6.3 Preliminary Analysis by Screening Curve

Before formulating the generation development plan using simulation tools, the Study team conducted a preliminary analysis using the screening curve method. This analysis provides basic information for generation development planning such as the cost of development and operation and the roughly estimated capacity required to develop each candidate unit in the future.

6.3.1 Screening Curve Analysis

The characteristics of future candidate units shown in Table 6.2.37 are used for the screening curve analysis. Figure 6.3.1 shows the results of the analysis.

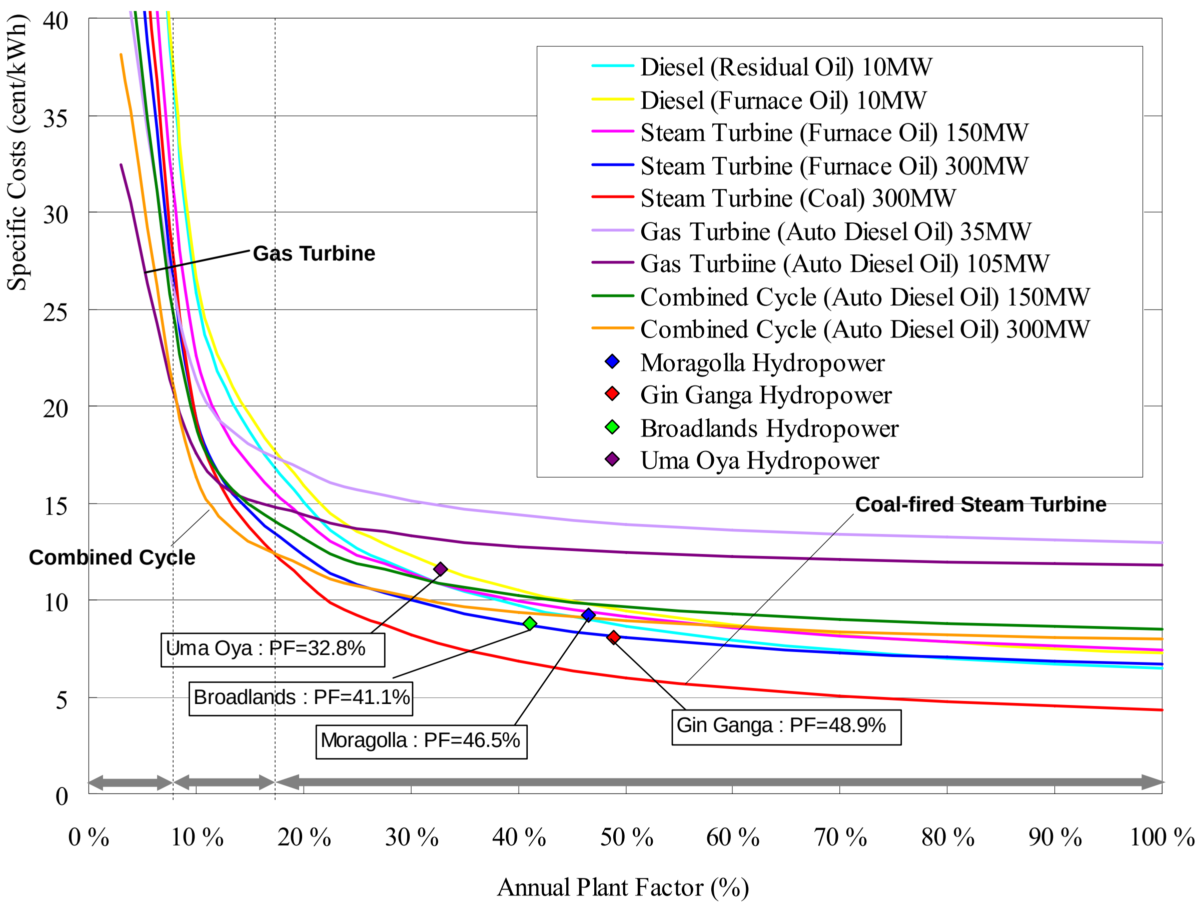


Figure 6.3.1 Results of Screening Analysis (Specific Cost)

As shown in Figure 6.3.1, the cost break point between a coal-fired steam turbine unit and an auto diesel oil-fired combined cycle unit is around 17% of the capacity factor in the screening curve and the cost break point between an auto diesel oil-fired combined cycle unit and a gas turbine unit is around 8% of the capacity factor. These results show that many coal-fired steam turbine units will likely be developed in consideration of economic operation of the system. It is also anticipated that none of the hydropower development projects will gain a competitive advantage over coal-fired thermal power development.

Figure 5.4.2 shows the results of another screening curve analysis on annual production cost.

The figure shows that variable cost of a coal-fired steam turbine power plant is remarkably lower than other candidate power plants. Also the figure shows that gas turbine power plants have an advantage for development as a plant for peak demand due to the fact that they have lower initial invest cost even though they have higher variable cost.

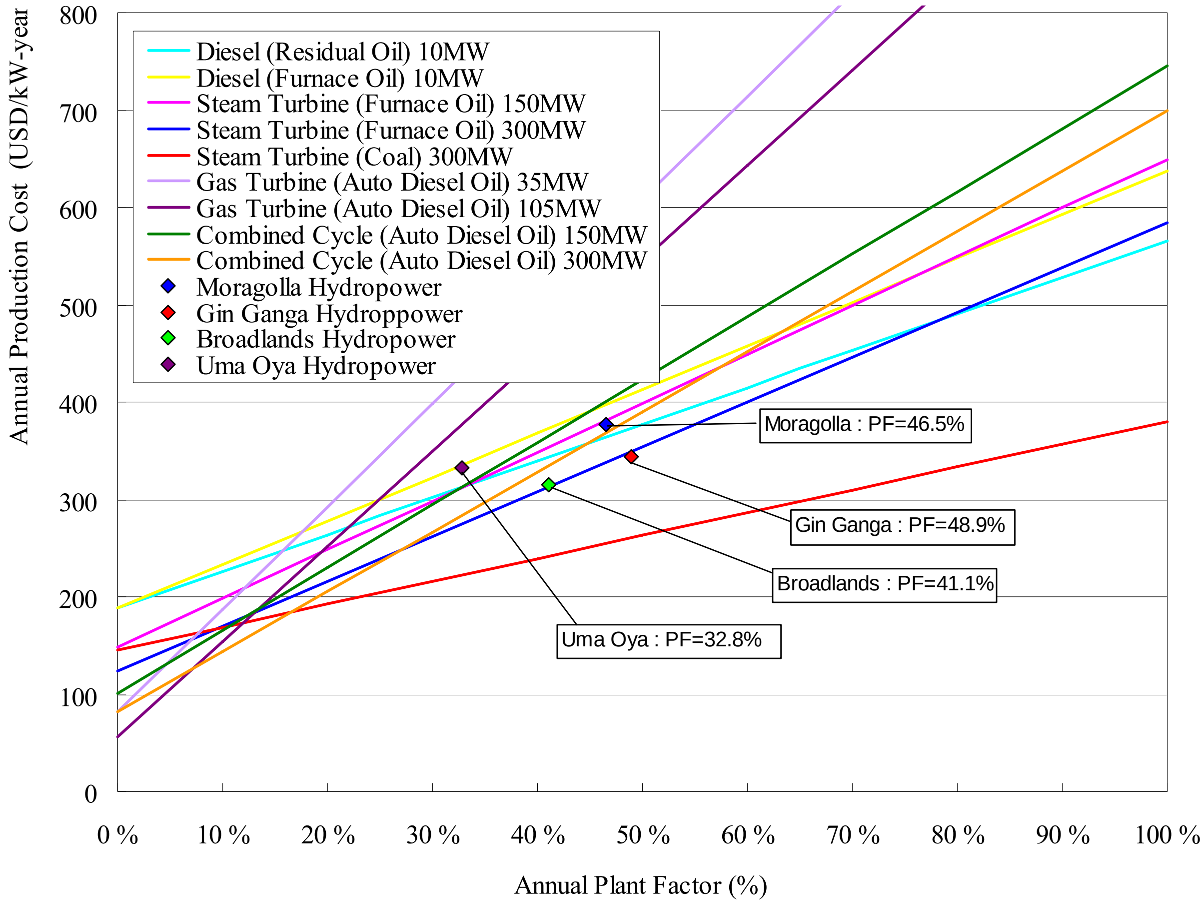


Figure 6.3.2 Results of Screening Analysis (Annual Production Cost)

Reference

The equation for calculating the annual production costs of candidate units in the screening analysis is as shown below:

Annual Production Cost = APC (US$/kW-year)

$$(APC) = [\,r\,]_i^T \text{ x } I + \frac{(i \text{ x } FIC)}{100} + 12 \text{ x } (O\&M_{fixed}) + 8.76 \text{ x } [(FC)_f + (O\&M_{variable})] \text{ x } \frac{f}{100}$$

$$[\,r\,]_i^T = \frac{i \text{ x } (1+i)^T}{(1+i)^T - 1}$$

where:

APC =Annual Production Cost
I = Investment Cost
FIC = Fuel Inventory Cost
FC = Fuel Cost
O&M = Operation and Maintenance Cost
T = Plant Life
i = Annual Interest Rate (12% in this case)
f = Average Annual Capacity Factor of the Plant (%)
$[\,r\,]_i^T$ = Annual Capital Recovery Factor (levelized annual fixed charge rate)

(Source: WASP-IV Manual, IAEA, 2000)

6.4 Simulation for Generation Development

6.4.1 Configuring Development Scenarios

The Study sets up development scenarios for the formulation of generation development plans from the perspective of a strategic environmental assessment (SEA). In this way, a plural number of alternative plans are formulated and evaluations from a variety of perspectives, including environmental, are integrated. The development scenario configured in the formulation of generation development plans is given below. Configuration of the zero option scenario was taken beyond the scenario configured for formulation of the generation development plan to the broader perspective involved in formulation of the Master Plan.

(1) Zero option scenario
The Master Plan not formulated
(2) Generation development scenario
(a) Scenario of Development of Large-scale Thermal Power Plant
There are no limitations on power source facilities to be developed
(b) Scenario of No-Development of Large-scale Thermal Power Plant
There are limitations on power plants to be developed (Installed Capacity 150 MW or less)
(c) Scenario of Hydropower Development Oriented
Promote the development of a promising candidate site for hydropower development
(d) Scenario of Natural Gas Supply
Natural gas will be provided from 2020 or later

Explanations of the various scenarios are provided below.

(1) Zero Option Scenario

A zero option scenario was configured in the master plan.

A zero option scenario considers what direction the power sector would take if this master plan were not formulated.

The CEB has adequate technical capabilities for formulating development plans in the various fields involved in the formulation of power development plans. It will be able to continue formulating its own development plans in the future, as well.

The power sector, however, faces severe conditions. The costs of power supply are high, for example, and power tariffs do not match them. Demand is increasing while supply is inadequate, so that the country faces the possibility of serious power shortages in the near future.

The financial situation of the CEB is deteriorating. These kinds of deterioration in conditions also appear to occur in a kind of vicious cycle, and it is impossible to escape from that cycle just by formulating technically appropriate power development plans. Conditions are expected to deteriorate still further in the future.

For the Master Plan, the official international agency known as the Japan International Cooperation Agency (JICA) presented recommendations for the formulation of long-term power development plans with environmental and social considerations. JICA also identified issues for power sector in organizational and institutional aspects and presented recommendations on them.

If comprehensive Master Plan were not presented, then the power sector would not have found any way to escape from the vicious cycle it had fallen into. Moreover, the CEB would probably not have had the opportunity to improve its own capabilities for framing and implementing the measures for escaping from the cycle itself.

(2) Generation Development Scenario

(a) Scenario of Development of Large-scale Thermal Power Plant

In this scenario, there are no limitations on the power plants to be developed. It is assumed that development of all the power sources shown in Table 6.2.37 as candidates for development is possible.

The context for this scenario configuration envisions that funding has been procured for the development of large-scale thermal power plants for the purpose of reducing supply costs.

(b) Scenario of No-Development of Large-scale Thermal Power Plant

Here it is envisioned that, of the power plants that are candidates for development, the 150 MW and smaller power plants are developed while large-scale thermal power plants are not. Consequently, the power plants shown below have been excluded as candidates for development.

・300 MW oil-fired steam turbine thermal power
・300 MW coal-fired steam turbine thermal power
・300 MW oil-fired steam turbine thermal power

The background of this scenario configuration is the assumption that funding procurement did not take place for the development of large-scale thermal power plants, which require enormous amounts of development funding.

There had long been a strong desire for the development of large-scale coal-fired thermal power plants. The fact is that such power plants have not been developed, however, and this scenario envisions the continuation of this state.

(c) Scenario of Hydropower Development Oriented

This scenario envisions the implementation of a promising hydropower development project from among candidates for development.

The background of this scenario configuration is the assumption that hydropower development receives low-interest financing through official development assistance. Consequently, in this scenario, the projects that received development priority through funding are assumed to have been implemented.

In light of this scenario configuration context, the development projects and their development year were decided on the basis of the results of sensitivity analysis (cases in which the discount rate was 2%, see Section 6.6).

The hydropower development projects that are to be implemented under the present scenario are shown below.

・Broadlands hydropower development project: Operation to begin in 2011
・Gin Ganga hydropower development project: Operation to begin in 2014
・Moragolla hydropower development project: Operation to begin in 2014
・Uma Oya hydropower development project: Operation to begin in 2016

(d) Scenario of Natural Gas Supply

This scenario envisions the adoption of natural gas, one of the new energy options.

The U.S. Agency for International Development (USAID) conducted a feasibility study in 2003 regarding the introduction of natural gas. The study concluded that demand for natural gas in Sri Lanka is so small that it would be difficult for a natural gas project to become economically efficient. As of November 2005, no concrete project is in existence. This scenario takes this situation into consideration and envisions that a supply of natural gas to the power sector will become available in the year 2020 or later.

As regards the determination of supply prices, the price of imported natural gas is generally linked with the price of oil. Therefore, the price was set on the basis of the average price of crude oil (CIF price at Colombo) from May 2004 to April 2005 (approximately 42 USD/barrel), just as for the other fuels in the Master Plan, and based on the relationship between the prices of imported crude oil and natural gas in Japan, at 6 USD/barrel.

6.4.2 WASP Simulation

The generation development plans for the Study were formulated using the WASP-IV simulation tool. This section will discuss the procedure of simulation using WASP-IV and the features of this kind of simulation.

(1) Objective Function

Simulations using WASP-IV seek to minimize costs as the expense of reliability. An objective function for that purpose is configured.

The costs that make up the objective function include capital costs, fuel costs and O&M costs. In addition to these, the cost corresponding to energy that is not supplied (unserved energy cost) is also taken into consideration.

The write-off of capital costs is taken into account by including the salvage value according to the remaining depreciation period as part of the objective function.

Object Function : B

B = SUM (I + S + F + M + U)
in discounted net present value

I	: Capital Cost
S	: Salvage Value
F	: Fuel Cost
M	: Operation and Maintenance Cost
U	: Un-served Energy Cost

(2) Power Demand

In the internal workings of WASP-IV, power demand is not a load curve arranged as a time series. Rather, it is expressed as a load duration curve. This load duration curve, together with the envisioned demand, yields the maximum annual demand. The use of this quantity expresses the load characteristic within WASP-IV. In order to simulate the detailed load characteristic, the year is divided into a maximum of 12 periods, each of which can be given a load duration curve and maximum demand.

(3) Generator Operating Characteristics

WASP-IV can deal with a number of different types of power plants, including hydropower, thermal power and nuclear power.

The operating characteristics of thermal power plant can be modeled for each generator unit by taking into account cost characteristics such as heat rate, the heating value and the O&M costs (fixed costs and variable costs), as well as anticipated parameters such as forced outage rate, spinning reserve and the maintenance days.

Meanwhile, it is possible to model the stochastic generation characteristic of a hydropower plants by taking into account the seasonal fluctuation in water flow, the average generation capacity and the available generation energy. These data can also be configured to model the operating patterns of different types of generator, such as the run-off river type and the reservoir type.

(4) Optimization Calculations

The variable costs of an existing or candidate generator unit can be calculated using the above power demand characteristic and the operating characteristic of the generator unit. By operating generator with lower-cost first, the simulation can be made to approach actual operating conditions quite closely.

Furthermore, the capital cost of a new generator unit can be added in and the objective function described above can be minimized. This will automatically derive sequence of generation development, which shows the minimum cost during the study period.

6.4.3 Simulation Results

A WASP simulation was carried out for each development scenario.

Conducting WASP simulations made it possible to obtain generation development plans that would minimize costs for the period of study under the given conditions of constraint. The results of power demand forecast in base case were used for the simulation.

(1) Large-scale Thermal Power Generation Development Scenario

(i) Number of developed generation units and capacity of developed plants

Table 6.4.1 shows the WASP simulation results (number of developed generation units and its capacity) under the large-scale thermal power development scenario.

Table 6.4.1 Number of Developed Generation Unit and Developed Capacity
(Large-scale Thermal Power Development Scenario)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel (Unit: MW)

Year	Peak Demand (MW)	Thermal Power										Hydropower				
		ST			GT			CCGT			DS	Upper Kotmale	Broadlands	Gin Ganga	Moragolla	Uma Oya
		Oil -fired 150MW	Oil -fired 300MW	Coal -fired 300MW	Oil -fired 35MW	Oil -fired 75MW	Oil -fired 105MW	Kerawala -pitiya 150MW	Oil -fired 150MW	Oil -fired 300MW	Diesel 100MW	150MW	35MW	49MW	27MW	150MW
2005	1,768															
2006	1,884															
2007	2,019															
2008	2,168									Fixed Development Plant						
2009	2,336				35		210	300								
2010	2,517					75	210									
2011	2,712			600								150				
2012	2,921			300												
2013	3,146			300												
2014	3,389			300												
2015	3,657			300												
2016	3,943			300												
2017	4,250			300												
2018	4,579			300												
2019	4,931			300												
2020	5,306			300			105									
2021	5,708			300			105									
2022	6,138			300			210									
2023	6,599			300	35		210									
2024	6,599			300			420									
2025	7,092			600												
Number of Units Developed		0	0	17	2	1	14	2	0	0	0	1	0	0	0	0
		Total: 37 units														
Developed Capacity (MW)		0	0	5,100	70	75	1,470	300	0	0	0	150	0	0	0	0
		Total: 7,165 MW														

The following matters can be discerned from Table 6.4.1.

a) Oil-fired steam turbine thermal power plants

This competes with coal-fired steam turbine thermal power, which is likewise a base power plant. As the fuel cost is higher than for coal, the number of units developed up to 2025 will be zero. This result is the same as the results obtained by the screening curve analysis in Section 6.3.1 (Figure 6.3.1 and Figure 6.3.2).

b) Coal-fired steam turbine thermal power plants

This type is most frequently developed as a base power plant because the fuel cost is more reasonable. This result matches with the preliminary study results from the screening curve discussed above in Section 6.3.1.

By 2025, there will be 17 development units (unit size of 300 MW). The newly developed capacity comes to a total of 5,100 MW, which is approximately 71% of the capacity of all new power plants developed by 2025.

c) Oil-fired gas turbine thermal power plants

Gas turbine thermal power plants have development priority as peak power unit. Development will extend to 17 units and 1,615 MW by 2025.

d) Oil-fired combined cycle thermal power plants

The range of plant factor which gives advantage for development to oil-fired combined cycle power plants is narrow (see Figure 6.3.2). The power plants developed by 2025, therefore, will consist only of the 300 MW Kerawalapitiya power plant, which is a fixed development project.

e) Diesel power plants

These compete with coal-fired thermal power plants as a base plant. However, the fuel cost, which is higher than for coal, prevented it from gaining development priority. It also competes with gas turbine thermal power plants as a peak power plant, but the initial development costs are higher than for gas turbine plant. Consequently, it did not gain development priority, and no units are to be developed by 2025 in this scenario. This result matches with the results from screening curve analysis in Section 6.3.1 (Figure 6.3.1 and Figure 6.3.2).

f) Hydropower plants

Development took place only at Upper Kotmale, a committed project in the Study. Other sites are not to be developed by 2025 due to the high initial development costs.

(ii) Installed capacity

Table 6.4.2, Figure 6.4.1 and Figure 6.4.2 show changes in the installed capacity and their component ratios by plant type under the large-scale thermal power development scenario.

In terms of component ratios, coal-fired thermal power plants will make up approximately 60% by 2025. The component ratio of combined cycle thermal power declined from 14.2% in 2005 to 5.5% in 2025. The component ratio of diesel power plants have also declined year by year so that all such power plants will have been eliminated by 2025. The component ratio of hydropower plants will have declined conspicuously from 51.2% in 2005 to 15.7% in 2025.

Table 6.4.2 Installed Capacity and Component Ratios
(Large-scale Thermal Power Development Scenario)

(Unit: MW, %)

Plant Type	Year									
	2005		2010		2010		2015		2020	
Hydropower	1,185.0	(51.2%)	1,185.0	(38.9%)	1,335.0	(29.4%)	1,335.0	(22.3%)	1,335.0	(15.7%)
Coal-fired Steam Turbine	0.0	(0.0%)	0.0	(0.0%)	1,800.0	(39.7%)	3,300.0	(55.2%)	5,100.0	(59.9%)
Diesel	587.8	(25.4%)	587.8	(19.3%)	131.0	(2.9%)	80.0	(1.3%)	0.0	(0.0%)
Combined Cycle	328.0	(14.2%)	628.0	(20.6%)	628.0	(13.8%)	628.0	(10.5%)	465.0	(5.5%)
Gas Turbine	215.0	(9.3%)	645.0	(21.2%)	645.0	(14.2%)	635.0	(10.6%)	1,615.0	(19.0%)
Total	2,315.8	(100.0%)	3,045.8	(100.0%)	4,539.0	(100.0%)	5,978.0	(100.0%)	8,515.0	(100.0%)

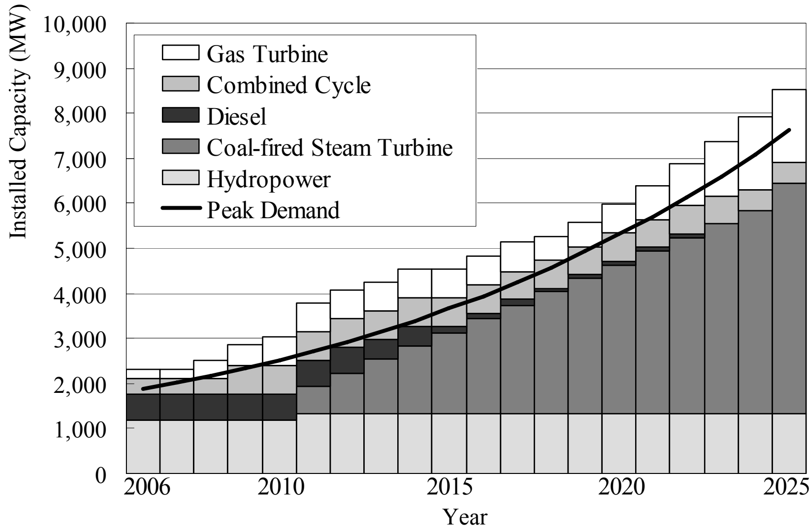


Figure 6.4.1 Capacity Additions by Plant Type (Large-scale Thermal Power Development Scenario)

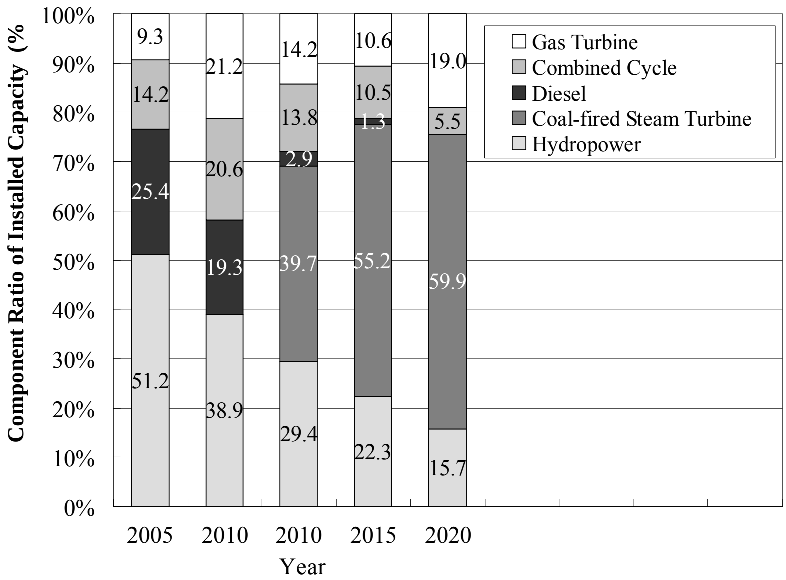


Figure 6.4.2 Component Ratio of Installed Capacity by Plant Type
(Large-scale Thermal Power Development Scenario)

(iii) Changes in annual generation energy

Table 6.4.3, Figure 6.4.3 and Figure 6.4.4 show changes in the annual generation energy and component ratio of power plants by type under the large-scale thermal power development scenario.

The component ratio of generation energy of coal-fired thermal power plants will exceed 80% in 2025. While the component ratio of combined cycle power plants will have risen to 29.1% in 2010, that share will decline with the introduction of coal-fired thermal power until it is at around 1% in 2025. The component ratio of hydropower generation facilities will decline from 52.2% in 2005 to 13.6% in 2025, showing a new intensification of the trend for thermal power to take a leading position.

Table 6.4.3 Annual Generation Energy and Component Ratio
(Large-scale Thermal Power Development Scenario)

(Unit: GWh, %)

Plant Type	Year									
	2005		2010		2010		2015		2020	
Hydropower	4,464	(52.2%)	4,464	(36.7%)	4,994	(28.2%)	4,994	(19.5%)	4,994	(13.6%)
Coal-fired Steam Turbine	0	(0.0%)	0	(0.0%)	11,681	(66.1%)	19,945	(77.7%)	30,820	(83.7%)
Diesel	3,369	(39.4%)	3,543	(29.1%)	355	(2.0%)	98	(0.4%)	0	(0.0%)
Combined Cycle	630	(7.4%)	2,639	(21.7%)	482	(2.7%)	426	(1.7%)	365	(1.0%)
Gas Turbine	86	(1.0%)	1,521	(12.5%)	172	(1.0%)	190	(0.7%)	659	(1.8%)
Total	8,549	(100.0%)	12,167	(100.0%)	17,684	(100.0%)	25,653	(100.0%)	36,838	(100.0%)

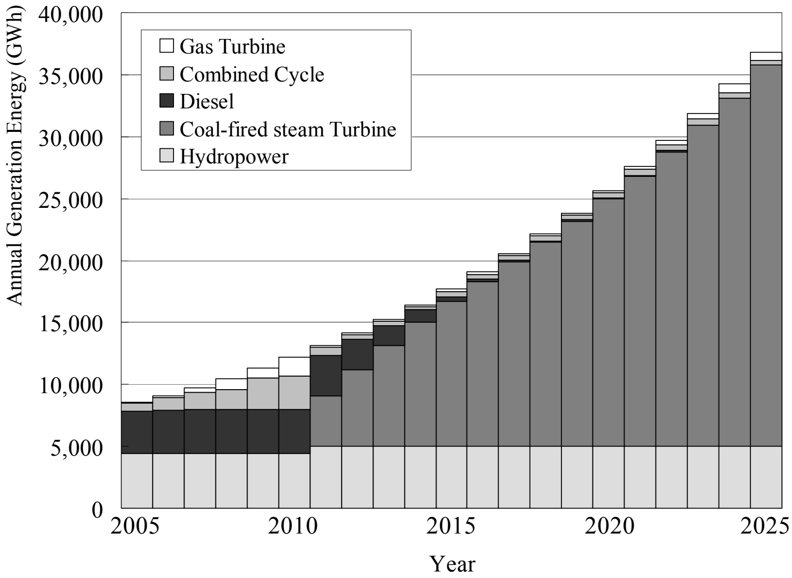


Figure 6.4.3 Generation Energy Additions by Plant Type
(Large-scale Thermal Power Development Scenario)

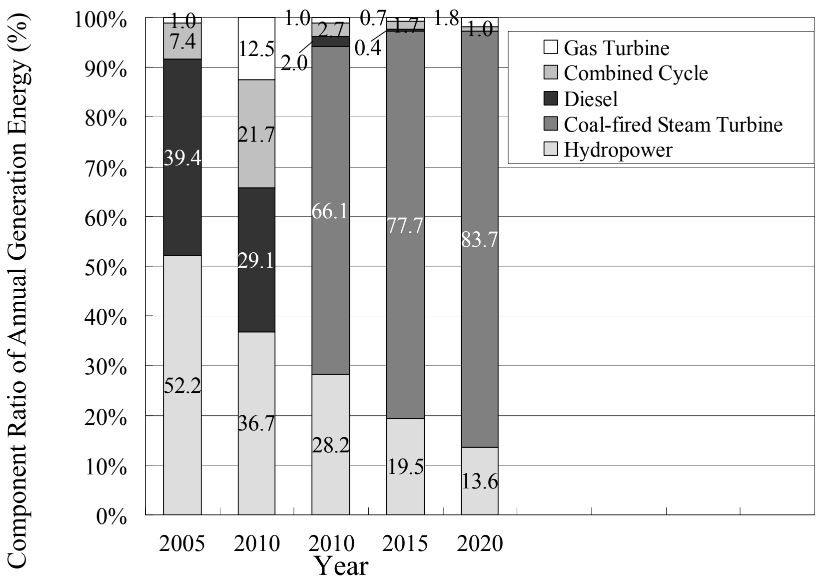


Figure 6.4.4 Component Ratio of Annual Generation Energy
(Large-scale Thermal Power Development Scenario)

(iv) Plant factor

Table 6.4.4 and Figure 6.4.5 show changes in annual plant factor by plant type under the large-scale thermal power development scenario.

The annual plant factor for coal-fired thermal power remained at approximately 70%, indicating that it was fulfilling its role as a base power plant. Meanwhile, the annual plant factor of diesel power facilities, combined cycle thermal power and gas turbine thermal power declined conspicuously after the installation of coal-fired thermal power plant. This was particularly evident in the case of diesel power plants, which had served to cover base demand before the introduction of coal-fired thermal power plants, and now finds that annual capacity factor will decline from 65.4% in 2005 to as low as 14.0% in 2020.

The current power purchase agreement (PPA) concluded with the IPP company allows the CEB to make requests to the IPPs in advance for the amount of power it is going to purchase from them. There is no figure set for the minimum amount of generation energy that must be purchased in the course of a year. (No take or pay or other such contracts have been concluded.) CEB is therefore able to decide the power of each generation unit by merit order, and consequently it will be able to reduce the plant factor of diesel power plants in this way without any problems.

Table 6.4.4 Annual Plant Factor (Large-scale Thermal Power Development Scenario)

(Unit: %)

Plant Type	Year				
	2005	2010	2015	2020	2025
Hydropower	(43.0%)	(43.0%)	(42.7%)	(42.7%)	(42.7%)
Coal-fired Steam Turbine			(74.1%)	(69.0%)	(69.0%)
Diesel	(65.4%)	(68.8%)	(30.9%)	(14.0%)	
Combined Cycle	(21.9%)	(48.0%)	(8.8%)	(7.7%)	(9.0%)
Gas Turbine	(4.6%)	(26.9%)	(3.0%)	(3.4%)	(4.7%)

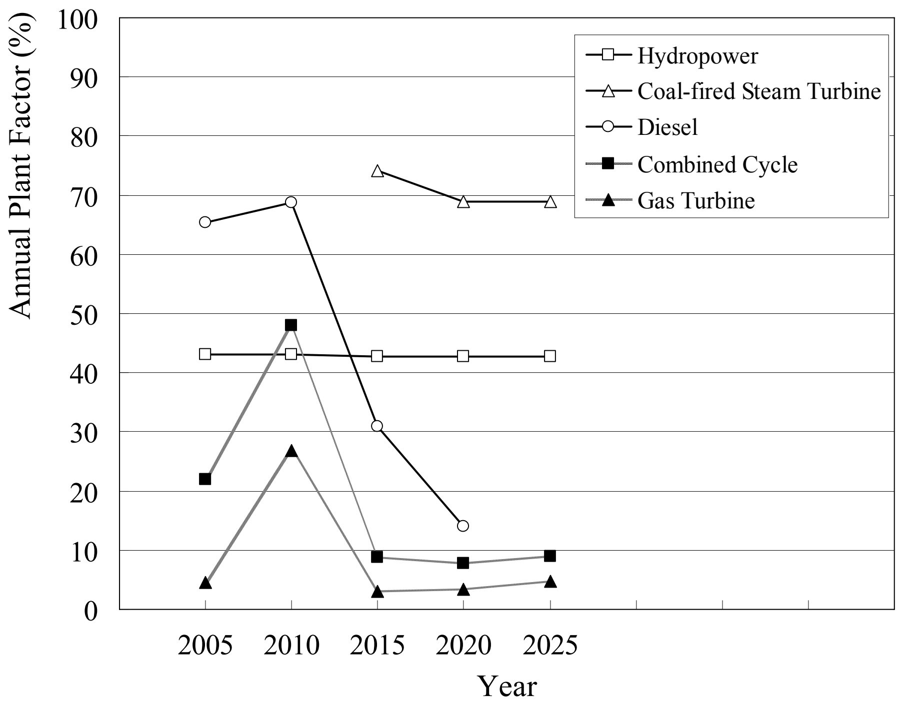


Figure 6.4.5 Changes in Annual Plant Factor (Large-scale Thermal Power Development Scenario)

(v) Fuel consumption

Table 6.4.5 and Figure 6.4.6 show the changes in fuel consumption under the large-scale thermal power development scenario.

Before 2011, when coal-fired thermal power will be developed, the development of new gas turbine plants and combined cycle plants will be accompanied by a conspicuous increase in the fuel consumption of auto diesel oil. The annual amount consumed in 2010 will reach 914 million liters. The development of coal-fired thermal power, as discussed above, will bring about a decline in the plant factor of these facilities, and consumption of this fuel will diminish significantly as a result. By 2020, the annual figure will be approximately one million liters. The amount utilized will gradually increase again from 2020 on, when new gas turbine facilities are developed.

The amount of coal consumption will increase dramatically. Annual consumption of coal is expected to exceed 11 million metric tons in 2025. This indicates that new coal procurement of 500,000 metric tons will be necessary every year, and the unfailing procurement of this fuel will be one issue for realization of these plans.

As of November 2005, the fuel consumed in the greatest quantity was furnace oil. The amount used is expected to drop to zero in 2015, with expiration of the contracts with IPP diesel power facilities.

As this shows, the introduction of coal-fired thermal power will result in the power sector shifting radically to a dependence on coal for its fuel. This suggests that it will be important to take measures in this regard for energy security.

Table 6.4.5 Fuel Consumption (Large-scale Thermal Power Development Scenario)

Fuel Type		Year				
		2005	2010	2015	2020	2025
Auto Diesel Oil	(million Liter)	103	914	127	133	271
Furnace Oil	(million Liter)	451	490	0	0	0
Residual Oil	(million Liter)	281	281	78	21	0
Naphtha	(million Liter)	53	112	27	18	17
Coal	(1,000 MTon)	0	0	4,252	7,260	11,219

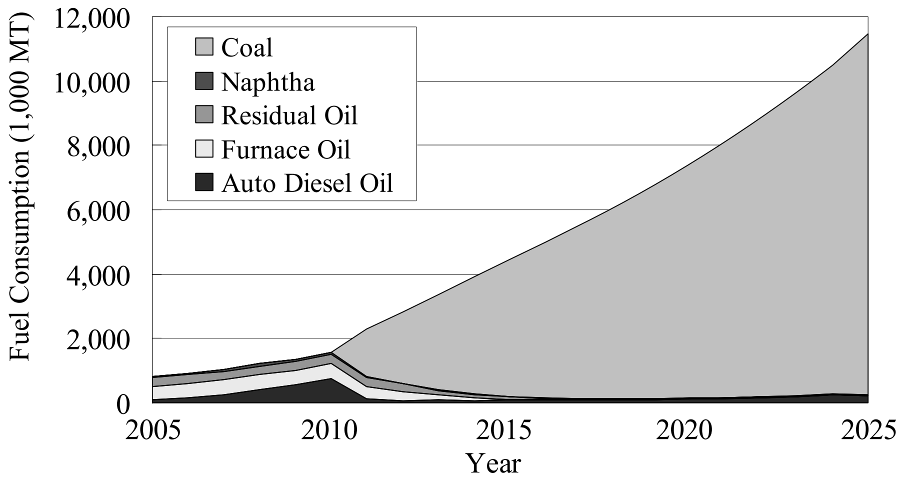


Figure 6.4.6 Changes in Fuel Consumption (Large-scale Thermal Power Development Scenario)

(vi) Capital investment

Table 6.4.6 shows the amount of new capital investment under the large-scale thermal power generation development scenario.

The amount of new capital investment will exceed US$7.3 billion by 2025. Almost all of the amount will be expended for the development of coal-fired thermal power plants in and after 2011. This means that new funding in the amount of US$450 million will have to be obtained every year. Successful procurement of these funds will be a precondition for these plans, and this can therefore be considered an issue for the realization of the plans.

Table 6.4.6 Capital Investment Cost (Large-scale Thermal Power Development Scenario)

(Unit: million USD)

Plant Type	Period				Total
	2006 - 2010	2011 - 2015	2016 - 2020	2021 - 2025	
Hydropower	0.0	0.0	0.0	0.0	0.0
Coal-fired Steam Turbine	0.0	2,347.4	1,956.2	2,347.4	6,650.9
Diesel	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	0.0	0.0	0.0	0.0
Gas Turbine	244.2	0.0	45.7	433.3	723.1
Total	244.2	2,347.4	2,001.8	2,780.6	7,374.0

Note: Investment cost for fixed development project, Kerawalapitiya CCGT and Upper Kotmale hydropower project is excluded.

(vii) System Cost

Table 6.4.7 shows the system cost up to 2025 under the large-scale thermal power development scenario.

The system cost as discussed here until 2025 is the objective function that WASP-IV seeks to minimize, as discussed in Section 6.4.2(1). This is the cost of capital investment over the period of the plan, the cost of fuel, the cost of operation and maintenance, and the cost of energy that is not supplied (unserved energy cost), at 2005 prices.

The system cost up to 2025 comes to US$5.921 billion (at 2005 prices). It is apparent that most of the amount is fuel costs.

Table 6.4.7. System Cost to 2025 (Large-Scale Thermal Power Development Scenario)

(Unit: million USD, Prices at Jan. 2005)

Item	Amount
(1) investment Cost	1,656
(2) Fuel Cost	3,551
(3) Operation and Maintenance cost	669
(4) Energy Not Served Cost	45
System Cost (1) + (2) + (3) + (4)	5,921

(2) No Large-scale Thermal Power Generation Development Scenario

(i) Number of developed generation units and capacity of developed plants

Table 6.4.8 shows the WASP simulation results (number of developed generation units and its capacity) under the no large-scale thermal power development scenario.

Table 6.4.8 Number of Developed Generation Unit and Developed Capacity
(No Large-scale Thermal Power Development Scenario)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel (Unit: MW)

Year	Peak Demand (MW)	Thermal Power										Hydropower				
		ST			GT			CCGT			DS	Upper Kotmale	Broadlands	Gin Ganga	Moragolla	Uma Oya
		Oil -fired 150MW	Oil -fired 300MW	Coal -fired 300MW	Oil -fired 35MW	Oil -fired 75MW	Oil -fired 105MW	Kerawala -pitiya 150MW	Oil -fired 150MW	Oil -fired 300MW	Diesel 100MW	150MW	35MW	49MW	27MW	150MW
2005	1,768															
2006	1,884															
2007	2,019															
2008	2,168										Fixed Development Plant					
2009	2,336				35		210	300								
2010	2,517										500					
2011	2,712										200	150				
2012	2,921										200					
2013	3,146										200					
2014	3,389										200			49		
2015	3,657				35						500					
2016	3,943						210				100					
2017	4,250										400		35			
2018	4,579						210				300					
2019	4,931						210				200					
2020	5,306						105				300					
2021	5,708						210				300					
2022	6,138						210				300					
2023	6,599						105				500					
2024	6,599						420				300					
2025	7,092						210				400					
Number of Units Developed		0	0	0	2	0	20	2	0	0	49	1	1	1	0	0
		Total: 76 units														
Developed Capacity (MW)		0	0	0	70	0	2,100	300	0	0	4,900	150	35	49	0	0
		Total: 7,604 MW														

The following points are apparent from Table 6.4.8.

The capacity of newly developed power plants up to 2025 will be 7,604 MW. This is approximately 6% more than under the large-scale thermal power development scenario. The reason for this is that the coal-fired thermal power plants and diesel power facilities, which have the major share of the composition in the two scenarios, have different forced outage rates. This is because, under the Master Plan, diesel power plants have a higher outage rate than coal-fired thermal power plants, as a result of which it was necessary to develop more diesel power plants in order to satisfy the required supply reliability.

a) Oil-fired steam turbine thermal power plants

This power plant competes with diesel power facilities, which compete as a base power unit, but did not gain development priority. Consequently, under these conditions, the number of units developed by 2025 will be zero. This result is the same as the results obtained by the screening curve analysis in Section 6.3.1 (Figures 6.3.1 and 6.3.2).

b) Coal-fired steam turbine thermal power plants

The scenario makes the assumption that large-scale thermal power plants will not be developed. Consequently, they are excluded from the power plants that are candidates for development.

c) Oil-fired gas turbine thermal power plants

Because large-scale thermal power plants were not developed, gas turbine thermal power gained a wider range of plant factor, which determines development priority. As a result, development was greater by 555 MW than under the large-scale thermal power development scenario.

d) Oil-fired combined cycle thermal power plants

Just as under the large-scale thermal power development scenario, the units developed by 2025 will consist only of the 300 MW Kerawalapitiya plant, which is a fixed development project.

e) Diesel power plants

Coal-fired thermal power, which is most promising as a base power plant, is excluded from the candidates for development under the scenario. Consequently, the next most promising plant type, which is diesel power, is deployed in greater numbers as a base power plant. The number of new units developed by 2025 will amount to 49, and the total newly installed capacity will be 4,900 MW.

f) Hydropower plants

In addition to the project at Upper Kotmale, where the decision for development had already been made, the 49 MW Gin Ganga hydropower site will be developed in 2014, and the 35 MW Broadlands hydropower site will be developed in 2017. The reason is that diesel power has become the main base power source, and the supply cost of the base capacity therefore increased as compared to coal-fired thermal power, so that these hydropower plants gained development priority. The result was the same as the screening curve analysis result (Figures 6.3.1 and 6.3.2) in Section 6.3.1.

(ii) Installed capacity

Table 6.4.9, and Figures 6.4.7 and 6.4.8 show changes in the installed capacity of power plants and their component ratios by plant type under the no large-scale thermal power development scenario.

The percentage share of diesel power facilities will have grown to approximately 54.7% by 2025, making it the largest component in the composition of power plants.

The component ratio of hydropower plants will decrease conspicuously, just as under the large-scale thermal power development scenario, to 15.8% by 2025.

Table 6.4.9 Installed Capacity and Component Ratios
(No Large-scale Thermal Power Development Scenario)

(Unit: MW, %)

Plant Type	Year									
	2005		2010		2010		2015		2020	
Hydropower	1,185.0	(51.2%)	1,185.0	(36.3%)	1,384.0	(31.9%)	1,419.0	(22.7%)	1,419.0	(15.8%)
Coal-fired Steam Turbine										
Diesel	587.8	(25.4%)	1,087.8	(33.4%)	1,931.0	(44.5%)	3,180.0	(50.9%)	4,900.0	(54.7%)
Combined Cycle	328.0	(14.2%)	628.0	(19.3%)	628.0	(14.5%)	628.0	(10.1%)	465.0	(5.2%)
Gas Turbine	215.0	(9.3%)	360.0	(11.0%)	395.0	(9.1%)	1,015.0	(16.3%)	2,170.0	(24.2%)
Total	2,315.8	(100.0%)	3,260.8	(100.0%)	4,338.0	(100.0%)	6,242.0	(100.0%)	8,954.0	(100.0%)

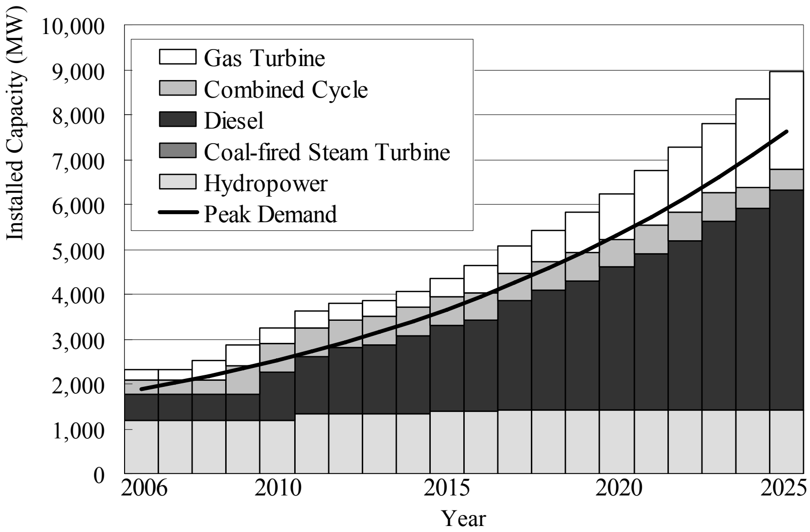


Figure 6.4.7 Capacity Additions by Plant Type (No Large-scale Thermal Power Development Scenario)

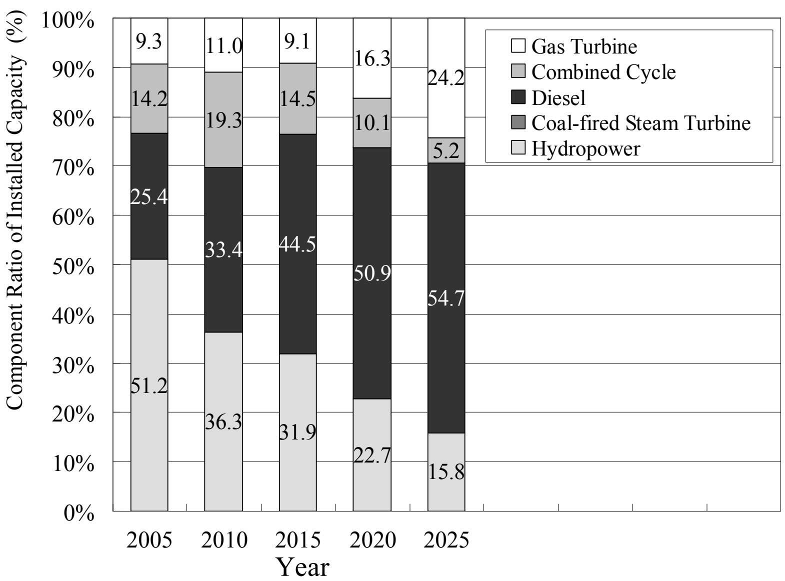


Figure 6.4.8 Component Ratio of Installed Capacity by Plant Type
(No Large-scale Thermal Power Development Scenario)

(iii) Changes in annual generation energy

Table 6.4.10, and Figures 6.4.9 and 6.4.10 show changes in the annual generation energy and component ratio of generation plants by type under the no large-scale thermal power development scenario.

The share of diesel power plants as a component ratio of generation energy will exceed 80% in 2025. This is approximately identical to the component percentage of coal-fired thermal power under the large-scale thermal power development scenario.

Table 6.4.10 Annual Generation Energy and Component Ratio
(No Large-scale Thermal Power Development Scenario)

(Unit: GWh, %)

Plant Type	Year									
	2005		2010		2010		2015		2020	
Hydropower	4,464	(52.2%)	4,464	(36.7%)	5,204	(29.4%)	5,330	(20.8%)	5,330	(14.5%)
Coal-fired Steam Turbine	0	(0.0%)	0	(0.0%)	0	(0.0%)	0	(0.0%)	0	(0.0%)
Diesel	3,369	(39.4%)	6,737	(55.3%)	11,840	(67.0%)	19,310	(75.3%)	29,819	(80.9%)
Combined Cycle	630	(7.4%)	840	(6.9%)	515	(2.9%)	601	(2.3%)	529	(1.4%)
Gas Turbine	86	(1.0%)	131	(1.1%)	122	(0.7%)	414	(1.6%)	1,162	(3.2%)
Total	8,549	(100.0%)	12,172	(100.0%)	17,681	(100.0%)	25,655	(100.0%)	36,840	(100.0%)

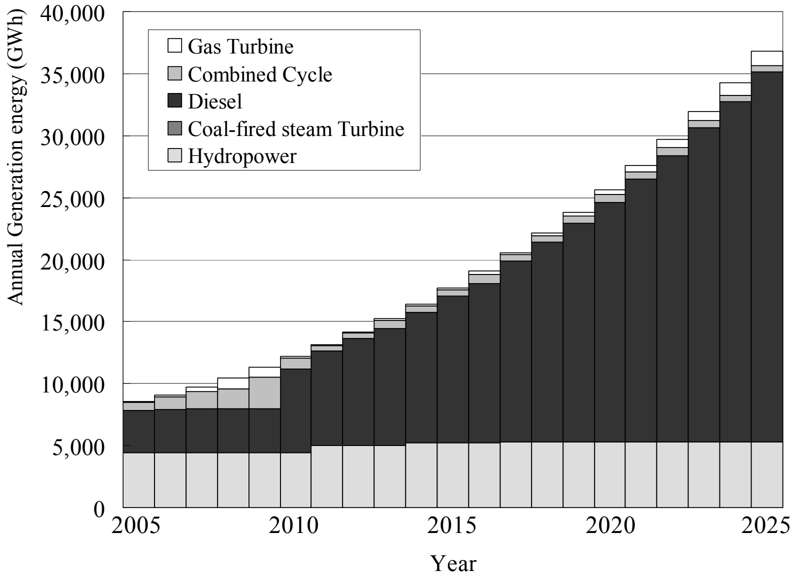


Figure 6.4.9 Generation Energy Additions by Plant Type
(No Large-scale Thermal Power Development Scenario)

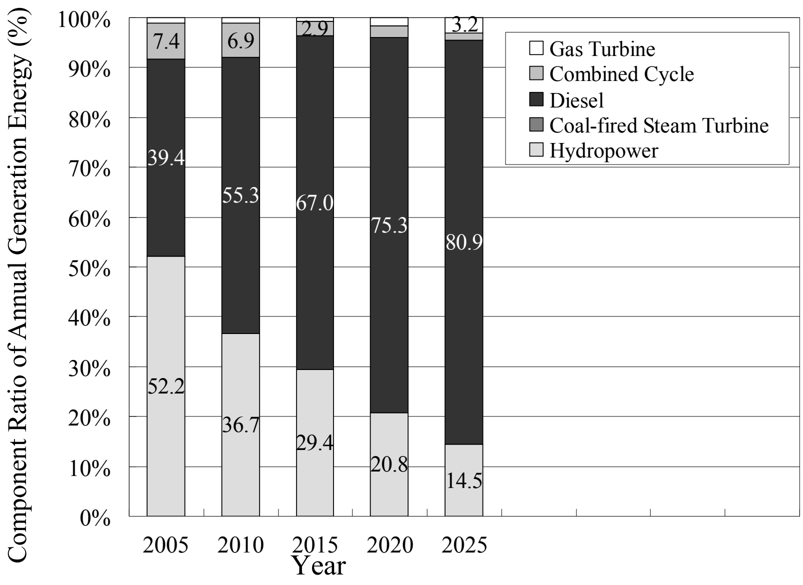


Figure 6.4.10 Component Ratio of Annual Generation Energy
(No Large-scale Thermal Power Development Scenario))

(iv) Plant factor

Table 6.4.11 and Figure 6.4.11 show changes in annual plant factor by plant type under the no large-scale thermal power development scenario.

The annual plant for diesel power plants remained at approximately 70%, indicating that they were fulfilling their role as a base power plant. The progressive development of diesel power plants is accompanied by a decrease in the plant factor of combined cycle thermal power, which will reach 13% in 2025. The plant factor of gas turbine thermal power will not change significantly.

Table 6.4.11 Annual Plant Factor (No Large-scale Thermal Power Development Scenario)

(Unit: %)

Plant Type	Year				
	2005	2010	2015	2020	2025
Hydropower	(43.0%)	(43.0%)	(42.9%)	(42.9%)	(42.9%)
Coal-fired Steam Turbine					
Diesel	(65.4%)	(70.7%)	(70.0%)	(69.3%)	(69.5%)
Combined Cycle	(21.9%)	(15.3%)	(9.4%)	(10.9%)	(13.0%)
Gas Turbine	(4.6%)	(4.2%)	(3.5%)	(4.7%)	(6.1%)

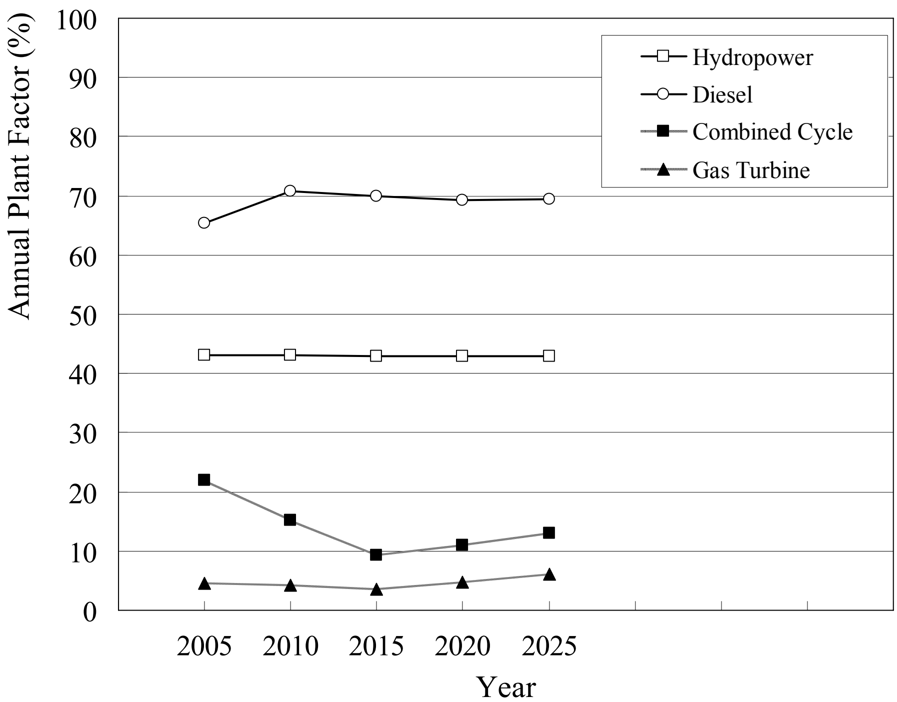


Figure 6.4.11 Changes in Annual Plant Factor (No Large-scale Thermal Power Development Scenario)

(v) Fuel consumption

Table 6.4.12 and Figure 6.4.12 show the changes in fuel consumption under the no large-scale thermal power development scenario.

The amount of furnace oil used as fuel in newly developed diesel power plants increases conspicuously. In 2025, the annual amount used will be 5.377 billion liters. This is approximately 12 times more than the annual amount used in 2005, and realization of the plan will require importation through CPC of furnace oil in amounts commensurate with this rate of consumption. Assuring the reliable supply of imported fuel will further require upgrading of handling facilities, and transportation of the fuel to power stations must also be made dependable.

The amount of auto diesel oil used will increase from 2020 on, reaching 459 million liters by 2025.

Table 6.4.12 Fuel Consumption (No Large-scale Thermal Power Development Scenario)

Fuel Type		Year				
		2005	2010	2015	2020	2025
Auto Diesel Oil	(million Liter)	103	165	119	234	459
Furnace Oil	(million Liter)	451	1,057	2,029	3,396	5,377
Residual Oil	(million Liter)	281	281	127	102	
Naphtha	(million Liter)	53	50	26	25	26
Coal	(1,000 MTon)					

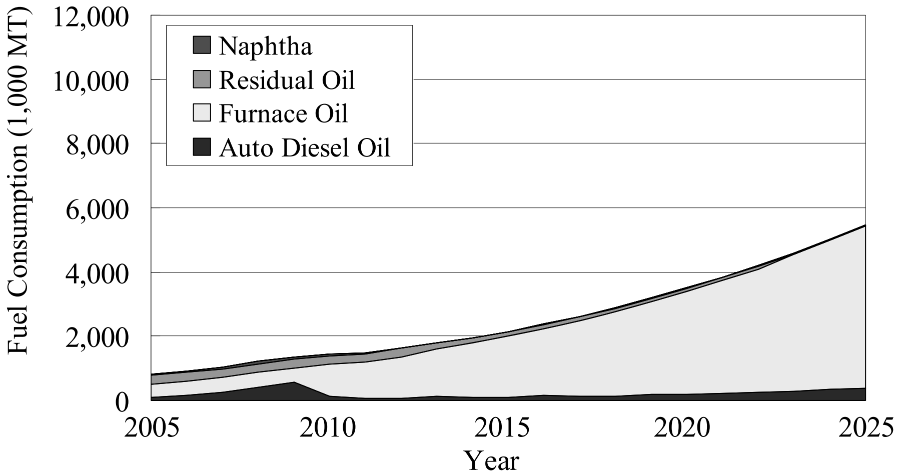


Figure 6.4.12 Changes in Fuel Consumption (No Large-scale Thermal Power Development Scenario)

(vi) Capital investment

Table 6.4.13 shows the amount of new capital investment under the no large-scale thermal power development scenario.

The amount of new capital investment will exceed US$9 billion by 2025, and is approximately 20% higher than the figure under the large-scale thermal power development scenario. The main reasons for this are the facts that, under the no large-scale thermal power development scenario, it will be necessary to develop more power plants, the majority of which will be hydropower projects that require a higher initial investment.

Table 6.4.13 Capital Investment Cost (No Large-scale Thermal Power Development Scenario)

(Unit: million USD)

Plant Type	Period				Total
	2006 - 2010	2011 - 2015	2016 - 2020	2021 - 2025	
Hydropower	0.0	165.0	108.0	0.0	273.0
Coal-fired Steam Turbine	0.0	0.0	0.0	0.0	0.0
Diesel	797.3	2,072.9	2,072.9	2,870.1	7,813.1
Combined Cycle	0.0	0.0	0.0	0.0	0.0
Gas Turbine	113.7	22.4	319.6	502.2	957.8
Total	910.9	2,260.2	2,500.4	3,372.3	9,043.9

Note: Investment cost for fixed development project, Kerawalapitiya CCGT and Upper Kotmale hydropower project is excluded.

(vii) System Cost

Table 6.4.14 shows system cost up to 2025 under the no large-scale thermal power development scenario.

System costs to 2025 are US$7.316 billion (at 2005 prices), 24% higher than system costs under the large-scale thermal power development scenario.

The two scenarios primarily differ in terms of fuel costs and of investment costs. Fuel costs in particular are approximately 30% higher under the no large-scale thermal power development scenario, indicating that failure to undertake development of coal-fired thermal power plants could result in an increase in generation costs throughout the system.

Table 6.4.14 System Cost to 2025 (No Large-Scale Thermal Power Development Scenario)

(Unit: million USD, Prices at Jan. 2005)

Item	Amount
(1) investment Cost	2,085
(2) Fuel Cost	4,557
(3) Operation and Maintenance cost	631
(4) Energy Not Served Cost	43
System Cost (1) + (2) + (3) + (4)	7,316

(viii) Installation of middle-speed diesel units

The Study Team conducted a case study for the installation of middle speed diesel units under the scenario of no large-scale thermal power development.

Based on the data of past project of diesel unit in Sri Lanka, it was assumed that development cost including interest during construction and life time for the middle-speed diesel units are 700 US dollars per kW and 15 years, respectively

Table 6.4.15 to 6.4.19 show the simulation results of the case.

Table 6.4.15 Number of Developed Generation Unit and Developed Capacity
(No Large-scale Thermal Power Development Scenario: Middle-speed Diesel)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel (Unit: MW)

Year	Peak Demand (MW)	Thermal Power										Hydropower				
		ST			GT			CCGT			DS	Upper Kotmale	Broadlands	Gin Ganga	Moragolla	Uma Oya
		Oil -fired 150MW	Oil -fired 300MW	Coal -fired 300MW	Oil -fired 35MW	Oil -fired 75MW	Oil -fired 105MW	Kerawala -pitiya 150MW	Oil -fired 150MW	Oil -fired 300MW	Diesel 100MW	150MW	35MW	49MW	27MW	150MW
2005	1,768															
2006	1,884															
2007	2,019															
2008	2,168										Fixed Development Plant					
2009	2,336				35		210	300								
2010	2,517										500					
2011	2,712										400	150				
2012	2,921										200					
2013	3,146										200					
2014	3,389										200					
2015	3,657										500					
2016	3,943										200					
2017	4,250										400					
2018	4,579						105				500					
2019	4,931				35		105				200					
2020	5,306										500					
2021	5,708						315				100					
2022	6,138						105				400					
2023	6,599						525				100					
2024	6,599						315				400					
2025	7,092				35		105				500					
Number of Units Developed		0	0	0	3	0	17	2	0	0	53	1	0	0	0	0
		Total: 76 units														
Developed Capacity (MW)		0	0	0	105	0	1,785	300	0	0	5,300	150	0	0	0	0
		Total: 7,640 MW														

Table 6.4.16 Installed Capacity and Component Ratios
(No Large-scale Thermal Power Development Scenario: Middle-speed Diesel)

(Unit: MW, %)

Plant Type	Year									
	2005		2010		2010		2015		2020	
Hydropower	1,185.0	(51.2%)	1,185.0	(36.3%)	1,335.0	(30.0%)	1,335.0	(21.1%)	1,335.0	(14.8%)
Coal-fired Steam Turbine										
Diesel	587.8	(25.4%)	1,087.8	(33.4%)	2,131.0	(47.8%)	3,880.0	(61.3%)	5,300.0	(59.0%)
Combined Cycle	328.0	(14.2%)	628.0	(19.3%)	628.0	(14.1%)	628.0	(9.9%)	465.0	(5.2%)
Gas Turbine	215.0	(9.3%)	360.0	(11.0%)	360.0	(8.1%)	490.0	(7.7%)	1,890.0	(21.0%)
Total	2,315.8	(100.0%)	3,260.8	(100.0%)	4,454.0	(100.0%)	6,333.0	(100.0%)	8,990.0	(100.0%)

Table 6.4.17 Annual Generation Energy and Component Ratio
(No Large-scale Thermal Power Development Scenario: Middle-speed Diesel)

(Unit: GWh, %)

Plant Type	Year									
	2005		2010		2010		2015		2020	
Hydropower	4,464	(52.2%)	4,464	(36.7%)	4,994	(28.2%)	4,994	(19.5%)	4,994	(13.6%)
Coal-fired Steam Turbine	0	(0.0%)	0	(0.0%)	0	(0.0%)	0	(0.0%)	0	(0.0%)
Diesel	3,369	(39.4%)	6,737	(55.3%)	12,286	(69.5%)	20,260	(79.0%)	30,591	(83.0%)
Combined Cycle	630	(7.4%)	840	(6.9%)	322	(1.8%)	302	(1.2%)	387	(1.1%)
Gas Turbine	86	(1.0%)	131	(1.1%)	82	(0.5%)	101	(0.4%)	868	(2.4%)
Total	8,549	(100.0%)	12,172	(100.0%)	17,684	(100.0%)	25,657	(100.0%)	36,840	(100.0%)

Table 6.4.18 Capital Investment Cost
(No Large-scale Thermal Power Development Scenario: Middle-speed Diesel)

(Unit: million USD)

Plant Type	Period				Total
	2006 - 2010	2011 - 2015	2016 - 2020	2021 - 2025	
Hydropower	0.0	0.0	0.0	0.0	0.0
Coal-fired Steam Turbine	0.0	0.0	0.0	0.0	0.0
Diesel	0.0	0.0	0.0	0.0	0.0
Combined Cycle	350.0	1,050.0	1,260.0	1,050.0	3,710.0
Gas Turbine	113.7	0.0	113.7	615.9	843.3
Total	463.7	1,050.0	1,373.7	1,665.9	4,553.3

Note: Investment cost for fixed development project, Kerawalapitiya CCGT and Upper Kotmale hydropower project is excluded.

Table 6.4.19 System Cost to 2025
(No Large-scale Thermal Power Development Scenario: Middle-speed Diesel)

(Unit: million USD, Prices at Jan. 2005)

Item	Amount
(1) investment Cost	1,166
(2) Fuel Cost	4,508
(3) Operation and Maintenance cost	632
(4) Energy Not Served Cost	42
System Cost (1) + (2) + (3) + (4)	6,348

(3) Hydropower Development Oriented Scenario

(i) Number of developed generation units and capacity of developed plants

Table 6.4.20 shows the results of a WASP simulation (number of development units and development capacity) under the hydropower development oriented scenario.

Table 6.4.20 Number of Developed Generation Unit and Developed Capacity
(Hydropower Development Oriented Scenario)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel (Unit: MW)

Year	Peak Demand (MW)	Thermal Power										Hydropower				
		ST			GT			CCGT			DS	Upper Kotmale	Broadlands	Gin Ganga	Moragolla	Uma Oya
		Oil -fired 150MW	Oil -fired 300MW	Coal -fired 300MW	Oil -fired 35MW	Oil -fired 75MW	Oil -fired 105MW	Kerawala -pitiya 150MW	Oil -fired 150MW	Oil -fired 300MW	Diesel 100MW	150MW	35MW	49MW	27MW	150MW
2005	1,768															
2006	1,884															
2007	2,019															
2008	2,168									Fixed Development Plant						
2009	2,336				35		210	300								
2010	2,517					75	210									
2011	2,712			600								150	35			
2012	2,921			300												
2013	3,146			300												
2014	3,389			300										49	27	
2015	3,657			300												
2016	3,943			300												150
2017	4,250															
2018	4,579			300												
2019	4,931			300												
2020	5,306			300			105									
2021	5,708			600												
2022	6,138			300												
2023	6,599			300			315									
2024	6,599			300			420									
2025	7,092			300	35		210									
Number of Units Developed		0	0	16	2	1	14	2	0	0	0	1	1	1	1	1
		Total: 40 units														
Developed Capacity (MW)		0	0	4,800	70	75	1,470	300	0	0	0	150	35	49	27	150
		Total: 7,126 MW														

Table 6.4.20 indicates the following:

a) Oil-fired steam turbine thermal power plants

The number of new development units is zero, just under the large-scale thermal power development scenario.

b) Coal-fired steam turbine thermal power plants

Sixteen new coal-fired thermal power units will be developed by 2005 in this scenario, representing a total capacity of 4,800 MW. This is a reduction of 1 unit (300 MW) against the large-scale thermal power development scenario, because part of the generation capacity of the hydropower plants under development will cover the base demand, reducing the required development capacity of coal-fired thermal power plant.

c) Oil-fired gas turbine thermal power plants

By 2025, 17 gas turbine thermal power plants with a capacity of 1,615 MW will be developed as a peak power plant. This figure for capacity is the same as the figure under the large-scale thermal power development scenario.

d) Oil-fired combined cycle thermal power plants

Just under the large-scale thermal power development scenario, the power plants developed by 2025 will consist only of the 300 MW Kerawalapitiya power plant, which is a fixed development power plant.

e) Diesel power plants

The number of new development units in this category is zero, just under the large-scale thermal power development scenario.

f) Hydropower plants

Development of hydropower plants in five locations (Upper Kotmale, Broadlands, Gin Ganga, Moragolla and Uma Oya) will bring the total capacity of new hydropower developments by 2025 to 411 MW, representing approximately 6% of the capacity of all new development plants.

(ii) Installed capacity

Table 6.4.21 and Figures 6.4.13 and 6.4.14 show changes in the in capacity of power plants and their component ratios by plant type under the hydropower development oriented scenario.

In 2025, the component ratio of coal-fired thermal power plants will make up 56.6% in total. In contrast with the large-scale thermal power development scenario, the development of hydropower plants at four locations, representing a total capacity of 261 MW, will increase the component ratio of hydropower plants in total to 18.8% in 2025.

Table 6.4.21 Installed Capacity and Component Ratios
(Hydropower Development Oriented Scenario)

(Unit: MW, %)

Plant Type	Year									
	2005		2010		2010		2015		2020	
Hydropower	1,185.0	(51.2%)	1,185.0	(38.9%)	1,446.0	(31.1%)	1,596.0	(26.9%)	1,596.0	(18.8%)
Coal-fired Steam Turbine	0.0	(0.0%)	0.0	(0.0%)	1,800.0	(38.7%)	3,000.0	(50.5%)	4,800.0	(56.6%)
Diesel	587.8	(25.4%)	587.8	(19.3%)	131.0	(2.8%)	80.0	(1.3%)	0.0	(0.0%)
Combined Cycle	328.0	(14.2%)	628.0	(20.6%)	628.0	(13.5%)	628.0	(10.6%)	465.0	(5.5%)
Gas Turbine	215.0	(9.3%)	645.0	(21.2%)	645.0	(13.9%)	635.0	(10.7%)	1,615.0	(19.1%)
Total	2,315.8	(100.0%)	3,045.8	(100.0%)	4,650.0	(100.0%)	5,939.0	(100.0%)	8,476.0	(100.0%)

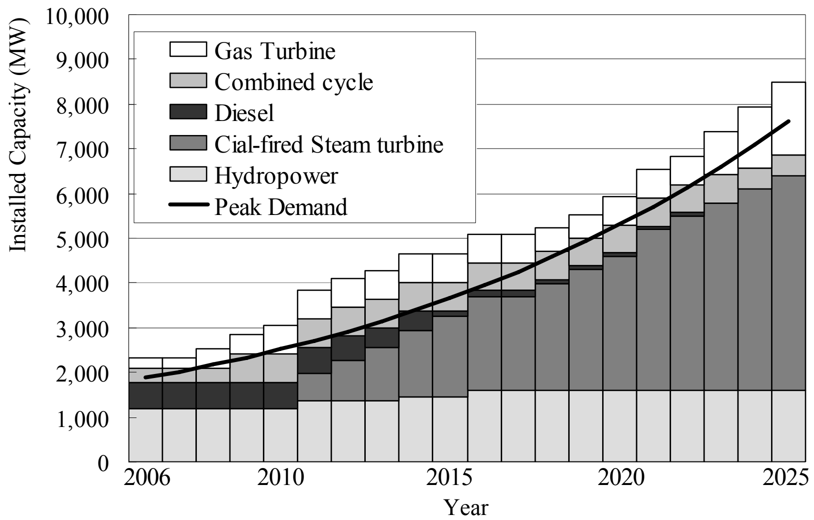


Figure 6.4.13 Capacity Additions by Plant Type (Hydropower Development Oriented Scenario)

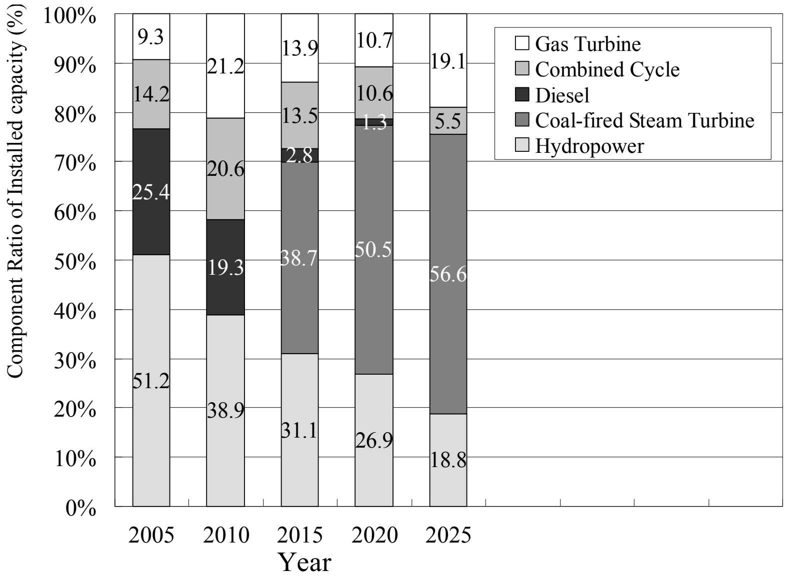


Figure 6.4.14 Component Ratio of Installed Capacity by Plant Type
(Hydropower Development Oriented Scenario)

(iii) Changes in annual generation energy

Table 6.4.22 and Figures 6.4.15 and 6.4.16 show changes in the annual generation energy and component ratios of plant type, under the hydropower development Oriented scenario.

Table 6.4.22 Annual Generation Energy and Component Ratio
(Hydropower Development Oriented Scenario)

(Unit: GWh, %)

Plant Type	Year									
	2005		2010		2010		2015		2020	
Hydropower	4,464	(52.2%)	4,464	(36.7%)	5,440	(30.8%)	5,871	(22.9%)	5,871	(15.9%)
Coal-fired Steam Turbine	0	(0.0%)	0	(0.0%)	11,427	(64.6%)	18,852	(73.5%)	29,840	(81.0%)
Diesel	3,369	(39.4%)	3,543	(29.1%)	296	(1.7%)	145	(0.6%)	0	(0.0%)
Combined Cycle	630	(7.4%)	2,639	(21.7%)	386	(2.2%)	565	(2.2%)	428	(1.2%)
Gas Turbine	86	(1.0%)	1,521	(12.5%)	135	(0.8%)	219	(0.9%)	697	(1.9%)
Total	8,549	(100.0%)	12,167	(100.0%)	17,684	(100.0%)	25,652	(100.0%)	36,836	(100.0%)

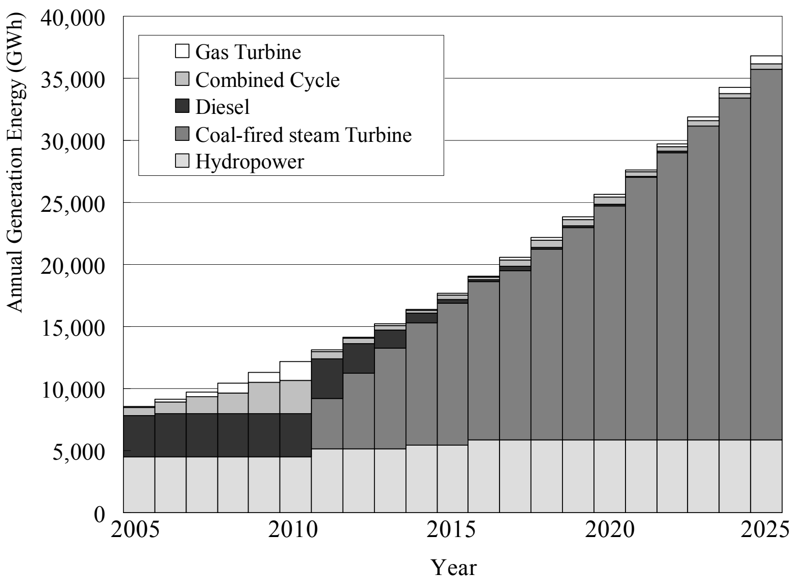


Figure 6.4.15 Generation Energy Additions by Plant Type
(Hydropower Development Oriented Scenario)

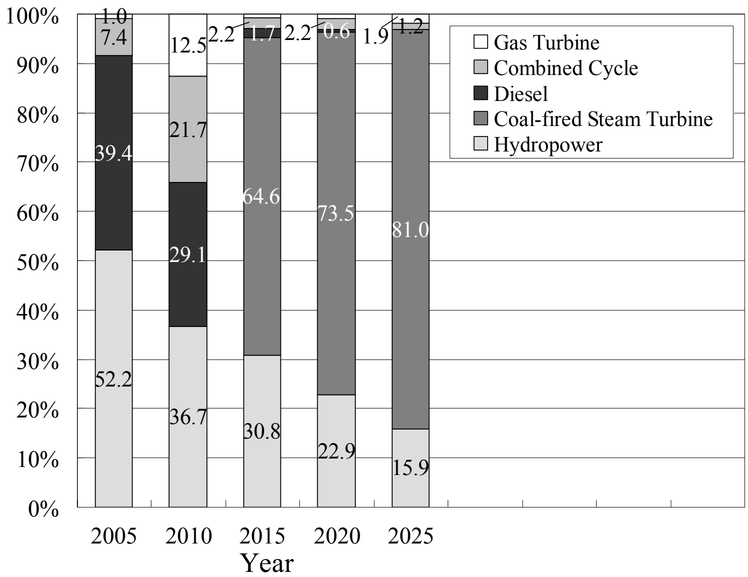


Figure 6.4.16 Component Ratio of Annual Generation Energy
(Hydropower Development Oriented Scenario))

(iv) Plant factor

Table 6.4.23 and Figure 6.4.17 show changes in the annual plant factor by plant type under the hydropower development oriented scenario.

The changes in annual plant factor for each plant type are almost identical to the changes in annual plant factor under the large-scale thermal power development scenario.

Table 6.4.23 Annual Plant Factor (Hydropower Development Oriented Scenario)

(Unit: %)

Plant Type	Year				
	2005	2010	2015	2020	2025
Hydropower	(43.0%)	(43.0%)	(42.9%)	(42.0%)	(42.0%)
Coal-fired Steam Turbine			(72.5%)	(71.7%)	(71.0%)
Diesel	(65.4%)	(68.8%)	(25.8%)	(20.7%)	
Combined Cycle	(21.9%)	(48.0%)	(7.0%)	(10.3%)	(10.5%)
Gas Turbine	(4.6%)	(26.9%)	(2.4%)	(3.9%)	(4.9%)

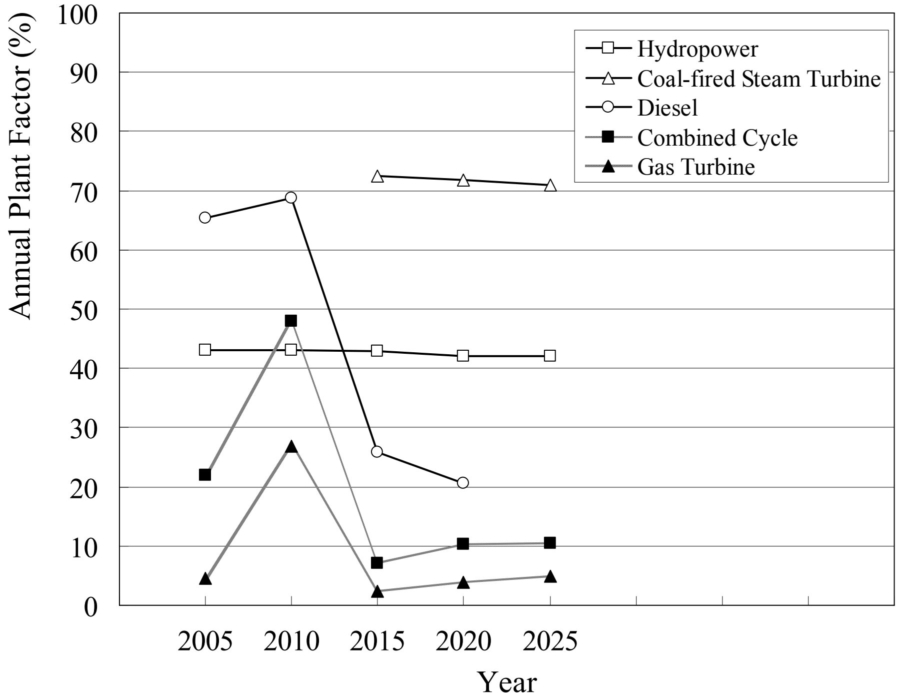


Figure 6.4.17 Changes in Annual Plant Factor (Hydropower Development Oriented Scenario)

(v) Fuel consumption

Table 6.4.24 and Figure 6.4.18 show changes in fuel consumption under the hydropower development oriented scenario.

The development of hydropower plants in four locations, representing a total capacity of 261 MW, reduces the annual consumption of coal in the 2025 profile by 357 kilo metric tons compared to the large-scale thermal power development scenario. This represents 3.2% of annual fuel consumption.

Table 6.4.24 Fuel Consumption (Hydropower Development Oriented Scenario)

Fuel Type		Year				
		2005	2010	2015	2020	2025
Auto Diesel Oil	(million Liter)	103	914	101	163	292
Furnace Oil	(million Liter)	451	490			
Residual Oil	(million Liter)	281	281	65	31	
Naphtha	(million Liter)	53	112	21	25	21
Coal	(1,000 MTon)			4,159	6,862	10,862

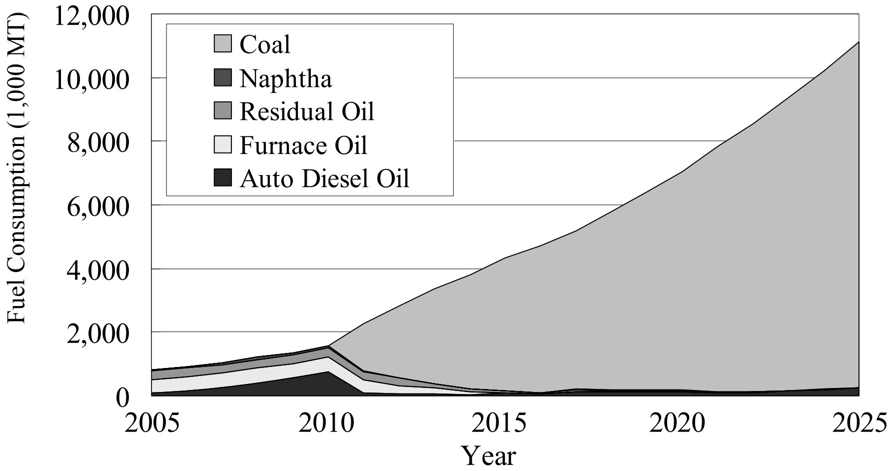


Figure 6.4.18 Changes in Fuel Consumption (Hydropower Development Oriented Scenario)

(vi) Capital investment

Table 6.4.25 shows the amount of new capital investment under the hydropower development oriented scenario.

The amount of new capital investment up to 2025 will be approximately US$7.84 billion. Promotion of hydropower development increases the figure by US$470 million when compared to the one of the large-scale thermal power development scenario.

Table 6.4.25 Capital Investment Cost (Hydropower development Oriented scenario)

(Unit: million USD)

Plant Type	Period				Total
	2006 - 2010	2011 - 2015	2016 - 2020	2021 - 2025	
Hydropower	0.0	372.6	487.6	0.0	860.2
Coal-fired Steam Turbine	0.0	2,347.4	1,564.9	2,347.4	6,259.7
Diesel	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	0.0	0.0	0.0	0.0
Gas Turbine	244.2	0.0	45.7	433.3	723.1
Total	244.2	2,720.0	2,098.2	2,780.6	7,843.0

Note: Investment cost for fixed development project, Kerawalapitiya CCGT and Upper Kotmale hydropower project is excluded.

(vii) System Cost

Table 6.4.26 shows system cost up to 2025 if hydropower development is promoted.

System costs to 2025 are US$6.025 billion (calculated at 2005 prices). This is higher than the figure under the large-scale thermal power Development scenario, but the difference between the two scenarios is negligible at US$104 million (approximately 1.8%).

The development of several hydropower plants in this scenario increases investment costs by US$190 million in system cost compared to the large-scale thermal power generation development scenario, but reduces fuel costs by US$79 million in system cost.

Table 6.4.26 System Cost to 2025 (Hydropower Development Oriented Scenario)

(Unit: million USD, Prices at Jan. 2005)

Item	Amount
(1) investment Cost	1,846
(2) Fuel Cost	3,472
(3) Operation and Maintenance cost	662
(4) Energy Not Served Cost	44
System Cost (1) + (2) + (3) + (4)	6,025

(4) Natural Gas Supply Scenario

(i) Number of developed generation units and capacity of developed plants

Table 6.4.27 shows the results of a WASP simulation (number of units and capacity developed) under the natural gas supply scenario.

Table 6.4.27 Number of Developed Generation Unit and Developed Capacity
(Natural Gas Supply Scenario)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel (Unit: MW)

Fixed Development Plant

Year	Peak Demand (MW)	Thermal Power												Hydropower				
		ST			GT			CCGT					DS	Upper Kotmale	Broadlands	Gin Ganga	Moragolla	Uma Oya
		Oil -fired 150MW	Oil -fired 300MW	Coal -fired 300MW	Oil -fired 35MW	Oil -fired 75MW	Oil -fired 105MW	Kerawala -pitiya 150MW	Oil -fired 150MW	Gas -fired 150MW	Oil -fired 300MW	Gas -fired 300MW	Diesel 100MW	150MW	35MW	49MW	27MW	150MW
2005	1,768																	
2006	1,884																	
2007	2,019																	
2008	2,168																	
2009	2,336				35		210	300										
2010	2,517					75	210											
2011	2,712			600										150				
2012	2,921			300														
2013	3,146			300														
2014	3,389			300														
2015	3,657			300														
2016	3,943			300														
2017	4,250			300														
2018	4,579			300														
2019	4,931			300														
2020	5,306			300			105											
2021	5,708			300			105											
2022	6,138			300	70		105											
2023	6,599			300								300						
2024	6,599			300			420											
2025	7,092			300								300						
Number of Units Developed		0	0	16	3	1	11	2	0	0	0	2	0	1	0	0	0	0
		Total: 36 units																
Developed Capacity (MW)		0	0	4,800	105	75	1,155	300	0	0	0	600	0	150	0	0	0	0
		Total: 7,185 MW																

Table 6.4.27 indicates the following:

a) Oil-fired steam turbine thermal power plants

The number of new development units in this category is zero, just under the large-scale thermal power development scenario.

b) Coal-fired steam turbine thermal power plants

Sixteen new coal-fired thermal power plants will be developed by 2025 in this scenario, representing a total capacity of 4,800 MW. This is a reduction of 1 unit (300 MW) against the large-scale thermal power development scenario, because the introduction of natural gas-fired combined cycle thermal power from 2020 will reduce the required capacity of coal-fired thermal power plants from that period.

c) Oil-fired gas turbine thermal power plants

As with coal-fired thermal power, the introduction of natural gas-fired combined cycle thermal power facilities from 2020 should see 15 units developed by 2025 in this plant type to provide a total capacity of 1,335 MW, a reduction of 280 MW compared with the development under large-scale thermal power development scenario.

d) Oil-fired combined cycle thermal power plants

Just under the large-scale thermal power development scenario, the oil-fired thermal power plants developed by 2025 will consist only of the 300 MW Kerawalapitiya facility, which is a fixed development project.

e) Natural gas-fired combined cycle power plants

Between 2020 and 2025, two units fueled by natural gas, a cheaper fuel than auto diesel oil, will be developed. These plants will represent a total capacity of 600 MW. However, despite the fact that the scenario assumes a supply of natural gas from 2020, the earliest year for development of a natural gas-fired combined cycle thermal power plant will be 2023. It will therefore not be until a later period that the effects of the introduction of natural gas become apparent.

f) Diesel power plants

The number of new development units in this category is zero, just under the large-scale thermal power development scenario.

g) Hydropower plants

Just under the large-scale thermal power development scenario, the hydropower facilities developed by 2025 will be at Upper Kotmale (150 MW), which is a fixed project for development.

(ii) Installed capacity

Table 6.4.28 and Figures 6.4.19 and 6.4.20 show changes in the installed capacity of power plants and their component ratios by plant type under the natural gas supply scenario.

In 2025, the component ratio of coal-fired thermal power plants will make up 56.2% in total, a figure approximately 4% lower than the percentage under the large-scale thermal power development scenario. In addition, in 2025, combined cycle thermal power plant represent approximately 12.5% of all plants, which is around two times the figure under the large-scale thermal power development scenario.

Table 6.4.28 Installed Capacity and Component Ratios (Natural Gas Supply Scenario)

(Unit: MW, %)

Plant Type	Year									
	2005		2010		2010		2015		2020	
Hydropower	1,185.0	(51.2%)	1,185.0	(38.9%)	1,335.0	(29.4%)	1,335.0	(22.3%)	1,335.0	(15.6%)
Coal-fired Steam Turbine	0.0	(0.0%)	0.0	(0.0%)	1,800.0	(39.7%)	3,300.0	(55.2%)	4,800.0	(56.2%)
Diesel	587.8	(25.4%)	587.8	(19.3%)	131.0	(2.9%)	80.0	(1.3%)	0.0	(0.0%)
Combined Cycle	328.0	(14.2%)	628.0	(20.6%)	628.0	(13.8%)	628.0	(10.5%)	1,065.0	(12.5%)
Gas Turbine	215.0	(9.3%)	645.0	(21.2%)	645.0	(14.2%)	635.0	(10.6%)	1,335.0	(15.6%)
Total	2,315.8	(100.0%)	3,045.8	(100.0%)	4,539.0	(100.0%)	5,978.0	(100.0%)	8,535.0	(100.0%)

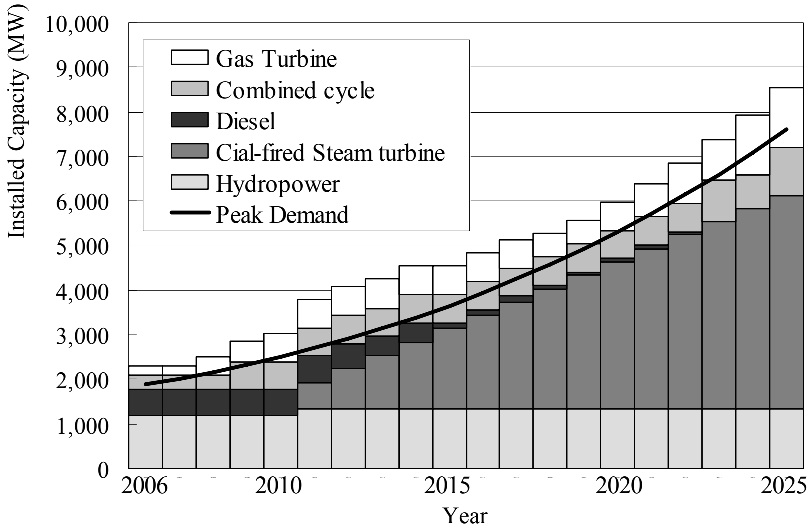


Figure 6.4.19 Capacity Additions by Plant Type (Natural Gas Supply Scenario)

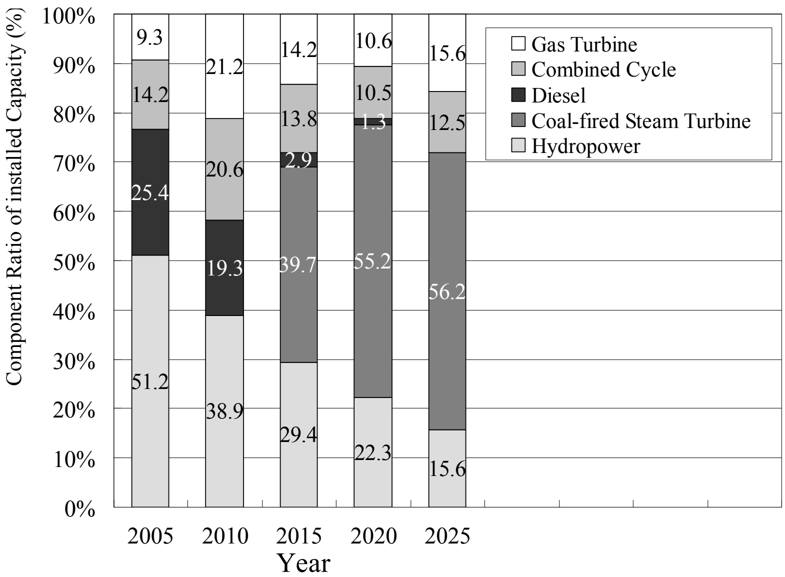


Figure 6.4.20 Component Ratio of Installed Capacity by Plant Type (Natural Gas Supply Scenario)

(iii) Changes in annual generation energy

Table 6.4.29 and Figures 6.4.21 and 6.4.22 show changes in the annual generation energy and component ratio of power plants by plant type under the natural gas supply scenario.

The generation energy of combined cycle power plants has increased, generation mix in the system is almost same as that under large-scale thermal power development scenario.

Table 6.4.29 Annual Generation Energy and Component Ratio (Natural Gas Supply Scenario)

(Unit: GWh, %)

Plant Type	Year									
	2005		2010		2010		2015		2020	
Hydropower	4,464	(52.2%)	4,464	(36.7%)	4,994	(28.2%)	4,994	(19.5%)	4,994	(13.6%)
Coal-fired Steam Turbine	0	(0.0%)	0	(0.0%)	11,681	(66.1%)	19,944	(77.7%)	30,401	(82.5%)
Diesel	3,369	(39.4%)	3,543	(29.1%)	355	(2.0%)	98	(0.4%)	0	(0.0%)
Combined Cycle	630	(7.4%)	2,639	(21.7%)	482	(2.7%)	426	(1.7%)	935	(2.5%)
Gas Turbine	86	(1.0%)	1,521	(12.5%)	172	(1.0%)	190	(0.7%)	506	(1.4%)
Total	8,549	(100.0%)	12,167	(100.0%)	17,684	(100.0%)	25,652	(100.0%)	36,836	(100.0%)

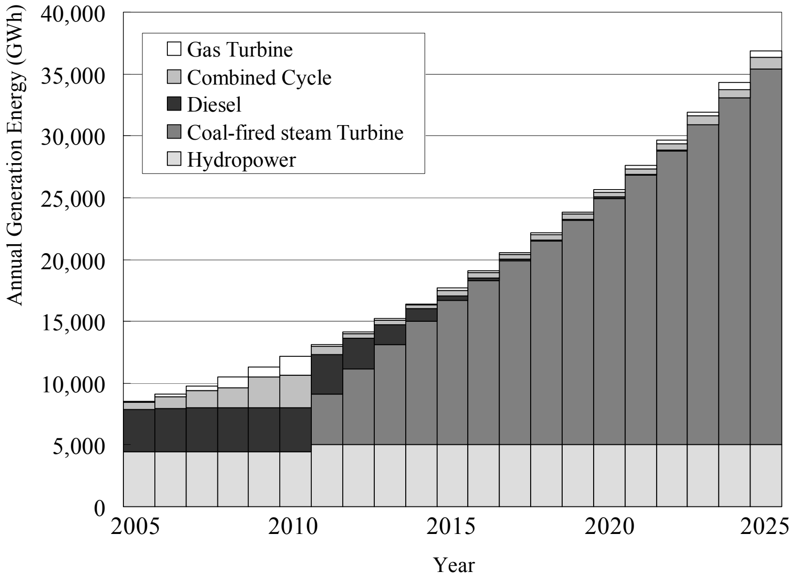


Figure 6.4.21 Generation Energy Additions by Plant Type (Natural Gas Supply Scenario)

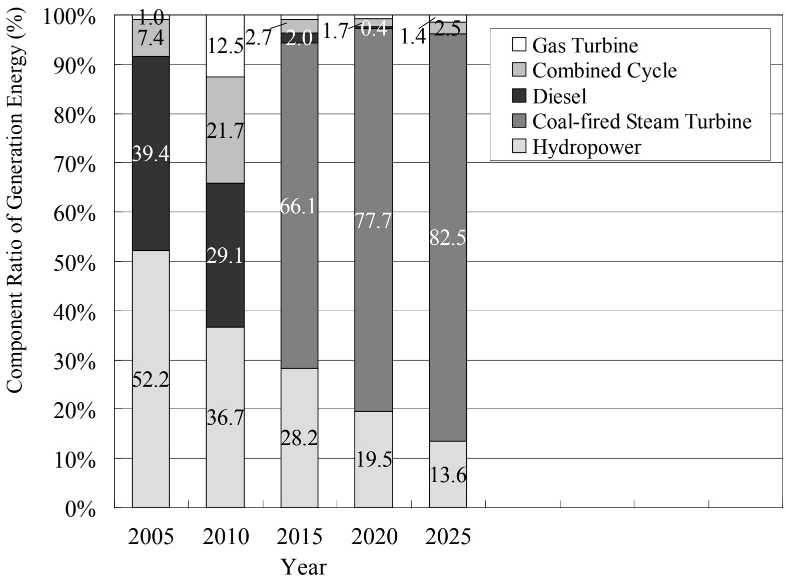


Figure 6.4.22 Component Ratio of Annual Generation Energy (Natural Gas Supply Scenario)

(iv) Plant factor

Table 6.4.30 and Figure 6.4.23 show changes in annual plant factor by plant type under the natural gas supply scenario.

The changes in annual plant factor for each plant type are almost identical to the changes in annual plant factors under the large-scale thermal power development scenario.

Table 6.4.30 Annual Plant Factor (Natural Gas Supply Scenario)

(Unit: %)

Plant Type	Year				
	2005	2010	2015	2020	2025
Hydropower	(43.0%)	(43.0%)	(42.7%)	(42.7%)	(42.7%)
Coal-fired Steam Turbine			(74.1%)	(69.0%)	(72.3%)
Diesel	(65.4%)	(68.8%)	(30.9%)	(14.0%)	
Combined Cycle	(21.9%)	(48.0%)	(8.8%)	(7.7%)	(10.0%)
Gas Turbine	(4.6%)	(26.9%)	(3.0%)	(3.4%)	(4.3%)

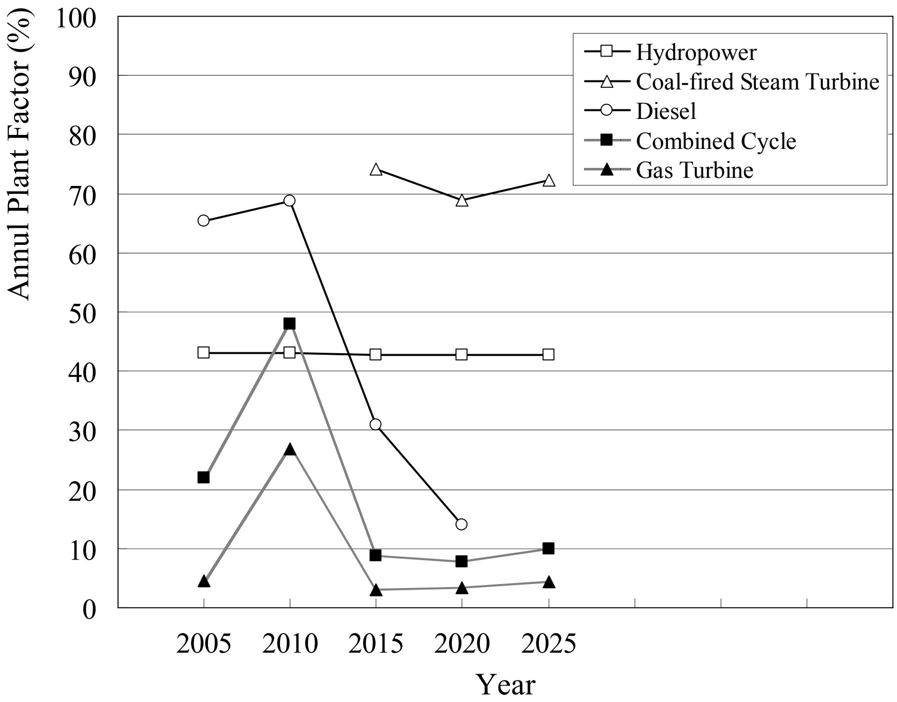


Figure 6.4.23 Changes in Annual Plant Factor (Natural Gas Supply Scenario)

(v) Fuel consumption

Table 6.4.31 shows changes in fuel consumption under the natural gas supply scenario.

The development of natural gas-fired combined cycle power plants, representing a total capacity of 600 MW, reduces the annual consumption of coal in the 2025 profile by 143 kilo metric tons in comparison to the large-scale thermal power development scenario. Similarly, the annual consumption of auto diesel oil is reduced by 108 million liters.

The annual consumption of natural gas in 2025 is 6,690 million scf, corresponding to approximately 6.69 million MMBTU.

Table 6.4.31 Fuel Consumption (Natural Gas supply Scenario)

Fuel Type		Year				
		2005	2010	2015	2020	2025
Auto Diesel Oil	(million Liter)	103	914	127	79	163
Furnace Oil	(million Liter)	451	490			
Residual Oil	(million Liter)	281	281	78	21	
Naphtha	(million Liter)	53	112	27		
Coal	(1,000 MTon)			4,252	7,260	11,066
Natural Gas	(million scf)				2,480	6,690

(vi) Capital investment

Table 6.4.32 shows the amount of new capital investment under the natural gas supply scenario.

The amount of new capital investment to 2025 is approximately US$7.31 billion. Development costs for combined cycle thermal power plants are lower than the corresponding costs for coal-fired thermal power plants, meaning there is a slight reduction (US$65 million) in the amount of capital investment in this scenario as compared to the large-scale thermal power generation development scenario, but the difference is negligible.

Table 6.4.32 Capital Investment Cost (Natural gas Supply Scenario)

(Unit: million USD)

Plant Type	Period				Total
	2006 - 2010	2011 - 2015	2016 - 2020	2021 - 2025	
Hydropower	0.0	0.0	0.0	0.0	0.0
Coal-fired Steam Turbine	0.0	2,347.4	1,956.2	1,956.2	6,259.7
Diesel	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	0.0	0.0	440.8	440.8
Gas Turbine	244.2	0.0	45.7	318.7	608.5
Total	244.2	2,347.4	2,001.8	2,715.6	7,309.0

Note: Investment cost for fixed development project, Kerawalapitiya CCGT and Upper Kotmale hydropower project is excluded.

(vii) System Cost

Table 6.4.33 shows system cost up to 2025 under the natural gas supply scenario.

System costs to 2025 total US$5.907 billion (calculated at 2005 prices). This is lower than the figure under the large-scale thermal power development scenario, but the difference between the two scenarios is negligible at US$14 million (approximately 0.2%).

The development of natural gas-fired combined cycle thermal power plants under this scenario reduces fuel costs by US$16 million against the large-scale thermal power generation development scenario.

Table 6.4.33 System Cost to 2025 (Natural Gas Supply Scenario)

(Unit: million USD, Prices at Jan. 2005)

Item	Amount
(1) investment Cost	1,658
(2) Fuel Cost	3,535
(3) Operation and Maintenance cost	669
(4) Energy Not Served Cost	46
System Cost (1) + (2) + (3) + (4)	5,907

6.5 Evaluation of Development Plans

The development plans formulated in each scenario were evaluated from a variety of perspectives. The evaluation criteria employed to evaluate the development plans are shown below.

1) System costs
   Economic efficiency of development plan
2) Operation of system
   Flexibility of system operation, problems in ensuring stable supply, etc.
3) Finances
   Effect on finances of CEB
4) Effect on natural and social environments
   Effect of development and operation of facility on surrounding natural and social environments
5) Others
   Other criteria used for evaluation

(1) System Costs

The system costs up to 2025 for each development plans discussed in Section 6.4.3 are shown again in Table 6.5.1.

Table 6.5.1 System Costs up to 2025 for each Development Plan

(Unit: million USD, NPV at 2005)

Development Scenario		Investment Cost	Fuel Cost	O&M Cost	ENS* Cost	**System Cost**
Large-scale Thermal Power Development		1,656	3,551	669	45	**5,921**
No Large-scale Thermal Power Development	Low-speed Diesel	2,085	4,557	631	43	**7,316**
	Middle-speed Diesel	1,166	4,508	632	42	**6,348**
Hydropower Development Oriented		1,846	3,472	662	44	**6,025**
Natural Gas Supply		1,658	3,535	669	46	**5,907**

*Note: Energy Not Served Cost

(2) System Operation

(i) Problems in system operation due to installation of a large number of diesel generators

Under the no development of large-scale thermal power scenario, a large number of small (10 MW) diesel generators will be installed to make up the future power system.

Governor-free operation of diesel generators is generally difficult, making it impossible to ensure sufficient spinning reserve in a system made up entirely of diesel generators.

It would therefore be impossible to recover the system to the appropriate level in the event of a drop in frequency, and there would also be the possibility that the diesel generators would stop automatically to prevent damage from such a drop in frequency. If this type of situation were to arise, it would not be possible to ensure the appropriate frequency throughout the system, leading to the possibility of a serious interruption of supply. These issues are discussed in detail in Section 7.7.3 (7).

(ii) Effect of accidental outage of one generation unit on system operation

Sudden breakdowns in generation units cause system frequency to drop. When this happens, the system seeks to recover the frequency in the system to the appropriated level by using spinning reserve in the system. However, if the capacity of the generator that has broken down is particularly large, it may be impossible to operate the system in this way.

As discussed in Section 6.4.3, the results of WASP simulations showed that 300 MW coal-fired thermal power facilities would be developed in all scenarios other than under the no development of large-scale thermal power scenario. Considering the scale of demand across the system as a whole, if a single one of these plants was to break down before around 2017, there is a chance that the stability of supply would be affected. However, regular system operation would be possible if appropriate countermeasures were adopted, including the employment of small generator units for coal-fired plant and appropriate operation of the system in the event of a breakdown. This is discussed in detail in Section 7.7.3 (6).

(3) Impacts on CEB Finances

The financial status of the CEB is particularly poor at present, and improvement of this situation is an essential prerequisite of sound management in the future.

Because they are considerably higher than other costs, the cost of developing power plants and operating them will have a significant effect on the CEB's finances. The Study Team therefore examined the effect of each development plan on the future financial status of the CEB. The details of this examination are presented in Sections 8.5 and 8.6.

Fuel costs represent a considerable proportion of total costs. Fuel costs under the no large-scale thermal power development scenario are higher than in other scenarios, and there is therefore reason for concern that this scenario would cause the CEB's financial status to decline in future. By contrast, the introduction of coal-fired thermal power in the other scenarios enables generation costs to be maintained at a low level, and these scenarios can therefore be expected to improve the CEB's finances.

(4) Effect on Natural and Social Environments

We evaluated the effect of each development plan on the surrounding natural and social environments.

As discussed in Section 9.4.2 of Chapter 9, we formulated an environmental scoping table for each plant type, and converted the effect of development and operation on environment into a numerical score.

Using this scoping table, we calculated an environmental impact score for each of the development plans based on the number of new generation units of each type developed by 2025 and their average plant factor until 2025.

Table 6.4.30 shows the environmental impact scores calculated for the development plans under each scenario.

Table 6.5.2 Environmental impact score for each development plan

Development Scenario		Environmental Impact Score
Development of Large-scale Thermal Power Plant		1,954 points
No Development of Large-scale Thermal Power Plant	Low-speed Diesel	2,428 points
	Middle-speed Diesel	2,452 points
Hydropower Development Oriented		2,036 points
Natural Gas Supply		1,950 points

Note: larger score means larger impact

The overall score for no large-scale thermal power development scenario is higher than those for other scenarios, because of the development of a larger number of new power plants under this scenario, and the fact that diesel power plants have a slightly higher environmental impact score per unit of capacity than other plants.

Despite the fact that the hydropower generation development oriented scenario has a low score for environmental impact from the perspectives of pollution and global warming, the scenario has a major impact on the social environment, involuntary resettlement of local residents due to appearance of reservoirs, etc., and its score is therefore also higher than that of the large-scale thermal power generation development scenario.

The employment of natural gas under the natural gas supply scenario means that the level of environmental impact in terms of pollution is lower in this scenario than in others, but the impact is higher from other perspectives. For example, combined cycle equipment requires construction of a larger facility, which in turn has a greater effect on the surrounding landscape. The discharge of hot waste water is another factor. Overall, the score under this scenario is almost equal to the score under the large-scale thermal power development scenario.

(5) Others

The natural gas supply scenario has been adopted as a development scenario by considering the diversification of energy sources in Sri Lanka.

However, at present there are no concrete natural gas projects on the table, and a past feasibility study[60] indicated that the low domestic demand for natural gas would make it difficult to guarantee the economic feasibility of a project.

It is therefore impossible to state at present that natural gas will definitely be introduced in the future.

In addition, the supply price for natural gas used in this scenario is purely hypothetical. Given that the supply price of natural gas varies widely from project to project, there is no guarantee that this price will be the actual price.

The lack of firm commitment to the implementation of projects to ensure the supply of natural gas therefore makes us doubt the feasibility of this scenario as compared to the other scenarios.

Based on the combined results of these evaluations from a variety of perspectives, the large-scale thermal power generation development scenario was made the base case in formulating the development plan, for the reasons discussed below.

Table 6.5.3 Results of Development Plan Evaluations

Development Scenario	Total Costs up to 2025*1	System Operation	CEB Finances	Environmental Impact Score	Others
Development of Large-scale TPP	5,921 MUSD	stable operation	improved	1,954 points	
No Development of Large-scale TPP*2	7,316 MUSD	with possibility for total system failure	probable collapse	2,428 points	
Hydropower-Oriented	6,025 MUSD	stable operation	improved	2,036 points	
Natural Gas Supply (in and after 2020)	5,907 MUSD	stable operation	improved	1,950 points	lack of clear prospects for natural gas introduction

*1 : 2005 NPV
*2 : In the case of low-speed generation units

- No Large-scale thermal power development scenario

  This scenario was inferior to the other scenarios from the perspective of economic efficiency, and evaluation results indicated a high possibility that it would cause the financial status of the CEB to deteriorate. The scenario was also judged as resulting in a higher level of impact on environment than the other scenarios. In addition, the fact that the system would be almost exclusively reliant on diesel generators raises the possibility of serious interruption of power supply if there is a drop in frequency in the system.

- Hydropower generation development promotion scenario

  This scenario was slightly inferior to the large-scale thermal power development scenario in terms of economic efficiency, and its impact on the surrounding environment was also a little bit greater.

- Natural gas introduction scenario

  Plans for the introduction of natural gas are poorly developed, and the potential for realization of this development scenario is at present lower than that of the other scenarios. In addition, the supply price for natural gas used in this survey is entirely hypothetical.

[60] Natural Gas Option Study by USAID June 2003

6.6 Sensitivity Analysis

For the base case, the Study Team carried out a sensitivity analysis on the contents as follows.

1) Fuel Price (Crude Price[61] of 60 USD/BBL and 80 USD/BBL)
2) Discount Rate (2% and 6%)

(1) Result of Sensitivity Analysis on Fuel Price

Fuel prices utilized in the generation development plan were set on the basis of crude oil prices in Colombo. In the base case, the crude oil price was about 41 US dollars per barrel.

If crude oil prices in Colombo rose to 80 US dollars per barrel, hydropower plants would take precedence over thermal power ones in development, and an additional three with a combined capacity of 234 MW would be built over the subject period. The addition of coal-fired capacity would be 300 MW higher than in the base case, and that of gas turbine capacity, 405 MW lower.

Tables 6.6.1 and 6.6.2 show the results of a WASP simulation (number of units and capacity developed) for the sensitivity analysis on fuel price.

Table 6.6.1 Number of Developed Generation Unit and Developed Capacity (Crude Oil 60 USD/BBL)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel (Unit: MW)

Year	Peak Demand (MW)	Thermal Power										Hydropower				
		ST			GT			CCGT			DS	Upper Kotmale	Broadlands	Gin Ganga	Moragolla	Uma Oya
		Oil -fired 150MW	Oil -fired 300MW	Coal -fired 300MW	Oil -fired 35MW	Oil -fired 75MW	Oil -fired 105MW	Kerawala -pitiya 150MW	Oil -fired 150MW	Oil -fired 300MW	Diesel 100MW	150MW	35MW	49MW	27MW	150MW
2005	1,768															
2006	1,884															
2007	2,019															
2008	2,168									Fixed Development Plant						
2009	2,336				70	75	105	300								
2010	2,517					150	105									
2011	2,712			600								150				
2012	2,921			300												
2013	3,146			300												
2014	3,389			300												
2015	3,657			600												
2016	3,943															
2017	4,250			300												
2018	4,579			300												
2019	4,931			300												
2020	5,306			300			105									
2021	5,708			600												
2022	6,138			300												
2023	6,599			300			315									
2024	6,599			600			105									
2025	7,092			300	35		210									
Number of Units Developed		0	0	18	3	3	9	2	0	0	0	1	0	0	0	0
		Total: 36 units														
Developed Capacity (MW)		0	0	5,400	105	225	945	300	0	0	0	150	0	0	0	0
		Total: 7,125 MW														

[61] CIF price at Colombo port

Table 6.6.2 Number of Developed Generation Unit and Developed Capacity (Crude Oil 80 USD/BBL)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel (Unit: MW)

Year	Peak Demand (MW)	Thermal Power										Hydropower				
		ST			GT			CCGT			DS	Upper Kotmale	Broadlands	Gin Ganga	Moragolla	Uma Oya
		Oil -fired	Oil -fired	Coal -fired	Oil -fired	Oil -fired	Oil -fired	Kerawala -pitiya	Oil -fired	Oil -fired	Diesel					
		150MW	300MW	300MW	35MW	75MW	105MW	150MW	150MW	300MW	100MW	150MW	35MW	49MW	27MW	150MW
2005	1,768															
2006	1,884															
2007	2,019															
2008	2,168									Fixed Development Plant						
2009	2,336				105	150		300								
2010	2,517					150	105									
2011	2,712			600								150	35			
2012	2,921			300												
2013	3,146			300												
2014	3,389			300										49		
2015	3,657			600												
2016	3,943															
2017	4,250			300												
2018	4,579			300												
2019	4,931			300												
2020	5,306			300												
2021	5,708			600												
2022	6,138			300												
2023	6,599			300	70		210									
2024	6,599			600			105									
2025	7,092			300			315									
Number of Units Developed		0	0	18	5	4	7	2	0	0	0	1	1	1	0	0
		Total: 39 units														
Developed Capacity (MW)		0	0	5,400	175	300	735	300	0	0	0	150	35	49	0	0
		Total: 7,144 MW														

(2) Result of Sensitivity Analysis on Discount Rate

At a discount rate of 2 %, all candidate hydropower sites would be developed, and an additional five plants with a combined capacity of 411 MW would be built over the subject period. As compared to the base case, the addition of coal-fired capacity would be 600 MW higher, and that of gas turbine capacity, 875 MW lower. At a discount rate of 6 %, the addition mix over the subject period would be the same as in the base case.

Tables 6.6.3 and 6.6.4 show the results of a WASP simulation (number of units and capacity developed) for the sensitivity analysis on discount rate.

Table 6.6.3 Number of Developed Generation Unit and Developed Capacity (Discount Rate 2 %)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel (Unit: MW)

Year	Peak Demand (MW)	Thermal Power										Hydropower				
		ST			GT			CCGT			DS	Upper Kotmale	Broadlands	Gin Ganga	Moragolla	Uma Oya
		Oil -fired 150MW	Oil -fired 300MW	Coal -fired 300MW	Oil -fired 35MW	Oil -fired 75MW	Oil -fired 105MW	Kerawala -pitiya 150MW	Oil -fired 150MW	Oil -fired 300MW	Diesel 100MW	150MW	35MW	49MW	27MW	150MW
2005	1,768															
2006	1,884															
2007	2,019															
2008	2,168															
2009	2,336				35		210	300								
2010	2,517					75	210									
2011	2,712			600								150	35			
2012	2,921			300												
2013	3,146			300												
2014	3,389			300										49	27	
2015	3,657			600												
2016	3,943															150
2017	4,250			300												
2018	4,579			300												
2019	4,931			300												
2020	5,306			300												
2021	5,708			300												
2022	6,138			600												
2023	6,599			300			105									
2024	6,599			600			105									
2025	7,092			600												
Number of Units Developed		0	0	19	1	1	6	2	0	0	0	1	1	1	1	1
		Total: 34 units														
Developed Capacity (MW)		0	0	5,700	35	75	630	300	0	0	0	150	35	49	27	150
		Total: 7,151 MW														

Fixed Development Plant

Table 6.6.4 Number of Developed Generation Unit and Developed Capacity (Discount Rate 6 %)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel (Unit: MW)

Year	Peak Demand (MW)	Thermal Power										Hydropower				
		ST			GT			CCGT			DS	Upper Kotmale	Broadlands	Gin Ganga	Moragolla	Uma Oya
		Oil -fired 150MW	Oil -fired 300MW	Coal -fired 300MW	Oil -fired 35MW	Oil -fired 75MW	Oil -fired 105MW	Kerawala -pitiya 150MW	Oil -fired 150MW	Oil -fired 300MW	Diesel 100MW	150MW	35MW	49MW	27MW	150MW
2005	1,768															
2006	1,884															
2007	2,019															
2008	2,168															
2009	2,336				35		210	300								
2010	2,517					75	210									
2011	2,712			600								150				
2012	2,921			300												
2013	3,146			300												
2014	3,389			300												
2015	3,657			300												
2016	3,943			300												
2017	4,250			300												
2018	4,579			300												
2019	4,931			300												
2020	5,306			300			105									
2021	5,708			300			105									
2022	6,138			300			210									
2023	6,599			600												
2024	6,599			300	35		315									
2025	7,092			300			315									
Number of Units Developed		0	0	17	2	1	14	2	0	0	0	1	0	0	0	0
		Total: 37 units														
Developed Capacity (MW)		0	0	5,100	70	75	1,470	300	0	0	0	150	0	0	0	0
		Total: 7,165 MW														

Fixed development Plant

6.7 Selection of Development Site

In formulating plans for the extension of the power system, locations for future development of power plants must be specified on the basis of the generation development plans that have been established. Specific locations for development have therefore been determined for each year and each plant type for the development of model thermal power plant shown in the results of WASP simulation.

6.7.1 Areas for Supply-Demand Balance

The selection of sites for power plants has a significant effect on plans to enhance the power system. Selecting an inappropriate site may hinder economical expansion of transmission system or the efficient operation of the system.

To minimize the construction costs involved in expanding the power system and reduce transmission losses, it is desirable to place the generation unit as close as possible to the area whose demand it will be supplying.

On this basis, the Study Team divided the country into two areas, with consideration of the distribution of power demand in different regions and current location of transmission system and specified the development site for power plants to keep well-balanced supply-demand in each area.

Figure 6.7.1 shows the forecasted maximum demand in 2025 by region.

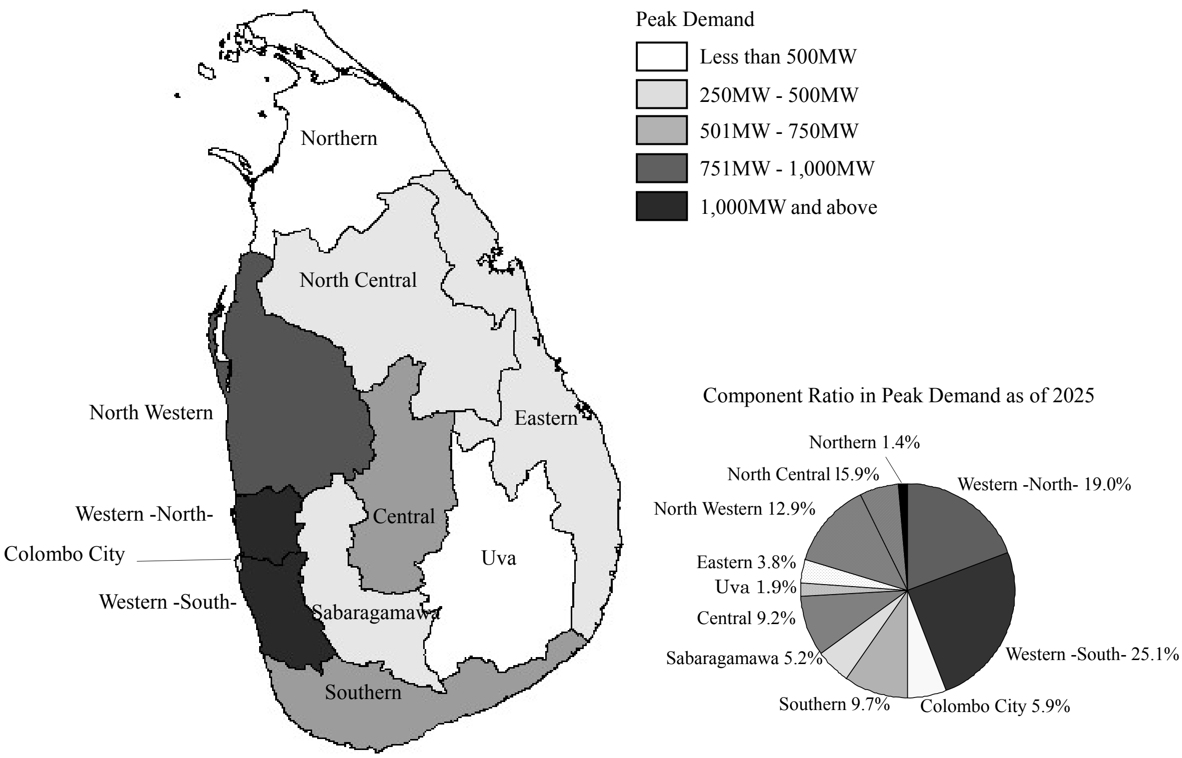


Figure 6.7.1. Forecasted Maximum Demand in 2025 by Region (Base Growth Scenario)

Figure 6.7.1 shows demand to be higher in the northwestern, western and southern regions and higher in Colombo than in other regions. The Study Team has therefore divided the country into two areas in which balanced demand can be ensured: an area that encompasses the regions named as the Western-Southern Area and an area encompassing other regions as the Northern-Central-Eastern Area.

Figure 6.7.2 shows the areas the Study Team used for making supply-demand balance.

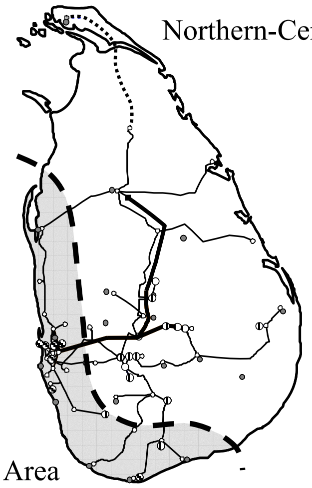


Figure 6.7.2. Areas for Supply-Demand Balance

6.7.2 Candidate Locations for Thermal Power Plants

(1) Candidate Locations for Coal-fired Thermal Power Facilities

As indicated in Section 6.2.8 (2), past surveys have been conducted of three potential locations for coal-fired thermal power plants: Around Puttalam, on the west coast, around Hambantota, on the south coast, and around Trincomalee, on the east coast. No surveys have been conducted in other areas, and the possibility of development of coal-fired thermal power plants in locations other than these three is at present unclear.

These three locations were therefore considered as the candidate locations for the development of coal-fired thermal power plant in the Study.

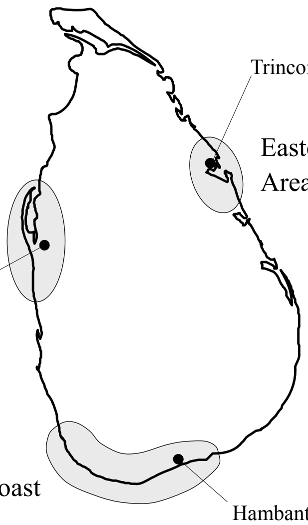


Figure 6.7.3 Prospective Areas for Development of Coal-fired Plants

(2) Candidate Locations for Gas Turbine Thermal Power Plants

Gas turbine thermal power plants are less location-dependent than coal-fired thermal power plants and other power plants, and there is accordingly a certain degree of flexibility in terms of the sites at which they can be placed. However, the efficient construction and operation of the power plants should be considered to decide the sites for development.

The Study Team selected sites for development of gas turbine power plant from among sites that were close to existing generation facilities, existing port facilities and areas in which the development of port facilities is planned.

6.8 Generation Development Plan (Base Case)

Table 6.8.1 shows details of the generation development plan (Base case).

Table 6.8.1 Details of Generation Development Plan (Base case)

Year	Coal-fired TPP	Gas Turbine TPP	Combined Cycle TPP	Hydropower Plant
2009		Kerawalapitiya 105MW Galle 105MW Trincomalee 35MW	Kerawalapitiya 300MW	
2010		Kerawalapitiya 105MW Paddirippu* 75MW Ampara* 75MW Jaffna 35MW		
2011	Western Coast Area (Puttalam) 600MW			Upper Kotmale 150MW
2012	Western Coast Area (Puttalam) 300MW			
2013	Southern Coast Area (Hambantota) 300MW			
2014	Southern Coast Area (Hambantota) 300MW			
2015	Southern Coast Area (Hambantota) 300MW			
2016	Southern Coast Area (Hambantota) 300MW			
2017	Eastern Coast Area (Trincomalee) 300MW			
2018	Eastern Coast Area (Trincomalee) 300MW			
2019	Eastern Coast Area (Trincomalee) 300MW			
2020	Western Coast Area 300MW	Puttalam 105MW Jaffna 35MW		
2021	Western Coast Area 300MW	Galle 105MW		
2022	Western Coast Area 300MW	Kerawalapitiya 105MW Puttalam 105MW		
2023	Western Coast Area 300MW	Panipitiya 210MW		
2024	Southern Coast Area 300MW	Sapugasukanda 105MW Sapugasukanda 105MW Panipitiya 105MW Matara 105MW		
2025	Southern Coast Area 600MW			
Total	5,100MW	1,620MW	300MW	150MW

*Note : Development of gas turbine power plants in eastern coast area premises implementation of a harbor project at Oluwil

In the southwestern area, the province with the most rapid demand growth would be the Western Province (northern half). For supply mainly to this area and Colombo, a coal-fired thermal power plant in the 900-megawatt class is to be constructed at Puttalam beginning in 2011. The demand is also forecast to increase in the Western Province (southern half) and the Southern Province, and this is motivating the construction of another coal-fired plant at Hambantota beginning in 2013. The plans for construction of a third coal-fired plant at Trincomalee beginning in 2017 are aimed at meeting the demand increase in the northern, central, and eastern area. The Study Team indicated places where coal-fired plants should be developed beginning in 2020 and it is necessary to make an effort for exploring new prospective candidate sites in these areas for future development and evaluating their feasibility.

The Study Team also examined the supply stability in the Northern, Eastern, and Southern provinces over the subject period. It found that it would be necessary to site power plant in these provinces for the purpose of system operation, and the Study Team put gas turbine thermal power plants in these areas.

6.9 Short-term Supply and Demand Balance

In the Study, new candidate units are developed from 2009 and a target level of supply reliability (LOLP of 0.822% or less) is achieved.

However, the only power generation facility scheduled for development between 2005 and 2008 is Kerawalapitiya combined cycle project, which is fixed for development in the Study. Therefore, the target supply reliability will not be reached between 2006 and 2008. This section discusses the short-term supply and demand balance by 2008.

6.9.1 Supply and Demand Balance by 2008

A study of the supply and demand balance by 2008 requires confirmation of demand, supply capacity and reliability index (LOLP). In addition, confirming the supply and demand balance without the supply capacity of the Kerawalapitiya thermal power plant, already fixed in the Study, it is possible to determine the effects if the project were not implemented or if its development were delayed.

Table 6.9.1 shows the supply and demand balance from 2006 and 2008 in the base case, and Table 6.9.2 shows the supply and demand balance for this period without Kerawalapitiya thermal power project.

Table 6.9.1 Supply and Demand Balance from 2006 to 2008 (Base Case)

		Year		
		2006	2007	2008
(a) Peak Demand	(MW)	1,884.0	2,019.0	2,168.0
(b) Installed capacity*	(MW)	2,295.8	2,295.8	2,495.8
・Existing	(MW)	2,295.8	2,295.8	2,295.8
・Additionally Developed	(MW)	0.0	0.0	200.0
(c) Available Generation Capacity (MW	(MW)	2,211.4	2,211.4	2,411.4
・Existing	(MW)	2,211.4	2,211.4	2,211.4
・Additionally Developed	(MW)	0.0	0.0	200.0
(d) Reserve Capacity (c) - (a)	(MW)	327.4	276.8	327.8
(e) Reserve Margin (d) ／ (a) x 10	(%)	17.4	13.7	15.1
(f) Supply Reliability (LOLP)	(%)	1.081	3.760	2.792

* Not considered seasonal derating for hydropower

Table 6.9.2 Supply and Demand Balance from 2006 to 2008 (Without Kerawalapitiya Project)

		Year		
		2006	2007	2008
(a) Peak Demand	(MW)	1,884.0	2,019.0	2,168.0
(b) Installed capacity*	(MW)	2,295.8	2,295.8	2,295.8
・Existing	(MW)	2,295.8	2,295.8	2,295.8
・Additionally Developed	(MW)	0.0	0.0	0.0
(c) Available Generation Capacity (MW	(MW)	2,211.4	2,211.4	2,411.4
・Existing	(MW)	2,211.4	2,211.4	2,211.4
・Additionally Developed	(MW)	0.0	0.0	200.0
(d) Reserve Capacity (c) - (a)	(MW)	327.4	276.8	127.8
(e) Reserve Margin (d) ／ (a) x 10	(%)	17.4	13.7	5.9
(f) Supply Reliability (LOLP)	(%)	1.081	3.760	7.948

* Not considered seasonal derating for hydropower

In the base case, the year when the supply and demand balance is most severe is year of 2007, with the supply reliability index rising to an LOLP of 3.760% (equivalent to 13.7 days per year). If Kerawalapitiya thermal power project is omitted, however, the most severe supply and demand balance occurs in 2008, with the supply reliability index rising to an LOLP of 7.948% (equivalent to 29 days per year).

The CEB has a target supply reliability of 0.822% (equivalent to 3 days per year). If power demand increases at the anticipated rate, power shortages will occur in 2006 and 2007. In particular, if Kerawalapitiya thermal power project is not implemented or its development is delayed, the duration of power interruption due to power shortage will rise to approximately one month per year. It is clear that the supply and demand situation will become an extremely critical one.

6.9.2 Additional Supply Capacity Required to Meet Target Supply Reliability

Using a WASP simulation, the Study Team calculated the supply capacity to meet the target supply reliability (LOLP of 0.822% or less).

It was decided that emergency diesel generators (unit capacity of 10MW) that can be installed to the system as one-year contract unit are prepared for the simulation.

Table 6.9.3 shows the necessary supply capacity to meet the target supply reliability for each of the years.

Table 6.9.3 Necessary Supply Capacity to meet Target Supply Reliability

	Capacity required to meet the target supply		
	2006	2007	2008
With Kerawalapitiya	30	190	160
Without Kerawalapitiya	30	190	370

*Note: Capacity for developmet of Diesel Generation Unit (10MW)

To meet the target supply reliability in the base case it would be necessary to install emergency diesel generators with the capacity of 190 MW in 2007. This additional capacity would be equivalent to approximately 8% of total installed capacity in the system. The capacity that would need to install if Kerawalapitiya combined cycle project were not implemented would be 370 MW in 2008, or approximately 14% of total supply capacity in the system.

Introducing such emergency diesel generators into the system would eliminate supply shortage in the short term. However, the supply cost of emergency diesel generators is high, and introducing emergency diesel units would increase supply costs for the system. Supply costs for the system are already high in November 2005 and are the principal cause of the CEB's worsening financial situation. Any additional increase in supply costs would further worsen the financial situation of the CEB, so the introduction of emergency diesel generators must be avoided if at all possible.

6.9.3 Measures for solving Supply Shortages

As mentioned above, introducing emergency diesel generators into the system would increase overall supply costs and must be avoided if at all possible.

The Study Team examined measures for solving supply shortages other than the introduction of emergency diesel generators.

(1) Measures on Generation Side

(i) Possibility of increasing supply capacity by rehabilitating existing power plants

- Hydropower plants

  The Study Team examined the possibility of increasing generation capacity by repairing problems affecting existing hydropower facilities. It was found that no such repairs are likely to lead to an effective increase in power output.

- Thermal power plants

  Power plants owned by IPPs produces more than half the generation capacity from thermal power. These IPP plants are already generating approximately at their rated output, and they appear to have no significant problem for the equipment.

Of the power stations owned by the CEB, the generation capacity of five units of Kelanitissa GT (old) power station and all units of Sapugasukanda diesel (old) power station have dropped approximately 10% due to aging. It is judged, however, that those derating capacity can not be recovered if repairs were carried out. The Kelanitissa GT (old) units are flushed with water when their output drops to around 16 MW, resulting in some improvement. Even so, the output level only rises to about 18 MW.

(ii) Possibility of increasing supply capacity by expanding existing power stations

- Hydropower plants

Plans to expand the maximum output of existing hydropower stations include a project at New Laxapana & Polpitiya hydropower station. The project takes two years to complete and will increase the output in 2008. However, since the generators would be shut down while construction is in progress, it is not desirable that the plan is implemented during the period between 2006 and 2008 when a serious power shortage is expected.

- Thermal power plants

Conversion of Kelanitissa GT7 units into a combined cycle facility could be expected to increase supply capacity by 55 MW. However, the period from the commencement of the technical appraisal through the start of operation would be approximately three years, so such capacity addition cannot be included among measures to increase short-term supply capacity by 2008.

(iii) Surplus generation capacity of IPP plants

In the case of several thermal power station owned by IPPs, the maximum output described in the Power Purchase Agreement (PPA) is slightly lower than the rated output of the facility. The CEB has requested IPPs to operate at output levels exceeding the maximum output described in their PPAs, and they complied. This surplus generation capacity could be used as emergency supply capacity.

Table 6.9.4 shows the rated capacity and maximum output capacity in PPA for IPP power plants.

Table 6.9.4 Rated Capacity and Maximum Output Capacity in PPA for IPP Power Plants

(Unit: MW)

Power Plants	Rated Capacity (a)	max. Capacity in PPA (b)	Remained Generation Capacity (a) - (b)
IPP Lakdhanavi Limited	22.52	22.52	0.00
IPP Asia Power Limited	51.00	49.00	2.00
IPP Colombo Power (Private) Limited	62.72	60.00	2.72
IPP ACE Power Horana	24.80	20.00	4.80
IPP ACE Power Matara	24.80	20.00	4.80
IPP Heladanavi (Private) Limited 1-6	100.00	100.00	0.00
IPP ACE Power Embilipitaya Limited 1-10	100.00	100.00	0.00
IPP AES Kelanitissa (Private) Lmited	163.00	163.00	0.00
Total	548.84	534.52	14.32

The total remained generation capacity is approximately 14 MW, which would account for nearly half the additional supply capacity of about 30 MW needed in 2006. Nevertheless, the amount of the capacity is insufficient to significantly reduce the supply shortages in 2007 and 2008.

As the above shows, there are almost no plans involving the repair or expansion of existing power generation facilities that can be expected to increase supply capacity in the short term by 2008. The possibility of solving supply shortages through measures from generation side, with the exception of installing emergency diesel generators into the system, is small. Therefore, <u>it is important that measures from operation and demand are implemented.</u>

(2) Measures on System Operation Side

(i) Brown outs

Brown out is an operational method used to control demand by dropping the voltage of the power system to between 90% and 95% of its normal voltage.

The amount of demand reduction that can be achieved by brown out is dependent on the consumption configuration of power and the voltage characteristics. Thus, the amount of reduction differs from system to system. For this reason, calculation of the anticipated reduction in power demand that can be achieved by conducting brown out is done using the actual results of past brown out as a basis. Since such data on demand reduction by brown out was not available through the Study, the Study Team could not estimate the amount of demand that could be reduced by implementing brown out.

The effect of brown out on the equipment and appliances of customers poses a problem. For example, an electric-magnetic switch opens and the electrical equipment or appliance stops when its magnetic contact power turns off. It is said that these problems only happens if the voltage drops to 90% or less. Thus, the effects on customers are considered to be minimal so long as a voltage of 90% of the normal level or higher is maintained.

(ii) Rotational black outs

Rotational black out is only conducted when the power system has insufficient supply capacity to meet demand, mainly peak demand, and stable system operation can no longer be maintained. The basic thinking regarding rotational black out is as follows.

[Basic thinking regarding Rolling Blackouts]

- Divide supply areas into certain groups in advance
- If a power deficit occurs, the power supply to one of the groups would be stopped
- Then the black out is rotated among these groups

(3) Measures on Demand Side

(i) Utilization of captive generation unit through the rebate scheme

One measure on demand side is the rebate scheme by implemented CEB aimed at customers who own captive generation units for use as backup units. Under this scheme, such customers are requested to operate their captive generation units during peak season (typically between January and July).

Under the rebate scheme, the CEB pays customers who operate their own generators a rebate equivalent to the difference between a purchase fee (this differs depending on the year; Rs. 7.85/kWh in 2001) and the normal power tariff.

The CEB monitors the energy (in GWh) by installing special meters at the locations of customers participating in the rebate scheme. However, since capacity is not monitored, it is impossible to track the equipment capacity of the customers.

According to the CEB's records, the generation energy from such captive generation units under the rebate scheme totaled approximately 28 GWh in June 2001. If it is assumed that all generators generate at maximum output over one month, the reduction in demand is estimated as about 38 MW in capacity.

Thus, the application of the rebate scheme is an effective measure on demand side for solving short-term supply shortages. In 2001, about 60% of total customers appreciable to the scheme actually participated in the rebate scheme. By providing additional incentives, such as raising slightly the purchase fee set by the CEB, the number of participating customers to the scheme could be increased. In this way it would be possible to contribute still more to the elimination of short-term supply shortages.

(ii) Purchasing surplus power from large-scale customers

As of November 2005, only two or three large-scale customers can sell surplus power to the CEB. For this reason, purchasing surplus power would contribute little to the alleviation of short-term supply shortages.

(iii) Incentive scheme to encourage purchases of captive generation units

This scheme was introduced on a time-limited basis during the power crisis of 1997 and after. Under the scheme, the CEB paid customers purchasing certain captive generators a portion of the purchase price (Rs. 3,000/kVA), with the maximum output during the preceding six months as the upper limit. The terms of the scheme specified that customers purchasing generators had to use them to produce 75% of their power needs for a set period of time.

The scheme has ended, but its reintroduction at a future time could be expected to curb short-term demand to some extent.

(iv) Load adjustment contract

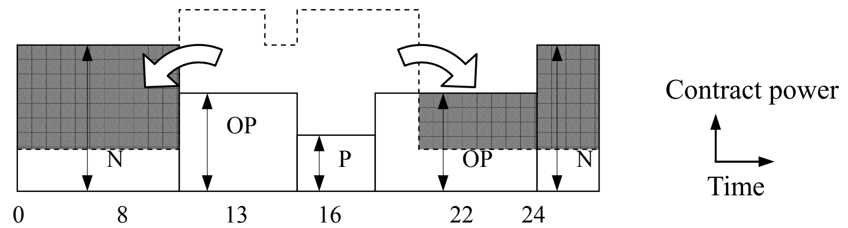
Load adjustment contract seems to be applicable to Sri Lanka because the initial cost for implementation is relatively low.

This section will introduce the load adjustment contract programs implemented in Japan. Under the contract, consumers have the obligation to reduce their demand during peak time in exchange for being provided with discounted electricity tariffs. The contract is made with specific customers in order to control their demand. The contract is classified into the following three types of contracts.

a) Annual load adjustment contract

The customer must control its power use according to the load curve or the contract power previously defined in the contract in exchange for special discounted tariffs.

Contracts are updated annually with costumers and the load curve pattern or contract power amount is decided on a monthly basis. Under such contracts, power demand is expected to shift to midnight. Customers who operate their generators in 24 hours are most applicable.



N: Contract power in nighttime OP: Contract power in off peak time N: Contract power in peak time

Figure 6.9.1 Annual Load Adjustment Contract

b) Interruptible load adjustment contract

The notice for demand control from the power company to the customer is issued immediately or 3 hours in advance. When customers accept this contract, a discounted electricity tariff can be applied. If customers reduce their demand in response to the notice, they can receive extra discounts.

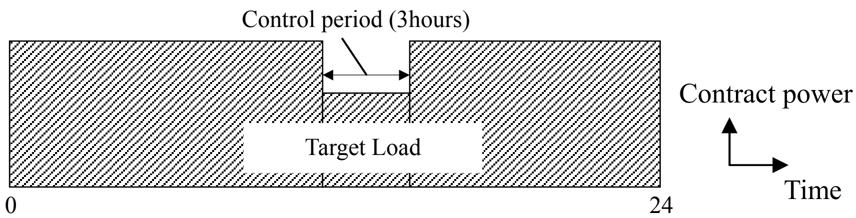


Figure 6.9.2 Interruptible Load Adjustment

c) Load management contract

The main differences between this contract and the others are that: 1) the costumers can decide the times to adjust their load among the special days contracted with the power company; and 2) the discount can be applied according to the result of their demand control.

In Japan, the special days are set up at weekdays in the summer when the annual maximum peak often occurs during this period. The special discount can be only applied to the customers who reduce their load by adjusting their production schedule or their holidays.

6.10 Recommendations on Generation Development Planning

(1) Recommendations on Formulation of Generation Development Plans

- **Formulation of generation development plans in coordination with power system planning**

The selection of sites for development will have a significant effect on power system plan

To increase the accuracy and reliability of the generation development plan, it will be necessary for CEB to achieve consistency between generation development plan and transmission development plan. In addition, to maximize the benefit from both plans, CEB should formulate them in a coordinated manner, feeding back the results of a study into the planning process of the other study and conducting combined studies of issues that affect both types of plan.

- **Importance of on-site surveys to increased planning accuracy and problem solving**

In the process of formulating the generation development plan, it is essential to collect and organize a diverse range of data so that the constraints and assumptions for the plan can be determined.

In addition to theoretical analysis, the implementation of on-site surveys able to provide up-to-the-minute and detailed data is important to improving the accuracy of the plans that are formulated. If these surveys are carefully planned and appropriately conducted, they can even indicate the way to the solutions for issues that are encountered.

The on-site surveys presently conducted by the CEB when it formulates plans do not fully meet these requirements, and the organization should therefore be enhanced to increase the frequency of its surveys, improve its survey structure and make its surveys more detailed.

(2) Recommendations on Future Generation Development

- **Prompt and sure execution of projects now under way for construction of large-scale coal-fired power plants**

Development of large-scale coal-fired power plants is indispensable for economical system operation. While there has been opposition to the project for considerations related to siting and environmental concerns, the course of the current project for construction of a coal-fired plant at Norochcholai will have a great impact on future generation development. It consequently should be swiftly and surely implemented.

- **Identification of new sites for large-scale coal-fired plants and ordering in terms of priority**

Relative to the capacity of large-scale coal-fired plants that must be developed over the coming years, only a very few candidate sites have been the subject of reliable studies, and this is a problem. Studies should be promptly made to identify candidate sites throughout Sri Lanka in order to expand the options for site selection and execute development at more economical sites. This should be accompanied by an ordering of all candidate sites, including those already studied, in terms of development priority.

- **Prompt implementation of the combined-cycle project at Kerawalapitiya**

The project for construction of a combined-cycle power plant at Kerawalapitiya as intended by the CEB is a major key for power supply prospects in 2007 and 2008. If this project is not completed, supply will fall into a status of critical tightness in these years. Considering the construction period and lead-time before construction, a financing agreement for the project must be concluded by the beginning of 2006 for its commissioning in the middle of 2009.

- **Importance of energy source diversification**

The future generation mix will depend heavily on coal-fired plants. For reasons of energy security, there is a strong need for development of generation facilities applying hydropower (as a domestic energy resource) and renewable energy. Efforts to develop these facilities should be continued.

Natural gas is another new fuel option that would presumably have the additional benefits of improvement of energy security through diversification of energy sources and stabilization of the system operation through installation of combined-cycle systems with a high load-following flexibility. As such, if natural gas is supplied to the power sector at reasonable price, it will become a promising fuel option after installation of coal-fired plants.

- **Necessity for generation development in northern and eastern regions**

The power demand forecast to 2025 indicates that demand will increase steadily in northern and eastern regions in Sri Lanka, and there is a possibility that it will be difficult to supply the demand by the grid. Prompt development of new power plants these regions will be essential to ensuring the stability of their energy supply.

(3) Recommendations on the Organization of the CEB as it Relates to Development Planning

- **Enhancement of the Generation Planning Branch**

At the time the Study was conducted, the CEB's Generation Planning Branch, which has responsibility for formulating generation development plan, consisted of one Chief Engineer and two technical staffs, all of whom were electrical engineers.

In the future, a study of inputs from broad-ranging studies that consider sites for coal-fired thermal power plants, improved planning with regard to candidate sites for hydropower plants, extension of existing power plants and system operation will be important in the formulation of generation development plans. On-site surveys that enable the collection of detailed data and assist in problem-solving will be of particular importance. It will also be essential for the Generation Planning Branch to hold discussions with the Ministry of Power and Energy (MPE) and coordinate with them, to ensure energy security following the introduction of coal-fired thermal power plants.

These requirements cannot be fulfilled with the present number of staff. To conduct its duties effectively and efficiently, the Generation Planning Branch will require at least six or seven staff members.

In addition, when the number of staff is increased, an effort should be made to place staff members with expertise in fields other than electrical engineering, including civil and mechanical engineering.

Chapter 7 Power System Plan

7.1 Investigation and Study Points for Optimal Power System Plan

In this study, the JICA Study Team adopted the system coordination method, which focuses on rational system configuration and effective use of the existing transmission facilities, in addition to the conventional system planning method. With this new method future load dispatching for each substation is determined to maximize transmission facility load flows under their capacity in normal state and emergency state. Especially in regard to the transfer study, overloaded operating pattern (overloading rate is changed chronologically after a fault) for transmission lines and transformers are set and adopted considering the design conditions in Sri Lanka, which are covered in section 7.5 and 7.6.

The JICA Study Team studied a large coal power development case (base case), which has been planned and will have a big impact on the Sri Lanka system in the near future. The JICA Study Team studied reconstruction of the 132kV interconnection between the northern area and the main system. Large coal-fired thermal power stations, in particular, will be the mainstay generation facilities that make up the base power source of the future. In 2025, they will make up approximately 60% of total facilities, and will exert a major influence on power system plan. The position in relation to major demand areas was also taken into consideration in determining the respective levels of development at the three candidate sites (Puttalam, Hambantota, Trincomalee), which were discussed in the section on the generation development plan. The optimal system configuration was considered with great care by studying alternative projects. As much thought as possible was given to the cases of power concentration as well, for which development had not progressed systematically.

Investigation and study steps, study items and results are shown below.

〔Investigation and Study Steps〕

I Grasp of Current Power System and Future System Plan
✓ Confirmation of the planning criteria and expansion causes, and the outline of the existing long-term transmission development studies (LTTDS, Grid Code)
✓ Problem finding for system operation and expansion of the transmission facilities
✓ Transmission facilities data and system operation information gathering & analysis

↓

II Case Study Description for Main Projects
✓ Transmission development measures for large coal power generation expansion (Puttalum, Trincomalee and Hambantota)
✓ Study of power supply for the northern area (Comparison between interconnection plan and generation installation plan in northern area)
✓ Power supply measures for the metropolitan Colombo area (countermeasures for improving supply reliability)

↓

III Establishment of Optimal Power System Configuration with Latest Demand Forecast and Generation Planning
✓ Outline of optimal power system establishment

↓

IV Preparation for Adapting System Coordination Method
✓ Review of load dispatching for each main grid substation
✓ Transmission facilities investigation for creating overloaded operating pattern
✓ Countermeasures against reactive power compensation
✓ Calculation of new transmission line constants

↓

V Overloaded Operating Pattern Considering Design Conditions In Sri Lanka
✓ Overloaded operating pattern of Over Head Transmission Lines (OHTL)
✓ Overloaded operating pattern of Underground Transmission Lines (UGTL)
✓ Overloaded operating pattern of transformers
✓ Attention items on operation utilizing overloaded operating pattern

VI Case Study
✓ Objectives for projects
✓ Items and conditions for analysis
✓ Results and assessment

VII Long-Term Long-Term Power System Plan
✓ Outline of Long-Term Power System Plan for 20 years
✓ Protective relay system development plan

VIII Desirable future study from the view point of power system plan
✓ Review of thermal capacity of transmission lines
✓ Effective use of aging facilities

7.2 Grasp of Current Power System and Future System Plan

7.2.1 Confirmation of Planning Criteria and Expansion Causes / Outline of the Existing Long-Term Transmission Development Planning

(1) Planning Criteria and Expansion Causes

The present planning criteria and expansion causes adopted by CEB[62] are shown below.

(i) Voltage Criteria

Table 7.2.1 Allowable Range of Voltage Variation

Bus Bar Voltage	Allowable Voltage Variation (%)	
	Normal Operating Condition	Single Contingency Condition
220kV	±5%	-10% to +5%
132kV	±10%	±10%
33kV	±1%	±1%

Source: LTTDS[63], Grid and Distribution System Code and Standard of Sri Lanka

(ii) Thermal Criteria

Systems should not exceed their continuous ratings and the capacity for OHTL differ depending on time (day-time or night-time). Therefore expansion objects can be changed by each analysis.

Table 7.2.2 Thermal Capacity for OHTL

Current Rating	ACSR				
	Tiger	Oriole	Lynx	Goat	Zebra
At 54℃ Day (A)	178	199	204	244	253
Night (A)	365	432	453	658	750
At 75℃ Day (A)	379	444	464	656	726
Night (A)	487	578	607	882	987

Source: LTTDS

Current Rating	XLPE Cable (mm2)	
	800	1,000
Whole Day (A)	1,006	1,115

Source: Rated Current Report by Olex (manufacturer)

Systems should not exceed their emergency ratings under the N-1[64] condition. Further details are provided in the 7.6, but basically 30 minutes at 135% operation of continuous rating for transmission lines (ACSR, XLPE) and 40 minutes at 125% operation of continuous rating for transformers are available.

(iii) Stability Criteria

Stability criteria should ensure system stability during and after a system disturbance as described below:

- ✓ Three-phase fault at any one overhead line terminal, cleared by the primary protection with successful and unsuccessful auto re-closing
- ✓ Loss of any generation unit
- ✓ Load rejection by loss of any transformer

The stability analysis is carried out under the two switching sequences given below:

62 CEB: Ceylon Electricity Board
63 LTTDS: Long Term Transmission Development Studies
64 N-1: State that One of Equipments is Broken

Table 7.2.3 Conditions for Stability Analysis

Switching Sequence	Steps
I. Successful Re-closing	1. t=0 Fault occurs 2. t=120ms, fault cleared and circuit tripped 3. t=620ms, circuit re-closed
II. Unsuccessful Re-closing	1. t=0 Fault occurs 2. t=120ms circuit tripped 3. t=620ms circuit re-closed with fault 4. t=740ms circuit tripped

(iv) Short Circuit Criteria

The short circuit criteria limit the maximum three-phase circuit currents shown below at the 132kV, 33kV and 11kV bus-bars of any grid substations (GS).

Table 7.2.4 Short Circuit Capacity Criteria

Bus-bar voltage	System	Maximum three-phase fault level (kA)
132kV and above	Over head	40.0
	UG cable	40.0
33kV	Over head	13.1
	UG cable	16.0
11kV	UG cable	20.0

(v) System Frequency Criteria

System frequency shall be 50Hz±1% under normal operations (Grid Code). If it is less than 48.75Hz due to a system fault, load shedding shall be conducted to keep the system stable until it can recover 50Hz±1%. Refer to the steps for load shedding outlined in section 7.2.3.

(2) Outline of Rational Long-Term Transmission Development Plan

(i) Planning Flow

The present planning flow is shown below.

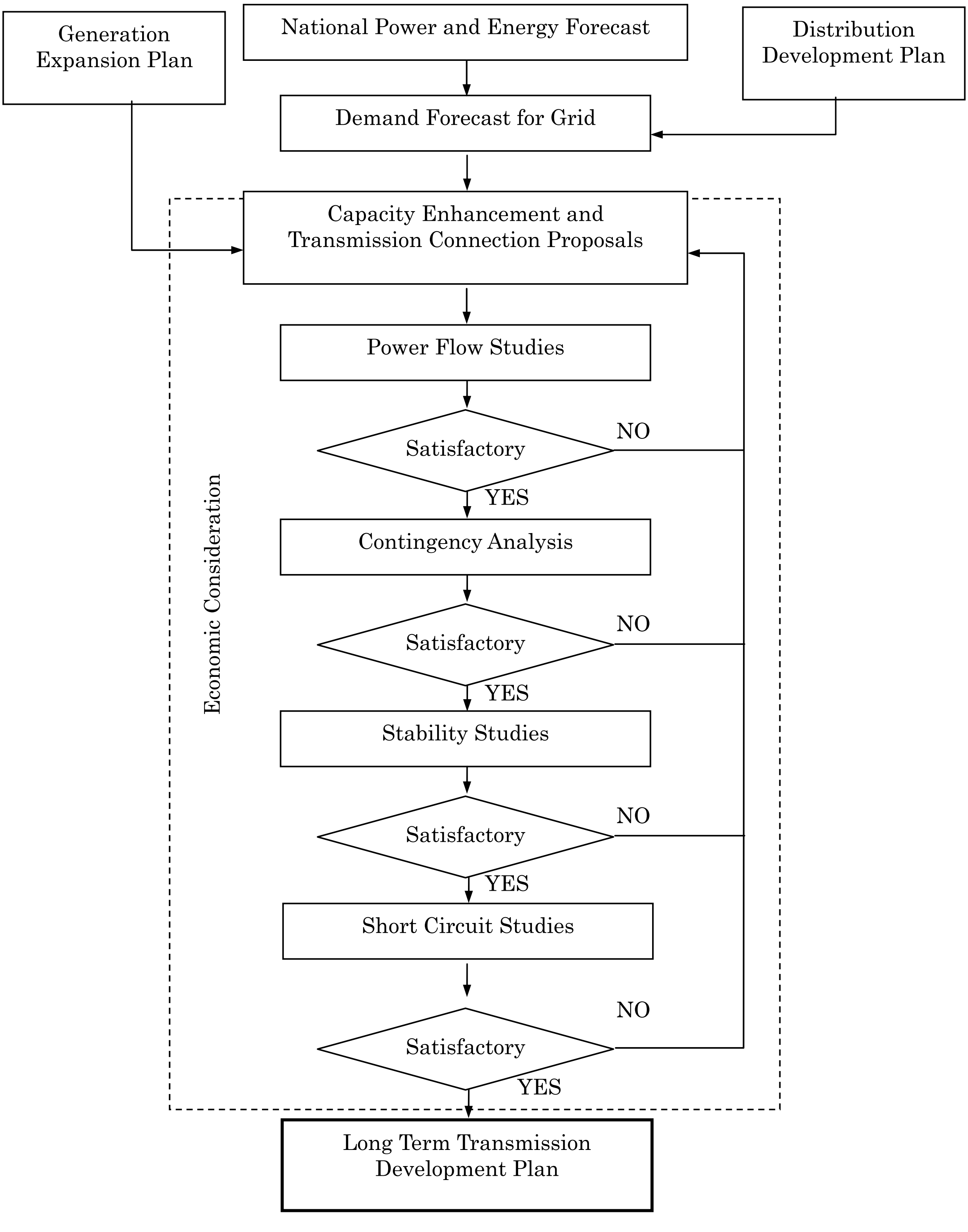


Figure 7.2.1 Planning Flow (Source: LTTDS)

(ii) Characteristics of Countermeasures for Equipment Needs in LTTDS

Countermeasures for equipment needs frequently seen in the latest LTTDS are shown below.

- ✓ Countermeasures against voltage drop of the Ampara GS and Valachchenai GS in the eastern area
- ✓ Countermeasures against voltage drop of Vavunia, Kilinochchi, Chunnakam and Trincomalee GSs in the northern area in the case of one circuit failure of 220kV or 132kV lines
- ✓ Countermeasures against overload of lines between the Kelaniya GS and Kolonnawa GS, between the Kolonnawa GS and Sub E GS and between the Kelanitissa GS and Sub F GS under the normal state and a single line outage

The equipment mentioned above is seen as the weak point of the power system. This is illustrated in the following figure.

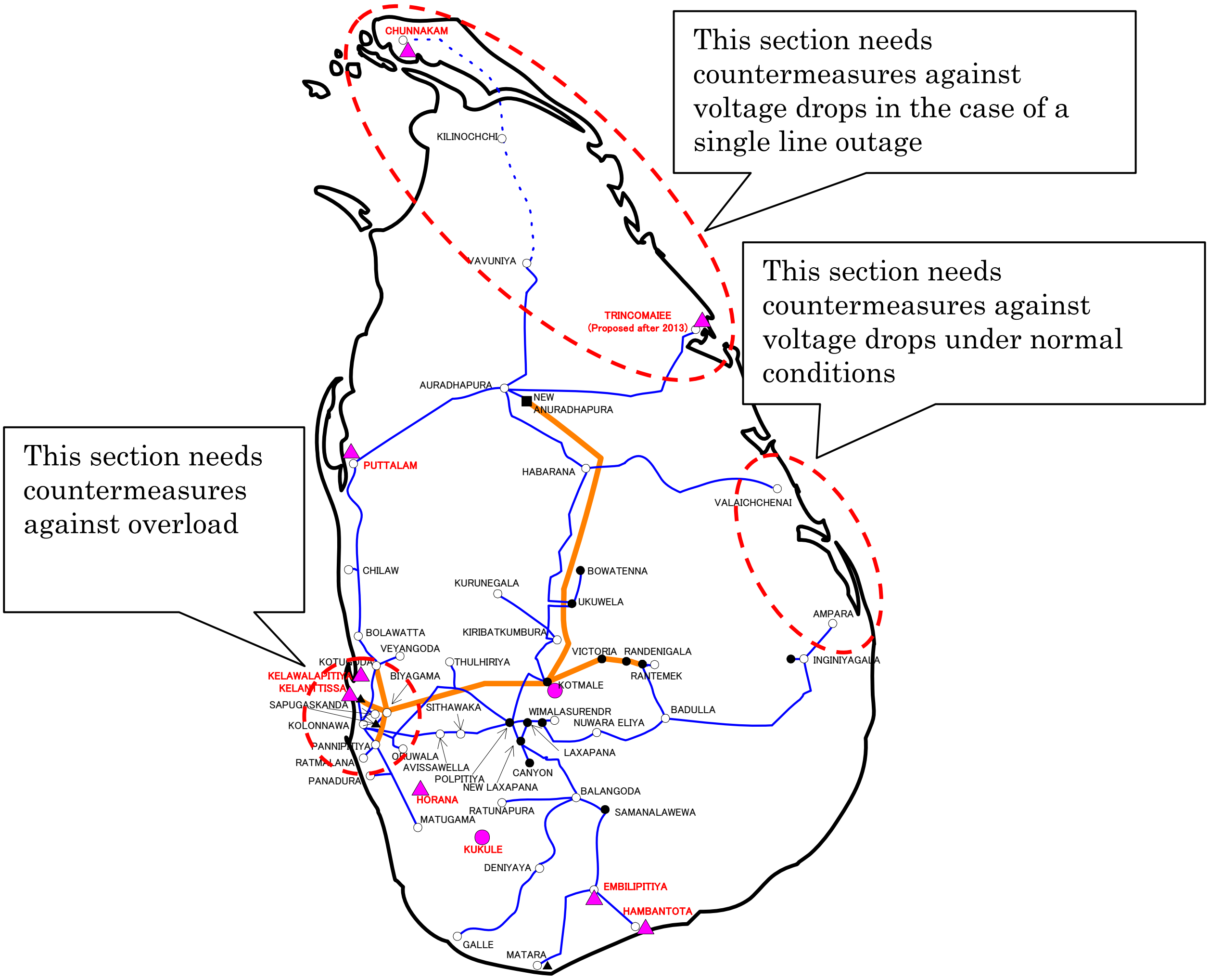


Figure 7.2.2 Problems of Power System as of 2005

(iii) List of Transmission Development Plans

Table in the Appendix 1 shows the latest list of transmission development plan. Transmission development plans are concentrated in 2007 and 2008.

7.2.2 Grasp Problems with System Configuration and System Operation

(1) Status of System Operation

At the moment power generated in the center of Sri Lanka is supplied to Colombo using 220kV lines between the Kotmale GS and the Biyagama GS and 132kV lines between the Polopitiya GS and Kolonnawa GS. As such, these lines support a heavy load. There have been blackouts for the entire system every year because of lightning hitting these lines.

Specifically, there were three blackouts to the entire system during the 2004 fiscal year and five such blackouts during the 2003 fiscal year. Two possible causes have been cited. One possible cause is a huge generation unit drop. When a generation unit responsible for 10% of system demand drops during peak time and when a generation unit responsible for 20% of system demand drops during off-peak time, some of the load is shed by load shedding scheme. Besides that, when one circuit of the 220kV lines supplying power from the Mahaweli complex in the center of Sri Lanka to the Colombo center was being inspected, there was a lightning strike to the remaining circuit. This resulted in route failure and eventually a blackout of the entire system.

(2) System Interconnection to Kerawarapitiya Power Station (PS)

However, CEB has not entered into a contract with the IPP[65], Kerawarapitiya PS (oil fired/ gas turbine), and the contract with JBIC for the transmission construction between Kerawarapitiya and the main grid has been concluded.

(3) Reconstruction of the Interconnection between Northern Area and Main Grid

The lines between the Vavunia GS and the Kilinochchi GS are going to be constructed using a JBIC[66] loan and the lines between the Kilinochchi GS and the Chunnakam GS are likewise to be constructed by a KFW[67] loan in 2007. However, land mines buried during the war need to first be removed. Actually, this project is not proceeding favorably. Table 7.2.5 shows the current condition of this project.

Table 7.2.5 Progress of Interconnection between North Grid and Main Grid

	Line Section	Finance	Progress
1	Vavuniya－Kilinochchi	JBIC	MOU[68] was concluded Bidding document is under preparation to select consultant Consultant will be selected among fund supplier countries Construction will be international bidding
2	Kilinochchi－Chunnakam	KFW	MOU was signed

(Source: CEB)

At present, the Jaffna area is supplied with electric power from small diesel generators, or in other words, off-grid operations. In this situation CEB is left with a deficit because the purchasing price from IPP is around twice as much as the selling price of CEB. Therefore CEB is eager to install its own generators in Jaffna, but CEB runs on the spot because of the high risk and lack of financing.

(4) Transmission Development Countermeasures against Supplying Power from Prospective Large Coal Power Generation Sites

(i) Case that new generation is installed in Puttalam Area

Together with the generation development in this area, new transmission lines are being built on the route from Kotugoda GS to Kerawarapitiya PS to Kelanitissa PS. The construction of overhead transmission lines is difficult, however, in the area south of Kerawarapitiya PS, because this area is slated for commercial development, and in the vicinity of Kelanitissa PS, because that area is subject

65 IPP: Independent Power Producer
66 JBIC: Japan Bank for International Cooperation
67 KFW: Kreditanstalt fur Wiederaufbau
68 MOU: Memorandum of Understanding

to transmission line congestion. Consequently, the line from Kerawarapitiya PS to Kelanitissa PS will be an underground transmission line.

(ii) Case of new generation installed in Hambantota Area

With respect to the new transmission lines project from the Hambantota GS to the Matugama GS accompanied by generation development in the Hambantota area, there is the "Shinharaja forest reserve" in the way and the route along the coast is a commercial advancement area. So the options for new transmission routes are limited. Considering these conditions, a route running among the "Shinharaja forest reserve", the "Peak Wilderness Sanctuary" and the "Uda Walawe National Park", and then passing by the Padduka GS and the Oruwara GS to finally connect to the Pannipitiya GS is desirable. In addition, there is extra installation space for the new lines at the Pannipitiya GS.

Another route being considered to supply power to the central region passes through Nuwara Eliya, where demand has shown conspicuous growth, to Upper Kotmale. This would be an effective route, but the area around Nuwara Eliya is mountainous and rugged, making transmission line construction difficult. Another possibility would be to pass through the Badulla GS. This substation is located in a built-up area, however, and the substation itself has no land to spare. It will be more effective, therefore, to route the line through the Bandarawela GS, which is planned for future construction, and to situate that as a trunk substation.

(iii) Case of new generation is installed in Trincomalee Area

With respect to the new transmission lines project from the Trincomalee GS to the Veyangoda GS accompanied by generation development in the Trincomalee area, there are a lot of sight-seeing places on the way. However, it is believed that obtaining a new route is not issue. Whereas, the harbor in this area has been used as a military port. So more detailed investigations will be needed.

(5) Power System Protection System

Protection relays attached to the 220kV lines is mechanical contact type and need to be replaced, but the target 220kV lines has a hydropower station that is in charge of the base load. So it is impossible to replace these relays. As a result, seven relays do not work at present. The reason is that transmission lines must be stopped for one to three days while relays are being replaced. It also requires a trip test, so that these power source lines from hydropower stations must be stopped for about three days. These circumstances make replacement impossible. This means that once there is a fault with the system, it might spread over the whole system.

(6) SCADA[69] System

The communication system between power stations and substations is inadequate. One of the main reasons for this is damage to microwave towers during the civil war. Therefore, in many cases power stations and substations are supervised and controlled over the telephone.

Now, only 17 out of 70 substations have adopted the SCADA system. In addition, the SCADA system has equipment to deal with SV[70] information but does not have remote control functions.

Construction of the SCADA system is proceeding with KFW funding, however, and system expansion within Colombo is being coordinated with the gradual construction of an optical communications network.

69 SCADA: Supervisory Control and Data Acquisition
70 SV: Super Vision

7.2.3 Transmission Facilities Data and System Operation Information Gathering / Analysis

(1) Case Study Conditions in LTTDS

Two case studies, day peak case and a night peak case, are basically conducted each year. And until 2010, each case has a rainy season case and dry season case to consider characteristic of season. The load characteristic is "constant power", which means that active power is constant in spite of the voltage changes.

(2) System Constant Collection and Analysis

The power system constants of the transmission lines and transformers were checked in detail using the typical number of constants for transmission lines, including new transmission lines (calculated by JICA Study Team), and substation equipment data provided by CEB. There were virtually no errors concerning transmission and substation facilities, and an extremely complete assortment of data appeared to be kept available. There were errors at several points, and these are recorded in Appendix 2. The constants for individual generation facilities were checked using test records from the time of construction, provided by CEB. Data for the governors and exciters from the time of construction were not available even in the CEB library, and therefore checks were made to determine whether the figures deviated from the prescribed values recommended by PSS/E for the various constants. The results are similarly recorded in Appendix 3.

(3) Transmission Line Capacity

Two rating currents, 54℃ and 75℃, are adopted. Old transmission lines adopt 54℃, but the current new lines all adopt 75℃. There have been capacity shortages with the existing lines designed for 54℃. Whenever there are capacity shortages, a study is carried out to determine whether the rating current can be changed or not. At the same time, sag problems (necessary distance between ground and conductor) should be considered.

(4) Load Shedding in case of System Disturbance

As it was explained for the case of system-wide blackouts, the load shedding scheme has five stages and is controlled automatically. The detailed scheme is shown below:

Table 7.2.6 Load Shedding Scheme

Stage	Target Frequency (Hz)	Breaking Time
1	48.75	100 ms
2	48.50	500 ms
3	48.25	1 s
4-I	48.00	1.5 s
4-II	48.00	4 s
5	47.50	100 ms

Source: System Operation Center in CEB (As of April 12, 2004)

(5) Loop Operations

To solve the heavy power flow problem, the lines between the Fort GS and the Kollupitiya GS are cut off at the Fort GS site. Then the lines between the Kolonnawa GS and Kotugoda GS are also cut off at the Kolonnawa GS site.

(6) Cable system in the Colombo City

The existing cables in Colombo are oil-filled cables and directly buried type. On the other hand, future cables will be XLPE and duct type.

(7) Installation of SCADA System

Now there are two computer lines for a SCADA system and an optical communications network is being established. Specifically, a network has been established up to the Chillaw GS in the north area and up to the Matugama GS and the Horana GS in the south area. In the future OPGW[71] and underground optical cables will be installed as the system expands. On the other hand, the SCADA system has not been installed in four IPPs (Heladhanavi PS, Lakdhanavi PS, Asia Power PS and ACE Power Matara PS) because of insufficient financing, and so CEB can not grasp the generation conditions.

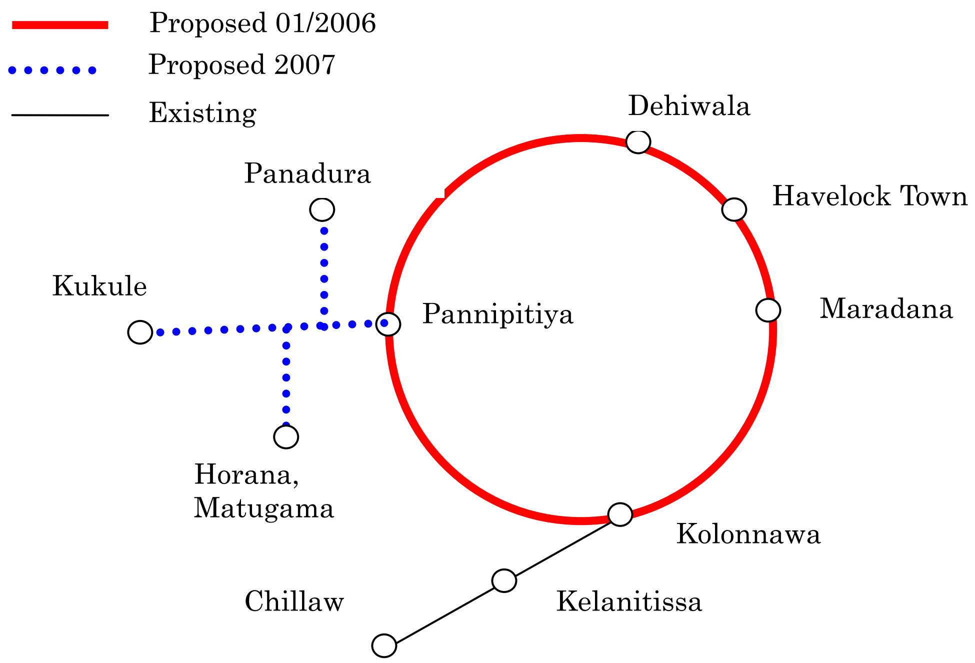


Figure 7.2.3 Present Optical Communications Network

(8) Demand and Supply Situation in North Area

The Chunnakam GS, as a main supplying point in the northern area, and the Kilinochchi GS have not functioned very much since the interconnection between the northern area and the main grid was broken during the nation's civil war. At present almost all electricity is supplied from two IPPs, Kool Air (Kankasanturai) and Aggreko (Chunnakam). Though CEB has its own Chunnakam PS next to the Chunnakam GS, they are aging and their total capacity is only about 4MW. So they are used as only back up. As for Kilinochchi, there is only one diesel generator (capacity only 1MW) near the Kilinochchi GS. This one supplies electricity to the neighboring agricultural area.

[71] OPGW: Optical Fiber Composite Aerial Ground Wire

7.3 Case Study Description for Main Projects

It is believed that three large projects will have major impacts on system configuration in the transmission development plan for Sri Lanka. First project is a countermeasure for power source lines for new large coal-fired thermal power, and the second project is power supply measures for the northern area where the interconnection is disrupted, and the third project is power supply measures for the metropolitan Colombo area.
The viewpoints for each project are explained in the following section.

7.3.1 Transmission Development Measures for Large Coal Power Generation Expansion

As mentioned earlier, Sri Lanka is working on the issue of changing its main source of power from hydro to thermal due to the urgent issue of insufficient water sources. A countermeasure to this is considered necessary, and will take the form of generation development of large coal-fired thermal power stations (Unit size: 300 MW) to a total of 5,100 MW by the year 2025.

The prospective development sites are Puttalam in the northwest section, Hambantota in the south section and Trincomalee in the northeast section. The JICA Study Team studied power source lines between the generation site and the large consumption area of Colombo for each of the three sites.

The perspective for power source lines is described below.

Long distance bulk power transmission to the metropolitan Colombo area from the large concentrated generation site is not a good idea considering system reliability and safety. Therefore, supplying power near the generation site and along the route at the highest possible level is a much more effective option. Considering these circumstances, studies were specifically made of the possibility of higher voltage systems and the possibility of introducing larger transmission lines to reduce losses, and the possibility of having appropriately located load supply substations.

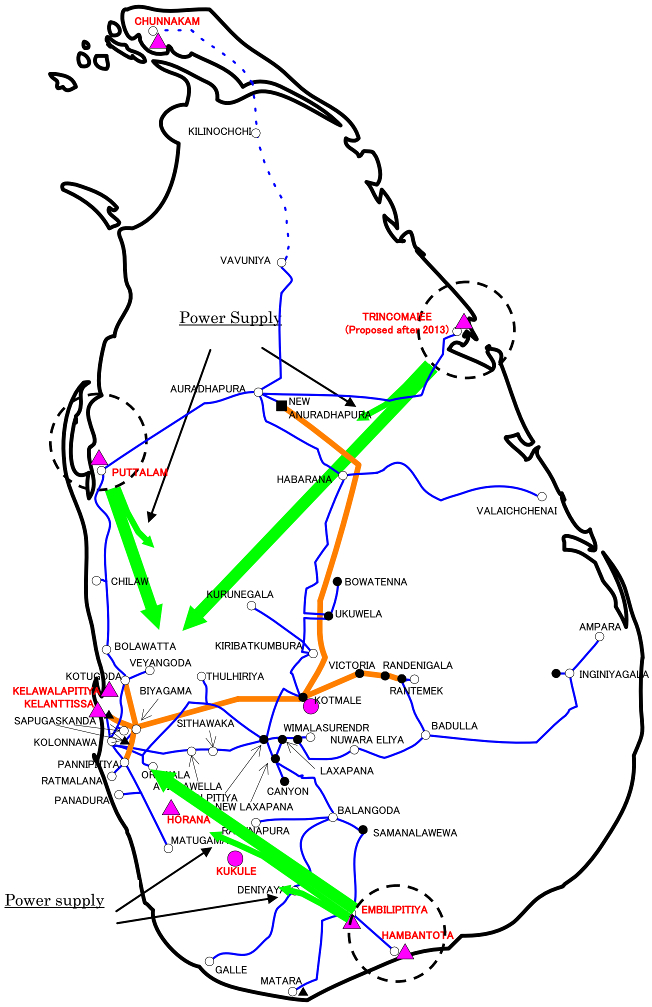


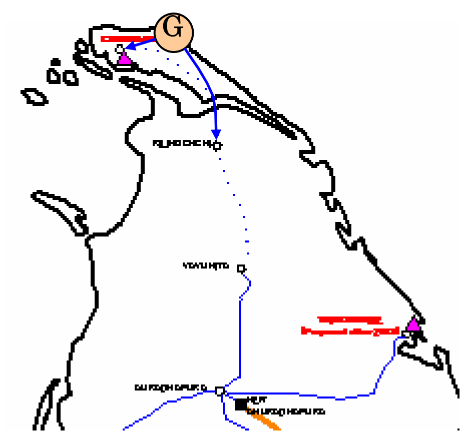
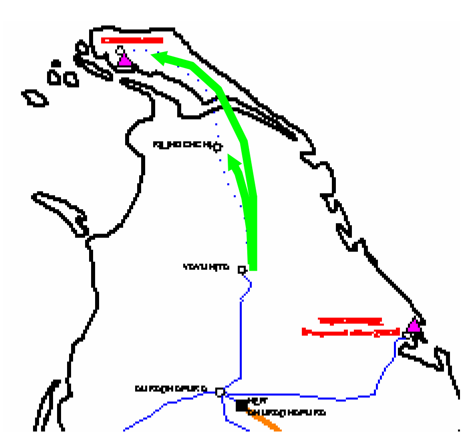
Figure 7.3.1 View of Power Source lines establishment

7.3.2 Study of Power Supply for Northern Area

The northern area was separated from the main grid due to the past nation's civil war and a stable power source is now lacking. To secure a stable power source for the northern area, the JICA Study Team compared two cases, which are the generation development in northern area case and the reconstruction of 132kV lines between Vavunia and Jaffna (Chunnakam) case.

The image of the power supply study for the northern area is shown below.

Table 7.3.1 Image of the Power Supply Study for the Northern Area

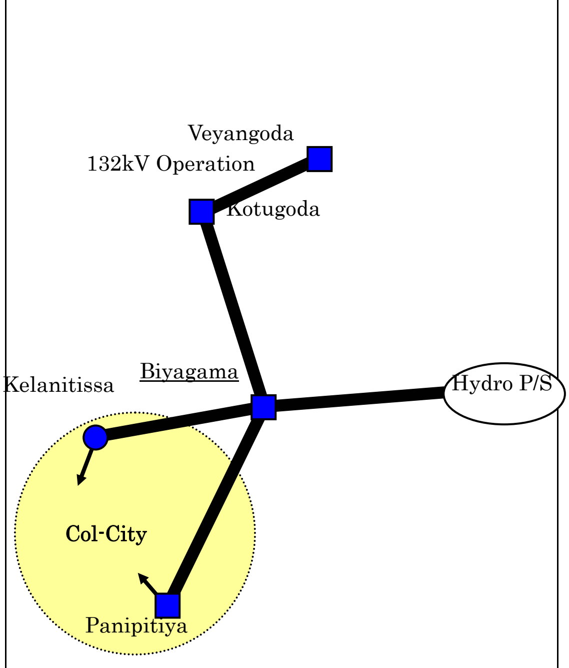
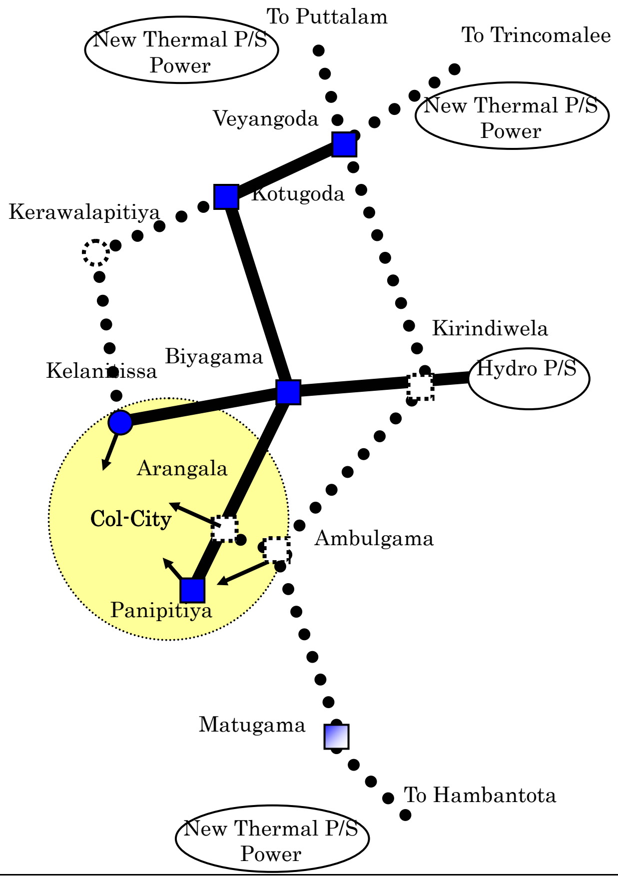
Generation Development in Northern Area	Reconstruction of Transmission Lines
	
New generation that has the capacity to meet demand for the next 20 years is installed. New generation is connected with 33kV lines to the Chunnakam GS and the Kilinochch GS.	Transmission lines that have the capacity to meet demand for 20 years are installed. Specifically, 132kV transmission lines from the Vavuniya GS through the Kilinochchi GS to the Chunnakam GS are reconstructed.

These two cases are compared in terms of economic and supply reliability considerations.

7.3.3 Power Supply Measures for Metropolitan Colombo

Metropolitan Colombo is especially packed with power demand in Sri Lanka at present. Electric power is concentrated in the Biyagama 220/132kV GS and then delivered to the main grid substations in the metropolitan area. Under this condition, if there is some serious fault, such as a bus fault in the Biyagama GS, power supply to the metropolitan area will be stopped or limited significantly. This problem can be avoided by taking large-scale generation and transmission countermeasures, as well as by reviewing the system configuration to provide multiple power sources supplying the metropolitan Colombo area and to form a flexible power interchange that is bidirectional both north and south. The present and future projected power system diagrams are shown below.

Table 7.3.2 Present and Future Power System for Metropolitan Colombo

<table>
<tr><th>Present (2005)</th><th>Future (around 2025)</th></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>The electric power is concentrated once at the Biyagama GS. There are few trunk substations to supply power to the metropolitan Colombo area.</td><td>The purpose is operation of a system with improved reliability and flexibility for supplying power to the metropolitan Colombo area. Besides that another purpose is load distribution to the areas surrounding metropolitan Colombo, which have shown a conspicuous growth in demand. To these ends, a second outer loop is to be constructed around the outside of the existing 220-kV transmission lines, and trunk substations are to be newly built.</td></tr>
</table>

7.4 Establishment Optimal Power System Configuration with Latest Demand Forecast and Generation Planning

The power system expansion is determined based on system analysis using the latest demand data and the power generation expansion plan. Therefore, the annual demand forecast for each area and any new generation expansion information, such as size, connecting point and installation year, are all important factors for the power system expansion.

7.4.1 Outline for Optimal Power System Configuration

The following concepts are taken into account when considering the power system configuration.

- ✓ Easy operation and low transmission loss
- ✓ Stable power supply while ensuring supply reliability
- ✓ Maintaining allowable voltage
- ✓ Maximizing capacity and characteristic for each generation and transmission system

Considering these conditions, when load dispatching for the main GSs is conducted based on load forecasts by province, equipment power flow in grid substations as well as higher voltage transmission systems shall be checked as to whether or not they exceed their capacity under normal conditions and during a single outage.

As shown in section 7.2.1, the power system in Sri Lanka has several week points. Voltage problems occur easily in the north and east areas, and overload problems occur easily in the areas with large consumption, such as Colombo and the areas neighboring Colombo. Of course these problems are solved by augmentation or new construction. However these problems might be also solved by reviewing load dispatch and power system configuration. Furthermore they also might be solved by using an overloaded operating pattern. In other words, more effective use of existing equipment.

In this study, the JICA Study Team will establish appropriate power system based on the above concepts.

7.5 Preparations for Adopting the System Coordination Method

As mentioned in the section 7.1, the JICA Study Team adopted the system coordination method, which focuses on the rational system configuration and effective use of the existing transmission facilities, to the conventional system planning method.

This conceptual approach is oriented primarily toward rational system operation and efficient, effective use of facilities. Specifically, this means:

<1> Optimized load distribution to every major substation at the demand forecast stage to increase the utilization of transmission and substation facilities.

<2> The study of load transfers during system faults involved setting facility overloaded patterns (time-series overload rates around the time of faults). These patterns took into consideration the overloaded capacity of transmission lines and transformers together with the environmental conditions in Sri Lanka.

The viewpoints regarding load dispatching for each grid substation and the establishment of overloaded operating pattern are described below.

7.5.1 Review of Load Dispatching for each Main Grid Substation

Main grid substations are power supply points for a load system, and they are also factors for determining the power flow for the trunk system. Therefore, the load dispatching work for main GSs is very important when determining system configuration.

Conventional load dispatching concept for each GS is shown below.

- ✓ Available output is calculated by multiplying transformer capacity by power factor.
- ✓ Loads are transferred to neighboring GSs so as not to exceed its capacity

This method, however, would not satisfy the national technical standards for power system operation in Sri Lanka if one bank failed in a substation that is subject to heavy load. On the contrary, the method has resulted in inefficient operation of facilities at substations that are subject to light loads.

Procedures for load dispatching are shown below.

(i) Demand forecasts by province

The total power for each province is calculated based on electric energy and load factor by province.

(ii) Future load dispatching in a province and load transfer adjustments in a province or between provinces

Load is dispatched for each GS considering the transformers capacity and the allowable short-term overload under the single transformer outage by province.

GS available capacity is calculated in two statuses, which are a) normal state and b) emergency state and then smaller size shall be selected as GS available capacity. The basic concept and specific examples are descried below:

- ✓ Basic concept
  - a) Normal state: 90% of rated capacity considering 10% margin as demand forecast error
  - b) Emergency state: 150% of rated capacity of remaining sound transformer when the largest transformer is out of service

  Smaller size shall be selected as GS available capacity.
- ✓ Specific example I (Different size capacity transformers, 10MVA x 2, 31.5MVA x 1)
  - a) Normal state: (10 x 2 + 31.5) x 0.9 x 0.95 = 44.0 (MW)
  - b) Emergency state: 10 x 2 x 1.5 x 0.95 = 28.5(MW)
  - a) > b): GS available capacity shall be 28.5(MW).
- ✓ Specific example II (Two same size transformers, 31.5MVA x 2)
  - a) Normal state: 31.5 x 2 x 0.9 x 0.95 = 53.8 (MW)

b) Emergency state: 31.5 x 1.5 x 0.95 = 44.8(MW)
a) > b): GS available capacity shall be 44.8(MW).

- ✓ Specific example III (Three same size transformers, 31.5MVA x 3)
  a) Normal state: 31.5 x 3 x 0.9 x 0.95 = 80.7 (MW)
  b) Emergency state: 31.5 x 2 x 1.5 x 0.95 = 89.7(MW)
  a) < b): GS available capacity shall be 80.7(MW).

Now, 95% is adopted as power factor to calculate GS available capacity.

(iii) Establishment of augmentation and new GSs plan

Regarding the load dispatching of (ii), even though load transfer is conducted and load flow exceeds its available capacity, transformer augmentation (up to three units) and new GS in the neighboring area are being considered.

(iv) Power Flow Dispatching Adjustment

Power flow of a 132kV system is revealed by the load dispatching for existing and new GSs based on the establishment of augmentation and new the GSs plan of (iii). At this stage, if there is power flow congestion or overload, review of load dispatching for the related GSs will be needed. This will result in appropriate system for which the power flow is balanced.

The result of load dispatch for GSs in accordance with the above procedures is shown in the figure “Load Transfer Forecast for each Grid Substation (as of 2010 and 2025)” in the Appendix 4. This load distribution diagram is known as a "turtle shell", and it enables an easier visual grasp of load distribution. Diagrams like these are in fact commonly used for system planning not only by CEPCO[72], but by many other power companies as well.

7.5.2 Transmission Equipment Investigation for Establishment of Overloaded Pattern

As mentioned in section 7.5.1, short-term transformer capacity, in other words overloaded operating pattern, was established and load dispatching for main GSs was conducted based on this capacity. The overloaded operating pattern was calculated by the program for short-term current rating calculation with transmission line specifications (overhead transmission lines, underground transmission lines) and conditions in Sri Lanka (e.g. air temperature). Those results and concepts are written in section 7.6.

To calculate an overloaded operating pattern, the JICA Study Team collected the design documents and the testing documents for transmission lines and transformers.

7.5.3 Countermeasures against Reactive Power Compensation

The active power at each substation is predicted following by demand forecasting. The reactive power for each substation was calculated using power factor values obtained by a survey of the latest three years or so. For new substations, a power factor (PF) of 0.85 was used to be on the safe side. As discussed in section 7.5.1, a power factor of 0.95 was assumed in figuring the available output of each substation. Maintaining a power factor of 0.95 for every substation not only means reducing the voltage drop due to reactive power flow, but is also important to the maximum utilization of transformer capacity. A phase modifying equipment plan has therefore been prepared that will deploy the minimum phase modifying equipment needed to satisfy the requirement of 0.95 power factor at those substations that do not keep that value. Table 7.5.1and 7.5.2 shows this optimum phase modifying equipment plan.

[72] CEPCO: Chubu Electric Power Company

Table 7.5.1 Optimum Phase Modifying Equipment Plan (2005～2020)

year	Phase modifying equipment 220kV System			Phase modifying equipment 132kV System		
	G/S	Size(MVA)	Remarks	G/S	Size(MVA)	Remarks
2005 - 2010				Ratmalana	30	Low PF
				Aniyakanda	10	Low PF
				katana	10	Low PF
				Pannipitiya	15	Low PF
				Kolonnawa New	15	Low PF
				Kosgama	15	Low PF
				Sapugaskanda	20	Low PF
				Biyagama	30	Low PF
				Veyangoda	10	Low PF
				Kurunegagala	+5(15)	Low PF
				Madampe	15	Low PF
				Dehiwala	15	Low PF
2011 - 2015	N_Habarana(Trunk)	80	Low Voltage	Pannipitiya	+5(20)	Low PF
				Galle	+10(50)	Low Voltage
				Col-F	10	Low PF
				Trincomalee	20	Low Voltage
				Col-A	15	Low PF
				Col-I	15	Low PF
				Sithawakapura	10	Low PF
				Sri Ja'pura	15	Low PF
				Horana	15	Low PF
				Deniyaya	15	Low PF
				Ambalangoda	15	Low PF
				Baddegama	15	Low PF
				Aniyakanda	+10(20)	Low PF
				katana	20	Low PF
				Kelaniya	20	Low PF
				Peligayoda	15	Low PF
				Kurunegagala	+5(20)	Low PF
				Bolawatte	10	Low PF
				Pannala	15	Low PF
				Kuliyapitiya	15	Low PF
				Polonnawa	15	Low PF
				Ukuwela	10	Low PF
				Nuwara Eliya	10	Low PF
				Wimalasrendra	20	Low PF
2016 - 2020	Kelantissa(Trunk)	70	Low Voltage	Dehiwala	+5(20)	Low PF
	Arangala(Trunk)	150	Low Voltage	Pannipitiya	+15(35)	Low PF
	Ambulgama(Trunk)_1	150	Low Voltage	Kegalle	15	Low PF
	Pannipitiya(Trunk)	+50(150)	Low Voltage	Col-E	10	Low PF
	Chilaw(Trunk)	80	Low Voltage	Kolonnawa	20	Low PF
				Kalutara	15	Low PF
				Latpandura	15	Low PF
				Deniyaya	+5(20)	Low PF
				Baddegama	+5(20)	Low PF
				Weligama	15	Low PF
				Balangoda	15	Low PF
				Embilipitiya	15	Low PF
				Ratnapura	15	Low PF
				Gampaha	15	Low PF
				Negombo	15	Low PF
				Dekatana	20	Low PF
				Maho	15	Low PF
				Makandura	15	Low PF
				Anuradapura	+5(25)	Low PF
				Valachchanai	15	Low PF
				Trincomalee	+5(25)	Low PF
				Palleke	15	Low PF
				Peligayoda	+5(20)	Low PF
				Madampe	+5(20)	Low PF

Table 7.5.2 Optimum Phase Modifying Equipment Plan (2021～2025)

year	Phase modifying equipment 220kV System			Phase modifying equipment 132kV System		
	G/S	Size(MVA)	Remarks	G/S	Size(MVA)	Remarks
2021 - 2025	Matugama(Trunk)	150	N-0,N-1	Col-E	+15(25)	Low PF
	Biyagama(Trunk)	+20(50)	Low Voltage	Col-F	+15(25)	Low PF
	Chilaw(Trunk)	+130(210)	Low PF, Vol	Kelantissa	20	Low PF
	Bandarawela(Trunk)	100	Low Voltage	Col-A	+5(20)	Low PF
	Kelanitissa(Trunk)	+30(100)	Low Voltage	Col-I	+5(20)	Low PF
				Col-C	15	Low PF
				Col_B	20	Low PF
				Col_K	15	Low PF
				Ratmalana	+5(35)	Low PF
				Matugama	+5(25)	Low PF
				Panadura	+5(25)	Low PF
				Pannipitiya	+5(40)	Low PF
				Kolonnawa New	+5(20)	Low PF
				Sri Ja'pura	+5(20)	Low PF
				Horana	+5(20)	Low PF
				Moratuwa	20	Low PF
				Gonaduwa	20	Low PF
				Bentota	15	Low PF
				Piliyandula	20	Low PF
				Migahatenna	15	Low PF
				Puwakpitiya	20	Low PF
				Waga	20	Low PF
				Arangala	20	Low PF
				Maharagama	20	Low PF
				Deniyaya	+10(30)	Low PF
				Hanmantota	15	Low PF
				Ambalangoda	+5(20)	Low PF
				Dikwella	15	Low PF
				Kamburupitiya	15	Low PF
				Weligama	+5(20)	Low PF
				Hikaduwa	20	Low PF
				Balangoda	+5(20)	Low PF
				Embilipitiya	+5(20)	Low PF
				Thulhiriya	+10(20)	Low Voltage
				Kegalle	+15(30)	Low PF, Vol
				Kotugoda	+10(50)	Low Voltage
				Gampaha	+5(20)	Low PF
				Negombo	+5(20)	Low PF
				Mirigama	10	Low PF, Vol
				Badalgama	20	Low PF
				Ja-Ela	20	Low PF
				Hanwella	20	Low PF
				Ekala	15	Low PF
				Andimbalama	15	Low PF
				Kurunegala	+20(40)	Low PF, Vol
				Pannala	+5(20)	Low PF
				Maho	+5(20)	Low PF
				Nattandiya	20	Low PF
				Makandura	+5(20)	Low PF
				Kuliyapitiya	15	Low PF
				Hettipola	20	Low PF
				Anamaduwa	15	Low PF
				Chilaw	15	Low PF
				Anuradhapura	+5(30)	Low PF
				Habarana	+5(15)	Low PF
				Polonnaruwa	+5(20)	Low PF
				Galenbindunnuwela	15	Low PF
				Paddirippu	20	Low PF
				Trincomalee	+10(35)	Low PF
				Ukuwela	+10(20)	Low PF, Vol
				Pallekele	+15(30)	Low PF, Vol
				Naula	15	Low PF
				Kandy	30	Low PF, Vol
				Matale	20	Low PF, Vol
				Lindula	20	Low PF
				Badulla	10	Low PF

And then table 7.5.3 shows the needed amount of phase modifying equipment at new grid substations.

Table 7.5.3 Calculation Concept of needed Amount of Phase Modifying Equipment

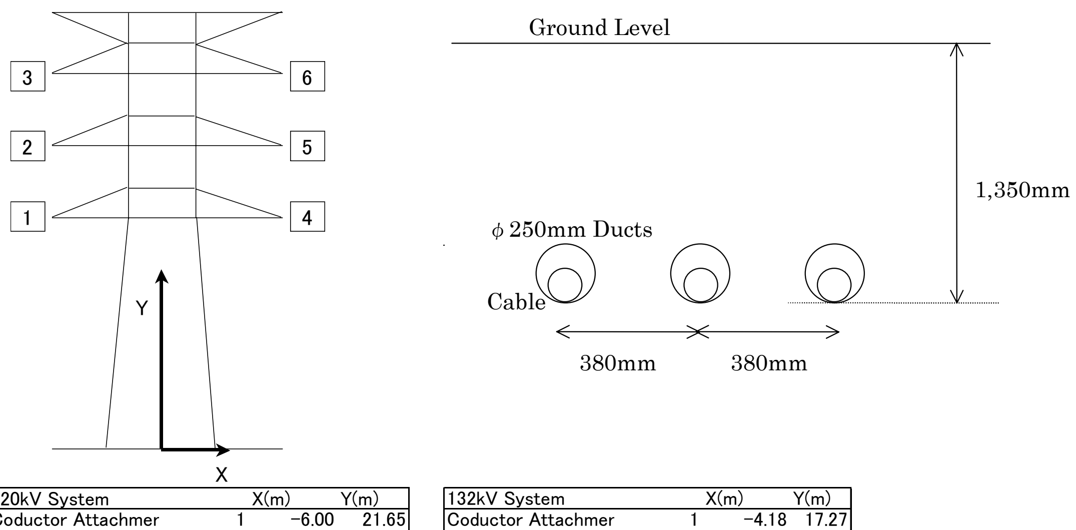
Type	Reactive Power		Needed Amount of Phase Modifying Equipment
	PF 0.85	PF 0.95	
31.5MVAx3	44.8MVAR	26.6MVAR	44.8 - 26.6 = 18.2 >> 20MVAR
31.5MVAx2	24.9MVAR	14.8MVAR	44.8 - 26.6 = 10.1 >> 15MVAR

7.5.4 Calculation of new Transmission Line Constants

The power system in Sri Lanka is constructed and equipped according to the British Standard. The system constants were calculated for the new overhead transmission lines and underground transmission lines that are planned to be put in over the next 20 years, and the table of standard transmission line constants was updated. Table 7.5.5 is a table of transmission line constants that includes the constants for both existing and future transmission lines. The standard steel tower configuration needed as a basis for calculating the new transmission line constants and the buried underground transmission line configuration are as shown in Figure 7.5.1.

Table 7.5.4 Transmission Line Constants（100MVA Base）

No.	kV	Conductor	Bundle	Cross-Section (sqmm)	R (pu/km)	X (pu/km)	B (pu/km)	Rate A Day(MVA)	Rate B Night(MVA)	Rate C Emergency(MVA)
1	132	COYOTE ACSR_54	1	130	0.001418	0.002416	0.000469	40	80	110
	132	COYOTE ACSR_75		130	0.001418	0.002416	0.000469	85	110	150
2	132	TIGAR ACSR_54	1	130	0.001418	0.002382	0.000473	40	80	110
	132	TIGAR ACSR_75		130	0.001418	0.002382	0.000473	85	110	150
3	132	ORIOLE ACSR_54	1	166	0.001096	0.002502	0.000484	45	95	130
	132	ORIOLE ACSR_75		166	0.001096	0.002502	0.000484	100	130	175
4	132	LYNX ACSR_54	1	175	0.001022	0.002301	0.000487	45	100	140
	132	LYNX ACSR_75		175	0.001022	0.002301	0.000487	105	135	185
5	132	LYNX LL-ACSR	1	175	0.000694	0.002370	0.000481	110	150	200
6	132	Bear_75	1	260	0.000628	0.002304	0.000495	130	175	235
7	220	Bear_75	1	260	0.000226	0.000867	0.001314	220	295	395
8	132	GOAT ACSR_75	1	320	0.000597	0.002268	0.000504	150	200	270
9	132	GOAT ACSR_75	2	320	0.000298	0.001699	0.000680	300	400	540
10	220	GOAT ACSR_75	1	320	0.000215	0.000854	0.001335	250	335	450
11	220	GOAT ACSR_75	2	320	0.000107	0.000612	0.001888	500	670	900
12	132	ZEBRA ACSR_54	1	400	0.000436	0.002221	0.000520	57	170	230
	132	ZEBRA ACSR_75		400	0.000436	0.002221	0.000520	165	225	300
13	132	ZEBRA ACSR_54	2	400	0.000218	0.001756	0.000703	114	340	460
	132	ZEBRA ACSR_75		400	0.000218	0.001756	0.000703	330	450	600
14	132	ZEBRA ACSR_54	4	400	0.000109	0.001264	0.000883	171	510	690
	132	ZEBRA ACSR_75		400	0.000109	0.001264	0.000883	495	675	900
15	220	ZEBRA ACSR_75	1	400	0.000157	0.000800	0.001445	275	375	505
16	220	ZEBRA ACSR_75	2	400	0.000079	0.000632	0.001952	550	750	1010
17	220	ZEBRA ACSR_75	4	400	0.000039	0.000493	0.002263	1100	1500	2020
18	132	ZEBRA LL-ACSR	1	400	0.000311	0.002233	0.000512	180	260	350
19	132	ZEBRA LL-ACSR	2	400	0.000156	0.001587	0.000711	360	520	700
20	132	ZEBRA LL-ACSR	4	400	0.000077	0.001264	0.000883	720	1040	1400
21	220	ZEBRA LL-ACSR	1	400	0.000112	0.000841	0.001356	305	430	580
22	220	ZEBRA LL-ACSR	2	400	0.000056	0.000609	0.001850	610	860	1160
23	220	ZEBRA LL-ACSR	4	400	0.000028	0.000493	0.002263	1220	1720	2320
24	132	CABLE Cu	1	350	0.000124	0.000205	0.054739	60	60	60
25	132	CABLE Cu	1	500	0.000104	0.000196	0.062342	120	120	120
26	132	CABLE CV	1	500	0.000221	0.001034	0.010191	160	160	215
27	132	CABLE CV	1	800	0.000127	0.000899	0.010507	230	230	310
28	132	CABLE CV	1	1000	0.000104	0.000884	0.011335	255	255	340
29	220	CABLE CV	1	1600	0.000024	0.000304	0.034416	750	750	1010
30	220	PHEASANT ACSR_75	1	640	0.000098	0.000815	0.001401	340	495	665
31	220	PHEASANT ACSR_75	2	640	0.000049	0.000596	0.001893	680	990	1330
32	220	PHEASANT ACSR_75	4	640	0.000024	0.000486	0.002294	1360	1980	2660
33	220	PARROT ACSR_75	1	760	0.000082	0.000804	0.001422	375	555	745
34	220	PARROT ACSR_75	2	760	0.000041	0.000590	0.001911	750	1110	1490
35	220	PARROT ACSR_75	4	760	0.000021	0.000483	0.002308	1500	2220	2980
36	400	ZEBRA 75℃	2	400	0.000024	0.000218	0.005157	1000	1360	1830
37	400	ZEBRA 75℃	4	400	0.000012	0.000182	0.006092	2000	2720	3660
38	400	PHEASANT 75℃	2	640	0.000015	0.000214	0.005258	1235	1800	2415
39	400	PHEASANT 75℃	4	640	0.000007	0.000180	0.006163	2470	3600	4830
40	400	PARROT 75℃	2	760	0.000012	0.000212	0.005298	1360	2015	2705
41	400	PARROT 75℃	4	760	0.000006	0.000180	0.006193	2720	4030	5410
42										
43										



220kV System		X(m)	Y(m)
Coductor Attachmer	1	-6.00	21.65
	2	-5.51	27.45
	3	-5.33	33.18
	4	6.00	21.65
	5	5.51	27.45
	6	5.33	33.18
Sag			10.93m
2/3Sag			7.29m
Subconductor spacing			0.4m
Insulator Length			2.83m

132kV System		X(m)	Y(m)
Coductor Attachmer	1	-4.18	17.27
	2	-3.875	21.62
	3	-3.83	25.9
	4	4.18	17.27
	5	3.875	21.62
	6	3.83	25.9
Sag			7.83m
2/3Sag			5.22m
Subconductor spacing			0.4m
Insulator Length			2.4m

Figure 7.5.1 Transmission Line Configuration for Calculation of Transmission Line Constant

7.6 Overloaded Operating Pattern Considerations of Design Conditions in Sri Lanka

Overloaded operation for transmission power system equipment is the method to utilize maximum capability of equipment considering the switching-over of power systems in the case of N-1 contingency. This view has not been taken into consideration in LTTDS. Therefore, the JICA Study Team will adopt it and establish a power system development plan incorporating effective use of the equipment.

It is possible to utilize the maximum capabilities of the equipment. So this method is used as a short-term countermeasure. Concretely, there are the two benefits shown below:

- Extending the time of expanding
- Reducing the expanding scale

In Sri Lanka where demand is forecasted to rise by around 7% every year, the system is expected to become a looped and meshed one instead of a radial one. Therefore, the switching-over of power systems and overloaded operations are expected to become more important. So adopting this view will contribute to the advancement of maintenance and operation skills in CEB.

7.6.1 Overloaded Operating Pattern of Overhead Transmission Lines

(1) View

Table 7.6.1 Conditions of Overloaded Operating Pattern Calculation (OHTL)

Items	Conditions
Lifetime of conductors	36 years
Limitation of allowable current (Normal condition) Limitation of overloaded operating period during fault	Less than rated current Less than 400 hours in total 30 minutes (fault period) × 20 times / year × 36 years = 400 hours < Basis > 90% of initial strength should remain after extinguishment. (Even though tensile strength is lost by 10%, the surface organization is not changed. There is no problem structurally. [a)])
Time to first switching-over	Five minutes or over
Calculation condition	Ambient temperature: 30℃ (night time) 35℃（day time） Wind velocity: 0.6m/sec Emissivity: 1.0 Intensity of solar radiation: 0.12W/cm2（day time） 0 W/cm2（night time）

a): Technical report from the Institute of Electrical Engineers of Japan

Temperatures established from verification tests are shown below:

- Continuous allowable temperature: 90℃
- Short-term allowable temperature: 120℃

In Sri Lanka the continuous allowable temperature is 75℃. So there is no problem under normal conditions. However, the short-term conductor temperature during faults shall not exceed 120℃. Besides that, the overloaded potion shall be switched to neighboring a system in 30 minutes to solve the overload problem. Overloaded operating patterns in the following subsections are for when conductor capacity at 75℃ is 100%. However, if system operation does not follows the pattern showned in Figure 7.6.1 and a line is operated at 100% of rated capacity under normal conditions, the conductor temperature will reach 120℃, which is rated short-term conductor temperature, within 5 minutes after faults. Therefore, the overloaded potion shall be switched to a neighboring system immediately so that the power flow will decrease to under 100% of the rated capacity and in order to solve the overload problem.

(2) Suggested Overloaded Operating Pattern

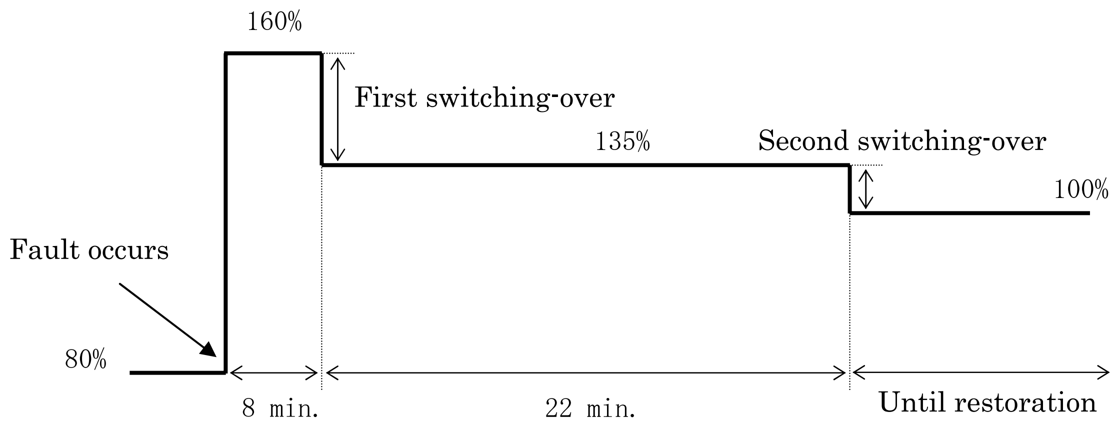


Figure 7.6.1 Suggested Overloaded Operating Pattern (OHTL)

7.6.2 Overloaded Operating Pattern for Underground Transmission Lines

(1) View

Table 7.6.2 Conditions of Overloaded Operating Pattern Calculation (UGTL)

Items	Conditions
Lifetime of cables	36 years
Limitation of allowable current (Normal condition) Limitation of overloaded operating period during fault	Less than rated current Less than 10 hours / month < Basis > There is no lifetime deterioration during operation. (Lifetime deterioration under rated capacity operation is equal to two months. On the other hand, lifetime deterioration under short-term overloaded operation is equal to 1.5 months. These values are so small that they can be treated as nothing. [a])
Time to first switching-over	Five minutes or more
Time to last switching-over	Less than eight hours (Taking time to identify the fault point is considered)
Calculation condition	Ground temperature: 30℃ Load factor: 0.8 Depth of burial: 1.35m (in the ducts) Type of burial: Duct type Thermal resistance of ground: 1.2k.m/W

a) Volume 53 - 3 of Electric Technology Research Association

Allowable temperatures based on verification tests are shown below:

- Continuous allowable temperature: 90℃
- Short-term allowable temperature: 105℃

In Sri Lanka the continuous allowable temperature is the same 90℃. So there is no problem under normal conditions. However, short-term conductor temperature during faults must not exceed 105℃. Besides that, most of the overloaded potion shall be switched to a neighboring system within 30 minutes and the rest within 8 hours in order to solve the overloaded problem. However, if system operation does not follow the pattern showned in Figure 7.6.2 and a line is operated under 100% operation of the rated capacity and normal conditions, the conductor temperature will reach 105℃, which is the rated short-term conductor temperature, in 20 minutes after first switching-over. Therefore the entire overloaded potion shall be switched to a neighboring system after the second switching-over so that the power flow will decrease to less than 100% of the rated capacity to solve the overload problem. The overloaded operating patterns in the following subsections are those in which the conductor capacity at 90℃ is 100%.

(2) Suggested Overloaded Operating Pattern

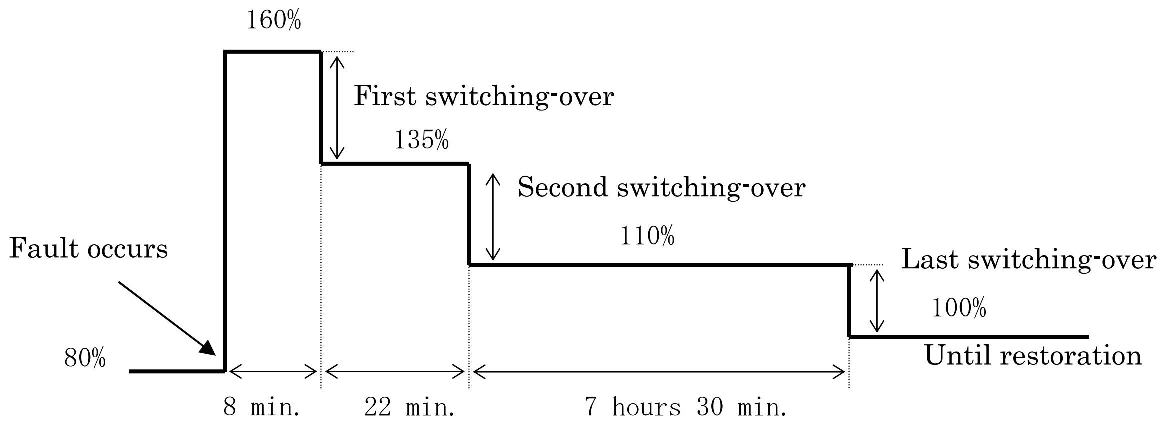


Figure 7.6.2 Suggested Overloaded Operating Pattern (UGTL)

7.6.3 Overloaded Operating Patterns of Transformers

(1) View

Table 7.6.3 Conditions of Overloaded Operating Pattern Calculation (Transformers)

Items	Conditions
Lifetime of transformers	30 years Ambient temperature: 25℃ (constant) Continuous operation under rated capacity operation Maximum temperature: 95℃
Limitation of allowable current	Less than 150% of rated current
Maximum temperature of winding	Less than 150℃
Limitation of oil temperature	Less than 100℃
Time to first switching-over	Five minutes or more
Calculation condition	Temperature rise of oil: 65K Average temperature rise of oil: 50K Average temperature rise of winding: 55K Load loss (copper loss): Depends on transformer size No-load loss (iron loss): Depends on transformer size Oil time constant: 2.0 Constant of oil: 0.8 Constant of winding: 1.0 (oil forced circulation) 0.8 (oil natural circulation) Difference between maximum temperature of winding and average one: 15K Ambient temperature: 32℃ (daily average)
Judgment condition	1% of yearly lifetime loss under operation at 95℃, maximum temperature.

a): Operating guideline for oil filled transformer (transformer reliability survey expert committee)

Allowable temperature based on verification test is shown below:

- Continuous allowable temperature: 95℃ (about 92℃ under continuous 90% of rated capacity operation)
- Short-term allowable temperature: 120℃

(2) Suggested Overloaded Operating Patterns

- ✓ Two Banks
  - ➢ Loss of lifetime: 2.13 days
  - ➢ Maximum oil temperature: 97.8℃
  - ➢ Maximum winding temperature: 104.7℃

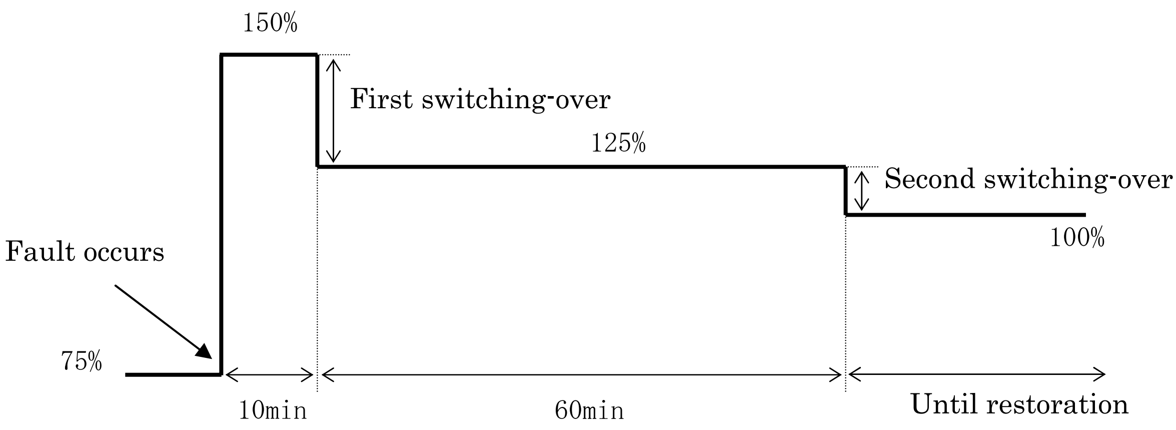


Figure 7.6.3 Suggested Overloaded Operating Pattern (Two Banks)

- ✓ Three Banks
  - ➢ Loss of lifetime: 2.21 days
  - ➢ Maximum oil temperature: 98.5℃
  - ➢ Maximum winding temperature: 105.4℃

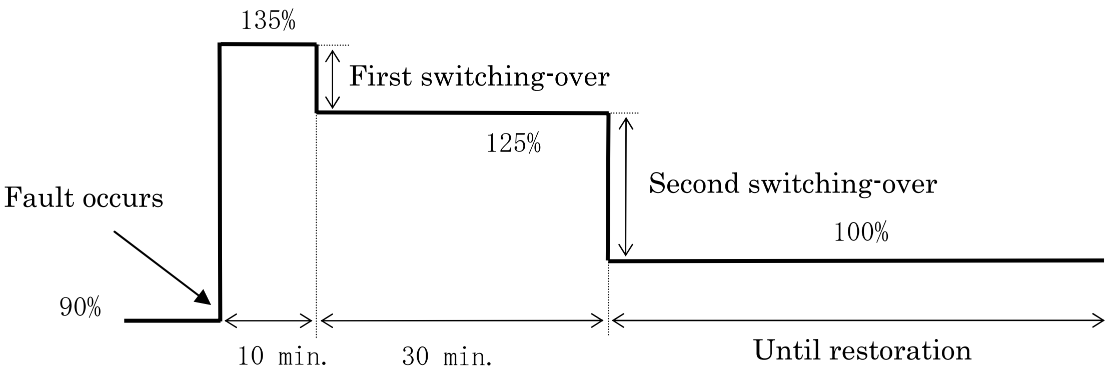


Figure 7.6.4 Suggested Overloaded Operating Pattern (Three Banks)

7.6.4 Attention Items on Operation Utilizing Overloaded Operating Pattern

Systems that have not been equipped with SCADA systems must operate using telephone communications, so that switching over the power system takes time. It is necessary, therefore, to be fully aware in advance of the following two points, and to make preparations for them.

- Establishment of a means of communication during system faults
- Advance study of load switching destinations and load switching capacity

7.7 Case Study

7.7.1 Project Objectives

As mentioned in section 7.3, it is believed that three large projects will have a considerable impact on system configuration in the transmission development plan for Sri Lanka. The first is power source lines measures for new large coal-fired thermal power, the second one is power supply measures for the northern area where the interconnection is disrupted, and the third is power supply measures for the metropolitan Colombo area. Future system configuration image and concepts are mentioned in section 7.3. This section introduces case study results for system analysis.

7.7.2 Items and Conditions for Analysis

(1) Large Coal Power Generation Project and Power Supply Measures for Metropolitan Colombo

It is assumed that Puttalam, Hambantota and Trincomalee are the prospective installation sites in this study. Detailed conditions for this study are outlined in the table below. And the study took into account the possibility that development would not proceed according to plan. The power concentration case, in which the power source is concentrated at one location, was examined. Trincomalee is situated farthest from the demand area, and power concentration seems inadvisable in terms of the demand-supply balance. Here, therefore, generation development at Trincomalee suited to demand is to be pursued.

Table 7.7.1 Conditions of Large Coal Power Generation Project and Power Supply Measures for Metropolitan Colombo

Items	Conditions	Remarks
Study Objects (remarkable objects)	Transmission system from three generation sites for the metropolitan area: Puttalam, Hambantota and Trincomalee	
Target year	Power system as of 2025	
Demand	Night peak (System Peak)	
Generation Dispatch Schedule	Thermal and Hydro maximum	
Analysis Points	Load flow analysis (normal state, N-1 state) Voltage Transient stability analysis Short circuit analysis	
Additional Study	Multiplying power supply points for Metropolitan Colombo	

(2) Measures for Power Supply to Northern Area

(i) Economic Comparison on Interconnection between Main Grid and Northern Grid

Table 7.7.2 Economic Comparison Conditions on Interconnection between Main Grid and Northern Grid

<table>
<tr><td rowspan="2">Cases</td><td colspan="2">Generation Expansion in Northern Area</td><td rowspan="2">Interconnection</td></tr>
<tr><td>Supplied by CEB only</td><td>Supplied by CEB mainly and IPPs as back-up</td></tr>
<tr><td rowspan="3">Conditions</td><td>➢ Installed number of units:
Units can meet peak demand (under N-1 condition) + one unit
➢ Supply Condition:
From IPPs before generation expansion, from CEB after that.</td><td>➢ Installed number of units:
Units can meet peak demand (under N-1 condition)
➢ Supply Condition:
From IPPs before generation expansion, 20% of consumption comes from IPPs and 80% comes from CEB after that.</td><td>➢ Kinds of transmission lines:
Lynx which has capacity to send demand in north area as of 2025
➢ Circuit Numbers;
Two circuits considering N-1 condition.
➢ Supply Condition:
From IPPs before interconnection, from CEB after that.</td></tr>
<tr><td colspan="2">➢ Construction Cost:
35MW Gas Turbine 22.4M US$
➢ Operation Cost:
CEB: 0.1270US $ / kWh
IPP: 0.1611US $ / kWh</td><td>➢ Construction Cost:
Chunnakam G/S
Kilinochchi G/S
Vavnia - Chunnakam: Lynx 2cct
15.4M US$
➢ Operation Cost:
CEB: 0.0576US $ / kWh
(CEB main grid, including construction cost of generation expansion to supply power to the north area.
➢ Transmission Loss: considered</td></tr>
<tr><td colspan="3">Economic Analysis Period: 20 years
Discount Rate: 10%（LTGEP[73] 2003）
Conversion Rate: 10.74USD / 1000LKR</td></tr>
</table>

(ii) Study of Optimum Power System and Power Development Plan in Northern Area based on Interconnection

Table 7.7.3 Condition of Optimum Power System Development Step in Northern Area

Items	Conditions	Remarks
Study Objects	Transmission Lines north of Anuradhapura GS (Including existing lines between Anuradhapura GS and Vavunia GS)	
Target year	2010, 2015, 2020, 2025	
Demand	Day Peak, Night peak (System Peak), System Bottom	
Generation Dispatch Schedule	Thermal and Hydro maximum	35MW each is installed at Jaffna in 2020 and 2020
Analysis Points	Load flow analysis (normal state, N-1 state) Voltage	

[73] LTGEP: Long Term Generation Expansion Plan

(3) Mini-Hydro Power Interconnection Study

As shown in Table 7.7.4, there are presently 39 small hydropower IPPs centered in the Central Area that are interconnected with the system. These small hydropower IPPs do not have on-line information sharing with CEB, and CEB consequently is unable to track generation conditions, connection status, or other factors. Moreover, the IPPs connect to the system and disconnect from it without determining the conditions of the system they are interconnecting with, so that they can have a negative impact on the system.

Table 7.7.4 Mini-Hydro IPPs Condition as of 2005 (MW)

Number	Sites	Operation starting	Capacity	Total Capacity
1	Balangoda	31-03-1999	2.65	27.5
		01-06-2001	3.2	
		14-08-2001	4.6	
		20-5-2002	2.5	
		02-09-2002	2.3	
		24-04-2004	0.8	
		24-05-2004	8.93	
		13-06-2004	2.52	
2	Deniyaya	9-2-1998	0.76	6.35
		01-08-1998	0.78	
		10-09-2004	4.21	
		01-02-2005	0.6	
3	Kiribathkumbura	23-06-2001	1.2	9.65
		08-10-2002	1.5	
		03-06-2003	3	
		02-12-2003	1.6	
		23-11-2004	2.35	
4	Nuwara Eliya	28-03-1996	0.07	4.41
		01-08-1999	0.11	
		01-06-1999	0.2	
		21-03-2000	2.53	
		18-05-2001	1.5	
5	Ratnapura	14-08-2003	3	15.08
		15-07-2004	2	
		21-07-2004	9.9	
		26-01-2005	0.18	
6	Seethawake	15-06-1999	0.55	7.43
		20-01-2001	1.28	
		17-04-2001	0.64	
		02-12-2003	0.8	
		19-01-2004	0.75	
		13-08-2004	1.01	
		10-09-2004	0.6	
		05-04-2005	1.8	
7	Wimalsurendra	30-04-1996	0.96	5.46
		26-06-1999	2.5	
		14-06-2002	1.3	
		16-03-2004	0.6	
		18-11-2004	0.1	
Ground Total				75.88

Consequently, the possible amount of small hydropower system connections was studied, with consideration given to the impact this would have on the system. The profiles studied were those for 2005 (hydropower maximum) and 2010 (hydropower and thermal power maximum), with the power factor for small hydropower IPPs assumed to be 0.8. The out puts of each IPPs are described in annex 11. The off peak system size was assumed to be 62% of the day peak (from the September 2004 daily load curve).

(4) Wind power Interconnection Study

There are plans for the interconnection of wind power generation in the vicinity of Puttalam. A study was therefore made of the possible size of the system interconnection and the impact it would have on the system.

As a rule, it is realistic to limit the interconnection of wind generated power to a range at which no special system countermeasures become necessary. Table 7.7.5 summarizes the features and analytical highlights of wind power generation.

Table 7.7.5 Features and Analytical Highlights of Wind Power Generation

<table>
<tr><th colspan="2"></th><th>Description</th><th>Items for Study from the System Plan Side</th></tr>
<tr><td colspan="2">Advantages</td><td>For Sri Lanka, energy resources are lacking, so this is a valuable domestically produced source of energy.
As are biomass, solar energy and others, it is environmentally friendly.</td><td></td></tr>
<tr><td rowspan="4">Issues</td><td>System</td><td>Due to the extremely high cost of power generation, support by a system of subsidies, tax incentives and other means is absolutely necessary.</td><td></td></tr>
<tr><td rowspan="2">Frequency Deviation</td><td>Storage batteries and flywheels for limiting output fluctuations must be installed in combination with wind power generation.</td><td rowspan="2">Devices to limit output fluctuation not considered.
48.75 Hz of initiation of load shedding as criterion.</td></tr>
<tr><td>Capacity for storage of wind-generated power during off peak times (23:00 to 06:00) when frequency regulation ability runs short is needed.
The below would be appropriate as a specific capacity:
Interconnected wind power generation rated output 100% x 7 hours</td></tr>
<tr><td>Transmission Line Capacity</td><td>Limitations are imposed by unused capacity of transmission lines.</td><td>Reinforcement and new installation of transmission lines not considered.
Determination based on N-1 criteria</td></tr>
</table>

(5) Study of Transmission Loss Reduction

A study was conducted to confirm the transmission loss-mitigating effect of the adoption of either low-loss transmission lines or large-size transmission lines. The ideal subject for the study was a line that carried a heavy load, where the impact would be greater. Therefore the power source lines from Puttalam PS, a large-scale power source that is planning to be installed first, was chosen. The study was conducted on the assumption of a large thermal power as the base load, and a power flow is the flow during day peak and that is maintained at a certain level throughout the day. Table 7.7.6 shows the conditions of the study.

Table 7.7.6 Condition of Transmission Loss Reduction

Items	Conditions	Remarks
Study Objects	Puttalam - Chilaw Zebra_4（400mm2）	
Alternative Lines	Large-size lines: Parrot_4 (760mm2) Low loss lines: Zebra LL[74]_4 (400mm2)	
Power Flow	at the certain level whole day 2011 to 2019: power flow of 2015 2020 to 2024: power flow of 2020 2025 to 2030: power flow of 2025	Day Peak
Factors of Economic Comparison	Economic Comparison Period: 20 years (from 2011) Discount Rate: 10% (LTGEP2003) Conversion Rate: 10.74USD / 1000LKR	
Construction Cost	Puttalam - Chilaw: 1,835.4MLKR[75] (Zebra_4 2cct) 2,571.1MLKR (Parrot_4 2cct) 2,781.1MLKR (Zebra LL_4 2cct)	
Operation Cost	0.05760US $ / kWh	
Escalation	Exclusion	

74 LL: Low Loss
75 MLKR: Million Lankan Rupee

7.7.3 Results and Assessment

(1) Large Coal Power Generation Project and Power Supply Measures for Metropolitan Colombo

(i) Most Economic Trunk Power System Plan

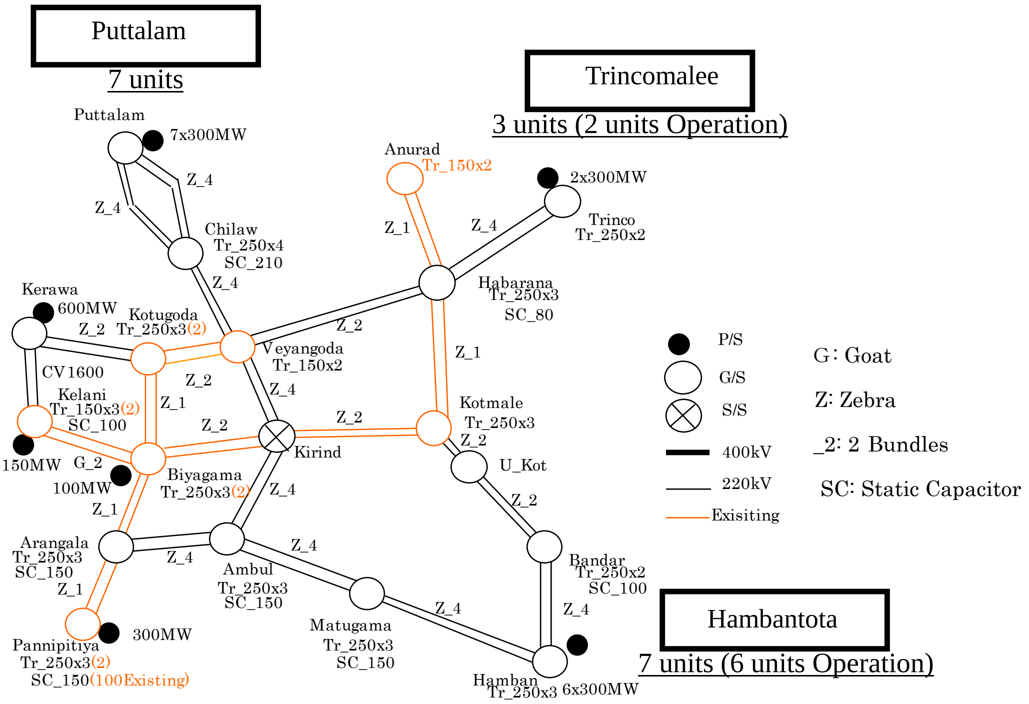


Figure 7.7.1 Optimum Power Development and Trunk Power System (2025, Night Peak)

Table 7.7.7 Most Economic Trunk Power System Development Cost (Unit of Cost: MLKR)

		Items	Volume	Cost (MLKR)
Cost	Lines	Chi - Vey	45.km	Zebra_4 2cct 16,434.7
		Put - Chi	140.km	
		Ham - Mat	135.6km	
		Tri - Hab	95.km	
		Ban - Ham	105.km	
		Vey - Kir	14.4km	
		Kir - Amb	22.2km	
		Ara - Amb	11.4km	
		Amb - Mat	58.2km	
		Ham - Vey	145.km	Zebra_2 2cct 4,720.8
		Kot - U_Kot	18.5km	
		U_Kot - Ban	48.km	
		Kotu - Ker	18.km	
		Ker - Kel	14.4km	CV_1600mm2 2cct 2,717.6
	Transformers	220 - 132 - 33 250MVA	30units	6,681.9
		220 - 132 - 33 150MVA	1units	181.4
	G/S	220kV-132kV	11places	4,168.0
	S/S	220kV	1places	369.8
	Phase Modifying Equipment (Trunk System)	SC (20MVR) Chi-210, Hab-80, Ban-100, Amb-150, Ara-150, Kel-100, Mat-150, Pan-50	49.5units	990.0
	Others			
	Total Cost			36,264.3

The coal-fired thermal power needed in 2025, according to WASP[76] calculations, is 5,100 MW (17 units x 300 MW). Of these, 14 units are power sources to be located in the area on the west side, including Colombo. Table 7.7.8 shows that the optimum development of power sources, located to minimize the reactive power compensating equipment needed for high-capacity and long-distance transmission, has seven units at Puttalam, seven units at Hambantota and three units at Trincomalee.

Table 7.7.8 Comparison among the Prospective ideas for Optimum Power Development Plan (2025 Night Peak)

	Puttalam	Hambantota	Remarks	Determination
1	7units (7units Operation)	7units (6units Operation)	Optimum Condition	◎
2	7units (6units Operation)	7units (7units Operation)	Additional reactive power compensating equipment is needed at Matugama	○
3	6units (5units Operation)	8units (8units Operation)	Additional reactive power compensating equipment is needed at Matugama	○

Additional development of up to eight units at Hambantota in the south is possible with the addition of voltage compensation devices (phase modifying capacitors and special transformers for use with phase modifying equipment) to the minimum extent considered necessary. The resulting cost of voltage compensation devices is approximately 400 MLKR. However, more than eight units development at Puttalam is impossible with the addition of voltage compensation devices. (For details, see Appendix 5.)

(ii) Power Concentration at Puttalam Case

As shown in Table 7.7.9, the stability limit means that when switching stations (S/S) are used, the possible size of the generation development only increases by 300 MW (one unit). With installation of a 400-kV system, which is one rank above the 220-kV level, the possible generation development amount only increases by 600 MW (two units). The development cost this entails is dramatically higher. The construction cost of the 400-kV system, in particular, is approximately three times that of construction of the 220-kV system. The impact is small relative to the magnitude of the substantial cost increase. If a 400-kV transmission line were to be constructed from Puttalam to Hambantota, to include a second outer loop, the generators would have greater synchronizing power and the impact would be apparent. If it were constructed from Puttalam to Veyangoda, however, the impact on the system as a whole would be slight.

If demand expands conspicuously, therefore, and still greater generation development becomes necessary, the construction of a new route would yield a more desirable solution than carrying out a drastic power concentration in the north. The possibility of a solution by 220-kV bus separation in Puttalam was also studied, but this did not improve the possible generation development size.

Table 7.7.9 Maximum Power Development in Northern Area (Puttalam) (2025 Night Peak)

<table>
<tr><th colspan="2">System Configuration</th><th>Installation of Additional S/Ss</th><th>Installation of 400kV System</th></tr>
<tr><td colspan="2">Trunk System</td><td>Puttalam - N_Chilaw:
Zebra_4 2cct×2 Routes
S/S 1 place×2_Routes
N_Chilaw - Veyangoda:
Zebra_4 2cct×1 Route</td><td>Puttalam - N_Chilaw:
Zebra_4 2cct×1 Route
S/S 1 place
Puttalam - N_Chilaw - Veyangoda:
Zebra_4 2cct×1 Route (400kV)</td></tr>
<tr><td rowspan="3">Maximum Power Development</td><td>Stability</td><td>2,400MW (8units)</td><td>2,700MW (9units)</td></tr>
<tr><td>N-1</td><td>2,400MW (8units)</td><td>3,000MW (10units)</td></tr>
<tr><td>Short Circuit</td><td colspan="2">Unit size is 300MW
2,700MW (Short circuit is under 40kA)
More than 3,000MW is available with circuit breaker and bus whose capacity is 50kA</td></tr>
<tr><td colspan="2">Cost</td><td>37,600MLKR</td><td>49,200MLKR</td></tr>
</table>

Please see the details in the Appendix 6

[76] WASP: Wien Automatic System Planning Package

(iii) Power Concentration at Hambantota Case

As shown in Table 7.7.10, the stability limit and N-1 limit mean that when switching stations are used, the possible size of the generation development only increases by 300 MW (one unit) just as in the case of a 400-kV-class installation. The development cost this entails is dramatically higher.

If demand expands conspicuously, therefore, and still greater generation development becomes necessary, then, just as in the case of power concentration in the north, the construction of a new route would yield a more desirable solution than carrying out a drastic power concentration in the south. The possibility of a solution by 220-kV bus separation in Hambantota was also studied, but this did not improve the possible generation development size.

Table 7.7.10 Maximum Power Development in Southern Area (Hambantota) (2025 Night Peak)

System Configuration		Installation of Additional S/Ss	Installation of 400kV System
Trunk System		Hambantota - Matugama: Zebra_4 2cct×1 Route Hambantota - Bandarawela: Zebra_4 2cct×1 Route	Hambantota - Matugama: Zebra_4 2cct×1 Route (400kV) Hambantota - Bandarawela: Zebra_4 2cct×1 Route S/S 1 place
Maximum Power Development	Stability	2,700MW (9units)	2,700MW (9units)
	N-1	2,700MW (9units)	3,000MW (10units)
	Short Circuit	Unit size is 300MW 2,700MW (Short circuit is under 40kA) More than 3,000MW is available with circuit breaker and bus whose capacity is 50kA	
Cost		37,800MLKR	49,300MLKR

Please see the details in the Appendix 7

(iv) High-Speed Relay System Adopting Case

Considering the fault clearance time of 120 msec specified in the existing Grid Code, the problem of stability means that excessive power concentration necessitates measures such as the installation of a 400-kV system, the addition of switching stations, or other such measures that entail enormous expense. It would be desirable, as a countermeasure to this, to employ relays capable of high-speed circuit breaking (with fault clearance time of 100 msec) for use with newly installed 220-kV trunk transmission lines. The relay system will be discussed later in section 7.8.3. High-speed circuit breaking with a time of 100 msec (5 cycles) is well within the norm for other developing countries, as well, and has already entered global widespread use. Consequently, it is not expected to add appreciably to the cost. Table 7.27 shows the results from a comparative study of possible degrees of power concentration. The transmission system here is the one representing the most economical development, as shown in section 7.7.3 (1)(A).

Table 7.7.11 Maximum Power Development with High-Speed Relay System (2025 Night Peak)

Area	Puttalam	Hambantota
Conventional Relay System (Fault Clearance Time: 120msec)	2,100MW (7units)	2,400MW (8units)
High-Speed Relay System (Fault Clearance Time: 100msec)	2,400MW N-1 issue (Chilaw - Veyangoda)	3,000MW Short Circuit Issue (More than 3,000MW is available with circuit breaker and bus at Hambantota whose capacity is 50kA)

Please see the details in the Appendix 8

(2) Measures for Power Supply to Northern Area

(i) Economic Comparison on Interconnection between Main Grid and Northern Grid

The night peak demand in 2025 is expected to be extremely small in the northern area (Jaffna), at approximately 70 MW, and even if this area is extended north of Kilinochchi, it should be no more than approximately 90 MW. Considering this in terms of thermal capacity, therefore, lynx (135 MVA: night time) is entirely adequate. An economic comparison made on this basis would yield the results as shown in Table 7.7.12.

Table 7.7.12 Result of Economic Comparison on Interconnection between Main Grid and Northern Grid

Case	Generation Expansion in Northern Area		Interconnection
	Supplied by CEB only	Supplied by CEB mainly and IPPs as back-up	
Results	Present Value (P.V): 230.0 M US $	P.V: 221.5 M US $	P.V: 117.5 M US $
	Initial Cost is big	Initial Cost can be reduced, though operation cost is expensive.	Initial cost and operation cost can be reduced.
	△	△	○

Please see the details in the Appendix 9

(ii) Study of Optimum Power System and Power Development Plan in Northern Area based on Interconnection

Separate development of the northern area alone would be uneconomical, as the results from the previous section clearly show. As demand in the northern area grows, however, the power transmission will be restricted. This is because of the problem of transmission limits due to voltage stability when transmitting power over the long distance such as approximately 200 km between Anuradhapura and Chunnakam. This is because, as shown in equation 7.1, as the length of transmission lines increases, the reactance increases and the stable transmitted power Pmax diminishes.

$$P\max = \frac{Vs \times Vr}{X}\sin 90 = \frac{Vs \times Vr}{X} \qquad \text{--- Equation 7.1}$$

Vs: Voltage of Sending End, Vr: Voltage of Receiving End, X: Reactance

To solve this problem, these solutions below are conceivable.

- ✓ Increases the value of Vs and Vr >> Higher voltage system installation
- ✓ Decreases the value of X >> Adopting multiple bundle conductor (Lynx_2, Lynx_4) or Expansion the distance between phases

But in any event, the transmission line construction cost would increase dramatically. When the total development cost is considered, including both generation and transmission, it is clear that such a project is not desirable. Consequently, a study was made of optimum development steps, including generation development, through the installation of small-scale power sources for peak power, which were suggested by WASP calculations, to deal with increasing demand in the northern area. Figures 7.7.2 to 7.7.5 show the optimum development steps yielded by the study. A T-off connection from Kilinochchi in 2025 would be effective in terms of cost. The relay settings are troublesome, however, and CEB has therefore tended not to utilize T-off connection in recent years. The situation could be handled in this case by means of a in and out connection.

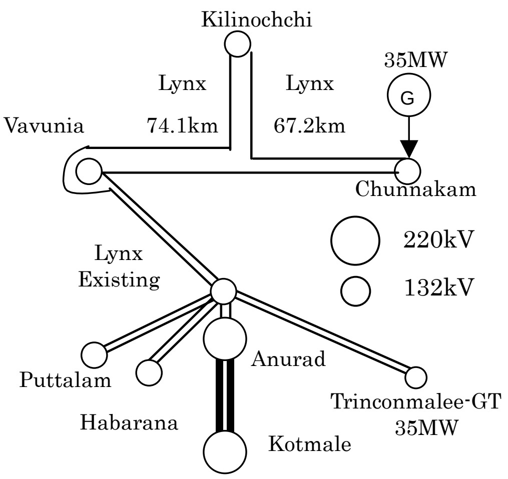


Figure 7.7.2 Diagram as of 2010 in Northern Area

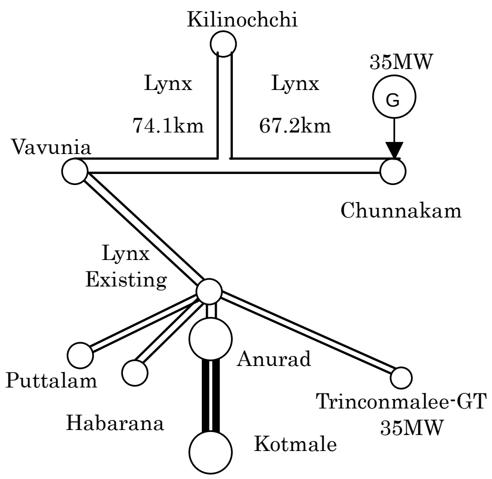


Figure 7.7.3 Diagram as of 2015 in Northern Area

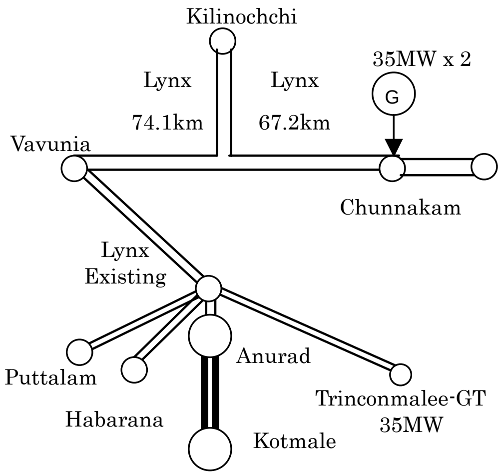


Figure 7.7.4 Diagram as of 2020 in Northern Area

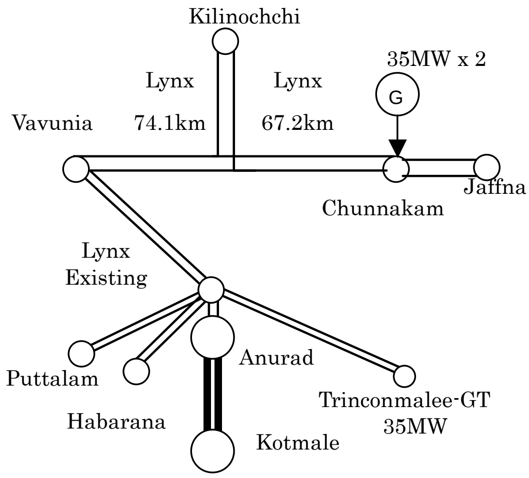


Figure 7.7.5 Diagram as of 2025 in Northern Area

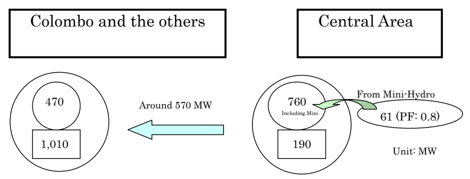
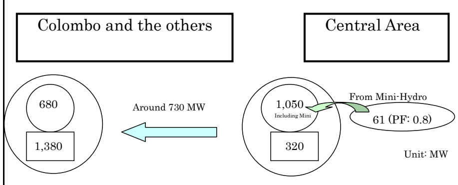
Please see the details in the Appendix 10

(3) Mini-Hydro Power Interconnection Study

When small hydropower IPPs interconnect to or disconnect from the system, problems, overloading, voltage deviation, frequency deviation arise in the vicinity of the interconnection point. Detailed checks were therefore made of overloading, voltage variation and frequency variation.

Table 7.7.13 shows the possible size of generation development from small hydropower interconnection in 2005. The table values are derived from a study of how much further system interconnection is possible other than by existing small hydropower facilities. The frequency values show the magnitude of variations that would result from the loss of small hydropower IPPs interconnected with Balangoda GS, where the largest hydropower IPP connects as of 2005. As will be made clear below, there is extra interconnection capability in the night time, but the transmission capacity of transmission lines diminishes in the day time, and interconnection is limited as a result. When the N-1 condition is taken into consideration, in particular, then clearly development of IPPs other than those currently interconnected with the system is impossible without development of the present system. Specifically, 43 MW of the 61 MW of active power should be subject to restrictions.

Table 7.7.13 Maximum Power Development by Mini-Hydro Power Interconnection (2005)

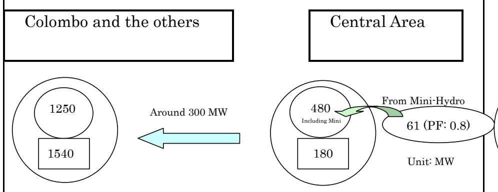
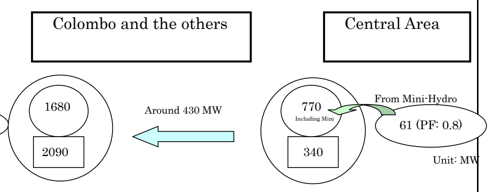
Case		Day Time	Night Time
Condition Before Additional Mini-Hydro Interconnection			
Maximum Power Development	Normal	44MW （Polpitiya - Kosgama）	309MW （Wimalsuredura Tr）
	N-1	0(-43)MW （Polpitiya - Thulhiriya）	199MW （Wimalsuredura Tr）
	Frequency	49.52Hz（No Problem）	49.66Hz（No Problem）
		Off Peak 49.17Hz (No Load shedding, No Problem)	

Please see the details in the Appendix 11

Table 7.7.14 shows the possible size of generation development from small hydropower interconnection in 2010. The table values are derived from a study of how much further system interconnection is possible other than by existing small hydropower facilities. The frequency values show the deviation that would result from the loss of small hydropower IPPs interconnected with Balangoda GS where the largest hydropower IPP connects as of 2005. There is extra interconnection capability in the night time, just as in the year 2005, but interconnection is limited in the day time. When the N-1 condition is taken into consideration, in particular, then clearly development of IPPs other than those currently interconnected with the system is impossible without development of the present system. Specifically, interconnection would be entirely impossible for 84 MW of the 61 MW of active power, which would be all of the present IPPs.

Up to this point, the interconnection size has been evaluated taking the N-1 condition into consideration. There will, of course, be ample transmission capacity available in the N-0 condition. In other words, equipping all of the hydropower IPPs with the generation control devices used for N-1 condition makes it possible to utilize the CEB transmission facilities to maximum effect. This case will be evaluated by means of a long-term economic comparison of the cost of installing generation control devices and the benefit of purchasing inexpensive power from hydropower IPPs.

Table 7.7.14 Maximum Power Development by Mini-Hydro Power Interconnection (2010)

Case		Day Time	Night Time
Condition Before Additional Mini-Hydro Interconnection			
Maximum Power Development	Normal	13MW (Polpitiya - Kosgama)	487MW (Balangoda Tr)
	N-1	0(-84)MW (Polpitiya - Kosgama)	266MW (Balangoda Tr)
	Frequency	49.66Hz (No Problem)	49.76Hz (No Problem)
		Off Peak 49.46Hz (No Load shedding, No Problem)	

Please see the details in the Appendix 11

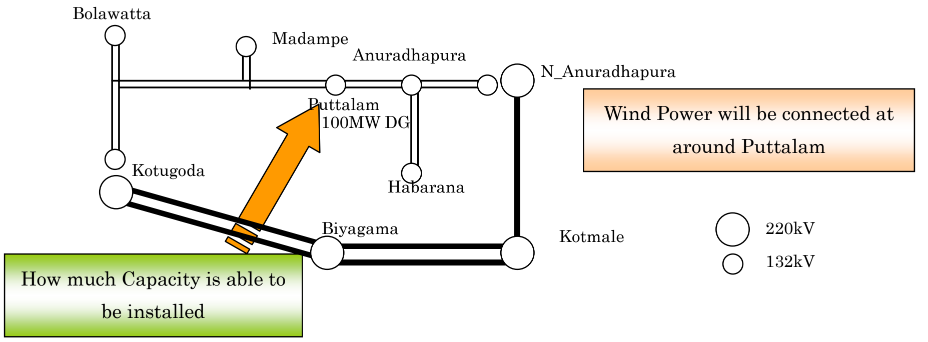
There are also the problems of harmonic and voltage deviation. Basically, calculations should be made to determine whether problems will occur when IPPs connect to the system. If there are problems, then they should be handled as problems on the side of the applicant for interconnection (the IPP or customer). Appendix 12 contains cases of measures taken in Japan that should serve as a useful reference in constructing the Sri Lankan system.

(4) Wind power Interconnection Study

When wind power IPPs interconnect to or disconnect from the system, problems, overloading, voltage deviation, frequency deviation, harmonic and so on arise in the vicinity of the interconnection point. Detailed checks were therefore made of overloading, voltage variation and frequency variation.

Table 7.7.15 shows the possible size of generation development from wind power interconnection in 2005. The frequency values show the magnitude of deviations that would result from the loss of all interconnected wind power generation facilities due to a sudden change in the wind. As will be made clear below, there is some available capacity in the transmission lines around Puttalam. Consequently, a certain amount of interconnection is possible. The greatest limitation on interconnection is determined by frequency drops during off-peak, and the limit value for development derived from that is 41 MW.

Table 7.7.15 Maximum Power Development by Wind Power Interconnection (2005)

<table>
<tr><th colspan="2">Case</th><th>Day Time</th><th>Night Time</th></tr>
<tr><td colspan="2">System Diagram</td><td colspan="2">
</td></tr>
<tr><td rowspan="3">Maximum Power Development</td><td>N-1</td><td>55MW
（Puttalam - Madampe_T - Bolawatta_T - Kotugoda）</td><td>210MW
（Puttalam - Madampe_T - Bolawatta_T - Kotugoda）</td></tr>
<tr><td rowspan="2">Frequency</td><td>49.04Hz (No Load shedding)</td><td>47.46Hz (Load shedding is needed)
100MW (Marginal volume without Load shedding)</td></tr>
<tr><td colspan="2">Off Peak
41MW (Marginal volume without Load shedding)</td></tr>
</table>

Please see the details in the Appendix 13

(5) Study of Transmission Loss Reduction

Since the demand size of night peak is the twice as that of System Bottom in Sri Lanka, even if a large thermal power is a source for base load, it is expected that the large thermal power will be obliged to be operated with power fluctuation. To prevent the complex calculation, economic evaluation was conducted under the assumption that power flow is constant as 70% of that at night peak (power flow at day peak). Table 7.7.16 shows the result.

Table 7.7.16 Study of Transmission Loss Reduction

	Normal Zebra (M US$)	Low Loss Zebra (M US$)	Parrot (M US$)
Puttalam - Chilaw: 70km 2cct Construction Cost (Incremental Cost)	19.7	29.9 (10.2)	27.6 (7.9)
Transmission Loss Reduction		6.1	9.7
Total		-4.1	1.8

Please see the details in the Appendix 14 (Figure in the Table: Present Value)

In this condition, initial investment is big, however, that investment is expected to retrieve by transmission loss reduction with adopting parrot. Nonetheless, as shown in the condition, power flow is assumed to be the same for five years and power flow is assumed to be constant (day peak value) not variable following load curve. It means laugh calculation. Therefore, the detailed review will be necessary with taking generation dispatch schedule into consideration carefully before this alternative is adopted. Especially, in case that power development does not proceed as planned like that there is power concentration at Puttalam rapidly, condition of power generation plan will be different very much and result will be also changed completely. So we must pay much attention to it.

With respect to this result, low loss Zebra lines do not yield enough effect. Nevertheless, the diameter of low loss Zebra line is the same as the one of normal Zebra and resistance is 70% of the normal Zebra moreover thermal capacity is bigger than normal Zebra. Considering these advantages, if Zebra is adopted at the early stage when power flow from the generation plant is small and then Zebra is replaced to low loss Zebra at the next stage when power development proceeds sufficiently, there could be cost merit by transmission loss reduction and effective use of existing towers. This case requires again that the detailed review will be necessary to determine whether the low loss lines are adopted and when these ones are adopted with taking generation dispatch schedule into consideration carefully.

(6) Study of Frequency Deviation under Loss of the Largest Generation Unit

(i) Investigation of System Frequency Characteristic Constant

As of 2005, the size of the Sri Lankan system is 1,700 MW at the night peak (system peak) and 1,200 MW at the day peak, with a system bottom of 700 MW. The individual generator with the greatest capacity is the 165 MW combined-cycle unit at Kelanitissa. This is extremely large, accounting for 20% or more of the system bottom. There are also many other generation facilities that have individual generators with capacity that is extremely large compared to the size of the system, and there are very many cases of generator loss resulting in conspicuous frequency drops. As explained above, the load shedding scheme has five stages. This has been limiting the frequency drops, but it makes control of demand-supply balance difficult, and the system experiences several total blackouts every year.

This study obtained 30 or more cases of frequency drops (fault data) that were followed by power source losses from the CEB load dispatching control center. The system frequency characteristic constant K was derived from these. In order to ascertain the system characteristics more accurately while acquiring fault data, all data from when load shedding was in operation and all uncertain data were excluded.

$$K(\%\mathrm{MW/Hz}) = \frac{dp/p}{df} \qquad \text{--- Equation 7.2}$$

dp: outage capacity (MW), p: demand (MW) at outage, df: maximum frequency drop at outage (Hz)

K indicates the strength of the system. It shows the rate of power source loss when the frequency drops by 1 Hz. Larger values of K mean smaller frequency variations due to loss of power sources. This K value can be used to evaluate the impact on the system of large-scale thermal power facilities of the 300 MW class that are scheduled to be added to the system in the future.

The value of K varies with the generator and the load, as shown in equation 7.3. In terms of load characteristics, the greater part of the nighttime load is from lighting. The daytime load, by contrast, also includes plant load and so on, and the type of load therefore changes. Considering, however, that industry in Sri Lanka is not large, and that the load characteristic constant is about one-third of the generator characteristic constant, it is likely that K is not very much affected by load. Next, in terms of generator characteristics, a difference emerge that is due to the speed regulation, as shown in equation 7.4. The speed regulations greater for thermal power than for hydropower, and this is why a difference emerges between them when the percentages of power generated by hydropower and thermal power differ between night and day.

The possibility that K would change by time of day was then taken into account and an analysis of the system frequency characteristic constant by time of day was carried out. Table 7.7.17 shows the results from an analysis of system frequency characteristic constants in Sri Lanka. Figure 7.7.6 presents a graph of the results from an analysis of system frequency characteristic constant for the whole day (optimized using the least square method).

Table 7.7.17 System Frequency Characteristic Constant "K"

Case	Day Peak (6～18)	Night Peak (18～23)	Off Peak (23～6)	Whole Day
K (%MW/Hz)	4.68	4.41	5.84	4.75

Please see the details in the Appendix 15

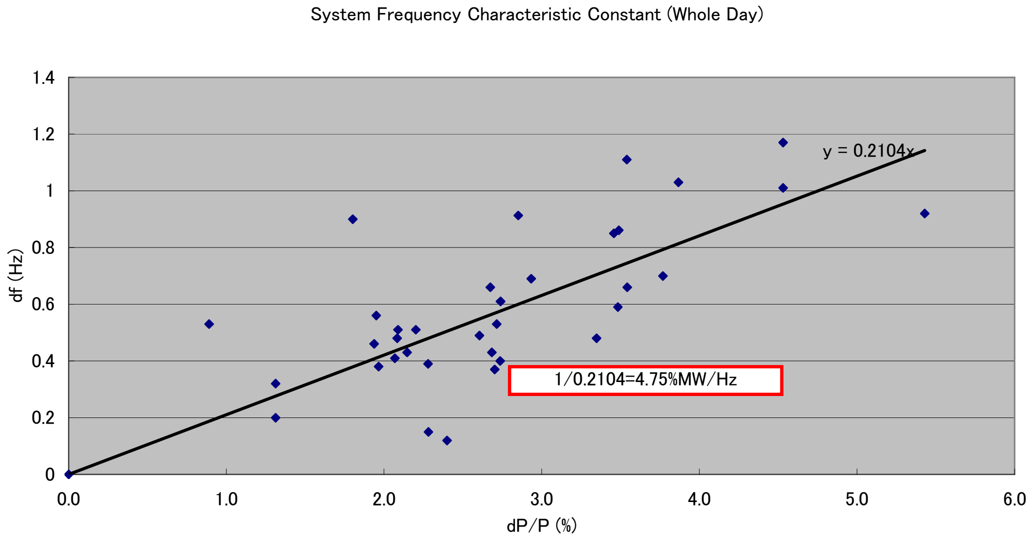


Figure 7.7.6 System Frequency Characteristic Constant (Whole Day)

$$K(\%\mathrm{MW/Hz}) = K_G + K_L \quad \text{--- Equation 7.3}$$

$$K_G = \frac{100 \times 100}{\varepsilon \times F_N} \quad \text{--- Equation 7.4}$$

KG: System Frequency Characteristic Constant of Generators (%MW/Hz), KL: System Frequency Characteristic Constant of Loads (%MW/Hz), ε :Speed Regulation, FN: Rated Frequency

There is no major difference between the nighttime and daytime values of K. The values during off-peak time appear large compared to the other data. However, this is mostly because there are only four points of measurement, and the data therefore lacks reliability. It will be necessary to collect more data and verify "K" at some future point.

(ii) Study of Frequency Deviation under Loss of the Largest Generation Unit

The system frequency characteristic constant of 4.75% MW/Hz for the whole day is then used to evaluate frequency deviations that occur when individual large thermal power generator is lost. Load shedding is not desirable from the viewpoint either of management or of system stability. Taking the lower frequency limit as the 48.75 Hz that occurs when load shedding begins, the available individual generator capacity is shown by equation 7.5.

$$CAP_{accept}\ (MW) = K\ (\%MW/Hz)\ X\ 1.25\ (Hz)\ X\ Day\ Peak\ Demand\ (MW) \qquad \text{--- Equation 7.5}$$

The most serious part of the frequency deviation problem is occurred during the off-peak period when demand is lowest. The profile of this problem must therefore be evaluated. Table 7.7.18 shows the calculation conditions.

Table 7.7.18 Calculation Conditions for Frequency Deviation

Items	Conditions	Remarks
Target year	2005～2025	Every Year
Demand	Day Peak（Off Peak）	
Unit Size of Generators	300MW (180MW)	Heat rate diminishes significantly under 60% of rated capacity. 96% of heat rate can be kept at 60% operation of rated capacity. So 180MW is the lowest available level at each condition.

Table 7.7.19 shows the results of a study of off-peak period. As will be made clear below, the question of whether 300 MW units can be added to the system even in 2025 does not have a single clear-cut answer.

Table 7.7.19 Acceptable Year of 300MW Unit Size Generators (Off Peak Case)

(Unit : MW)

	Year														
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Night Peak	2,606	2,800	3,010	3,235	3,476	3,736	4,016	4,318	4,642	4,989	5,364	5,767	6,202	6,670	7,174
Day Peak	1,846	1,982	2,128	2,284	2,453	2,634	2,829	3,038	3,263	3,503	3,763	4,043	4,344	4,668	5,017
Off Peak	1,145	1,229	1,319	1,416	1,521	1,633	1,754	1,883	2,023	2,172	2,333	2,507	2,693	2,894	3,110
Acceptable Outage Capacity	68	73	78	84	90	97	104	112	120	129	139	149	160	172	185

The 165-MW combined cycle unit at Kelanitissa shows that the permissible values for off-peak periods are already unmet at present. Under these conditions, it is not reasonable to apply restrictions only to new thermal power generation facilities.

The distinctive features of the various time periods are presented in organized form in Table 7.7.20. The load curve for Sri Lanka as a whole has the pattern of nighttime peaks due to electric lights but the load curve for Colombo, where industry is concentrated, shows daytime peaks. This is because of the conspicuous industrial expansion in Colombo, which is the center of demand. Nighttime, on the other hand, brings mainly domestic lighting demand.

The load during the daytime period must be protected without load shedding, for the purpose of continuing industrial expansion, among other reasons. In contrast, there is the matter of the load during the off-peak period from late night to early morning. As also discussed thoroughly with CEB, and in careful consideration of the current conditions of the system in Sri Lanka, the best choice for protecting the system during the off-peak period appears to be the previous method of load shedding.

Table 7.7.20 Distinctive Features of the Each period

Target Area	Peak Time	Type of Load
Metropolitan Colombo and the Vicinity of Colombo	Day Peak	Main load is plant load, industrial load and office load
The Other Areas	Night Peak	Main load is domestic lighting

The available individual generator capacity is calculated using this daytime peak period load as the base, and the results are shown in Table 7.7.21. From 2018 on, it will be possible to bring in 300 MW. Operation will be held back from a full level for the time being, however, to reach 80% operation in or after 2022, and full operation around 2025.

Table 7.7.21 Acceptable Year of 300MW Unit Size Generators (Day Peak Case)

(Unit : MW)

	Year														
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Night Peak	2,606	2,800	3,010	3,235	3,476	3,736	4,016	4,318	4,642	4,989	5,364	5,767	6,202	6,670	7,174
Day Peak	1,846	1,982	2,128	2,284	2,453	2,634	2,829	3,038	3,263	3,503	3,763	4,043	4,344	4,668	5,017
Acceptable Outage Capacity	110	118	126	136	146	156	168	180	194	208	223	240	258	277	298

Acceptable

There are 300 MW power sources currently scheduled for input from 2011 to 2017, and the following two alternatives are available regarding available individual generator capacity for that period.

Table 7.7.22 Generator Unit Size Issue from to 2017

No.	Alternatives	Cost	Affect to the System	Progress
1	Divided into 150MW x 2	17% cost up at each unit compared to alternative 2 (Total cost until 2030 is increased by 4.8%)	Frequency drop problem is remaining by existing large power generation	
2	300MW with Load shedding	Cheap	Difficult full operation Reconsideration of the amount of Load shedding and load shedding scheme	Both FS[77] and DD[78] were implemented

Finally, as of 2005, governor-free operation is being carried out only at Victoria and a limited number of other facilities. When further large-scale coal-fired thermal power generation facilities with high capacity and governor-free capability are installed, the system can be expected to show greater tolerance to frequency drops. The system frequency characteristic constant is also expected to show improvement. It is important that efforts should continue beyond the current survey so that, after the addition of large-scale power sources, in particular, continuing surveys of system frequency characteristic constants are made and the results are reflected in future decisions regarding individual generator capacity.

(iii) Frequency Deviation Forecast after Installing Large Thermal Power Generation (Consideration)

When system frequency fluctuates, the output deviations of the generators, which are under governor free operation, are represented in equation 7.6.

[77] FS: Feasibility Study
[78] DD: Detailed Design

$$\Delta Pm[pu] = \frac{\Delta f[pu]}{\varepsilon[pu]}$$ --- Equation 7.6

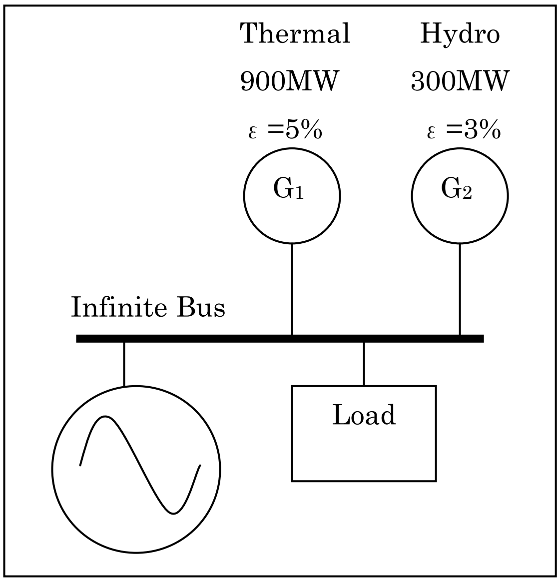
And, when two generators connect to the system in parallel, the output deviations are represented in equation 7.7.

$$\Delta f[pu] = \varepsilon_1[pu] \times \Delta P_1[pu] = \varepsilon_1[pu] \times \frac{\Delta P_1}{P_{1n}} = \varepsilon_2[pu] \times \Delta P_2[pu] = \varepsilon_2[pu] \times \frac{\Delta P_2}{P_{2n}}$$

$$\Delta Pm[pu] = \Delta P_1[pu] + \Delta P_2[pu] = \left(\frac{\Delta P_{1n}}{\varepsilon_1[pu]} + \frac{\Delta P_{2n}}{\varepsilon_2[pu]} \right) \times \Delta f[pu]$$

$$\Delta P_1 = \frac{P_{1n} \times \Delta f[pu]}{\varepsilon_1[pu]} = \left(\frac{\frac{P_{1n}}{\varepsilon_1[pu]}}{\frac{P_{1n}}{\varepsilon_1[pu]} + \frac{P_{2n}}{\varepsilon_2[pu]}} \right) \times \Delta Pm$$ --- Equation 7.7

Here a simple case study will be given in order to convey a more concrete grasp of this phenomenon. Envision a system where a 300 MW hydropower station (envision an existing hydropower station with a 3% speed regulation) and a 900 MW coal-fired thermal power station (envision a newly added thermal power station with a 5% speed regulation) operating governor-free in parallel. In this system, the output variation in generators when other power sources experience a 100 MW loss will be as shown below.



$$\Delta P_1 = \left(\frac{\frac{900}{0.05}}{\frac{900}{0.05} + \frac{300}{0.03}} \right) \times 100 = 64.3MW$$

$$\Delta P_2 = \left(\frac{\frac{300}{0.03}}{\frac{900}{0.05} + \frac{300}{0.03}} \right) \times 100 = 35.7MW$$

As will be made clear below, the generation assignments that accompany power source loss will be in proportion to generator capacity and will be in inverse proportion to the speed generation. Newly added thermal power sources are inferior to hydropower facilities in terms of the speed generation. They have a distinct impact, however, because their absolute quantities are larger, and they are thought to contribute to improvement of the system frequency characteristic constant.

(7) Small Diesel Generators Cascade Tripping Problem

(i) Present Situation in Sri Lanka

165MW combined cycle gas-turbine, which is the biggest, and a lot of small size diesel gas turbines (unit size is less than 10MW) are connected to the Sri Lankan power system at present. Considering the maximum demand (1,700MW: Night Peak), if such large unit is dropped, we can not operate system without load shedding. In addition, even though load shedding is adopted, there were a few cases that frequency was under 48Hz. Following this frequency drop, problem that gives negative impact to the system occurs due to cascade dropping of small size diesel gas turbines.

(ii) The Reason that Cascade Tripping Occurs

When the frequency fluctuates stable operation of generation plant becomes difficult. Basically the system of diesel generation is almost same as engine of cars so diesel generation is strongly resistant against frequency fluctuation. On the other hand limit of overloading is possible to be strict.

Unfortunately in this study, the JICA Study Team can not state what is a problem, because the JICA Study Team was not supplied sufficient information, detailed condition when the cascade tripping occurred and specification of diesel generation especially relay system. Nevertheless it is indisputable that diesel generators were parallel off to prevent failures before reaching frequency that equipment trouble is expected. Moreover it is strong possibility that parallel off points of some generators are set at over 48.75Hz, which is the first stage of the load shedding.

(iii) Countermeasure against the Cascade Tripping

It is difficult to identify the common value because marginal frequency is different by generators. Therefore, detailed investigation for each generator is seemed to be necessary followed by the flow below:

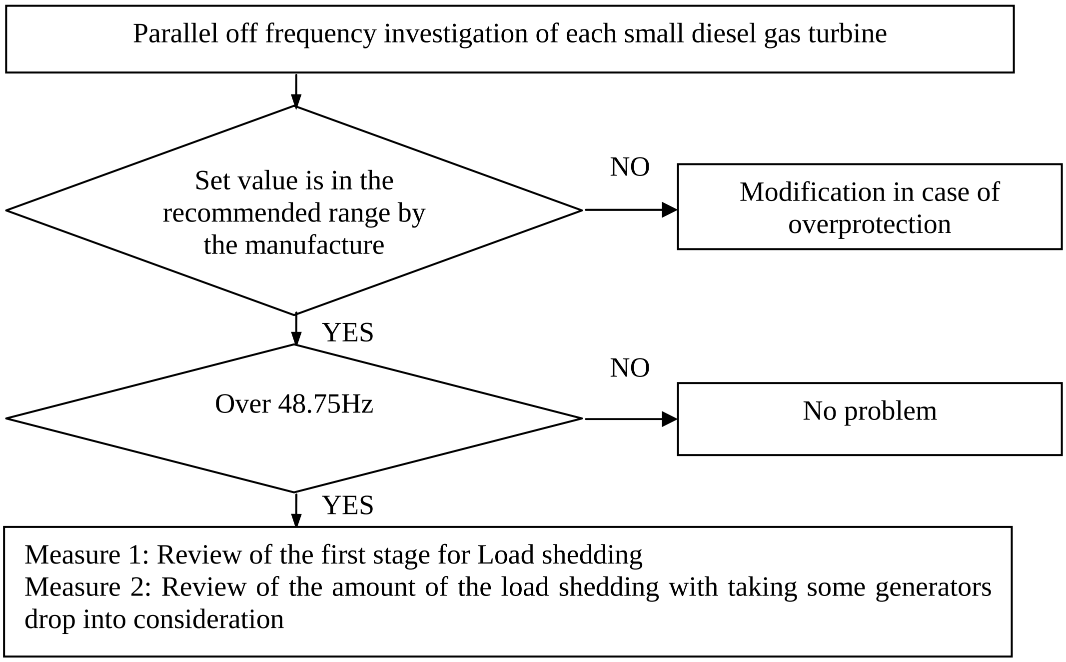


Figure 7.7.7 Flow for Cascade Tripping Prevention

(iv) Operation Guideline in Japan

It is hardly expected that frequency drops rapidly in Japan which has huge system demand. However countermeasure listed in the table 7.7.23 is considered to prevent equipment from being broken. As it is descried before, characteristic is different by equipment. Therefore the value mentioned in the list is rough standard.

Table 7.7.23 Marginal Parallel off Frequency of Equipment

Items	Phenomenon	50Hz	60Hz
Turbine	Resonance of blade	48.5Hz	58.0, 58.5, 59.0Hz
Boiler	Capacity deterioration of the auxiliary system	47.5Hz	57Hz
Generator	Over excitation	47.6Hz	57.1Hz
Turbine	Shaft oscillation	30～43Hz	40～53Hz

(Source: Text for Electric Power Techniques presented by Central Research Institute of Electric Power Industry)

(v) Problems Resulting from Increase of Diesel Generation

Small diesel generation is one effective option as short-term generation countermeasure because of low investment cost. Nevertheless, from the view point of power system, small diesel generation does not contribute to the frequency deviation control when large scale power source except small diesel generation drops. Because small diesel generation has little or nothing governor-free and its inertia is small. In the future power generation development, not large-scale thermal power generation but small diesel is developed, system frequency characteristic constant will be smaller and consequently frequency deviation problem hardly be solved.

On the other hand, small diesel generators expect to be basically connected to the distribution system (33kV system). If these are connected to local area and concentrated, short circuit, voltage deviation and distribution lines problems will be concerned.

(8) Voltage Increase Problem during Light Load Period (System Bottom)

There is little power flow and lines are just charged during light load period. Therefore, problem that voltage of power system especially at the end of system increases by Ferranti effect occurs. Since demand size of day peak is about 70% of that of night peak, reactive power is consumed at the load side and voltage increase problem is possible to be solved by dealing in phase modifying capacitors at each substation appropriately. However, generators should be under leading phase operation during light load period to absorb the lagging reactive power in the system. In particular, generators in the central area such as Victoria and generators in the North area are required leading phase operation as of 2010. When outer loop system will be completed in 2015, moreover generators at Hambantota are required leading phase operation. After 2020, other generators at Kerawarapitiya, Puttalam and Trincomalee are required leading phase operation. The leading operation capacity is around 40% of rated capacity, however, it depends on power system condition and type of facilities. Table 7.7.24 shows the list of power generation facilities required leading phase operation. And please see the details in the appendix 17

Table 7.7.24 Power Generation Facilities Required Leading Phase Operation during Light Load Period

Year	220kV System	132kV System
2010	Victoria, Kotmale, Randenigala	Chunnakam, Trincomalee
2015	Victoria, Kotmale, Randenigala, Hambantota	-
2020	Victoria, Kotmale, Hambantota, Puttalam, Trincomalee, Kerawalapitiya	-
2025	Victoria, Hambantota, Puttalam, Trincomalee, Kerawalapitiya	-

7.8 Long-Term Power System Plan

7.8.1 Outline of the Long-Term Power System Plan for 20 Years

There are mainly three points regarding the transmission development. First of all there is compliance with N-1 criteria, secondly the demand and supply balance for each area, and thirdly flexible power system operation. "Grid Substation Plan (2005 to 2025)" and "Transmission Lines Plan (2005 to 2025) shown in this section presents output based on these points. And “Power System Diagram as of 2010, 2015, 2020 and 2025” are attached in the Appendix 16. The substation demand and power generation dispatch schedule for each study profile here are as shown in Appendix 18. Studies of the daytime peak period (around 14:00), the nighttime peak period (around 19:00), and the nighttime off-peak period were made for each profile. The study was conducted on the basic assumption that hydro- and thermal power stations would both be operated to the maximum extent within the range allowing optimum system plan. The load characteristic was defined as a constant power characteristic.

Table 7.8.1 Grid Substation Plan (2005 to 2015)

year	Grid Stations, Switching Stations 220kV System			year	Grid Stations, Switching Stations 132kV System		
	G/S	Size(MVA)	units		G/S	Size(MVA)	units
2005 – 2010	Kotomale	250	1	2005	Horana	31.5	2
				2006	Ampara	31.5	1
					Havelock Town(Col A)	31.5	2
					Maradana(Col I)	31.5	2
					Sri J'Pura	31.5	2
					Dehiwala	31.5	2
					Madampe	31.5	1
				2007	Ambalangoda	31.5	2
					Galle	31.5	3
					Deniyaya	31.5	2
					Aniyakanda	31.5	2
					Pannala	31.5	2
					Maho	31.5	1
					Chunnakam	31.5	2
					Kilinochchi	31.5	1
					Polonnaruwa	31.5	1
					Medagama	31.5	1
				2008	Katana	31.5	2
					Kotugoda	31.5	2
					Kurunegara	31.5	1
					Pallekele	31.5	2
					Naula	31.5	1
				2009	Havelock Town (Col A)	31.5	1
					Maradana(Col I)	31.5	1
					Veyangoda	31.5	1
					Vavunia	31.5	2
					Padirippu	31.5	2
				2010	Kosgama	31.5	1
					Kolonawa New	31.5	1
					Panadura	31.5	1
					Athurigiriya	31.5	1
					Baddegama	31.5	2
					Weligama	31.5	2
					Kegalle	31.5	2
					Kelaniya	31.5	1
					Puttalam	31.5	1
					Anuradhapura	31.5	1
					Habarana	31.5	1
					Wimalasurendra	31.5	1

year	Grid Stations, Switching Stations 220kV System			year	Grid Stations, Switching Stations 132kV System		
	G/S	Size(MVA)	units		G/S	Size(MVA)	units
2011 – 2015	Habarana	250	2	2011	Pannipitiya	31.5	1
	Kelanttissa	150	+1(3)		Dekatana	31.5	2
	Pannipitiya	250	+1(3)		Peligayoda	31.5	2
	Matugama	250	2		Kuliyapitiya	31.5	2
	Hambantota	250	2		Pannala	31.5	1
	N-CHW	250	2		Valachchnai	31.5	2
	Ambulgama(S/S)	250	0	2012	Kalutara	31.5	2
	Arangama(S/S)	250	0		Matara	31.5	1
	Kirindiwela(S/S)	250	0		Hambantota	31.5	2
					Aniyakanda	31.5	1
					Katana	31.5	1
					Anuradhapura	31.5	1
					Ukuwela	31.5	1
				2013	Horana	31.5	1
					Maho	31.5	1
					Naula	31.5	1
					Badulla	31.5	1
				2014	Colombo Sub B	31.5	2
					Kotahena(Col C)	31.5	2
					Moratuwa	31.5	2
					Latpandura	31.5	2
					Sri J'Pura	31.5	1
					Sithawakapura	31.5	1
					Deniyaya	31.5	1
					Kelaniya	31.5	1
					Polonnaruwa	31.5	1
					Trincomalee	31.5	1
					Kandy	31.5	2
					Matale	31.5	2
				2015	Dehiwala	31.5	1
					Embilipitiya	31.5	1
					Makandura	31.5	2
					Nuwara Eliya	31.5	1

*Note : "+" represents the number of additional lines or units.
The number in parentheses represents total after augmentation.

Table 7.8.2 Grid Substation Plan (2016 to 2025)

year	Grid Stations, Switching Stations 220kV System			year	Grid Stations, Switching Stations 132kV System		
	G/S	Size(MVA)	units		G/S	Size(MVA)	units
2016 - 2020	Rantembe	250	+1(2)	2016	Gonaduwa	31.5	2
	N-CHW	250	+2(4)		Ambalangoda	31.5	1
	Kotomale	250	+1(2)		Baddegama	31.5	1
	Rantembe	250	+1(3)		Gampaha	31.5	2
	Ambulgama	250	+3(3)		Negombo	31.5	2
	Arangama	250	+3(3)		Mirigama	31.5	2
	Matugama	250	+1(3)		Peligayoda	31.5	1
	Biyagama	250	+1(3)		Nattandiya	31.5	2
	Hambantota	250	+1(3)		Minneriya	31.5	2
	Habarana	250	+1(3)	2017	Bentota	31.5	2
	Trincomalee	250	1		Weligama	31.5	1
					Kegalle	31.5	1
					Anamaduwa	31.5	2
					Hettipola	31.5	2
					Galenbindunnuwewa	31.5	2
				2018	Colombo Sub K	31.5	2
					Puwakupitiya	31.5	2
					Waga	31.5	2
					Badalgama	31.5	2
					Ja-Ela	31.5	2
					Kadawatta	31.5	2
					Dekatana	31.5	1
					Lindula	31.5	2
					Pallekele	31.5	1
				2019	Kolonawa New 2	31.5	2
					Arangala	31.5	2
					Maharagama	31.5	2
					Kalutara	31.5	1
					Latpandura	31.5	1
					Moratuwa	31.5	1
					Dikwella	31.5	2
					Hikaduwa	31.5	2
					Kegalle	31.5	1
					Negombo	31.5	1
					Makandura	31.5	1
					Jaffna	31.5	2
					Valachchanai	31.5	1
				2020	Anguruwella	31.5	2
					Balangoda	31.5	1
					Kuliyapitiya	31.5	1
					Maho	31.5	1
					Polonnaruwa	31.5	1
					Bandarawela	31.5	2

year	Grid Stations, Switching Stations 220kV System			year	Grid Stations, Switching Stations 132kV System		
	G/S	Size(MVA)	units		G/S	Size(MVA)	units
2021 - 2025	Kotugoda	250	+1(3)	2021	Piliyandula	31.5	2
	Kotomale	250	+1(3)		Kamburupitiya	31.5	2
	Trincomalee	250	+1(2)		Hambantota	31.5	1
	Bandarawela	250	2		Ratnapura	31.5	1
					Hanwella	31.5	2
					Ekala	31.5	2
					Andimbalama	31.5	2
					Mirigama	31.5	1
					Kadwatta	31.5	1
					Chilaw	31.5	2
					Hettipola	31.5	1
					Kandy	31.5	1
				2022	Colombo Sub B	31.5	1
					Migahatenna	31.5	2
					Maharagama	31.5	1
					Puwakupitiya	31.5	1
					Waga	31.5	1
					Ja-Ela	31.5	1
					Gampaha	31.5	1
					Nattandiya	31.5	1
					Nilaveli	31.5	2
					Padirippu	31.5	1
				2023	Ambulgama	31.5	2
					Arangala	31.5	1
					Hikaduwa	31.5	1
					Badalgama	31.5	1
					Anamaduwa	31.5	1
					Kilinochchi	31.5	1
					Matale	31.5	1
					Lindula	31.5	1
				2024	Kotahena(Col C)	31.5	1
					Colombo Sub K	31.5	1
					Pilyandula	31.5	1
					Dikwella	31.5	1
					Kamburupitiya	31.5	1
					Hanwella	31.5	1
					Ekala	31.5	1
					Andimbalama	31.5	1
					Chilaw	31.5	1
					Galenbindunnuwewa	31.5	1
					Minneriya	31.5	1
				2025			

Table 7.8.3 Transmission Lines Plan (2005 to 2015)

year	Transmission Lines 220KV System						Transmission Lines 132KV System					
	From	To	kinds	bundles	cct	km	From	To	kinds	bundles	cct	km
2005							Horana	Horana-T	zebra	1	2	20.0
2006							Col_I(Maradana)	Kolonnawa	CV1000	1	1	4.8
							Col_A(Havelock Town)	Col_I(Maradana)	CV800	1	1	4.9
							Col_A(Havelock Town)	Dehiwara	CV800	1	1	7.5
							Dehiwara	Pannipitiya	CV1000	1	1	8.5
2007							Matugama	Ambalangoda	zebra	1	2	28.0
							Aniyakanda	Aniyakanda-T	zebra	1	2	5.0
							Puttalam	Maho	zebra	1	2	42.0
							Pannala	Pannla-T	zebra	1	2	15.0
							Vavunia	Kilinochchi	Lynx	1	2	74.1
							Kilinochchi	Chunnakam	Lynx	1	2	67.2
							Habarana	Valachchanai	zebra	1	1	99.7
							Kotomale	Kiribathukumbra	zebra	2	2	22.5
							Rantambe	Ampara	zebra	1	2	130.0
2008	Kotugoda	Kerawalapitiya	zebra	2	2	18.0	Ukuwela	Palleke	zebra	1	2	18.0
	Kerawalapitiya	Kelantissa	CV1600	1	2	14.4						
	Kotomale	Anuradhapura	zebra	1	+1(2)	163.0						
2009							Valachchanai	Paddirippu	zebra	1	2	69.0
							Ampara	Paddirippu	zebra	1	2	35.0
2010	Randenigala	Rantanbe	zebra	1	+1(2)	3.1	Ambalangoda	Baddegama	zebra	1	1	19.2
							Baddegama	Galle	zebra	1	1(Future 2)	16.8
							Galle	Welligama	zebra	1	1(Future 2)	19.5
							Matara	Welligama	zebra	1	1(Future 2)	14.5
							Thulhiliya	Kegalle	zebra	1	2	18.7
							Veyangoda	Thulhiriya	zebra	1	2	25.0
							New Chilaw	Bolawata	zebra	1	2	22.6
2011	Kotmale	Upper Kotmale	zebra	2	2	18.5	Biyagama	Dekatana	zebra	1	2	6.0
	Veyangoda	Kirindiwela	zebra	4	2	14.4	Peligayoda	Kelaniya	Lynx	1	2	5.4
	kirindiwela	Ambulgama	zebra	4	2	22.2	New Chilaw	Kuliyapitiya	zebra	1	2	21.0
	Ambulgama	Arangala	zebra	4	2	11.4	Hambantota	Matara	zebra	1	2	83.4
	Ambulgama	Matugama	zebra	4	2	58.2	Kolonnawa(North)	Arangala(North)	zebra	1	2	14.0
	Puttalam	N_Chilaw	zebra	4	2	70.0	Kolonnawa(South)	Arangala(South)	zebra	1	2	14.0
	New Chilaw	Veyangoda	zebra	4	2	45.0	Arangala	Ambulgama	zebra	1	2	11.4
							Ambulgama	Kosgama T	zebra	1	2	10.1
							Kosgama T	Kosgama	zebra	1	2	0.5
							Kosgama T	Polpitiya	zebra	1	2	34.0
2012							Kalutara	Matugama	zebra	1	2	19.2
2013	Matugama	Hambantota	zebra	4	2	135.6						
2014							Col_C(Kotahena)	Kelantissa	CV500	1	1	1.6
							Col_C(Kotahena)	Col_B	CV500	1	1	2.0
							Col_B	Kolonnawa	CV500	1	1	4.2
							Moratowa	Pannipitiya	zebra	1	2	6.0
							Moratowa	Panadura	zebra	1	2	9.0
							Matugama	Latpandura	Lynx	1	2	13.2
							Kiribathkumbura	Kandy	zebra	1	2	10.8
							Kandy	Palleke	zebra	1	2	9.0
2015							Bolawatta	Makandura	zebra	1	2	16.20
							Makandura	Pannala	zebra	1	2	6.00

*Note : "+" represents the number of additional lines or units.
The number in parentheses represents total after augmentation.

Table 7.8.4 Transmission Lines Plan (2016 to 2025)

year	Transmission Lines 220KV System						Transmission Lines 132KV System					
	From	To	kinds	bundles	cct	km	From	To	kinds	bundles	cct	km
2016							Pannala_T	N_Chilaw	zebra	1	2	5.00
							Gampaha	Dekatana	zebra	1	2	15.0
							Kotugoda	Gampaha	zebra	1	2	16.2
							Bolawatta	Negonbo	Lynx	1	2	13.2
2017	Trincomalee	N_Habarana	zebra	4	2	95.0	Bentota	Bentota-T	zebra	1	2	12.0
	N_Habarana	Veyangoda	zebra	2	2	145.0	Anamaduwa	Anamaduwa-T	Lynx	1	2	10.8
							Hettipola	Chilaw	zebra	1	2	30.0
2018							Kolonnawa	Col_K	CV500	1	1	5.0
							Col_K	Sri J'pura	CV500	1	1	5.0
							Sithawaka	Puwakupitiya	Lynx	1	2	4.0
							Kosgama	Waga	Lynx	1	2	4.8
							Katana	Badalgama	zebra	1	2	10.8
							Kotugoda	Ja-Ela	zebra	1	2	4.2
2019							Pannipitiya	Maharagama	zebra	1	2	4.8
							Hikaduwa	Baddegama	Lynx	1	2	10.2
							Jaffna	Chunnakam	Lynx	1	2	10.8
2020	Puttalam	N_Chilaw	zebra	4	2	70.0	Bandarawela	Bandarawela-T	zebra	1	2	18.0
2021	Hambantota	Bandarawela	zebra	4	2	105.0	Kamburupitiya	Kamburupitiya-T	Lynx	1	2	7.5
	Bandarawela	Upper Kotmale	zebra	2	2	48.0	Thulhiliya	Thulhiriya-T	zebra	1	2	23.9
							Kosgama	Kosgama-T	zebra	1	2	0.5
							Galle	Baddegama	zebra	1	+1(2)	16.8
							Galle	Welligama	zebra	1	+1(2)	19.5
							Matara	Welligama	zebra	1	+1(2)	14.5
							Ambulgama	Anguruwela	zebra	1	2	36.0
							Habarana	Minneriya	zebra	1	+1(2)	19.8
2022							Matugama	Migahatenna	zebra	1	2	16.2
							Nilaveli	Trincomalee	Lynx	1	2	15.0
2023												
2024												
2025												

Power system mainly progresses from time to time in tandem with the development of large-scale power sources. Table 7.8.5 sets forth the long-term trunk system plans in five-year segments and enumerates the distinctive features of the various stages of development up to the year 2025.

Table 7.8.5 Trunk System Plan

Period	Distinctive Features of Development
2005 to 2010	The period that trunk system develops in the vicinity of Colombo in tandem with the power generation development at Kerawrapitiya.
2011 to 2015	The period that trunk power lines and second outer loop around Colombo are constructing in tandem with the power generation development at Puttalam and Hambantota.
2016 to 2020	The period that trunk power lines are constructing in tandem with the power generation development at Trincomalee. The period that trunk power lines are reinforcing in tandem with the power generation development at Puttalam.
2021 to 2025	The period that trunk power lines are reinforcing in tandem with the power generation development at Hambantota.

7.8.2 Trunk Power System Establishment (Consideration)

(1) Study of Trunk Lines Conductor Size

(i) Puttalam - Chilaw - Veyangoda

It is essential condition that trunk lines require the capacity to supply power in 2025 of this master plan's final year. Besides that, power concentration is expected considerably. So finally trunk lines shall need capacity to be able to supply power when 2,400MW of maximum available development at Puttalam (Case that high-speed relay system is adopted) operates.

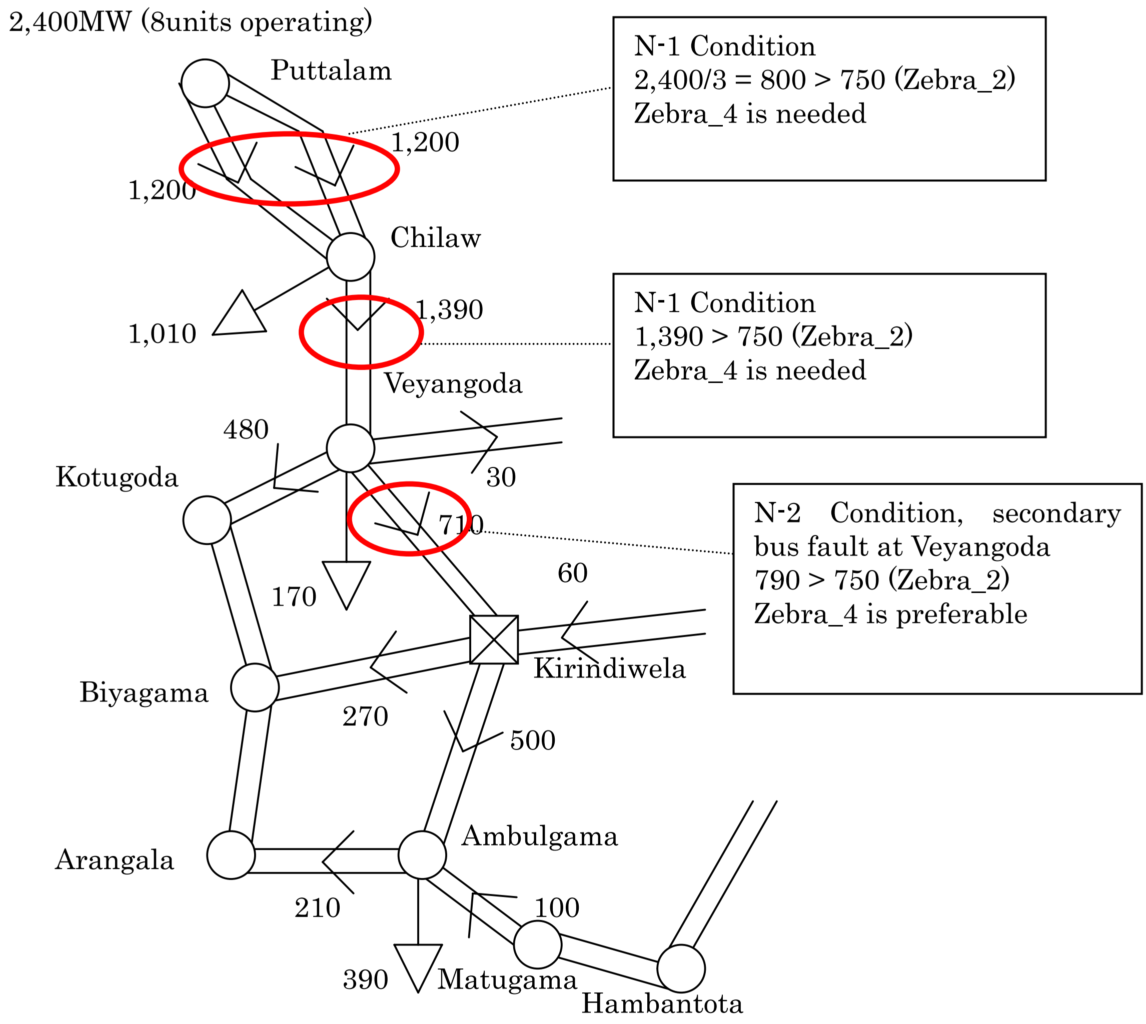


Figure 7.8.1 Study of Trunk lines Conductor Size (Northern Area)

(ii) Hambantota - Matugama, Hambantota - Upper_Kotmale

It is essential condition that trunk lines require the capacity to supply power in 2025 of this master plan's final year. Besides that, power concentration is expected considerably. So finally trunk lines shall need capacity to be able to supply power when 2,700MW of maximum available development at Hambantota (Case that high-speed relay system is adopted) operates.

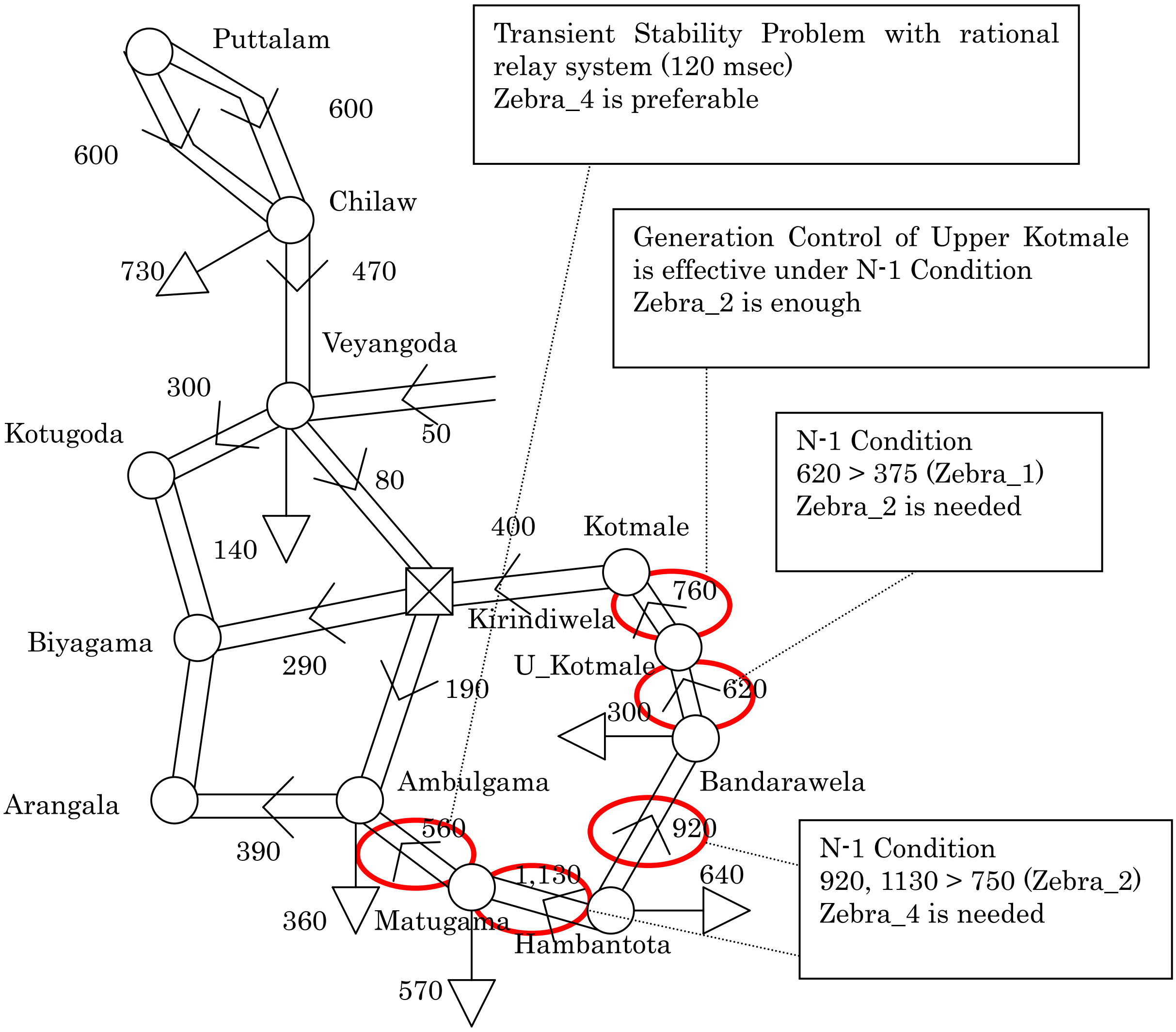


Figure 7.8.2 Study of Trunk lines Conductor Size (Southern Area)

(iii) Second Outer Loop

It is desirable that there is a little power flow on this second outer loop because second outer loop is an interconnection. However installing large size transmission lines is desirable to improve synchronizing power of generators located at edge of system and to enable power interchange to be smooth between western north province and western province. As it is clear in (i), in case of power concentration at northern area, the power flow between Veyangoda and Kirindiwela could be 710MW in normal state and 790 MW in emergency state that there is fault with secondary bus at Veyangoda GS. It means that there is possibility that Zebra_4 is necessary for the second outer loop. Considering uncertain factors such as future power generation site and interconnection point, to construct whole second outer loop with zebra_4, which is the same as the one used for power lines, is preferable

(2) Two Routes for Important Power Lines

Since the power flow at the large-scale power lines from Puttalam and Hambantota are huge, if route failure (2 circuits failure at the same time) occurs, large scale load shedding will be needed. In addition, in the worst case, it is possible to cause system collapse followed by route failure. Basically there is no problem while N-1 criterion, which is worldwide standard, is satisfied. However considering the Sri Lankan characteristics that most of demand is supplied using these large-scale power lines, to give consideration to the countermeasures against route failure is necessary to improve reliability.

Countermeasure of changing from double circuits in one route to double circuits in two routes is the optimum from the viewpoint of reliability. Nonetheless, construction cost becomes 1.6 times (132kV zebra case) more expensive than the original one because additional route, towers and foundations are necessary. More than that, acquiring land for two routes is hard to say optimum countermeasure from the viewpoint of environmental and social considerations. Table 7.8.6 shows the factors why double circuits in two routes is discussed worldwide. After reliability and cost are taken into consideration, not the countermeasure of double circuits in two routes but the other countermeasures described in the table 7.8.6 are adopted in almost cases. In CEPCO there has been discussion about the countermeasure of double circuits in two routes, however this countermeasure was adopted in the heavy snowy area only and now that is not acceptable.

Table 7.8.6 Factors why Double Circuits in Two Routes is Discussed

Factors	Possibility in Sri Lanka	Countermeasures (Except Double Circuits in Two Routes)
Tower collapse due to snow and ice accretion	Impossible	Tower design reinforcement by review of snow and ice accretion weight
Tower collapse due to galloping	Impossible	Tower design reinforcement by galloping phenomenon analysis (Galloping is the phenomenon that conductors with unbalanced ice or snow accretion oscillate up and down by strong wind. Therefore galloping is unexpected to occur in tropical area like Sri Lanka.)
Line to line fault due to galloping	Impossible	Expanding the distance between phases by review of distance design between phases
Route failure due to lightning	Possible	Insulation strength reinforcement by review of insulation design
Tower collapse due to land slide	Possible	✓ Avoidance of route where land slide possibly occurs (Boring test, Groundwater level test, Soil density test, Surface oscillation measurement test) ✓ Countermeasure to pretend land slide physically (Pile or anchor setting, Groundwater shutting by chemical grouting, Slope protection)

The most serious problem against route failure is lightning, therefore insulation strength reinforcement by review of insulation design is the most efficient countermeasure. Two useful and concrete methods about review of insulation design are described below. Nevertheless, it is impossible to prevent failures due to lightning completely and it is meaningless on cost performance to pretend failures due to lightning next to 100%. Adequate allowable failure rate should be adopted to the insulation design considering power system condition in Sri Lanka. Important power lines in CEPCO are designed not to occur more serious than 4LG fault (2 circuits failure at the same time).

(i) Insulation Design Reinforcement against Failures due to Lightning

Table 7.8.7 shows the useful countermeasures for insulation design reinforcement against failures due to lightning. Especially the countermeasure of distance expansion between horns and the countermeasure of reduction of tower grounding resistance are useful. However as mentioned before, overprotective design is costly and uneconomic. Therefore CEPCO's design is presented as a reference to help CEB design. Design for 275kV, which is the closest to the trunk system (220kV) in Sri Lanka, is presented here. And surge protective devices for 220kV class is under development. So adoption that system is difficult at present.

Table 7.8.7 Insulation Design Reinforcement Countermeasures against Failures due to Lightning

Useful Countermeasures	Reference data CEPCO（275kV System）	Remarks
Distance expansion between horns	2,300mm	Design failure rate: 2 / 100km*year Actual record: 1.1 / 100km*year (1973 to 2001) Density of lightning: 0 to 6 / km2*year (Investigation implemented by WMO[79] in 1953 shows that there is little difference of density of lightening between Sri Lanka and Japan.)
Reduction of tower grounding resistance	13Ω	
Shielding angle reduction	0 degree (Shielding efficiency: 98%)	
Surge protective devices installation	No record (There is adoption record 154kV and lower voltage)	The other power companies (KEPCO[80]) are developing devices. (These devices are costly because of large size and heavy weight and high spec to withstand large lightning)

(ii) Unbalanced Insulation Design

Unbalanced insulation design is the method to set insulation strength difference between two circuits. More than 10% insulation strength difference between stronger side and weaker side is common. And it is the basic concept that the insulation strength at weaker side is designed to withstand switching surge.

The number of route failure declines by adopting this method but the number of failure itself does not decline. And if the insulation strength at weaker side is set weaker than standard design, the number of failure will increase. It is natural but paying attention to that is necessary.

7.8.3 Protective Relay System Development Plan

(1) Protective Relay System Restructuring of Existing Trunk Power Lines for Hydro Power

(i) Process of Restructuring

As noted earlier, the upgrading of relays on the existing trunk power lines for hydropower (Rantambe-Kotugoda) is expected to involve some rather difficult problems. It should be possible to address those problems, however, through the below countermeasures.

✓ Case 1 (Transmission lines cannot be stopped)

Relays cannot be replaced until the system status makes it possible to stop the transmission lines. The Victoria-Rantambe section, in particular, is presently a single circuit transmission line, so stopping it is impossible. If it is possible to operate the system by separating the 220-kV system into east and west sides, then the upgrading will be possible. If system operation does not allow transmission lines west of Victoria, including the zebra_2 double-circuit system, to be stopped, then the present condition should be maintained until a power source on the same hydropower base is created that can replace the present power source (a power source capable of base load supply to interconnect with load-side systems that include Colombo). There is no alternative but to concentrate carefully on maintenance so that no faults occur.

✓ Case 2 (One circuit of a double-circuit transmission line can be stopped)

The Kotmale GS does not currently have a transformer linking 220-kV and 132-kV systems and is serving only as a switching station. In other words, the 220-kV system and the 132-kV system are separate. The hydropower facilities that are interconnected with the 220-kV system generate a maximum of about 400 MW during the monsoon season. The zebra_2 double-circuit system west of

[79] WMO: World Meteorological Organization
[80] KEPCO: Kansai Electric Power Company

Victoria has a transmission line single-circuit capacity of 550 MVA (daytime), which means that it is basically capable to transmit maximum power of 400MW with single-circuit. Consequently, one of the transmission line circuits can be stopped and the relays can be replaced. It would be desirable, however, to do the replacement work during the dry season, when the upstream power flow is smaller.

(ii) Study of Restructuring Equipment

Since this is a trunk system, it would be desirable to install replacements that utilize a digital PCM[81] system for transmitting relay information. This would make it necessary to lay optical cable--work that is generally done by winding optical cable around an existing overhead ground wire. The cost therefore increases in direct proportion to the distance.

On the other hand, although there are several cost-reducing alternatives, they are difficult to adopt for the reasons outlined below.

Communications systems that use the PLC[82] method only require the installation of terminal equipment at each substation and therefore can be expected to reduce costs. The transmission information capacity is low, however, making these systems unsuitable for the current differential relay system. They are used mainly with distance relays. This system also experiences a much larger number of malfunctions caused by noise than the PCM method, and that makes it difficult to implement on this hydropower system, which is both a loop system and a trunk system. Another possibility is the conventional FM[83] method, which uses analog signals. This is subject to modulation error and other such problems, however, which make this method difficult to adopt.

(2) Protective Relay System of New Trunk Power Lines

Considering the dramatic improvement in system stability resulting from shortening of fault clearance times, and the promotion of SCADA systems for adoption, it would be desirable to install OPGW on all new trunk transmission lines. High-speed circuit breaking and other such matters are also a consideration for relays. In that light, it would be desirable to utilize PCM, which is mainly used for a current differential relay system. It should be entirely possible to achieve a fault clearance time of five cycles (100 msec) from the occurrence of a fault to the circuit breaking operation, if the relay operating time is taken to be two cycles (40 msec) and the circuit breaking operation is considered to take three cycles (60 msec).

[81] PCM: Pulse Code Modulation
[82] PLC: Power Line Carrier
[83] FM: Frequency Modulation

7.9 Desirable Future Study from the view point of Power System Plan

7.9.1 Review of Thermal Capacity of Transmission Lines

The overhead transmission line thermal capacity in Sri Lanka is largely determined by the design temperature of transmission lines, which is 75°C. Some of the conventional facilities, however, are designed to operate at 54°C, and review for gradual upgrading to 75°C is currently underway in conjunction with a study of necessary distances below the wires. As explained in section 7.6, the design temperature has been determined on the condition that lines will maintain their rated strength and shape following extinguishment. Acceleration testing showed that continuous operation over a 36-year period at 80°C would result in 10% strength deterioration (within rated range), but the lines do not actually operate under full load in real use. It has been decided from the record of past performance in Japan that a temperature of 90°C does not cause any problems, and the allowable transmission line temperature has consequently been set at 90°C[84].

The environments in Japan and Sri Lanka are different, so it is difficult to generalize. Operation at 80°C secures both strength and shape, however, and review of the allowable temperature would therefore appear necessary, both to improve transmission line thermal capacity and to reduce costs. The study will also require detailed surveys of the design conditions (weather conditions in Sri Lanka), acceleration and strength testing, distance between line and ground, and so on. Table 7.9.1 shows projected transmission capacity increases for representative transmission lines.

Table 7.9.1 Projected Overhead Transmission Line Thermal Capacity Increases

Type		at 75℃ Current Rating (A)	at 80℃ Increment (Compared with that at 75℃)	at 90℃ Increment (Compared with that at 75℃)
Lynx	Day	464	About 10%	About 25%
	Night	607	About 5%	About 15%
Zebra	Day	726	About 10%	About 30%
	Night	987	About 5%	About 15%

Condition of the calculation is the same as that used for overloaded operation pattern

7.9.2 Effective Use of Aging Facilities

Deterioration in overhead transmission lines occurs primarily from rust development on steel towers and on conductors. There are also some lines in Sri Lanka, as shown in Table 7.9.2, that have been in use for 40 years or more, and these require caution. This deterioration over time is ordinarily addressed by replacing lines and rebuilding steel towers, but this is expensive. The remaining thickness of the steel is therefore tested using an electromagnetic thickness gauge, and the condition of the line strands is surveyed using sampling tests. Means such as these are used to evaluate the facilities and determine whether their life can be extended. Making the appropriate improvements to facilities can be expected to reduce costs.

Similar statements can be made about transformers, circuit breakers and other such substation equipment. The deterioration of insulating oil is evaluated by analysis of insulating oil samples, and the insulating oil or insulating gas in circuit breakers is sampled for evaluation. These and other such means are used to evaluate the possibility of extending facility life.

In either case, the establishment of diagnostic indicators will be necessary as know-how for future maintenance of the facilities.

[84]: Technical report from the Institute of Electrical Engineers of Japan

Table 7.9.2 List of Commencement Year for Transmission Lines

132kV LINEs	YRCOM
KOLONNAWA-KOTUGODA	1960
KOTUGODA - BOLAWA	1960
ORUWALA SPUR	1960
POL'YA PS-KOLONNAW	1960
BADULLA-INGINIYAGA	1963
BOLAWATTA - PUTTAL	1963
KIRIBATHKUMBURA-KU	1963
KOLONNAWA-KELANITI	1963
NEW LAXAPANA-BALAN	1963
OLD LAXAPANA-WIMAL	1963
BALANGODA-GALLE	1964
ANURADHAPURA -TRIN	1971
KOLONNAWA-PANNIPIT	1971
OLD LAXAPANA-POLPI	1971
PANNIPITIYA - RATM	1971
POL'YA PS-ANURADHA	1971
POL'YA PS-KOLONNAW	1971
SAPUGASKANDA SPUR	1971
THULHIRIYA SPUR	1971
NEW LAXAPANA-POLPI	1974
OLD LAXAPANA-NEW L	1974
NEW LAXAPANA-CANYO	1983
UKUWELA PS-BOWATEN	1983
UKUWELA SPUR	1983
KOTHMALE SPUR	1984
BIYAGAMA - KELANIT	1985
BIYAGAMA-SAPUGASKA	1985
PANNIPITIYA - MATU	1985
BIYAGAMA - PANNITI	1986
RANTEMBE PS - BADU	1986
KIRIBATHKUMBURA SP	1989
BALANGODA-SAMANALA	1992
SAMANALAWEWA PS-EM	1992
KIRIBATHKUMBURS SP	1994
CHILAW SPUR	1995
HABARANA - VALACHC	1995
PANADURA SPUR	1995
POTHUWATAWANA/MADA	1997

220kV LINEs	YRCOM
RANDENIGALA PS-RANT	1985
KOTMALE PS-VICTORIA	1985
BIYAGAMA - KOTUGODA	1985
BIYAGAMA - KOTMALE	1985
VICTORIA PS - RANDEN	1985

Table 7.9.3 List of Commencement Year for Transformers

No.	Substation	Unit Number	YRCOM
1	Biyagama	1,2	1983
2	Kotugoda	1,2	1981
3	Rantambe	1	No Data
7	Bolawatta	1,2	1986
9	Sapugaskanda-GS	1,2,3	1981
10	Puttalam	1,2	1993
11	Anuradhapura	1	1969
		2	1975
		3	1968
13	Trincomalee	1,2	1978
14	Habarana	1	1969
		2	1968
		3	1968
15	Kiribathkumbura	1,2	1986
16	Kurunegala	1,2	1986
17	Ukuwela-GS**	1,2	1968
19	Thulhiriya	1,2	1989
20	Kelanitissa	1,2	1980
24	Fort (Colombo F)	1,2,3	1984
25	Kollupitiya (Colombo E)	1,2,3	1984
26	Kolonnawa**	1,2	1957
		3	1962
27	Ratmalana	1	No Data
		2	1973
		3	1994
28	Oruwala		No Data
29	Pannipitiya	1,2	1982
30	Pannipitiya	3	1994
31	Matugama	1,2	1993
32	Galle	1,2	1980
		3	1987
34	Wimalasurendra	1,2	1989
35	Balangoda	1,2	1963
36	Deniyaya	1	1975
		2	1972
		3	1969
37	Embilipitiya	1	1978
		2	1975
38	Badulla	1	1983
		2	1987
40	Nuwaraeliya	1,2	No Data
42	Panadura	1	1993
		2	1994

Chapter 8 Economic and Financial Analysis

8.1 Financial Statement Analysis

The financial crisis of CEB has been repeatedly pointed out by various parties. This chapter will analyze the pro forma financial statements of CEB, in order to assess the actual situation of CEB. At the time of this analysis, the figures for 2004 have not been officially approved. Therefore, the analysis is based on the preliminary figures.

8.1.1 Profit and Loss Statement

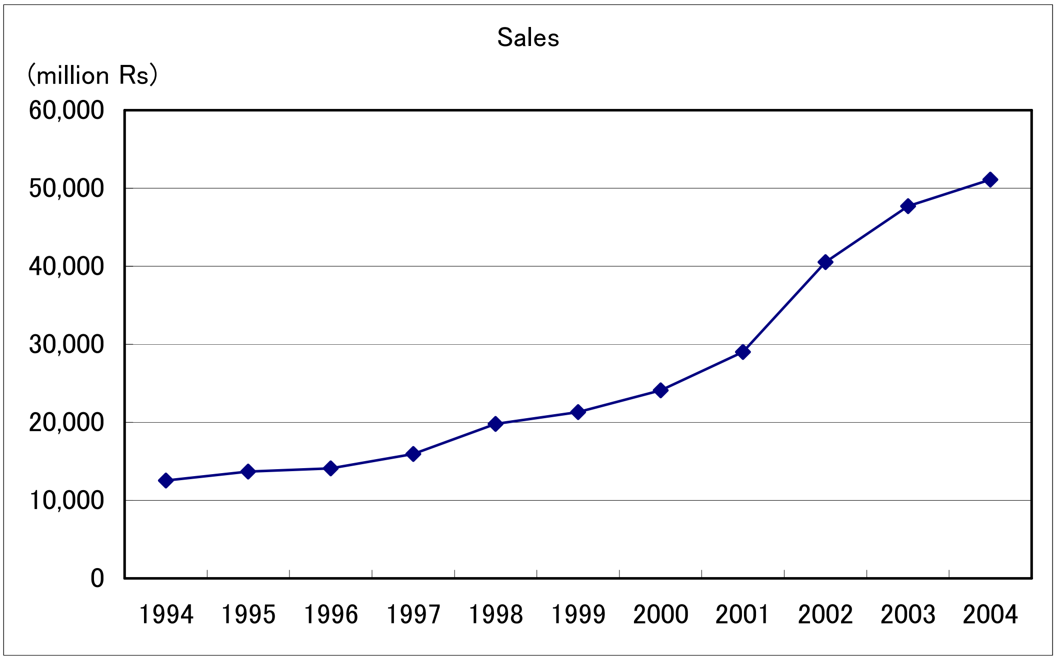
The table shows the profit and loss statement for CEB.

Table 8.1.1 Profit and Loss Statement
(million Rps)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Sales	12,533	13,709	14,100	15,932	19,787	21,304	24,086	29,029	40,544	47,719	51,114
Fuel	912	987	3,950	5,534	2,553					11,023	17,386
GenHire			562	1,309	104					4,725	5,193
PowerPurchase			1,206	1,228	2,475					14,636	19,738
Generation Cost	912	987	5,718	8,071	5,132	0	0	0	0	30,383	42,318
Trans/Dist Cost	1,389	1,574	1,982	2,515	2,836	0	0	0	0	7,854	7,165
Administration	905	818	1,039	1,298	1,754					2,350	819
Other expenses	843	953	1,518	716	1,359					2,461	2,529
Depreciation	3,362	3,694	4,223	4,815	5,078					7,662	9,346
Operatiing Profi	5,122	5,683	-379	-1,483	3,628	4,880	-6,507	-6,112	-4,771	-2,991	-11,063
Interest Charges	2,741	2,324	2,360	2,464	2,806	1,905	2,425	4,822	6,552	5,969	6,437
Other Income	1,408	1,868	2,834	1,858	1,331	1,260	2,209	1,734	3,837	5,210	2,310
Net Profit	3,789	5,227	96	-2,089	2,153	4,235	-6,723	-9,200	-7,486	-3,750	-15,189

Source: CEB

Sales have been increasing at an aggressive pace (Figure). As the power sales (kWh) grew at 7-8% annually, the sales also grows. Along with the effect of the tariff increase, the annual growth of the sales is 15%. Due to the strong demand, the sales haven't seen any decline in spite of the frequent complaints about the high tariff. In 2004, however, the sales grew by only 7%, which some points out as the effect of the tariff.



Source: CEB

Figure 8.1.1 CEB's Sales

The cost structure showed drastic changes in the past ten years. The fuel cost, which occupied a mere 7% of the total sales, has exploded into occupying 34% of the total sales. Another fast growing item is the power purchase cost that started in 1996. In 2004, it is 39% of the total sales.

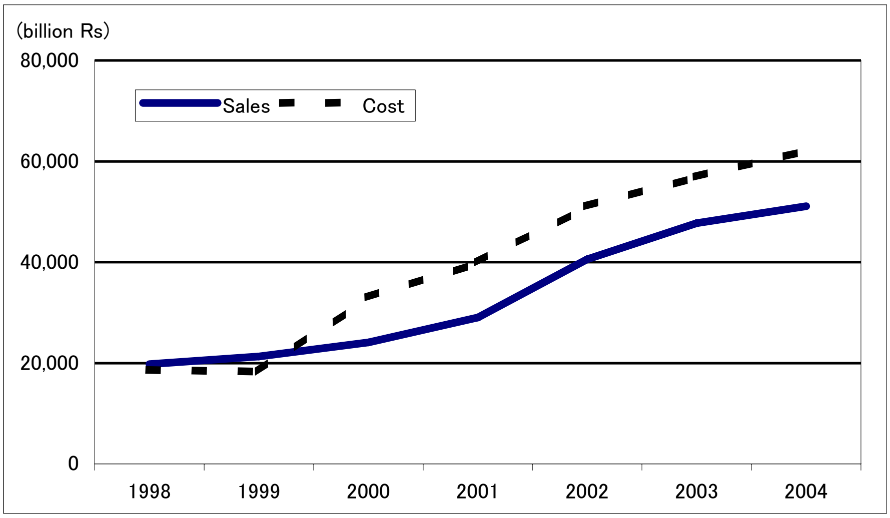
As the sales increases, transmission and distribution costs also showed a steady increase. From 1994, it grew at an annual rate of 18%, which is slightly more than the growth of the sales. The transmission and distribution costs are roughly around 12% of sales, which is an adequate level. The steady trend of the cost shows that the expenses have been properly checked over the years.

Administration costs are kept at extremely low levels. Between 1994 and 2003, it grew only by 11% annually. The figure for 2004, which is lower than that of 1994, seems to be an anomaly, although the reasons are not clear. The administration costs were only 7% of the sales in 1994, and in 2003, it is only 5%. This shows a proper control of the costs. Other costs also showed 11% growth annually, which seems to be in line with the administration costs.

Depreciation cost is three times the level of 1994, showing a 10% annual increase. Had the power development proceeded as planned, this would have increased significantly. Due to the delays for various reasons discussed in other chapters, the level of investment has generally been kept low, and the growth is not significant.

As a whole, it is clear that the rapid increase of the generation cost has made a drastic impact on CEB's finances. Only ten years ago, CEB had 40% profit ratio from operations, but as the generation cost increased, the ratio is now a negative 20%. The annual loss reaches 11 billion Rs, which exceeds the depreciation of 9.3 billion Rs. The CEB is in the red from a purely cash point of view, as we will see in the cash flow section.

Interest charges grew rather slow at an annual rate of 9%. Closer observation shows that the growth was not uniform. During 1994-2000, the figure was steady around 2 billion Rs, but in 2001 and 2002, the figure more than doubled, probably due to some capital investment. If the planned investments had been in place, this should have showed a much rapid increase, but along with depreciation, it remains stagnant.



Source: CEB

Figure 8.1.2 Trend of sales and Cost

As a whole, cost of power supply has continuously exceeded the sales, which caused a continuous deficit. The net profit before tax has shown a deficit since 2000. The deficit amount has shown some decline in 2000 to 2003, but this was merely due to the tariff increase that took place. Even this wasn't enough to turn a profit, and in 2004, CEB showed a record deficit. As mentioned, this is due to the increase in generation cost, especially fuel cost and power purchase cost. Other cost items were relatively small to begin with, and has been kept in check. Therefore, it is clear that the largest issue for CEB is the generation cost. Decreasing its reliance on expensive power purchase, and the normalization of the fuel mix is an immediate concern.

8.1.2 Balance Sheet

Total assets have shown gradual increase since 1999, but due to the delays in the new generation plants, the growth has been somewhat slow. New capacity relied much on power purchase, which spared CEB to hold assets of their own. Between 2003 and 2004, the total amount of plants and equipments grew only about 20%, while capital work in progress even shows a decline.

As for current assets, accounts receivables show a significant growth in 2004, from 11 billion Rs to 13 billion Rs. The level of receivables reach 25% of sales, which indicates that although sales grew by 3 billion Rs, the contribution to the cash flow was much smaller, only one third.

On the equity portion, equity increased by the additional contributed capital, although this was more than absorbed by the negative retained earning. Equity (capital & reserve) shows an apparent increase, but it is only achieved by the re-evaluation of its assets, an accounting exercise.

Long term debts are increasing, due to constant borrowing. On the other hand, in the current liabilities, accounts payable has increased bu 11.5 billion Rs in 2004. With these increase in liabilities, the debt ratio which was 28% in 1999 has grown to 43%. It is alarming that the current liabilities are almost as large as the non-current liabilities, which shows that CEB is currently running excessively on short term financing. It is more alarming that the major portion of the short term liability is the accounts payable, which reaches more than half of the CEB's annual expenses. Essentially, CEB is financing its operations by delaying its payment obligations.

Table 8.1.2 CEB's Balance Sheet

(million Rs)

Balance Sheet	1999	2000	2001	2002	2003	2004
Fixed Assett					239,007	263,615
plant&Equipment					211,927	242,937
Work in Progress					24,528	17,993
Subsidiary					725	725
Insurance Reserve					1,827	1,960
Current Asset					18,027	19,451
Inventories					5,983	5,562
Accounts Recieivable					10,999	13,001
Cash					1,046	888
Total Assets	184,216	204,887	231,224	246,826	257,033	283,067
Equity&Liabilities						
Capital and Reserve	130,920	144,940	146,388	149,874	152,370	161,538
Contributed Capital					16,176	17,536
Capital Reserve					17,613	17,613
Revaluation Reserve					140,279	163,384
Depreciation Reserve					23	23
Self Insurance Reserve					2,051	2,307
Retained Earnings					-23,772	-39,325
Non-Current Liabilities	43,520	47,789	55,800	65,282	66,368	70,385
Borrowing					43,171	45,159
Benefit Plan					1,648	1,466
Consumer Deposit					3,409	3,767
Deferred Income					18,140	19,993
Current Liabilities	9,775	12,158	29,036	31,670	38,295	51,144
Borrowings					7,597	8,885
Accounts Payables					30,010	41,507
Deferred Incomes					688	752
Total Liabilities	53,295	59,947	84,836	96,952	104,663	121,529
Total Equity&Liabilities	184,215	204,887	231,224	246,826	257,033	283,067

Source: CEB

8.1.3 Cash Flow

Cash flow situation was not enviable in 2003, and the condition further deteriorated in 2004. As mentioned in the Balance sheet section, the receivables are extremely high at 25% of the total sales, and it has increased by 2 billion Rs between 2003-2004. The actual sales growth was 3 billion Rs. Therefore, the increase in sales did not lead much to increased cash income. Cash flow from sales showed 1.27 billion Rs of Cash inflow, but it is revealed that much of this amount was due to the increase in accounts payable. In essence, CEB was delaying various payments in order to retain cash at hand.

Investment grew from 12.47 billion Rs in 2003 to 16.16 billion Rs in 2004, although the increase is rather small. Also, the cash flow from financing shows that 2003 relied heavily on borrowing, and 2004 relied on proceeds from the contributed capital of 1.36 billion Rs, which basically serves as a subsidy from the government.

The cash position (including cash equivalents) were already negative as of 2002, but 2003 and 2004 showed a further decline. From a financial point of view, CEB is experiencing a severe cash shortage. The negative cash position is achieved by a 6 billion Rs overdraft, which far exceeds the cash at hand and cash in the banks.

8.1.4 The Effect of the Tsunami

The effects of the Tsunami that occurred at the year end of 2004 have also affected the finances of CEB. The financial statements for 2004 state 2.26 million Rs for Tsunami related expenditure. This is low, although it is natural since the Tsunami hit Sri Lanka in the very last days of fiscal 2004.

Most of the damages and related expenditures will be included in the accounts of 2005. At the moment, a total expenditure of 710 million Rs is expected in 2005. Most of this figure goes to the Southern region, which is the most affected area.

Although this is not a small amount, its effect on CEB's finances is not significant. As of 2004, the net loss before tax is 15.2 billion Rs. An extra 710 million Rs of expense will only slightly worsen the situation. Of course, since CEB is already in bad financial shape, this additional expenditure is an unwelcome burden. However, it should not be considered as any excuse for the financial deterioration of CEB.

Table 8.1.3 CEB Cash Flow

(million Rs)

Cash Flow		2003	2004
Net Profit before tax		-3,750	-15,190
adjustment for	Depreciation	7,662	9,346
	Consumer contribution	-676	-752
	Government Grant	-12	-12
	Damages charged against self insurance	0	-147
	Loss(profit) in sales of fixed asset	-9	32
	Provision for gratuity	572	-102
	interest expenses	6,199	6,644
	interest income	-230	-208
Operating Porfit before Working Capital		9,756	-389
	Increase in payables	875	11,053
	Changes in current account	0	-720
	Increase in receivables	826	-2,372
	Increase in Inventories	-493	421
Cash from Operations		10,964	7,992
	interest paid	-6,199	-6,644
	Gratuity paid	-80	-80
Net Cash flows from operation		4,685	1,268
Cash flow from investment			
	Insurance reserve	-88	238
	purchase of property, plants & Equipment	-12,471	-16,162
	Investment in non-cap. Work in progress	0	6,535
	Sales of fixed assets	206	82
	interest	230	208
Net CF from investment		-12,123	-9,099
CF from financing			
	Contrbuted capital	337	1,360
	Consumer contributions	2,278	2,681
	Long term borrowing	4,014	1,896
	Consumer deposits	334	358
NetCF fromn financing		6,963	6,295
Net (decrease)/increase in cash		-475	-1,537
Cash at year beginning		-3,145	-3,621
Cash at year end		-3,621	-5,157

Source: CEB

8.2 Cost and Tariff

As of 2004, the total power supply cost stands at 10.27Rs/kWh. On the other hand, tariff stands at a mere 7.67Rs/kWh. As mentioned, CEB faces a large deficit. This discrepancy between the cost and the tariff is the major cause of this deficit.

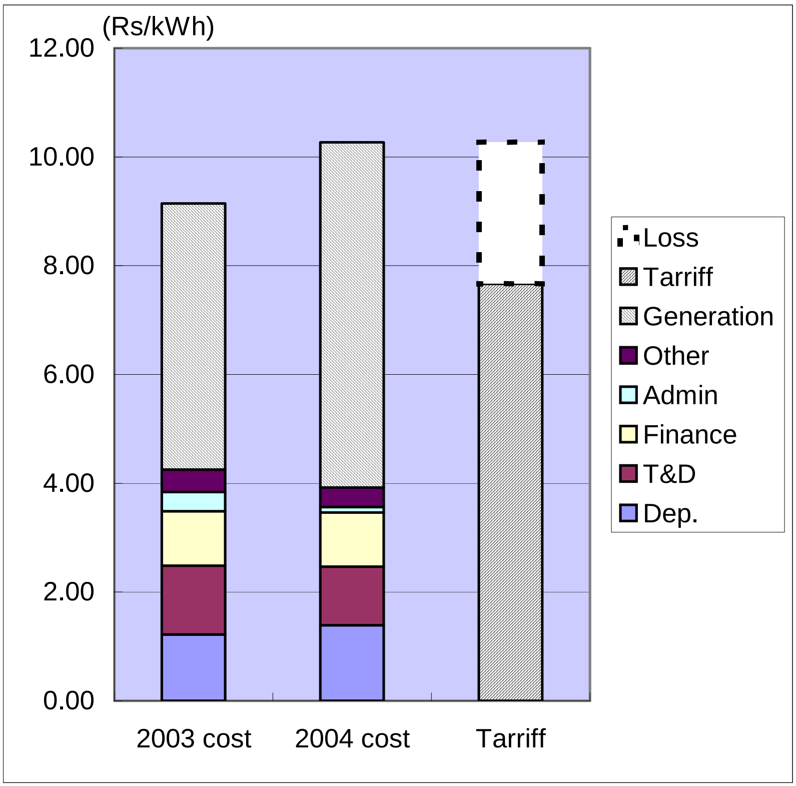
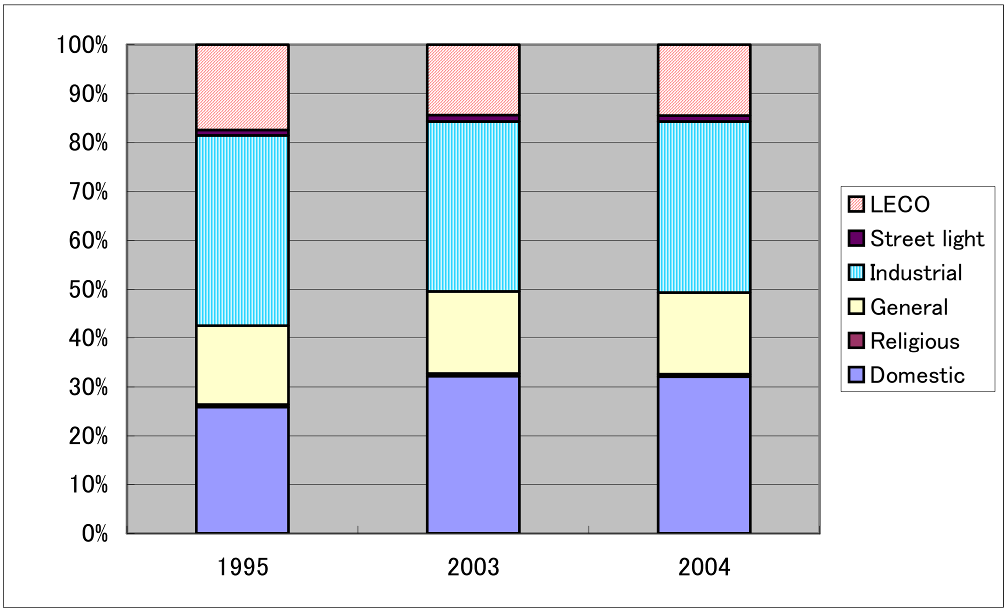


Figure 8.2.1 Supply Cost and Tariff

Many power utilities around the world utilized a tariff adjustment formula, so that the increase in power purchase costs and fuel costs can be passed through on to the tariff. Such measures would avoid the current CEB situation. In the case of CEB, however, much of the cause of the high cost comes from a distorted condition where it uses diesel and other power source as base loads. Originally, these were intended as emergency back-ups. Therefore, simply passing through these costs on to the end users may not be appropriate.

The demand (GWh) breakdown by the user type is shown in the figure. Compared to 1995, the proportion of domestic demand has increased. From the revenue aspect, in 1995, the sales from industrial uses were about three times the sales from domestic use. In 2004, it is about two times. Domestic use has lower price elasticity than industrial use. Therefore, the use of tariff as a demand management tool will have some limits, and drastic tariff increases will be harder to pull off. On the other hand, industrial tariffs have already experienced increases, and concerns have been raised about the effect of the high tariffs on the competitiveness of Sri Lanka's industry and investment promotion.



Source: CEB

Figure 8.2.2　Demand by User Type (by GWh)

8.3　Summary of CEB Finances

As clearly shown, CEB's finances are not in a good condition.　Due to very high power purchase and fuel cost, the whole sales are almost completely consumed by the generation cost.　CEB has continuously shown deficit since 2000.　Tariff increase has led to higher sales, but due to increased accounts receivables, it has not contributed too much to the cash situation.　In order to make up for the cash shortage, CEB is delaying its payment obligations, and even with this desperate measure, its cash position is continually negative through massive overdraft.

Demand has increased steadily.　With the current situation where supply costs far exceeds the tariff, however, this increase in demand means increased loss for CEB.　Demand in 2005 is already progressing at a higher rate than 2004, which means that CEB's financial condition in 2005 will further deteriorate.　With its huge negative cash position, the situation seems to be critical.

The important point here, however, is that their financial problems mostly concern their short-term cash situation.　The total debt of the CEB is only 43% of their total asset.　This level in itself is not a problem.　In many other Asian countries, power sector utilities often take on much more debt that may rise above even 70% of the total asset.　Since power generation is capital intensive, this is quite natural.　For CEB, the level of long-term debt is rather too low, due to the stalling of their power plant investments.

Their short-term debt, on the other hand, is truly alarming.　In order to cover for their operational losses, they are cash strapped to the extent that they must rely a huge portion of their cash demand on the increasing accounts payable.　They are delaying their payment obligation to their suppliers in order to save cash.　As a result, their current debt and non-current debt are at the same level, which is highly unusual.

Therefore, their most important financial issue at hand is to show some profits on their Profit and Loss statement.　If this is achieved, their short-term cash problem would be eased, and it would be easier to get long term financing to pursue the necessary large-scale investment.

8.4 Long-term Investment Plan

(1) Long-term investment plan

Table 8.4.1 shows the long-term investment plan for base case in the Master Plan.

Table 8.4.1 Long-term Investment Plan (Base Case)

Year	Gross Generation Energy (GWh)	Investment Cost (billion Rs.)			
		Generation	Transmission	Other	Total
2005	8,549	0.0	5.9	10.0	15.9
2006	9,105	0.0	7.6	10.0	17.6
2007	9,732	0.0	5.0	10.0	15.0
2008	10,464	0.0	3.0	10.0	13.0
2009	11,291	10.6	5.4	10.0	26.0
2010	12,168	12.2	8.2	10.0	30.4
2011	13,115	65.8	3.7	10.0	79.5
2012	14,125	32.9	4.8	10.0	47.7
2013	15,214	32.9	4.5	10.0	47.4
2014	16,390	32.9	2.9	10.0	45.7
2015	17,684	32.9	5.0	10.0	47.9
2016	19,068	32.9	7.6	10.0	50.5
2017	20,551	32.9	5.3	10.0	48.1
2018	22,140	32.9	4.4	10.0	47.3
2019	23,839	32.9	5.0	10.0	47.9
2020	25,653	37.2	6.8	10.0	53.9
2021	27,594	37.2	3.2	10.0	50.4
2022	29,676	41.4	2.1	10.0	53.5
2023	31,903	50.0	1.8	10.0	61.8
2024	34,287	43.5	0.9	10.0	54.4
2025	36,837	65.8	0.1	10.0	75.9
Total		626.8	93.2	210.0	930.0

The investment costs of the generation development and transmission development are based on the base case for the power development plan. For other investments, it is assumed that the current level of investment would continue indefinitely.

As shown in the table, the total amount of necessary investment during 2005-25 for the sector as a whole would be about 930 billion Rs. This translates into an annual average of 44.3 billion Rs, or 443 million USD. If we focus on the period after 2012, the annual average is about 50 billion Rs. The high level of investment is unavoidable, since in order to meet the soaring demand, a 300 MW class generation capacity needs to be installed almost every year. Figure 8.4.1 shows the relation between the annual generation energy and the annual investment.

The sharp peak of investment in 2011 represents the addition of 600MW generation capacity.

The current annual investment of CEB is about 16 billion Rs. Therefore, the future level of investment would be 2.8 times the current level.

The bearer of this high level of investment would be determined by the future development of the power sector reform. For example, if it is decided that all the generation capacity would be installed by IPPs, CEB (or the remaining public power utility) would only bear the investment for transmission and other investments. In this case, the CEB's annual investment would remain at 15-16 billion Rs, which is the same as the current level.

In this case, the power purchase payment to these IPPs would become an issue. Even now, the cost of the expensive purchased power has contributed significantly to the power supply cost, and consequently, the increasing loss. Although the details would differ with the specific power purchase agreement, relying on IPPs as the base power supply would more likely increase the supply cost.

Also, according to interviews with the existing IPPs reveal that private operators consider

300MW plants to be too large and risky as an attractive investment. Since risk preference may change overtime, there may be other investors that would be willing to bear such risk, although this seems unlikely in the near future. Therefore, the scenario that all of the planned generation capacity would be procured by IPPs would be rather unrealistic.

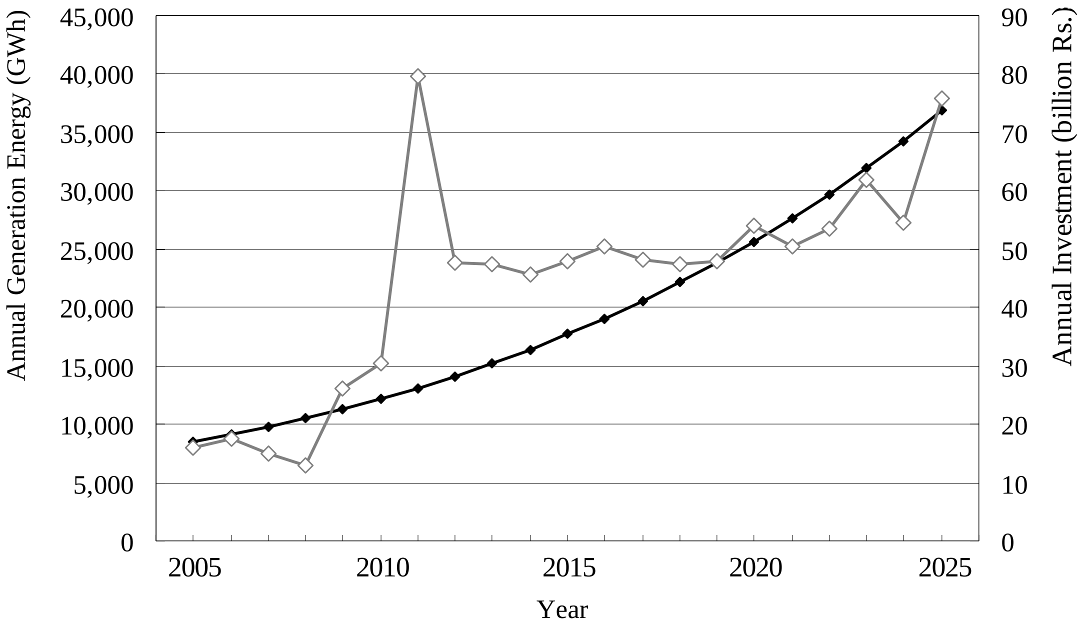


Figure 8.4.1 Annual Generation Energy and Annual Investment

Therefore, in order to utilize the large-scale coal thermal plants in the most effective way, it would be practical for the public sector to procure most of the planned generation capacity by themselves.

8.5 Forecast of the Tariff/Unit Cost under the Master Plan

Based on the investment plan that is proposed in this master plan, the future power supply unit cost is calculated, and compared with the "without case".

The comparison is made between cases where large coal thermal plants are introduced, and where supplies continue to rely on diesel. Also, diesel case is further divided into two cases, where the middle-speed generation units were used, and a case where a global average low-speed unit was used.

Also, in order to simplify the simulation, the following assumptions are made;

(1) In order to reject the effects of various financing schemes, it is assumed that all investments are treated as cost in the year that they are incurred, which will be directly transferred to the cost. The profit margins of the IPPs are not considered.

(2) Transmission cost and distribution cost, as well as overheads are assumed to increase along with the sold power. It is also assumed that the current interest payment and debt repayments would continue indefinitely at 2004 levels. In reality, many loans will be fully repaid during this period, so this assumption will overestimate the actual cost.

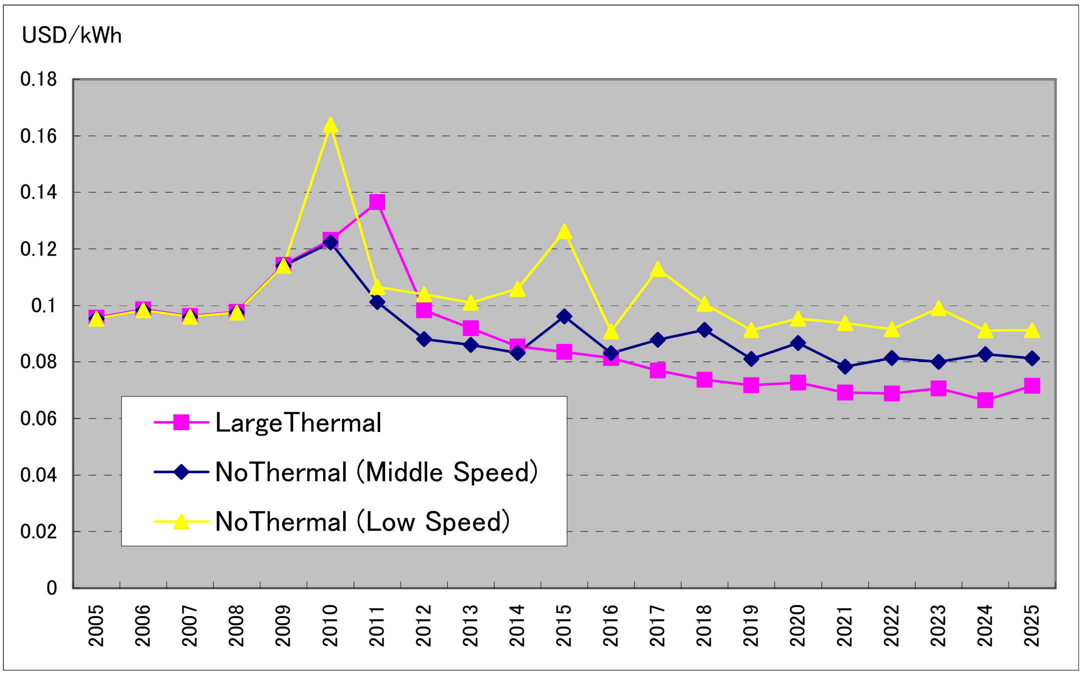


Figure 8.5.1　Unit Cost Forecast, where all investments are incurred in a single year

Table 8.5.1　Unit Cost Forecast, where all investments are incurred in a single year

(Uscent/kWh)

year	2005	2006	2007	2008	2009	2010	2015	2020	2025
LargeThermal	9.6	9.9	9.6	9.8	11.4	12.3	8.3	7.3	7.2
NoThermal (LowSpeed)	9.5	9.8	9.6	9.7	11.4	16.4	12.6	9.5	9.1
NoThermal (MiddleSpeed)	9.5	9.8	9.6	9.7	11.4	12.2	9.6	8.7	8.1

The results show that in either case, supply needs to rely on expensive diesel and power purchases.　Therefore, unit cost necessarily goes up.

After that, under the master plan, the cost will rise in the year of investment.　This, however, will quickly drop as low cost fuel will be fully utilized.　If 300MW class coal plants are installed almost every year as the master plan suggests, the cost will drop to a very competitive level, also allowing the tariff to fall.　The figure here shows the unit cost that does not include any excessive profits for CEB and Generation companies, but even if those were included, the tariff should become comparable to levels in other parts of Asia.

If, on the other hand, the future supply relied on the middle-speed diesel generators available, the unit cost would never fall.　With the increased demand, the investment would be spread out to a wider user base, which may decrease the unit cost slightly, although not much.

If we consider a more realistic case where future diesel generators are lower speed at international average, the unit cost would rather rise than fall.

The current tariff is at 7 US cents per kWh, which is at a loss.　Even this level is causing dissatisfaction from the people, although it isn't significantly high compared to international levels. This level, however, is not sustainable, since no firm can operate indefinitely at a loss.

The introduction of large scale thermal plants will surely solve this problem.　It would enable the power sector to operate at a profit, even with the current tariff.　On the other hand, further reliance on diesel will worsen the loss, forcing the tariff to rise sooner or later.　Many have raised concern about the effects of high tariffs on the industrial competitiveness and the investment attraction. These concerns will not be answered through the continued reliance on diesel.

Tariff is ultimately determined by the power supply cost. If it is lower than the supply cost, and lacking subsidies or other source of income, the difference must be borrowed, which is unsustainable in the long run.

Transmission and distribution costs have increased only a little more rapidly than sales since 2000 in spite of the expanding gap (deficit) between costs and revenue as was found by the financial analysis in this study, and the self-help efforts of the CEB are therefore taking effect. The biggest cause of the increase in the deficit, on the other hand, is the rise in prices paid for purchase of power from emergency diesel power generators. The increase in oil fuel prices, which have jumped in recent years, has been an especially big factor.

As mentioned, however, this problem is the short-term debt. The long term debt has not show much increase since there has been not much large scale investment that requires long term debt. It is the short-term debt, especially the accounts payable that is ballooning to come up with the required cash. If the operation turns a profit, this cash shortage would be eased and long-term finance would be obtainable.

Therefore, the tariff needs to be revised so that the operation shows some profit, and maintain that profit into the future. To achieve this, the following points need to be met;

- Raise the tariff temporally by about 25%. This should be a short-term raise, maybe up until 2012.
- When increasing, there should be a commitment that with the future completion of the large-scale coal thermal power plant, the tariff would come down.
- There should be a tariff adjustment formula that allows the pass-through of the fuel cost, the power purchase cost, and foreign exchange.

The temporal tariff increase would improve CEB’s financial health. In order to make this increase more acceptable, there should be a clear commitment that this would be brought down with the completion of the large coal thermal plants. This should also provide additional support for the faster procurement of the future plants.

The pass-through formula is also important. The recent rise in the fuel cost and the power purchase cost is beyond CEB’s control. They should not be held responsible. This was one of the main causes of the recent increase in its operational loss. To avoid such situation in the future, an automatic tariff adjustment formula that includes a pass-through clause for fuel, power purchase, and foreign exchange. The current rise in oil prices is likely to peak off in the near future. Therefore, such formulas would more likely lower the tariff levels in the near future. By introducing the formula when it would lower the tariff, it would become more acceptable for the customers.

The current tariff structure consists of the base tariff (capacity charge) and the power tariff. Under the current condition of power shortage, it is desirable to increase the power factor as much as possible to increase the effective power. Tariff structure can assist such improvement. In the case of Japan, customers above 85% power factor will receive a discount, while those lower than that would be charged extra. This induces the customers to install capacitors to improve the power factor. Similar methods can be employed in Sri Lankan tariff structure to make better use of the existing generation capacity.

8.6 CEB Finances after the Master Plan

The finances of CEB and its separated firms will depend largely on the progress of the structural reform in the power sector. It would be impossible to make any accurate financial statements for these firms, unless the whole picture has become clearer.

It is obvious, however, that the drastic decrease in the generation cost will allow the power sector as a whole to escape the current permanent loss position. Due to the huge increase in power sales, even if the current expensive power purchase continued, the additional income would more than offset that effect.

With large scale thermal plants, it would be possible to introduce various donor aids at a favorable term, enabling the investment to be spread over a long period. If a typical terms of a large multi donor (1.25%, 25 years, 5 year grace period) would be applied to the first several years, the unit cost would be as follows:

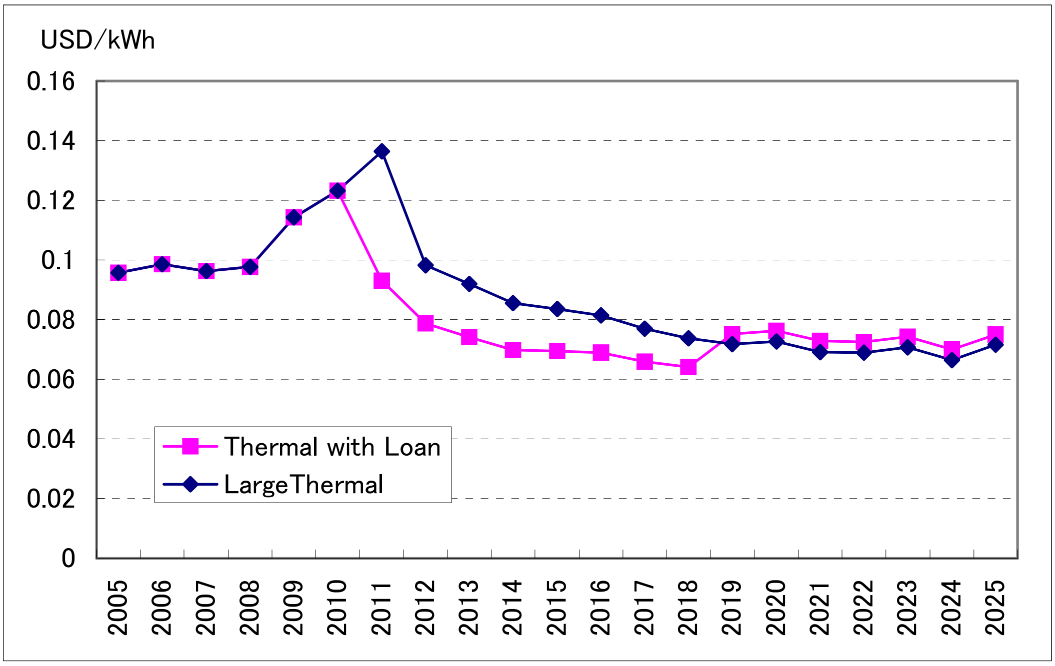


Figure 8.6.1 Unit Cost Forecast, where a typical terms of a large multi donor would be applied to the first several years

With the investments spread over more than 20 years, and with very low interest, the unit cost will immediately go down after the operation start. It is questionable, however, whether the current CEB finances would make such a loan feasible. CEB needs to improve its finances through various arrangements during the structural reform process.

Similar arrangements using loans may be possible with diesel generators. It would be difficult, however, to get such long term donor loans at favorable terms. Therefore, the drop in the unit cost would be limited.

8.7 Conclusion of CEB Financial Analysis

The current power tariff has already become a huge source of complaints from the people, while being unable to meet the actual cost. In the next future years, demand would have to be met by additional diesel and power purchase, which would either result in further increase in the tariff, and/or uncreased debts for CEB. After that, however, if this master plan is met and large scale power plants are installed, costs will go down enough to enable current tariff levels to cover the cost. Also, this benefit will be achieved earlier if long term donor loans can be used at favorable terms.

If this is not achieved, Sri Lanka would be forced to rely on expensive diesel generations. In this case, costs will remain at current levels at best, or even further increase if the commercial IPPs would demand the high level of return. Tariffs would have to be sharply increased at some point. This may be politically difficult. Therefore, the realization of this master plan is absolutely necessary for the future of the power sector in Sri Lanka.

Also in the short run, tariff increase should be considered to ease the short term financial difficulty. As mentioned, CEB's financial difficulty lies in the short term position. If the short term debt issue is resolved, CEB has the borrowing power to finance the master plan.

Chapter 9 Environmental and Social Considerations

9.1 Legal Framework for Environmental and Social Considerations

(1) Legal Framework of Environmental and Social Conditions in Sri Lanka

The following are the names of the relevant laws, regulations, guidelines, policies and strategies, regarding environmental and social considerations (ESC) for this Study.

① National Environmental Act
② EIA Guidelines
③ Coast Conservation Act
④ Fauna and Flora Protection Act
⑤ Revised & Proposed Environmental Standards (not finalized yet)
⑥ National Environmental Policy
⑦ Land Acquisition Act
⑧ National Involuntary Resettlement Policy
⑨ Environmental Strategies on Power Sector
⑩ Action Plan for Environmental Strategies on Power Sector

(2) EIA Guidelines

The very requirement of EIA is stated in Amendment Act No.56 of 1988 for the National Environmental Act No.47 of 1980 (NEA). The NEA incorporating Act No.56 of 1988 included a provision on EIA contained in Part ⅣC of the statute entitled "Approval of Projects"

The section 23Z of the statute states 'The Minister (in charge of the subject of Environment[85]) shall ・・・・ determine the projects and undertakings in respect of which approval would be necessary ・・・・." Under the provisions of this section, 23Z, the EIA process applies only to "**Prescribed Projects**" which have been specified by the Minister and will be implemented through designated Project Approving Agencies (PAA).

This study is on the Master Plan. Therefore, the EIA process in Sri Lanka is not applied to this study.

(a) Prescribed projects for EIA

The 'prescribed projects[86]' contain the following types of projects, which are possibly in relation with power sector development.

1. All river basin development and irrigation projects excluding minor irrigation works (as defined by Irrigation Ordinance chapter 453)
2. Reclamation of Land, wetland area exceeding 4 hectares
3. Extraction of timber covering land area exceeding 5 hectares
4. Conversion of forests covering an area exceeding 1 hectare into non-forest uses
5. Clearing of land areas exceeding 50 hectares
6. Mining and Mineral Extraction

8. Port and harbor development
9. Power generation and transmission
   - ◆ Construction of hydroelectric power stations exceeding 50 MW
   - ◆ Construction of thermal power plants having generation capacity exceeding 25 MW at a single location or capacity addition exceeding 25 MW to existing plants
   - ◆ Construction of nuclear power plants

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[85] In NEA, the word 'The Minister' appears without definition. The meaning of the word is defined by the context, if not with any specification at appearance.
[86] Appendix 4 of 'Guidance for implementing the environmental impact assessment (EIA) process, Central Environmental Authority, Third Edition 1998 (referred to as the EIA Guidelines)' lists them.

- All renewable energy based electricity generating stations exceeding 50 MW

10. Transmission lines
    - Installation of overhead transmission lines of length exceeding 10 kilometer and voltage above 50 Kilovolts

12. Resettlement
    - Involuntary resettlement exceeding 100 families other than resettlement effected under emergency situations.
13. Water supply
    - (Including) all ground water extraction projects of capacity exceeding 1/2 million cubic meters per day (0.5 x 106 m3/day)
    - Construction of water treatment plants of capacity exceeding 1/2 million cubic meters (0.5 x 106 m3)
14. Pipelines
    - Laying of gas and liquid (excluding water) transfer pipelines of length exceeding 1 km

17. All tunneling projects
18. Disposal of Waste
    - Construction of any solid waste disposal facility with a capacity exceeding 100 tons per day
    - Construction of waste treatment plants treating toxic or hazardous waste.
19. Development of all Industrial Estates and Parks exceeding an area of 10 hectares

31. Industries that involve the manufacture, storage or use of Radio Active Materials as defined in the Atomic Energy Authority Act No.19 of 1969 or Explosives as defined in the Explosive Act, No.21 of 1956, excluding for national security reasons.

In addition to the above list, the following two types of projects are required of EIA under the Coast Conservation Act and Fauna and Flora Protection Act.

- Projects which are having their components located within the "Coastal Zone" as defined in the Coast Conservation Act.
- Projects which are located within one mile of the boundary of any National Reserve declared under Fauna and Flora Protection Act.

(b) Project Approving Agencies for EIA

Project Approving Agencies[87] set out in the Gazette Extraordinary No. 859/14 of 23rd February 1995 include the following agencies in relation with the power sector.

1) The respective Ministries to which the following subjects are assigned:

(C) Energy[88]

2) The Department of Coastal Conservation
3) The Department of Wildlife Conservation
4) The Urban Development Authority
5) The Central Environment Authority established by the National Environmental Act, No.47 of 1980

8) The Mahaweli Authority of Sri Lanka
9) The Board of Investment of Sri Lanka

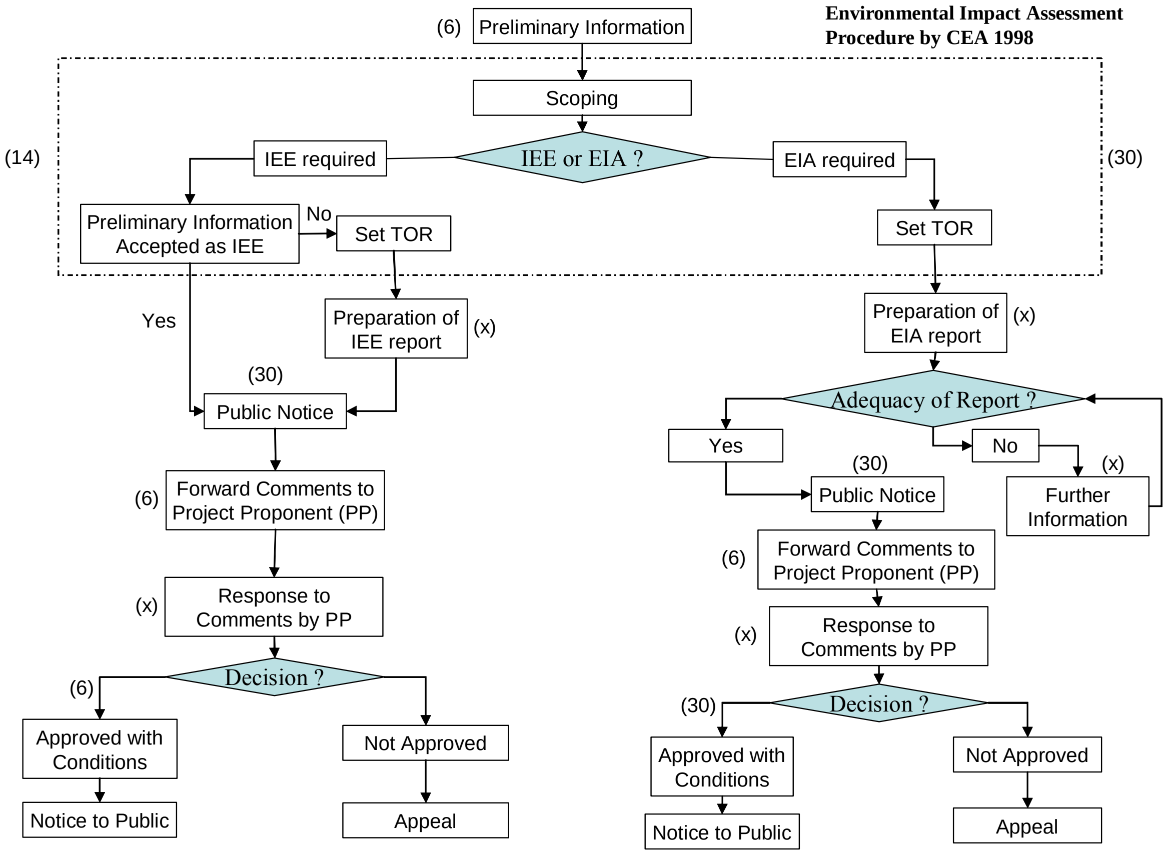
[87] Appendix 6 of the EIA Guidelines
[88] In Sri Lanka, it corresponds to Ministry of Power and Energy.

Later the following agencies were added to the list of Project Approving Agencies.

- Geological Survey and Mines Bureau
- Tourist Board

(c) Standard EIA Procedure (EIA flowchart)

The standard EIA procedure in Sri Lanka can be seen in the next figure shown in the last page of the EIA Guidelines No1.



NOTE: Bracketed figures indicate Maximum number of days

(3) Protected Area

(a) There are six categories of the protected areas as below:

- Strict Natural Reserve:

  No one is allowed to enter except with approval for the purpose of survey
- National Park:

  No one is allowed to enter, except for approved visitors who have educational and sightseeing purposes
- Nature Reserve:

  Limited traditional activities, like fishing, which do not cause environmental destruction, are permitted
- Jungle Corridor:

  The passages of the wild animals. However, they are not legally declared as protected areas, yet.

- Buffer Zone:

  Surroundings of the protected areas. However, they are not yet legally declared as protected areas.

- Sanctuary:

  Traditional activities are allowed in the private owned areas in the sanctuaries. However, they are not allowed in the state owned sanctuaries.

The legally declared protected areas are as follows:

Categories	Nos.	Area（ha）
National Parks	16	5,061.13
Nature Reserves	2	479.52
Sanctuaries	54	2,785.74
Strict Natural Reserves	3	315.73
Total	75	8,642.12

（Department of Wildlife Conservation: December 2003）

(b) Marine Protected Area

There are two Marine Protected Areas, i.e., Hikkaduwa Marina and Bar Reef Marine in Kalupitiya, where prohibited fishing activities include: collection of coral/sand/marines resources, construction activities, waste disposal, and disturbance of breeding grounds.

(c) Fisheries Management Area（FMA）

Fishing activities are limited in the methods, time and areas in the below-listed Fisheries Management Areas. The regulations of each area are described in the Gusset No. 1038/16, 1998.07.30 as the revision of the Fisheries and Aquatic Protection Act 1996.

- Negombo Lagoon
- Rekawa Lagoon (between Matara and Hambantota)
- Udukiriwala Reservoir (Hambantota, close to Weeraketiya)
- Batticaloa Lagoon
- Bolgoda Reservoir (Moratuwa-Panadula)
- Off Yala
- Muruthawela Reservoir (Hambantota)
- Parakurama Samudra (Polonnaruwa)
- Ridiyagama Reservoir (Hambantota)
- Kiriibbanweva Reservoir (Moneragala)
- Urusitaweva Reservior (Moneragala)
- Madihapolhena (Matara)
- Thotamuraginigasmulla (Matara)

(d) Wet Zone relating to the habitat of waterfowl

There are two wet zones which were declared under the Ramsar Convention, i.e., Bundala and Anawirudawa.

(e) Archeological Sensitive Areas

In addition to EIA, Archeological Impact Assessment will be needed if some facilities are constructed in the Archeological Sensitive Areas declared by the Archeological Department.

(4) Environmental Standards

Item	Standards	Regulation	Monitoring bodies	Institutions for control violation
Emission Standards Heat Input Capacity > 73MW Firing oil, Oil/Wood **Proposed figure**	▪ NOx: 130mg/MJ ▪ SOx: 340mg/MJ ▪ TSP：40mg/MJ ▪ Opacity：20%	Proposed in the “Revised & Proposed Environmental Standards”	CEA & Project offices of CEB	CEA
Emission Standards Heat Input Capacity > 73MW Firing Coal, Coal/Wood **Proposed figure**	▪ NOx: 300mg/MJ ▪ SOx: 520mg/MJ ▪ TSP：40mg/MJ ▪ Opacity：20%	Proposed in the “Revised & Proposed Environmental Standards”		
Liquid Waste discharged to marine water	• Temperature：45℃ • Total Suspended Solids (TSS): 150mg l^{-1} • 5day Biological Oxygen Demand（BOD）: 100mg l^{-1} • pH: 6 - 8	Gazette 595/16, 1999.02.02	CEA & Project offices of CEB	CEA
Noise（Industrial area）	70dB（daytime） 60dB（night）	Gazette 924/12, 1996.05.23	CEA & Project offices of CEB	CEA, Police

Note: There are regulations for solid and liquid waste disposals and noise; however, the regulations for emission gas are still under discussion.

9.2 Outline of the Plan

(1) Title of the Cooperation Project, and Names of the Project Proponent and Consultants

<Title>: Master Plan Study on the Development of Power Generation and Transmission System in Sri Lanka
<Proponent>: Ceylon Electricity Board (CEB)
<Consultants>: Chubu Electric Power Co., Inc.; Nomura Research Institute, Ltd.

(2) Outline of the Project

The Study aims at developing a comprehensive master plan of twenty (20) years for generation and transmission system expansion for Sri Lanka as a whole including North and East provinces.

The contents of the Master Plan (Study) include the following:

① Demand forecast
② Lowest-cost generation expansion planning
③ Transmission system development planning
④ Long-term investment planning
⑤ Tariff study
⑥ Economic and financial analysis
⑦ Environmental and social considerations (ESCs)
⑧ Power sector development policy study

Total Capacity of Existing Power Facilities: 2294 MW (July 2004, including IPP)
Peak Demand is 3400-4000 MW at 2015, 6600-9100 MW at 2025.
Approximately 2800 MW and 7200 MW need to be developed by 2015 and 2025, respectively.

The Study is not about a single project but regarding the optimization of development projects for power generation and transmission facilities. The locations of those projects are all over the country. Scales of operation vary in size from small scale of renewable energy (equal to or less than several MW), through 150 MW hydropower generation to a large scale of 900 MW coal thermal power generation (consisting of three 300 MW units).

In theory, Strategic Environmental Assessment (SEA) can be applied to the whole master plan including alternative policies in demand forecast and sector policies. However, the policy for the national economy and the energy sector are beyond the scale of the Study. In practice, SEA has been applied to the optimization of development projects for power generation and transmission facilities, such as selection of site and facility types.

ESCs at IEE level, meaning that the assessments are based on review of the existing documents and short field reconnaissance, were conducted on some prioritized large scale projects.

- (Upper Kotomale Hydro-power 150 MW) JBIC pledged, Tender done.
- (CEB Puttalam Coal thermal power 300 MW)
  FS and EIA (1998), DD (Jan. 2000) and Agreement of Land Acquisition made
- Expansion of Puttalam Coal thermal power 300 – 600 MW
- Trincomalee thermal power, 300 MW x 3 units USTDA site selection survey 1988
- Hambantota thermal power, 300 MW x 3 units USTDA site selection survey 2001

- Kerawalapitiya combined cycle power plant project, 150MW x 2 units, JICA FS 1999
- Other projects

  (Broadlands Hydro-power, 35 MW) JICA FS & EIS study 2003

  Uma Oya trans-basin Hydro-power, 150 MW and other Uma Oya projects

  Gin Ganga Hydro-power, 49 MW

  Jaffna thermal power, 20 – 30 MW (short term), 50 – 100 MW (mid term)

Note: The projects in gray were out of scope of this study's ESC since they had already been through certification of EIA, FS study or Donor's Pledge.

9.3 Objectives and Method of ESC

(1) Objectives (TOR for ESC)

The project needs SEA, for which a tentative TOR was proposed by CEB officials and the JICA preliminary study team as below:

(a) Review existing government policies, laws, regulations, guidelines and strategies for ESC in the power sector. Study current implementation status and issues associated with them.

(b) Carry out Strategic Environmental Assessment (SEA[89]) for the power generation plans during the master plan.

- Carry out environmental scoping for the candidate power generation projects, for those locations have been decided or proposed, by identifying major environmental and social impacts using the preliminary checklist.
- Analyze and evaluate environmental and social impacts of the different types of technologies in the case of thermal power plants.

(c) Capacity building of the CEB to strengthen their capacity for ESCs.

- Investigate present situations and issues on environment management and social consideration of CEB by reviewing some case studies and hearings from major stakeholders.
- Suggest necessary technical capacities, human resources and organizational arrangement for CEB to carry out ESCs at an appropriate level.
- Suggest practical measures to implement the above suggestions. The measures may include conducting seminars and workshops for NGOs and general public, assisting in development of existing draft environmental management guidelines/manuals for CEB officials.

(2) EIA Requirement

EIA is not required at this stage (master plan) in Sri Lanka. The country has no legal requirement for SEA either. However, JICA TOR for this study requires SEA with the policy of the JICA Environmental and Social Guidelines 2004.4. ESC study at IEE level should also be done according to the JICA Guidelines.

(3) Study Area

The whole Sri Lanka including North and East provinces

(4) Study period

2004.12 - 2006.2

IC/R 2004.2 It/R 2005.7 DF/R 2005.12 F/R 2006.2

[89] It was confirmed between CEB and the Study team at the time of inception that the views of SEA would also be applied to the transmission system plan.

(5) Scope of Work

(a) Data collection
(b) Demand forecast
(c) Least cost generation expansion planning
(d) Transmission system development planning
(e) Long-term investment planning
(f) Tariff study
(g) Financial analysis
(h) Environmental and social considerations
(i) Power sector development policy study
(j) Preparation of master plan

(6) Information Disclosure and Public Participation

Need to facilitate information disclosure and encouragement of stakeholder participation in the Master Plan, providing opportunities for stakeholders and the planners to share their perceptions of the plan studied by the survey, and lay the groundwork for basic acceptance of the drafted plan.

JICA TOR for the study team required the following;

(a) Facilitate implementation of the “master plan seminars” for such stakeholders as central/local government officials, NGOs, and intellectuals, and ensure information disseminations and stakeholders' participation.
(b) Facilitate information dissemination of the master plan study from time to time by utilizing the media.

Note:

- The “master plan seminars” were held three times during the period of the master plan study, i.e., at the completion of inception, interim and draft final reports.
- The CEB was the host of the seminars; JICA Study Team, JICA Sri Lanka Office, and the Japanese Embassy in Sri Lanka supported the implementation of the seminars/workshops.

< The preparation meeting and Seminars >

Field survey	Main survey content	Planned seminar and meetings
1st phase (February)	Explanation and discussion of survey content. Data gathering and analysis.	First seminar (Explanation of purpose & plan of the Study)
2nd phase (April)	Review of plan preparation methods, and field survey.	Meetings to prepare for stakeholder meetings.
3rd phase (July)	Preparation of the outline of the Master Plan	Second Seminar/ First Stakeholder Meeting 1) Explanation of the overall goals. 2) Workshops with subgroups to deal with specific themes. 3) Overall meetings (Sharing of the results of studies on individual technical issues).
4th phase (October)	Preparation of the comprehensive master plan.	
5th phase (December)	Explanation and discussion of the draft final Master Plan.	Third Seminar/ Second Stakeholder Meeting. (Information disclosure and assistance for consensus formation, mainly on the content of the final draft.)

9.4 Evaluation of Impacts (SEA and IEE at the Master Plan)

9.4.1 Stakeholders

(1) Scope of Stakeholders

We have identified the following relevant groups and organizations as stakeholder on this power sector master plan.

Administrative Organizations Concerned	MPE, Public Utilities Commission, Dep. National Planning, Dep. External Resources, MENR (CEA, EMA, Forest Dep., Wildlife Dep.), Coastal Conservation Dep., Irrigation Dep., Mahaweli Authority, NWEA (Environmental Authority of NW province), Energy Conservation Fund (ECF), Ceylon Petroleum Corporation (CPC), MRRR, National Steering Committee for Mine Action (NSCMA), Task Force for Rebuilding the Nation (TAFREN), Urban Dev. Authority(UDA) National Water Resources Secretariat (NWRS), Min. of Land (MOL), Ports Authority(PA) Board of Investment(BOI)
Local Authority	Administrations of 9 provinces, CAARP (Conflict Affected Area Rehabilitation Program), Eastern Province Divisional Secretary of CAARP for Trinco & Jaffna, Government Agent of Jaffna
Public	Key Locals of important projects, Engineers, Students, Religious Leaders (Buddhism, Hindu, Christian, Muslim)
Business	Chamber of Commerce, Chamber of Industries, Investors, Private and Small Power Producers
NGO	Energy Forum, Sri Lanka Energy Managers Association, Green Movement of Sri Lanka, Environmental Foundation Limited, Energy Journals, Praja Mula Organization, IUCN (International Union for Conservation of Nature and Natural Resources) and others
Academic	Univ. of Moratuwa, Univ. of Peradeniya, Univ. of Ruhuna, Univ. of Colombo, Open University Expert on Engineering/ Energy Economics, Sociology, and others
Donors	Embassy of Japan, JICA, JBIC, WB, ADB, USAid, KfW, Others

(2) Stakeholders Meeting

(a) The First Seminar (at the Inception)

Date : 11th February 2005 9:30 – 13:00 (Half day seminar)
Place : Taj Samudra Hotel

We assisted CEB to hold the seminar with presentations and Q&A sessions on the issue of study purpose and the plan's technical aspect, ESC aspect, and institutional aspect. The total participants were 74, which included 11 people from the concerned administrative organizations, 3 NGOs, 1 from a donor agency. The rest of the participants were 39 CEB personnel including 7 counterpart members, 9 from relevant Japanese organizations, and 11 study team members.

The topics were felt to be a little too technical. Therefore, the contents of discussion became difficult for other participants than CEB staff to understand. Another reflection is on the relatively small number of general stakeholders, compared with the participants from CEB that hosted the seminar.

In questions given from the participants, we found more questions that showed concerns to the high electricity tariff and high costs in purchasing power from private businesses. Someone also pointed out that more time might better be allocated for discussion and Q&A sessions so that general stakeholders could more easily understand the contents of the plan. He also recommended us to facilitate the talk with administrative organizations, NGOs and IPP people.

(b) The Preparation Meeting for the Second Seminar

Date : 2nd May 2005
Place : CEB Head Office Building

16 participants discussed on the desirable format, way of notification, materials, scope of participant, and schedule for the second seminar. 5 participants were from administrative organizations and NGO. 5 CEB personnel, 2 personnel from JICA and 4 study team members also participated in the meeting.

It was requested that prior information on the coming seminar and its subject should be given so that participants could prepare for the meeting. A participant, observing the current situation of Sri Lanka, noted that biased information was being given to the public and villagers by different interest groups. Another participant commented that effort for public awareness on true situation of power sector was appreciated.

(c) The Second Seminar/ the First Stakeholder Meeting (at the Interim)

Date : 12th July 2005 9:10 – 16:30（Whole day seminar/ workshop)
Place : Colombo Plaza Hotel

In the morning session, the study team made presentation and expressed their view on 'present status and issues in the Sri Lanka power sector' and 'Directions in the future power development of Sri Lanka' on the stage of outlining M/P. In the afternoon, participants split into two subgroups to hold participatory workshops. One group discussed about the technical issues like power supply and power facilities development. The other one discussed the institutional issues that included the investment environment, renewable energy and ESC. Both CEB and the study team allocated facilitators in each group and lead the discussions for the process in theme setting, problems selection, exchange of views with written cards and summary speech to other group. Finally the results of subgroup discussions were reviewed in the whole group session.

The general publics were invited by newspaper announcement (4 announcements in 3 languages, Sinhalese, Tamil and English). The number of registration finally reached 150 one day before the seminar. On the day 111 people actually participated. 36 were CEB people including 7 counterpart members and 11 the study team. So, the participants from outside were 64 in total, with administrative officer, local authority, donors, general public, NGOs, academics, business personnel all together.

We observed many favorable responses to the meeting style and contents. However, it was to a reflection that the sufficient participants were not invited from local authorities. Also most academics were from engineering backgrounds, with only one invited as social consideration expert.

In Q&A session, they made questions on various problems and issues, such as the method of power demand forecast, inquiry to alternative power sources and the possibility of alternative energy, how to handle environmental cost and external cost factor, issue of system loss and information disclosure. The second seminar received a wider range of interests and concerns by the participants, compared with the first. And we may observe it favorably.

(d) The Third Seminar/ the Second Stakeholder Meeting (at the Draft Final)

Date : 8th December 2005 9:10 – 13:30 (Half day seminar/ workshop)
Place : Trans Asia Hotel

The study team explained about the draft final master plan, including the topics on the background of the study, and the analyses, evaluation and recommendations for power development plan, environmental and social considerations, financial issues, and policy and institutional issues.

In total, 122 people participated in the seminar, including the Secretary of MPE. 39 were from CEB, including 7 counterpart personnel, and 8 from the study team. So, the participants from outside were 75 in total, with 14 administrative officers, 4 key local authority and personnel, 12 from donors, 25 general public, 3 NGOs, 3 academics and 14 business personnel all together.

In the Q&A session, many questions were raised on the possibility of facilitating non-conventional renewable energy, such as biomass energy (dendro) and wind power generation. CEB answered that they are actually studying those power as small supply source. CEB and the study team, however, added that non-conventional renewable energy cannot be major power sources because of small generation capacity, according to their basic observations. Other participants concerns were about high electricity tariff and political interference on a master plan.

9.4.2 Scoping

This master plan study stretches over many existing and prospective project plans. It is thus difficult to describe ‘Spatial and Time Range’ and ‘Range of Impacts to be assessed’ as a simple set of ranges for the total master plan since different projects are on the different stages and vary in those ranges. Those ranges should be described in respective scoping for important prospective projects concerned. However, we prepared the comprehensive preliminary checklist on ESC impacts specifically arranged for an upstream planning stage of power development. This checklist was used to make scoping at the master plan stage by type of facility and for candidate individual projects.

In this study, two kinds of scoping have been conducted. One is on different types of power facilities, and the other is on different candidate projects at planned sites. The former evaluates the levels of possible environmental and social impacts if a standard facility of each type would be developed. The latter evaluates the possible environmental and social impacts of candidate projects currently in consideration of development feasibility, especially considering site conditions and based on existing relevant environmental assessment reports and short site visits.

Table 9.4.1 shows ‘Criteria for Scoping Items’, Table 9.4.2 does the result of ‘Scoping by Power Facility Type’ and Table 9.4.3 does that of ‘Scoping by Project Site’.

<u>Application of scoping results to alternative scenarios</u>

1. Conduct scoping on each power facility type, using the criteria for scoping items (Table 9.4.1).
2. Table 9.4.2 shows the results of scoping by power facility type (Table 9.4.2).
3. The scoping grade (A, B, C) on Table 9.4.2. are converted into numerical values with the conversion factor of Table 9.4.5.＜A→3, B→1, C→0.1＞, which is assumed to be corresponding to A as large impacts, B as medium or unknown Impacts, and C as negligible impacts (Table 9.4.7).
4. The items of scoping (the left column on Table 9.4.2) are weighted by reflecting the local value of each item for the society concerned (Sri Lanka in this study). A, B, and C in weights show the assumed magnitude in Sri Lankan society, A as gravely important, B as fairly important and C as less important. These A, B and C are converted into the numerical weights with the conversion factor of Table 9.4.4.＜A→3, B→2, C→1＞. The magnitudes of importance were basically decided by local experts, CEB counterparts of various backgrounds, with the support of the study team. The weights can be decided with broader discussion among local stakeholders when time should permit. The scores of Table 9.4.7 (raw scoping scores) are given, with the raw scores of Table 9.4.2 multiplied by the weights of Table 9.4.4.
5. For hydro power generation facilities, impact levels may be mostly dependant on the construction of facility. However, for thermal power plants, impact levels of some items are dependant on the duration of working hours of the plants, called ‘plant factors’. Table 9.4.6 identified such items.
6. Table 9.4.8 shows the impact scores for base case scenario. For hydropower plants, specific project site values are used, based on Table 9.4.3.
7. The scores of operation dependant items (darkened cell on Table 9.4.8) are multiplied by the plant factor of the concerned facility. The factors are given by the WASP-Ⅳsimulation on each alternative scenario. For example, ‘Global warming for Coal Thermal without a cooling tower’ has the impact score 6 on Table 9.4.7. and 8.674 on Table 9.4.8. The proportion of the assumed plant factor (50%) with the calculated factor (72.3%) was multiplied on 6, which resulted in 8.674. Table 9.4.8 shows impact scores of the base scenario.
8. Finally, the total score of respective facility on Table 9.4.8 is multiplied by the number of the concerned facility that will be developed under each alternative scenario. Then total scores of all facility types are added up to give total environmental impact scores for respective scenarios.

Table 9.4.1 (a) Criteria for Scoping Items (1/6)

Category	Environmental Items	Check Items	Facility: Hydo Power	Facility: Thermal Power	Facility: Geo-thermal Power	Facility: Trans-mission Line
Social Environment	**Involuntary Resettlement**	(1) Do the prospective projects contain any physical transformation, such as facility construction and land reclamation, which is anticipated to cause involuntary resettlement in project implementation ? Does it bring a large scale (more than a few hundred families) resettlement and land expropriation or a limited scale (less than several families) resettlement and land expropriation ?	O	O	O	O
		(2) If resettlement is anticipated, is it possible to change the plan to avoid it ? If it is not avoidable, is it possible to make any alternative plans to minimize the impacts ?	O	O	O	O
		(3) If resettlement is unavoidable, is it likely that the concerned inhabitants will agree to resettle once the situation has been properly explained to them, including the necessary resettlement and compensation plans? Do you anticipate any difficulties in obtaining their agreements?	O	O	O	O
		(4) Is it practically possible to carry out socio-economic surveys for anticipated resettlement inhabitants, to hold public hearings, to make proper resettlement and compensation plans preserving and restoring their living standards, and to prepare and maintain financial measures and implementation structures to realize the plans ? Are these processes guaranteed under the legal system ?	O	O	O	O
		(5) Does the resettlement bring any large disadvantages to the socially vulnerable, such as women, children, the elderly, the poor people, ethnic minorities, and indigenous people ? For instance, hardships related to securing drinking water, educational conditions, medical facilities, job opportunities, and inevitable changes in lifestyles.	O	O	O	O
		(6) Have you observed a political dictatorship in the region that will make it difficult to take the proper measures mentioned above in the event that resettlement is unavoidable?	O	O	O	O
		(7) Is it possible to establish a system to monitor the impacts on the resettled inhabitants and to take sustainable measures for providing them with livelihood support?	O	O	O	O
	Minority or weak people of society	(1) Does the plan (and projects) ignores or has the possibility to ignore lives and benefits of the social minorities and the weak, such as women, children, the elderly, handicapped people, the poor people, ethnic minorities, indigenous people, religious minorities, migrants and veterans, by removing their means of production and living and compelling them to change their basic lifestyles ? Are there any countermeasures for avoiding the above?	O	O	O	O
		(2) Does the plan sufficiently take into account the basic rights and subsistance right of the social minorities and the weak ?	O	O	O	O
		(3) Does the plan damage socio-economic infrastructures of the social minorities and the weak, such as hospitals, schools and roads ?	O	O	O	O
		(4) Are considerations given to reduce impacts on the culture and lifestyle of ethnic minorities and indigenous people? Is the project planner (proponent) aware of this need and ready to hold discussions with these groups? Is this guaranteed under the legal system ?	O	O	O	O
		(5) Are considerations given to reduce impacts on the culture and lifestyle of ethnic minorities or indigenous people when they are living in the right-of-way ? Is the project planner (proponent) aware of this need and ready to hold discussions with these groups? Is this guaranteed under the legal system ?				O

Table 9.4.1 (b) Criteria for Scoping Items (2/6)

Category	Environmental Items	Check Items	Facility: Hydo Power	Facility: Thermal Power	Facility: Geo-thermal Power	Facility: Trans-mission Line
Social Environment	Inequality and separation in society	(1) Are considerations given to distribute project benefits evenly among the concerned society ? Is there a possibility that adverse impacts will converge (or gather) on one particular region or social group ?	O	O	O	O
		(2) Is it possible that the plan may cause friction between different interests in the society?	O	O	O	O
		(3) Is there any possibility that the plan will result in physical separation of traffic, communications, social exchanges, commutes to work and other such items due to the blockage of routes and the disconnection of communication means?	O	O	O	O
	Cultural heritage	Are there any possibilities that the plan damages the local archeological, historical, cultural, and religious heritage sites ?	O	O	O	O
	Local landscape	Are there any adverse impacts on famous aesthetic landscape? Are there any claims from inhabitants hoping to preserve the landscape ? In this case, is it possible to review the plan and take any necessary countermeasures ?	O	O	O	O
	Economic activities (regional/local)	(1) Are there any adverse impacts on agriculture, livestock farming and small fishery, such as loss of farmlands and grassland and blocking of livestock's path, due to construction of large scale facilities, reservoirs, power plants close to river mouths or on coastlines, transmission lines, and access roads ?	O	O	O	O
		(2) Are there any adverse impacts on land use downstream of a dam or an intake ? In particular, does reduction in the supply of fertile soil to downstream areas adversely affect agricultural production?	O			
		(3) Does existence of a dam adversely affect water transport by river vessels or water utilization by local	O			
	Water Usage	(1) Does intake of water (both surface and ground) and discharge of used and waste water adversely affect any downstream water supply sources, due to water flow decrease, lowered ground water level, and deterioration of water quality ?	O	O	O	
		(2) Can the minimum water flow needed for water usage be maintained downstream of a dam or intake?	O			
		(3) Does reduction in water flow downstream (of a dam or an intake) or seawater intrusion adversely affect downstream water use and land use ?	O			
		(4) Does intake of water (both surface and ground) and discharge of heated cooling water adversely affect the existing conditions of water and river utilization, especially fishery ?		O		
		(5) Does intake of water (both surface and ground) and discharge of wastewater adversely affect the existing conditions of water and river utilization ?			O	
	Contagious or Infectious disease	(1) Are there any risks that the inflow of workers associated with the project will result in an outbreak of disease, including communicable diseases like HIV? Will it be possible to take proper measures to protect public health, if necessary?	O	O	O	O
		(2) Are there any risks that water-borne or water-related diseases, such as schistosomiasis, malaria and filariasis, will be introduced ?	O	O	O	
	Accidents	Do the prospective projects include large scale civil works which cause a large amount of traffic of heavy vehicles and equipment ?	O	O	O	O

Table 9.4.1 (c) Criteria for Scoping Items (3/6)

Category	Environmental Items	Check Items	Facility			
			Hydo Power	Thermal Power	Geo-thermal Power	Trans-mission Line
Natural Environment	Protected Area	Is it possible to locate the planned facilities so as to avoid protected areas designated by the national legislation or international treaties and conventions ? Will the project activities affect the protected areas?	O	O	O	O
	Geographical /Geological Features	(1) Is it likely that a large-scale alteration of topographic features and geologic structures will be brought about in the surrounding areas of the planned sites, such as land excavation, dredging and reclamation ?	O	O	O	O
		(2) Is it conceivable that the planned facilities will be inevitably situated in areas where topographic features and geologic structures are fragile and may easily result in slope failure, land slides and differential settlement ? In such a case, is there any measure to avoid or mitigate the possible impacts ?	O	O	O	O
		(3) Is it possible to avoid selecting a site where civil works such as land cutting and filling are frequently used on slopes with possible land failures and landslides ? Is it readily possible to take proper measures to prevent slope failures and landslides?	O	O	O	O
		(4) Is there a good risk that soil runoff will occur at land cutting and filling areas, spoil-banks, or borrowing pits ? Is it readily possible to take proper measures to prevent soil runoff ?	O	O	O	O
	Sediment & Hydrology	(1) When a hydropower plant with a dam and reservoir is concerned, do they usually make proper surveys and take sufficient mitigation measures for impacts on upstream and downstream riverbeds, and for erosion and sedimentation of rivers ?	O			
		(2) Is it likely that such structures as dams and weirs will be of the size that may cause changes to a river system or hydrological impacts on the surface or ground water flow ?	O			
		(3) Is there any plan to extract ground water or steam that may affect the ground water system or ground water usage in the surrounding area ?		O	O	
	Ecosystems/ Wildlife	(1) Does the planned project site extend over primeval forests, tropical natural forests, biological corridors or ecologically important habitats such as coral reefs, mangroves and tidal flats ?	O	O	O	O
		(2) Does the planned project site extend over the protected habitats and biological corridors of precious species designated by the country's laws or international treaties and conventions?	O	O	O	O
		(3) Is it likely that the project activities may cause serious impacts on important ecosystems even if the project site is outside of those systems ? For instance, are there any risks of deforestation and poaching under development activities, scattering or falling of atmospheric pollutants and oxides, desertification, or the drying of swamps ? Is there any risks that non-native species, pests and vectors are introduced through tree-planting and imported soil ?	O	O	O	O
		(4) Do they plan to install any blocking structures in the river where important migratory fish species are supposed to live ? If such biological information is insufficient, are there plans to take proper considerations for conducting the necessary surveys and measures ?	O			
		(5) Is there any plan to install such facilities that may possibly affect river systems where rich ecosystems or precious aquatic lives, fauna and flora keep habitats ?	O	O	O	

Table 9.4.1 (d) Criteria for Scoping Items (4/6)

Category	Environmental Items	Check Items	Facility			
			Hydo Power	Thermal Power	Geo-thermal Power	Trans-mission Line
Natural Environment	**Ecosystems/ Wildlife**	(6) Do they plan to take surface or ground water, and discharge thermal effluent and seepage water, which may affect water volume, temperature and quality of rivers and surrounding aquatic ecosystems ?	O	O	O	
		(7) In cases where the project site is located in an undeveloped area, is there a risk that the natural environment would be severely damaged by the local development and unexpected migration of people from outside? Is it in the scope of plan to take proper countermeasures to manage those issues ?	O	O	O	O
	Global warming	Does the planned power plant emit considerable greenhouse gases?		O		
Pollutions & Public Hazards	**Air Pollution**	(1) In selection of the project, do they employ a design policy to control air pollutants such as sulfur oxides (SOx), nitrogen oxides (NOx), soot and dust emitted from the power plant during operation ?		O		
		(2) In the case of coal-fired power plants, does the project include countermeasures to avoid air pollution due to fugitive coal dust from coal piles, coal handling facilities, and dust from coal ash disposal sites ?		O		
		(3) During planning is proper consideration given to multiple and cumulative impacts on the area that may be adversely affected by fixed and mobile sources of pollutants around the site.		O		
		(4) In the case of geothermal power plants, does the project include countermeasures against air pollution due to hydrogen sulfide emitted from the power plant ?			O	
	Water Pollution	(1) When a dam lake or a reservoir is concerned, is it possible to conduct an assessment study for water quality degradation and to take measures to control water pollution ? is it financially possible to prepare the proper budget for such measures ? For instance, 1) Can they prevent the impacts on aquatic lives and fishes due to the proliferation of water grass and abnormal outbreaks of animal/plant plankton ? 2) Can they supply the project cost for countermeasures against corrosion of trees in the dam lake or reservoir ? 3) Can they take measures for environmental management of waste water and garbage due to the inflow of waste around the watershed, and activities around the dam lake or reservoir such as tourism and fish farming after the development ? 4) Can they take measures for controlling the water quality of discharged water ? 5) Is it possible to follow environmental standards against the decrease of downstream water flow ?	O			
		(2) Do they include in the plan the cost for treating drain water from the power plant including thermal effluent ? Do they cover the cost enough to meet the effluent standards and environmental standards downstream.?		O		
		(3) In the case of coal fired power plants, do they include in the plan countermeasures against leachate from coal piles and coal ash disposal sites ?		O		
		(4) Do they include measures in the plan for treating fuel waste, drain water containing oil and leaked water from the power plant?		O		
		(5) In the case of geothermal power plants, do they include in the plan the cost of countermeasures against water pollution by arsenic and mercury during geothermal utilization ?			O	
		(6) Do they consider the measures against river water pollution due to soil runoff from the bare lands resulting from activities such as land cutting and filling ?	O	O	O	O

Table 9.4.1 (e) Criteria for Scoping Items (5/6)

Category	Environmental Items	Check Items	Facility			
			Hydo Power	Thermal Power	Geo-thermal Power	Trans-mission Line
Pollutions & Public Hazards	Soil Contamination	(1) Is there a risk of polluting the bottom sludge in a dam lake due to sedimentation of waste and rotted trees ?	O			
		(2) Is there a risk of concentrated pollutants in the riverbed soil caused by decreased river flow due to water intake and so on ?	O	O		
		(3) In the case of coal thermal power plants, is there a risk of soil contamination due to leachates from coal piles and coal ash disposal sites ?		O		
		(4) In the case of geothermal power plants, is there a risk of soil contamination caused by pollutants such as arsenic and mercury during geothermal utilization ?			O	
		(5) Is there a risk of hazardous earth and sand problems due to imported earth and sand or exposed underground earth and sand in such case as site development, land filling and cutting ?	O	O	O	O
	Waste	(1) Is there a good outlook for the proper treatment and disposal of earth and sand generated by excavation ? For instance, the plans for disposal criteria, disposal site and treatment methods.	O	O	O	O
		(2) Does the plan include a sub-plan for disposal and management of wastes such as debris and driftwood flowing in the reservoir, especially at intakes or dams ?	O			
		(3) Does the plan include a management plan for treatment and disposal of wastes such as waste oils and chemicals, coal ash and by-product gypsum from flue gas desulfurization that come out of the power plant operation ?		O		
	Noise & Vibration	(1) Do noise and vibrations during the operation of the power plant comply with ambient environmental standards, and occupational health and safety standards?	O	O	O	
		(2) Has the boundary of the site been planned so that it will not be near private homes either now or in the future? If such an arrangement is not possible, do they plan to install silencer walls or vibrating protection equipment for meeting the concerned standards?	O	O	O	
		(3) In the case of coal-fired power plants, do they consider the control of noise from the facilities for coal unloading, coal storage areas and facilities for coal handling in the site plan and the facility plan?		O		
	Others (Subsidence)	(1) Does the plan involve extraction of a large volume of groundwater that may cause subsidence ?		O		
		(2) Is there a risk of subsidence caused by steam extraction during geothermal power generation ?			O	
	(Odor)	Is there a risk of offensive odor due to air pollutants, water pollution, soil contamination and wastes ?	O	O	O	O
	(Radio interference)	Is there a risk of radio interference by transmission line towers and so on ? Is it likely that adequate countermeasures will be taken if significant radio interference is expected ?				O

Table 9.4.1 (f)　Criteria for Scoping Items (6/6)

Category	Environmental Items	Check Items	Facility			
			Hydo Power	Thermal Power	Geo-thermal Power	Trans-mission Line
Pollutions & Public	**Accidents**	(1) In the case of dam construction, have they selected a proper location where emergency discharge is less frequently required and downstream danger are reduced ?	○			
		(2) In the case of a gas fired thermal power plant, have considerations at the planning stage been given to securing the safety of the gas pipelines? For example, have the sites and plans been considered so as to decrease the risk of explosions due to natural, human, facility or material factors? Has the site been selected so as to minimize damage in the event that there is an explosion?		○		
		(3) In the case of an oil thermal power plant, have considerations at the planning stage been given to raising the safety of fuel transportation? For example, have they selected sites while taking into consideration sailing route conditions and ship traffic to decrease the risk of oil spills caused by running aground or collisions involving large tankers.		○		
		(4) In the case of a coal fired thermal power plant, have considerations been giving in the planning of facilities and cost to prevent spontaneous combustion at the coal piles?		○		
		(5) In the case of a geothermal power plant, have considerations been giving in the planning phase to securing the safety of steam pipes?			○	
		(6) In the case of transmission lines, have considerations been given in the facility site plan to reduce the risks of local residents having accidents involving high voltage transmission lines?				○

Table 9.4.2 Scoping by Power Facility Type

	Item	Weight for Item	Hydro Power			Thermal Power														Geo-thermal	Trans-mission & Sub-station
						Steam Turbine						Combined Cycle				Gas Turbine		Diesel			
			Dam/Re-servoir	Run-of-river	Mini/ Micro hydro	Coal*		Gas* (LNG)		Oil* (Furnace Oil)		Gas* (LNG)		Oil* (Auto Diesel)		Gas (LNG)	Oil (A.D.)**	Oil (F.O.)**	Oil (R.O.)**		
Social Environment	Involuntary Resettlement	A	A	B	C	B	B	B	B	B	B	B	B	B	B	C	C	C	C	B	B
	Minority or weak people of society	C	A	C	C	B	B	B	B	B	B	B	B	B	B	C	C	C	C	B	C
	Inequality and separation in society	B	A	B	C	B	B	B	B	B	B	B	B	B	B	C	C	C	C	B	C
	Cultural heritage	A	A	B	C	B	B	B	B	B	B	B	B	B	B	C	C	C	C	B	C
	Local landscape	A	A	B	C	A	A	A	A	A	A	A	A	A	A	C	C	C	C	A	A
	Economic activities (regional or local)	C	A	B	C	A	A	A	A	A	A	A	A	A	A	B	B	B	B	B	C
	Water Usage	B	A	A	B	A	C	A	C	A	C	A	C	A	C	C	C	C	C	C	C
	Contagious or Infectious disease	C	B	B	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C
	Accidents	C	B	B	C	B	B	B	B	B	B	B	B	B	B	C	C	C	C	B	C
Natural Environment	Protected Area	A	A	A	C	A	A	A	A	A	A	A	A	A	A	B	B	B	B	A	A
	Geographical /Geological Features	B	B	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C
	Sediment & Hydrology	C	A	B	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	A	C
	Ecosystems/ Wildlife	A	A	A	C	A	C	A	C	A	C	A	C	A	C	C	C	C	C	B	C
	Global warming	B	C	C	C	A	A	A	A	A	A	A	A	A	A	B	B	B	B	C	C
Pollutions & Public Hazards	Air Pollution	A	C	C	C	A	A	B	B	A	A	B	B	A	A	C	B	A	A	B	C
	Water Pollution	A	A	B	C	A	B	A	B	A	B	A	B	A	B	C	C	C	C	A	C
	Soil Contamination	C	C	C	C	B	B	B	B	B	B	B	B	B	B	C	C	C	C	B	C
	Wastes	B	A	B	C	A	A	C	C	B	B	C	C	B	B	C	B	B	B	C	C
	Noise & Vibration	B	B	B	C	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	C
	Others	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	B
	Accidents	B	A	B	C	B	B	A	A	A	A	A	A	A	A	A	A	A	A	B	A

Note (1): ABCs of 'Impact evaluation'; A = Large impacts; B = Medium or Unknown impacts; C = Negligible Impacts
Note (2): Evaluation of an Impact Level is applied to the possibility, not the level after mitigation
Note (3): ABCs of 'Impact evaluation' are different categories from those of 'Weights for item'. ABCs of the latter shows the assumed magnitude of significance in the society of Sri Lanka in this order.
Note (4): * Right side row is applied to thermal power plants with cooling tower system for condenser cooling water.
Note (5): ** A.O. stands for 'Auto Diesel'; F.O. stands for 'Furnace Oil'; R.O. stands for 'Residual Oil'.

Table 9.4.3 Scoping by Project Site

		Weight for Item	Norochchole (Puttalam)	Trincomalee	Hambantota	Kerawala-pitiya	Jaffna South Chnkn		Gin Ganga	Umaoya (Inbasin)	Umaoya (Transbasin)	Moragolla	Upper Kotmale	Broadland	Kotmale	New Laxapana	Polpitiya	Victoria	Samanala-wewa
			CS	CS	CS	OP	CS		CS	CS	CS	CS	OP	OP	EP	EP	EP	EP	EP
			Coal Thermal ST	Coal Thermal ST	Coal Thermal ST	Combined Cycle	Diesel		Hydropower Dam, Reservoir	Hydropower Dam, Reservoir	Hydropower Dam, Reservoir	Hydropower Dam, Reservoir	Hydropower Run-of-River	Hydropower Run-of-River	Hydropower Dam, Reservoir	Hydropower Dam, Reservoir	Hydropower Dam, Reservoir	Hydropower Dam, Reservoir	Hydropower Dam, Reservoir
Social Environment	Involuntary Resettlement	**A**	B	A*	B	C	B	C	A	A	B	B	A	B	C	C	C	C	C
	Minority or weak people of society	**C**	B	C	B	C	C	C	B	B	B	C	B	C	C	C	C	C	C
	Inequality and separation in society	**B**	B	C	C	C	C	C	B	A	A	B	B	B	C	C	C	C	C
	Cultural heritage	**A**	C	C	C	C	C	C	C	C	C	C	A	C	C	C	C	C	C
	Local landscape	**A**	B	A	B	C	B	C	A	B	B	B	A	B	B	C	C	C	C
	Economic activities (regional or local)	**C**	B	B	B	C	B	B	B	B	B	C	A	B	C	C	C	C	C
	Water Usage	**B**	B	B	B	B	C	C	A	A	A	A	A	A	B	B	B	B	B
	Contagious or Infectious disease	**C**	C	C	C	C	C	C	B	B	B	B	B	B	C	C	C	C	C
	Accidents	**C**	B	B	A	B	B	B	B	B	B	B	B	B	B	B	B	B	B
Natural Environment	Protected Area	**A**	C	C	C	C	B	C	A	C	C	C	C	B	C	C	C	C	C
	Geographical /Geological Features	**B**	B	B	B	C	C	C	B	B	A	C	A	C	B	B	B	B	B
	Sediment & Hydrology	**C**	C	C	B	B	C	C	A	A	A	B	A	B	C	C	C	C	C
	Ecosystems/ Wildlife	**A**	B	A	B	C	C	C	A	B	B	C	B	B	C	C	C	C	C
	Global warming	**B**	A	A	A	A	B	B	C	C	C	C	C	C	C	C	C	C	C
Pollutions & Public Hazards	Air Pollution	**A**	A	A	A	B	B	B	C	C	C	C	C	C	C	C	C	C	C
	Water Pollution	**A**	A	A	A	A	B	B	B	B	B	B	B	B	C	C	C	C	C
	Soil Contamination	**C**	B	B	B	B	B	B	C	C	C	C	C	C	C	C	C	C	C
	Wastes	**B**	A	A	A	B	B	B	B	A	A	B	B	B	C	C	C	C	C
	Noise & Vibration	**B**	B	B	B	B	A	B	B	C	C	B	C	B	C	B	B	B	B
	Others	**C**	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C
	Accidents	**B**	A	A	A	A	A	A	B	A	A	B	B	B	B	B	B	B	B

Note (1): A = Large impacts; B = Medium or Unknown impacts; C = Negligible Impacts; CS = Candidate Site; OP = Ongoing Project; EP = Expansion Plan for Existing Facility
Note (2): Evaluation of an Impact Level is applied to the possibility, not the level after mitigation
Note (3): ABCs of 'Impact evaluation' are different categories from those of 'Weights for item'. ABCs of the latter shows the assumed magnitude of significance in the society of Sri Lanka in this order.
Note (4): * Supposedly no resettlement of residents, but government facilities and buildings (military base) need to be moved. The candidate facility locates within the area regulated by the Aviation Control Act

Table 9.4.4 Weights for Scoping Items

Item		Weight for Item	Weight
Social Environment	Involuntary Resettlement	A	3.0
	Minority or weak people of society	C	1.0
	Inequality and separation in society	B	2.0
	Cultural heritage	A	3.0
	Local landscape	A	3.0
	Economic activities (regional or local)	C	1.0
	Water Usage	B	2.0
	Contagious or Infectious disease	C	1.0
	Accidents	C	1.0
Natural Environment	Protected Area	A	3.0
	Geographical /Geological Features	B	2.0
	Sediment & Hydrology	C	1.0
	Ecosystems/ Wildlife	A	3.0
	Global warming	B	2.0
Pollutions & Public Hazards	Air Pollution	A	3.0
	Water Pollution	A	3.0
	Soil Contamination	C	1.0
	Wastes	B	2.0
	Noise & Vibration	B	2.0
	Others	C	1.0
	Accidents	B	2.0

Weight Grade	Weight
A	3.0
B	2.0
C	1.0

Table 9.4.5 Scores for Scoping Grade

Scoping Grade	Score
A	3
B	1
C	0.1

Table 9.4.6 Operation Dependant Items

Item		Category	
		Hydro	Thermal
Social Environment	Involuntary Resettlement	Facility	Facility
	Minority or weak people of society	Facility	Facility
	Inequality and separation in society	Facility	Facility
	Cultural heritage	Facility	Facility
	Local landscape	Facility	Facility
	Economic activities (regional or local)	Facility	Facility
	Water Usage	Facility	Facility
	Contagious or Infectious disease	Facility	Facility
	Accidents	Facility	Facility
Natural Environment	Protected Area	Facility	Facility
	Geographical /Geological Features	Facility	Facility
	Sediment & Hydrology	Facility	Facility
	Ecosystems/ Wildlife	Facility	Facility
	Global warming	Facility	Operation
Pollutions & Public Hazards	Air Pollution	Facility	Operation
	Water Pollution	Facility	Facility
	Soil Contamination	Facility	Facility
	Wastes	Facility	Operation
	Noise & Vibration	Facility	Operation
	Others	Facility	Facility
	Accidents	Facility	Facility

Table 9.4.7 Impact Scores by Power Facility Type

	Item	Weight for Item	Hydro Power			Thermal Power														Geo-thermal	Trans-mission & Sub-station
						Steam Turbine						Combined Cycle				Gas Turbine		Diesel			
			Dam/Re-servoir	Run-of-river	Mini/ Micro hydro	Coal*		Gas* (LNG)		Oil* (Furnace Oil)		Gas* (LNG)		Oil* (Auto Diesel)		Gas (LNG)	Oil (A.D.)**	Oil (F.O.)**	Oil (R.O.)**		
Social Environment	Involuntary Resettlement	A	9	3	0.3	3	3	3	3	3	3	3	3	3	3	0.3	0.3	0.3	0.3	3	3
	Minority or weak people of society	C	3	0.1	0.1	1	1	1	1	1	1	1	1	1	1	0.1	0.1	0.1	0.1	1	0.1
	Inequality and separation in society	B	6	2	0.2	2	2	2	2	2	2	2	2	2	2	0.2	0.2	0.2	0.2	2	0.2
	Cultural heritage	A	9	3	0.3	3	3	3	3	3	3	3	3	3	3	0.3	0.3	0.3	0.3	3	0.3
	Local landscape	A	9	3	0.3	9	9	9	9	9	9	9	9	9	9	0.3	0.3	0.3	0.3	9	9
	Economic activities (regional or local)	C	3	1	0.1	3	3	3	3	3	3	3	3	3	3	1	1	1	1	1	0.1
	Water Usage	B	6	6	2	6	0.2	6	0.2	6	0.2	6	0.2	6	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Contagious or Infectious disease	C	1	1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Accidents	C	1	1	0.1	1	1	1	1	1	1	1	1	1	1	0.1	0.1	0.1	0.1	1	0.1
Natural Environment	Protected Area	A	9	9	0.3	9	9	9	9	9	9	9	9	9	9	3	3	3	3	9	9
	Geographical /Geological Features	B	2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Sediment & Hydrology	C	3	1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	3	0.1
	Ecosystems/ Wildlife	A	9	9	0.3	9	0.3	9	0.3	9	0.3	9	0.3	9	0.3	0.3	0.3	0.3	0.3	3	0.3
	Global warming	B	0.2	0.2	0.2	6	6	6	6	6	6	6	6	6	6	2	2	2	2	0.2	0.2
Pollutions & Public Hazards	Air Pollution	A	0.3	0.3	0.3	9	9	3	3	9	9	3	3	9	9	0.3	3	9	9	3	0.3
	Water Pollution	A	9	3	0.3	9	3	9	3	9	3	9	3	9	3	0.3	0.3	0.3	0.3	9	0.3
	Soil Contamination	C	0.1	0.1	0.1	1	1	1	1	1	1	1	1	1	1	0.1	0.1	0.1	0.1	1	0.1
	Wastes	B	6	2	0.2	6	6	0.2	0.2	2	2	0.2	0.2	2	2	0.2	2	2	2	0.2	0.2
	Noise & Vibration	B	2	2	0.2	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	0.2
	Others	C	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1
	Accidents	B	6	2	0.2	2	2	6	6	6	6	6	6	6	6	6	6	6	6	2	6
Total Score			93.7	49.0	6.0	85.5	65.0	77.7	57.2	85.5	65.0	77.7	57.2	85.5	65.0	21.2	25.7	31.7	31.7	57.0	31.0

*: Right side row is applied to thermal power plants with cooling tower system for condenser cooling water.

Table 9.4.8 Impact Scores for Base Scenario

	Item	Hydro Power					Thermal Power														Geo-thermal	Trans-mission & Sub-station
							New Steam Turbine						New Combined Cycle					Gas Turbine		Diesel		
		Moragolla	Gin Ganga	Broad-lands	Uma Oya	Upper Kotmale	Coal*		Gas*		Oil*		Kerawala-pitiya	Gas*		Oil*		Gas	Oil	Oil		
Social Environment	Involuntary Resettlement	3	9	3	3	9	3	3	3	3	3	3	0.3	3	3	3	3	0.3	0.3	0.3	3	3
	Minority or weak people of society	0.1	1	0.1	1	1	1	1	1	1	1	1	0.1	1	1	1	1	0.1	0.1	0.1	1	0.1
	Inequality and separation in society	2	2	2	6	2	2	2	2	2	2	2	0.2	2	2	2	2	0.2	0.2	0.2	2	0.2
	Cultural heritage	0.3	0.3	0.3	0.3	9	3	3	3	3	3	3	0.3	3	3	3	3	0.3	0.3	0.3	3	0.3
	Local landscape	3	9	3	3	9	9	9	9	9	9	9	0.3	9	9	9	9	0.3	0.3	0.3	9	9
	Economic activities (regional or local)	0.1	1	1	1	3	3	3	3	3	3	3	0.1	3	3	3	3	1	1	1	1	0.1
	Water Usage	6	6	6	6	6	6	0.2	6	0.2	6	0.2	2	6	0.2	6	0.2	0.2	0.2	0.2	0.2	0.2
	Contagious or Infectious disease	1	1	1	1	1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Accidents	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.1	0.1	0.1	1	0.1
Natural Environment	Protected Area	0.3	9	3	0.3	0.3	9	9	9	9	9	9	0.3	9	9	9	9	3	3	3	9	9
	Geographical /Geological Features	0.2	2	0.2	6	6	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Sediment & Hydrology	1	3	1	3	3	0.1	0.1	0.1	0.1	0.1	0.1	1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	3	0.1
	Ecosystems/ Wildlife	0.3	9	3	3	3	9	0.3	9	0.3	9	0.3	0.3	9	0.3	9	0.3	0.3	0.3	0.3	3	0.3
	Global warming	0.2	0.2	0.2	0.2	0.2	8.674	6	6	6	6	6	1.078	6	6	1.078	6	2	0.144	2	0.2	0.2
Pollutions & Public Hazards	Air Pollution	0.3	0.3	0.3	0.3	0.3	13.01	9	3	3	9	9	0.539	3	3	1.617	9	0.3	0.217	9	3	0.3
	Water Pollution	3	3	3	3	3	9	3	9	3	9	3	9	9	3	9	3	0.3	0.3	0.3	9	0.3
	Soil Contamination	0.1	0.1	0.1	0.1	0.1	1	1	1	1	1	1	1	1	1	1	1	0.1	0.1	0.1	1	0.1
	Wastes	2	2	2	6	2	8.674	6	0.2	0.2	2	2	0.359	0.2	0.2	0.359	2	0.2	0.144	2	0.2	0.2
	Noise & Vibration	2	2	2	0.2	0.2	8.674	6	6	6	6	6	0.359	6	6	1.078	6	6	0.433	6	6	0.2
	Others	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1
	Accidents	6	2	2	6	2	2	2	6	6	6	6	6	6	6	6	6	6	6	6	2	6
Total Score		32.0	63.0	34.3	50.5	61.2	97.5	65.0	77.7	57.2	85.5	65.0	24.6	77.7	57.2	66.6	65.0	21.2	13.6	31.7	57.0	31.0

*: Right side row is applied to thermal power plants with cooling tower system for condenser cooling water.

9.4.3 Proposed Plan and Alternatives (including without project situation)

(1) Alternatives including without project option

The following are the alternatives considered in this study.

1) Zero option scenario

Without this master plan, what will happen in the future?

(If the power sector in Sri Lanka, without a master plan, goes on under the same conditions as it is, the given conditions will have a good resemblance to the alternative scenario ② shown below.

2) Alternative scenarios

① Scenario where large thermal power plants are developed

② Scenario where large thermal power plants are not developed (no more than 150MW per generation unit)

③ Scenario where hydropower plants are promoted (for favorable hydropower projects)

④ Scenario where natural gas are supplied for power generation

Table 9.4.9 Comparison of Alternative Generation Development Scenarios

Developmet Scenario	Total Cost up to 2025*1	System Operation	CEB Finance	Environmental Impact Score	Others
Development of Large Thermal TPP	5,921 MUSD	stable operation	improved	1,954 point	
No Development of Large Thermal TPP	7,316 MUSD*2	with possibility of total system	probable collapse	2,428 point	
Hydropower Oriented	6,025 MUSD	stable operation	improved	2,036 point	
Natural Gas Supply	5,907 MUSD	stable operation	improved	1,950 point	lack of clear prospects of natural gas introduction

*1 : 2005NPV

*2 : with low speed unit

(2) Proposed Plan and Overall Evaluation of Scoping Results

Comparison of Alternative Scenarios

Regarding the above alternative scenarios, the environmental impact scores of Table 9.4.9 have been derived through the procedure of '8 in the section 9.4.2'. Environmental and social impacts can be controlled under the large thermal power Scenario ① where many coal thermals are developed, to the least level next to the natural gas supply Scenario ④. To the other way around, the non-large thermal power Scenario would bring in the largest impacts.

The result is derived from the following reason, we observed. It is certain that the development of coal thermal generation units of 300 MW will cause not small impacts, regarding thermal power generation. However, if the power demand would be supplied by small-scale diesel power plants as alternative to large thermals, they would probably bring in even larger environmental and social impacts since the number of the introduced units must be very large. As for hydropower generation facilities, relatively larger scale of environmental and social impacts will be caused by the facility development, compared with the scale of facility developed.

Proposed Plan

At the end of 2004, Sri Lanka was populated by 19 million people and the electricity supply rate reached 65%, with approximately two thirds of the nation enjoying the benefit of power supply. The increase of industrial demand for power should also be supposed to make a room for the structural change in the industry which light industry like tea plantation dominates in, and to enable industrial development. This way, power development is necessary to respond to the increase of household and industrial power demand. (See the Chapter 4)

In case of the Zero Option Scenario, where the scenario assumes that any large thermal power facilities would not be introduced in the master plan, the present unstable conditions in power supply would be more strained in the near future and become similar to the situation given by the above alternative Scenario ②. (See the section 6.4.1) In that case, electricity supply would be no more moderately charged and stable. Under the zero option scenario, it can be supposed, that the possibility of large-scale blackouts of power, higher tariff and frequent power cuts would increase and inevitably result in the damage on people's living and the constraint on industrial development. We must assume that the Zero Option Scenario would actually bring about a heavy bloke on the bedrock of people's life.

After the comparison with the Zero Option Scenario and the alternative scenarios, the large thermal power Scenario is here proposed as the base case in the master plan, with integrated comparison from environmental and social aspects as well as development costs, reliability of system operation and financial evaluation. (See the section 6.4.1 for further reference)

It is surely recommendable that the CEB counterparts should continue to reexamine the scoping format and tools to update the evaluation in response to the development of given conditions and necessity. It is also to be understood that periodical exchange of opinions with stakeholders will certainly be useful for smooth site selection of power generation facilities. Further, it should be noted that the necessary EIA, environmental impact assessment, is still required in the progress of individual projects that would follow the master plan with SEA, strategic environmental assessment, on environmental and social impacts. When individual projects come in, the proper EIA procedure should be taken and the appropriate stakeholder meetings should be conducted to keep the transparency of decision making process.

(3) Candidate Project Profiles

Sites for Coal P/P

Puttalam <300MW x 3>

- F/S 1998, EIA 1998, D/D Jan. 2000
- Conceptual Resettlement & Compensation Plan, Oct. 1998
- postponed with political order due to social & political oppositions after EIA approval

Trincomalee <300MW x 3>

- F/S in 1988.
- Best location for coal unloading
- But four candidate sites would violate the aviation act, regarding an existing airport.

Hambantota <300MW x 3>

- Site Identification Survey in 2001
- F/S, EIA & D/D needed for issues on water supply, ash dumping, coal stockyard, salt industry & resettlement.

Sites for Other Thermal P/P

Kerawalapitiya （C/C IPP by Korean company) <300MW>

- CEB has not received any decision from the Tender Board, yet.
- Min. of Urban Development
- Located 500 m inland.
- Drainage issue for thermal effluent water.

Jaffna (Diesel Candidate Sites) <30MW?>

- 3 Sites: Chunnakam; South-Pannai Beach; North-Point Pedro
- Chunnakam is an existing substation site. Enough land owned by CEB. But, considerations are necessary for transportation and installation of heavy machines and equipment.
- Other 2 sites are located on the coastline. Approach is shallow water for the South while the North may be deeper. But both sites should clear the issue of Security Zone. Resettlement

are supposedly few because of the Security Zone Clearance. Both need more survey for any decision.

Sites for Hydro power generation

Umaoya (inbasin)-UMAO 021<31.4MW>, 042<41.8MW> in Mahaweli Basin

- Reservoir Inundated Area is characteristic in Small farmers, Moslem Communities, Veg. Cultivation (Tea, Tobacco, Cabbage, Potato, Chili, Beans), Cattle-breeding, Open Scrub Forest
- Upper Catchment Management Program by MENR/ADB for watershed conservation → Land is not thick forest, concerned for soil erosion
- Resettlement: very few for 021 site, around 1500 (assumed) for 042

Umaoya (transbasin) <150MW> Mahaweli → Kirindi Basin

- 19 km tunnel. Underground Power Station. Using reservoir waters of Umaoya and Mahatotilaoya
- Coordination with irrigation sector (in Kirindioya) is the main issue.
- Tamil, Moslem Communities at outlet area

Moragolla <27MW with Kotmale Diversion> in Mahaweli Basin

- Reservoir inundation area: Tea and Potato cultivation, many bathing site for local people, no forest land
- Resettlement: around 30 houses, 150 people for 100 m clearance from reservoir

Gin Ganga <48.9MW> in Gin Basin

- GTZ master plan study in late 1980s' located the site as GING074.
- Sinharaja Forest (National Heritage Wilderness Area & World Heritage Site) is on the right bank of the Gin Ganga River. High Biodiversity.
- Resettlement was assumed to be around 1,600 persons.

Sites for Ongoing Hydropower projects

Broadlands <35MW, Run-of-River type > in Kelani basin

- Resettlement: 16 houses, 17-20 families/shops, (around 80 people?) on the waterway route
- Loss of forest, garden, forest products. Loss of whitewater rafting. Loss of scenic landscape of natural forest. A forest reserve near power house

Upper Kotmale <150MW, Run-of-River type > in Mahaweli Basin

- JICA F/S in 1985, D/D in 1995, JBIC SAPROF and EIA in 2000, Revised Resettlement Action Plan in 2004 (Resettlement 498 Families, around 50 buildings).
- Initial EIA study 1993-1994. Final decision on approval of EIA in March 2000 after prolonged dispute and a court case. Many (around 20) successive cabinet decisions still issued up to now.
- National Environmental (Upper Kotmale HPP Monitoring) Regulations No.1 of 2003
- 6 tributary/waterfall including Devon and St.Clair Falls
  → Cabinet decision to utilize 1 tributary, only St.Clair fall.
- Tourists: 4-5 months/yr ＊100-200/day → 12000 – 15000 people/yr

Sites for Hydropower Expansion Plans

Victoria <140 MW> in Mahaweli Basin

- Power generation is constrained with irrigation water requirements.

Kotmale <20 MW>, 20 % of existing capacity> in Mahaweli Basin

- Power generation is constrained with irrigation water requirements.
- Reserved forest; spotted deer, wild cat, wild boar

New Laxapana <72.5MW> in Kelani basin

- Not required of irrigation or other water usage
- Leakage of water from existing structure, water quality degradation

Polpitiya <47.9 MW> in Kelani basin

- Not required of irrigation or other water usage

Samanalawewa <120 MW> in Walawe Basin

- Irrigation to 2500 families, 850ha of paddy fields
- 400 people resettled, 900 ha inundated, 100 ha reforested. Leakage from the dam site.

Existing Private Projects of Mini Hydro Stations by Independent Power Producers, for reference

Carolina Mini Hydro Station <2.7 MW> (near New Laxapana)

- Owner: Mark Mareni Services Pv. Operation started in 1999
- Max Q 3.8 m3/sec
- 15 L/ sec of maintained water flow for original river in dry season
- Construction; 230 million Rp.
- 1 station manager, 3 assistants, 3 operators, 22 laborers (6 x 2 shift + 10 security guards)

Way-Ganga Power Station <9MW> (near Samanalawewa)

- Sri Lankan owner in finance, hotel and power business
- Operation started in 2000
- 1 weir, 3.7 km channel (max depth- 8m, width- 3.7 m)
- Construction; 1 billion Rp.
- 1999 IEE (Initial Environmental Examination) for 1 year
- 8 house resettled

9.4.4 Key Impacts Identified and Mitigation

At this master plan study stage, the following typical impacts by different facility types are conceivable regarding the prospective developments, and corresponding mitigation measures shall be considered.

'Impacts' have been considered from SEA standpoint in comparing alternative scenarios for the MP, as shown in the Scoping Tables. Considering the proposed plans of large thermal scenario, the accumulative impacts should be considered.

'Mitigation' measures should be taken when the candidate projects are to be implemented after the MP. The descriptions are given here for educational purpose.

(1) Impacts possibly caused by and mitigation required on different facility types

Coal Thermal Power Plant（Key Impacts）

- Coal thermal power plants may cause impacts on air pollution such as SOx, NOx, soot and dust, impacts on water pollution such as leachate from coal piles and ash disposal sites, and problems regarding the disposal and treatment of waste such as coal ash.
- Other possible impacts are on existing water utilization by intake or discharge of condenser cooling water, impacts on ecosystems and wildlife by thermal water discharge, and problems caused by noise and vibration.
- Careful consideration should also be given to impacts on environmentally protected areas and secondary impacts on them, impacts on local landscape, and any impacts on such economic activities as agriculture and fishery in cases where the power plant is developed at the mouth of river or along the coastal areas.

Coal Thermal Power Plant（Mitigation）

- Disclosure of planning and decision making process
  (Transparent discussion with properly represented stakeholders from the early stage of planning to eliminate unfair intervention of politics and abuse of power)

- Proper Resettlement Plan and Compensation Plan, Residents' Consensus and Proper Implementation
- Careful Consideration of Layout, Shape, and Color of Power Plants
- Utilizing Proper Quality Fuels
- Adopting Generation Equipment with High Efficiency
- Adopting a Taller Stack
- Adopting Electric Static Precipitators
- Adopting Flue Gas Desulfurizer (and Exhaust Gas Denitrizer)
- Countermeasures against Thermal Effluent
- Recycle Use and Management of Waste such as Coal Ash

Combined-Cycle Thermal Power Plant（Key Impacts and Mitigation）

- Impacts are mostly similar to those of a coal thermal power plant with respect to air pollution.
- Impacts includes the followings;
    - air pollution such as NOx depending on the project location
    - water quality by thermal water discharge
    - existing water utilization by intake or discharge of condenser cooling water
    - ecosystems and wildlife by thermal water discharge
    - noise and vibration
    - and environmentally protected areas, local landscape, & economic activities.
- Therefore the mitigation measures are mostly similar to those for a coal thermal plant, except for electric static precipitators and coal ash management

Gas Turbine Thermal Power Plant（Key Impacts and Mitigation）

- A gas turbine power plant itself causes less impact than the other types of thermal power because of smaller unit capacity. It can avoid impacts on social environment with less difficulty because it can be developed anywhere with a small amount of space.
- However, careful consideration should be given to noise and vibration and fuel safety (pipelines or storage tanks) because the plants can be situated close to urban residences in a load center.
- If many plants of this type gather in one place, a same sort of environmental considerations are necessary as those on a large-scale thermal power plant, such as a combined cycle thermal power plant.

Diesel-Cycle Power Plant（Key Impacts and Mitigation）

- Diesel power plants are likely to be situated in urban areas. Therefore, careful considerations should be given to noise and vibration and air pollution.
- Especially, specific attention on air pollution should be necessary if the diesel power plant uses a fuel of harmful constituents, such as heavy fuel oil.
- SOx and NOx emission per energy produced are higher than the other types of thermal power generation. The amount of particulate emission per energy produced is next to coal thermal and CO2 emission is similar to the other thermal plants.
- Therefore, if many plants of diesel power aggregate and cause cumulative impacts, they may bring in even larger impacts for total energy generated than the other type of thermal power generation.

Hydropower Plant（Key Impacts and Mitigation）

Consideration should be given to the impacts on the following;

- water utilization, ecosystems and wildlife along the areas affected by river diversion, and environmentally protected areas,
- (a dam/ reservoir type) involuntary resettlement, change in life style especially for minorities and weak members of society, physical separation of local society by a reservoir, disappearance of a heritage due to submergence, and change in the local landscape,

- sedimentation in a reservoir, erosion at downstream riverbanks, water deterioration in a reservoir such as eutrophication and turbidity for long-term issues due to waste flowing into a reservoir, and
- issues on slope collapses and landslides around a reservoir caused by the existence of a reservoir and fluctuation in a water level, downstream safety involving discharge from a dam and an outlet, and safety against dam collapse,
- (a run-of-river type) require resettlement based on the project plan, so careful considerations are also necessary for this issue.

Transmission Lines（Key Impacts and Mitigation）

- Identification of the distribution of environmental protected areas and cultural assets and avoidance of transmission routes passing through those areas
- a recommendation of items of consideration at the stage of planning, design and construction.
    - Study of land usage along the grid route
    - Safety measures under overhead wires
- As for impact by the electric magnetic fields (EMF), public organizations have expressed their view that EMF does not have harmful impacts on the human body with comprehensive assessment of many studies. Public organizations meant here are World Health Organization (WHO), International Commission on Non-Ionizing Radiation Protection (ICNIRP), The American Physical Society (APS), The National Academy of Science (NAS), National Institute of Environmental Health Sciences (NIEHS), National Radiological Protection Board (NRPB), Ministry of Economy, Trade and Industry, Japan (METI), and Ministry of Environment, Japan (MOE).

Substation（Key Impacts and Mitigation）

- Transmission lines connect power plants and substations. The surrounding areas near substations may be crowded with many transmission lines connected.
- In this case, the transmission lines may cause impacts on the local landscapes and make it harder to reach a consensus on their construction in densely populated urban areas.
- Effective consideration should be given to substations that may be crowded with many transmission lines like those mentioned above. Such considerations include selecting a location in advance where the local landscape is of low profile and the area is less populated. If an additional transmission line is planned to connect to an existing substation, one of the countermeasures is to change the location of the substation and build a new substation.

(2) Accumulative impacts of coal ash by the proposed base case and its mitigation

The proposed base case scenario plans the development of 5100 MW of coal thermal power facility all together. With this size of coal thermal facility, large amount of coal ash will appear as the waste of the plant operation. The amount of produced coal ash heavily depends on the scale of a plant unit, the plant factor of the concerned plant, the type of coal used, and plant conditions and maintenance. Therefore, the precise estimation is difficult. However, rough estimation might be useful at this master plan stage, using simple comparison with the existing facility.

In general, it can be assumed that a 300 MW coal thermal unit consumes 500,000 [ton / year] and that average lifetime of a coal thermal is 30 years. The amount of coal ash is reduced to 10 % of the coal used. Coal ash in fly ash form is equivalent to 2 ton / m^3.

Therefore, according to the base case scenario, the total volume of coal ash produced approximately equal to;

$$1/10 \times (500{,}000 \text{ [ton /year] } / 300 \text{ [MW]}) / 5100 \text{ [MW] } \times 30 \text{ [years] } / 2 \text{ [ton/ m}^3\text{]}$$
$$= 12.75 \text{ million m}^3$$

Let us refer to another case, for comparison. The Hekinan thermal power station, in Japan, boasts 4100 MW of output capacity, consisting of three 700 MW units and two 1000 MW units. Annual consumption of coal is approximately 10 million ton. Annually produced coal ash is roughly 1 million ton. It is planned at the Hekinan site that about 10% of coal ash produced should be disposed at coal ash disposal site, with the remaining 90% of ash recycled as concrete admixture or soil conditioner. Note that this recycle rate might be only possible with top-end machines and high quality bituminous coal. The plant factor at the Hekinan is 80% as a base power source.

The estimation of total coal ash produced will be derived from the following equation.

1 [million ton/ year] / 4100 [MW] / 5100 [MW] x 30 [years] / 2 [ton/ m^3]
= 18.66 million m^3

So, it may be safely assumed that 12 – 19 million m^3 of coal ash will be produced as waste according to the coal thermal power development in the proposed base case. Note that 1 million m^3 is a cube 100 m on a side. 12 – 19 of such cubic space should be necessary for waste disposal site though the recycling of coal ash could decrease the total space necessary.

9.4.5 Monitoring

'Monitoring' is recommended to CEB as routine and periodical environmental management activity. Currently, monitoring is being conducted at sites of power station by consulting firms under TOR by CEB. SPM, SO_2 and NO_2 for air quality, pH, COD, BOD and Suspended Solids (SS) for water quality, and Noise and Vibration are measured, referring to monitoring reports for Kelanitissa and Sapugaskanda power stations. The monitoring items may satisfy the tentative regulation for environmental standards. However, the following points may well be clearer, observing the above reports.

- ■ A good map around the site should be attached to the reports, to clarify the relation of the emission or effluent point with the sampling points and supposed affected area.
- ■ Sampling points should be multiple, rather than a single point.

The broader view on environmental monitoring is also recommended, referring to the next table.

Air pollution	Water pollution
■ Sulfur oxides (SOx)	■ Pollution indicators of dams and lakes: COD; water plants; zooplanktons; amount of floating garbage; change in surrounding environment (e.g. tourism, fish culture)
■ Nitrogen oxides (NOx)	■ Indicators of water quality of rivers and downstream of discharged water: Organic pollution; BOD; COD; thermal discharged water (water temperature), others
■ Smoke dust	■ Leaching water from coal storage and coal ash disposal facilities
■ Carbon dioxide (CO_2) Carbon monoxide (CO)	■ Waste water treatment and leakage of waste fuel, oil content and others
■ Ozone (O_3)	■ Pollution by soil runoff
■ Control of coal ash (fly ash, etc.)	
■ Hydrogen sulfide (geothermal power generation)	
■ Hydrocarbon	
■ Trace metal	
Soil pollution	**Others**
■ Bottom deposit in dams reservoirs (waste and rotten trees)	■ Waste materials such as waste oil, chemicals, coal ash, and by-product plaster
■ Bottom deposit soil in rivers (zones where flow has decreased)	■ Noise, vibration
■ Pollution by leaching water	■ Decrease in ground water level, subsidence of ground
■ Exposure of harmful earth and sand at cut earth and filling	■ Offensive foul odor
	■ Radio disturbance
Safety measures	
■ Communication and warning system for water discharge	■ Control of flammable and combustible fuel and materials
■ Safety of gas pipelines	■ Maintenance and checking of high-voltage electric power lines, and observation on situation beneath the lines
■ Transportation safety on fuel shipping route	

9.4.6 Environmental Management by CEB

'Environmental Management' is important in a project life cycle. Regarding generation or transmission projects, environmental impact assessment is conducted and necessary mitigation measures are taken to avoid, alleviate or control adverse impacts. As outputs of an assessment, environmental monitoring and management plans are attached to the assessment report to manage environmental activities in the implementation and operational phase of the concerned project. This type of environmental management is a component of total environmental and social consideration related to a specific project life.

However, environmental management has another meaning. Environmental affairs should be managed not only in individual projects but also in relation with all corporate activities as a corporation body. It is important as an essential part of sophisticated corporate activity at the present age. For such environmental management activity, the followings are commonly found basic requirements.

① Issue corporate policy or statements on total environmental management, regarding the corporate activity
② Organize the appropriate section in charge of environmental management issues that has proper power, authority and capacity
③ Set the corporate targets for environmental protection and conservation, and prepare the corporate environmental action plan
④ Keep track of the balance in costs and outputs for environmental management (Keep environmental accounting and incorporate it into the total corporate accounting)
⑤ Keep communication and working with society and harmony with local environment
⑥ Regularly make environmental monitoring to keep track of environmental conditions at sites of significant operation, make periodical reporting and take counter measures when problems are found
⑦ Gather information on environmental assessment, monitoring and accounting to the environmental section and keep good databases on them
⑧ Be aware of global environmental issues and trend
⑨ Educate employees to raise environmental awareness and environmental management capacity
⑩ Learn the opinions of, be evaluated by and get comments from a third party outside the company

CEB Environmental Policy can be seen in 'Annual Report of CEB, 2003' currently. For the next step, it is recommended that CEB should have the statement of the Corporate Environmental Management Policy independently from the annual report, and that the policy should be accompanied with clear targets and programs of an action plan. To start with, an assessment of CEB's environmental activities is also recommendable. (on ① and ③)

CEB set up the Environmental Unit in 'Transmission Design and Environment Section' about ten years ago. The Environmental Unit should be the coordinator of the activity ① and ③, and the major player of ④ and ⑦. The current work force of the Unit is consisting of only one Senior Engineer (Class II) and an Assistant, which is not enough considering these tasks. Three or four proper engineers should be necessary to cover the wide range of fields for these tasks. (on ①, ②, ③, ④ and ⑦)

- environmental considerations, monitoring and management that are spreading over thermal power plants, hydropower plants and alternative energy sources (one or two)
- social consideration and public consultation (one)
- environmental accounting (one)

In CEB, environmental monitoring has been conducted by 'the Environment, Civil Maintenance and Dam Safety Section' and each generation plant unit, which is under Generation Addl.GM[90]. On

[90] Additional General Manager

the other hand, the Environmental Unit is under Transmission Addl.GM. With the present organizational formation, the information on environmental assessments and monitoring are not systematically and regularly gathered to the Environment Unit. The scope, method and schedule of environmental monitoring activities seem to be up to each plant unit at local sites. It should be better for quality control that the Environment Unit could manage (check or coordinate at appropriate level) the terms of reference (TOR) and counter measures on CEB's environmental monitoring activities though the conduct of monitoring may well be done at local units. Similar situation can be observed on the Activity ④. Considering these, the following points should be enhanced as the function of the Environment Unit. (on ④, ⑤, ⑥ and ⑦)

- Integration of environmental studies, monitoring and accounting information at the environmental unit
- Strengthening the environmental unit and regular communication with relevant activities in the company
- Working with society & harmony with local environment

Finally the communication with society, stakeholders and third-party organizations are definitely very important, observing the Sri Lankan Society, the past projects, the investment environment and international standards and guidelines for environmental and social considerations and management. The past electrical power development projects in Sri Lanka sometimes faced heavy social backlash and political oppositions. The donors and international guidelines on environmental considerations put more and more importance on social consideration and public consultation in environmental impact assessment process. The global community is now intensifying the discussion on issues such as global warming, accumulated and complex impacts of human activities, and environmental degradation, hazards and social instability. To constantly catch up with and respond with these issues, CEB should keep the transparency of its corporate activity and interactive communication with the surrounding society. The following actions are recommended to realize these objectives. (on ⑤, ⑧, ⑨ and ⑩)

- Issue annual environmental report on CEB activity
- Set up a public communication network or set up an environmental advisory committee, consisting of broad stakeholders and third parties, with the Environmental Unit provided the workforce of the Unit itself be strengthened
- Hold a open seminar or internal educational meetings on global environmental issues and cases
- Conduct CEB employees environmental awareness survey
- Be evaluated by and have comments from outside the company over CEB environmental and social activities on the papers of annual environmental report

Attachment

A.1 Environmental Strategies and Their Action Plan on Power Sector

1. Environmental Strategies on Power Sector

The environment-related strategies for the energy sector stated by the Ministry of Environment and Natural Resources are as follows:

(1) Ensure that adequate attention is paid to safeguard environmental and cultural values, including conserving landscapes of high recreational value and preserving Sri Lanka's natural beauty when developing hydro-power resources and planning power distribution.
(2) Pay adequate attention to controlling air pollution caused by fuels and particulate substances within safe limits by using high quality fuels and adopting appropriate pollution abatement technologies when developing thermal generation; and avoid discharge of heated water if that would cause serious environmental damages.
(3) Reduce excessive loss of electricity during transmission and distribution.
(4) Promote conservation in the use of electricity and other forms of energy.
(5) Pursue a systematic program for using new and renewable sources of energy for power generation, where feasible.
(6) Test the feasibility of using biomass fuel for power generation, and promote it if feasible.

2. Action Plan for Environmental Strategies on the Power Sector

The Action Plan for Environmental Strategies on the power sector under the strategies is as follows:

(1) Gazette regulations under the National Environmental Act specifying maximum gaseous and particulate emissions from thermal plants in line with internationally accepted norms, and enforce regulations once gazetted. (Priority: immediate）
(2) Take suitable safeguard to minimize environmental pollution from thermal generation of electricity by the use of appropriate fuels and technologies to reduce particulate emissions and NOx, and SOx, and by ensuring that thermal effluents damage and are in accordance with the relevant standards. (Immediate)
(3) Incorporate social and environmental costs, i.e., cost of mitigating damages, when working out the lowest cost of electricity generation in assessing different options. (Immediate)
(4) In developing further hydro-power generation schemes, pay adequate attention to safeguarding the environment, taking into account impacts, inter alia, on ecology, land degradation, biodiversity and scenic attractions. (Immediate)
(5) Study the introduction of aerial bundled conductors and extend their use where feasible. (Short term)
(6) Investigate the causes for excessive power loss during transmission and distribution, and take corrective action to minimize it. (Immediate)
(7) Continue and expand trials on the feasibility of growing biomass fuel and using it for power generation, and progressively implement power generation by biofuel if feasible.（Immediate）

Chapter 10 Identification of Issues in the Organizational and Institutional Aspect

10.1 Summarization of Problems Facing Power Development in Sri Lanka

To focus solely on power development plans, as far as the Ceylon Electricity Board (CEB) is concerned, the major question at present is how to promptly begin new large-scale power development projects, and particularly the construction of a coal-fired plant that has been delayed so far. However, the tardy start of this project is only one of the problems on the surface; the problems saddling the power sector inclusive of the CEB are more structural in nature and deeper.

There can be no doubt that the opposition movement and other siting difficulties are one of the reasons for the delayed start of the coal-fired plant project, but resolution of these difficulties would not necessarily mean that all else would proceed smoothly. More specifically, Sri Lanka cannot expect to promote investment in power development and the sustained advancement of the power sector without a resolution of various current structural problems, i.e., disposal of the debt held by the CEB, revision of the tariff scheme, which does not cover the cost, and placement of the CEB management on self-supporting footing.

The fact that the CEB is not self-supporting financially was clear also from the results of the financial analysis conducted for the Master Plan. For Sri Lanka, the CEB is virtually synonymous with the power industry. Unless its structural problems are corrected, there will be no prospects for sustained advancement, not only for the CEB but also for the power sector itself.

The various obstacles that have emerged in connection with financing for the Norochocholai project at Puttalam for a coal-fired plant stem precisely from this situation. Even supposing that financing could be arranged for this project, subsequent projects are bound to encounter the same type of funding difficulties unless the prevailing structural problems are resolved. A dismissal of the problem as merely a matter of obtaining financing for the Puttalam project would only postpone the resolution of fundamental problems that absolutely must be corrected.

For this reason, to pave the way for sustained power development into the future, the government must swiftly make clear determinations on the points noted below, which are the central ones for structural reform, and finish the reform, which now remains at a standstill.

- Presentation of the details of CEB unbundling and the schedule for the building of a new power sector structure. In so doing the government must expressly describe the procedure for disposal of the CEB accumulated debt and the revenue sources for this task.
- Clear definition of the division of roles between the post-unbundling CEB subsidiaries and private enterprises in the long-term plan for power development. As particular focus here, the government must once again set forth the relationship between the subsidiaries and independent power producers (IPPs) as regards involvement in execution of projects for construction of thermal power plants.
- Prompt revision of the power tariff scheme in light of the need to retrieve cost of power purchase from diesel-based IPPs as an emergency measure.

10.1.1 Unbundling of the CEB

The biggest reason why the CEB should be unbundled is the current political intervention in CEB management in various areas. This intervention makes it impossible for the CEB to be managed autonomously as a corporation. As a result, the CEB has been criticized by third parties for inefficient management and, moreover, left with accumulated debt large enough to jeopardize its continued operation.

Politics has been heavily involved in the tariff issue. Political considerations worked against tariff hikes and effectively delayed revisions. It is, naturally, necessary for the CEB to make its own efforts to cut costs and reduce its deficit, but the key factor behind the rapid increase in deficit since 2000 has been the tariff schemes, which makes it impossible to retrieve cost increases due to external causes.

Political intervention in problems that ought to be discussed as purely matters of management only made their resolution more difficult. To exclude political intervention from its management as well, the government must equip the CEB with conditions proper to a corporate enterprise. Specifically, this is to be done by unbundling the current CEB organization, which is a government-owned vertically-integrated monopoly; making the generation, transmission, and distribution divisions mutually and completely independent; clarifying the cost structure and management responsibility of each division; and reducing costs through improvement of efficiency.

At present, the major question on which the Government of Sri Lanka and lending institutions (i.e., the Asian Development Bank (ADB) and Japan Bank for International Cooperation (JBIC)) are unable to reach an agreement is the shape of the CEB after unbundling. The proposal set forth in the Concept Paper submitted by the Committee on Power Sector Reforms in July envisioned the transfer of the generation, transmission, and distribution functions to subsidiaries in which the CEB holds shares. In this proposal, there would be one generation subsidiary, one transmission subsidiary (also serving as a single buyer), and two or more distribution subsidiaries. The Paper, nevertheless, is still vague on the subject of management independence after the unbundling, and could possibly sow the seeds of future problems, as follows.

- Labor problems have come prominently to the surface. The proposal notes fairly detailed measures on this front, such as the nomination of the members of the director boards by labor unions and initiatives for prevention of attempts to block privatization, but makes absolutely no mention of the organizational structure of each subsidiary after unbundling, the division of responsibilities and authority between the CEB and the subsidiaries, and the schedule for unbundling.
- Even as regards the organization of the subsidiaries, for example, the proposal states that there would be one generation company but does not mention the findings of studies as to whether it would be advisable to establish a single enterprise for both thermal power and hydropower, which have completely different cost structures.
- Unions are involved fairly deeply in management, and this involvement must be examined from various perspectives to ascertain whether or not it is proper. Considering the current situation in Sri Lanka, union problems could very well escalate into political problems. There is an undeniable possibility that management problems at the new subsidiaries could also escalate into political ones.
- It is important to protect employment levels, but this is a matter for discussion between management and the unions as representatives of the employees on equal footing. Direct involvement of labor in management is liable to invite a conflict of interests between the two.

10.1.2 The Tariff Issue

Observers continue to point mainly at low management efficiency as a cause of the CEB deficit. The chief criticism is that reduction of the total system loss of 18.2%[91] is a primary requisite for improvement of its financial position. While the observations about management problems are correct, it is also true that transmission and distribution costs have decreased since 2000 in spite of the expanding deficit between costs and revenue as was found by the financial analysis in this study, and the self-help efforts of the CEB are therefore taking effect. The biggest cause of the increase in the deficit, on the other hand, is the rise in prices paid for purchase of power from emergency diesel power generators. The increase in oil prices, which have jumped in recent years, has been an especially big factor.

In contracts for purchase of power from IPPs (i.e., the emergency diesel power generators), the CEB as the off-taker assumes the risk associated with a rise in fuel prices and fluctuation of exchange rates for the foreign currency needed for investment. The cost increase due to these external factors exceeds the CEB management responsibilities.

[91] As of 2004. Although this level is no particularly low as compared to those in other developed countries, the CEB is targeting a reduction to about 14% in the context of its business plan. There are corresponding rates of 12% in Indonesia and 15% in Vietnam.

10.1.3 Promotion of Investment in Generation

Governmental policy clearly states that the execution of thermal power projects is to be left to private-sector investment based on the build-operate-and-transfer (BOT) or build-own-and-operate (BOO) schemes as a general rule. As found in this report, however, to keep abreast of the growth in the demand for power will require construction of an additional thermal power plant in the 300,000kW class every year, on the average. In reality, this addition could by no means be entirely accomplished by IPPs.

Meanwhile, risks attached to power sector investment in Sri Lanka are still quite high in the eyes of private-sector investors[92]. Viewed from the standpoint of these investors, if projects are promoted through BOT/BOO schemes, they should be regarded as unable to assume the investment risks without full guarantees by the government.

In light of this investment climate, it would be utterly impossible to develop thermal power plants solely with private-sector investment. This point demands a revision of the prevailing official policy. What is needed is, on the contrary, the construction of a platform for the raising of funds through collaboration between the CEB, including its future subsidiaries, and the private sector.

10.2 Policy Recommendations for Ppromotion of Structural Reform

10.2.1 Presentation of a Detailed Schedule for CEB Unbundling and Establishment of Subsidiaries

The government ought to present a detailed picture of the CEB unbundling and schedule for the same, and promptly complete the structural reform.

The report on the reform approved by the government in July 2005 does not paint a detailed portrait of the new sectoral order ushered in by the CEB unbundling and establishment of subsidiaries. It also does not show the schedule for implementation. Considering that three years have already passed since the passage of the Electricity Reform Act, the progress of the reform thus far must be termed slow.

A clear presentation of the reform particulars and schedule is a precondition for resumption of funding from lenders. If the postponement of large-scale thermal power projects is allowed to continue in lieu of prospects for financing, it is bound to pose a serious impediment to power supply. By the same token, further purchase from emergency diesel power generators to compensate for the delay in thermal power plant construction will obviously lead to the financial collapse of the CEB. The resolution of this problem must not be deferred any longer.

10.2.2 Disposal of CEB Accumulated Debt

The government must explicitly state how the accumulated debt held by the CEB is to be wiped out. If the post-unbundling CEB and the new subsidiaries are to develop business in an autonomous and stable manner, measures must be devised to remove the accumulated debt from them and dispose of it separately.

As evidenced by the liquidation of the National Power Corporation in the Philippines and the sinking of the debt held by the former National Railroads in Japan, one option would be to establish an organization for debt service and transfer the accumulated debt to it. The question is how this debt can be repaid or amortized. Funding sources are required, and the government must consider the question of whether the funding can be supplied by the national finances, requires a new special tax instated to erase this debt, or could come from the profits of CEB and the subsidiaries for incremental repayment upon further postponement of the repayment period. In addition, the last option would also demand identification of the party, which is to assume the burden of interest payment over this period.

[92] Neither Moody's nor Standard & Poor's rates sovereign risks

10.2.3 Involvement of the Monitoring and Advisory Committee in Board Appointments (Assurance of Management Autonomy)

Avoidance of arbitrary determinations by the Ministry of Power and Energy (MPE), which has jurisdiction over the CEB, in appointments to the boards of the CEB and the subsidiaries, calls for involvement by the Monitoring and Advisory Committee stipulated in the Electricity Reform Act to assure the fairness of such appointments.

10.2.4 Autonomy of Subsidiary Management Free of Involvement by the CEB

As stated in the Concept Paper, assurance of the management autonomy of the subsidiaries resulting from CEB unbundling is the pillar of the new power sector structure.

Although the CEB will continue to subsist as a holding company for the subsidiaries in the new order, it must transfer all authority related to plans for power development and capital investment to the subsidiaries. In other words, in addition to the routine work of facility operation, all work related even to the formulation of plans for power development and transmission must be considered part of the role of the subsidiaries, i.e., the generation company and transmission company. Similarly, the job of making long-term demand forecasts and plans for power development belongs to the transmission company, which will also be the single buyer; it naturally should not be viewed as under the authority of the CEB. The CEB must be no more than a shareholder, and must not become directly involved in the business planning by the subsidiaries.

In principle, the generation subsidiary and private-sector IPPs would invest in generation facilities based on the long-term plans announced by the single buyer and the solicitation of generation projects in line with these plans. Involvement by the CEB as a shareholder in this process would detract from not only the management autonomy but also the fairness of power transactions.

10.2.5 Establishment of Newly Developed Power Plants as Separate Companies

The CEB generation subsidiary is anticipated to own all of the existing hydropower and thermal power facilities. Any power plants newly built with the input of public funds (e.g., the Norochocholai coal-fired plant project and the Upper Kotomare hydropower project) ought to be established as entities separate from this generation company.

This is because, under a single buyer arrangement, a biased expansion favoring the CEB subsidiary is liable to distort the market in a situation demanding reduction of costs through competition among IPPs and other generation firms. The creation of a generation company with a monopolistic share of the market is not in keeping with the purpose of the structural reform.

10.2.6 Instatement of Automatic Adjustment Formula into the Tariff Scheme

To resolve the backspread resulting from the current level of tariff revenue and power supply cost, the government should immediately revise the tariff scheme to allow reflection of cost increases due to external factors.

As noted in the official report on structural reform, the tariff scheme must be revised in accordance with the new structure of the sector. It is the role of the Public Utilities Commission (PUC) to construct and approve the new scheme.

As for the model of power transactions after the reform, the transmission company as the single buyer would purchase bulk power in accordance with power purchasing agreements, for supply to final consumers at tariffs including the costs of the transmission and distribution companies. In this flow of transactions, the generation cost must be transferred from the generation company to the transmission and distribution companies, and ultimately reflected in the tariffs paid by the final consumers.

There is a particularly pressing need for resolution of the current inability of the CEB to pass on increases in fuel costs and prices in power purchase from IPPs to consumers. Even within the context of the existing tariff scheme of the CEB, the authorities ought to instate an automatic price adjustment formula for fluctuation in fuel prices, exchange rates, and prices applied in power purchasing based on agreements concluded between the generation company and the CEB as an off-taker, so that increases can be quickly (ideally, every quarter) passed on to final consumers. Such a formula has been instated in other countries. In Southeast Asia, it is included in rate-based tariff schemes in the countries of Thailand and Indonesia. In Japan, too, adjustments are made for fluctuation in fuel costs and exchange rates on a quarterly basis.

Even at a stage preceding consummation of the reform, the PUC should check the procedure for tariff revisions to assure transparency.

10.2.7 Revision of Policy on Thermal Power Projects

As related above, considering the investment climate in Sri Lanka, it would not be realistic to depend solely on the private sector for the investment needed for construction of the thermal power plants that will be required beginning in the second half of the 2000s and into the 2010s. For this reason, the prevailing power sector policy should be revised in favor of approaches to the use of both public and private funds for thermal power projects.

What is needed for power development in Sri Lanka at present is not a complete separation between the roles of the public and private sectors but application of schemes for public and private partnership (PPP) grounded in cooperation between the two.

Similarly, options for private-sector investment are hardly restricted to BOO/BOT schemes; flexible arrangements must be made to allow application of build-and-lease (BL) and build-and-transfer (BT) schemes, under which facilities would be constructed and owned by the private investors but operated by the generation subsidiary of the CEB.

10.2.8 The CEB Generation Company and Foreign-Affiliated IPPs as on Equal Footing

In the new power sector order, new generation projects will in principle be established through submission of proposals by the CEB generation company(s) and IPPs in response to open tenders held by the single buyer and selection of the best proposal. In other words, in this respect, the CEB generation company(s) and the private-sector IPPs would have to vie with each other in submission of project proposals in a competitive environment.

Under the current system, however, the CEB can use soft loans, but additionally pays the interest on them to the government; it does not reap the whole benefit of the low interest rates. It is also paying an import tariff in procurement of equipment. In contrast, the foreign-affiliated IPPs are given various incentives including exemption from import tariffs, reduction of the enterprise tax, and accelerated depreciation of facilities. The CEB is consequently not on completely equal footing with them.

If the key premise is that the structural reform centered around CEB unbundling will be a fundamental solution for rebuilding the sector, which is now on the verge of financial collapse, and achieving a breakthrough in the power crisis now confronting the country, the government should also make provisions for placing the CEB and IPPs on equal footing. While it would obviously be unreasonable to apply the incentives enjoyed by the foreign-affiliated firms to the CEB subsidiaries, measures such as a lowering of the interest payable on soft loans and reduction of tariffs on import of equipment for capital investment must be considered.

10.3 Other Matters

10.3.1 Promotion of Rural Electrification (RE)

RE is one of the major policy tasks for improvement of the electrification ratio in Sri Lanka. On-grid electrification, i.e., electrification by extension of distribution lines, is an agendum that must be promoted within the framework of business strategy of the distribution subsidiaries to be established in the future.

Promotion of off-grid electrification using renewable energy is exemplified by the ESD Project, which was begun in the late 1990s, and the succeeding RERED Project. These projects are achieving actual results. In its policy on RE, the government has made it clear that off-grid electrification is to make use of the energies of various principals, including private companies, non-governmental organizations (NGOs), and local cooperatives.

To pursue off-grid electrification in this way, it would be advisable to make maximum use of the market mechanism and have private enterprises and NGOs initiate projects in parallel with the structural reform. To support these activities in the market, besides tapping funds provided by international lenders and passing them on to investors, the government ought to condition the investment climate in the regulatory aspect by simplifying the requirements for enterprise licensing and approval of tariff schemes that would enable enterprises to retrieve their investment.

10.3.2 Role of Government (Complete Separation of Policy-Making and Regulation)

The prospects for the sure progress of power development in the future genuinely depend on the completion of the structural reform. This is why the government must execute the reform in its entirety as quickly as possible.

Under the new sectoral order, all of the regulatory authority will be transferred from the MPE to the PUC. The MPE will therefore function as a policy-making organ.

The PUC has already been established, but cannot function unless the Electricity Reform Act is completely effected (the authority consequently still remains with the MPE). At the present stage, however, a prompt revision of tariffs is needed to resolve the financial problems at the CEB, and the PUC should be involved in the review work to this end right from the start.

Chapter 11 Recommendations for the Future Advancement of the Power Sector

11.1 Recommendations Related to the Power Development Plan

(1) Prompt Implementation of the Combined-cycle Project at Kerawalapitiya

The project for construction of a combined-cycle power plant at Kerawalapitiya as intended by the CEB is a major key for power supply prospects in near future. If this project is not completed or delayed, supply will fall into a status of critical tightness especially in 2008. Considering the construction period and lead-time before construction, a financing agreement for the project must be concluded by the beginning of 2006 for its commissioning in the middle of 2009.

(2) Prompt and Sure Execution of Projects Now Under Way for Construction of Large-scale Coal-fired Power Plants

Development of large-scale coal-fired power plants is indispensable for economical system operation. While there has been opposition to the project for considerations related to siting and environmental concerns, the course of the current project for construction of a coal-fired plant at Norochcholai will have a great impact on future generation development. It consequently should be swiftly and surely implemented.

(3) Identification of New Sites for Large-scale Coal-fired Plants and Ordering in Terms of Priority

Relative to the capacity of large-scale coal-fired plants that must be developed over the coming years, only a very few candidate sites have been the subject of reliable studies, and this is a problem. Studies should be promptly made to identify candidate sites throughout Sri Lanka in order to expand the options for site selection and execute development at more economical sites. This should be accompanied by an ordering of all candidate sites, including those already studied, in terms of development priority.

(4) Importance of Energy Source Diversification

The future generation mix will depend heavily on coal-fired plants. For reasons of energy security, there is a strong need for development of generation facilities applying hydropower (as a domestic energy resource) and renewable energy. Efforts to develop these facilities should be continued.

Natural gas is another new fuel option that would presumably have the additional benefits of improvement of energy security through diversification of energy sources and stabilization of the system operation through installation of combined-cycle systems with a high load-following flexibility. As such, if natural gas is supplied to the power sector at reasonable price, it will become a promising fuel option after installation of coal-fired plants.

(5) Importance of Expansion of the Trunk System

In the plans for development of transmission and substation facilities over the subject period, emphasis ought to be placed on expansion of the trunk system by, for example, construction of the 220 kV No. 2 outer loop trunk transmission line in the Colombo area, where the demand is concentrated, and 220 kV transmission and substation facilities for supply from large-scale thermal power facilities.

(6) Importance of System Interconnection between the Main Grid and the Northern Grid

For reasons of both economical expansion of power facilities and supply reliability, the northern grid should be connected to the main grid. For this purpose, the current project for reconstruction of transmission lines should be completed on schedule.

11.2 Recommendations Related to Organizations and Institutions

(1) Completion of the Structural Reform

A fundamental reform of the sector is absolutely essential for promotion of long-term investment and increase in the overall efficiency. To this end, the government must present a detailed vision and schedule for CEB unbundling, and swiftly complete the reform, which is currently stalled.

(2) Clear Statement of the Approach to Disposal of CEB Accumulated Debt

Accumulated debt must be off-loaded from the post-unbundling CEB and the subsidiaries by establishment of a separate organization to dispose of it, for example, so that they can develop their business in a self-supporting and stable manner.

The task in this connection is to clarify the method of debt repayment or amortization. This demands the determination of financial sources for debt disposal and detailed study of procedure for assurance of these sources and repayment.

(3) Assurance of the Autonomy of Subsidiary Management Free of Involvement by CEB

As a holding company for the subsidiaries in the new order, CEB should not become directly involved in the power development planning or formulation of other business plans by the subsidiaries. This is necessary to assure the fairness of power transactions after the reform and the autonomy of subsidiary management.

(4) Revision of Policy on Thermal Power Projects

In light of the prevailing investment climate, dependence solely on private funds for construction of the thermal power plants that must be developed over the coming years would not be a realistic option. The government should revise its current policy on wholly private sector funding of thermal power projects and make arrangements for procurement of funds through public-private partnership (PPP) schemes.

(5) Establishment of Power Plants Developed with Public Funds as Separate Companies

Inclusion of future power plants constructed with public funds within the CEB generation subsidiary is liable to distort the market by inducing preferential treatment for and expansion of a certain entrant (i.e., the CEB generation subsidiary). Therefore, any power plants built with the input of public funds ought to be established as entities separate from this generation company.

(6) Clear Definition of the Role of Government (Separation of Policy-Making and Regulation)

As a result of the reform, the regulatory authority in the power sector will be transferred from the MPE to the PUC. Under this arrangement, the MPE ought to function as a policy-making authority.

In addition, revision of power tariffs is urgently needed for resolution of the current financial problems at the CEB, and the PUC ought to become involved in the revision process starting right from the present.

(7) Instatement of an Automatic Adjustment Formula into the Tariff Scheme

The power tariff scheme should be revised by instating a formula for automatic adjustment to enable cost increases caused by external factors (i.e., fuel costs, exchange rate fluctuation, and fluctuation in prices applied in power purchasing based on contracts concluded between generation companies and the single buyer) to be smoothly passed on to the tariffs paid by the final consumers. Even at a stage prior to completion of the reform, the PUC should make checks to assure the transparency of this work.

Appendices

Appendix 1

Long Term Transmission Development Plan (2004 LTTDS)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
220kV	220/132kV Inter-bus Transformer				KOTMALE 1 x 250MVA						
220kV	Augment & Rehabilitation of Transformer						RANTEMBE +1 x 105MVA				
220kV	New Transmission Line / Equipment					KOTMALE - NEW ANURADHAPURA Zebra, 1cct 163km		RANDENIGALA - RANTEMBE 2xZebra, 1cct 3.1km			
132kV	132/33kV New Grid Substation	RATNAPURA 2 x 31.5MVA ATHURUGIRIYA 2 x 31.5MVA	HORANA 2 x 31.5MVA	HAVELOCK TOWN (Col A) 2 x 31.5MVA MARADANA (Col I) 2 x 31.5MVA DEHIWALA 2 x 31.5MVA SRI J'PURA 2 x 31.5MVA	NEW GALLE 2 x 31.5MVA MAHO 1 x 31.5MVA MEDAGAMA 1 x 31.5MVA POLONNARUWA 1 x 31.5MVA PANNALA 2 x 31.5MVA AMBALANGODA 2 x 31.5MVA ANIYAKANDA 2 x 31.5MVA KILINOCHCHI 1 x 31.5MVA CHUNNAKAM 2 x 31.5MVA	PALLEKELE 2 x 31.5MVA RAMTEMBE 1 x 31.5MVA NAULA 1 x 31.5MVA KOTAHENA (Col C) 2 x 31.5MVA KATANA 2 x 31.5MVA	PADIRIPPU 2 x 31.5MVA	KEGALLE 1 x 31.5MVA		Colombo Sub B 2 x 31.5MVA	Colombo Sub K 2 x 31.5MVA
132kV	Augment & Rehabilitation of Grid Substation	THULHIRIYA +1 x 31.5MVA	AMPARA +1 x 31.5MVA	MADAMPE +1 x 31.5MVA	DENIYAYA +1 x 31.5MVA	KURUNEGALA +1 x 31.5MVA KOTUGODA +2 x 31.5MVA	HAVELOCK TOWN (Col A) +1 x 31.5MVA MARADANA (Col I) +1 x 31.5MVA VEYANGODA +1 x 31.5MVA	KOSGAMA +1 x 31.5MVA PANADURA +1 x 31.5MVA KELANIYA +1 x 31.5MVA WIMALASURENDRA +1 x 31.5MVA, -1 x 15MVA OLD ANURADHAPURA +1 x 31.5MVA -2 x 10MVA OLD GALLE +2 x 31.5MVA -2 x 30MVA	SRI J'PURA +1 x 31.5MVA VALACHCHENA +2 x 31.5MVA -2 x 10MVA	MATARA +1 x 31.5MVA MAHO +1 x 31.5MVA UKUWELA +1 x 31.5MVA NUWARA ELIYA +1 x 31.5MVA	PANNALA +1 x 31.5MVA HORANA +1 x 31.5MVA
132kV	New Transmission Line / Equipment	KELANIYA - KHD - SAPUGASKANDA Zebra, 4cct 3.6km 2cct 1km BALANGODA - RATNAPURA Zebra, 2cct 40km ATURUGIRIYA GS Double in/out Lynx, 2cct 1.5km	HORANA GS Single in/out Zebra, 2cct 20km	SRI J'PURA GS T off Connection Zebra, 2cct 0.1km PANNIPITIYA - DEHIWALA CV1000, 1cct 9km Col I - KOLONNAWA CV1000, 1cct 4.6km Col A - Col I CV800, 1cct 6.3km DEHIWALA - HAVELOCK TOWN CV800, 1cct 8.5km	MATUGAMA - AMBALANGODA Zebra, 2cct 28km ANIYAKANDA GS Single in/out Zebra, 2cct 5km PANNALA GS Single in/out Zebra, 2cct 14km AMBALANGODA - NEW GALLE Zebra, 1cct 36km MATARA - NEW GALLE Zebra, 1cct 34km NEW GALLE GS Double in/out Lynx, 2x2cct 0.2km PUTTALAM - MAHO Zebra, 1cct 42km AMPARA - RANTEMBE Zebra, 2cct 130km MEDAGAMA GS Zebra, T off 1cct 0.1km HABARANA - VALACHCHENA Zebra, 1cct 99.7km	KELANITISSA - Col C CV500, 1cct 1.6km KOLONNAWA - Col C CV500, 1cct 6.2km UKUWELA - PALLEKELE Zebra, 2cct 18km NAULA GS Single in/out Lynx, 2cct 0.5km KATANA GS Double in/out BOLAWATTE GS _Double in/out	AMPARA - PADIRIPPU Zebra, 2cct 35km	THULHIRIYA - KEGALLE Zebra, 2cct 18.7km THULHIRIYA - VEYANGODA Zebra, 2cct 25km		Colombo B GS Single in/out PUTTALAM - MAHO Stringing 2nd	KOLONNAWA - Col K CV500, 1cct 5km or Col A - Col K CV500, 1cct 4km SRI J'PURA - Col K CV500, 1cct 5km
132kV	Reconstruction of Transmission Line	KOLONNAWA - KELANIYA Coyote to Zebra KELANIYA - KOTUGODA Coyote to Zebra KELANITISSA - KOLONNAWA Invar, 2cct 2km			KOTHMALE - KIRIBATHKUMBURA Zebra, 2cct 22.5km KILINOCHCHI - VAVUNIYA Lynx, 2cct 74.1km KILINOCHCHI - CHUNNAKAM Zebra, 2cct 67.2km MADAMPE GS Double T-off to Single in/out		KOLONNAWA - J'PURA - PNNIPITIYA Zebra, 2cct 12.9km Double T-off to Single in/out	KOLONNAWA - ATHURUGIRIYA Zebra, 2cct 14km ATHURUGIRIYA - POLPITIYA Zebra, 2cct 52km			ANURADHAPURA - HABARANA Zebra, 2cct 49km NEW CHILAW - BOLAWATTA Zebra, 2cct 22.6km
Other Equipment		PNNIPITIYA GS BSC 10MVar ATHURUGIRIYA GS BSC 20MVar THULHIRIYA GS BSC 10MVar			MADAMPE GS BSC 30MVar AMBALANGODA GS BSC 2 x 5MVar ANIYAKANDA GS BSC 2 x 5MVar	PALLEKELE GS BSC 4 x 5MVar KATANA GS BSC 10MVar			VALACHCHENA GS BSC 20MVar		

Modified Point of Transmission Lines and Transformers Data

PSSE Original DATA from CEB

Red letters: Data shold be changed to the standard value

Transmission Lines Data (100MVA base)

From			To			ID	Target Data to be checked						Standard Value					
							R (pu/km)	X (pu/km)	B (pu/km)	capacity RateA	capacity RateB	capacity RateC	Rate A (MVA)	Rate B	Rate C	R (pu)	X (pu)	B (pu)
1300	KELAN-1	132.00	1900	COL_C_1	132.00	1	**0.00044**	0.00167	0.01401	180	180	180	160	160	160	0.000354	0.001654	0.016305
1430	COL_I_1	132.00	1435	COL_A_1	132.00	1	**0.00112**	**0.00597**	**0.06725**	230	230	230	225	225	225	0.000621	0.004404	0.051482
1430	COL_I_1	132.00	1550	KOLON-1	132.00	1	**0.00071**	0.00417	0.05288	255	255	255	255	255	255	0.000501	0.004245	0.054407
1435	COL_A_1	132.00	1890	DEHIW_1	132.00	1	**0.00151**	0.00805	0.09073	230	230	230	225	225	225	0.000951	0.006741	0.078800
1550	KOLON-1	132.00	1750	COL_E-1	132.00	1	**0.00158**	**0.00294**	**0.12119**	120	120	120	120	120	120	0.001208	0.002285	0.094261
1550	KOLON-1	132.00	1920	COL_K132	132.00	1	**0.00138**	0.00522	0.04379	180	180	180	160	160	160	0.001105	0.005168	0.050954
1550	KOLON-1	132.00	1940	COL_B_13	132.00	1	**0.00116**	0.00439	0.03678	180	180	180	160	160	160	0.000928	0.004341	0.042801
1560	PANNI-1	132.00	1890	DEHIW_1	132.00	1	**0.00139**	0.00816	0.10346	255	255	255	255	255	255	0.000888	0.007518	0.096346
1690	HABAR-1	132.00	1705	NEWANU-1	132.00	2	0.02133	0.10861	0.02543	165	**100**	**140**	165	225	255	0.021329	0.108611	0.025429
1840	JPURA_1	132.00	1920	COL_K132	132.00	1	**0.00138**	0.00522	0.04379	180	180	180	160	160	160	0.001105	0.005168	0.050954
1900	COL_C_1	132.00	1940	COL_B_13	132.00	1	**0.00055**	0.00209	0.01752	180	180	180	160	160	160	0.000442	0.002067	0.020382

Transformers Data (100MVA base)

From			To			Standard Value	Target Data to be checked			
						X	X	RateA	RateB	RateC
1220	KOTMA-1	132.00	2220	KOTMA-2	220.00	0.056	**0.04**	250	250	250

Appendix 3

GENROU (Round Roter Generator Model) Type

Type	Bus ID	Bus	Type	unit	T'do	T"do	T'qo	T"qo	Inertia	Speed Damping D	Xd	Xq	X'd	X'q	X"d=X"q	Xl	S(1.0)	S(1.2)	Remarks
GT	1300	KELAN-1 132.00	'GENROU'	1	5.568	0.03	1.09	0.16	7.23	0.5	2.38	1.72	0.231	1.2	0.17	0.1	0.03	0.4	Decomposition to 16MW×3
GT	1300	KELAN-1 132.00	'GENROU'	1A	5.568	0.03	1.09	0.16	7.23	0.5	2.38	1.72	0.231	1.2	0.17	0.1	0.03	0.4	
GT	1300	KELAN-1 132.00	'GENROU'	1B	5.568	0.03	1.09	0.16	7.23	0.5	2.38	1.72	0.231	1.2	0.17	0.1	0.03	0.4	
GT	1300	KELAN-1 132.00	'GENROU'	1C	5.568	0.03	1.09	0.16	7.23	0.5	2.38	1.72	0.231	1.2	0.17	0.1	0.03	0.4	
ST(retired)	1300	KELAN-1 132.00	'GENROU'	2	6.97	0.036	1.09	0.19	4	0.5	1.79	1.72	0.23	1.2	0.12	0.1	0.03	0.4	steam terbine's data No Existing
GT	1300	KELAN-1 132.00	'GENROU'	3	6.64	0.049	1.18	0.066	8	0.5	1.81	1.77	0.259	0.344	0.179	0.1	0.125	0.589	
CC(GT)	2300	KELAN-2 220.00	'GENROU'	1	6.85	0.032	1	0.16	4	0.5	1.75	1.68	0.2262	0.437	0.163	0.0875	0.1	0.4	
CC(ST)	2300	KELAN-2 220.00	'GENROU'	2	6.85	0.032	1	0.16	4	0.5	1.75	1.68	0.2262	0.437	0.153	0.0875	0.1	0.4	
CC(GT)	2300	KELAN-2 220.00	'GENROU'	3	7.55	0.032	1	0.16	8	0.5	2.16	1.68	0.283	0.437	0.163	0.0875	0.1	0.4	
CC(ST)	2300	KELAN-2 220.00	'GENROU'	4	5.53	0.032	1	0.16	4	0.5	1.68	1.68	0.219	0.437	0.204	0.0875	0.1	0.4	
CC(2007)	2305	KERAWAL2 220.00	'GENROU'	1	6.85	0.032	1	0.16	4	0.5	1.75	1.68	0.2262	0.437	0.163	0.0875	0.1	0.4	
CC(2007)	2305	KERAWAL2 220.00	'GENROU'	2	6.85	0.032	1	0.16	4	0.5	1.75	1.68	0.2262	0.437	0.153	0.0875	0.1	0.4	
CC(2007)	2305	KERAWAL2 220.00	'GENROU'	3	6.85	0.032	1	0.16	4	0.5	1.75	1.68	0.2262	0.437	0.163	0.0875	0.1	0.4	
CC(2007)	2305	KERAWAL2 220.00	'GENROU'	4	6.85	0.032	1	0.16	4	0.5	1.75	1.68	0.2262	0.437	0.153	0.0875	0.1	0.4	
GT(2013)	2305	KERAWAL2 220.00	'GENROU'	5	6.85	0.032	1	0.16	4.5	0.5	1.75	1.72	0.27	1.31	0.163	0.1	0.03	0.4	
Coal(2009)	2815	PUTTA-2 220.00	'GENROU'	1	6.85	0.032	1	0.16	4	0.5	1.75	1.68	0.2262	0.437	0.16	0.0875	0.1	0.4	
Coal(2009)	2815	PUTTA-2 220.00	'GENROU'	2	6.85	0.032	1	0.16	4	0.5	1.75	1.68	0.2262	0.437	0.16	0.0875	0.1	0.4	
	3301	KELAN-3A 33.000	'GENROU'	1	6.97	0.029	1.09	0.15	4.5	0.5	1.79	1.72	0.23	1.2	0.147	0.1	0.03	0.4	No existing
	3302	KELAN-3B 33.000	'GENROU'	1	6.97	0.029	1.09	0.15	4.5	0.5	1.79	1.72	0.23	1.2	0.149	0.1	0.03	0.4	No existing
Typical Value presented by PTI					6	0.05	1	0.05	3	0	1.4	1.35	0.3	0.6	0.2	0.1	0.03	0.4	

Appendix 3

GENSAL (Salient Pole Generator Model) Type

Type	Bus ID	Bus	Type	unit	T'do	T"do	T"qo	Inertia	Speed Damping D	Xd	Xq	X'd	X"d	Xl	S(1.0)	S(1.2)	Remarks
Hydro	1100	LAX-1 132.00	'GENSAL'	1	5.2	0.068	0.12	3	0.5	1.15	0.66	0.255	0.16	0.1	0.03	0.25	Decomposition to 12.5MW×2
Hydro	1100	LAX-1 132.00	'GENSAL'	1A	5.2	0.068	0.12	3	0.5	1.15	0.66	0.255	0.16	0.1	0.03	0.25	
Hydro	1100	LAX-1 132.00	'GENSAL'	1B	5.2	0.068	0.12	3	0.5	1.15	0.66	0.255	0.16	0.1	0.03	0.25	
Hydro	1100	LAX-1 132.00	'GENSAL'	2	5.2	0.068	0.12	3	0.5	1.75	0.66	0.46	0.219	0.1	0.03	0.25	Decomposition to 8.33MW×3
Hydro	1110	LAX-1 132.00	'GENSAL'	2A	5.2	0.068	0.12	3	0.5	1.75	0.66	0.46	0.219	0.1	0.03	0.25	
Hydro	1110	LAX-1 132.00	'GENSAL'	2B	5.2	0.068	0.12	3	0.5	1.75	0.66	0.46	0.219	0.1	0.03	0.25	
Hydro	1110	LAX-1 132.00	'GENSAL'	2C	5.2	0.068	0.12	3	0.5	1.75	0.66	0.46	0.219	0.1	0.03	0.25	
Hydro	1110	N-LAX-1 132.00	'GENSAL'	1	8.6	0.056	0.12	3.32	0.5	0.9	0.55	0.23	0.15	0.1	0.03	0.25	
Hydro	1110	N-LAX-1 132.00	'GENSAL'	2	8.6	0.056	0.12	3.32	0.5	0.9	0.55	0.23	0.15	0.1	0.03	0.25	
Hydro	1120	WIMAL-1 132.00	'GENSAL'	1	5.2	0.074	0.13	3	0.5	1.28	0.66	0.27	0.147	0.1	0.03	0.25	
Hydro	1120	WIMAL-1 132.00	'GENSAL'	2	5.2	0.074	0.13	3	0.5	1.28	0.66	0.27	0.147	0.1	0.03	0.25	
Hydro	1130	POLPI-1 132.00	'GENSAL'	1	5.2	0.084	0.15	2.83	0.5	1.12	0.66	0.23	0.156	0.1	0.049	0.158	
Hydro	1130	POLPI-1 132.00	'GENSAL'	2	5.2	0.084	0.15	2.83	0.5	1.12	0.66	0.23	0.156	0.1	0.049	0.158	
Hydro	1140	CANYO-1 132.00	'GENSAL'	1	5.2	0.06	0.11	3.8	0.5	1.1	0.66	0.32	0.18	0.1	0.03	0.25	
Hydro	1140	CANYO-1 132.00	'GENSAL'	2	5.2	0.06	0.11	3.8	0.5	1.1	0.66	0.32	0.18	0.1	0.03	0.25	
Hydro	1170	SAMAN-1 132.00	'GENSAL'	1	7.58	0.07	0.15	3.18	0.5	1.03	0.57	0.288	0.135	0.1	0.057	0.256	
Hydro	1170	SAMAN-1 132.00	'GENSAL'	2	7.58	0.07	0.15	3.18	0.5	1.03	0.57	0.288	0.135	0.1	0.057	0.256	
Hydro	1200	UKUWE-1 132.00	'GENSAL'	1	8	0.055	0.03	3.2	0.5	1.1	0.58	0.28	0.22	0.09	0.179	0.5	
Hydro	1200	UKUWE-1 132.00	'GENSAL'	2	8	0.055	0.03	3.2	0.5	1.1	0.58	0.28	0.22	0.09	0.179	0.5	
Hydro	1210	BOWAT-1 132.00	'GENSAL'	1	5.2	0.073	0.13	4	0.5	0.87	0.66	0.157	0.148	0.1	0.259	0.625	
Hydro	1410	KUKULE-1 132.00	'GENSAL'	1	5	0.05	0.11	2.84	0	1.12	0.84	0.23	0.2	0.112	0.19	0.7	
Hydro	1410	KUKULE-1 132.00	'GENSAL'	2	5	0.05	0.11	2.84	0	1.12	0.84	0.23	0.2	0.112	0.19	0.7	
Hydro	2220	KOTMA-2 220.00	'GENSAL'	1	8	0.049	0.11	3.02	0.5	1	0.6	0.25	0.19	0.1	0.083	0.339	
Hydro	2220	KOTMA-2 220.00	'GENSAL'	2	8	0.049	0.11	3.02	0.5	1	0.6	0.25	0.19	0.1	0.083	0.339	
Hydro	2220	KOTMA-2 220.00	'GENSAL'	3	8	0.049	0.11	3.02	0.5	1	0.6	0.25	0.19	0.1	0.083	0.339	
Hydro	2225	UPKT-2 220.00	'GENSAL'	1	6.7	0.048	0.1	4.3	0.5	1.03	0.63	0.29	0.177	0.1	0.03	0.25	
Hydro	2225	UPKT-2 220.00	'GENSAL'	2	6.7	0.048	0.1	4.3	0.5	1.03	0.63	0.29	0.177	0.1	0.03	0.25	
Hydro	2230	VICTO-2 220.00	'GENSAL'	1	7.57	0.061	0.08	3.44	0.5	0.952	0.6	0.239	0.186	0.127	0.075	0.219	Decomposition to 70MW×3
Hydro	2230	VICTO-2 220.00	'GENSAL'	1A	7.57	0.061	0.08	3.44	0.5	0.952	0.6	0.239	0.186	0.127	0.075	0.219	
Hydro	2230	VICTO-2 220.00	'GENSAL'	1B	7.57	0.061	0.08	3.44	0.5	0.952	0.6	0.239	0.186	0.127	0.075	0.219	
Hydro	2230	VICTO-2 220.00	'GENSAL'	1C	7.57	0.061	0.08	3.44	0.5	0.952	0.6	0.239	0.186	0.127	0.075	0.219	
Hydro	2240	RANDE-2 220.00	'GENSAL'	1	6.2	0.04	0.09	3.65	0.5	1	0.63	0.32	0.21	0.153	0.064	0.211	
Hydro	2240	RANDE-2 220.00	'GENSAL'	2	6.2	0.04	0.09	3.65	0.5	1	0.63	0.32	0.21	0.153	0.064	0.211	
Diesel(2012retired)	3590	SAPUG-3A 33.000	'GENSAL'	1	3.6	0.021	0.09	0.53	0.5	2.2	1.06	0.358	0.241	0.173	0.075	0.26	Decomposition to 5.5MW×4
Diesel(2012retired)	3590	SAPUG-3A 33.000	'GENSAL'	1A	3.6	0.021	0.09	0.53	0.5	2.2	1.06	0.358	0.241	0.173	0.075	0.26	
Diesel(2012retired)	3590	SAPUG-3A 33.000	'GENSAL'	1B	3.6	0.021	0.09	0.53	0.5	2.2	1.06	0.358	0.241	0.173	0.075	0.26	
Diesel(2012retired)	3590	SAPUG-3A 33.000	'GENSAL'	1C	3.6	0.021	0.09	0.53	0.5	2.2	1.06	0.358	0.241	0.173	0.075	0.26	
Diesel(2012retired)	3590	SAPUG-3A 33.000	'GENSAL'	1D	3.6	0.021	0.09	0.53	0.5	2.2	1.06	0.358	0.241	0.173	0.075	0.26	
Diesel(2012retired)	3670	MATARA-3 33.000	'GENSAL'	1	3.8	0.027	0.09	0.83	0.5	2.34	1.13	0.381	0.258	0.1	0.093	0.242	Decomposition to 5MW×4
Diesel(2012retired)	3670	MATARA-3 33.000	'GENSAL'	1A	3.8	0.027	0.09	0.83	0.5	2.34	1.13	0.381	0.258	0.1	0.093	0.242	
Diesel(2012retired)	3670	MATARA-3 33.000	'GENSAL'	1B	3.8	0.027	0.09	0.83	0.5	2.34	1.13	0.381	0.258	0.1	0.093	0.242	
Diesel(2012retired)	3670	MATARA-3 33.000	'GENSAL'	1C	3.8	0.027	0.09	0.83	0.5	2.34	1.13	0.381	0.258	0.1	0.093	0.242	
Diesel(2012retired)	3670	MATARA-3 33.000	'GENSAL'	1D	3.8	0.027	0.09	0.83	0.5	2.34	1.13	0.381	0.258	0.1	0.093	0.242	
Diesel(2013retired)	4420	HORANA_G 11.000	'GENSAL'	1	3.8	0.027	0.09	0.83	0.5	2.34	1.13	0.381	0.258	0.1	0.093	0.242	Decomposition to 5MW×4
Diesel(2013retired)	4420	HORANA_G 11.000	'GENSAL'	1A	3.8	0.027	0.09	0.83	0.5	2.34	1.13	0.381	0.258	0.1	0.093	0.242	
Diesel(2013retired)	4420	HORANA_G 11.000	'GENSAL'	1B	3.8	0.027	0.09	0.83	0.5	2.34	1.13	0.381	0.258	0.1	0.093	0.242	
Diesel(2013retired)	4420	HORANA_G 11.000	'GENSAL'	1C	3.8	0.027	0.09	0.83	0.5	2.34	1.13	0.381	0.258	0.1	0.093	0.242	
Diesel(2013retired)	4420	HORANA_G 11.000	'GENSAL'	1D	3.8	0.027	0.09	0.83	0.5	2.34	1.13	0.381	0.258	0.1	0.093	0.242	
Hydro	4251	RANTE-G1 12.500	'GENSAL'	1	5.1	0.059	0.1	2.62	0.5	1.16	0.66	0.32	0.185	0.147	0.106	0.463	
Hydro	4252	RANTE-G2 12.500	'GENSAL'	1	5.1	0.059	0.1	2.62	0.5	1.16	0.66	0.32	0.185	0.147	0.106	0.463	
Diesel	1310	SAPUG-1P 132.00	'GENSAL'	1	3.92	0.05	0.19	3.2	0.5	2.4	1.9	0.42	0.215	0.099	0.1	0.246	
Diesel	1310	SAPUG-1P 132.00	'GENSAL'	2	3.92	0.05	0.19	3.2	0.5	2.4	1.9	0.42	0.215	0.099	0.1	0.246	
Typical Value presented by PTI					5	0.05	0.06	5.084	1	1.5	1.2	0.4	0.25	0.12	0.03	0.25	

Appendix 3

GENSAL (Salient Pole Generator Model) Type

Type	Bus ID	Bus	Type	unit	T'do	T''do	T''qo	Inertia	Speed Damping D	Xd	Xq	X'd	X''d	Xl	S(1.0)	S(1.2)	Remarks
Diesel(2013retired)	1310	SAPUG-1P 132.00	'GENSAL'	3	3.92	0.05	0.19	3.2	0.5	2.2	1.9	0.37	0.25	0.099	0.1	0.246	Decomposition to 18MW×4
Diesel(2013retired)	1310	SAPUG-1P 132.00	'GENSAL'	3A	3.92	0.05	0.19	3.2	0.5	2.2	1.9	0.37	0.25	0.099	0.1	0.246	
Diesel(2013retired)	1310	SAPUG-1P 132.00	'GENSAL'	3B	3.92	0.05	0.19	3.2	0.5	2.2	1.9	0.37	0.25	0.099	0.1	0.246	
Diesel(2013retired)	1310	SAPUG-1P 132.00	'GENSAL'	3C	3.92	0.05	0.19	3.2	0.5	2.2	1.9	0.37	0.25	0.099	0.1	0.246	
Diesel(2013retired)	1310	SAPUG-1P 132.00	'GENSAL'	3D	3.92	0.05	0.19	3.2	0.5	2.2	1.9	0.37	0.25	0.099	0.1	0.246	
	1310	SAPUG-1P 132.00	'GENSAL'	4	4.3	0.05	0.19	3.2	0.5	1.98	1.9	0.31	0.21	0.099	0.1	0.3	No exisiting
Diesel	4595	KHD-G 11.000	'GENSAL'	1	5.5	0.049	0.14	1	0.5	2.38	1.51	0.44	0.23	0.1	0.03	0.25	Decomposition to 6.375MW×8
Diesel	4595	KHD-G 11.000	'GENSAL'	1A	5.5	0.049	0.14	1	0.5	2.38	1.51	0.44	0.23	0.1	0.03	0.25	
Diesel	4595	KHD-G 11.000	'GENSAL'	1B	5.5	0.049	0.14	1	0.5	2.38	1.51	0.44	0.23	0.1	0.03	0.25	
Diesel	4595	KHD-G 11.000	'GENSAL'	1C	5.5	0.049	0.14	1	0.5	2.38	1.51	0.44	0.23	0.1	0.03	0.25	
Diesel	4595	KHD-G 11.000	'GENSAL'	1D	5.5	0.049	0.14	1	0.5	2.38	1.51	0.44	0.23	0.1	0.03	0.25	
Diesel	4595	KHD-G 11.000	'GENSAL'	1E	5.5	0.049	0.14	1	0.5	2.38	1.51	0.44	0.23	0.1	0.03	0.25	
Diesel	4595	KHD-G 11.000	'GENSAL'	1F	5.5	0.049	0.14	1	0.5	2.38	1.51	0.44	0.23	0.1	0.03	0.25	
Diesel	4595	KHD-G 11.000	'GENSAL'	1G	5.5	0.049	0.14	1	0.5	2.38	1.51	0.44	0.23	0.1	0.03	0.25	
Diesel	4595	KHD-G 11.000	'GENSAL'	1H	5.5	0.049	0.14	1	0.5	2.38	1.51	0.44	0.23	0.1	0.03	0.25	
Diesel	4444	BARGE-G1 11.000	'GENSAL'	1	4.9	0.056	0.1	1.62	0.1	1.35	0.77	0.39	0.29	0.18	0.111	0.436	
Diesel(2007)	3730	CHUNNA-3 33.000	'GENSAL'	1	4.3	0.05	0.06	3.2	0.5	1.98	1.9	0.31	0.21	0.099	0.1	0.3	
DG(2005)	1660	Embilipitiya	'GENSAL'	1	3.6	0.033	0.06	7.704	0.5	1.77	0.88	0.48	0.16	0.15	0.1	0.3	should be added
DG(2005)	1810	Ladanavi Puttlam	'GENSAL'	1	5.8	0.033	0.13	1.29	0.5	2.03	1.02	0.352	0.237	0.176	0.1	0.3	should be added
Typical Value presented by PTI					5	0.05	0.06	5.084	1	1.5	1.2	0.4	0.25	0.12	0.03	0.25	

Excitors

	Type	Node	Name	Type	I	TA/TB	TB	K	TE	Emin	Emax	Remarks
				Checked Dynamic Data								
To 12.5MW×2	Hydro	1100	LAX-1 132.00	'SEXS'	1	0.1	10	300	0.05	0	3	
To 8.33MW×3	Hydro	1100	LAX-1 132.00	'SEXS'	2	0.1	10	300	0.05	0	3	
OK	Hydro	1110	N-LAX-1 132.00	'SEXS'	1	0.1	10	300	0.05	0	3	
OK	Hydro	1110	N-LAX-1 132.00	'SEXS'	2	0.1	10	300	0.05	0	3	
OK	Hydro	1120	WIMAL-1 132.00	'SEXS'	1	0.1	10	300	0.05	0	3	
OK	Hydro	1120	WIMAL-1 132.00	'SEXS'	2	0.1	10	300	0.05	0	3	
OK	Hydro	1130	POLPI-1 132.00	'SEXS'	1	0.1	10	300	0.05	0	3	
OK	Hydro	1130	POLPI-1 132.00	'SEXS'	2	0.1	10	300	0.05	0	3	
OK	Hydro	1140	CANYO-1 132.00	'SEXS'	1	0.1	10	300	0.05	0	3	
OK	Hydro	1140	CANYO-1 132.00	'SEXS'	2	0.1	10	300	0.05	0	3	
To 16MW×3	GT	1300	KELAN-1 132.00	'SEXS'	1	0.1	10	300	0.05	0	3.5	Initial condition NG
shold be removed	ST(retired)	1300	KELAN-1 132.00	'SEXS'	2	0.1	10	300	0.05	0	3	
OK	GT	1300	KELAN-1 132.00	'SEXS'	3	0.1	10	300	0.05	0	3.5	Initial condition NG
OK	Hydro	2220	KOTMA-2 220.00	'SEXS'	1	0.1	10	300	0.05	0	3	
OK	Hydro	2220	KOTMA-2 220.00	'SEXS'	2	0.1	10	300	0.05	0	3	
OK	Hydro	2220	KOTMA-2 220.00	'SEXS'	3	0.1	10	300	0.05	0	3	
OK	Hydro	2225	UPKT-2 220.00	'SEXS'	1	0.1	10	300	0.05	0	3	
OK	Hydro	2225	UPKT-2 220.00	'SEXS'	2	0.1	10	300	0.05	0	3	
To 70MW×3	Hydro	2230	VICTO-2 220.00	'SEXS'	1	0.1	10	300	0.05	0	3	
OK	Hydro	2240	RANDE-2 220.00	'SEXS'	1	0.1	10	300	0.05	0	3	
OK	Hydro	2240	RANDE-2 220.00	'SEXS'	2	0.1	10	300	0.05	0	3	
OK	CC	2300	KELAN-2 220.00	'SEXS'	1	0.1	10	200	0.05	0	3	
OK	CC	2300	KELAN-2 220.00	'SEXS'	2	0.1	10	200	0.05	0	4	
OK	CC	2300	KELAN-2 220.00	'SEXS'	3	0.1	10	200	0.05	0	3.5	Initial condition NG
OK	CC	2300	KELAN-2 220.00	'SEXS'	4	0.1	10	200	0.05	0	4	
To 5.6MW×4	Diesel(2012retired)	3590	SAPUG-3A 33.000	'SEXS'	1	0.1	10	300	0.05	0	6	
OK	Hydro	4251	RANTE-G1 12.500	'SEXS'	1	0.1	10	300	0.05	0	3	
OK	Hydro	4252	RANTE-G2 12.500	'SEXS'	1	0.1	10	300	0.05	0	3	
OK	Diesel	1310	SAPUG-1P 132.00	'SEXS'	1	0.1	10	300	0.05	0	5	
OK	Diesel	1310	SAPUG-1P 132.00	'SEXS'	2	0.1	10	300	0.05	0	6	Out of PTI range
To 18MW×4	Diesel(2013retired)	1310	SAPUG-1P 132.00	'SEXS'	3	0.1	10	300	0.05	0	6	Out of PTI range
No existing		1310	SAPUG-1P 132.00	'SEXS'	4	0.1	10	300	0.05	0	5	
OK	Diesel(2007)	3730	CHUNNA-3 33.000	'SEXS'	1	0.1	10	200	0.05	0	6	Out of PTI range
OK	CC(2007)	2305	KERAWAL2 220.00	'SEXS'	1	0.1	10	200	0.05	0	3	
OK	CC(2007)	2305	KERAWAL2 220.00	'SEXS'	2	0.1	10	200	0.05	0	3	
OK	CC(2007)	2305	KERAWAL2 220.00	'SEXS'	3	0.1	10	200	0.05	0	3	
OK	CC(2007)	2305	KERAWAL2 220.00	'SEXS'	4	0.1	10	200	0.05	0	3	
OK	GT(2013)	2305	KERAWAL2 220.00	'SEXS'	5	0.1	10	200	0.05	0	3	
OK	Coal(2009)	2815	PUTTA-2 220.00	'SEXS'	1	0.1	10	200	0.05	0	3	
OK	Coal(2009)	2815	PUTTA-2 220.00	'SEXS'	2	0.1	10	200	0.05	0	3	
OK	Diesel	4444	BARGE-G1 11.000	'SEXS'	1	0.1	10	200	0.05	0	3	
OK	Hydro	1210	BOWAT-1 132.00	'SEXS'	1	0.1	10	300	0.05	0	3	
should be added	DG(2005)	1660	Embilipitiya	'SEXS'	1	0.1	10	300	0.05	0	6	
should be added	DG(2005)	1810	Ladanavi Puttlam	'SEXS'	1	0.1	10	300	0.05	0	6	

Excitors

	Type	Node	Name	Type	I	TA/TB	TB	K	TE	Emin	Emax	Cswitch	re/rfd	Remarks
				Checked Dynamic Data										
OK	Hydro	1410	KUKULE-1 132.00	'SCRX'	1	0.1	10	200	0.05	0	4.5	0	10	
OK	Hydro	1410	KUKULE-1 132.00	'SCRX'	2	0.1	10	200	0.05	0	4.5	0	10	

Appendix 3

Excitors

	Type	Node	Name	Checked Dynamic Data Type	I	TR	KA	TA	VRMAX	VRMIN	KE	TE	KF	TF		E1	SE(E1)	E2	SE(E2)	Remarks
To 6.375MW×8	Diesel	4595	KHD-G 11.000	'IEEET1'	1	0.03	40	0.001	4.5	0	1	0.35	0.04	0.32	0	3.38	0.01	4.5	0.05	

Governors

	Type	Node	Name	Checked Dynamic Data Type	I	R	r	Tr	Tf	Tg	VELM	Gmax	Gmin	TW	At	Dturb	QNL	Remarks
To 12.5MW×2	Hydro	1100	LAX-1 132.00	'HYGOV'	1	0.05	0.3	5.2	0.05	0.5	0.2	0.95	0	1.3	1.1	0.5	0.08	
To 8.33MW×3	Hydro	1100	LAX-1 132.00	'HYGOV'	2	0.05	0.3	5.2	0.05	0.5	0.2	0.95	0	1.3	1.1	0.5	0.08	
OK	Hydro	1110	N-LAX-1 132.00	'HYGOV'	1	0.05	0.3	5.2	0.05	0.5	0.2	0.95	0	1.3	1.1	0.5	0.08	
OK	Hydro	1110	N-LAX-1 132.00	'HYGOV'	2	0.05	0.3	5.2	0.05	0.5	0.2	0.95	0	1.3	1.1	0.5	0.08	
OK	Hydro	1120	WIMAL-1 132.00	'HYGOV'	1	0.05	0.43	5.2	0.05	0.5	0.2	1	0	1.3	1.1	0.5	0.08	
OK	Hydro	1120	WIMAL-1 132.00	'HYGOV'	2	0.05	0.43	5.2	0.05	0.5	0.2	1	0	1.3	1.1	0.5	0.08	
OK	Hydro	1130	POLPI-1 132.00	'HYGOV'	1	0.05	0.43	5.2	0.05	0.5	0.2	0.85	0	1.3	1.1	0.5	0.08	
OK	Hydro	1130	POLPI-1 132.00	'HYGOV'	2	0.05	0.43	5.2	0.05	0.5	0.2	0.85	0	1.3	1.1	0.5	0.08	
OK	Hydro	1140	CANYO-1 132.00	'HYGOV'	1	0.05	0.43	5.2	0.05	0.5	0.2	0.81	0	1.3	1.1	0.5	0.08	
OK	Hydro	1140	CANYO-1 132.00	'HYGOV'	2	0.05	0.43	5.2	0.05	0.5	0.2	0.81	0	1.3	1.1	0.5	0.08	
OK	Hydro	1210	BOWAT-1 132.00	'HYGOV'	1	0.05	0.43	5.2	0.05	0.5	0.2	1	0	1.3	1.1	0.5	0.08	
OK	Hydro	1410	KUKULE-1 132.00	'HYGOV'	1	0.05	0.46	8	0.05	0.5	0.2	0.86	0	1.3	1.1	0.5	0.08	
OK	Hydro	1410	KUKULE-1 132.00	'HYGOV'	2	0.05	0.46	8	0.05	0.5	0.2	0.86	0	1.3	1.1	0.5	0.08	
OK	Hydro	2220	KOTMA-2 220.00	'HYGOV'	1	0.05	0.3	5.2	0.05	0.5	0.2	0.85	0	1.3	1.1	0.5	0.08	
OK	Hydro	2220	KOTMA-2 220.00	'HYGOV'	2	0.05	0.3	5.2	0.05	0.5	0.2	0.85	0	1.3	1.1	0.5	0.08	
OK	Hydro	2220	KOTMA-2 220.00	'HYGOV'	3	0.05	0.3	5.2	0.05	0.5	0.2	0.85	0	1.3	1.1	0.5	0.08	
OK	Hydro	2225	UPKT-2 220.00	'HYGOV'	1	0.05	0.3	5.2	0.05	0.5	0.2	0.95	0	1.3	1.1	0.5	0.08	
OK	Hydro	2225	UPKT-2 220.00	'HYGOV'	2	0.05	0.3	5.2	0.05	0.5	0.2	0.95	0	1.3	1.1	0.5	0.08	
To 70MW×3	Hydro	2230	VICTO-2 220.00	'HYGOV'	1	0.05	0.3	5.2	0.05	0.5	0.2	0.85	0	1.3	1.1	0.5	0.08	
OK	Hydro	2240	RANDE-2 220.00	'HYGOV'	1	0.05	0.3	5.2	0.05	0.5	0.2	0.85	0	1.3	1.1	0.5	0.08	
OK	Hydro	2240	RANDE-2 220.00	'HYGOV'	2	0.05	0.3	5.2	0.05	0.5	0.2	0.85	0	1.3	1.1	0.5	0.08	
OK	Hydro	4251	RANTE-G1 12.500	'HYGOV'	1	0.05	0.43	5.2	0.05	0.5	0.2	0.8	0	1.3	1.1	0.5	0.08	
OK	Hydro	4252	RANTE-G2 12.500	'HYGOV'	1	0.05	0.43	5.2	0.05	0.5	0.2	0.8	0	1.3	1.1	0.5	0.08	

Governors

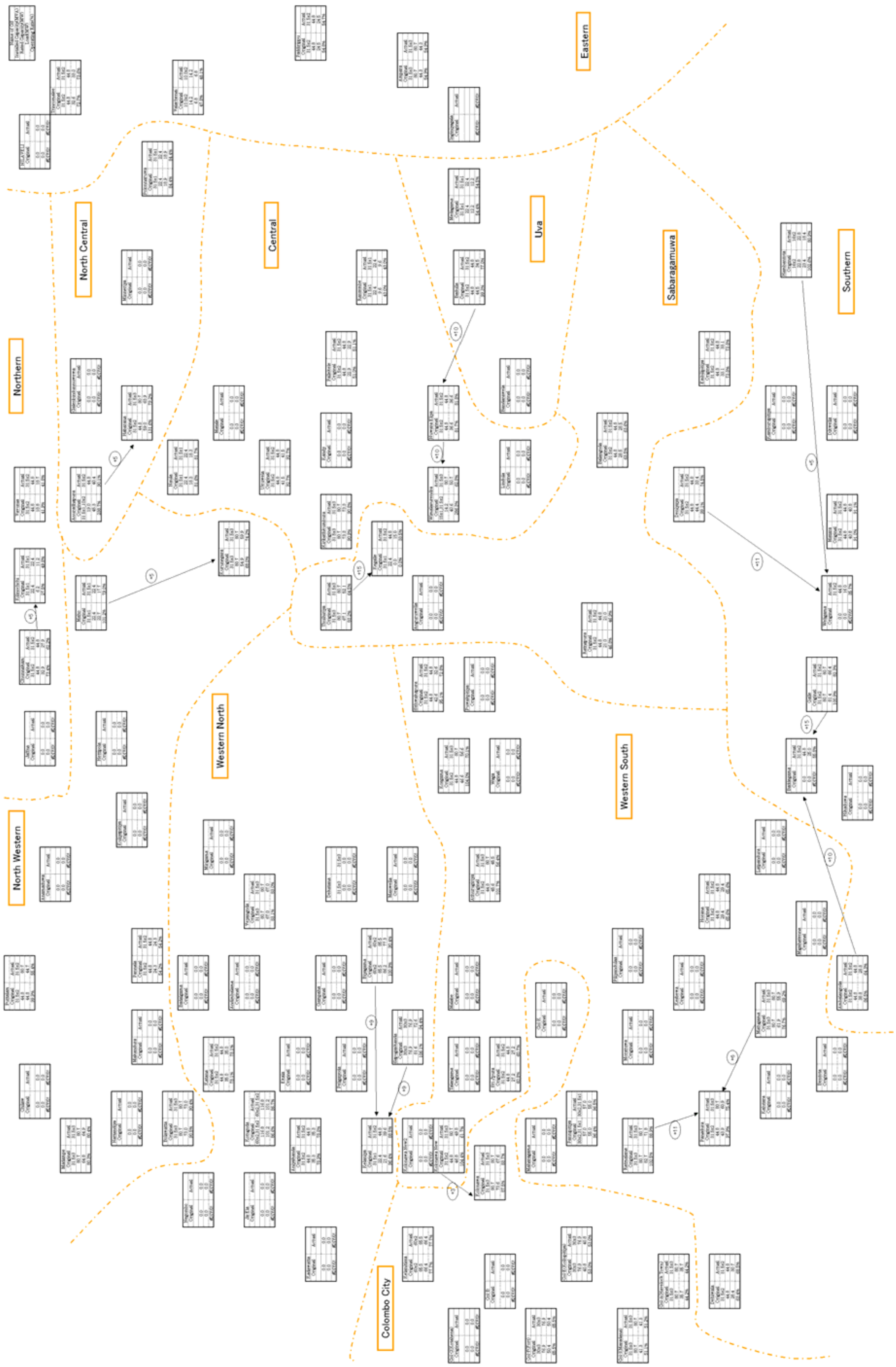
	Type	Node	Name	Checked Dynamic Data Type	I	R	T1	T2	T3	AT	KT	Vmax	Vmmin	Dturb	Remarks
To 16MW×3	GT	1300	KELAN-1 132.00	'GAST'	1	0.05	0.4	0.1	3	1	2	0.95	-0.05	0	initial condition NG
OK	GT	1300	KELAN-1 132.00	'GAST'	3	0.05	0.4	0.1	3	1	2	0.95	-0.05	0	
OK	CC(2007)	2305	KERAWAL2 220.00	'GAST'	1	0.05	0.4	0.1	3	1	2	0.95	-0.05	0	
OK	CC(2007)	2305	KERAWAL2 220.00	'GAST'	3	0.05	0.4	0.1	3	1	2	0.95	-0.05	0	
OK	GT(2013)	2305	KERAWAL2 220.00	'GAST'	5	0.05	0.4	0.1	3	1	2	0.95	-0.05	0	
OK	CC	2300	KELAN-2 220.00	'GAST'	1	0.05	0.4	0.1	3	1	2	0.95	-0.05	0	
OK	CC	2300	KELAN-2 220.00	'GAST'	3	0.05	0.4	0.1	3	1	2	0.95	-0.05	0	

Governors

	Type	Node	Name	Checked Dynamic Data Type	I	R	T1	Vmax	Vmin	T2	T3	Dt	Remarks
shold be removed	ST(retired)	1300	KELAN-1 132.00	'TGOV1'	2	0.05	0.1	0.95	0	1.8	6	0	
To 5.6MW×4	Diesel(2012retired)	3590	SAPUG-3A 33.000	'TGOV1'	1	0.05	0.5	0.85	0.3	1.8	6	0	
OK	Diesel(2007)	3730	CHUNNA-3 33.000	'TGOV1'	1	0.05	0.5	1.08	0.3	1.8	6	0	
OK	CC(2007)	2305	KERAWAL2 220.00	'TGOV1'	2	0.05	0.1	0.95	0	1.8	6	0	
OK	CC(2007)	2305	KERAWAL2 220.00	'TGOV1'	4	0.05	0.1	0.95	0	1.8	6	0	
OK	CC	2300	KELAN-2 220.00	'TGOV1'	2	0.05	0.1	0.95	0	1.8	6	0	
OK	CC	2300	KELAN-2 220.00	'TGOV1'	4	0.05	0.1	0.95	0	1.8	6	0	
should be added	DG(2005)	1660	Embilipitiya	'TGOV1'	1	0.05	0.5	1.08	0.3	1.8	6	0	
should be added	DG(2005)	1810	Ladanavi Puttlam	'TGOV1'	1	0.05	0.5	1.08	0.3	1.8	6	0	

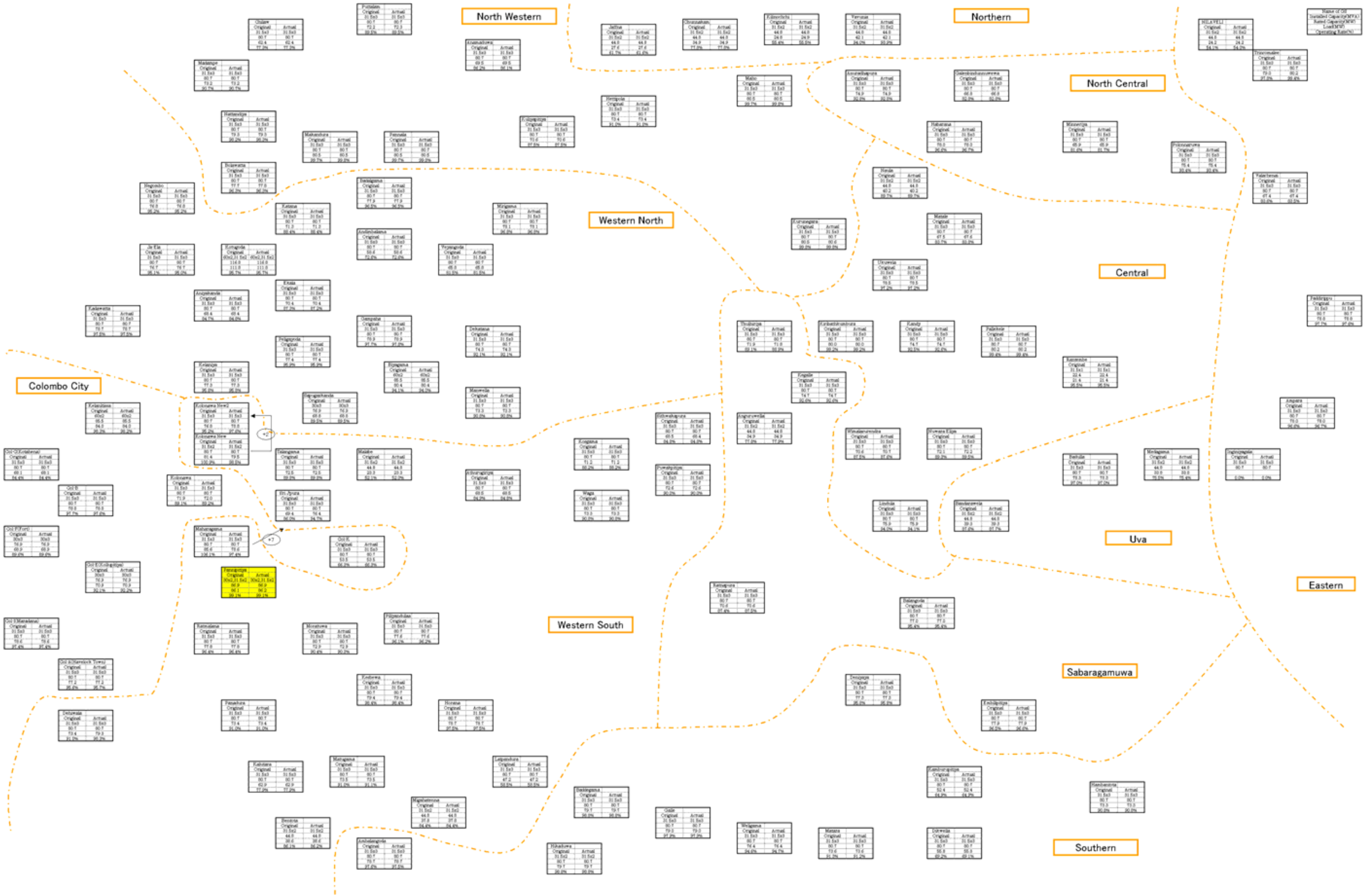
Appendix 4

Load Transfer Forecast for Each Grid Substation (2010)

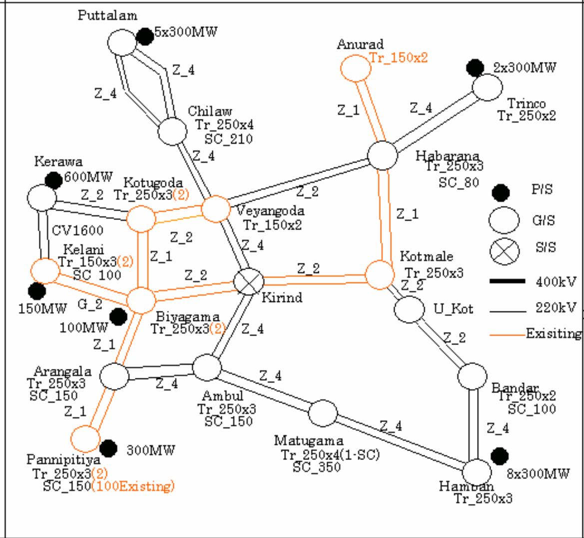
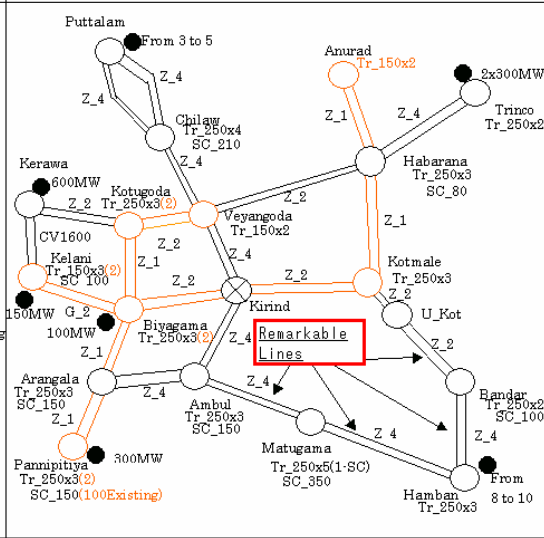
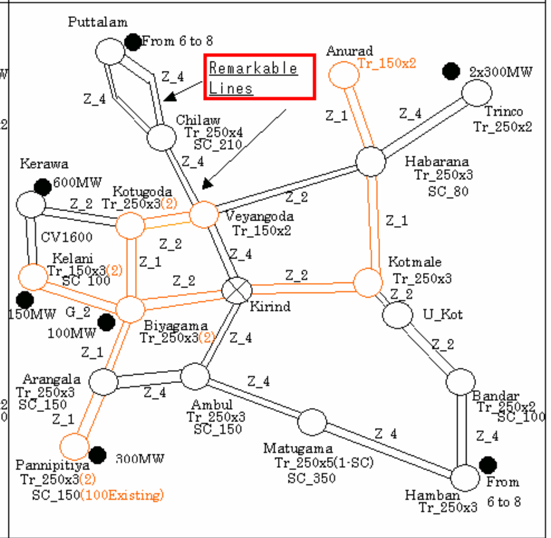


Appendix 4

Load Transfer Forecast for Each Grid Substation (2025)



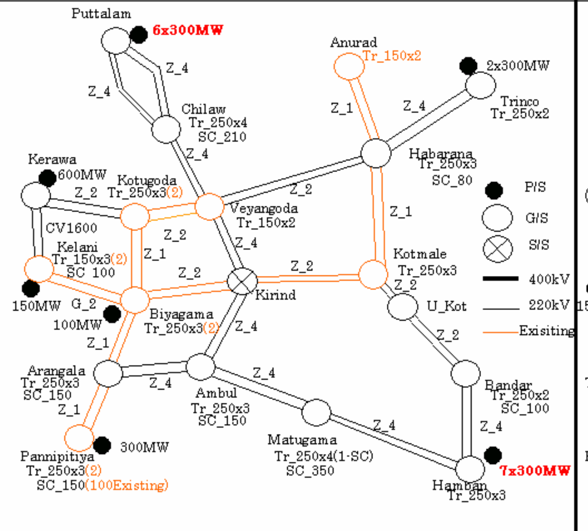
Outline for Power Concentration Case Study

	Base Case	Power Concentration in Southern Area	Power Concentration in Northern Area
Single Line Diagram			

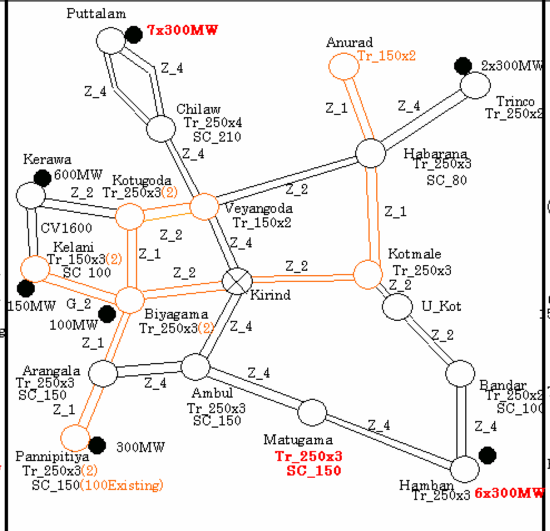
Cost		Base Case Items	Base Case Volume	Base Case Cost (MLKR)	Southern Items	Southern Volume	Southern Cost (MLKR)	Northern Items	Northern Volume	Northern Cost (MLKR)
	Lines	Chi - Vey	45.km	Zebra_4 2cct 16,434.7						
		Put - Chi	140.km							
		Ham - Mat	135.6km							
		Tri - Hab	95.km							
		Ban - Ham	105.km							
		Vey - Kir	14.4km							
		Kir - Amb	22.2km							
		Ara - Amb	11.4km							
		Amb - Mat	58.2km							
		Ham - Vey	145.km	Zebra_2 2cct 4,720.8						
		Kot - U_Kot	18.5km							
		U_Kot - Ban	48.km							
		Kotu - Ker	18.km							
		Ker - Kel	14.4km	CV_1600mm2 2cct 2,717.6						
	Transformers	220 - 132 - 33 250MVA (Matu- 1units included)	31units	6,904.6						
		220 - 132 - 33 150MVA	1units	181.4						
	G/S	220kV-132kV	11places	4,168.0						
	S/S	220kV	1places	369.8						
	Phase Modifying Equipment (Trunk System)	SC (20MVR) Chi-210, Hab-80, Ban-100, Amb-150, Ara-150, Kel-100, Mat-150, Pan-50 ,Mat-200(SC)	59.5units	1,190.0						
	Others									
	Total Cost			36,687.0						
Remarks		A								

Best Allocation Checking for Generators

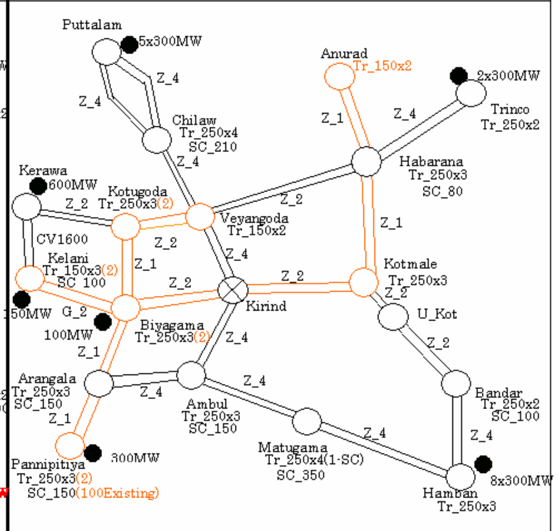
Alternative A – Single Line Diagram



Alternative B – Single Line Diagram



Base Case from Generation View Point – Single Line Diagram



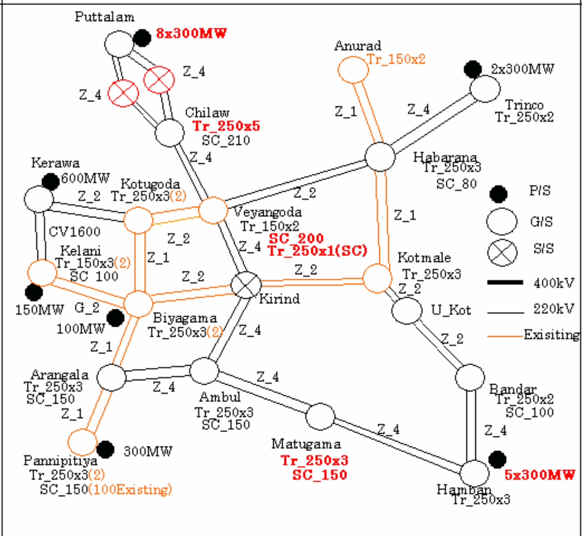
		Alternative A			Alternative B			Base Case from Generation View Point		
Single Line Diagram		(see diagram above)			(see diagram above)			(see diagram above)		
Cost		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
		Base Cost		36,687.0	Base Cost		36,687.0	Base Cost		36,687.0
	Lines			0.0			0.0			
	Transformers	220 - 132 - 33 250MVA	units	0.0	220 - 132 - 33 250MVA (Mat_-1unit)	-1units	-222.7			
			units	0.0		units	0.0			
	G/S		places	0.0		places	0.0			
	S/S	220kV	places	0.0	220kV	places	0.0			
	Phase Modifying Equipment	SC (20MVR)	.units	0.0	SC (20MVR) Mat_-200MVAR	-10.units	-200.0			
	Others									
	Total Cost			36,687.0			36,264.3			36,687.0
Technical Assesment										
N-0		OK			OK			OK		
N-1 (SS is not considered)		OK			OK			OK		
Dynamic Stability		Put - Chi	Ham - Mat	Ham - Ban	Put - Chi	Ham - Mat	Ham - Ban	Put - Chi	Ham - Mat	Ham - Ban
		OK	OK	OK	OK	OK	OK	OK	OK	OK
Effect of S/S		-	-	-	-	-	-	-	-	-
Short Circuit		OK (Under 40kA)			OK (Under 40kA)			OK (Under 40kA)		
Assesment		A			S (In case that 6 units in South are operated at any time)			A		
Remarks					SC and Transformer for SC can be reduced					
Total Remarks		The maximum number of genarators in Northern area is 7. The number is can be 8 with extra high expence. The maximum number of genarators in Southern area is 8. The number is can be 9 with extra high expence.								

Red letters represent the difference between base case and the other's case

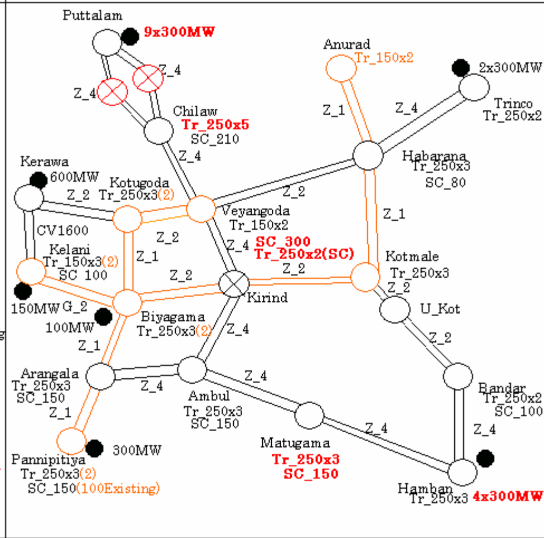
Case that Power Stations are Concentrated in North Area

Single Line Diagram

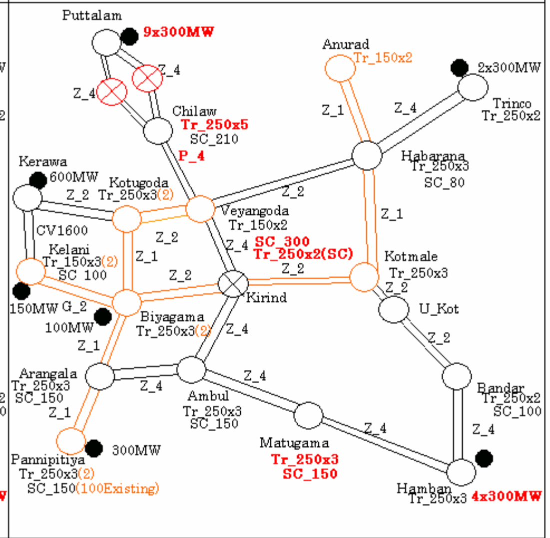
Alternative A-1



Alternative A-2



Alternative A-3



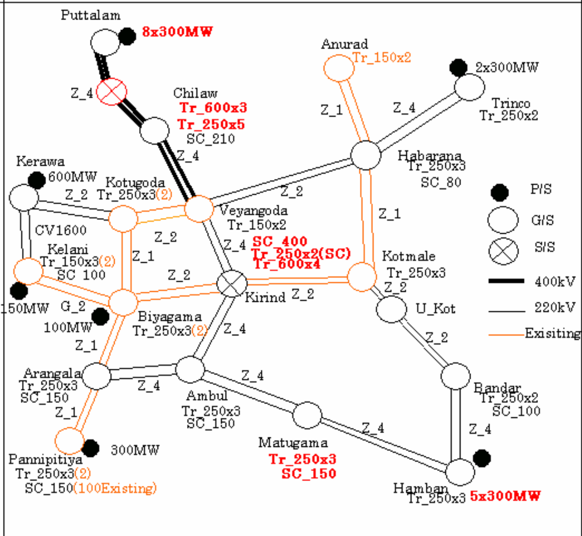
		A-1 Items	A-1 Volume	A-1 Cost (MLKR)	A-2 Items	A-2 Volume	A-2 Cost (MLKR)	A-3 Items	A-3 Volume	A-3 Cost (MLKR)
Cost		Base Cost		36,687.0	Base Cost		36,687.0	Base Cost		36,687.0
	Lines			0.0			0.0	Chi - Vey(Zebra_4) Chi - Vey(Parrot_4)	-45 km 45 km	-1,179.9 1,450.8
	Transformers	220・132・33 250MVA (Chi_1 unit, Vey_1unit, Mat_-1unit)	1units	222.7	220・132・33 250MVA (Chi_1 unit, Vey_2unit, Mat_-1unit)	2units	445.5	220・132・33 250MVA (Chi_1 unit, Vey_2unit, Mat_-1unit)	2units	445.5
			units	0.0		units	0.0		units	0.0
	G/S		places	0.0		places	0.0		places	0.0
	S/S	220kV	2places	739.7	220kV	2places	739.7	220kV	2places	739.7
	Phase Modifying Equipment	SC (20MVR) Vey_200, Mat_-200	.units	0.0	SC (20MVR) Vey_300, Mat_-200	5.units	100.0	SC (20MVR) Vey_300, Mat_-200	5.units	100.0
	Others									
	Total Cost			37,649.4			37,972.1			38,243.0
Technical Assesment										
N-0		OK			OK			OK		
N-1 (SS is not considered)		OK			N.G. (In case of one line failure between Veyangoda and N_Chilaw, the other line is overloaded or transformers at N_Chilaw are overloaded with system configulation change.)			OK		
Dynamic Stability		Put220 - Chi	Chi220 - Vey		Put220 - Chi	Chi220 - Vey		Put220 - Chi	Chi220 - Vey	
		N.G	OK		-	-		N.G	OK	
Effect of S/S		OK	OK		-	-		N.G	OK	
Short Circuit		OK (Under 40kA)			OK (Under 40kA)			OK (Under 40kA)		
Assesment		B			N.G.			N.G.		
Remarks		One unit can be added with two S/Ss, however it costs a lot of money and is not so effective.								

Red letters represent the difference between base case and the other's case

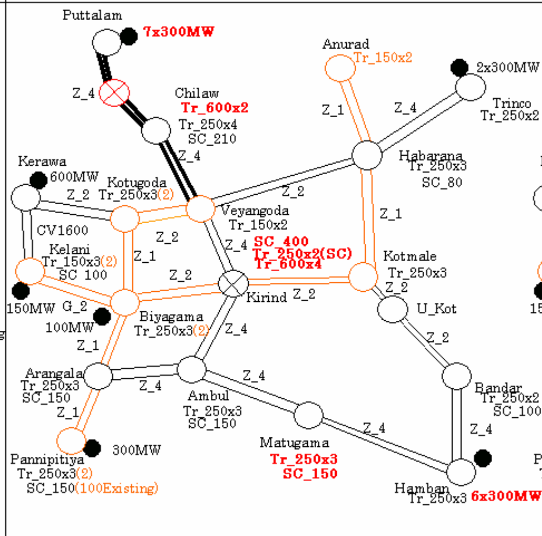
Case that Power Stations are Concentrated in North Area

Single Line Diagram

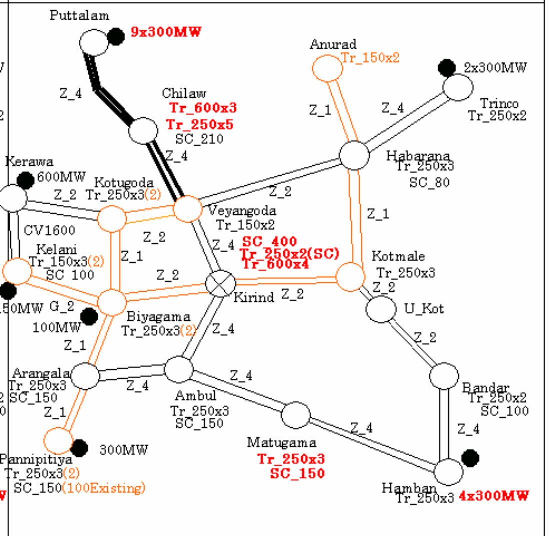
Alternative B-1



Alternative B-2 (Just Confirmation)



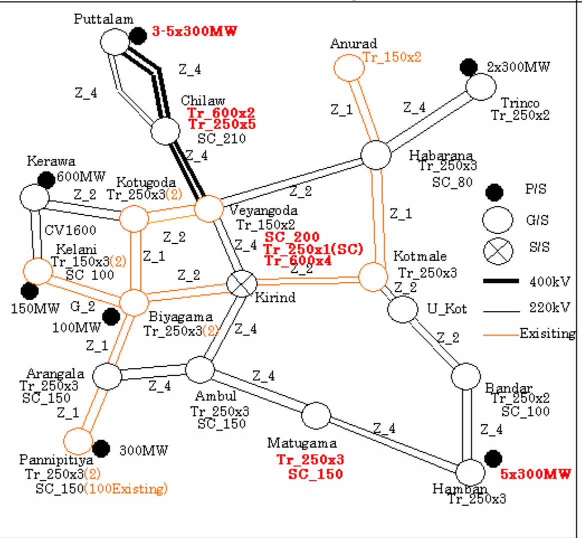
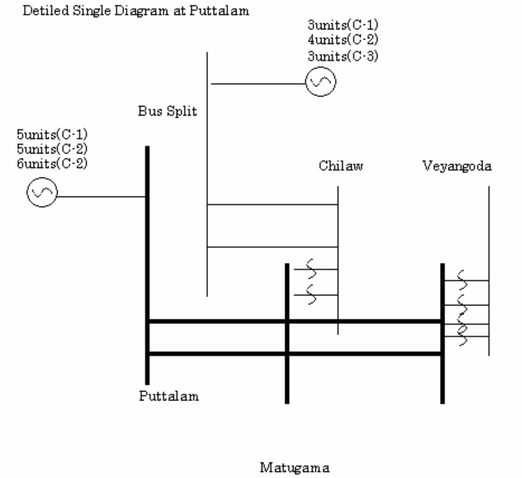
Alternative B-3



		B-1 Items	B-1 Volume	B-1 Cost (MLKR)	B-2 Items	B-2 Volume	B-2 Cost (MLKR)	B-3 Items	B-3 Volume	B-3 Cost (MLKR)
Cost		Base Cost		36,687.0	Base Cost		36,687.0			
	Lines	Put - Chi	-140.km	Zebra_4 2cct -3670.8	Put - Chi	-140.km	Zebra_4 2cct -3670.8			
		Chi - Vey	-45.km	Zebra_4 2cct -1,179.9	Chi - Vey	-45.km	Zebra_4 2cct -1,179.9			
		Put - Chi Chi - Vey	70.km 45.km	Zebra_4 2cct(400kV) 7,855.7	Put - Chi Chi - Vey	70.km 45.km	Zebra_4 2cct(400kV) 7,855.7			
	Transformers	220 - 132 - 33 250MVA (Chi_1 unit, Vey_2unit, Mat_-1unit)	2units	445.5	220 - 132 - 33 250MVA (Vey_2unit, Mat_-1unit)	1units	222.7			
		440 - 220 600MVA	7units	6,853.0	440 - 220 600MVA	6units	5,874.0			
	G/S		places	0.0		places	0.0			
	S/S	400kV	1places	1,240.7	220kV	1places	369.8			
	Phase Modifying Equipment	SC (20MVR) Vey_400, Mat_-200	10.units	200.0	SC (20MVR) Vey_400, Mat_-200	10.units	200.0			
	Others									
	Total Cost			48,431.1			46,358.5			
Technical Assesment										
N-0		OK			OK			OK		
N-1 (SS is not considered)		OK			OK			N.G.(Capacity Over between Puttalam and New Chilaw)		
Dynamic Stability		Put400 - Chi			Put400 - Chi					
		N.G.			N.G.					
Effect of S/S		OK			OK					
Short Circuit		OK (Under 40kA)			OK (Under 40kA)					
Assesment		C			C					
Remarks		Very High Cost Thinking of route failure, 1 route is not good for reliability.			Very High Cost Thinking of route failure, 1 route is not good for reliability.					

Red letters represent the difference between base case and the other's case

Case that Power Stations are Concentrated in North Area

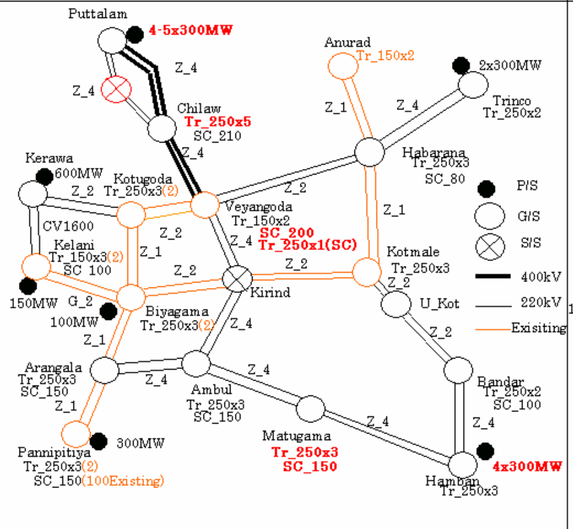
		Alternative C-1 (Bus Split)								
Single Line Diagram										
Cost		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
		Base Cost		36,687.0						
	Lines	Put - Chi	-70.km	Zebra_4 2cct -1835.4						
		Chi - Vey	-45.km	Zebra_4 2cct -1,179.9						
		Put - Chi Chi - Vey	70.km 45.km	Zebra_4 2cct(400kV) 7,855.7						
	Transformers	220 - 132 - 33 250MVA (Chi_1 unit, Vey_1unit, Mat_-1unit)	1units	222.7						
		440 - 220 600MVA	6units	5,874.0						
	G/S		places	0.0						
	S/S	220kV	places	0.0						
	Phase Modifying Equipment	SC (20MVR) Vey_200, Mat_-200	.units	0.0						
	Others									
	Total Cost			47,624.1						
Technical Assesment										
N-0		OK								
N-1 (SS is not considered)		OK								
Dynamic Stability		Put220 - Chi	Put400 - Chi							
		OK	OK							
Effect of S/S		-	-							
Short Circuit		OK (Under 40kA)								
Assesment		C								
Remarks										

Red letters represent the difference between base case and the other's case

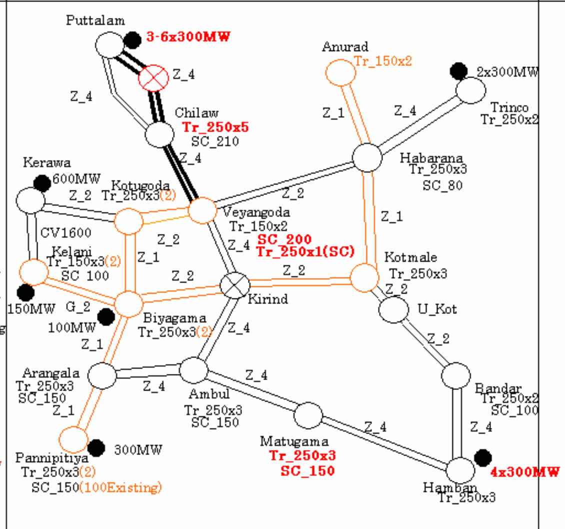
Case that Power Stations are Concentrated in North Area

Single Line Diagram

Alternative C-2(Bus Split)



Alternative C-3(Bus Split)



		C-2 Items	C-2 Volume	C-2 Cost (MLKR)	C-3 Items	C-3 Volume	C-3 Cost (MLKR)	Items	Volume	Cost (MLKR)
Cost		Base Cost		36,687.0	Base Cost		36,687.0			
	Lines	Put - Chi	-70.km	Zebra_4 2cct -1835.4	Put - Chi	-70.km	Zebra_4 2cct -1835.4			
		Chi - Vey	-45.km	Zebra_4 2cct -1,179.9	Chi - Vey	-45.km	Zebra_4 2cct -1,179.9			
		Put - Chi Chi - Vey	70.km 45.km	Zebra_4 2cct(400kV) 7,855.7	Put - Chi Chi - Vey	70.km 45.km	Zebra_4 2cct(400kV) 7,855.7			
	Transformers	220 - 132 - 3x250MVA (Chi_1 unit, Vey_2unit, Mat_-1unit)	2units	445.5	220 - 132 - 3x250MVA (Chi_1 unit, Vey_2unit, Mat_-1unit)	2units	445.5			
		440 - 220 600MVA	6units	5,874.0	440 - 220 600MVA	6units	5,874.0			
	G/S		places	0.0		places	0.0			
	S/S	220kV	1places	369.8	400kV	1places	1,240.7			
	Phase Modifying Equipment	SC (20MVR) Vey_300, Mat_-200	5.units	100.0	SC (20MVR) Vey_300, Mat_-200	5.units	100.0			
	Others									
	Total Cost			48,316.6			49,187.5			
Technical Assesment										
N-0		OK			OK					
N-1 (SS is not considered)		OK			OK					
Dynamic Stability		Put220 - Chi	Put400 - Chi		Put220 - Chi	Put400 - Chi				
		N.G	OK		OK	N.G.				
Effrct of S/S		OK	-		-	OK				
Short Circuit		OK (Under 40kA)			OK (Under 40kA)					
Assesment		C			C					
Remarks		Very High Cost			Very High Cost					

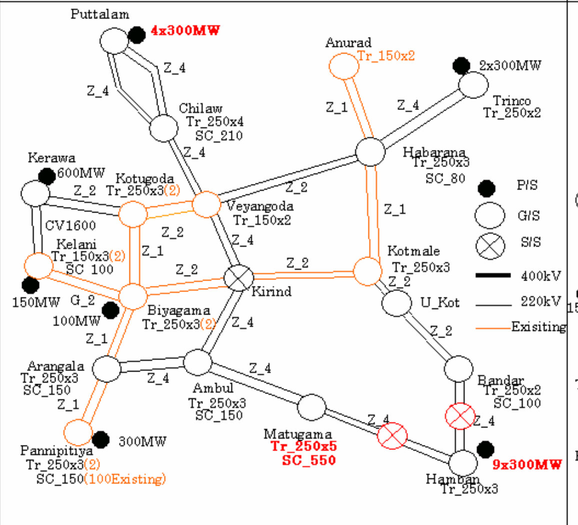
Red letters represent the difference between base case and the other's case

Appendix 7

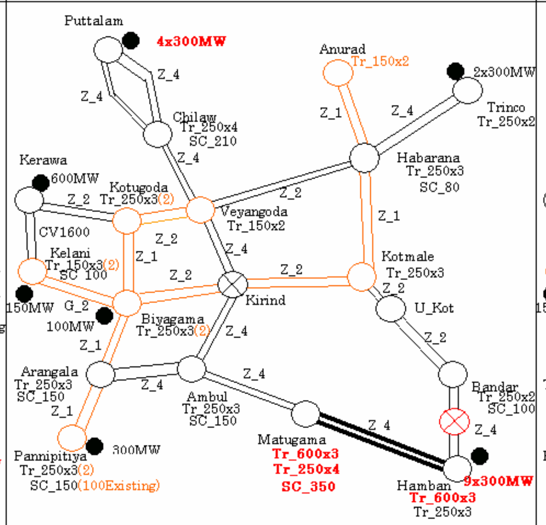
Case that Power Stations are Concentrated in South Area

Single Line Diagram

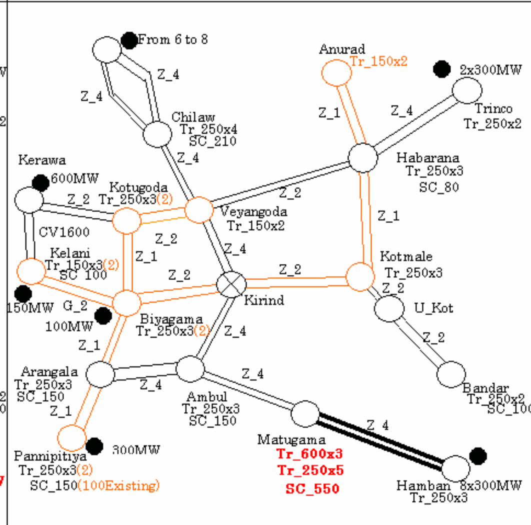
Alternative A-1



Alternative B-1



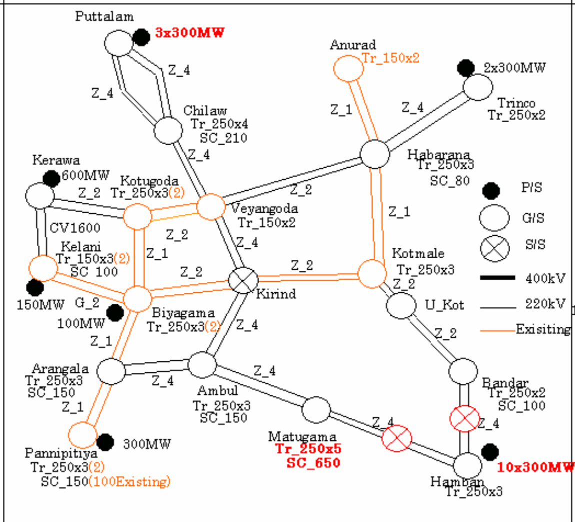
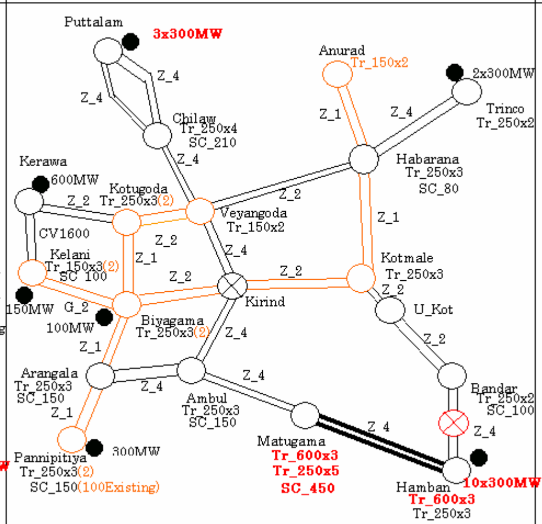
Alternative C



		Alternative A-1			Alternative B-1			Alternative C		
		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
Cost		Base Cost		36,687.0	Base Cost		36,687.0	Base Cost		36,687.0
	Lines			0.0	Ham - Mat(220 Z_4) Ham - Mat(400 Z_4)	-135.6km 135.6km	-3,555.4 9,262.8			
	Transformers	220 - 132 - 33 250MVA (Mat_1unit)	1units	222.7	220 - 132 - 33 250MVA	units	0.0			
			units	0.0	440 - 220 600MVA	6units	5,874.0			
	G/S		places	0.0		places	0.0			
	S/S	220kV	2places	739.7	220kV	1places	369.8			
	Phase Modifying Equipment	SC (20MVR) Mat_200	10.units	200.0	SC (20MVR)	.units	0.0			
	Others				Line Switch 400kV	4units	649.6			
	Total Cost			37,849.4			49,287.9			36,687.0
Technical Assesment										
N-0		OK			OK			N.G.		
N-1 (SS is not considered)		OK			OK					
Dynamic Stability		Mat - Ham	Ham - Ban		Mat - Ham	Ham - Ban	Ham Tr			
		N.G.	N.G.		OK	N.G.	OK			
Effect of S/S		OK	OK		-	OK	-			
Short Circuit		OK (Under 40kA)			OK (Under 40kA)					
Assesment		B			C			N.G.		
Remarks		One unit can be added with two S/Ss, however it costs a lot of money and is not so effective.			Very High Cost			1 route is not enough to supply power even if total power in Hambantota is 240MW(8 units)		

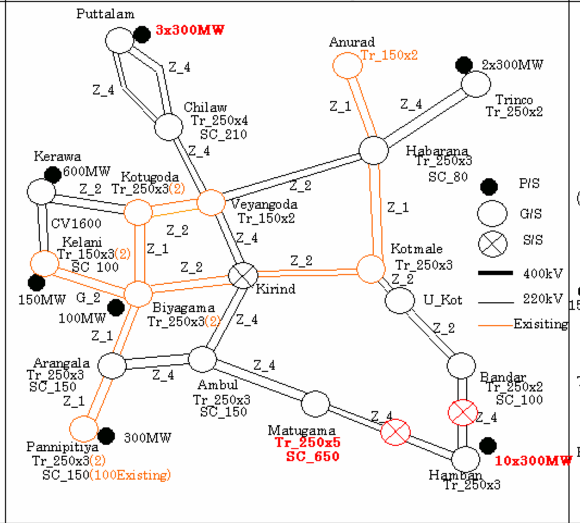
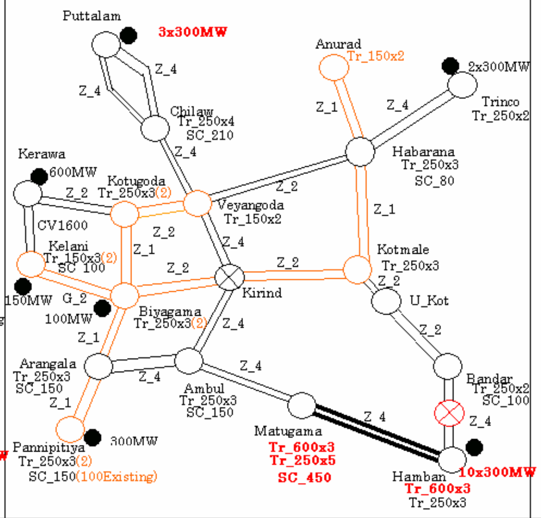
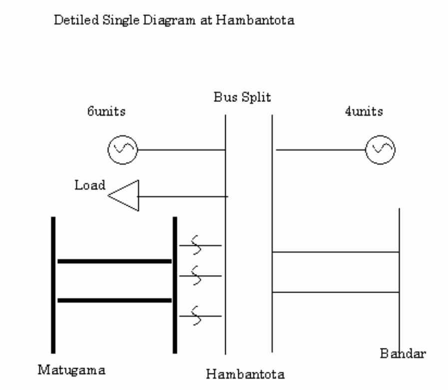
Red letters represent the difference between base case and the other's case

Case that Power Stations are Concentrated in South Area

		Alternative A-2			Alternative B-2					
Single Line Diagram										
Cost		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
		Base Cost		36,687.0	Base Cost		36,687.0			
	Lines			0.0	Ham - Mat(220 Z_4) Ham - Mat(400 Z_4)	-135.6km 135.6km	-3,555.4 9,262.8			
	Transformers	220 - 132 - 33 250MVA (Mat-1units)	1units	222.7	220 - 132 - 33 250MVA (Mat-1units)	1units	222.7			
			units	0.0	440 - 220 600MVA	6units	5,874.0			
	G/S		places	0.0		places	0.0			
	S/S	220kV	2places	739.7	220kV	1places	369.8			
	Phase Modifying Equipment	SC (20MVR) Mat-300	15.units	300.0	SC (20MVR) Mat-100	5.units	100.0			
	Others				Line Swith 400kV	4units	649.6			
	Total Cost			37,949.4			49,610.6			
Technical Assesment										
N-0		OK			OK					
N-1 (SS is not considered)		N.G. (In case of one line failure between Matugama and Hambantota, the system does not converge.)			OK					
Dynamic Stability		Mat - Ham	Ham - Ban		Mat - Ham	Ham - Ban	Ham Tr			
		N.G.	N.G.		OK	N.G.	N.G.			
Effect of S/S		N.G.	N.G.		-	N.G.				
Short Circuit		NG 41.8KA (Over 40kA)			NG 41.8KA (Over 40kA)					
Assesment		N.G.			N.G.					
Remarks					Very High Cost					

Red letters represent the difference between base case and the other's case

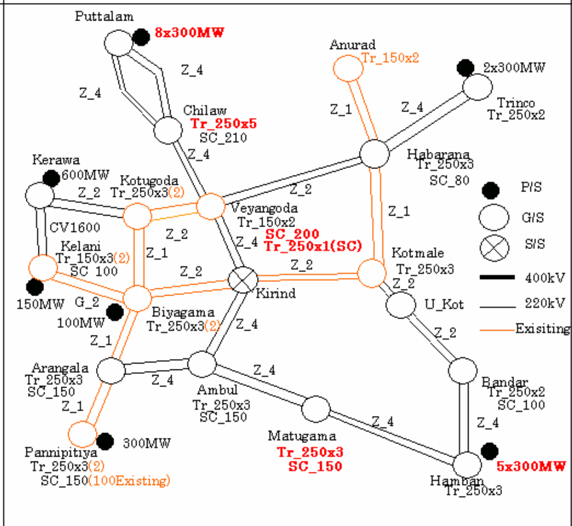
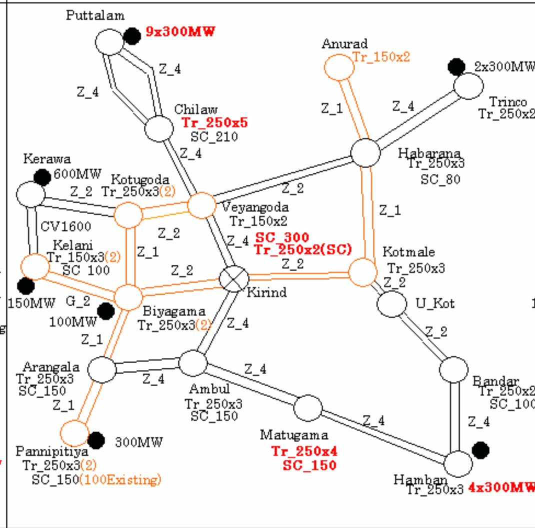
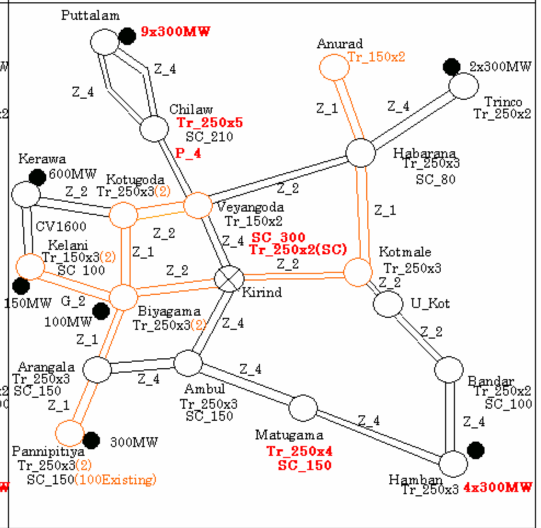
Case that Power Stations are Concentrated in South Area

	Alternative A-2(Bus Split)	Alternative B-2(Bus Split)	
Single Line Diagram			

		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
Cost		Base Cost		36,687.0	Base Cost		36,687.0			
	Lines			0.0	Ham - Mat(220 Z_4) Ham - Mat(400 Z_4)	-135.6km 135.6km	-3,555.4 9,262.8			
	Transformers	220 - 132 - 33 250MVA (Mat-1units)	1units	222.7	220 - 132 - 33 250MVA (Mat-1units)	1units	222.7			
			units	0.0	440 - 220 600MVA	6units	5,874.0			
	G/S		places	0.0		places	0.0			
	S/S	220kV	2places	739.7	220kV	1places	369.8			
	Phase Modifying Equipment	SC (20MVR) Mat-300	15.units	300.0	SC (20MVR) Mat-100	5.units	100.0			
	Others				Line Swith 400kV	4units	649.6			
	Total Cost			37,949.4			49,610.6			
Technical Assesment										
N-0		OK			OK					
N-1 (SS is not considered)		N.G(Matugama to Hambantota line is bottleneck even if 500MVAR SC installed at Matugama)			OK					
Dynamic Stability		Mat - Ham	Ham - Ban		Mat - Ham	Ham - Ban	Ham Tr			
		N.G.	N.G.		OK	N.G.	N.G.			
Effect of S/S		OK	N.G.		-	N.G.				
Short Circuit		OK			OK					
Assesment		N.G.			N.G.					
Remarks					Very High Cost					

Red letters represent the difference between base case and the other's case

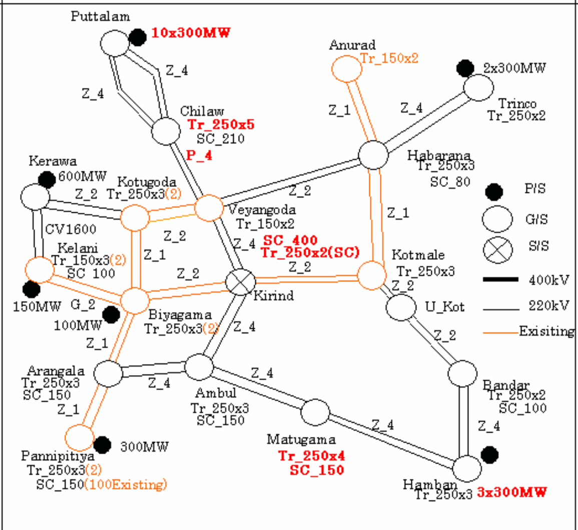
Case that Power Stations are Concentrated in North Area (Fault Clearance: 100ms)

		Alternative A-1			Alternative A-2			Alternative B-1		
Single Line Diagram										
Cost		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
		Base Cost		36,687.0	Base Cost		36,687.0	Base Cost		36,687.0
	Lines			0.0			0.0	Chi - Vey(Zebra_4) Chi - Vey(Parrot_4)	-45 km 45 km	-1,179.9 1,450.8
	Transformers	220 · 132 · 33 250MVA (Chi_1unit, Vey_1unit, Mat_-1unit)	1units	222.7	220 · 132 · 33 250MVA (Chi_1unit, Vey_2unit, Mat_-1unit)	2units	445.5	220 · 132 · 33 250MVA (Chi_1unit, Vey_2unit, Mat_-1unit)	2units	445.5
			units	0.0		units	0.0		units	0.0
	G/S		places	0.0		places	0.0		places	0.0
	S/S	220kV	places	0.0	220kV	places	0.0	220kV	places	0.0
	Phase Modifying Equipment	SC (20MVR) Vey_200, Mat_-200	units	0.0	SC (20MVR) Vey_300, Mat_-200	5 units	100.0	SC (20MVR) Vey_300, Mat_-200	5 units	100.0
	Others									
	Total Cost			36,909.7			37,232.4			37,503.3
Technical Assesment										
N-0		OK			OK			OK		
N-1 (SS is not considered)		OK			N.G. (In case of one line failure between Veyangoda and N_Chilaw, the other line is overloaded or transformers at N_Chilaw are overloaded with system configulation change.)			OK		
Dynamic Stability		Put220 - Chi	Chi220 - Vey		Put220 - Chi	Chi220 - Vey		Put220 - Chi	Chi220 - Vey	
		OK	OK		-	-		OK	OK	
Effect of S/S		OK	OK		-	-		OK	OK	
Short Circuit		OK (Under 40kA)			OK (Under 40kA)			OK (Under 40kA)		
Assesment		A			N.G			B		
Remarks		100 msec of the clearance time is effective. 8 is the marginal number of unit in the Northern area.						100 msec of the clearance time is effective. One unit can be added with Parrot.		

Red letters represent the difference between base case and the other's case

Appendix 8

Case that Power Stations are Concentrated in North Area (Fault Clearance: 100ms)

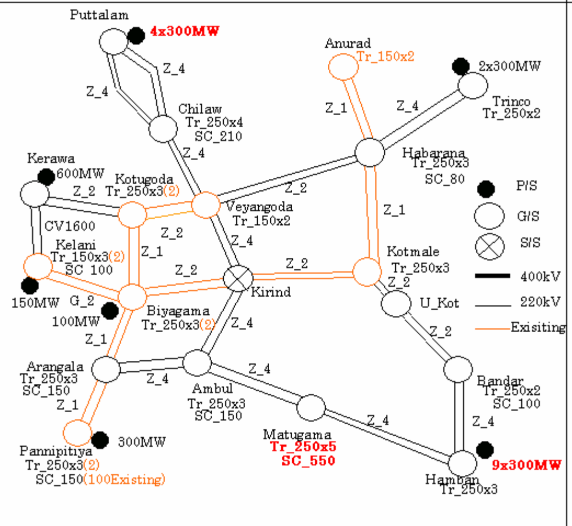
		Alternative B-2								
Single Line Diagram										
Cost		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
		Base Cost		36,687.0						
	Lines	Chi - Vey(Zebra_4) Chi - Vey(Parrot_4)	-45.km 45.km	-1,179.9 1,450.8						
	Transformers	220 - 132 - 33 250MVA (Chi_1unit, Vey_2unit, Mat_-1unit)	2units	445.5						
			units	0.0						
	G/S		places	0.0						
	S/S	220kV	places	0.0						
	Phase Modifying Equipment	SC (20MVR) Vey_400, Mat_-200	10.units	200.0						
	Others									
	Total Cost			37,603.3						
Technical Assesment										
N-0		OK								
N-1 (SS is not considered)		N.G. (In case of one line failure between Puttalam and N_Chilaw, the system does not converge. And line failure between N_Chilaw and Veyangoda is likewise.)								
Dynamic Stability		Put220 - Chi	Chi220 - Vey							
		-	-							
Effect of S/S		-	-							
Short Circuit		NG 40.8KA (Over 40kA)								
Assesment		**N.G.**								
Remarks		System can not be sustained even if there is 400MVAR SC at Veyangoda.								

Red letters represent the difference between base case and the other's case

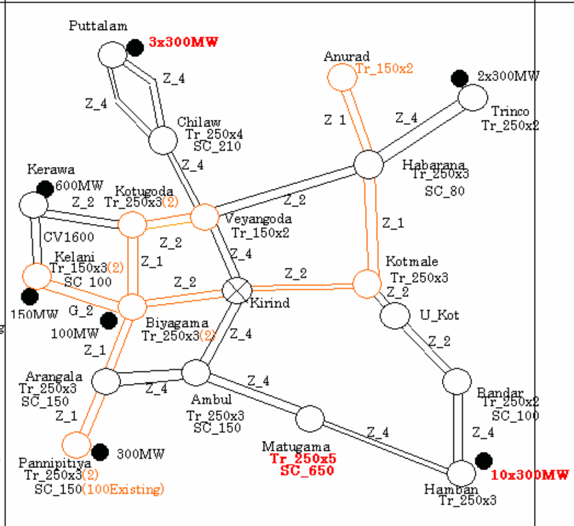
Case that Power Stations are Concentrated in South Area (Fault Clearance: 100ms)

Single Line Diagram

Alternative A-1



Alternative A-2



		Alternative A-1			Alternative A-2					
Cost		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
		Base Cost		36,687.0	Base Cost		36,687.0			
	Lines			0.0			0.0			
	Transformers	220 - 132 - 33 250MVA (Mat_1unit)	1units	222.7	220 - 132 - 33 250MVA (Mat-1units)	1units	222.7			
			units	0.0		units	0.0			
	G/S		places	0.0		places	0.0			
	S/S	220kV	places	0.0	220kV	places	0.0			
	Phase Modifying Equipment	SC (20MVR) Mat_200	10.units	200.0	SC (20MVR) Mat-300	15.units	300.0			
	Others									
	Total Cost			37,109.7			37,209.7			
Technical Assesment										
N-0		OK			OK					
N-1 (SS is not considered)		OK			OK					
Dynamic Stability		Mat - Ham	Ham - Ban		Mat - Ham	Ham - Ban				
		OK	OK		OK	OK				
Effect of S/S		OK	OK		OK	OK				
Short Circuit		OK (Under 40kA)			NG 41.7KA (Over 40kA)					
Assesment		A			N.G.(A)					
Remarks		100 msec of the clearance time is effective. 9 is the marginal number of unit in the Southern area.			10 units is acceptable with 50kA-Line switch.					

Red letters represent the difference between base case and the other's case

Result on Countermeasure for Power Supply to Northern Area

Interconnection Case

	Year	Construction Cost (M US$)	O&M of IPP (M US$)	O&M of CEB in Main Grid (M US$)	Cost for Producing Loss Energy (M US$)	Total (M US$)	P.V (M US$)	Remarks
	2004							
0	2005		15.3			15.3	15.3	Present Year
1	2006		16.1			16.1	14.7	
2	2007	22.93	0.0	6.1	0.06	29.1	24.0	LTTDS 2004
3	2008		0.0	6.4	0.07	6.5	4.9	
4	2009		0.0	6.8	0.08	6.9	4.7	
5	2010		0.0	7.2	0.08	7.2	4.5	
6	2011		0.0	7.5	0.09	7.6	4.3	
7	2012		0.0	8.0	0.10	8.1	4.1	
8	2013		0.0	8.4	0.12	8.5	4.0	
9	2014		0.0	8.9	0.13	9.0	3.8	
10	2015		0.0	9.4	0.14	9.5	3.7	
11	2016		0.0	9.9	0.16	10.0	3.5	
12	2017		0.0	10.4	0.18	10.6	3.4	
13	2018		0.0	11.0	0.20	11.2	3.2	
14	2019		0.0	11.6	0.22	11.8	3.1	
15	2020		0.0	12.2	0.24	12.5	3.0	
16	2021		0.0	12.9	0.27	13.2	2.9	
17	2022		0.0	13.6	0.30	13.9	2.8	
18	2023		0.0	14.4	0.34	14.7	2.6	
19	2024		0.0	15.2	0.38	15.6	2.5	
20	2025		0.0	16.0	0.42	16.4	2.4	
						Total Present Value	117.5	

After interconnection is installed, 100% of Total consumption in Jaffna area is supplied from CEB

Discount Rate = 10% Source: LTGEP2003

Generation Expantion Plan (CEB Only)

	Year	Power Plant Construction Cost (M US$)	O&M of IPP (M US$)	O&M of CEB in Jaffna (M US$)	Total (M US$)	P.V (M US$)	Remarks
	2004						
0	2005		15.3		15.3	15.3	Present Year
1	2006		16.1		16.1	14.7	
2	2007		17.0		17.0	14.1	
3	2008		18.0		18.0	13.5	
4	2009	44.8	0.0	14.9	59.7	40.8	
5	2010		0.0	15.8	15.8	9.8	
6	2011		0.0	16.6	16.6	9.4	
7	2012	22.4	0.0	17.6	40.0	20.5	
8	2013		0.0	18.5	18.5	8.6	
9	2014		0.0	19.6	19.6	8.3	
10	2015		0.0	20.6	20.6	8.0	
11	2016		0.0	21.8	21.8	7.6	
12	2017		0.0	23.0	23.0	7.3	
13	2018		0.0	24.2	24.2	7.0	
14	2019		0.0	25.6	25.6	6.7	
15	2020		0.0	27.0	27.0	6.5	
16	2021		0.0	28.5	28.5	6.2	
17	2022		0.0	30.1	30.1	5.9	
18	2023		0.0	31.7	31.7	5.7	
19	2024		0.0	33.5	33.5	5.5	
20	2025	22.4	0.0	35.3	57.7	8.6	
					Total Present Value	230.0	

Considering N-1 condition, the number of units includes back-up.

Discount Rate = 10% Source: LTGEP2003

Generation Expantion Plan (CEB and IPP as Back-up)

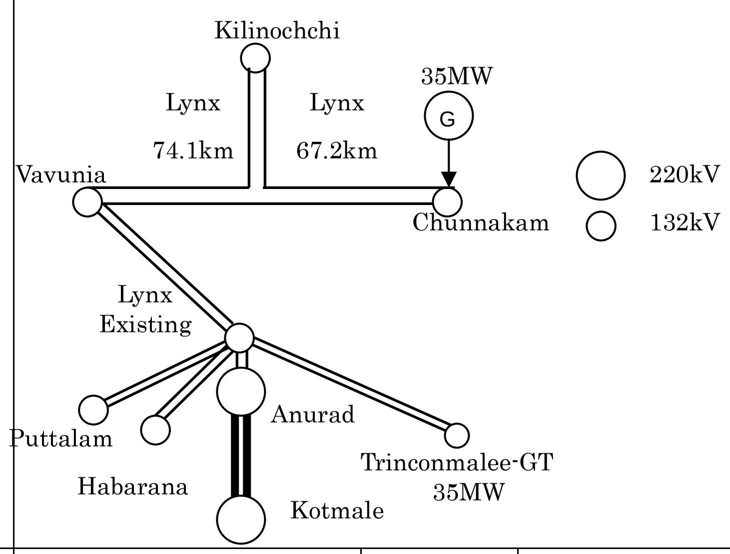
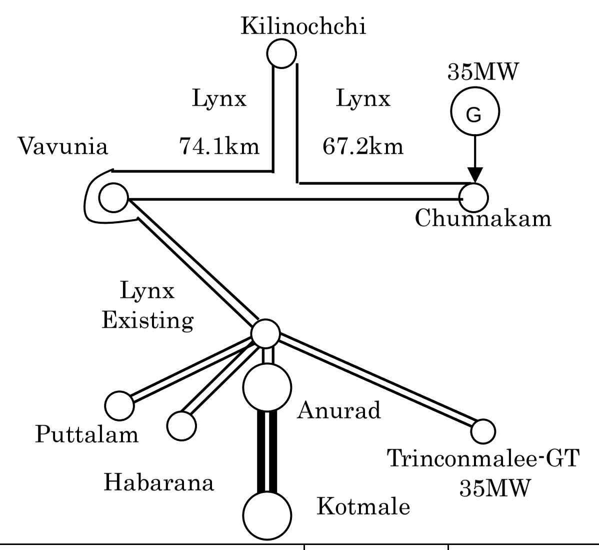
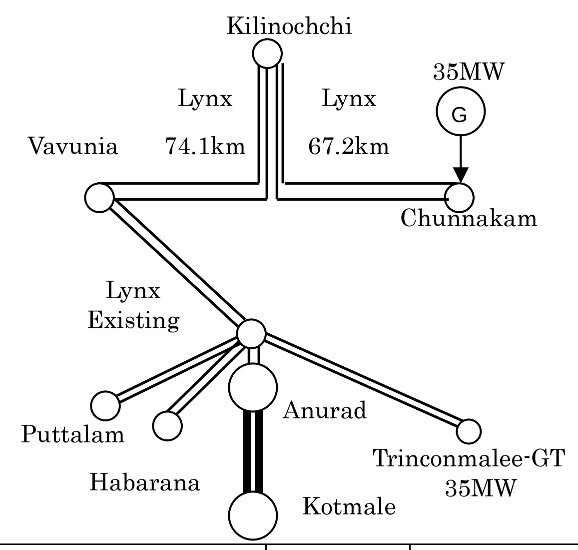
	Year	Power Plant Construction Cost (M US$)	O&M of IPP (M US$)	O&M of CEB in Jaffna (M US$)	Total (M US$)	P.V (M US$)	Remarks
	2004						
0	2005		15.3		15.3	15.3	Present Year
1	2006		16.1		16.1	14.7	
2	2007		17.0		17.0	14.1	
3	2008		18.0		18.0	13.5	
4	2009	22.4	3.8	12.0	38.1	26.1	
5	2010		4.0	12.6	16.6	10.3	
6	2011		4.2	13.3	17.5	9.9	
7	2012	22.4	4.5	14.0	40.9	21.0	
8	2013		4.7	14.8	19.5	9.1	
9	2014		5.0	15.6	20.6	8.7	
10	2015		5.2	16.5	21.7	8.4	
11	2016		5.5	17.4	22.9	8.0	
12	2017		5.8	18.4	24.2	7.7	
13	2018		6.1	19.4	25.5	7.4	
14	2019		6.5	20.5	27.0	7.1	
15	2020		6.8	21.6	28.4	6.8	
16	2021		7.2	22.8	30.0	6.5	
17	2022		7.6	24.0	31.7	6.3	
18	2023		8.0	25.4	33.4	6.0	
19	2024		8.5	26.8	35.3	5.8	
20	2025	22.4	9.0	28.2	59.6	8.9	
					Total Present Value	221.5	

80% of Total consumption in Jaffna area is supplied from CEB

Discount Rate = 10% Source: LTGEP2003

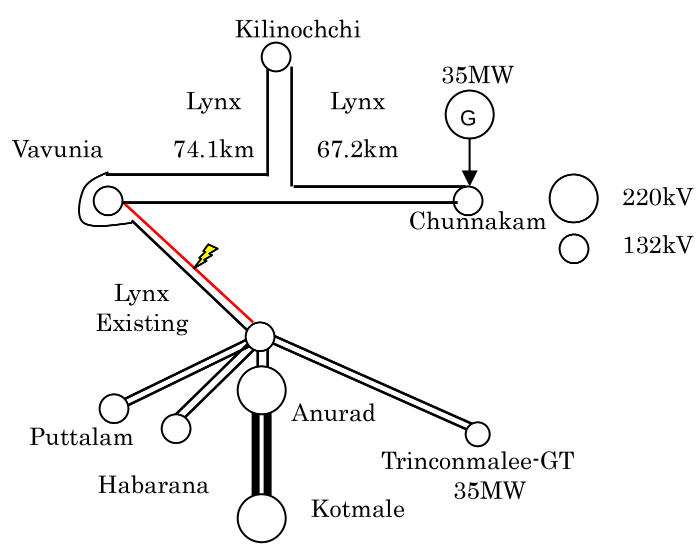
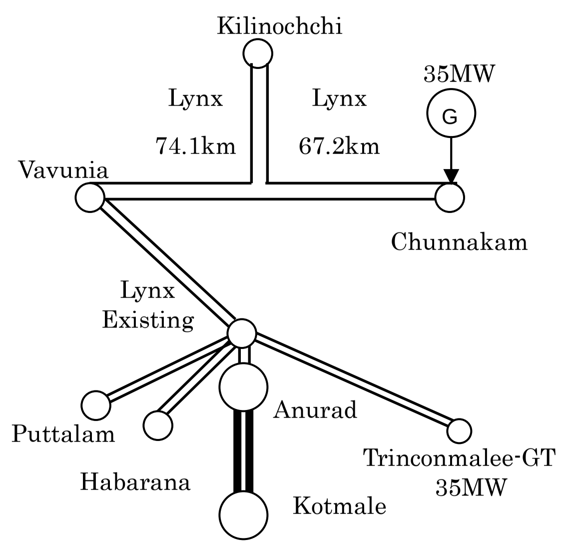
Interconnection between North Area and Main Grid (Generator is installed from the beginning)

Base Data: 2010 Night Peak (New Demand and Generators are considered)

		Alternative A			Alternative B			Alternative C		
Single Line Diagram										
Cost		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
	Lines	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km)	Lynx 2cct 141.3km	1,268.9	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km)	Lynx 2cct 141.3km	1,268.9	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km)	Lynx 2cct 141.3km	1,268.9
	Phase Modifying Equipment	SC (Chunnakam) 5MVAR	0units	0	SC (Chunnakam) 5MVAR	0units	0	SC (Chunnakam) 5MVAR	0units	0
	Others	132kV line bay	6 units	109.8	132kV line bay	4 units	73.2	132kV line bay	8 units	146.4
	Total Cost	Excluding Generator Construction Cost		1,378.7	Excluding Generator Construction Cost		1,342.1	Excluding Generator Construction Cost		1,415.3
Remarks										
Assessment on System Condition		B			A			C		

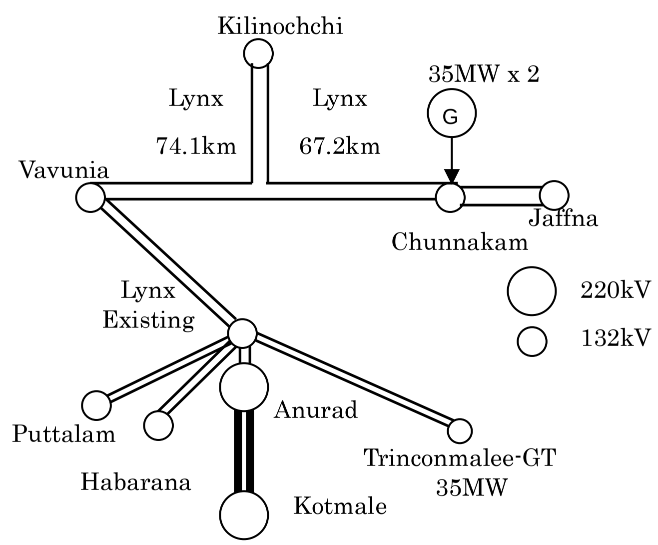
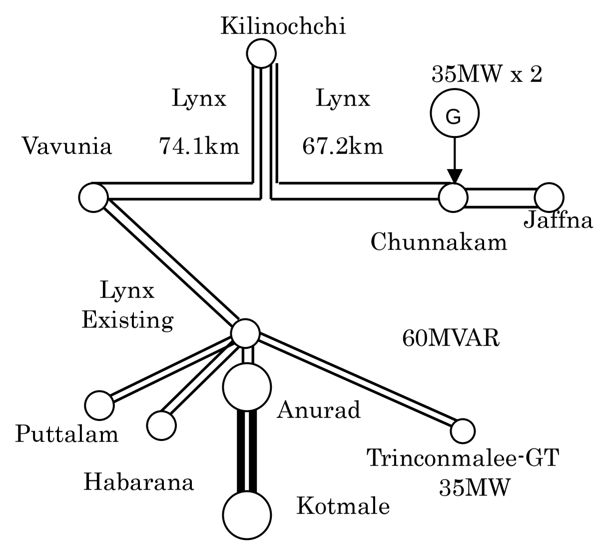
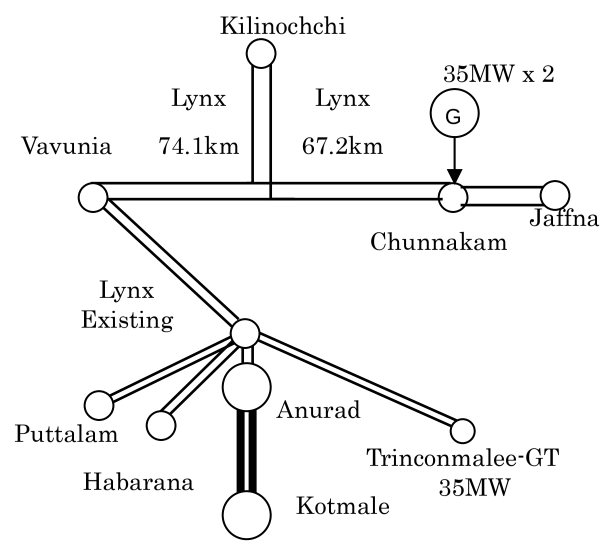
Interconnection between North Area and Main Grid (Generator is installed from the beginning)

Base Data: 2015 Night Peak (New Demand and Generators are considered)

		Alternative A			Alternative B					
Single Line Diagram										
Cost		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)			
	Lines	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km)	Lynx 2cct 141.3km	1,268.9	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km)	Lynx 2cct 141.3km	1,268.9			
	Phase Modifying Equipment	SC (Chunnakam) 5MVAR	units	0	SC (Chunnakam) 5MVAR	units	0			
	Others	132kV line bay	4 units	73.2	132kV line bay	6 units	109.8			
	Total Cost	Excluding Generator Construction Cost		1,342.1	Excluding Generator Construction Cost		1,378.7			
Remarks		If the line between Anuradhapura and Vavunia is failure, the system can not supply power to Vavunia. If the line between Anuradhapura and Kirinochchi is failure, the voltage at Kilinochchi is under 0.9 pu. (0.893)								
Assessment on System Condition		Not Good			A					

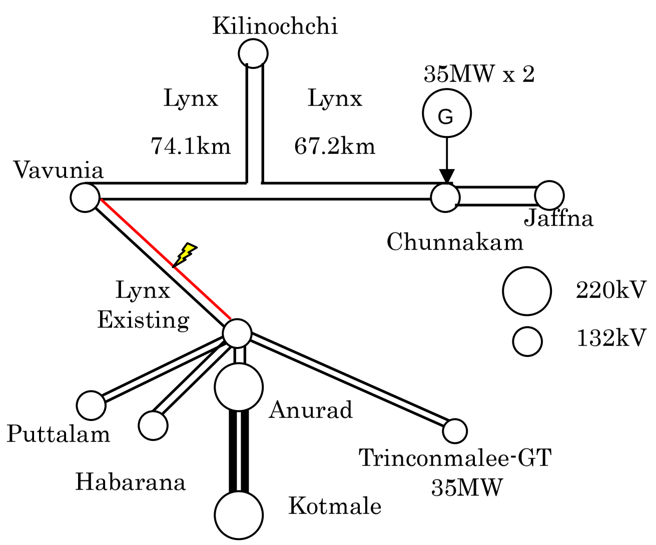
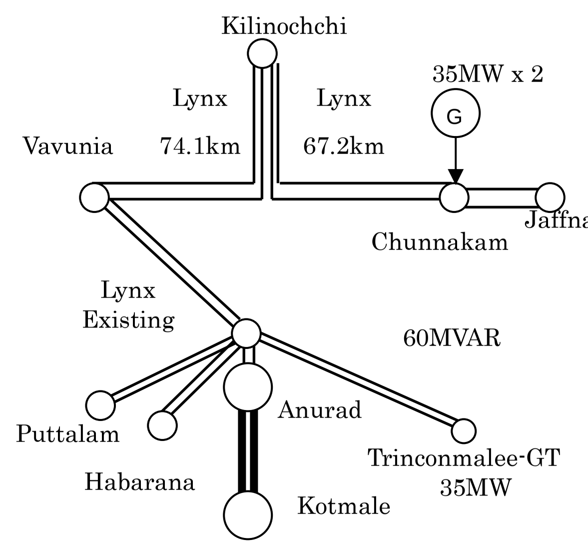
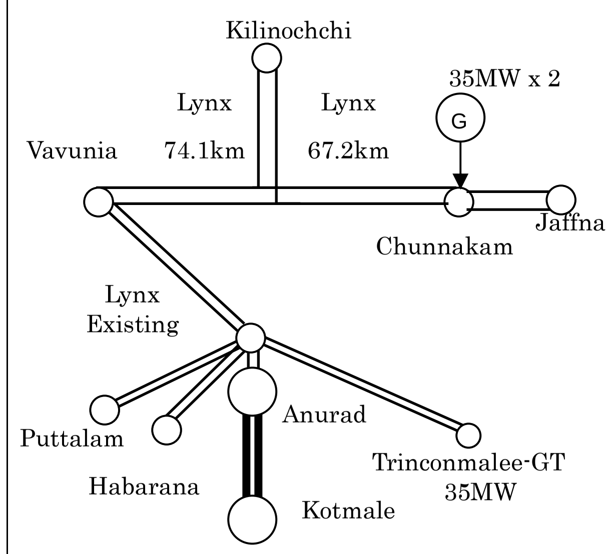
Interconnection between North Area and Main Grid (Generator is installed from the beginning)

Base Data: 2020 Night Peak (New Demand and Generators are considered)

		Alternative A			Alternative B			Alternative C		
Single Line Diagram										
Cost		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
	Lines	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km) Chu - Jaf(Lynx 10.8km)	Lynx 2cct 152.1km	1,365.9	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km) Chu - Jaf(Lynx 10.8km)	Lynx 2cct 152.1km	1,365.9	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km) Chu - Jaf(Lynx 10.8km)	Lynx 2cct 152.1km	1,365.9
	Phase Modifying Equipment	SC (Chunnakam) 5MVAR	units	0	SC (Chunnakam) 5MVAR	units	0	SC (Chunnakam) 5MVAR	units	0
	Others	132kV line bay	6 units 4 units	183.0	132kV line bay	8 units 4 units	219.6	132kV line bay	6 units 4 units	183.0
	Total Cost	Excluding Generator Construction Cost		1,451.9	Excluding Generator Construction Cost		1,585.5	Excluding Generator Construction Cost		1,451.9
Remarks								Tower conversion cost (very small) is needed		
Assessment on System Condition		A			B			A-		

Interconnection between North Area and Main Grid (Generator is installed from the beginning)

Base Data: 2025 (New Demand and Generators are considered)

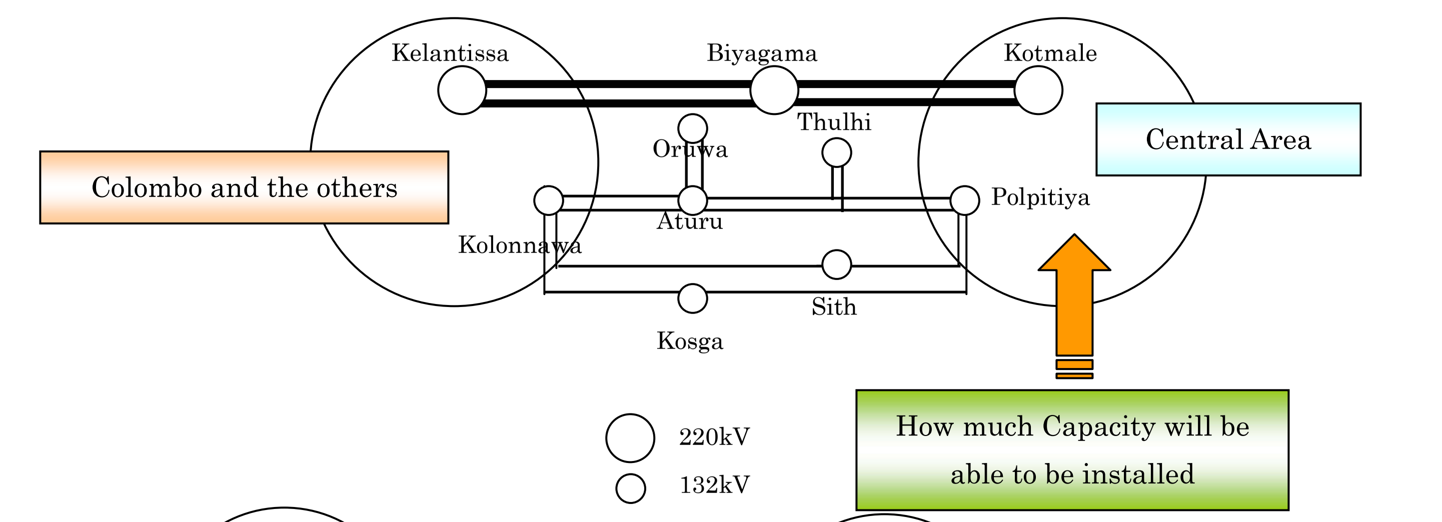
		Alternative A			Alternative B			Alternative C		
Single Line Diagram										
Cost		Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)	Items	Volume	Cost (MLKR)
	Lines	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km) Chu - Jaf(Lynx 10.8km)	Lynx 2cct 152.1km	1,365.9	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km) Chu - Jaf(Lynx 10.8km)	Lynx 2cct 152.1km	1,365.9	Vav - Kil (Lynx 74.1km) Kil - Chu(Lynx 67.2km) Vav- Chu(Lynx 141.3km) Chu - Jaf(Lynx 10.8km)	Lynx 2cct 152.1km	1,365.9
	Phase Modifying Equipment	SC (Chunnakam) 5MVAR	units	0	SC (Chunnakam) 5MVAR	0units	0	SC (Chunnakam) 5MVAR	units	0
	Others	132kV line bay	6 units 4 units	183.0	132kV line bay	8 units 4 units	219.6	132kV line bay	6 units 4 units	183.0
	Total Cost	Excluding Generator Construction Cost		1,451.9	Excluding Generator Construction Cost		1,585.5	Excluding Generator Construction Cost		1,451.9
Remarks		If the line between Anuradhapura and Vavunia is failure, the system, the voltage at Kilinochchi is under 0.9 pu. (0.889)						Tower conversion cost (very small) is needed		
Assessment on System Condition		Not Good			B			A		

Affect to the Main Grid by Mini-Hydro Interconnection

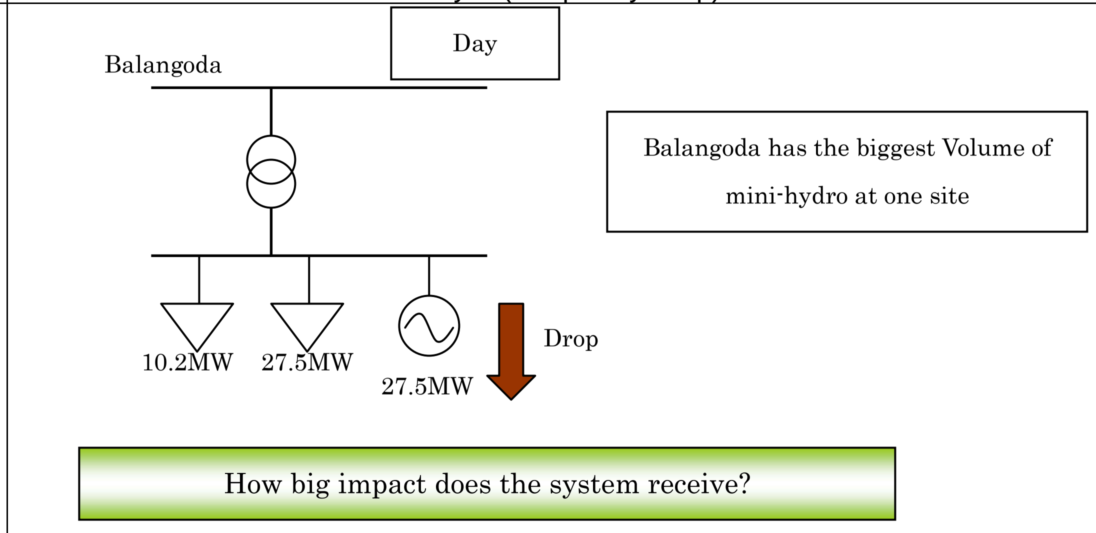
Base Data: 2005 Hydro Maximum Case (New Demand and Generators are considered)

Single Line Diagram

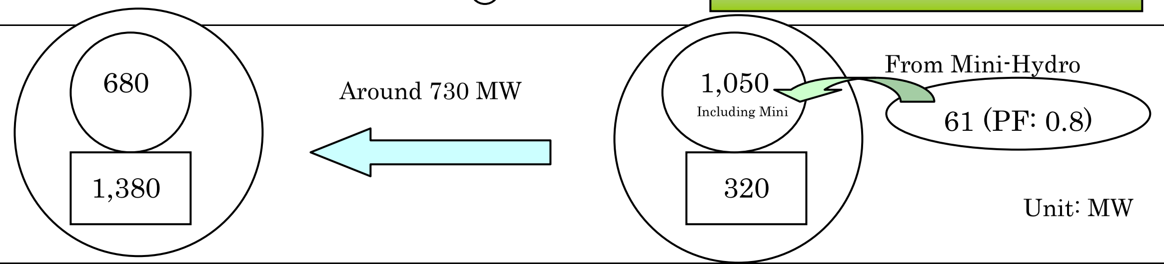
Study A (N-0, N-1)



Study B (Frequency Drop)



Pre Condition (Night)



Result (Night)

Study A (N-0, N-1)

Bottle Neck	Marginal Volume (Normal state) (MW)	
Wimalsurendura Tr	308.9	
Deniyaya Tr	329.1	
Sithawaka - Kolonnawa	459.9	
Ratnapura Tr	461.6	
Bottle Neck	**Marginal Volume (N-1 State) (MW)**	**Causes (N-1)**
Wimalsurendura Tr	**198.7**	Wimalsurendura Tr 1unit failure
N-Laxapana - Polpitiya	223.0	N-Laxapana – Polpitiya 1cct Open
Deniyaya Tr	224.1	Deniyaya Tr 1unit failure
Ratnapura Tr	241.1	Ratnapura Tr 1unit failure

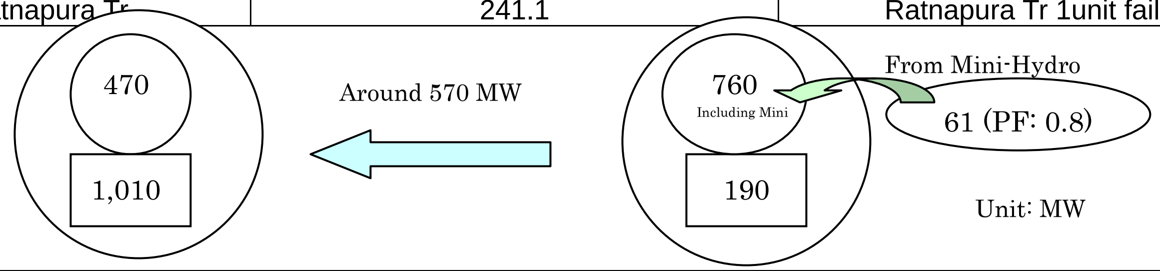
Study B (Frequency Drop)

dF = 1/4.75 x100x (27.5 / 1700) = 0.34

49.66Hz > 48.75 Hz → No Load Shedding

49.66Hz > 49.5Hz (Grid Code) → No Problem

Pre Condition (Day)



Result (Day)

Study A (N-0, N-1)

Bottle Neck	Marginal Volume (Normal state) (MW)	
Polpitiya - Kosgama	44.4	
Polpitiya - Thulhiriya	80.3	
Sithawaka - Kolonnawa	116.7	
N-Laxapana - Polpitiya	129.1	
Bottle Neck	**Marginal Volume (N-1 State) (MW)**	**Causes (N-1)**
Polpitiya - Thulhiriya	**0 (-42.6)**	Polpitiya - Thulhiriya 1cct Open
Polpitiya - Sithawaka	0 (-39.9)	Kosgama - Polpitiya 1cct Open
Polpitiya - Kosgama	0 (-27.1)	Polpitiya - Sithawaka 1cct Open
N-Laxapana - Polpitiya	17.2	N_Laxapana – Polpitiya 1cct Open

Study B (Frequency Drop)

dF = 1/4.75 x100x (27.5 / 1200) = 0.48

49.52Hz > 48.75 Hz → No Load Shedding

49.52Hz > 49.5Hz (Grid Code) → No Problem

During Off Peak
Demand is 62% of Day Peak (Daily load curve as of Sep in 2004)

dF = 1/4.75 x100x (27.5 / 700) = 0.83

49.17Hz > 48.75 Hz → No Load Shedding

49.17Hz < 49.5Hz (Grid Code) → However, It can recover to the acceptable range after governor operating

Summary

Study A (N-0, N-1)

Total around 20MW, 61MW as of existing working amount - 42.6 as of additional mini-hydro installed, is acceptable from the view point of thermal capacity.
All mini-hydro power plants can not be connected during day peak.

Study B (Frequency Drop)

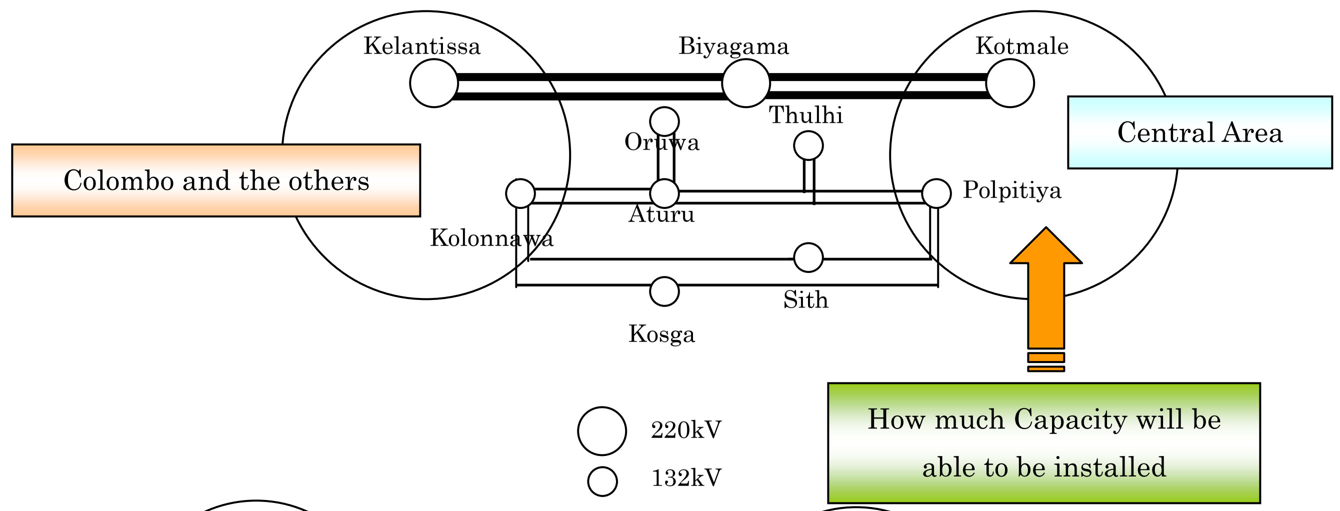
No Problem

Affect to the Main Grid by Mini-Hydro Interconnection

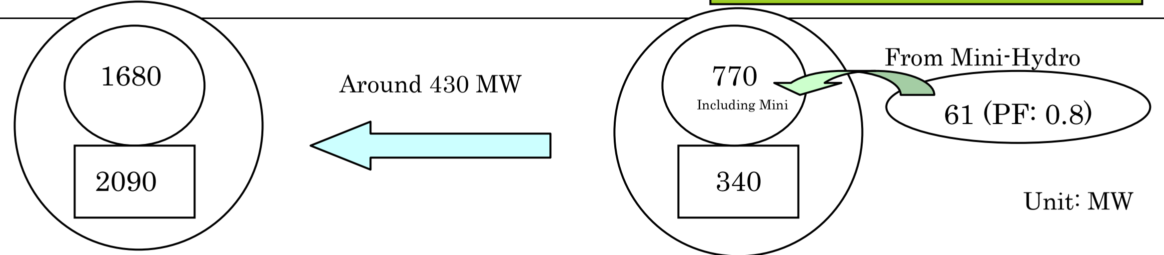
Base Data: 2010 Hydro and Thermal Maximum Case (New Demand and Generators are considered)

Study A (N-0, N-1)

Single Line Diagram



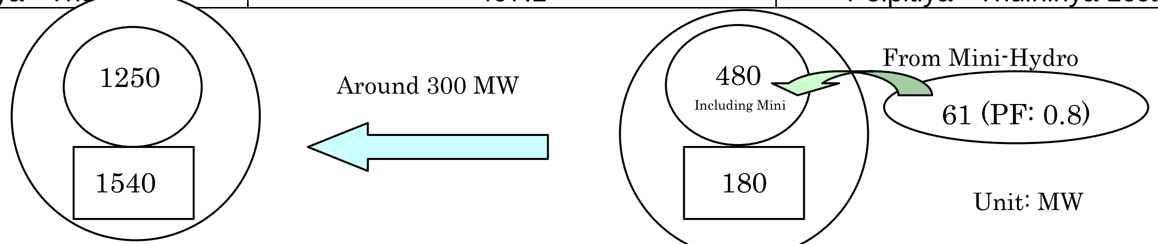
Pre Condition (Night)



Result (Night)

Bottle Neck	Marginal Volume (Normal state) (MW)	
Balangoda Tr	486.5	
Ratnapura Tr	503.6	
N-Laxapana - Polpitiya	636.7	
Deniyaya Tr	639.2	
Bottle Neck	**Marginal Volume (N-1 State) (MW)**	**Causes (N-1)**
Balangoda Tr	**266.0**	Balangoda Tr 1unit failure
Ratnapura Tr	283.1	Ratnapura Tr 1unit failure
N-Laxapana - Polpitiya	361.8	N-Laxapana - Polpitiya 1cct Open
Polpitiya - Thulhiriya	407.1	Polpitiya - Thulhiriya 1cct Open

Pre Condition (Day)



Result (Day)

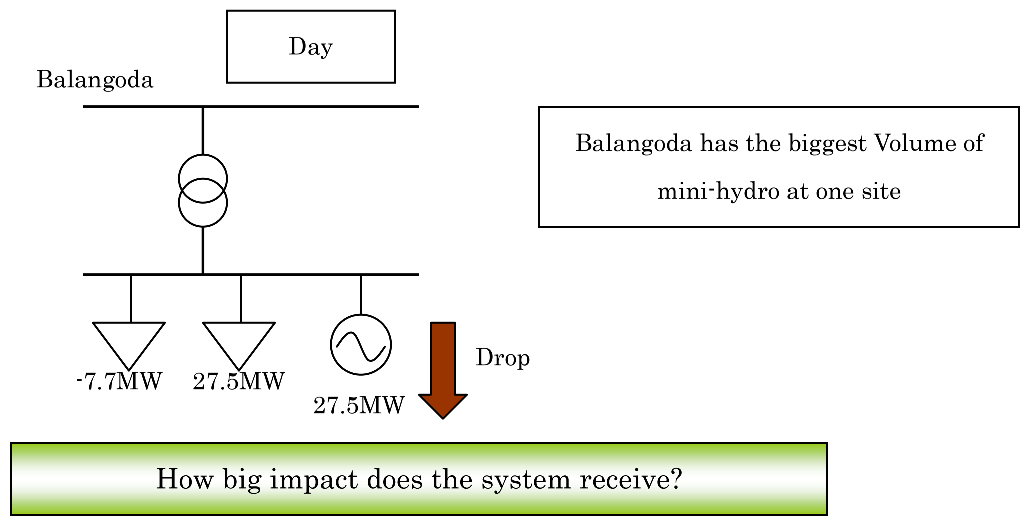
Bottle Neck	Marginal Volume (Normal state) (MW)	
Polpitiya - Kosgama	12.7	
Polpitiya - Thulhiriya	189.6	
Sithawaka - Kolonnawa	208.1	
N-Laxapana - Polpitiya	211.1	
Bottle Neck	**Marginal Volume (N-1 State) (MW)**	**Causes (N-1)**
Polpitiya - Kosgama	**0 (-84.3)**	Polpitiya - Sithawaka 1cct Open
Polpitiya - Sithawaka	4.1	Kosgama - Polpitiya 1cct Open
N-Laxapana - Polpitiya	74.4	Galle - Baddegama 1cct Open
Polpitiya - Thulhiriya	76.8	Polpitiya - Thulhiriya 1cct Open

Summary

Total around 0MW(-23.3MW), 61MW as of existing working amount - 84.3 as of additional mini-hydro installed, is acceptable from the view point of thermal capacity.
Any mini-hydro power plants can not be connected during day peak.

Study B (Frequency Drop)

Single Line Diagram



Pre Condition (Night)

Out put of hydraulic power generation in central area declines, as compared with 2005. Because the excess capability of transmission lines in central area declines, as load increases. Out put of hydraulic power generation in central area is necessary to be reduced.

Result (Night)

dF = 1/4.75 x100x (27.5 / 2430) = 0.24

49.76Hz > 48.75 Hz → No Load Shedding

49.76Hz > 49.5Hz (Grid Code) → No Problem

Pre Condition (Day)

Out put of hydraulic power generation in central area declines, as compared with 2005. Because the excess capability of transmission lines in central area declines, as load increases. Out put of hydraulic power generation in central area is necessary to be reduced.

Result (Day)

dF = 1/4.75 x100x (27.5 / 1720) = 0.34

49.66Hz > 48.75 Hz → No Load Shedding

49.66Hz > 49.5Hz (Grid Code) → No Problem

During Off Peak
Demand is 62% of Day Peak (Daily load curve as of Sep in 2004)

dF = 1/4.75 x100x (27.5 / 700) = 0.54

49.46Hz > 48.75 Hz → No Load Shedding

49.46Hz < 49.5Hz (Grid Code) → However, It can recover to the acceptable range after governor operating

Summary

No Problem

Appendix 11

Mini-Hydro Impact Analysis (Operating Condition of Mini Hydro)

2005

Night Peak Case

80% Operation for Hydro_Maximum

		Pre P	Pre Q	Mini P	Mini P (80%)	Estimated P	Estimated Q
3770	KIRIB-3 33.000	69.1	37.3	9.65	7.72	61.38	33.1
3120	WIMAL-3 33.000	17	10.9	5.46	4.37	12.632	8.1
3520	NUWAR-3 33.000	38.2	17.4	4.41	3.53	34.672	15.8
3640	DENIY-3 33.000	22.1	14.8	6.35	5.08	17.02	11.4
3740	RATNAP-3 33.000	15	9.3	15.08	12.06	2.936	1.8
3510	SITHA-33 33.000	29	14.8	7.43	5.94	23.056	11.8
3630	BALAN-3 33.000	47.9	27	27.5	22.00	25.9	14.6
				75.88	60.70		

60% Operation for Thirmal Maximum

		Pre P	Pre Q	Mini P	Mini P (60%)	Estimated P	Estimated Q
3770	KIRIB-3 33.000	69.1	37.3	9.65	5.79	63.31	34.2
3120	WIMAL-3 33.000	17	10.9	5.46	3.28	13.724	8.8
3520	NUWAR-3 33.000	38.2	17.4	4.41	2.65	35.554	16.2
3640	DENIY-3 33.000	22.1	14.8	6.35	3.81	18.29	12.2
3740	RATNAP-3 33.000	15	9.3	15.08	9.05	5.952	3.7
3510	SITHA-33 33.000	29	14.8	7.43	4.46	24.542	12.5
3630	BALAN-3 33.000	47.9	27	27.5	16.50	31.4	17.7
				75.88	45.53		

Day Peak Case

80% Operation for Hydro_Maximum

		Pre P	Pre Q	Mini P	Mini P (80%)	Estimated P	Estimated Q
3770	KIRIB-3 33.000	34.6	18.6	9.65	7.72	26.88	14.4
3120	WIMAL-3 33.000	7.7	5	5.46	4.37	3.332	2.2
3520	NUWAR-3 33.000	19.1	8.7	4.41	3.53	15.572	7.1
3640	DENIY-3 33.000	11.7	7.9	6.35	5.08	6.62	4.5
3740	RATNAP-3 33.000	7.5	4.6	15.08	12.06	-4.564	-2.8
3510	SITHA-33 33.000	21.1	10.8	7.43	5.94	15.156	7.8
3630	BALAN-3 33.000	37.7	21.3	27.5	22.00	15.7	8.9
				75.88	60.70		

60% Operation for Thirmal Maximum

		Pre P	Pre Q	Mini P	Mini P (60%)	Estimated P	Estimated Q
3770	KIRIB-3 33.000	34.6	18.6	9.65	5.79	28.81	15.5
3120	WIMAL-3 33.000	7.7	5	5.46	3.28	4.424	2.9
3520	NUWAR-3 33.000	19.1	8.7	4.41	2.65	16.454	7.5
3640	DENIY-3 33.000	11.7	7.9	6.35	3.81	7.89	5.3
3740	RATNAP-3 33.000	7.5	4.6	15.08	9.05	-1.548	-0.9
3510	SITHA-33 33.000	21.1	10.8	7.43	4.46	16.642	8.5
3630	BALAN-3 33.000	37.7	21.3	27.5	16.50	21.2	12.0
				75.88	45.53		

Mini-Hydro Impact Analysis (Operating Condition of Mini Hydro)

2010

Night Peak Case

80% Operation for Hydro_Maximum

		Pre P	Pre Q	Mini P	Mini P (80%)	Estimated P	Estimated Q
3770	KIRIB-3 33.000	73.3	39.6	9.65	7.72	65.58	35.4
3120	WIMAL-3 33.000	50.7	32.7	5.46	4.37	46.332	29.9
3520	NUWAR-3 33.000	36.6	16.7	4.41	3.53	33.072	15.1
3640	DENIY-3 33.000	33.4	24.6	6.35	5.08	28.32	20.9
3740	RATNAP-3 33.000	21	13	15.08	12.06	8.936	5.5
3510	SITHA-33 33.000	32.6	16.7	7.43	5.94	26.656	13.7
3630	BALAN-3 33.000	28.5	16.2	27.5	22.00	6.5	3.7
				75.88	60.70		

60% Operation for Thirmal Maximum

		Pre P	Pre Q	Mini P	Mini P (60%)	Estimated P	Estimated Q
3770	KIRIB-3 33.000	73.3	39.6	9.65	5.79	67.51	36.5
3120	WIMAL-3 33.000	50.7	32.7	5.46	3.28	47.424	30.6
3520	NUWAR-3 33.000	36.6	16.7	4.41	2.65	33.954	15.5
3640	DENIY-3 33.000	33.4	24.6	6.35	3.81	29.59	21.8
3740	RATNAP-3 33.000	21	13	15.08	9.05	11.952	7.4
3510	SITHA-33 33.000	32.6	16.7	7.43	4.46	28.142	14.4
3630	BALAN-3 33.000	28.5	16.2	27.5	16.50	12	6.8
				75.88	45.53		

Day Peak Case

80% Operation for Hydro_Maximum

		Pre P	Pre Q	Mini P	Mini P (80%)	Estimated P	Estimated Q
3770	KIRIB-3 33.000	36.6	19.8	9.65	7.72	28.88	15.6
3120	WIMAL-3 33.000	25.3	16.4	5.46	4.37	20.932	13.6
3520	NUWAR-3 33.000	18.3	8.3	4.41	3.53	14.772	6.7
3640	DENIY-3 33.000	17.7	11.9	6.35	5.08	12.62	8.5
3740	RATNAP-3 33.000	10.5	6.5	15.08	12.06	−1.564	−1.0
3510	SITHA-33 33.000	23.8	12.2	7.43	5.94	17.856	9.2
3630	BALAN-3 33.000	14.3	8.1	27.5	22.00	−7.7	−4.4
				75.88	60.70		

60% Operation for Thirmal Maximum

		Pre P	Pre Q	Mini P	Mini P (60%)	Estimated P	Estimated Q
3770	KIRIB-3 33.000	36.6	19.8	9.65	5.79	30.81	16.7
3120	WIMAL-3 33.000	25.3	16.4	5.46	3.28	22.024	14.3
3520	NUWAR-3 33.000	18.3	8.3	4.41	2.65	15.654	7.1
3640	DENIY-3 33.000	17.7	11.9	6.35	3.81	13.89	9.3
3740	RATNAP-3 33.000	10.5	6.5	15.08	9.05	1.452	0.9
3510	SITHA-33 33.000	23.8	12.2	7.43	4.46	19.342	9.9
3630	BALAN-3 33.000	14.3	8.1	27.5	16.50	−2.2	−1.2
				75.88	45.53		

Appendix 12

Countermeasure against Harmonic and Voltage Deviation (Report to CEB during 2nd Work)

I. Current Circumstance and Problems on Small Hydro Electric Power Connection to Main Grid in Sri Lanka

In Sri Lanka, the number of existing small hydro electric power IPPs which have power selling contract with CEB and connect to main grid as of Feb in 2005 is 41.

Most of them gather around middle of Sri Lanka, e.g. Nuwala Eliya and Wimalasurendra and Balangoda. The size of them is from 0.07MW to 9.9MW. To sum up them, it is 75.63MW.

All of them are connected to 33kV distribution lines. Harmonic and voltage drop when IPPs connect to main grid or trip have been serious problems recently.

II. Reasons for Small Hydro Electric Power Interconnection to Main Grid

- However there is a contract of maximum dealing power, necessary technique and restriction supposed to be power generation connected to main has not been established.
- IPPs connect to main grid or trip themselves, besides that, they do not give the information to CEB.
- The SCADA system is installed to only 17 of 70 all in CEB power system. CEB intend to install the SCADA system to IPPs but it has not been proceeded due to budget shortage. Therefore CEB does not grasp power generation and connecting status for all IPPs.

III. Countermeasures of Institutions

In Japan, to make distributed generation possible to connect to main grid, technical criteria are described in "Technical Guideline of Connecting to Main Grid for Distributed Power Generation (JEAG 9701 (2001))". Not only Chubu Electric Power Company but all electric power suppliers are compliant with it.

Basically, it is mentioned that harmonic and voltage drop because of system interconnection are IPP's problems. IPPs are coached to adapt some countermeasures to prevent power system from suffering these problems.

In Sri Lanka, CEB should summarize necessary technical criteria for IPPs whose power generation connects to main grid as soon as possible. And then when CEB contract with IPPs, CEB should check whether system interconnection meet technical criteria.

To be refereed, important points related to these issues in "Technical Guideline of Connecting to Main Grid for Distributed Power Generation" are described below:

1 Background and Objective

As the number of business group is getting increase, distributed power generation such as small hydro electric power generation, electric power generation with refuse incineration, fuel cell generation, and sunlight power generation has been increasing since Electric Utility Low was revised in October of 1995. Because bidding system for public electrical power supplier was established and deregulation of power generation was realized.

These distributed power generation are connected to the main grid. So it is concerned that power quality might be poor or maintenance and operation might be affected.

Moreover, it was confirmed that transparency and fairness of information related to system interconnection should be kept when IPPs connect to the main grid not to affect anything to other customers through system.

Therefore technical criteria needed for system interconnection are summarized in this guideline.

2 Restrictions

2.1 Restrictions on Harmonic (for all Voltage)

Reducing harmonic distortion factor for all current to 5% or lower and for each current is desirable.

2.2 Restriction on Voltage Flicker (for all Voltage)

Criteria about voltage flicker is shown below:

ΔV_{10} (It's own flicker value at the connecting point where generation is set) ≦0.23V

With respect to voltage flicker of wind power generation, it is occurred by inrush current or power variation. Main reason of the former is continuous changing parallel on and off because of wind velocity change, and the one of the latter is wind velocity change.

2.2.1 Voltage flicker by continuous changing parallel on and off

Voltage flicker is related to voltage deviation and frequency. So restricting voltage deviation or reducing frequency of parallel on and off is necessary

Countermeasures against voltage deviation:

- Reactive power compensation by SVC (Static Var Compensator)
- Adapting soft start using thyristor
- Reducing system impedance by replacing the existing lines to thick ones

And countermeasures against frequency of parallel on and off:

- Changing the condition for parallel on and off from instantaneous wind velocity to average wind velocity

2.2.2 Voltage flicker by power variation

Countermeasures against this power variation:

- Reactive power compensation by SVC (Static Var Compensator)
- Reducing system impedance by replacing the existing lines to thick ones

2.3 Restriction on Voltage Deviation (for 22kV or higher)

2.3.1 In case that there is a possibility that system voltage exceeds appropriate value (**1～2%±normal voltage**) because generators are connected to the system, generator's owners are responsible for voltage regulation automatically.

2.3.2 In case of synchronous generators, they have damper winding (including no damper winding synchronous generators have prevention effect which is equal or greater to one of damper winding synchronous generators against hunting) and also have equipment checking synchronous automatically. In case of induction motors and if there is possibility that system voltage exceeds appropriate range (**2%±normal voltage**), some equipments such as current limiting reactor are should be installed by the generator's owner. And if troubles are not removed, generator's owner shall adapt synchronous generators instead of induction motors.

2.3.3 In case that self-commuted invertors are adapted, they shall have function keeping synchronous. And in case that externally commuted invertors are adapted and if there is possibility that system voltage exceeds appropriate range (**2%±normal voltage**) due to instantaneous voltage drop during parallel in, some equipments such as current limiting reactor are should be installed by the generator's owner. And if troubles are not removed, generator's owner shall adapt self-commuted invertors instead of externally commuted invertors.

2.4 Restriction on Voltage Deviation (for 6.6kV or lower)

2.4.1 In case that there is a possibility that load-side system voltage exceeds appropriate value (101±6V, 202±20V) because generators are connected to the distribution system and drop out, generator's owners are responsible for shedding loads automatically. And if troubles are not removed, generator's owner shall reinforce existing lines or adapt private lines to connect to main grid.

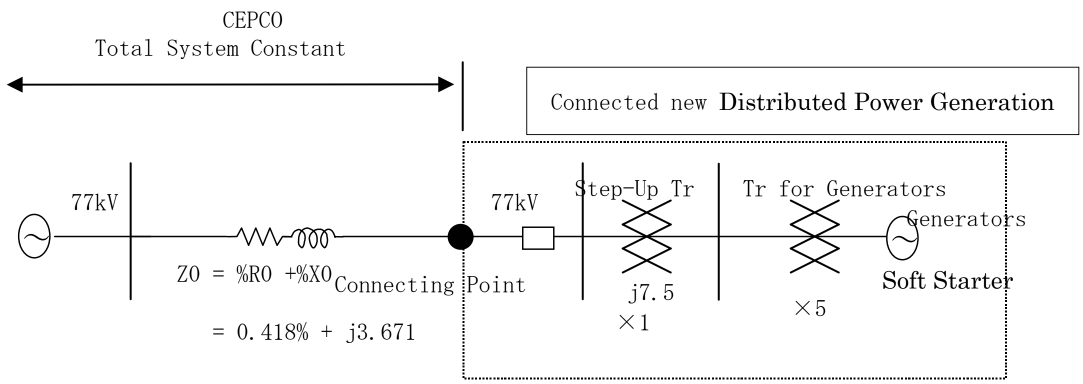
2.4.2 In case that there is a possibility that load-side system voltage exceeds appropriate value (101±6V, 202±20V) because of inverse power flow, generator's owners are responsible for voltage regulation automatically. And if troubles are not removed, generator's owner shall reinforce existing lines or adapt private lines to connect to main grid.

2.4.3 In case of synchronous generators, they shall have damper winding (including no damper winding synchronous generators have prevention effect which is equal or greater to one of damper winding synchronous generators against hunting) and also shall have equipment checking synchronous automatically. In case of induction motors and if there is possibility that system voltage exceeds appropriate range (**10%±normal voltage**), some equipments such as current limiting reactor, conductor used for compensating start-up, or generator having soft-starter are should be installed by the generator's owner. And if troubles are not removed, generator's owner shall adapt synchronous generators instead of induction motors.

2.4.4 In case that self-commuted invertors are adapted, they shall have function keeping synchronous. And in case that externally commuted invertors are adapted and if there is possibility that system voltage exceeds appropriate range (**10%±normal voltage**) due to instantaneous voltage drop during parallel in, some equipments such as current limiting reactor are should be installed by the generator's owner. And if troubles are not removed, generator's owner shall adapt self-commuted invertors instead of externally commuted invertors.

IV. Voltage Deviation Study (Actual Case in CEPCO)

1 Outline the System Configuration



Step-up Transformers

Rated Capacity	1,800kVA
Reactance	5.5%(Machine Base) 30.555%(10MVA Base)
Number	5

Generators

Type	Induction Generator
Rated Capacity	1,808kVA
Rated Output	1,650kW
Reactance	17.6%(Machine Base) 97.245%(10MVA Base)
Number	5

2 Result

2.1 Voltage Deviation Study when New Power Generation is connected to Grid

Study system is 77kV. So voltage deviation shall be smaller than 2%. However, in this case, soft starter system is adapted to generators. Therefore, result is reference value.

$$\Delta V = \sqrt{\frac{R0^2 + X0^2}{R0^2 + (X0 + Xt + XG)^2}} \times 100$$

$$2.73\% = \sqrt{\frac{0.418^2 + 3.671^2}{0.418^2 + (3.671 + 7.5 + 30.555 + 97.245)^2}}$$

2.2 Voltage Deviation Study when New Power Generation is tripped

$$\Delta V = \%R0 \times P(p.u) + \%X0 \times Q(p.u)$$

$$\pm 2 \geq 0.418 \times \frac{8.3}{10} + 3.671 \times \frac{Q}{10}$$

$$901k\,\mathrm{var} \leq Q \leq -1{,}277k\,\mathrm{var}$$

The available range for power factor is from lead 87.8% to lag 79.1%. If this system does not meet it, some countermeasures are necessary to be taken into consideration. For example, capacitor for phase compensator or automatic power factor regulator (APFR).

V. Countermeasures against Harmonic

Powerful and famous countermeasures against harmonic are shown hereinafter.

1.1 Multiplying pulse

This is a way that reduces lower degree harmonic current by increasing the number of pulse of Electric Power Converter. It contributes to reduce harmonic. The relationship between the number of pulse of electric power converter and the number of harmonic current is represented as the formula below:

Generated the number of harmonic current is:

$$n = k \times P \pm 1$$

k: 1,2,3,.....

P: the number of pulse

As this formula mentioned, in case of 12 pulses electric power converter, five-degree and seven-degree harmonic current is not generated theoretically. Therefore adapting 12 pulses converter is so effective. However, a little five-degree and seven-degree harmonic current can be created due to unbalanced circuit.

1.2 Absorbing harmonic current

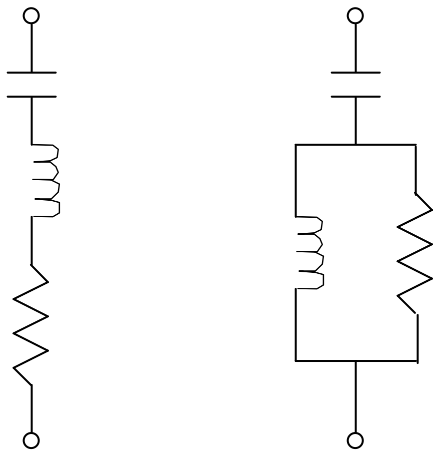
This is a way that reduces harmonic by absorbing harmonic current.

1.2.1 Passive Filter

This is a harmonic current absorbing equipment, which is combined some capacitor with some reactor to be low impedance shunt circuit against particular frequency or particular frequency region. It is divided into two types, tuned filter and high degree filter.

Tuned filters consist of series L-C-R circuit. They become low impedance and have much effect against tuned frequency. Making the value of "Q", which represents sharpness of resonance, bigger, enhances effect. However it causes higher possibility of none-synchronous and filters overloading.

High degree filters are low impedance against wide range of frequency. They are responsible for higher degree harmonic and are combined with tuned filters for each lower degree harmonic to absorb whole harmonic as total system.



Tuned Filter High Degree Filter

1.2.2 Power Factor Improvement Capacitor (at Customers)

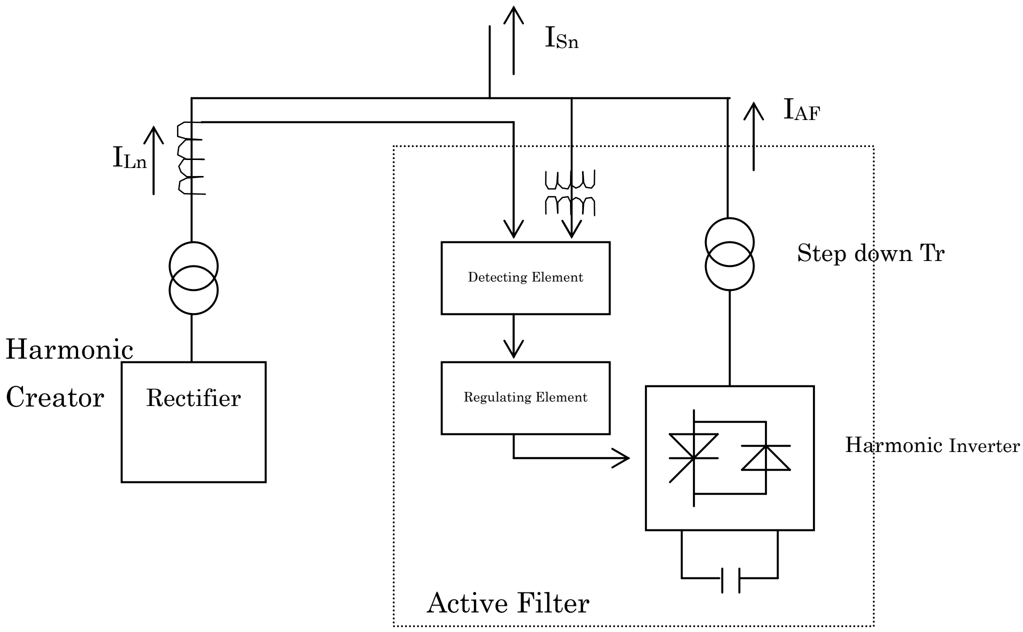
Power factor improvement capacitors with 6% series reactor have effect-absorbing harmonic. If these are installed at lower voltage side of receiving transformer, they can reduce outflow current of five degree harmonic by from 30% to 50% .It depends on the value of leakage inductance of receiving transformers.

1.3 Canceling of Harmonic Current

This is a way that reduces harmonic by canceling harmonic current.

1.3.1 Active Filter

After detecting harmonic current, this equipment creates current, which has different polarity and can remove it. This equipment is shown in the next diagram. It consists of harmonic inverter, transformer, harmonic detector and current regulator.

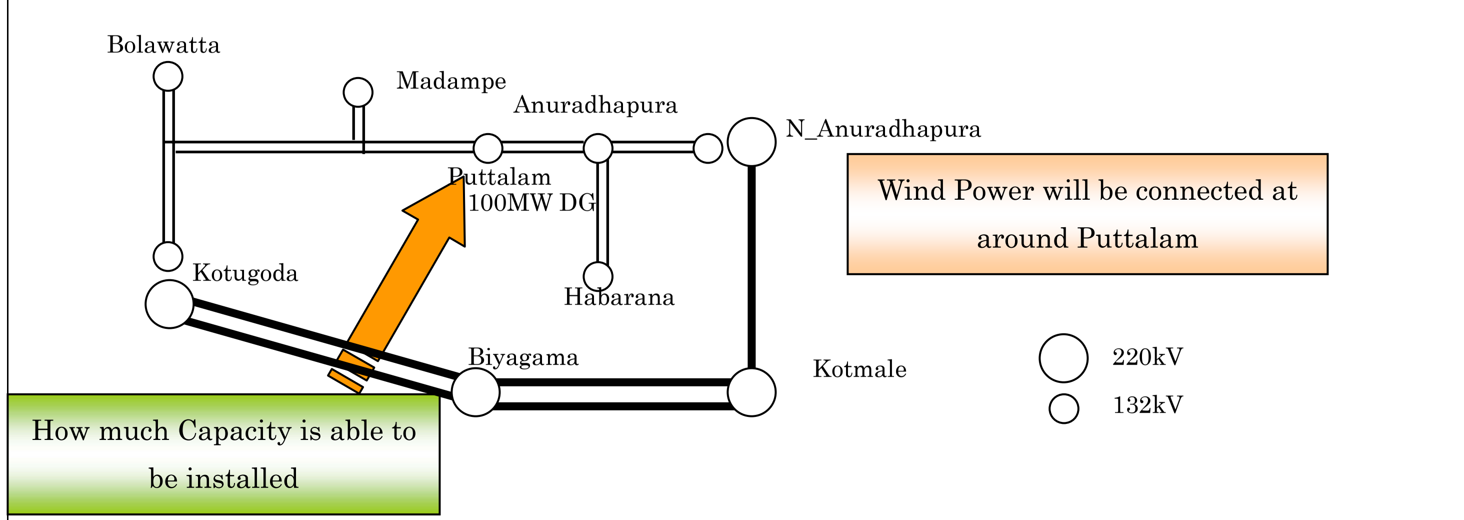


1.3.2 Δ-Δ, Δ-Y Transformer

Dedicated transformers are usually used for electric power converter like rectifiers. There are four kinds of connection between primary side and secondary side for three phase transformers. They are Δ-Δ, Δ-Y, Y-Y and Y-Δ. Now, if the Δ-Δ and Δ-Y connection transformers are installed at same bus in combination, each five degree and seven degree harmonic current through primary side is opposite and cancel each other. Therefore harmonic can be reduced.

Affect to the Main Grid by Wind-Power Interconnection

Base Data: 2005 Thermal Maximum Case (New Demand and Generators are considered)

<table>
<tr><th></th><th colspan="3">N-1 Study</th><th>Frequency Drop Analysis</th></tr>
<tr><td>Single Line Diagram</td><td colspan="3"></td><td></td></tr>
<tr><td rowspan="3">Result (Day)</td><td>Study Items</td><td>Marginal Volume (MW)</td><td>Bottle Neck</td><td rowspan="3">dF = 1/4.75 x100x (55 / 1200) = 0.96
49.04Hz > 48.75 Hz → No Load Shedding
49.04Hz < 49.5Hz (Grid Code) → However, It can recover to the acceptable range after governor operating</td></tr>
<tr><td>N-1</td><td>55MW
(Puttalam - Madam_T - Bolaw_T - Kotugoda) 1cct is outage</td><td>Puttalam - Madam_T - Bolaw_T - Kotugoda</td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td rowspan="3">Result (Night)</td><td>Study Items</td><td>Marginal Volume (MW)</td><td>Bottle Neck</td><td rowspan="2">dF = 1/4.75 x100x (210 / 1700) = 2.60
47.46Hz < 48.75 Hz → Load Shedding

dF = 1/4.75 x100x (100 / 1700) = 1.24
48.76Hz > 48.75 Hz → No Load Shedding

100MW is the marginal from the view point of no load shedding</td></tr>
<tr><td>N-1</td><td>210MW
In case that (Puttalam - Madam_T - Bolaw_T - Kotugoda) 1cct is outage</td><td>Puttalam - Madam_T - Bolaw_T - Kotugoda</td></tr>
<tr><td></td><td></td><td></td><td>During Off Peak
Demand is 62% of Day Peak (Daily load curve as of Sep in 2004)
dF = 1/4.75 x100x (41 / 700) = 1.23
48.77Hz > 48.75 Hz → No Load Shedding
41MW is the marginal from the view point of no load shedding</td></tr>
<tr><td rowspan="4">Summary</td><td>Classification</td><td>Marginal Volume (MW)</td><td>Causes</td><td>Remarks</td></tr>
<tr><td>Day</td><td>55MW</td><td>N-1 Problem</td><td></td></tr>
<tr><td>Night</td><td>100MW</td><td>Frequency Drop Problem</td><td></td></tr>
<tr><td>Off Peak</td><td>41MW</td><td>Frequency Drop Problem</td><td></td></tr>
<tr><td>Remarks</td><td colspan="3"></td><td></td></tr>
</table>

Appendix 14

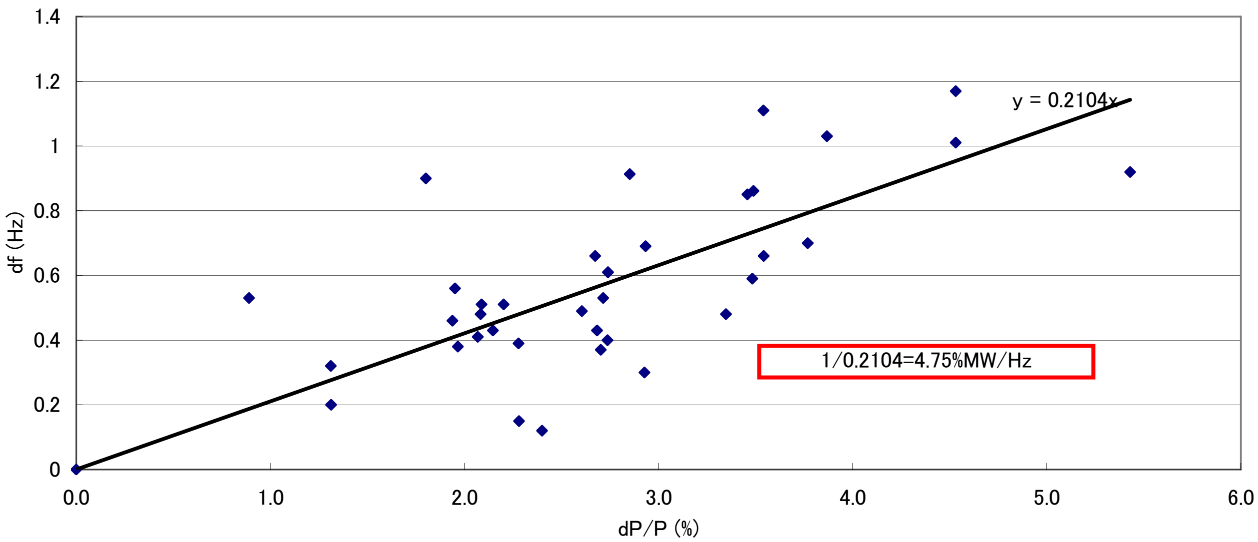
Result on Transmission Loss Reduction

			Zebra_4		Zebra LL_4				Parrrot_4				
	Year	Power Flow (MW)	Zebra_4 TL Cost (M US$)	TL Loss (M US$)	TL Incremental Cost	Reduced TL Loss (M US$)	Total (M US$)	P.V (M US$)	TL Incremental Cost	Reduced TL Loss (M US$)	Total (M US$)	P.V (M US$)	Remarks
0	2011	600	19.712	2.523	-10.157	0.757	-9.400	-9.400	-7.901	1.211	-6.690	-6.690	Present Year
1	2012	600		2.523		0.757	0.757	0.688		1.211	1.211	1.101	
2	2013	600		2.523		0.757	0.757	0.626		1.211	1.211	1.001	
3	2014	600		2.523		0.757	0.757	0.569		1.211	1.211	0.910	
4	2015	600		2.523		0.757	0.757	0.517		1.211	1.211	0.827	
5	2016	600		2.523		0.757	0.757	0.470		1.211	1.211	0.752	
6	2017	600		2.523		0.757	0.757	0.427		1.211	1.211	0.684	
7	2018	600		2.523		0.757	0.757	0.388		1.211	1.211	0.621	
8	2019	600		2.523		0.757	0.757	0.353		1.211	1.211	0.565	
9	2020	900		1.388		0.404	0.404	0.171		0.656	0.656	0.278	2 route
10	2021	900		1.388		0.404	0.404	0.156		0.656	0.656	0.253	Break Even Poit for Parrot
11	2022	900		1.388		0.404	0.404	0.141		0.656	0.656	0.230	
12	2023	900		1.388		0.404	0.404	0.129		0.656	0.656	0.209	
13	2024	900		1.388		0.404	0.404	0.117		0.656	0.656	0.190	
14	2025	900		1.362		0.404	0.404	0.106		0.656	0.656	0.173	
15	2026	900		1.362		0.404	0.404	0.097		0.656	0.656	0.157	
16	2027	900		1.362		0.404	0.404	0.088		0.656	0.656	0.143	
17	2028	900		1.362		0.404	0.404	0.080		0.656	0.656	0.130	
18	2029	900		1.362		0.404	0.404	0.073		0.656	0.656	0.118	
19	2030	900		1.362		0.404	0.404	0.066		0.656	0.656	0.107	
20	2031	900		1.362		0.404	0.404	0.060		0.656	0.656	0.098	
					Total Present Value			-4.079				1.855	

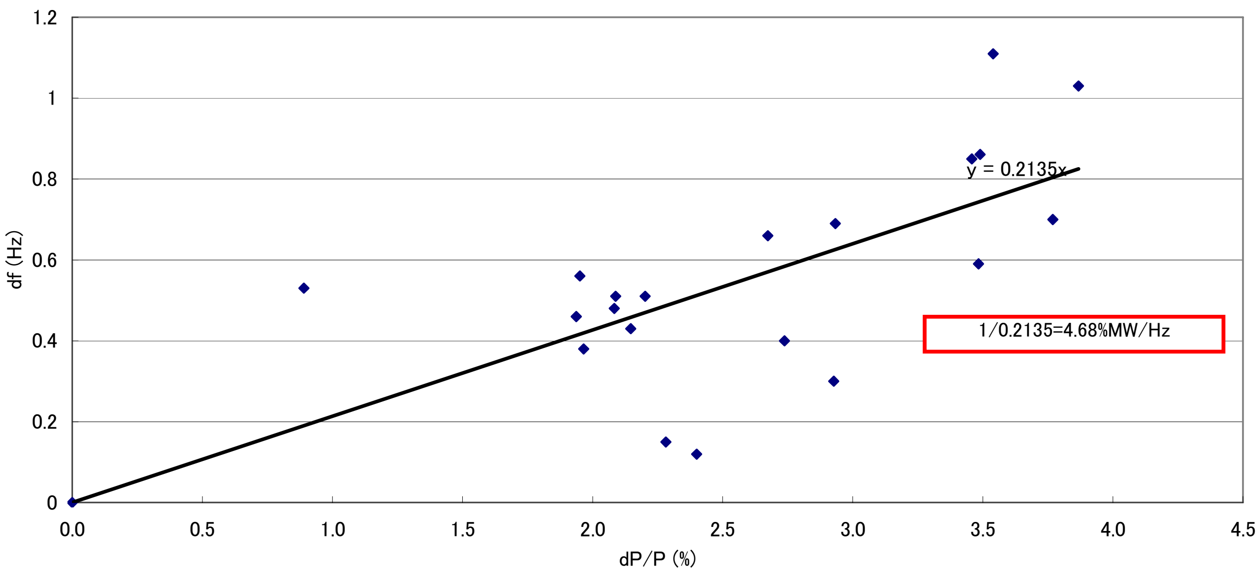
Conversion Rate	10.74 USD/1000LKR	Source: LTGEP2003, 01st January 2002
Discount Rate =	10%	Source: LTGEP2003
Operation Cost	0.0000576 M US$/MWh	CEB Average Generation Cost Includng Fuel and O/M Cost

Puttalam - Chilaw: 70km	Total	Only Conductor	
Zebra_4 2cct	1835.4 MLKR	1.52MLKR/km	
Parrot_4 2cct	2571.1 MLKR	2.89MLKR/km	Tower size is the same as that of the Zebra_4
Zebra LL_4 2cct	2781.1 MLKR	3.265MLKR/km	

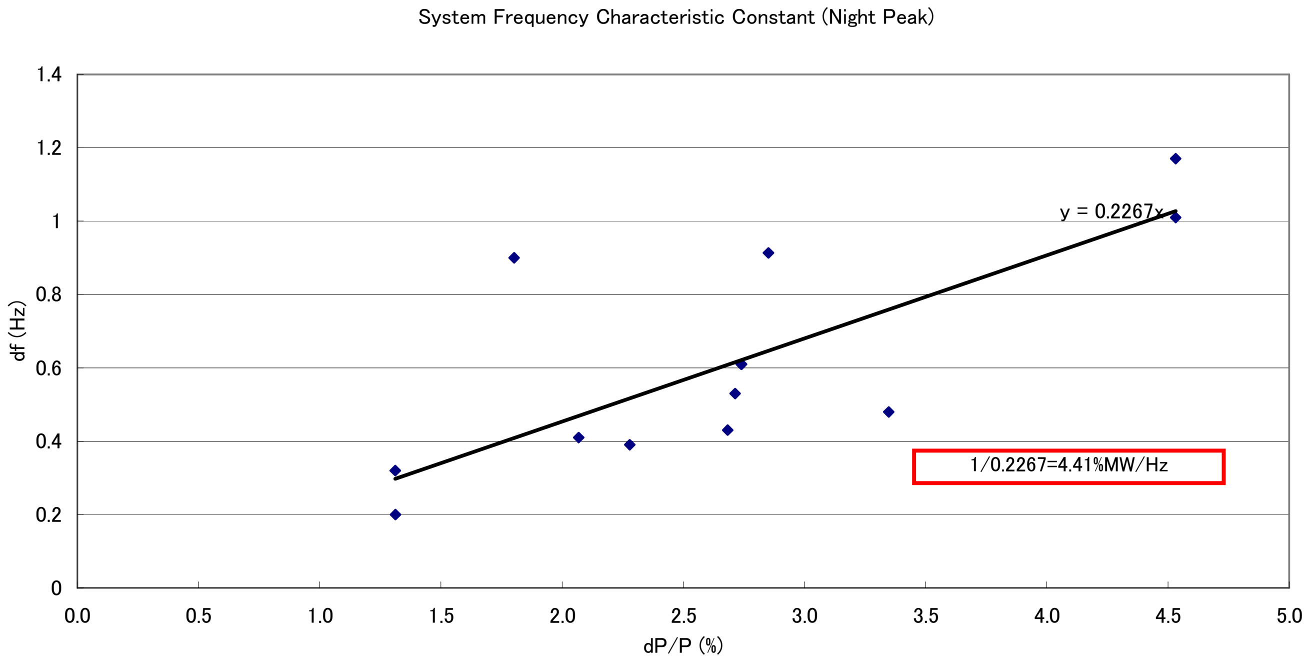
System Frequency Characteristic Constant (Whole Day)

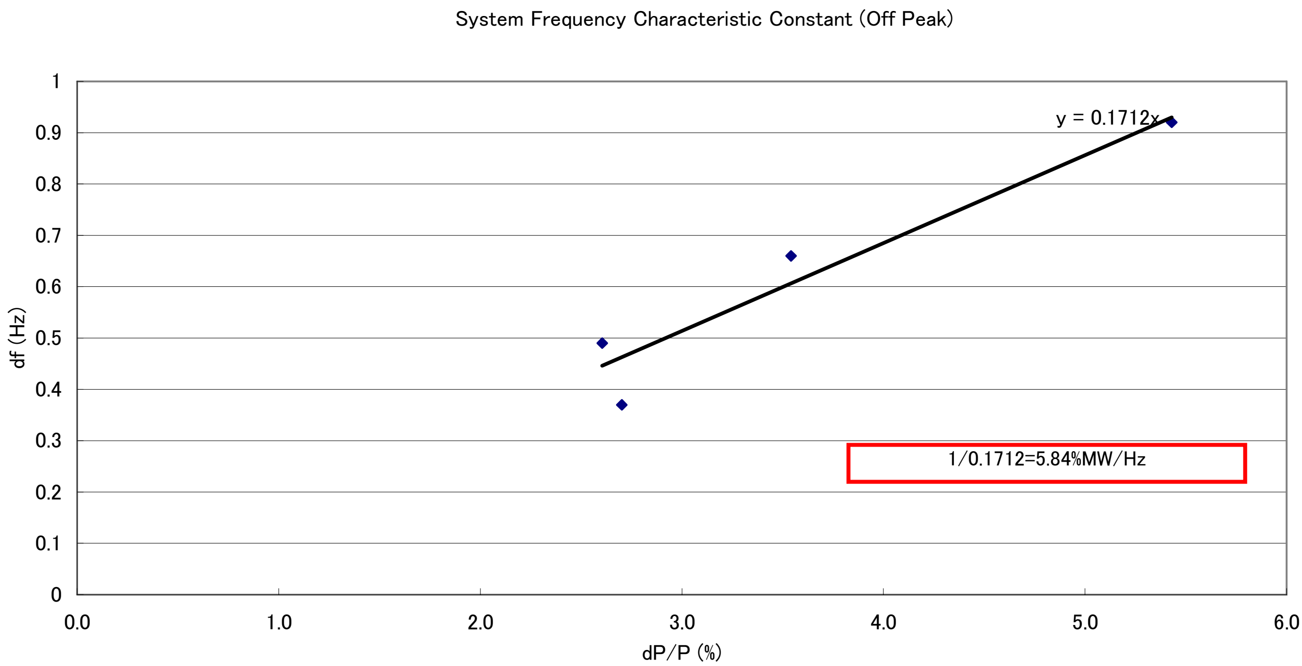


System Frequency Characteristic Constant (Day Peak)

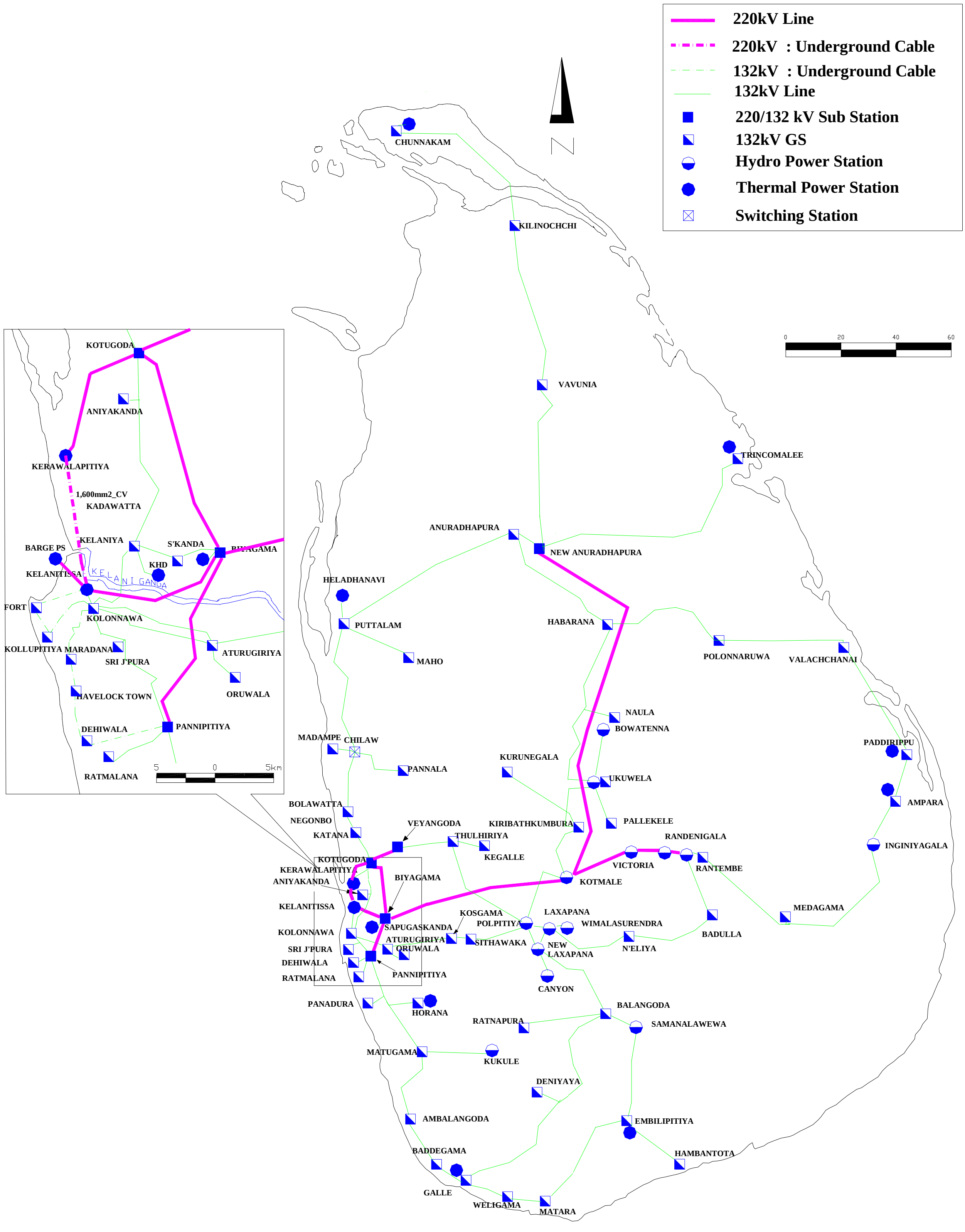


Appendix 15

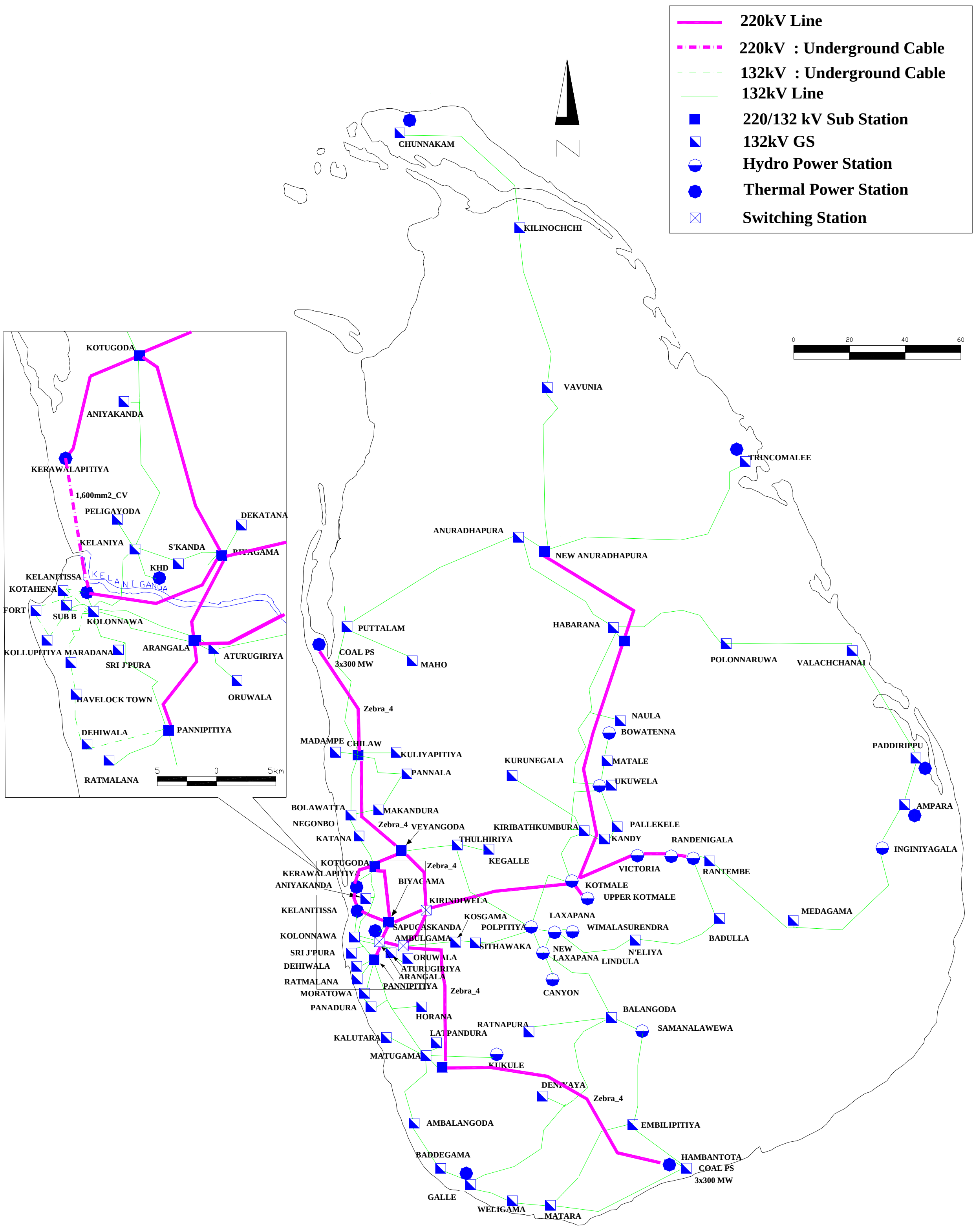

System Frequency Characteristic Constant (Night Peak)
df (Hz)
dP/P (%)
y = 0.2267x
1/0.2267=4.41%MW/Hz
1.4
1.2
1
0.8
0.6
0.4
0.2
0
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0


System Frequency Characteristic Constant (Off Peak)
df (Hz)
dP/P (%)
y = 0.1712x
1/0.1712=5.84%MW/Hz
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0.0
1.0
2.0
3.0
4.0
5.0
6.0

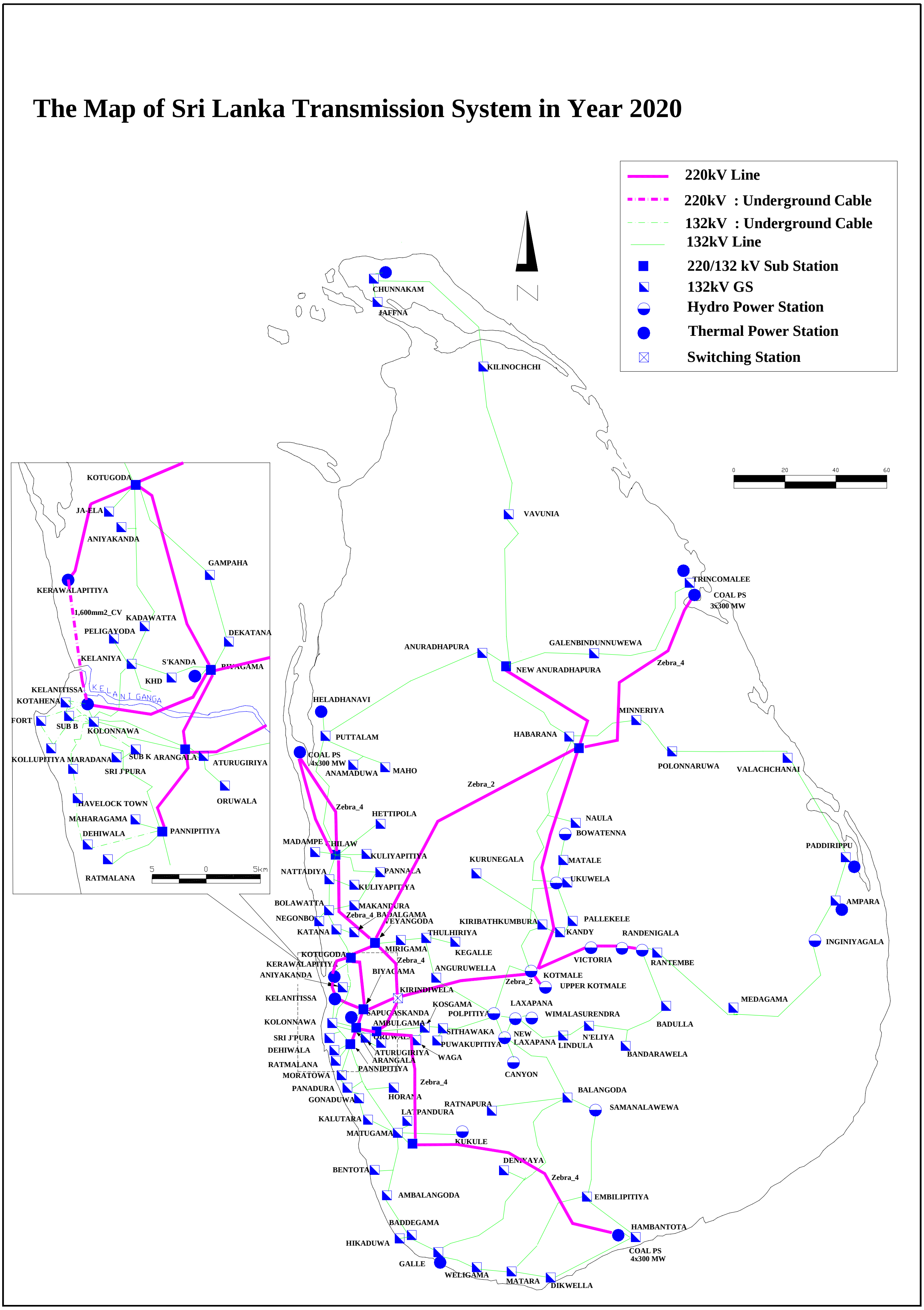
The Map of Sri Lanka Transmission System in Year 2010



The Map of Sri Lanka Transmission System in Year 2015



The Map of Sri Lanka Transmission System in Year 2020



The Map of Sri Lanka Transmission System in Year 2025