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DEMOCRATIC SOCIALIST REPUBLIC OF SRI LANKA

MINISTRY OF LANDS, IRRIGATION AND MAHAWELI DEVELOPMENT

THE STUDY ON EXTENSION OF THE MORAGAHAKANDA AGRICULTURAL DEVELOPMENT PROJECT

MASTER PLAN

(PHASE-II)

VOLUME-III ANNEXES

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LIST OF REPORTS

ABBREVIATIONS

CB	Central Bank of Sri Lanka
CEB	Ceylon Electricity Board
CECB	Central Engineering Consultancy Bureau
DA	Department of Agriculture
DCS	Department of Census and Statistics
FAO	Food and Agriculture Organization, United Nations
FD	Forest Department
GDP	Gross Domestic Product
GNP	Gross National Product
GOJ	Government of Japan
GOSL	Government of Sri Lanka
IBRD	International Bank for Reconstruction and Development (World Bank)
ID	Irrigation Department
IDB	Industrial Development Board
JICA	Japan International Cooperation Agency
MADR	Ministry of Agricultural Development and Research
MASL	Mahaweli Authority of Sri Lanka
MEA	Mahaweli Economic Agency
MECA	Mahaweli Engineering and Construction Agency
MFP	Ministry of Finance and Planning
MLLD	Ministry of Lands and Land Development
MMD	Ministry of Mahaweli Development
MTI	Ministry of Trade and Industries
NCP	North Central Province
NCRB	North Central River Basin
NWDZ	North-Western Dry Zone
SEDZ	South-Eastern Dry Zone
SD	Survey Department
UNDP	United Nations Development Programme
WMP	Water Management Secretariat
GA	Government Agent Division
AGA	Assistant Government Agent Division
GS	Grama Sevaka Division

REPORTS

MGDP	Master Plan Mahaweli Ganga Development Project (UNDP/FAO, 1968)
AMDP	Accelerated Mahaweli Development Programme (NEDECO, 1977)
ISS	Implementation Strategy Study (NEDECO,1978)
HCP	Hydrological Crash Programme (NEDECO, 1981)
TDS	Transbasin Diversion Study (Electrowatt, 1981 & 1984)
MWRMP	Mahaweli Water Resources Management Project (ACRES,1986)

ABBREVIATIONS OF MEASUREMENT

Length

cm = Centimeter
m = Meter
km = Kilometer
ft = Foot
yd = Yard

Area

cm^2 = sq.cm = Square centimeter
m^2 = sq.m = Square meter
ha = Hectare
km^2 = sq.km = Square kilometer

Volume

cm^3 = cu.cm = Cubic centimeter
l = lit = liter
kl = Kiloliter
m^3 = cu.m = Cubic meter
gal. = Gallon
MCM = Million Cubic Meters

Weight

mg = Milligram
g = Gram
kg = Kilogram
ton = Metric ton
lb = Pound

Time

sec = s = Second
min = Minute
h = Hour
d = Day
y = Year

Electrical Measures

V = Volt
A = Ampere
Hz = Hertz (cycle)
W = Watt
kW = Kilowatt
MW = Megawatt
GW = Gigawatt

Other Measures

% = Percent
PS = Horsepower
° = Degree
' = Minute
" = Second
°C = Degree centigrade
10^3 = Thousand
10^6 = Million
10^9 = Billion (milliard)

Derived Measures

m^3/s = m^3/sec = Cubic meter per second
cusec = Cubic feet per second
mgd = Million gallon per day
kWh = Kilowatt hour
MWh = Megawatt hour
GWh = Gigawatt hour
kWh/y = Kilowatt hour per year
kVA = Kilovolt ampere
BTU = British thermal unit

Money

Rs. = Sri Lanka Rupees
US$ = US dollar
Yen = Japanese Yen

CONVERSION FACTORS

	From Metric System			To Metric System		
Length	1 cm	=	0.394 inch	1 inch	=	2.54 cm
	1 m	=	3.28 ft = 1.094 yd	1 ft	=	30.48 cm
	1 km	=	0.621 mile	1 yd	=	91.44 cm
				1 mile	=	1.609 km
Area	1 cm^2	=	0.155 sq.in	1 sq.ft	=	0.0929 m^2
	1 m^2	=	10.76 sq.ft.	1 sq.yd	=	0.835 m^2
	1 ha	=	2.471 acres	1 acre	=	0.4047 ha
	1 km^2	=	0.386 sq.mile	1 sq.mile	=	2.59 km^2
Volume	1 cm^3	=	0.0610 cu.in	1 cu.ft	=	28.32 lit
	1 lit	=	0.220 gal. (imp.)	1 cu.yd	=	0.765 m^3
	1 kl	=	6.29 barrels	1 gal. (imp.)	=	4.55 lit
	1 m^3	=	35.3 cu.ft	1 gal. (US)	=	3.79 lit
	10^6 m^3	=	811 acre-ft	1 acre-ft	=	1,233.5 m^2
Energy	1 kWh	=	3,413 BTU	1 BTU	=	0.293 Wh
Temperature	°C	=	(°F-32) 5/9	°F	=	1.8°C + 32
Derived Measures						
	1 m^3/s	=	35.3 cusec	1 cusec	=	0.0283 m^3/s
	1 kg/cm^2	=	14.2 psi	1 psi	=	0.703 kg/cm^2
	1 ton/ha	=	891 lb/acre	1 lb/acre	=	1.12 kg/ha
	10^6 m^3	=	810.7 acre-ft	1 acre-ft	=	1,233.5 m^3
	1 m^3/s	=	19.0 mgd	1 mgd	=	0.0526 m^3/s

EXCHANGE RATE

US$1.0 = J. Yen 140.0 = Rs. 32.5

ANNEX-G

POWER MARKET AND HYDROPOWER

ANNEX - G

POWER MARKET AND HYDROPOWER

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ANNEX-G POWER MARKET AND HYDROPOWER

G.1 POWER MARKET

G.1.1 Organization

The organization diagram for the energy sector is shown in Fig. G.1-1. The principal Government authority in energy matters is the Ministry of Power and Energy. The two main state corporations under this Ministry are the Ceylon Electricity Board (CEB) and the Ceylon Petroleum Corporation. The Ministry has an Energy Coordinating Unit, which is in charge of coordinating energy matters with other Ministries and government bodies.

The entire public power supply system in Sri Lanka is undertaken by the CEB which was established in 1969. The CEB is presently supplying electric power and energy to its consumers both directly and indirectly through the Lanka Electricity Company (LECO). The LECO was established in 1983 to take over and improve the retail supply of power within municipalities, previously handled by 218 local authorities, who obtained bulk supplies from the CEB.

The organization structure of the CEB as of February 1988 is shown in Fig. G.1-2. The CEB is managed by General Manager under the supervision of 8 member Board of Directors. The CEB has the following six departments besides managerial organization: Commercial, Generation Group, Region A, Region B, Transmission and Generation Projects, and Transmission and Generation Planning. Each department is controlled by an Additional General Manager or Deputy General Manager.

G.1.2 Existing Power Supply System

The Sri Lanka power supply system (CEB System) is predominantly dependent on hydropower. Thermal powerplants are used for backing up the hydro-shortfalls and to tide over interim periods between commissioning of hydropower plants. There are two existing hydropower complexes in Sri Lanka; Kehelgamu-Maskeli Complex and Mahaweli Complex.

The total installed capacity of generating facilities owned by CEB has reached 1,116 MW in 1988, consisting of 916 MW of hydropower plants and 200 MW of thermal powerplants. Out of the said facilities, hydropower plants can generate 3,682 GWh under normal hydrological conditions, supplemented by a firm thermal availability of 1,265 GWh, according to the CEB's estimates. Under very dry conditions, hydro energy reduces to a firm level of 2,538 GWh, giving a firm energy output of 3,803 GWh with thermal energy. A list of the existing powerplants are given in Table G.1.1. The location of powerplants is shown in Fig. G.1-3.

The transmission network in Sri Lanka uses voltages of 220 kV, 132 kV and 66 kV. Voltages of 220 kV and 132 kV are employed for the trunk lines and voltage of 66 kV is applied for short distance only. The length of transmission lines was 1,688 km as of the end of 1987, consisting of 122 km of 220 kV line, 1,199 km of 132 kV line and 367 km of 66 kV line. The transmission network is presented in Fig. G.1-3.

There were 31 grid substations as of the end of 1986, of which 3 are operated with a primary voltage of 220 kV, 24 with 132 kV. Primary distribution is made by 33 kV and 11 kV lines and their lengths as of 1985 are 7,909 km and 1,145 km respectively.

Load dispatching in the generation and transmission system in Sri Lanka is centralized at the CEB System Control Center located at Kolonnawa.

G.1.3 Present Power Demand

The power demand of the CEB system in 1987 is summarized as follows:

Sold energy (GWh)	2,253	
- Domestic and religions	382	(16.9%)
- Small and medium industries	489	(21.7%)
- Heavy industries	378	(16.8%)
- Commercial and hotels	418	(18.6%)
- Local authorities	571	(25.3%)
- Street lighting	15	(0.7%)
Energy losses (GWh)	454	
Energy generation (GWh)	2,707	
Peak Power demand (MW)	570	
Annual load factor (%)	54.2	

The generation in 1987 was affected by the power cuts imposed between August 12 and September 30, from noon to 2:00 p.m. and from 4:30 to 6:00 p.m. The production restrictions were caused by a persistent drought, which resulted in less than expected hydro output, and to a lesser degree by malfunctioning of some of generating plant. The total generation in 1987 was 2,707 GWh, only 2% higher than in 1986. Without the power cuts the generation could have been about 2,750 GWh or 3.7% higher than in 1986. The peak demand reached 570 MW, up by 5.6% from 540 MW peak in 1986. The total energy sales of the CEB in 1987 amounted to 2,253 GWh, up by 0.9% from the previous year's figure of 2,232 GWh. The power cuts record is shown in Table G.1.5.

These are low growth rates when compared with past rates and are likely to be the result of less than optimal performance of Sri Lanka's economy due to the civil disturbances in the country, and to a lesser extent also due to low outputs in the agricultural sector, as a result of the 1986/87 drought.

G.1.4 Power Tariff

The electric base tariff presently effective in the fiscal year 1988 is shown in Table G.1.2. The average tariff of CEB on the whole of Sri Lanka in 1986 was Rs. 1.50 per kWh.

G.1.5 Historical Trend of Power Market

The historical trend of peak power demand and energy sales and generation in the past 16 years are shown in Table G.1.3 and Fig. G.1-7.

Total energy consumption has increased at an average rate of 9% since 1965. However, the trend for the recent six years showed a lower rate (8%) due to insufficient power generating capacity, or in other words, supply constraints in 1980 and 1981. In 1983, a decline in the volume of water stored by the dams due to long-term drought and increased unit costs of thermal generation due to increased oil prices resulted in a low growth rate for energy consumption.

The installed capacity and generated energy by hydropower plants and thermal powerplants since 1975 is presented in Table G.1.4. Installed capacity and generated energy by hydropower development could not keep pace with the rapid demand increase from 1978 and thermal generation has accordingly increased yearly from 1978. The power situation was, however, improved in 1984, with the completion of the Victoria hydropower station and the Sapugaskanda diesel powerplant.

Transfer of thermal power to hydropower also has been progressed and the generated energy by hydropower plants rapidly increased yearly from 1984. In 1984, due to the large share of generated output attributed to hydropower, fuel energy cost largely decreased. These facts show the importance of hydropower development in Sri Lanka which is a non-oil producing country and presently suffers from a trade balance deficit.

G.1.6 Power System Load Characteristics

The recorded values of annual energy consumption and peak demand have resulted in annual load factors varying between 51.6% in 1980 and 57.4% in 1962, with an average value of 54.5% over the period 1961-1985.

Fig. G.1-4 shows hourly load curves taken from CEB records in 1986. The load curves indicate a 24-hour base load of about 200 MW (about 40% of peak), a 16-hour middle range load of about 300 MW (about 60% peak) and a 2-3 hour peak load of about 500 MW. This daily load pattern is typical throughout the year as seasonal effects are not very significant.

A normalized typical weekly load duration curve derived from daily load curve is shown in Fig. G.1-5(1). The average weekly load factor is 52%. Fig. G.1-5(2) gives the normalized annual load duration curve, with a load factor of 55%. It is seen that the annual curve is similar in general form to the weekly curve, although somewhat elongated. This reflects the fact that there is relatively little change in load levels through the year due to seasonal effects, and the annual curve essentially represents the aggregated weekly load curves.

Table G.1.6 and Fig. G.1-5(3) show the monthly peak load variation based on recorded data from the period 1972-1986, having the two cases; the monthly values derived from the actual historical records including the underlying annual growth in demand, and the monthly values detrended for the annual growth to give the purely seasonal variations. It is seen that there are only small and irregular deviation from the mean monthly value except in April.

G.1.7 Demand Forecast

A number of independent forecasts have also been carried out by various consultants, notably Sir Alexander Gibb & Partners (November 1978), Sogreah (December 1978), NEDECO (January 1979), Black & Veatch International (BVI - March 1985), and Lahmeyer International (1986).

The most recent of these is the Lahmeyer work of 1986, which was carried out in close cooperation with staff from the CEB Commercial Branch and represented a major effort to upgrade and extend CEB's forecasting procedures and methodology. Full details are represented in Table G.1.7, for reference.

The commercial branch of the CEB is responsible for making forecasts of electricity demand as the basis for planning of the development of the generation and transmission systems. The CEB forecasts are updated annually, based on the latest available statistics, as well as past trends is electrical demand growth.

CEB's latest official forecast, referred to in "Long Range Generation Expansion Plan - 1987", prepared using the trend method, is so called "Planning Forecast" based on the latest available data, and is considered to be consistent with long-term historical growth rates. In addition to this "Planning Forecast", "high" and "low" band forecast (respectively 10% above and below the planning forecast) were developed for the purposes of sensitivity analysis.

The planning forecast represents a CEB's current best estimate of future demand growth and is officially adopted as their basis for generation system planning. Although the CEB's forecast was prepared up to year 2002, it is tentatively extended to year 2020 in this study, assuming appropriate growth rates, for planning purpose.

According to the forecast, power demand growth is anticipated at a rate of 8.2% for 1988 to 1990, 10% for 1991 to 1995, 9.5% for 1996 to 2000, 8.5% for 2001 to 2005, 8.0% for 2006 to 2010, 7.5% for 2011 to 2015 and 7.0% for 2016 to 2020. The peak power demand and generation forecast are summarized as follows and shown in Table G.1.8 and Fig. G.1-7.

Year	Peak Demand (MW)	Generation (GWh)	Load Factor (%)
1988	593	2,990	57.5
1990	682	3,500	58.5
1995	10,890	5,630	59.0
2000	1,710	8,860	59.0
2002	2,020	10,430	59.0
2005	2,580	13,320	59.0
2010	3,780	19,580	59.0
2015	5,440	28,110	59.0
2020	7,630	39,420	59.0

G.2 HYDROPOWER SITUATION AND POTENTIAL

G.2.1 Existing and On-going Hydropower Stations

Hydropower is an essentially valuable resource in Sri Lanka, since coal and petroleum resources have not yet been found. The Government has consequently and continually pursued a policy of hydropower development.

Hydropower development was implemented in the Kehelgamu-Maskeli basin in 1950, while the Mahaweli development was commenced in the late 1960. Since then, hydropower development had been continued. In 1978, the Government formulated the Accelerated Programme to spur development of the Mahaweli Ganga. Under the Accelerated programme, a series of large scale hydropower development schemes have been planned and almost completed.

The majority of the existing hydropower plants comprises two main cascade system; the Kehelgamu-Maskeli (K-M) Complex, and the Mahaweli Complex. The Kehelgamu-Maskeli Complex consists of the Old Laxapana I (25MW), Old Laxapana II (25MW), New Laxapana (100 MW), Wimalasurendra (50 MW), Samanala (75 MW) and Canyon I (30 MW) power stations, totalling 305 MW in installed capacity. The Mahaweli Complex is composed of the Ukuwela(38 MW), Bowatenna (40 MW), Victoria (210 MW), Randenigala (122 MW) and Kotmale (201 MW) power stations, totaling 611 MW in installed capacity.

The Kehelgamu-Maskeli Complex develops a water head of 1,045 m and it creates reservoirs having a net storage capacity of 163 MCM. The Mahaweli Complex has a water head of 640 m and a net reservoir storage of 900 MCM.

In addition to the existing power stations, there are three power stations under construction; Canyon II (30MW), Samanalawewa (120MW) Rantembe (50MW) in the Mahaweli Complex, and on-going Moragahakanda power station (25 MW).

G.2.2 Proposed Hydropower Schemes

The various existing, under construction and candidate hydropower schemes are diverse in character and location, ranging from run-off-river to over year storage plants. They are estimated to be equivalent to about 2,000 MW, of which 1,116 MW are already developed or under construction as mentioned in the previous Sub-section G.2.1.

There are many candidate hydropower schemes in the Kehelgamu-Maskeli Complex and the Mahaweli Complex previously selected by the CEB and various consultants. Out of these schemes, the followings were given high priority of development by the CEB: Broadland (40 MW), Kukule (180 MW), Jasmin (100 MW), and Caledonia (44 MW), Talawakele (204 MW), Kotmale Extension, Upper Uma Oya (150 MW) and Lower Uma Oya (96 MW) situated in the Mahaweli Complex. As for the Caledonia and Talawakele schemes located in the Upper Kotmale Oya basin, the feasibility study was completed by JICA in August 1987. Regarding the Kotmale Extension, the basic design was prepared by the Mahaweli Authority in October 1985. The locations of the proposed schemes by the CEB shown in Fig. G.2-1.

In addition, the Moragahakanda Project located in the Amban Ganga, having the dual purpose of hydropower and irrigation, was proposed for development in a Feasibility Report in 1979 (JICA), and the updating for this report was completed for early implementation in May 1988. Under the present Polgolla diversion policy, i.e. long term average of 875 MCM, optimization of the reservoir capacity was carried out in the Supplementary Note of the updated Moragahakanda Project in March 1989. This project will have the power station with an installed capacity of 25 MW (2x12.5 MW).

Further to the above-mentioned schemes, this study proposed the four hydropower schemes in the Mahaweli Complex according to the preliminary technical and economic study based on the result of the field reconnaissance and existing data such as topographical maps and geological information; Watawala and Ulapane in the main stem of the Mahaweli Ganga,Wewatenna in the Badullu Oya, a tributary of the Mahaweli Ganga, and Sudu Ganga, a tributary of the Amban Ganga. In this study, it was taken into account that the schemes would have reservoirs to be able to regulate seasonal runoff fluctuation, and also to contribute to irrigation located in the downstream area.

As mentioned above, the following hydropower schemes located in the Mahaweli Ganga basin were selected for this master plan study:

(1) Watawala
(2) Ulapane
(3) Caledonia
(4) Talawakele
(5) Kotmale Extension
(6) Upper Uma Oya (Scheme-1000)
(7) Lower Uma Oya (Scheme-500)
(8) Wewatenna
(9) Sudu Ganga

The locations of the selected hydropower schemes are shown in Fig. G.2-2. The principal features of the selected hydropower schemes for the Master Plan are presented in Table 2.4.

G.2.3 Study on Hydropower Plant for the Proposed Schemes

The study on hydropower plant for the proposed schemes was made, based on the following assumptions, conditions and criteria:

(1) Output of generating unit is calculated by the following formula:

$$P = 9.8\ Q.He.\ Ut.Ug.$$

Where,
P : Power output (kW)
Q : Plant discharge (m^3/sec)
He : Net Head (m) = H - h
H : Gross head (m)

h	:	Head loss (m)
Ut	:	Turbine efficiency
Ug	:	Generator efficiency = 0.98

The turbine efficiencies are obtained from the simplified formula, which is represented as a function of net head, as shown below:

Hmax	:	Maximum net head (m)
Hrated	:	Rated head (m)
Hmin	:	Minimum net head (m)
Ut	:	Turbine efficiency
H=Hrated	:	Ut = C1
H> Hrated	:	Ut = C1-C2(H-Hrated)/(Hmax-Hrated)
H< Hrated	:	Ut = C1-C3(H-Hrated)/(Hrated-Hmin)

	C1	C2	C3
Hmax< 150 m	0.930	0.040	0.055
150m <Hmax< 400 m	0.945	0.065	0.080
400m < Hmax	0.900	0.020	0.020

The head loss at each plant discharge, consisting of friction loss of headrace tunnel and penstock line and minor losses, is presented by the following formula:

$$h = hmax\,(Q/Qmax)^2$$
$$= C \cdot Q^2$$

Where,	h	:	Head loss at plant discharge Q, (m)
	hmax	:	Head loss at max.plant discharge Qmax, (m)
	C	:	Coefficient = hmax/ $(Qmax)^2$

(2) Rated output/installed capacity and maximum plant discharge are obtained by the following equations:

$$Pmax = Pf/(p.f.)$$
$$Pf = 9.8\ Qf \cdot Hf \cdot Ut \cdot Ug$$
$$Qmax = Pmax/9.8\ Hr \cdot Ut \cdot Ug.$$

Where,	Pmax	:	Rated output (Installed capacity) (kW)
	Pf	:	Firm power output (kW)
	p.f.	:	Plant factor
	Qf	:	Firm discharge (m^3/sec)
	Hf	:	Net head at firm discharge (m)
	Qmax	:	Maximum plant discharge
	Hy	:	Rated head (m)

(3) By simulation calculation of monthly power output for the period, for which monthly mean discharge data are available, monthly power output for each month was obtained. The 90% dependable maximum power output was assumed as the effective peak power output of the due month. The mean value of the peak power output of 12 months from January to December was defined as the dependable peak power output.

(4) The 90% dependable mean power output was assumed as the effective mean power output of the due month. The mean value of the effective mean power output of 12 months from January to December was defined as the firm power output. The firm energy output was obtained by multiplying the firm power output by annual operative hours at 8,760 hours. The average annual energy output is the mean value of annual energy output for the period, for which monthly mean discharge data are available. The secondary energy output is the balance between the average annual energy output and the firm energy output.

(5) The plant factor of 20% (about 5-hour peak operation) was adopted for determination of the rated output (installed capacity) in preliminary economic analysis.

(6) The type of turbine was selected in accordance with the head and discharge as shown in Fig. G.2-3.

(7) The following consideration was taken into account to decide the number of units in the case study. In general, the hydroelectric power plant has to be operated in a wide range of the operating heads and in many cases a considerable and seasonal variation of the flow. In this connection, large units operating with the small gate openings have a low efficiency, excessive vibration, and accelerated damage from cavitation.

Based on the above assumptions, conditions and criteria, the principal features for the proposed hydropower schemes were obtained as shown below:

Scheme	Installed Capacity (MW)	Max.Plant Discharge (m^3/sec)	Rated Head (m)	Annual Energy (GWh)	Type of Turbine (Nos.)
(1) Watawala	18	11.5	179	49 (31,18)	Francis (2)
(2) Ulapane	44	47.5	109	91 (95,16)	Francis (3)
(3) Caledonia	44	35.0	144	135 (70,65)	Francis (1)
(4) Talawakele	204	50.0	468	674 (364,310)	Francis (3)
(5) Kotmale Extension	240	112.3	233	49 (209,-150)	Francis (3)
(6) Upper Uma Oya (Scheme-1000)	150	39.7	434	342 (201,141)	Pelton (3)
(7) Lower Uma Oya (Scheme-500)	96	45.5	251	310 (192,118)	Francis (3)
(8) Wewatenna	22	22.8	114	42 (22,20)	Francis (2)
(9) Sudu Ganga	45	101.2	47	122 (74,48)	Francis (2)

Remarks : (1) The values in brackets of annual energy show firm and secondary energies.

G.2.4 Hydropower Generation

The range of hydrological characteristics of the different plants, (together with the seasonal storage available in several of the schemes, particularly the plants forming the Mahaweli Complex) will allow the CEB considerable operational flexibility to balance generation and spillage between the plants and to maximize the overall level of firm hydropower energy output. When operated in this way, the system is referred to as the "Integrated Hydropower System" and the total level of firm energy is termed as the "System Firm Energy".

Both the CEB itself and a number of its consultants have carried out studies to determine the integrated system output under various conditions. Apart from differences in the basic assumptions, the computed results also vary due to differences between the computer models used, both as to the detail with which the system is represented and as to the algorithms adopted for reservoir operations. Based on its own studies, the CEB has defined an approximate relationship for the integrated system output as the sum of the individual unit firm energies plus 25% of the sum of the unit secondary energies.

The most recent estimates of the integrated system output carried out by CEB, using the latest available hydrological data, are referred to in the "Long Range Generation Expansion Plan, August 1987". Its summary is shown in Table G.2.1, together with the output of the proposed schemes, which was estimated by the water balance study in ANNEX L. According to the said table, the total installed capacity and annual energy in the integrated system are 2,314 MW and 7,074 GWh, comprising firm energy of 4,989 GWh and secondary energy of 2,085 GWh.

G.2.5 Position of Hydropower in the Future System

In principle, a development programme of powerplant in the future system is prepared, based on the result of economic analysis applying certain criteria. The CEB has carried out the economic analysis employing the least-cost criteria to establish the development programme upto 2002, and its result is referred to in the "Power Generation Expansion Plan, August 1987". According to this programme, it was recommended that thermal powerplants such as coal-fired and diesel plants would be introduced to the system, after commissioning of the Samanalawewa Hydropower Station in 1993, instead of hydropower plants.

Besides the said expansion programme based on the economic analysis, availability of the natural resources in Sri Lanka should be taken into account in the preparation of future expansion programme. Coal and petroleum resources as fuel for thermal plants have not yet been found in Sri Lanka. In this situation, hydropower is an essentially valuable resource in Sri Lanka. In this view, it is recommended that the available hydropower potential should be developed as much as possible. As a result of this hydropower development, foreign exchange saving will be made by reducing imports of coal and petroleum. The Government has consequently and continually pursued a policy of hydropower development.

Assuming that the hydropower plants would be developed in combination with the thermal powerplants, a load sharing of the said two powerplants in the future system was demonstrated on the assumed annual load duration curve according to the following assumptions and conditions :

(1) A future load duration curve was assumed by modifying the current load duration curve, as shown in Fig. G.1-5(2), from 55% to 59% annual load factor.

(2) Base and middle loads in the system would be covered by the thermal powerplants, while peak loads would be shared by the hydropower plants.

(3) Demonstration of the system load sharing was made for the two cases: an integrated system of existing and under construction hydropower plants (Case 1), and integrated system of all hydropower plants including proposed plants (Case 2).

(4) The system marginal reserve was assumed to be 15% of the total installed capacity of the system powerplants.

(5) The firm energy to be generated by the integrated hydropower system was adopted for the demonstration of system load sharing. Such condition would be in the driest year. The plant factors for the integrated hydropower system are 0.33 for Case 1 and 0.26 for Case 2, as referred to Table G.2.1

(6) The secondary energy, which will be produced by the integrated hydropower system in richer hydrological years than the driest year would cover some portions of middle and base load portions instead of thermal energy. For this case, the system load sharing was also demonstrated on the annual load duration curve. The plant factors of the integrated hydropower system are 0.46 for Case 1 and 0.39 for Case 2.

Based on the above assumptions and conditions, the load duration curves showing the load sharing were obtained as shown in Fig. G.2-4. The load allotment is summarized in Table G.2.2.

According to the results in Table G.2.2, the plant factor of the integrated hydropower system would just meet that of the peak portion of the annual load duration curve in 1998 for Case 1 (existing and under construction plants) and in 2008 for Case 2 (existing, under construction and proposed plants). These load allotments are called the "Ideal System Load Allotment".

For Case 2, there is insufficient time to develop the eleven proposed hydropower schemes upto 2008 with financial resources available aspect. Therefore, an appropriate interval-stage hydropower development was tentatively adopted and the system power generation expansion plan, in combination with thermal power development was prepared for reference as shown in Table G.2.2 and Fig. G.2-5.

G.2.6 Description of the Proposed Hydropower Schemes

The design conditions and criteria of the proposed hydropower schemes are mentioned in the later ANNEX-K. Based on the design condition and criteria, the design of the project facilities and structures was made, and the major features of each scheme are presented in Table G.2.4. It is noted that the Wewatenna scheme was deleted from the list of the proposed schemes, since the economic evaluation showed that the scheme is not feasible. The followings are the description of the proposed hydropower schemes:

(1) Watawala Scheme

The proposed Watawala damsite is located about 2 km upstream from the bridge near Watawala in the main stem of the Mahaweli Ganga. The catchment area at the damsite is 69 km^2. The valley narrows at this point, and topographic and surface geological conditions indicate that it will be possible to construct a concrete gravity dam to the height required at this location for optimum site development.

Field observations show the rock types of the damsite to be mainly interbedded garnetiferous quartz-feldspathic gneiss (type khondalite) and charnockitic gneiss. The slope to the river is about 40° and apart from isolated blocks of gneiss at the riverbed level, there is little talus overburden. The rock in limited exposure is well weathered and drilling will be required to determine the depth of the weathering.

From the above topographic and geological conditions, a concrete gravity type was selected as the dam type. The dam crest is set at EL. 1,034 m. The dam has a total volume of 92,000 m^3 with 60 m high and 200 m long. The gated overflow spillway is located at the middle portion of the dam.

The reservoir high and low water levels were designed to be EL. 1,032 m and EL. 1,024 m respectively. The said drawdown creates a net storage capacity of 20 MCM. The average annual runoff of 3.9 m^3/sec or 123 MCM flows into the reservoir from the river basin with a catchment area of 69 km^2.

A diversion tunnel with 6 m diameter and upstream and downstream cofferdams will be constructed at a distance of 150 m in the left bank to keep dry conditions for dam construction.

The headrace tunnel (2,100 m long and 2.4 m in diameter) is routed along the river course in the left bank. The penstock and powerhouse were designed to be of above-ground type. The penstock line has a length of 220 m and inside diameter varying from 2.2 m to 1.7 m. The powerhouse is positioned just downstream of the waterfall. The tailwater level is set at EL. 840 m. The rock formation of the headrace tunnel route and powerhouse site is all interbedded gneiss (charnockite) through garnetiferous quartz-feldspathic gneiss with graphite flakes (most prevalent) to limestone, although no exposures of the latter were observed at the site. The powerhouse accommodates the generating equipment of two units (9MW each).

The proposed quarry site is a thick-bedded and massive charnockite hill with thin overburden located in the right bank of the Mahaweli Ganga. The charnockite is a good resistant construction material which forms a satisfactory concrete aggregate. The transportation distance will be 1 to 2 km.

The general plan and profile of the Watawala scheme are shown in Fig. G.2-6.

(2) Ulapane Scheme

The proposed Ulapane damsite is situated about 600 m downstream from the confluence of the Kotmale Oya with the main stem of the Mahaweli Ganga. This site is suitable for construction of a dam across the relatively narrow gorge. The catchment area at the damsite was estimated at 237 km^2.

Field observations show that the rock types of the damsite consists mainly of interbedded garnetiferous quartz-feldspathic gneiss (type khondalite) and charnockitic gneiss. Apart from blocks of gneiss at riverbed level, there is little talus overburden. It seems that there is no geological problem for construction of a rockfill dam, if an appropriate foundation treatment is applied.

The rockfill dam has a total filling volume of 2.4 MCM with the crest at EL. 603 m (500 m in crest length and 70 m high). The proposed quarry site is located at the left bank hill, which is formed by a thick-bedded and massive charnockite. This rock is suitable as fill materials and concrete aggregate. The transportation distance will be 2 to 3 km. Impervious material will be obtained from a gently sloping hill on the right bank about 2.5 km downstream of the damsite. Available rockfill and impervious materials will be sufficient for the required filling volume.

The overflow spillway equipped with gates is constructed in the right abutment of the rockfill dam.

The diversion conduit is made in the spillway body to divert river water during dam construction. Immediately after completion of the diversion conduit with an appropriate height of spillway body, the upstream and downstream cofferdams are constructed.

A 10 m drawdown of the reservoir between the high water level at EL. 600 m and the low water level at EL. 590 m creates a net storage capacity of 150 MCM. The reservoir receives the average annual runoff of 13.4 m^3/sec or 423 MCM from the catchment basin.

The headrace tunnel (5,000 long and 4.5 m in diameter) was designed to be aligned in the left bank of Mahaweli Ganga. The penstock line (200 m long) and powerhouse are of the above-ground type. The diameter of the penstock pipe varies from 2.8 m to 2.4 m. The powerhouse, which accommodates the generating equipment with two units of 22 MW, is located at the opposite side of the outlet of the tailrace tunnel of the existing Kotmale Power Station. The tailwater level is set at EL. 480 m.

The rock formation for the headrace tunnel route and power station site is composed of a basic hypersthene gneiss (charnockite) and limestone.

The general plan and profile of the Ulapane Hydropower scheme are presented in Fig. G.2-7.

(3) Caledonia Scheme

The Upper Kotmale Hydropower Development consists of the Caledonia scheme and the Talawakele scheme. The Caledonia scheme is the upstream scheme. The general plan and profile of the Upper Kotmale Hydropower Development are exhibited in Fig G.2-8.

The preliminary designs of the project structures has been made in the Feasibility Study prepared by JICA in 1987. The followings are the summary of the design:

The proposed Caledonia damsite is located about 800 m downstream from the confluence of the Dambagastalawa Oya and Agra Oya, upper tributaries of the Kotmale Oya. The catchment area at the damsite is 235 km^2 including those of the tributary intakes, which would yield an annual average runoff of 13 m^3/sec or 432 MCM. The Caledonia damsite is positioned on the unnamed anticline which plunges upstream of the site.

Rock at the Caledonia damsite is very hard and compact charnockite with relatively minor jointing and schistosite. Foundation of the dam accordingly puts no particular constraints on selection of dam type. On the basis of topographical features at the site, either a concrete gravity type or fill type is considered appropriate. A comparative study in terms of construction cost resulted in choice of the concrete gravity type as more economically favorable. The main dimensions of the dam are: crest EL. 603 m, 500 m long in crest, and 70 m high. The dam has a total concrete volume of 250,000 m^3.

A non-gated open spillway was designed to be provided in the nearly entire width of the dam. The spillway is of the overflow type.

The diversion tunnel method was selected from economical point of view. The diversion tunnel of a standard horseshoe type with 7.2 m diameter and 395 m long was laid out on the left bank.

Reservoir high and low water levels were determined at EL. 1,360 m and EL. 1,353 m respectively. The drawdown provides a net storage capacity of 30 MCM. A flood control space of 3.5 m is reserved above the high water level.

The general plan and typical cross section of the Caledonia dam are exhibited in Fig. G.2-9.

The headrace tunnel route from Caledonia dam to Caledonia power station was planned along the St. Clair syncline. As few fissures are present in the syncline structure, it is well suited for a tunnel. Accordingly no special problems are anticipated in tunnel excavation.

The headrace tunnel has a total length of 3,300 m and an inside diameter of 3.9 m.

The penstock line, powerhouse and tailrace were designed to be of the underground type. The penstock tunnel, consisting of the inclined and horizontal portions, is 218 m in total length and an inside diameter varying from 2.8 m to 2.4 m. The powerhouse will have a space to house the generating equipment: one unit of 44 MW. The tailwater level is controlled by the reservoir water level of the Talawakele, varying from EL. 1,200 m to EL. 1,193 m.

(4) Talawakele Scheme

The Talawakele scheme is the downstream scheme of the Upper Kotmale hydropower development. The preliminary design was prepared in the Feasibility Study performed by JICA in 1987. The following is a summary of the design:

The Talawakele damsite is located about 350 m downstream from Talawakele railway bridge. The topographic maps and site reconnaissance indicate that the valley narrows at this point and is therefore suitable for dam construction.

The Talawakele area is underlain by metamorphosed sediments of the Khondalite Series, comprising quartzite, khondalite (quartz-feldspar-garnet gneiss), and charnockite (medium-grained gabbroic rock). At the damsite, the predominant rock type is a massive charnockite which is satisfactory as a foundation and for concrete aggregates.
The topographic and surface geological conditions indicate that it is feasible to construct a dam to the height required at this location. However, the reservoir inundates the town of Talawakele, and extensive road and rail facilities.

The concrete gravity dam consisting of gated overflow section and non-overflow section was selected as the dam type in view of technical and economical points. The dam has a concrete volume of 18,000 m^3 with dimensions of crest EL. 1,203 m, crest length 102 m and height 30 m.

The 7 m drawdown between the high water level at EL. 1,200 and low water level at EL. 1,193 m provides a net storage capacity of 2 MCM utilized for daily regulation.

The half closure coffering method will be adopted as a temporary diversion work in view of lower construction cost and construction period than a diversion tunnel method.

The plan and elevation of the Talawakele dam are presented in Fig. G.2-10.

The Talawakele Scheme has an overall long tunnel, and both headrace and tailrace tunnels are in pressure. The headrace tunnel with 13,066 m long and 4.4 m diameter, passes through the Talawakele structure bend and intersects the Belton-Meddecumbura anticline and parallel NW-SE tending lineament.

The Talawakele scheme has four tributary intakes, consisting of the Devon Oya, Puna Oya No.1 and No.2 and Pudal Oya intakes. The catchment areas of the Talawakele scheme were estimated at 363 km^2 on the Kotmale Oya and 66 km^2 on the tributaries. The annual average runoff from these catchment basis is 21.1 m^3/sec or 665 MCM.

As the power station is to be underground, the penstock is likewise an underground structure. For the underground penstock, the penstock structure is of the buried type, with concrete backfilling between the excavated line and pipe, in view of good geological conditions and economic considerations. The pipe inside diameter varies from 4.7 m to 3.4 m. The penstock length is 734 m.

Due to topographical constraints, the power station was planned to be the underground type. The powerhouse has a space to accommodate three units (68 MW each) of generating equipment. The Talawakele power station was planned for construction within a broad syncline structure. As almost all excavation is to be within level gneiss (khondalite), no special problems are expected. Bedding is highly stratified, and the danger of a rock burst is anticipated to be minor.

The tailrace outlet is located in the left bank of the Kotmale Oya, about 20 km downstream from the confluence with the Pundal Oya.

(5) Kotmale Extension Scheme

The existing Kotmale Project is one of the five major headworks projects undertaken under the AMDP. The Kotmale Project has a 87 m high rockfill dam at Kadadora village in Nuwara Eliya District, across Kotmale Oya, a right bank tributary of the Mahaweli Ganga. The catchment area at the damsite is 562 km^2. The dam created a reservoir having an effective storage capacity of 174 MCM between the high water level at EL. 703 m and low water level at EL. 665 m, corresponding to about 18% of the average annual inflow of 984 MCM at the damsite (1949-87). A chute spillway equipped with 4 radial gates is located on the right abutment of the dam.

Water impounded in the reservoir is taken at a power intake situated on the right periphery of the reservoir at about 230 m upstream of the dam axis. It is conveyed through a headrace tunnel of horse-shoe shape, 4.3 m diameter in initial 165 m and 4.4 m diameter in the balance 6,450 m upto surge shaft, and a pressure shaft of circular shape, 4.3 m diameter in the first 215 m and 3.8 m diameter in the balance 185 m long.

An underground powerhouse accommodates 3 units of generating equipment (3 units x 67 MW) with Francis turbines operating under a rated head of 201.5 m. The powerhouse cavern is located on the left bank of the Attabage river near its confluence with the Mahaweli Ganga. A 1,402 m long tailrace consisting of 1,128 m long tunnel and 275 m long cut and cover conduit of horse-shoe section of

4.4 m diameter connects to the Mahaweli Ganga. The tailwater level is at EL. 480 m.

The basic design of the future raising (extension) of dam and spillway has been made in the Report on Future Raising of Dam and Spillway prepared by MASL in October 1985. The followings are the summary of the design.

The reservoir high water level is raised from EL. 703.5 m to EL. 731.5 m and the existing low water level is maintained. This raising arises the increase of the effective storage volume from 174 MCM to 383 MCM, corresponding to about 39% of the recorded average annual inflow at the damsite (1949-86).

The dam crest is set at EL. 735 m. The construction to be carried out by raising of the dam crest consists of additional foundation excavation, foundation treatment and additional embankment of about 4.4 MCM. The crest level of spillway is proposed to be at EL. 716.5 m as against EL. 688 m of the existing level. The additional construction works of spillway is composed of additional concrete work of spillway section, provision of non-overflow blocks at the left abutment and dismantling and relocation of existing radial gates.

The powerplant has an installed capacity of 240 MW (3 units of 80 MW) operating under a rated head of 233 m. The increase of the effective reservoir storage capacity will produce an incremental energy of 59 GWh per annum. The said storage also contributes transfer from secondary energy to firm energy. The annual energy output of the expanded powerplant comprises a firm energy output of 479 GWh and secondary energy output of 35 GWh against 270 GWh and 185 GWh of the existing one respectively.

The general plan and typical section of the Kotmale raising scheme are shown in Fig. G.2-11.

(6) Upper Uma Oya Scheme (Scheme-1000)

The Upper Uma Oya Scheme(Scheme-1000) is the upper part of the two-stage development of the Uma Oya system for hydropower production.

The scheme has three intakes, comprising the Mahatotila Oya, Uma Oya and Hal Oya intakes. These intakes require a seasonal regulation reservoir or a daily regulation poundage.

The Mahatotila dam is located about 250 m upstream from the existing national road bridge or about 600 m upstream from the confluence of the Uma Oya and the Mahatotila Oya. The Mahatotila reservoir having a net storage capacity of 60 MCM with 70 m drawdown between the high water level at EL. 970 m and low water level at EL. 900 m is created by the rockfill dam of 90 m high and 560 m in crest length. The crest elevation is set at EL. 973 m, with 3 m freeboard above the high water level. The total embankment volume of the Mahatotila dam is 3.9 MCM.

The gated overflow spillway was designed to be provided in the right abutment of the dam, and is of an overflow type having a stilling basin as the energy dissipator.

The Uma Oya intake is situated about 3 km upstream from the confluence with the Mahatotila Oya. Water taken from the Hal Oya flows into the headrace tunnel at 5 km point from the Mahatotila intake. The Uma Oya and Hal Oya intakes have daily regulation poundage, which are 1 MCM each. Those dams are of the low concrete gravity type.

The catchment area of the Upper Uma Oya scheme is composed of the following tributary basins and the annual runoff from these catchment basins was estimated to be 9.4 m^3/sec or 296 MCM:

Mahatotila	168 km^2
Uma Oya	204 km^2
Hal Oya	49 km^2
Total	421 km^2

The whole of the proposed Upper Uma Oya scheme is situated within the highly metamorphosed rocks of the Highland series consisting of quartz feldspar gneiss, biotite gneiss, garnetiferous gneiss, charnockite and charnockitic gneiss, with some pegmatitic intrusion. At the Mahatotila damsite, the predominant rock types are charnockite and gneiss. There is no geological difficulty to construct the rockfill dam at this site. Far the other two low concrete gravity dams, there should also be no geological problem.

The necessary materials for the construction of a rockfill dam appear to be available on site: Core material may be obtained from weathered charnockite (much better suited for this purpose than weathered quartz-feldspar gneiss).

A diversion conduit is provided in the spillway body to divert river water during dam construction. Upstream and downstream cofferdams are constructed to keep dry conditions in the rockfill dam construction area.

From the Mahatotila dam, the headrace tunnel runs to the west and then northwest to cross underneath the Uma Oya where an intake structure captures the run-off as mentioned above. The tunnel and the intake structure are within the charnockites and the various gneisses of the Highland series, and no particular geotechnical problems are anticipated. From the Uma Oya crossing the headrace tunnel runs due north to the Hal Oya from where it continues in a northeasterly direction to the surge shaft/penstock tunnel and powerhouse complex on the left bank of the Uma Oya. Along this alignment, the tunnel crosses a number of synclines and anticlines and intersects obliquely some aerophoto lineaments. Good to very good tunnelling conditions are expected.

The headrace tunnel is of a circular cross-section having a total length of 12.2 km and a 4.5 m diameter. The penstock tunnel connecting to the above-ground powerhouse has an inside diameter, varying from 3.8 m to 2.9 m and a total length of 700 m. The above-ground powerhouse was designed to house the generating equipment with 3 units of 50 MW. The tailwater from the turbine is returned to the Uma Oya. The tailwater level is at EL. 500 m.

The surge chamber and penstock tunnel are expected to be in competent rock. Most of the powerhouse excavation will be in rock with thin overburden.

The profile and general plan are presented Figs. G.2-12 and G.2-13 respectively.

(7) Lower Uma Oya Scheme (Scheme-500)

The Lower Uma Oya scheme is the lower part of the two stage development of the river for hydropower generation. It will exploit the head between the tailwater level of the Upper Uma Oya scheme and the Randenigala reservoir water level. The scheme utilizes the runoff from the remaining Uma Oya catchment basin (100 km^2) and Madulla Oya catchment basin (101 km^2) in addition to the regulated flow from the upper Uma Oya (421 km^2), totaling a catchment area of 622 km^2. An annual average runoff of 14.1 m^3/sec or 445 MCM was estimated to flow from these catchment basins.

The Uma Oya intake weir, with a daily regulation capacity of 1.5 MCM, is located about 1.5 km downstream from the Upper Uma Oya power station, or 26 km upstream from the confluence with the Mahaweli Ganga. The dam was designed to be a concrete gravity type with 25 m in height, consisting of the overflow (spillway) and non-overflow sections. The normal intake water level was designed at EL. 500 m.

The Madulla intake weir is located at the 6.5 km point of the headrace tunnel from the Uma Oya intake and has a daily regulation poundage of 1.5 MCM. The weir is of concrete gravity type having a height of 25 m, composing of overflow (spillway) and non-overflow sections. The normal intake water level is at EL. 495 m.

The Uma Oya weir site lies in the zone of the Khondalite Series, consisting of charnockitic gneiss, quartz-feldspathic gneiss, quartzite and limestone. The riverbed is formed by outcrops of fresh rock, mainly charnockite and quartz feldspar gneiss in places covered by thin layer of sandy or gravelly alluvial deposits. Due to the massive nature of the bedrock, energy dissipation at the downstream end of the spillway chute will not cause any problems. The geological conditions for the Madulla Oya weir site would be almost similar to those for the Uma Oya weir site.

The geological condition of the headrace tunnel from the Uma Oya intake to the Madulla Oya intake consists of generally massive charnockite, which would offer favorable tunneling conditions. The headrace and penstock tunnels connecting the Madulla Oya intake with the powerhouse and tailrace tunnel are formed by lithological units such as charnockite, quartz-feldspar gneiss, quartzite, etc. The underground structural conditions in this section would be also favorable.
The headrace tunnel is of circular cross-section with an inside diameter of 4.8 and its total length of 15 km. The underground penstock line has a total length of 1,000 m and an inside diameter varying from 4.1 m to 3.0 m. The underground type was

selected for the powerhouse, with enough space for two units of 32 MW. The water from the turbine is diverted to the Randenigala reservoir through the tailrace tunnel with a total length of 700 m and an inside diameter of 3.6 m. The water release to the Randenigala reservoir will have the following advantage compared with the water release to the Rantembe reservoir: 1) Covering of water deficit for irrigation caused in the Randenigala reservoir in hydrologically dry years, and 2) In case of the water release to the Rantembe reservoir, no improvement of the operational situation of the Mahaweli cascade is hydrologically expected, because of a small storage volume. The tailwater will fluctuate between EL. 232 m and EL. 203 m according to the operating water level of the Randenigala reservoir.

The profile and general plan of the Lower Uma Oya scheme is shown in Figs. G.2-12 and G.2-14 respectively.

(8) Sudu Ganga Scheme

The Sudu Ganga scheme was planned as a single purpose scheme to utilize the diverted water from the Mahaweli Ganga through the Polgolla diversion and the runoff from the own catchment basin of the Sudu Ganga, with a catchment area of 305 km^2 and head obtaining by damming up. The average annual diverted discharge and average annual runoff were estimated at 33.6 m^3/sec and 7.1 m^3/sec respectively.

The damsite is located about 8 km upstream from the confluence of the Amban Ganga and the Sudu Ganga. The rock in this area belongs to the Khondalite Series of Archaean metamorphic rocks, mainly charnockitic gneiss and quartz-feldspathic gneiss, with interbedded quartzite and limestone. The rocks observed at the site are mainly good massive charnockitic gneisses with some minor interbedded quartzite. No limestone was seen. There is an extremely light overburden at the site. The stream bed itself is entirely rock and the dam axis lies along a rocky ridge of charnockite. The charnockite would be used as suitable materials for rockfill and concrete aggregate.

In view of these geological conditions and the availability of the materials, a rockfill type was selected for the dam. The gated spillway and non-overflow section as concrete gravity type for the purpose of arrangement of the powerhouse is located in the left abutment of the dam. The spillway is of an overflow type. The reservoir has a net storage capacity of 100 MCM with a 25 m drawdown between the high water level at EL. 325 m and low water level at EL. 300 m.

Coffering and diversion conduit method was designed to be applied for river diversion during construction of the rockfill dam. The diversion conduit is provided in the spillway body. Immediately after reaching an appropriate height of the spillway body, coffering is commenced in both the upstream and downstream portions. The river flow is diverted through the conduit and by overflowing the spillway body, if flood runoff exceeds the capacity of the conduit.

The powerhouse is located adjacent to the spillway at the immediate downstream portion of the dam. The powerhouse is connected with the reservoir by a 120 m long penstock with an inside diameter, varying from 3.5 m to 3.1 m. The powerhouse accommodates the generating equipment of 2 units (22.5 MW each). The tailwater is set at EL. 270 m.

The general plan and profile are presented in Fig. 2-15.

G.3 INDEPENDENT ECONOMIC EVALUATION

G.3.1 General

Although the comprehensive project evaluation is carried out in the later ANNEX-L, a preliminary independent economic evaluation was demonstrated in this sub-section. The evaluation was made for the cases; "without" and "with" incremental benefits of the downstream power stations (Case 1 and Case 2 respectively).

The economic analysis was made in terms of economic cost per kWh, net annual benefit (annual benefit less annual cost) and benefit-cost ratio under the following conditions:

- Financial cost was converted into economic cost computed by the Standard Conversion Factor. The construction cost of the respective power schemes is estimated in the later ANNEX-J.
- The opportunity cost of capital was taken to be 10%.
- The economic life of project was adopted as 50 years after commissioning of the project.

G.3.2 Power Benefit

(1) Unit Power Benefit

The conventional approach to economic analysis of a hydropower project is to define its benefit as the cost saved in construction and operation (fuel cost) of the cheapest alternative facility that could provide power supplies of equivalent quality to the intended beneficiaries.

The cheapest alternative thermal facilities to meet system load sharing portions are gas turbine and diesel generator for peak load, oil-fired steam plant for middle load and coal-fried steam plant for base load. For this project, diesel generation, considered as the most viable alternative hydropower by the CEB, was selected as the cheapest alternative energy source, since the proposed hydropower plants are characterized by peak generation, 5.0 hours of firm operation. The necessary construction and operation costs for such facilities required to replace the project are adopted as the project benefit.

Accordingly, the peak generation supply under the present project was evaluated on the basis of the diesel alternative. Thus, for power output (kW) and firm energy (kWh) which correspond to supply for peak load, a diesel station was considered as an alternative. While, for secondary energy, fuel costs of coal thermal stations which are to be introduced before the project are considered as an alternative, since the secondary energy of hydropower will save fuel consumption at coal thermal stations, as mentioned above.

For the secondary energy of the project, full amount is assumed effective for fuel cost saving in coal thermal generation, as there will be abundant thermal generation which can effectively be replaced by generation under the project.

The kW and kWh benefits are the annual costs per kW and kWh of diesel power station respectively, which is equivalent to the hydropower stations, as stated above. The calculation of unit kW and kWh values is made as follows:

1) Alternative facility : Diesel generator or coal thermal
2) Capacity : 20 -30 MW class
3) Unit construction cost : US$480/kW
4) Service life : 20 years
5) Adjustment factor :

(Unit:%)

	Diesel	Coal Thermal	Hydro
Transmission loss	1.0	3.0	4.0
Forced outage	5.0	3.0	0.5
Auxiliary power use	2.0	7.0	0.5
Overhaul	18.0	15.0	1.0

- Capacity (kW) adjustment factor =

$$\frac{(1-0.04) \times (1-0.005) \times (1-0.005) \times (1-0.01)}{(1-0.01) \times (1-0.05) \times (1-0.02) \times (1-0.18)} = 1.2450$$

- Energy (kWh) adjustment factor for diesel =

$$\frac{(1-0.04) \times (1-0.005)}{(1-0.01) \times (1-0.05)} = 1.0156$$

- Energy (kWh) adjustment factor for coal thermal =

$$\frac{(1-0.04) \times (1-0.005)}{(1-0.03) \times (1-0.03)} = 1.0152$$

6) Capacity value

Discount rate : 10%

Annual capitalized cost: :
US$480/kW x (1+0.12*1) x 1.245 x 0.1175 = US$78.7/kW

*1: Ratio of replacement cost

Annual O&M cost: :
US$480/kW x 0.03 = US$14.4/kW

Total annual cost (kW value):
US$(78.64+14.40)/kW = <u>US$93.1/kW</u>

7) Firm energy value

Fuel Cost *1	:	US$0.275/kg
Caloric value	:	10,800 kcal/kg
Plant efficiency	:	34.0%
Heat rate	:	2,529 kcal/kWh
Energy value	:	US$0.0644/kWh
O&M value	:	US$0.0020/kWh
Net energy value	:	US$0.0664/kWh
Adjusted energy value	:	US$0.0664/kWh x 1.0156
		= US$0.0674

Remarks: *1: Fuel cost in 2000 at 1987 constant price recommended by ADB

8) Secondary energy value

Fuel cost	:	US$0.048/kg
Caloric value	:	5,300 kcal/kWh
Plant efficiency	:	27.0%
Heat rate	:	3,185 kcal/kWh
Energy value	:	US$0.0288/kWh
O&M value	:	US$0.0006/kWh
Net energy value	:	US$0.0294/kWh
Adjusted energy Value	:	US$0.0294/kWh x 1.0152
		= US$0.0298/kWh

(2) Annual Power Benefit

The annual power benefit consists of the annual capacity and energy benefits, as mentioned above. The annual capacity benefit was obtained by multiplying the dependable peak power by the unit capacity benefit. While annual energy benefit was given by multiplying the annual energy output by the unit energy benefit. Dependable peak power and annual energy output for each hydropower scheme were estimated by the water balance study employing the simulation model as referred to in ANNEX-I. Their results are listed in Sub-section G.2.3. The unit benefits are presented in the preceding paragraph.

Based on the above conditions and criteria, the annual power benefits for the respective schemes were calculated and their results are as follows:

	Scheme	Annual Benefit (US$ Million)
(1)	Watawala	4.11
(2)	Ulapane	9.32
(3)	Caledonia	10.75
(4)	Talawakele	52.75
(5)	Kotmale Extension	13.25
(6)	Upper Uma Oya (Scheme - 1000)	29.74
(7)	Lower Uma Oya (Scheme - 500)	25.39
(8)	Wewatenna	5.24
(9)	Sudu Ganga	8.63

In addition to the above benefits, the proposed hydropower schemes would contribute to transfer from secondary energy to firm energy for the downstream power stations resulting from the firming-up discharge by regulation. The benefit to be yielded by the said energy transfer was defined as the incremental benefit. In other words, the incremental benefit is the balance between the benefits with and without the upstream hydropower developments.

The followings are the basic conditions, assumptions and criteria for estimating the incremental benefit:

(1) Although the incremental firm discharge was calculated by the comprehensive balance study, the following simplified estimation criterion was preliminarily adopted in the study. The incremental firm discharge was the balance between the regulated firm discharge and 95% dependable natural runoff. This discharge would produce an incremental firm energy output of the downstream power station.

(2) The incremental energy output of the downstream power station was calculated by the following formula:

$$\begin{aligned} dEf &= dPf \cdot T \\ &= g \cdot dQf \cdot He \cdot Ut \cdot Ug \cdot T \end{aligned}$$

Where,

dEf	:	Incremental annual firm energy output (kWh)
dPf	:	Incremental average firm power output (kW)
T	:	Annual operation hours at 8,760 hours
dQf	:	Incremental firm discharge (m^3/sec)
He	:	Average head of downstream power station (m)
Ut	:	Turbine efficiency
Ug	:	Generator efficiency

(3) The downstream power stations in the respective schemes are listed below:

1)	Watawala	:	Ulapane, Victoria, Randenigala & Rantembe
2)	Ulapane	:	Victoria, Randenigala & Rantembe
3)	Caledonia	:	Kotmale, Victoria, Randenigala & Rantembe
4)	Talawakele	:	Nil
5)	Kotmale Extension	:	Victoria, Randenigala & Rantembe
6)	Upper Uma Oya (Scheme-1000)	:	Lower Uma Oya, Randenigala & Rantembe
7)	Lower Uma Oya (Scheme-500)	:	Randenigala & Rantembe
8)	Wewatenna	:	Nil
9)	Sudu Ganga	:	Bowatenna & Moragahakanda

(4) For the Victoria, Randenigala and Rantembe power stations, it was assumed that 65% of the incremental firm discharge was taken for the benefit evaluation, since the 65% average discharge of the Mahaweli Ganga is flowing downstream, after diverting the water to the Amban Ganga basin through Polgolla diversion tunnel.

(5) As to the Uma Oya Scheme, all the discharge from the basin was evaluated as the incremental discharge of the Randenigala power stations, because the natural runoff flows into the Rantembe reservoir, if the Uma Oya scheme is not developed.

(6) The incremental unit energy benefit was defined as the balance between the firm and secondary energy benefits and it was calculated to be US$0.0376/kWh.

Based on the above conditions, assumptions and criteria, the annual incremental benefit obtainable by the downstream power stations was estimated in Table G.3.3 and their results are as follows:

Scheme	Incremental Annual Benefit (US$ Million)
(1) Watawala	1.41
(2) Ulapane	4.51
(3) Caledonia	4.79
(4) Talawakele	-
(5) Kotmale Extension	7.66
(6) Upper Uma Oya (Scheme - 1000)	2.21
(7) Lower Uma Oya (Scheme - 500)	0.75
(8) Wewatenna	-
(9) Sudu Ganga	0.73

G.3.3 Economic Cost

The details of the cost estimate for the hydropower schemes are mentioned in ANNEX-J and the its summary is shown in Table G.3.4.

As for the Upper Kotmale scheme, the joint facilities costs of the Caledonia scheme should be allocated to the two power schemes, Caledonia and Talawakele, since the Caledonia reservoir has a function of river flow regulation for both the Caledonia and Talawakele power stations, as follows:

Annual benefit (US$1,000)				
Caledonia, Case 1	:			10,750
Caledonia, Case 2	:			15,540
Talawakele	:			52,750
Joint facilities (US$1,000)				
General items	:	5,400 x 44,700/104,100	:	2,300
Main dam	:			42,600
Hydromechanical works	:			2,100
Sub-total	:			47,000
Total cost including indirect cost :		47,000 x 156,400/104,100	:	70,600
Cost allocation (US$1,000)				
Case 1 :				
Caledonia :				
Joint cost	:	70,600 x 10,750/63,500	:	12,000
Specific cost	:			85,800
Sub-total	:			97,800
Talawakele :				
Joint cost	:	70,600 x 52,750/63,500	:	58,600
Specific cost	:			215,700
Sub-total	:			274,300
Case 2 :				
Caledonia :				
Joint cost	:	70,600 x 15,540/68,290	:	16,100
Specific cost	:			85,800
Sub-total	:			101,900
Talawakele :				
Joint cost	:	70,600 x 52,750/68,290	:	54,500
Specific cost	:			215,700
Sub-total	:			270,200

Based on the estimate construction cost and conditions mentioned in Subsection G.3.1, the economic cost for each hydropower scheme was calculated in Table G.3.4.

G.3.4 Economic Evaluation

The preliminary economic analysis was made for each scheme on the basis of the annual benefits and costs, and the followings are the benefit cost ratios:

Scheme	Benefit Cost Ratio*		Ranking	
	Case 1	Case 2	Case 1	Case 2
Watawala	0.93	1.25	6	4
Ulapane	0.82	1.21	7	5
Caledonia	1.12	1.55	4	2
Talawakele	1.96	1.99	1	1
Kotmale Extension	0.57	0.90	9	8
Upper Uma Oya (Scheme-1000)	1.22	1.31	2	3
Lower Uma Oya (Scheme-500)	1.13	1.17	3	6
Wewatenna	0.62	0.62	8	9
Sudu Ganga	1.05	1.14	5	7

Remark: Discount rate = 10%

As seen above, the Caledonia, Talawakele and Upper Uma Oya schemes are more economically promising than the other four schemes excluding the Kotmale Extension and Wewatenna schemes which are not economically viable. However, as for the Kotmale Extension schemes, it is valuable to review in detail in the future in viewpoint of maximum utilization of valuable hydropower potential. Therefore, the Kotmale Extension scheme was included in this study, but given the lowest priority. As to the Wewatenna scheme, it is deleted from this study, but subject to the future study in connection to the development of the SEDZ area.

TABLES

Table G.1.1 EXISTING GENERATION CAPACITY - 1988
(CEB POWER SYSTEM)

	Capacity (MW)		Mean Annual Energy (GWh)		
	Units (No.xCap.)	Total Installed	Firm	Secondary	Total
1. Hydropower Kehelgamu - Maskeli Complex					
Old Laxapana I	3x8.33	25	253	42	295
Old Laxapana II	2x12.5	25	-	-	-
New Laxapana	2x50	100	439	80	519
Wimalasurendra	2x25	50	84	36	120
Samanala	3x37.5	75	384	75	459
Canyon I	1x30	30	144	35	179
Sub-total		305	1,304	268	1,572
Mahaweli Complex					
Ukuwela	2x19	38	164	-	164
Bowatenna	1x40	40	49	15	64
Victoria	3x70	210	447	439	886
Kotmale	3x67	201	270	232	502
Randenigala	2x61	122	304	190	494
Sub-total		611	1,234	876	2,110
Total Hydropower		916	2,538	1,144	3,682
2 Thermal Power					
Kelanitissa (Gas Turbine)	6x20	120	725	-	725
Sapugaskanda (Diesel)	4x20	80	540	-	540
Total Thermal		200	1,265	0	1,265
Total System		1,116	3,803	1,144	4,947

Remarks: Plant Factor : Firm ; 0.32
Hydropower, Total; 0.46

Total System, Firm ; 0.39
Total; 0.51

Table G.1.2 CEB TARIFF - EFFECTIVE FROM 1988-01-01

Domestic	First 10 units @ Rs. 0.55 per unit 10 - 100 units @ Rs.1.05 per unit 100 - 450 units @ Rs.2.00 per unit Above 450 units @ Rs. 2.50 per unit Fuel adjustment charge when in operation is applicable on units in excess of 100 per month					
Religious & Charitable Institutions	First 150 units @ Rs.0.60 per unit + Fixed charge Rs.5/= per month Above 150 units @ Rs.2.00 per unit Fuel adjustment charge when in operation is applicable in units in excess of 150 per month					
Street Lighting	Rs.1.80 per unit + Fuel Adjustment Charge					
Other Categories	General purpose	Indus-trial	Hotels	Industrial (Time of Day)	Hotels	Bulk Supply to Licenses
Supply at 400/230V Contract demand less than 50kVA						
Unit Charge (Rs./Unit)	2	1.75	1.95	-	-	
	+	+	+	-	-	
Fixed Charge (upto 10kVA) (Rs. per month)	20 or	20 or	20 or	-	-	
Fixed Charge (above 10kVA) (Rs. per month)	100	100	100			
Supply at 400/230V Contract demand 50kVA & above						
Demand charge (Rs./kVA) per month	125	110	125	50	50	30
	+	+	+	+	+	+
Unit Charge (Rs./Unit)	1.9	1.6	1.85	1.50 (OFF PEAK) + 2.45 (PEAK 6 PM TO 9 PM)	1.50 (OFF PEAK) + 2.45 (PEAK 6 PM TO 9 PM)	0.40 (BLOCK A) + 0.80 (BLOCK B)
	+	+	+	+	+	+
Fixed charge (Rs.) per month	200	200	200	200	200	1.45 (BLOCK C)
HT Supply 11kV, 33kV, & 132kV						
Demand charge (Rs./kVA) per month	115	95	115	45	45	25
	+	+	+	+	+	+
Unit Charge (Rs./Unit)	1.8	1.5	1.75	1.45 (OFF PEAK) + 2.20 (PEAK 6 PM TO 9 PM)	1.45 (OFF PEAK) + 2.20 (PEAK 6 PM TO 9 PM)	0.35 (BLOCK A) + 0.75 (BLOCK B) 1.35 (BLOCK C)
	+	+	+	+	+	
Fixed charge (Rs.) per month	200	200	200	200	20	

Remarks: The fuel adjustment charge will be expressed as a percentage and is applicable on the unit charges only. The fuel adjustment charge when in operation shall apply to all general purposes, industrial and hotel consumers.

Block A: 120% of the sum of approved units used per month by religious premises and approved charitable institution consuming up to 10 units per month, plus 120% of 10 units x (number of domestic consumers consuming above 10 units per month)

Block B: 120% of the sum of units used in excess of 10 units per month by domestic consumers consuming in excess of 10 units and upto 100 units per month,plus 120% of 90 units x (number of domestic consumers consuming in excess of 100 units per month).

Block C: All units in excess of the sum of units in BLOCK A and BLOCK B, plus fuel adjustment charge.

Table G.1.3 PEAK POWER DEMAND, ENERGY CONSUMPTION, LOSSES AND GENERATION

Year	Energy (GWh) Domestic & Relegious	Small & Medium Industries	Heavy Industries	Commercial & Hotels	Local Authorities	Street Lighting	Total Consumption	Per Capita Sale	Losses	Total Generation	Power Demand (MW)	Factor (%)
1961	40	86	-	56	76	-	258	-	50	308	-	-
1962	41	106	-	57	78	-	282	-	62	344	69	56.9
1963	42	127	-	57	83	-	309	-	63	372	74	57.4
1964	44	137	-	60	92	-	333	-	168	401	83	55.2
1965	46	148	-	65	101	-	360	-	68	428	89	54.9
1966	48	185	-	72	119	-	424	-	69	493	105	53.6
1967	57	195	36	75	132	-	489	-	92	591	122	54.4
1968	55	212	60	81	148	-	556	-	91	647	135	54.7
1969	59	229	73	82	161	-	604	-	106	710	147	55.1
1970	63	245	98	88	178	-	662	53(12.5) <1	124	786	163	55.0
1971	65	209	165	93	181	11	722	57(12.6)	127	849	173	56.0
1972	73	221	215	97	183	12	810	64(12.7)	134	944	200	53.9
1973	82	273	194	108	198	12	866	66(13.1)	114	980	199	56.2
1974	83	257	220	118	202	13	892	67(13.3)	119	1,011	215	53.7
1975	85	255	268	123	222	13	965	71(13.5)	114	1,079	219	56.2
1976	95	255	261	140	237	14	999	73(13.7)	134	1,133	240	53.9
1977	107	257	262	148	253	14	1,041	75(13.9)	176	1,217	261	53.2
1978	119	292	300	159	276	15	1,161	82(14.2)	224	1,385	291	54.3
1979	153	304	328	201	296	16	1,298	90(14.5)	228	1,526	329	52.9
1980	191	306	320	223	336	17	1,392	95(14.7)	276	1,668	369	51.6
1981	217	331	347	220	381	9	1,503	100(15.0)	369	1,872	413	51.7
1982	258	365	374	235	418	9	1,686	112(15.1)	380	2,066	431	54.7
1983	305	367	383	244	433	10	1,792	116(15.4)	322	2,114	437	55.2
1984	309	404	387	308	458	11	1,877	120(15.6)	374	2,250	487	52.7
1985	346	446	404	350	502	12	2,060	130(15.8)	404	2,464	515	54.6
1986	369	480	445	381	543	13	2,232	139(16.1)	420	2,652	540	56.1
1987	381	489	378	419	570	16	2,253	137(16.4)	454	2,707	570	54.2

Remarks: <1 : Population in Million

Table G.1.4 INSTALLED CAPACITY AND GENERATION ENERGY BY HYDROPOWER PLANTS AND THERMAL POWERPLANTS

Year	Installed Capacity (MW) Hydro	Thermal	Total	Annual Generated Energy (GWh) Hydro (1)	Thermal	Total (2)	Increase Rate (%)	(1)/(2) (%)
1975	291	70	361	1,078.4	0.1	1,078.5	6.6	100.0
1976	329	70	399	1,108.6	24.2	1,132.8	5.0	97.9
1977	329	70	399	1,214.4	2.1	1,216.5	7.4	99.8
1978	329	70	399	1,338.5	42.7	1,381.2	13.5	96.9
1979	329	70	399	1,461.2	64.3	1,525.5	10.4	95.8
1980	329	90	419	1,479.4	188.8	1,668.2	9.4	88.7
1981	369	130	499	1,571.2	300.1	1,871.3	12.2	84.0
1982	369	190	559	1,608.1	457.6	2,065.7	10.4	77.8
1983	399	190	589	1,217.2	897.4	2,114.6	2.4	57.6
1984	609	200	809	2,090.7	170.0	2,260.7	7.0	92.4
1985	609	200	809	2,394.6	69.4	2,464.0	8.9	97.2
1986	801	264	1,065	2,645.6	7.0	2,652.0	7.6	99.7
1987	801	270	1,071	2,177.0	530.0	2,707.0	2.1	80.4

Table G.1.5 POWER CUTS (1980 - 1987)

Year	Period of Power Cut From	To	(Days)	Power Cut (GWh)	Relative Cut (%) Period	Year
1980	20 May	-	28 Jul	70	11.3	3.5
1981	20 Feb	-	10 Jan	111	11.1	5.4
1982		-		-	-	-
1983	01 Nov	-	31 Dec		4.6	0.9
1984	01 Jan	-	07 Feb	38	5.5	1.0
1985		-		-	-	-
1986		-		-	-	-
1987	12 Aug	-	30 Sep	50	9.6	1.8
Average Powercut					5.3	1.6

Table G.1.6 MONTHLY PEAK LOAD VARIATION

Month	Peak Load as % of Annual Peak	
	Histerical <1	Detrended <2
Jan	93.6	99.0
Feb	93.5	98.4
Mar	93.7	98.0
Apr	92.2	95.9
May	94.2	97.5
Jun	94.9	97.7
Jul	95.7	97.9
Aug	96.2	97.8
Sep	98.7	99.7
Oct	99.2	99.8
Nov	100.0	100.0
Dec	99.3	99.9

Remarks: <1: Derived from the actual historical records including the underlying annual growth in demand.

<2: Detrended for the annual growth to give the purely seasonal variations.

Table G.1.7 LONG TERM DEMAND FORECAST AT GENERATION LEVEL (1986 FORECAST)

	1990	1995	2000	2005	2010	2015	2020
LOW							
Energy (GWh)	3,330	4,480	5,820	7,620	9,830	12,200	14,860
Peak Load (MW)	680	940	1,260	1,660	2,150	2,670	3,280
Load Factor (%)	55.9	54.4	52.7	52.4	52.2	52.2	51.7
Growth Rate (%)	6.4	6.1	5.5	5.5	5.2	4.2	4.2
BASE							
Energy (GWh)	3,580	5,130	7,220	9,990	13,760	18,670	25,150
Peak Load (MW)	750	1,090	1,580	2,190	3,030	4,120	5,580
Growth Rate (%)	54.5	53.7	52.2	52.1	51.8	51.7	51.5
Load Factor (%)	8.3	7.5	7.1	6.7	6.6	6.2	6.2
HIGH							
Energy (GWh)	3,780	5,950	8,620	12,410	17,870	25,330	35,920
Peak Load (MW)	780	1,230	1,840	2,670	3,890	5,540	7,910
Growth Rate (%)	55.3	55.2	53.5	53.1	52.4	52.2	51.8
Load Factor (%)	9.8	9.5	7.7	7.6	7.5	7.3	7.3
ADB							
Energy (GWh)	3,410	4,750	6,490	8,950	12,280	16,270	21,550
Peak Load (MW)	720	1,010	1,400	1,950	2,670	3,550	4,740
Growth Rate (%)	54.1	53.7	52.9	52.4	52.5	52.3	51.9
Load Factor (%)	7	6.9	6.5	6.5	6.5	5.8	5.8

Table G.1.8 PEAK DEMAND AND GENERATION FORECAST (JULY 1987)

Year	Peak Demand (MW)	Generation Forecast (GWh)	Growth Rate (%)	Load Factor (%)
1988	593	2,986	-	57.5
1989	630	3,230	8.2	58.5
1990	682	3,495	8.2	58.5
1991	744	3,845	10.0	59.0
1992	818	4,229	10.0	59.0
1993	900	4,652	10.0	59.0
1994	990	5,118	10.0	59.0
1995	1,089	5,629	10.0	59.0
1996	1,193	6,166	9.5	59.0
1997	1,306	6,750	9.5	59.0
1998	1,430	7,391	9.5	59.0
1999	1,566	8,094	9.5	59.0
2000	1,714	8,861	9.5	59.0
2001	1,860	9,614	8.5	59.0
2002	2,018	10,431	8.5	59.0
2005	2,578	13,323	8.5	59.0
2010	3,788	19,578	8.0	59.0
2015	5,438	28,106	7.5	59.0
2020	7,627	39,419	7.0	59.0

Remarks: The demand up to 2002 was taken from the "Long Range Generation Expansion Plan", CEB, August 1987, and the projected demand was extended to 2020.

Table G.2.1 FUTURE HYDROPOWER GENERATION CAPACITY

Power Station	Installed Capacity (MW)	Annual Energy (GWh) Firm	Secondary	Total
1. Kehelgamu - Maskeli Complex				
1) Existing & Under Construction				
Old Laxapana I	25	253	42	295
Old Laxapana II	25	-	-	-
New Laxapana	100	439	80	519
Wimalasurendra	50	84	36	120
Samanala	75	384	75	459
Canyon I	30	144	35	179
Canyon II	30		34	34
Samanalawewa	120	409	20	423
Sub-total	455	1,713	322	2,035
2) Extension				
SamanalawEwa	120	-	-	-
3) Proposed				
Broadlands	40	53	92	145
Kukule	180	384	8	392
Jasmin	100	180	88	268
Sub-total	320	617	188	805
Total	895	2,330	510	2,840
3. Mahaweli Complex				
1) Existing & Under Construction				
Ukuwela	38	164		164
Bowatenna	40	49	15	64
Victoria	210	447	439	886
Kotmale	201	270	232	502
Randenigala	122	304	190	494
Rantembe	50	174	72	246
Sub-total	661	1,408	948	2,356
2) Extension				
Victoria	70	-	-	-
Kotmale	39	209	-150	59
Sub-total	109	209	-150	59
3) Proposed				
Watawela	18	31	18	49
Ulapane	44	75	16	91
Caledonia	44	70	65	135
Talawakele	204	364	310	674
Upper Uma Oya	150	201	141	342
Lower Uma Oya	96	192	118	310
Sudu Ganga	45	74	48	122
Moragahakanda	26	35	61	96
Sub-total	649	1,042	777	1,819
TOTAL	1,419	2,659	1,575	4,234
GRAND TOTAL	2,314	4,989	2,085	7,074

Remarks: Plant Factor:

1. Kehelgamu - Maskeli Complex	Existing & Under Construction:	0.43	0.51
	Total :	0.30	0.36
2. Mahaweli Complex	Existing & Under Construction:	0.24	0.41
	Total :	0.21	0.34
3. Whole Complex	Existing & Under Construction:	0.33	0.45
	Total :	0.25	0.35

Table G.2.2 LOAD ALLOTMENT IN FUTURE SYSTEM

Item	Existing & Under Const. Hydropower Plants (Case 1)	All Hydropower Plants (Case 2)
(1) Year	1998	2008
(2) Peak Capacity (MW)		
1) Hydropower<1	1,091	2,289
2) Therman		
Existing	200	200
Expansion	183	877
Sub-total	383	1,077
3) Total, 1) & 2)	1,474	3,366
4) Marginal Reserve <2	221	505
5) Total Thermal Expansion <3	404	1382
6) Total System, 3) + 4)	1,695	3,871
(3) Annual Firm Energy (GWh)		
1) Hydropower	3,121	4,989
2) Thermal		
Existing	1,265	1,265
Expansion	3,232	11,143
Sub-total	4,497	12,408
3) Total	7,618	17,397
(4) Annual Firm & Secondary Energy (GWh)		
1) Hydropower		
Firm	3,121	4,989
Secondary	1,270	2,085
Sub-total	4,391	7,074
2) Thermal		
Existing	1,265	1,265
Expansion	1,965	9,117
Sub-total	3,227	10,382
3) Total, 1) + 2)	7,618	17,456

Remarks: <1: Old Laxapana II excluded
<2: To be covered by thermal
<3: Sum of expansion and marginal reserve

Table G.2.3 LONG-TERM POWERPLANTS EXPANSION PLAN (TENTATIVE) (1/2)

Year	Energy Demand (GWh)	Annual Energy (GWh)				Total
		Hydropower		Thermal Power		
		Extension	Total	Extension	Total	
1990			3,132		1,265	
1991	3,845		3,132	1,314	2,606	5,738
1992	4,229		3,132		2,606	5,738
1993	4,652		3,132	1,314	3,920	7,052
1994	5,118		3,132		3,920	7,052
1995	5,629	35	3,167	4,380	8,300	11,467
1996	6,166		3,167		8,300	11,467
1997	6,750	434	3,601		8,300	11,901
1998	7,391		3,601		8,300	11,901
1999	8,094		3,601		8,300	11,901
2000	8,861		3,601		8,300	11,901
2001	9,614		3,601		8,300	11,901
2002	10,431		3,601	4,380	12,680	16,281
2003	11,318		3,601		12,680	16,281
2004	12,280		3,601		12,680	16,281
2005	13,323	384	3,985		12,680	16,665
2006	14,389		3,985		12,680	16,665
2007	15,540		3,985	4,380	17,060	21,045
2008	16,783		3,985		17,060	21,045
2009	18,126	233	4,218	8,760	25,820	30,038
2010	19,578		4,218		25,820	30,038
2011	21,046		4,218		25,820	30,038
2012	22,625	201	4,419	8,760	34,580	38,999
2013	24,322		4,419		34,580	38,999
2014	26,146		4,419		34,580	38,999
2015	28,106	192	4,611	8,760	43,340	47,951
2016	30,073		4,611		43,340	47,951
2017	32,179	106	4,717	8,760	52,100	56,817
2018	34,431		4,717		52,100	56,817
2019	36,841	74	4,791	8,760	60,860	65,651
2020	39,420	209	5,000		60,860	65,860

Remarks:			
	1995	Moragahakanda	(26 MW)
	1997	Upper Kotmale	(248 MW)
	2003	Victoria	(70 MW)
	2005	Samanalewewa (Extension) & Kukule	(300 MW)
	2009	Jusmin & Broadland	(140 MW)
	2012	Upper Uma Oya (Scheme-1000)	(150 MW)
	2015	Lower Uma Oya (Scheme-500)	(96 MW)
	2017	Watawale & Ulapane	(62 MW)
	2019	Sudu Ganga	(45 MW)
	2020	Kotmale (Extension)	(39 MW)

Table G.2.3 LONG-TERM POWERPLANTS EXPANSION PLAN (TENTATIVE) (2/2)

Year	Peak Demand at Generation (MW)	Requir-ed Capacity (MW)	Avail-able Capacity (MW)	Capacity of Hydropower (MW)		Capacity of Thermal Power (MW)	
				Exten-sion	Total Installed	Exten-sion	Total Installed
1990							200
1991	774	890	1,120		1,091	150	350
1992	818	941	1,120		1,091		350
1993	900	1,035	1,364		1,091	150	500
1994	990	1,139	1,364		1,091		500
1995	1,089	1,252	2,117	26	1,117	500	1,000
1996	1,193	1,372	2,117		1,117		1,000
1997	1,306	1,502	2,365	248	1,365		1,000
1998	1,430	1,645	2,365		1,365		1,000
1999	1,566	1,801	2,365		1,365		1,000
2000	1,714	1,971	2,365		1,365		1,000
2001	1,860	2,139	2,365		1,365		1,000
2002	2,018	2,321	2,365		1,365	500	1,500
2003	2,190	2,519	2,935	70	1,435		1,500
2004	2,376	2,732	2,935		1,435		1,500
2005	2,578	2,965	3,235	300	1,735		1,500
2006	2,784	3,202	3,235		1,735		1,500
2007	3,007	3,458	3,735		1,735	500	2,000
2008	3,247	3,734	3,735		1,735		2,000
2009	3,507	4,033	4,875	140	1,875	1,000	3,000
2010	3,788	4,356	4,875		1,875		3,000
2011	4,072	4,683	4,875		1,875		3,000
2012	4,378	5,035	6,025	150	2,025	1,000	4,000
2013	4,708	5,414	6,025		2,025		4,000
2014	5,059	5,818	6,025		2,025		4,000
2015	5,438	6,254	7,121	96	2,121	1,000	5,000
2016	5,819	6,692	7,121		2,121		5,000
2017	6,226	7,160	8,183	62	2,183	1,000	6,000
2018	6,662	7,661	8,183		2,183		6,000
2019	7,128	8,197	9,228	45	2,228	1,000	7,000
2020	7,627	8,771	9,267	39	2,267		7,000

Remarks			
	1995	Moragahakanda	(26 MW)
	1997	Upper Kotmale	(248 MW)
	2003	Victoria	(70 MW)
	2005	Samanalewewa (Extension) & Kukule	(300 MW)
	2009	Jusmin & Broadland	(140 MW)
	2012	Upper Uma Oya (Scheme-1000)	(150 MW)
	2015	Lower Uma Oya (Scheme-500)	(96 MW)
	2017	Watawala & Ulapane	(62 MW)
	2019	Sudu Ganga	(45 MW)
	2020	Kotmale (Extension)	(39 MW)

Table G.2.4 MAJOR FEATURES OF CANDIDATE HYDROPOWER SCHEMES (1/2)

Item	Unit	Watawala	Ulapane	Caledonia	Talawakele	Kotmale*1 Extension
1. General						
River		Mahaweli Ganga	Mahaweli Ganga	Kotmale Oya Mahaweli Ganga	Kotmale Oya Mahaweli Ganga	Kotmale Oya Mahaweli Ganga
Catchment area	(km2)	69	220	235	363	562
Annual average	(m3/s)	3.8	12.1	13.1	20.0	31.2
Runoff	(MCM)	119	381	412	631	984
2. Dam						
Type		Concrete gravity	Rockfill with Concrete gravity	Concrete gravity	Concrete gravity	Rockfill
Crest elevation	(EL. m)	1,034	603	1,365	1,203	735
Crest length	(m)	200	500	270	102	945
Height	(m)	60	70	70	20	115
Volume	(1000m3)	92	2,370	250	18	4,270
3. Spillway						
Design capacity	(m3/s)	800	6,500	2,470 (175 km2)	3,500 (297 km2)	5,560
Dimension nos.xBxH	(m)	2x8x7	3x18x15	-	3x8x12	3x14x15
4. Reservoir						
Flood water level	(EL. m)	1,032	600	1,363.5	1,200	732.8
High water level	(EL. m)	1,032	600	1,360	1,200	731.5
Rated water level	(EL. m)	1,024	597	1,353	1,198	723
Low water level	(EL. m)	1,010	590	1,341	1,193	665
Net storage volume	(MCM)	20	150	30	2	382.9
5. Headrace Tunnel						
Length	(m)	2,100	5,000	2,982	13,066	6560
Inside diameter	(m)	2.4	4.5	3.9	4.4	4.4
6. Surge Tank						
Height	(m)	55	50	55	93	168
Inside diameter	(m)	7	15	15	15	12
7. Penstock Tunnel/Line						
Type		Above-ground	Above-ground	Tunnel	Tunnel	Tunnel
Length	(m)	220	200	218	734	402
Inside diameter	(m)	2.2-1.7	2.8-2.4	4.1- 3.2	4.7-3.4	4.8-5.5
8. Power Station						
Firm discharge	(m3/s)	2.3	9.5	6.7	9.2	29.8
Max. plant discharge	(m3/s)	11.5	47.5	35.0	50.0	112.3
Gross head	(m)	192-170	120-110	167-141	545-490	251.5-185
Rated head	(m)	179	109	144	468	233
Installed capacity	(MW)	2x9	2x22	1x44	3x68	3x80
Dependable peak power	(MW)	15.9	40.6	44	204	39 *
Annual energy output	(GWh)	49	91	135	674	59 *
Firm		31	75	70	364	209 *
Secondary		18	16	65	310	-150 *
Type		Above-ground	Above-ground	Underground	Underground	Underground
Nos.of unit		2	3	1	3	3
Type of Turbine		Francis	Francis	Francis	Francis	V.Rrancis
Tailwater level	(EL-m)	840	480	1,200-1,193	731.5-703	480
9. Construction Cost	(US$ 10^6)	44.2	117	156.4	215.7	236.6

Remarks: * shows incremental value.
*1 Referred to 'Kotmale Hydropower Project', Report on Future Raising of Dam and Spillway, October 1985, Halcrow Water

Table G.2.4 MAJOR FEATURES OF CANDIDATE HYDROPOWER SCHEMES (2/2)

Item	Unit	Upper Uma Oya Scheme - 1000	Lower Uma Oya Scheme - 500	Wewatenna	Sudu Ganga
1. General					
River		Uma Oya Mahaweli Ganga	Uma Oya Mahaweli Ganga	Badulu Oya Mahaweli Ganga	Sudu Gganga Mahaweli Ganga
Catchment area	(km2)	421	622	267	305
Annual average	(m3/s)	11.2	16.6	6.6	36.5
Runoff	(MCM))	394	523	207	1,152
2. Dam					
Type		Rockfill with Concrete gravity	Concrete gravity	Rockfill with Concrete gravity	Rockfill with Concrete gravity
Crest elevation	(EL. m)	973	502	233	328
Crest length	(m)	565	150	500	400
Height	(m)	90	25	80	55
Volume	(1000m3)	3,900	15	2,700	1,320
3. Spillway					
Design capacity	(m3/s)	1,700	3,700	1,500	2,000
Dimension nos.xBxH	(m)	3x7x10	3x10x12	3x8.5x12	3x9x12
4. Reservoir					
Flood water level	(EL. m)	970	500	230	325
High water level	(EL. m)	970	500	230	325
Rated water level	(EL. m)	947	498	220	317
Low water level	(EL. m)	910	495	200	300
Net storage volume	(MCM)	60	1.5	90	100
5. Headrace Tunnel					
Length	(m)	12,200	15,000	3,000	-
Inside diameter	(m)	4.5	4.8	3.1	-
6. Surge Tank					
Height	(m)	80	30	50	-
Inside diameter	(m)	15	15	12	-
7. Penstock Tunnel/Line					
Type		Tunnel	Tunnel	Above-ground	Above-ground
Length	(m)	700	1,000	150	120
Inside diameter	(m)	3.8-2.9	4.1-3.0	2.0-1.7	3.5-3.1
8. Power Station					
Firm discharge	(m3/s)	7.9	9.1	4.3	23.6
Max. plant discharge	(m3/s)	39.7	45.5	22.8	101.2
Gross head	(m)	470-400	297-263	125-90	55-30
Rated head	(m)	434	251	114	47
Installed capacity	(MW)	3x50	3x32	2x11	2x22.5
Dependable peak power	(MW)	128.9	96	19.7	23.8
Annual energy output	(GWh)	342	310	69	122
Firm		201	192	36	74
Secondary		141	118	33	48
Type		Above-ground	Under-ground	Above-ground	Above-ground
Nos.of unit		3	3	2	2
Type of Turbine		Pelton	Francis	Francis	Francis
Tailwater level	(EL-m)	500	232-203	105	270
9. Construction Cost	(US$10^6)	249.1	228.5	85.5	83.1

Table G.2.5 PRINCIPAL FEATURES OF EXISTING MULTIPURPOSE DAMS OF MAIN SYSTEM (1/2)

Item		Unit	M-1 Kotmale Dam	M-2 Polgolla Dam	M-3 Victoria Dam	M-4 Randenigala Dam	M-5 Rantembe Dam
A. Hydrology							
1. Catchment Area		km2	562	1,292	1,891	2,365	3,111
2. Average Annual Discharge (1949-87)		MCM	985	2,133 *1	1,984 *1	2,528 *1	3,126 *1
		m3/s	31.1	67.9	63.9	81.2	101.8
(Polgolla diversion of 875MCM)							
B. Reservoir							
1. Extreme Max. WL		El.m	704.3	446.4	441.2	236.2	155.0
2. Normal Max. WL		El.m	703.0	440.8	438.0	232.0	152.0
3. Min. Operating WL		El.m	665.0	438.4	370.0	203.0	140.0
4. Low WL		El.m	(665.0)	-	(357.6)	(170.0)	-
5. Storage Capacity	- Normal Max. WL	MCM	172.9	4.1	721.2	861.4	22
	- Min. Ope. WL	MCM	22.2	2	34	303.4	4.4
6. Design Spillway Discharge		m3/s	5,560	-	7,900	8,085	10,235
7. Low Level Outlet Capacity		m3/s	133	1	760	200	180
C. Dam							
1. Type of Dam		-	Rockfil	C.Gravity	C.Arch	Rockfill	C.Gravity
2. Crest Length		m	600	144	520	485	415
3. Height		m	87	14.6	122	94	43.5
D. Hydraulic Turbine							
1. Number of Unit		Nos.	3	2	3(6)	2	2
2. Type of Turbine		-	V.Francis	V.Francis	V.Francis	Francis	V.Francis
3. Rated Power		MW	3x67	2x19	3x70	2x63	2x24.5
4. Rated Head		m	201.5	78	190	78	31.5
5. Discharge		m3/s	3x38	2x28.3	3x46.7	2x90	2x90
E. Generator							
1. Rated Power		MW	3x90	2x21.4	3x82.5	2x82	2x34.5
2. Power Factor		-	0.85	0.85	0.85	0.85	
3. Efficiency		%	98	99	97	98	
F. Conveyance Structure							
1. Intake Tunnels	- Length	m	6,560	5,200	5,665	-	-
	- Diameter	m	6.2	5.9	6.2	-	-
	- Capacity	m3/s	114	56.6	140	-	-
2. Penstock	- Length	m	120	239	209	270	20
	- Diameter	m	4.8-5.5	2x2.7	3x3.0	6.2	2x4.2
	- Capacity	m3/s	3x38	2x28.3	3x46.7	2x90	2x90
G. Remarks							

Remark: *1 Runcase D109 (Polgolla diversion; 898 MCM)

Source: Ref. Mahaweli Water Resources Management Project, Studies of Operating Policy Options, ACRES, 1985

Table G.2.5 PRINCIPAL FEATURES OF EXISTING MULTIPURPOSE DAMS OF MAIN SYSTEM (2/2)

Item	Unit	M-6 Minipe Dam	M-7 Bowatenna Dam	M-8 Moragahakanda Dam	M-9 Elahera Dam	M-10 Angamedilla Dam
A. Hydrology						
1. Catchment Area	km2	3,120	506	782	782	1,363
2. Average Annual Discharge (1949-81)	MCM	3,126	1,343 *1	968 *1	921 *1	964*1
	m3/s	102	42.1	29.0	37.5	19.1
(Polgolla diversion of 875MCM)						
B. Reservoir						
1. Extreme Max. WL	El.m	120.0	252.8	195.6	-	
2. Normal Max. WL	El.m	114.0	251.8	195.0	138.8	
3. Min. Operating WL	El.m	Weir crest	243.8	170.0	Weir Crest	
4. Low WL	El.m	114.0m	-	(150)	138.8m	
5. Storage Capacity - Normal Max. WL	MCM	LB Sill	52.0	902.8	E-M Sill	
- Min. Ope. WL	MCM	11.9m	17.1	217.2	133.8m	
6. Design Spillway Discharge	m3/s	RB Sill	4,340	3,400		
7. Low Level Outlet Capacity	m3/s	111.1m	1	(100)		
C. Dam						
1. Type of Dam	-	C.Gravity	C.Gravity	Rockfill	Concrete	
2. Crest Length	m	229	226	+C.Gravity	29	
3. Height	m	9.0	30	Max.	No Power	
		No Power			Unit	
D. Hydraulic Turbine		Unit			C.Canal	No Power
1. Number of Unit	Nos.	C.Canal	1	1(1)	E-M Canal	Unit
2. Type of Turbine	-	Minipe LB	V.Francis	Rockfill,	42.5m3/s	C.Canal
		18.4m3/s		C.Gravity	31,100ha	To P.Samudra
3. Rated Power	MW	6,100ha	40	26	To Minneriya	14.2m3/s
4. Rated Head	m	Minipe RB	52.7	54.8	42.5m/s	10,100ha
5. Discharge	m3/s	64.0m3/s	94.9	56.6	22,700ha	
		55,400ha			To Giritale	
E. Generator					8.5m3/s	
1. Rated Power	MW		47.1	30.5	3000ha	
2. Power Factor	-		0.85	0.85		
3. Efficiency	%		99	-		
F. Conveyance Structure						
1. Intake Tunnels - Length	m		1,240	-		
- Diameter	m		6.1	-		
- Capacity	m3/s		94.9	-		
2. Penstock - Length	m		72	87		
- Diameter	m			3.9-3.2		
- Capacity	m3/s		94.9	56.6		
G. Remarks			Irr. Tunnel			
			D=3.9m			
			Lit.=6.836m			
			Q=28.3m3/s			

Remarks: *1 Runcase D109 (Polgolla diversion; 898 MCM)

Source: Ref. Mahaweli Water Resources Management Project, Studies of Operating Policy Options, ACRES, 1985

Table G.3.1 FUEL PRICE PROJECTIONS RECOMMENDED BY ADB (Price in US$ per BBL for Oil and US$ per MT for Coal)

Year	Curde Oil	Oil Sulfer Res. Oil	Coal
1987	16.00	13.67	35.50
1988	15.23	13.92	36.35
1989	16.46	14.18	37.21
1990	16.70	14.45	38.10
1991	17.15	15.32	39.56
1992	18.23	16.24	41.08
1993	19.05	17.22	42.66
1994	19.91	18.26	44.30
1995	20.80	19.37	46.00
1996	22.34	20.81	47.14
1997	23.98	22.34	48.31
1998	25.75	23.99	49.51
1999	27.65	24.76	50.74
2000	29.70	25.67	52.00
2001	31.89	29.71	53.29
2002	34.24	31.90	54.61
2003	36.77	34.26	53.96
2004	39.48	36.79	57.35
2005	42.39	39.51	58.77
2006	46.52	12.42	60.23
2007	48.88	45.50	61.73