2.4. Project Implementation Programme

(1) As discussed in the foregoing Sections, if the problems associated with the submerged agricultural plantations in the upstream area are settled successfully, this Project should be developed since there are no other major detrimental environmental impacts, and the economic status is sound. In line with this policy, the implementation programme for the project is described hereunder.

(2) This feasibility grade design is supported by the results of the following field investigations.

(a) Topographical survey

Reservoir area :	Aerophoto maps of 1979 with a scale of 1/10,000 covering an area of about 346 km^2 (28 sheets)
Main dam, spillway, diversion tunnels, waterways and powerhouse:	Surveyed maps of 1987 with a scale of 1/500 covering an area of 1.9 km^2 (30 sheets)
Saddle dams I and II:	Surveyed maps of 1987 with a scale of 1/500 covering an area of 0.4 km^2 (8 sheets)
Quarry site:	Surveyed maps of 1987 with a scale of 1/500 covering an area of 0.9 km^2 (17 sheets)
River cross section in the downstream river channel below the dam:	Cross section profiles of 1987 with a vertical scale of 1/100 and a horizontal scale of 1/500 covering the river course for about 30 km (30 sections)
Datum point survey for main and Saddle dam sites, and quarry site:	Datum points (8 points) installed in 1987

(b) Boring investigation (1987)

Main dam	:	3 holes,	190 m
Spillway	:	3 holes,	130 m
Powerhouse	:	1 hole,	20 m
Saddle dam I	:	4 holes,	160 m
Saddle dam II	:	2 holes,	55 m
Quarry site	:	4 holes,	160 m
Borrow area (granitic)	:	2 holes,	40 m
Reregulating pondage	:	3 holes,	30 m
Total	:	22 holes,	785 m

(c) Seismic prospecting (1987)

Main dam	:	3 lines,	1,621 m
Saddle dam I	:	1 line,	506 m
Quarry site	:	3 lines,	2,109 m
Total	:	7 lines,	4,236 m

(d) Laboratory test

Rock material tests	:	Uniaxial test (18 samples)
		Stability test (3 samples)
Soil material tests	:	Granitic material (7 samples)
		Conglomeratic material (1 sample)
		Tuffaceous sand stone material (5 samples)
		Sediment material (3 samples)
		Total 16 samples

(3) The field investigations detailed above are considered appropriate for the level of feasibility design, however, further field investigation as given below will be required for the detail design stage.

(a) Topographic survey

Preparation of aerialphotogrametric map (S=1/10,000)	: 410 km^2
Preparation of survey map (S=1/500)	: 1.0 km^2
Route survey of transmission line	: 7 km

(b) Boring investigation : 104 holes, 4,300 m

(c) Geological investigation by adits: 7 adits, 360 m

(d) Laboratory, testing of materials : rock, soil materials, concrete and water

(e) Hydraulic model test : Spillway (1 unit)
Power intake (1 unit)

(4) Field investigation will also be required for the design of preparatory works to be carried out by others. These works are:

(a) Access road : 3 km

(b) Relocation of timber transportation road : 8 km

(c) Power transmission line for construction use: 66 km

(d) Owner's base camp facilities: 2,500 m^2 (Building only)

(e) Telecommunication facility : 1 unit

(5) For the investigation, planning, design and training associated with the environmental measures, the following items will be required to be carried out:

(a) Suspension of the development of agricultural plantations within the proposed reservoir area, and the investigation of the alternative candidate sites for such plantations. Implementation of the relocation programme.

(b) Development of an aquaculture industry and implementation of a pilot project.

(c) Training for environmental measures.

(d) Detail field investigation for fauna and flora.

(e) Clear felling of the forest within the impoundment area.

(f) Investigation and planning of the forest reserve for preservation of the reservoir bank, and implementation of afforstation.

(g) Detailed field investigation of sedimentation.

(h) Monitoring (water quality and public health).

(i) Compensation for inundation. Establishment of inventory and criteria for compensation rates.

(j) Relocation of the roads within the proposed reservoir area.

(k) Construction of a fish ladder.

(l) Construction of re-regulating pondage.

(m) Installation of hydrological telemetering and discharge warning systems.

(6) Detail design is scheduled to be carried out within a 21 months period based on the concepts set out below. The environmental measures should not however be limited to the period of detail design. Some items will be completed during the overall period up to Project completion, and others will continue after this time.

	Work Item	Implemented by	With assistance of
(a)	Field investigation	Local consultant	Foreign consultant
(b)	Detail design for the main works	Foreign consultant	Local consultant
(c)	Preparation of the tender documents for the main works	"	"
(d)	Prequalification of the tenderers for the main works	"	"
(e)	Design and preparation of the tender documents for the preparatory works	Local consultant	-
(f)	Supervision of the preparatory works	Project owner	Local consultant
(g)	Environmental measures	"	Foreign and local consultants

The following summarises the engineering cost required for the detail design (contingency exclusive).

Work Item	Local Currency	Foreign Currency	Total
	10^3M$	10^3M$	10^3M$
Field investigation	4,886	-	4,886
Detail design	1,149	5,988	7,137
Total	6,035	5,988	12,023

(7) Tendering for the main works will be by International Competitive Bidding, following the prequalification of tenderers. A programme time of 19 months has been allowed from the time of issue of tender documents to the signing of the Contract.

Tender period	3 months
Tender evaluation and determination of the successful tenderer	9 months
Contract negotiation	7 months
Total	19 months

(8) Preparation of the construction drawings for the main works will be commenced immediately after tender opening, and is planned to be completed within 16 months.

(9) The estimated quantities of the major items of the main work are tabulated as below:

Excavation, common	$5.3 \times 10^6 m^3$
Excavation, rock	$1.5 \times 10^6 m^3$
Embankment, rock	$4.0 \times 10^6 m^3$
Embankment, earth	$1.4 \times 10^6 m^3$
Excavation, tunnel	$240 \times 10^3 m^3$
Explosive material	2,500 tons
Concrete	$300 \times 10^3 m^3$
Cement	130×10^3 tons
Re-bar	12,800 tons
Metal work	3,100 tons

(10) The construction period necessary for completion of the main works is estimated to be 50 months.

The schedule from the commencement of detail design to the completion of construction works is as follows:

(a)	Detail design	21 months
(b)	Tender and contract	19 months
(c)	Construction supervision	50 months
	Total	90 months

Note: 1. Construction supervision includes:

(a) Civil construction up to Completion
(b) Erection and commissioning of plant

It does not include supervision of civil or electro-mechanical work during Maintenance periods (i.e. following Completion and following Taking-Over).

2. Some additional provision will be necessary to cover engineering supervision during the Maintenance period following final civil works completion, and similarly for electro-mechanical works.

The total engineering cost (without contingency) required preparation for construction, erection and commissioning supervision (including the services for construction drawings and during the tender and contract periods) is given below. The construction supervision is planned to be carried out by the foreign consultant in association with the local consultant.

Work Item	Local Currency 10^3M$	Foreign Currency 10^3M$	Total 10^3M$
Construction supervision	6,651	32,182	38,833

(Excluding Contingencies)

Table 1 Main Features of the Lebir Dam (Multi-purpose)

Location	: Ulu Kelantan District, Kelantan State
River	: Lebir River, of the Kelantan River System
Location of the main dam:	37 km upstream of Kuala Kerai where the Lebir River joins the Galas River, i.e. 3 km upstream of Tualang Bridge (Gua Musang-Kuala Kerai Highway).
Riverbed Elevation	: EL. 24.0 m
Hydrological Data	: Drainage area 2,474 km^2
	Annual mean flow 112.6 m^3/s (average of 1950 to 1984)
	Minimum flow (April, - dry season) 51.1 m^3/s (average of 1950 to 1984)
	Maximum flood recorded 4,200 m^3/s (1967)
	Design flood discharge of the dam (10,000 year return) 10,600 m^3/s
	50 year return flood 5,260 m^3/s
	Annual precipitation in the catchment area 2,250 mm

Reservoir:

Items	Water Level (EL, m)	Reserved Capacity ($10^6 m^3$)	Submerged Area (km^2)
Design flood water level	88.1	3,955	226
Surcharge water level	84.9	3,276	195
High water level for generation	80.0	2,392	154
Low water level for generation	60.0	502	46
Emergency low water level	50.0	167	21
Design silt level	47.0	117	15

Geology:	Dam foundation	- Tuff, tuffaceous sand stone and conglomerate	
	Quarry site	- Tuff	
Inundation	:	Maximum area submerged (WL 88.1 m)	22,600 ha
		Forest	7,900 ha
		Agricultural plantation	14,700 ha
		People to be relocated	4,694 persons
		Lebir riverine settlers	500 persons (100 households)
		Settlers in the land development area	4,050 persons (675 households)
		Orang Asli	144 persons
Compensation for Resettlement	:	Agricultural plantation	10,000 ha
		Lebir riverine settlement	809 ha
		Orang Asli settlement	22 ha
		Population to be relocated	4,694 persons (775 households)
		Relocation road	75 km
Environmental Countermeasures	:	Installation of hydrological telemetering and discharge warning system	1 set
		Re-regulating pondage	
		Dam height	5.4 m
		Elevation of overflow sill	EL.25.4 m
		Reserved capacity	870,000 m^3
		Fish ladder (tentative plan)	750 m
		Forest reserve for preservation of the reservoir bank erosion	

Power Scheme :

High water level (HWL)	:	EL.80.00 m
Low water level (LWL)	:	EL.60.00 m
Effective depth and storage for power generation	:	20 m, 1,890 x $10^6 m^3$ (211 GWh, amount converted in terms of energy)
Tailrace water level (tailrace channel end)	:	EL.28.00 m
Maximum gross head	:	52.00 m
Maximum effective head	:	49.66 m
Firm/peak water discharge	:	80/640 m^3/s
Internal diameter, length and number of pressure tunnels	:	8.6 m, 202.8 m x 2 lines
Turbines	:	Vertical shaft Kaplan (125 rpm), 2 units x 136,800 kW, Maximum discharge of 640 m^3/s 320 m^3/s x 2 units
Generators	:	A three-phase, synchronous and enclosed type with a vertical shaft and damper windings, 2 units x 149,000 kVA
Voltage and length of the related transmission line	:	275 kV and 7 km
Annual possible generation	:	373.3 GWh
Maximum output	:	267.6 MW
Annual mean maximum output (Average of 35 years)	:	240.5 MW
Annual mean inflow	:	112.6 m^3/s (396 GWh, amount converted in terms of energy)
Specific cost for power facilities	:	262.2 x 10^6M$
Annual mean benefit (1987 price)	:	M$63.8 x 10^6

Flood Control Scheme :

Crest elevation of dam	:	EL.92.0 m
Design flood discharge (10,000 year return)	:	10,600 m^3/s

Design flood water level	:	EL.88.1 m
Base flood discharge (50 year return)	:	5,250 m^3/s
Surcharge water level (in case of 50 year flood)	:	EL.84.9 m
Peak discharge	:	2,950 m^3/s
Maximum flood discharge in the past (1967)	:	4,200 m^3/s
High water level for generation	:	EL.80.0 m
Flood control capacity		
EL.84.9 - EL.80	:	884 x $10^6 m^3$
EL.88.1 - EL.80	:	1,563 x $10^6 m^3$
Type of spillway	:	Free overflow chute type
Overflow sill elevation	:	EL.80.0 m
Overflow sill width	:	150.0 m
Flood mitigation benefit (2000 level, 1987 price)	:	16.98 x 10^6 M$
	:	27.3 x 10^6 M$ (Basin-Wide Study base)

Agricultural Irrigation Scheme:

Possible irrigable area (including the existing areas and the new projects)	65,326 ha
Water requirements based on the existing programme (excluding the regulation by the Lebir dam)	
Irrigation water suply	90 m^3/s
Domestic and industrial water supply	20(5) m^3/s
Residual flow for saline abatement	80 m^3/s
Total	190 (175) m^3/s

Figures in brackets are extracted from Kemasin-Semarak Study

10 year draught discharge at Guillemard Bridge	95 m^3/s
Daily firm rate of discharge of the Lebir dam*	80 m^3/s
Emergency discharge of the Lebir dam**	335 x $10^6 m^3$ (50 m^3/s x 77 days)
Specific cost for irrigation facilities (1986 price)	M$160.4 x 10^6

Net agricultural benefit (Case 5) on the annual average (Economic price of 1999 to 2049)	M$15.0 x 10^6

* At times when the discharge is made at 640 m^3/s over a period of 3 to 4 hours (after reservation of flow in the reservoir is made), the corresponding flow at the pumping station for irrigation 90 km downstream will still remain in the allowable range of 70 to 80 m^3/s, due to the modulating effect of the river course. (Refer to Section 11.12.1.)

** Emergency discharge of 45 to 80 m^3/s up to 335 x $10^6 m^3$ reserved between LWL 60 m and WL 50 m is possible through the bottom outlet (inlet sill level of EL.50 m).

Main Dam :

Type	:	Rockfill with center earth core
Crest elevation	:	EL.92 m
Dam height	:	73 m
Crest length	:	638 m
Slope of the upstream face	:	1 : 1.85 (EL.59 m with a berm width of 12.5 m)
Slope of the downstream face	:	1 : 1.75 (EL.40 m with a berm width 10.0 m)
Bottom length of the dam	:	265 m
Bottom elevation of the dam	:	EL.19.0 m
Foundation rock	:	Green and purple tuff
Dam volume	:	2,900,000 m^3 (including 392,000 m^3 of core)

Saddle Dam I

Type	:	Rockfill with center earth core
Crest elevation	:	EL.92.0 m
Dam height	:	67 m
Crest length	:	448 m

Slope of the upstream face	:	1 : 1.85 (EL.59 m with a berm width of 10 m)
Slope of the downstream face	:	1 : 1.75
Bottom length of the dam	:	218 m
Bottom elevation of the dam	:	EL.25.0 m
Foundation rock	:	Tuffaceous sand stone and conglomerate
Dam volume	:	1,532,000 m^3 (including 261,000 m^3 of core)

Saddle Dam II

Type	:	Earthfill
Crest elevation	:	EL.92.0 m
Dam height	:	37 m
Slope of the upstream face	:	1 : 3.5 (EL.67 m with a berm width of 10 m)
Slope of the downstream face	:	1 : 3.0
Foundation rock	:	Weathered tuff, tuffaceous sand stone and intrusion meta-dacites
Dam volume	:	742,000 m^3 (including 89,000 m^3 of core)

Spillway:

Type	:	Ungated concrete free overflow chute type
Overflow sill elevation	:	EL.80.0 (HWL for generation)
Overflow sill width	:	150 m
Length of chute	:	270 m (Overflow weir to bucket)
Chute width	:	95.0 m
Stilling basin	:	Bucket type (upper level of EL.29 m and lower level of EL.26 m)

Design flood discharge	:	10,600 m^3/s (10,000 year return flood)
Spillway capacity	:	6,400 m^3/s
Concrete volume	:	122,000 m^3

Diversion Tunnel :

Type	:	Tunnel
Planned flood discharge	:	5,260 m^3/s
Section	:	Circular reinforcing concrete Inside dia. 12.0 m x 2 lines
Length	:	585 m (No.1 Tunnel) and 576 m (No.2 Tunnel)
Intake sill elevation	:	EL.29.0 m
Outlet sill elevation	:	EL.26.0 m
Slope	:	0.51% (No.1 Tunnel) and 0.52% (No.2 Tunnel)
Discharge capacity	:	3,250 m^3/s (WL.58.3 m)
Geology	:	Green tuff
Concrete volume	:	80,000 m^3

Bottom Outlet :

Location	:	Inside the diversion tunnel No.1
Type/diameter	:	Jet flow gate type, diameter of 2.0 m
Intake level	:	EL.50.0 m
Discharge capacity	:	Maximum 84.0m^3/s and Minimum 46.0m^3/s at WL 50 m

Power Intake :

Type	:	Side intake (Inclined type)/Gate shaft
Intake volume	:	320 m^3/s per gate

No. of intake	:	2
Intake sill level	:	EL.48.0 m
Size of intake portal	:	Width 15.0 to 13.3 m Height 11.6 m
Gate shaft	:	Upper level EL.92.0 m Inside dia. 12.0 m
Gate	:	Two main gates 8.6 m wide x 8.6 m high Two maintenance gates 8.6 m wide x 8.6 m high
Concrete volume	:	12,000 m^3

Pressure Tunnel :

Type	:	Circular reinforced concrete tunnel (partially embedded steel penstock)
No. of tunnels	:	2
Inside diameter	:	8.6 m to 7.4 m
Length	:	196.8 m (No.1) and 208.8 m (No.2)
Steel weight	:	920 ton
Concrete volume	:	8,000 m^3

Powerhouse :

Type	:	Above ground type
Size	:	29 m wide, 73 m long and 59 m high
Foundation level	:	EL.45.0 m
Turbine center level	:	EL.21.1 m
Tailrace yard water level	:	EL.28.78 m (Maximum discharge of 640 m^3/s)
Lowest foundation level	:	EL.3.0 m
Foundation rock	:	Green tuff

Turbine	:	Vertical shaft Kaplan (125 rpm), 2 units x 136,800 kW Maximum discharge of 640 m^3/s 320 m^3/s x 2 units
Generator	:	A three-phase, synchronous and enclosed type with a vertical shaft and damper windings, 2 units x 149,000 KVA
Main transformer	:	Outdoor type transformer 275 kV, 149,000 kVA x 2 units
Concrete volume	:	74,000 m^3

Tailrace :

Type	:	Open type waterway, rectangular section with a concrete lining
Length	:	Tailrace bay 40 m, tailrace channel 499 m
Width	:	Invert width of 20.0 m and sidewall gradient of 1 : 1
Tailrace end level	:	EL.21.0 m
Waterway slope	:	1/3,000
Water depth	:	7.0 m (Maximum discharge of 640 m^3/s)
Concrete volume	:	12,000 m^3

Switchyard :

Type	:	Outdoor type
Ground level	:	EL.53.0 m
Size of switchyard	:	89 m wide x 124 m long
Voltage	:	275 kV
Bus configuration	:	Double bus
No. of outgoing circuits	:	4 circuits

Associated Transmission Line :

Voltage	:	275 kV
No. of circuits	:	Double circuit
Total length	:	7 km

Project Cost :

	$x10^6$M$
Preparatory work	13.4
Civil work	251.5
Metal work	21.6
Electro-mechanical work	148.9
Environment	134.8
Detailed design	13.2
Construction supervision	42.7
Owner's administration	14.0
Total	640.1 (including contingency)

Local cost	M$ 325.2 million
Foreign cost	M$ 314.9 million

Economic Feasibility :

	EIRR %		FIRR %
Power	8.6	(below 6)	20
Power + Flood Control	12.8	(10.7)	-
Power + Flood Control + Agricultural Irrigation	13.9	(12.4)	-

Dam construction cost per m^3 of the reserved capacity : M$0.10/$m^3$

Figures in brackets of EIRR are the calculation results using the alternative fuel cost of NEB purchase base.

3. Background of the Project

3. Background of the Project

3.1. Topography and Geology of the Project Area

3.1.1. Topography

Peninsular Malaysia forms the continuation of two backbone mountain ranges extending from north-northwest to south-southeast, and has long and narrow lowlands between and on both sides of the mountain ranges, as shown in Fig.3-1.

The western mountain range has 2,000 m class peaks of which G. Korbu (2,183 m) is the highest, while the eastern mountain range has lower peaks with altitudes of 1,000 m to 1,500 m. G. Mandi Angin (1,459 m) is the highest of these.

The oval-shaped central lowland, is between the backbone mountain ranges, and extends for some 150 km from Gua Musang, the southern-most tip with a width of some 40 km in the widest zone. The Lebir River is one of the largest rivers in the northeastern region of the Peninsula, running almost directly towards a north-northwest direction along the western edge of the eastern mountain range.

The Lebir River joins the Galas River (The Nenggiri River on the upper reaches) at Kuala Kerai, to create the Kelantan River, which flows into the South China Sea at Kota Bharu. The catchment area at the proposed dam site is 2,474 km^2.

3.1.2. Geology

According to the available geological data, general geological distributions and structures of Peninsular Malaysia are as shown in Fig.3-2.

The dominant geological trend of the Peninsula is from north-northwest to south-southeast, and is the same as the topographical trend.

Mountain ranges in the Peninsula consist mainly of granite, which intruded several times into sedimentary rocks and pyroclastic rocks of the Mesozoic and Palaezoic during many periods from late Cretaceous to early Tertiary. Lowlands in the Peninsula, on the other hand, are comprised chiefly of sedimentary rock groups, pyroclastic rock groups and lave groups, which are believed to be of the Palaeozoic Permian through the Mesozoic Jurassic. Rock groups of the Quarternary are widely found along the coast line of the Peninsula.

Sedimentary rocks consist mainly of sands, quartzose sandstones, shales and conglomerates which are alternately interbedded. Pyroclastic rocks consist predominantly of tuffs, tuff breccias and lapilli tuffs. In addition, limestones and acidic and intermediate lavas exist locally. Granite groups consist mainly of granite and granodiorites.

3.2. Meteorological and Hydrological Conditions in the Project Area

3.2.1. Meteorological Conditions

Northeast and southwest monsoons greatly affect weather conditions in Kelantan State.

Peninsular Malaysia has four seasons in a year, two monsoon seasons, and two intermediate seasons in between. Climatic phenomena, such as temperature, humidity, sunshine, rainfall, etc. vary according to the seasons.

Generally, the southwest monsoon season starts from late May or early June and ends in September. After a further two months, the northeast monsoon season starts from late October or early

November and ends in March. After another two months, the southwest monsoon season starts again.

During the northeast monsoon season of October through March, the temperature is relatively low in general with less sunshine and much rainfall on the east coast of Peninsular Malaysia, including Kelantan State. Changes in temperature are not so distinct. In contrast, climatic conditions in the southwest monsoon season normally show a reverse trend.

According to the observation records taken from 1968 to 1972, the annual mean temperature at Kota Bharu is 26.9°C. The maximum mean temperature is 28.1°C in May and minimum mean temperature is 25.9°C in January. The difference between the maximum mean temperature and the minimum mean temperature is only 2.2°C. There is not a great variation in temperature throughout the year. The daily change in temperature is relatively large, however and the minimum temperature being about 24°C at around 6 o'clock in the morning, and the maximum temperature of about 30°C is reached at around 1 o'clock in the afternoon. The mean temperature difference between the maximum and minimum exceeds 6°C. In a period of five years from 1968 to 1972, the highest temperature recorded was 36.7°C and the lowest temperature 18.3°C. The mean relative humidity during the same 5 years is a high value of 80.7%. Every year, the minimum relative humidity is 79.1% in March and the maximum relative humidity is 82.2% in November. The difference in relative humidity between the maximum and the minimum was only 3%. There is a greater daily variation than seasonal relative humidity variation. As with the change in temperature, the maximum relative humidity is about 94% around 6 o'clock in the morning and the minimum is about 68% from the noon time to 1 o'clock in the afternoon; thus there is a variation of 26%.

The daily mean sunshine per year is 7.03 hours; the shortest time is less than 5 hours in November and December, and the longest time 8.7 hours is in the intermonsoon season of March and April. In this connection, statistics indicate that there are 182 days of rainfall a year, which means rain every 2 days. There seems no remarkable correlation between the seasons and rainy days. The mean values show that there is little seasonal variation in rainy days.

3.2.2. Precipitation

The east coast of Peninsular Malaysia, including Kelantan State, has plentiful rainfall. Generally, there is an annual mean rainfall of about 3,505 mm on the coastal area and several kilometers inland of the sea coast. However, the annual mean rainfall decreases further inland, reaching about 2,540 mm on the eastern foot of the Central Mountain Range.

The observation record from 1950 to 1975 indicates that the Lebir River Basin belongs to a zone of less rainfall in the Kelantan River Basin. The annual precipitation is in the range of 2,000 mm to 2,250 mm. This is due to the blocking of the northeast monsoon by the coastal mountain range east of the Lebir River Basin. In the monsoon season, from November to March, precipitation on the coastal plain east of the mountain range is nearly 2,000 mm. The precipitation in the Lebir River Basin, however, is only about 1,000 mm.

Fig. 3-3 shows mean monthly rainfalls recorded at typical rainfall gauging stations in the tributaries of the Kelantan River. Rainfall patterns can be classified into three types; the rainfall pattern as recorded at Gua Musang and Bertang on the upper reaches, the 2nd rainfall pattern at Dabong, Bongor and Lalok on the Middle reaches, and the third type at Kota Bharu on the coast.

In Kota Bharu, precipitation is greatest during the northeast monsoon season from October to January, and is very low in other seasons. The least precipitation occurs in February, increasing gradually until the next season of the northeast monsoon. In contrast, the precipitation at Lalok in December, during the northeast monsoon, is much higher than in other months, and it comes down to a minimum in February. This rainfall pattern is similar to that of the coastal area. The precipitation pattern at Lalok shows the same characteristics as at Gua Musang, in that there is one peak in May and another in September.

A diagram showing isohyets for December 1983, December 1984, and November 1986, when there were floods, was prepared by DID as shown on Fig.3-4 to 3-6. According to the figures, precipitation is observed heaviest in Kota Bharu, located at the mouth of the Kelantan River. These figures also show that the Lebir River basin has more precipitation than the Galas River basin.

3.3. Electrical Power Situation in Malaysia

3.3.1. Outline

The share of electricity, gas and water sales in the gross domestic products (G.D.P.) in Malaysia has risen from 1.4% p.a. to 1.7% p.a. during the period from 1980 to 1985, as shown in Table 3-1. It is expected to reach 2% p.a. in 1990.

The average annual growth rate of G.D.P. in Malaysia is shown in Table 3-2, and those for electricity, gas and water sales are in Table 3-3.

Using the above figures, elasticity values of electricity, gas and water sales toward G.D.P. were calculated, and are shown in Table 3-4. As can be clearly seen from Tables 3-2, 3-3 and 3-4, the growth rate of electricity, gas and water sales has been proven sound, irrespective of the economic growth.

On Table 3-5 the actual records of energy demand by source in 1980 and 1985 are shown and the amount needed for 1990 forecast. The power sector occupied a share of 9.3% of the total energy every year from 1980 to 1985 in terms of a converted caloric value. It is further expected to rise to 9.8% in 1990. Consequently, an average annual growth rate of the whole energy demand during a period from 1985 to 1990 is estimated to be 7%, and that for electricity is most likely to be 8.3%. This constitutes a definite tendency of "Shift to Electricity".

Table 3-6 shows the primary supply of energy by source. Crude oil still occupies a rather high share, but its growth rate is predicted as nil. Instead of crude oil, petro-products, natural gas and coal/coke are expected to show a sharp growth rate. The hydro sector (not necessarily limited to power generation) is expected to show a small growth rate.

3.3.2. Power Demand Forecast and Power Revenue

Table 3-7 shows the actual NEB records of the number of power consumers and energy sold by the type of use during the period from 1981 to 1985. In this table, it is found that the industrial sector occupies the biggest share of all the energy sold, followed by the commercial sector, and then domestic use. This order was unchanged throughout the same period. However, the average annual growth rate of all the energy sold remained at 8.4%, because the industrial sector utilized energy at the considerably low rate of 3.7%, although domestic use, the commercial sector and the mining sector represented high rates of 14.7%, 11.4% and 10.2% respectively. Comparing the average annual growth rate of the number of consumers with that of the energy sold, it is found that while the basic units (energy sold/number of consumers) for domestic use and the commercial sector are increasing, the amount for the other sectors is decreasing. The basic unit for all the energy sold shows a decreasing tendency.

Table 3-8 shows the number of consumers, energy sold and power revenue in 1985, under the jurisdiction of the NEB, classified by area and type of consumers in terms of percentage. The energy sold and power revenue show percentages in the twenties in respective areas, except the eastern area where they are less than 10%. The largest share of power revenue is contributed by the industrial sector, followed by the commercial sector and domestic use in third place. This is commensurate to the shares of power sales mentioned above.

Table 3-9 shows a tabulation of changes in average power revenue by the type of consumers during the period from 1981 to 1985. As far as the power tariff per unit sold in 1985 is concerned, public use and lighting are the most expensive at 29.55 cents/kWh followed by the commercial sector of 24.86 cents/kWh, and then by domestic use. The industrial sector and the mining sector, each use approximately 20 cents/kWh. The average tariff per unit for all the energy sold in 1985 comes to 22.26 cents/kWh. The industrial sector recorded the highest average growth rate of the power tariff in the same period of 2.5%, and domestic use recorded the lowest of 1.9%. An average rate for the whole power revenue accounts for 2.4%. Considering the consumer price index for the same period, the average growth rate of which was 3.5%, it may be said that the average power tariff in real terms has been somewhat lowered.

Table 3-10 represents a system load forecast for the NEB's integrated system. The following show average annual growth rates of energy sold, generated energy, and the system peak load and changes in load factors during the periods from 1986 to 1991, 1991 to 1996 and 1986 to 1996:

F/Y	1986/1991	1991/1996	1986/1996
Sales	7.1 %	6.6 %	6.8 %
Generation	7.3 %	6.7 %	7.0 %
System peak load	7.2 %	6.5 %	6.9 %
Load factor	+0.5 %	+0.5 %	+1.0 %

As shown above, the average annual growth rate of the energy sold, generated energy and the system peak load accounts for 7% in the first 5 years, 6% in the second 5 years, and about 7% throughout the entire period. Furthermore, comparing the growth rate of the energy sold with that of the energy generated, the latter is found a little higher. This means an increase of the total loss ratio of the power system. Likewise, the fact that a growth rate of the system peak load is found to be a little bit less than that of the energy generated means a rise of the load factor.

3.3.3. Power Supply Policy and Power Development Program

Table 3-11 shows the generated energy by source recorded for 1980 and 1985, and forecasted for 1990 in terms of a converted calorific value. The oil-fired thermal power plant which occupied the biggest share in 1985 would be, to a great extent, replaced by the gas-fired thermal power plant in 1990, as oil-to-gas fuel conversion would have been further promoted. In addition to this, it is planned to introduce the coal-fired thermal power plant into the power system in an effort to achieve fuel diversification. Hydropower plants are planned to be developed one by one, to share some 20% of the total power generation by 1990. The share of power generation from the primary supply of energy will gradually increase, and is expected to reach about 9%.

Table 3-12 shows the progress of rural electrification. It is found here that the number of households and villages with electricity accounts for a higher growth rate of more than 10% for the period from 1981 through 1985.

Table 3-13 shows records of the generated/purchased energy, sent out energy and energy sold during the period from 1981 through 1985. An average annual growth rate of respective energy accounts for 8%. The station use rate is found at approximately 5%, and the transmission loss is approximately 10%.

Table 3-14 represents an actual record of purchased energy, the amount of which is found very small. Energy purchased, especially after 1983, has been descending to an amount of less than 1.0% of all the sent-out energy to become almost negligible.

Table 3-15 shows installed capacity by source, and the energy generated by source, recorded by NEB from 1981 through 1985, together with relevant plant factors. The thermal power plant, except for the combined cycle, occupies about 40% of the total installed capacity and about 60% of the total energy generated. In each power plant, the thermal power plant accounts for the largest value of 54.0%, followed by the gas-turbine with 34.1%. In view of this, it can be said that the thermal power plant plays a vital role in the base load supply in the current NEB power supply system. Concerning the combined cycle which began operation in December 1984, the plant factor accounts for a rather low value of 20.9% in 1985. However, taking the economic characteristics into account, the combined cycle will never fail to play an important role in the base load supply after 1996.

Table 3-16 exhibits an installed capacity by source and shares of respective sources envisaged by NEB for 1991. The installed capacity of the gas turbine accounts for 72 MW (1.5%) and that of the hydropower plant accounts for 1,284 MW (26.3%) including the Piah new hydropower station. On the other hand, since the fuel-conversion plan is being promoted for most of the existing oil-fired thermal plants, the number of conventional gas-fired thermal plants will increase correspondingly. Consequently, the installed capacity of the oil-fired thermal plants will rapidly decrease to 405 MW (8.3%). The total installed capacity of gas-fired thermal power plants will be at 2,528 MW (51.7%), including those converted from oil-fired and the combined cycle. Furthermore, a coal-fired thermal power plant with a capacity of 600 MW (12.3%) is planned for development. The total installed capacity envisaged for 1991 will be 4,889 MW.

Finally, tabulated below is a comparison of the system peak load and the installed capacity in 1991, and thereafter up to 1995 with no additional capacity installed.

F/Y	System Peak Load (MW) (A)	Installed Capacity (MW) (B)	Ratio B/A
1991	3,207	4,889	1.52
1992	3,440	"	1.42
1993	3,661	"	1.34
1994	3,895	"	1.26
1995	4,142	"	1.18

Considering an allowance in the power load forecast, maintenance outage, forced outage, unusual water shortage,etc., reserve margin is required to cope with the above situation. Depending to some extent upon the characteristics of the power system, the ratio (B/A) is very roughly estimated to be at 1.3% or over. Therefore, some additional capacity should be installed after 1994 at the latest.

- Reference data

  . The Fifth Malaysia Plan (1986 - 1990)
  . Statistical Bulletin (year ending 31 August, 1985) published by National Electricity Board of the States of Malaya)
  . 36th Annual Report (year ending 31 August, 1985) published by National Electricity Board of the States of Malaya)

3.4. Flood Damages in the Lower Reaches of the Kelantan River

The northeast coast of Peninsular Malaysia, influenced by monsoons occurring from November through the following February in the South China Sea, has abundant rainfall with an annual mean precipitation of 2,700 mm. Accordingly, the lower reaches of the Kelantan River in Kelantan State suffer from floods regularly every year. The characteristics of this river basin are as follows:

(1) The downstream river basin of the Kelantan River is in the rainy region.

(2) Generally, there is much precipitation causing floods along the east coast. This decreases further in the inland area.

(3) In the upstream river basin of the Kelantan River, plantation of oil palm has in recent years been developed by FELDA and KESEDAR, and the construction of the Kuala Kerai - Gua Musang Highway has been completed. This is thought to have caused an increase in the sediment discharge into the river, which in turn is a cause of sediment deposit at the Kelantan River mouth.

Increased assets in furnishing the infrastructure also leads to an increase in flood damage (including damage due to landslides, etc.).

(4) Inundation is caused, not only by floods in the Kelantan River, but also by floods in such minor rivers as the Golok River, located on the border with Thailand, the Kemasin River, and the Semerak River, which are on the east coast.

(5) The low level land from Machang to Kota Bharu is, in particular, regularly ravaged by floods.

It is thought that the above characteristics of the Kelantan River basin both bring about flood damage in the lower reaches of the Kelantan River.

During periods of flooding, the trunk roads in the submerged area are paralyzed. Traffic is cut off, and the activities of the local populace are severely disrupted by floods. People are forced to evacuate to, schools, temples, etc., in all parts of the State.

Physical damage is severe to, among other things, crops (rice crop, vegetables, fruit, rubber, tobacco, palm trees, coconuts, etc.) due to inundation and flooding. Cattle and other animals die, and public utilities, roads, bridges, irrigation channels, schools, hospitals, people's houses and buildings in general are badly damaged. Railway lines, telephone and telecommunication systems, power supply system, and water supply system, are also damaged. Many people have also been carried away, and lost because of flooding.

The heaviest flood recorded is thought to have occurred in 1927, but there is no available data on the water level, etc.

The greatest flood since then occurred in January, 1967, and the flooded area was extensive (about 1,700 km^2) as indicated in Fig. 3-8. The population affected by this flood was 536,800 people, which corresponded to 84% of the total population of Kelantan State. About 125,000 of the people were forced to evacuate their homes, and death claimed a total of 38.

3.5. Agriculture in the Downstream Area of the Kelantan River

The total area of 15,042 km^2 of Kelantan State can be topographically divided into the coastal region and the hinterland. Most of the area is in the hinterland. The coastal region represents 2,354 km^2, or 15.6 percent of the total, and the hinterland covers 12,688 km^2 or 84.4 percent.

Kelantan State has ten administrative districts. The seven districts in the coastal region are Kota Bharu, Tumpat, Pasir Mas, Bachok, Pasir Puteh, Machang and Tanah Merah. The hinterland consists of the three districts of Kuala Kerai, Gua Musang and Jeli.

The population in the State for 15 years from 1970 through 1985 has increased from 689,749 in 1970 to 1,026,298 in 1985, and the rate of increase in the last five years has been 2.8 percent, which is more than the 2.6 percent of the rest of Peninsular Malaysia. The population in the State occupies about 7.9 percent of the total of Peninsular Malaysia.

The 1985 population in the coastal region was 898,709 or 87.6% and 127,589 or 12.4% in the hinterland.

The growth rates for the last 15 years were 146 % in the coastal region and 171 % in the hinterland. The socio-economic reasons for the higher growth rate in the hinterland would be the development of cropping acreage of oil palm with the arable land reclamation policy promoted by the Government, and the increased mobility of the population as a result of the construction of the highway.

The population of 898,709 in the coastal region is broken down to 325,399 in Kota Bharu, 141,282 in Pasir Mas, 103,173 in Tumpat, 97,373 in Pasir Puteh and 88,736 in Bachok. Kota Bharu has the largest population of the coastal region. According to the 1980

Population Census, about 70 % of the population that immigrated into Kota Bharu originated from the four districts of Pasir Mas, Tumpat, Pasir Puteh and Bachok. Conversely, according to the same Census, about 60 percent of the population that immigrated into Kuala Kerai and Ulu Kelantan originated from the four districts of Kota Bharu, Pasir Mas, Pasir Puteh and Bachok. The five districts mentioned above are considered to be the areas chronically damaged by flooding.

The following table shows the trends of cropping areas from 1976 to 1984. For these nine years, the cropped acreages of oil palm, fruits and Virginia tobacco have increased, but on the other hand, of paddy, peanuts, water melon and short-term crops of chili, etc. have all decreased.

- Trend of the Cropped Acreage -

(unit: ha)

Crop	1976 Coastal Region	1976 Hinter-land	1976 Total	1984 Coastal Retion	1984 Hinter-land	1984 Total
Permanent Crops						
Rubber	71,493	46,209	117,702	67,616	48,532	116,148
Coconut	17,820	693	18,513	17,076	614	17,690
Oil-palm	4,953	6,579	11,532	9,669	27,471	37,140
Fruits	4,372	1,109	5,481	6,205	2,439	8,644
Others	1,127	58	1,185	524	198	722
Food Crops						
Paddy	72,580	753	73,333	20,432	573	21,005
Corn	724	157	881	577	99	676
Pineapple	574	64	638	526	109	635
Banana	1,283	1,092	2,375	1,392	1,348	2,740
Tapioca	545	51	596	213	22	235
Vegetable	1,075	90	1,165	1,708	153	1,861
Groundnuts	2,785	164	2,949	659	59	718
Watermelon	1,568	68	1,636	824	52	876
Others	957	153	1,110	1,128	116	1,244
Short Term Crops						
Chili & Others	839	110	949	324	90	414
Virginia Tobacco	4,674	53	4,727	6,846	-	6,846
Others	108	9	117	360	-	360
Total	187,477	57,412	244,889	136,079	81,875	217,954

Source: SEPU, Kelantan

The total area cropped in the coastal region of the State has decreased from 76.6 % in 1976 to 62.5 % in 1984. Such a decrease could be attributable to a reduction in the acreage cropped with paddy in the coastal region and an increase in the oil palm acreage in the hinterland. The main reasons for the decrease in the cropped acreage of paddy in the coastal region are considered to be damages from flooding, which has frequently occurred in recent years, a decline in the paddy growers' enthusiasm, due to their anxiety about flooding, and an outgoing of farm labour to gain non-farm income, leading to an increase in idle lands. Naturally, there are other reasons.

A great proportion of the paddy fields in the coastal region comprise 31,800 ha of the KADA Project Area, and 15,000 ha in the Kemasin-Semerak Project Area. The KADA Project has been implemented under the Fourth and Fifth Malaysia Plan, which was implemented since 1972.

The Kemasin-Semerak Project is to be implemented in the framework of the Integrated Agricultural Development Project, IADP. During the Fifth Malaysia Plan, Kemasin IADP is to be completed, and each IADP of Semerak, Sg. Golok, Sg. Nal/Sg. Sokor will be started.

According to the Fifth Malaysia Plan, GDP per capita in the Kelantan State amounts to 1,740 M$ (1978 price). This value is only 46 % of the average GDP per capita value in Malaysia. The first industry's share in GDP in the Kelantan State decreased from 43 % in 1980 to 39 % in 1985. As a greater part of GDP in the agricultural sector depends upon the production amount in the coastal region, the revitalization of agricultural production there will be a problem to be solved in the future.

In particular, the Fifth Malaysia Plan directs the future production of rice. Future production efforts will be concentrated in the granary area. The production of paddy in the existing paddy field outside these granary areas will be gradually phased out and replaced by other more remunerative crops. Kemubu and Kemasin-Semerak in Kelantan State are directed as the granary area mentioned above.

Crop commercialization to be promoted in the existing paddy field located in the non-granary area will contribute to the vitalization of agricultural production in the coastal region.

Table 3 - 1 Share of Electricity, Gas and Water (EGW) Sales in GDP

F.Y.		1980	1981	1982	1983	1984	1985	1986
EGW*		640	689	721	798	890	988	1,513
GDP*		44,702	47,790	50,456	53,636	57,706	59,344	75,599
Share of EGW	(%)	1.4	1.4	1.4	1.5	1.5	1.7	2.0

* Note : US$ x 10^6, 1978 Price Level

Reference : (A)

Extent : Nation-wide

Table 3 - 2 Average Annual Growth Rate of GDP

Unit : %

From / To	1980	1981	1982	1983	1984
1981	6.9	-	-	-	-
1982	6.2	5.6	-	-	-
1983	6.3	5.9	6.3	-	-
1984	6.6	6.5	6.9	7.6	-
1985	5.8	5.6	5.6	5.2	2.8

* Note

Reference : (A)

Extent : Nation-wide

Table 3 - 3 Average Annual Growth Rate of EGW

Unit : %

From / To	1980	1981	1982	1983	1984
1981	7.7	-	-	-	-
1982	6.1	4.6	-	-	-
1983	7.6	7.6	10.7	-	-
1984	8.6	8.9	11.5	11.5	-
1985	9.1	9.4	11.3	11.3	11.0

* Note

Reference : (A)

Extent : Nation-wide

Table 3 - 4 Elasticity of EGW toward GDP

Unit : %

From / To	1980	1981	1982	1983	1984
1981	1.12	-	-	-	-
1982	0.98	0.82	-	-	-
1983	1.21	1.29	1.70	-	-
1984	1.30	1.37	1.61	1.51	-
1985	1.57	1.68	1.98	2.17	3.93

* Note

Reference : (A)

Extent : Nation-wide

Table 3 - 5 Energy Demand by Source

F.Y.	1980 PJ	1980 (%)	1985 PJ	1985 (%)	1990 PJ	1990 (%)	Average Growth Rate (85/90)(%)
Petroleum Products	232.2	(69.6)	318.5	(66.8)	432.8	(64.7)	6.3
Electricity	30.9	(9.3)	44.1	(9.3)	65.8	(9.8)	8.3
Coal and Coke	0.9	(0.3)	18.1	(3.8)	39.0	(5.8)	16.6
Charcoal	8.8	(2.6)	8.5	(1.8)	8.3	(1.2)	Δ0.5
Gas	0.9	(0.3)	11.6	(2.4)	18.4	(2.8)	9.7
Fuel Wood	33.4	(10.0)	37.6	(7.9)	57.2	(8.6)	8.8
Palm Oil Wastes	26.3	(7.9)	38.3	(8.0)	47.4	(7.1)	4.4
Total	333.4	(100.0)	476.7	(100.0)	668.9	(100.0)	7.0

* Note: PJ = Petrajoule = 10^{15} Joule

Reference : (A)

Extent : Nation-wide

Table 3 - 6 Primary Supply of Energy

F.Y.	1980 PJ	1980 (%)	1985 PJ	1985 (%)	1990 PJ	1990 (%)	Average Growth Rate (85/90)(%)
Crude Oil	246.9	(55.1)	360.2	(53.0)	360.2	(41.7)	0
Petroleum Products	97.4	(21.8)	60.7	(8.9)	102.0	(11.8)	10.9
Natural Gas	2.3	(0.5)	122.8	(18.1)	179.5	(20.8)	7.9
Hydro Power	16.2	(3.6)	19.4	(2.9)	20.7	(2.4)	1.3
Coal and Coke	2.2	(0.5)	19.3	(2.8)	74.9	(8.7)	31.2
Charcoal	3.0	(0.7)	-	-	-	-	-
Fuel Wood	53.5	(11.9)	58.9	(8.7)	78.0	(9.0)	5.8
Palm Oil Mill Wastes	26.3	(5.9)	38.3	(5.6)	47.8	(5.6)	4.5
Total	447.8	(100.0)	679.6	(100.0)	863.1	(100.0)	4.9

*Note

Reference : (A)

Extent : Nation-wide

Table 3 - 7 Number of Consumers and Energy Sold by Category

F.Y.	1981	1982	1983	1984	1985	Average Growth Rate (81/85) (%)
No. of Consumers						
Domestic	1,180,866	1,316,127	1,548,599	1,687,594	1,832,406	11.6
Commercial	204,175	216,351	250,649	270,033	284,165	8.6
Industrial	2,993	2,962	4,175	4,041	4,274	9.3
Mining	61	58	538	485	434	63.3
Public & Lighting	2,033	2,149	2,820	3,009	3,397	13.7
Total	1,390,128	1,537,647	1,806,781	1,965,162	2,124,676	11.2
Sold Energy (GWh)						
Domestic	1,301.6	1,457.0	1,804.1	2,000.2	2,249.2	14.7
Commercial	2,333.1	2,517.6	2,876.7	3,165.6	3,590.7	11.4
Industrial	3,814.5	4,033.1	3,793.0	4,170.4	4,419.3	3.7
Mining	284.8	285.3	487.9	462.9	420.2	10.2
Public & Lighting	68.8	74.9	85.5	94.4	100.9	10.1
Total	7,802.8	8,367.9	9,047.2	9,893.5	10,780.3	8.4

*Note

Reference : (B)

Extent : NEB

Table 3 - 8 Number of Consumers, Energy Sold and Power Revenue by Area and Type of Consumers in 1985

(Unit: %)

Area	No. of Consumers	Energy Sold	Power Revenue
Eastern	19.7	7.8	8.2
Southern	24.9	20.2	20.1
Selangor	12.8	22.5	21.9
Federal Territory	14.5	23.2	24.1
Northern (including Perak)	28.1	26.3	25.7
Total	100.0	100.0	100.0
Types of Consumers			
Domestic	86.2	20.9	20.1
Commercial	13.4	33.3	37.2
Industrial	0.2	41.0	38.1
Mining	-	3.9	3.4
Public & Lighting	0.2	0.9	1.2
Total	100.0	100.0	100.0

* The share of power revenue by type of consumers was calculated with reference to the energy sold on Table 3-7 and the average revenue on Table 3-9.

*Note

Reference : (C)

Extent : NEB

Table 3 - 9 Average Power Revenue by Type of Consumers

Unit : cents/kWh

F.Y.	1981	1982	1983	1984	1985	Average Growth Rate (81/85) (%)
Types of Consumers						
Domestic	19.88	21.40	21.42	21.38	21.41	1.9
Commercial	22.98	24.88	24.91	24.89	24.86	2.0
Industrial	18.70	20.43	20.72	20.68	20.66	2.5
Mining	18.02	19.49	19.52	19.36	19.58	2.1
Public & Lighting	27.01	29.04	29.29	29.45	29.55	2.3
Total	20.22	21.98	22.20	22.19	22.26	2.4

*Note

Reference : (B)

Extent : NEB

Table 3 - 10 NEB Load Forecast 1987

Demand Forecast, Normal Scenario

Year	Total Sales Twh	LLN Sales TWh		LLN Integrated System Generation TWh	Peak Load MW	
1986*	11.890	11.421		13.236	2268	
1987	12.663	12.365	(8.26)	14.376	2460	(8.46)
1988	13.442	13.167	(6.49)	15.349	2622	(6.61)
1989	14.285	14.033	(6.57)	16.397	2797	(6.67)
1990	15.191	14.962	(6.62)	17.520	2984	(6.69)
1991	16.277	16.071	(7.41)	18.856	3207	(7.47)
1992	17.416	17.233	(7.23)	20.256	3440	(7.27)
1993	18.499	18.338	(6.42)	21.588	3661	(6.42)
1994	19.648	19.511	(6.39)	22.999	3895	(6.38)
1995	20.869	20.754	(6.37)	24.495	4142	(6.35)
1996	22.166	22.074	(6.36)	26.081	4404	(6.32)
1997	23.543	23.474	(6.34)	27.763	4681	(6.29)
1998	25.007	24.961	(6.33)	29.547	4975	(6.27)
1999	26.563	26.540	(6.32)	31.440	5286	(6.25)
2000	28.216	28.216	(6.32)	33.449	5615	(6.24)
2001	29.935	29.935	(6.09)	35.486	5957	(6.09)
2002	31.758	31.758	(6.09)	37.647	6320	(6.09)
2003	33.691	33.691	(6.09)	39.940	6705	(6.09)
2004	35.745	35.743	(6.09)	42.372	7113	(6.09)
2005	37.920	37.920	(6.09)	44.952	7546	(6.09)
2006	40.135	40.135	(5.84)	47.578	7987	(5.84)
2007	42.480	42.480	(5.84)	50.357	8454	(5.84)
2008	44.961	44.961	(5.84)	53.295	8948	(5.84)
2009	47.588	47.588	(5.84)	56.413	9470	(5.84)
2010	20.368	50.368	(5.84)	59.708	10024	(5.84)

* Actual

*Note

Reference : NEB

Extent : NEB

Table 3 - 11 Generated Energy by Source

F.Y.	1980 PJ (%)	1985 PJ (%)	1990 PJ (%)
Oil-fired	28.34 (87.2)	33.29 (65.8)	11.25 (14.2)
Gas-fired	0.10 (0.3)	4.71 (9.3)	40.07 (50.6)
Hydro Power	4.06 (12.5)	12.60 (24.9)	15.60 (19.7)
Coal-fired	- (-)	- (-)	12.28 (15.5)
Total Generated Energy	32.5 (100.0)	50.6 (100.0)	79.2 (100.0)
Total Generated Energy / Primary Supply of Energy (%)	7.26	7.45	9.18

*Note

Reference : (B)

Extent : Nation-wide

Table 3 - 12 Progress of Rural Electrification

F.Y.	1981	1982	1983	1984	1985	Average Growth Rate (81/85)(%)
No. of Households with electricity	423,147	475,842	549,250	601,475	649,679	-
Growth Rate (%)	-	12.5	15.4	9.5	8.0	11.3
No. of Villages with electricity	5,330	6,157	7,395	8,181	8,865	-
Growth Rate (%)	-	15.5	20.1	10.6	8.4	13.6

*Note

Reference : (B)

Extent : NEB

Table 3 - 13 Generated/Purchased, Sent-out and Energy Sold (GWh)

F.Y.		1981	1982	1983	1984	1985	Average Growth Rate (81/85)(%)
Generated & Purchased	(a)	9,100	9,817	10,731	11,705	12,730	8.8
Sent-out	(b)	8,666	9,302	10,181	11,149	12,171	8.9
$\frac{(a) - (b)}{(a)}$	(%)	4.8	5.2	5.2	4.8	4.4	-
Energy Sold	(c)	7,803	8,368	9,047	9,894	10,780	8.4
$\frac{(b) - (c)}{(b)}$	(%)	10.0	10.0	11.1	11.3	11.4	-

*Note

Reference : (B)

Extent : NEB

Table 3 - 14 Purchased Energy (GWh)

F.Y.	1981	1982	1983	1984	1985
The Perak River Hydro Electric Power Co.Ltd.	211.1	223.2	18.6	-	-
Public Utilities Board Singapore	86.6	63.0	50.3	63.4	73.9
Egat-Thailand	-	2.1	11.9	4.2	7.2
Other Supplies	4.0	1.9	0.9	1.6	1.4
Total Purchased	301.7	290.2	81.7	69.2	82.5
$\frac{\text{Total Purchased}}{\text{Sent out}}$ (%)	3.5	3.1	0.8	0.6	0.7

*Note

Reference : (B)

Extent : NEB

Table 3 - 15 Installed Capacity, Generated Energy and Plant Factor

F.Y.	1981	1982	1983	1984	1985	Share (%) in 1985
Total Installed Capacity (MW)				2,916	3,792	(100.0)
Gas-turbine	100	100	100	260	260	(6.9)
Diesel	127	126	139	188	204	(5.4)
Hydro	613	613	726	846	1,147	(30.2)
Thermal	1,330	1,560	1,612	1,612	1,570	(41.4)
Combined Cycle	-	-	-	-	600	(15.8)
Sub-total	2,170	2,399	2,577	2,906	3,781	(99.7)
Rural (Diesel)	-	-	-	10	11	(0.3)
Total Generated Energy (GWh)	9,100	9,817	10,731	11,705	12,730	(100.0)
Gas-turbine	259	288	354	357	777	(6.1)
Diesel	300	335	393	252	313	(2.5)
Hydro	1,423	1,217	1,476	2,813	3,003	(23.6)
Thermal	6,797	7,665	8,407	8,193	7,433	(58.4)
Combined Cycle	-	-	-	-	1,097	(8.6)
Sub-total	8,780	9,506	10,630	11,614	12,624	(99.2)
Rural (Diesel)	15	18	19	21	24	(0.2)
Purchased	305	293	82	69	82	(0.6)

Plant Factor (in 1985)

	Gas-turbine	Diesel	Hydro	Thermal	Combined
PF (%)	34.1	17.5	29.9	54.0	20.9

*Note
Reference : (B)
Extent : NEB

Table 3 - 16 Installed Capacity in 1991

Plant Type	Installed Capacity (MW)		(Share : %)
Gas-turbine	4 x 18 =	72	(1.5)
Hydro		1,284*	(26.3)
Oil-fired	3 x 25 = 3 X 110 =	405**	(8.3)
Gas-fired		2,528	(51.7)
Conventional			
TJPS I	4 x 50 =	200	
PGPS	2 x 120 =	240	
TJPS II	3 x 105 =	315	
PKPS I	2 x 300 =	600	
Sub-total		1,355	(24.0)
Combined Cycle			
PAKA	3 x 291 =	873	
CBPS	1 x 300 =	300	
Sub-total		1,173	(27.7)
Coal-fired	2 x 300 =	600	(12.3)
Total		4,889	(100.0)

Note* 1,284 MW consisting of Woh (150), JOR (100), Chenderoh (39), Bersia (69), Kenering (114), Temenggor (348), Kenyir (400) and Piah (64).

** 405 MW consisting of PRAI I (75) and PRAI II (330).

Rerence : NEB

Extent : NEB

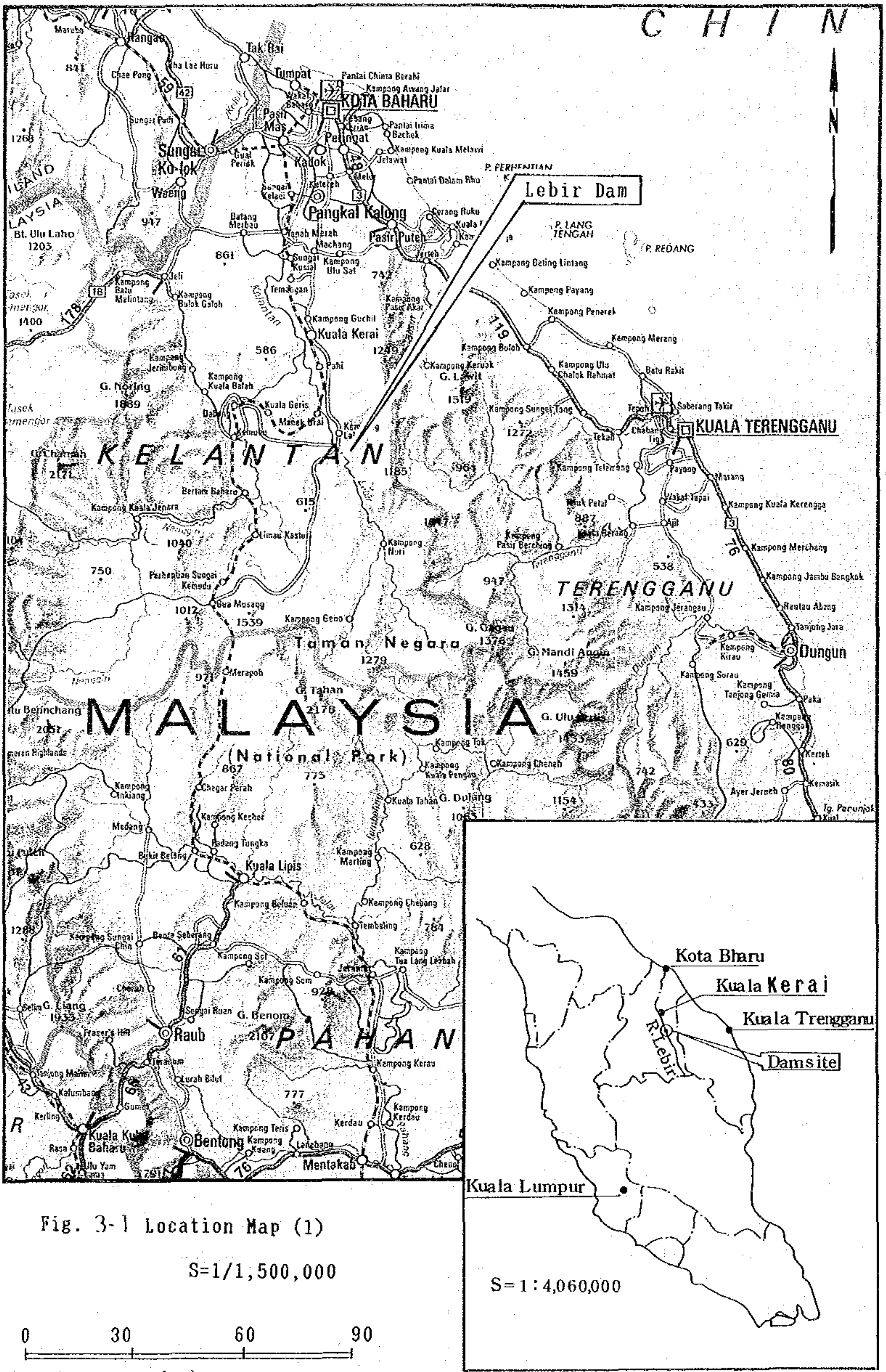
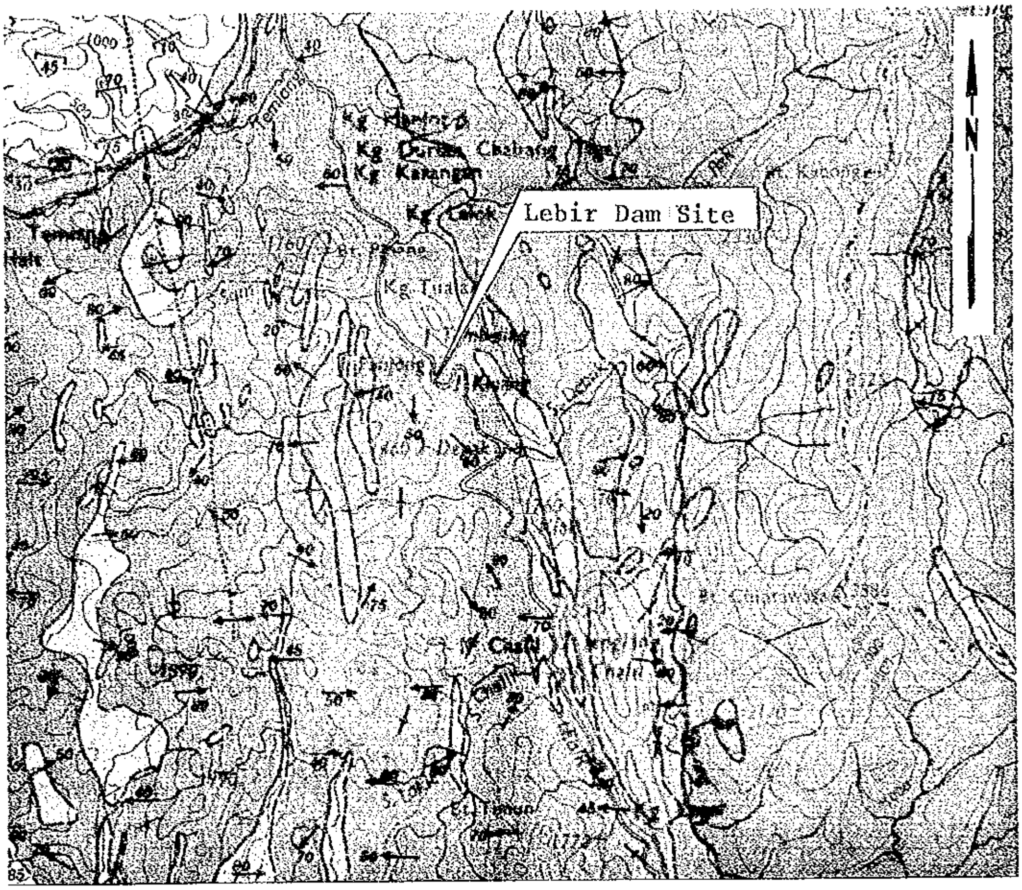


Fig. 3-1 Location Map (1)

S=1/1,500,000

0 30 60 90

(km)

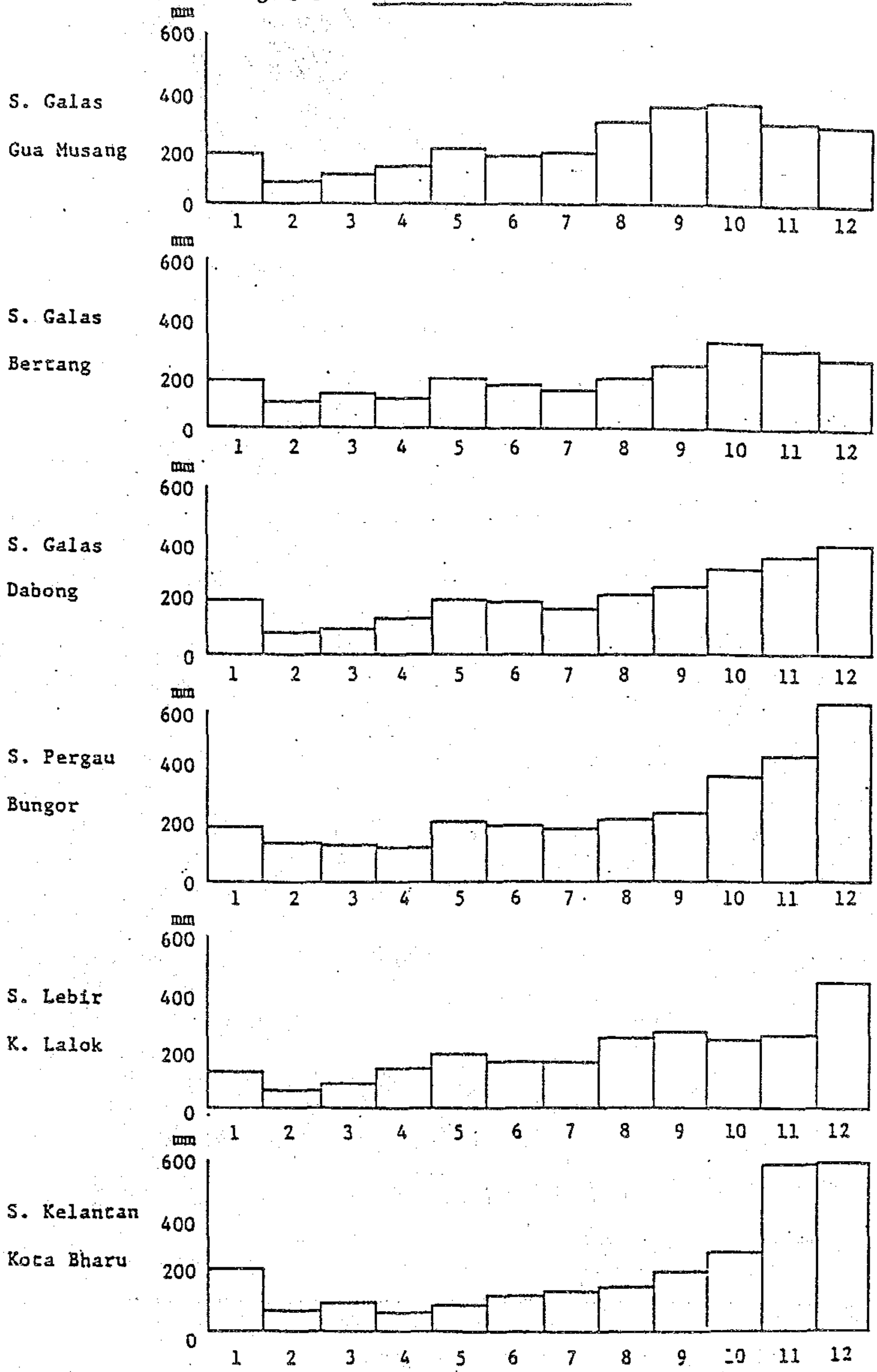


QUATERNARY RECENT TO PLEISTOCENE	ALLUVIUM		Shown only along the coastal plain, where in addition to recent deposits, raised beaches are common. Alluvium deposits also occur inland along river valleys.
POST-GRANITE POSSIBLY TERTIARY	YOUNGER DYKES Dolerite and Lamprophyre		Swarms of narrow dolerite-quartz dolerite-lamprophyre dykes filling regional fractures, mainly in granites of Central Trengganu. Not shown (SEE ILLUSTRATION IN TEXT OF MEMOIR 13)
MESOZOIC AND POSSIBLY SOME LATE PALAEOZOIC	INTRUSIVES Undifferentiated Granite Rocks		Mainly granite and granodiorite with marginal development of tonalite in many places, and quartz diorite rarely. Includes granite porphyry, aplite, and pegmatite, as well as the many hybrid rock-types of the "Stong Injection Complex", a portion of the Main Range Granite.
	AND ASSOCIATED Quartz porphyry		The only occurrence shown is the Temangan dyke. Elsewhere quartz porphyry occurs as a phase of the granites and as dykes cutting the sediments and Taku Schists.
	Syenite		Syenitic variations of granite intrusives occur at a number of localities, but most occurrences are of minor extent. The only syenite differentiated and shown is that on Pulau Perhentian Kechil.
	Diorite		An intrusive-extrusive complex. The andesitic extrusive phase may predominate.
TRIASSIC TO CARBONIFEROUS	IN PART METAMORPHOSED — VOLCANICS Basic		Andesite flows, tuffs, and agglomerates, with minor interbedded shale. Pyroclastics are predominant.
	Acid to Intermediate		Tuffs, flows, and subordinate agglomerates, mainly of rhyolite, but including minor bands of dacite, trachyte, and andesite, together with subordinate intercalated shale and quartzite. Pyroclastics are predominant.
TRIASSIC TO PERMIAN AND POSSIBLY SOME CARBONIFEROUS	SEDIMENTS Argillaceous		Shales predominate, with minor mudstone and siltstone. In some areas calcareous and tuffaceous varieties are common. Included are minor arenaceous beds and some limestone.
	Arenaceous		Mainly quartzites, with subordinate interbedded grit, greywacke, conglomerate, and shale.
	Calcareous		Limestone, mostly crystalline, compact, well-bedded, with massive jointing. Generally forms outstanding topographic features.
EXACT AGE UNKNOWN BUT NOT YOUNGER THAN MIDDLE — LOWER TRIASSIC POSSIBLY PRE-CARBONIFEROUS	METAMORPHIC ROCKS		Taku schists, regionally metamorphosed rocks, comprising mica-garnet schists, quartz schists, amphibole schist, and serpentine. In addition the undifferentiated metamorphic equivalents of the sediments and to a generally lower degree, the volcanics, are widespread. Schists and gneisses occur prominently in the general area of the "Stong Injection Complex", a hybridized portion of the Main Range Granite in the southwest corner of the map area.
SYMBOLS		45	Geological boundary defined-approximate or assumed. Inclined strata, dip in degrees. Vertical strata. Inclined foliation, dip in degrees. Vertical foliation. Inclined joint plane, dip in degrees. Vertical joint plane. Anticlinal axis. Fault

0 5 10
(km)

Fig. 3-2 Regional geological Map (S=1/250,000)

Fig. 3-3 Mean Monthly Rainfalls



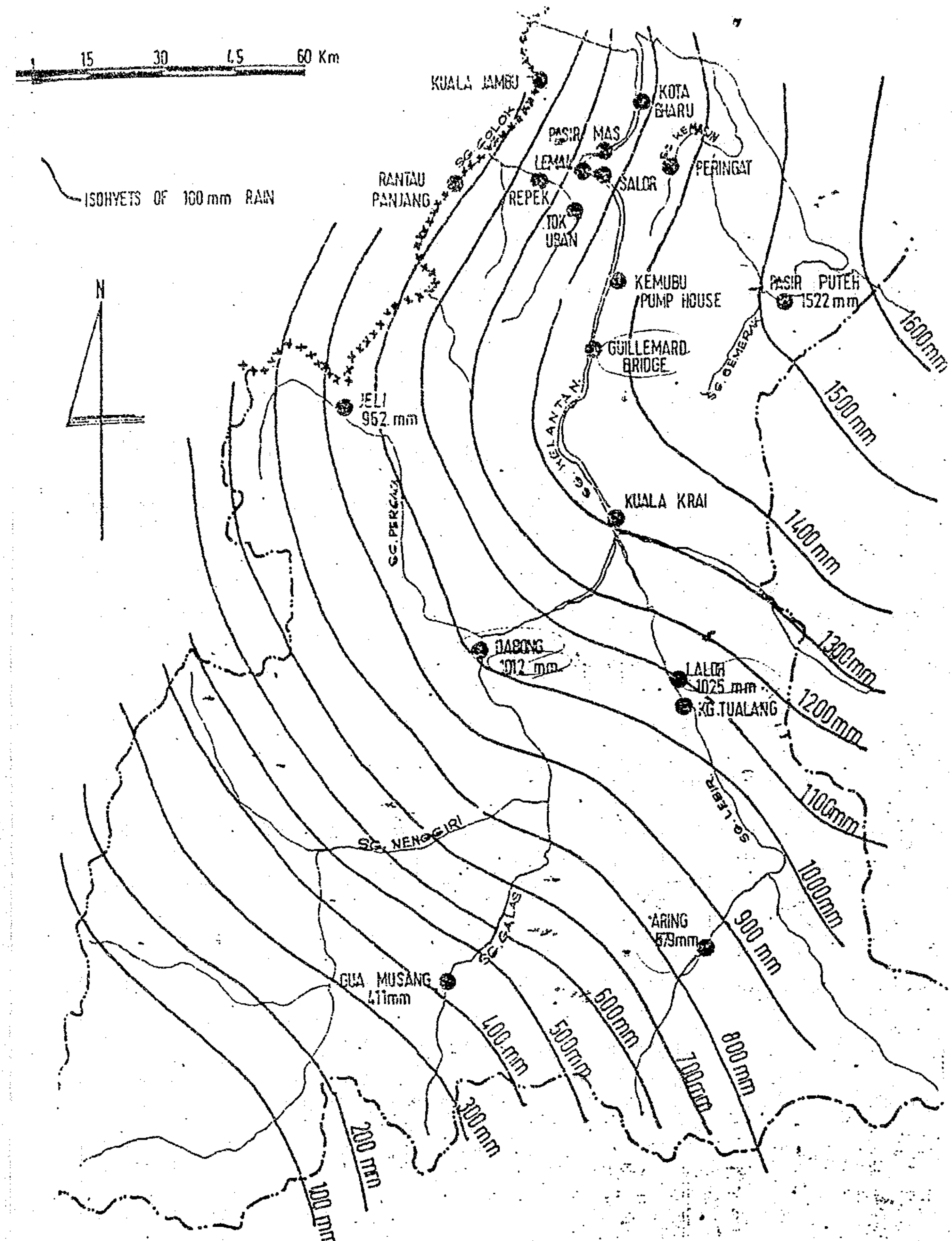


Fig. 3-4 Isohyets of rainfall
(Dec.2 to Dec.15 during the 1983 flood)

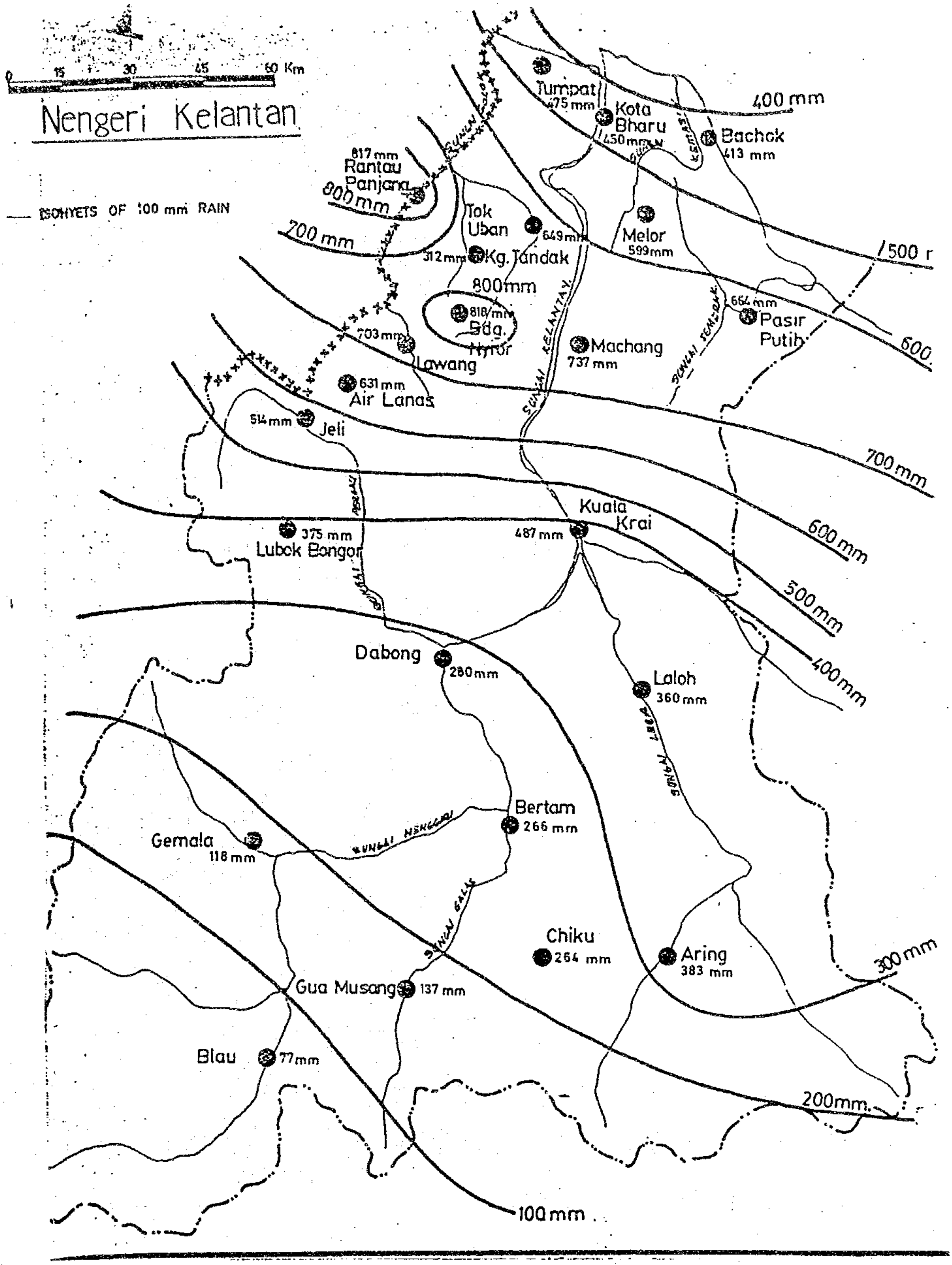


Fig. 3-5 Isohyets of rainfall
(Dec.19 to Dec.25 during the 1984 flood)

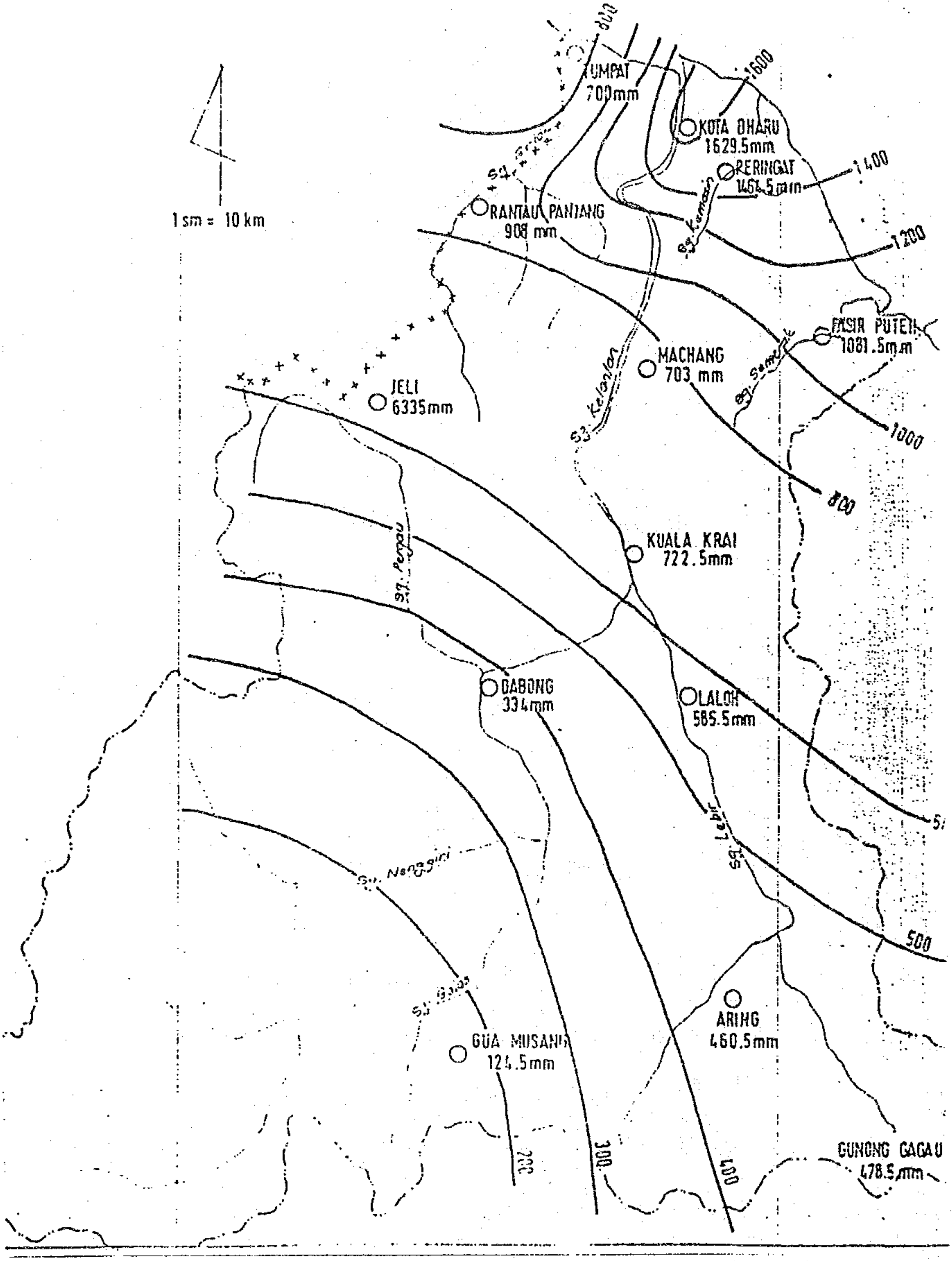
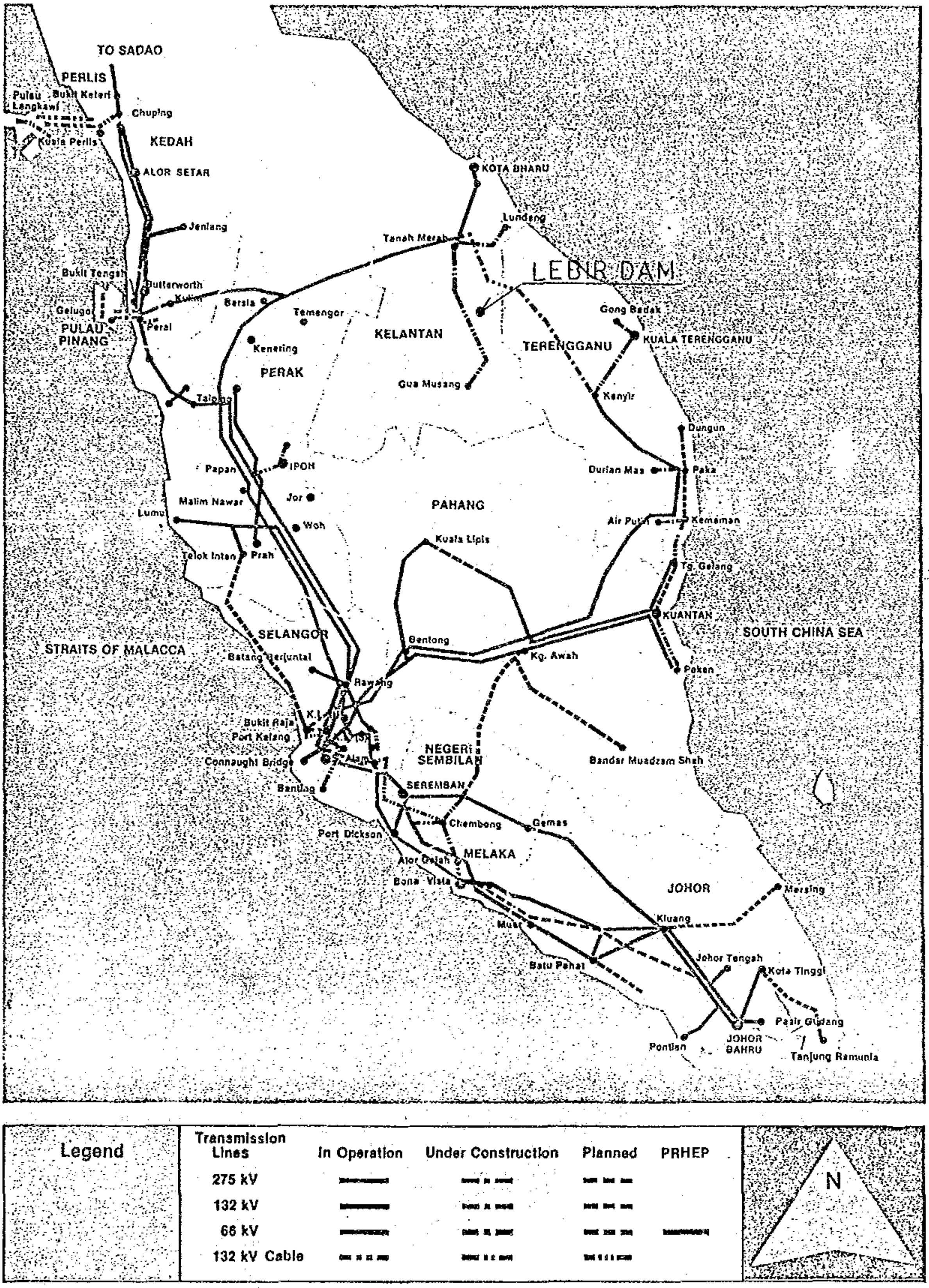


Fig. 3-6 Isohyets of rainfall
(Nov.25 to Dec.2 during the 1986 flood)

Fig. 3-7

THE NATIONAL GRID (Year ending 31 August 1985)



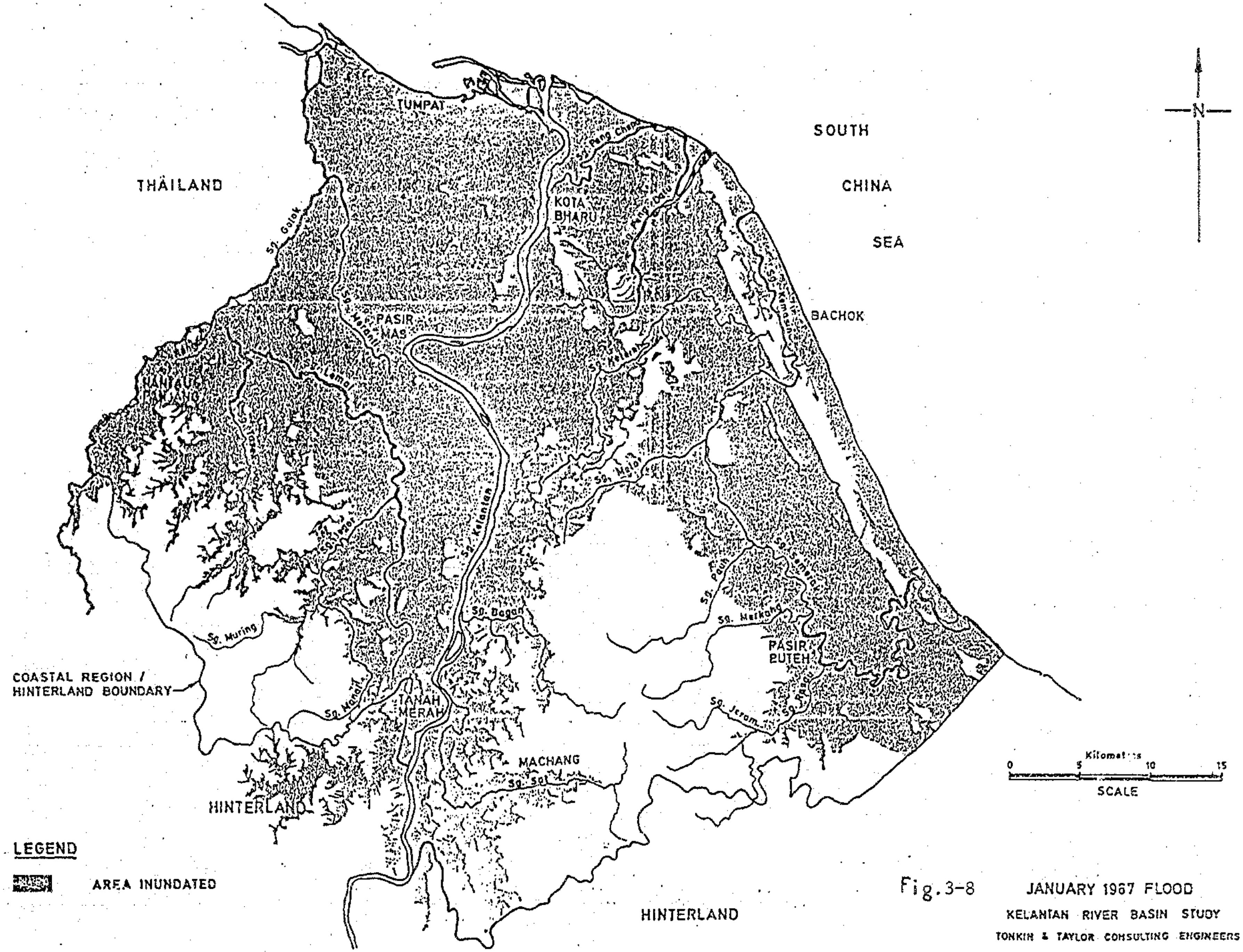


Fig.3-8 JANUARY 1967 FLOOD
KELANTAN RIVER BASIN STUDY
TONKIN & TAYLOR CONSULTING ENGINEERS

4. Topography and Geology

(Refer to Volume 2)

5. Hydrology

(Refer to Volume 2)

6. Power Planning

6. Power Planning

6.1. Power Demand Forecast and Necessity of Hydro-Power Plant

6.1.1. Power Demand Forecast

Table 6-1 shows a part of the energy and demand forecast made by NEB. Taking into account that the Lebir Dam Project is at present planned to be commissioned in or about the year 2000, the subsequent annual average rate of growth in power generation is as follows:

Period	Annual Rate of Growth (%)
2000 - 2005	6.09
2006 - 2010	5.84
2000 - 2010	5.97

For the first five years in the first decade after the year 2000, the annual average rate of growth was estimated to be 6.09% and for the second five years 5.84%. During the second half, the growth rate is expected to reduce slightly. However, for the decade as a whole, an anticipated annual growth rate of about 6% is predicted.

The yearly load factor is not expected to vary, and should remain at 68% each year.

6.1.2. Characteristics of Power Demand

Table 6-2 shows the load duration classified by month and season based on the actual records of NEB for 1986. From this data, the duration curves according to the season are shown in Figs. 6-1 and 6-2. Fig. 6-3 shows a comparison of the two duration curves indicated in Figs. 6-1 and 6-2 to identify the seasonal features. As clearly shown in Fig. 6-3, the duration curves are quite similar to each other. To simplify the studies, a modified duration curve, as indicated in Fig. 6-4, was prepared taking Fig. 6-3 into account.

It is possible to apply this modified duration curve to any season of any year, since as described above, the yearly load factor does not vary and there is no remarkable difference in the seasonal duration curves. The seasonal load factor from the modified duration curve on Fig. 6-4 is calculated to be 69.175%.

6.1.3. Power Demand at Sending End

In studying power planning, the demand and supply balance should be made at the sending end. The reason for this is, that if the study is done at the generating end, the power demand of each alternative at the generating end is required to be of different value and hence involves greater complexity in comparing alternatives of different station use rates.

Table 6-3 shows the energy and capacity at the generating and sending ends, and also the yearly load factor. The values at the generating end are the forecast requirements by NEB, as shown in Table 6-1. The values are based on the sending end and these were calculated on a station use rate of 5%, taking the past records of NEB into account. For the purpose of the study each year has been divided into two halves. The seasonal load factor of each half (6 months) is 69.175%, and the duration curves are to follow the form of the modified duration curve. The yearly load factor was based on the values forecast by NEB. Taking these conditions into account, Table 6-3 shows the output at the sending end of the first half and second half of each year. Table 6-4 shows the sent out energy conveyed from the sending end, for the first and second halves of each year, and the average monthly energy output.

6.1.4. Capability of the Existing Reservoir Type Hydro-Power Plant

Table 6-5 shows the installed capacity and generating energy of the existing reservoir type hydro-power plants. As shown in this Table, the total installed capacity is 931 MW and the generating energy during the two halves of the year is 210.8 GWh each on a monthly average. The respective values at the sending end are 923.6 MW and 209.1 GWh. The annual generating energy at the sending end is 2,509.8 GWh and its plant factor is about 31%. Assuming that there be no construction/expansion programme concerning reservoir type hydro-power plants in the future, the sending end ratios of generating energy/energy demand, of the existing reservoir type hydro-power plants are as follows:

Year	Ratio of generating energy/energy demand at the sending end of the reservoir type hydro-power plants
2000	7.9 %
2005	5.9 %
2010	4.4 %

6.1.5. Required Peak Supply Capability

Figs. 6-5 and 6-6 show samples of the required peak supply capability during each month of the first half of 1999. These figures indicate the same subjects. These figures indicate a situation where generating energy and installed capacity at the sending end of the existing reservoir type hydro-power plants, ideally fits existing requirements without any loss to meet power demand.

If the case is considered in which the peak supply capability was developed at more than that illustrated in Fig.6-5, the existing reservoir type hydro-power plants as a whole would not be able to meet power demands unless the output can be saved.

On the other hand, taking the case in which the peak supply capability was developed at less than that illustrated in Fig.6-6, the deficiency of the low plant factor has to be supplemented by the middle supply capability. From these considerations, the required peak supply capability illustrated in these two figures is usually an economically usable amount. Table 6-6 shows the required peak supply capability sought by applying the above concept separately to the first half and second half of each year.

Table 6-7 shows the percentages of the required peak supply capacity to the system peak demand computed from the required peak supply capacity indicated in Table 6-6 and the demand at the sending end in Table 6-3. It is understood from Table 6-7 that the percentage of the required peak supply capacity to the system peak demand increases within the range from about 12% to about 16% during the period of the years 2000 to 2010.

6.1.6. Necessity of Hydro-Power Plant

As described above, it is formulated that the required peak supply capability tends to be on a gradual increase in future, while the supply capability share of the existing reservoir type hydro-power plants will be lowered.

Development of the peak supply capability does not necessarily mean that reservoir type hydro-power plants should be constructed. However, they are easy to start and stop, and capable of efficient control of output, hence, they can be regarded as the most efficient means of power generation from the technical point of view based on peak supply capability.

In Malaysia, fuel conversion in the existing thermal power plants from oil to natural gas, development of combined cycles with natural gas as the fuel, development of coal-fired power plants from the view point of energy security, etc. for the future are all under consideration.

It is also economically significant to develop hydro-power plants which utilize energy resources that are basically inexhaustible.

6.2. Study on Magnitude of Power Development

6.2.1. Parameters of Alternative Cases

To formulate plans for a comparison of dam type power development scales, the various parameters were selected as follows:

(1) Dam height :

Dam height has a relationship to head and storage capacity, and has been studied in the HWL range, EL 85-60 m for power generation, taking into account topographical and geological features of the dam site. The total storage capacity will be 3,300 x $10^6 m^3$ at HWL 85 m and it will be 500 x $10^6 m^3$ at HWL 60 m.

(2) Firm discharge (Qf):

Firm discharge means the discharge to be used for 24 hours/day throughout a year, and has a relation to power output and generated energy.

The firm discharge (Qf) has been studied between 40 m^3/s and 100 m^3/s taking into account the annual mean discharge of 112.15 m^3/s and the minimum mean average discharge of 49.3 m^3/s (1981) based on the estimated monthly average of stream-flow at the dam site for the past 35 years (1950 - 1984) in Table 5-2.

(3) Peak ratio (α) :

Peak ratio (α) is given by the ratio between the maximum discharge (Qm) (firm discharge within the peak operating hours for peak generation) and the firm discharge (Qf), and is selected to within such range as the continuous operating hours at the peak load are between 3 and 6 hours, where the plant factor is 25% to 12.5% and α becomes 4 to 8 times.

(4) Minimum water level:

Minimum water level means the lowest operating water level in the reservoir and has a relation to effective storage capacity and head. This has been taken as EL.50 m at the lowest, on account of a design silt face elevation of EL.47m.

The cases studied in this Section 6.2 are shown on Table 6-8.

6.2.2. Rules of Reservoir Operation

The rules of reservoir operation to determine the monthly discharge for power generation necessary for calculation of the generating output and energy of comparative plans for the development scale were determined as follows:

The purposes of the study as stated in Section 6.2.1. are to identify the optimum development scale, based on a combination of the parameters of dam heights (HWL of reservoir), storages of reservoir (LWL of reservoir) and output of the power plant (discharges for maximum power and firm power). Therefore, such rules as the maintenance of high water levels in the reservoir throughout the year, as common conditions to each comparative development plan, were adopted without setting any seasonal and/or monthly target water levels for the reservoir.

(1) Outline of the rules of reservoir operation

(a) Where the water level in the reservoir is at high water level.

i. Where the inflow Qi to the reservoir is less than the firm discharge Qf, and the discharge for power generation Qp being equal to the firm discharge Qf, the deficiency qd1 = Qf - Qi shall be supplemented from storage, and the water level of the reservoir will be lowered.

ii. Where the inflow Qi to the reservoir is more than the firm discharge Qf, the discharge for power generation qp shall be equal to the inflow Qi to the dam.

iii. Where the inflow Qi to the reservoir is more than the maximum discharge Qm, and the discharge for power generation Qp is equal to the maximum discharge Qm, the remaining discharge qd2 = Qi - Qm will overflow from the dam, and the water level of the dam will remain at HWL.

(b) Where the water level in the reservoir is not high,

i. Where the inflow Qi to the reservoir is less than the firm discharge Qf and the discharge for power generation is equal to the firm discharge Qf, the deficiency qd1 = Qf - Qi shall be supplemented from storage, and the water level of the reservoir will be lowered. (the same as in i. above)

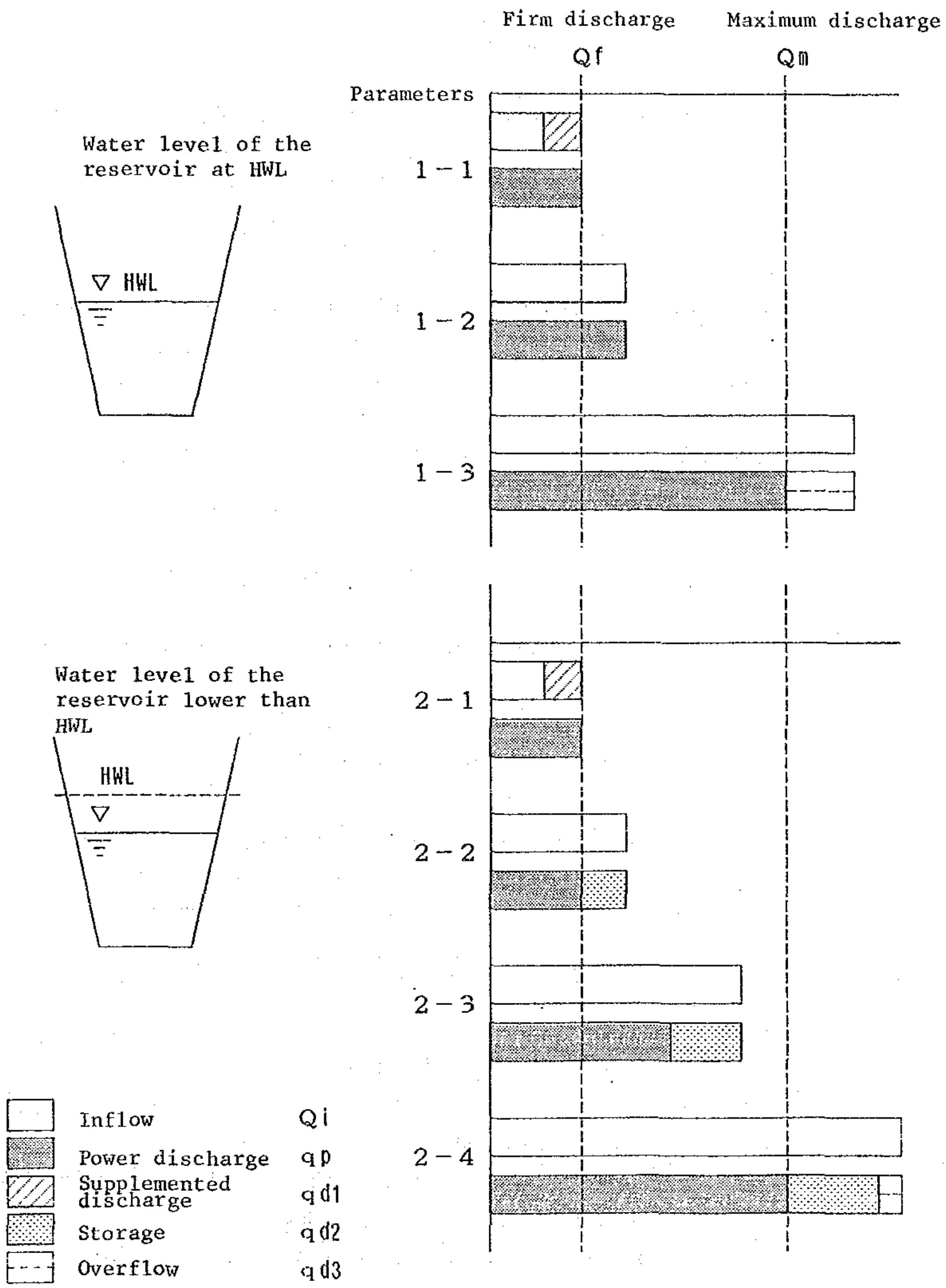
ii. Where the inflow Qi to the reservoir is more than the firm discharge Qf and the discharge for power generation qp is equal to the firm discharge Qf the excess inflow qd2 = Qi - Qf will remain stored in the reservoir, and the water level will rise.

iii. Where the total excess inflow qd2 is stored in the reservoir and the water level reaches HWL and overflows, the overflow shall be used for power generation. In other words, the discharge for power generation qp shall be the firm discharge Qf + overflow, and the water level of the reservoir will be HWL.

iv. Where the above discharge for power generation qp exceeds the maximum discharge Qm, and the discharge for power generation qp is equal to the maximum discharge Qm, the excess discharge qd3 = Qi - Qm - qd2 will overflow from the dam.

The above data is illustrated in the following Figure.

Model of Resevoir Operation Rules



6.2.3. Power and Energy Generation

(1) Conditions of Calculation

In the foregoing Section 6.2.2, reservoir operation rules were examined for the total 81 cases of the project development scale, which were enumerated in Section 6.2.1. The stream flow data used for the calculation is given in Table 5-2. These are monthly flows at the dam site for 35 years covering the period of 1950 to 1984. The storage-water level curve at the dam site given in Fig.7-5 was applied.

The calculations were made using the following formula:

Power - P (kW)

$P = 9.8 \times \quad \times (H_1 - H_T - h) \times Qp$

Where, : combined efficiency of turbine and generator = 0.88

H_1 : Reservoir water level (EL. m)

H_T : Tailrace water level (EL. 27 m)

h : Head loss in water conduit (EL. 2.5 m)

Qp : Peak power discharge* (m^3/sec.)

* Qp = Qmax when the reservoir water level is at the water level corresponding to the rated head of turbine

Energy - E (kWh)

$E = P \times D \times Qpf/Qp \times 24$ (kWh/month)

Where, P : Power output (kW)

D : Number of days in the month

Qpf : 24-hour power discharge (m^3/sec.) as determined by the reservoir operation rule.

Qp : Peak power discharge* (m^3/sec.)

* Peak power discharge at the reservoir water

level other than the water level corresponding to the rated head of turbine is determined by the following equations:

$$h_o^{\cdot} \geq h_o \qquad Qp = Qmax \cdot \frac{h_o}{h_1} \ (m^3 /sec.)$$

$$h_1 < h_o \qquad Qp = Qmax \cdot \sqrt{\frac{h_o}{h_1}} (m^3 /sec.)$$

where, h_o (m) = design base head and
h_1 (m) = any discretionary headhead

For the above calculations, a level value 2 m below HWL was taken as the water level corresponding to the rated head of turbine, H_o for each development scale, i.e.

$$h_o = H_o - H_T - \Delta h$$
$$h_1 = H_o^{\cdot} - H_T - \Delta h$$

The values used for the calculation of evaporation losses are from the records of actual measurement taken at the Cameron Highlands:

Monthly evaporation rates are tabulated below:

Jan.	101 mm	Jul.	104 mm
Feb.	102	Aug.	101
Mar.	118	Sep.	101
Apr.	110	Oct.	97
May	102	Nov.	90
Jun.	102	Dec.	87
			Σ 1,215 mm

(2) Calculation Results

(a) Relationship between firm and effective discharge

The larger the firm discharge to be obtained by regulating the seasonal fluctuations of the river flow is, the larger the effective storage capacity (Qf

m^3/sec.) required. The relationship between firm discharge and necessary effective storage of the various cases is shown below:

Firm discharge (m^3/sec.)	50	60	70	80	90	100
Effective storage ($10^6/m^3$)	731	1,216	1,741	2,347	3,109	3,130
Minimum water level of the reservoir (m)	81	78	74	67.5	51	50

For Qf = 100 m^3/sec., the storage capacity is required to be more than 3,130 x $10^6 m^3$, where HWL is set at EL.85 m and LWL will be below EL. 50 m.

(b) Generation stoppage due to drought

The extent of the storage capacity in the reservoir relates to the reliability with which the firm discharge (Qf) can be maintained during periods of drought. Larger storage capacity enables Qf to be maintained through drought periods of greater severity. Should the available storage be less than is needed in relation to a particularly severe drought, the reservoir level will fall below the planned L.W.L., and as a consequence the flow to the power station will fall below Qf.

The reservoir operation calculations have been performed under conditions that possible low water level (LWL) is at EL. 50m, when the dead storage is 167 x $10^6 m^3$ and variation in head is = 50 m - 29.5 m / 85 m - 29.5 m for the plan of HWL 85 m or = 50 m - 29.5 m / 70 m - 29.5 m for HWL 70 m, and where power generation will stop during the months having reservoir water levels below EL. 50 m.

The operation calculations were made for 420 months (35 years x 12 months) for each development scale. As a result, the number of months during which generation will be stopped is shown in percentages, as given in the table below:

Rate of Generation Stoppage (%)

HWL \ Qf (m^3/sec.)	40	50	60	70	80	90	100
EL. 85 m		0	0	0	0	1.7	5.5
80		0	0	0	0	3.8	7.6
75		0	0	0.2	1.7	5.7	9.5
70		0	0	1.0	3.8	7.4	12.1
65		0	0.5				
60	0.2						

As shown above, if Qf = 100 m^3/sec. is selected, power generation stoppage months will be 5.5% despite the raising of the HWL up to EL. 85 m.

In this study, the development scales which will cause power generation outage of more than 2.5% are considered inadequate and have therefore been abandoned. The remainder of the development scales were further examined.

(c) Reservoir low water level and intake level

After the calculations of reservoir operation, the low water levels derived in the calculation of the respective development scales are as given below:

Reservoir Low Water Level

(EL. m)

HWL \ Qf (m^3/sec.)	40	50	60	70	80	90	100
EL. 85 m		81.0	78.0	73.9	67.1	50*	--
80		75.1	71.0	64.2	52.3	--	--
75		68.2	62.5	52.6	50*	--	--
70		60.9	51.6	50*	--	--	--
65		51.3	50*				
60	51.0						

The development scales with * mark are cases where the reservoir water level will go down to the lowest limit of EL. 50 m under certain operating conditions, while cases without any figure and marked by " - " are those to be abandoned because of power generation outage exceeding 2.5%.

In the next step, the intake sill level was calculated on the basis of the low water level obtained as above. The calculations of necessary inlet sill levels of the intake were made by taking the inlet depth hd = 2D, where D is the internal diameter of the water conduit. The results are given below:

Inlet Sill Level of Intake

(EL. m)

HWL \ Qf (m^3/sec.)	40	50	60	70	80	90	100
EL. 85 m		69.2	65.2	61.3	53.5	38.3*	--
80		63.3	58.2	51.6	38.7*	--	--
75		56.4	49.7	40.0*	36.4*	--	--
70		49.1	38.8*	37.4*	--	--	--
65		43.0*	40.9*				
60	44.9*						

In the above table, the figures with * mark are below the estimated sediment level in the reservoir, i.e. EL. 47 m, and therefore, considered to be inadequate. In these cases, the power generation stoppage months previously computed are listed, as shown in the following table.

Generation Stoppage Months (%)
at LWL of EL. 50 m or above

HWL (EL. m)	Qf (m^3/sec.)	Intake Water Sill Level (EL. m)	Generation Stoppage (%)
85	90	38.3	1.7
80	80	38.7	0
75	80	36.4	1.7
75	70	40.0	0.2
70	70	37.4	1.0
70	60	38.8	0
65	60	40.9	0.5
65	50	43.0	0
60	40	44.9	0.2

As shown above, each case still has some margin below the 2.5 % limit of power generation stoppage.

By taking LWL of EL.60 m , or EL 55 m for some cases, as the lowest condition, the reservoir operation calculations in these cases were made and the months of power generation stoppage obtained as listed below:

Generation Stoppage Months at LWL EL. 60 m or 55 m

HWL (EL. m)	Qf (m^3/sec.)	LWL (EL. m)	Generation Stoppage (%)
85	90	60	2.9*
80	80	60	0.9
75	80	60	2.6*
75	70	60	0.7
70	70	60	3.1*
70	60	60	0.5
65	60	55	1.6
65	50	55	0.2
60	40	55	1.0

Screening away the cases marked with *, it was found that among the remainder, the cases of; 1) HWL = EL. 80 m, Qf = 80 m^3/sec.; 2) HWL = EL. 75 m, Qf = 70 m^3/sec., and 3) HWL = EL. 70 m, Qf = 60 m^3/sec. are possible development scales subject to taking LWL at EL. 60 m.

Two other cases: 4) HWL = EL.65 m, Qf = 50 m^3/sec, and 5) HWL = EL.60 m, Qf = 40 m^3/sec are possible, but the case of: 6) HWL = EL.65 m, Qf = 60 m^3/sec is discarded because the required elevation of the intake sill is found to be lower than EL.47 m (DSL) even though it clears the criterion with regard to stoppage of generation.

From these studies as mentioned above, 35 development cases were screened out of the total 81 cases planned in the previous Section 6.2.1. and listed in the following table.

Since the firm power discharge Qf = 60 m^3/sec. is possible even for the smallest dam scale, namely HWL = EL. 70 m, the cases of Qf = 50 m^3/sec. were not further elaborated when WHL equals 70 m or above.

The possible development cases are summarized below.

Possible Development Cases (0 marked)

HWL (EL.m) \ Qf (m^3/sec)	40	50	60	70	80
85	-	-	0	0	0
80	-	-	0	0	0
75	-	-	0	0	-
70	-	-	0	-	-
65	-	0	-	-	-
60	0	-	-	-	-

L W L (EL. m)

HWL (EL.m) \ Qf (m^3/sec)	40	50	60	70	80
85			78.0	73.9	67.1
80			71.0	64.2	60.0
75			62.5	60.0	-
70			60.0	-	-
65	-	56.0	-	-	-
60	56.0	-	-	-	-

Available Depth (m)

HWL (EL.m) \ Qf (m^3/sec)	40	50	60	70	80
85			7.0	11.1	17.9
80			9.0	15.8	20.0
75			12.5	15.0	-
70			10.0	-	-
65	-	9.0	-	-	-
60	4.0	-	-	-	-

Intake Sill Level (EL. m)

HWL (EL.m) \ Qf (m^3/sec)	40	50	60	70	80
85			65.2	61.3	53.5
80			58.2	51.6	47.0
75			49.7	47.4	-
70			47.2	-	-
65		47.0	-	-	-
60	50.0	-	-	-	-

Usable Storage

($10^6 m^3$)

Qf (m^3/sec) / HWL (EL.m)	40	50	60	70	80
85	-	-	1,216	1,741	2,347
80	-	-	1,126	1,647	1,819
75	-	-	1,045	1,102	-
70	-	-	617	-	-
65	-	389	-	-	-
60	175	-	-	-	-

Generation Stoppage Months (%)

Qf (m^3/sec) / HWL (EL.m)	40	50	60	70	80
85	-	-	0	0	0
80	-	-	0	0	0.9
75	-	-	0	0.7	-
70	-	-	0.5	-	-
65	-	0	-	-	-
60	0	-	-	-	-

(d) Ineffective discharge (Spilling Water)

Where the effective storage capacity is small, an ineffective discharge is caused because the reservoir can not regulate the seasonal fluctuations of river flow and is not drawn down from the full condition. The following table shows a result of the reservoir operation calculations.

Ineffective Discharge (m^3/s year)

α \ Qf (m^3/sec)	40	50	60	70	80	90	100
4	26	19	14	10	7	5	4
5	-	15	11	7	5	3	2
6	17	12	8	5	4	3	2
8	12.1	7.9	5.1	3.3	2.1	1.2	0.8

Annual mean inflow to the reservoir is 112.6 m^3/s. Mean evaporation volume = 1,215 mm x 121.5 km^2 (This is equivalent to a loss of inflow of 4.7 m^3/s).

Effective inflow = Annual mean inflow - evaporation loss

= 122.6 - 4.7 m^3/s = 107.9 m^3/s

In the case where 2 m^3/s is being discharged ineffectively, the river usage factor becomes 98%. Where the firm discharge 80 m^3/s is applied, the usage factor of river becomes remarkably high.

(3) Generation output and energy of comparative plans for development scale

For cases screened out, as mentioned above, power generation output and plant factors are within the following range:

At the largest development scale (HWL = EL. 85 m)

Power output	P = 113 - 301 MW
Energy output	E = 377 - 417 GWh
Plant factor	P.f. = 0.38 - 0.16

At the medium size development scale (HWL = EL. 70 m)

Power output	P = 82 - 123 MW
Energy output	E = 280 - 300 GWh
Plant factor	P.f. = 0.39 - 0.28

At the smallest development scale (HWL = EL. 60 m)

Power output	P = 20 MW
Energy output	E = 142.1 GWh
Plant factor	P.f. = 0.80

Power generation, energy production and mean plant factor corresponding to each comparative plan for development scale are summarized on Table 6-9. Also, on Table 6-2-1 of Appendix, the data on reservoir water level, effective storage, ineffective discharge and generation stoppage months are enumerated.

6.2.4. Selection of Optimum Development Scheme

In selecting the optimum development scheme among the various alternatives discussed in Section 6.2.3., an economic comparison of alternatives was made taking into account total benefits arising from power development, flood control, and agricultural irrigation, and the construction costs, since this project is to be developed as a multipurpose scheme. The details of the economic comparison are stated in the respective Sections of the Interim Report prepared in February, 1988, and the following are a summary of information extracted from the report.

Power benefits :

Combined cycle is selected as an alternative power source of hydro-power. Its annual value is as follows (refer to Section 6.4.):-

MW value:	180.474 M$/kW-year	(i=8%)
	209.091 "	(i=10%)
	240.085 "	(i=12%)

where, i = discount rate
MWh value: 37.289 M$/MWh

Flood control benefits :

The flood control benefits in the year 2000 due to the reservation of flood control capacity above the HWL for power generation, and a natural overflow type spillway with 160 m long overflow sill, are estimated as follows based on 1987 price levels (refer to Chapter 7 in the Interim Report of February, 1988).

	Flood control benefit (per year)
HWL 85 m	25.72×10^6 m$
HWL 80 m	21.64 "
HWL 75 m	17.99 "
HWL below 70 m	12.71 "

Agricultural benefits :

The agricultural benefits arising from an effective use of the daily dscharge of 80 m^3/s for the agricultural productions in the downstream reaches of the Kelantan River and a production increase of paddy in 19,326 ha of the new paddy field in addition to the existing 46,000 ha, are estimated as follows (refer to Chapter 13 in the Interim Report of February, 1988):-

Net incremental benefit per year	5.97×10^6 M$	(i=8%)
	3.98 "	(i=10%)
	2.09 "	(i=12%)

It is understood from the difference between the above benefits and the annual expenditures of the total project cost that the following cases are prospective.

HWL (m)	Qf (m^3/s)	α	MW	GWh	Net benefit i=8%	i=10%	($x10^6$M$) i=12%
85	80	5	188	402	Δ1.33	Δ22.93	Δ47.54
85	80	6	225.6	407	0.45	Δ21.39	Δ46.27
85	80	8	300.8	416	2.14	Δ20.77	Δ46.91
80	80	5	170.7	365	0.03	Δ18.89	Δ40.35
80	80	6	204.9	370	1.67	Δ17.45	Δ39.17
80	80	8	273.2	380	1.85	Δ18.67	Δ42.00
80	70	6	179.3	377	0.18	Δ18.98	Δ40.71

The total project cost adopted for the above calculation is largely based on estimated figures which represent an improvement over the rough figures at the Interim Report Stage. Thus, the net benefit becomes minus, excepting only 6 cases with a discount rate of 8%. However, the relative differences among each case are observed, and the following trends are identified.

i. The case with the higher dam is generally more profitable.

ii. The case with the larger peak ratio and power output is more effective.

From the result of the above, the case of HWL = 80 m, Qf = 80 m^3/s and α = 8 is proposed as a optimum plan. Though similar economic effect can be expected from the case of HWL = 85 m, Qf = 80 m^3/s and α = 8, it was considered more desirable to have a smaller inundation area arising from the dam construction.

The result of calculation of costs and benefits is shown on Table 6-10.

6.3. Determination of Main Features of Optimum Plan

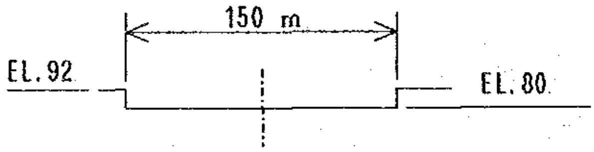
6.3.1. High Water Level for Power Generation

In the previous Section, the high water level for power generation in the optimum plan of a multi purpose dam scheme was calculated to be EL.80 m. In this Section, in the case of expanding the flood control capacity i.e. to reduce the reserved capacity for power generation, the propriety of high water level is reconfirmed from the relationship between flood control benefits and losses of power benefit.

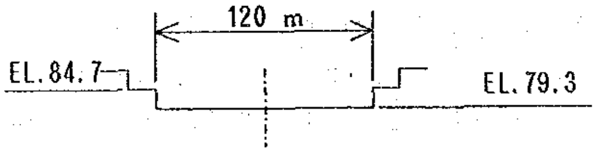
For this purpose, the following variations of spillway were selected, and the fluctuations of net benefit arising from power generation and flood control were computed:-

Selected Variations

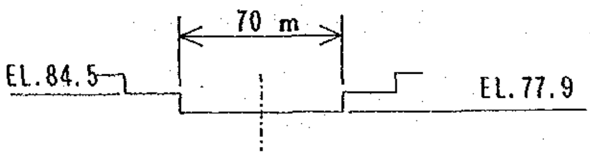
Case 1



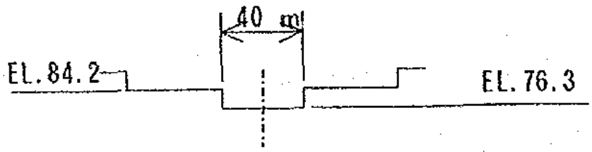
Case 2



Case 3



Case 4



Net Benefit

Case	MW	GWh	Power Benefit 10^6M$	Flood Inflow m^3/s	Flood discharge m^3/s	Peak cut off ratio %	Flood control benefit 10^6M$	Total net benefit 10^6M$
1	267.7	373.3	69.87	5,560	3,190	43	16.98	86.85
2	262.0	366.6	68.46	5,560	2,920	47	17.90	86.36
3	246.2	358.6	64.85	5,560	2,260	59	19.87	84.72
4	227.6	348.1	60.57	5,560	1,660	70	21.25	81.82

Note 1) Power benefit was calculated based on MW value: M$ 209.1/year and MWh value M$ 37.289 when the discount rate of 10% was adopted (refer to Section 6.4.)

2) Flood inflow corresponds to the 50 to 100 year return flood.

3) For calculation of the flood benefit, Section 7.6 is referred. (2000 year level, 1987 price)

Although the Project cost will not be decreased to such extent that Case 2 through Case 4 provide higher economic benefit because the required dam height among the alternatives is unchanged, the construction cost of the spillway would increase in Case 2 through Case 4 due to lowering of the elevation of the crests, and the unit cost of the generating equipment per kW would be increased.

As shown in the above table, if a HWL below EL.80 m were to be adopted for expanding the flood control purpose, the total net benefit as a multi purpose dam would be decreased. Therefore, EL. 80 m is adopted as the optimum high water level for this project.

6.3.2. Determination of Optimum Diameter of Penstock Tunnel

Waterway sizing is a very significant factor in hydro-power scheme design.

The diameter of the penstock tunnel has been evaluated on the basis of the lowest annual costs of construction plus power loss due to hydraulic friction in the waterway. Two and three penstock tunnel plans were evaluated and compared. Each result is shown below.

Two tunnels plan

Tunnel diameter m	Flow velocity in the tunnel m/s	Head loss in the tunnel m	kW loss	kWh loss	Loss benefit M$	Construction cost of tunnel M$	Annual cost for the works M$	Total cost M$
				$x10^6$	$x10^6$	$x10^6$	$x10^6$	$x10^6$
10.09	4.0	0.952	5,140	7.16	1.34	39.71	5.24	6.58
9.52	4.5	1.222	6,600	9.19	1.72	35.06	4.63	6.35
9.03	5.0	1.530	8,260	11.50	2.15	30.96	4.09	6.24
8.61	5.5	1.877	10,130	14.11	2.64	27.01	3.57	6.21
8.24	6.0	2.261	12,200	17.00	3.18	24.96	3.29	6.47
7.92	6.5	2.685	14,500	20.20	3.78	23.22	3.07	6.85
7.63	7.0	3.146	16,980	23.65	4.42	21.74	2.87	7.29

Three tunnels plan

Tunnel dia-meter m	Flow velocity in the tunnel m/s	Head loss in the tunnel m	kW loss	kWh loss	Loss benefit M$	Construction cost of tunnel M$	Annual cost for the works M$	Total cost M$
				$x10^6$	$x10^6$	$x10^6$	$x10^6$	$x10^6$
8.24	4.0	1.002	5,140	7.16	1.34	38.24	5.05	6.39
7.77	4.5	1.288	6,950	9.68	1.81	34.36	4.54	6.35
7.37	5.0	1.619	8,740	12.17	2.28	31.25	4.13	6.41
7.03	5.5	1.989	10,740	14.96	2.80	28.79	3.80	6.60
6.73	6.0	2.403	12,970	18.06	3.38	26.59	3.51	6.89
6.46	6.5	2.862	15,450	21.52	4.03	24.80	3.27	7.30
6.23	7.0	3.363	18,160	25.30	4.73	23.24	3.07	7.80

Note 1) Power benefit was calculated based on MW value: M$ 209.1/year and MWh value M$37.289 when the discount rate of 10% was adopted. (refer to Section 6.4.)

2) For calculation of the construction cost, unit rates indicated in Section 13.2. were used.

3) 640 m^3/s was used as the maximum discharge for power generation.

From the result of the above, the optimum is when the flow velocity in the tunnel is in the range 4.5 m/s to 5.5 m/s.

Judging from the topography at the left bank of the dam where the penstock tunnel is located, it seems that the depth of cover over the tunnel may be low. With this in mind the diameters selected are 8.6 m for the two tunnels plan and 7.8 m for the three tunnels plan.

6.3.3. Number of Penstock Tunnel and Generation Unit

For the proper selection of the number of penstock tunnels and generation units, the power system, past experience of the manufacturer of generation units, transportation condition and ease of operation and maintenance shall be carefully considered. To determine the optimum plan from the economic view point, the construction costs of two cases, i.e. 1) two tunnels with two generation units and 2) three tunnels with three generation units were compared.

The following table shows the results of this comparison:-

Item		Two tunnels with two generation units	Three tunnels with three generation units
Waterway tunnel civil work	Excavation	104,250 m^3	114,990 m^3
	Concrete	20,370 m^3	26,280 m^3
	Cost	27.005 x 10^6M$	33.073 x 10^6M$
Powerhouse civil work	Excavation	235,000 m^3	247,690 m^3
	Concrete	74,000 m^3	78,290 m^3
	Cost	43.431 x 10^6M$	43.567 x 10^6M$
Electro-mechanical work	Period	23 months	26 months
	Cost	137.7 x 10^6M$	156.8 x 10^6M$
Total	Cost	208.1 x 10^6M$	233.4 x 10^6M$

Note 1) Excavation of the waterway tunnel includes for excavavation of the power intake. The volume of open excavation was converted into tunnel excavation using a unit ratio.

2) A tunnel diameter of 7 m corresponding to the flow velocity of 5.5 m/s was adopted for the three tunnels plan.

As understood from the above, there is little difference in the cost of the powerhouse civil work between two and three tunnels plans. Though small differences can be observed in the waterway tunnel and electro-mechanical works, the two tunnels plan is cheaper (by 25 x 10^6M$) than the three tunnels plan overall. Therefore, the two tunnels plan with two generation units is adopted for this project.

In this case, the diameter of tunnel and capacity of each generation unit becomes 8.6 m and 133.8 MW respectively.

6.3.4. Cross Section and Length of Tailrace Channel

An economic comparison was made to investigate possible optimization of the tailrace channel cross-section and its downstream location distance from the powerhouse. The results are shown below.

(1) Determination of the cross section of tailrace channel

The following table shows the power loss converted into monetary terms against variations of the channel slope, where 500 m has been adopted as the minimum length of tailrace channel.

Calculations are on the basis of a peak discharge of 640 m^3/s from the tailrace.

Waterway slope	Head loss m	kW loss	kWh loss	Loss benefit M$
			x10^6	x10^6
1/1000	0.500	2,697	3.748	7.032
1/1500	0.333	1,800	2.501	4.693
1/2000	0.250	1,348	1.874	3.515
1/2500	0.200	1,079	1.500	2.813
1/3000	0.167	897	1,247	2.339
1/3500	0.143	770	1.070	2.007
1/4000	0.125	676	0.940	1.763
1/4500	0.111	598	0.831	1.559
1/5000	0.100	539	0.749	1.405

The construction cost and annual cost relating to various cross-sections of the tailrace channel are shown below. A trapezoidal section was adopted for the channel and fixed at a slope of 1 to 1. As a parameter, the invert width was varied.

Invert width = 15 m

(cost: $x10^6$)

Waterway slope	Uniform flow depth (m)	Flow velocity (m/s)	Excavation (m^3)	Concrete (m^3)	Construction cost M$	Annual cost for the works M$	Total cost M$
1/1000	5.9	5.22	477,000	12,800	6.07	0.80	1.57
1/1500	6.6	4.51	501,000	13,400	6.37	0.84	1.36
1/2000	7.2	4.08	520,000	13,800	6.58	0.87	1.26
1/2500	7.6	3.74	536,000	14,200	6.78	0.89	1.20
1/3000	8.0	3.51	550,000	14,500	6.94	0.92	1.18
1/3500	8.3	3.31	561,000	14,700	7.06	0.93	1.15
1/4000	8.6	3.15	572,000	14,900	7.18	0.95	1.14
1/4500	8.9	3.02	576,000	15,200	7.28	0.96	1.13
1/5000	9.2	2.91	592,000	15,400	7.43	0.98	1.13

Invert width = 20 m

(cost: x 10^6)

Waterway slope	Uniform flow depth (m)	Flow velocity (m/s)	Excavation (m^3)	Concrete (m^3)	Construction cost M$	Annual cost for the works M$	Total cost M$
1/1000	5.1	5.06	512,000	9,500	5.56	0.73	1.50
1/1500	5.7	4.38	533,000	9,900	5.79	0.76	1.28
1/2000	6.2	3.96	551,000	10,300	6.00	0.79	1.18
1/2500	6.6	3.66	566,000	10,600	6.16	0.81	1.12
1/3000	7.0	3.44	581,000	10,900	6.33	0.84	1.10
1/3500	7.3	3.25	592,000	11,200	6.47	0.85	1.07
1/4000	7.6	3.10	602,000	11,400	6.59	0.87	1.06
1/4500	7.8	2.97	611,000	11,600	6.70	0.88	1.05
1/5000	8.1	2.87	621,000	11,800	6.81	0.90	1.05

Invert width = 30 m

(cost: x10^6)

Waterway slope	Uniform flow depth (m)	Flow velocity (m/s)	Excavation (m^3)	Concrete (m^3)	Construction cost M$	Annual cost for the works M$	Total cost M$
1/1000	4.1	4.73	590,000	11,000	6.42	0.85	1.62
1/1500	4.6	4.12	610,000	12,000	6.77	0.89	1.41
1/2000	5.0	3.73	630,000	12,100	6.93	0.91	1.30
1/2500	5.3	3.45	640,000	12,400	7.07	0.93	1.24
1/3000	5.6	3.24	654,000	12,600	7.21	0.95	1.21
1/3500	5.9	3.09	664,000	12,800	7.32	0.97	1.19
1/4000	6.1	2.94	675,000	13,000	7.44	0.98	1.17
1/4500	6.3	2.82	683,000	13,200	7.53	0.99	1.16
1/5000	6.5	2.72	691,000	13,300	7.61	1.00	1.15

Invert width = 40 m

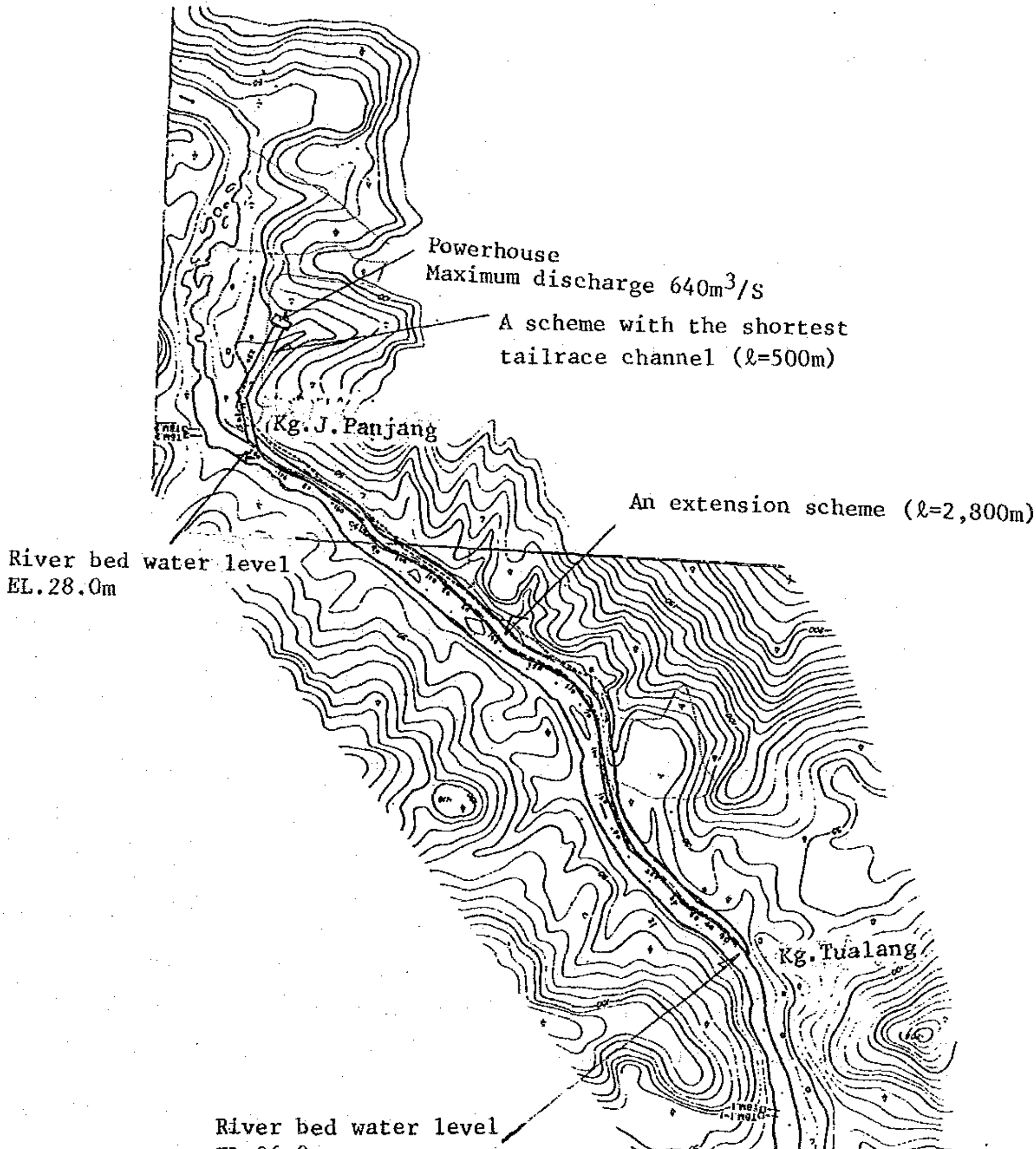
(cost: x10^6)

Waterway slope	Uniform flow depth (m)	Flow velocity (m/s)	Excavation (m^3)	Concrete (m^3)	Construction cost M$	Annual cost for the works M$	Total cost M$
1/1000	3.4	4.36	680,000	13,600	7.61	1.00	1.73
1/1500	3.9	3.86	700,000	14,000	7.83	1.03	1.55
1/2000	4.2	3.49	710,000	14,300	7.96	1.05	1.44
1/2500	4.5	3.25	727,000	14,500	8.12	1.07	1.38
1/3000	4.7	3.04	736,000	14,700	8.23	1.09	2.44
1/3500	5.0	2.91	750,000	14,900	8.37	1.10	1.32
1/4000	5.2	2.79	759,000	15,000	8.45	1.12	1.31
1/4500	5.4	2.68	769,000	15,200	8.56	1.13	1.30
1/5000	5.5	2.57	773,000	15,300	8.61	1.14	1.29

The above results show that the waterway with a gentle slope less than 1/3,000 is more economical and the invert width of 20 m becomes the most advantageous scheme. It is therefore proposed to adopt a scheme with the slope of 1/3,000 and an invert width of 20 m since this shows the lowest construction cost.

(2) Study on the length of tailrace channel

An extension scheme of the tailrace channel to further downstream near Kg. Tualang is studied in addition to a scheme with the shortest tailrace channel. The arrangements are shown on the following page.


Powerhouse
Maximum discharge 640m3/s
A scheme with the shortest
tailrace channel (ℓ=500m)
Kg.J.Panjang
An extension scheme (ℓ=2,800m)
River bed water level
EL.28.0m
Kg.Tualang
River bed water level
EL.26.8m

By extending the tailrace channel to 2,300 m downstream, 1.2 m of river head can be obtained. The slope of the tailrace channel for the extension portion will accordingly be 1.2/2,300 (=1/1,917).

Based on the above features, the economic evaluation was made as below:

Annual incremental benefit arising from an extension scheme of the tailrace.

kW value = 6,473 kW x M\$209/kW = 1.353 x M\$$10^6$
kWh value = 9.02 x 10^6 kWh x M\$0.0372/kWh = M\$0.336 x 10^6

Total M\$1.689 x 10^6

Additional cost relating to the extension scheme (2,300 m)

Construction cost M\$10,190/m
(based on a basis of invert width = 20 m
and slope of tailrace channel = 1/2,000

Thus, the total construction cost for the extension scheme becomes M\$23.437 x 10^6. The annual cost will therefore be M\$3.09 x 10^6 on a basis of a discount rate at 10%.

Benefit by cost for an extension scheme of the tailrace.

B/C = 1.689/3.09 = 0.547

As understood from the above, since only low economic benefits are expected from the above extension scheme, the tailrace channel scheme having a minimum length is to be adopted for this project as the optimum scheme.

6.3.5. Power Generation and Energy Production

Based on the basic features discussed in the foregoing Sections, the power generation and energy production as an optimum scheme are computed as stated below:

(1) Head losses in the waterway

Head losses for 640 m^3/s discharge during peak generation are calculated as follows:

Items	Waterway No.1 (m)	Waterway No.2 (m)
- Intake loss	0.118	0.118
- Screen	0.055	0.055
- Friction loss of tunnel	0.509	0.549
- Bend in tunnel	0.422	0.424
- Contraction of tunnel	0.003	0.003
- Draft tube	0.078	0.078
- Contraction of tailrace bay	0.037	0.037
- Lowering of water level of tailrace bay	0.566	0.566
- Slope of tailrace channel	0.179	0.179
- Other margin	0.363	0.348
Total	2.330	2.357

(2) Calculation result of reservoir operation

Stated below is a calculation result of the reservoir operation as discussed in Sections 6.2.2. and 6.2.3.

Basic condition for calculation:

HWL	80.0 m
LWL	60.0 m
Maximum discharge	640 m^3/s
River water level at the tailrace	28.0 m
Head loss	2.34 m
Overall efficiency of turbine and generator	0.88

Results of calculation

Maximum output	267.600 MW
Annual energy generated (Average of 35 years from 1950 to 1984)	373.28 GWh
Annual averaged plant factor	15.9%

Monthly energy generated

	GWh
March	26.50
April	23.84
May	25.98
June	23.63
July	22.64
August	22.64
Subtotal (Dry season)	145.23
September	22.91
October	28.20
November	36.70
December	68.98
January	44.65
February	26.61
Subtotal (Rainy season)	228.05
Total (throughout a year)	373.28

Monthly inflows, fluctuations of the reservoir inflow, level, power output and energy production for 35 years are illustrated in Figs.6-7, 6-8 and 6-9 respectively.

6.4. Evaluation of Power Benefits

The power benefits attributable to the Lebir Hydro-Power Plant can be evaluated according to costs which will be incurred in case the output and energy provided by this plant to the power system is substituted by other alternative power generation systems. These power benefits can be computed out of the two elements, fixed, and variable costs at the sending end.

6.4.1. Fixed Cost

Table 6-11 shows the calculation conditions and results of the fixed costs of the proposed power sources presently under consideration by NEB for development.

The following are the calculation results:

		Annual Fixed Cost ($/kW - Year) (Discount Rate = 0.1)
Peaking Gas-turbine	(G 90W)	243.98
Port Klang - type I	(G 300)	251.21
Port Klang - type II	(C 299)	362.62
Combined Cycle	(CCYE)	274.16
	(CCYW)	209.09
Coal-fired	(C 500)	375.27

The calculation results show that the combined cycle power plant CCYW (300 MW) is the lowest in fixed cost, and the coal-fired power plant C500 (500 MW) the most expensive.

6.4.2. Variable Costs

Table 6-12 shows conditions such as fuel price, etc., necessary for the calculation of variable costs. Out of those data, fuel prices other than coal, and the minimum load conditions, were based on the data of NEB, while other conditions were estimated by JICA Study Team.

Table 6-13 shows the calculation conditions and results of the variable costs of the proposed power sources presently under consideration by NEB for development. The station use rates were estimated by JICA Study Team from the data available.

From the calculation results, values at the rated loads are as follows:

Plant		Variable Cost ($/MWh) (in 1995)	Remarks ($/MBTU)	($/)
Peaking Gas-turbine	(G 90W)	42.220	3.3	
Port Klang - type I	(G 300)	32.869	3.3	
Port Klang - type II	(C 299)	48.135		113.7
Combined Cycle	(CCYE)	24.218	2.5	
	(CCYW)	31.328	3.3	
Coal-fired	(C500)	47.774		113.7

According to these calculation results, the combined cycle CCYE (291 MW) is the lowest in variable cost and the coal-fired C299 (300 MW) the most expensive.

6.4.3. Total Cost

Table 6-14 shows the total costs ($/kW - year) at the minimum loads (see Table 6-12), and at the rated loads calculated using annual fixed costs shown in Table 6-11, and variable costs in Table 6-12.