = 1719.3 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 44.4750
TOTAL GENERATION COST = TK 192790.0

GRAND TOTAL OF GENERATION COST = TK 431374.7

SET B: Case Study 7 CL

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	38.61	5059.4120
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	132.6	14903.460
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	191.1	18348.790
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	114.1	

INCREMENTAL COST OF RECEIVED POWER = 94.930020
WATER USED = 827.65 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 12.9980
TOTAL GENERATION COST = TK 100161.0

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	46.90	7119.6310
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	116.1	

INCREMENTAL COST OF RECEIVED POWER = 124.39480
WATER USED = 842.09 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 17.0000
TOTAL GENERATION COST = TK 132629.4

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G.	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	165.0	63291.850
11	K A P G	113.0	

INCREMENTAL COST OF RECEIVED POWER = 432.84010
WATER USED = 819.13 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 59.3320
TOTAL GENERATION COST = TK 238663.8

GRAND TOTAL OF GENERATION COST = TK 471454.3

Consequently, the recent increase in hydro generation capacity of BPDB power system is justified. Moreover the hydro plant should be run at its maximum capacity at the peak load period for more economic operation of the system.

6.2.3 Case study - Set C.

Introduction:

From the above two studies it is obvious that maximum hydro loading should be at the system peak load period. And hydro generation capacity has to be increased. So the consequence of extra generation capacity is to be evaluated. Again care must be taken about the annual inflow to the reservoir and the reservoir capacity. If the annual water inflow is too low in that case it is uneconomic to increase the capacity. But the hydrological study in the recent years giving the information of a quite impressive amount of water inflow which justifies the planned increase in the hydro capacity to 230 MW (description of the Kaptai hydro electric power plant along with the recent hydrological data have been given in section 6.1.2). It is important to find out whether or not there is scope for further increase in hydro generation capacity. The following studies were carried out with the object in view, using increased loading at BL, IL, and PL periods, because of increasing system demand from year to year.

Here two studies have been carried out considering the following:

i) Hydro plant can generate upto 300 MW.

ii) Hydro plant can generate upto 350 MW.

Base load (BL) = 705.4 MW

Intermediate load (IL) = 1015.0 MW

Peak load (PL) = 1370.0 MW

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	33.29	4571.8640
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	137.2	13409.940
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	215.9	

INCREMENTAL COST OF RECEIVED POWER = 88.466860
WATER USED = 1607.3 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.0310
TOTAL GENERATION COST = TK 90774.89

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	110.1	21178.080
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	2.872	

INCREMENTAL COST OF RECEIVED POWER = 238.70490
WATER USED = 58.696 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 36.6100
TOTAL GENERATION COST = TK 152713.7

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	60.00	37375.960
09	B O G G	56.38	36273.730
10	G O A G	200.0	78911.000
11	K A P G	3.617	

INCREMENTAL COST OF RECEIVED POWER = 924.15050
WATER USED = 63.556 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 141.622
TOTAL GENERATION COST = TK 307886.9

GRAND TOTAL OF GENERATION COST = TK 551375.6

SETC : Case Study

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	44.26	5615.3700
02	S I D G	27.56	4932.4220
03	S H A G	18.00	3348.7700
04	A S H G	207.7	22290.460
05	A S M G	72.00	13034.420
06	G H M G	34.27	5549.8890
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	9.628	

INCREMENTAL COST OF RECEIVED POWER = 101.80060
WATER USED = 102.91 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 15.5000
TOTAL GENERATION COST = TK 110405.3

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	45.32	5723.8930
02	S I D G	28.66	5045.3370
03	S H A G	18.00	3348.7700
04	A S H G	221.8	23732.410
05	A S M G	72.00	13034.420
06	G H M G	38.96	6030.7920
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	298.3	

INCREMENTAL COST OF RECEIVED POWER = 103.08830
WATER USED = 2292.1 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.9870
TOTAL GENERATION COST = TK 112549.5

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	57.52	35160.500
09	B O G G	52.04	32359.170
10	G O A G	200.0	78911.000
11	K A P G	10.44	

INCREMENTAL COST OF RECEIVED POWER = 879.26160
WATER USED = 108.26 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 133.758
TOTAL GENERATION COST = TK 301756.9

GRAND TOTAL OF GENERATION COST = TK 524711.7

SET C : Case study

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	39.94	5187.4050
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	150.3	16604.110
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	204.6	19645.370
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	81.48	

INCREMENTAL COST OF RECEIVED POWER = 96.555100
WATER USED = 593.01 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.6500
TOTAL GENERATION COST = TK 103286.2

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	52.78	6526.6530
02	S I D G	36.42	5880.5830
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	72.02	9588.0800
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	171.8	

INCREMENTAL COST OF RECEIVED POWER = 112.15550
WATER USED = 1260.5 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 14.5480
TOTAL GENERATION COST = TK 126090.6

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	167.3	36973.630
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	300.7	

INCREMENTAL COST OF RECEIVED POWER = 314.01350
WATER USED = 2313.0 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 36.4410
TOTAL GENERATION COST = TK 168509.3

GRAND TOTAL OF GENERATION COST = TK 397886.1

BL

SET D : Case Study

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	33.29	4571.8640
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	90.00	10943.730
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	137.2	13409.940
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	215.9	

INCREMENTAL COST OF RECEIVED POWER = 88.466860
WATER USED = 1607.3 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.0310
TOTAL GENERATION COST = TK 90774.89

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	110.1	21178.080
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	2.872	

INCREMENTAL COST OF RECEIVED POWER = 238.70490
WATER USED = 58.696 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 36.6100
TOTAL GENERATION COST = TK 152713.7

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	60.00	37375.960
09	B O G G	56.38	36273.730
10	G O A G	200.0	78911.000
11	K A P G	3.617	

INCREMENTAL COST OF RECEIVED POWER = 924.15050
WATER USED = 63.556 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 141.622
TOTAL GENERATION COST = TK 307886.9

GRAND TOTAL OF GENERATION COST = TK 551375.6

SET D: Case Study

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	44.75	5665.3610
02	S I D G	28.07	4984.4370
03	S H A G	18.00	3348.7700
04	A S H G	214.2	22954.710
05	A S M G	72.00	13034.420
06	G H M G	36.44	5771.4200
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	+.4691E-01	

INCREMENTAL COST OF RECEIVED POWER = 102.39580
WATER USED = 39.695 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 15.7540
TOTAL GENERATION COST = TK 111393.0

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	44.73	5663.2560
02	S I D G	28.05	4982.2470
03	S H A G	18.00	3348.7700
04	A S H G	213.9	22926.740
05	A S M G	72.00	13034.420
06	G H M G	36.35	5762.0920
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	310.0	

INCREMENTAL COST OF RECEIVED POWER = 102.37080
WATER USED = 2392.9 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 11.7910
TOTAL GENERATION COST = TK 111351.4

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	230.0	59258.520
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	60.00	37375.960
09	B O G G	56.38	36273.740
10	G O A G	200.0	78911.000
11	K A P G	3.617	

INCREMENTAL COST OF RECEIVED POWER = 924.15060
WATER USED = 63.556 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 141.622
TOTAL GENERATION COST = TK 307886.9

GRAND TOTAL OF GENERATION COST = TK 530631.4

SET B: Case Study

STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR

1 DEMAND = 705.4000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	39.94	5187.4050
02	S I D G	24.00	4577.2760
03	S H A G	18.00	3348.7700
04	A S H G	150.3	16604.110
05	A S M G	72.00	13034.420
06	G H M G	33.00	5420.9670
07	G H H G	204.6	19645.370
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	81.48	

INCREMENTAL COST OF RECEIVED POWER = 96.555100
WATER USED = 593.01 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 13.6500
TOTAL GENERATION COST = TK 103286.2

STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR

2 DEMAND = 1015.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	57.21	7036.1540
02	S I D G	41.04	6410.7040
03	S H A G	18.00	3348.7700
04	A S H G	300.0	32078.160
05	A S M G	72.00	13034.420
06	G H M G	91.67	11845.840
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	143.1	

INCREMENTAL COST OF RECEIVED POWER = 117.54810
WATER USED = 1042.0 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 15.6580
TOTAL GENERATION COST = TK 129388.0

STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR

3 DEMAND = 1370.0000

UNIT NO	GENERATING STN NAME	GENERATION MEGA WATTS	COST OF GEN TAKA/HR
01	S I K G	60.00	7368.4800
02	S I D G	80.00	11877.020
03	S H A G	60.00	10532.020
04	A S H G	300.0	32078.160
05	A S M G	116.9	22814.720
06	G H M G	110.0	14046.040
07	G H H G	210.0	20166.000
08	B H E G	18.00	8277.2050
09	B O G G	24.00	11768.520
10	G O A G	40.00	15422.200
11	K A P G	351.1	

INCREMENTAL COST OF RECEIVED POWER = 247.57410
WATER USED = 2756.4 ACRE-FT PER HOUR
CONVERSION FACTOR FOR HYDRO UNIT = 27.5940
TOTAL GENERATION COST = TK 154350.4

GRAND TOTAL OF GENERATION COST = TK 387024.6

	Maximum Hydro loading at	Cost of Generation i) P_{Hmax} = 300 MW	ii) P_{Hmax} = 350 MW
Typical weekday (predicted)	BL	551375.60	551375.60
	IL	524711.70	530631.40
	PL	397886.10	387024.60
	CL	471454.30	471454.30

Discussion:

The above study reveals the following facts:

When the loading of the hydro plant capacity is increased from 300 MW to 350 MW it is found that

i) CL and BL costs remain unchanged.

ii) IL cost increases.

iii) PL cost decreases (i.e, maximum cost benefit).

Therefore the suggestions for BPDB power network utility service is to

i) load the hydro plant at peak load period with the maximum capacity of hydro generation.

ii) increase the hydro generation capacity.

6.3 Concluding remark on the results:

The inferences from the three sets of studies are given below:

1) When hydro capacity is 130 MW, to achieve the maximum cost benefit of generation, hydro maximum generation should have been at the peak load period. And whatever the case may be the hydro unit should always be in the running condition that is for the whole day to avoid spillage. From the table 6.1 and table 6.2 it is clear that for the low value of hydro capacity utility service has to spend more generation expenditure every year even when they run their hydro plant at its maximum capacity.

2) When the hydro capacity is 230 MW. There is a significant amount of savings, although the energy to be used as water to produce hydroelectric power is constant for all the cases.

3) If the hydro capacity could be increased from the 230 MW to 300 MW or 350 MW there is a further savings results which is detailed in the table 6.2.

Details of the scheduling pattern are given in the computer printout set-A, set-B and set-C. Some (details of weekend study) of them are not included because of the large number.

Table 6.1

Season/ day	For maximum hydro generation at	Cost of generation when P_{Hmax}=130MW Taka/Hr.	when P_{Hmax}=230MW Taka/Hr.	comment on result (cost benifit) Taka/Hr.
Winter weekend	BL	318740.90	321677.90	2937.0(loss)
	IL	306425.60	301966.90	4458.7(gain)
	PL	304084.50	289432.30	14652.2(gain)
	CL	307390.00	307390.00	000.0
Winter/ weekday	BL	343076.30	344205.00	1128.70(loss)
	IL	336449.60	332356.80	4092.80(gain)
	PL	323912.60	313967.90	9944.70(gain)
	CL	326503.50	326503.50	0.00
Summer/ weekend	BL	318079.70	320736.00	2656.3(loss)
	IL	310472.10	313740.60	3268.50(loss)
	PL	305269.80	298301.80	6968.00(gain)
	CL	309923.70	309923.70	0.00
Summer/ weekday	BL	362852.10	362945.50	0093.40(loss)
	IL	349559.90	365662.60	16102.70(loss)
	PL	339048.60	330875.00	8173.60(gain)
	CL	343571.81	343571.80	0.00
Rainy/ weekend	BL	338526.40	337087.20	1439.20(gain)
	IL	337647.40	343723.80	6076.40(loss)
	PL	326919.40	319847.20	7072.20(gain)
	CL	328685.70	328685.70	0.00
Rainy/ weekday	BL	410911.90	411789.60	10877.70(loss)
	IL	382933.90	413385.00	30451.10(loss)
	PL	376169.80	359013.40	17156.40(gain)
	CL	387452.40	387452.40	0.00
Typical predicted future weekday	BL	509375.30	551160.50	41785.20(loss)
	IL	472617.90	494224.50	21606.60(loss)
	PL	464926.90	431374.70	33552.20(gain)
	CL	471454.30	471454.30	0.00

Assuming more possible generation of hydro units :
Another study is carried out for the following data;

i) Hydro maximum generation of 300 MW and 350.0 MW

Considering the predicted load pattern,
where BL = 705.4 MW ; Duration = 12 Hours,
IL =1015.0 MW ; Duration = 8 Hours,
PL =1370.0 MW ; Duration = 4 Hours.

For the study: Table 6.2

Maximum hydro generation at	Cost of generation (in Taka/Hr.) When P_{Hmax}=(130MW)	(230MW)	(300MW)	(350MW)
Base load	509375.30	551160.50	551375.60	551375.60
Int. load	472617.90	494224.50	524711.70	530631.40
Peak load	464926.90	431374.70	397886.10	387024.60
Const load	471454.30	471454.30	471454.30	471454.30

Table 3

Unit commitment

Case 2 (set A)

Ref. figure 6.2 (Winter weekday)

Base load (BL) = 550.00 MW

Intermediate load(IL) = 750.00 MW

Peak load (PL) = 1025.00 MW

Merit order unit commitment

Priority	Bus name	P_{MX}	P_{MN}	Capacity	Hour	Loading period
	KAPG(1)	130.	0.0	130.0	24	BL, IL, PL
1	GHHG(8)	340.	63.0	210.0	24	BL, IL, PL
2	ASHG(5)	640.	153.0	300.0	24	BL, IL, PL
3	SIKG(2)	700.	171.0	60.0	24	BL, IL, PL
4	GHMG(7)	810.	204.0	110.0	24	BL, IL, PL
5	SIDG(3)	890.	228.0	80.0	12	IL, PL
6	SHAG(4)	950.	242.0	60.0	12	IL, PL
7	ASMG(6)	1180.	318.0	230.0	12	IL, PL
8	GOAG(11)	1380.	358.0	200.0	4	PL
9	BOGG(10)	1460.	382.0	80.0		
10	BHEG(9)	1520.	400.0	60.0		

Table 4

Unit commitment

Case 4 (set A)

Ref. figure 6.4 (Summer weekday)

Base load (BL) = 575.00 MW

Intermediate load(IL) = 690.00 MW

Peak load (PL) = 1090.00 MW

Merit order unit commitment

Priority	Bus name	P_{MX}	P_{MN}	Capacity	Hour	Loading period
	KAPG(1)	130.	0.0	130.0	24	BL, IL, PL
1	GHHG(8)	340.	63.0	210.0	24	BL, IL, PL
2	ASHG(5)	640.	153.0	300.0	24	BL, IL, PL
3	SIKG(2)	700.	171.0	60.0	24	BL, IL, PL
4	GHMG(7)	810.	204.0	110.0	24	BL, IL, PL
5	SIDG(3)	890.	228.0	80.0	16	IL, PL
6	SHAG(4)	950.	242.0	60.0	16	IL, PL
7	ASMG(6)	1180.	318.0	230.0	6	PL
8	GOAG(11)	1380.	358.0	200.0	6	PL
9	BOGG(10)	1460.	382.0	80.0		
10	BHEG(9)	1520.	400.0	60.0		

Table 5
Unit commitment

Case 6 (set A)

Ref. figure 6.6 (Rainy season weekday)

Base load (BL) = 670.00 MW

Intermediate load(IL) = 837.1 MW

Peak load (PL) = 1153.00 MW

Merit order unit commitment

Priority	Bus name	P_{MX}	P_{MN}	Capacity	Hour	Loading period
	KAPG(1)	130.	0.0	130.0	24	BL, IL, PL
1	GHHG(8)	340.	63.0	210.0	24	BL, IL, PL
2	ASHG(5)	640.	153.0	300.0	24	BL, IL, PL
3	SIKG(2)	700.	171.0	60.0	24	BL, IL, PL
4	GHMG(7)	810.	204.0	110.0	24	BL, IL, PL
5	SIDG(3)	890.	228.0	80.0	24	BL, IL, PL
6	SHAG(4)	950.	242.0	60.0	15	IL, PL
7	ASMG(6)	1180.	318.0	230.0	15	IL, PL
8	GOAG(11)	1380.	358.0	200.0	3	PL
9	BOGG(10)	1460.	382.0	80.0		
10	BHEG(9)	1520.	400.0	60.0		

Table 6
Unit commitment

Case 7 (set A)

(Typical predicted future weekday)

Base load (BL) = 705.4 MW

Intermediate load(IL) = 1015.0 MW

Peak load (PL) = 1370.0 MW

Merit order unit commitment

Priority	Bus name	P_{MX}	P_{MN}	Capacity	Hour	Loading period
	KAPG(1)	130.	0.0	130.0	24	BL, IL, PL
1	GHHG(8)	340.	63.0	210.0	24	BL, IL, PL
2	ASHG(5)	640.	153.0	300.0	24	BL, IL, PL
3	SIKG(2)	700.	171.0	60.0	24	BL, IL, PL
4	GHMG(7)	810.	204.0	110.0	24	BL, IL, PL
5	SIDG(3)	890.	228.0	80.0	24	BL, IL, PL
6	SHAG(4)	950.	242.0	60.0	24	BL, IL, PL
7	ASMG(6)	1180.	318.0	230.0	12	IL, PL
8	GOAG(11)	1380.	358.0	200.0	12	IL, PL
9	BOGG(10)	1460.	382.0	80.0	4	PL
10	BHEG(9)	1520.	400.0	60.0	4	PL

CONCLUSIONS AND RECOMMENDATIONS

CHAPTER 7

7.1 INTRODUCTION:

In Bangladesh the only public utility service for Electrical power supply is BPDB (Bangladesh Power Development Board). They have hydro thermal power system. Within a very short time, it will start generating hydro power upto 230 MW. Now its maximum hydro generation is 130 MW. The hydro reserve is not enough to supply 230 MW or 130 MW throughout the day (Energy limited). But it is quiet possible to run the plant at its maximum capability for few hours. The cost of generation of a hydro plant is always assumed to be zero. So normally one may think of running the hydro plant throughout the day with a maximum possible constant generation. In that case the generation will definitely be well below the maximum generation capacity. So it is necessary for the utility system to know the situation for which the maximum fuel economy may be achieved. The most interesting thing is that, although the amount of water energy utilized to produce effective hydroelectric power is constant, yet it has been found that there is a difference in cost economy depending upon the period of loading of the hydro plant in the system.

In the economic evaluation Z_{BUS} matrix along with the load flow solution have been used for determining the effect of transmission loss coefficients. All the generator power limit constraints have been utilized. For the hydro plant the energy limitation and generation constraints have been taken into account. Hydro plant characteristics and amount of hydro energy that can be used in terms of acre-feet is obtained from the BPDB rule curve data and from daily discharge data.

7.2 CONCLUSION:

From the analysis of the results obtained, it is clear that to get the best cost benefit, hydro units have to be run in such a way that during the period of study it would confine its maximum generation mainly within the peak load period. From the results it is obvious that for energy limited hydro units like those in Bangladesh have to be run during peak load. Again it has been found that if it is possible to generate more power from the same energy limited hydro plants, more economy results. The hydro plants must supply power to the grid during the peak load and float on bus during base load to supply the reactive vars also acts as a spining reserve.

The theoretical basis for the economic solution of hydro thermal power system have been developed in the previous chapters. And the flow diagram is used for computer program. A number of study have been carried out for base load, intermediate load and peak load period . A significant fact is that, for thermal systems hour by hour study can be made, but for a hydro thermal power system each study must span over a longer period (few hours or a day or a week) because of available water energy constraints associated with a reservoir.

It is also important to note that usual practice are to fix the generators at the power limits when they cross the limit. But it is shown in this work that the minimum/ maximum incremental cost of generation multiplied by the penalty factor of the plant must be compared with the global incremental cost of received power during that instant as detailed in sections 4.4-4.6 before fixing the unit at the power limit. Because constraints are always present in any system, their effects should not be neglected.

7.3 Recommendation for further research:

This is the first time any work on a hydrothermal power system has been carried out in BUET. Most of the previous works on economic operation of BPDB power network neglected the influence of the hydro plant or considered the hydro plant to be a constant source of power. Almost in all cases it has been assumed that hydro generation is a very small fraction of the total demand. But the study carried out here reveals its importance. Further work on this field may be of the following category:

i) Long range scheduling of hydro thermal power system.

ii) Solution of the economic scheduling problem of BPDB hydro thermal power network with complete data.

iii) Development of the exact characteristics of the hydro power plants using the instantaneous data.

iv) Using another method of unit commitment to get highest cost benefit.

v) Work on the on-line control of the economic power dispatch.

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Flow diagram for hydro-thermal economic dispatch.

start

1 Read the following data
Number of buses, number of thermal generating bus and hydro generating bus and number of voltage controlled bus.
Coefficients of generator characteristics (thermal and hydro)
Line impedance data
Limiting value of the generation of the generating plants
Limiting value of the bus reactive power
Number of hours in the total study period and each sub interval
Load in each bus for each interval

2 Formation of Y_{BUS} matrix (considering equivalent impedance diagram)

3 Z_{BUS} matrix from Y_{BUS} matrix

4 Estimate water conversion factor Gama γ

5 Initial value of generating plant
Initial value of bus voltage

a

(a)

(6) Set load flow iteration count μ

(7) Compute the net bus powers using the relationships given by,
$S_j^{(\mu)} = P_j^{(\mu)} + Q_j^{(\mu)}$ $[P_j = P_{gj} - P_{Lj},\ Q_j = Q_{gj} - Q_{Lj}]$

(8) Load flow analysis

(9) Compute total loss of power
$P_{Loss} = \sum_{i=1}^{N} P_i^{(\mu)}$

(10) Compute
$\alpha_{iK}^{(\mu)}, \beta_{iK}^{(\mu)}$

(11) Compute incremental transmission loss for each bus using the data obtained from Z_{BUS} matrix and load flow solution data
$(ITL)_i^{(\mu)} = 2\sum_{K=1}^{N}(P_K\alpha_{iK} - Q_K\beta_{iK})$

(12) Estimate lambda $\lambda^{(\mu)}$

(13) Compute incremental cost using the relationship
$(IC)_i^{(\mu)} = \lambda^{(\mu)}[1-(ITL)_i]$, $i = 1, 2 \cdots N$

(14) Compute power generation using equation
$P_{gi}^{(\mu)} = \{2P_D + \sum_{i=1}^{N} \beta_i/\gamma_i\}/\sum 1/\gamma_i$

Check the active power balance equation with the tolerance

(B)

If no then update lambda and repeat from step 12.
If yes go to the next step

Check the generation value with the previous value
If their differences are not within tolerance
then advance iteration count of load flow and
repeat from step 7
Otherwise next step

Compute all line powers and generated
powers for the respective interval loading
including hydro power

If all intervals are complete
Go for the next step
otherwise repeat from step 6 with
the data for the next interval

Compute total hydro discharge

If total hydro use is within the tolerance
go to the next step
Otherwise if hydro use is less than the allowable
discharge decreament Gama and repeat from step 6
with the first interval data
Otherwise if greater than the allowable water volume
inrease Gama and repeat from step 6
with the first interval data

A - 4

Calculate the detail of loading of the generating units for each interval and also calculate the incremental cost of received power water conversion factor water use for each interval.

↓

STOP

Economic dispatch for all thermal system:

0 Start

↓

1 Assume initial value of bus power for all buses

↓

2 Load flow study
using the load flow study calculate loss
and total demand

↓

3 Calculate incremental transmission loss and then
bus penalty factor for all generating buses

↓

4 Estimate lambda λ

↓

5 Solve for each P_i such that
penalty factor * incremental cost = Lambda
for all the generating buses

↓

6 check the demand with the total generation
If satisfied go to the next step
Otherwise take new value of Lambda and calculate

↓

7 Compare new power generation with the previous value
If difference is within the lolarence solution
achieved (next step)
If not repeat from the load flow study (step 2)

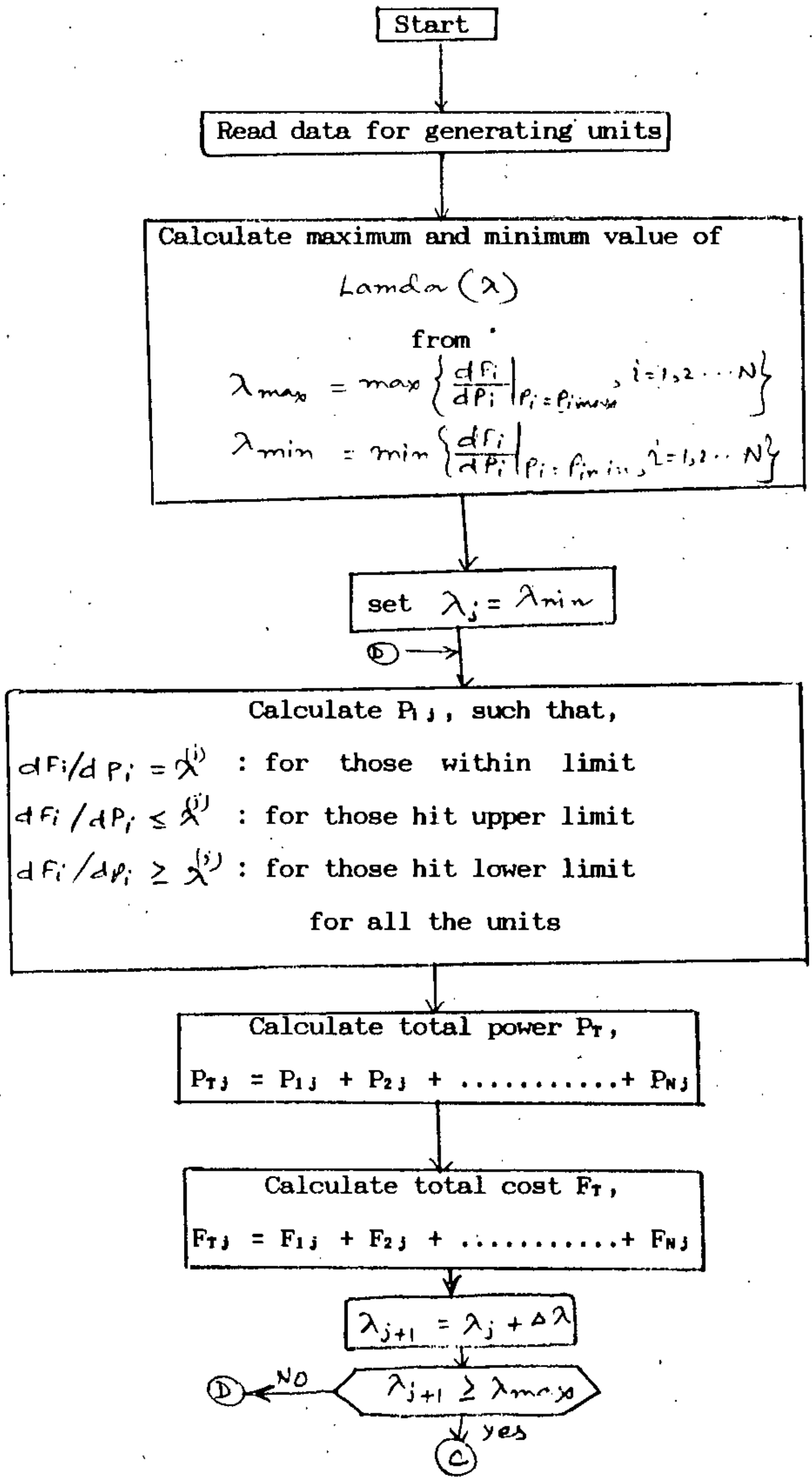
↓

8 Print the detail of solution

↓

STOP

Flow chart for composit cost curve:



Least square curve fit
using the data points,
P_{Tj}, F_{Tj}, : for j = 1,2,3,.....

STOP

Program for Z_{BUS} fromation

```
      COMPLEX A(20,20),P(50),DIVSR, AMULPR
      OPEN(5,FILE='ZB.DAT',STATUS='OLD')
      OPEN(6,FILE='ZB.OUT',STATUS='NEW')
      READ (5,1) N1,((A(I,J),J=1,N1),I=1,N1)
1     FORMAT(I3/(8F8.3))
      WRITE(6,2) ((A(I,J),J=1,N1),I=1,N1)
2     FORMAT(///2X,'THE ORIGINAL MATRIX IS--'//////(4(F8.3,'+J(',F8.3,'
     +)')//))
      N11=N1+1
      N2=2*N1
      DO 21 I = 1,N1
      DO 21 J = N11,N2
21    A(I,J)=(0.0,0.0)
      JJ=N1
      DO 22 I=1,N1
      JJ=JJ+1
22    A(I,JJ)=A(I,JJ)+(1.0,0.0)
      N=N2
      M=N1
      K=1
      DO 11 II=1,M
      CHR = CABS(A(II,II))
C
      IF(CHR) 7, 3, 7
3     I1=II+1
      DO 4 I2=I1,M
      J1=II
      CHRJ=CABS(A(I2,J1))

5     DO 6 J2=1,N
      P(J2)=A(II,J2)
      A(II,J2)=A(I2,J2)
      A(I2,J2)=P(J2)
6     CONTINUE
7     DIVSR=(1.0,0.0)*A(K,K)
      DO 8 J=1,N
      A(K,J)=A(K,J)/DIVSR
8     CONTINUE
      DO 10 I=1,M
      IF(I.EQ.K)GO TO 10
      AMULPR=(1.0,0.0)*A(I,K)
      DO 9 J=1,N
      A(I,J)=A(I,J)-A(K,J)*AMULPR
9     CONTINUE
10    CONTINUE
      K=K+1
11    CONTINUE

      WRITE(*,*)  ((A(I,J),J=N11,N),I=1,M)
      WRITE(6,12)  ((A(I,J),J=N11,N),I=1,M)
12    FORMAT(////20X,'THE INVERSE MATRIX IS '//(4(1X,F7.5,'+J(',F7.5,')'
     +)//))
      END
```

```
C     LEAST SQUARE CURVE FITTING
      DIMENSION X(20),Y(20),F(20,6),FT(6,20),A(6,7),B(6),C(6)
      OPEN(3,FILE='A:FT.DAT')
      OPEN(5,FILE='A:FT.OUT')
      WRITE (5,*) 'DILDER'
C     READ IN THE NUMBER OF C'S AND NUMBER OF DATA POINTS
      READ(3,*) M,N
      DO 60 I=1,N
C     READ X-Y VALUES OF DATA POINTS
 60   READ (3,*) X(I),Y(I)
C
C     GENERATE THE F MATRIX
      DO 4 I=1,N
      F(I,1)=1.
      F(I,2)=X(I)
 4    F(I,3)=X(I)*X(I)
C     WRITE(5,*) ((F(I,J),J=1,M),I=1,N)
C
C
C     GENERATE THE TRANSPOSE OF THE F MATRIX
      DO 5 I=1,N
      DO 5 J=1,M
      FT(J,I)=F(I,J)
  5   CONTINUE
C     WRITE(5,*) 'TRANPOSE OF A MATRIX'
C     WRITE(5,*) ((FT(J,I),J=1,M),I=1,N)
C
C     DETERMINE COEFFICIENT MATRIX OF SIMULTANEOUS EQUATION SYSTEM
      CALL MATMPY(FT,F,A,M,N,M)
C     WRITE(5,*) 'MATRIX MULTIPLICATION A'
C     WRITE(5,*) ((A(I,J),J=1,M),I=1,M)
      CALL MATMPY(FT,Y,B,M,N,1)
C     WRITE(5,*) (B(I),I=1,M)
      DO 6 I=1,M
 6    A(I,M+1)=B(I)
      MP1=M+1
      CALL CHLSKY(A,M,MP1,C)
      WRITE(5,*) (C(I),I=1,M)
      WRITE(5,73) (C(I),I=1,M)
73    FORMAT('THE REQUIRED EQUATION IS'// '    PG = (',E12.5,')+ (',E12.
     +5,') * (IC)','+ ( ',E12.5,' ) * (IC)**2.0'/)
      STOP
      END
      SUBROUTINE MATMPY(A,B,C,M,N,L)
      DIMENSION A(6,20),B(20,6),C(6,7)
C     WRITE(5,*) 'SUBROUTINE MATMPY'
      DO 12 I=1,M
      DO 12 J=1,L
      C(I,J)=0.
      DO 12 K=1,N
12    C(I,J)=C(I,J)+A(I,K)*B(K,J)
      RETURN
      END
      SUBROUTINE CHLSKY (A,N,M,X)
      DIMENSION A(6,7),X(6)
      DO 13 J=2,M
13    A(1,J)=A(1,J)/A(1,1)
      DO 18 I=2,N
      J=I
      DO 15 II=J,N
```

```
      SUM=0.
      JM1=J-1
      DO 14 K=1,JM1
14    SUM=SUM+A(II,K)*A(K,J)
15    A(II,J)=A(II,J)-SUM
      IP1=I+1
      DO 17 JJ=IP1,M
      SUM=0.
      IM1=I-1
      DO 16 K=1,IM1
16    SUM=SUM+A(I,K)*A(K,JJ)
17    A(I,JJ)=(A(I,JJ)-SUM)/A(I,I)
18    CONTINUE
C     LL=N+1
      X(N)=A(N,N+1)
      L=N-1
      DO 110 NN=1,L
      SUM=0.
      I=N-NN
      IP1=I+1
      DO 19 J=IP1,N
19    SUM=SUM+A(I,J)*X(J)
110   X(I)=A(I,M)-SUM
      RETURN
      END
```

Program for economic dispatch of B-4
hydro-thermal power system:

```
      PARAMETER (NN=11,MM=24*NN,NH=11)
      COMMON WAT,PGH, X, Y, Z, RS

      CHARACTER NAME (11)*9
      DIMENSION PD(24),PL(24,NN),PG(24,NN),A(NN),PGMX(NN),PGMN(NN),
     + WALOT(3), ALP(NN),BET(NN),GAM(NN),LAMX(NN),LAMN(NN),R(3,NN)
     + ,.DEMAND(3),TC(3),GC(NN)
      REAL LAMDA,LAMX,LAMN

      DATA PD/24*0.0/,PG/MM*0.0/,A/NN*1.0/

      DATA NAME / ' S I K G ',' S I D G ',' S H A G ',' A S H G ',
     + ' A S M G ',' G H M G ',' G H H G ',' B H E G ',' B O G G ',
     + ' G O A G ', ' K A P G '/

      DATA PGMX/60.,80.,60.,300.,200.,110.,210.,60.,35.,230.,3000. /
      DATA PGMN/15.,20.,25.,80.,70.,35.,55.,23.,15.,55.,0.0    /

      DATA  R(1,1),R(1,2),R(1,3),R(1,4),R(1,5),R(1,6),R(1,7),R(1,8),
     + R(1,9),R(1,10),R(1,11)/12.0E3 ,12.0E3 ,12.0E3 ,12.0E3 ,12.0E3,
     + 12.0E3 , 12.0E3, 5.0,5.0,5.0, 2.1  /

      DATA  R(2,1),R(2,2),R(2,3),R(2,4),R(2,5),R(2,6),R(2,7),R(2,8),
     + R(2,9),R(2,10),R(2,11)/12.0E3 ,12.0E3 ,12.0E3 ,12.0E3 ,12.0E3,
     + 12.0E3 , 12.0E3, 5.0,5.0,5.0, 2.6  /

      DATA  R(3,1),R(3,2),R(3,3),R(3,4),R(3,5),R(3,6),R(3,7),R(3,8),
     + R(3,9),R(3,10),R(3,11)/12.0E3 ,12.0E3 ,12.0E3 ,12.0E3 ,12.0E3,
     + 12.0E3 , 12.0E3, 5.0,5.0,5.0, 2.3  /

      DATA EPS2/30.0/

      DATA DEMAND/3*0.0/

      OPEN (9,FILE='OP.OUT',STATUS='NEW')
      OPEN (9,FILE='OP1.DAT',STATUS='NEW')

      GT=0.0

C     READ LOAD DATA FOR EACH PERIOD AND
C     COEFFICIENTS OF GENERATOR CHARACTERISTICS
C     READ LINE DATA AND LIMIT OF REACTIVE VAR
C     INFORMATION OF VOLTAGES AT DIFFERENT BUSES

      DO 1 I=1,NN-1
      ALP(I)=R(1,I)*ALP(I)
      BET(I)=R(1,I)*BET(I)
      GAM(I)=R(1,I)*GAM(I)
1     CONTINUE

      DO 101 I=1,NN
      WRITE(*,*)ALP(I),BET(I),GAM(I)
101   CONTINUE

      NB=NN

C      WRITE(*,'(A)') ' 2;1H UNIT1     UNIT2      UNIT3 '
```

```
      DO 200 IH = 1,3
      ALP(NH)=ALP(NH)*R(IH,NH)
      BET(NH)=BET(NH)*R(IH,NH)
      GAM(NH)=GAM(NH)*R(IH,NH)

       X=ALP(NH)
       Y=BET(NH)
       Z=GAM(NH)
       RS=R(IH,NH)

      DO 4 I=1,NB
      LAMX(I)= BET(I)+2.0*GAM(I)*PGMX(I)
      LAMN(I)= BET(I)+2.0*GAM(I)*PGMN(I)
4     CONTINUE

      DO 2 I =1,NN
      DEMAND(IH)=DEMAND(IH)+PL(IH,I)
2     CONTINUE
      WRITE(*,*) ' DEMAND = ',DEMAND(IH)


      RT1=RS


20    DO 21 I=1,NN
      A(I)=1.0
      PG(IH,I)=0.0
21    CONTINUE

      ALP(NH)=ALP(NH)*RS/RT1
      BET(NH)=BET(NH)*RS/RT1
      GAM(NH)=GAM(NH)*RS/RT1
      LAMX(NH)=LAMX(NH)*RS/RT1
      LAMN(NH)=LAMN(NH)*RS/RT1

      X=ALP(NH)
      Y=BET(NH)
      Z=GAM(NH)

18    CONTINUE
      PD(IH)=0.0
      DO 5 K=1,NB
      IF(A(K).EQ.0.0) WRITE(*,'(A12,I2,A)')'20HUNIT:',K,'EXCLUDED'
      PD(IH)=PD(IH)+PL(IH,K)+PG(IH,K)*(A(K)-1.0)
5     CONTINUE
C      WRITE(*,'(A\)')' 18;20HPD(1)'
      WRITE(*,*) PD(IH)

      SUM=0.0
      DSUM=0.0
      DO 6 I=1,NB
      SUM=  SUM + (BET(I)/GAM(I))*A(I)
      DSUM= DSUM + A(I)/GAM(I)
6     CONTINUE
```

```
      IF(DSUM.EQ.0.0) THEN
      WRITE(*,*) ' ALL STATIONS CROSS THE LIMIT'
      STOP 1
                      ENDIF
      LAMDA= (2.0*PD(IH)+SUM)/DSUM

      DO 7 I=1,NB
      IF (A(I) .EQ. 1.0) THEN
         PG(IH,I)=((LAMDA-BET(I))/(2.0*GAM(I)))
      ENDIF
 7    CONTINUE

C     WRITE (*,*) PG(IH,I)

      COUNT=0.0
      DO 8 I=1,NB
      IF(PG(IH,I).GT.PGMX(I)) THEN
      PG(IH,I)=PGMX(I)
      A(I)=0.0
      COUNT=COUNT+1.0
                                ENDIF
      IF(PG(IH,I).LT.PGMN(I)) THEN
      PG(IH,I)= PGMN(I)
      A(I)=0.0
      COUNT=COUNT+1.0
                                ENDIF
8     CONTINUE

       WRITE(*,'(A19,F2.0,A8)') ' CNT=',COUNT
 11    IF(COUNT.EQ. 0.0)GO TO 19

      TEMP=0.0
      DO 16 K=1,NB
      TEMP=TEMP+PG(IH,K)*(A(K)-1.0)+PL(IH,K)
16    CONTINUE
      SUM=0.0
      DSUM=0.0
      DO 17 I=1,NB
      SUM=  SUM + (BET(I)/GAM(I))*A(I)
      DSUM= DSUM + A(I)/GAM(I)
17    CONTINUE

      IF(DSUM.EQ.0.0) THEN
      WRITE(*,*) ' ALL STATIONS CROSSED THE LIMIT'
      STOP 2
                      ENDIF
      LAMDA= (2.0*TEMP +SUM)/DSUM


      DO 14 I=1,NB
      IF(A(I).LT. 1.0) THEN
      IF(ABS(PG(IH,I)-PGMN(I)).LE. 0.0001.AND.LAMN(I).LT.LAMDA)A(I)=1.0
      IF(ABS(PG(IH,I)-PGMX(I)).LE. 0.0001.AND.LAMX(I).GT.LAMDA)A(I)=1.0
      ENDIF
 14   CONTINUE
      WRITE(*,'(A7,6F10.2)')(PG(1,I),I=1,11)
```

```
      GO TO 18
19    PGH=PG(IH,NH)
      WRITE(*,*)'HYDRO GENERATION= ',PGH

      CALL WATER

      IF (ABS(WAT-WALOT(IH)).LE. EPS2)GO TO 13
      IF (WAT .GT. WALOT(IH)) THEN
      RT1=RS
      RS=RS+.35
      R(IH,NH)=RS
      GO TO 20
      ENDIF
      IF (WAT .LT. WALOT(IH)) THEN
      RT1=RS
      RS=RS-.029
      R(IH,NH)=RS
      GO TO 20
      ENDIF

13    COST=0.0
      WRITE (*,*) (PG(IH,I),I=1,NB),LAMDA
      WRITE(*,*)'WATER USED=',WAT, 'CONV FACTOR=',R(IH,NH)
      WRITE(*,*) (ALP(I),BET(I),GAM(I),I=1,NN)
      DO 201 K=1,NN-1
      COST=COST+ALP(K)+BET(K)*PG(IH,K)+GAM(K)*PG(IH,K)*PG(IH,K)
201   CONTINUE
      WRITE (*,*) 'GEN COST= TK ' , COST , ' FOR HOUR  ', IH

      ALP(NH)=ALP(NH)/R(IH,NH)
      BET(NH)=BET(NH)/R(IH,NH)
      GAM(NH)=GAM(NH)/R(IH,NH)

      IF (IH .EQ. 1)THEN
      WRITE(9,203)
203   FORMAT(2X,'STUDY FOR BASE LOAD PERIOD, DURATION = 12 HOUR'/)
      ELSEIF (IH .EQ. 2)THEN
      WRITE(9,204)
204   FORMAT(2X,'STUDY FOR INTERMEDIATE LOAD PERIOD, DURATION= 8 HR'/)
      ELSEIF (IH .EQ. 3)THEN
      WRITE(9,205)
205   FORMAT(2X,'STUDY FOR PEAK LOAD PERIOD, DURATION = 4 HR'/)
      ENDIF
      WRITE(9,206) IH, DEMAND(IH)
206   FORMAT(3X,I2, '   DEMAND =',F10.4/)

      WRITE(9,202)
202   FORMAT(1X,'UNIT','   GENERATING STN','   GENERATION','   COST OF
     + GEN')
       WRITE(9,213)
213   FORMAT(1X,'NO',6X,'   NAME ',5X,'   MEGA WATTS',4X,' TAKA/HR'/)

      DO 207 L=1,NH-1
      GC(L)=ALP(L)+BET(L)*PG(IH,L)+GAM(L)*PG(IH,L)*PG(IH,L)
      TC(IH)=TC(IH)+GC(L)
      WRITE(9,208)L,NAME(L),PG(IH,L),GC(L)
208   FORMAT(3X,I2.2,4X,A9,7X,G12.4,1X,G14.8)

207   CONTINUE
```

```
      WRITE(9,209)NH,NAME(NH),PG(IH,NH)
209   FORMAT(3X,I2.2,4X,A9,7X,G12.4/)
      WRITE(9,210)LAMDA, WAT, R(IH,NH)
210   FORMAT(2X,'INCREMENTAL COST OF RECEIVED POWER =',G14.8/5X,'WATER
     + USED =',G12.5,'ACRE-FT PER HOUR'/2X,'CONVERSION FACTOR FOR HYDRO
     +UNIT =',G14.6/)
      WRITE(9,211)TC(IH)
211   FORMAT(3X,'TOTAL GENERATION COST = TK ',G14.7/)

      GT = GT + TC(IH)

200   CONTINUE
      WRITE (9,212)GT
212   FORMAT(2X, 'GRAND TOTAL OF GENERATION COST = TK',G14.7/)

      STOP
      END

      SUBROUTINE WATER
      PARAMETER(NH=11)
      COMMON WAT,PGH, X, Y, Z, RS

      QW=( X+ Y*PGH + Z*PGH*PGH )/RS
      WAT = QW

      RETURN
      END
```

Program for economic dispatch
(all thermal)

B-9

```
      PROGRAM
      PARAMETER(NN=41,MM=33)

      COMPLEX YSHT,YSER,SERY,SHTY,Y,VI,VII,SUM,S,R,DX,ZSER,SERZ,
     +VN,CMP,A,B,V,X,ZBUS
      INTEGER SB,EB
      REAL LENGTH,MAGV,ITL,LPA,IC,LAMDA

      COMMON/XX/NB,X(66,66), ZBUS(33,33)
      COMMON/YY/VA,P,Q,QMAX,QMIN,V,VSPEC,VN,DELTA,VI,VII,EPS1,EPS2,MB,Y
      COMMON WAT,PGH,X,Y,Z,RS

      DIMENSION LINE(NN),SB(NN),EB(NN),LENGTH(NN),YSHT(NN),YSER(NN),
     +SERY(NN),SHTY(NN),A(NN),B(NN,NN),V(NN),P(NN),Q(NN),QMAX(NN),
     +QMIN(NN),VSPEC(NN),ZSER(NN),SERZ(NN),VN(MM),Y(MM,MM),ALPHA(NN,NN),
     +BETA(NN,NN),ITL(NN),DELTA(NN),PG(MM),PL(MM),IC(MM),LPA(MM),
     +BTA(MM),GAM(MM),LAMDA(50),PLS(30),SUM2(24),ALPHP(NN,NN),BETAP(NN
     +,NN),TPG(MM),YABS(NN,NN),PSI(NN,NN);RZ(NN,NN),TG(NN),VA(MM)
     +,PGT(50)

      OPEN (5,FILE='SL.DAT',STATUS='OLD')
      OPEN (6,FILE='SL.OUT',STATUS='NEW')


      READ(5,31) NB,NL,MB,EPS1 ,EPS2

      DO 32 I=1,NB
32    PG(I)=0.0

      WRITE(*,*)  NB,NL,MB,EPS1 ,EPS2

      DO 67 I=2,11
67    READ(5,77) PG(I)
77    FORMAT(F8.3)

      DO 69 I=1,11
69    READ(5,'(3F9.4)') LPA(I),BTA(I),GAM(I)
      DO 1 I=1,NB
      DO 1 J=1,NB
1     Y(I,J)=CMPLX(0.0,0.0)

      DO 2 I=1,NL

      READ(5,31) LINE(I),SB(I),EB(I),LENGTH(I),YSHT(I),ZSER(I)
31    FORMAT(3I5,F5.1,4F10.3)

      SHTY(I)=YSHT(I)*LENGTH(I)
      SERZ(I)=ZSER(I)*LENGTH(I)
      SERY(I)=1.0/SERZ(I)

      L=SB(I)
      M=EB(I)
      Y(L,L)=Y(L,L)+SERY(I)+SHTY(I)/2.
      Y(M,M)=Y(M,M)+SERY(I)+SHTY(I)/2.
      Y(L,M)=Y(L,M)-SERY(I)
2     Y(M,L)=Y(M,L)-SERY(I)
```

```
      WRITE(6,34)
34    FORMAT('1',T38,'LINE DATA'//T8,'LINE',T15,'SB',T19,'EB',T24,
     +'LENGTH',T36,'SHUNT ADMITTANCE',T58,'SERIES IMPEDANCE'/)

      DO 3 I = 1,NL
3     WRITE(6,35) LINE(I),SB(I),EB(I),LENGTH(I),SHTY(I),SERZ(I)
35    FORMAT(' ',T6,3I5,F8.1,4X,2F9.4,4X,2F9.4)

      WRITE(6,36)
36    FORMAT(////T10,'BUS ADMITTANCE MATRIX'//)

      DO 4 I=1,NB
4     WRITE(6,37) (Y(I,J),J=1,NB)
37    FORMAT (4(F9.4,1X,F9.4,1X)/)

      DO 38 I=1,NB
      DO 38 J=1,NB
38    X(I,J)=Y(I,J)

      CALL ZBUSM

      WRITE(6,39)
39    FORMAT(////T10,'BUS IMPEDANCE MATRIX '//)

      WRITE (6,40)((ZBUS(I,J),J=1,NB),I =1,NB)
40    FORMAT(2(2X,E14.6,'+j (',E14.6,')',4X))

      K=MB+1


      READ (5,41) (PL(I),I=1,NB)
      WRITE(*,*) (PL(I),I=1,NB)

      DO 42 I=1,NB
      P(I)=PG(I)-PL(I)
42    CONTINUE

      READ (5,41) (Q(I),I=K,NB)
      WRITE(*,*) (Q(I),I=K,NB)

      READ (5,41) V(1),(VSPEC(I),I=2,MB)
      WRITE(*,*) V(1),(VSPEC(I),I=2,MB)

      READ (5,41) (QMIN(I),QMAX(I),I=2,MB)
      WRITE(*,*) (QMIN(I),QMAX(I),I=2,MB)
41    FORMAT(8F8.3)

      GO TO 600

111   DO 43 I=1,NB
43    P(I)=PG(I)-PL(I)

600   DO 62 I=1,NB
      TG(I)=PG(I)
62    CONTINUE
```

```
      CALL SLF
      WRITE(*,'(A,I2)') ' RETURN FROM SLF...',MB
      DO 63 I=1,NB
      PG(I)=P(I)+PL(I)
      WRITE(*,*)'PG(',I,')',PG(I)
63    CONTINUE

      DO 64 I=1,NB
      IF(ABS(PG(I)-TG(I)).GT. 0.1)GO TO 65
64    CONTINUE

      GO TO 23

65    DO 44 I=1,NB
      DO 44 NU=1,NB
      IF (ABS(AIMAG(Y(I,NU))).LE.1.E-07)THEN
      PSI(I,NU)=0.0
      GOTO 68
          ENDIF
      IF (ABS(REAL(Y(I,NU))).LE.1.E-07)THEN
      PSI(I,NU)=3.141593/2
      GOTO 68
          ENDIF
      PSI(I,NU)=ATAN2(AIMAG(Y(I,NU)),REAL(Y(I,NU)))
68    YABS(I,NU)=CABS(Y(I,NU))
      RZ(I,NU) = REAL(ZBUS(I,NU))

44    CONTINUE


      DO 45 J=1,NB
      DO 45 K=1,NB
      ALPHA(J,K)=(RZ(J,K)/(VA(J)*VA(K)))*COS(DELTA(J)-DELTA(K))
      BETA(J,K)=(RZ(J,K)/(VA(J)*VA(K)))*SIN(DELTA(J)-DELTA(K))
45    CONTINUE

      DO 46 I=1,NB
      DO 46 J=1,NB
      DO 46 K=1,NB
      FX= 1.0/(YABS(I,J)*VA(J)*SIN(DELTA(J)-DELTA(I)+PSI(I,J)))
      FY= 1.0/(YABS(I,K)*VA(K)*SIN(DELTA(K)-DELTA(I)+PSI(I,J)))
      ALPHP(J,K)=(BETA(J,K)/VA(I))*(FX-FY)
      BETAP(J,K)=(ALPHA(J,K)/VA(I))*(FY-FX)
46    CONTINUE

      SUM1=0.0

      DO 47 J=1,NB
      DO 47 K=1,NB
      SUM1 = SUM1+ ((P(J)*P(K)+Q(J)*Q(K))*ALPHP(J,K)-(P(J)*Q(K)-Q(J)*
     +P(K))*BETAP(J,K))
47    CONTINUE

      DO 48 I=1,NB
      ITL(I)=0.0
      SUM2(I)=0.0
48    CONTINUE
```

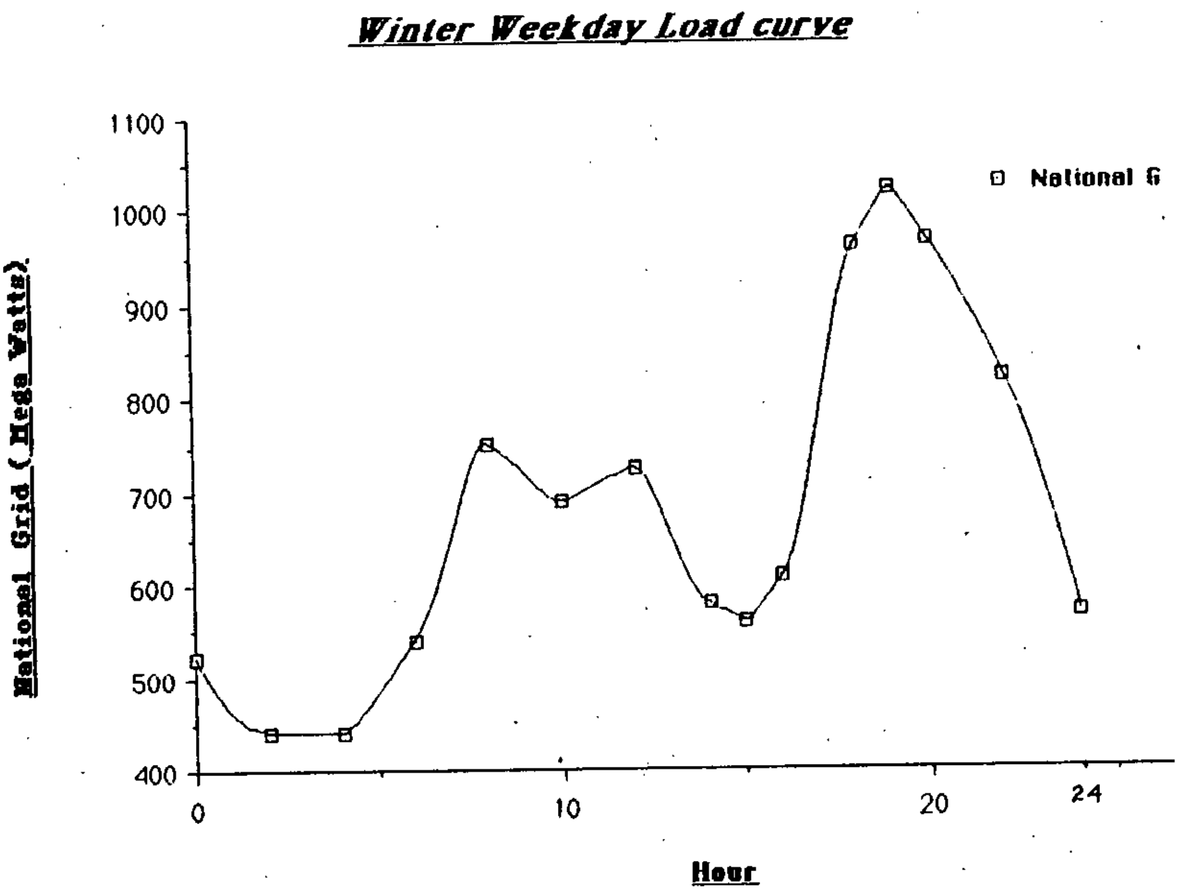
```
      DO 49 I=1,NB
      DO 49 K=1,NB
      SUM2(I)= SUM2(I)+2.0*(P(K)*ALPHA(I,K)-Q(K)*BETA(I,K))
49    CONTINUE

      DO 50 I=1,NB
      ITL(I)=ITL(I)+SUM1+SUM2(I)
50    CONTINUE

      PLS(K1)=0.0
      DO 51 I=1,NB
      DO 51 J=1,NB
      PLS(K1)=PLS(K1)+(ALPHA(I,J)*(P(I)*P(J)+Q(I)*Q(J))+BETA(I,J)*(Q(I)*
     +P(J)-P(I)*Q(J)))
51    CONTINUE

      WRITE(6,52)K1, PLS(K1)
52    FORMAT(5X,I2, '  LINE LOSS=',F10.7)

      WRITE(6,53)(I,ITL(I),I=1,NB)
53    FORMAT(5X,'ITL(',I2,') =',E12.5/)


C     NEW BLOCK

61    PLT =0.0
      DO 186 I=1,NB
      PGT(K1) = PGT(K1) +PG(I)
      PLT = PLT + PL(I)
186   CONTINUE
      PTD=PLT+PLS(K1)
      K1=K1+1
      IL=IL+1
      IF (IL.GT.1) GO TO 599
      LAMDA(1)=2.5
      GO TO 602
599   IF (IL.GT.2) GO TO 601
      LAMDA(2)=2.7
      GO TO 602
601   LAMDA(IL)=LAMDA(IL-1)+(PTD-PGT(IL-1))*((LAMDA(IL-1)-LAMDA(IL-2))/
     +(PGT(IL-1)-PGT(IL-2)))
602   DO 54 I=1,11
54    IC(I)=LAMDA(I)*(1.0-ITL(I))
      DO 60 I=1,11
60    TPG(I)=PG(I)

      DO 55 I=1,11
55    PG(I)=(IC(I)-BTA(I))/(2.0*GAM(I))
      DO 56 I=1,11
      IF (ABS(PG(I)-TPG(I)).GT.0.1)GO TO 61
56    CONTINUE

23     WRITE(6,66)(I,PG(I),I=1,11)
66     FORMAT(5X,'PG(',I2,') = ',F8.4)
```

```
      WRITE(6,202)
202   FORMAT(1X,'UNIT','   GENERATING STN','   GENERATION','   COST OF
     + GEN')
       WRITE(6,213)
213   FORMAT(1X,'NO',6X,'   NAME ',5X,'   MEGA WATTS',4X,' TAKA/HR'/)

      DO 207 L=1,NH-1
      GC(L)=ALP(L)+BET(L)*PG(IH,L)+GAM(L)*PG(IH,L)*PG(IH,L)
      TC(IH)=TC(IH)+GC(L)
      WRITE(6,208)L,NAME(L),PG(IH,L),GC(L)
208   FORMAT(3X,I2.2,4X,A9,7X,G12.4,1X,G14.8)

207   CONTINUE
      WRITE(6,209)NH,NAME(NH),PG(IH,NH)
209   FORMAT(3X,I2.2,4X,A9,7X,G12.4/)
      WRITE(6,210)LAMDA, WAT, R(IH,NH)
210   FORMAT(2X,'INCREMENTAL COST OF RECEIVED POWER =',G14.8/5X,'WATER
     + USED =',G12.5,'ACRE-FT PER HOUR'/2X,'CONVERSION FACTOR FOR HYDRO
     +UNIT =',G14.6/)
      WRITE(6,211)TC(IH)
211   FORMAT(3X,'TOTAL GENERATION COST = TK ',G14.7/)

      GT = GT + TC(IH)

200   CONTINUE
      WRITE (6,212)GT
212   FORMAT(2X, 'GRAND TOTAL OF GENERATION COST = TK',G14.7/)

      STOP
      END


      SUBROUTINE ZBUSM
      COMPLEX A,P(50),DIVSR, AMULPR,ZBUS
      COMMON/XX/  N1,A(16,16),ZBUS(8,8)

      WRITE(*,'(A)') ' ENTERING ZBUSM.....'
      WRITE(6,2) ((A(I,J),J=1,N1),I=1,N1)
2     FORMAT(///2X,'THE ORIGINAL MATRIX IS--'//////(4(F8.3,'+j(',F8.3,'
     +)')//))
      N11=N1+1
      N2=2*N1
      DO 31 I = 1,N1
      DO 31 J = N11,N2
31    A(I,J)=(0.0,0.0)
      JJ=N1
      DO 22 I=1,N1
      JJ=JJ+1
22    A(I,JJ)=A(I,JJ)+(1.0,0.0)
      N=N2
      M=N1
      K=1
      DO 11 II=1,M
      CHR = CABS(A(II,II))

      IF(CHR) 7, 3, 7
3     I1=II+1
```

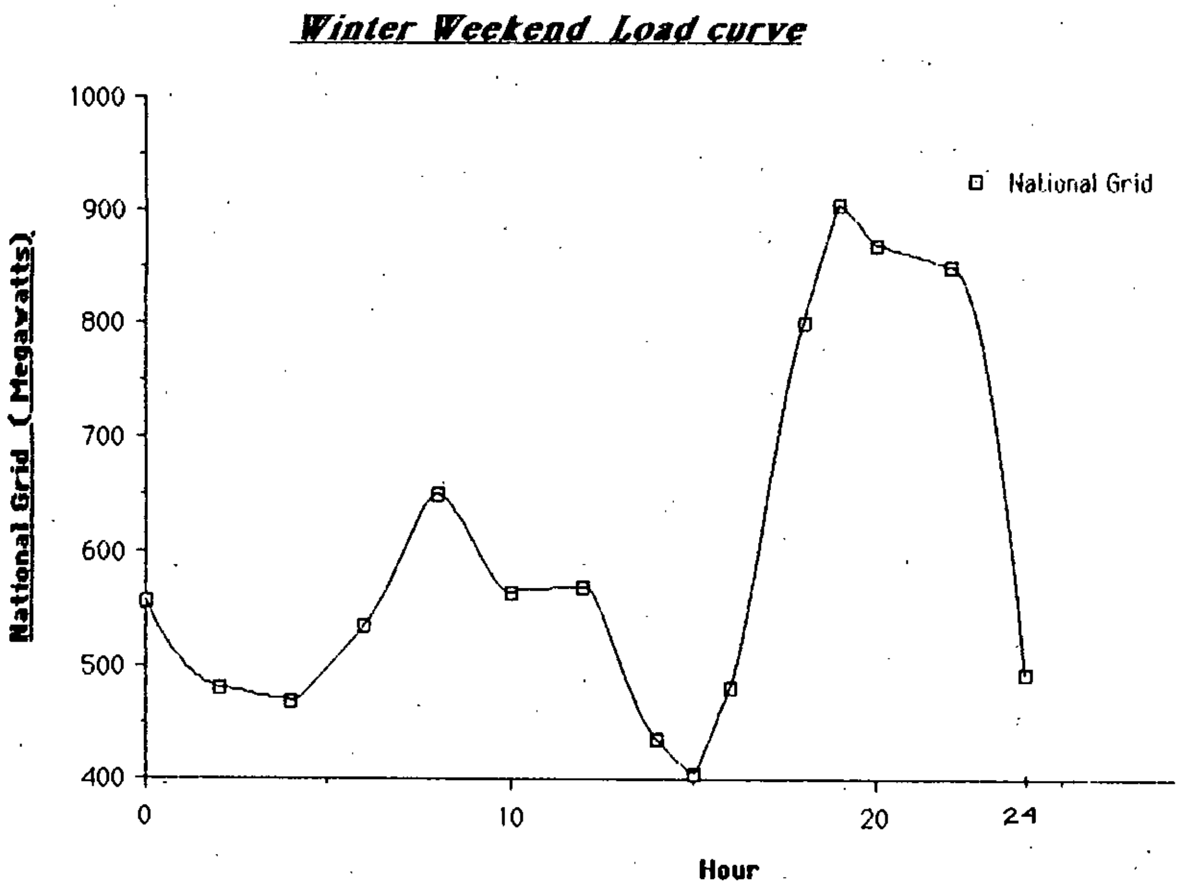
```
      DO 4 I2=I1,M
      J1=II
      CHRJ=CABS(A(I2,J1))

      IF(CHR)5,4,5
4     CONTINUE
5     DO 6 J2=1,N
      P(J2)=A(II,J2)
      A(II,J2)=A(I2,J2)
6     A(I2,J2)=P(J2)

7     DIVSR=(1.0,0.0)*A(K,K)
      DO 8 J=1,N
      A(K,J)=A(K,J)/DIVSR
8     CONTINUE
      DO 10 I=1,M
      IF(I.EQ.K)GO TO 10
      AMULPR=(1.0,0.0)*A(I,K)
      DO 9 J=1,N
      A(I,J)=A(I,J)-A(K,J)*AMULPR
9     CONTINUE
10    CONTINUE
      K=K+1
11    CONTINUE
      DO 74 I=1,N1
      DO 73 JD=1,N1
      J=N1+JD
      ZBUS(I,JD)=A(I,J)
73    CONTINUE
74    CONTINUE
      WRITE(*,*)  ((A(I,J),J=N11,N),I=1,M)
      WRITE(6,12)  ((A(I,J),J=N11,N),I=1,M)
12    FORMAT(////20X,'THE INVERSE MATRIX IS '//(4(1X,F8.5,'+j(',F8.5,')'
     +)//))
      RETURN
      END

      SUBROUTINE SLF

      PARAMETER(NN=14,MM=8)
      COMPLEX Y,VI,VII,SUM,S,R,DX,VN,CMP,A,B,V,X,ZBUS
      DIMENSION A(NN),B(NN,NN),V(NN),P(NN),Q(NN),QMAX(NN),
     +QMIN(NN),VSPEC(NN),VN(MM),Y(MM,MM),DELTA(NN),VA(MM)
      COMMON/YY/VA,P,Q,QMAX,QMIN,V,VSPEC,VN,DELTA,VI,VII,EPS1,EPS2,MB,Y
      COMMON/XX/NB,X(16,16),ZBUS(8,8)
      WRITE(*,'(A)') ' ENTERING SLF.......'
      NB=MM
      K=MB+1
      DO 5 I=2,NB
      IF(I.LT.K)Q(I)=0.0
      V(I)=CMPLX(1.0,0.0)
      IF(I.GT.MB)A(I)=(CMPLX(P(I),(-Q(I))))/Y(I,I)
      DO 51 J=1,NB
      IF (I.NE.J)B(I,J)=Y(I,J)/Y(I,I)
51    CONTINUE
5     CONTINUE
      N=0
6     DVMAX=0.0
      I=2
7     VII= V(I)
```

```
      IF(I-MB)8,8,15
8     V(I)=(V(I)/CABS(V(I)))*VSPEC(I)
      SUM=CMPLX(0.0,0.0)
      DO 9 L=1,NB
9     SUM=SUM+Y(I,L)*V(L)
      Q(I)=-AIMAG(SUM * CONJG(V(I)))
      IF (Q(I)-QMAX(I)) 10,14,11
10    IF (Q(I)-QMIN(I)) 12,14,14
11    Q(I)=QMAX(I)
      GO TO 13
12    Q(I)=QMIN(I)
13    V(I)=VII

14    A(I)=(CMPLX(P(I),(-Q(I))))/Y(I,I)

15    SUM=CMPLX(0.0,0.0)
      VI=V(I)
      DO 16 L=1,NB
16    IF(L.NE.I)SUM=SUM+B(I,L)*V(L)

      VN(I)=A(I)/CONJG(V(I))-SUM
      DX=VN(I)-VI
      VN(I)=VI+EPS1*DX

      DELV=CABS(VN(I)-VII)
      IF(DELV.GE.DVMAX)DVMAX=DELV

      I=I+1

      IF(I.LE.NB)GO TO 7

      DO 17 I=2,NB
17    V(I)=VN(I)

      N=N+1

      IF (DVMAX.LE.1.E-04)GO TO 19
      IF(N.LT.100)GO TO 6
      WRITE(6,106)N
106   FORMAT(///,T10,'CONVERGENCE NOT OBTAINED IN',I3,'ITERATIONS')
19    SUM =CMPLX(0.0,0.0)
      DO 20 I=1,NB
20    SUM=SUM+Y(1,I)*V(I)
      P(1)=REAL(SUM*CONJG(V(1)))
      Q(1)=-AIMAG(SUM*CONJG(V(1)))
      DO 27 I=1,NB
      DELTA(I)=ATAN2(AIMAG(V(I)),REAL(V(I)))
27    VA(M)=CABS(V(M))
      RETURN
      END

      SUBROUTINE WATER
      PARAMETER (NH=11)
      COMMON WAT, PGH, X,Y,Z,RS

      QW = (X+Y*PGH+Z*PGH*PGH)/RS
      WAT=QW
      RETURN
      END
```

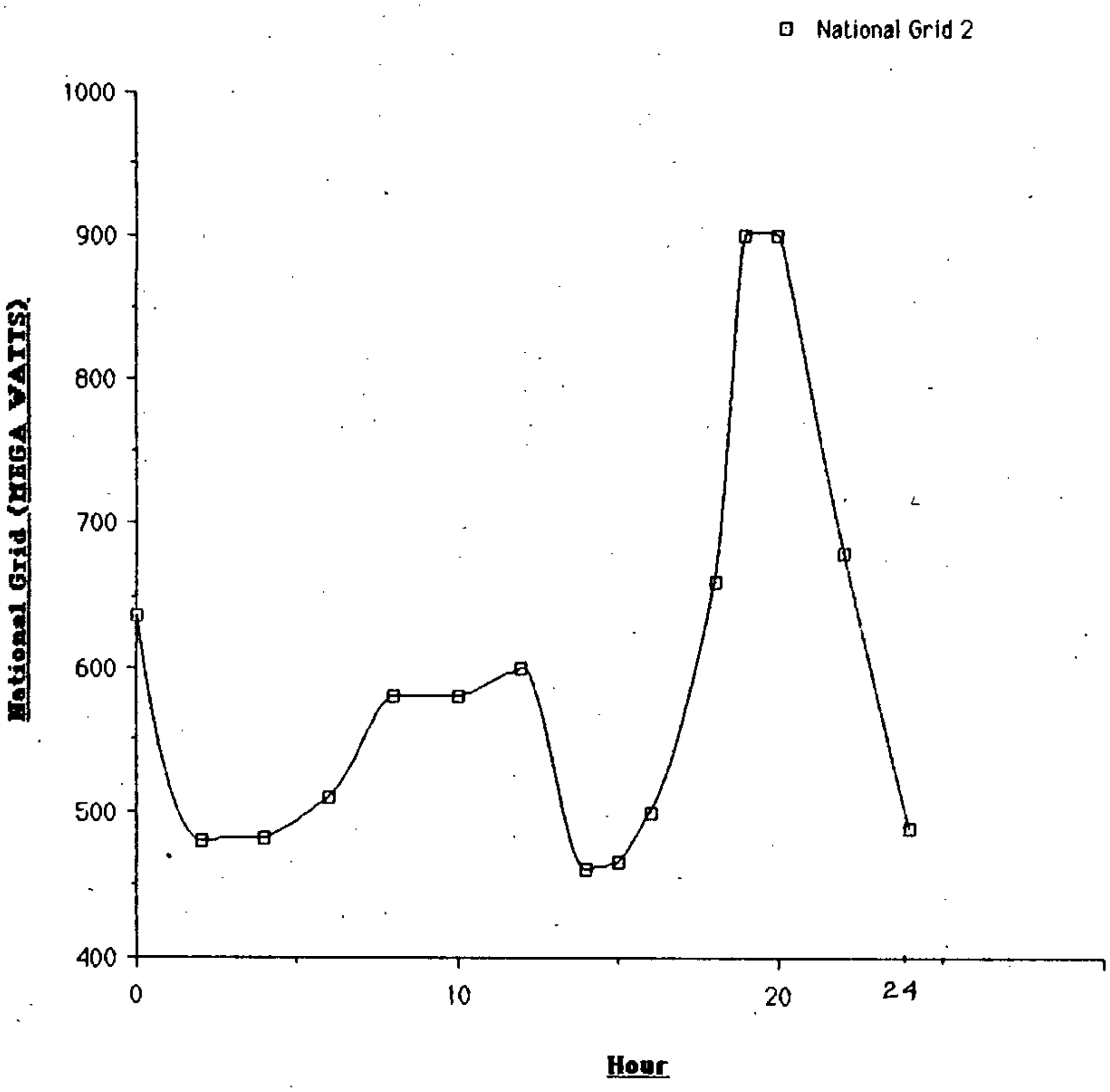
C. 1



Winter Weekday Load curve
National Grid (Mega Watts)
1100
1000
900
800
700
600
500
400
0
10
20
24
Hour
National G

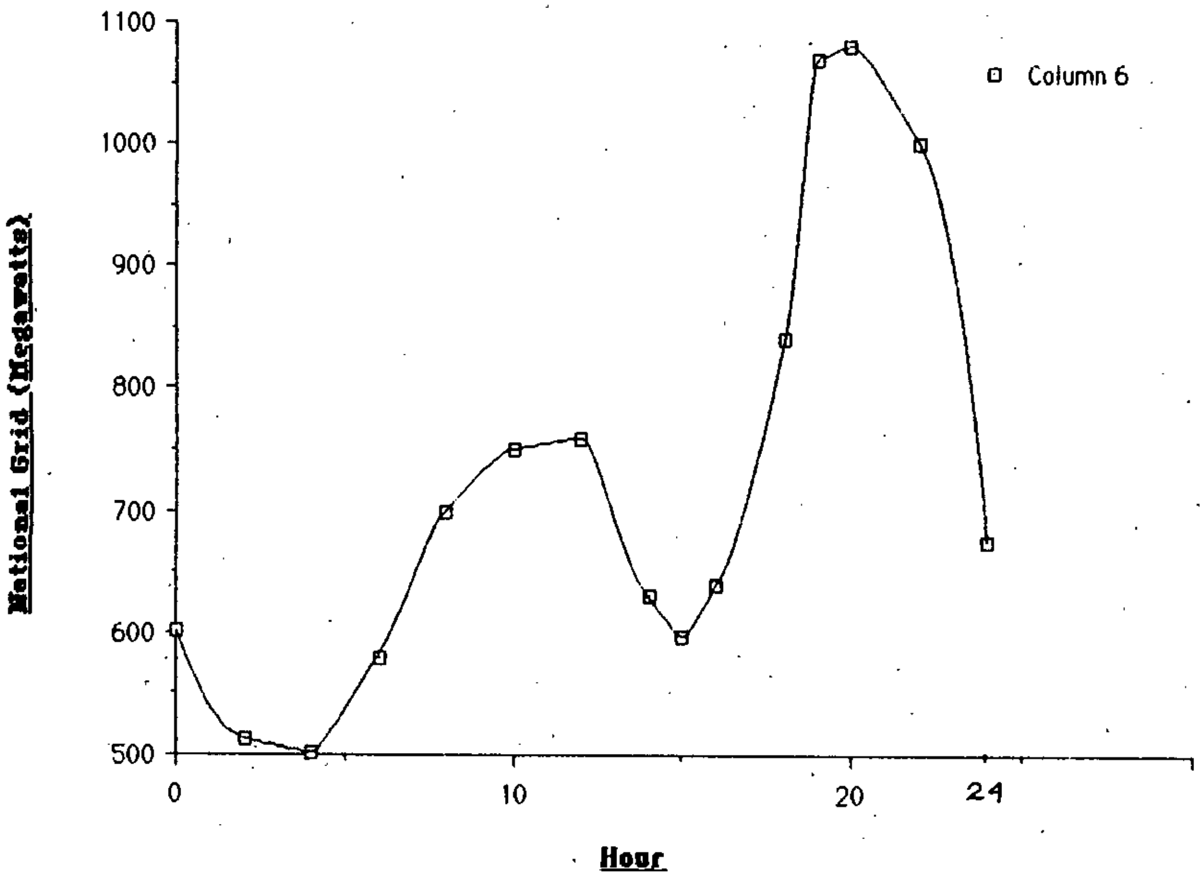

Winter Weekend Load curve
1000
900
800
700
600
500
400
National Grid (Megawatts)
National Grid
0
10
20
24
Hour

SUMMER WEEKEND LOAD CURVE



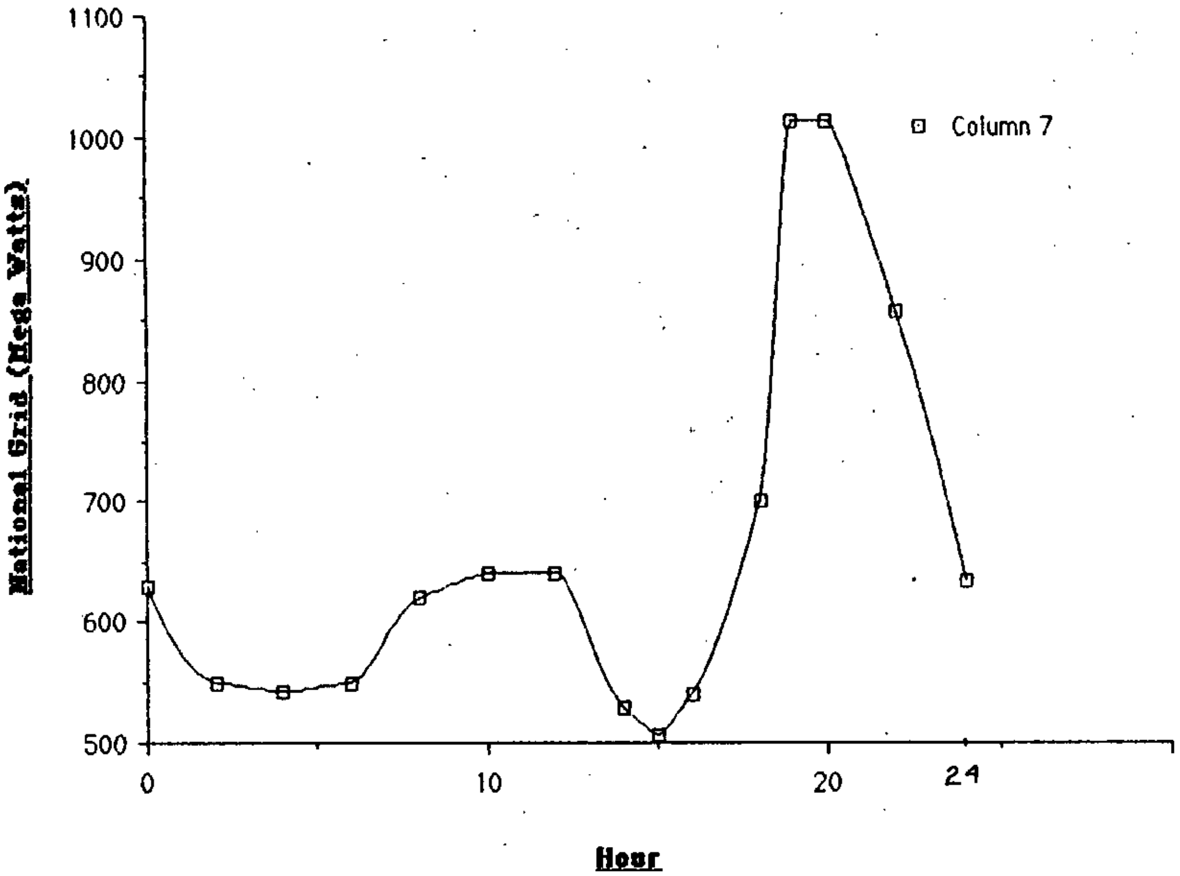
c. 4

SUMMER WEEKDAY LOAD CURVE

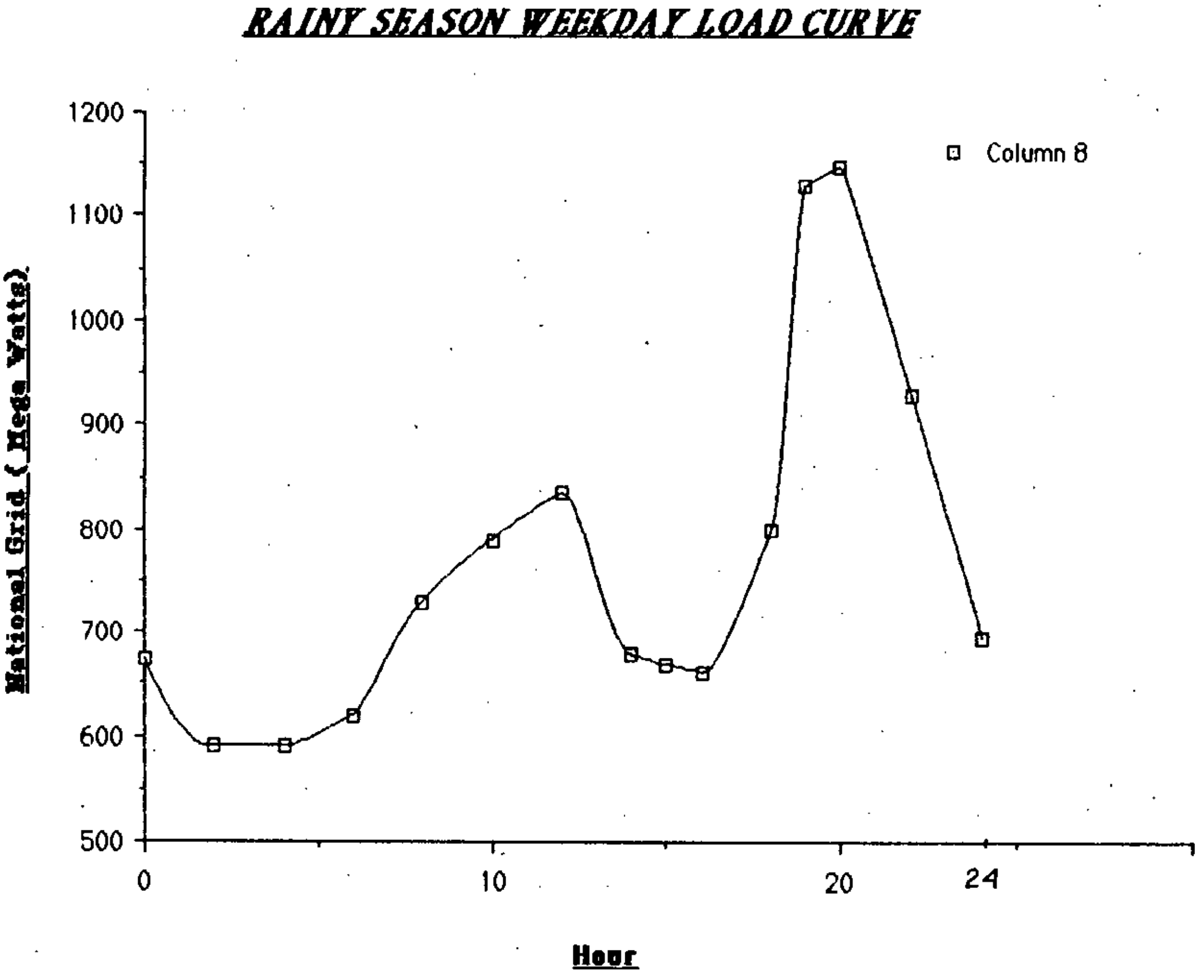


C-25

RAINY SEASON WEEKEND LOAD CURVE

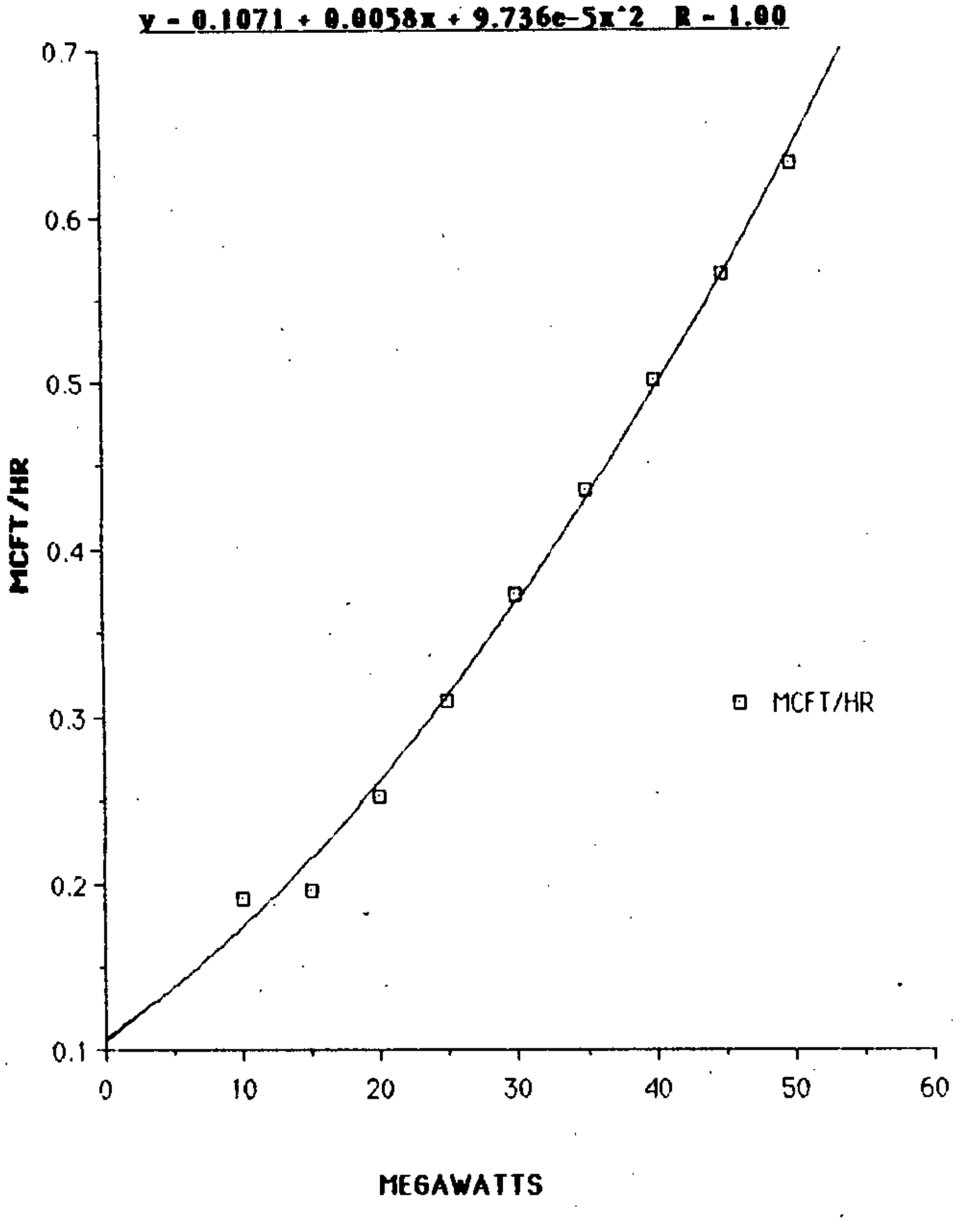


C - 6

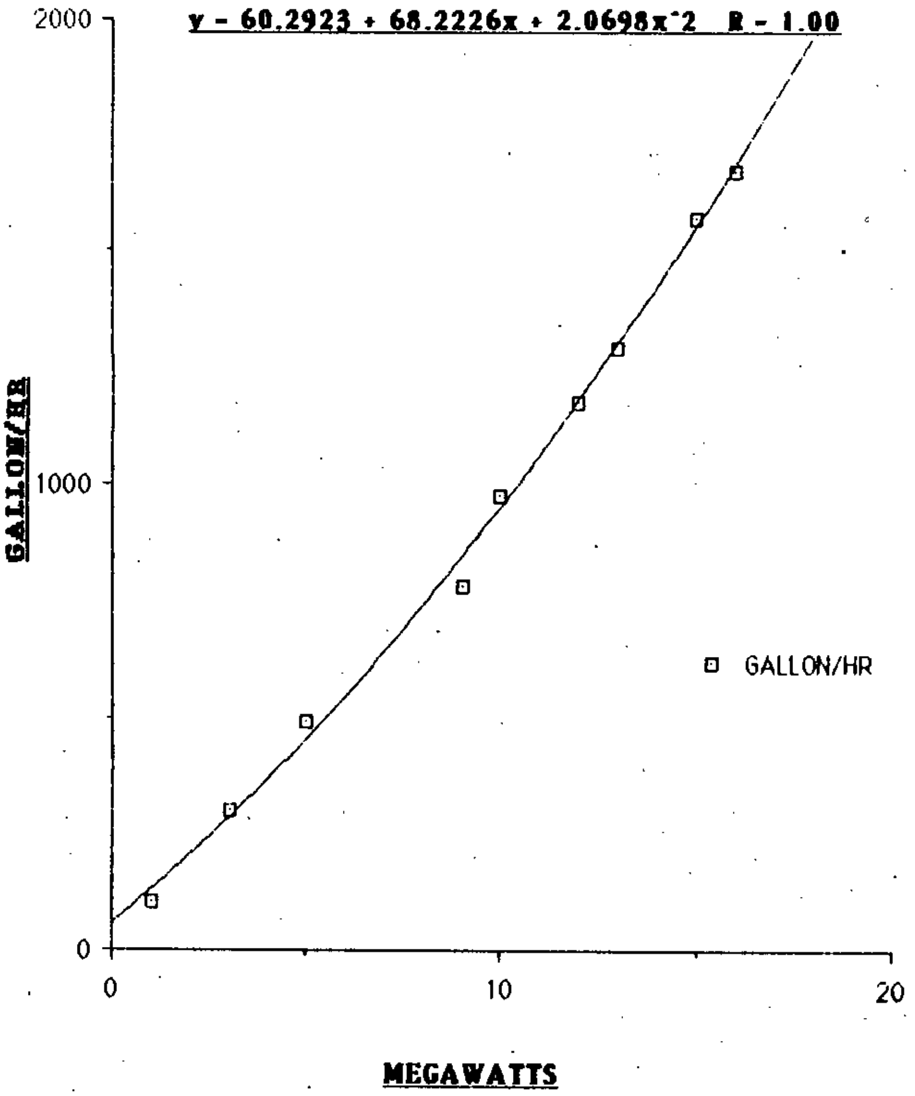


RAINY SEASON WEEKDAY LOAD CURVE
Column 8
National Grid (Mega Watts)
1200
1100
1000
900
800
700
600
500
0
10
20
24
Hour

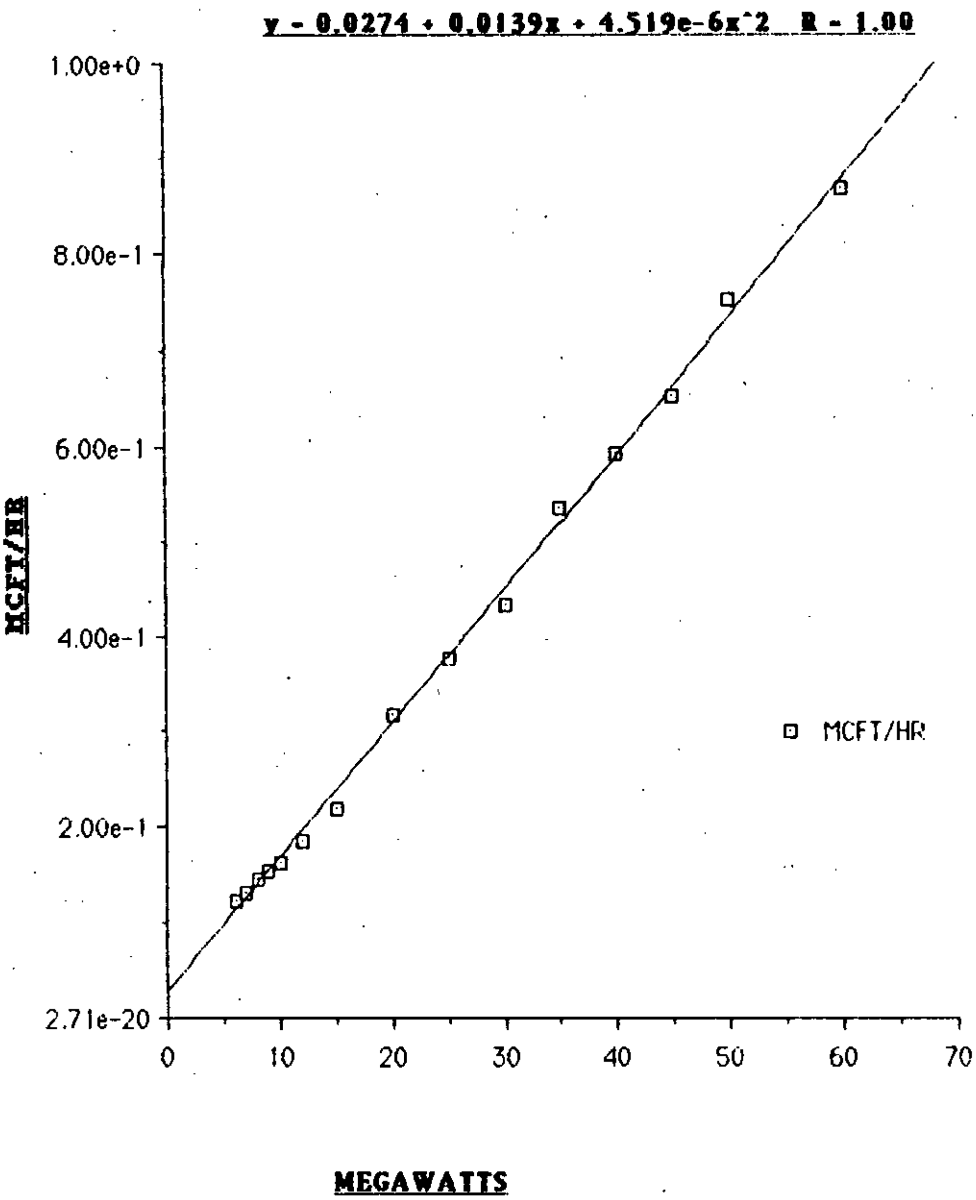
Siddhirgonj 50 MW unit

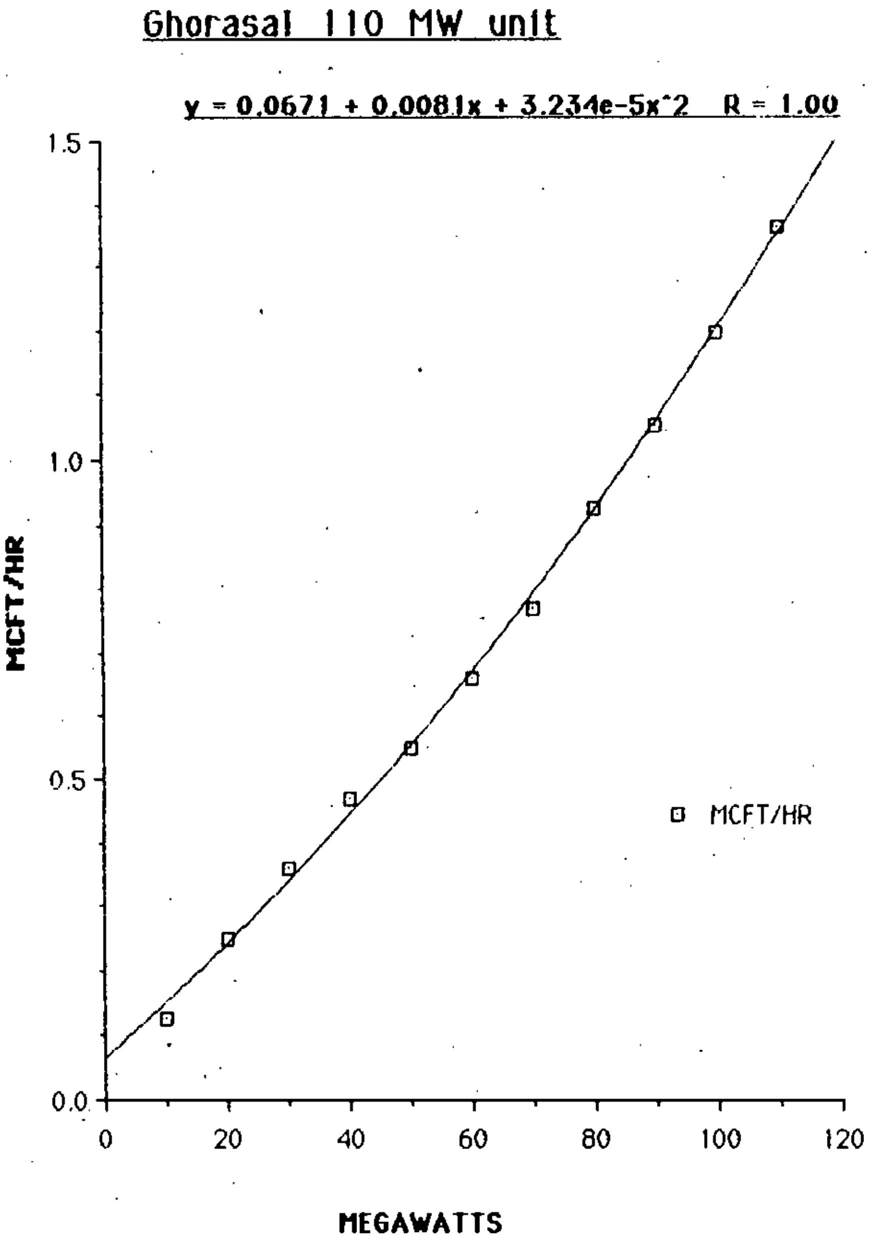


Saidpur Thakurgaon 20 MW unit

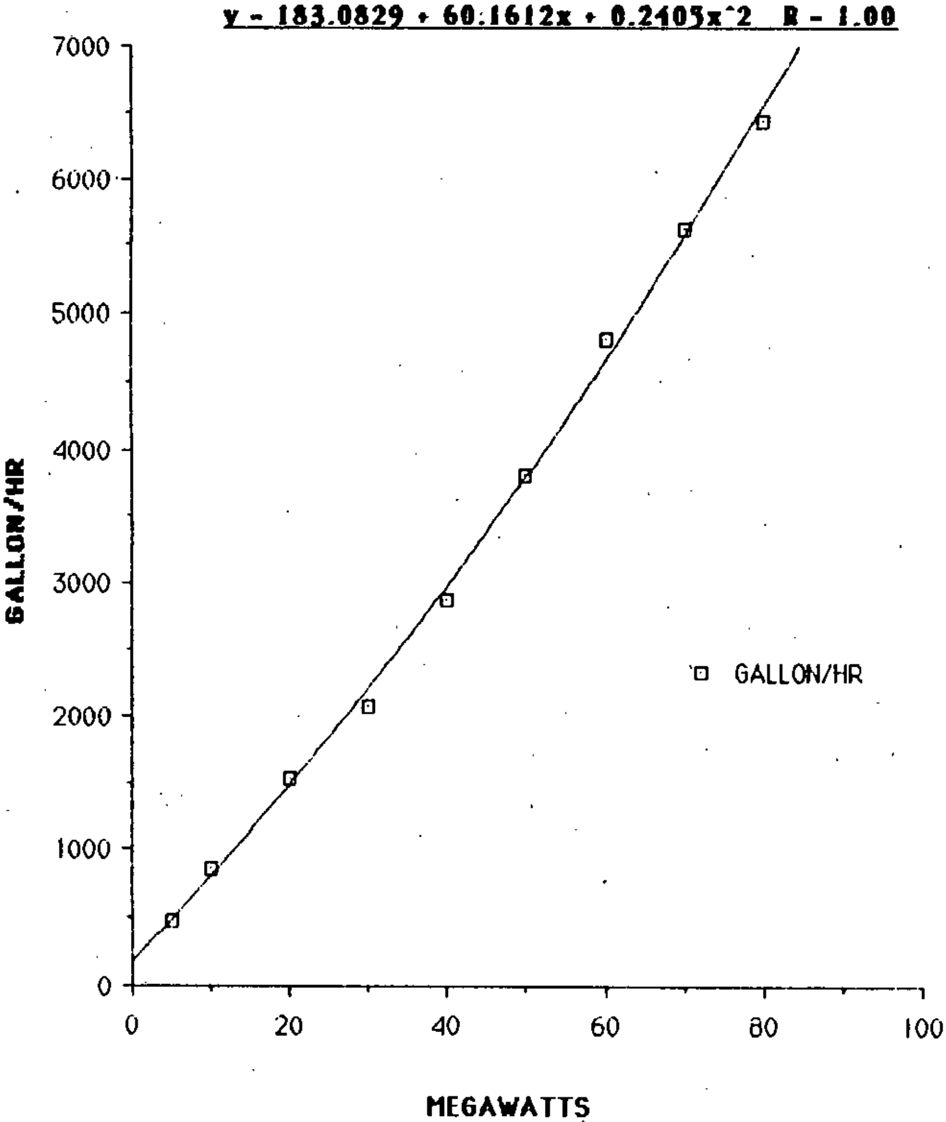


Shahjibazar 60 MW unit



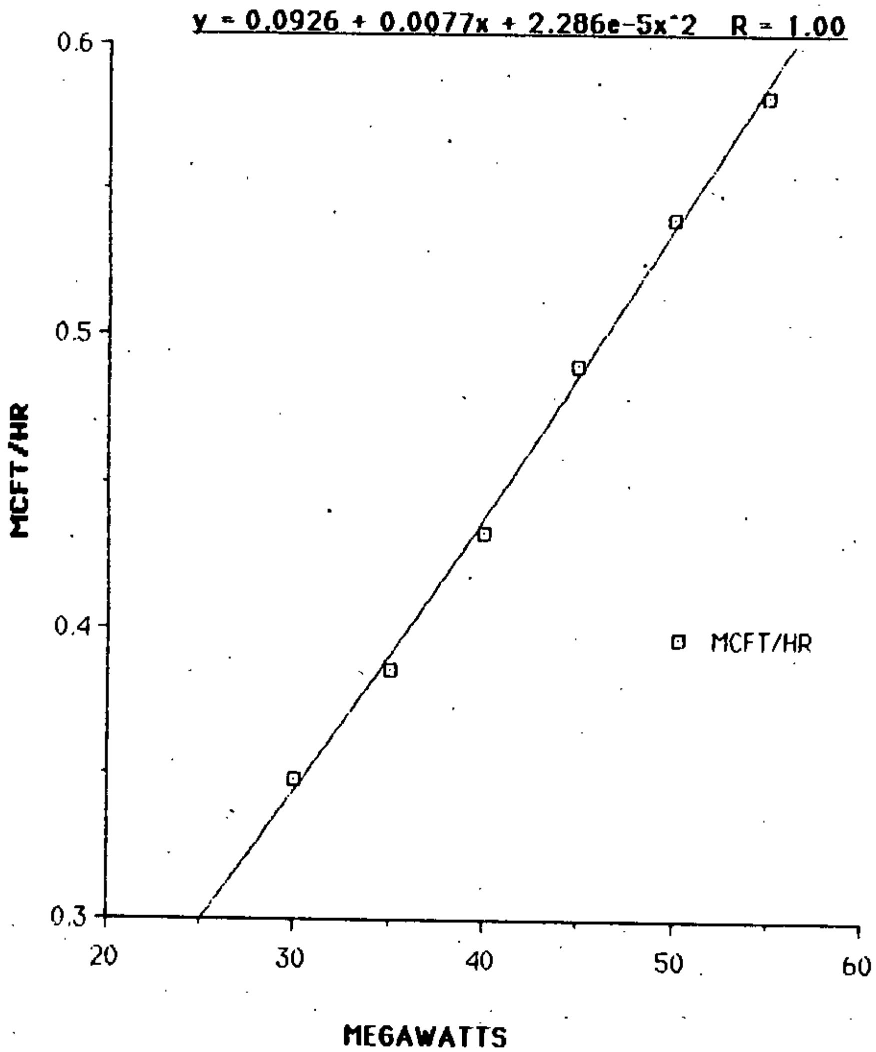

Ghorasal 110 MW unit
y = 0.0671 + 0.0081x + 3.234e-5x^2 R = 1.00
1.5
1.0
0.5
0.0
MCFT/HR
0
20
40
60
80
100
120
MEGAWATTS
MCFT/HR

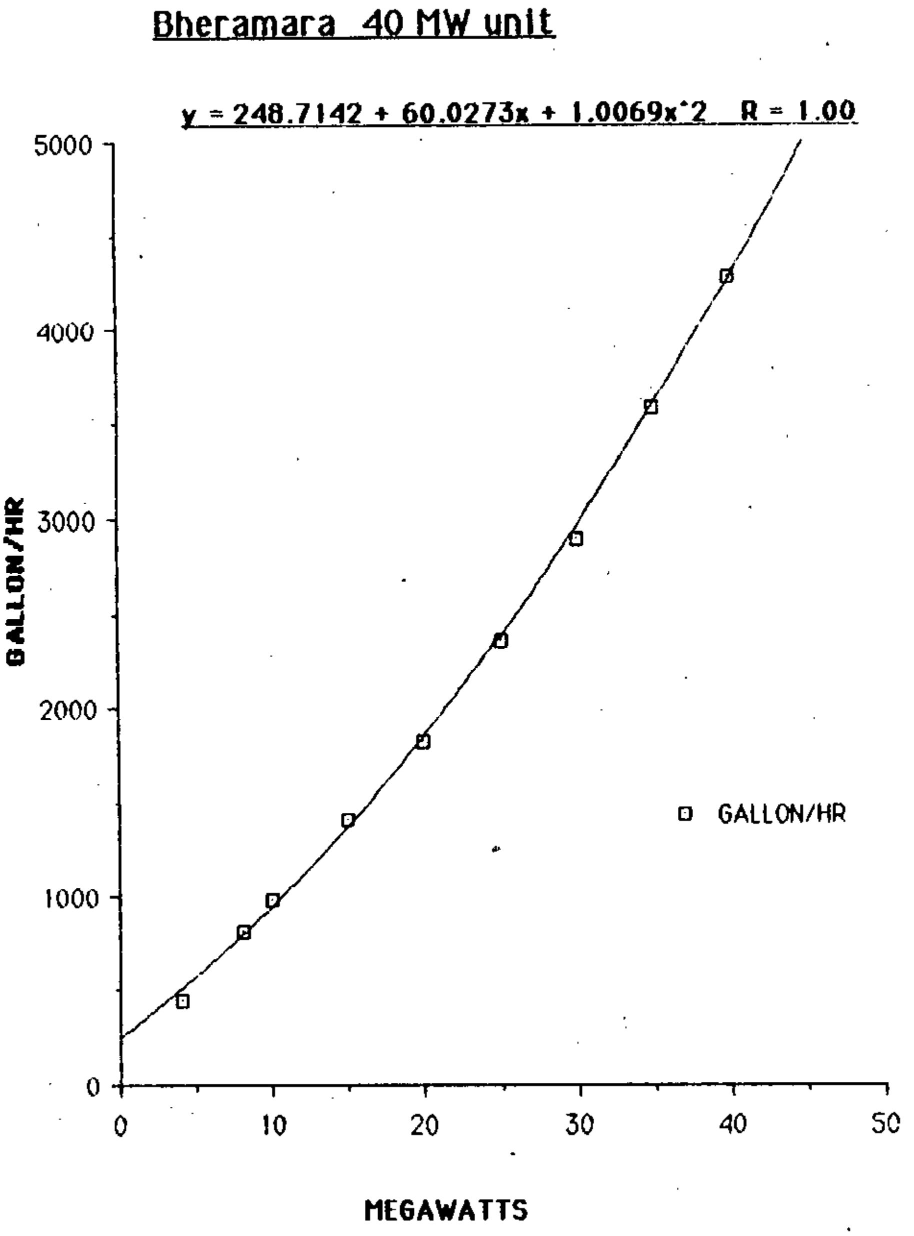
Goalpara 80 MW unit



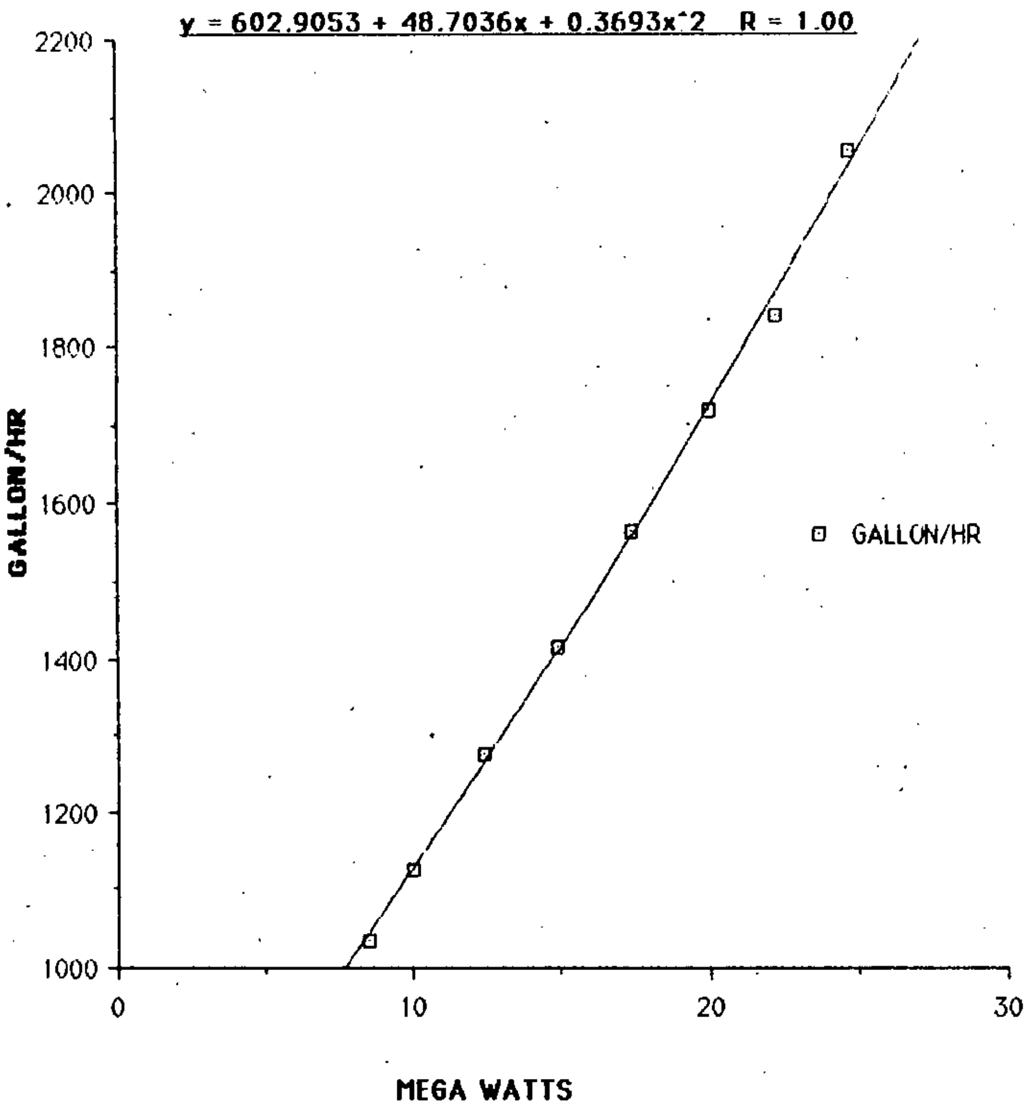
D-6

Ghorasal 55 MW unit

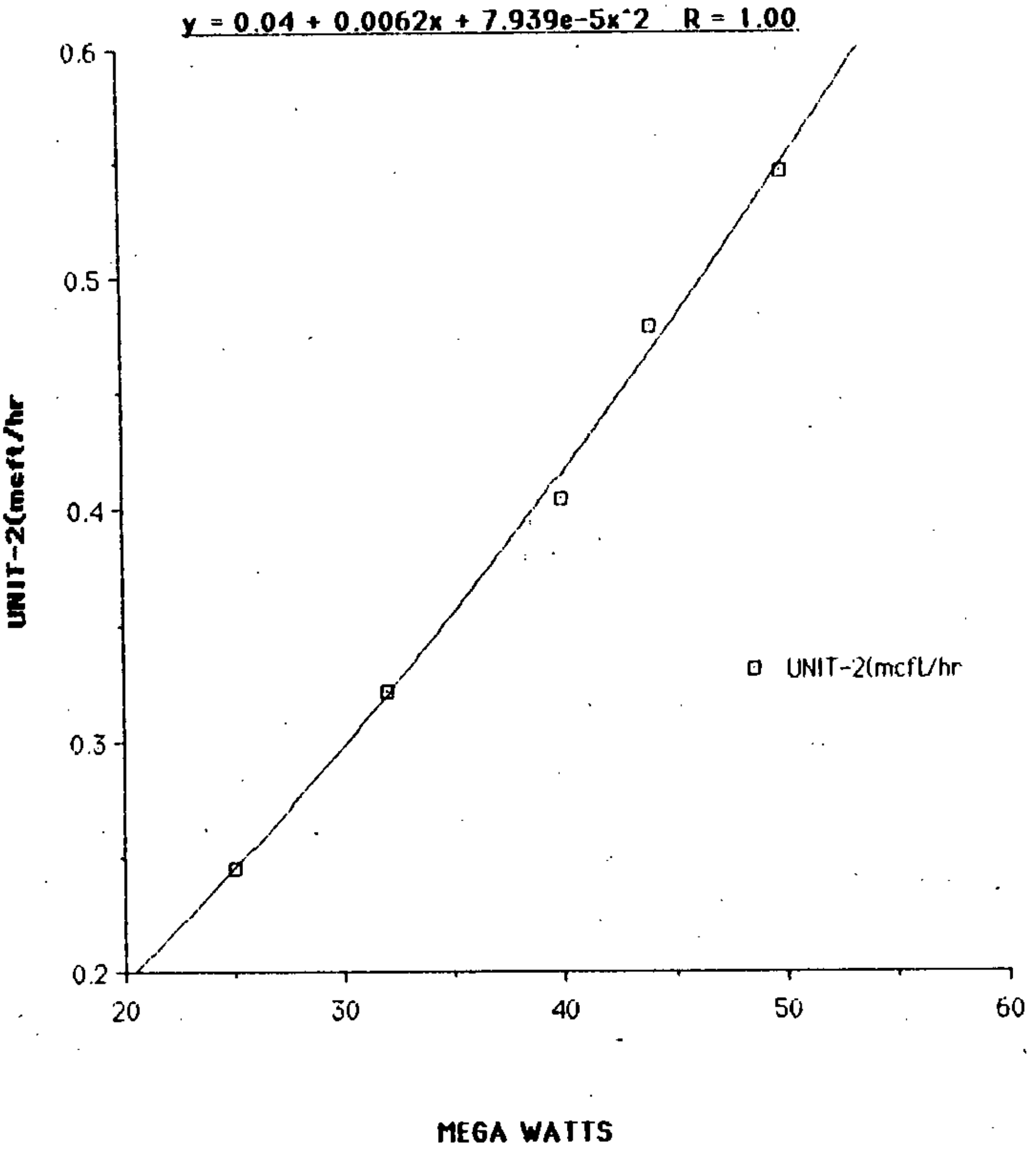



Bheramara 40 MW unit
y = 248.7142 + 60.0273x + 1.0069x^2 R = 1.00
5000
4000
3000
2000
1000
0
GALLON/HR
0
10
20
30
40
50
MEGAWATTS
GALLON/HR

Barisal 25 MW unit

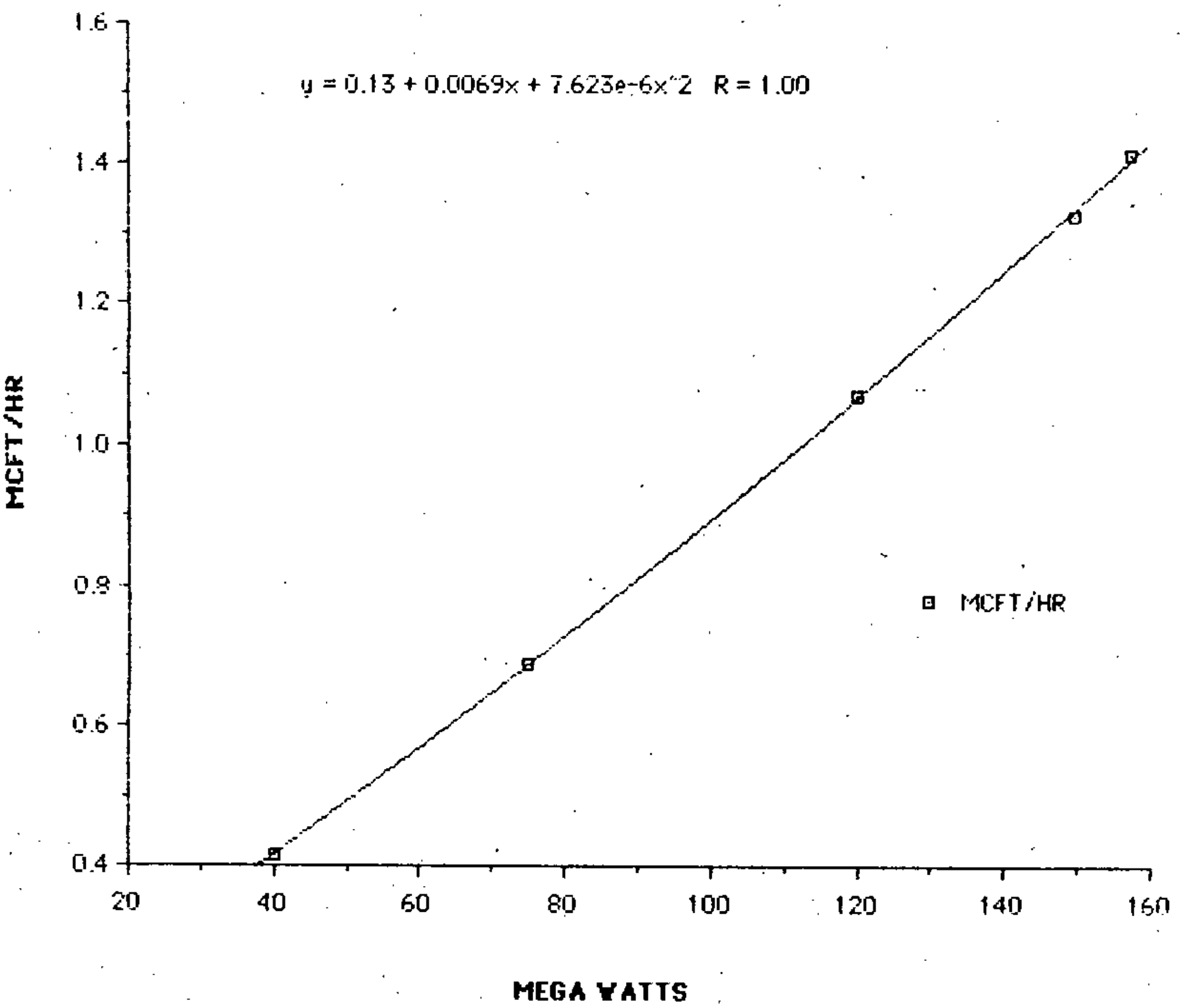


Ashuganj 50 MW unit 2

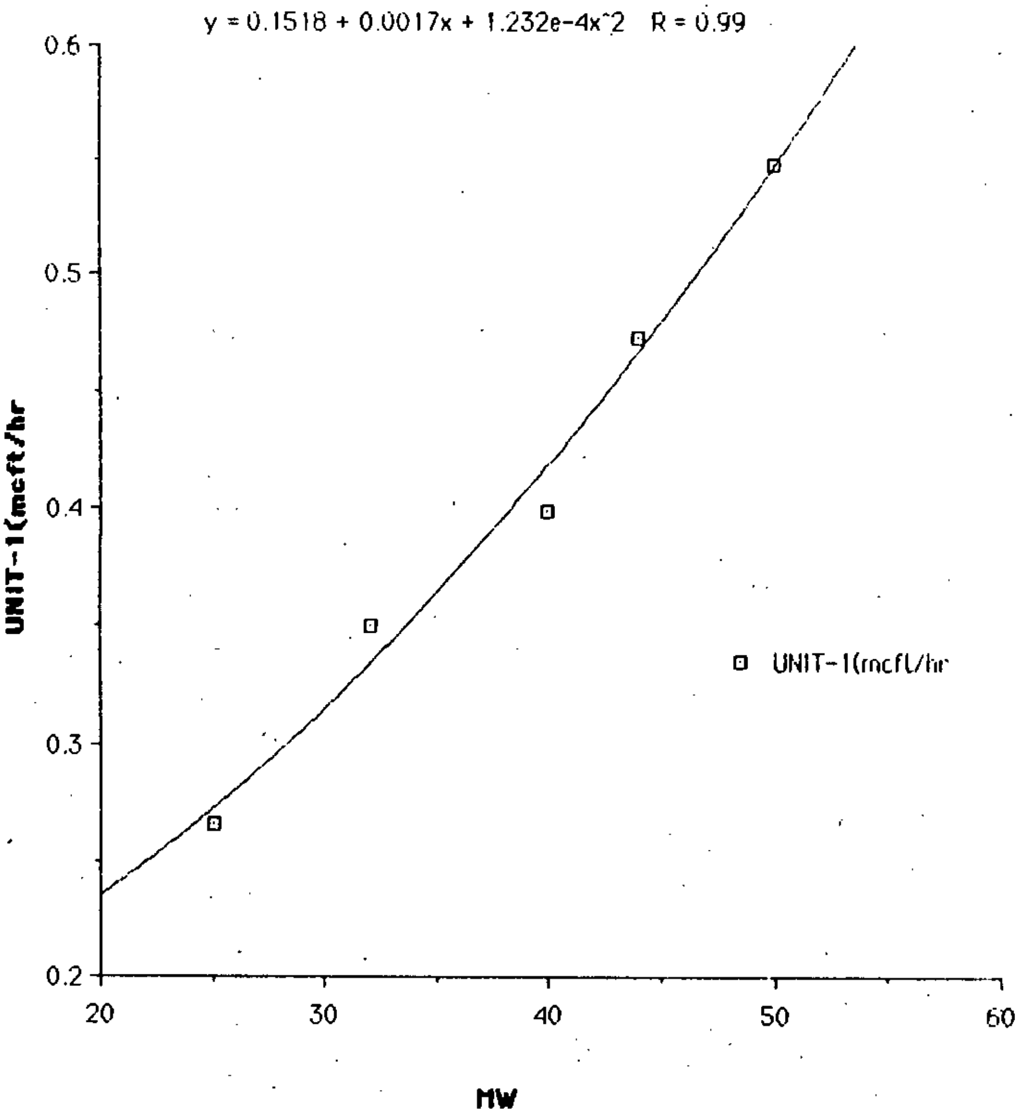


D-12

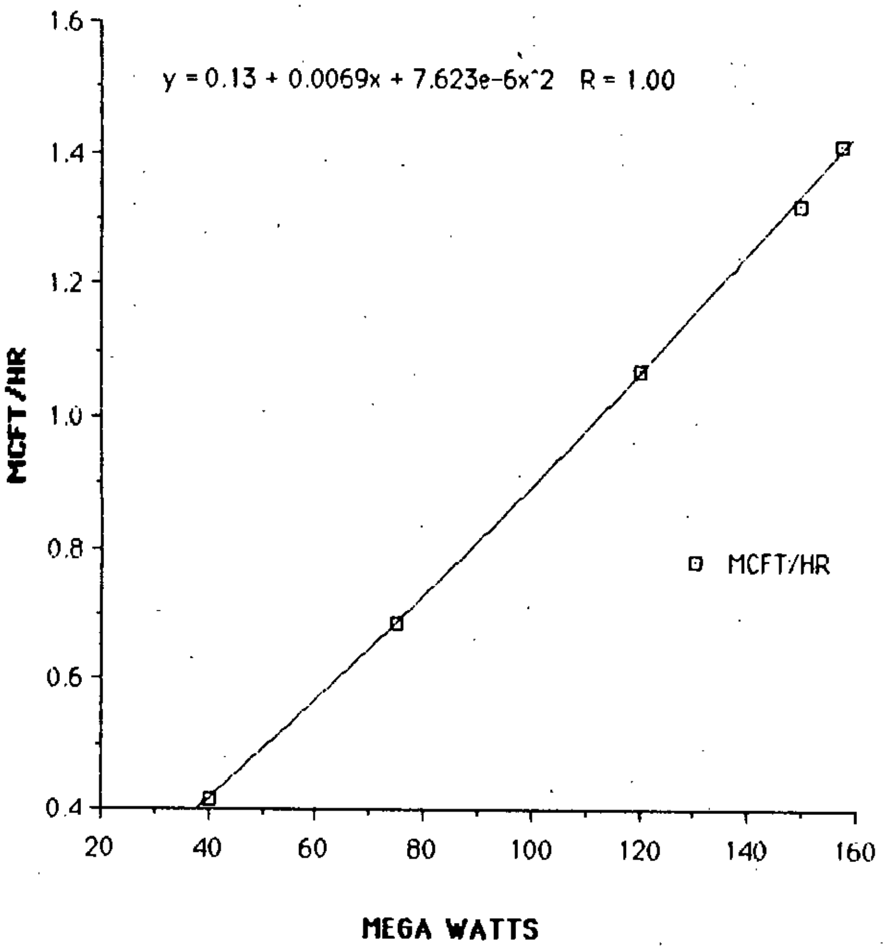
Ashuganj 150 MW unit

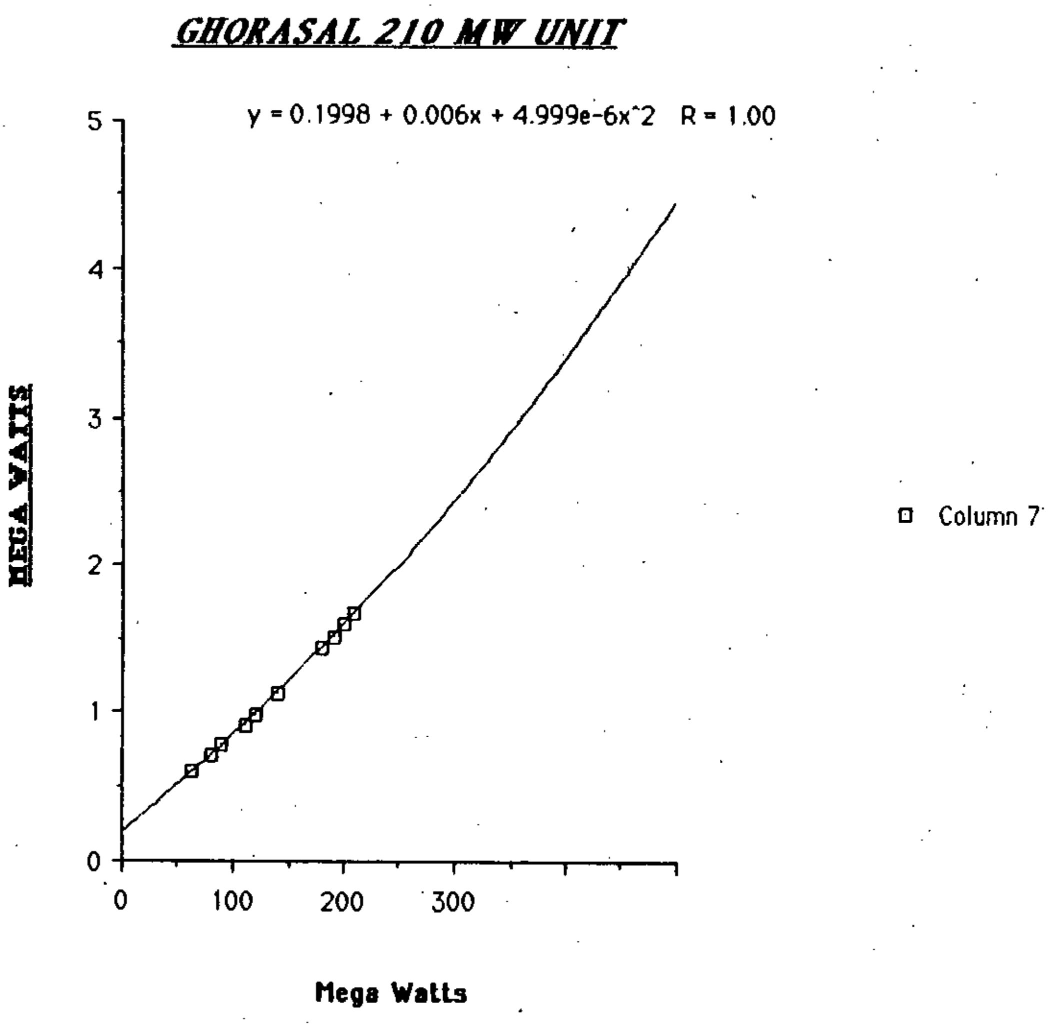


Ashuganj 50 MW unit 1



Ashuganj 150 MW unit




GHORASAL 210 MW UNIT
y = 0.1998 + 0.006x + 4.999e-6x^2 R = 1.00
MEGA WATTS
0
1
2
3
4
5
0
100
200
300
Mega Watts
Column 7

Parameters for 11 - Machine System

Line Data

LINE		IMPEDANCE		
From	To	R (P.u)	X(p.u)	Y-shunt(p.u)
KAPG	CHAN	0.0046	0.0177	0.0021
CHAN	MADA	0.0178	0.0677	0.079
KAPG	MADA	0.0224	0.0855	0.01
MADA	FENI	0.0564	0.2153	0.0253
MADA	FENI	0.0564	0.2153	0.0253
SIKG	MADA	0.0093	0.0355	0.0042
SIKG	MADA	0.0093	0.0355	0.0042
MADA	KULS	0.0070	0.0266	0.0031
SIKG	HALI	0.0088	0.0337	0.004
HALI	KULS	0.0112	0.0426	0.005
KULS	BARU	0.0065	0.0248	0.0029
KULS	BARU	0.0065	0.0248	0.0029
KAPG	BARU	0.0288	0.110	0.0129
KAPG	BARU	0.0288	0.110	0.0129
FENI	COMI	0.0281	0.1071	0.0126
FENI	COMI	0.0281	0.1071	0.0126
COMI	ASMG	0.0333	0.1653	0.018
COMI	ASMG	0.0333	0.1653	0.018
ASMG	GHMG	0.0251	0.0958	0.0112

ASMG	GHMG	0.0251	0.0958	0.0112
ASHG	GHHG	0.0066	0.0327	0.0328
ASHG	GHHG	0.0066	0.0327	0.0328
ASMG	SHAG	0.0299	0.1142	0.0134
ASMG	SHAG	0.0299	0.1142	0.0134
SIDG	GHMG	0.0255	0.0972	0.0114
SIDG	GHMG	0.0255	0.0972	0.0114
GHHG	TONH	0.004	0.02	0.02
GHHG	TONH	0.004	0.02	0.02
GHHG	TONH	0.004	0.02	0.02
GHHG	TONH	0.004	0.02	0.02
MIRP	TONM	0.0084	0.0342	0.0035
MIRP	TONM	0.0084	0.0342	0.0035
POST	MIRP	0.0167	0.0684	0.0069
POST	MIRP	0.0167	0.0684	0.0069
SIDG	POST	0.0135	0.0551	0.0056
SIDG	POST	0.0135	0.0551	0.0056
SIDG	ULLO	0.0088	0.0361	0.0037
SIDG	ULLO	0.0088	0.0361	0.0037
TONH	ISUH	0.021	0.1042	0.1045
TONH	ISUH	0.021	0.1042	0.1045
BHEG	FARI	0.0806	0.238	0.0262
FARI	MPUR	0.0496	0.1465	0.0161
MPUR	BARI	0.0434	0.1282	0.0141
BARI	BAGE	0.0512	0.1512	0.0168
BAGE	GOAG	0.0333	0.0985	0.0099
GOAG	BHEG	0.1252	0.3698	0.0406

GOAG	NOAP	0.0174	0.0513	0.0056
NOAP	JESS	0.0198	0.0586	0.0064
JESS	JHEN	0.0347	0.1025	0.0113
JHEN	BATT	0.0355	0.0989	0.0109
BATT	BHEG	0.0174	0.0513	0.0056
BHEG	ISUM	0.0074	0.022	0.0022
BHEG	ISUM	0.0074	0.022	0.0022
BOGG	ISUM	0.0788	0.2329	0.0235
BOGG	ISUM	0.0788	0.2329	0.0235
ULLO	TONM	0.0112	0.0456	0.0048
ULLO	TONM	0.0112	0.0456	0.0048
SIDG	COMI	0.0508	0.1912	0.0334
SIDG	COMI	0.0508	0.1912	0.0334
ASMG	ASHG	0.0	0.06	0.0
TONM	TONH	0.0	0.05	0.0
GHMG	GHHG	0.0	0.06	0.0
ISUM	ISUH	0.0	0.03	0.0