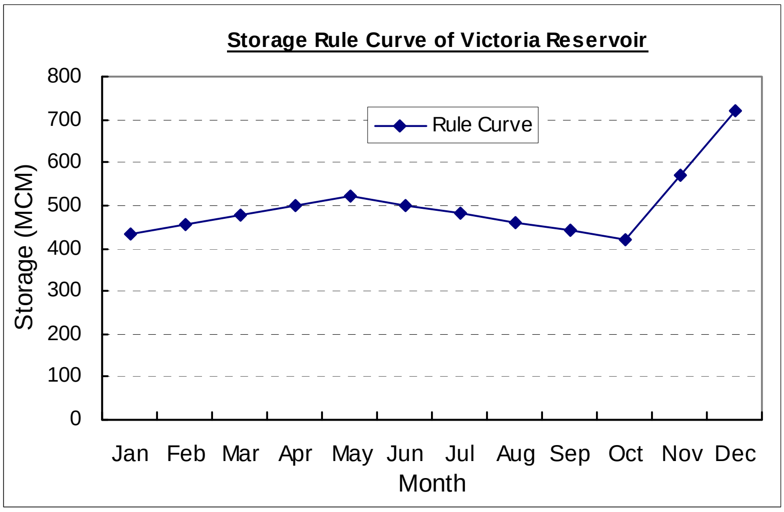
### 6.1.6 Power Generation Simulation

#### (1) Review of Reservoir Operation Rule

In the comparative study on the alternative options, the operation rule of the Victoria reservoir is revised. The purpose of revising reservoir operation rule is to produce more energy by the hydropower generation, and to compare the energy output for all options with applying the revised operation rule of the Victoria reservoir.

#### (2) Current Reservoir Operation Rule

The operation rule of the Victoria reservoir was studied together with the Randenigala reservoir in "Mahaweli Water Resources Management Project" which was funded by the Canadian International Development Agency (CIDA) in 1985. In the study, the operation rule curve was formulated assuming the irrigation demand had higher priority than the power demand. The objective of the operation was to maximize the total power energy output of Victoria, Randenigala and Rantambe Hydropower Stations with satisfying the downstream irrigation demand. The optimal storage rule curve of the Victoria reservoir developed in the study is shown in **Figure 6.1.6-1**.

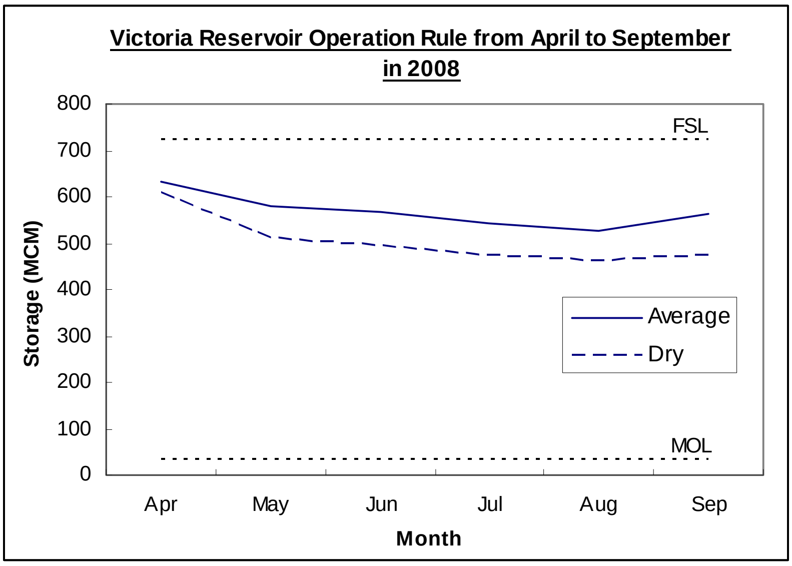



*Source: MASL*

**Figure 6.1.6-1**
**Optimal Rule Curve Suggested in "Mahaweli Water Resources Management Project"**

MASL conducts simulation study, every six months, using past 30-year inflow data and irrigation requirement with applying this optimal rule curve shown in **Figure 6.1.6-1**. Monthly reservoir water levels with 50% and 80 % exceeding probability obtained by the simulation are used to prepare operation rule curves. The result of the simulation is used to develop the operation rule for April to September and from October to March, and is compiled in the "Seasonal Operation Plan" issued by MASL.

An example of the operation rule from April to September in 2008 is shown in Figure 6.1.6-2.




** Average : 50% exceedance probability,*
*Dry : 80% exceedance probability*

*Source: "Seasonal Operation Plan 2008", MASL*

**Figure 6.1.6-2**
**Operation Rule Curve of the Victoria Reservoir from April to September in 2008**

The operation rule of the Victoria reservoir is used to monitor the actual operation of the reservoir so as not to largely deviate from the operation rule curve.

### (3) Optimization of Reservoir Operation

#### 1) Methodology

The operation rule to maximize total power generated by Victoria and Randenigala Hydropower Stations is to be established in the examination on the optimization of reservoir operation. "Dynamic Programming" (DP) is one of the popular techniques that have been applied to optimizing reservoir operation. The DP is designed to provide the optimal solution when the best decision follows after another. In the Study, DP is applied to obtain the optimal reservoir operation.

The generalized dynamic programming software package called "CSUDP"[1] is used in the Study.

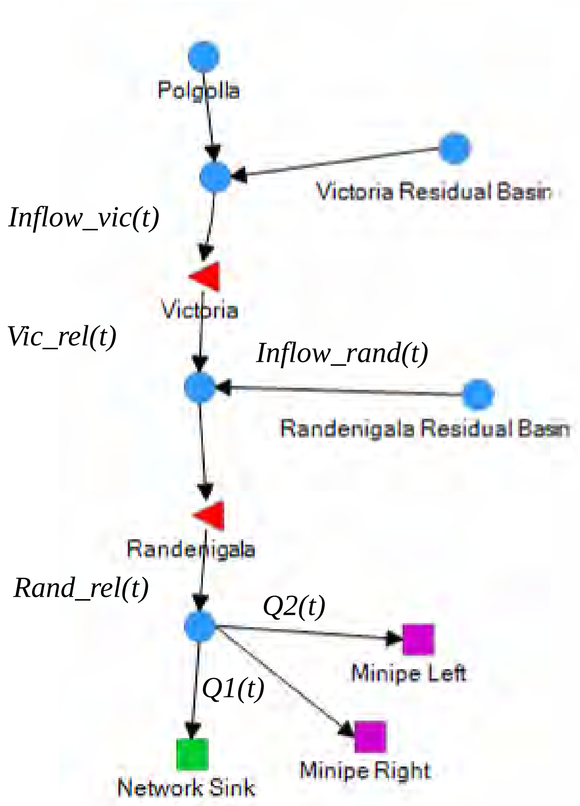
#### 2) Data Set

The monthly inflow of the Victoria reservoir and irrigation demand provided by MASL is used for the Study. The duration of the data is 22 years from 1985 to 2006.

[1] Labadie, J.W., (2003) "Generalized dynamic programming package: CSUDP." Documentation and user manual, Department of Civil Engineering, Colorado State University, Fort Collins, Colorado.

### 3) Model Structure

The Victoria and Randenigala system is indicated as a network model, and the structure of the model is shown in **Figure 6.1.6-3**;




**This network structure is depicted by MODSIM, a network simulation software package.*

**Figure 6.1.6-3 Network Model of the Victoria and Randenigala System**

The model shown in **Figure 6.1.6-3** is applied to DP.

### 4) Objective Function

The objective function is a recursive function with maximizing the hydropower generation in the Victoria and Randenigala Hydropower Stations. The form of the objective function is;

$$\text{Objective function:} \quad Maximize \sum_{i=1}^{m} Vic\_ene(t) + Rnd\_ene(t) - penalty$$

Where,

*Vic_ene(t)* : Energy output of the Victoria Hydropower Station (GWh) at the time “t”.

*Rnd_ene(t)* : Energy output of the Randenigala Hydropower Station (GWh) at the time “t”.

*penalty* : Penalty imposed to objective function when the downstream irrigation demand are not met.

*m* : Number of time steps.

The energy output of the hydropower is calculated by using a function composed of the hydraulic head and its release as follows;

Energy = $g \times Q_{power} \times He \times \varepsilon \times t$

Where,

| | | |
|---|---|---|
| $g$ | : | Gravity acceleration ($m/s^2$) |
| $Q_{power}$ | : | Power discharge ($m^3/s$) |
| $He$ | : | Effective head (m) |
| $\varepsilon$ | : | Combined efficiency |
| $t$ | : | Generation hour (hr) |

The constraint of the objective function is that the discharge from the Victoria reservoir should fulfill the downstream irrigation demand, because the downstream demands have higher priority than the hydropower use. This constraint is represented by the penalty term involved in the objective function.

This penalty term is very large negative number and is imposed only if the downstream demand is not met in the iterative process. In this way, *dynamic programming* allocates water for the irrigation demand prior to hydropower generation. The purpose of employment of 'penalty' term instead of using simple constraints is to avoid optimization program easily fallen into infeasible solution during iteration process.

**5) Decision Variables**

Decision variables are;

| | | |
|---|---|---|
| *Vic_rel(t)* | : | Release from the Victoria Hydropower Station at time "t" |
| *Rnd_rel(t)* | : | Release from Randenigala Hydropower Station at time "t" |
| *Q1(t)* | : | Supply for Irrigation to "Minipe Right Bank" |
| *Q2(t)* | : | Supply for Irrigation to "Minipe Left Bank" |

**6) Reservoir (State) Functions**

The state functions of the reservoir for the Victoria and Randenigala reservoirs are expressed by water balance of the reservoir as follows.

- Victoria reservoir

  *Vic_vol(t) = Vic_vol(t-1) + Inflow_vic(t) – Vic_rel(t)*

- Randenigala reservoir

  *Rand_vol(t) = Rand_vol(t-1) + Inflow_rand(t) + Vic_rel(t) – Rand_rel(t)*

**7) Constraints**

The constraints of the model are;

a. Water level of the Victoria reservoir and Randenigala reservoir should be more than the minimum operating level.

b. All variables are positive numbers.

### 8) Optimization Result

By using the inflow and irrigation demand data from 1985 to 2006, DP provides the optimum reservoir operation for 22 years to maximize the hydropower generation in Victoria and Randenigala Hydropower Stations as shown in **Figure 6.1.6-4**.

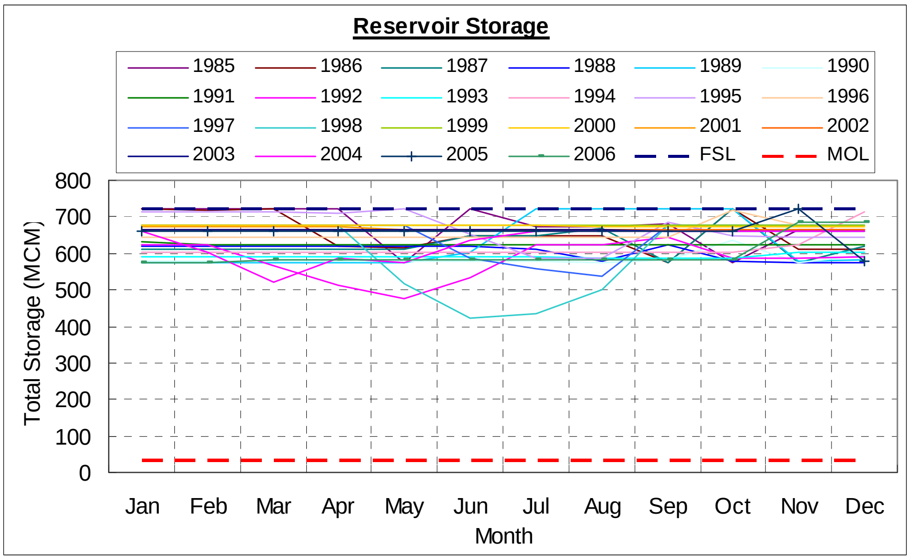



**Figure 6.1.6-4 DP Result: Reservoir Volume Fluctuation**

As shown in **Figure 6.1.6-4**, the DP result shows that the reservoir water level stays around 600 MCM to 700 MCM. This means reservoir water level is better to maintain high water level to obtain high power output by high hydraulic head and efficiency.

### 9) Operation Rule

The optimization result gives the optimum monthly storage for the duration of 22 years. However, the result does not give general operation rule. In general, the reservoir operation rule is obtained by interpreting the result of optimum monthly storage. The reservoir operation rule is obtained a) by drawing all the water level fluctuations for 22 years computed by using the optimization model, and then b) by depicting the lowest, the highest and average storage volume for each month. **Figure 6.1.6-5** shows the monthly average, the highest and the lowest of the reservoir volume on every month.

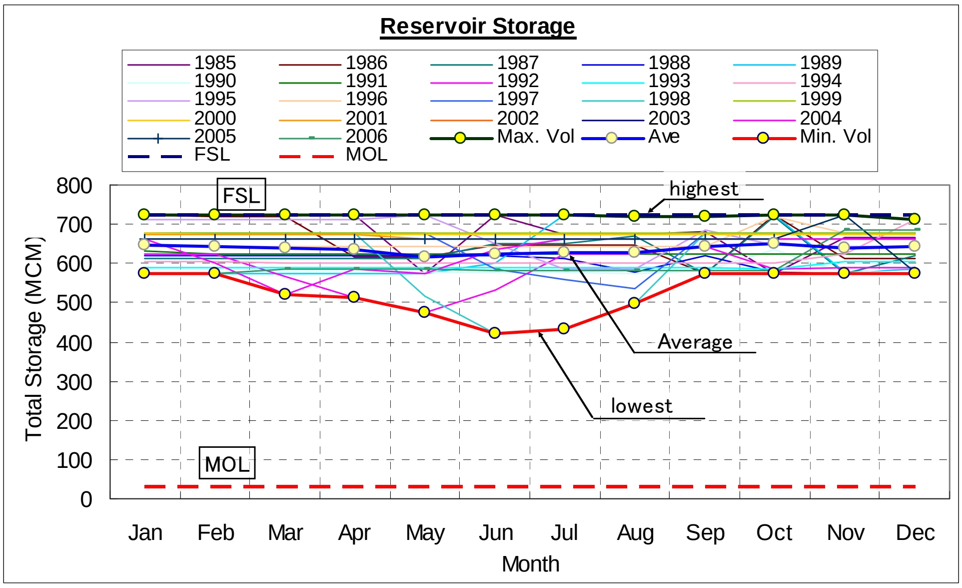



**Figure 6.1.6-5 Reservoir Storage Volume Boundaries**

The lowest and highest water levels for each month were then depicted. The lowest water level with a red line is named as the low target water level, and the highest water level with a black line is named as the high target water level. The effective storage of the Victoria reservoir between FSL and MOL are divided into four, namely Zone A, Zone B1, Zone B2 and Zone C as shown in **Figure 6.1.6-6**.

In Zone A, the release for power generation of the Victoria Hydropower Station should be less than the maximum plant discharge, and the Station is operated during peak hours (3 hours). In Zone B1, the maximum plant discharge is used for generation during peak hours, and the firm energy output can be obtained. In Zone B2, firm and secondary energy output can be obtained. In zone C, the water of the Victoria reservoir is unrestrictedly released until the water level of the Victoria reservoir is lowered to that of Zone B2.

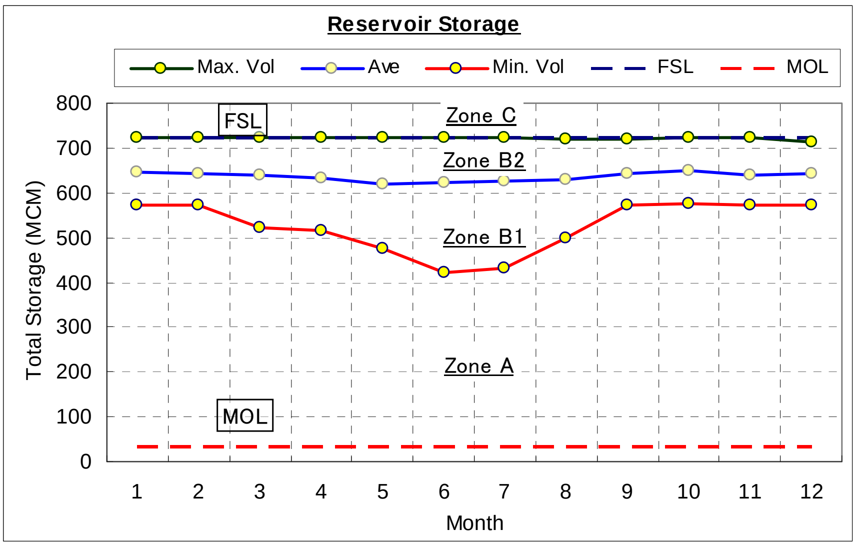



**Figure 6.1.6-6 Storage Zone of the Victoria Reservoir**

The detailed operation rules of each zone are as follows;

Zone A

$Hr$ = 3 hours

$Q_{power} = (Vol\_vic(t) – Vol\_MOL) / (Midtrgt(t) - Vol\_MOL) * (Q_{max} - Q_{min}) + Q_{min}$

Where,

| | | |
|---|---|---|
| $Hr$ | : | Hours of generation |
| $Q_{power}$ | : | Discharge for hydropower generation |
| $Vol\_vic(t)$ | : | Storage volume of the Victoria reservoir at the time “t” |
| $Vol\_MOL$ | : | Storage volume of the Victoria reservoir at MOL |
| $Midtrgt(t)$ | : | Medium target of storage volume at the time “t” |
| $Q_{max}$ | : | Maximum plant discharge |
| $Q_{min}$ | : | Minimum discharge for power generation |

Zone B1

$Hr$ = 3 hours

$Q_{power} = Q_{max}$

Where,

| | | |
|---|---|---|
| $Hr$ | : | Hours of generation |
| $Q_{power}$ | : | Discharge for hydropower generation. |
| $Q_{max}$ | : | Maximum plant discharge |

Zone B2

$Q_{power} = Q_{max}$

$Hr = Vol\_in(t) / Vol\_max$

Where,

| | | |
|---|---|---|
| $Hr$ | : | Hours of generation (≥3) |
| $Vol\_in(t)$ | : | Volume of inflow at the time “t”, and |
| $Vol\_max$ | : | Volume required for 1 hour generation with the maximum plant discharge. |

If $Hr$ is calculated to be less than 3, then $Hr$ is set to 3.

Zone C

$Q_{power} = Q_{max}$

$H$ = until reach to high target level.

$= (Vol\_in(t) + Vol\_vic(t\text{-}1) – Hightgt(t)) / (Vol\_max)$

Where,

| | | |
|---|---|---|
| $Hr$ | : | Hours of generation (≥3) |
| $Vol\_in(t)$ | : | Volume of inflow at the time “t”, |
| $Vol\_vic(t)$ | : | Storage volume of the Victoria reservoir at the time “t”, |
| $Hightgt(t)$ | : | High target of the Victoria reservoir at the time “t”, and |
| $Vol\_max$ | : | Volume required for 1 hour generation with the maximum plant discharge. |

If *Hr* is calculated to be less than 3, then *Hr* is set to 3.

### (4) Generation Method of Pumped Storage Option

As discussed in **Section 6.1.11**, WASP study for the period from 2008 to 2027 analyzes the pumped storage option with condition of maximum possible annual energy assuming duration of generation was 1,000 hours a year. The analysis shows that energy by pumped storage power increases after the year 2021 and that the average annual generation hour amounts to 374 hours a year from 2021 to 2027.

In consideration of the result of WASP study, the simulation of power generation on the pumped storage option assumes the generation method combining pumped storage type which generates power for 374 hours per annum using pumped-up water and conventional type power generation using storage water with natural stream flow.

### (5) Simulation on Power Generation

The water balance simulation is carried out using 22 years monthly inflow and irrigation demand to calculate the power and energy by the expanded power station. It is noted that spillout discharge is deducted from the inflow because it was not used for hydropower generation. The duration of the data is from January 1985 to December 2006. The data used for the simulation study is shown in **Table 6.1.6-1**.

**Table 6.1.6-1 Data Used for Simulation Study**

| Data | Duration | Data type |
|---|---|---|
| Inflow | Jan 1985 to Dec 2006 | Monthly Inflow discharge data at Polgolla diversion with inflow from residual basin. Spillout discharge is deducted from inflow. |
| Irrigation Demand | Jan 1985 to Dec 2006 | Monthly demand quantity of Minipe Cut Left bank and Minipe Cut Right Bank |
| Spillout discharge | Jan 1985 to Dec 2006 | Spillout discharge recorded at Victoria reservoir |

The inflow from the residual river basin to the Victoria and the Randenigala reservoirs are estimated by the ratio of area at the Victoria dam basin to the residual basin area between the Victoria and the Randenigala dam.

The hydropower simulation program was developed particularly for the Study on Microsoft Excel VBA, and used for the Study. The water balance simulation is carried out by applying time series data from 1985 to 2006 to the simulation program. The result of the annual energy, dependable power output and firm and secondary energy of each option are shown in **Table 6.1.6-2**.

**Table 6.1.6-2 Annual Energy and Power Output**

| | # of units | Expansion plant | Existing + Expansion plant | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Installed Capacity (MW) | Annual Energy (GWh) | Firm Energy* (GWh) | Secondary Energy** (GWh) | 95% Dependable Capacity (MW) | Pump-up Energy (GWh) | Net Annual Energy (GWh) |
| Basic Option | 3 | 213 | 651 | 452 | 198 | 359 | | 651 |
| | 2 | 140 | 651 | 381 | 271 | 336 | | 651 |
| Downstream Option | 3 | 219 | 652 | 449 | 203 | 361 | | 652 |
| | 2 | 143 | 652 | 378 | 275 | 333 | | 652 |
| Pumped Storage Option | 3 | 198 | 729 | 445 | 284 | 396 | -106 | 623 |
| | 2 | 128 | 711 | 343 | 368 | 310 | -68 | 643 |

*Note: * "Firm energy" means the total of power generated during 3-hour peak duration.*
*** "Secondary energy" means the total of power generated in duration except 3-hour peak time.*

As shown in **Table 6.1.6-2**, the annual energy and power output are almost the same for downstream and basic options although the downstream option has higher design effective head than that of the basic option as described in **6.1.5 (5)**. The reason is that the simulation resulted in that gross head between the Victoria and the Randenigala Reservoirs is generally smaller than the designed gross head. This is due to that the tailrace water level of the new powerhouse is depending on the Randenigala Reservoir water levels, and the water level of Randenigal Reservoir is raised by the discharge from the Victoria powerhouse[2].

Annual energy of the pumped storage options apparently is larger than that of other options. However, in consideration of energy for pump-up operation, as indicated in the right column in **Table 6.1.6-2,** the net annual energy of pumped storage option is consequently smaller than others.

In summary, the simulation study result shows that the annual energy of the basic option and downstream option does not give significant difference, even though the downstream option places the powerhouse at lower elevation than that of the basic option. For the pumped storage option, the net annual energy is not improved since the additional energy for pumping up the water to the Victoria reservoir is necessary.

### 6.1.7 Geological Conditions

The tunnel alignment of the Victoria Hydropower Station was changed during construction, because the original alignment encountered poor geological conditions. After construction of the Power Station, the fault was identified and indicated in the geological maps issued by Geological Survey and Mines Bureau.

The tunnel alignment for the basic option will not meet the fault, because the alignment is selected in parallel to the existing alignment, but those of the downstream option and pumped storage option may encounter the fault. When either of the two options is selected as optimal one, further

[2] Water levelof the Randenigala reservoir is not calculated in hydropower simulation. The water level of the reservoir is estimated with another water balance simulation program, and its result is attached to Appendix II.

geological investigation should be necessary during feasibility study stage or during detailed design stage, and measures to cope with the fault should be prepared before commencement of construction works.

The above geological conditions may need additional construction cost and additional period up to completion of the construction work of the downstream option and pumped storage option (see **Section 7.2**).

### 6.1.8 Construction Planning

#### (1) New Access Tunnel and New Access Road

Study Team examined necessity of new access tunnels and new access roads necessary for construction of each option. The result is shown in **Table 6.1.8-1.**

**Table 6.1.8-1 New Access Tunnel and New Access Road**

| | | New Access Tunnel | New Access Road |
|---|---|---|---|
| Basic Option | 3 units | Not necessary | Not necessary |
| | 2 units | Not necessary | Not necessary |
| Downstream Option | 3 units | 1 tunnel with 500 m | 2 roads with total length of 2.8 km |
| | 2 units | 1 tunnel with 500 m | 2 roads with total length of 2.8 km |
| Pumped Storage Option | 3 units | 1 tunnel with 500 m and 1 tunnel with 600 m | 2 roads with total length of 3.7 km |
| | 2 units | 1 tunnel with 500 m and 1 tunnel with 600 m | 2 roads with total length of 3.7 km |

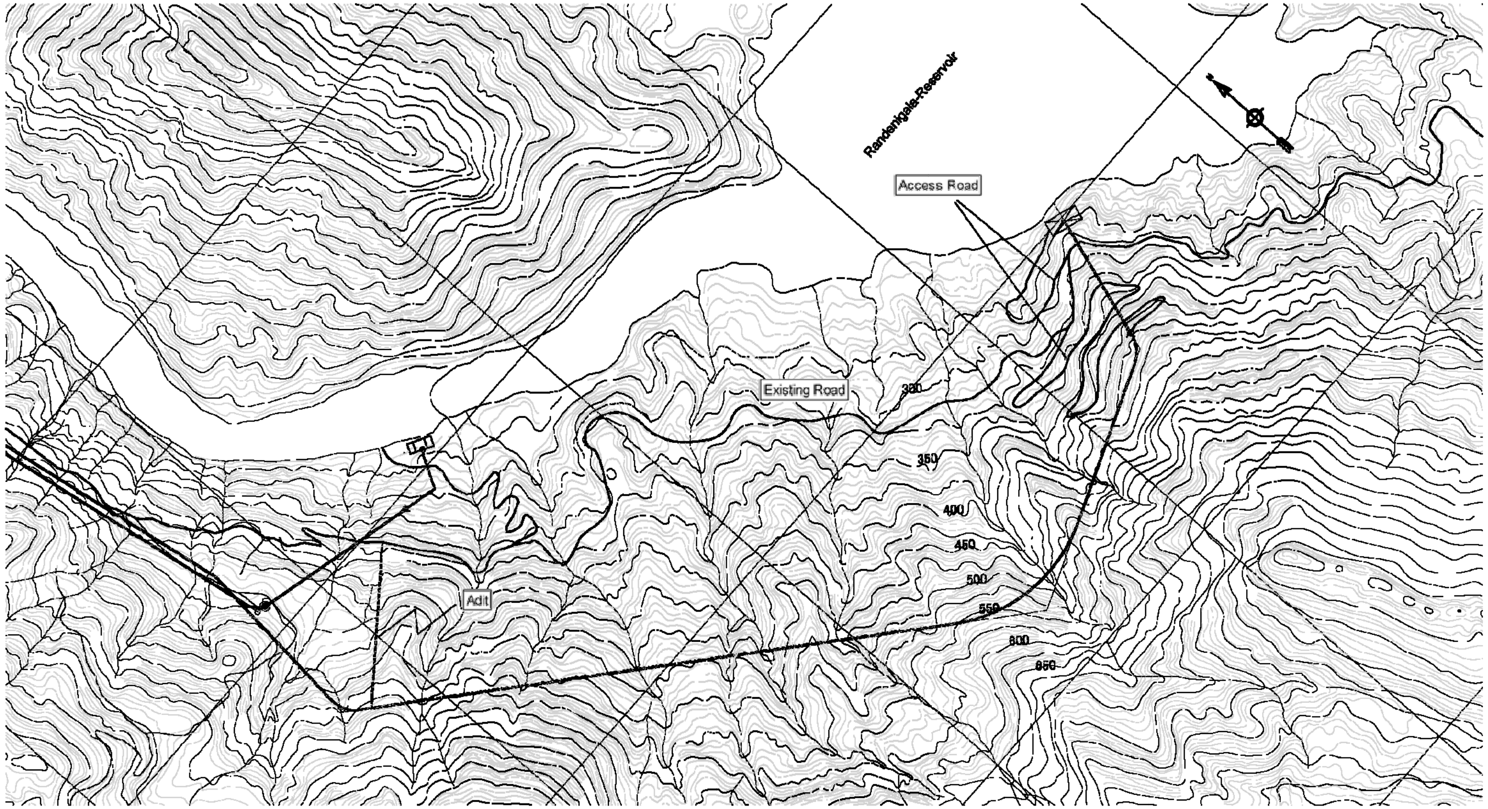
The general plan of new access tunnels and roads for the downstream and pumped storage options are shown in **Figure 6.1.8-1** and **Figure 6.1.8-2**, respectively.

#### (2) Construction Period

Total construction period for each option is studied, and the result shown in **Table 6.1.8-2**.

**Table 6.1.8-2 Construction Period and Period of Drawdown of Randenigala Reservoir**

| | | Construction Period (year) | Period of Drawdown of Randenigala Reservoir (year) |
|---|---|---|---|
| Basic Option | 3 units | 5.0 | 0 |
| | 2 units | 5.0 | 0 |
| Downstream Option | 3 units | 5.5 | 1.0 |
| | 2 units | 5.5 | 1.0 |
| Pumped Storage Option | 3 units | 6.0 | 1.5 |
| | 2 units | 6.0 | 1.5 |

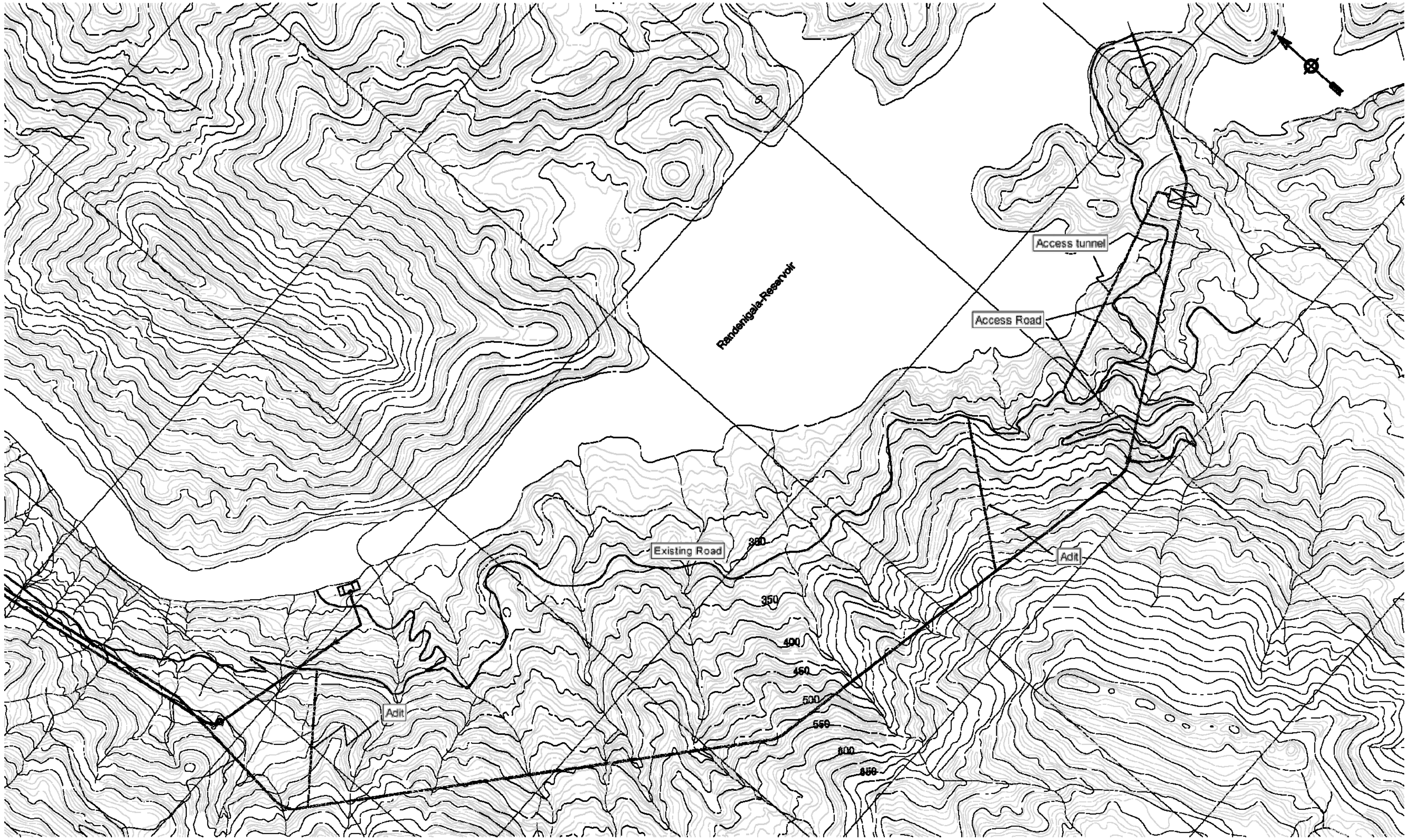



PLAN
scale a

SCALE a 0 1 km

**Figure 6.1.8-1 Downstream Option: Access Road and Adit**

| |
|---|
| Fesibility Study for Expansion of Victoria Hydropower Station |
| Downstream Option, Access Road and Adit |




PLAN
scale a

SCALE a 0 1 km

Fesibility Study for Expansion of Victoria Hydropower Station

Pumped Storage Opion, Access Road and Adit

Figure 6.1.8-2 Pumped Storage Option: Access Road and Adit

### 6.1.9 Environmental and Social Considerations

The study on the environmental and social impacts is examined in preliminary study level. The anticipated impacts caused by each option are assessed in **Chapter 8**. According to the study on the environmental and social aspect for each alternative option, the basic is the least impacts among three alternatives, while the pumped storage option imposes the largest impact on the environment, and the downstream option is the middle of the basic and the pumped storage option.

### 6.1.10 Benefit and Cost Analysis (B/C Analysis)

#### (1) Method

Three alternative options are compared by annualized economic benefit and cost of each option (B/C analysis). Economic benefit is composed of capacity and energy benefits. The capacity benefit is costs comprised of capital cost (construction cost) and fixed O&M cost of the alternative gas turbine plant which has equivalent generation capacity. The energy benefit consists of the fuel cost and variable O&M cost of the alternative gas turbine (in peak duration) and coal-fired thermal plant (in off-peak duration).

1) Capacity benefit (US$/kW) : Capital cost (construction cost) and fixed O&M cost
2) Energy benefit (US$/kWh) : Fuel cost and variable O&M cost

The capacity and energy benefit is annual value; and the benefit of each alternative option can be obtained by combining these two benefits.

The cost is annualized value converted from the total project cost. The conversion of the total project cost to annualized cost is made by using the following equation:

$$(Construction\ Cost + IDC) \times \beta + Annual\ Operation\ \&\ Maintenance\ Cost$$

Where,

*IDC* : Interest during construction

$\beta$ : Capital recovery factor = $i \times (1 + i)^t/\{(1 + i)^t-1\}$

Where,

$i$ : Discount rate (= 10%)

$t$ : Operation period (= 50 years)

In the economic aspect, the optimal option is determined as one with the maximum B/C.

#### (2) Economic Data

Economic data on alternative thermal power plants are mainly obtained from the "Generation Expansion Plan 2008-2022 (Draft)" prepared by CEB. Those data were derived from the value at the beginning of 2007.

**Table 6.1.10-1 Economic Data Used for B/C Analysis**

| Item | Unit | | | |
|---|---|---|---|---|
| Type of alternative thermal plant | | Gas Turbine | Coal-W.C. | |
| Installed capacity | MW | 75 | 3 x 300 | |
| Annual fixed O&M cost | US$/kW-month | 0.487 | 0.624 | |
| Variable O&M cost | USCts/kWh | 0.3883 | 0.2442 | |
| Time availability (Maximum annual PF) | % | 84.4 | 86.6 | |
| Scheduled annual maintenance duration | days | 30 | 40 | |
| Forced outage rate | % | 8 | 2.74 | |
| | | | | |
| Calorific value | kCal/kg | 10550 | 6300 | |
| Minimum operating level | % | 30 | 90 | |
| Heat rate at full load operating level | kCal/kWh | 2857 | 2293 | |
| | | | | |
| Capital cost incl. IDC | US$/kW | 548.7 | 1374.31 | |
| Constructino Period | years | 1.5 | 4 | |
| Economic life time | years | 20 | 30 | |
| | | | | |
| | | Gas turbine | Coal | Hydro*2 |
| Station use | % | 2.7*1 | 8.0*3 | 0.45 |
| Scheduled annual maintenance | % | 8.00 | 2.74 | 1.90 |
| Forced outage | % | 8.20 | 11.00 | 0.50 |
| Transmission loss*2 | % | 3.20 | 3.20 | 3.20 |
| *1: Station use in Gas turbine is average of the record from 1996 to 2006 | | | | |
| *2: Data given by CEB | | | | |
| *3: General value | | | | |
| | | | | |
| Fuel cost*2 | USCts/kWh | 17.28 | 5.1 | - |
| interest rate | % | 10 | 10 | 10 |

*Source: Generation Expansion Plan 2008-2022 (Draft), 2008, CEB*

## (3) Project Cost

### 1) Construction Cost

Construction cost of the three options are estimated by referring to unit prices of major work items of the civil works for the Upper Kotmale Hydropower Project and by taking into account international market price for equipment. Timing of cost estimation is as of the beginning in 2007 at the same time as estimation of cost for the alternative thermal power plant.

Environmental cost (costs for compensation, mitigation, and monitoring), administration & engineering fee, and contingency are added into the construction cost of each option. The environmental cost for each option is referred to that estimated by the subcontractor for the environmental and social consideration survey (EIA Study) and consists of compensation cost, mitigation cost and monitoring cost as mentioned in **Section 7.3**. Because the environmental cost is the price of as October 2008, it is converted the price as of the beginning of 2007 by using CPI in Sri Lanka.

The construction cost of each option is as shown in **Table 6.1.10-2**;

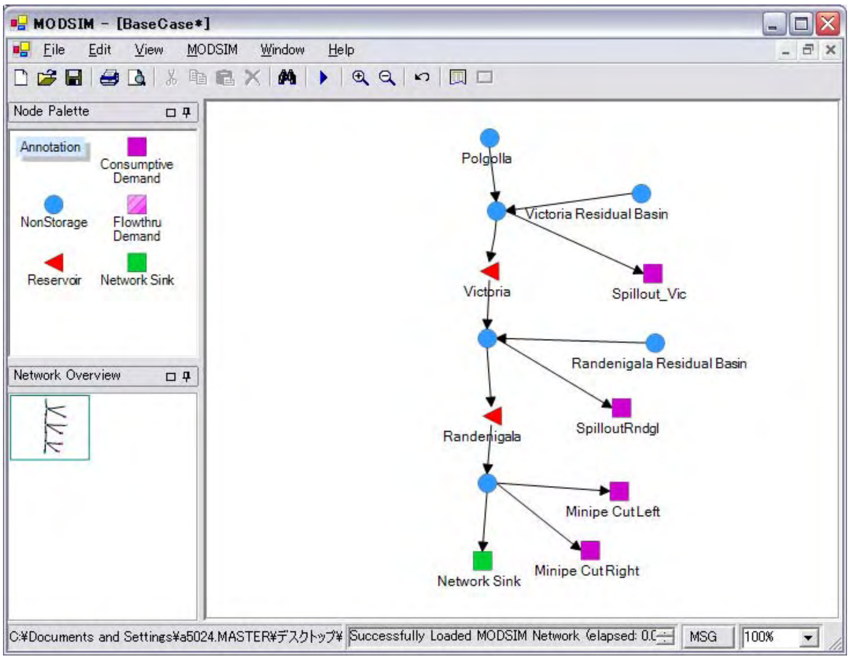
**Table 6.1.10-2 Project Construction Cost for Each Option**

(unit: mil. US$)

| Item | Basic Peak Duration: 3 hours | | Downstream Peak Duration: 3 hours | | Pumped Storage | |
|---|---|---|---|---|---|---|
| | 3 units | 2 units | 3 units | 2 units | 3 units | 2 units |
| A Preparatory Works | 1.5 | 1.5 | 2.0 | 2.0 | 2.5 | 2.5 |
| B Civil works | 56.8 | 41.5 | 90.0 | 66.3 | 150.1 | 118.1 |
| C Equipment & Transmission Line | 82.5 | 67.0 | 82.5 | 67.9 | 123.4 | 95.7 |
| D Total (A to C) | 140.8 | 110.0 | 174.5 | 136.2 | 276.0 | 216.3 |
| E Environmental Cost | 1.5 | 1.5 | 1.9 | 1.9 | 2.2 | 2.2 |
| F Administration & Engineering Fee | 14.1 | 11.0 | 17.5 | 13.6 | 27.6 | 21.6 |
| G Contingency | 15.7 | 12.2 | 19.4 | 15.2 | 30.6 | 24.0 |
| H Total construction cost | 172.1 | 134.7 | 213.3 | 166.9 | 336.4 | 264.1 |

### 2) Reduction of Energy of Randenigala Power Station during Construction

The downstream option and pumped storage option require drawdown of the Randenigala reservoir water level during the construction of the outlet structure. To confirm the impact of the drawdown during the construction stage, the water balance simulation is carried out by using the inflow and downstream demand obtained in the Study. The model of the water balance study is developed by the network river basin simulation software package "MODSIM"[3] as shown in **Figure 6.1.10-1**.




*Source: CEB*

**Figure 6.1.10-1 Water Balance Simulation Model**

[3] Labadie, J.W., (2005) "MODSIM: River Basin Management Decision Support System," Chapter 23 in Watershed Models, V. Singh and D. Frevert, eds., CRC Press Boca Raton, Florida.

The data used in this water balance are:

- Inflow : Monthly Inflow discharge data at Polgolla diversion given by MASL.
- Residual Basin Inflow : Inflow calculated in proportion to the river basin area.
- Demand : Monthly demand quantity of "Minipe Cut Left Bank" and "Minipe Right Bank" given by MASL.
- Spill out : Spillout discharge is the water quantity not used for hydropower generation.

The operation of the Victoria and Randenigala reservoirs and hydropower stations is envisaged as shown in the **Table 6.1.10-3.**

**Table 6.1.10-3 Operation Rule during Construction**

| | Basic Option | Downstream option | Pumped Storage Option |
|---|---|---|---|
| Victoria | Normal | Hydropower generation considering with irrigation demand | Hydropower generation considering with irrigation demand |
| Randenigala | Normal | Lowering WL to 209<br>Generating like run-of-river type | Lowering to 207 mASL.<br>No hydropower generation. |

In the simulation of the above water balance, the Rendenigala reservoir water level is lowered to the sill elevation as described before. Following **Table 6.1.10-4** shows the reduction of the annual energy by the Victoria and the Randenigala hydropower stations combined.

**Table 6.1.10-4 Reduction of Annual Energy during Construction**

| Item | Unit | Basic option | Downstream Option | Pumped Storage Option |
|---|---|---|---|---|
| Reduction of Annual Energy | GWh/year | 0 | 108 | 349 |
| Duration of drawdown | year | 0 | 1 | 1.5 |
| Total reduction of energy | GWh | 0 | 108 | 524 |

As shown in the above table, annual energy of the downstream option will be decreased of 108 GWh, and that of the pumped storage option will be decreased by 524 GWh during construction.

The reduction of energy in downstream option and pumped storage option is assumed to be recovered by the coal-fired thermal power plant generation. The increment cost of the coal-fired thermal power generation is;

$E \times C_1$

Where,

$E$ : Total energy recovered by coal-fired thermal power generation (kWh)

$C_1$ : kWh value of coal-fired thermal power generation (US$/kWh)

The reduction of energy is calculated around 108 GWh/year for downstream option and 349 GWh/year for pumped storage option. The duration of the reduction of energy is 1.0 year for downstream option and 1.5 years for pumped storage option.

Annualized costs of the reduction energy are;

Downstream option:

$108 \text{ (GWh/year)} \times 10^6 \times 1.0 \text{ (year)} \times 0.0534 \text{ US\$/kWh} \approx 5.8 \text{ Mill. US\$}$

Pumped storage option:

$349 \text{ (GWh/year)} \times 10^6 \times 1.5 \text{ (year)} \times 0.0534 \text{ US\$/kWh} \approx 28.0 \text{ Mill. US\$}$

The electricity generated by the coal power plant is accounted as the cost of the downstream and pumped storage option.

### 3) Pump-up Cost

In this analysis energy required for pumping up water in the pumped storage option is assumed to be provided by the thermal power plant with least cost, which is coal-fired thermal power plant. The cost of pumping water is obtained by energy required for pumping water multiplying kWh value of coal-fired thermal power generation.

$Ep \times C_1$

Where,

$Ep$ : Energy required for pumping water per annum (kWh/year)

$C_1$ : kWh value of coal-fired thermal power generation (US$/kWh)

The costs due to pumping up water are shown in **Table 6.1.10-5**.

**Table 6.1.10-5 Pump-up Cost of Pumped Storage Option**

| | | Pumped Storage Option | |
|---|---|---|---|
| | Unit | 3 units | 2 units |
| kWh value by coal | US$/kWh | 0.053 | 0.053 |
| Pump-up energy | GWh/year | 106 | 68 |
| Pump-up cost | Mill. US$/year | 6 | 4 |

The costs of the all options are summarized in **Table 6.1.10-6**. The cost shown in the **Table 6.1.10-6** is converted to annualized cost by using the equation shown in **6.1.10 (1)**. The annualized project cost is shown in **Table 6.1.10-7**.

**Table 6.1.10-6 Summary of the Project Cost**

| Item | Unit | Basic | | Downstream | | Pumped Storage | |
|---|---|---|---|---|---|---|---|
| | | 3 hrs | 3 hrs | 3 hrs | 3 hrs | | |
| | | 3 units | 2 units | 3 units | 2 units | 3 units | 2 units |
| Preparatory Works | Mill. US$ | 1.5 | 1.5 | 2.0 | 2.0 | 2.5 | 2.5 |
| Civil works | Mill. US$ | 56.8 | 41.5 | 90.0 | 66.3 | 150.1 | 118.1 |
| Equipment & Transmission Line | Mill. US$ | 82.5 | 67.0 | 82.5 | 67.9 | 123.4 | 95.7 |
| Environmental Cost | Mill. US$ | 1.5 | 1.5 | 1.9 | 1.9 | 2.2 | 2.2 |
| Administration & Engineering Fee | Mill. US$ | 14.1 | 11.0 | 17.5 | 13.6 | 27.6 | 21.6 |
| Contingency | Mill. US$ | 15.7 | 12.2 | 19.4 | 15.2 | 30.6 | 24.0 |
| Reduction of Energy | GWh/year | 0 | 0 | 108 | 108 | 349 | 349 |
| Period of reduction | years | 0 | 0 | 1 | 1 | 1.5 | 1.5 |
| kWh value by coal | US$/kWh | 0.053 | 0.053 | 0.053 | 0.053 | 0.053 | 0.053 |
| Cost of reduction of energy covered by Coal power | Mill. US$ | 0 | 0 | 5.8 | 5.8 | 28.0 | 28.0 |
| Total construction cost | Mill. US$ | 172.1 | 134.7 | 213.3 | 166.9 | 336.3 | 264.1 |
| Total construction cost incl. cost of reduction of energy | Mill. US$ | 172.1 | 134.7 | 219.1 | 172.7 | 364.3 | 292.1 |
| Pumped storage generation hours | hours/year | | | | | 374 | 374 |
| Pump-up power | MW | | | | | 198 | 128 |
| Pump-up efficiency | % | | | | | 70 | 70 |
| Pump-up hours | hours/year | | | | | 534 | 534 |
| Pump-up energy | GWh/year | | | | | 106 | 68 |
| Pump-up cost (using coal kWh value) | Mill. US$/year | | | | | 6 | 4 |

In **Table 6.1.10-6**, the pump-up hours of 534 is obtained by the pumped storage generation hours and efficiency of pumping up water (i.e. 534 = 374 / 0.7).

**Table 6.1.10-7 Annualized Project Cost of Each Option**

| Item | Unit | Basic | | Downstream | | Pumped Storage | |
|---|---|---|---|---|---|---|---|
| | | 3 hrs | 3 hrs | 3 hrs | 3 hrs | | |
| | | 3 units | 2 units | 3 units | 2 units | 3 units | 2 units |
| 1) Additional capacity | MW | 213 | 140 | 219 | 143 | 198 | 128 |
| 2) Installed capacity including existing units of 210 MW | MW | 423 | 350 | 429 | 353 | 408 | 338 |
| 3) Dependable capacity | MW | 359 | 336 | 361 | 333 | 396 | 310 |
| 4) Annual Energy | GWh | 651 | 651 | 652 | 652 | 729 | 711 |
| Firm Energy* | GWh | 452 | 381 | 449 | 378 | 445 | 343 |
| Secondary Energy** | GWh | 198 | 271 | 203 | 275 | 284 | 368 |
| 5) Total Construction cost | Mill. US$ | 172.1 | 134.7 | 213.3 | 166.9 | 336.3 | 264.1 |
| Construction cost: civil works | Mill. US$ | 56.8 | 41.5 | 90.0 | 66.3 | 150.1 | 118.0 |
| Equipment & Transmission Line | Mill. US$ | 82.5 | 67.0 | 82.5 | 67.9 | 123.4 | 95.7 |
| Construction cost: others | Mill. US$ | 32.8 | 26.2 | 40.8 | 32.7 | 62.8 | 50.4 |
| 6) Construction period | years | 5 | 5 | 5.5 | 5.5 | 6 | 6 |
| 7) Economic life of hydropower | years | 50 | 50 | 50 | 50 | 50 | 50 |
| 8) Interest rate | % | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| 9) Capital recovery factor | % | 10.1 | 10.1 | 10.1 | 10.1 | 10.1 | 10.1 |
| 10) O&M rate for civil works | % | 0.50 | 0.50 | 0.50 | 0.50 | 0.50 | 0.50 |
| 11) O&M rate for Equipment & Transmission Line | % | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |
| 12) Annual O&M Cost | Mill. US$/year | 1.5 | 1.2 | 1.7 | 1.4 | 2.6 | 2.0 |
| 13) Interest during construction(IDC) | Mill. US$ | 34.4 | 26.9 | 46.9 | 36.7 | 80.7 | 63.4 |
| 14) Annualized cost: Construction, IDC and O&M: [ 5) + 13) ] × 9) + 12) | Mill. US$/year | 22.3 | 17.5 | 27.9 | 21.9 | 44.7 | 35.1 |
| 15) Cost of reduction of energy during construction | Mill. US$ | - | - | 5.8 | 5.8 | 28.0 | 28.0 |
| 16) Annualized Cost of 15) | Mill. US$/year | - | - | 0.6 | 0.6 | 2.8 | 2.8 |
| 17) Pump-up cost (using coal kWh value) | Mill. US$/year | - | - | - | - | 5.8 | 3.7 |
| Annualized cost: 14) + 16) + 17) | Mill. US$/year | 22.3 | 17.6 | 28.5 | 22.5 | 53.1 | 41.5 |

*Note: * "Firm energy" means the total of power generated during 3-hour peak duration.*
*** "Secondary energy" means the total of power generated in duration except 3-hour peak time.*

As shown in **Table 6.1.10-7**, annualized cost of the pumped storage option is higher than the other options. The annualized cost of the basic option is lower than that of other options for 2-unit and 3-unit options.

### (4) Benefit

As described in the previous section, economic benefit is composed of capacity and energy benefits using alternative gas turbine and coal-fired power plant. The benefit of firm energy and secondary energy is corresponding to kWh value of gas turbine and coal-fired thermal power plant, respectively.

In the B/C analysis, the benefits of the expansion are calculated as the difference between those of the existing power plant as "without expansion", and those of the existing and expansion of each alternative option as "with expansion". The benefit is an increment of benefit accrued from "with expansion" case. Thus the difference between "with expansion" case and "without expansion" case is the benefit of the option.

The benefit of each option is shown in **Table 6.1.10-8**.

**Table 6.1.10-8 Summary of Benefits for Each Option**

| Description | Unit | Existing | Existing + Expansion Plant | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Basic Option | | Downstream | | Pumped Storage | |
| | | | 3 units | 2 units | 3 units | 2 units | 3 units | 2 units |
| Power and Energy of Victoria Power Station | | | | | | | | |
| 1. Annual Energy (Including generation by existing generators) | GWh | 632 | 651 | 651 | 652 | 652 | 729 | 711 |
| Firm Energy* | GWh | 230 | 452 | 381 | 449 | 378 | 445 | 343 |
| Secondary Energy** | GWh | 402 | 198 | 271 | 203 | 275 | 284 | 368 |
| 2. Dependable Peak Capacity | MW | 210 | 359 | 336 | 361 | 333 | 396 | 310 |
| Power and Energy of Alternative Thermal Plant | | | | | | | | |
| 3. Power to be Generated (Gas) | MW | 248 | 425 | 397 | 427 | 394 | 468 | 367 |
| 4. Annual Energy (Gas) | GWh/yr | 235 | 463 | 389 | 459 | 386 | 455 | 351 |
| 5. Annual Energy (Coal) | GWh/yr | 435 | 215 | 293 | 220 | 297 | 307 | 398 |
| 6. kWh-Value (Gas) | US$/MWh | 177 | 177 | 177 | 177 | 177 | 177 | 177 |
| 7. kWh-Value (Coal) | US$/MWh | 53 | 53 | 53 | 53 | 53 | 53 | 53 |
| 8. kW-Value (Gas) | US$/kW | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| 9. Annual Benefit (Gas) for capacity | Mill.US$/yr | 17.5 | 29.9 | 27.9 | 30.0 | 27.7 | 32.9 | 25.8 |
| 10. Annual Benefit (Gas) for firm energy | Mill.US$/yr | 41.6 | 81.8 | 68.8 | 81.2 | 68.3 | 80.4 | 62.1 |
| 11. Annual Benefit (Coal) for secondary energy | Mill.US$/yr | 23.2 | 11.5 | 15.6 | 11.8 | 15.9 | 16.4 | 21.3 |
| 12. Annual Benefit (Gas & Coal) | Mill.US$/yr | 82.3 | 123.1 | 112.4 | 122.9 | 111.8 | 129.7 | 109.1 |
| Increment of Benefit | Mill.US$/yr | 0.0 | 40.9 | 30.1 | 40.6 | 29.6 | 47.4 | 26.9 |

*Note: * "Firm energy" means the total of power generated during 3-hour peak duration.*
*** "Secondary energy" means the total of power generated in duration except 3-hour peak time.*

The figures of "Increment of Benefit" shown in **Table 6.1.10-8** are corresponding to the benefit of each option.

### (5) Unit Construction Cost

Unit construction cost is a cost per installed capacity of the expansion plant. The unit construction cost of each alternative option is calculated as shown in **Table 6.1.10-9**.

**Table 6.1.10-9 Unit Construction Cost of Alternative Options**

| Item | Unit | Basic Option | | Downstream Option | | Pumped Storage Option | |
|---|---|---|---|---|---|---|---|
| | | 3 units | 2 units | 3 units | 2 units | 3 units | 2 units |
| Unit Construction Cost | US$/kW | 808 | 962 | 974 | 1,167 | 1,699 | 2,063 |

### (6) Result of B/C Analysis

The ratio of the benefit to the cost (B/C) for all options is shown in **Table 6.1.10-10**.

**Table 6.1.10-10 Summary of B/C Analysis**

| Item | Unit | Basic Option | | Downstream Option | | Pumped Storage Option | |
|---|---|---|---|---|---|---|---|
| | | 3 units | 2 units | 3 units | 2 units | 3 units | 2 units |
| Installed capacity | MW | 213 | 140 | 219 | 143 | 198 | 128 |
| Benefit | Mill. US$/year | 40.9 | 30.1 | 40.6 | 29.6 | 47.4 | 26.9 |
| Cost | Mill. US$/year | 22.3 | 17.5 | 28.5 | 22.5 | 53.1 | 41.5 |
| B / C | | 1.83 | 1.72 | 1.43 | 1.32 | 0.89 | 0.65 |

As shown in the above table, the B/C of 3-unit expansion in the basic option is the largest among all options. B/C values of the basic options for both 2-unit and 3-unit expansion are larger the other options. Pumped storage option is less than 1.0. This means its cost is larger than the benefit.

Therefore, the basic option with 3 units (210 MW class) is the most economical option with respect to the B/C analysis.

## 6.1.11 Study Using WASP-IV

Study Team examined analytical models of the three alternative options, the input data of WASP-IV (power development planning tool) of each option were provided to CEB, and CEB analyzed three alternative options with WASP-IV. Study Team also conducted an analysis by using the same input data, as agreed with CEB during the 1st Work in Sri Lanka (February 2008), and the procedure and result are described below. For the purpose of the Study, each option was analyzed as fixed and forced project.

### (1) Purpose of Analysis

When three alternative options are independently developed respectively, it is analyzed which alternative option will have the least total cost (capital cost of new power sources and O&M cost of the power stations) for the power system operation of CEB for the examination period (2008-2027) by using WASP-IV. It has aimed to confirm the validity of the result of the economic comparison examined in the previous section.

### (2) Examination of Analysis Model of Alternative Options

Study Team determined the WASP-IV analytical model of each alternative option, considering that the expansion of the hydropower station was analyzed and that there are limitations for the input data for WASP-IV, as follows.

#### 1) Basic Option

- In WASP-IV, the expansion plan was defined as a candidate power plant because the capacity was not revocable during the examination period.
- Capacity of the reservoir was included in the existing hydropower station because the capacity of the Victoria reservoir did not change after expansion. The capacity of reservoir of expansion was set to be 0.
- Because an increase in the annual energy after expansion was a little, it was assumed that periodical power supply (Inflow Energy, Minimum Generation, Average Capacity) for the expansion was set to be 0.

#### 2) Downstream Option

The model for downstream option was to be the same as above-mentioned in 1).

#### 3) Pumped Storage Option

- The pumped storage power station was defined as a development candidate.
- After expansion of pumped storage power station, the operation of the existing hydropower station was assumed to be just like the current state.
- The maximum feasible energy of pumped storage station was estimated as 3 hours a day (for about 1,000 hours a year) according to the peak time duration of the demand in Sri Lanka.

### (3) Provision of Input Data for WASP-IV to CEB for Each Alternative Option

2-unit option and 3-unit of the generator were examined in the economic comparisons of the alternative options. As a result, in the examination of WASP-IV, 3-unit option was selected as expansion candidate power station in each alternative option, because 3-unit option had larger B/C than that of 2-unit option in economic comparison. The input data of WASP-IV provided to CEB are shown in **Table 6.1.11-1** and **Table 6.1.11-2**.

- ➢ The construction cost of the downstream option is set to be higher than that of the basic option, because it includes cost for longer waterway.
- ➢ The construction cost of the pumped storage option is set to be higher than that of the other two options because the waterway is longer than the downstream option.
- ➢ The commissioning year of the pumped storage option is set in 2016 in consideration of the construction period (six years).
- ➢ Inflow energy of the basic option and the downstream option is set to be 0.1 in an actual analysis, because the error occurs when 0 values are input in WASP-IV.

**Table 6.1.11-1 WASP-IV Input Data for Basic and Downstream Options**

| Item | Unit | Basic | Downstream |
|---|---|---|---|
| Installed Capacity | MW | 213 | 223 |
| Storage Capacity | GWh | 0 | 0 |
| Inflow Energy | GWh | 0.1 | 0.1 |
| Minimum Generation | GWh | 0 | 0 |
| Average Capacity | MW | 0 | 0 |
| O&M Cost | $/kW/month | 0.391 | 0.391 |
| Depreciable Capital Cost | | | |
| Domestic | $/kW | 404.5 | 480.1 |
| Foreign | $/kW | 404.5 | 480.1 |
| Interest Rate during Construction | % | 10 | 10 |
| Plant Life | years | 50 | 50 |
| Construction Period | years | 5 | 5.5 |
| Operation year | year | 2015 | 2015 |

**Table 6.1.11-2 WASP-IV Input Data for Pumped Storage Option**

| Item | Unit | Pumped Storage |
|---|---|---|
| Installed Capacity | MW | 209 |
| Cycle Efficiency | % | 70 |
| Pumping Capacity | MW | 209 |
| Generation Capacity | MW | 209 |
| Maximum Feasible Energy | GWh | 17.4 |
| O&M Cost | $/kW/month | 0.391 |
| Depreciable Capital Cost | | |
| Domestic | $/kW | 810.8 |
| Foreign | $/kW | 810.8 |
| Interest Rate during Construction | % | 10 |
| Plant Life | years | 50 |
| Construction Period | years | 6 |
| Operation year | year | 2016 |

### (4) Study Using WASP-IV

CEB and Study Team examined the total cost for the alternatives, using optimal power development planning simulation tool, WASP-IV, and it was confirmed that both results were the same.

Except input data on the three alternative options provided by Study Team to CEB, those for the demand, the existing stations, the reliability criterion, and the power development candidates, etc. prepared by CEB were used. The result outline is shown as follows.

#### 1) Cost

The cost of each alternative option calculating by WASP-IV is shown in **Table 6.1.11-3,** and the differences from the cost of the basic option are shown in **Table 6.1.11-4**.

When three alternative options of total costs are compared, the cost for the basic option was the lowest and the downstream option follows it, and the cost for the pumped storage option is the highest.

**Table 6.1.11-3 Cost of Each Option on WASP-IV Result**

(Million $)

| | Basic Option | Downstream Option | Pumped Storage Option |
|---|---|---|---|
| Operation Cost | 17,559 | 17,559 | 17,461 |
| Capital Cost | 9,361 | 9,413 | 9,624 |
| Total Cost | 26,919 | 26,972 | 27,085 |

**Table 6.1.11-4 Difference of Costs of Basic Option and Other Options**

(Million $)

| | Basic Option | Downstream Option | Pumped Storage Option |
|---|---|---|---|
| Operation Cost | – | 1 | -97 |
| Capital Cost | – | 52 | 263 |
| Total Cost | – | 53 | 166 |

a) Basic Option

A total cost is lower than that of the downstream option and pumped storage option. This is because the expansion power station of the basic option is located adjacent to the existing power station and the construction cost of the option is lower than that of the other options.

b) Downstream Option

The operation cost becomes a marginal rise compared with that of the basic option, and the capital cost has risen. Because the annual energy of expansion is the same as the basic option but the install capacity increases, the operation cost increases. The capital cost increases, because the construction cost has risen due to longer waterway than that of the basic option.

c) Pumped Storage Option

The total cost is higher than that of the basic option and downstream option. The operation cost is lower than that of the basic option, because merits for pumped storage scheme is deemed. The capital cost has risen, because the power development plan of thermal power plants is different from that for the basic option, and the higher construction cost than that of the basic option is set.

**2) Power Development Plan**

a) Basic Option

A new power plant is not developed until 2010, and high LOLP (Loss of Load Probability) is generated. After the diesel plants commence to operate in 2011, the coal thermal power plants begin to operate in 2013, and the expansion of the Victoria hydropower station starts to operate in 2015. Hence, LOLP is below the criterion value.

### Table 6.1.11-5 Power Development Plan of Basic Option

| YEAR | %LOLP | NAME<br>SIZE (MW)<br>TYPE<br>CAP(MW) | STF1<br>150<br>FOIL | STF3<br>300<br>FOIL | CST<br>300<br>COLW | GT1<br>35<br>ADSL | GT2<br>75<br>ADSL | GT3<br>105<br>ADSL | CCY1<br>150<br>ADSL | CCY3<br>300<br>ADSL | CTRC<br>250<br>COLT | CPUC<br>285<br>COLW | INC1<br>500<br>INTC | HYDA<br>213<br>HYDR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 3.236 | 0 | | | | | | | | | | | | |
| 2009 | 3.081 | 0 | | | | | | | | | | | | |
| 2010 | 0.801 | 0 | | | | | | | | | | | | |
| 2011 | 0.587 | 325 | | | | 5 | 2 | | | | | | | |
| 2012 | 0.077 | 0 | | | | | | | | | | | | |
| 2013 | 0.001 | 785 | | | | | | | | | 2 | 1 | | |
| 2014 | 0.001 | 285 | | | | | | | | | | 1 | | |
| 2015 | 0 | 1,013 | | | 1 | | | | | | 2 | | | 1 |
| 2016 | 0 | 300 | | | 1 | | | | | | | | | |
| 2017 | 0 | 300 | | | 1 | | | | | | | | | |
| 2018 | 0.007 | 300 | | | 1 | | | | | | | | | |
| 2019 | 0.018 | 300 | | | 1 | | | | | | | | | |
| 2020 | 0.178 | 300 | | | 1 | | | | | | | | | |
| 2021 | 0.423 | 300 | | | 1 | | | | | | | | | |
| 2022 | 0.325 | 500 | | | | | | | | | | | 1 | |
| 2023 | 0.255 | 600 | | | 2 | | | | | | | | | |
| 2024 | 0.47 | 600 | | | 2 | | | | | | | | | |
| 2025 | 0.659 | 500 | | | | | | | | | | | 1 | |
| 2026 | 0.731 | 600 | | | 2 | | | | | | | | | |
| 2027 | 0.723 | 675 | | | 2 | | 1 | | | | | | | |
| TOTAL | | 7,683 | 0 | 0 | 15 | 5 | 3 | 0 | 0 | 0 | 4 | 2 | 2 | 1 |

| | | | | | |
|---|---|---|---|---|---|
| ADSL | : | AUTO DSL GT/CCY | COLT | : | COAL -TRINCO- |
| FOIL | : | FURNACE OIL/STM | RENW | : | FUEL |
| ROIL | : | RESID OIL DSL/ENGN | INTC | : | Interconnection |
| NAPH | : | NAPHTHA OECF CCY | HYDR | : | HYDROELECTRIC |
| COLW | : | COAL -WEST/SOUTH- | PUMP | : | PUMPED STORAGE |

b) Downstream Option

The power development plan of the downstream option is similar to the basic option excluding the expansion for Victoria hydropower station is the downstream option.

**Table 6.1.11-6 Power Development Plan of Downstream Option**

| YEAR | %LOLP | NAME<br>SIZE (MW)<br>TYPE<br>CAP(MW) | STF1<br>150<br>FOIL | STF3<br>300<br>FOIL | CST<br>300<br>COLW | GT1<br>35<br>ADSL | GT2<br>75<br>ADSL | GT3<br>105<br>ADSL | CCY1<br>150<br>ADSL | CCY3<br>300<br>ADSL | CTRC<br>250<br>COLT | CPUC<br>285<br>COLW | INC1<br>500<br>INTC | HYDA<br>223<br>HYDR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 3.236 | 0 | | | | | | | | | | | | |
| 2009 | 3.081 | 0 | | | | | | | | | | | | |
| 2010 | 0.801 | 0 | | | | | | | | | | | | |
| 2011 | 0.587 | 325 | | | | 5 | 2 | | | | | | | |
| 2012 | 0.077 | 0 | | | | | | | | | | | | |
| 2013 | 0.001 | 785 | | | | | | | | | 2 | 1 | | |
| 2014 | 0.001 | 285 | | | | | | | | | | 1 | | |
| 2015 | 0 | 1,023 | | | 1 | | | | | | 2 | | | 1 |
| 2016 | 0 | 300 | | | 1 | | | | | | | | | |
| 2017 | 0 | 300 | | | 1 | | | | | | | | | |
| 2018 | 0.007 | 300 | | | 1 | | | | | | | | | |
| 2019 | 0.018 | 300 | | | 1 | | | | | | | | | |
| 2020 | 0.178 | 300 | | | 1 | | | | | | | | | |
| 2021 | 0.423 | 300 | | | 1 | | | | | | | | | |
| 2022 | 0.325 | 500 | | | | | | | | | | | 1 | |
| 2023 | 0.255 | 600 | | | 2 | | | | | | | | | |
| 2024 | 0.47 | 600 | | | 2 | | | | | | | | | |
| 2025 | 0.659 | 500 | | | | | | | | | | | 1 | |
| 2026 | 0.731 | 600 | | | 2 | | | | | | | | | |
| 2027 | 0.723 | 675 | | | 2 | | 1 | | | | | | | |
| TOTALS | | 7,693 | 0 | 0 | 15 | 5 | 3 | 0 | 0 | 0 | 4 | 2 | 2 | 1 |

c) Pumped Storage Option

In power development during the examination period, one coal thermal power (300 MW) increases and Interconnection (500 MW) is canceled in comparison with that of the basic option.

**Table 6.1.11-7 Power Development Plan of Pumped Storage Option**

| YEAR | %LOLP | NAME<br>SIZE (MW)<br>TYPE<br>CAP(MW) | STF1<br>150<br>FOIL | STF3<br>300<br>FOIL | CST<br>300<br>COLW | GT1<br>35<br>ADSL | GT2<br>75<br>ADSL | GT3<br>105<br>ADSL | CCY1<br>150<br>ADSL | CCY3<br>300<br>ADSL | CTRC<br>250<br>COLT | CPUC<br>285<br>COLW | INC1<br>500<br>INTC | HYDA<br>223<br>HYDR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 2.829 | 0 | | | | | | | | | | | | |
| 2009 | 2.353 | 0 | | | | | | | | | | | | |
| 2010 | 0.703 | 0 | | | | | | | | | | | | |
| 2011 | 0.813 | 290 | | | | 4 | 2 | | | | | | | |
| 2012 | 0.111 | 0 | | | | | | | | | | | | |
| 2013 | 0.001 | 785 | | | | | | | | | 2 | 1 | | |
| 2014 | 0.001 | 285 | | | | | | | | | | 1 | | |
| 2015 | 0 | 800 | | | 1 | | | | | | 2 | | | |
| 2016 | 0 | 209 | | | | | | | | | | | | 1 |
| 2017 | 0 | 600 | | | 2 | | | | | | | | | |
| 2018 | 0 | 300 | | | 1 | | | | | | | | | |
| 2019 | 0.002 | 300 | | | 1 | | | | | | | | | |
| 2020 | 0.041 | 300 | | | 1 | | | | | | | | | |
| 2021 | 0.123 | 300 | | | 1 | | | | | | | | | |
| 2022 | 0.358 | 300 | | | 1 | | | | | | | | | |
| 2023 | 0.28 | 600 | | | 2 | | | | | | | | | |
| 2024 | 0.689 | 500 | | | | | | | | | | | 1 | |
| 2025 | 0.743 | 600 | | | 2 | | | | | | | | | |
| 2026 | 0.723 | 635 | | | 2 | 1 | | | | | | | | |
| 2027 | 0.717 | 675 | | | 2 | | 1 | | | | | | | |
| TOTALS | | 7,479 | 0 | 0 | 16 | 5 | 3 | 0 | 0 | 0 | 4 | 2 | 1 | 1 |

Energy output by each power generation type is shown in **Table 6.1.11-8** and annual operation hours of pumped storage generation are shown in **Table 6.1.11-9**.

3 hours a day were assumed as pumped storage hours in consideration of the peak demand duration in Sri Lanka, and the maximum possible generation energy was set as 1,000 hours (3 hours × 365 days) per annum. However, the maximum in the examination period as shown in **Table 6.1.11-9** is 464 hours, and the operation time of the pumped storage power plant is less than assumed.

**Table 6.1.11-8 Annual Energy of Pumped Storage Option**

(GWh)

| YEAR | PUMP | HYDR | ADSL | FOIL | ROIL | NAPH | COLW | COLT | RENW | INTC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 0 | 4,375 | 925 | 2,277 | 1,278 | 901 | 0 | 0 | 361 | 0 | 10,117 |
| 2009 | 0 | 4,375 | 1,156 | 2,816 | 1,278 | 1,035 | 0 | 0 | 434 | 0 | 11,094 |
| 2010 | 0 | 4,375 | 592 | 4,621 | 1,276 | 712 | 0 | 0 | 506 | 0 | 12,082 |
| 2011 | 0 | 4,375 | 1,322 | 4,887 | 1,277 | 915 | 0 | 0 | 578 | 0 | 13,354 |
| 2012 | 0 | 4,797 | 725 | 4,371 | 1,268 | 696 | 2,023 | 0 | 650 | 0 | 14,530 |
| 2013 | 0 | 4,797 | 102 | 2,332 | 583 | 168 | 3,815 | 3,414 | 650 | 0 | 15,861 |
| 2014 | 0 | 4,797 | 65 | 1,957 | 527 | 123 | 5,624 | 3,414 | 650 | 0 | 17,157 |
| 2015 | 0 | 4,797 | 12 | 305 | 155 | 26 | 5,913 | 6,812 | 650 | 0 | 18,670 |
| 2016 | 7 | 4,797 | 112 | 685 | 305 | 127 | 6,748 | 6,838 | 650 | 0 | 20,269 |
| 2017 | 1 | 4,797 | 18 | 317 | 147 | 32 | 9,160 | 6,821 | 650 | 0 | 21,943 |
| 2018 | 4 | 4,797 | 24 | 333 | 131 | 60 | 10,920 | 6,843 | 650 | 0 | 23,762 |
| 2019 | 8 | 4,797 | 31 | 350 | 128 | 65 | 12,768 | 6,903 | 650 | 0 | 25,700 |
| 2020 | 36 | 4,797 | 98 | 166 | 135 | 152 | 14,774 | 7,005 | 650 | 0 | 27,813 |
| 2021 | 62 | 4,797 | 125 | 180 | 142 | 182 | 16,841 | 7,097 | 650 | 0 | 30,076 |
| 2022 | 97 | 4,797 | 161 | 227 | 165 | 215 | 18,994 | 7,209 | 650 | 0 | 32,515 |
| 2023 | 76 | 4,797 | 116 | 169 | 58 | 160 | 21,738 | 7,291 | 650 | 0 | 35,055 |
| 2024 | 80 | 4,797 | 58 | 148 | 53 | 133 | 23,178 | 7,358 | 650 | 1,352 | 37,807 |
| 2025 | 77 | 4,797 | 51 | 128 | 0 | 117 | 26,379 | 7,419 | 650 | 1,139 | 40,757 |
| 2026 | 76 | 4,797 | 51 | 129 | 0 | 108 | 29,669 | 7,474 | 650 | 975 | 43,929 |
| 2027 | 79 | 4,797 | 70 | 118 | 0 | 101 | 33,087 | 7,521 | 650 | 919 | 47,342 |

**Table 6.1.11-9 Operation Time of Pumped Storage Generation**

| Year | Operation time (Hour) |
|---|---|
| 2016 | 33 |
| 2017 | 5 |
| 2018 | 19 |
| 2019 | 38 |
| 2020 | 172 |
| 2021 | 297 |
| 2022 | 464 |
| 2023 | 364 |
| 2024 | 383 |
| 2025 | 368 |
| 2026 | 364 |
| 2027 | 378 |

### 6.1.12 Result of Comparative Study

As described in **Section 6.1.11**, WASP analysis concluded that 3-unit expansion of the basic option is selected as the option with the least cost to CEB grid among the three alternatives. In terms of economic aspect, the result of comparative study on three alternatives is summarized in **Table 6.1.12-1.**

**Table 6.1.12-1 Summary of Comparative Study**

| Item | Unit | Basic Option | | Downstream Option | | Pumped Storage Option | |
|---|---|---|---|---|---|---|---|
| | | 3 units | 2 units | 3 units | 2 units | 3 units | 2 units |
| 1) Additional capacity | MW | 213 | 140 | 219 | 143 | 198 | 128 |
| 2) Installed capacity including existing units of 210 MW | MW | 423 | 350 | 429 | 353 | 408 | 338 |
| 3) Dependable capacity | MW | 359 | 336 | 361 | 333 | 396 | 310 |
| 4) Annual Energy | GWh | 651 | 651 | 652 | 652 | 729 | 711 |
| Firm Energy* | GWh | 452 | 381 | 449 | 378 | 445 | 343 |
| Secondary Energy** | GWh | 198 | 271 | 203 | 275 | 284 | 368 |
| 5) Unit Construction Cost | US$/kW | 812 | 969 | 981 | 1,178 | 1,708 | 2,078 |
| 6) Annualized Cost | Mill. US$/year | 22.3 | 17.5 | 28.5 | 22.5 | 53.1 | 41.5 |
| 7) Annualized Benefit | Mill. US$/year | 40.9 | 30.1 | 40.6 | 29.6 | 47.4 | 26.9 |
| 8) B/C ( 7) / 6) ) | | 1.83 | 1.72 | 1.43 | 1.32 | 0.89 | 0.65 |
| 9) Environmental and Social Consideration | | Best | | Second best | | Third best | |

*Note: * "Firm energy" means the total of power generated during 3-hour peak duration.*
*** "Secondary energy" means the total of power generated in duration except 3-hour peak time.*

Study Team concludes that the basic option with 3 units is the optimal option from the viewpoint of economic, environmental and construction aspects.

## 6.2 Optimization of Expansion Plan

According to the result of the comparative study on the alternative options, the basic option with 3 units with the total capacity of 213 MW class is selected as the optimal option among the three alternatives. In this section, the following details of the expansion plan are examined.

(1) Unit capacity and number of units,
(2) Normal intake water level, and
(3) Priority of operation for existing and expansion plant.

In item (3), Study Team examines operation rule for prioritizing the use of existing and expansion units for generating power in order to economical use of the hydropower station.

### 6.2.1 Number of Units and Unit Capacity

In the comparative study on the alternative options, the unit capacity was tentatively fixed to 70 MW. In the Study, the optimum number of unit is studied by fixing the total capacity to 210 MW class. The number of units and unit capacity examined in the Study is as follows.

(1) 70 MW class × 3 units
(2) 105 MW class × 2 units
(3) 210 MW class × 1 unit

In general, the following factors are considered for the examination of the number of unit:

(1) System Frequency Deviation under Loss of the Unit
(2) Maintenance Activities
(3) Constraint of Transportation for Heavy Equipment Parts
(4) Economic Validity

#### (1) System Frequency Deviation under Loss of the Unit

JICA Report “Master Plan Study on the Development of Power Generation and Transmission System in Sri Lanka” in 2006 shows the study of frequency deviation under loss of the largest generation unit. The study of the Victoria Expansion was carried out by the same methodology.

The Power System of Sri Lanka has the Load Shedding Scheme, and the Scheme is operated automatically when system frequency becomes less than 48.75 Hz. Therefore, the unit capacity of the Victoria Expansion was studied in order that the frequency deviation of the Unit-Trip would be within 1.25 Hz.

The Study should be carried out for the Night Peak Time when the Victoria Hydropower Station will be expected to be operated as peak power sources after expansion. Because smaller demand causes larger frequency deviation, the Study should be carried out for the minimum demand in the Night Peak Time. The actual demands in 2006 and 2007, **Figure 6.2.1-1** and **Figure 6.2.1-2,** show that the minimum demands in the Night Peak are almost equal to the average demand in the year. The annual demands in future were calculated by the annual energy demands which were estimated by CEB in “Time Trend Forecast 2008 (04.09.2008)” described in **4.1.4** of **Chapter 4**. Also in order to calculate the frequency deviation, 4.75% MW/Hz of the System Frequency Characteristic Constant shown in the JICA Report in 2006 was adopted in the Study. This constant indicates 1.0 Hz of frequency deviation for changing 4.75% of demand or generation in MW.

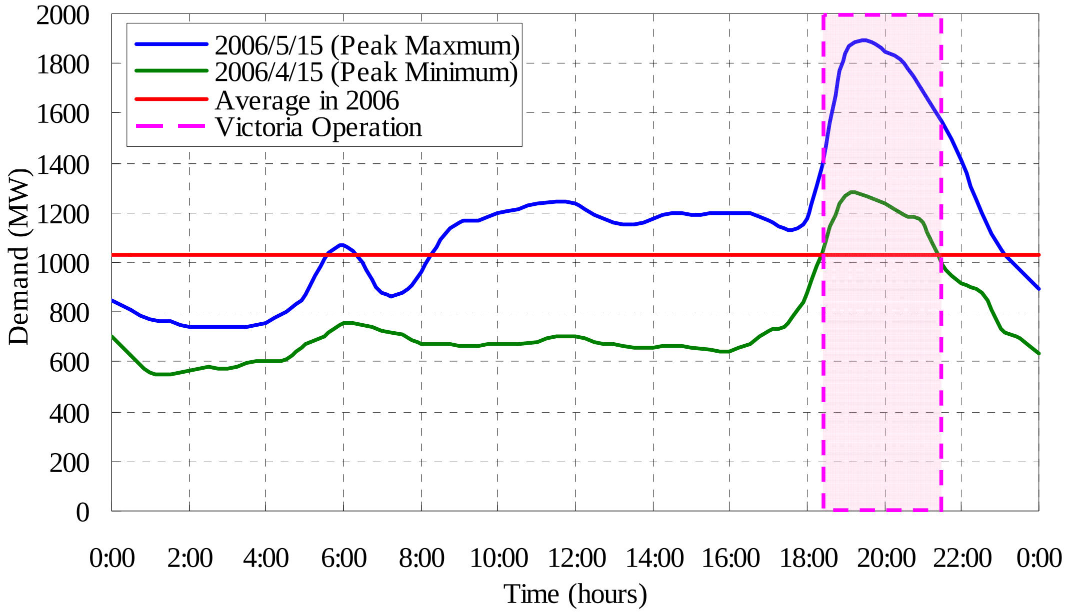
**Table 6.2.1-1** shows the results of the study of allowable unit capacity loss at the Night Peak, and 100 MW Class of the unit capacity will be nearly acceptable maximum for the Night Peak in 2016. On the other hand, 210 MW Class of the unit capacity will not be acceptable in 2016 due to possibility to cause large frequency deviation and be acceptable after 2026.

Consequently, the unit capacity for 1-unit option is not allowable, and that for 2- or 3-unit options is desirable for the expansion units.

In consideration of alternative equipment during shut-down for maintenance, smaller unit capacity is desirable, and the unit capacity for 2- or 3-unit options is desirable.

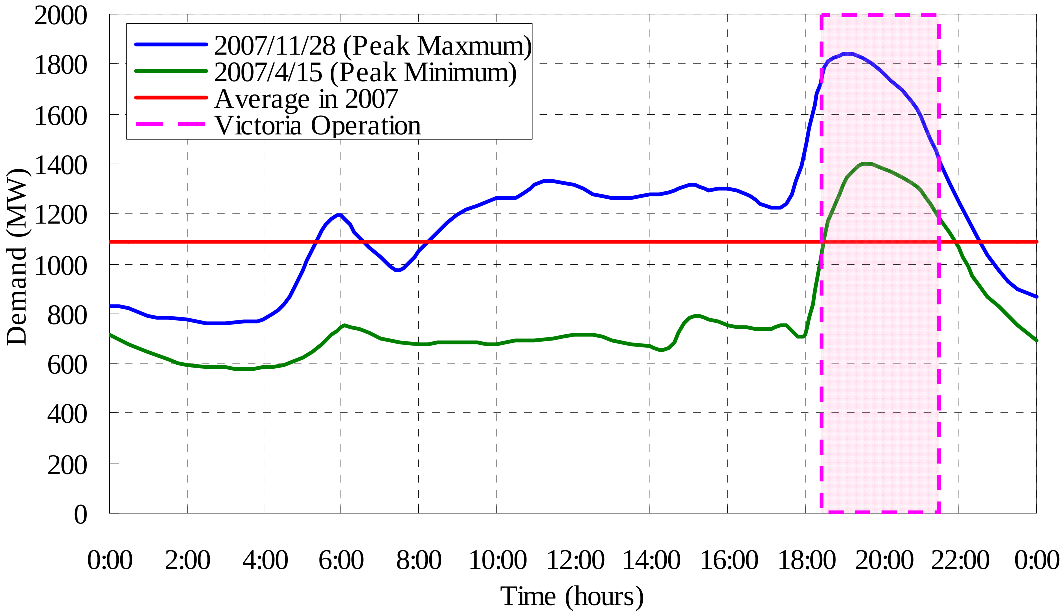
While, from the viewpoint of operation, larger unit capacity as much as possible is desirable, because more number of small units requires more complicated operation to cope with rapidly increasing demand during the Night Peak.

In summary, the unit capacity for 2- or 3-unit option is recommended from the aspect of frequency deviation under loss of the unit, and that for 2-unit option is preferable in consideration of operation in addition to the frequency deviation.




*Source of the daily demand record on 2006/5/15 and 2006/4/15: CEB*

**Figure 6.2.1-1 Daily Load Curve in 2006**




*Source of the daily demand record on 2007/11/28 and 2007/4/15: CEB*

**Figure 6.2.1-2 Daily Load Curve in 2007**

**Table 6.2.1-1 Acceptable Sudden System Outage Capacities for Future**

| | **Year** | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** |
| Energy (GWh) * | 13,559 | 14,496 | 15,401 | 16,412 | 17,476 | 18,652 | 19,908 | 21,248 | 22,679 | 24,206 | 25,835 | 27,574 | 29,430 | 31,412 | 33,526 |
| Demand (MW) ** | 1,548 | 1,655 | 1,758 | 1,874 | 1,995 | 2,129 | 2,273 | 2,426 | 2,589 | 2,763 | 2,949 | 3,148 | 3,360 | 3,586 | 3,827 |
| Acceptable Outage Capacity (MW) | 92 | 98 | 104 | **111** | 118 | 126 | 135 | 144 | 154 | 164 | 175 | 187 | 199 | 213 | 227 |

* *Source: Energy Demand from "Time Trend Forecast 2008 (04.09.2008)", CEB*
** *Minimum demand in the night peak estimated by Study Team*

### (2) Maintenance Activities

In term of maintenance, unit capacity size does not make remarkable difference in the length of its period per annum, required man power, and the number of parts to be replaced. The larger number of units will have longer maintenance period and more O&M cost as a whole of a power station. Hence, the smaller numbers of units is desirable from the viewpoint of maintenance activities.

2-unit option is more desirable than 3-unit option in term of maintenance, because the unit capacity for 1-unit option is not allowable from aspect of frequency deviation under loss of the unit in above (1) and the 1-unit option is eliminated. This result shows the same as that in consideration of operation in addition to the viewpoint of frequency deviation under loss of the unit as mentioned in (1).

### (3) Constraint of Transportation for Heavy Equipment Parts

In this sub-section, Study Team examines whether or not heavy parts and large parts of generating equipment of each unit capacity option can be transported without any constraint from the Colombo port where generating equipment will be unloaded to the Victoria Hydropower Station. Transportation route is considered as the national highway (Category A) from the Colombo port via Kandy up to the entrance to existing access road to the Station and the existing access road to the Station.

There seems to be no constraint to transport parts for 3-unit option, because those for the existing equipment were transported during Stage I construction period.

The heaviest one is estimated as the main transformer with around 60 tons, and the largest one is considered as the runner with around 5 m in diameter for 1-unit option, while, those are 40 tons and around 3.5 m for 2-unit option.

Allowable loads against bridges on the transportation route should be considered, to haul heavy parts. Study Team asked Road Development Authority about constraints at transporting those. According to RDA, i) the contractor of the equipment should submit an application with weight of heavy parts and details of transportation vehicles when those with heavier than around 50 tons pass on Category A bridges, ii) RDA will check whether or not such loads are within allowable design loads of Category A bridges, and iii) RDA will give the applicant the transportation permission, when such loads is proved allowable. It was recorded that 68 ton main transformer was transported on Category A bridges during the construction of the Kukule Hydropower Station, according to information from CEB. Hence it is considered that the main transformer with 60 tons can be transported on Category A bridges. While, Category A road is 7.4 m wide with 2 lanes. Parts with 5 m in size can be transported on Category A roads, in the case that the contractor submits application to RDA. Therefore, there seems to be no constraint to transport heavy or large parts for 1-unit option.

Regarding the existing access road branching from the national highway to the Station, the minimum width is 4 m and radius of curves is around 12 m in minimum. It is considered that the access road should be constructed newly to transport the runner for 1-unit option and that the access road should be improved for 2-unit option. Those costs will be included into construction cost for each option in the examination of the economic validity mentioned in (4).

### (4) Economic Validity

#### 1) Study Scenario

The number of units and unit capacity is studied for the following cases.

a. 70 MW class × 3 units
b. 105 MW class × 2 units
c. 210 MW class × 1 unit

### 2) Comparison Method

Each option is compared by the benefit and cost analysis. The methodology of the comparison method for benefit and cost analysis is same as the method applied in the comparative study of alternative option which is described in **Section 6.1**.

### 3) Benefit

The benefits of each unit option are examined for annual energy and dependable output. The annual energy and dependable output is obtained by simulating the power generation. The method and data used for the power generation simulation is the same data used in the comparative study described in **Section 6.1**. The result of the simulation study is shown in **Table 6.2.1-2**.

**Table 6.2.1-2 Annual Energy and Dependable Capacity of Each Option**

| Number of Units | Expansion | Existing + Expansion | | | |
|---|---|---|---|---|---|
| | Installed Capacity for Expansion Plant (MW) | Annual Energy (GWh) | Firm Energy* (GWh) | Secondary Energy** (GWh) | 95% Dependable Capacity (MW) |
| 3 units | 215 | 647 | 452 | 195 | 354 |
| 2 units | 214 | 649 | 451 | 197 | 357 |
| 1 unit | 213 | 649 | 451 | 198 | 358 |

*Note:* * *"Firm energy" means the total of power generated during 3-hour peak duration.*
** *"Secondary energy" means the total of power generated in duration except 3-hour peak time.*

As shown in **Table 6.2.1-2**, the difference between 2-unit and 3-unit options is negligibly small, but the smaller number of units slightly increases 95% dependable capacity. Using the result of simulation in **Table 6.2.1-2**, the benefit of each option is calculated as shown in the following **Table 6.2.1-3**.

**Table 6.2.1-3 Annualized Benefit for Each Option**

| Description | Unit | Existing | Expansion + Existing | | |
|---|---|---|---|---|---|
| | | | 3 units | 2 units | 1 unit |
| 1. Annual Energy | GWh | 634 | 647 | 649 | 649 |
| Firm Energy* | GWh | 230 | 452 | 451 | 451 |
| Secondary Energy** | GWh | 404 | 195 | 197 | 198 |
| 2. Dependable Peak Capacity | MW | 209 | 354 | 357 | 358 |
| 3. Power to be Generated (Gas) | MW | 247 | 419 | 422 | 423 |
| 4. Energy to be Generated (Gas) | GWh/yr | 235 | 462 | 462 | 462 |
| 5. Energy to be Generated (Coal) | GWh/yr | 437 | 211 | 213 | 214 |
| 6. kWh-Value (Gas) | US$/MWh | 176.7 | 176.7 | 176.7 | 176.7 |
| 7. kWh-Value (Coal) | US$/MWh | 53.4 | 53.4 | 53.4 | 53.4 |
| 8. kW-Value (Gas) | US$/kW | 70.3 | 70.3 | 70.3 | 70.3 |
| 9. Annual Benefit (Gas) for capacity | Mill.US$/yr | 17.3 | 29.5 | 29.7 | 29.8 |
| 10. Annual Benefit (Gas) for firm energy | Mill.US$/yr | 41.5 | 81.7 | 81.6 | 81.6 |
| 11. Annual Benefit (Coal) for secondary energy | Mill.US$/yr | 23.4 | 11.2 | 11.3 | 11.4 |
| 12. Annual Benefit (Gas & Coal) | Mill.US$/yr | 82.2 | 122.4 | 122.6 | 122.8 |
| Increment of Benefit | Mill.US$/yr | 0 | 40.2 | 40.4 | 40.6 |

*Note: * "Firm energy" means the total of power generated during 3-hour peak duration.*
*** "Secondary energy" means the total of power generated in duration except 3-hour peak time.*

**Table 6.2.1-3** shows that the increment of the benefit, i.e. the annualized benefit of each expansion plan, is almost the same for each unit option, although the smaller number option obtains slightly more benefit.

**4) Cost**

The existing overhead traveling (OHT) cranes are used for 3-unit expansion plan, since it is expected that the generator weight is almost the same with existing equipment.

2-unit option needs to install a new OHT crane because equipment will be heavier than that of 3-unit option. Using existing OHT crane for 2-unit option may be possible by reinforcing existing powerhouse structure, but the detailed structural calculation report for the existing Victoria powerhouse and as-built drawings for reinforcement of main structure members were not available. Hence, the loads, load combination, and reinforcement arrangements are unknown. Therefore, reinforcement of the powerhouse structure is substantially not possible.

The cost for new access road for the 1-unit option and for improvement of the existing access road for 2-unit option is considered.

The project cost of each unit option is shown in **Table 6.2.1-4** below.

**Table 6.2.1-4 Project Cost of Each Option**

| Item | Unit | Number of Expansion Units | | |
|---|---|---|---|---|
| | | 3 units | 2 units | 1 unit |
| Preparatory Works | Mill. US$ | 1.5 | 1.5 | 3.9 |
| Civil works | Mill. US$ | 55.8 | 55.9 | 58.6 |
| Equipment | Mill. US$ | 88.1 | 83.1 | 79.3 |
| Environmental Cost | Mill. US$ | 1.5 | 1.5 | 1.9 |
| Administration & Engineering Fee | Mill. US$ | 14.5 | 14.1 | 14.2 |
| Contingency | Mill. US$ | 16.2 | 15.6 | 15.8 |
| Total construction cost | Mill. US$ | 177.7 | 171.7 | 173.6 |
| Annualized cost: | Mill. US$/year | 23.1 | 22.3 | 22.5 |

As shown in **Table 6.2.1-4**, the equipment cost of the smaller number is lower, but the total cost the 2-unit option is slightly lower than the other two options.

**5) Benefit and Cost Analysis**

The ratios of the cost to the benefit for 2-unit and 3-unit option are tabulated in **Table 6.2.1-5.**

**Table 6.2.1-5 Result of B/C Analysis**

| Item | Unit | Number of Expansion Units | | |
|---|---|---|---|---|
| | | 3 units | 2 units | 1 unit |
| Expansion Capacity | MW | 215 | 214 | 213 |
| Benefit | Mill. US$/year | 40.2 | 40.4 | 40.6 |
| Cost | Mill. US$/year | 23.1 | 22.3 | 22.5 |
| B / C | | 1.74 | 1.81 | 1.80 |

As shown in **Table 6.2.1-5**, the 2-unit option gives better B/C than that of the other two options.

### (5) Selection of Number of Units

According to the study on system frequency deviation and the B/C analysis, the 2-unit expansion plan is the most economical. Therefore, the number of unit for expansion plant is determined to two with 105 MW class of unit capacity.

## 6.2.2 Normal Intake Water Level

In the comparative study, the normal intake water level was empirically set at EL. 415 m, by one third of available drawdown (FSL – MOL of the reservoir) below FSL of the Victoria reservoir as shown in **Figure 6.2.2-1**. In this optimization of the expansion plan, the normal intake water level is determined in terms of economical aspects.

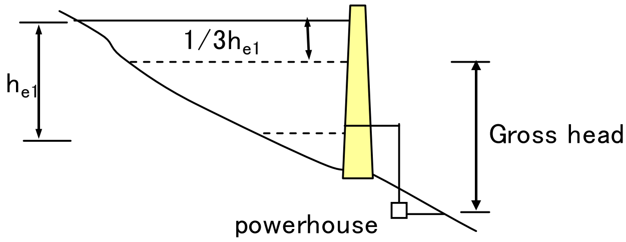
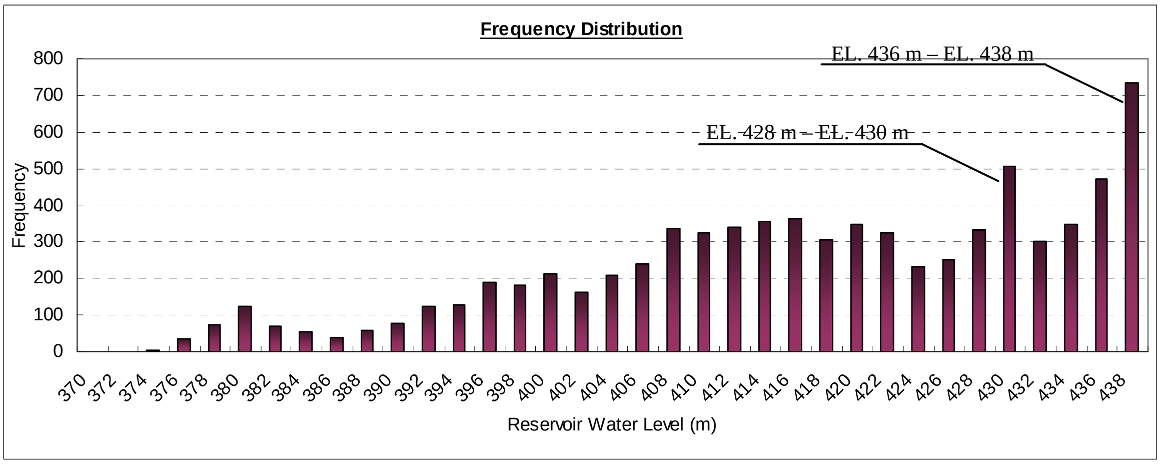



**Figure 6.2.2-1 Normal Intake Water Level in the Comparative Study**

It is better to set the normal intake water level at the reservoir water level which appears most frequently during operation period. As shown in **Figure 6.2.2-2**, the daily mean reservoir water levels in the past 22 years are densely recorded in the ranges from EL. 428 m to EL. 430 m and from EL. 436 m to EL. 438 m. Hence, the five cases of the normal intake water level above EL. 415 m as shown in **Table 6.2.2-1** are examined in the Study.




*Source: Victoria Hydropower Station, CEB*

**Figure 6.2.2-2 Frequency of Reservoir Water Level**

**Table 6.2.2-1 Examined Normal Intake Water Level**

| Normal Intake Water Level (EL. m) |
|---|
| 415 |
| 425 |
| 430 |
| 435 |
| 438 |

The simulation on the power generation is carried out to examine the annual energy for each normal intake water level listed in **Table 6.2.2-1**. The benefit is also calculated using the annual energy and dependable capacity. The result of the simulation is shown in **Table 6.2.2-2**.

**Table 6.2.2-2**
**Annual Energy and Dependable Capacity for Each Normal Intake Water Level**

| Normal Intake Water Level (EL. m) | Expansion plant | Existing + Expansion plant | | | |
|---|---|---|---|---|---|
| | Installed Capacity (MW) | Annual Energy (GWh) | Firm Energy* (GWh) | Secondary Energy** (GWh) | 95% Dependable Capacity (MW) |
| 415 | 213 | 647 | 451 | 196 | 356 |
| 425 | 225 | 638 | 462 | 176 | 380 |
| 430 | 232 | 635 | 467 | 168 | 379 |
| 435 | 237 | 631 | 467 | 164 | 377 |
| 438 | 241 | 630 | 464 | 166 | 367 |

*Note: * "Firm energy" means the total of power generated during 3-hour peak duration.*
*** "Secondary energy" means the total of power generated in duration except 3-hour peak time.*

According to **Table 6.2.2-2**, higher normal intake water level option produces less annual energy but more firm energy and dependable capacity. By using the energy output and dependable power, the annualized benefit of each normal water level option is calculated and summarized in **Table 6.2.2-3**.

**Table 6.2.2-3 Annualized Benefit of Each Normal Intake Water Level**

| Description | Unit | Normal Intake Water Level for Expansion Plant | | | | |
|---|---|---|---|---|---|---|
| | | **415** | **425** | **430** | **435** | **438** |
| Annualized Benefit | Mill. US$/yr | 40.1 | 43.1 | 43.4 | 43.0 | 41.8 |

Following **Table 6.2.2-4** shows the project cost for each normal water level.

**Table 6.2.2-4 Project Cost for Each Normal Water Level Option**

| Item | Unit | Normal Intake Water Level for Expansion Plant | | | | |
|---|---|---|---|---|---|---|
| | | **415** | **425** | **430** | **435** | **438** |
| Preparatory Works | Mill. US$ | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Civil works | Mill. US$ | 55.9 | 56.2 | 56.4 | 56.5 | 56.6 |
| Equipment | Mill. US$ | 84.5 | 85.5 | 85.9 | 86.5 | 86.8 |
| Environmental Cost | Mill. US$ | 1.5 | 1.5 | 1,5 | 1.5 | 1.5 |
| Administration & Engineering Fee | Mill. US$ | 14.2 | 14.3 | 14.4 | 14.5 | 14.5 |
| Contingency | Mill. US$ | 15.8 | 15.9 | 16.0 | 16.0 | 16.1 |
| Total construction cost | Mill. US$ | 173.4 | 174.9 | 175.7 | 176.5 | 177.1 |
| Annualized cost: | Mill. US$/year | 22.5 | 22.7 | 22.8 | 22.9 | 23.0 |

As shown in **Table 6.2.2-4**, the civil works and equipment costs are slightly increased as the normal intake water level is raised.

By using the project cost and benefit for each normal water level, the B/C for each option is calculated as shown in **Table 6.2.2-5** and **Figure 6.2.2-3**.

**Table 6.2.2-5 B/C for Each Normal Water Level Option**

| Item | Unit | Normal Intake Water Level for Expansion Plant | | | | |
|---|---|---|---|---|---|---|
| | | **415** | **425** | **430** | **435** | **438** |
| Installed capacity | MW | 213 | 225 | 232 | 237 | 241 |
| Benefit | Mill. US$/year | 40.1 | 43.1 | 43.4 | 43.0 | 41.8 |
| Cost | Mill. US$/year | 22.5 | 22.7 | 22.8 | 22.9 | 23.0 |
| B / C | | 1.78 | 1.89 | 1.90 | 1.87 | 1.82 |

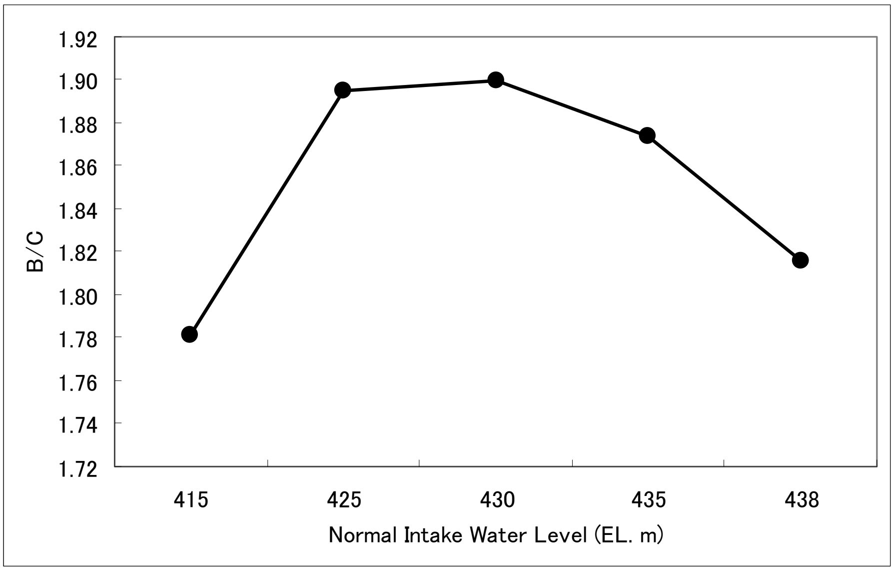



**Figure 6.2.2-3 Relation of B/C and Normal Intake Water Level**

As shown in **Table 6.2.2-5** and **Figure 6.2.2-3**, the Normal Intake Water Level of EL.430 m is economically optimum for the expansion units.

### 6.2.3 Operation Priority between the Existing and Expansion Units

Study Team examines operation rule for prioritizing the use of existing and expansion units for generating power in order to maximize annual energy. There are three ways of prioritizing the use of generating units considered as follows;

Rule 1 : Using both existing and expansion units in the same way,
Rule 2 : Using existing units first, then the expansion units, and
Rule 3 : Using expansion units first, then the existing units.

Simulation on the power generation is conducted based on the above three alternative rules. **Table 6.2.3-1** shows the energy and dependable capacity simulated.

**Table 6.2.3-1 Annual Energy and Dependable Capacity for Each Alternative Rule**

| Normal Intake Water Level (EL. m) | Expansion plant | Existing + Expansion plant | | | |
|---|---|---|---|---|---|
| | Installed Capacity (MW) | Annual Energy (GWh) | Firm Energy* (GWh) | Secondary Energy** (GWh) | 95% Dependable Capacity (MW) |
| Rule 1 (Same priority) | 232 | 635 | 467 | 168 | 379 |
| Rule 2 (Expansion plant use first) | 232 | 640 | 446 | 193 | 266 |
| Rule 3 (Existing plant use first) | 232 | 640 | 446 | 194 | 266 |

*Note: * "Firm energy" means the total of power generated during 3-hour peak duration.*
*** "Secondary energy" means the total of power generated in duration except 3-hour peak time.*

Rules 2 and 3 generate slightly more annual energy than that of Rule 1, but less firm energy and dependable capacity than those of the Rule 1.

By using the annual energy output and dependable power, the annualized benefit of each alternative rule is calculated and summarized in **Table 6.2.3-2**

**Table 6.2.3-2 Annualized Benefit of Each Normal Intake Water Level**

| Description | Unit | Priority of Operation | | |
|---|---|---|---|---|
| | | Rule 1 | Rule 2 | Rule 3 |
| Annualized Benefit | Mill. US$/yr | 43.4 | 31.8 | 31.7 |

The operation "Rule 1" gives the largest benefit. This is caused due to the decrease in the dependable capacity when prioritizing the operation of hydropower generation.

The cost of each scenario is the same as the normal water intake level of EL.430 m in **Table 6.2.2-4**.

The B/C of each alternative rule is shown in **Table 6.2.3-3**.

**Table 6.2.3-3 B/C for Each Operation Priority Option**

| Item | Unit | Priority of Operation | | |
|---|---|---|---|---|
| | | Rule 1 | Rule 2 | Rule 3 |
| Installed capacity | MW | 232 | 232 | 232 |
| Benefit | Mill. US$/year | 43.4 | 31.8 | 31.7 |
| Cost | Mill. US$/year | 22.8 | 22.8 | 22.8 |
| B / C | | 1.90 | 1.38 | 1.38 |

According to **Table 6.2.3-3**, the operation Rule 1 has the largest B/C, and it is recommended to operate same manner for existing and expansion units.

### 6.2.4 Optimal Expansion Plan

The number of units, the normal intake water level, and operation priority of existing and expansion units are examined to optimize the expansion plan.

The results are summarized below;

Number of units : 2 units
Normal intake water level : EL. 430 m

Operation rule of existing and expansion units： Same operation for existing and expansion plants.

### 6.2.5 Maximum Possible Power Generation

In the comparative study on alternative options and optimization of expansion plant, spillout and sand-flushing discharge were deducted from inflow for power generation simulation, since those discharges were not used for hydropower generation. In this section, the spillout discharge is taken into account as available water for hydropower generation.

In the calculation of hydropower generation, the reservoir operation rule suggested in **Section 6.1** was applied and power generation by existing hydropower station, existing and expansion hydropower plant was simulated. For the expansion hydropower generation, the installed number of units is two and normal intake water level of EL. 430 m was used as selected in the previous section. The operation rule of the existing and expansion plant is the same as suggested in the **Section 6.2.4**.

The result of the power generation simulation is shown in **Table 6.2.5-1**.

**Table 6.2.5-1**
**Annual Energy and Dependable Capacity when the Spilled Discharge is not Deducted**

| | Energy and Power by Existing and Expansion plant | | | |
|---|---|---|---|---|
| | Annual Energy (GWh) | Firm Energy* (GWh) | Secondary Energy** (GWh) | 95% Dependable Capacity (MW) |
| (1) Spilled discharge is deducted | | | | |
| Existing Only | 634 | 230 | 404 | 209 |
| Existing + Expansion Plant | 635 | 467 | 168 | 379 |
| (2) Spilled discharge is not deducted | | | | |
| Existing Only | 689 | 230 | 459 | 209 |
| Existing + Expansion Plant | 716 | 469 | 247 | 385 |

*Note: * "Firm energy" means the total of power generated during 3-hour peak duration.*
*** "Secondary energy" means the total of power generated in duration except 3-hour peak time.*

As shown in **Table 6.2.5-1**, annual energy increases from 634 GWh to 689 GWh in the case of the existing plant only, and from 635 GWh to 716 GWh after expansion . Those increment of the energy are mainly is accrual of the secondary energy, and there is no significant difference in the firm energy and dependable capacity.