CEYLON ELECTRICITY BOARD

LONG TERM GENERATION EXPANSION PLAN 2015-2034

Transmission and Generation Planning Branch
Transmission Division
Ceylon Electricity Board
Sri Lanka
July 2015

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Long Term Generation Expansion Planning Studies
2015- 2034

Compiled and prepared by
The Generation Planning Unit
Transmission and Generation Planning Branch
Ceylon Electricity Board, Sri Lanka

Long-term generation expansion planning studies are carried out every two years by the Transmission & Generation Planning Branch of the Ceylon Electricity Board, Sri Lanka and this report is a bi-annual publication based on the results of the latest expansion planning studies. The data used in this study and the results of the study, which are published in this report, are intended purely for this purpose.

Price Rs. 3000.00

Foreword

The 'Report on Long Term Generation Expansion Planning Studies 2015-2034', presents the results of the latest expansion planning studies conducted by the Transmission and Generation Planning Branch of the Ceylon Electricity Board for the planning period 2015-2034, and replaces the last of these reports prepared in April 2014.

This report, gives a comprehensive view of the existing generating system, future electricity demand and future power generation options in addition to the expansion study results.

The latest available data were used in the study. The Planning Team wishes to express their gratitude to all those who have assisted in preparing the report. We would welcome suggestions, comments and criticism for the improvement of this publication.

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ACRONYMS

ADB	-	Asian Development Bank
bcf	-	Billion Cubic Feet
BOO	-	Build, Own and Operate
CCY	-	Combined Cycle Power Plant
CEA	-	Central Environmental Authority
CEB	-	Ceylon Electricity Board
CECB	-	Central Engineering Consultancy Bureau
CIDA	-	Canadian International Development Agency
CIF	-	Cost, Insurance and Freight
CPC	-	Ceylon Petroleum Corporation
CDM	-	Clean Development Mechanism
CER	-	Certified Emission Reduction
DSM	-	Demand Side Management
EIA	-	Environmental Impact Assessment
ENPEP	-	Energy and Power Evaluation Package
ENS	-	Energy Not Served
EOI	-	Expression Of Interest
ESP	-	Electrostatic Precipitator
EWE	-	Electrowatt Engineering
FGD	-	Flue Gas Desulphurization
FOR	-	Forced Outage Rate
GDP	-	Gross Domestic Product
GHG	-	Green House Gases
GIS	-	Geographic Information System
GT	-	Gas Turbine
HHV	-	Higher Heating Value
IAEA	-	International Atomic Energy Agency
IDC	-	Interest During Construction
IEA	-	International Energy Agency
IPCC	-	Inter-Governmental Panel on Climate Change
IPP	-	Independent Power Producer
ITDG	-	Intermediate Technology Development Group
JBIC	-	Japan Bank for International Cooperation
JICA	-	Japan International Cooperation Agency
LKR	-	Sri Lanka Rupees
KPS	-	Kelanatissa Power Station
LDC	-	Load Duration Curve
LF	-	Load Factor
LNG	-	Liquefied Natural Gas
LOLP	-	Loss Of Load Probability
LTGEP	-	Long Term Generation Expansion Plan
OECF	-	Overseas Economic Co-operation Fund
O&M	-	Operation and Maintenance

OTEC	-	Ocean Thermal Energy Conversion
mscfd	-	Million Standard Cubic Feet per Day
MMBTU	-	Million British Thermal Units
MTPA	-	Million Tons Per Annum
NCRE	-	Non Conventional Renewable Energy
NG	-	Natural Gas
PF	-	Plant Factor
PM	-	Particulate Matter
PPA	-	Power Purchase Agreement
PV	-	Present Value
RFP	-	Request For Proposals
SDDP	-	Stochastic Dual Dynamic Programming
SYSIM	-	SYstem SImulation Model
USAID	-	United States Agency for International Development
US$	-	American Dollars
WASP	-	Wien Automatic System Planning Package
WB	-	World Bank
WHO	-	World Health Organization

EXECUTIVE SUMMARY

The Ceylon Electricity Board (CEB) is under a statutory duty to develop and maintain an efficient, coordinated and economical system of Electricity Supply for the whole of Sri Lanka. Therefore, CEB is required to generate or acquire sufficient amount of electricity to satisfy the demand. CEB methodically plans its development activities in order to provide reliable, quality electricity to the entire nation at affordable prices.

This report presents the Generation Expansion Planning Studies carried out by the Transmission and Generation Planning Branch of the Ceylon Electricity Board for the period 2015-2034. The Report also includes information on the existing generation system, generation planning methodology, system demand forecast and investment and implementation plans for the proposed projects and recommends the adoption of the least cost plant sequence derived for the base case and also emphasizes the need to implement the plan to avoid energy shortfalls. The Load Forecast used is given in Table E.1.

The methodology adopted in the studies optimally selects plant additions from given thermal as well as hydropower generation expansion candidates, which will, together with existing and committed power plants meet the forecast electricity demand with a given level of reliability complying with National Energy Policy & Strategies (2008).

The Policy analyses have been carried out to facilitate identification of Energy Mix & Fuel Diversification Policies and Climate Change Mitigation Actions. Possible electricity demand growth variations, the impact on variation in discount rate and fuel price have been considered in the sensitivity studies. Each plant sequence presented in this report is the least cost plant sequence for the given scenario.

During the year 2014, 24MW Uthuru Janani Power Plant, 1x300MW of Puttalam Coal fired Power Plant (Stage - II) and 1x 300MW of Puttalam Coal fired Power Plant (Stage - III) were commissioned.

The candidate thermal power plant options considered in the study were 600MW Super critical and 300MW high efficient sub critical coal-fired steam plants, 300MW LNG fired combined cycle plants, 600MW Nuclear power plants, 35MW & 105MW Diesel-fired Gas Turbines and 150MW & 300MW Combined Cycle Plants.

35MW Broadlands (2017), 120MW Uma Oya (2017) and 31MW Morogolla (2020) were considered as committed Hydro Power Projects. The commissioning schedules of the hydro projects given by the respective Project were used in the preparation of the Long Term Generation Expansion Plan. The proposed hydro power plants, 15MW Thalpitigala by year 2020 and 20MW Gin Ganga by year 2022 were considered as candidate plants considering the Cabinet approvals secured by the Ministry of the Irrigation. The proposed 20MW Seethawaka Ganga will be developed by Ceylon Electricity Board by year 2022.

The earliest possible date of commissioning of 2x250MW Coal Plants by Trincomalee Power Company Limited was taken as year 2020 considering the present progress of the project. The other candidate coal-fired power plants were considered from year 2022 based on the progress of the feasibility studies. The earliest possible dates for commissioning of gas turbine and combined cycle plant were taken as 2018 and 2019 respectively.

In the Base Case Plan, the contribution from NCRE too was considered and the different NCRE technologies were modeled appropriately. The energy contribution from NCRE plants were maintained above 20% from 2020 onwards complying with the Government Policies. Capacity contribution from Biomass, Wind and Solar plants were taken in to the consideration and delays in implementation would cause significant impact in capacity and energy balances.

The first 100MW Semi dispatchable wind farm by 2018 at Mannar will be developed by Ceylon Electricity Board and the remaining 275 MW Mannar wind farm will be developed in two phases. The main objective of the development of the wind farm by Ceylon Electricity Board is to pass the economic benefit of the indigenous resource to all the electricity users in the Country.

The viability of introducing LNG fired power plants was also studied. The LNG fuel option was considered with terminal cost and without terminal cost for the present LNG fuel prices to determine the breakeven price for LNG. LNG fuel option with a LNG terminal is not economically competitive with the other fuel options.

Due consideration was given to the availability of natural gas in the Mannar Basin and utilization of the natural gas as a fuel option for the power sector. Separate scenarios were studied introducing indigenous Natural Gas in Mannar Basin by year 2020 to determine the quantity requirement and appropriate price. However, due to the following reasons, the scenario was not recommended as the Base Case Plan 2015-2034 though the present value of the scenario is lower than the recommended Base Case:

- Discovery of the natural gas resources is still at very early stages.
- Gas quantities are not quantified with reasonable accuracy.

- Gas price delivered to the plants is very much indicative. The price of gas is considered as 15.5USD/MMBTU (10.5USD/MMBTU without Royalty, Profit and Tax) at the well and additional 1 USD/MMBTU was added as the delivery cost.
- Conversion costs of the existing plants are indicative and actual costs may vary.
- Costs of additional storages and infrastructure to be developed for the existing power plants were not considered.

It was considered that 60MW Barge Mounted Power Plant will be operated by CEB after acquiring the plant at the end of the Power Purchase Agreement on 30th June 2015. 100MW Ace Embilipitiya Plant was retired from April 2015,according to the Power Purchase Agreement. It was also considered that 163MW AES Kelanitissa Power Plant would be operated by CEB after acquiring the plant at the end of the Power Purchase Agreement in 2023. All the other IPP Plants were retired as the contract agreements expire.

Base Case Plan is given in the Table E.2 and also in the Table 7.1 of the Long Term Generation Expansion Plan. The Capacity Balance, Energy Balance and Dispatch Schedule are given in Annex: 7.2, Annex: 7.3 and Annex: 7.4 respectively.

Table E.1 - Base Load Forecast : 2015-2039

Year	Demand		*Net Losses	Generation		Peak
	(GWh)	Growth Rate (%)	(%)	(GWh)	Growth Rate (%)	(MW)
2015	11516	4.1%	10.73	12901**	4.5%	2401
2016	12015	4.3%	10.68	13451**	4.3%	2483
2017	12842	6.9%	10.62	14368	6.8%	2631
2018	13726	6.9%	10.57	15348	6.8%	2788
2019	14671	6.9%	10.51	16394	6.8%	2954
2020	15681	6.9%	10.46	17512	6.8%	3131
2021	16465	5.0%	10.40	18376	4.9%	3259
2022	17288	5.0%	10.35	19283	4.9%	3394
2023	18155	5.0%	10.29	20238	5.0%	3534
2024	19069	5.0%	10.23	21243	5.0%	3681
2025	20033	5.1%	10.18	22303	5.0%	3836
2026	21050	5.1%	10.12	23421	5.0%	4014
2027	22125	5.1%	10.07	24601	5.0%	4203
2028	23243	5.1%	10.01	25829	5.0%	4398
2029	24402	5.0%	9.96	27100	4.9%	4599
2030	25598	4.9%	9.90	28410	4.8%	4805
2031	26827	4.8%	9.84	29756	4.7%	5018
2032	28087	4.7%	9.79	31135	4.6%	5235
2033	29395	4.7%	9.73	32565	4.6%	5459
2034	30759	4.6%	9.68	34055	4.6%	5692
2035	32184	4.6%	9.62	35611	4.6%	5934
2036	33673	4.6%	9.57	37235	4.6%	6187
2037	35231	4.6%	9.51	38934	4.6%	6451
2038	36862	4.6%	9.46	40711	4.6%	6726
2039	38569	4.6%	9.40	42571	4.6%	7013
5 Year Average Growth	6.24%			6.17%		5.32%
10 Year Average Growth	5.76%			5.70%		4.86%
20 Year Average Growth	5.31%			5.24%		4.65%
25 Year Average Growth	5.17%			5.10%		4.57%

***** Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded.

**Generation fixed for Energy Marketing Branch Energy Demand Forecast 2015-2016, prepared based on values provided by each Distribution Divisions.

Table E.2 Results of Generation Expansion Planning Studies – Base Case Plan 2015-2034

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.175
2018	**100 MW Mannar Wind Park Phase I**	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.299
2019*	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.140
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100 MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.164
2021	**50 MW Mannar Wind Park Phase II**	-	-	0.360
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**2x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.015
2023	**25 MW Mannar Wind Park Phase III**	*163 MW Combined Cycle Plant (KPS – 2)*+	163 MW AES Kelanitissa Combined Cycle Plant++ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.096
2024	**25 MW Mannar Wind Park Phase III**	**1x300 MW New Coal plant – Southern Region**	-	0.040
2025	**1x200 MW PSPP***** **25 MW Mannar Wind Park Phase III**	-	4x9 MW Sapugaskanda Diesel Ext.	0.028
2026	**2x200 MW PSPP*****	-	-	0.003
2027	-	**1x300 MW New Coal plant – Southern Region**	-	0.002
2028	-	-	-	0.010
2029	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.007
2030	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.005
2031	-	-	-	0.029
2032	-	**2x300 MW New Coal plant – Southern Region**	-	0.003
2033	-	-	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS – 2)	0.142
2034	-	**1x300 MW New Coal plant – Southern Region**	-	0.118
Total PV Cost up to year 2034, **US$ 12,960.51 million** [LKR 1,704.96 billion]+				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.

\+ PV cost includes the cost of Projected Committed NCRE, **US$ 1527.9 million** based on economic cost, and an additional Spinning Reserve requirement is kept considering the intermittency of NCRE plants with a cost of **US$ 471.5 million**.

***** In year 2019, minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2025 and 2026 respectively.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

With regard to the energy, it is apparent that coal will be the major source of power during the study period with its share reaching 40% by 2020 and 60% by 2034. However, the contribution from renewable energy power plants too will be considerable with a share of more than 40% by 2025 and 35% by 2034.

It is observed that, emission of local pollutants such as SO_X and NO_X will come down with the decrease of oil fired generation, however per unit emission of CO_2 would increase the value 0.65kg/kWh. Due to the introduction of high efficient coal plants and high integration of NCRE, the rate of increase of CO_2 emissions gradually decreases. The total CO_2 emission from the electricity sector even in year 2034 would be around 21Million tons and both total CO_2 emission and per capita CO_2 emission would be comparatively low.

In the short term context up to year 2020, it is observed that there might be difficulty in operating the system resourcefully due to the foreseen delays in implementation of Uma Oya and Broadlands hydro power projects. Requirement of the 3 x35MW Gas turbines arose mainly due to the retirement of 210MW of thermal plants in years 2018 & 2019 and to meet the electricity demand by maintaining the planning criteria such as LOLP and reserve margin of the generation system. However, it is observed that reserve margin in year 2019 is below 2.5% minimum specified in the Grid Code. Reserve Margin violation situations were experienced previously and the demand was met with difficulty. Therefore, short-term developments such as demand growth, generator availability and hydrology have to be monitored closely.

In the long term, it is important that coal plant development programme is implemented in accordance with the Base Case Plan. Therefore, timely implementation of the coal plants in the pipe line is important and delaying these plants any further would affect the economic development of the Country.

The introduction of 3x200MW Pump Storage Power Plant (PSPP) is important with the development of coal power as well as with the prominent peak and off-peak characteristics of the daily demand pattern. The implementation of 3 x 200 MW Pump Storage Power Plant will reduce the off-peak coal power operational issues and improve the efficiency of the coal power plants. Also, PSPP will enhance the NCRE absorption capability to the system and reduce the curtailment of NCRE power generation. However, it should be emphasized that PSPP development should be considered after minimum of 2500MW of coal base generation plants are committed. The introduction of the PSPP is not economically justifiable in to the system, solely to overcome the curtailments due to higher integration of NCRE.

Scenarios were carried out restricting the implementation of coal power plants to determine the cost impact with Base Case Plan. In first scenario, coal power development was restricted to 50% of the total generation throughout the study period. LNG and Nuclear plants were forced to bridge the gap. The second scenario, coal plants were not allowed after year 2027 and LNG power plants were selected to bridge the gap.

The total investment required for implementing the Base Case Plan 2015-2034 in the next 20 years is approximately USD 12.96 Billion without considering the projects for which funds have already been committed.

It is imperative that the power plants are implemented as scheduled in Base Case 2015-2034.

<u>Immediate Actions to be taken:</u>

(i) Commissioning of 120MW Uma Oya and 35 MW Broadlands by year 2018.

Expected annual energy generation of Uma Oya and Broadlands hydro power projects are 231GWh and 126GWh respectively. Both plants will also serve as low cost peaking plants in the future and no other new power plants will be available in the system until year 2020.

(ii) Commissioning of 100MW Wind farm by years 2018 & 2021.

100MW wind farm is expected to generate approximately 320 GWh annually and wind farm will be one of the major energy contributors to the system from year 2018 onwards.

(iii) 3 x 35MW of Gas Turbines by year 2019

In a total power failure situation, immediate restoration of Colombo power could only be possible using power plants of this kind having black start capabilities. Further, this plant will have the capability of operating in the sync-con mode to provide reactive power to improve voltage levels. Power plant would operate to provide peak power as well depending on the availability hydro power for peak power generation. It is important to note that this Power plant will have very low plant factor. Currently 5x17MW frame V gas turbines are used for the above purposes, and they are scheduled to retire by 2018.

(iv) 2 x250MW Coal Power Plant by TPCL must be available by year 2020.

Any further implementation delay of the plants would cause major capacity shortage and lead to a severe power crisis from year 2020 onwards.

(v) 2 x300MW New Trincomalee Coal Power Plants must be available by year 2022

Implementations of the power plants need to be expedited to commission the power plant on schedule.

The Summary of Case Studies and Cost Determine Analyses during the preparation of the Long Term Generation Expansion Plan 2015-2034 are given in Table E.3 and E.4.

Table E.3 - Summary of Case Study Analyses

No.	Study Option	Total Cost (mn US$)	Remarks
1	Base Case	12,960.51	20% Energy from NCRE considered from 2020 onwards. 3x200MW PSPP introduced in 2025 after committing 2600MW Coal Power generation.
2.	Reference Case	12,892.07	Only existing NCRE plants as at 1st January 2015 were included.
3.	High Demand Case	15,049.49	Demand forecast considering 1% high GDP growth with base population growth. Average Demand Growth 5.7%.
4.	Low Demand Case	10,906.67	Demand forecast considering GDP growth reduction of 2.5% (2014-2017) and 1.5% (2018 onwards) with base population growth and growth in Service sector share from 59% to 61% in total GDP reducing the Industrial sector. Average Demand Growth 3.8%
5.	Demand Side Management Case	10,759.16	Scenario was derived considering the estimation of energy savings and implementation cost provided by Sri Lanka Sustainable Energy Authority (SLSEA). Average Demand Growth 4.3 %
6.	High Discount Case (15%)	9,752.75	
7.	Low Discount Case (3%)	21,452.70	
8.	Coal price High (50%), Oil and LNG Base Price Case	14,243.43	LNG was not selected as least cost option.
9.	Coal and Oil price 50% High, LNG Base Price Case	16,506.34	LNG was not selected as least cost option.
10.	Fuel Price Escalation Case	14,080.72	LNG was not selected as least cost option.
11.	No additional coal plants permitted after 2600 MW of Coal Case	12,965.01	No additional coal plants were permitted as candidate plants after develop 2600 MW of Coal plants.
12.	Energy Mix with Nuclear Case	13,034.16	Energy mix diversified in to LNG and nuclear fuel options. Coal plant development limited to around 50% of energy share.
13.	Natural Gas Average Penetration Case	11,891.84	To optimize the use of estimated 300bcf of Natural Gas quantity in Mannar basin conversion of existing combined cycle plants and the development of a new plant was considered after 2020 NG energy share (approximately) is 7% initially reaching a peak of 19% in 2027 and gradually reducing to 12% over the planning period
14.	Natural Gas High Penetration Case	11,902.65	Considering further potential of NG in Mannar basin approximately 50% energy share was maintained through indigenous resources (NG, NCRE, Hydro)
15.	HVDC Interconnection Case	12,760.51	1x500 MW HVDC connection was selected in year 2025. HVDC Interconnection costs are based on draft final report of “Supplementary Studies for the Feasibility Study on India-Sri Lanka Grid Interconnection Project, November 2011”.

Table E.4 – Cost Determine Analyses

No.	Analysis	Remarks
1.	Natural Gas fuel Breakeven price considering NG availability from year 2021 in Mannar Basin	Breakeven NG price is 8.7 $/MMBTU
2.	LNG fuel option with full terminal cost	Breakeven LNG price including ¼ terminal cost is 5.9 $/MMBTU
3.	Social Damage Cost applied to variable cost of coal	No major difference could be observed from the Base Case capacity additions for Social Damage cost of 0.1€-cent/kWh. Coal plants were delayed for 2€-cent/kWh. All coal plants were replaced by LNG combined cycle power plants for 4.8€-cent/kWh.

CHAPTER 1
INTRODUCTION

1.1 Background

The Electricity sector in Sri Lanka is governed by the Sri Lanka Electricity Act, No. 20 of 2009 amended by Act No. 31 of 2013. Ceylon Electricity Board (CEB) , established by an CEB Act No. 17 of 1969 (as amended), is under legal obligation to develop and maintain an efficient, coordinated and economical system of Electricity supply in accordance with any Licenses issued. CEB is responsible for most of the generation and distribution licenses while being sole licensee for transmission. CEB has been issued a generation license, a transmission license and four distribution licenses. Lanka Electricity Company (LECO), a subsidiary of CEB is the other distribution licensee and there are several Independent Power Producers, whose production is also purchased by CEB. The Public Utilities Commission of Sri Lanka (PUCSL) is the regulator of the sector and was established by the PUCSL Act No. 35 of 2002 and empowered by the Electricity Act. The Sri Lankan power system has a total dispatchable installed capacity of approximately 3500MW by end of year 2014. The maximum demand recorded in 2014 was 2152MW.

Generation expansion planning is a part of the process of achieving the above objectives. In order to meet the increasing demand for electrical energy and to replace the thermal plants due for retirement, new generating stations need to be installed as and when necessary. The planning studies presented in this report are based on the Annual Report 2013 of Central Bank of Sri Lanka and electricity sector data up to 2013. The information presented has been updated to December 2014 unless otherwise stated.

The generating system has to be planned taking into consideration the electricity demand growth, generation technologies, environmental considerations and financial requirements. It is necessary to evaluate each type of candidate generating plant, both thermal and hydro and select the optimum plant mix schedule in the best interest of the country.

1.2 The Economy

In the last five years (2009-2013), the real GDP growth in the Sri Lanka economy has varied from -3.5% in 2009 to 7.2% in 2013. In 2014, Sri Lanka has achieved a growth rate of 7.4%. Details of some demographic and economic indicators are given in Table 1.1.

Table 1.1- Demographic and Economic Indicators of Sri Lanka

	Units	2008	2009	2010	2011	2012	2013	2014
Mid-Year Population	Millions	20.22	20.48	20.68	20.87	20.33	20.48	20.68
Population Growth Rate	%	1.1	1.1	1.0	1.0	0.9	0.8	0.9
GDP Real Growth Rate	%	6	3.5	8	8.2	6.3	7.2	7.4
GDP /Capita (Market prices)	US$	2,011	2,054	2,397	2,836	2,922	3,280	3625
Exchange Rate (Avg.)	LKR/US$	108.33	114.94	113.06	110.57	127.6	129.1	130.56
GDP Constant 2002 Prices	Mill LKR	2,365,501	2,449,214	2,645,542	2,863,691	3,045,288	3,266,041	3,506,664

Source: Annual Report 2014, Central Bank of Sri Lanka

1.2.1 Electricity and Economy

Electricity demand growth rate in the past has most of the times revealed a direct correlation with the growth rate of the country's economy. However, the elasticity of consumption of electricity with respect to GDP is less significant in the recent past. Figure 1.1 shows growth rates of electricity demand and GDP from 1994 to 2014.

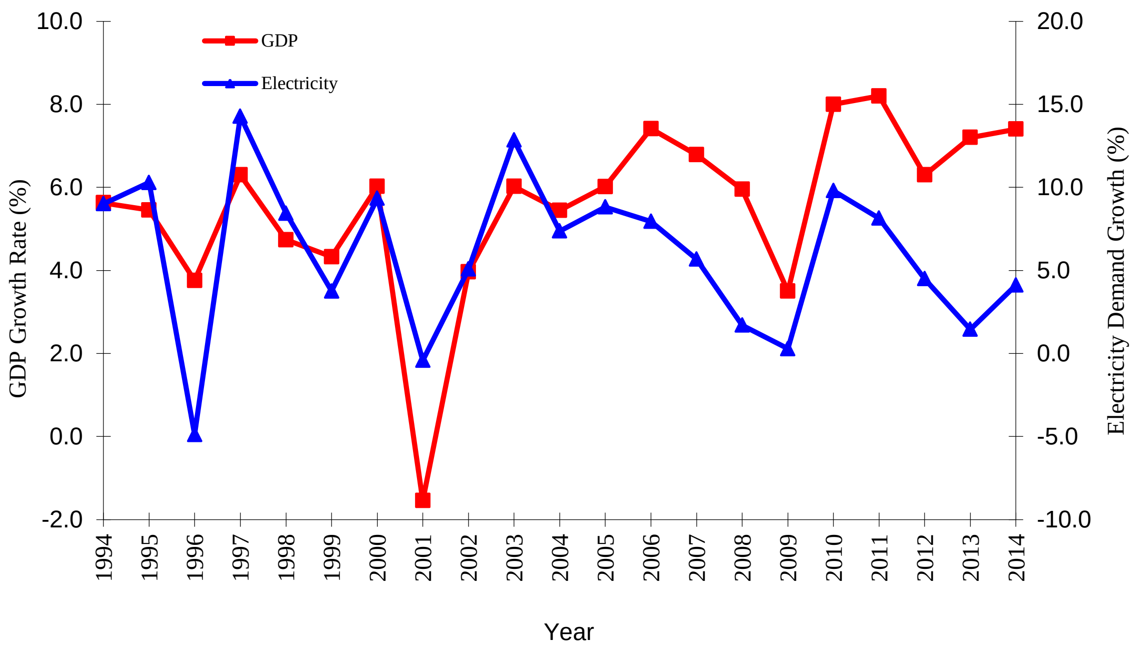


Figure 1.1 - Growth Rates of GDP and Electricity Sales

1.2.2 Economic Projections

The Central Bank of Sri Lanka expects 8% average GDP growth rate in real terms in the four years from 2015 to 2018. The Central Bank GDP growth rate forecast is depicted in Table 1.2.

Table 1.2 - Forecast of GDP Growth Rate in Real Terms

Year	*2014*	*2015*	*2016*	*2017*	*2018*
2013 Forecast	7.8	8.2	8.3	8.4	
2014 Forecast		7.0	7.5	8.0	8.0

Source: Annual Reports 2013 & 2014, Central Bank of Sri Lanka

1.3 Energy Supply and Demand

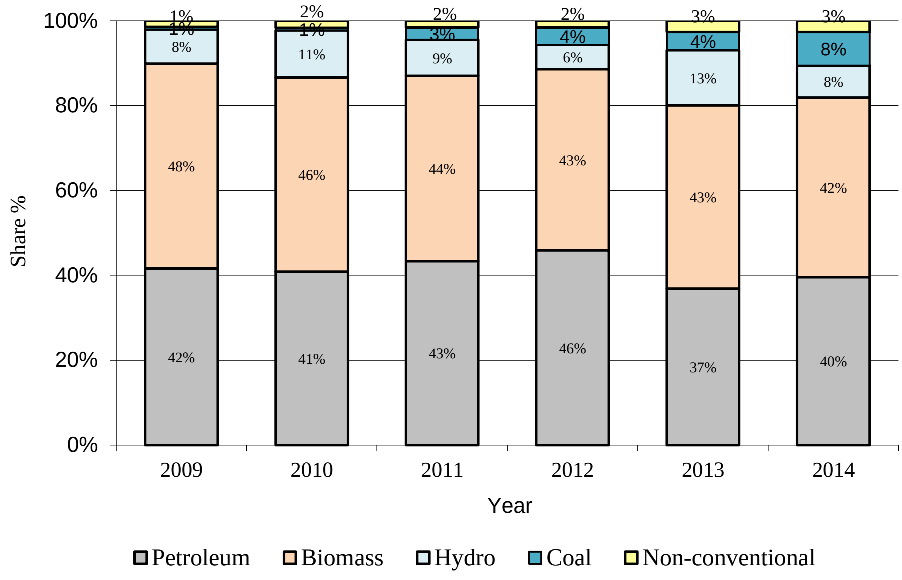
1.3.1 Energy Supply

Biomass or fuel wood, petroleum and hydro are the major primary energy supply sources, which cater the Sri Lanka energy demand with a per-capita consumption of about 0.4 tons of oil equivalent (TOE). Biomass or fuel wood, which is mainly a non-commercial fuel, at present provides approximately 45 percent of the country's total energy requirement. Petroleum turns out to be the major source of commercial energy, which covers about 40 percent of the energy demand.

Although electricity and petroleum products are the major forms of commercial energy, an increasing amount of biomass is also commercially grown and traded. Hydropower which covers 8% of the total primary energy supply is the main indigenous source of primary commercial energy in Sri Lanka. Estimated potential of hydro resource is about 2000MW, of which more than half has already been harnessed. Further exploitation of hydro resources is becoming increasingly difficult owing to social and/or environmental impacts associated with large-scale development. Apart from these, there is a considerable potential for wind power development. The first commercial wind power plants were established in 2010 and the total capacity of wind power plants by end of 2014 is 124MW. 100MW wind farm at Mannar Island is at the initial development stage and steps have been initiated to harness the wind potential in Sri Lanka in optimum and economical manner. A small quantity of Peat has been located in the extent of marshy lands to the North of Colombo. However, the master plan study, 1989 [4] has indicated that the quality and extent of the reserve would not prove to be commercially viable for extraction and use as a source in power generation.

As at present, the total fossil fuel requirement of the country is imported either as crude oil or as refined products and used for transport, power generation, industry and other applications. Apart from this, initiatives have been launched in towards oil exploration with the prime intention of harnessing potential petroleum resources in the Mannar Basin. Exploration license has been awarded to explore for oil and natural gas in the Mannar Basin off the north-west coast and drilling of the test wells has been carried out. At present, natural gas has been discovered in Mannar basin (off shore from Kalpitiya Pennisula) with a potential of 70 mscfd. Discoverable gas amount of this reserve is estimated approximately 300 bcf.

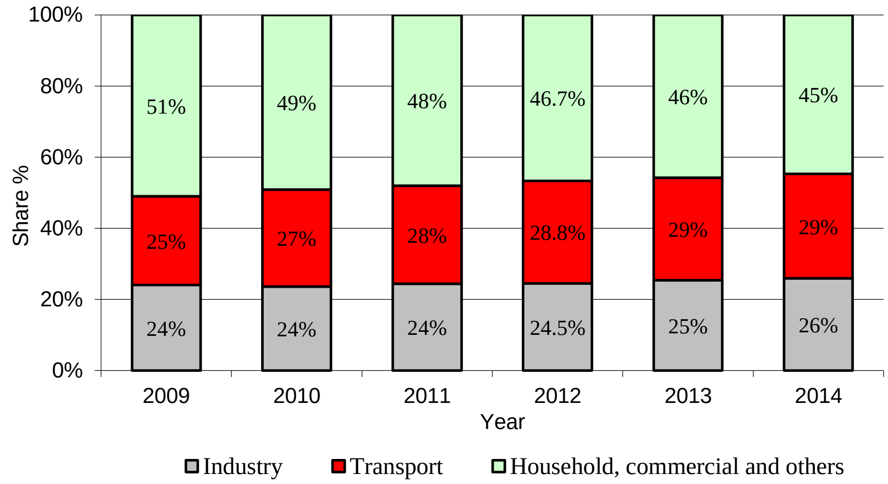
In 2014 the primary energy supply consisted of Biomass (4911 ktoe), Petroleum (4595 ktoe), Coal (921 ktoe), Hydro (876 ktoe) and non-conventional renewable sources (297 ktoe). The share of these in the gross primary energy supply from 2009 to 2014 is shown in Figure 1.2. Hydro electricity is adjusted to reflect the energy input required in a thermal plant to produce the equivalent amount of electricity.



Source: Sri Lanka Sustainable Energy Authority

Figure 1.2 - Share of Gross Primary Energy Supply by Source

1.3.2 Energy Demand



Source: Sri Lanka Sustainable Energy Authority

Figure 1.3 - Gross Energy Consumption by Sectors including Non-Commercial Sources

Sectorial energy consumption trend from 2009 to 2014 is shown in Figure 1.3. According to the above chart, household and commercial sector appears to be the largest sector in terms of energy consumption when all the traditional sources of energy are taken into account. Further, it shows a decreasing trend while transport sector shows an increasing trend.

The consumption for 2014 is made up of biomass (4884 ktoe), petroleum (3247 ktoe), coal (62 ktoe) and electricity (951 ktoe). Due to poor conversion efficiency of biomass, the composition of the net (or useful) energy consumption in the domestic sector could be different from the above. On the other hand, being the cheapest and most easily accessible source of energy, fuel wood still dominates the domestic sector consumption. Even though it is traded in urban and suburban areas fuel wood is still classified as a non-commercial form of energy.

1.4 Electricity Sector

1.4.1 Access to Electricity

By the end of December, 2014, approximately 98% of the total population had access to electricity from the national electricity grid. When the planned electrification schemes are implemented it is expected that this will increase further. Figure 1.4 shows the percentage level of electrification district wise as at end of 2014.

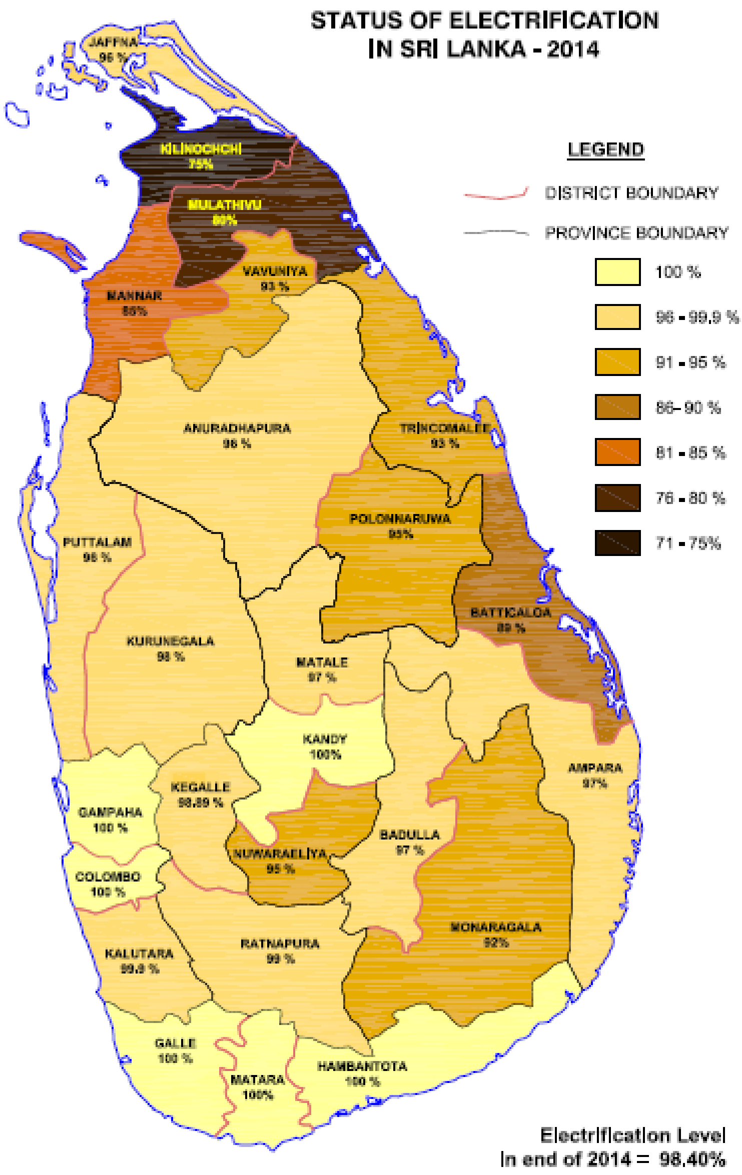


Figure 1.4 - Level of Electrification

1.4.2 Electricity Consumption

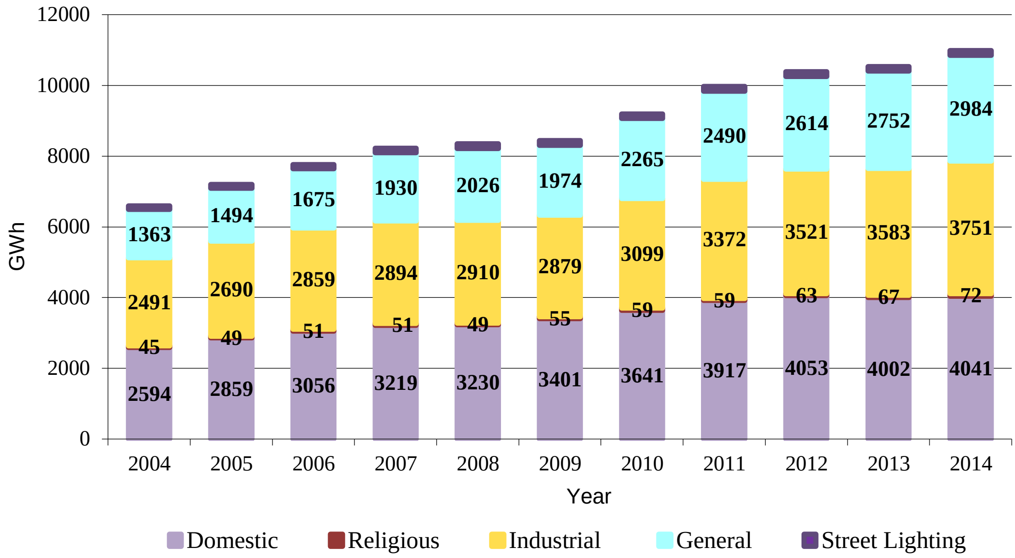


Figure 1.5 - Sectorial Consumption of Electricity (2004 - 2014)

The amount of energy consumed by each sector (i.e. each tariff category) from 2004 to 2014 is shown in Figure 1.5 while Figure 1.6 depicts sectorial electricity consumption share in 2014. These Figures reveal that the industrial and commercial (general purpose, hotel, government) sectors' consumption together is more than the consumption in the domestic sector. This is a pleasing situation for an economy with ambitious GDP growth projections.

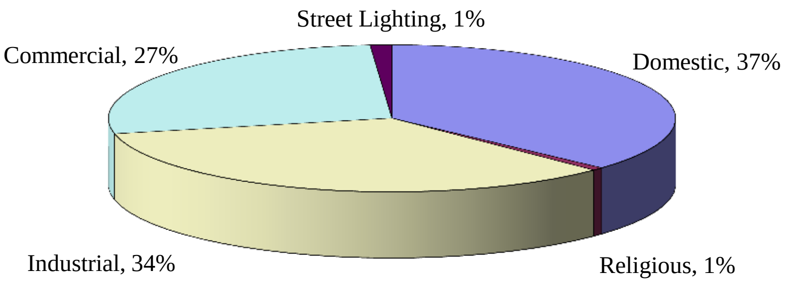


Figure 1.6 - Sectorial Consumption of Electricity (2014)

The average per capita electricity consumption in 2013 and 2014 were 519kWh per person and 535 kWh per person respectively. Generally it has been rising steadily; however in the period 2007 – 2009 with the slowing down of the electricity growth, the per capita consumption has stagnated. A similar trend is observed during 2012 to 2013. Figure 1.7 illustrates the trend of per capita electricity consumption from 2004 to 2014.

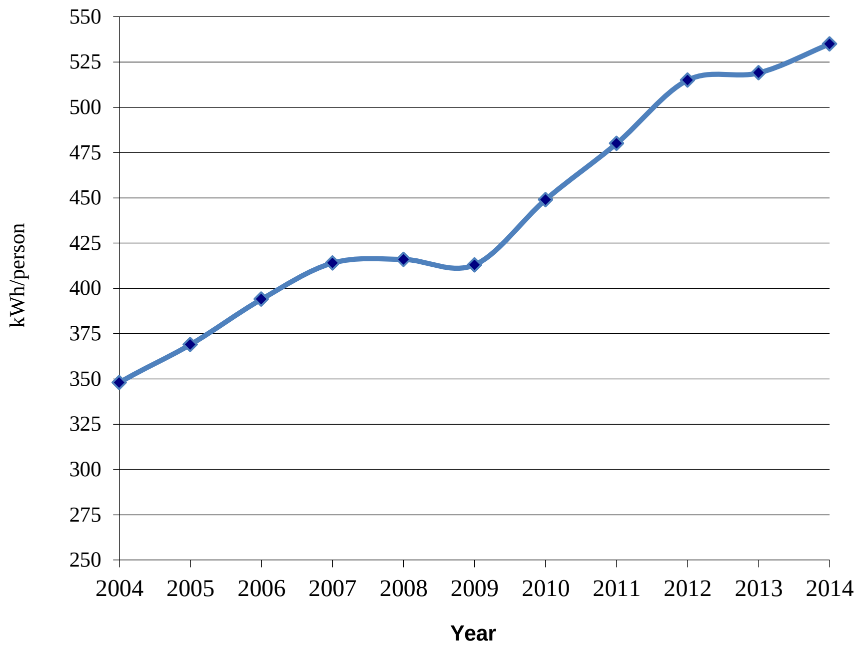


Figure 1.7 – Per Capita Electricity Consumption (2004-2014)

1.4.3 Capacity and Demand

Sri Lanka electricity requirement was growing at an average annual rate of around 6% during the past 20 years, and this trend is expected to continue in the foreseeable future. The total installed capacity including NCRE and peak demand over the last twenty years are given in the Table 1.3 and graphically shown in Figure 1.8.

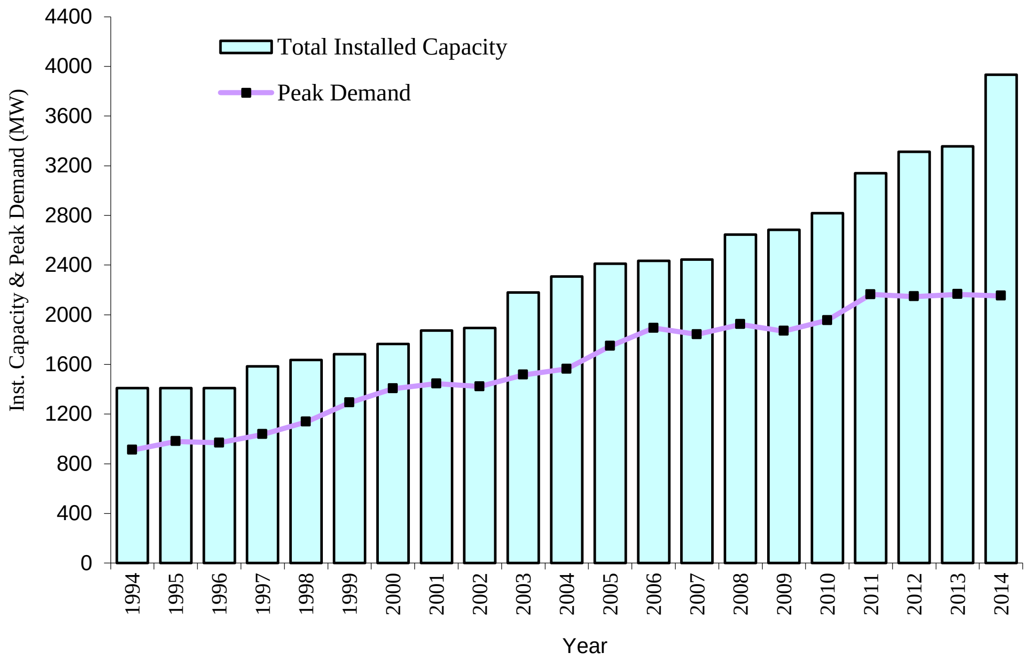


Figure1.8 – Total Installed Capacity and Peak Demand

Table 1.3 - Installed Capacity and Peak Demand

Year	Installed Capacity	Capacity Growth	Peak Demand	Peak Demand Growth
	MW	(%)	MW	(%)
1994	1409	0%	910	12%
1995	1409	0%	980	8%
1996	1409	0%	968	-1%
1997	1585	12%	1037	7%
1998	1636	3%	1137	10%
1999	1682	3%	1291	14%
2000	1764	5%	1404	9%
2001	1874	6%	1445	3%
2002	1893	1%	1422	-2%
2003	2180	15%	1516	7%
2004	2280	5%	1563	3%
2005	2411	6%	1748	12%
2006	2434	1%	1893	8%
2007	2444	0.4%	1842	-2.7%
2008	2645	8%	1922	4%
2009	2684	1%	1868	-3%
2010	2818	5%	1955	5%
2011	3141	11%	2163	11%
2012	3312	5%	2146	-1%
2013	3355	1%	2164	1%
2014	3932	17%	2152	-1%
Last 5 year avg. growth		8.68%		2.43%
Last 10 year avg. growth		5.58%		2.34%
Last 20 year avg. growth		5.55%		4.23%

1.4.4 Generation

In early stages the electricity demand of the country was mainly supplied by hydro generation and the contribution from thermal generation was minimal. With the time, thermal generation has become prominent. At present, thermal generation share is much higher than that of hydro. Electricity Generation during the last twenty years is summarized in Table 1.4 and graphically shown in Figure 1.9.

Table 1.4 - Electricity Generation 1990-2014

Year	Hydro Generation			Thermal Generation		Self-Generation		Total
	GWh		%	GWh	%	GWh	%	GWh
1990	3145		99.8	5	0.2	0	0.0	3150
1991	3116	-0.93%	92.3	260	7.7	0	0.0	3376
1992	2900	-7.45%	81.9	640	18.1	0	0.0	3540
1993	3796	23.60%	95.4	183	4.6	0	0.0	3979
1994	4089	7.17%	93.2	275	6.3	22	0.5	4386
1995	4514	9.42%	94.0	269	5.6	17	0.4	4800
1996	3249	-38.94%	71.8	1126	24.9	152	3.4	4527
1997	3448	5.77%	67.0	1463	28.4	235	4.6	5146
1998	3915	11.93%	68.9	1654	29.1	114	2.0	5683
1999	4175	6.23%	67.6	1901	30.8	97	1.6	6173
2000	3197	-30.59%	46.7	3486	51.0	158	2.3	6841
2001	3113	-2.70%	47.0	3407	51.4	105	1.6	6625
2002	2696	-15.47%	38.8	4114	59.2	136	2.0	6946
2003	3314	18.65%	43.5	4298	56.5	0	0.0	7612
2004	2964	-11.81%	36.3	5080	62.3	115	1.4	8159
2005	3455	14.21%	39.4	5314	60.6	0	0.0	8769
2006	4638	25.51%	49.4	4751	50.6	0	0.0	9385
2007	3950	-17.42%	40.3	5864	59.8	0	0.0	9811
2008	4138	4.54%	41.8	5763	58.3	0	0.0	9893
2009	3908	-5.89%	39.7	5975	60.6	0	0.0	9856
2010	5720	31.68%	53.8	4994	47.0	0	0.0	10628
2011	4743	-20.60%	41.1	6785	58.9	2.9	0.03	11528
2012	3463	-36.96%	29.3	8339	70.7	1.4	0.01	11801
2013	7182	51.78%	60.1	4773	39.9	0	0.0	11962
2014	4862	-47.72%	39.2	7556	60.8	0	0.0	12418
Last 5 year av. Growth		-3.98%		10.91%				3.97%
Last 10 year av. Growth		3.87%		3.99%				3.94%

* Note: Wind & small hydro generation is included in Hydro Generation Figure

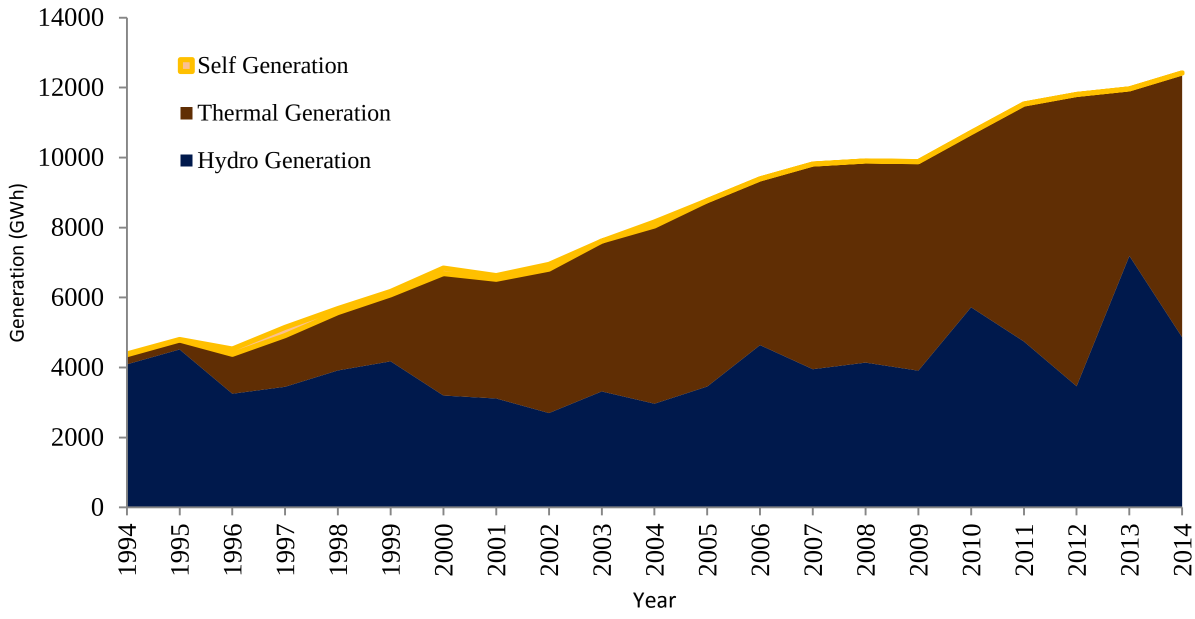


Figure 1.9 - Hydro Thermal Share in the Recent Past

1.5 Planning Process

CEB is under a statutory duty to develop and maintain an efficient, co-coordinated and economical system of electricity supply for the whole of Sri Lanka. In order to fulfill the above duty, CEB revises the Long Term Generation Expansion Plan (LTGEP) once in two years. Intensive studies are conducted by the Transmission and Generation Planning Branch of the CEB in order to prepare this plan. A coordinating committee representing the relevant Branches of CEB meets during the study period to review the study inputs and the findings.

Operating information on the existing generating plants is obtained from records maintained in the Generation Planning Branch and the individual power stations. Certain operational information and system limitations are obtained from the System Control Centre and the Generation Division of CEB. Details and costs of candidate thermal and hydro plants which are to be considered for system addition are obtained from various pre-feasibility and feasibility studies commissioned by CEB in the recent past. These data are used on computer models and a series of simulations are conducted to derive the feasible optimum generation expansion sequence.

1.6 Objectives

The objectives of the generation planning studies conducted by CEB are,

(a) To investigate the feasibility of new generating plants for addition to the system in terms of plant and system characteristics.
(b) To specifically investigate the future operations of the hydro-thermal system in order to determine the most economical operating policy for reservoirs, hydro and thermal plants.
(c) To conduct system simulation studies to determine the economically optimum mix of generating plants to meet the forecast demand and the acceptable reliability levels in the 20 year period ahead.
(d) To investigate the robustness of the economically optimum plan by analyzing its sensitivity to changes in the key input parameters.

1.7 Organization of the Report

The next Chapter, Chapter 2 of the report, presents the existing and committed generation system of Sri Lanka. The past and forecast electricity demand with the forecasting methodology is explained in Chapter 3. Conventional and renewable generation options for the future system expansions are discussed in Chapters 4 and 5 respectively. Chapter 6 explains the Generation expansion planning guidelines, methodology and the parameters while the expansion planning results are given in Chapter 7. Chapter 8 describes required implementation schedule and financing for the generation projects. Environmental implications of the expansion plan are discussed in Chapter 9 and finally, Chapter 10 provides a comparison of this year plan with the previous plan.

CHAPTER 2
THE EXISTING AND COMMITTED GENERATING SYSTEM

The existing generating system in the country is mainly owned by CEB with a considerable share owned by the private sector. Until 1996 the total electricity system was owned by CEB. Since 1996, private sector has also participated in power generation. The existing generating system in the country has approximately 3932MW of installed capacity by end of 2014 including non-dispatchable plants of capacity 437MW owned by private sector developers. The majority of dispatchable capacity is owned by CEB (i.e. about 80% of the total dispatchable capacity), which includes 1356.5MW of hydro and 1444MW of thermal generation capacity. Balance dispatchable capacity, which is totally thermal plants, is owned by Independent Power Producers (IPPs).

2.1 Hydro and Other Renewable Power Generation

Hydropower is the main renewable source of generation in the Sri Lanka power system and it is mainly owned by CEB. However, other renewable sources such as mini hydro, wind, solar, dendro, and biomass are also connected to the system, which are owned by the private sector developers.

2.1.1 CEB Owned Hydro and Other Renewable Power Plants

Most of the comparatively large scale hydro resources in Sri Lanka have been developed by the CEB. At present, hydro projects having capacities below 10MW (termed mini hydro), are allowed to be developed by private sector as run-of river plants and larger hydro plants are to be developed by the CEB. Since these run-of river type mini hydro plants are non-dispatchable, they are modeled differently from CEB owned hydro plants in the generation expansion planning simulations. The operation and maintenance cost of these CEB hydro power plants was taken as 13.547 US$/kW per annum.

(a) Existing System

The existing CEB generating system is mostly based on hydropower (i.e.1376.95MW hydro out of 2820.95MW of total CEB installed capacity). Approximately 49% of the total existing CEB system capacity is installed in 17 hydro power stations. In 2014, only 29.4 % of the total energy demand was met by the hydro plants, compared to 50% in 2013. Details of the existing and committed hydro system are given in Table 2.1 and the geographical locations of the Power Stations are shown in the Figure 2.1.

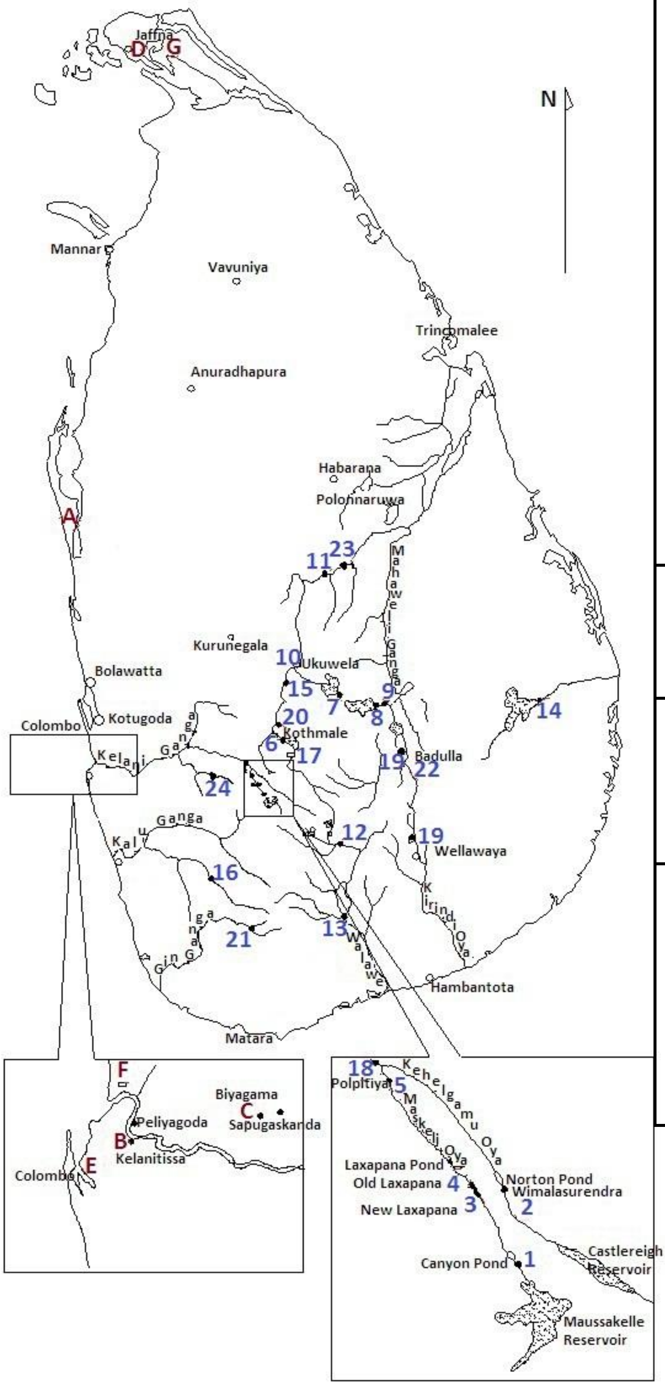
The major hydropower schemes already developed are associated with Kelani and Mahaweli river basins. Five hydro power stations with a total installed capacity of 354.5MW (26% of the total hydropower capacity) have been built in two cascaded systems associated with the two main tributaries of Kelani River, Kehelgamu Oya and Maskeliya Oya (Laxapana Complex). The five stations in this complex are generally not required to operate for irrigation or other water requirements; hence they are primarily designed to meet the power requirements of the country. Castlereigh and Moussakelle are the major storage reservoirs in the Laxapana hydropower complex located at main tributaries Kehelgamu Oya and Maskeliya Oya respectively. Castlereigh reservoir with storage of 60 MCM feeds the Wimalasurendra Power Station of capacity 2 x 25MW at Norton-bridge, while Canyon 2 x 30MW is fed from the Moussakelle reservoir of storage 115 MCM.

Table 2.1 - Existing and Committed Hydro and Other Renewable Power Plants

Plant Name	Units x Capacity	Capacity (MW)	Expected Annual Avg. Energy (GWh)	Active Storage (MCM)	Rated Head (m)	Year of Commissioning
Canyon	2 x 30	60	160	107.9 (Moussakelle)	204.2	1983 - Unit 1 1989 - Unit 2
Wimalasurendra	2 x 25	50	112	53.6 (Castlereigh)	225.6	1965
Old Laxapana	3x 9.5+ 2x12.5	53.5	286	0.245 (Norton)	472.4	1950 1958
New Laxapana	2 x 58	116	552	0.629 (Canyon)	541	Unit 1 1974 Unit 2 1974
Polpitiya	2 x 37.5	75	453	0.113 (Laxapana)	259.1	1969
Laxapana Total		**354.5**	**1563**			
Upper Kotmale	2 x 75	150	409	0.8	473.1	Unit 1 - 2012 Unit 2 - 2012
Victoria	3 x 70	210	865	688	190	Unit 1 - 1985 Unit 2 - 1984 Unit 3 - 1986
Kotmale	3 x 67	201	498	154	201.5	Unit 1 - 1985 Unit 2&3 –'88
Randenigala	2 x 61	122	454	558	77.8	1986
Ukuwela	2 x 20	40	154	4.1	75	Unit 1&2 – '76
Bowatenna	1 x 40	40	48	18	51	1981
Rantambe	2 x 24.5	49	239	4.4	32.7	1990
Mahaweli Total		**812**	**2667**			
Samanalawewa	2 x 60	120	344	168.2	320	1992
Kukule	2 x 35	70	300	1.7	180	2003
Small hydro		20.45				
Samanala Total		**210.45**	**644**			
Existing Total		**1376.95****	**4874**			
Committed						
Broadlands	2x17.5	35	126	-	57	2017
Moragolla	2x15.5	31	97.6	-	69	2020
Multi-Purpose Projects						
Uma Oya	2x60	120	231	0.7	704	2017
Gin Ganga	2x10	20	66	0.2	-	-
Thalpitigala	2x7.5	15	52.4	11.42	93	-
Moragahakanda	(2x5) + 7.5 + 7.5	25	114.5	430	38 34 34	Unit 1-2017 Unit 2-2020 Unit 3-2022
Total		**246**	**687.5***			

Note: * ***According to feasibility studies.***

** ***3MW wind project at Hambantota not included.***



No.	Power Plant	Capacity MW
	Hydro Power Plants (Existing)	
1	Canyon	60
2	Wimalasurendra	50
3	New Laxapana	116
4	Old Laxapana	53.5
5	Polpitiya	75
6	Kotmale	201
7	Victoria	210
8	Randenigala	122
9	Rantambe	49
10	Ukuwela	40
11	Bowatenna	40
12	Samanalawewa	120
13	Udawalawe	6
14	Inginiyagala	11.25
15	Nilambe	3.2
16	Kukule	70
17	Upper Kotmale	150
	Hydro Power Plants (Committed)	
18	Broadlands	35
19	Uma Oya	120
20	Moragolla	31
	Hydro Power Plants (Candidate)	
21	Gin Ganga	20
22	Thalpitigala	15
23	Moragahakanda	25
24	Seethawaka	20
	Thermal Power Plants	
A	Puttalam Coal	900
B	Kelanithissa PP, AES PP	543
C	Sapugaskanda PP, Asia Power	211
D	Uthuru Janani	27
E	CEB Barge	64
F	West Coast PP	300
G	Northern Power	38

Figure 2.1 - Location of Existing, Committed and Candidate Power Stations

The development of the major hydro-power resources under the Mahaweli project added seven hydro power stations (*Ukuwela, Bowatenna, Kotmale, Upper Kotmale, Victoria, Randenigala and Rantambe*) to the national grid with a total installed capacity of 812MW (59% of the total hydropower capacity). Three major reservoirs, *Kotmale, Victoria and Randenigala*, which were built under the accelerated Mahaweli development program, feed the power stations installed with these reservoirs. The latest power station in this system is 150MW Upper Kotmale hydro power plant.

Polgolla - diversion weir (across Mahaweli Ganga), downstream of Kotmale and upstream of Victoria, diverts Mahaweli waters to irrigation systems via Ukuwela power station (40MW). After generating electricity at Ukuwela power station the water is discharged to Sudu Ganga, upstream of Amban Ganga, which carries water to Bowatenna reservoir. It then feeds both Bowatenna power station (40MW) and mainly Mahaweli System-H by means of separate waterways. Water discharged through Bowatenna power station goes to Elahera Ela and is available for diversion to Mahaweli systems D and G.

The schematic diagrams of the hydro reservoir networks are shown in Annex 2.1. Unlike the Laxapana cascade, the Mahaweli system is operated as a multi-purpose system. Hence power generation from the associated power stations is governed by the down-stream irrigation requirements as well. These requirements being highly seasonal constrain the operation of power stations during certain periods of the year.

Samanalawewa hydro power plant of capacity 120MW was commissioned in 1992. Samanalawewa reservoir, which is on Walawe River and with storage of 278MCM, feeds this power plant. Kukule power project which was commissioned in 2003, is run-of river type plant located on Kukule Ganga, a tributary of Kalu Ganga. Kukule power plant is 70MW in capacity and which provides an average of 300GWh of energy per year.

The contribution of the three small hydro plants (Inginiyagala – 11.25MW, UdaWalawe - 6MW and Nilambe – 3.2MW) to the National Grid is comparatively small (20.45MW) and is dependent on irrigation water releases from the respective reservoirs.

Due to recent rehabilitation work carried out at Ukuwela, New Laxapana, Old Laxapana and Wimalasurendra Power Stations, the efficiency of above plants has been increased. Also the Capacity of Ukuwela, Old Laxapana and New Laxapana has been increased as a result of the above rehabilitation work.

In addition to the above hydro plants, CEB has a 3MW wind plant at Hambantota. This project was implemented as a pilot project in order to see the feasibility of wind development in Sri Lanka.

(b) Committed Plants

The 35MW Broadlands hydropower project located near Kithulagala on the Maskeliyaoya was considered as a committed plant. The dam site of the project is to be located near Polpitiya power house and in addition to the main dam, there will be a diversion weir across Kehelgamuoya. The project has a 0.2 MCM storage reservoir and it is expected to generate 126GWh energy per annum. It will be added to the system in 2017.

120MW Uma Oya multipurpose hydro power project was considered as a committed plant. Under Uma Oya multipurpose hydro power project, two small reservoirs will be built close to Welimada where the water from these two reservoirs will be diverted through a tunnel to the underground power house located at Randeniya near Wellawaya. It is expected to generate 231GWh of annual energy and Umaoya power plant will be added to the system in 2017. This project is implemented by the Ministry of Irrigation and Water Resources.

Moragolla Hydro Power project with a reservoir of 4.6MCM is located on the Mahaweli River close to Ulapane village in Kandy District of Central Province. This committed power plant is having a capacity of 31MW and 97.6 GWh of mean annual energy. This plant will be added to the system in 2020.

Gin Ganga (20MW), Thalpitigala (15MW) and Moragahakanda (25MW) are three Irrigation Projects with a power generation component. These projects will add another 233GWh to the system and will be developed by Ministry of Irrigation and Water Resource Management.

2.1.2 Hydro and Other Renewable Power Plants Owned by IPPs

Government of Sri Lanka has taken a policy decision to develop hydropower plants below 10MW capacities by the private sector. Many small hydro plants and other renewable power plants have been connected to the system since 1996. Total capacity of these plants is approximately 442MW as at 10th January 2015. These plants are mainly connected to 33kV distribution lines. CEB has signed standard power purchase agreements for another 275MW.

In this study, a capacity and energy contributions from these mini hydro and other non-conventional renewable energy plants were considered in the base case as committed and modeled accordingly. The figures were projected based on expected development according to current project pipeline records. The projected committed development used in this study is given in Table 2.2.

Table 2.2 –Projected Committed Development of NCRE

Projected Year	Committed NCRE Capacity Projection (MW)	Projected Year	Committed NCRE Capacity Projection (MW)
2015	437	2025	1367
2016	487	2026	1407
2017	562	2027	1482
2018	727	2028	1537
2019	802	2029	1617
2020	972	2030	1672
2021	1062	2031	1717
2022	1142	2032	1772
2023	1217	2033	1832
2024	1297	2034	1897

2.1.3 Capability of Existing Hydropower Plants

The Sri Lankan power system is still highly dependent on hydropower. Hence, it is necessary to assess the energy generating potential of the hydropower system to a high degree of accuracy. However, this assessment is difficult owing to the multipurpose nature of some reservoirs, which have to satisfy the downstream irrigation requirements as well. Further, the climatic conditions of Sri Lanka is characterized by the monsoons, causing inflows to the reservoirs as well as the irrigation demands to fluctuate over the year exhibiting a strong seasonal pattern.

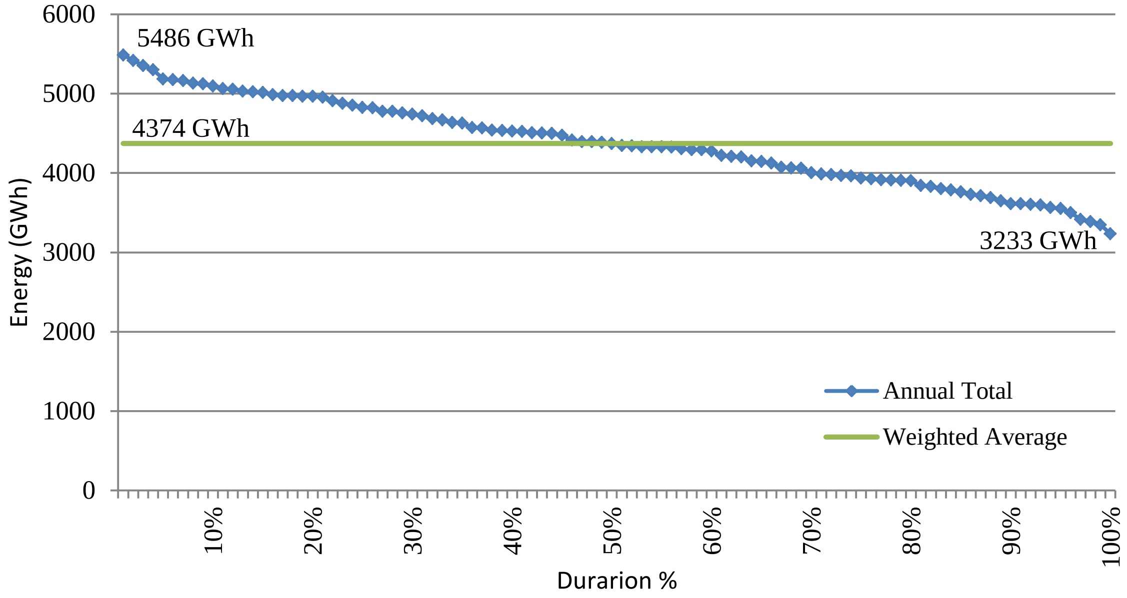


Figure 2.2 - Potential of Hydropower system from past 33 years hydrological data

The annual energy variation of the existing hydro system, using the inflow data from 1979 to 2012 and based on SDDP computer simulation is shown in Figure 2.2. This shows that the capability of the hydropower system could vary as much as from 3233 GWh to 5486 GWh provided the required thermal plants are available in the system for optimal dispatch. The corresponding summary of the hydrology simulation is given in Table 2.3 with probabilities of 10% (very wet), 20 %(wet), 40% (medium), 20% (dry) and 10% (very dry) hydro conditions.

Figure 2.3 shows the monthly variation of average hydro energy and capacity over a year.

Table 2.3 – Expected Monthly Hydro Power and Energy Variation of the existing hydro plants for the Selected Hydro Conditions

→ Drier

Month	**Very Wet**		**Wet**		**Medium**		**Dry**		**Very Dry**		**Average**	
	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)
Jan	140.1	680.3	126.6	740.6	105.3	663.1	94.1	635.9	84.8	604.2	109.0	669.0
Feb	225.0	712.0	214.0	705.2	197.2	668.0	213.7	715.6	183.6	642.5	205.0	686.8
Mar	344.8	962.1	311.0	899.6	309.6	877.7	308.7	883.3	284.5	839.1	311.0	887.8
Apr	408.7	999.3	362.0	946.4	343.8	919.0	314.5	854.9	307.7	871.3	344.0	914.9
May	484.1	1138.2	466.2	1111.1	407.8	1021.0	365.7	932.6	321.3	841.4	410.0	1015.1
Jun	484.8	1100.1	450.0	1084.2	394.8	1049.3	357.6	994.8	323.7	972.5	400.0	1042.8
Jul	479.0	1033.9	469.5	1036.1	433.8	1007.5	386.8	971.4	335.2	919.3	426.0	999.8
Aug	431.4	967.6	437.5	970.0	376.0	943.2	346.1	902.6	319.5	890.4	382.0	937.6
Sep	494.3	1059.5	452.2	1021.2	397.5	943.8	351.5	853.0	311.5	787.8	400.0	937.1
Oct	617.2	1135.3	566.0	1109.3	483.2	1033.8	424.2	986.9	411.2	948.6	494.0	1041.2
Nov	579.2	1129.9	526.0	1108.2	482.1	1044.8	348.4	930.3	320.8	871.5	458.0	1025.8
Dec	554.4	1161.5	536.2	1151.6	443.2	1053.1	328.7	891.2	277.6	862.5	433.0	1032.2
Total	5243		4917		4374		3846		3481		4374	

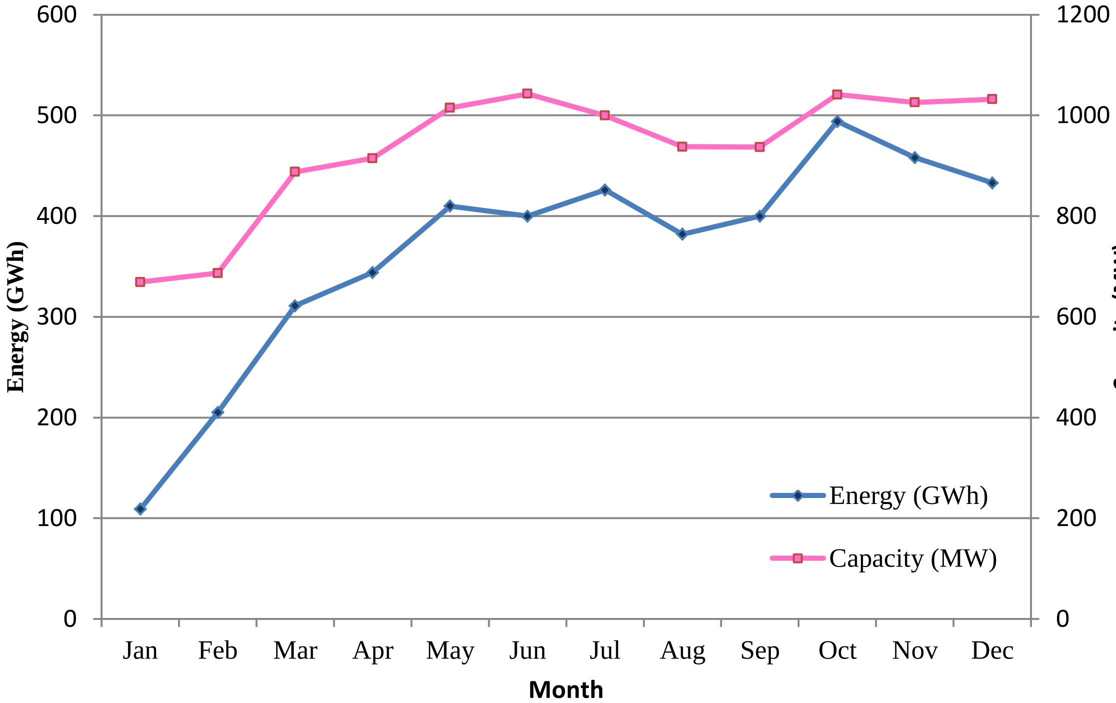


Figure 2.3 - Monthly average hydro energy and capacity variation

2.2 Thermal Generation

2.2.1 CEB Thermal Plants

(a) Existing

Majority of the present thermal power generating capacity in the country is owned by CEB with a total capacity of 1444MW. It is made up of Puttalam Coal plant 900MW, Kelanitissa Gas Turbines 195MW, Kelanitissa Combined Cycle plant 16MW, Sapugaskande Diesel plants 160MW and 24MW diesel plant at Chunnakam. The Puttalam Coal plant 900MW funded by EXIM Bank China commissioned in 2011 (Phase I) and 2014 (Phase II) was the latest thermal power plant addition to the CEB system.

(b) Plant Retirements

For planning purposes, it was considered that 4x20MW Gas Turbines at Kelanitissa and 4x20MW diesel plants at Sapugaskanda are due for retirement in 2017 and 2019 respectively. 115MW Kelanitissa Gas Turbine and 4x10MW Sapugaskanda were considered for retirement in 2023 and another 4x10MW Sapugaskanda Diesel extension are due in 2025. Capacity and energy details of the existing and committed thermal plants are shown in Table 2.4. Cost and technical details of the existing thermal generation plants as input to the 2014 Expansion Planning Studies is summarized in Table 2.5.

(c) Committed

After the commissioning of Stage II and III of Puttalam Coal Power Plant there are no committed thermal power plants to be added to CEB system.

Table 2.4 - Details of Existing and Committed Thermal Plants

Plant Name	No of Units x Name Plate Capacity (MW)	No of Units x Capacity used for Studies (MW)	Annual Max. Energy (GWh)	Commissioning
Puttalam Coal Power Plant				
Puttalam CPP	3 x 300	3 x 275	-	2011 & 2014
Puttalam Coal Total	**900**	**825**	**-**	
Kelanitissa Power Station				
Gas turbine (Old)	4 x 20	4 x 16.3	417	Dec 81, Mar 82, Apr 82,
Gas turbine (New)	1 x 115	1 x 113	707	Aug 97
Combined Cycle	1 x 165	1 x 161	1290	Aug 2002
Kelanitissa Total	**360**	**339.2**	**2414**	
Sapugaskanda Power				
Diesel	4 x 20	4 x 17.4	472	May 84, May 84, Sep 84, Oct 84
Diesel (Ext.)	8 x 10	8 x 8.7	504	4 Units Sept 97 4 Units Oct 99
Sapugaskanda Total	**160**	**139.2**	**976**	
Other Thermal Power				
UthuruJanani	3 x 8.9	3 x 8.67		Jan 2013
Existing Total Thermal	**1446.7**	**1329.4**	**3390**	

Table 2.5 - Characteristics of Existing and Committed CEB Owned Thermal Plants

		Kelanitissa			Sapugaskanda		Puttalam Coal	Other
Name of Plant	**Units**	**GT (Old)**	**GT (New)**	**Comb. Cycle (JBIC)**	**Diesel (Station A)**	**Diesel (Ext.) (Station B)**	**Coal (Phase I & II)**	**Uthuru Janani**
Basic Data								
Engine Type		GE FRAME 5	FIAT (TG 50 D5)	VEGA 109E ALSTHOM	PIELSTIC PC-42	MAN B&W L58/64	-	Wartsila 20V32
Fuel Type		Auto Diesel	Auto Diesel	Naphtha	Res. Oil	Res. Oil	Coal	Fuel Oil
Inputs for studies								
Number of sets		4	1	1	4	8	3	3
Unit Capacity	MW	16.3	113	161	17.4	8.7	275	8.67
Minimum operating level	MW	16.3	79	98	17.4	8.7	200	8.67
Calorific Value of the fuel	kCal/kg	10500	10500	10880	10300	10300	6300	10300
Heat Rate at Min. Load	kCal/kWh	4022	3085	2269	2245	2015	2597	2178
Incremental Heat Rate	kCal/kWh	0	2337	1359	0	0	1793	0
Heat Rate at Full Load	kCal/kWh	4022	2860	1897	2245	2015	2378	2178
Fuel Cost	USCts/GCal	8858	8858	8282	6187	6187	1553	6508
Full Load Efficiency	%	21	30	45	38	43	36	39
Forced Outage Rate	%	29	34.3	8.38	9.34	4.47	5.0	2.7
Scheduled Maintenance	Days/Year	35	52	30	50	47	52	38
Fixed O&M Cost	$/kWmonth	3.56	0.21	2.22	10.05	9.21	5.02	2.08
Variable O&M Cost	$/MWh	0.77	5.98	3.23	6.82	2.03	3.49	9.91

Note: All costs are in January 2015 US$ border prices. Fuel prices are based on World Bank Published and CPC provided average fuel prices of 2014. Heat rates and calorific values are given in HHV.

2.2.2 Independent Power Producers (IPPs)

(a) Existing

Apart from the thermal generating capacity owned by CEB, Independent Power Producers have commissioned diesel power plants and combined cycle power plants given in Table 2.6.

Table 2.6 - Details of Existing and Committed IPP Plants

Plant Name	Name Plate Cap. (MW)	Cap. used for Studies	Min . Guarenteed Ann. Energy (GWh)	Commissioning	Contract Period. (Yrs.)
Independent Power Producers					
Asia Power Ltd	51	50.8	330	1998 June	20
Colombo Power (Pvt) Ltd +	64	60	420	2000 July	15
AES Kelanitissa (Pvt.) Ltd	163	163	-	GT- March 2003	
				ST - October 2003	20
ACE Power Embilipitiya Ltd ++	100	99.5	697	2005 April	10
West Coast (pvt)Ltd.	300	270	-	2010 May	25
Northern Power	38	30	-	2009 December	10
Existing Total IPP	**716**	**673.3**			
Committed	-	-	-		
Committed Total IPP	**-**	**-**	**-**		

Note

+ After retirement of Colombo Power (Pvt) Ltd, CEB intend to buy out the plant and operate as CEB owned plant

++ ACE Power Embilipitiya Power Plant scheduled to retire by April 2015.

CHAPTER 3
ELECTRICITY DEMAND: PAST AND THE FORECAST

3.1 Past Demand

Demand for electricity in the country during the last fifteen years has been growing at an average rate of about 5.2 % per annum while peak demand has been growing at a rate of 3.1% per annum as shown in Table 3.1. However the peak demand has grown at a rate of 2.4% during the last 5 years and energy demand has been growing at a rate of 4.5% per annum. In 2014, the 12,418GWh of electricity generated to meet the demand which had been only 8,769 GWh ten years ago. The recorded maximum demand within the year 2014 was 2,152MW which was 2,164MW in year 2013 and 1,748MW ten years ago.

Table 3.1 - Electricity Demand in Sri Lanka, 2000 – 2014

Year	Demand	Avg. Growth	Total energy Losses+	Generation	Avg. Growth	Load Factor **	Peak	Avg. Growth
	(GWh)	(%)	(%)	(GWh)	(%)	(%)	(MW)	(%)
2000	5425*	10.2	21.4	6687	10.1	54.2	1404	8.8
2001	5341*	-1.5	19.7	6520	-2.5	51.5	1445	2.9
2002	5638*	5.6	19.2	6810	4.4	54.7	1422	-1.6
2003	6209	10.1	18.4	7612	11.8	57.3	1516	6.6
2004	6782*	9.2	17.1	8043	5.7	58.7	1563	3.1
2005	7255	7.0	17.3	8769	9.0	57.3	1748	11.8
2006	7832	8.0	16.6	9389	7.1	56.6	1893	8.3
2007	8276	5.7	15.7	9814	4.5	60.8	1842	-2.7
2008	8417	1.7	15.0	9901	0.9	58.6	1922	4.3
2009	8441	0.3	14.6	9882	-0.2	60.4	1868	-2.8
2010	9268	9.8	13.5	10714	8.4	62.6	1955	4.7
2011	10026*	8.2	13.1	11528	7.6	60.8	2163	10.6
2012	10475*	4.5	11.2	11801	2.4	62.8	2146	-0.8
2013	10624	1.4	11.2	11962	1.4	63.1	2164	0.8
2014	11063	4.1	10.9	12418	3.8	65.9	2152	-0.6
Last 5 year		4.5%			3.8%			2.4%
Last 10 year		4.8%			3.9%			2.3%
Last 15 year		5.2%			4.5%			3.1%

*Include Self-Generation
**Load Factor excludes self-generation and NCRE peak
+Includes generation auxiliary consumption

Figure 3.1 shows a considerable decrease in percentage of the System Losses during 2000-2012. The major contribution towards this decrement is the decrease in Transmission & Distribution Losses. Figure 3.2 shows the System Load Factor, Load factor calculated including NCRE (Mini hydro, Wind

& Solar) and Self-Generation. Overall improvement in the load factor including NCRE can also be observed in the linear trend as shown in Figure 3.2 and in 2014 it is calculated as 62.22%.

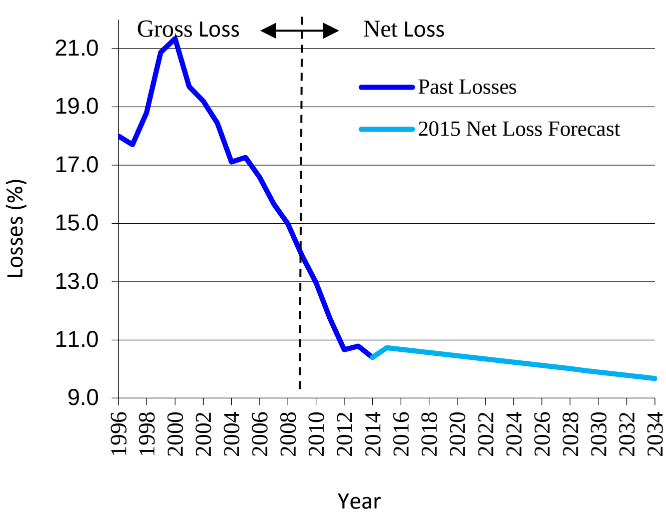


Figure 3.1 - Past Losses and Forecast Loss

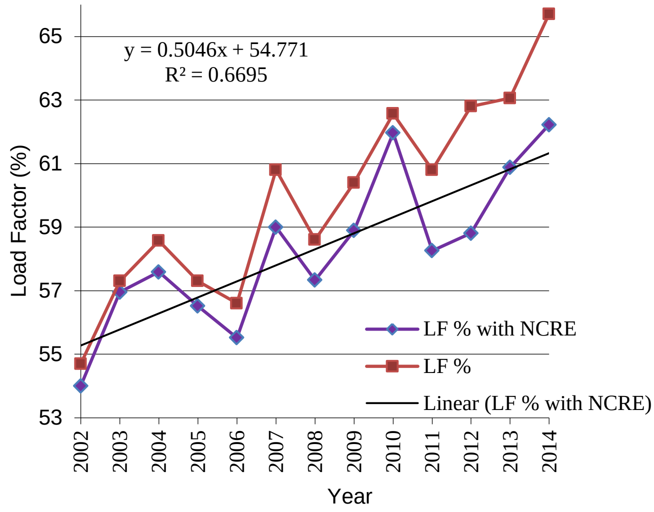


Figure 3.2 – Linear Trend in the Load Factor

Figure 3.3 shows the country's daily load curve recorded on the day of annual peak for previous eight years. From the Figure 3.3, it is seen that the shape of the load curve has not changed much during the last eight years. The system peak demand occurred only for a short period from about 19.00 to 22.00 hours daily. The recorded maximum system peak is 2,164MW in year 2013, while in year 2014 the peak is 2,152MW.

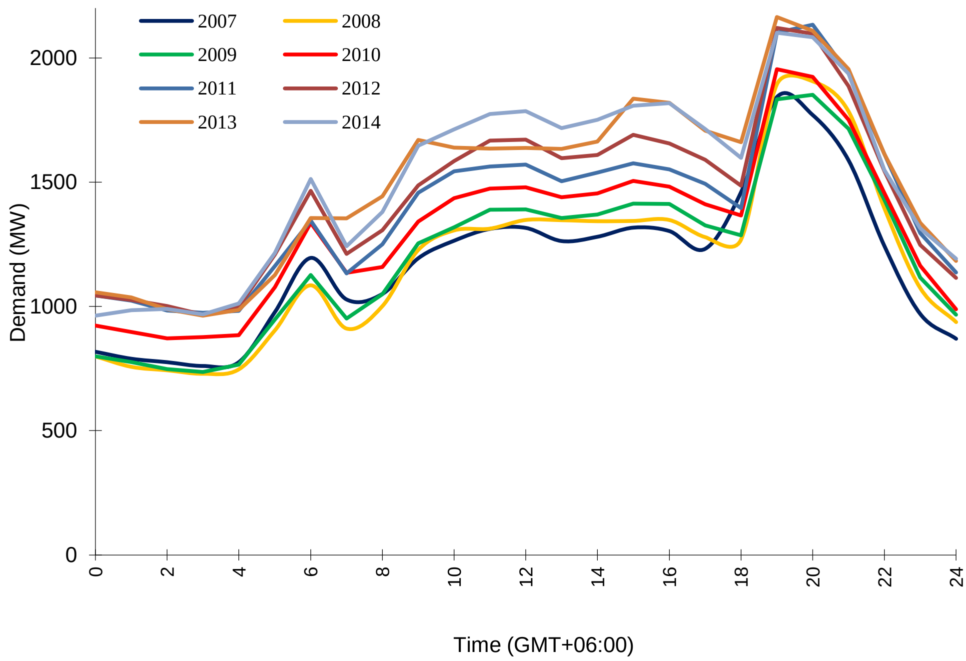


Figure 3.3 - Change in Daily Load Curve over the years

Figure 3.4 shows the consumption shares among different consumer categories in the recent past. In 2014, share of domestic consumption in the total demand was 37% while that of industrial and commercial sectors were 34% and 27% respectively. Religious purpose consumers and street lighting, which is referred as the other category, together accounted only for 2%. Similarly in 2005 (10 years ago), share of domestic, industrial, commercial and religious purpose & street lighting consumptions in the total demand, were 40%, 37%, 21% and 2% respectively.

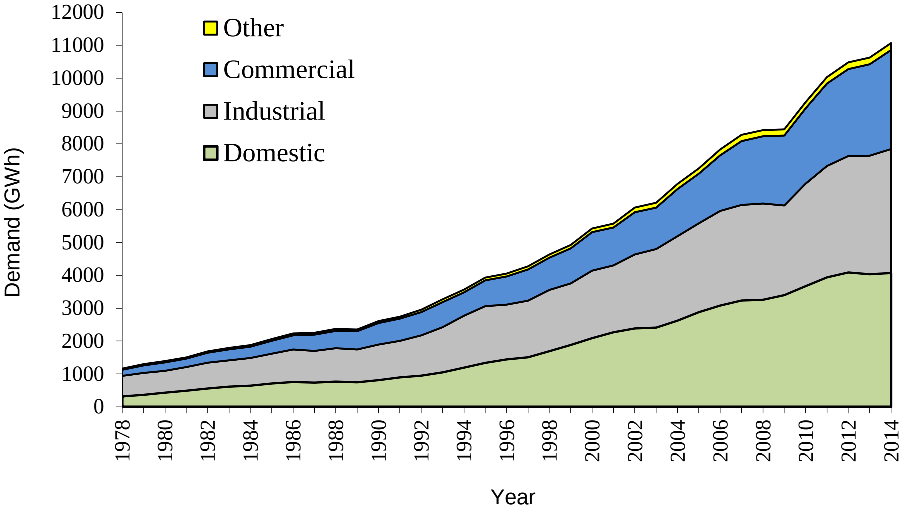


Figure 3.4 - Consumption Share among Different Consumer Categories

3.2 Econometric Demand Forecasting Methodology

Econometric modelling has been adopted by CEB for the future electricity demand forecast. In these models, the sales figures of the past were analysed against several independent variables given in Table 3.2 using regression technique. During the process some of the insignificant independent variables were removed depending on their inability to describe the behaviour of the dependent variable.

Table 3.2 – Variables Used for Econometric Modeling

Sector	Domestic	Industrial	Commercial	Other
Variables	GDP	GDP	GDP	Past Demand
	GDP Per Capita	Previous Year GDP	Previous Year GDP	
	Population	Population	Population	
	Avg. Electricity Price	Avg. Electricity Price	Avg. Electricity Price	
	Previous Year Demand	Previous Year Demand	Previous Year Demand	
	Domestic Consumer Accounts	Agriculture Sector GDP	Agriculture Sector GDP	
	Previous Year Dom. Consumer Accounts	Industrial Sector GDP	Industrial Sector GDP	
		Service Sector GDP	Service Sector GDP	

As shown above, Industrial sector GDP, Agriculture sector GDP and Service sector GDP were taken as new independent variables for the analysis. Sector wise GDP and its percentage share to the total GDP were further analysed for the period from 1978 to 2013. It is noted that the GDP structure has not been changed significantly over time. Base year is 2013 and the percentage share for Agriculture, Industry and Services are 11%, 31% and 58% respectively.

The resulting final regression coefficients together with assumptions about the expected growth of the independent variables are then used to project the electricity demand for different sectors under investigation.

To capture different consuming habits of various consumer categories, sector wise forecasts were prepared separately. Therefore, ‘Domestic’, ‘Industrial’, ‘Commercial’ (including General Purpose, Hotels and Government) and ‘Other’ (Religious purpose and Street Lighting) were analysed separately to capture the different consuming habits within categories. The following are the derived multiple linear regression models used in econometric analysis.

Domestic Sector

In regression analysis, it was found that two variables: Gross Domestic Product Per Capita and Previous year Domestic Consumer Accounts were significant independent variables for the domestic sector demand growth.

Ddom (t) i = 84.602 + 6.017 GDPPC (t) i + 0.661 CAdom (t-1)

Where,

Ddom (t) - Electricity demand in domestic consumer category (GWh)
GDPPC (t) - Gross Domestic Product Per Capita (’000s LKR)
CAdom (t-1) - Domestic Consumer Accounts in previous year (in ’000s)

Industrial Sector

Industrial differs from domestic sector in terms of significant variables. The significant variables for electricity demand growth in this sector are Industrial sector GDP and previous year Electricity demand in Industrial consumer category.

In previous studies overall GDP was used as an independent variable which was replaced by Industrial sector GDP in this study.

Di (t) i = 36.173 + 0.395 GDPi (t) + 0.933 Di (t-1)

Where,

Di (t) - Electricity demand in Industrial consumer categories (GWh)
GDPi - Industrial Sector Gross Domestic Product (in ’000 LKR)
Di (t-1) - Previous year Electricity demand in Industrial consumer category (GWh)

Commercial (General Purpose) Sector

Commercial sector significant variables for electricity demand growth are Service Sector GDP and previous year Electricity demand in Commercial consumer category, same as the industrial sector. Although there are differences between the identification of Commercial (General Purpose) sector in CEB Tariff category and Service sector identified in the statistics of Central Bank of Sri Lanka, Service sector GDP was selected as the most significant variable in regression analysis.

Dcom (t) i = -232.48 + 1.023 GDPser (t) + 0.423 Dcom (t-1)

Where,

Dcom (t) - Electricity demand in Commercial consumer categories (GWh)

GDPser - Service Sector Gross Domestic Product (in '000 LKR)

Dcom (t-1) - Previous year Electricity demand in Commercial consumer category (GWh)

Other Sector

The two consumer categories: Religious purpose and Street Lighting are considered in the 'Other Sector'. Because of the diverse nature of the consumers included in this category, this category was analysed without any links to other social or demographic variables. Hence, the time-trend analysis was performed to predict the demand in this sector.

ln (Dos(t)) = -106.07 + 0.0554 t

Where,

t - Year

Cumulative Demand

Once the energy forecasts were derived for the four sectors separately, they were added together to derive the total energy demand forecast.

Net Losses

Estimated total net (transmission and distribution loss excluding generation auxiliary) energy loss were added to the total energy demand forecast in order to derive the net energy generation forecast. A target of net Transmission and Distribution loss of 10.5% in 2019, 10.0% in 2028 and 9.5% in 2037 was used in the studies. Total net energy loss forecast to be achieved with time is shown in Table 3.3. Figure 3.1 shows the reductions of expected system losses from 2015 to 2034 with the expected improvements to the network, while rest of the graph shows the gross and net energy losses in the past.

Load Factor

Future load factors were derived by fitting a linear curve to the adjusted past load factors. Since contribution of mini hydro, wind & other such Non-Conventional Renewable plants affects the peak demand, load factors were adjusted by adding their capacity contribution to the peak demand. Figure 3.2 shows the trend of adjusted load factors in the past thirteen years. Peak demand forecast was derived using the load factor forecast and energy generation forecast. A target of improving system load factor of 67.5% by 2030 and 68.5% by 2035 were used in studies.

3.3 Econometric Demand Forecast

The GDP growth rate projection given in CBSL 2013 annual report shown in Table 1.2 was used from 2014 to 2017 for total GDP and sector wise GDP (Agriculture, Industry and Services) forecasts of the base case plan. Also the population forecast given by the Department of Census & Statistics was used. The total energy demand forecast, the expected system energy generation and peak demand forecast are prepared by using the above mentioned system losses and load factors for the planning horizon. In addition to that a number of forecasts are prepared in order to visualize the sensitivity of the factors considered for the forecast. Table 3.3 shows the 'Base Load Forecast'.

Table 3.3 - Base Load Forecast 2015-2039

Year	Demand		*Net Losses	Generation		Peak
	(GWh)	Growth Rate (%)	(%)	(GWh)	Growth Rate (%)	(MW)
2015	11516	4.1%	10.73	12901**	4.5%	2401
2016	12015	4.3%	10.68	13451**	4.3%	2483
2017	12842	6.9%	10.62	14368	6.8%	2631
2018	13726	6.9%	10.57	15348	6.8%	2788
2019	14671	6.9%	10.51	16394	6.8%	2954
2020	15681	6.9%	10.46	17512	6.8%	3131
2021	16465	5.0%	10.40	18376	4.9%	3259
2022	17288	5.0%	10.35	19283	4.9%	3394
2023	18155	5.0%	10.29	20238	5.0%	3534
2024	19069	5.0%	10.23	21243	5.0%	3681
2025	20033	5.1%	10.18	22303	5.0%	3836
2026	21050	5.1%	10.12	23421	5.0%	4014
2027	22125	5.1%	10.07	24601	5.0%	4203
2028	23243	5.1%	10.01	25829	5.0%	4398
2029	24402	5.0%	9.96	27100	4.9%	4599
2030	25598	4.9%	9.90	28410	4.8%	4805
2031	26827	4.8%	9.84	29756	4.7%	5018
2032	28087	4.7%	9.79	31135	4.6%	5235
2033	29395	4.7%	9.73	32565	4.6%	5459
2034	30759	4.6%	9.68	34055	4.6%	5692
2035	32184	4.6%	9.62	35611	4.6%	5934
2036	33673	4.6%	9.57	37235	4.6%	6187
2037	35231	4.6%	9.51	38934	4.6%	6451
2038	36862	4.6%	9.46	40711	4.6%	6726
2039	38569	4.6%	9.40	42571	4.6%	7013
5 Year Avg. Growth	6.24%			6.17%		5.32%
10 Year Avg. Growth	5.76%			5.70%		4.86%
20 Year Avg. Growth	5.31%			5.24%		4.65%
25 Year Avg. Growth	5.17%			5.10%		4.57%

*****Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded.

**Generation fixed for Energy Marketing Branch Energy Demand Forecast 2015-2016, prepared based on values provided by each Distribution Divisions.

3.4 Development of END USER Model (MAED) for Load Projection

Model for Analysis of Energy Demand (MAED) has been developed for Load Projection using Bottom-Up approach by the International Atomic Energy Agency (IAEA). Energy Demand Calculation module utilizes extensive analysis of end use energy demand data and identifies technological, economic and social driving factors influencing each category of final consumption and their relations to the final energy. Final Electricity demand projection is then separately taken into Electric Power Demand module for further analysis. In that module Industry, Transportation, Household and Service sectors are considered separately.

Secondary electricity demand (net generation) is calculated taking into consideration Transmission & Distribution losses. The model divides the Main Sectors into Sub Sectors as shown in Table 3.4 and when modelling the subsectors several representative load profiles were selected. Main Sector is represented by the aggregated load profile determined by the model. Peak electricity demand is calculated using the Load Factor percentage determined from the above load profiles. Also the rural and urban household percentage share assumed as 80%: 20% up to 2024, 75%:25% in 2025 and 70%:30% in 2030 to reflect the urbanization related to development with time.

Table 3.4, shows the Main and Sub sector client breakdown used for electricity demand calculation.

Table 3.4 – Main & Sub Sector Breakdown

Main Sector	Sub Sectors (Clients)	
Industry	Process Industry	
	Petroleum & Gas Industry	
	Industries with different working patterns	7 working days with constant load
		6 working days with constant load
		6 working days with day time operation
Service	Public & Private sector offices	
	Hotel	
	Public & Private Hospital	
	Educational Institutes	
	Marine & Aviation	
Household	Urban	
	Rural	

Three scenarios were developed to analyse demographic, socio-economic and technological parameter development of the country as follows;

Reference Scenario (RS)

This is the baseline scenario which carries historic growth rates of all sectors to the future years and anticipated energy demand predictions which would most likely to occur in the future. GDP growth rate projections are in line with econometric forecast.

Low Economic Growth Scenario (LEG Scenario)

In this scenario economic growth was dampened compared to the Reference Scenario and more pessimistic approach was taken in projecting sector wise energy demands.

High Electricity Penetration Scenario (HEP Scenario)

This scenario was developed with the assumption that demands for electricity will increase shifting from other energy forms. This assumption is based on that the cost of electricity generation will decrease with the addition of low cost power plants to the system. The demography and the GDP composition remain in line with the Reference Scenario. Electricity use in all the sectors, Industry, Transport, Household and Services will increase compared to the Reference Scenario.

Table 3.5 shows the annual average growth rate of Total Energy Demand and Electricity Demand for 2010-2035 planning horizon for each scenario.

Table 3.5 – Annual Average Growth Rate 2010 – 2035

Scenario	Total Energy Demand Growth Rate %	Electricity Demand Growth Rate %
Reference	5.3	5.1
Low Economic Growth	3.9	3.7
High Electricity Penetration	6.4	6.2

Table 3.6, shows the sectorial total secondary electricity consumption for Reference scenario, its percentage share, Peak electricity demand & the load factor percentage over the planning horizon.

Table 3.6 – MAED Reference Scenario

Sector	Unit	2010	2015	2020	2025	2030	2035
Industry	GWh	3616	5246	7332	9637	12538	15928
Transport	GWh	1	13	44	86	138	189
Households	GWh	4309	5857	7098	8628	10463	12692
Services	GWh	2735	3552	4498	5556	6792	8191
Total	GWh	10661	14668	18971	23908	29931	36999
Industry	%	33.92	35.76	38.65	40.31	41.89	43.05
Transport	%	0.01	0.09	0.23	0.36	0.46	0.51
Households	%	40.42	39.93	37.41	36.09	34.96	34.30
Services	%	25.66	24.22	23.71	23.24	22.69	22.14
Peak	MW	1903	2604	3321	4139	5110	6274
Load Factor	%	63.95	64.31	65.03	65.65	66.87	67.32

Projected final energy demands for above three scenarios are given in Figure 3.5 and peak demand projection is given in Figure 3.6.

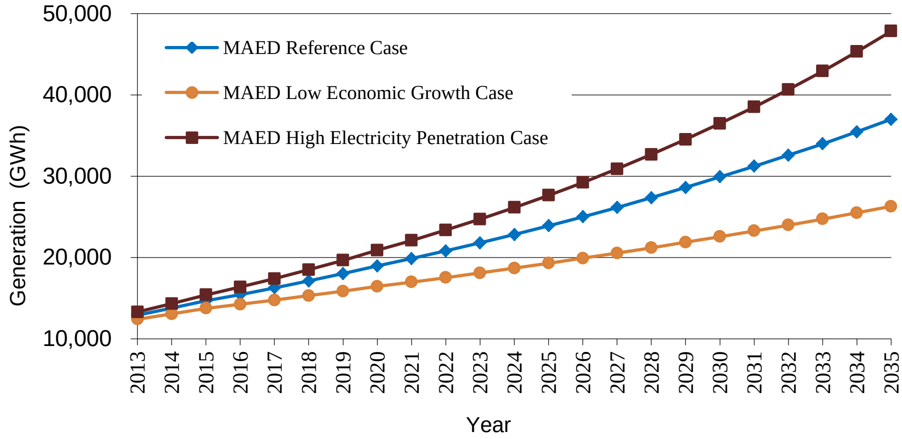


Figure 3.5 - Generation Load Forecast Comparison

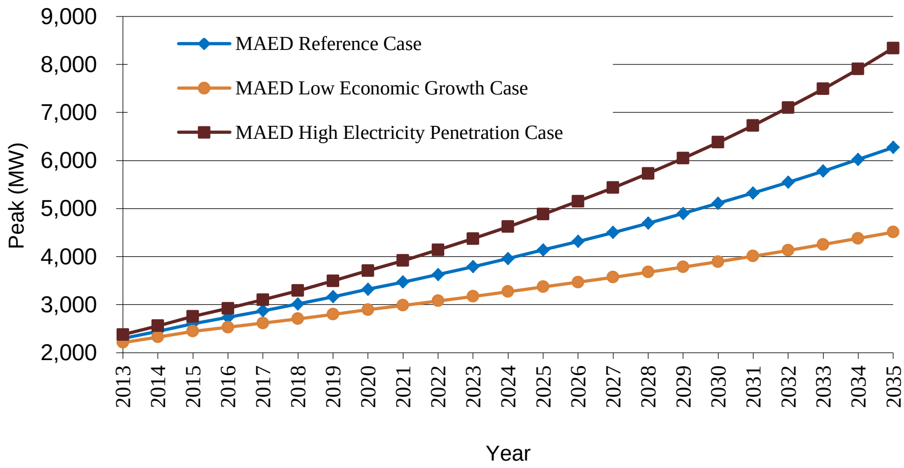


Figure 3.6 – Peak Demand Forecast Comparison

3.5 Sensitivities to the Demand Forecast

Sensitivity studies were carried out considering variations in the main factors such as GDP Growth, Sector wise GDP share over the planning horizon and population growth. Sensitivity studies carried out for the demand forecast are listed below. The effects of these variations on the base case generation expansion plan are described in Chapter 7 to 10.

1. **Low Load Forecast** – was prepared considering base population growth, reduced GDP growth compared to the Base Demand forecast and the increased contribution of the Service sector to the total GDP (from 58.5% to 61%). Reduction of the GDP growth rate of the Low Demand scenario compared to the Base demand scenario is 2.5% for the period of 2014 to 2017 which is based on CBSL GDP growth rate projection and it is 1.5% for the period of 2018 to 2039.

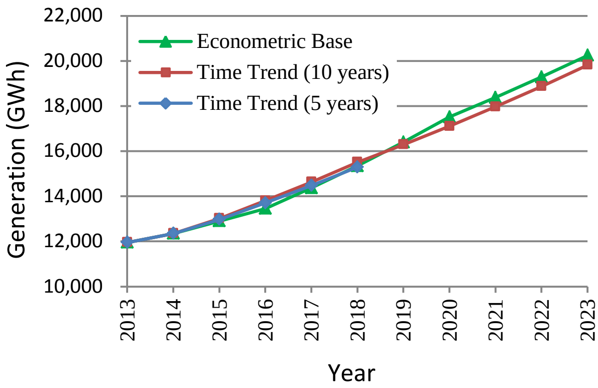
2. **High Load Forecast** - was prepared considering base population growth, high GDP growth and assuming the same GDP sector percentage as of 2013. 1% increase was assumed for the GDP growth of High Demand Scenario compared to the Base demand scenarios. The system requirements in order to achieve higher economic targets are identified here. These are useful to identify the future economic goals.

3. **Forecast with Demand Side Management (DSM) Measures -** DSM is required in order to improve the load factor of the system and to improve the efficiency at consumer end. DSM scenario was derived considering the estimation of energy savings provided by Sri Lanka Sustainable Energy Authority.

4. **Time Trend Forecast –** This forecast was projected purely based on time trend approach. Three time trend forecasts were prepared using the past 25, 10 and 5 year generation figures, starting from 1990, 2004 and 2009 respectively.

5. **MAED Load Projection –** This is derived from MAED software by considering end user energy demand data and identifying technological, economic and social driving factors influencing each category of final consumption and their relations to the final energy.

Load forecast of the above sensitivity studies are presented in Annex 3.1. Figure 3.7 & Figure 3.8 shows graphically, the energy generation and peak load forecast for the above four scenarios including base load forecast.



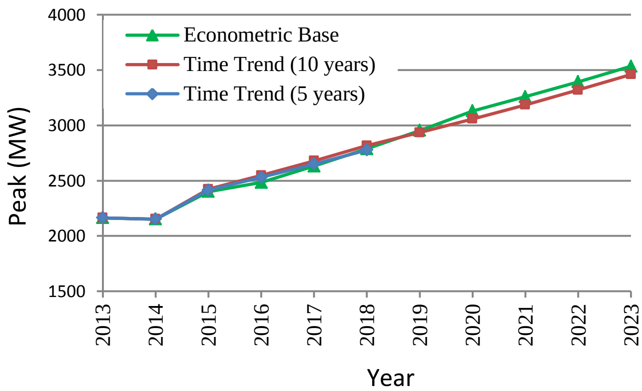
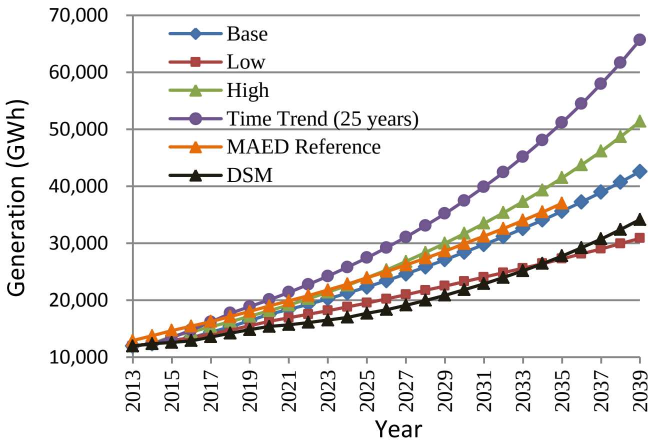


Figure 3.7 - Generation and Peak Load Forecast of Time Trend 5 year & 10 year with Base



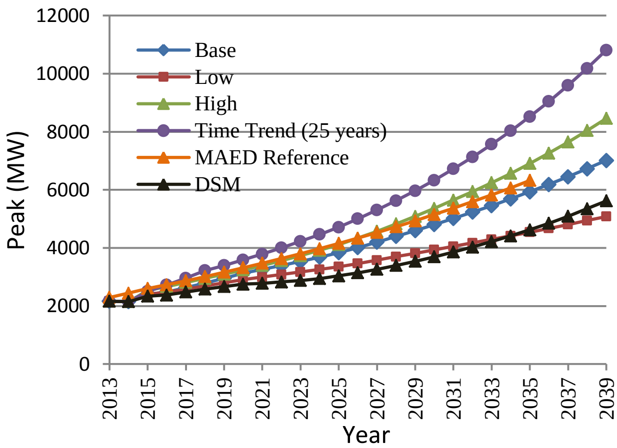


Figure 3.8 - Generation and Peak Load Forecast of Low, High, Time Trend 25 year, MAED with Base

3.6 Comparison with Past Forecasts

Demand forecast is reviewed once in two years with the revision of Long Term Generation Expansion Plan. This enables to capture the latest changes in the electricity demand as well as associating econometric variables. Table 3.7 shows the comparison of various base case generation forecasts used in the previous expansion plans and their percentage variation against the actual generation. It is important to note that the demand forecast is prepared based on the expected future developments. The non-achievement of projected economic growth is also a reason for the negative deviation in demand from the forecast. Similarly, electricity system expansions are required to cater to the demand, which would result the expected developments. The system expansions are affected by several factors and that leads to delay the expected expansions. Therefore it always has a tendency to result a lower actual demand growth than the forecasted values.

Table 3.7 – Comparison of Past Forecast in GWh

Year	2008 Gen. Forecast*	2009 Gen. Forecast*	2010 Gen. Forecast*	2011 Gen. Forecast	2012 Gen. Forecast	Actual Gen. (Gross)	Actual Gen. (Net)
2008	9863 (-0.4%)					9901	
2009	10307 (+4.3%)	10045 (+1.6%)				9882	
2010	11250 (+5.0%)	10775 (+0.6%)	10740 (+0.2%)			10714	
2011	11959 (+3.7%)	11528 (+0.0%)	11715 (+1.6%)	11938 (+5.1%)		11528	11353
2012	12730 (+7.9%)	12132 (+2.8%)	12464 (+5.6%)	12922 (+10.2%)	12086 (+3.1%)	11801	11725
2013	13559 (+13.4%)	12869 (+7.6%)	13402 (+12.0%)	13955 (+17.4%)	12566 (+5.7%)	11962	11898
2014	14496 (+16.7%)	13586 (+9.4%)	14315 (+15.3%)	15120 (+22.5%)	13502 (+9.4%)	12418	12357

Note: * Indicate the Gross Generation Forecast. Within bracket figures indicate the percentage deviation of forecast generation with Reference to Actual Generation (Gross) in 2008, 2009 & 2010 forecasts. 2011 & 2012 forecasts deviation indicated with Reference to Actual Generation (Net).

CHAPTER 4
CONVENTIONAL GENERATION OPTIONS FOR FUTURE EXPANSION

Hydro power, fossil fuel based thermal power, nuclear-based thermal power are the primary energy options to be considered in meeting the future electricity demand. A large number of factors including cost of development, operation and maintenance costs and environmental effects have to be evaluated in order to consider the suitability of these primary options. All costs incurred in environmental mitigation measures are included in the cost figures given in this report. In addition to these conventional generation options, non-conventional generation options are also considered in order to serve the future electricity demand. Non-conventional generation options are discussed in detail in Chapter 5 and the India-Sri Lanka Electricity Grid Interconnection option is briefly described in latter part of this chapter.

4.1 Hydro Options with a Projected committed development

4.1.1 Candidate Hydro Projects

The hydro potential in the country has already been developed to a great extent. Several prospective candidate hydro projects have been identified in the Master Plan Study [4], 1989. These include 27 sites capable of generating electricity at a long-term average cost of less than 15 USCts/kWh (in 1988 prices) and having a total capacity of approximately 870MW. A part of the above hydro potential already been exploited under the Upper Kotmale Hydro Power Project, which is in operation.

However, some major hydro projects identified in the Master Plan Study are in the developing stage, especially Broadlands (35MW) and Moragolla (31MW). Some major irrigation projects such as Uma Oya (120MW), Gin Gaga (20MW), Moragahakanda (25MW) and Thalpitigala (15MW) are also to be completed in near future. Gin Gaga, Thalpitigala and Moragahakanda projects are constructed by Ministry of Irrigation and Water Resource Management.

Expansion planning studies presented in this report have considered Seethawaka (20MW) as a prospective hydro candidate. Seethawaka River project was identified in the Master Plan produced by CEB in 1989 as Sita014. The project was initially identified as a 30MW capacity producing 123 GWh per year. However, due to Social and Environmental considerations, the project is scaled down to 20MW hydro power plant with an 8 MCM pond, delivering 48 GWh of energy annually. Presently CEB is carrying out the feasibility study of the project.

The criteria given below were generally adopted in generation planning exercises in selecting the hydro projects from the large number of hydro sites identified in the master plan study.

a) Projects less than 15MW were not considered as candidates in order to give priority for the large projects.

b) Whenever, feasibility study results were available for any prospective project, such results were used in preference to those of the Master Plan Study. (Studies conducted under the Master Plan study were considered to be at pre-feasibility level).

c) Estimated specific cost as well as physical and technical constraints are considered as the priority order for the selection of candidates.

However, many identified projects within these criteria have been developed by CEB, as well as by the private sector sometimes with reduced energy/capacity benefits.

Further, private sector is allowed to develop hydro power projects below 10MW under a Standard Power Purchase Agreement.

4.1.2 Available Studies on Hydro Projects

In addition to 1989 Master Plan study, following studies of selected prospective hydro sites have been completed.

(a) Feasibility of the Broadlands Hydropower Project was studied under the “Study of Hydropower Optimization in Sri Lanka” in February 2004 by the J- Power and the Nippon Koei Co., Ltd., Japan [5]. This study was funded by the Japan International Cooperation Agency (JICA). Under this study, several alternative schemes studied previously by Central Engineering Consultancy Bureau (CECB) in 1986 and 1991 [6 and 7] were reviewed.

(b) A Pre-feasibility study on *Uma Oya* Multi-purpose Project (a trans-basin option) was completed by the CECB in July 1991 [8] where the diversion of Uma Oya, a tributary of Mahaweli Ganga was studied. The development proposed in this study was used as a candidate in the present expansion studies. In 2001, SNC Lavalin Inc. of Canada was engaged to conduct the feasibility study on Uma Oya with the assistance of Canadian International Development Agency (CIDA). However, only Phase I of the study was completed by the consultants.

(c) The Pre-Feasibility study on Gin 074 Hydro Power Project in July 2008 proposes four options for the energy development using Gin Ganga basin. Considering above proposed four options in the study, Generation Development Studies Section of CEB is investigating the possibility of harnessing energy from the remaining water of Gin Ganga after the diversion of Gin- Nilwala Diversion Project.

(d) A feasibility study for Moragolla hydro power project was carried out in 2010/11 with Kuwait Fund for Arab Economic Development (KFAED). In 2013, Nippon Koei Co Ltd carried out the detail designs and preparation of tender document with the assistance of Asian Development Bank.

(e) In October 2013 Sri Lanka Energies (Pvt) Ltd studied two options for Seethawaka Hydro Power Project and CEB had decided to develop the option with a reservoir for maximum use of the river for power generation.

(f) “Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka” carried out by JICA funds in December 2014 explore the future options to meet the peak power demand. This study lists the options to meet the peak power requirement and their environmental, social and financial impacts are analyzed. Pumped storage power plant option has been selected as the most suitable option and several sites have been proposed in priority order considering social, environmental and financial impacts.

4.1.3 Details of the Candidate hydro Projects

The basic technical data of the selected projects are summarized in Table 4.1 [see Annex 4.1 for further details]. A summary of the capital cost is given in Table 4.2.

Table 4.1 - Characteristics of Candidate Hydro Plants

Project	River Basin	Ins. Capacity (MW)	Annu. Energy (GWh)	Storage (MCM)
Seethawaka	Kelani	20	48(@ 29% PF)	8.0
Thalpitigala	Uma Oya	15	52.4(@40% PF)	17.96
Gin Gaga	Gin	20	66	0.3

Specific cost of the hydro plants was calculated using the expected energy and the estimated project and maintenance costs which are shown in Table 4.3. These calculations are based on 10% discount rate, which is the rate used for planning studies. Furthermore, as an indicative comparison, specific cost at different capacities of the hydro project are shown in the Figure 4.1(a) & (b) with the screening curves of some other selected set of candidate thermal plants.

Table 4.2 - Capital Cost Details of Hydro Expansion Candidates

Plant	Capacity (MW)	Pure Const. Cost US$/kW		Total Cost (US$/kW)	Const Period (Yrs)	IDC at 10% (% pure costs)	Const. Cost as Input to Analysis incl. IDC (US$/kW)		Total Cost incl. IDC (US$/kW)	Economic Life (Years)
		Local	Foreign				Local	Foreign		
Seethawaka	20	690.5	1420.9	2111.4	4	18.53	818.5	1684.2	2502.7	40
Thalpitigala*	15									
Gin Gaga*	20									

Exchange rate US$ 1 = LKR 131.55, IDC = Interest during Construction

*Detail cost breakdown is not feasible as hydro power is a secondary benefit and developed by Ministry of Irrigation and Water Resource Management

Table 4.3 - Specific Cost of Candidate Hydro Plants

PROJECT/PLANT	CAPACITY (MW)	SPECIFIC COST (For maximum plant factor)	
		USCts/kWh	LKR/kWh
Seethawaka	20	9.03	11.87

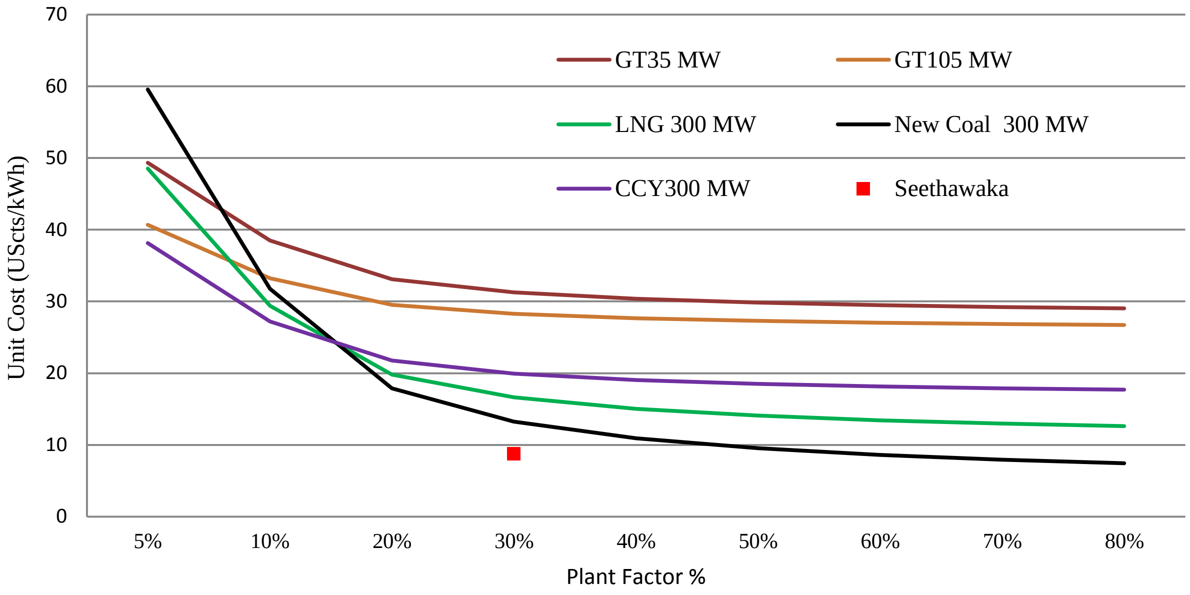


Figure 4.1 (a) - Specific cost comparison of Seethawaka Hydro project at Different Plant Factors

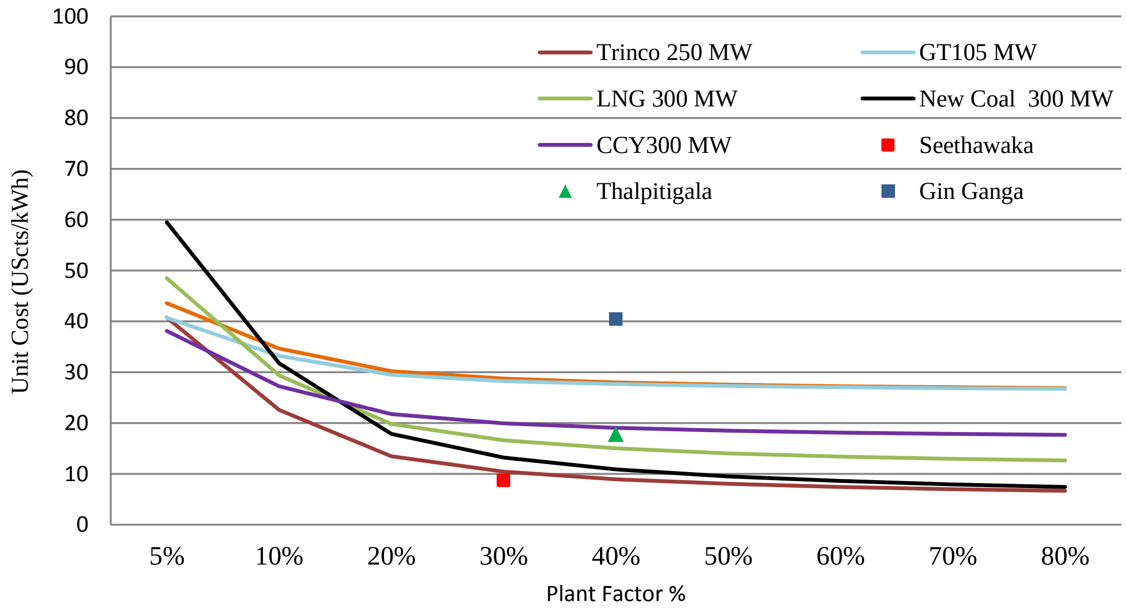


Figure 4.1 (b) - Specific cost comparison of the irrigation hydro Projects at different plant factors

4.1.4 Current status of Non-Committed Hydro Projects

(a) Seethawaka: Generation Development Studies Section has taken steps to initiate feasibility study together with the Environmental Impact Assessment (EIA) of the project.

(b) Thalpitigala and Gin Ganga: Ministry of Irrigation and Water Resource Management has taken steps to construct the two projects as multipurpose Hydro Projects.

4.2 Hydro Capacity Extensions

The Sri Lankan power system is gradually transforming into a thermal based system. In view of this, it would be pertinent to prepare the hydropower system for peaking duty. This aspect was further studied under the JICA funded "Hydro Power Optimization Study of 2004". Given below is a brief summary of possible expansions of existing hydro stations studied under the "Hydro Power Optimization Study" [5].

4.2.1 Samanalawewa

Samanalawewa project has a potential for additional peaking capacity. The existing Samanalawewa power station has two generators rated at 60MW each. In addition to these, studies have indicated that further two units of 60MW can be added for peaking operation. During construction stage of Samanalawewa, provisions such as a bifurcation with bulk head gate and a space for an addition of two 60MW units have been made to extend the capacity of the power plant to 240MW. The extension comprises of construction of Diyawini Oya reservoir.

The Stage II Feasibility Study report done by CECB in April 2002 recommends installation of one additional 60MW capacity without developing the Diyawini Oya dam. The major factor in consideration for selecting single unit expansion was the impact on financial revenue caused by decrease of total annual energy due to the head loss occurred by high velocity in existing low pressure tunnel. A summary of expansion details are shown in Table 4.4.

Table 4.4 – Expansion Details of Samanalawewa Power Station

	Unit	Existing	Existing + 1 Unit Expansion	Existing + 2 Units Expansion
Plant Capacity	MW	120	180	240
Peak Duration	hrs	6	4	3
95% Dependable Capacity	MW	120	172	225
Primary Energy	GWh	262	259	254
Secondary Energy	GWh	89	55	0
Total Energy	GWh	351	314	254

Source: The Study of Hydropower Optimization in Sri Lanka, Feb 2004

4.2.2 Laxapana Complex

During the Phase E of the Master Plan for the Electricity Supply in Sri Lanka, 1990 [9], some upgrading measures at Laxapana Complex have been studied. Also, under the Hydro Power Optimization Study further studies were carried out to upgrade Wimalasurendra Power Station, New Laxapana power station & Old Laxapana Power Station. And also for upgrading of the Samanalawewa and Polpitiya Power Stations, studies were carried out during the period of February to June 2010 by POYRY Energt AG, Switzerland.

(a) Wimalasurendra and New Laxapana Project: Under the upgrading of Wimalasurendra and New Laxapana Power Stations, planned replacement of generator, turbine governor excitation & controls and transformer protection have been completed by the Generation Division. Capacity of the New Laxapana Power Station is increased from 100MW to 115.2MW.

(b) Old Laxapana Project: Planned replacement of generator, turbine governor excitation & controls were completed increasing the plant efficiency and the plant capacity has been increased from 50MW to 53.5MW.

(c) Polpitiya Project: Expansion of Polpitiya Power Station is expected to be implemented under this project.

4.2.3 Mahaweli Complex

The "Hydro Power Optimization Study of 2004" suggested possible expansions of Ukuwela, Victoria and Rantambe Power Stations due to high plant factors. Out of those it is difficult to expand Rantambe for peaking requirements because it has to comply with water release for irrigation demand at any time.

(a) ***Victoria Expansion:*** CEB has identified expansion of Victoria Hydro Power Plant as an option to meet the peak power demand. A feasibility study has been done in 2009 and considered three options for the expansion. They are: Addition of another power house nearby existing power plant (Base option), Addition of a surface type power house 2km downstream of the existing power house (Downstream Option) and using Victoria and Randenigala reservoirs as a pump storage power plant (pump storage option).

From the feasibility study, it was concluded that the addition of the new power house closer to the existing power plant is an economically viable option as provisions have already been made for the expansion when the existing power plant was constructed. Under this expansion, two units of 114MW each will be added. This expansion could double the capacity of Victoria while the energy benefits are as follows.

Table 4.5 – Details of Victoria Expansion

	Annual Energy (GWh)	Peak Energy (GWh)	Off-Peak Energy (GWh)	95% Dependable Capacity
Spilled Discharge Deducted				
Existing Only	634	230	404	209
Existing + Expansion	635	467	168	379
Spilled Discharge not Deducted				
Existing Only	689	230	459	209
Existing + Expansion	716	469	247	385

Source: Feasibility Study for Expansion of Victoria Hydropower Station, June 2009

This expansion scheme has an advantage of not lowering the reservoir water level during construction period since the intake facilities for the expansion project were already constructed during the initial construction phase of the existing power plant. As of October 2008, this project requires approximately US$ 222 million for implementation. Further analysis of the project is required before incorporating into the Long Term Generation Expansion Plan.

(b) Upper Kotmale Diversion: Diversion of Pundalu Oya and Pundal Falls tributary is proposed under this project. The Upper Kothmale diversion project will increase the annual energy generation of Upper Kothmale Hydro Power Plant by 39GWh. For the implementation of above project, Operation of Upper Kothmale Hydro Power Plant needs to be interrupted for 6 months resulting reduction of 150MW capacity and 200GWh on average over the six month period.

(c) Kotmale Project: Provision for capacity expansion has been kept in the existing Kotmale Power Station. At present 3 x 67MW generators are installed in the Kotmale Power Station with an annual average energy output of 455 GWh. The amount of energy could be increased by about 20% by raising the dam crest from elevation 706.5m to 735.0 masl.

(d) Ukuwela Project: During the rehabilitation work carried out by the Generation Projects Branch at Ukuwela Power Station, turbines and generators have been replaced resulting increase plant efficiency and capacity. Capacity of each unit is now 19.3MW which was 18MW before rehabilitation.

4.2.4 Pump Storage Option

The daily peak power demand of the country typically occurs between 6.00pm and 10.00pm and it is expected that the same pattern of demand will persist in the future. Currently the peak demand is met by existing hydro and thermal power generation. In the future with the limited development of hydro potentials and the retirement of aged thermal power plants, new solutions for meeting the peak demand have to be explored. With the development of coal power plants with the prominent peak and off-peak characteristics of the daily demand pattern, CEB has taken timely initiative to study the peak power generation options specially pump storage hydro power plant. Accordingly, CEB initiated the study on "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" with the technical assistance from JICA.

During the study, all the possible peaking options were examined and following options were considered as feasible.

- Hydro Power Plant Capacity Extension
- Pump Storage Power Plant
- LNG Combined Cycle Power Plant
- Gas Turbine Power Plant

Mainly load following capability and power plant characteristics, environmental and social considerations and economic aspects of above options were evaluated and the study concluded that the Hydro Plant Capacity Extensions and Pump Storage Hydro Power Plants are the most suitable options for future development. Accordingly, the Victoria Expansion project is expected to be completed first and later the development of Pump Storage Power plant is considered necessary to meet the peak demand.

The scope of the Study "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" includes the identification of most promising candidate site for the future development of pump storage power plant. At the initial stage the study identified 11 potential sites for the development of 600MW Pump Storage Power Plant and all the sites were investigated and ranked in terms of Environmental, Topographical, Geological and Technical aspects. The preliminary screening process identified three promising sites for the detailed site investigations as shown in Figure 4.2. According to the ranking Halgran Oya, Maha Oya and Loggal Oya which were located in NuwaraEliya, Kegalle and Badulla districts were selected as the most suitable sites for future development.

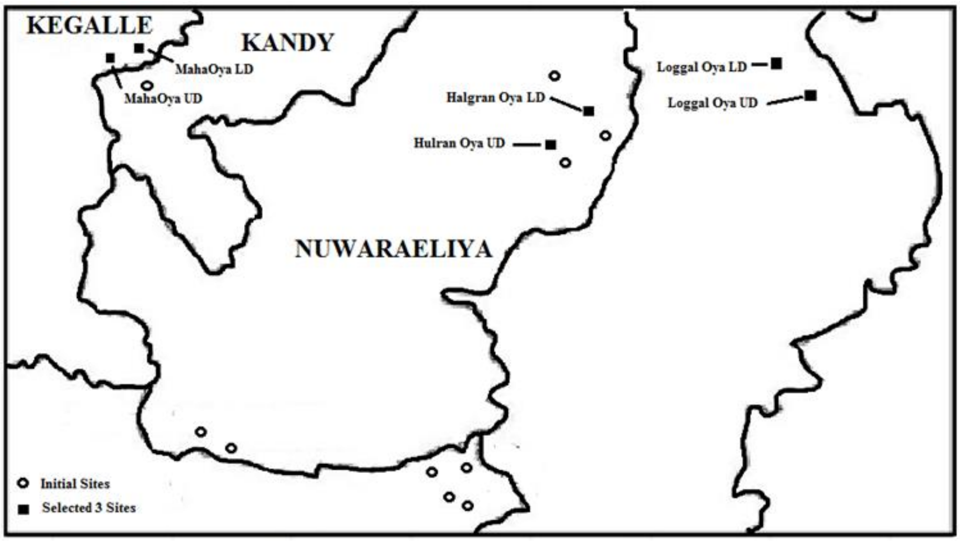


Figure 4.2 – Three Selected Sites for PSPP after Preliminary Screening

After the detail site investigations carried out for the above three sites the study concluded that the Maha Oya site as the most promising site for the development of the future Pumped Storage Power Plant.

The study concludes that the optimum capacity of the proposed Pump Storage power plant should be 600MW considering the peaking requirement beyond 2025.The unit capacity of pump storage power plant was determined considering the System limitations in terms of frequency deviations and manufacturing limitations of high head turbines. The study considered 200MW unit size for the baseline case and 150MW unit size is also analyzed as an alternative. Unit size will be finalized during the detail design stage.

4.3 Thermal Options

4.3.1 Available Studies for Thermal Plants

Several studies had been conducted to assess the future thermal options for electricity generation in Sri Lanka. These studies include:

a) Feasibility Study for Trincomalee Coal-Fired Power Station conducted in 1988 [10]: The feasibility study on Trincomalee coal-fired power station considered a site capacity of 900MW when fully developed (3x300MW in a phased development). The investment cost and other relevant parameters were reviewed during the 1995 Thermal Generation Options Study[12].

b) Thermal Generation Options, 1988 [11] and Thermal Generation Options, 1996 [12]

c) Special Assistance for Project Formulation (SAPROF) for Kelanitissa Combined Cycle Power Plant (1996) [13]

d) Review of Least Cost Generation Expansion Studies (1997) [14]

e) Coal Fired Thermal Development Project – West Coast (1998) [15]: Feasibility study and the preparation of contract documents (engineering services) for construction of the first 300MW coal power plant on the West Coast in Kalpitiya in the Puttalam District with the assistance of Japan Bank for International Cooperation . The selected site with an area of 103 ha is suitable to accommodate the entire power plant in its final capacity of 900MW with all auxiliary and ancillary buildings, the coal stockyard, ash disposal area, switchyard etc. and including a 43 ha buffer zone.

f) Feasibility Study for Combined Cycle Power Development Project at Kerawalapitiya -1999 [16]

g) Sri Lanka Electric Power Technology Assessment. Draft Report (Final), (July 2002) [17]

h) Master Plan Study for the Development of Power Generation and Transmission System in Sri Lanka, 2006 [27].

i) A note on stability of Diesel units on the Sri Lanka Power system, 2004 [25].

j) Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka [29].

k) Energy Diversification and Enhancement Project Phase IIA- Feasibility Study for Introducing LNG to Sri Lanka,2014

l) Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka (Ongoing)

4.3.2 Thermal Power Candidates

Several power generation technologies were considered in the initial screening of generation options based on the studies listed above. The reciprocating diesel plants are not included for the planning studies considering the possible contribution from such plants to the system instability [25] and the recommendation made by the Committee on Policy on Addition of Diesel Engines. Following are the thermal power generation technologies considered for the initial screening process:

(i) Coal Fired Thermal Power Plant
(ii) Oil fired Combined Cycle Power Plants
(iii) Oil fired Gas Turbine Plants
(iv) Natural Gas fired Combined Cycle Power Plant
(v) Super Critical Coal Fired Thermal Power Plant
(vi) Nuclear Power Plant

Large number of generation technology alternatives with different capacities cannot be used in the detailed study at once due to practical and computational difficulties. Therefore, preliminary screening has to be done in order to reduce the number of alternatives by choosing the most economically optimum set of generation technologies. The Screening Curve Method was used to reduce the number of alternatives. After the initial screening nine alternative expansion options, which are described in Section 4.3.3, were chosen for the detailed planning studies. The results of the screening curve analysis are given in Annex 7.1.

4.3.3 Candidate Thermal Plant Details

Capital costs of projects are shown in two components: The foreign cost and the local cost. During the pre-feasibility and feasibility studies, capital costs have been estimated inclusive of insurance and freight for delivery to site (CIF basis). Local costs, both material and labour, have been converted to their border price equivalents, using standard conversion factors. The standard conversion factor applied to all local costs is 0.9. No taxes and duties have been added to the plant costs. Whenever results of the project feasibility studies were available, these were adopted after adjusting their cost bases to reflect January 2015 values.

The thermal plant cost database, which was revised during the Thermal Generation Options Study [12] , The Review of the Least Cost Generation Plan [14], and Master Plan Study on the Development of Power Generation and Transmission System in Sri Lanka [27] has been adjusted to accommodate US dollar to SL Rupees exchange rate variations as well as rupee and dollar escalations. No escalation is applied to capital costs during the study period, thus assuming that all capital costs will remain fixed in constant terms throughout the planning horizon.

A summary of the capital costs and economic lifetimes of candidate plants taken as input to the present studies after the preliminary screening is given in Table 4.6. Operating characteristics of these plants are shown in Table 4.7. The detailed characteristics of the candidate thermal plants are given in Annex 4.3.

Table 4.6 - Capital Cost Details of Thermal Expansion Candidates

Plant	NET Capacity (MW)	Pure Unit Construction Cost -NET basis- (US$/kW)		Total Unit Cost (US$/kW)	Const: Period (Yrs)	IDC at 10% (% of Pure capital cost)	Const. Cost Incl. of IDC (US$/kW) -NET basis- (US$/kW)		Total Unit Cost Incl. of IDC (Net) (US$/kW)	Economic life (Years)
		Local	Foreign				Local	Foreign		
Gas Turbine-Auto Diesel	35	119.7	617.2	736.9	1.5	6.51	127.5	657.4	784.9	20
Gas Turbine-Auto Diesel	105	81.5	419.7	501.2	1.5	6.51	86.8	447.0	533.8	20
Combined Cycle -Auto Diesel	144	282.9	772.8	1055.7	3	13.54	321.2	877.4	1198.6	30
Combined Cycle -Auto Diesel	288	228.8	624.9	853.7	3	13.54	259.9	709.5	969.4	30
Coal Plant-Trincomalee PCL	227	523.4	645.6	1169	4	18.53	620.4	765.2	1385.6	30
New Coal Plant	270	357.6	1430.4	1788	4	18.53	423.9	1695.5	2119.4	30
Super Critical Coal Plant	564	383	1531.9	1914.9	4	18.53	453.9	1815.8	2269.7	30
Combined Cycle -LNG	287	149.7	959.1	1108.8	3	13.54	170.0	1089.0	1259.0	30
Combined Cycle – LNG-plant with full terminal cost*	287	495.9	2328.7	2824.7	4.5	21.12	600.7	2820.6	3421.3	30
Nuclear Power Plant	552	1007.2	3601.9	4609.1	5	23.78	1246.8	4458.5	5705.3	60

All costs are in January 2015 border prices. Exchange rate US$ 1 = LKR 131.55, IDC = Interest during Construction

*LNG terminal cost is apportioned appropriately in the screening curve analysis

Table 4.7 – Characteristics of candidate thermal plants

Plant	NET Capacity	Heat Rate (kCal/kWh)		Full Load Efficiency (Net,HHV)	FOR	Scheduled Maint. Days	Fixed O&M Cost	Variable O&M Cost
	(MW)	At Min. Load	Avg. Incr.	%	%	(Yr)	($/kW Month)	(USCts/ kWh)
Gas Turbine-Auto Diesel	35	3060	0	28.1	8	30	0.690	0.557
Gas Turbine-Auto Diesel	105	4134	2310	30.1	8	30	0.530	0.417
Combined Cycle Plant -Auto Diesel	144	2614	1462	46.6	8	30	0.549	0.470
Combined Cycle Plant -Auto Diesel	288	2457	1454	48.1	8	30	0.414	0.355
Coal Plant – Trincomalee PCL	227	2895	2157	33	5	40	2.92	0.560
New Coal plant	270	2810	1935	38.4	3	45	4.47	0.590
Super Critical Coal Plant	564	2248	1833	41	3	45	4.50	0.590
Combined Cycle Plant-LNG	287	2457	1462	47.9	8	30	0.381	0.497
Nuclear Power Plant	552	2723	2340	32	0.5	40	7.62	17.60

All costs are in January 2015 border prices. Exchange rate US$ 1 = LKR131.55, FOR = Forced Outage Rate
Heat values of petroleum fuel and coal based plants are in HHV

4.3.4 Fuel

Petroleum based fuels, Coal, Natural gas being the primary sources of fuel, were studied for this long term power generation expansion plan. Additionally LNG and Nuclear have also been studied under the present context considering technical constraints. In early years CEB used the World Bank fuel Price forecasts for planning scenarios. Considering the volatility present in fuel prices, constant fuel prices are mainly used in long term planning studies. Therefore, the fixed prices in constant terms were used for this planning study and then the price sensitivity of the plan was tested for 50 percent increase in price of each fuel type separately and their escalation.

(i) Petroleum products (Auto Diesel, Fuel oil, Residual Oil, Naphtha): In the present context, all fossil fuel-based thermal generation in Sri Lanka would continue to depend on imports (However, it should be noted that oil exploration activity is presently on going in the Mannar basin). Ceylon Petroleum Corporation (CPC) presently provides all petroleum products required for thermal power stations. In this study, oil prices used were obtained from Ceylon Petroleum Corporation and adjusted to reflect the economic values. Table 4.8 shows the fuel characteristics and the fuel prices used in the analyses. Further, it is important to note that all the heat contents given are based on higher heating value (HHV).

(ii) Coal: Coal is a commonly used fuel options for electricity generation in the world. CEB identified coal as an economically attractive fuel option for electricity generation in 1980's. But No coal plants were built until 2011 due to several environmental and social issues. At present, 900MW first coal power plant is in operation at Puttalam which was built in two stages. It is important to note that past fuel prices show that the coal prices are not closely linked with the petroleum prices. However, recently coal prices too has shown an increased volatility. Several coal types were defined in the study based on the calorific value for different expansion alternatives. The CIF values at Colombo on Coal prices were used in the studies to reflect economic values. Characteristics of coal types are given in Table 4.8.

Table 4.8 – Oil and Coal - Prices and Characteristics for Economic Analysis

Fuel Type	Heat Content (kCal/kg)	Specific Gravity	Border Prices of fuel types ($/bbl)**	Border Prices of fuel types Rs/l
Auto Diesel	10500	0.84	124.2	102.8
Fuel oil	10300	0.94	100.2	82.9
Residual oil	10300	0.94	95.5	78.8
Naphtha*	10880	0.76	108.9	90.1

	Heat Content (kCal/kg)	Price ($/MT)	Remarks
Coal type1	6300	97.86	Type 1- Lakvijaya Power plant*
Coal type2	6300	97.10	Type 2- Super Critical Coal Power plant*
Coal type3	5900	89.39	Type 3- New Coal Power plant
Coal type4	5500	81.69	Type 4- Trincomalee PCL coal plant
			(Coal types and prices are according to the design calorific value of each plant and expected coal unloading costs)

Source: Oil prices from Ceylon Petroleum Corporation, Coal price from Lanka Coal Pvt Ltd
All costs are based on border prices. Exchange rate US$ 1 = LKR 131.55- January 2015
* Difference between the price of Coal type 1 and type 2 is due to the estimated barging and handling costs.
** Coal price is given in the units of $/Mton

(iii) Liquefied Natural Gas

Liquefied Natural Gas (LNG) as a fuel for Gas Turbine and Combined Cycle plants is an attractive option from environmental perspective. LNG supply in Sri Lanka would add diversification to the country's fuel mix and in turn for the energy mix. Moreover, LNG has the advantage that it is readily burnt in combustion turbines that are characterized by high efficiency. There is no commercially developed gas field in Sri Lanka though discoverable gas reserves have been identified.

Indian, Bangladesh and other Gas sources are located far from Sri Lanka, which makes cross border pipeline projects economically unattractive. Hence natural gas transport by means of shipping as LNG is a better option for Sri Lanka. Following four recent studies have reviewed and evaluated LNG as a fuel option for Sri Lanka:

1. Sri Lanka Electric Power Technology Assessment Draft Report (Final), (July 2002) [17]
2. Sri Lanka Natural Gas Options Study, USAID-SARI/Energy Program (Revised June 2003) [18]
3. Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka – 2010 (JICA funded),phase I [29]
4. Energy diversification enhancement by introducing Liquefied Natural Gas operated power generation option in Sri Lanka. –Phase IIA [34]

The first two studies have concluded that the potential demand for gas in the country is very small since the demand for LNG is mainly from the power sector. However, the above JICA funded study (phase I) conducted in 2010 concluded that under certain conditions, such as low LNG prices (similar to the price obtained by India in 2008/09), LNG too could be competitive with coal and would be a viable fuel. However, the price assumptions made JICA Study seemed too optimistic in the global context.

The second phase of the above study identified that the Colombo North Port as the best site for development of a LNG terminal from several promising candidate sites including Hambantota and Trincomalee. LNG requirement of the country was determined considering the conversion possibilities of the existing Combined Cycle power plants located in Colombo and other sectors such as Industrial and Transport sectors. The study has also identified, Kerawalapitiya as the most suitable location for the development of new LNG fired power plants by considering the technical, economic, social and environmental aspects. LNG facility suitable for Sri Lanka would consist of an LNG import facility (via tanker ships), domestic storage, regasification unit and a power plant. However, a recent development of the FSRU (Floating Storage and Regasification Unit) which can be moored in the sea has a faster implementation possibility. Natural gas prices in recent years and technological advances have lowered costs of regasifying, shipping, and storing LNG in the global market. In addition, other sectors, such as vehicular fuel and industry can use LNG as a substitute.

According to the "Study for Energy diversification enhancement by introducing LNG Operated Power Generation options in Sri Lanka", there are different LNG pricing mechanisms adopted in different regions of the world and the current LNG pricing system particularly in Asian market is linked with the Japanese average import LNG price (CIF) which is indexed against the Average Japanese imported Crude oil price, i.e. Japanese Crude Oil Cocktail (JCC). The above study suggests that the linkage of 12.7% with Japanese Crude Cocktail (JCC) reflects the appropriate LNG price for Sri Lanka.

Accordingly, considering the average JCC prices, LNG Price of 13.69 $/MMBTU has been used for the long term generation expansion planning study (2015-2034).

(iv) Natural Gas

In September 2007, the Petroleum Resources Development Secretariat which was established under the Petroleum Resources Act, N0 26 of 2003 to ensure proper management of the petroleum resources industry in Sri Lanka, launched its first Licensing Round for exploration of oil and gas in the Mannar Basin off the north-west coast and in 2008 exploration activities initiated with the awarding of one exploration block (3000 sqkm) in Mannar Basin. Two wells namely 'Dorado and 'Barracuda' have been drilled , 'Dorado' indicates the availability of natural gas and it is estimated to have approximately 300 bcf of recoverable gas reserves. Gas production rate predicted is 70 mscfd. This amount is equivalent to approximately 0.5 mtpa. Based on the above most likely quantity of natural gas, it is estimated that it could cater 1000MW capacity for approximately 15 years with a plant factor of 30-50%.
The cost of natural gas to be used in the study is derived in consultation with PRDS based on their economic projections. PRDS predicts progressive reduction of natural gas price with time, and expect 30% to 50% reduction of the initial price by the end of economic limits of the Dorado and Barracuda supplies respectively. Natural Gas price of 11.5USD/MMBTU was used in this study, which includes the economic cost of 10.5USD/MMBTU and 1USD/MMBTU transportation cost. This excludes the state fiscal gains through royalty, government profit, tax, interest and other bonuses and fees. Details and Results of the case studies performed regarding introducing Natural gas for power Generation are presented in the chapter 7.

Table 4.9 – LNG and NG - Prices and Characteristics for Economic Analysis

Fuel Type	Heat Content (kCal/kg)	Border Prices of fuel ($/MMBTU)
LNG	13000	13.69
NG	13000	11.50*

*exclusive of Royalty, Tax and Profit

(v) Nuclear

Nuclear plants are inherently large in capacity compared to other technologies for power generation. From technical point of view, the capacity of the present system is considerably small to accommodate a Nuclear power plant of typical size. However, cabinet approval has been given to consider nuclear as an option to meet the future energy demand and also to consider Nuclear Power in the generation planning exercise and to carry out a pre-feasibility study on the Nuclear Option. Nuclear option was included in this study as a candidate plant from year 2030 onwards. In addition, a project proposal too has been forwarded to IAEA for requesting technical assistance for supporting energy planning and Prefeasibility study for Nuclear Power and Human Resources Development in Nuclear Power Engineering.

4.3.5 Screening of Generation Options

A preliminary screen of generation options is carried out in order to identify most appropriate expansion options. It is a cumbersome and computationally difficult process to handle large number of generation options in a detailed analysis. The screening curve analysis which is based on specific Generation cost is employed in the initial screening and the method is described in the section 6.3 in detail.

Thermal plant database, which was updated by Electrowatt Engineering (EWE) during the Thermal Generation Options Study in 1996 [12] and again reviewed during the Review of Least Cost Generation Expansion Study in 1997 [14] and confirmed during the Master Plan study 2006 [27] was extensively used during the current planning study. However, adjustments have been made to the cost base to reflect January 2015 values. Whenever feasibility study results are available for any prospective project, such results were used in preference to the above studies.

4.3.6 Thermal Plant Specific Cost Comparison

The specific costs of the selected candidate plants for different plant factors are tabulated in the Table 4.10. These specific costs are derived in the screening curve methodology which considers the capital Investments cost, Operation and Maintenance cost, Fuel cost and economic life time of a given generation alternative. It reveals how different technologies perform at different plant factors. Accordingly, Peak Load Power plants are cost effective at low plant factor operation whereas base load plants such as Coal and Nuclear are attractive options for higher plant factor operations. However, in actual simulations, the size of the generation units are taken into account and it would make a significant effect in the final plant selection.

Table 4.10 - Specific Cost of Candidate Thermal Plants in USCts/kWh (LKR/kWh)

Plant \ Plant Factor	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8
35MW Gas Turbine	38.50 (50.64)	33.08 (43.52)	31.27 (41.14)	30.37 (39.95)	29.83 (39.24)	29.47 (38.77)	29.21 (38.43)	29.02 (38.17)
105MW Gas Turbine	33.24 (43.73)	29.52 (38.84)	28.28 (37.21)	27.66 (36.39)	27.29 (35.90)	27.04 (35.58)	26.87 (35.34)	26.73 (35.17)
150MW Combined Cycle Plant	30.50 (40.12)	23.73 (31.22)	21.48 (28.25)	20.35 (26.77)	19.67 (25.88)	19.22 (25.28)	18.90 (24.86)	18.66 (24.54)
300MW Combined Cycle Plant	27.23 (35.82)	21.77 (28.64)	19.96 (26.25)	19.05 (25.06)	18.50 (24.34)	18.14 (23.86)	17.88 (23.52)	17.68 (23.26)
300MW Coal Plant-Trinco	22.58 (29.71)	13.50 (17.76)	10.47 (13.78)	8.96 (11.79)	8.05 (10.59)	7.45 (9.80)	7.02 (9.23)	6.69 (8.80)
300MW New Coal Plant	31.76 (41.78)	17.87 (23.51)	13.24 (17.42)	10.93 (14.38)	9.54 (12.55)	8.61 (11.33)	7.95 (10.46)	7.46 (9.81)
600MW Super Critical Coal Plant	33.15 (43.61)	18.48 (24.30)	13.58 (17.87)	11.14 (14.65)	9.67 (12.72)	8.69 (11.43)	7.99 (10.51)	7.47 (9.82)
300MW LNG plant (Incl: apportioned terminal cost*)	29.38 (38.65)	19.81 (26.06)	16.62 (21.86)	15.03 (19.77)	14.07 (18.51)	13.43 (17.67)	12.97 (17.07)	12.63 (16.62)
600MW Nuclear Plant	67.87 (89.28)	36.25 (47.69)	25.71 (33.83)	20.44 (26.89)	17.28 (22.73)	15.17 (19.96)	13.67 (17.98)	12.54 (16.50)
5MW Dendro Plant	34.45 (45.32)	22.36 (29.42)	18.33 (24.12)	16.32 (21.47)	15.11 (19.88)	14.30 (18.82)	13.73 (18.06)	13.30 (17.49)

Note: 1 US$ = LKR 131.55

*LNG terminal cost is apportioned appropriately and included in the plant capital cost

4.3.7 Current Status of Non-Committed Thermal Projects

(a) **Trincomalee Coal Power Project**

Government of Sri Lanka (GOSL) and Government of India (GOI) entered into a Memorandum of Agreement (MOA) in 2006 to develop a coal power plant in Trincomalee as a joint venture between Ceylon Electricity Board and National Thermal Power Corporation Ltd. of India. Trincomalee Power Company Limited (TPCL) was established as the joint venture company for the implementation of the Trincomalee Power Project with the total capacity of 500MW. Several alternative sites were explored in 2008 under a Strategic Environmental Assessment for setting up the proposed power project in Trincomalee region and based on various techno economical and environmental considerations a site near Sampoor village was identified for the Feasibility Study.

Agreements for Power purchase, Implementation, Land Lease, Coal Supply and agreements with Board of Investment have been signed and the feasibility study of the project was completed. The Environmental Impact Assessment was opened for public comments in the first quarter of 2015 and the Basic design and technical specifications are now being finalized.

The project consists of two units of 250MW and the generated power will be transmitted at 220kV level to the major load centers. The Project requires around 500 acres for the implementation and consists of the main power block, coal handling plant, coal storage yard, ash disposal system, sea water cooling system, other building facilities and a green belt.

(b) **New Coal fired Power Plant – Trincomalee -2**

Ceylon Electricity Board completed the Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka with the financial assistance of New Energy and Industrial Technology Development Organization (NEDO) of Japan and the study was carried out by Electric Power Development Co., Ltd.(J-POWER) in 2013 and 2014. Under the above study, candidate sites were studied from South-West to South Coast Area and in Trincomalee Bay area considering, technical, environmental and social conditions and finally three sites at southern coast, site in Hambantota port area and a site at Sampur area in Trincomalee were selected as the most suitable sites for future coal power development.

In 2014, the Feasibility Study for High Efficient and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka commenced under the same program and the study was conducted for the site in Sampur area in Trincomalee. Basic thermal plant design has been prepared for 1200MW(4 x 300MW) development considering technical, geological and environmental considerations. High Efficient and Eco Friendly Coal fired thermal power plant equipped with several emission control technologies to reduce emission levels significantly was studied. The Environmental Impact Assessment of the proposed project is expected to conduct as the next step.

(c) **Coal power plants in the Southern Coast**

Southern Coal Power Project: The Government of Sri Lanka (GOSL) / Ceylon Electricity Board (CEB) invited Expressions of Interest from reputed firms for developing, building and operating of four coal fired generating units of 300MW capacity on BOO basis. CEB has identified locations near KaraganLewaya, Mirijjawila, Mirissa and, Mawella as prospective sites in Southern coast and Athuruwella in the Western Coast for future Coal fired power plants. This procurement process was not continued. Recent Pre-Feasibility Study for High Efficient and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka selected Hambantota port and Mawalla locations as prospective sites in southern coast for coal power development.

Mawella Coal Power Development Project: The Mawella site was studied under a pre-feasibility level as a candidate site for coal power development together with the other thermal options in 1988. The study proposed 600MW coal power plants at the site. Further the above mentioned recent Pre-Feasibility Study for High Efficient and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka has also identified Mawella Site as a suitable candidate site for future coal power development.

4.4 India-Sri Lanka Electricity Grid Interconnection

Governments of India and Sri Lanka signed a Memorandum of Understanding (MOU) in 2010 to conduct a feasibility study for the interconnection of the electricity grids of the two countries. This feasibility study was carried by CEB and Power Grid Corporation Indian Limited (POWERGRID) jointly with the main objective to provide the necessary recommendations for implementation of 1000MW HVDC interconnection project.

In 2002, NEXANT with the assistance of USAID carried out the Pre-feasibility for Electricity Grid Interconnection. In 2006, POWERGRID, India reviewed and updated the study with USAID assistance.

Various Line route options and connection schemes were analyzed during the pre-feasibility studies. Consequently the route option was selected for the feasibility study consist of 130km 400kV HVDC overhead line segment from Madurai to Indian sea coast , 120km of 400kV Under-Sea cable from Indian sea coast to Sri Lankan Sea coast, 110km Overhead line segment of 400kV from Sri Lankan sea coast to Anuradhapura and two converter stations at Madurai and Anuradhapura. Both HVDC technologies; Conventional Line Commuted Conversion and Voltage Source Conversion have been considered in the feasibility study.

The feasibility study has considered the technical, economical, legal, regulatory and commercial aspects in trading electricity between India and Sri Lanka. The feasibility study is yet to be finalized.

CHAPTER 5
NON CONVENTIONAL RENEWABLE GENERATION OPTIONS FOR FUTURE EXPANSION

Renewable energy sources are continuously replenished by natural processes. A renewable energy system converts the energy in sunlight, wind, falling water, sea-waves, geothermal heat or biomass into heat or electricity without exhausting the source. Most of the renewable energy comes either directly or indirectly from sun and wind and can never be exhausted, and therefore they are called renewable.

The large or regulated hydro plants are considered as conventional generation options. Therefore only non-conventional renewable options considered for system expansion are described in this chapter. Most of NCRE power plants are non-dispatchable due to their intermittent nature and are developed in small capacities. The reliability level of electricity supply from plants running on renewable sources is also low since the renewable sources are directly affected by changes in natural phenomena like wind, sun, water flow in streams etc. Therefore, system absorption of non-conventional renewable energy needs to be studied carefully.

Sri Lanka has exploited large conventional renewable resources (hydro) to almost its maximum economical potential. Non-Conventional Renewable Energy (NCRE) has become a prime potential source of energy for the future due to the low impact on environment compared with conventional sources of energy. Sri Lanka has a history of enabling local development of renewable energy resources in the electricity systems. This includes:

- Hydropower
- Wind Energy
- Biomass
- Solar Power
- Power from Municipal Solid Waste

As of 10th January 2015, approximately 442MW of NCRE power plants are connected to the National Grid. Out of this, contribution from mini hydro is 293MW while biomass-agricultural & industrial waste penetration is 23.5MW. Contribution to the system from solar power and wind power is 1.4MW and 124MW respectively.

Though, the Ceylon Electricity Board initiated renewable energy development, it is presently the private sector, which is mainly involved in the NCRE development. The renewable energy industry is rapidly growing in the country with both local and foreign investment. In comparison with the conventional large power plants, the total contribution from the NCRE sector to the National Grid still remains small but continues to increase and in 2014 the energy share of NCRE was 9.8%. Table 5.1 shows the system development and renewable energy development during the last 12 years in the Sri Lankan system. Recently a three tiered tariff has been introduced as an incentive for NCRE development. Annex 5.1 gives the NCRE tariff effective from 01/01/2012.

As stated in Chapter 2.1.2 the existing mini hydro/NCRE plants were included in this study in the base case. Table 5.2 gives the projected future development of NCRE up to 2034. Capacity contribution from NCRE was considered during the study.

Table 5.1 – Energy and demand contribution from non-conventional renewable sources

Year	Energy Generation (GWh)		Capacity (MW)	
	Non-Conventional Renewable	System Total	Non-Conventional Renewable	Total System Installed Capacity
2003	120	7612	39	2483
2004	206	8043	73	2499
2005	280	8769	88	2411
2006	346	9389	112	2434
2007	344	9814	119	2444
2008	433	9901	161	2645
2009	546	9882	181	2684
2010	724	10714	212	2818
2011	722	11528	227	3141
2012	730	11801	320	3312
2013	1178	11962	367	3355
2014	1215	12418	442	3932

Source: www.ceb.lk

Table 5.2 – Projected future development of NCRE (Assumed as committed in Base Case Plan)

Year	Cumulative Mini hydro addition (MW)	Cumulative Wind addition (MW)	Cumulative Biomass addition (MW)	Cumulative Solar addition (MW)	Cumulative Total NCRE Capacity (MW)	Annual Total NCRE Generation (GWh)	Share of NCRE from Total Generation %
2015	293	124	24	1	442	1516	11.7%
2016	313	124	34	16	487	1677	12.5%
2017	338	144	49	31	562	1945	13.5%
2018	363	244	74	46	727	2561	16.7%
2019	388	254	99	61	802	2872	17.5%
2020	413	354	124	81	972	3496	20.0%
2021	438	404	129	91	1062	3797	20.7%
2022	458	454	129	101	1142	4047	21.0%
2023	473	499	134	111	1217	4287	21.2%
2024	483	544	144	126	1297	4553	21.4%
2025	493	589	149	136	1367	4777	21.4%
2026	508	599	154	146	1407	4906	20.9%
2027	543	619	164	156	1482	5167	21.0%
2028	578	619	174	166	1537	5371	20.8%
2029	618	639	184	176	1617	5649	20.8%
2030	653	639	194	186	1672	5853	20.6%
2031	658	659	204	196	1717	6011	20.2%
2032	663	679	224	206	1772	6240	20.0%
2033	668	699	249	216	1832	6503	20.0%
2034	673	719	279	226	1897	6801	20.0%

Note: Present Value of Base Case with “assumed as committed NCRE” is 68.4 MUSD higher than the Reference Case.

5.1 NCRE Study for 2015 to 2025

With the increase share of non dispatchable NCRE power plants in the power system, problems related to power quality, power system stability, economic operation due to intermittency could be experienced. Hence, special consideration should be given when integration of especially wind and solar to the national grid due to the intermittent nature of these sources. Therefore, detailed system planning and operations studies are required to determine the NCRE share of both dispatchable and non-dispatchable plants that could be connected to system.

Accordingly, a comprehensive study on "Integration of Non-Conventional Renewable Energy Based Generation into Sri Lanka Power Grid"[35] was carried out by CEB in 2015. In this study, the absorption of NCRE based generation to the system was extensively studied considering resource estimation, grid availability, system stability, curtailment requirements etc. WASP (Wien Automatic System Planning), SDDP (Stochastic Dual Dynamic Programming), NCP, SAM (System Advisor Model) and PSSE (Power System Simulation for Engineering) planning and simulation tools were used for the study.

5.2 NCRE Resource Estimation

Variation in NCRE generation needs to be absorbed by the conventional generators. Hence, accurate wind and solar generation forecasting is important. Wind and solar power production forecasts in addition to load forecast need to be prepared acquiring new software tools.

Short term variations are not seen in generation from Biomass and Small Hydro plants. Generation from wind and solar plants are intermittent (e.g. depending on the variations in the wind speed and solar radiation).

5.2.1 Estimating Wind Energy Production

Wind speed measurement data contains hourly and 10 minutes information. Wind data collected by the Sustainable Energy Authority (SEA) and by existing power plants have been used to determine the wind profiles. 10-minute information is more useful for integration studies, since it provides sub-hourly information critical for determining short-term variability and system impacts. Wind measurement data shown in Table 5.3 has been used in the study.

Table 5.3: Wind measurement site locations and time period

Recodered by	Location	2009	2010	2011	2012	2013
SEA	Nadukuda-Mannar			Jun-Dec	Jan Feb	
SEA	Nantnathan-Mannar			May-Dec	Jan-Dec	Jan
SEA	Seethaeliya-Nuwar Eliya			Jun-Dec	Jan-July	
SEA	Udappuwa-Puttalam	Feb-May/ Sep-Dec	Jan-Oct			
SEA	Silawathura-Mannar			June-Dec	Jan-Oct	
RMA	Nadukuda-Mannar				June-Dec	Jan-May

Mannar - 2012 and 2013 data recorded at Nadukuda by SEA were used to build the annual wind profile for Mannar at 60m elevation.

Puttalam -2009 and 2010 data recorded at Udappuwa by SEA were used to develop the annual wind profile for Puttalam at 50m elevation.

Hillcountry -2011 and 2012 data recorded at Seethaeliya by SEA were used to develop the annual wind profile for Hill country model at 50m elevation.

Considering the limited availability of the continuous wind speed measurement data for several years, series of annual data was prepared by combining data recoded at parts of the two consecutive years to determine a continuous one year wind speed pattern. It was assumed that the same seasonal pattern of wind takes place in every year for each site.

Wind Plant Modelling

Wind plant modeling to estimate annual energy production and hourly capacity variation were carried out using the software named System Advisory Model (SAM) developed by National Renewable Energy Laboratory (NREL). SAM model is designed to make performance predictions and cost estimates of energy for grid-connected renewable power projects based on installation, operating costs and system design parameters that user specifies as inputs to the model. Hourly wind speed data prepared for each site location is given as an input to the SAM software and then the wind plant/farm should be modeled specifying turbine and farm characteristics. Basic design elements given in Table 5.4 were considered in modeling each wind plant. Existing 124MW of wind capacity was modeled using the Puttalam model.

Table 5.4: Wind plant design elements

Location	Mannar	Puttalam	Hill country	Northern
Block Capacity	25MW	20MW	10MW	20MW
Wind profile	Mannar	Puttalam	Hill country	Mannar
Turbine capacity (MW)	2.5x10	2 x10	0.6 x17	2 x10
Plant availability	91%	91%	91%	91%

Figure 5.1, 5.2 and 5.3 shows the power output and wind speed variation of Mannar (25MW), Puttalam (20MW) and Hill Country (10MW) Wind Plants respectively. Table 5.5 lists the annual plant factors and annual energy of each plant.

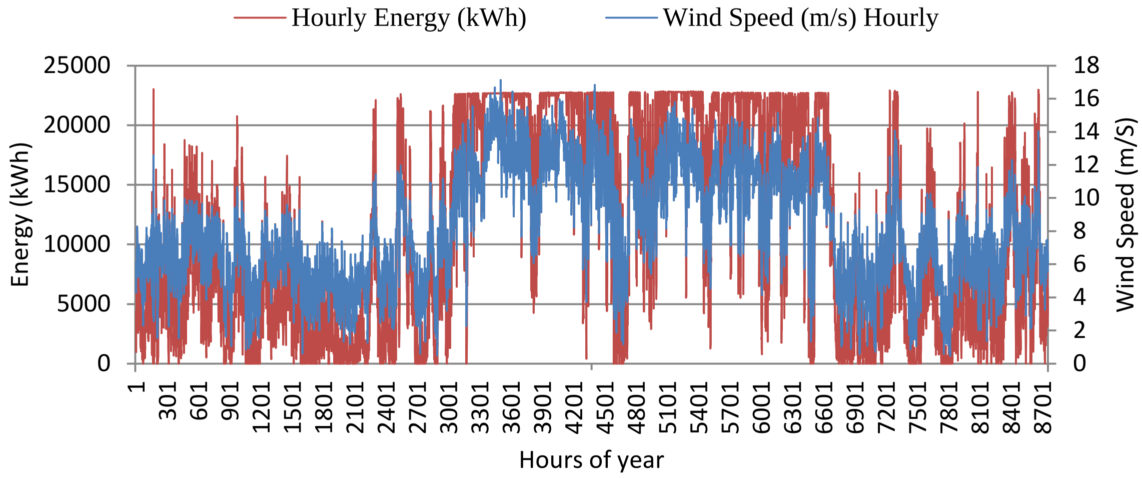


Figure 5.1: Power Output for Mannar 25MW wind farm

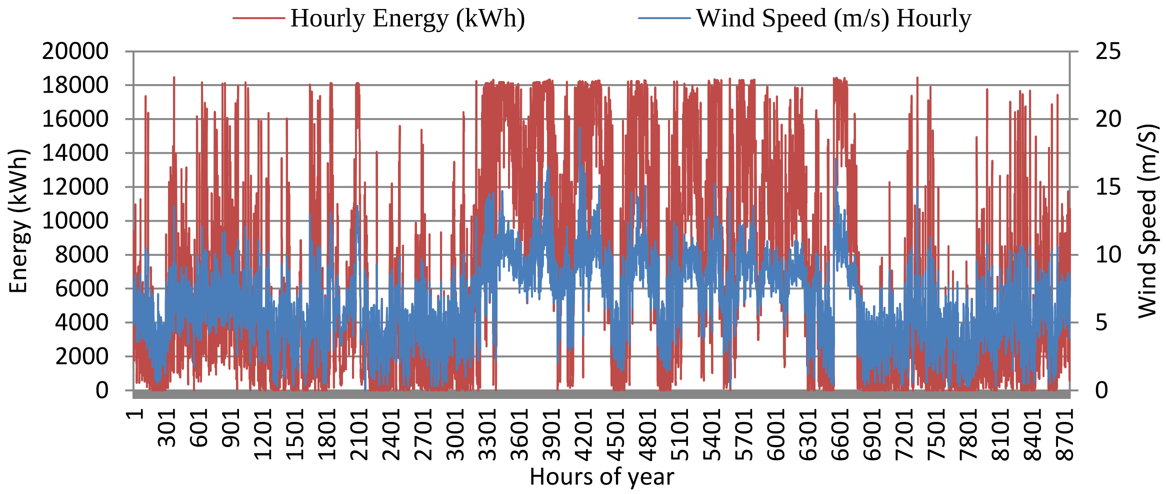


Figure 5.2: Power Output for Puttalam 20MW wind farm

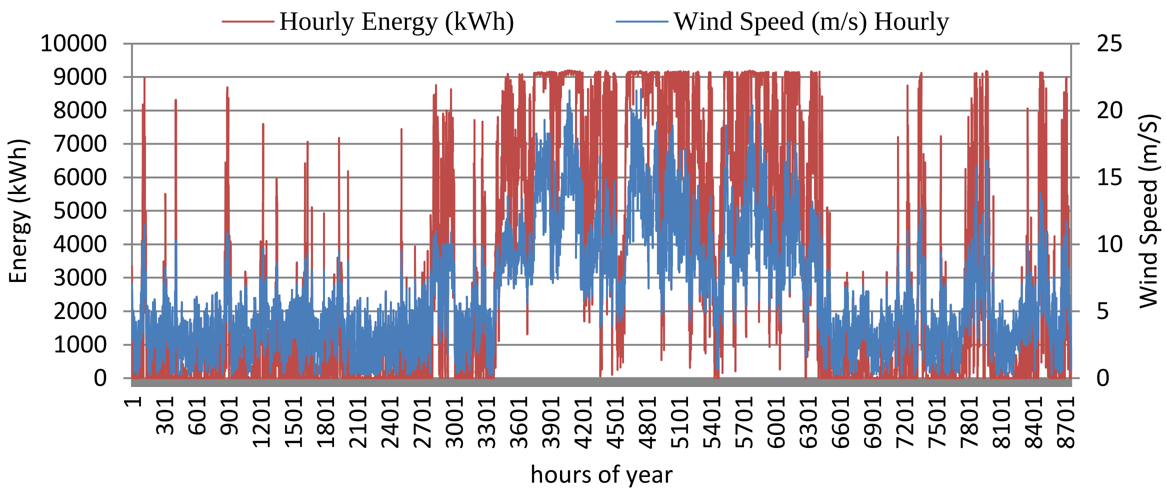


Figure 5.3: Power Output for Hill country 10MW wind farm

Table 5.5: Wind plant energy production

Location	Mannar	Puttalam	Hill country	Northern
Block Capacity	25MW	20MW	10MW	20MW
Annual Plant Factor	42.3%	31.4%	25.9%	42.2%
Annual Energy(GWh)	93	55	23	74

In addition to the above annual figures for wind energy generation, hourly variation of wind plant output was obtained for the short-term dispatch analysis.

5.2.2 Estimating Mini Hydro Energy Production

Historical data on Mini-hydro energy production and Plant factors from 1998 to 2009 were used for deriving an energy profile for Mini Hydro model. The model was also verified with the information prepared by the System Control Centre. Existing Mini Hydro capacity of 293.3MW was considered and annual capacity additions were taken according to the NCRE development targets for the study. The annual plant factor of the model is 37.4 % in the average Hydro Condition. The average monthly energy output of existing mini hydro capacity of 293.3MW is shown in Figure 5.4

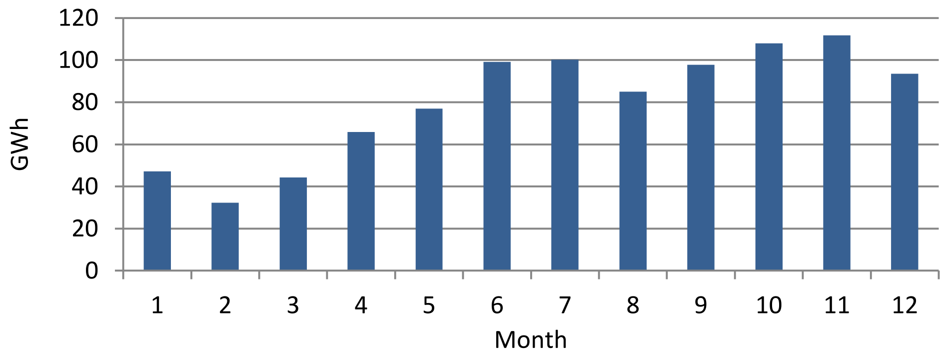


Figure 5.4: Average Monthly Energy Output of Existing Mini hydro Capacity 293.3MW

5.2.3 Estimating Solar Energy Production

Solar radiation measurements; 10 minute data of Global Horizontal Irradiance (GHI), Direct Normal Irradiance (DNI) and Diffuse Horizontal Irradiance (DHI) have been obtained from SEA at Hambantota and Kilinochchi. For Hambantota, one year (2012) data were available and for Kilinochchi, complete data for year 2014 and data for several months in 2013 and 2015 were available. Input data was screened to identify discontinuities. The data of a complete year used as input to the System Advisor Model (SAM). From the available data, hourly inputs were constructed as Watts per square meter (W/m^2).

Several assumptions were made during the solar energy estimation. The availability of the plants was taken as 90%. In these two sites, only GHI and DHI was available. DNI was calculated with available GHI and DHI. The typical commercial PV module and inverter characteristics in built in SAM were used. Solar Outputs were considered as given in Table 5.6.

Table 5.6: Solar output plant factor

Location	Plant Factor
Hambantota	16.3%
Kilinochchi	14.5%

Figures 5.5 (a) and 5.5 (b) show the monthly solar energy variation and annual capacity output from Kilinochchi 10MW Solar Power Plant while Figures 5.6 (a) and 5.6 (b) show the monthly solar energy variation and annual capacity output from Hambantota 10MW Solar Power Plant.

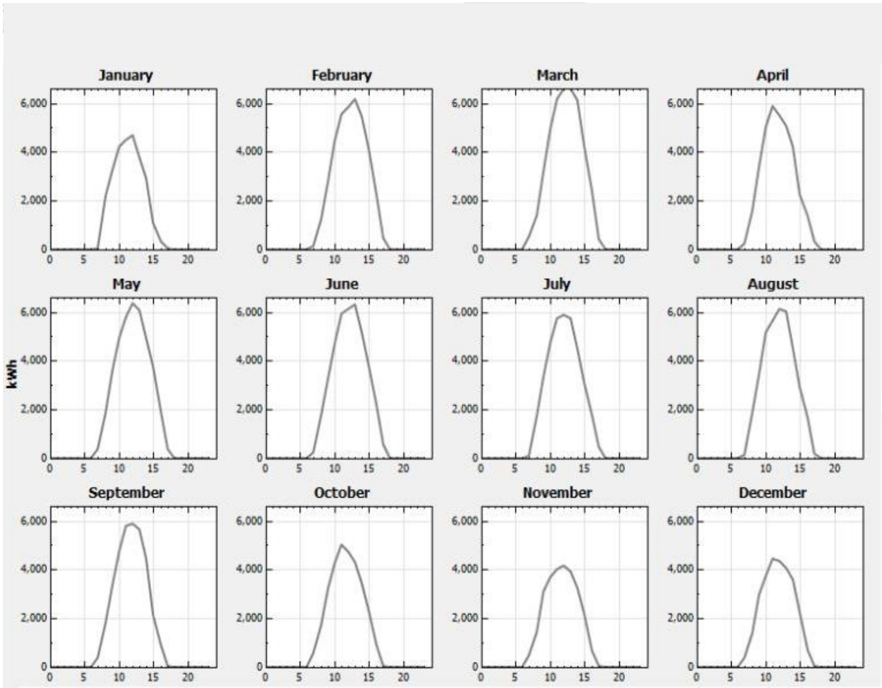


Figure 5.5 (a): Monthly Solar Energy Variation of Kilinochchi 10MW Plant

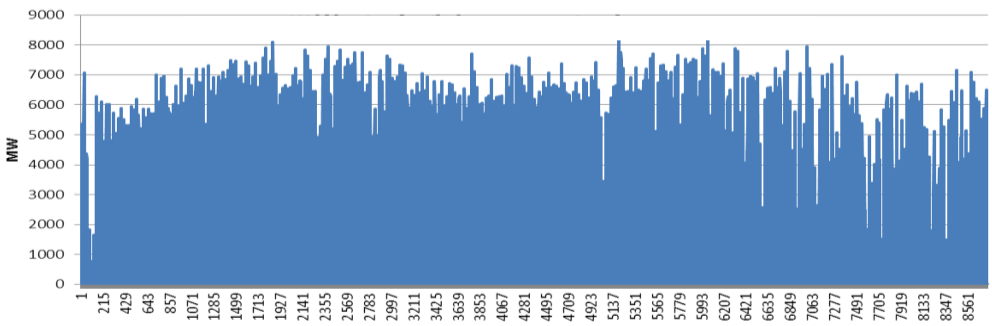


Figure 5.5 (b): Capacity Output of Kilinochchi 10MW Plant

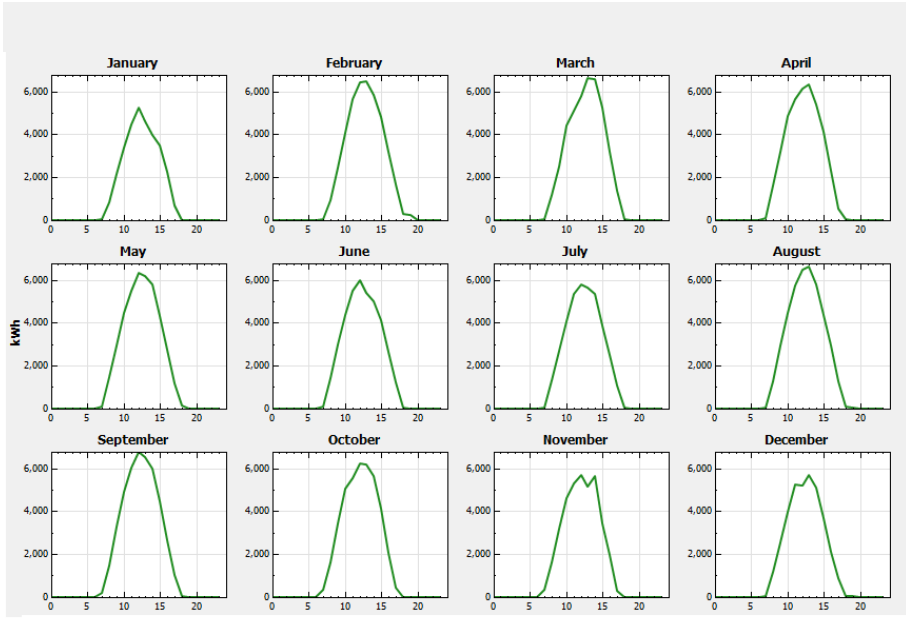


Figure 5.6 (a): Monthly Solar Energy Variation of Hambantota 10MW Plant

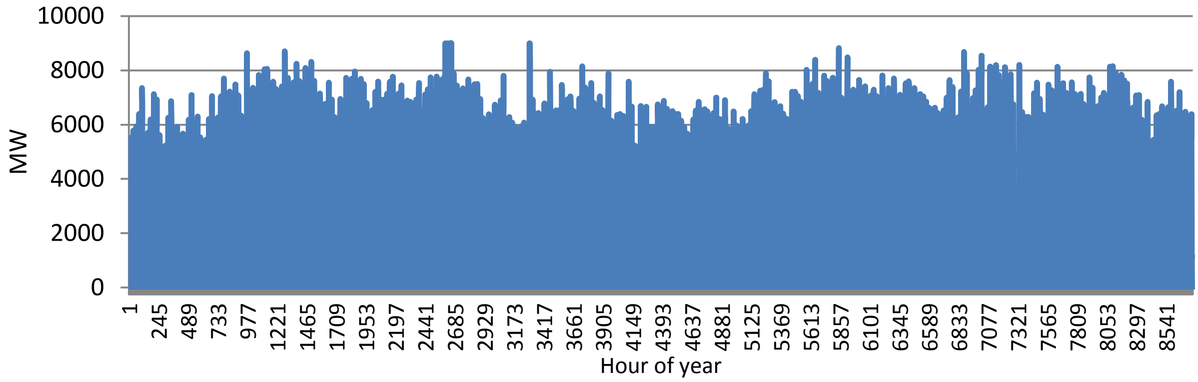


Figure 5.6 (b): Capacity Output of Hambantota 10MW Plant

5.2.4 Estimating Biomass Energy Production

Biomass Plants were modelled as thermal plants of dispatchable nature.

5.3 Municipal Solid Waste

Power generation using solid waste is being considered by the most of Local Authorities in the country. This could be a satisfactory solution for proper disposal of solid wastes. However, so far waste to power project has not been implemented even though several Letters of Intent(LOI) had been issued by Ceylon Electricity Board and Sri Lanka Sustainable Energy Authority to developers.

5.4 Other

Other forms of renewable energy such as Wave, OTEC, Solar Chimney, and other solar thermal applications are still at the experimental stage. However, these technologies have been given the opportunity to develop by offering a tariff in the NCRE tariff. Solar power too is considered under this category.

5.5 Net Metering

The use of batteries and inverters for storage of electricity is expensive to micro – scale electricity producers. The “Energy Banking Facility” for such micro-scale generating facilities, commonly known as the “Net Energy Metering Facility” by the electricity utilities for their electricity consumers has been introduced in Sri Lanka. This scheme allows any electricity consumer to install a renewable energy based electricity generating facility and connect it to the CEB’s electricity network. The electricity network connection scheme shall be approved by CEB.

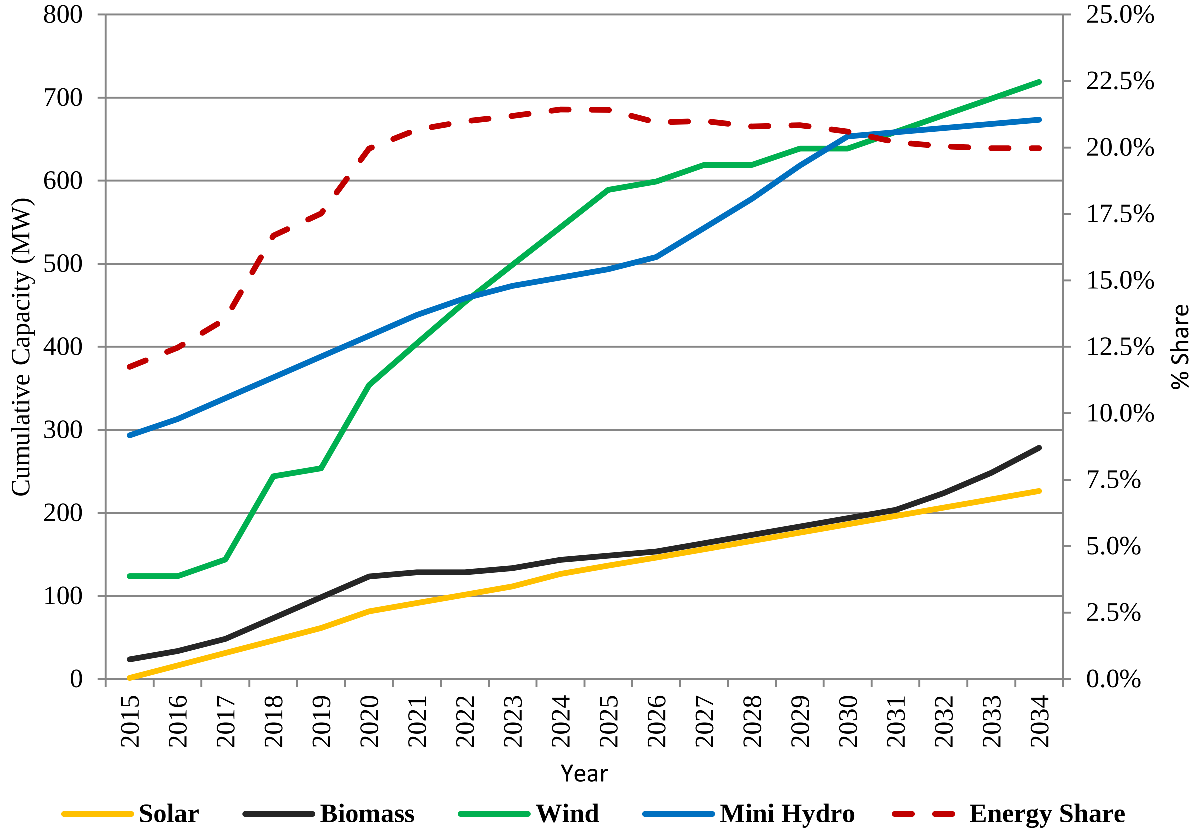
The utility energy meter is replaced with an Import/Export meter. The electrical energy consumed from the grid is considered as import energy and electrical energy generated and supplied to the grid is considered as export energy.

At the end of each billing period, CEB reads the consumer’s export and import meter readings. The electricity bill is prepared giving credit to the export, and charging the consumer for the difference between the import and the export. If the export is more than the import in any billing period, the consumer receives an export credit, and is credited towards his next month’s consumption. Such credits may be carried-over to subsequent months, as long as there is no change in the legal consumer for the premises.

The key factor in this process is that there will be no financial compensation for the excess energy exported by the consumer. All exports are set-off against the consumer’s own consumption, either in the current billing period or future billing periods. Accordingly, consumers are compelled to select the capacity of the renewable energy facility to reasonably match his requirements. Facilities with contract demand less than 1000 kVA (Upper capacity as per the Revision No. 1, January 2014) are allowed to install “net” metering equipment and generally it is installed on the low voltage side. For Solar based Generation, according to the National Demand forecast 2015 – 2039, ten times growth of number of net metering consumers is assumed in 2030 compared to 2013.

5.6 Inclusion of NCRE in the LTGEP

Renewable sources of energy will play a supplementary role in the national context while playing a very important role in decentralised applications, in meeting electrical energy needs of rural and remote communities. NCRE has not been considered as a candidate in this study due to its intermittent nature. However, development of NCRE as shown in Table 5.2 has been assumed as committed and modelled accordingly. Figure 5.7 illustrates the capacity additions and future NCRE energy share which reaches 20% in 2020 and increases to 21% in 2025 and then maintains at 20% during rest of the planning period.



Plant factors- Mini Hydro- 39%, Biomass-80%, Solar-17% and Wind (Mannar)-38%, Wind (Hill Country and Other) - 32%

Figure 5.7: NCRE Addition for 20% energy share in 2020

Addition of generators with high inertia such as coal facilitates system integration of NCRE power plants. However, during load demand period of the day due to operational limitations, generation from NCRE power plants especially wind power may have to curtail. To overcome the situation and obtain the maximum benefit to the country, it is proposed to develop 375MW wind farm at Mannar as semi dispatchable plants. Therefore, CEB plans to develop all three phases (phase I, phase II & phase III) of Mannar wind farm, to pass the maximum benefit to the electricity consumers of the country.

5.7 Development of NCRE

Government of Sri Lanka established the Sustainable Energy Authority (SEA) on 01 October 2007, enacting the Sri Lanka Sustainable Energy Authority Act No. 35 of 2007 of the Parliament of the Democratic Socialist Republic of Sri Lanka. SEA is expected to develop indigenous renewable energy resources and drive Sri Lanka towards a new level of sustainability in energy generation and usage; to declare energy development areas; to implement energy efficiency measures and conservation programmes; to promote energy security, reliability and cost effectiveness in energy delivery and information management.

The objective of the SEA is to identify, promote, facilitate, implement and manage energy efficiency improvements and energy conservation programmes in domestic, commercial, agricultural, transport, industrial and any other relevant sector. SEA will guide the nation in all its efforts to conserve energy resources through exploration, facilitation, research & development and knowledge management in the journey of national development. Also SEA will promote energy security, reliability and cost-effectiveness of energy delivery to the country by policy development and analysis and related information management. Further the authority will ensure that adequate funds are available to implement its objects, consistence with minimum economic cost of energy and energy security for the nation, thereby protecting natural, human and economic wealth by embracing best sustainability practices. Relating to power development, SEA will hold two key sensitive parts namely declaration of energy development area and on-grid & off-grid renewable energy resources. CEB and SEA will have to play a complementary role to each other in the future in order to optimise the power generation from NCRE.

Further, Government of Sri Lanka established the Sri Lanka Energies (Pvt) Ltd, a 100% Ceylon Electricity Board owned company on 12th July 2012 to accelerate the electricity generation through renewable energy resources.

CHAPTER 6
GENERATION EXPANSION PLANNING METHODOLOGY AND PARAMETERS

CEB considers the project options from all possible sources including CEB owned generation developments, large thermal plants from the independent power producers and supply of non-conventional renewable energy sources in order to meet the system demand. Several factors are taken in to account in this process of selecting the appropriate power development project. Commercially exploitable potential, technical feasibility studies, environment impact assessment and economic feasibility are the main factors of this selection process. Together with these factors, the Draft Grid Code of Public Utilities Commission of Sri Lanka, Planning guidelines of Ministry of Power and Energy and National Energy Policy are also taken into consideration in the planning process. Long Term Generation Expansion Plan is the outcome of the selection process. The methodology adopted in the process is described in this chapter.

6.1. Grid Code Generation Planning

Draft Generation Planning Code in the Grid Code issued by the Transmission Licensee is considered in preparing the Long Term Generation Expansion Plan 2015-2034.

6.2. National Energy Policy and Strategies

Ministry of Power and Energy gazetted the National Energy Policy & Strategies of Sri Lanka in June 2008. This document spells out the implementing strategies, specific targets and milestones through which the Government of Sri Lanka and its people would endeavor to develop and manage the energy sector in the coming years. Specific new initiatives are included in this policy to expand the delivery of affordable energy services to a larger share of the population, to improve energy sector planning, management and regulation.

Institutional responsibilities to implement each policy element and associated strategies to reach the specified targets are also stated in this document. The “National Energy Policy and Strategies of Sri Lanka” is elaborated in three sections in this policy document as follows.

- “Energy Policy Elements” consists of the fundamental principles that guide the development and future direction of Sri Lanka’s Energy Sector.
- “Implementing Strategies” states the implementation framework to achieve each policy element.
- “Specific Targets, Milestones and Institutional Responsibilities” state the national targets, and the planning and institutional responsibilities to implement the strategies.

Following nine major policy elements are addressed in the “Energy Policy Elements”,

- Providing Basic Energy Needs
- Ensuring Energy Security
- Promoting Energy Efficiency and Conservation
- Promoting Indigenous Resources
- Adopting an Appropriate Pricing Policy

- Enhancing Energy Sector Management Capacity
- Consumer Protection and Ensuring a Level Playing Field
- Enhancing the Quality of Energy Services
- Protection from Adverse Environmental Impacts of Energy Facilities

"Implementing Strategies" elaborate the broad strategies to implement the above policy elements. It covers all the policy elements separately and clear strategies are proposed to implement them.

Some policy elements, specific targets and milestones related to electricity sector are to be addressed in the plan in order to identify financial and other institutional requirement related to the policy. These policy elements include:

- Providing electricity at the lowest possible cost to enhance the living standard of the people,
- Ensuring energy security by diversified energy mix,
- Consideration of efficiency improvements and indigenous resources for the future developments,
- Consideration of system reliability, proven technologies, appropriate unit sizes etc. to improve quality of supply,
- Consideration of environmental impacts.

Electricity generation targets envisaged for the year 2015 under specific targets and milestones for Fuel Diversity and Security in the guidelines published in 2008 are shown in Table 6.1.

Table 6.1– Electricity generation targets envisaged for the year 2015

Year	Electrical Energy Supplied to the Grid as a Share of the Total			
	Conventional Hydroelectric	Maximum from oil	Coal	Minimum from Non-conventional Renewable Energy
2015	28%	8%	54%	10%

Considering the present installed capacity and operation of power plants, this target can be achieved in year 2015. National Energy Policy and Strategies of Sri Lanka should be reviewed and revised after a period of three years. The guidelines published in 2008 were used in the preparation of the LTGEP 2015-2034.

Presently, it is being discussed how to achieve energy security, considering the other alternative options of fuels, giving due consideration to environmental aspects such as CO_2 emission, renewable energy integration, fuel diversity etc. Fuel diversification road map should be developed after considering all sectors of the economy. In the Long-Term Generation Expansion Plan 2015-2034, case studies were carried out to facilitate the information required for reviewing of the National Energy Policy to enhance the fuel diversity on the basis of achieving Energy Security.

6.3 Preliminary Screening of Generation Options

There are many technologies from many prime sources of energy in various stages of development. However, it is difficult to analyze in detail all these options together. Therefore, several power generation technologies are considered in the initial screen of generation options to select the technologies and prime source of energy to be included in the LTGEP.

Details of the screening curve methodology are given in Annex 6.1. The results of the screening curve analysis are explained in section 7.1 in Chapter 7. The detailed planning methodology described in section 6.4 to section 6.7 is used to finalize the Least Cost Generation Expansion Plan.

6.4. Planning Software Tools

State of the art optimization and simulation models are used in the detailed generation planning exercise. Internationally accepted planning methodologies, wherever possible, are adopted during the formulation of the Long Term Generation Expansion Plan.

The Stochastic Dual Dynamic Programming (SDDP) and NCP software tools developed by PSR (Brazil), Model For Analysis of Energy Demand (MAED), Model for Energy Supply Strategy Alternatives and their General Environmental Impacts (MESSAGE) and Wien Automatic System Planning (WASP) package - WASP IV developed by International Atomic Energy Agency (IAEA) were extensively used in conducting the system expansion planning studies to determine optimal Long Term Generation Expansion Plan.

6.4.1 SDDP and NCP Models

Stochastic Dual Dynamic Programming (SDDP) model is an operation planning tool which simulates the hydro and thermal generation system to optimize the operation of hydro system. More than 30 years of historical inflow data for existing, committed and candidate hydro plants were taken into account by the model to stochastically estimate the future inflow patterns and then simulates with total system to estimate energy and capacity availabilities associated with plants. Hydro plant cascade modeling and reservoir level detail modeling has been done to more accurately represent the actual operation. Maximum of hundred scenario simulations can be done with the model to represent different hydro conditions.

The potential of hydropower system estimated using SDDP model is used as input information to WASP IV package. Since WASP package could accommodate only a maximum of five hydro conditions, hundred scenario outputs of SDDP were rearranged and divided into five hydro conditions, Very Wet, Wet, Average, Dry and Very Dry considering probability levels.

Short term dispatch analysis was carried out using NCP software in order to observe the operational issues of the developed Base Case Plan.

6.4.2 MAED Model

The Model for Analysis of Energy Demand (MAED) relies upon the end use demand projection methodology that was originally developed at IEJE of the University of Grenoble, France and known as MEDEE-2. Respecting the general structure of MEDEE-2, the International Atomic Energy Agency (IAEA) developed the present MAED model by introducing important modifications concerning the parameters required to be specified as input data, equations used to calculate energy demand of some sectors, and some additional modules to analyse hourly electricity consumption to construct the load duration curve of the power system. MAED consists with mainly two modules, namely a module for energy demand analysis (MAED_D) and module for hourly electric power demand calculations (MAED_EL).

Details and results of the scenario analysis is given in Chapter 3. Output of MAED demand projection was compared with the base demand forecast which was prepared using econometric method and the comparison is given in chapter 3.

6.4.3 WASP Package

Generation Planning Section uses the latest version of the WASP package (WASP IV) for its expansion planning studies. WASP is used to find the economically optimal expansion policy for a power generating system within user-specified constraints. WASP IV has seven modules. It utilizes probabilistic estimation of system production costs, expected cost of unserved energy and reliability to produce the optimal generation expansion sequence for the system for the stipulated study period. Also, it can be used to carry out power generation expansion planning taking into consideration fuel availability and environment constraints. Probabilistic Simulation, Linear Programming and Dynamic Programming are the simulation and optimization methods used in WASP-IV.

6.4.4 MESSAGE Software

Model for Energy Supply Strategy Alternatives and their General Environmental Impacts (MESSAGE) is designed for setting up models of energy systems for optimization. MESSAGE was originally developed at International Institute for Applied Systems Analysis (IIASA). The IAEA later acquired MESSAGE software and several enhancements have been made in it.

MESSAGE is designed to formulate and evaluate alternative energy supply strategies considering user defined constraints. The modelling procedure is based on building the energy flow network which describes the whole energy system, starting from available energy resources, moving to primary and secondary level energy and ending with modelling the final level demand categorizing the demand types such as heat, motor fuel and electricity. Energy demand and supply patterns can be included in to the model. The underlying principle of MESSAGE is optimization of an objective function under a set of constraints that define the feasible region containing all possible solutions of the problem. Although, MESSAGE is a long term optimization model it is possible to model the chronological demand curve.

MESSAGE software was used to analyze the Base Case Plan. All the parameters from final demand of electricity to primary and secondary level input fuel for power plants were modeled as energy chains in the system, and 20 year time horizon was used in the study. Energy flow chart of the electricity system is given in Annex 6.2. Model results for the Base Case Plan are given in chapter 7.

6.5 Hydro Power Development

Hydro resource is one of the main indigenous sources of energy and lifetime of a hydro plant is quite high compared to the other alternative sources. Therefore, these hydro plants are considered separately outside the LTGEP. In this alternate process, economic analysis is carried out for each project with the consideration of avoided thermal plant of the LTGEP. Then technical feasibility studies and environmental impact assessments are processed for economically feasible projects. Once all these requirements are fulfilled and funds are committed, the project is incorporated to the LTGEP as a committed plant.

6.6 Assessment of Environmental Implications and Financial Scheduling

Though the environmental effects of each thermal and hydro option are considered in the initial selection, overall assessment of environmental implications is carried out for the proposed LTGEP. The plant emissions are assessed after the possible environmental mitigation measures are taken.

Other two aspects of the planning process are the implementation and financing. In fact, the total period of implementation of a project including feasibility studies varies from 4 years for a gas turbine and 8 years for a coal-fired plant. Similarly implementation period of a hydro plant is in the range of 7 to 8 years. Therefore, implementation scheduling is an important item of the planning process. Furthermore, generation system expansion is highly capital intensive. Therefore, financial schedule is prepared in order to identify the financial requirement which is essential for sourcing of funds and for projecting electricity tariffs.

6.7 Modeling of NCRE

As stated in Chapter 5, NCRE was not included as candidates. According to the Grid Code, only the existing NCRE plants are considered as committed in the Reference Case. However, a projected development was considered as committed and incorporated in to the Base Case of the LTGEP. The main technologies of NCRE; mini-hydro, wind, solar and dendro were modeled in the WASP. Dendro plants were modeled as thermal power plants. Wind and solar additions were projected annually and taking into account the actual resource profiles of wind and solar. The demand profiles were modified to reflect both capacity and energy contributions from these NCRE power plants. Mini hydro was included in the WASP as lumped ‘run of the river’ hydro power plants. The probabilistic monthly energy was calculated based on past performance of mini hydro plants.

6.8 Study Parameters

The preparation of the plan is based on several parameters and constraints. These include technical and economical parameters and constraints which are to be used as input to WASP IV. Parameters and constraints given in Grid Code were used in the studies and those are described in detail.

6.8.1 Study Period

The results of Base Case and all sensitivity studies are presented in the report for a period of 20 years (2015-2034). In this regard, the studies were conducted for a period of 25 years (2015-2039).

6.8.2 Economic Ground Rules

All analyses were performed based on economic (border) prices for investments and operations. The exchange rate used in the present study is 131.55 LKR/USD. This is the average value of January 2015 exchange rates. All costs are based on 1st of January 2015.

6.8.3 Plant Commissioning and Retirements

It was assumed that the power plants are commissioned or retired at the beginning of each year. Such limitations are common in the long term planning tools.

6.8.4 Cost of Energy Not Served (ENS)

The average loss to the economy due to electrical energy not supplied has been estimated as 0.63 USD/kWh (in 2015 prices). This value has been derived by escalating the ENS figure given by PUCSL as 0.5 USD/kWh in 2011.

6.8.5 Loss of Load Probability (LOLP)

LOLP is a reliability index that indicates the probability that some portion of the load will not be satisfied by the available generation capacity. It is defined as the percentage of time during the system load exceeds the available generation capacity in the system. According to the Draft Grid Code LOLP maximum value is given as 1.5%. This corresponds to cumulative failure duration of 5.5 days/year for the generating system.

6.8.6 Reserve Margin

Reserve margin is the other available reliability criteria of the WASP-IV module. This is a deterministic reliability index which is the measure of the generation capacity available over and above the amount required to meet the system load requirements. Minimum value of 2.5% and Maximum value of 20% have been applied for the studies.

6.8.7 Discount Rate

The discount rate is used in order to analyze the economic costs and benefits at different times. The discount rate accounts several factors such as time value of money, earning power, budget constraints, purchasing power, borrowing limitations and utility of the money. Considering these facts, 10% discount rate was used for planning studies. Sensitivity to the discount rate is analyzed by applying lower and higher discount rates.

6.8.8 Plant Capital Cost Distribution among Construction Years

The distribution of plant capital cost among construction period is carried out by assuming “S” curve function relating expenditure to time based on 10% discount rate. The resultant annual cost distributions for individual power plants are given in the Investment Program shown in Table 8.1 in Chapter 8. However optimization process considers only the total cost and is not affected by this cost distribution.

6.8.9 Assumptions and Constraints Applied

The following were the assumptions and constraints that were applied to all studied cases.

a) All costs are based on economic prices for investment on generating plants. Furthermore, thermal plants will be dispatched in strict merit order, resulting in the lowest operating cost.

b) All plant additions and retirements are carried out at the beginning of the year.

c) Gas Turbine plants can be available only by January 2018. For Gas Turbines, the construction period is about 1.5 years, but in the absence of any detailed designs for a power station, it may require 2 years for the pre-construction and construction activities.

d) Committed Power Plants are shown in the Table 6.2 below.

Table 6.2 Committed Power Plants

Power Plant	**Capacity (MW)**	**Year of Operation**
Hydro		
Broadlands HPP	35	2017
Uma Oya HPP	120	2017
Moragolla HPP	31	2020

e) The Candidate Power Plants with earliest possible commissioning year are depicted in the Table 6.3 below.

Table 6.3 Candidate Power Plants

Power Plant	**Capacity (MW)**	**Year of Operation**
Thermal		
Gas Turbine	35 / 105	2018
Coal Plants Trincomalee Coal Power Company Limited	2 x 250	2020
LNG operated Combined Cycle Plant	300	2022
New Coal Plant	300	2022
Supercritical Coal Plant	600	2025
Nuclear Power Plant	600	2030
Hydro		
Seethawaka HPP	20	2020
Thalpitigala HPP	15	2020
Gin Ganga HPP	20	2022

f) 5MW Dendro Power Plant is modeled from the data received from Sustainable Energy Authority. Where the number of Dendro power plants allowable for a particular year of base case study was predefined.

g) Plant Retirements of CEB owned and IPP plants are given in Table 6.4.

Table 6.4 Plant Retirement

Power Plant	No of Units x Unit Capacity (MW)	Year of Retirement
CEB Owned Thermal Plants		
Gas Turbine (Old)	4 x17	2017
Gas Turbine (New)	115	2023
Sapugaskanda Diesel Plant	4 x18	2019
Sapugaskanda Diesel Plant (Ext.)	4 x 9	2023
Sapugaskanda Diesel Plant (Ext.)	4 x 9	2025
IPP Plants		
ACE Power Embilipitiya Ltd	100	2015
Asia Power Plant	49	2018
Nothern Power Plant	30	2020

h) Term of contracts of IPP Plants: 60 MW Colombo Power plant will be operated as a CEB power plant at the end of its PPA period in 2015 until 2020. The contract of 163 MW AES Power Plant at Kelanitissa will expire in 2023 and it will be operated as a CEB plant until 2033.

i) Net generation values were used in planning studies instead of gross values.

j) Future Wind Farms are to be developed as Semi-dispatchable Power Plants.

k) All new NCRE Plants are capable to curtail the generation when necessary.

CHAPTER 7
RESULTS OF GENERATION EXPANSION PLANNING STUDY

This chapter presents the results of the Base Case analysis for 2015-2034 planning horizon in detail and describes the key results of the scenario analysis on several policy directions and sensitivity analysis on important technical and economic parameters. Results on Environmental Impacts of case analysis are discussed comparatively in the Chapter 9.

7.1 Results of the Preliminary Screening of Generation Options

For the preliminary screening exercise of alternative options, three coal fired steam plant technologies, two oil fired steam plants, two oil-fired gas turbines, two oil fired combined cycle power plants, Natural Gas fired combined cycle plant and a Nuclear Power plant were considered. For evaluating alternative generation technologies with varying capital investments, Operation costs, Maintenance costs life time and etc, it is necessary to employ an indicator common for all plants. Specific generation cost expressed in US Cents/ kWh calculated at different plant factors for each plant was used to screen the initial generation technology alternatives before carrying out the detailed expansion planning studies. Discount rate of 10%, which is considered as the base discount rate for the National Planning studies, is used for the above screening process and the sensitivity of the preliminary screening is tested for 3% and 15% discount rates. The specific generation costs for selected thermal plants calculated for 3%, 10% and 15 % discount rates are shown in Annex 7.1.
From the screening curve analysis, the following candidate technologies were selected including committed power plants as suitable options for detailed generation expansion planning studies.

- 35MW Auto Diesel fired gas turbine
- 105MW Auto Diesel fired gas turbine
- 150MW Auto Diesel fired combined cycle power plant
- 300MW Auto Diesel fired combined cycle power plant
- 300MW Coal fired thermal power plant
- 600MW Super Critical Coal power plant
- 250MW Coal Power plant Trincomalee Power Company Limited
- 300MW LNG fired combined cycle power plant
- 600MW Nuclear Power plant

Detailed generation expansion planning studies were conducted with the above alternatives in order to identify the least cost plant development sequence to meet the Base Demand Forecast.

In addition to the above alternatives derived from the screening analysis 3x200MW Pump Storage Power Plant (PSPP) was introduced to the system. Introduction of PSPP was based on the results of two studies, “Development Planning on Optimal Power generation for Peak Demand in Sri Lanka” [33] and “Integration of Non-Conventional Renewable Energy Based Generation into Sri Lanka Power Grid” [35]. In each scenario, PSPP was introduced to the system if at least 2000MW of coal plant capacities are in operation to overcome the system limitation. PSPP unit with adjustable speed type will also facilitate the reduction of curtailment of NCRE in the Base Case Plan.

7.2 Base Case Plan

The Base Case Plan is given in Table 7.1 and required capacity additions according to the Base Case Plan are given in the Table 7.2. In this study, committed power plants have been fixed according to the present implementation schedule.

The total present value (PV) cost of the Base Case Plan including the cost of development of NCRE for the period 2015-2034 is USD 12,960.51 million (LKR 1,704,954.5 million) in January 2015 values.

Generally, in Long Term Generation Expansion studies only the costs which affect future decision making process are considered. Hence the capital costs of committed plants and expenditure arising from the capital costs of existing plants (e.g. loan repayment of CEB plants or capacity payment to IPP plants) are not reflected in the total least cost of the system (PV) which is the optimized result of WASP studies.

The Reference Case was developed following the PUCSL guidelines in addition to the Base Case Plan and it considers only the NCRE power plants capacities already in operation as of 1st January 2015. The Total present value (PV) of the Reference Case plan for the period 2015-2034 is USD 12,892 million.

Table 7.1– Generation Expansion Planning Study - Base Case (2015 – 2034)

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15MW CEB Barge Power Plant	4x15MW Colombo Power Plant 14x7.11MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35MW Broadlands HPP* *120MW Uma Oya HPP*	-	4x17MW Kelanitissa Gas Turbines	0.175
2018	**100MW Mannar Wind Park Phase I**	**2x35MW Gas Turbine**	8x6.13MW Asia Power	0.299
2019*****	-	**1x35MW Gas Turbine**	4x18MW Sapugaskanda Diesel	1.140
2020	*31 MW Moragolla HPP* **15MW Thalpitigala HPP**** **100MW Mannar Wind Park Phase II**	**2x250MW Coal Power Plants Trincomalee Power Company Limited**	4x15MW CEB Barge Power Plant 6x5MW Northern Power	0.164
2021	**50MW Mannar Wind Park Phase II**	-	-	0.360
2022	**20MW Seethawaka HPP***** **20MW Gin Ganga HPP**** **50MW Mannar Wind Park Phase III**	**2x300MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.015
2023	**25MW Mannar Wind Park Phase III**	*163 MW Combined Cycle Plant* *(KPS – 2)*+	163MW AES Kelanitissa Combined Cycle Plant++ 115MW Gas Turbine 4x9MW Sapugaskanda Diesel Ext.	0.096
2024	**25MW Mannar Wind Park Phase III**	**1x300MW New Coal plant – Southern Region**	-	0.040
2025	**1x200MW PSPP***** **25MW Mannar Wind Park Phase III**	-	4x9MW Sapugaskanda Diesel Ext.	0.028
2026	**2x200MW PSPP*****	-	-	0.003
2027	-	**1x300MW New Coal plant – Southern Region**	-	0.002
2028	-	-	-	0.010
2029	-	**1x300MW New Coal plant – Trincomalee -2, Phase – II**	-	0.007
2030	-	**1x300MW New Coal plant – Trincomalee -2, Phase – II**	-	0.005
2031	-	-	-	0.029
2032	-	**2x300MW New Coal plant – Southern Region**	-	0.003
2033	-	-	165MWCombined Cycle Plant (KPS) 163MWCombined Cycle Plant (KPS–2)	0.142
2034	-	**1x300MW New Coal plant – Southern Region**	-	0.118
Total PV Cost up to year 2034, **US$ 12,960.51 million** [LKR 1,704.96 billion]+				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.

\+ PV cost includes the cost of Projected Committed NCRE, **US$ 1527.9 million** based on economic cost, and an additional Spinning Reserve requirement is kept considering the intermittency of NCRE plants with a cost of **US$ 471.5 million**.

***** In year 2019, Minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2025 and 2026 respectively.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5MW respectively.

Table 7.2: Generation Expansion Planning Study - Base Case Capacity Additions (2015 – 2034)

Year	Capacity Addition (MW)							LOLP (%)
	Peak Demand (MW)	Gas Turbine	Major Hydro	Pumped Hydro	Coal	NCRE	Total	
2015	2401					22	22	0.077
2016	2483					45	45	0.150
2017	2631		155			75	230	0.175
2018	2788	70				165	235	0.299
2019	2954	35				75	110	1.140
2020	3131		46		500	170	716	0.164
2021	3259					90	90	0.360
2022	3394		40		600	80	720	0.015
2023	3534					75	75	0.096
2024	3681				300	80	380	0.040
2025	3836			200		70	270	0.028
2026	4014			400		40	440	0.003
2027	4203				300	75	375	0.002
2028	4398					55	55	0.010
2029	4599				300	80	380	0.007
2030	4805				300	55	355	0.005
2031	5018					45	45	0.029
2032	5235				600	55	655	0.003
2033	5459					60	60	0.142
2034	5692				300	65	365	0.118
Total		**105**	**241**	**600**	**3200**	**1477**	**5623**	

7.2.1 System Capacity Distribution

The supply mix of the power sector is moving towards thermal based generation system with the increases of demand since the total hydro capacity remains nearly the same over the planning horizon in the Base Case scenario. Retirement of existing thermal capacities also necessitates new capacity additions and plant retirement details are given in Table 7.1. In the year 2025, the share of coal based generation capacity is 37% and it gradually becomes 48% by 2034. Current Hydro capacity contribution is 35% under average hydro condition where as it will be 26% and 18% in the year 2025 and 2034 respectively. Current share of oil based capacity is 30% and it gradually decreases in the first half of the planning period and then the capacity share changes from 12% in 2025 to 5% in 2034. Pumped Hydro capacity will be introduced to the system in 2025 and its capacity contribution in 2034 is 7%.

Present total installed capacity is 3932MW and out of that 3493MW is dispatchable power plants and the Chapter 2 includes the detailed information of the existing generation system. 1023MW of existing thermal capacity is due to retire during the 20 year planning period and three units of 35MW gas turbine are added to the system in 2018 and 2019 for operational requirements. Future addition of hydro capacity is 241MW including 186MW of committed plants and 55MW of new hydro power plants as shown in the Table 7.1. 3200 MW of coal power plants are added during planning period 2015-2034and mainly coal based generation units serve the base load requirement of the system. As shown in the Table 5.2, 1477MW of NCRE capacity additions over the 20 year period is expected and the total NCRE capacity increases to 1367MW in 2025 and 1883MW in 2034. The first 200MW Pumped Storage Hydro power plant unit is added in 2025 followed by another two units of same capacity in 2026. The Wind Power Park of 375MW capacity in Mannar Island is expected to be implemented in phases starting from year 2018 to 2025.

Capacity additions by plant type are summarised in five year periods in Table 7.3 and graphically represented in Figure 7.1. Capacity balance of the system is presented in Annex 7.2. Information on the capacity share is illustrated in the Figure 7.2 and the variation of the total renewable capacity contribution over the years is shown in the Figure 7.3.

Table 7.3: Capacity Additions by Plant Type

Type of Plant	2015 - 2019	2020 - 2024	2025-2029	2030-2034	Total Capacity Additions	
	(MW)	(MW)	(MW)	(MW)	(MW)	%
Gas Turbines	105				**105**	1.87%
Major Hydro	155	86			**241**	4.29%
Pumped Hydro			600		**600**	10.67%
Coal		1400	600	1200	**3200**	56.91%
NCRE	381.9	495	320	280	**1476.9**	26.27%
Total	**642**	**1,981**	**1,520**	**1,480**	**5,623**	100.00%

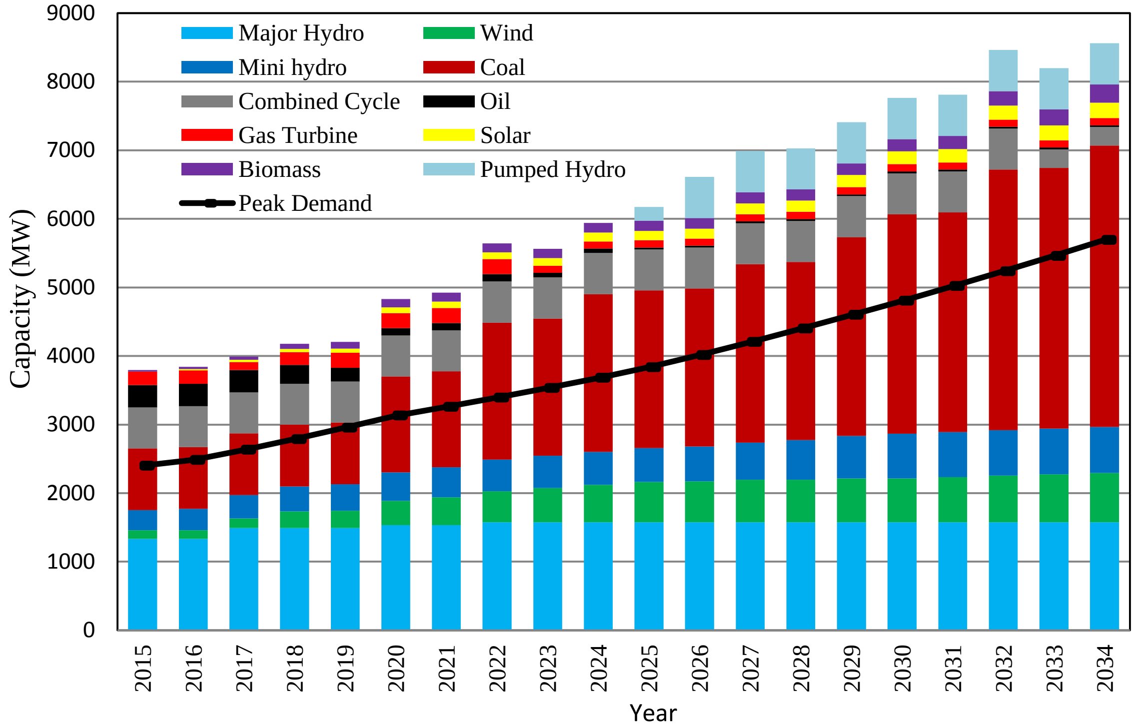


Figure 7.1 –Cumulative Capacity by Plant Type in Base Case

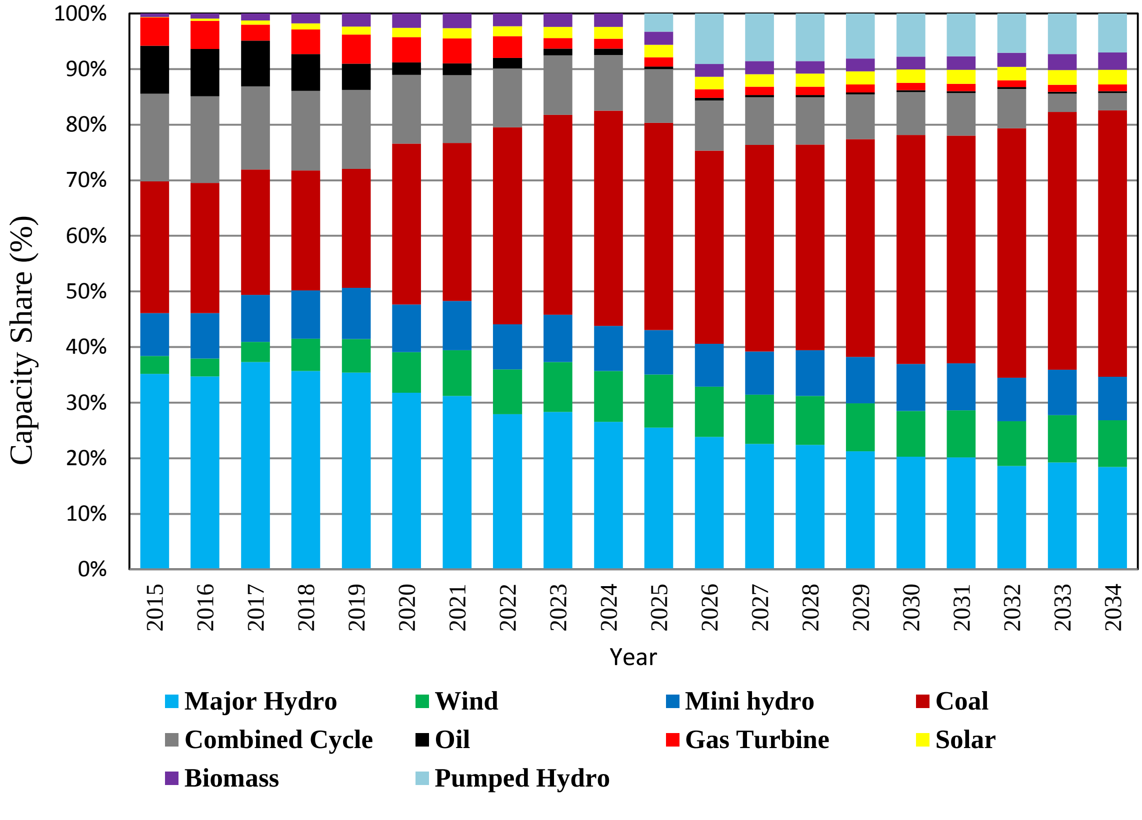


Figure 7.2 – Capacity Mix over next 20 years in Base Case

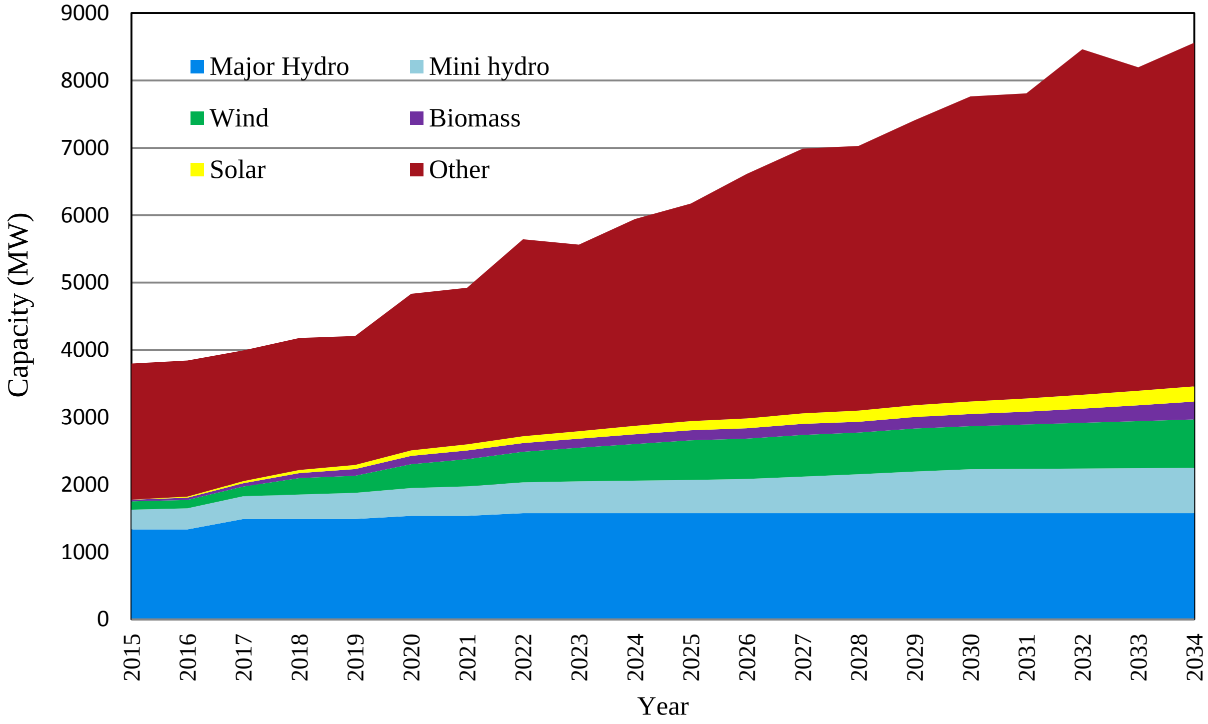


Figure 7.3 – Capacity wise Renewable Contribution over next 20 years

7.2.2 System Energy Share

At present 34% of the total energy demand is met by hydro generation whereas 55% is met by thermal generation. Current NCRE contribution to the National Electricity Demand is 11%. Future energy supply scenario of the Base Case Plan is graphically represented in Figure 7.4. The hydro generation share slightly increases with addition of new hydro power plants during the first half of the planning period and thereafter continues to contribute at the same level. Beyond 2020, Coal becomes the major energy contributor of the system and the energy share gradually increases with the addition of new Coal power plants to cater the increasing national demand. Coal energy share is 40% in 2020 and will increase up to 62% by 2034. As shown in the Figure 7.4 Combined Cycle plants contribute smaller energy share over the planning period and the energy contribution from other oil fired power plants including Diesel power plants and IPPs decreases from 13% in 2015 to 3% by 2025 with the gradual retirement of oil plants. Energy contribution from NCRE increases from present 11% to 20% by 2020 and thereafter continues to maintain the same contribution over the planning period which is the optimum NCRE penetration levels to the system. Percentage energy share of each plant type is given in Figure 7.5 and Energy Balance of the system is given in Annex 7.3. The Annual expected generation and plant factors under different hydro conditions for the Base Case Plan are given in Annex 7.4.

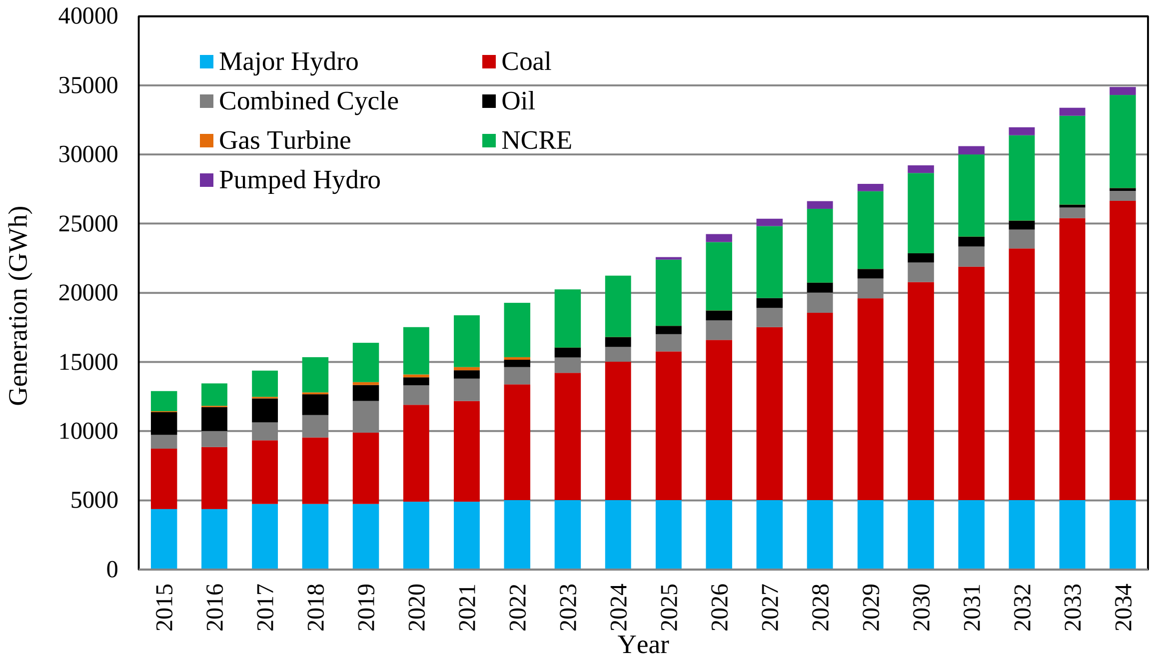


Figure 7.4– Energy Mix over next 20 years in Base Case

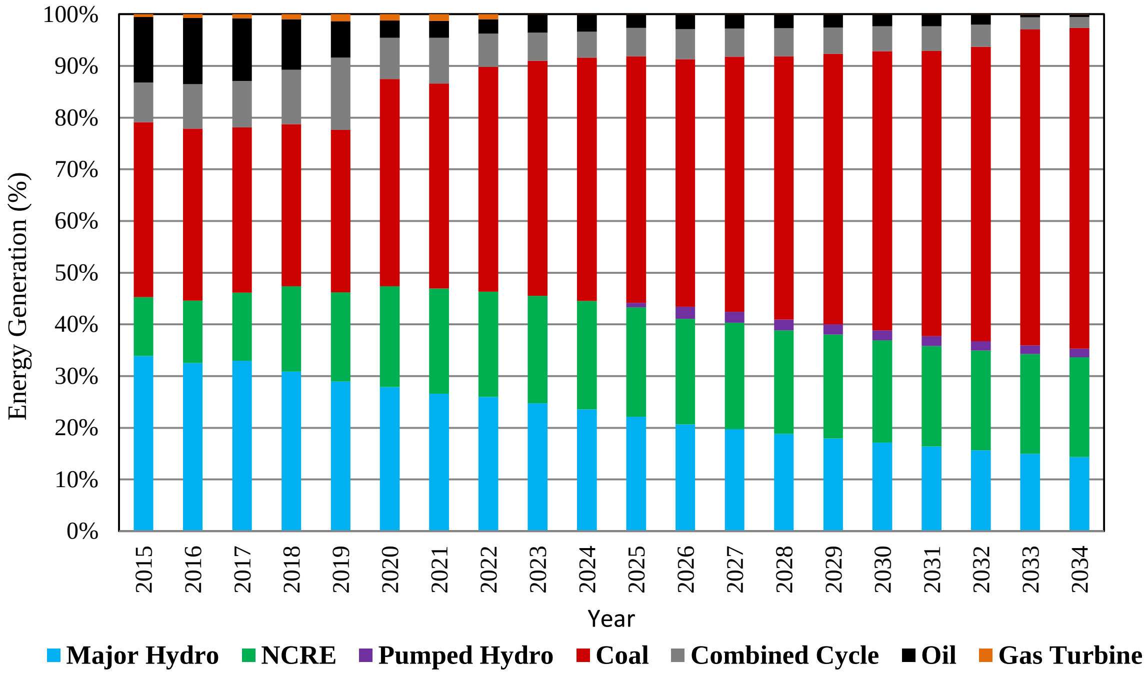


Figure7.5 – Percentage Share of Energy Mix over next 20 years in Base Case

Contribution from NCRE based generation is highlighted in Figure 7.6 and the Figure 7.7 illustrates the variation of total renewable share in the total system for the 20 year study period. It is observed that beyond 2022, NCRE energy curtailments are increasing [35]. The introduction of PSPP by year 2025 facilitates the operation of NCRE capacities without curtailments [35]. To implement the optimum NCRE Energy share, major coal plants identified in the Base Case plan must be implemented on schedule to ensure the stability of the power system.

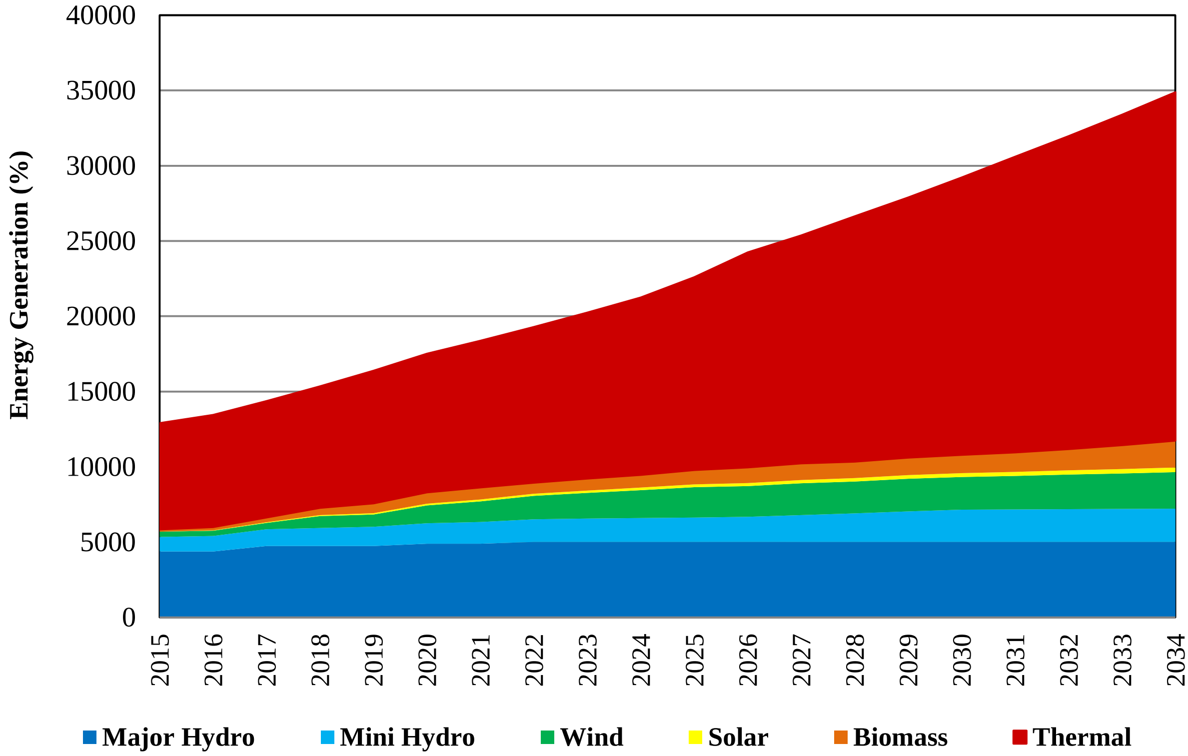


Figure 7.6 –Renewable Contribution over next 20 years based on energy resource

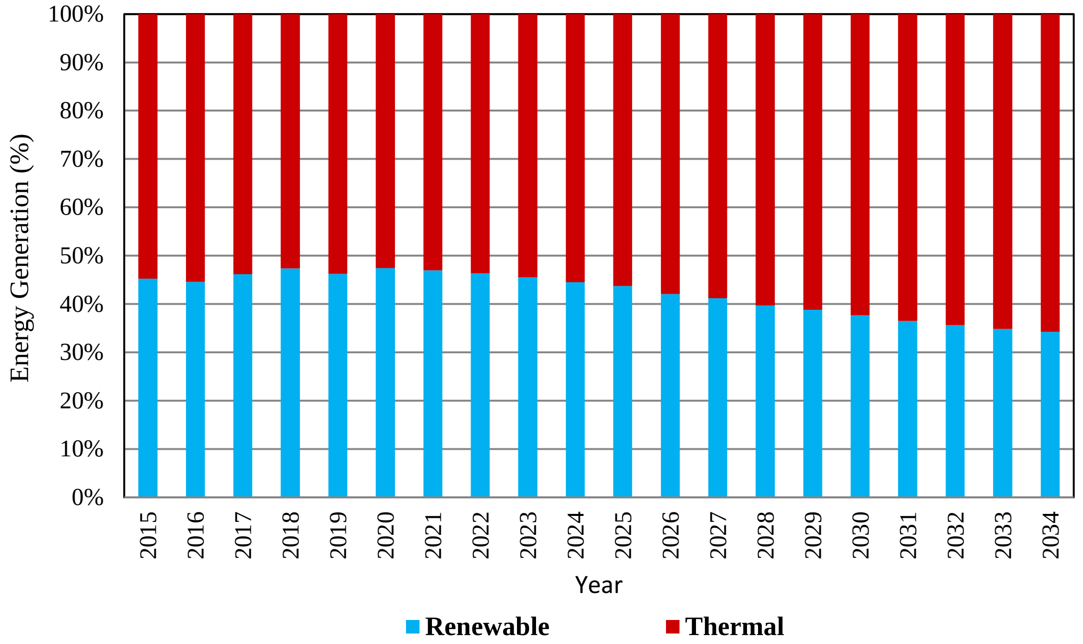


Figure 7.7 Percentage Share of Renewables over next 20 years in Base Case

7.2.3 Fuel, Operation and Maintenance Cost

Expected expenditure on fuel, operation and maintenance (O&M) of the Generation System from 2015 to 2034 is summarized in Table 7.4 in five year periods. Required Fuel quantities and the expected expenditure on fuel for the Base Case Plan over the next 20 years are given in Annex 7.5. Total fuel cost up to year 2034 is expected to be in the order of around 18,513 million US Dollars in constant terms. Expected fuel quantities and associated costs of fuel in the Base Case are graphically represented in Figure 7.8 and Figure 7.9

Table 7.4: Cost of Fuel, Operation and Maintenance of Base Case

Units: million US$

Year	**Operation and Maintenance Cost**					**Fuel Cost**
	Hydro	Pump Hydro	Thermal	NCRE	Total	
2015– 2019	96.7	0.0	645.0	290.1	1031.8	3740.1
2020 – 2024	105.7	0.0	797.3	591.6	1494.6	3976.1
2025 – 2029	106.7	26.0	1076.7	800.1	2009.4	5009.6
2030 – 2034	106.8	30.0	1493.4	1062.4	2692.6	5787.9

Total fixed and variable O&M cost over next 20 years is in the order of about 7,228 Million USD in constant terms.

According to the Base Case Plan, the consumption of fossil fuels in the power sector gradually increases since the available and expected renewable energy contribution is limited. Coal being the major source of fuel, the fuel quantity required increases nearly by 430,000 tons per annum on average after 2020. A base load coal power plant of capacity 300MW typically consumes approximately 800,000 tons per annum and it can vary depending on energy generated, plant characteristics and fuel characteristics. The expected annual coal requirement for the existing Lakviyaya Coal Power Plant and the future development of coal plants in Trincomalee region and Southern region as per the Base Case Plan is shown in the Figure 7.10 and details are given in Annex 7.5

In year 2015, nearly 422,940 tons of heavy fuel (residual and furnace oil) is burnt in Oil power stations and this consumption decreases to 170,450 tons in 2025 in the average hydro condition. Diesel consumption is estimated to be 52,930tons in 2015 and 75,250 tons in 2025. The total consumption of oil decreases within the first 10 years to a low value with the phasing out of oil plants. Expected growth of Biomass plant capacities requires a notable amount of fuel quantity annually due to its own characteristics as a fuel.

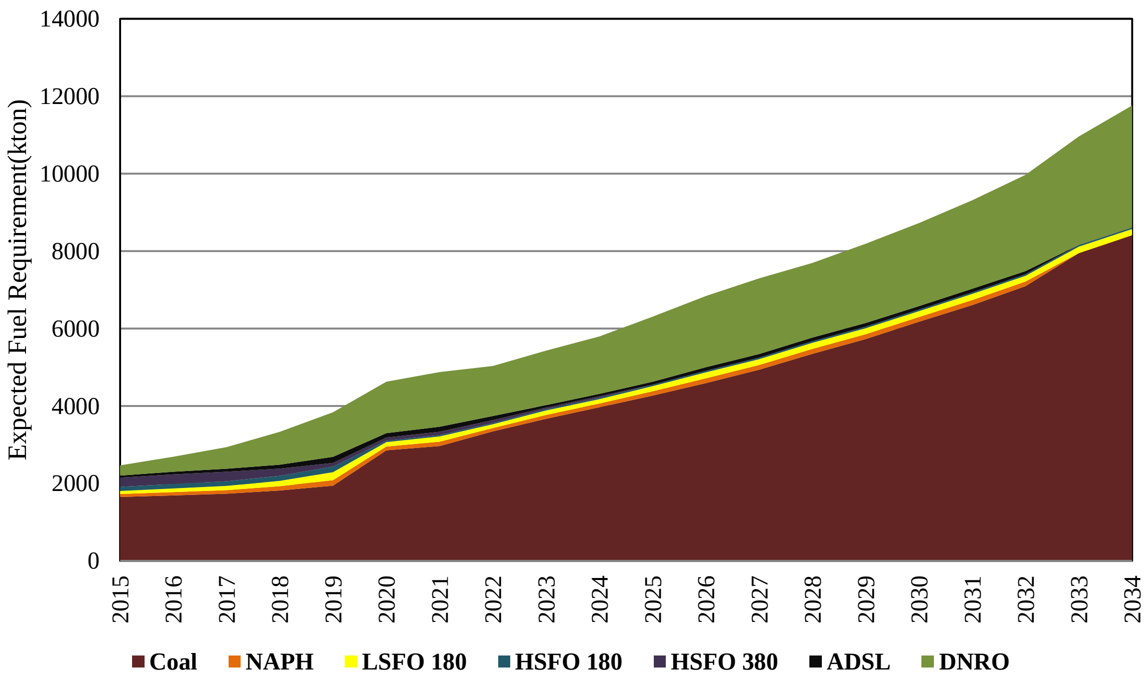


Figure 7.8- Fuel Requirement of Base Case

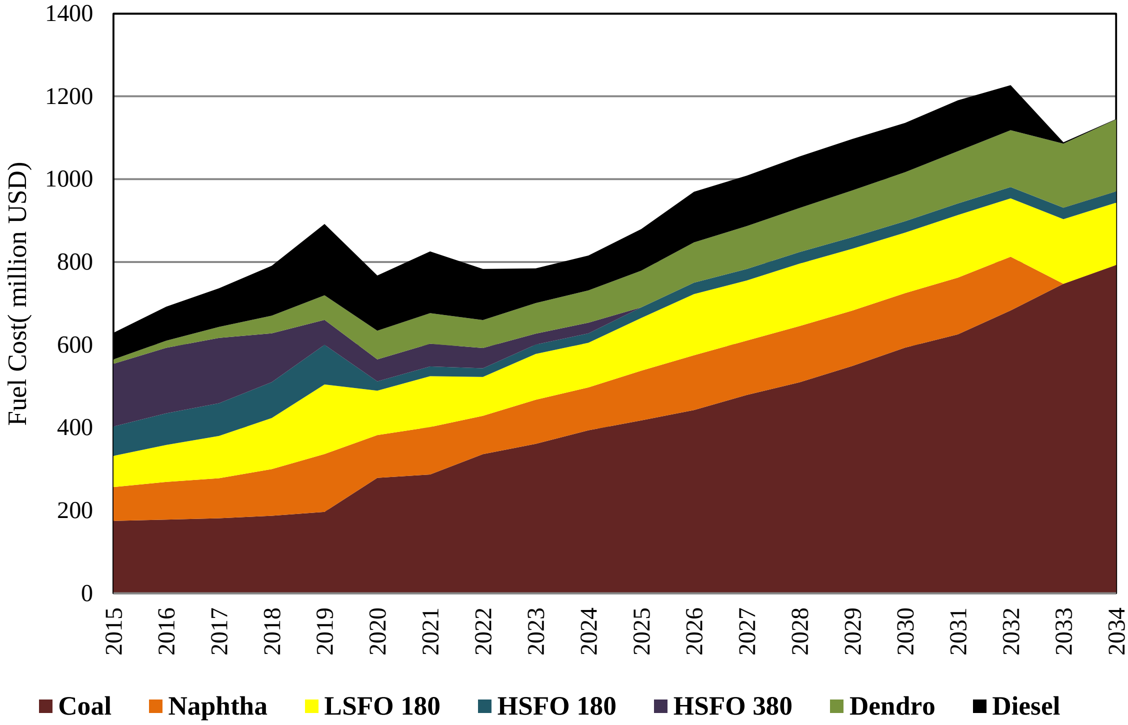


Figure 7.9- Expected Variation of Fuel Cost of Base Case

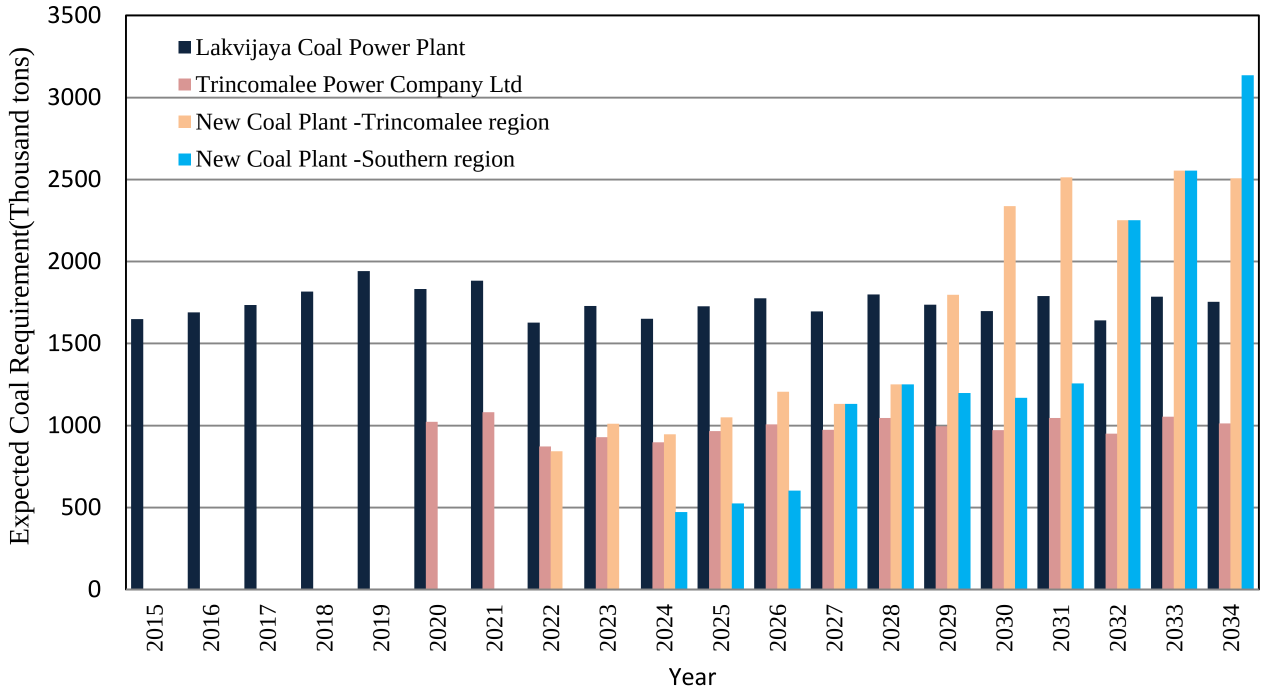


Figure 7.10- Expected Annual Coal Requirement of the Base Case

7.2.4 Reserve Margin and LOLP

System Reserve Capacity in the worst hydro condition starts at 15.3% in the planning period and decreases up to -1.3% by 2019 due to retirement of several power plants and no major capacity additions in initial years. From 2020 onwards, addition of coal power plants and Hydro plants increases and maintains the reserve margin at the stipulated level. Reserve Margin variation throughout the 20 year period is shown in the Figure 7.11. System Reserve Margin with total installed capacity including intermittent NCRE capacities appears to be higher than the actual available Reserve Margin in the critical hydro condition.

Loss of Load Probability of the system and does not exceed the maximum limit of 1.5% during the planning period to ensure the reliability of the system from LOLP perspective. The value slightly increases in the years where no new capacities are added and the variation clearly shows the inverse relationship to the reserve margin in the Figure 7.11.

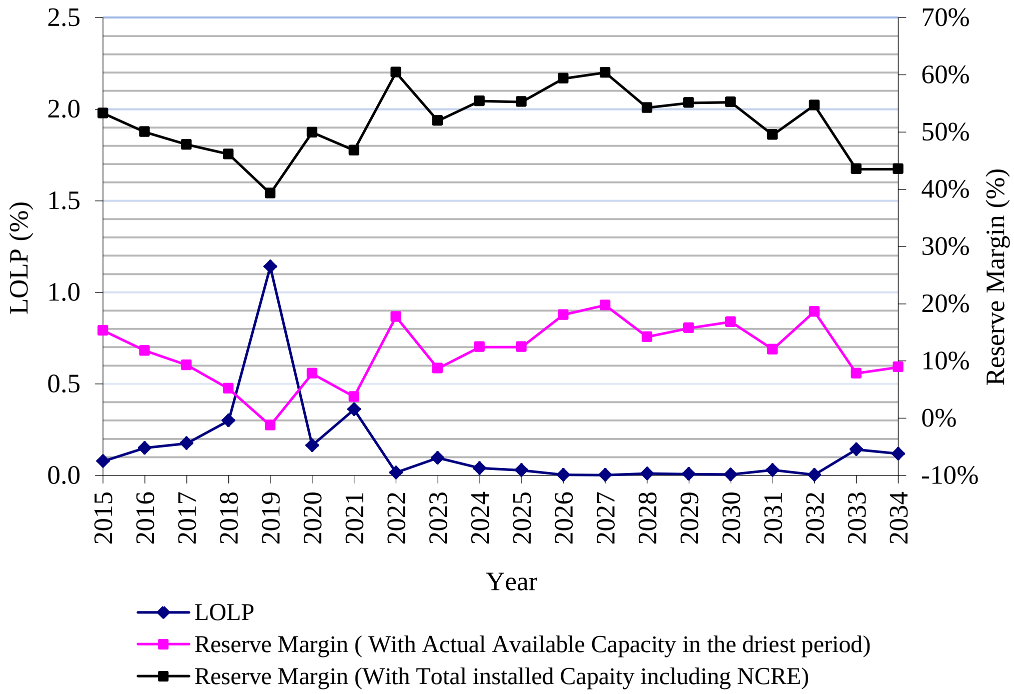


Figure 7.11 – Variation of Critical Reserve Margin and LOLP in Base Case

7.2.5 Spinning Reserve Requirement

The Operating Reserve requirement for the system operation is considered in long term Expansion planning exercise. An operating reserve equivalent to the largest unit in operation was kept in previous long term planning studies for contingency purpose. As the Base Case Plan 2015-2034 focused on higher penetration levels of intermittent NCRE capacities, requirement of additional operating reserve has been considered. Therefore, 10% of the installed NCRE capacity is kept as operating reserve for regulation purpose in addition to the largest unit capacity for contingency purpose at a given operating condition. Additional operating reserve of 10% is to be reviewed through detailed analysis and using experience in system operation with higher levels of NCRE penetration.

7.2.6 Base Case analysis using MESSAGE Energy Planning tool

MESSAGE software was used to further analyze the Base Case Scenario. Energy chains were constructed to model the energy flow between supply side and demand side. Selected years were modelled in detail to represent seasonal (dry/wet) impact and demand variation. Seasons were represented with daily demand curves dividing a day into several demand blocks. Demand data of the year 2013 was used to construct the daily demand curves. Capacity contribution of power plants in year 2030 (During March/April) season is depicted in the Figure 7.12. It is observed that pumped storage power plants (PSPP) supply electricity during night peak and day time periods.

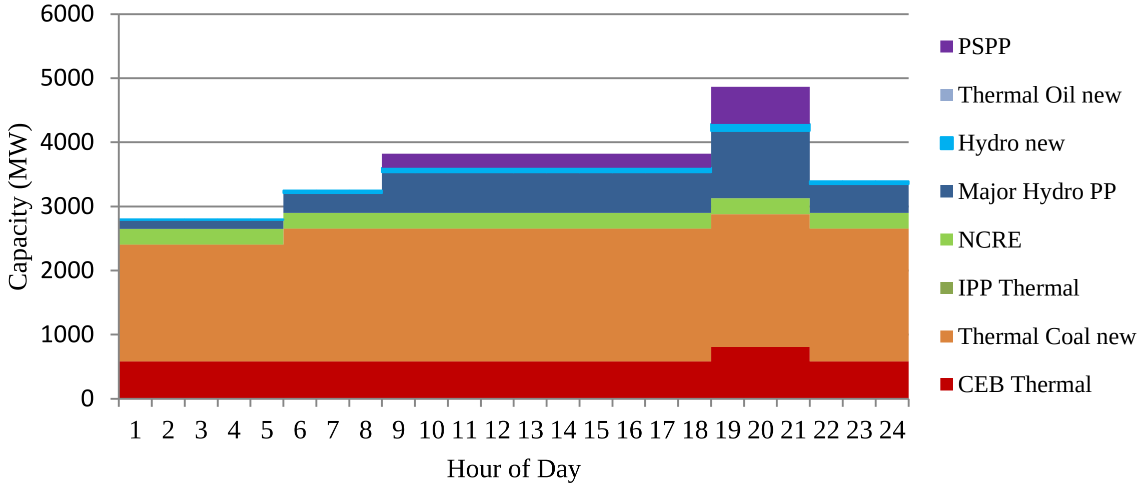


Figure 7.12 – Capacity Contribution from Power Plant in a Day in March /April 2030

Energy flow from primary and secondary level fuel supply to final level electricity demand used in the model is given in the Table 7.5.

Table 7.5: Final Demand of Electricity and Primary/Secondary Supply

Year	Final demand (ktoe)	Secondary Electricity demand (ktoe)	Primary/Secondary Input for Electricity Generation (ktoe)*
2014	951.2	1,065.0	2,066.8
2016	1,033.1	1,156.6	2,331.8
2018	1,180.2	1,319.7	2,673.4
2020	1,348.3	1,505.8	3,345.6
2022	1,486.5	1,658.1	3,746.3
2025	1,722.5	1,941.5	4,247.8
2030	2,201.0	2,559.8	5,721.9

* Excluding energy conversion loss of hydro power plants

7.2.7 Investment, Pricing and Environmental Implications

Investment requirement for the Base Case Plan is discussed in Chapter 8. Environmental implications of the Base Case Plan are presented in chapter 9. Deviations of the Base Case Plan from previous year plan are discussed in Chapter 10.

7.3 Impact of Demand Variation on Base Case Plan

Low demand and High demand growth cases were analysed in order to identify the effects of changes in demand on the Base Case Plan. Demand growth in high demand forecast is 5.7% which is 0.5% higher than the growth in Base demand forecast. This demand increase results an increase of 16.1% in the total present worth cost compared to the Base Case over the planning horizon. Also the demand growth in Low demand forecast is 3.8% which is 1.4% lower than the growth in Base demand forecast. This demand reduction results in reduction of 15.8% in the total present worth cost of the Base Case over the planning horizon. The resulting plans for the High and Low Demand Cases are given in Annex 7.7 and Annex 7.8 respectively. The respective demand forecasts used for the sensitivities are given in Annex 3.1.

7.3.1 Capacity Distribution and Fuel Requirement

The capacity additions in year 2015, 2020, 2025, 2030 and 2034 for Low, Base and High Demand Scenarios are shown in Figure 7.13. In comparison with the Base Case Scenario, Coal plant capacity requirement in Low demand case is reduced by 1200MW while Gas Turbine capacity remain the same at end of the planning horizon. Also additional capacities of Coal Power Plants of 600MW, Gas Turbine 70MW and Combined Cycle 150MW are required for High demand case compared with Base Case capacity requirement.

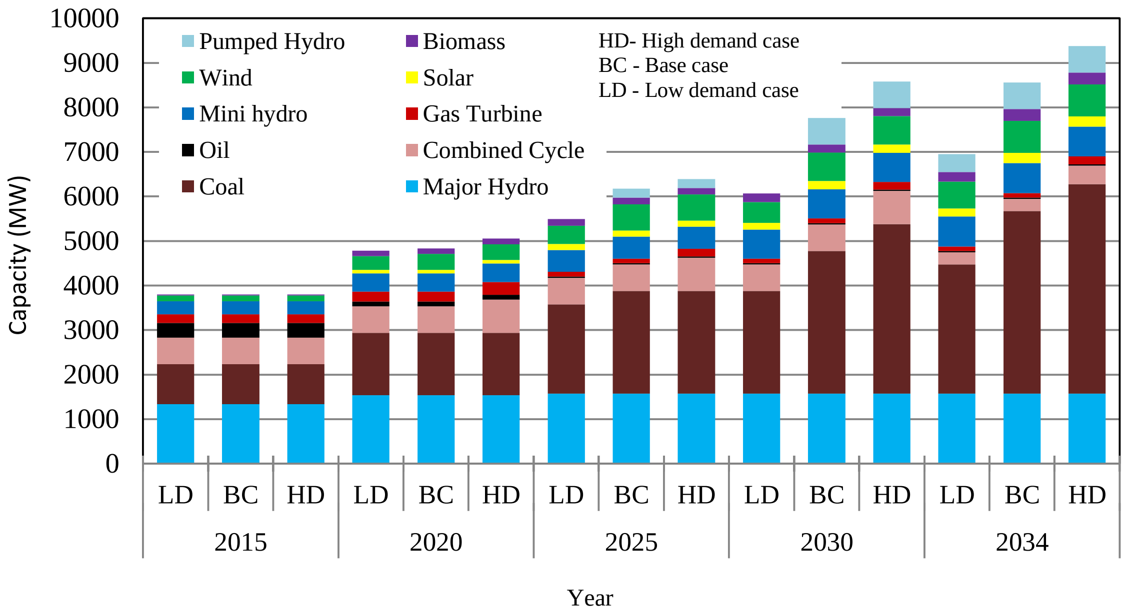


Figure 7.13 The Capacity Additions in Low, Base and High Demand Scenarios

Similarly, fuel requirement for Low, Base and High demand Scenarios vary over the planning period 2015-2034. Consumption of Coal increases in all three Cases which relates to the plant addition.

7.4 Impact of Discount rate Variation on Base Case Plan

To analyse the effect of discount rate on Base Case Plan, two additional Scenarios were carried out for discount rates of 3% and 15%.

3% discount rate Scenario was carried out to investigate whether high capital cost plants are selected at lower discount rate. However, hydro power plants with high capital cost such as Thalpitigala and Ging Ganga were not selected. These two plants were fixed as in the Base Case Plan. In Low Discount Rate Scenario Pump Storage Power Plant was selected at the end of the study period. Therefore, it was forced in 2025 as in the Base Case Plan due to technical requirements.

Plant sequences for the above High Discount Rate & Low Discount Rate Scenarios are given in Annex 7.9 and Annex 7.10 respectively.

7. 5 Impact of Fuel Price Sensitivity on Base Case Plan

In the Base Case Plan, fuel prices were assumed to be constant throughout the planning horizon. However it is important to consider the impact of price escalations in the study. Therefore, two separate scenarios were done applying fuel price escalations. One scenario considered the year by year escalation of global fuel prices, predicted by the International Energy Agency and the other Case examined the effect of increase in coal and oil prices.

7.5.1 Fuel Price Escalation based on International Energy Agency Forecast

World Energy Outlook 2014, published by International Energy Agency which gives indicative price variations of Coal, Oil and Gas up to 2040 depending on the policy settings was referred to obtain the fossil fuel price escalations. Annual price escalations for oil, natural gas and coal were applied throughout the planning period for optimization assuming all fuel types follows the escalation pattern given by International Energy Agency. The Figure 7.14, below shows the fuel price variations throughout the planning horizon and its percentage values are given in the Table 7.6 in 2015 price base. Base Case was re-optimized with these fuel prices, and no major deviations observed apart from the cost increase.

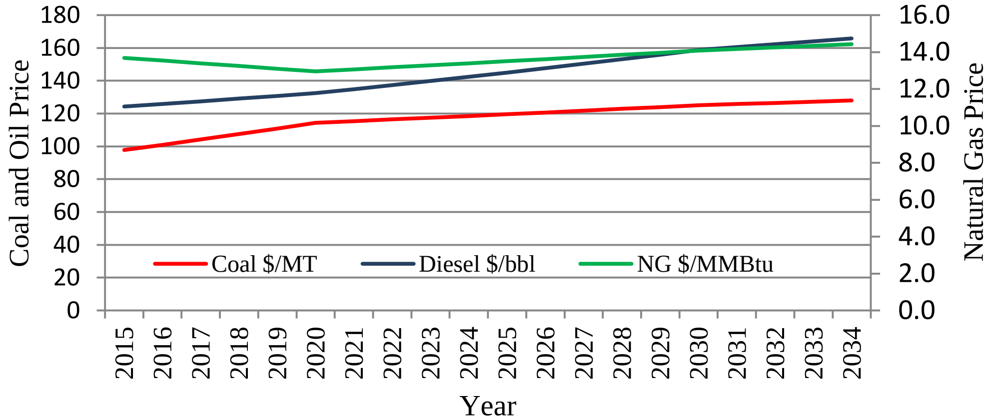


Figure 7.14 Fuel Price Escalations in the planning horizon

Table 7.6: Fuel Price Escalation percentages (2015 price base)

	2020	2025	2030	2034
Coal	16.9%	22.2%	27.8%	30.8%
Oil (Diesel)	6.7%	16.7%	27.8%	33.5%
Natural Gas	-5.3%	-1.3%	2.9%	5.3%

7.5.2 High Coal Price Scenario

In this Scenario, the effect of a high coal price was examined. High coal price scenario assumed a coal price increase of 50% while Petroleum and LNG prices remain unchanged. Table 7.7 shows the coal price used for Base Case Scenario and High Coal Price scenario.

Table 7.7: Coal Prices used for Base Case and High Coal price Scenarios

	Trincomalee JV project	Lakvijaya Coal Plant	New Coal Plant	Supercritical Coal Plant
Base Case Coal Price (Colombo CIF)	81.69 USD/MT	97.86 USD/MT	89.39 USD/MT	97.10USD/MT
50% high Coal Price (Colombo CIF)	122.53USD/MT	146.79USD/MT	134.09USD/MT	145.64USD/MT

In High coal price scenario, one unit of Trincomalee -2, Phase -1 Plant was delayed from 2022 to 2023. The New Coal Plant planned in 2024 in the Base Case Plan was delayed until 2027 and all the Coal Power Plants selected in Base Case from 2027 to 2032 were delayed by one year. Total number of coal plants at the planning horizon remained unchanged. No other fuel options were selected in the optimization process as a replacement for coal.

The total Present Value cost of the Scenario is 1, 282.91 MUSD higher than the Base Case Scenario and Plant sequence for High Coal Price scenario is given in Annex 7.11.

7.5.3 High Coal and Oil Price Scenario

In this Scenario, the effects of both high Coal price and high Oil price were studied. High Coal and Oil Price Scenario assumed 50% increase of both oil and coal prices while LNG price remained unchanged. The Coal & Oil prices used for the analysis are given in Table 7.7 and Table 7.8 respectively.

Table 7.8: Oil Prices used for Base Case Plan and High Coal & Oil price Scenario

	Auto Diesel	Fuel Oil (3%S)	Fuel Oil (2%S)	Residual Oil	Naptha (Local)	Naptha Special
Base Case Oil Price (Colombo CIF)	124.2 ($/bbl)	100.2 ($/bbl)	104.4 ($/bbl)	95.2 ($/bbl)	93.5 ($/bbl)	108.9 ($/bbl)
50% high Oil Price (Colombo CIF)	186.3 ($/bbl)	150.3 ($/bbl)	156.5 ($/bbl)	142.9 ($/bbl)	140.3 ($/bbl)	163.3 ($/bbl)

In this Scenario, the New Coal Plant in 2024 was advanced to 2023 and 300MW New Coal Plant in 2032 was advanced to 2031 while the other Plant additions remained unchanged. Total number of Coal plants at the planning horizon was not changed. The total Present Value cost of the Scenario is 3,545.81 MUSD higher than the Base Case Scenario and plant sequence is given in Annex 7.12.

7.6 Restricted Coal Development Scenarios

7.6.1 Energy Mix Scenario

Considering the energy policy element to ensure energy security through enhancing fuel diversification, a separate scenario was studied by imposing a limit on coal power development to estimate the financial implications on the least cost generation expansion plan. In this scenario Pumped Storage Power Plants are delayed until year 2030 until sufficient amount of low cost base load plants are available in the system. Capacity additions were maintained to keep the coal energy share around 50% and LNG energy share around 10%. Nuclear power plants are introduced in year 2030 allowing a fifteen year lead time. First LNG fired combined cycle power plant of capacity 300MW is selected in 2024 and second plant was selected in 2028. The energy dispatch and energy share from Coal, LNG and Nuclear from the total energy are given in the Table 7.9 and the resulting plant addition and cost variation is given in Annex 7.13.

Table 7.9: Energy share in Energy Mix Scenario with introducing Nuclear

Year	Coal (GWh)	Coal (%)	LNG (GWh)	LNG (%)	Nuclear (GWh)	Nuclear (%)
2015	4,371	34%	0		0	
2016	4,478	33%	0		0	
2017	4,595	32%	0		0	
2018	4,815	31%	0		0	
2019	5,145	31%	0		0	
2020	7,030	40%	0		0	
2021	7,288	40%	0		0	
2022	8,826	46%	0		0	
2023	9,553	47%	0		0	
2024	10,304	48%	1,884	9%	0	
2025	10,857	49%	2,120	10%	0	
2026	11,304	48%	2,589	11%	0	
2027	12,755	52%	2,179	9%	0	
2028	13,143	51%	2,941	11%	0	
2029	13,536	50%	3,516	13%	0	
2030	12,113	41%	2,725	9%	3,664	13%
2031	12,813	42%	3,076	10%	3,784	12%
2032	13,312	42%	3,572	11%	3,918	12%
2033	15,330	46%	2,574	8%	3,874	12%
2034	15,687	45%	3,211	9%	3,966	11%

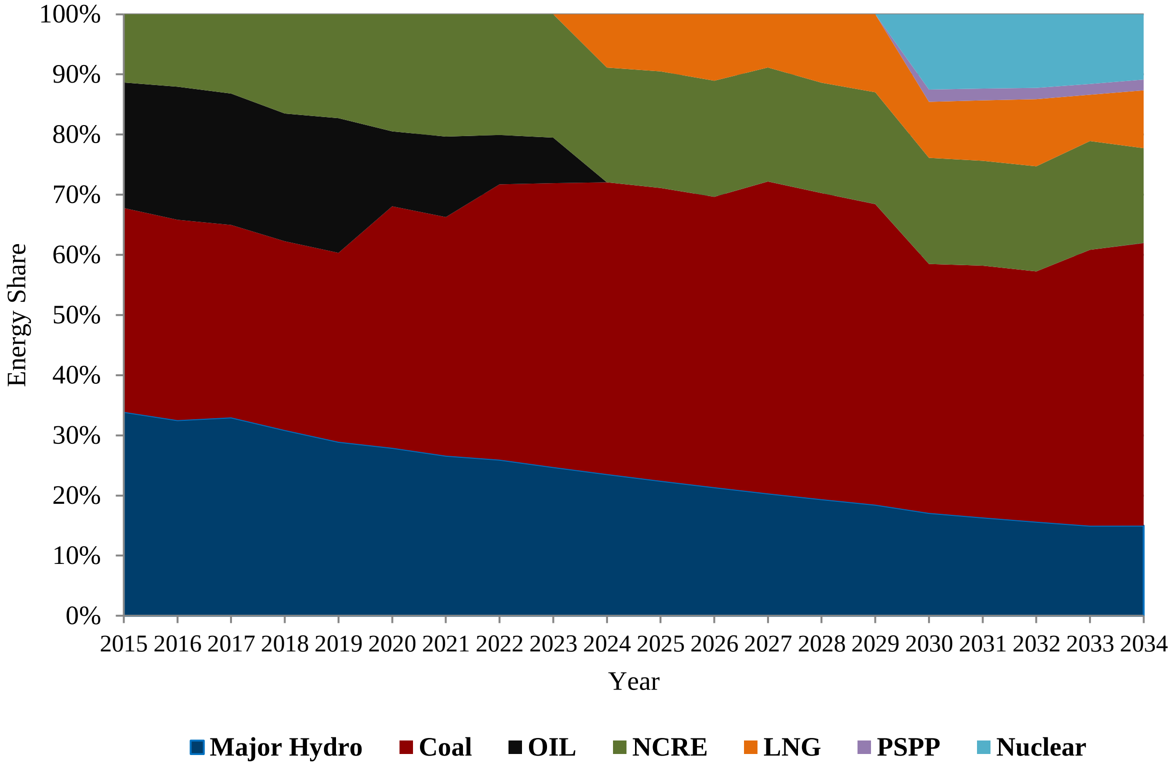


Figure 7.15– Energy share in Energy Mix Scenario

7.6.2 Coal Restricted Scenario

This scenario was studied to figure out the impact of restricting total coal power development to 2600MW. The plant sequence follows the Base Case Plan until the development of 2600MW of coal power in 2027.

According to the results, first 300MW LNG fired combined cycle power plant was selected in 2031 and thereafter one LNG fired combined cycle plant was added in each year until 2034. At the planning horizon, four units of 300MW LNG fired combined cycle power plant with a terminal is operational. The plant addition sequence is given in Annex 7.14 and the energy contribution from each source is given in the Table 7.10.

Table 7.10: Energy share in Coal Restricted Scenario

Year	Coal (GWh)	Coal (%)	LNG (GWh)	LNG (%)
2015	4,371	34%	0	0%
2016	4,478	33%	0	0%
2017	4,595	32%	0	0%
2018	4,815	31%	0	0%
2019	5,145	31%	0	0%
2020	7,016	40%	0	0%
2021	7,280	40%	0	0%
2022	8,380	43%	0	0%
2023	9,209	45%	0	0%
2024	10,008	47%	0	0%
2025	10,765	48%	0	0%
2026	11,595	48%	0	0%
2027	12,520	49%	0	0%
2028	13,564	51%	0	0%
2029	14,380	52%	0	0%
2030	15,100	52%	0	0%
2031	15,313	50%	1196	4%
2032	15,471	48%	2359	7%
2033	16,121	48%	3987	12%
2034	16,192	46%	5259	15%

The energy contribution from LNG in 2031 is 4% and it gradually increases to 15% by 2034. As annual capacity additions are illustrated in the Figure 7.16, the "Coal Restricted after 2027" Scenario was able to maintain the system reserve margin from the 2028 to 2030 without any capacity additions. Thereafter, LNG based generation capacities were selected to the system to overcome capacity shortages. It is observed that in the Base Case Plan even with adequate capacity to maintain reserve margin, two coal plants of 300MW were selected in 2029 and 2030 due to economic reasons.

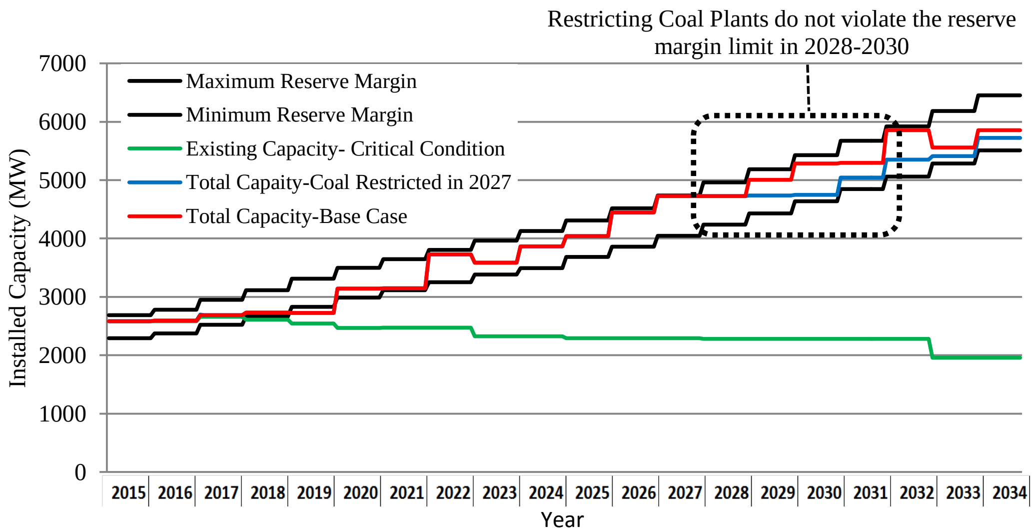


Figure 7.16 Annual Capacity Additions- Base Case vs Coal Restricted Scenario

7.7 Natural Gas Breakeven Price Analysis

Studies were carried out to determine the breakeven price of Natural Gas and Liquefied Natural Gas generation options with Coal power generation options. The NG price of 11.5 US$/MMBTU and LNG price (Colombo CIF) of 13.69 US$/MMBTU was used in the Base Case study. Breakeven price was determined with respect to Colombo CIF price of 89.39 US$/MT for coal.

7.7.1 LNG Breakeven Price

The LNG pricing mechanism for the Long Term Generation Expansion plan is described in the Section 4.3.4 and it is assumed that it is linked to the Japanese Crude Cocktail (JCC) Prices. Accordingly, monthly variation of the derived Colombo CIF price of LNG in 2014 is shown in Figure 7.17.

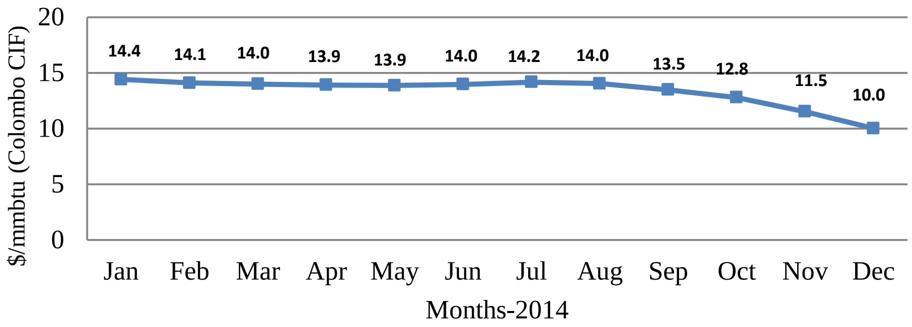
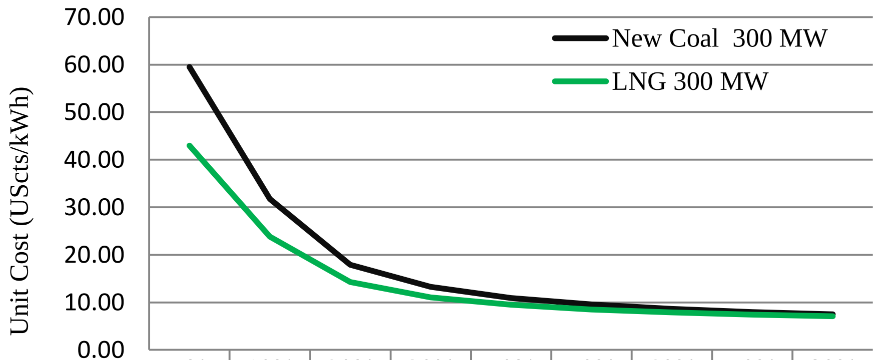


Figure 7.17 Variation of JCC linked LNG price (CIF Colombo)

To determine the breakeven price of LNG with Coal, it was assumed that LNG terminal of capacity 1MTPA could cater for 4 plants of 300MW of Combined Cycle Power Plants. Terminal cost is apportioned among the 4 plants equally. LNG is competitive with coal at LNG price of 5.9US$/MMBTU with apportioned the quarter terminal cost. Figure 7.18 shows the resulting screening curves at this breakeven price.



	5%	10%	20%	30%	40%	50%	60%	70%	80%
New Coal 300 MW	59.54	31.76	17.87	13.24	10.93	9.54	8.61	7.95	7.46
LNG 300 MW	42.99	23.84	14.27	11.08	9.48	8.52	7.89	7.43	7.09

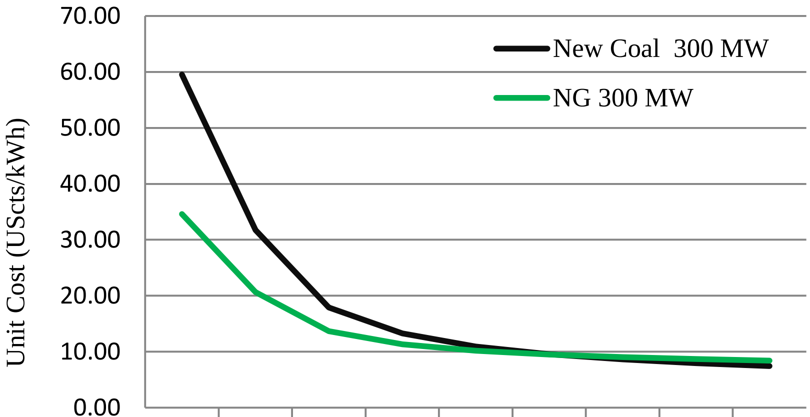
Unit Cost vs Plant Factor

Figure 7.18: Screening Curves for LNG Breakeven Price of 5.9 US$/MMBTU

7.7.2 NG Breakeven Price

The breakeven price of NG was determined as 8.7 US$/MMBTU and it is slightly higher than the LNG breakeven price due to the reason that a Terminal is not included in the NG Scenario.

The Figure 7.19 shows the screening curve for the Natural Gas Breakeven Case and the reduction in the capital cost plant can be observed. The price difference between of NG and LNG Breakeven prices is 2.8 US$/MMBTU. Both curves also show the advantage of operating Natural Gas Fired Power Plant as middle load plant compared to base load operation.



	5%	10%	20%	30%	40%	50%	60%	70%	80%
New Coal 300 MW	59.54	31.76	17.87	13.24	10.93	9.54	8.61	7.95	7.46
NG 300 MW	34.59	20.64	13.66	11.34	10.18	9.48	9.01	8.68	8.43

Unit Cost vs Plant Factor

Figure 7.19: Screening Curves for NG Breakeven Price of 8.7 US$/MMBTU

Although CDM benefit could be applied to Natural Gas Power Plants, due to very low CER (Certified Emission Reduction) prices, this Case was not analysed. Prices in the European Union Emission Trading System (EU ETS) remained low during past three years due to economic downturn in the region and without the demand from EU ETS. Kyoto credit prices also reached their lowest in 2013 and 2014, with Certified Emission Reductions (CERs) price of US$0.51 (€0.37). Therefore, although this benefit could be applied to the Natural Gas power plants no significant benefit can be obtained with the above CER prices compared to Base Case Plan.

7.8 Natural Gas Availability in Sri Lanka by 2020

Two Scenarios were studied to analyse the utilization of natural gas potential in Mannar Basin under two different Natural Gas penetration levels.

7.8.1 Natural Gas Average Penetration Scenario

If Sri Lanka is to utilize the natural gas available in Mannar Basin for power generation, initially it can cater 165MW Kelanitissa (KPS) Combined Cycle Power Plant, 165MW AES Combined Cycle

Power Plant and 300MW West Coast Combined Cycle Power Plant after converting to operate on Natural Gas. To utilize natural gas in an optimum manner, it is also recommended to construct a new 300MW Combined Cycle Power Plant at Kerawalapitiya in 2023. NG available at 'Dorado' well would suffice for this requirement for approximately 15 years.

Considering the retirement of the two Combined Cycle plants at Kelanitissa, a new Natural Gas Combined Cycle plant of capacity 300MW is proposed in 2033. Instead, the extension of two plants could also be considered. The plant schedule is shown in Annex 7.15.

However, due to the following reasons, the above Scenario was not recommended as the Base Case Plan 2015-2034, although the NPV of the Scenario is lower than the recommended Base Case:

(i) Discovery of the natural gas resources is still at very early stages.
(ii) Gas quantities are not quantified with reasonable accuracy.
(iii) Gas price delivered to the plants is very much indicative. The price of gas is considered as 15.5USD/MMBTU including Royalty, Profit and Tax. 10.5USD/MMBTU without Royalty, Profit and Tax at the well and additional 1USD/MMBTU was added as the delivery cost.
(iv) Conversion costs of the existing plants are indicative and actual costs may vary.
(v) Costs of additional storages and infrastructure to be developed for the existing power plants were not considered.

If Sri Lanka is to utilize Natural Gas for power generation, the sustainability of gas supply in future should be considered. Then the next phases of exploration should be continued and continuous gas supply must be ensured for the operation of the plants beyond 2034.

Further the volumetric analysis of the existing discoveries of natural gas has indicated a combined reservoir potential in excess of 2TCF. According to Petroleum Resources Development Secretariat, if that potential is recoverable, commercially viable and timely tapped, it would be able to meet the requirement of approximately 100MW power plant capacity even beyond the 15 year period. Moreover, the entire Mannar Basin indicates a substantial risked potential of natural gas and yet to be verified conducting more exploration studies in the identified potential areas. If not, Country will be compelled to go for imported Liquefied Natural Gas option, which would not be least cost.

The conversion of existing Combined Cycle plants along with the addition of a 300MW new plant in 2023 will enable to maintain a 7% - 19% energy share in the system with an annual plant factor in the range of 30% to 60%. Resulting energy share is shown in Figure 7.20. The cumulative NG requirement for this Scenario is approximately 300bcf. Annual and cumulative NG requirement is shown in Table 7.11.

Table 7.11: Natural Gas requirement for Natural Gas Average Penetration Scenario

Year	Natural Gas Fuel Requirement		
	Annual Quantity (mmcf)	Cumulative Annual Quantity (bcf)	Daily Requirement (mmscfd)
2021	9,855	10	27
2022	9,048	19	25
2023	17,298	36	47
2024	19,765	56	54
2025	22,816	79	63
2026	25,780	105	71
2027	29,547	134	81
2028	27,257	161	75
2029	24,863	186	68
2030	28,598	215	78
2031	26,980	242	74
2032	25,510	267	70
2033	22,341	290	61
2034	26,218	316	72

According to the above results, initial consumption of the gas is low and it increases gradually over the years. In this analysis, it is considered to utilize 300bcf potential throughout the planning horizon. If the gas is utilized at a rate of 70mscfd per day, gas would exhaust within approximately 10 years. When considering the production rate of 70 mmscfd from Dorado well it is observed that storage facilities will be required to cater for the daily requirement of gas for power generation.

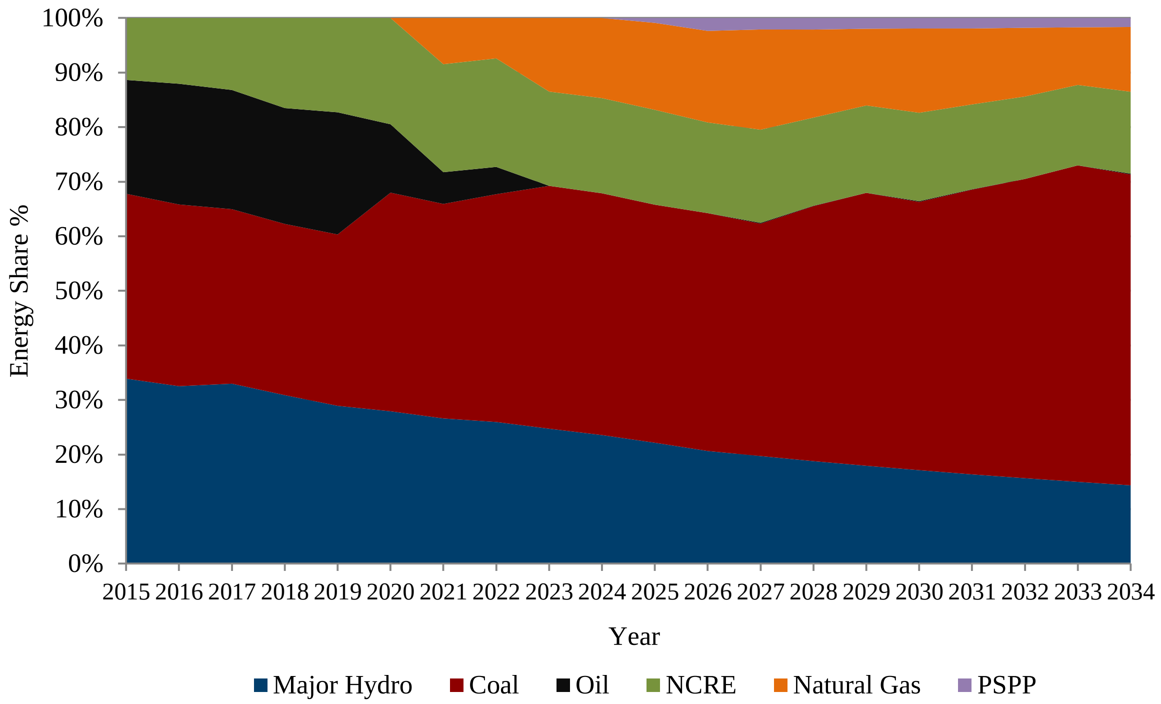


Figure 7.20: Percentage share of energy for Natural Gas Average Penetration Scenario

7.8.2 High Natural Gas Penetration Scenario

Assuming the availability of Natural Gas in excess of 'Dorado' well, another scenario was analysed to maintain approximately 50% energy share from indigenous sources including major hydro, NCRE and NG. The plant schedule is given in Annex 7.16 and the energy share of the various fuel options in this scenario is shown in Figure 7.21.

The cumulative NG requirement for the 20 year period in this Scenario is approximately 450bcf. The annual and cumulative NG requirement is shown in Table 7.12. Peak production rate is assumed to be more than 70MMscfd for this Scenario, and depending on the consumption, storage facilities will be necessary to achieve daily requirement.

Table 7.12: Natural Gas requirement for Natural Gas High Penetration Scenario

Year	NG Fuel Requirement		
	Annual mmcf	Cumulative bcf	Daily Requirement mmscfd
2021	13,504	14	37
2022	10,879	24	30
2023	23,865	48	65
2024	27,600	76	76
2025	30,527	106	84
2026	34,668	141	95
2027	37,996	179	104
2028	35,260	214	97
2029	32,579	247	89
2030	35,713	283	98
2031	45,423	328	124
2032	43,059	371	118
2033	39,855	411	109
2034	42,518	453	116

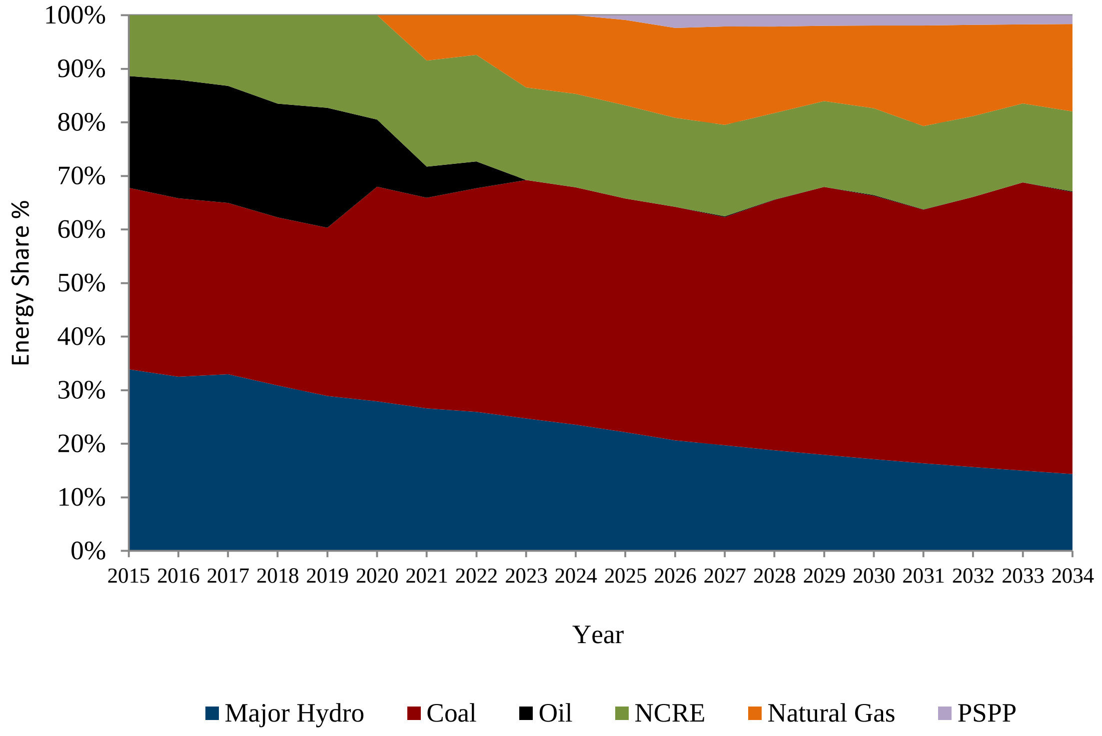


Figure 7.21: Percentage share of energy for Natural Gas High Penetration Scenario

7.8.3 Impact of Natural Gas Price delivered at Power Plant

Natural Gas price of 11.5USD/MMBTU was used in the analysis given in section 7.8.1 and 7.8.2, which includes the economic cost of 10.5USD/MMBTU and 1USD/MMBTU transportation cost. It was assumed that the cost of gas pipeline infrastructure including the return on investment will be recovered through this transportation cost.

NG price of 11.5USD/MMBTU delivered at power plant is used for middle load operation to utilize 300bcf of available gas quantity within 15 year period.

Serious consideration must be given to devise a gas pricing formula as the present world market price of gas also at around 8-10USD MMBTU and two year average is approximately 13.69USD/MMBTU.

When a transportation cost of 1USD/MMBTU is considered, the approximate present value of gas transportation cost for the above two Scenarios are as follows.

Table 7.13: Present Value of Gas Transportation Cost

	USD mil
Scenario 1	103
Scenario 2	144

Although a price of 11.5USD/MMBTU was used in the analysis, actual price will be 16.5USD/MMBTU when state fiscal gains such as Royalty, Profit and Tax are considered. Increase in cost when the state fiscal gains of 5USD/MMBTU are incorporated to the Natural gas price is indicated in the Table 7.14.

Table 7.14: Present Value Cost Increase of the Scenarios due to State Fiscal Gains

	USD/MMBTU
Scenario 1	482
Scenario 2	674

7.9 HVDC Interconnection Scenario

The Base Case Plan was re-optimized considering a 500MW HVDC Interconnection between Sri Lanka and India and the expansion schedule is attached in Annex 7.17. The HVDC Interconnection was allowed for selection from 2025. Cost data and other technical parameters were taken from the "Supplementary Studies for the Feasibility Study on India-Sri Lanka Grid Interconnection Project" draft final report, November 2011[40]. A summary of the cost data taken as input to the study is given in Table 7.15 and further reviewing is required.

Table 7.15: Input Cost Data for the HVDC Interconnection Scenario

Plant	Capacity	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost
	(MW)	(US$/kW)	($/kW Month)	(USCts/kWh)
India-Sri Lanka HVDC Interconnection	500	1,108.00	0.423	6.97

In HVDC Interconnection Scenario following observations are made:

(a) 1 x 500MW HVDC Interconnection was selected in 2025.

(b) Pump Storage Power Plant (PSPP) which was allowed from 2025 & not selected within planning horizon.

(c) HVDC Interconnection has replaced only oil fired thermal power plants. This should be further studied.

(d) Table 7.16 shows generation from coal power plants in this scenario and the generation capability of coal power plants selected under the scenario at 80% plant factor, during the period 2015-2034.

Table 7.16: Comparison of HVDC Interconnection Scenario with Base Case Scenario

Year	HVDC Interconnection Scenario		Excess Coal Energy of HVDC Case @ PF 80% (GWh)
	Coal Energy Dispatch** (GWh) A	Total Coal Generation Capability* (GWh) B	B-A
2025	9,324	12,748	3,424
2026	10,320	14,640	4,320
2027	11,253	16,532	5,279
2028	12,350	18,424	6,074
2029	13,400	20,316	6,916
2030	14,528	20,316	5,788
2031	15,414	20,316	4,902
2032	16,698	22,208	5,510
2033	18,790	24,101	5,311
2034	19,696	24,101	4,405

* Total Coal based energy available with corresponding Coal plant capacities at 80% annual plant factor
** Total generation from Coal Power plants considering NCRE intermittency

Above results show the excess Coal power generation of HVDC interconnection Scenario considering 80% annual plant factor for Coal power plants. HVDC interconnection technical parameters, amount of energy import & export with annual plant factors and related costs should be further reviewed.

HVDC Interconnection should be further studied with proposed NCRE capacity additions and system absorption capabilities due to unavailability of Pump Storage Power Plant.

7.10 Demand Side Management Scenario

The saving potential from the DSM activities for the Industrial, General Purpose, Hotel and Domestic tariff categories were given by Sri Lanka Sustainable Energy Authority (SLSEA) with the cost for the implementation of such DSM measures. Demand growth with Demand Side Management is 4.3 % which is 0.9% lower than the growth in Base Demand Forecast. This demand reduction results in 17% reduction in the total present value cost of the Base Case Plan over the planning horizon and the resultant expansion schedule is given in Annex 7.18.

Table 7.17 compares the plant additions and cost comparison of Base and DSM case over the planning horizon. Therefore reduction of 4 Coal power plants can be observed in DSM case.

Table 7.17: Major Plant Additions & Costs of Base & DSM Cases

Plant Type	Base Case	DSM Case
GT – 35MW	3	3
New Coal – 300MW	9	5
Coal – TPCL 250MW	2	2
Major Hydro	6	6
PSPP – 200MW	3	2
Total PV Cost up to year 2034 (US$ million)	12,960.51	10,759.16*

* Including DSM implementation cost of US$ 892.92 million

Implementation of DSM measures shows the considerable decrease in to total PV cost compared with the Base Case Plan. But it shows that implementation cost of US$ 892.92 million for DSM activities such as introduction of efficient fans, efficient refrigerators, Building Management System (BMS), efficient pumps, efficient motors, efficient compressors etc. are high.

7.11 Social and Environmental Damage Cost Analysis

Several Scenarios were studied to investigate the effect of coal power plants in the Base Case Plan by giving a monetary value to the social and environmental damage. Damage cost values were taken from the report "Sri Lanka: Environmental Issues in the Power Sector" [36] and escalated in the analysis to investigate whether coal plants will be replaced by any other technology.

Above report includes several damage cost values for coal, based on different studies. Out of the studies given in the Report, World Bank Six Cities Study which indicates a damage cost of 0.1 €-cent/kWh is the more relevant to Sri Lanka since it includes several Asian countries in the study. Other studies indicate damage cost values for coal up to 6 €-cent/kWh. Damage cost was included in the variable cost of coal power plants

Table 7.18 indicates the results of the analysis of several scenarios and incremental cost due to accounting for the social and environmental damage cost for coal.

Table 7.18: Analysis of Social and Environmental damage Cost Scenarios

Damage Cost (€-cent/kWh)	Observation	Incremental Cost (USD million)
0.1	• No major difference could be observed in the sequence.	100.04
2.0	• Coal plants were delayed and number of power plants remains unchanged at the end of planning horizon. • LOLP increased due to reduction of energy supply.	1,833.77
4.8	• All coal power plants capacities were replaced by LNG fired Combined Cycle power plants	4282.82

7.12 Comparison of Energy Supply alternatives in 2030

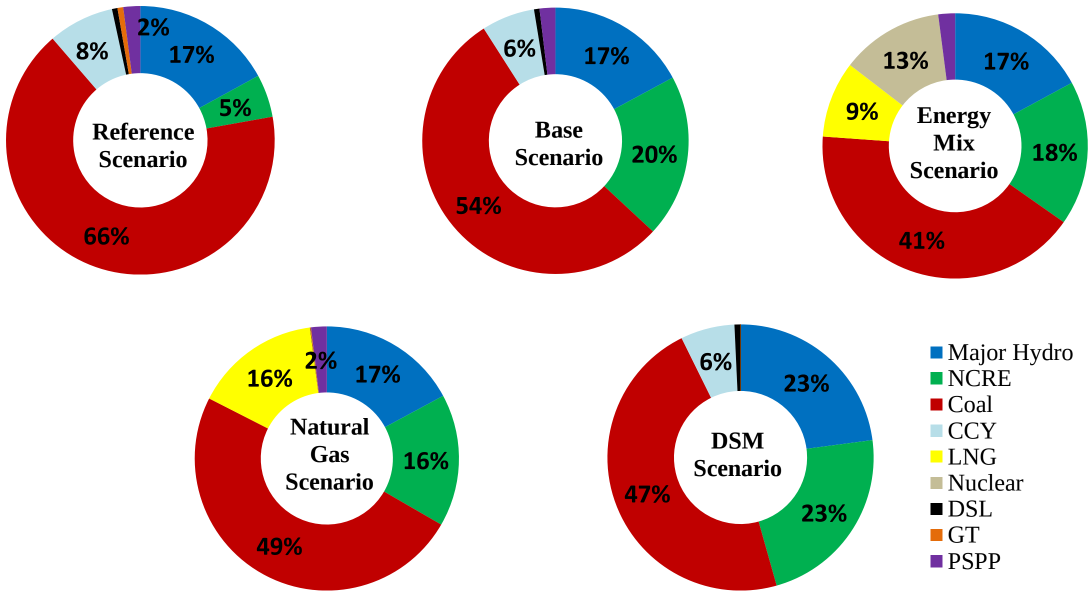


Figure 7.22: Energy share comparison in 2030

The Figure 7.22 illustrates the energy mix in different key scenarios in 2030. The Base Case Scenario complied with the National Energy Policy Elements with realistic cohesiveness. Compared with Base Case Scenario, Reference Scenario shows higher PV Cost and with low integration of NCRE. Energy Mix Scenario enhances the energy security policy by diversifying the fuel mix further in to LNG and Nuclear, but it shows much higher PV cost. In the Natural Gas Scenario, economical extraction of NG from Mannar basin and the timeline of availability are still at the very initial stage without firm realistic quantities and price. Implementation of DSM measures results in considerable decrease in to total PV cost compared with the Base Case Scenario. Further DSM implementation shall be beneficial to the overall economy of the country due to reduction in CO_2 emission and import of fossil fuels.

7.13 Summary

The total present value of cost over the planning horizon for Base Case and 15 different Scenarios studied are summarized in Table 7.19.

Table 7.19: Comparison of the Results of Expansion Planning Scenarios

Scenario	Present Value of costs during the planning horizon	Deviation of NPV from Base Case	
	(Million USD)	(Million USD)	%
Base Case	12,960.51		
Reference Case	12,892.07	(68.44)	(0.53)
High Demand	15,049.49	2,088.99	16.12
Low Demand	10,906.67	(2,053.84)	(15.85)
DSM	10,759.16	(2,201.35)	(16.99)
High Discount	9,752.75	(3,207.75)	(24.75)
Low Discount	21,452.70	8,492.19	65.52
Coal Price high	14,243.43	1,282.93	9.90
Coal and Oil price high	16,506.34	3,545.83	27.36
Fuel Price Escalation	14,080.72	1,120.22	8.64
Coal Restricted	12,965.01	11.14	0.09
Energy Mix with Nuclear	13,034.16	73.66	0.57
Natural Gas Average Penetration	11,891.84	(1,068.67)	(8.25)
Natural Gas High Penetration	11,902.65	(1,057.86)	(8.16)
HVDC Interconnection	12,760.51	(200.00)	(1.54)

CHAPTER 8
IMPLEMENTATION AND FINANCING OF GENERATION PROJECTS

This Chapter elaborates on the required investment and the implementation plan for the generation projects in the Base Case and the issues related to that.

8.1 Committed Power Plants in the Base Case Plan

8.1.1 Committed Plants

Broadlands Hydro Power Project (35MW), Uma Oya Hydro Power Project (120MW) and Moragolla Hydro Power Project (31MW) have been considered as committed in the present study.

8.1.2 Present Status of the Committed and Candidate Power Plants

A brief description of the current status (as of end 2014) of the committed projects and proposed projects for which commitments should be made are given below:

1. Feasibility of the Broadlands hydro power project was investigated under the "Study of Hydro Power Optimization in Sri Lanka" in February 2004 by the JICA consultants, J-Power and the Nippon Koei Co. Ltd., Japan [5]. Under this study several alternative schemes studied by Central Engineering Consultancy Bureau (CECB) in 1989 and 1991 [6 and 7] were reviewed. The main construction works of the project commenced in August 2013 by China National Electric Engineering Co. Ltd (CNEEC) with the financing from Industrial and Commercial Bank of China (ICBC) and Hatton National Bank of Sri Lanka. At present the main water tunnel, Kehelgamu Oya diversion tunnel and dam foundation excavation works are in progress.
2. Detailed design of Moragolla Hydro power project was completed in November 2013 by NIPPON KOEI in joint venture with NIPPON KOEI INDIA PVT LTD. Funds from ADB has secured for implementation of this project. CEB is in the process of engaging consultants for construction supervision. Bid documents are also being reviewed.
3. A Pre-feasibility study on Uma Oya Multi-purpose Project (a trans-basin option) was completed by the CECB in July 1991 [8] where the diversion of Uma Oya, a tributary of Mahaweli Ganga was studied. In 2001, SNC Lavalin Inc. of Canada was engaged to conduct the feasibility study on Uma Oya with the assistance of Canadian International Development Agency (CIDA). However, this study was not completed. Funds were obtained from the Government of Iran for implementation of the project. FARAB Energy & Water Projects of Iran is the main contractor and the contract is effective from April 2010.The plant is scheduled to be commissioned by 2017.
4. A Feasibility Study has been done by Sinohydro Corporation Limited, China for Thalpitigala Reservoir project which is under the Ministry of Irrigation and Water Resource Management.
5. Gin-Nilwala trans-basin diversion project is under the Ministry of Irrigation and Water Resource Management. Feasibility study for the project was conducted by China CAMC Engineering Co. Ltd in 2012 and it was reviewed by Mahaweli Consultancy Bureau (Pvt) Ltd in April 2014[39]. The approval process of Environmental Impact Assessment (EIA) is in progress.

6. Moragahakanda Multi-Purpose Project under the Ministry of Irrigation and Water Resource Management is now in construction stage. Under this project three generators will be commissioned in 2017, 2020 and 2022.
7. The Prefeasibility study to identify suitable option for Seethawaka Ganga Hydro Power Project has been completed by Sri Lanka Energies Pvt Ltd. The Environmental Impact Assessment process was initiated. CEB is in the process of engaging consultants to carry out the feasibility study and the EIA.
8. CEB initiated the study on "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" with the technical assistance from JICA through the Government of Sri Lanka in 2013 [33]. This study was completed in December 2014 and identifies the future options to meet the peak power demand in Sri Lanka. Pumped Storage Power Plant option has been selected as the most suitable option and several sites have been suggested in priority order considering their social, environmental and financial impacts.
9. NTPC India, CEB and the Government of Sri Lanka entered into a MOA on 29th December 2006 for the development of 2x250MW Coal based thermal power project in Sampur in Sri Lanka through a Joint Venture Agreement. Accordingly, a Joint Venture Company, Trincomalee Power Co. Ltd (TPCL) was formed on 6th September 2011. The Feasibility study for the project was completed by NTPC consultants in October 2013[38]. EIA process is in the progress.
10. Pre-feasibility study on High Efficient Coal Fired Thermal Power Plant in Sri Lanka was initiated in June 2013 with the financial assistance from New Energy and Industrial Technology Development Organization (NEDO), Japan [37]. The purpose of the study was to identify a suitable location to implement High-Efficient Coal Fired Thermal Power Plant in Sri Lanka. Site at Sampur was selected as the best site for this project. Consultants appointed by NEDO. completed the feasibility for the Sampur site in April 2015. CEB is in the process of obtaining the environmental clearance for the project.

8.2 Candidate Power Plants in the Base Case Plan from 2015 to 2027

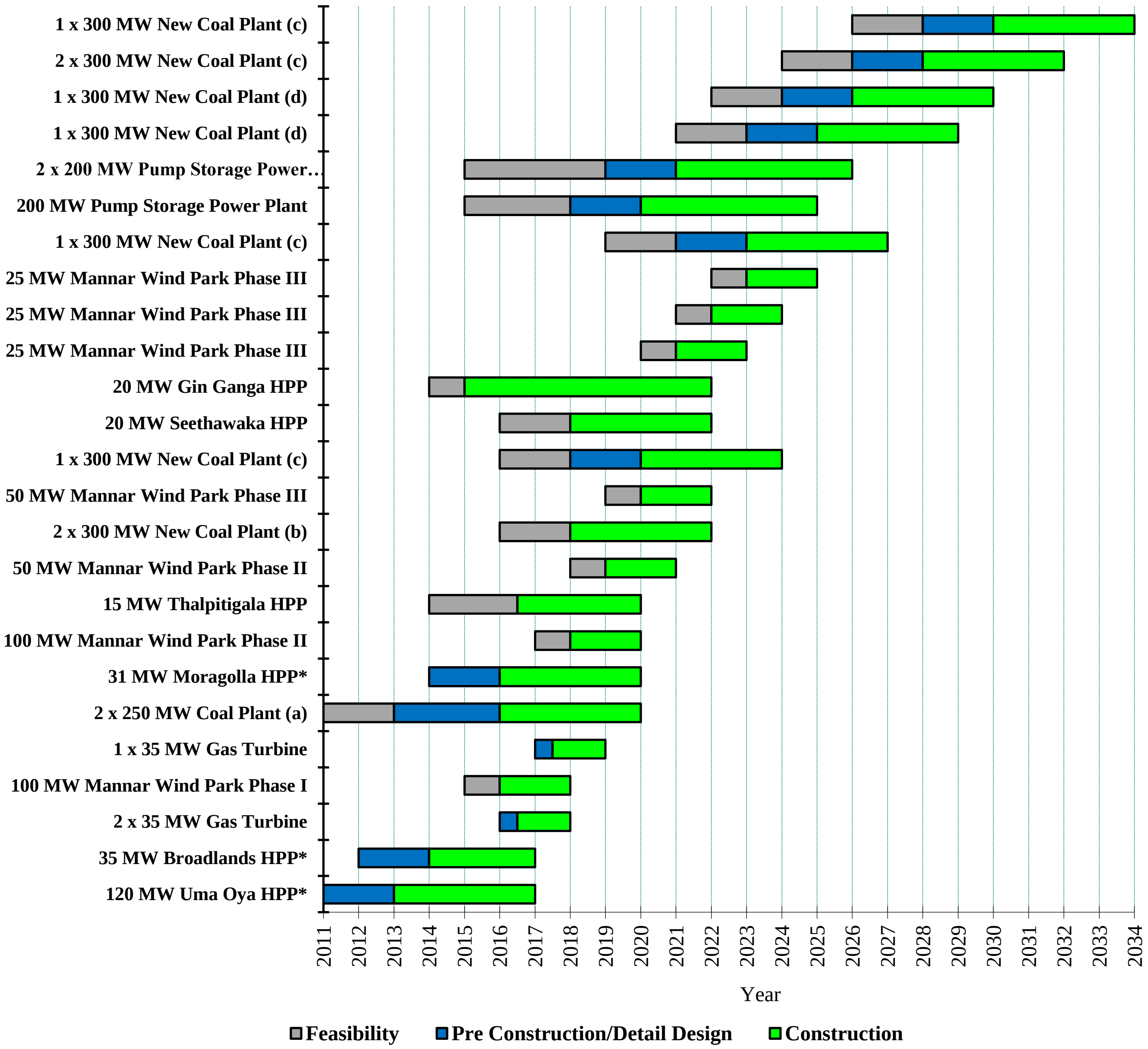
The proposed plants up to 2027 according to the Base Case are given below:

- 2x35MW Gas Turbine in 2018
- 100MW Mannar Wind Park Phase I in 2018
- 35MW Gas Turbine in 2019
- 2x250MW TPCL Coal Plant in 2020
- 15MW Thalpitigala HPP in 2020
- 100MW Mannar Wind Park Phase II in 2020
- 50MW Mannar Wind Park Phase II in 2021
- 20MW Seethawaka HPP in 2022
- 20MW Gin Ganga HPP in 2022
- 2x300MW New Coal Plant-Trincomalee-2, Phase-I in 2022
- 50MW Mannar Wind Park Phase III in 2022
- 25MW Mannar Wind Park Phase III in 2023
- 1x300MW New Coal Plant-Southern Region in 2024
- 25MW Mannar Wind Park Phase III in 2024
- 200MW Pump Storage Power Plant in 2025
- 25MW Mannar Wind Park Phase III in 2025
- 2x200MW Pump Storage Power Plant in 2026
- 1x300MW New Coal Plant-Southern Region in 2027

In the present study, 2022 was considered as the earliest possible year of commissioning of the first candidate coal power plant other than 2 x 250MW coal power developments in 2020 by Trincomalee Power Co. Ltd (TPCL).

8.3 Implementation Schedule

The implementation schedule for both committed and proposed power plants in the Base Case is shown in Figure 8.1.



*Committed Plants

(a) 2 x 250MW Coal-Trincomalee Power Company Ltd
(b) New Coal-Trincomalee-2, Phase-I
(c) New Coal-Southern Region
(d) New Coal-Trincomalee-2, Phase-II
Plants assumed as in operation from 1st January each year

Figure 8.1 - Implementation Plan 2015 – 2034

8.4 Required Investment for Base Case Plan 2015 – 2034

The annual investment requirement for the twenty year period from 2015 to 2034 is graphically shown in Figure 8.2. The details of the costs are tabulated in Table 8.1. Costs with regard to committed/on-going projects are not included in this table, and only the investments for new major projects and 375MW Mannar wind park are included.

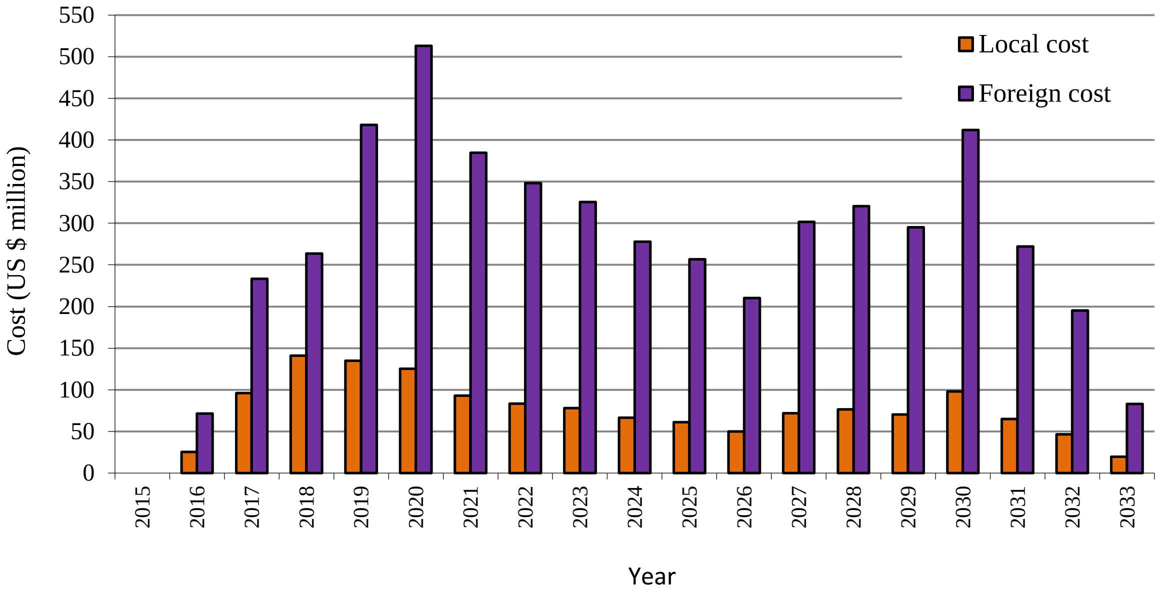


Figure 8.2 - Investment Plan for Base Case 2015 – 2034

8.5 Recommendations for the Base Case Plan

It is observed that the system can operate within the LOLP limits even in year 2015. In year 2019 minimum Reserve Margin has violated due to generation capacity limitation. Therefore timely implementation of proposed plants is crucial to avoid capacity shortages, energy shortages and high cost alternative generation.

Major recommendations for the Base Case Plan are:

(a) Implementation of 3x 35MW Gas Turbine Units by year 2018 & 2019:

Implementation of 3 x 35MW of GT units would replace following power plants which are due for retirement in the near future.

- 4x20MW frame V Gas Turbine units at Kelanitissa by 2018
- 51MW Asia Power Ltd power plant at Sapugaskanda by 2018
- 4x20MW Sapugaskanda Power Station A by 2019

Kelanitissa was selected as the most suitable site due to the availability of infrastructure facilities including fuel storage and handling, transmission interconnection etc.

This plant will be designed with black start capability, frequency controlling facility and synchronous condenser mode operation.

(b) Implementation of 35MW Broadlands, 120MW Uma Oya and 31MW Moragolla hydro power projects as per scheduled:

Implementation of 35MW Broadlands & 120MW Uma Oya by year 2017 and 31MW Moragolla by year 2020 would be important to provide peak power and to avoid any capacity and energy shortages as shown in Figure 8.4.

(c) Implementation of 2x250MW TPCL Coal Power Plant by year 2020 at Sampur:

Trincomalee Power Company Limited is responsible for the implementation and operation of the 2x250MW coal power plant at Sampur. In LTGEP 2011-2025, this was planned to be commissioned by 2017. Due to implementation delays, commissioning year was further delayed to 2018 in LTGEP 2013-2032. Therefore, timely implementation of 2x 250MW TPCL Coal Power Plant at Sampur is essential to avoid capacity shortage from year 2020 onwards.

(d) Implementation of 2x300 MW New Coal Plant-Trincomalee-2, Phase-I in year 2022 at Trincomalee:

Sampur area in Trincomalee has been identified as the most suitable location for the implementation of 2x300MW new coal power plant by year 2022, for which feasibility study has already been conducted. Land for the project needs to be secured early.

(e) Impacts of implementation delays in Broadlands, Uma Oya, 2x 250 MW TPCL Coal and 2x300 MW New Coal Plant up to year 2025:

Figure 8.3 shows the cumulative capacity addition in Base Case Plan from 2015 to 2025, which consist firm system capacity without intermittent resources to serve the peak demand. If any delay of implementation of 35MW Broadlands (2 year delay), 120MW Uma Oya (2 year delay), 2x 250MW TPCL (1 year delay) and 2x300MW New Coal Plant (2 year delay) would cause reserve margin violations and higher LOLP due to firm system capacity shortage from year 2018 onwards. The system would rely on the intermittent resources to serve the peak demand as shown in Figure 8.4. Therefore, plants identified in the Base Case Plan should be implemented as per schedule commissioning years in order to avoid the power crisis from year 2018 onwards.

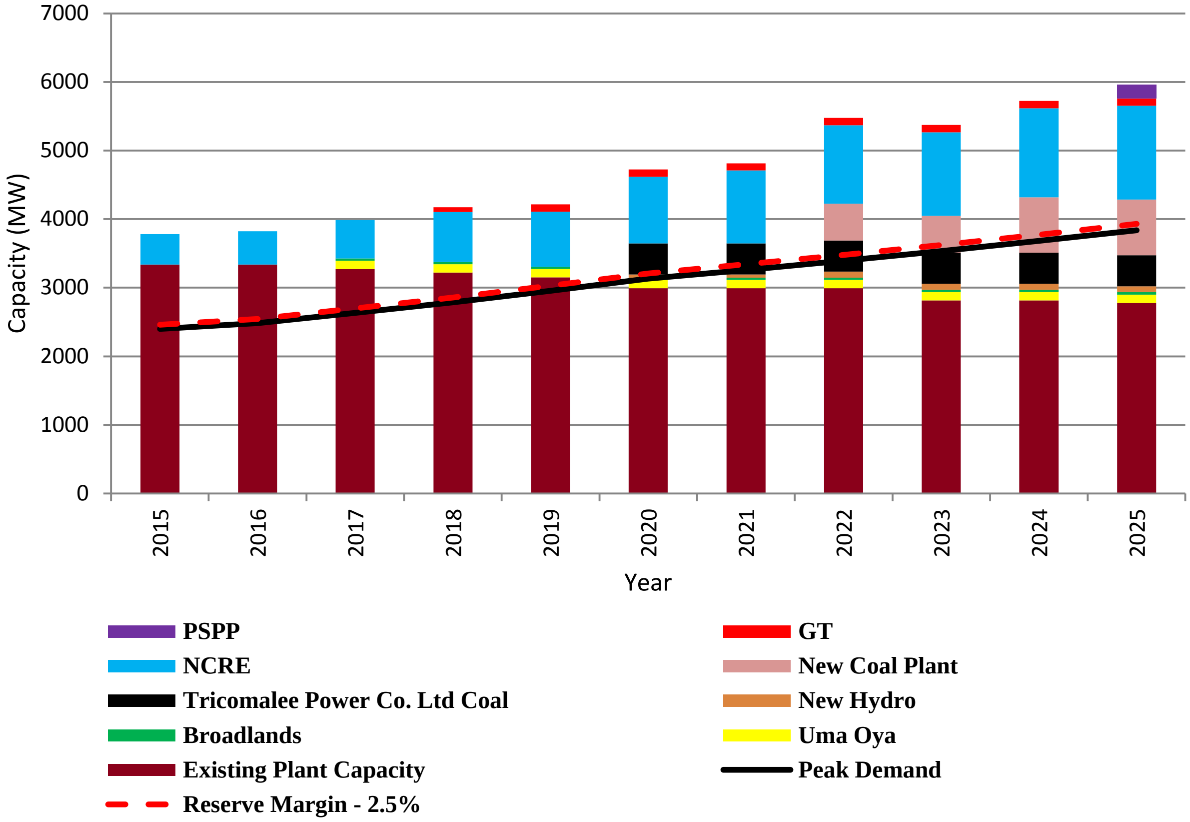


Figure 8.3 – Base Case Plan Cumulative Capacity Addition 2015 - 2025

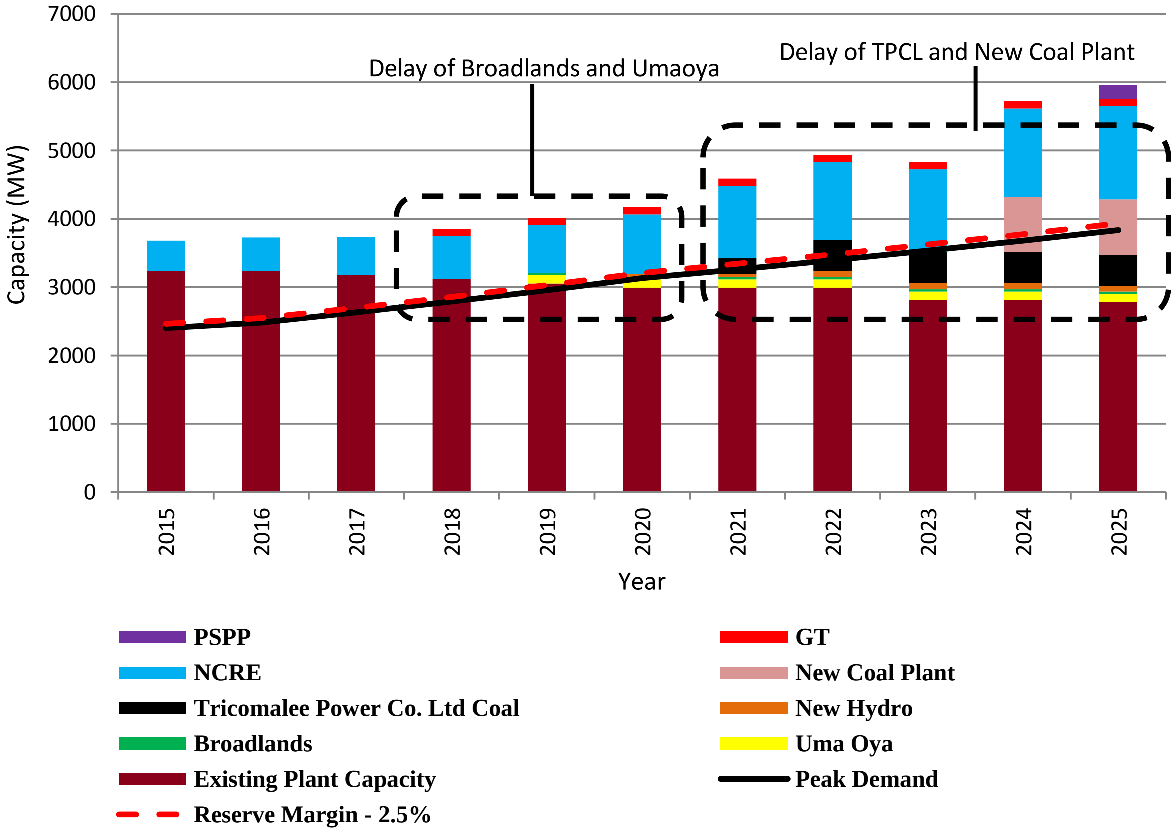


Figure 8.4 - Base Case Plan Cumulative Capacity Addition with Plant Delays

(f) Implementation of 20MW Seethawaka Hydro Power projects by year 2022:

Implementation of 20MW Seethawaka Hydro Power project by year 2022 is important to avoid capacity & energy shortages.

(g) Implementation of 3x 200MW Pump Storage Power Plants by year 2025 & 2026:

Pump Storage Power Generation option is important with committed and planned coal power development as well as with the prominent peak and off-peak characteristics of the daily demand pattern. Therefore, the implementation of 600MW Pump Storage Power Plant will support to overcome the operational limitations of coal power plants during off peak hours and to maintain the efficiency of the coal power plants. Also, PSPP will enhance the NCRE absorption capability to the system and reduce the curtailment of NCRE power generation.

(h) Implementation of Wind and other NCRE Power Plants as per the NCRE Schedule:

20% of energy share through NCRE is considered in the Base Case Plan from year 2020 onwards. NCRE plants should be implemented according to the plan to avoid capacity shortages as capacity contribution from NCRE has taken into consideration. Significant contribution to capacity and energy share by Biomass Plants are considered. Therefore, it is important to implement Biomass based generation plants on time. All future wind power plants will be developed as semi dispatchable wind parks.

(i) Identification of suitable locations for the remaining Coal plants, identified in the Base Case Plan and to carry out feasibility studies:

Identification of suitable locations for future coal plants is important for timely implementation of the projects. Locations should be met with technical, environmental and social requirements.

(j) Environmental implication of identified plants in the Base Case Plan:

Base Case Plan has identified 9x300MW new coal power plants except 2x 250MW TPCL Coal Power Plant at Sampur. Introduction of High Efficient Coal Power Plants would minimize environmental impacts.

8.6 Investment Requirement Variation for Scenarios

The investment requirements for following scenarios are compared against investment requirement of the Base Case Plan for the 20 year period from 2015 to 2034.

1. Reference Scenario
2. Demand Side Management (DSM) Scenario
3. Low Demand Scenario
4. Coal Restricted Scenario
5. Natural Gas Average Penetration Scenario
6. Energy Mix with Nuclear Scenario

Total investments for the above scenarios are compared with Base Case Plan in Figure 8.5. Energy Mix scenario shows the highest investment requirement due to diversification of fuel into LNG and Nuclear and introduction of Pump Storage Power Plant during the period from 2026 to 2028. Investment for Reference Scenario is higher than the Base Case Plan, because of having 2 Nos additional coal power plants. However, overall present value of the Reference Case is lower than the Base Case Plan.

Natural Gas Average Penetration Scenario shows a lower investment than Base Case plan. This is mainly due to the conversion of existing 165MW Kelanitissa Combined Cycle Power Plant (KPS), 270MW West Coast Power Plant and 163MW AES Kelanitissa Power Plant to Natural Gas during the period from 2021 to 2023.

Low Demand Scenario and DSM Scenario show the minimum investment due to demand reduction compared with Base Case demand.

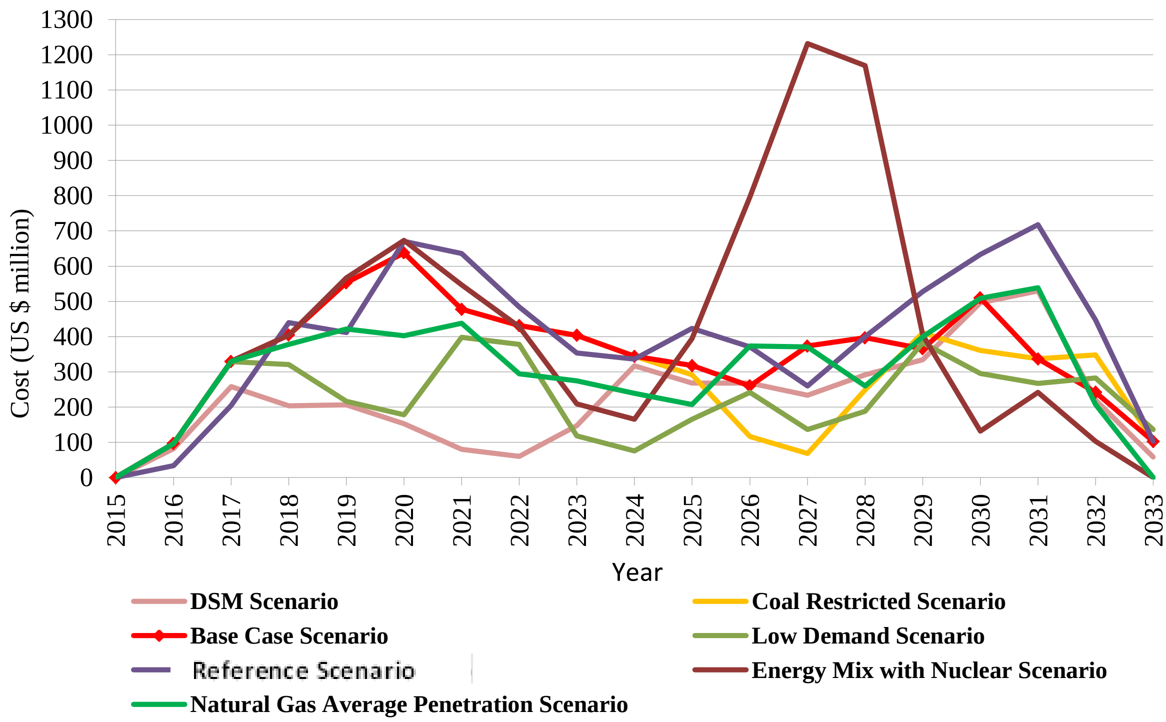


Figure 8.5 – Investment Requirement in Scenarios

Table 8.1 Investment Programme for Major Expansion Projects (Base Case), 2015-2034 (Costs in million US$, Exch. Rate:131.55 LKR/US$)

YEAR & PLANT	2015		2016		2017		2018		2019		2020		2021		2022		Total		Grand
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	Total
2018 - 35 MW Gas Turbine - 2 units																			
Base Cost			0.7	3.7	6.6	33.9											**7.3**	**37.6**	**44.9**
Contingencies			0.1	0.5	1.0	5.1											**1.1**	**5.6**	**6.7**
Port Handling & other charges (5%)				0.2		2.0											**0.0**	**2.2**	**2.2**
Total			0.8	4.4	7.6	41.0											**8.4**	**45.4**	**53.8**
2018 - 100 MW Mannar Wind Park Phase I																			
Base Cost			10.3	41.2	22.2	88.7											**32.5**	**129.9**	**162.4**
Contingencies			1.8	7.3	3.9	15.7											**5.7**	**22.9**	**28.7**
Port Handling & other charges (5%)				2.4		5.2											**0.0**	**7.6**	**7.6**
Total			12.1	50.9	26.1	109.6											**38.2**	**160.4**	**198.6**
2019 - 35 MW Gas Turbine - 1 unit																			
Base Cost					0.3	1.8	3.3	17.0									**3.6**	**18.8**	**22.4**
Contingencies					0.1	0.3	0.5	2.5									**0.6**	**2.8**	**3.4**
Port Handling & other charges (5%)						0.1		1.0									**0.0**	**1.1**	**1.1**
Total					0.4	2.2	3.8	20.5									**4.2**	**22.7**	**26.9**
2020 - 15 MW Thalpitigala HPP - 1 unit	**(Constructed by Ministry of Irrigation & Water Resource Managment)**																		
Base Cost																			
Contingencies																			
Port Handling & other charges (5%)																			
Total																			
2020 - 250 MW Trinco Coal Plant- 2 units																			
Base Cost			10.8	13.3	54.1	66.7	99.6	122.8	42.3	52.1							**206.8**	**254.9**	**461.7**
Contingencies			1.6	2.0	8.1	10.0	14.9	18.4	6.3	7.8							**30.9**	**38.2**	**69.1**
Port Handling & other charges (5%)				0.8		3.8		7.1		3.0							**0.0**	**14.7**	**14.7**
Total			12.4	16.1	62.2	80.5	114.5	148.3	48.6	62.9							**237.7**	**307.8**	**545.5**
2020 - 100 MW Mannar Wind Park Phase II																			
Base Cost							10.3	41.2	22.2	88.7							**32.5**	**129.9**	**162.4**
Contingencies							1.8	7.3	3.9	15.7							**5.7**	**22.9**	**28.7**
Port Handling & other charges (5%)								2.4		5.2							**0.0**	**7.6**	**7.6**
Total							12.1	50.9	26.1	109.6							**38.2**	**160.4**	**198.6**
2021 - 50 MW Mannar Wind Park Phase II																			
Base Cost									5.1	20.6	11.1	44.4					**16.2**	**64.9**	**81.2**
Contingencies									0.9	3.6	2.0	7.8					**2.9**	**11.5**	**14.3**
Port Handling & other charges (5%)										1.2		2.6					**0.0**	**3.8**	**3.8**
Total									6.1	25.4	13.0	54.8					**19.1**	**80.2**	**99.3**
2022 - 300 MW New Coal Plant - Trincomalee - 2, Phase - I - 2 units																			
Base Cost							8.8	35.0	44.0	175.9	80.9	323.6	34.3	137.3			**168.0**	**671.8**	**839.8**
Contingencies							1.3	5.3	6.6	26.4	12.1	48.5	5.2	20.6			**25.2**	**100.8**	**126.0**
Port Handling & other charges (5%)								2.0		10.1		18.6		7.9			**0.0**	**38.6**	**38.6**
Total							10.1	42.3	50.6	212.4	93.0	390.7	39.5	165.8			**193.2**	**811.2**	**1004.4**
Annual Total			**25.3**	**71.3**	**96.3**	**233.3**													

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Table 8.1 Investment Programme for Expansion Projects (Base Case), 2015-2034 (Cont.) (Costs in million US$, Exch. Rate:131.55 LKR/US$)

YEAR & PLANT	2018		2019		2020		2021		2022		2023		2024		2025		Total		Grand
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	Total
2022 - 20 MW Seethawaka HPP - 1 unit																			
Base Cost	0.6	1.3	3.1	6.4	5.8	11.9	2.4	5.0									**11.9**	**24.6**	**36.5**
Contingencies	0.1	0.2	0.5	1.0	0.9	1.8	0.4	0.8									**1.9**	**3.8**	**5.7**
Port Handling & other charges (5%)		0.1		0.4		0.7		0.3									**0.0**	**1.4**	**1.4**
Total	0.7	1.6	3.6	7.8	6.7	14.4	2.8	6.1									**13.8**	**29.8**	**43.6**
2022 - 20 MW Gin Ganga HPP - 1 unit			**(Constructed by Ministry of Irrigation & Water Resource Managment)**																
Base Cost																			
Contingencies																			
Port Handling & other charges (5%)																			
Total																			
2022 - 50 MW Mannar Wind Park Phase III																			
Base Cost					5.1	20.6	11.1	44.4									**16.2**	**64.9**	**81.2**
Contingencies					0.9	3.6	2.0	7.8									**2.9**	**11.5**	**14.3**
Port Handling & other charges (5%)						1.2		2.6									**0.0**	**3.8**	**3.8**
Total					6.1	25.4	13.0	54.8									**19.1**	**80.2**	**99.3**
2023 - 25 MW Mannar Wind Park Phase III																			
Base Cost							2.6	10.3	5.5	22.2							**8.1**	**32.5**	**40.6**
Contingencies							0.5	1.8	1.0	3.9							**1.4**	**5.7**	**7.2**
Port Handling & other charges (5%)								0.6		1.3							**0.0**	**1.9**	**1.9**
Total							3.0	12.7	6.5	27.4							**9.6**	**40.1**	**49.7**
2024 - 300 MW New Coal Plant - Southern Region - 1 unit																			
Base Cost					4.3	17.5	22.0	87.9	40.4	161.7	17.1	68.6					**83.8**	**335.7**	**419.5**
Contingencies					0.7	2.6	3.3	13.2	6.1	24.3	2.6	10.3					**12.7**	**50.4**	**63.1**
Port Handling & other charges (5%)						1.0		5.1		9.3		3.9					**0.0**	**19.3**	**19.3**
Total					5.0	21.1	25.3	106.2	46.5	195.3	19.7	82.8					**96.5**	**405.4**	**501.9**
2024 - 25 MW Mannar Wind Park Phase III																			
Base Cost									2.6	10.3	5.5	22.2					**8.1**	**32.5**	**40.6**
Contingencies									0.5	1.8	1.0	3.9					**1.4**	**5.7**	**7.2**
Port Handling & other charges (5%)										0.6		1.3					**0.0**	**1.9**	**1.9**
Total									3.0	12.7	6.5	27.4					**9.6**	**40.1**	**49.7**
2025 - 200 MW Pump Storage Power Plant- 1 unit																			
Base Cost					1.3	5.3	5.6	21.9	12.5	49.5	13.0	51.4	4.2	16.6			**36.6**	**144.7**	**181.3**
Contingencies					0.2	0.8	0.8	3.3	1.9	7.4	1.9	7.7	0.6	2.5			**5.4**	**21.7**	**27.1**
Port Handling & other charges (5%)						0.3		1.3		2.8		3.0		1.0			**0.0**	**8.3**	**8.3**
Total					1.5	6.4	6.4	26.5	14.4	59.7	14.9	62.1	4.8	20.1			**42.0**	**174.7**	**216.7**
2025 - 25 MW Mannar Wind Park Phase III																			
Base Cost											2.6	10.3	5.5	22.2			**8.1**	**32.5**	**40.6**
Contingencies											0.5	1.8	1.0	3.9			**1.4**	**5.7**	**7.2**
Port Handling & other charges (5%)												0.6		1.3			**0.0**	**1.9**	**1.9**
Total											3.0	12.7	6.5	27.4			**9.6**	**40.1**	**49.7**
Annual Total	**141.2**	**263.5**	**134.9**	**418.1**	**125.3**	**512.8**													

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Table 8.1 Investment Programme for Expansion Projects (Base Case), 2015-2034 (Cont.) (Costs in million US$, Exch. Rate:131.55 LKR/US$)

YEAR & PLANT	2021		2022		2023		2024		2025		2026		2027		2028		Total		Grand
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	Total
2026 - 200 MW Pump Storage Power Plant- 1 unit																			
Base Cost	1.3	5.3	5.6	21.9	12.5	49.5	13.0	51.4	4.2	16.6							**36.6**	**144.7**	**181.3**
Contingencies	0.2	0.8	0.8	3.3	1.9	7.4	1.9	7.7	0.6	2.5							**5.4**	**21.7**	**27.1**
Port Handling & other charges (5%)		0.3		1.3		2.8		3.0		1.0							**0.0**	**8.3**	**8.3**
Total	1.5	6.4	6.4	26.5	14.4	59.7	14.9	62.1	4.8	20.1							**42.0**	**174.7**	**216.7**
2026 - 200 MW Pump Storage Power Plant- 1 unit																			
Base Cost	1.3	5.3	5.6	21.9	12.5	49.5	13.0	51.4	4.2	16.6							**36.6**	**144.7**	**181.3**
Contingencies	0.2	0.8	0.8	3.3	1.9	7.4	1.9	7.7	0.6	2.5							**5.4**	**21.7**	**27.1**
Port Handling & other charges (5%)		0.3		1.3		2.8		3.0		1.0							**0.0**	**8.3**	**8.3**
Total	1.5	6.4	6.4	26.5	14.4	59.7	14.9	62.1	4.8	20.1							**42.0**	**174.7**	**216.7**
2027 - 300 MW New Coal Plant - Southern Region - 1 unit																			
Base Cost					4.3	17.5	22.0	87.9	40.4	161.7	17.1	68.6					**83.8**	**335.7**	**419.5**
Contingencies					0.7	2.6	3.3	13.2	6.1	24.3	2.6	10.3					**12.7**	**50.4**	**63.1**
Port Handling & other charges (5%)						1.0		5.1		9.3		3.9					**0.0**	**19.3**	**19.3**
Total					5.0	21.1	25.3	106.2	46.5	195.3	19.7	82.8					**96.5**	**405.4**	**501.9**
2029 - 300 MW New Coal Plant - Trincomalee - 2, Phase - II - 1 unit																			
Base Cost									4.3	17.5	22.0	87.9	40.4	161.7	17.1	68.6	**83.8**	**335.7**	**419.5**
Contingencies									0.7	2.6	3.3	13.2	6.1	24.3	2.6	10.3	**12.7**	**50.4**	**63.1**
Port Handling & other charges (5%)										1.0		5.1		9.3		3.9	**0.0**	**19.3**	**19.3**
Total									5.0	21.1	25.3	106.2	46.5	195.3	19.7	82.8	**96.5**	**405.4**	**501.9**
Annual Total	**93.1**	**384.8**	**83.3**	**348.1**	**78.0**	**325.6**	**66.4**	**277.7**	**61.1**	**256.5**									

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Table 8.1 Investment Programme for Expansion Projects (Base Case), 2015-2034 (Cont.)

(Costs in million US$, Exch. Rate:131.55 LKR/US$)

YEAR & PLANT	2026		2027		2028		2029		2030		2031		2032		2033		Total		Grand
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	**Total**
2030 - 300 MW New Coal Plant - Trincomalee - 2, Phase - II - 1 unit																			
Base Cost	4.3	17.5	22.0	87.9	40.4	161.7	17.1	68.6									**83.8**	**335.7**	**419.5**
Contingencies	0.7	2.6	3.3	13.2	6.1	24.3	2.6	10.3									**12.7**	**50.4**	**63.1**
Port Handling & other charges (5%)		1.0		5.1		9.3		3.9									**0.0**	**19.3**	**19.3**
Total	5.0	21.1	25.3	106.2	46.5	195.3	19.7	82.8									**96.5**	**405.4**	**501.9**
2032 - 300 MW New Coal Plant - Southern Region - 2 units																			
Base Cost					8.8	35.0	44.0	175.9	80.9	323.6	34.3	137.3					**168.0**	**671.8**	**839.8**
Contingencies					1.3	5.3	6.6	26.4	12.1	48.5	5.2	20.6					**25.2**	**100.8**	**126.0**
Port Handling & other charges (5%)						2.0		10.1		18.6		7.9					**0.0**	**38.6**	**38.6**
Total					10.1	42.3	50.6	212.4	93.0	390.7	39.5	165.8					**193.2**	**811.2**	**1004.4**
2034 - 300 MW New Coal Plant - Southern Region - 1 unit																			
Base Cost									4.3	17.5	22.0	87.9	40.4	161.7	17.1	68.6	**83.8**	**335.7**	**419.5**
Contingencies									0.7	2.6	3.3	13.2	6.1	24.3	2.6	10.3	**12.7**	**50.4**	**63.1**
Port Handling & other charges (5%)										1.0		5.1		9.3		3.9	**0.0**	**19.3**	**19.3**
Total									5.0	21.1	25.3	106.2	46.5	195.3	19.7	82.8	**96.5**	**405.4**	**501.9**
Annual Total	**50.0**	**210.1**	**71.8**	**301.5**	**76.3**	**320.5**	**70.3**	**295.3**	**98.0**	**411.8**	**64.8**	**272.0**	**46.5**	**195.3**	**19.7**	**82.8**	**1402.3**	**5180.9**	**6583.2**

Note:

(i) The cost included only the Pure Construction Cost and excluded the cost for Feasibility, EIA, Pre-Construction, Detail Design etc.

(ii) Distribution of the Pure Costruction Cost over the construction period of the plants is carried out by assuming a "S" Curve. S Curve parameters are shown in the Chapter 6.

(iii) Only 375MW of Wind power plants at Mannar Region is considered in the Investment Programme.

CHAPTER 9
ENVIRONMENTAL IMPLICATIONS

The impact of electricity generation on the environment could be due to one or several factors including: particulate emissions; gaseous emissions (CO_2, SO_X, NO_X etc.); warm water discharges into lakes, rivers or sea; liquid and solid waste (sludge, ash); inundation (in the case of large reservoirs) and changes of land use. Although many of these are common to any development project, particulate and gaseous emissions are of primary importance in the case of electricity generation using fossil fuels. This chapter describes the environmental impact of the implementation of Base Case Generation Expansion Plan and other selected scenarios.

9.1 Greenhouse Gases

The current IPCC (Intergovernmental Panel on Climate Change) guidelines define six major greenhouse gases. These include three direct Green House Gases (GHGs); Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O) and three precursor gases; Carbon Monoxide (CO), Oxides of Nitrogen (NO_x), and Non-Methane Volatile Organic Compounds (NMVOC). In addition, atmospheric Ozone (O_3) (though present only in very minute quantities) is also considered as a GHG. Apart from these, water vapour (H_2O) is one of the biggest contributors for global warming though it is not commonly categorised as a GHG with other gases.

9.2 Country Context

GHG emissions in Sri Lanka from fuel combustion, both in absolute as well as in per capita terms are low even in comparison to other countries in South Asia shown in Table 9.1. Emission level calculated per unit of GDP is also less in Sri Lanka when compared to other countries in the world. This could be mainly due to dominance of hydropower generation in the electricity sector and the low energy intensity in the production sector.

Table 9.1 - Comparison of CO_2 Emissions from fuel combustion

Country	kg CO_2/2005 US$ of GDP	kg CO_2/2005 US$ of GDP Adjusted to PPP	Tons of CO_2 per Capita	GDP per capita (current US$)
Sri Lanka	**0.41**	**0.10**	**0.78**	**2,922**
Pakistan	0.99	0.20	0.77	1,252
India	1.41	0.35	1.58	1,485
Indonesia	1.02	0.22	1.76	3,551
Thailand	1.15	0.32	3.84	5,480
China	1.81	0.63	6.08	6,093
France	0.15	0.17	5.10	40,925
Japan	0.26	0.31	9.59	46,679
Germany	0.25	0.26	9.22	43,932
USA	0.36	0.36	16.15	51,496
World	0.58	0.38	4.51	

Source: IEA CO_2 Emissions from Fuel Combustion (2014 Edition) -2012 data, World Bank website 2012 data

Until mid-nineties, significant thermal generation occurred only in the drought years as seen in Figure 1.9. Hence, the power sector has so far contributed very little to GHG emissions. However, this situation has been changing since 1995. Proposed expansion sequence predicts an increase in the thermal generation share to 65% by 2034 from approximately 55% share of present thermal generation as most of the new plants to be added to the system in the foreseeable future are fossil fuelled. Hence, a substantial increase in the use of fossil fuels in the power sector seems inevitable.

In 1994, Government of Sri Lanka has approved ambient air quality standards and it was amended in 2008. At present, all thermal power projects have to comply with these ambient air quality standards shown in Table 9.2.

But only a proposed set of stack emission standards is currently in place. Nevertheless, these proposed standards shown in Table 9.2 are used as a guide in the EIA process of thermal power plants of Sri Lanka.

Table 9.2 - Ambient Air Quality Standards and Proposed Stack Emission Standards of Sri Lanka

Pollutant ***Type***	Ambient Air Quality Std. (μg/m^3)				Proposed Stack Emission Std. (mg/MJ)	
	Annual level	24 hour level	8 hour level	1 hour level	Coal	Liquid Fuel
Nitrogen dioxides (NO_2)	-	100	150	250	300	130
Sulphur Dioxides (SO_2)	-	80	120	200	520	340
PM10	50	100	-	-	-	-
PM2.5	25	50	-	-	-	-
Total Suspended Particles(TSP)	-	-	-	-	40	40

Source: Central Environmental Authority

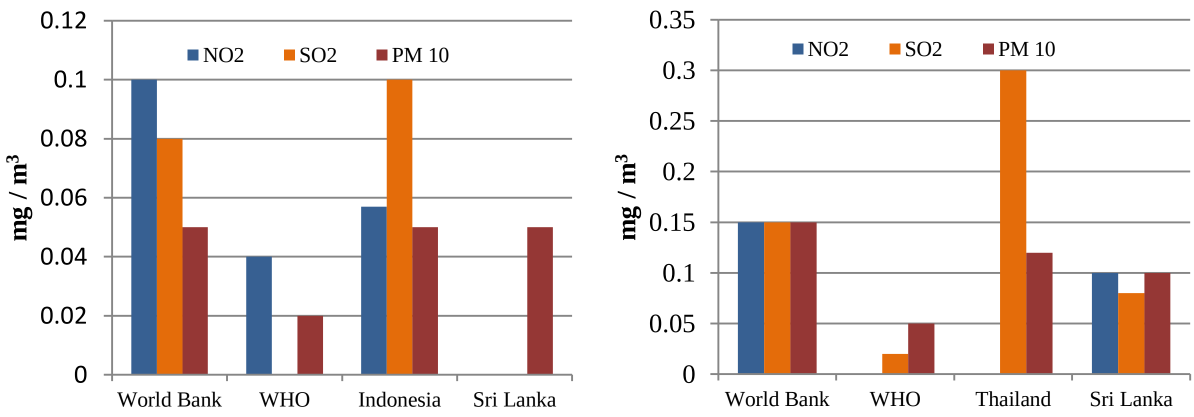
Table 9.3 - Comparison of Ambient Air Quality Standards of Different Countries and Organisation

(All values in mg/m3)

Pollutant	Averaging time	World Bank	WHO	India	Indonesia	Thailand	Pakistan	**Sri Lanka**
Nitrogen Dioxide (NO_2)	Annual	0.1	0.04	0.04	0.1	0.057	0.04	**-**
	24 hours	0.15	-	0.08	0.15	-	0.08	**0.1**
	8 hour						-	**0.15**
	1 hour	-	0.2	-	0.4	0.32	-	**0.25**
Sulphur Dioxide (SO_2)	Annual	0.08	-	0.05	0.06	0.1	0.08	**-**
	24 hours	0.15	0.02	0.08	0.365	0.3	0.12	**0.08**
	8 hour						-	**0.12**
	1 hour					0.78	-	**0.2**
	10 minute	-	0.5	-			-	**-**
PM 10	Annual	0.05	0.02	0.06		0.05	0.12	**0.05**
	24 hours	0.15	0.05	0.1	0.15	0.12	0.15	**0.1**
PM 2.5	Annual	-	0.01	0.04		0.025	0.015	**0.025**
	24 hours	-	0.025	0.06		0.05	0.035	**0.05**

Pollutant	Averaging time	World Bank	WHO	India	Indonesia	Thailand	Pakistan	**Sri Lanka**
Total Suspended	Annual	0.08	-	-	0.09	0.1		-
Particulate	24 hours	0.23	-	-	0.23	0.33		-
Suspended	Annual						0.36	**0.1**
Particulate Matter	24 hours						0.5	**0.3**

Source: World Wide Web, Central Environmental Authority



(a) Annual Average *(b) 24 hour Average*

Figure 9.1 - Comparison of Ambient Air Quality Standards

When compared with the standard specified by the World Bank (Existing) and WHO as shown in Table 9.3 and Figure 9.1, it is evident that Sri Lanka has very stringent ambient air quality standards for SO_2 emissions. The standard for particulate matter is also higher than the existing World Bank standards though not the highest of all.

A comparison of proposed Sri Lankan Stack Emission standards with those of World Bank and some Asian Countries is shown in Table 9.4. It can be seen that proposed Sri Lankan Stack Emission standards are somewhere between the European Commission standards and the standards of some neighbouring Asian Countries such as China, Thailand and Vietnam.

Table 9.4 - Comparison of Emission Standards of Different Countries and Organisations

(All values in mg/MJ)

Pollutant	**Sri Lanka (Proposed)**	World Bank (Proposed)	Vietnam	China (Industry)	Thailand	European Commission
Nitrogen Oxides	**300**	365	487	450	500	200
Sulphur Dioxide	**520**	700	175	400	350	200
Suspended Particulate	**40**	50	200	50	700	30

Source: Central Environmental Authority, EPDC Database

Figure 9.2 compares the stack emission levels of existing and proposed coal power plants in Sri Lanka with the standards.

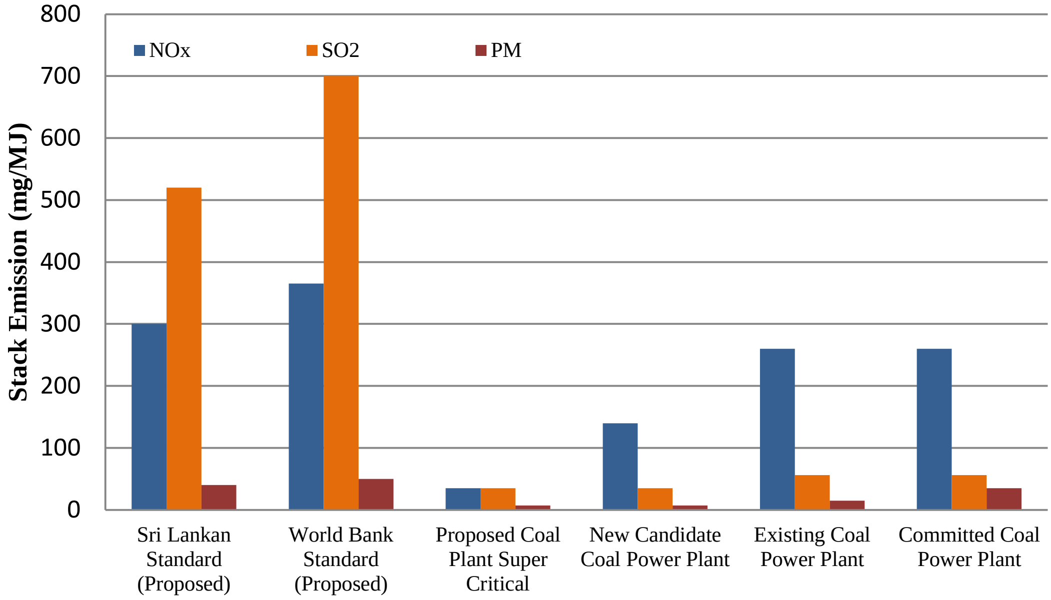


Figure 9.2 - Comparison of Stack Emission Standards and Stack Emission Levels of Coal Power Plants

9.3 Uncontrolled Emission Factors

One of the problems in analysing the environmental implications of electricity generation is correctly assessing the 'emission coefficients' or more commonly the 'emission factors'. Choice of different sources can always lead to overestimation or underestimation of real emissions. Table 9.5 lists the uncontrolled emission factors *(emissions without considering the effect of control technologies in addition to the standard emission control devices used in planning studies)* which are based on the given calorific values.

Table 9.5 - Uncontrolled Emission Factors (by Plant Technology)

Plant Type	Fuel Type	NCV (kcal/kg)	NCV (kJ/kg)	Sulphur Content (%)	Emission Factor Particulate (mg/MJ)	CO_2 (g/MJ)	SO_2 (g/MJ)	NOx (g/MJ)
Diesel Engine	Fuel Oil	10300	43124	3.5	13.0	76.3	1.709	1.200
Diesel Engine	Residual FO	10300	43124	3.5	13.0	77.4	1.639	1.200
Coal Steam	Coal	6300	26377	0.6	40.0	94.6	0.455	0.300
Gas Turbine	Auto Diesel	10500	43961	1.0	5.0	74.1	0.453	0.280
Comb. Cycle	Auto Diesel	10500	43961	1.0	5.0	74.1	0.453	0.280
Comb. Cycle	Naphtha	10880	45552	0	0	73.3	0	0.28
Comb. Cycle	Natural Gas	13000	54428	0	0.0	56.1	0.000	0.020
Dendro	Dendro	3224	13498	0	255.10	0.0	0.0	0.2

Sources: Thermal Generation Options Study [12], 2006 IPCC Guidelines

Basically, CO_2 and SO_2 emission factors are calculated based on the fuel characteristics, while NOx emissions, which depend on the plant technology, are obtained from a single source [12]. Generally, particulate emissions depend both on the plant technology and the type of fuel burnt. Therefore, the emissions could be controlled by varying the fuel characteristics and by adopting various emission control technologies.

9.4 Emission Control Technologies

According to the expansion sequence of Base Case mentioned in Chapter 7 (Table 7.1), 3200MW of Coal plants and 105MW of Gas Turbines are to be added to the Sri Lankan system in the next 20 years starting from 2015. The impact on the environment due to particulate and air-emissions from these additions and the effectiveness of using control devices to mitigate those impacts are analysed here. Particulate matter (PM) and three types of gaseous emissions were considered in the analysis, viz. SO_2, NOx and CO_2.

When applying control technologies, it is always necessary to have an idea about the availability and capability of different control technologies. Studies have shown that, in many cases, the use of state-of-the-art engineering practices could meet the stipulated air quality standards without specific control devices. However, there are instances where emission control is mandatory.

For example in the case of coal plants, the use of high-quality, low-sulphur coal (0.65% S) reduces SO_x emissions to levels below the standard, but definitely there has to be some form of control over particulate emissions. Lakvijaya coal power plant has a Sea Water Flue Gas Desulfurization unit (FGD) installed for further reduction of SOx emissions and an Electrostatic Precipitator (ESP) for control of PM.

Hence, in the present study control technologies considered in the proposed coal plants are as follows; ESPs for the control of particulate emissions, sea water FGD for control of SOx and low NOx burners and two stage combustion for the control of NOx. Coal power plants in Sri Lanka are mostly designed for low sulphur coal (0.65% sulphur) as fuel. Selective Catalytic Reduction (SCR) is also considered as an option for reduction of NOx.

The Low-NOx burners are an integrated part of most of the commercially available combined cycle plants, which are capable of reducing NOx emissions to a very low level.

Carbon Capture and Storage (CCS) is a technology that collects and concentrates the CO_2 emitted from large point sources such as power plants, transports it to a selected site and deposit it, preventing the release into the atmosphere. With the rising global energy consumption, technologies such as CCS become inevitable to avoid atmospheric greenhouse gas emissions and related climate consequences. Nevertheless, the technology is still being developed and improved.

Table 9.6 shows the abatement factors of typical control technologies available for controlling emissions, during and/or after combustion. The values used in the study are shown shaded. The costs of the control technologies considered are included in the project costs of candidate plants of the LTGEP.

Table 9.6 - Abatement Factors of Typical Control Devices

(Factors in %)

Device	SOx	NO_X	TSP	PM	CO	CH_4	NMVOC
Fabric Filter			99.5	99.5			
Electro Static Precipitator			99.2	90			
ESP				99.8			
SCR		75.7					
Dry FGD	50						
Wet FGD	92.5		90	90			
Sea Water FGD	93.9						
Low NOx Burner – Coal		25			-10	-10	-10
Low NOx Burner – CCY *		80					

Sources: Decades Manual & Coal feasibility Study Reports

TSP - Total Suspended Particles

FGD - Flue Gas Desulphurisation

NMVOC - Non Methane Volatile Organic Compounds

CCY - Combined Cycle Plants

SCR - Selective Catalytic Reduction

* - (NOx abatement % for CCY plants is based on a reduction from 350 ppm to 70 ppm)

9.5 Emission Factors Used

In the present study, emission factors were either calculated based on stoichiometry or taken from the actual measured values or calculated based on design and operational data for candidate plants. Emission factors were chosen from a single source [12] where sufficient data were not available. Table 9.7 shows the actual and proposed coal power plant data used in the study. When comparing with the standard values for coal power plants in Table 9.5 it is clear that the performance of the coal power plants in Sri Lanka is much satisfactory.

Table 9.7 - Emission Factors of the coal power plants

Plant Type	NCV of coal	NCV of coal	Sulphur	Emission Factor			
			Content	Particulate	CO_2	SO_x	NO_x
	(kcal/kg)	(kJ/kg)	(%)	(mg/MJ)	(g/MJ)	(g/MJ)	(g/MJ)
Coal Steam-New Coal Candidate	5900	24702	0.8	7.00	94.6	0.035	0.140
Coal Steam-Super Critical	6300	26377	0.8	7.00	94.6	0.035	0.035
Coal Steam-TPCL	5500	23027	0.65	35.00	98.3	0.056	0.260
Coal Steam-Lakvijaya Power Station	6300	26377	0.7	15.00	94.6	0.056	0.260

9.6 Environmental Implications – Base Case

Presented below is a quantitative analysis of the emissions associated with the Base Case generation expansion plan described in Chapter 7. The total particulate and gaseous emissions (controlled) under the Base Case plan are shown in Table 9.8 and Figure 9.3.

Table 9.8 – Air Emissions of Base Case

1000 tons/year

Year	PM	SO_2	NO_x	CO_2
2015	1.7	55.2	21.2	6,483
2016	2.1	58.9	22.5	6,788
2017	2.8	60.3	23.2	7,003
2018	3.8	59.2	21.1	7,240
2019	4.7	47.9	17.4	7,715
2020	6.0	32.7	16.6	8,997
2021	6.3	35.1	17.3	9,393
2022	5.8	30.2	17.5	10,328
2023	6.4	25.5	15.3	10,859
2024	6.5	25.4	16.4	11,692
2025	7.4	20.1	15.2	12,407
2026	8.0	22.7	16.3	13,288
2027	8.3	22.8	17.6	14,230
2028	8.5	23.7	18.6	15,085
2029	8.9	23.8	19.8	16,103
2030	9.2	23.7	21.2	17,216
2031	9.8	24.7	22.4	18,118
2032	10.5	23.8	24.2	19,501
2033	11.7	24.6	24.8	20,410
2034	13.0	24.3	26.4	21,564

With the introduction of coal based generation, CO_2 emission shows a continuous increasing trend. However, after introduction of high efficient coal power plants from 2022 onwards, the rate of increase of CO_2 emissions gradually decreases. Generally the particulate shows an increasing trend with time. The sudden increase of particulate in 2020 is due to the introduction of Trincomalee Power Company coal power plant. With integration of more biomass based generation into the system, PM emissions show a gradual increase over time. SO_x and NO_x emissions decrease during 2018-2024 due to the retirement of oil power plants and then the increasing trend is continued.

According to Figure 9.4, per kWh emissions of SO_x and NO_x shows a levelised trend while per unit CO_2 emissions would rise annually. Decrease in SO_x and NO_x emissions is mainly due to the use of low sulphur fuels (such as coal) and control measures taken to reduce NO_x emissions. Further the retirement of Diesel fired power plants with heavy SO_x and NO_x pollutants has led to much lower per unit emission levels in the longer run.

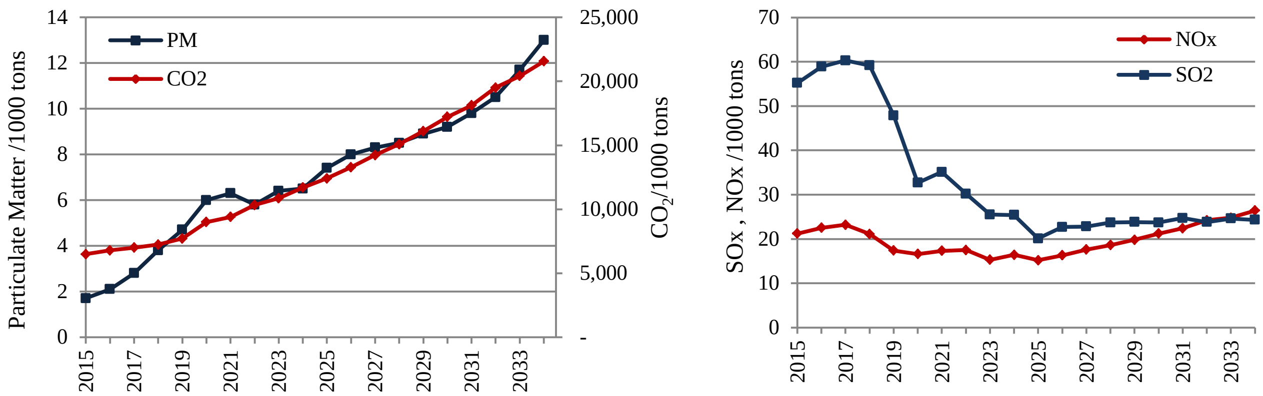


Figure 9.3 – PM, SO_2, NO_x and CO_2 emissions of Base Case Scenario

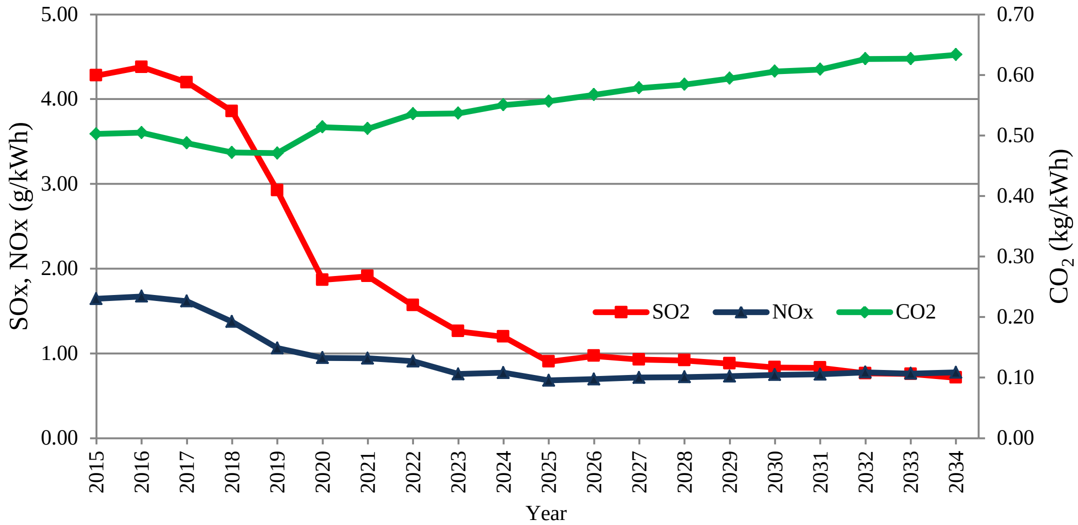


Figure 9.4 – SO_2, NO_x and CO_2 emissions per kWh generated

9.7 Environmental Implications – Other Scenarios

Following scenarios, which are expected to have significant effects on environment, are evaluated against the Base Case emissions.

1. Reference Scenario
2. Coal Restricted Scenario
3. Energy Mix with Nuclear Scenario
4. Natural Gas Average Penetration Scenario
5. Demand Side Management (DSM) Scenario

From the Figure 9.5 it is evident that the scenarios with NG power plants in the system have lower SO_x emissions than other scenarios due to zero SO_x emission factors from NG fired combined cycle plants. Coal restricted scenario has slightly higher SO_2 emissions during 2029 to 2031 due to delivery of higher energy from oil power plants and existing coal power plants. Demand Side Management scenario has lower SO_x emission compared to Base Case due to reduction of demand.

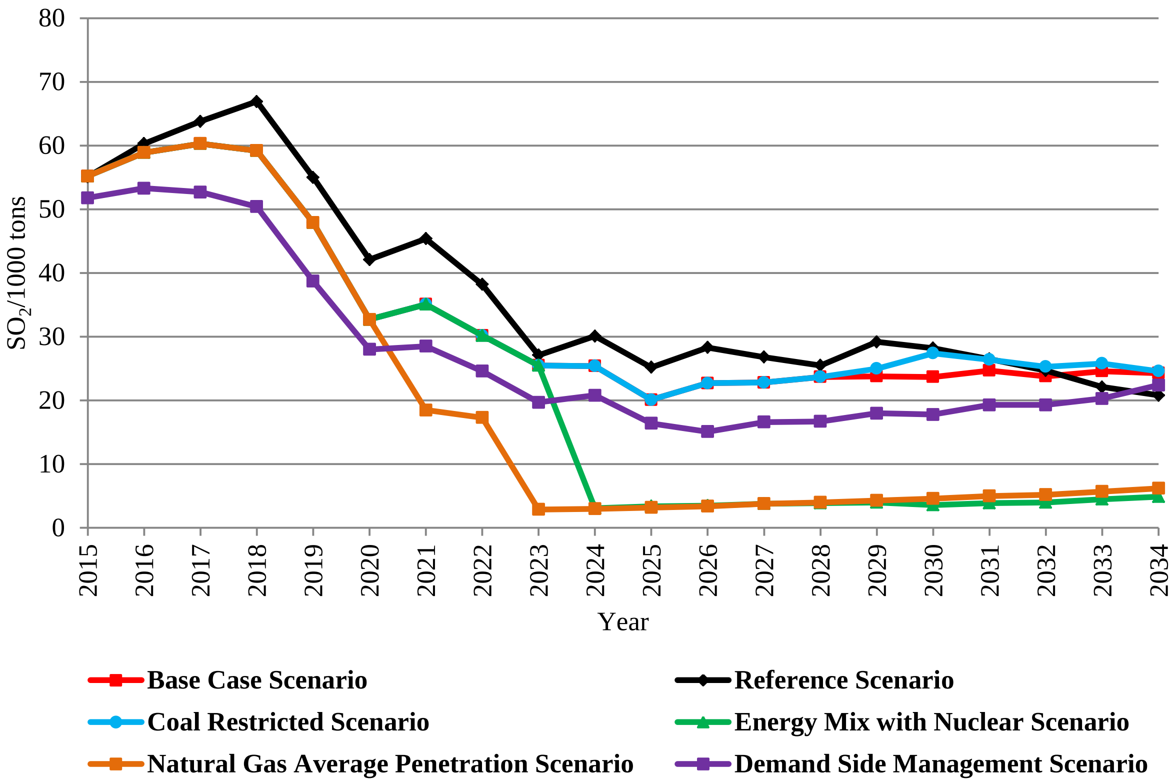


Figure 9.5 – SO_2 Emissions

In all scenarios, both SO_2 and NOx emission levels significantly reduce during 2018-2024 period due to retirement of oil power plants. NOx emission levels gradually increase with the introduction of the coal power plants to the system. Figure 9.6 shows the NOx emissions comparison of various scenarios.

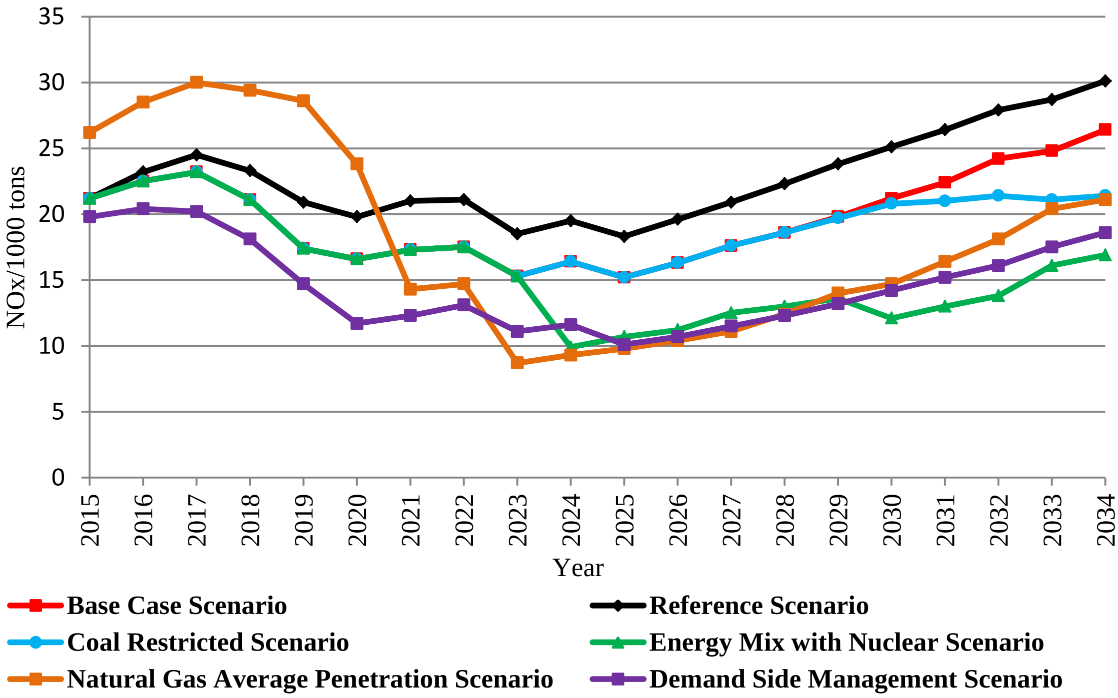


Figure 9.6 – NOx Emissions

The CO_2 emission factors of NG fired combined cycle plants are about 50% less than that of coal fired power plants. Reference Scenario has higher emissions compared to Base Case Scenario due to limitation of NCRE penetration to the system. Coal Restricted scenario, Energy Mix scenario and Natural Gas Average Penetration scenario introduce NG combined cycle power plants to the system in 2031, 2024 and 2021 respectively and hence reduction in associated CO_2 emissions are observed. The rapid drop of CO_2 emissions in the Energy Mix scenario in 2030 is due to the introduction of nuclear power plant. DSM scenario shows the least CO_2 emissions due to the reduction of 4 x 300MW Coal power plants compared with Base Case plan. Figure 9.7 shows the CO_2 emission comparison of various scenarios.

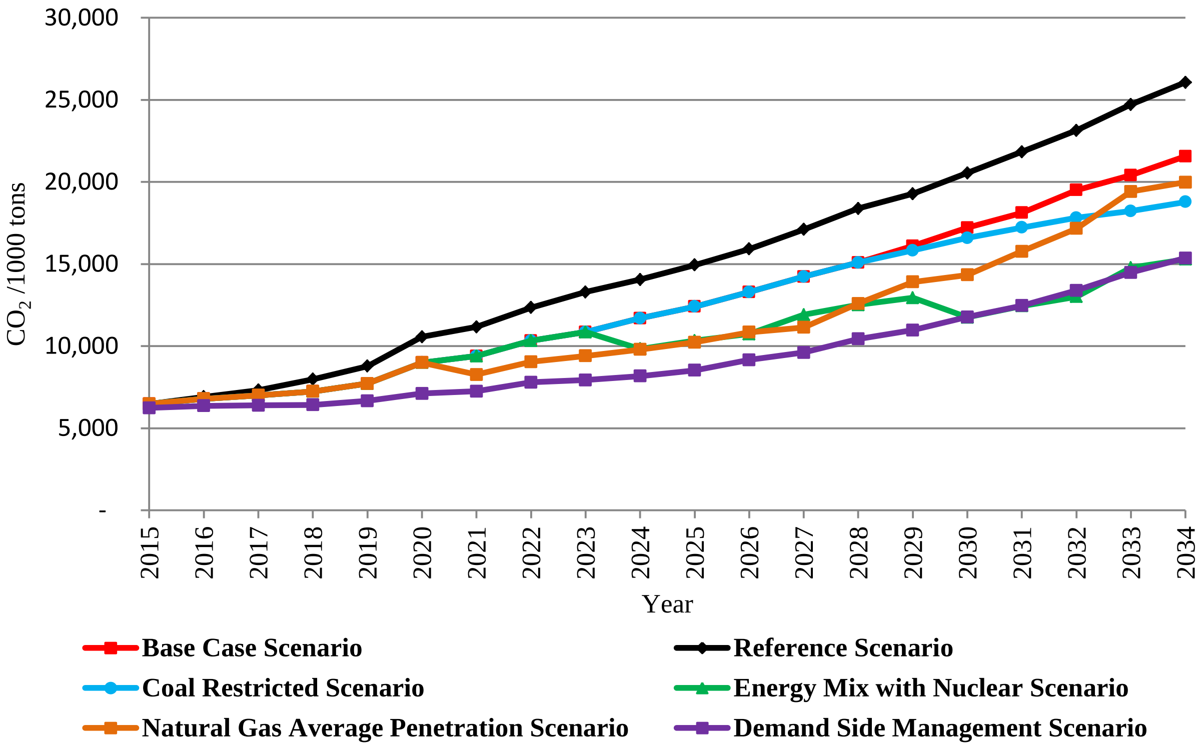


Figure 9.7 – CO_2 Emissions

Similarly particulate emission factors of NG fired combined cycle plants are equal to zero compared to coal fired power plants. Figure 9.8 shows the PM emission comparison of various scenarios. Due to the introduction of more biomass generation plants in the Base Case, PM emissions are higher than the Reference Case.

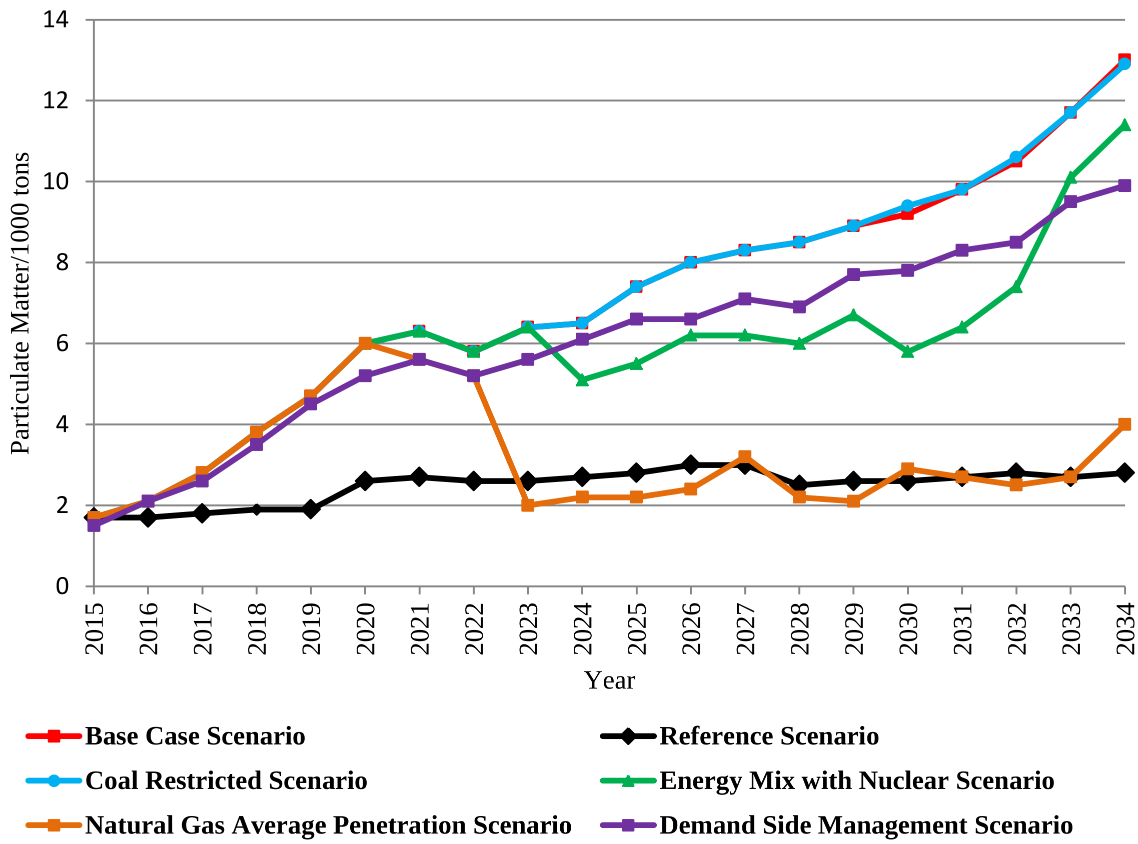


Figure 9.8 – Particulate Matter Emissions

Comparison of total CO_2 emission with total system cost is shown in Figure 9.9.

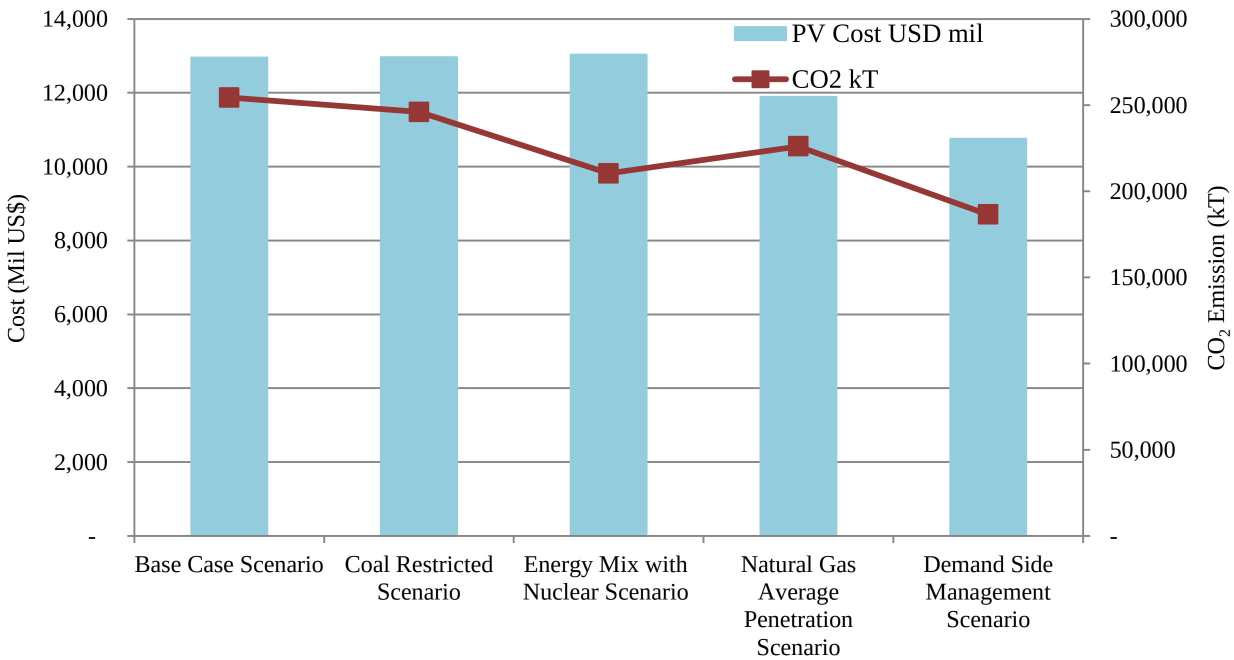


Figure 9.9 – Comparison of System Cost with CO_2 Emissions

Further, the incremental cost of each case was analysed by comparing the cost differences and the reduction of CO_2 emissions in each case compared to Base Case Plan and shown in Figure 9.10. It is observed that carbon revenue of 0.53USD/CO_2 ton and 1.67USD/CO_2 ton would be needed to implement the Coal Restricted scenario and Energy Mix scenario respectively. To implement, Natural Gas Average Penetration scenario and DSM scenario 37.74USD/CO_2 ton and 32.40USD/CO_2 ton is available compared with present value cost and CO_2 emissions in Base Case Plan.

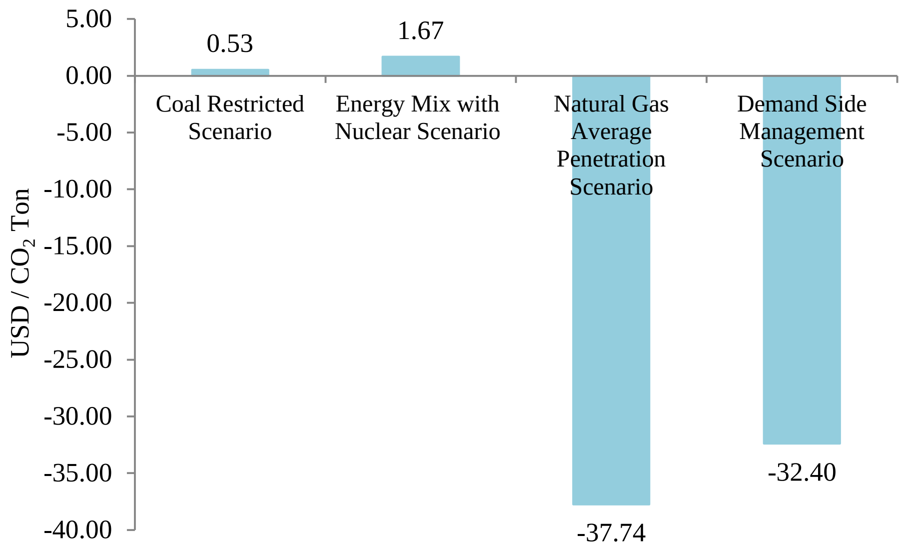
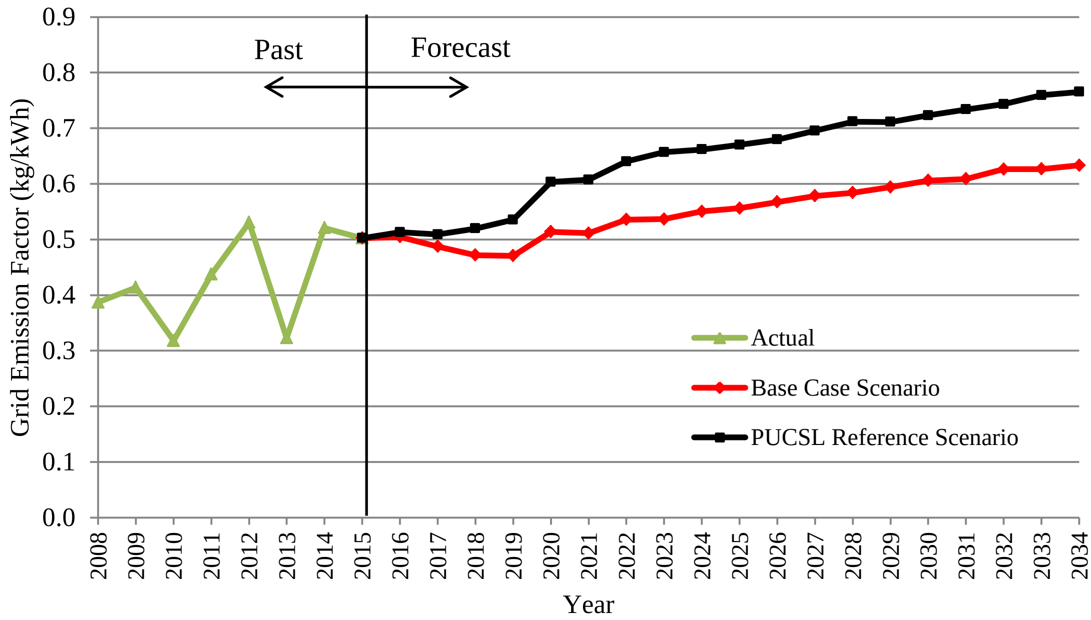


Figure 9.10 – Comparison of Incremental Cost for CO_2 reduction

Figure 9.11 shows the past actual and forecast values of grid emission factors for the Base Case and the Reference Scenarios.



Note: Source for actual CO_2 emissions –Sustainable Energy Authority

Figure 9.11 – Grid Emission Factor Comparison

9.8 Climate Change

The term Climatic Change is used to refer specifically to climate change caused by human activity; for example, the United Nations Framework Convention on Climate Change defines climate change as "a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods." In the latter sense climate change is synonymous with global warming.

Due to the increasing global concern on climate change, in 1988, the United Nations Environment Programme and the World Meteorological Organisation jointly established the Intergovernmental Panel on Climate Change (IPCC) with a directive to assess the best scientific options on climate change, its potential impacts, and possible response strategies. With the increased political concerns about climate change, the United Nations Framework Convention on Climate Change (UNFCCC) was formulated on the basis of initial IPCC findings. In 1992, the UNFCCC was established and signed by almost all countries at the Rio Summit.

The decision making body of UNFCCC is known as Conference of Parties (COP) which meets annually. The Kyoto Protocol was accepted in COP3 in Kyoto, Japan in 1997. The major feature of the Kyoto Protocol is that it sets binding targets for 37 industrialised counties and the European Community for reducing Green House Gas (GHG) emissions. It will amount to an average of 5% against 1990 levels over the five year period 2008-2012 (European Union at United Nations, 2008). Energy related carbon dioxide emission is one of the main GHG causes of climate change. But the goal of Kyoto Protocol is to lower overall emissions of six greenhouse gases - carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, hydro-fluorocarbons and per-fluorocarbons (UNFCCC, 2008). Recognising that industrialised countries (countries in Annex I of the Kyoto Protocol) are principally responsible for the current high levels of GHG emissions in the atmosphere as a result of more than 150 years of industrial activity, the protocol places the heavier burden on developed nations under the principle of "common but differentiated responsibilities". The Kyoto Protocol was adopted in Kyoto, Japan, on 11 December 1997 and entered into force on 16th February 2005. Under the Kyoto Protocol, Annex I countries must meet their targets primarily through national measures. However, the Kyoto Protocol offers them an additional means of meeting their target by the way of three market based mechanisms.

- Emission trading – known as "the carbon market"
- The Clean Development Mechanism (CDM)
- Joint Implementation (JI)

Under the Protocol, countries' actual emissions have to be monitored and precise records have to be kept to the trades carried out. Only the Clean Development Mechanism allows economical emission credit trading among Annex I and non-Annex I Countries.

Thirteenth Conference of Parties (COP13) was held in Bali in December 2007. This conference resulted in the adoption of Bali Road Map which consisted of several forward looking climate decisions. Launching of Adaptation Fund, a review of Kyoto Protocol, Decisions on Technology transfer and Reducing Deforestation related emissions and Ad-Hoc Working Group (AWG) negotiations on a Long Term Corporative Agreement (LCA) and Kyoto Protocol (KP) were included in this road map.

The efforts to take a decision on the extension of the Kyoto Protocol prior to the ending of its 1st commitment period on 31st December 2012, specially at the COP15/CMP5 in Copenhagen, COP 16/CMP6 in Cancun and COP17/CMP7 in Durban failed and only in at the COP18/CMP8 in Doha that an agreement was reached. Accordingly at Doha, parties agreed for a second commitment period up to 31.12.2020, a revised list of greenhouse gases and commitment by parties to reduce GHG emission by at least 18% below 1990 levels. However, the expected reductions are comparatively low and there is a significance difference in the parties to the second commitment compared to the previous with parties such as Japan, Canada, and Russia not being included for the second commitment.

At the COP17/CMP7, in Durban in 2011, a significant development in the climate change negotiations occurred. The parties agreed to launch a process to develop a protocol or a legal instrument or a legally binding agreement under the convention applicable to all parties. This process is implemented through subsidiary body under the convention, the Ad Hoc Working Group on the Durban Platform for Enhanced Action (ADP). This legally binding agreement was to be agreed upon on or before 2015 and to be implemented by 2020.

But at the COP19/CMP9 in Warsaw in 2013 the governments advanced the timeline for the development of the 2015 agreement with the intention of developing the initial draft by December 2014, and submitting the formal draft text by May 2015, all with a view to enabling the negotiations to successfully conclude in December 2015. Countries decided to initiate or intensify domestic preparation for their Intended Nationally Determined Contributions (INDCs) towards the 2015 agreement, which will come into force from 2020. Parties ready to do this will submit clear and transparent plans during 2015. As a party to UNFCC, Sri Lanka also needs to prepare INDCs.

Kyoto Protocol has not imposed any obligation for non-Annex I countries. As a non-Annex I country, Sri Lanka ratified the Kyoto Protocol in 2002. It is estimated that the total emission contribution of GHG emissions from Sri Lanka is less than 0.05% of the global total. Although emission levels are much less than the global values, Sri Lanka has adopted many policy measures that would result in mitigating emissions.

Government of Sri Lanka has given more priority for the Energy Sector which is highly dependent on imported fossil fuel which is 37% in 2013 and to reduce the present trend, sustainable energy policies are enforced to absorb more NCRE to the system.

In February 2009, the Ministry of Environment and Natural Resources as the Designated National Authority (DNA), to the UNFCC and Kyoto protocol, at the time, developed a draft national CDM policy. The objective of the national CDM policy is *"to achieve sustainable development a) through developing and establishing the institutional, financial, human resources and legal/legislative framework necessary to participate in Clean Development Mechanism (CDM) activities and b) through developing a mechanism for trading of "Certified Emission Reduction" earned through CDM activities for the Government of Sri Lanka."*

In Sri Lanka, the key sectors to implement CDM projects can be identified as energy, industry, transport, agriculture, waste management, forestry and plantation. Among these, the energy sector has been identified as having the highest potential.

First CDM project in Sri Lanka was registered in 2005 with UNFCCC. Since then, 17 projects have been registered by the end of 2013. Broadlands Hydro Power Project undertaken by CEB was registered as a CDM project. The estimated emission reduction from the project is approximately 83 kilo tonnes of CO_2 equivalent per annum.

The National Energy Policy and Strategies of Sri Lanka (2008) states that by 2015, Sri Lanka will endeavour to reach a target of at least 10% of the total energy supplied to the grid from Non-Conventional renewable resources. Also, it states that a review of technical limits and financial constraints of absorbing NCRE will be carried out.

Generation, Transmission and Distribution Loss reduction is also an important measure implemented by CEB towards the path of providing sustainable energy. In 2009 the transmission and distribution loss (as a percentage of net generation) was 13.9% and by 2013 it has been reduced to 10.79%. Energy conservation from Demand Side Management which involves education and awareness of the consumers on purchasing energy efficient appliances, designing households and commercial establishments to be more energy efficient are some measures being carried out in the power sector. All those measures reduce the thermal power generation and result in reduction of GHG emissions.

Even up to mid-nineties the Sri Lankan power sector was mainly hydro based with the contribution being over 90%. With the almost full utilization of the available major hydro power potential, CEB had to turn to thermal power which was mainly oil based. First Coal plant of 300MW capacity was only established in 2011 and second & third coal power plants in 2014. In 2013, Sri Lanka has achieved a level of economic development of close to 3000 USD per capita income with a comparatively low effect on the global GHG emission. Therefore, Sri Lanka has every right to utilise available resources in order to continue in the development path with the least economic effect on its people.

LTGEP has been worked out based on the economically optimal plant additions in order to meet the forecast electricity demand. In Base Case Plan, the major contribution for power generation comes from coal power in the future and this situation will contribute significantly to the GHG emissions in comparison with current level. Any proposal to shift from coal to a higher cost technology / fuel in order to reduce the GHG emissions should include suitable compensation by an international mechanism.

CEB has already taken steps to reduce emissions through efficient technologies for coal power plants and also taken decision to develop remaining major hydro power projects.

In LTGEP, NCRE energy share is increased more than 20% from 2020 onwards and this would result in reduction of emissions from power generation considerably. With the introduction of 3x200MW Pumped Storage Power Plant and high NCRE, green credential of the system would be maintained at 35%-40% of the country’s energy share.

10.1 Introduction

It is worthwhile to examine the deviations of the results of the present study from the last generation expansion plan, and to analyse the causal factors for such deviations. The causes for the differences between the current study (LTGEP 2014 for the period of 2015-2034) and LTGEP 2012 for the period of 2013 – 2032 are as follows:

- Demand forecast
  - Sector wise GDP was used as independent variables instead of total GDP
  - Load Factor improvement by analysing contribution from NCRE
- Fuel price variations
- Revised hydro power generation potential
- Introducing high efficiency Coal Plant as a candidate
- Introducing 3x200MW Pumped Storage Power Plants
- Integrating the results of the study "Integration of Non-Conventional Renewable Energy Based Generation into Sri Lanka Power Grid".

10.2 Demand Forecast

This year demand forecast study was developed adopting a sector-wise approach and the econometric method was used to derive demand projections for each sector as described in Chapter 3. The new Peak demand and Energy demand forecast growth rates are 4.57% and 5.17% while Peak demand and Energy demand in LTGEP 2012 are 4.9% and 5.2% respectively. Both were calculated for 25 years period. Figure 10.1(a), Figure 10.1 (b) and Figure 10.2 show the Comparison of 2012 and 2014 load forecasts and installed capacity additions between LTGEP 2012 and current plan respectively.

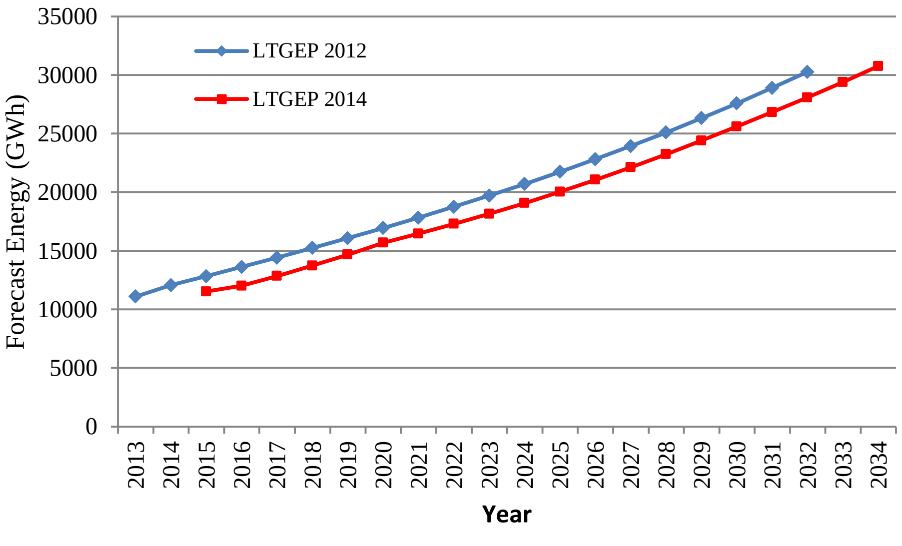


Figure 10.1(a) - Comparison of 2012 and 2014 Energy Demand Forecasts

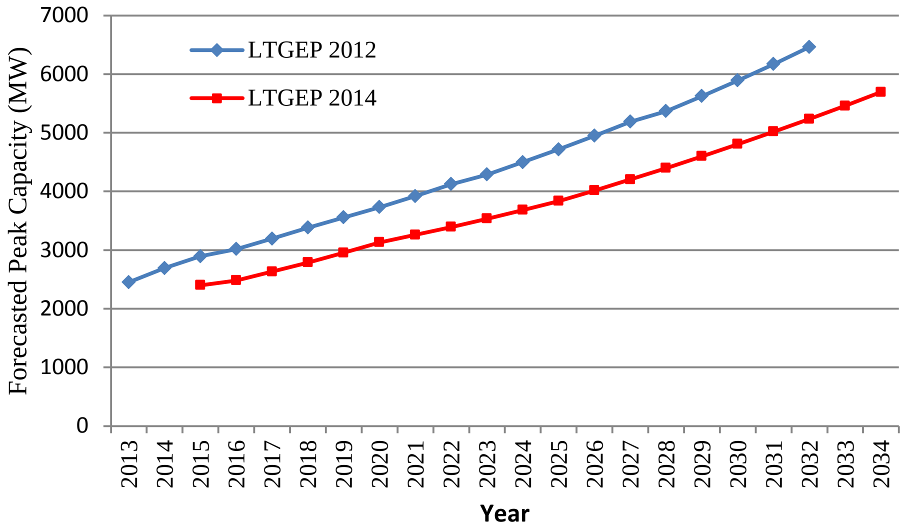


Figure 10.1(b) - Comparison of 2012 and 2014 Peak Demand Forecast

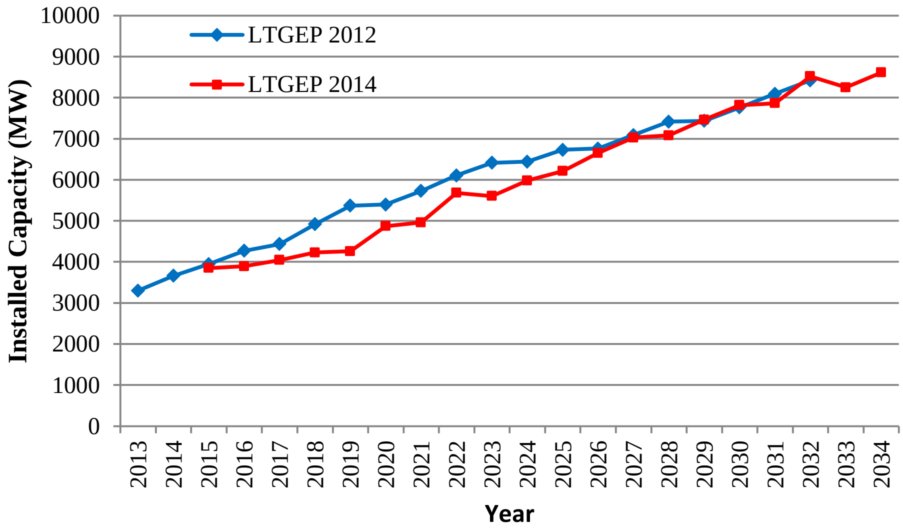


Figure 10.2 – Comparison of Total Installed Capacity Addition (Including NCRE) between LTGEP (2012) and Current Plan (2014)

Figures 10.3 and 10.4 show the capacity mix and energy mix in the selected years 2013, 2016, 2019, 2022, 2025, 2028, 2031 and 2034 for both LTGEP 2012 and the current plan (LTGEP 2014).

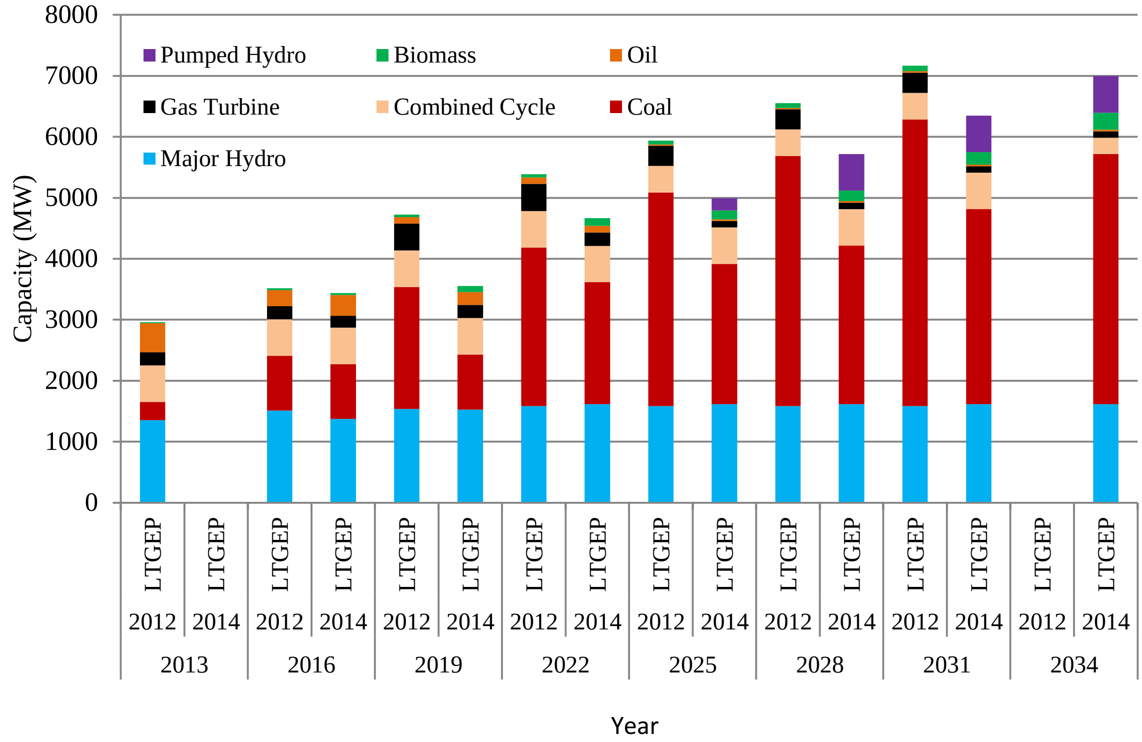


Figure 10.3 - Capacity Mix

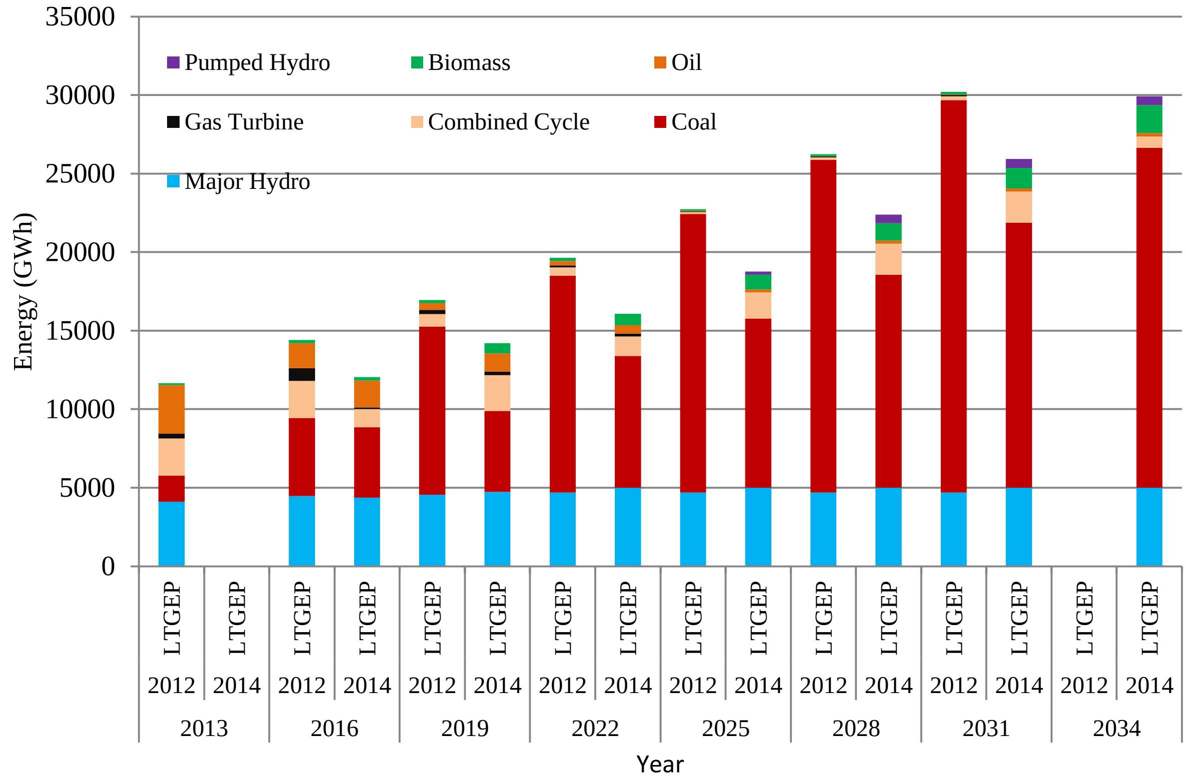


Figure 10.4 - Energy Mix

Projected demand growth rate in LTGEP 2014 is less than the previous plan. Minimum reserve margin of 2.5% and maximum reserve margin value of 20% were used in both LTGEP 2012 and the LTGEP 2014 plan.

According to the SDDP output data, weighted average hydro power potential in LTGEP 2014 is higher than that of LTGEP 2012.

20% of energy contribution from NCRE sources from year 2020 onwards was considered including capacity contribution in LTGEP 2014, whereas energy contribution from NCRE was 11% in LTGEP 2012.

SO_x and NO_x emissions are lower in the LTGEP 2014 than the expected level of emission in LTGEP 2012. Comparison of SOx and NOx emissions depicts in Figure 10.5. Also the comparison of CO_2 and Particulate emissions is shown in Figure 10.6.

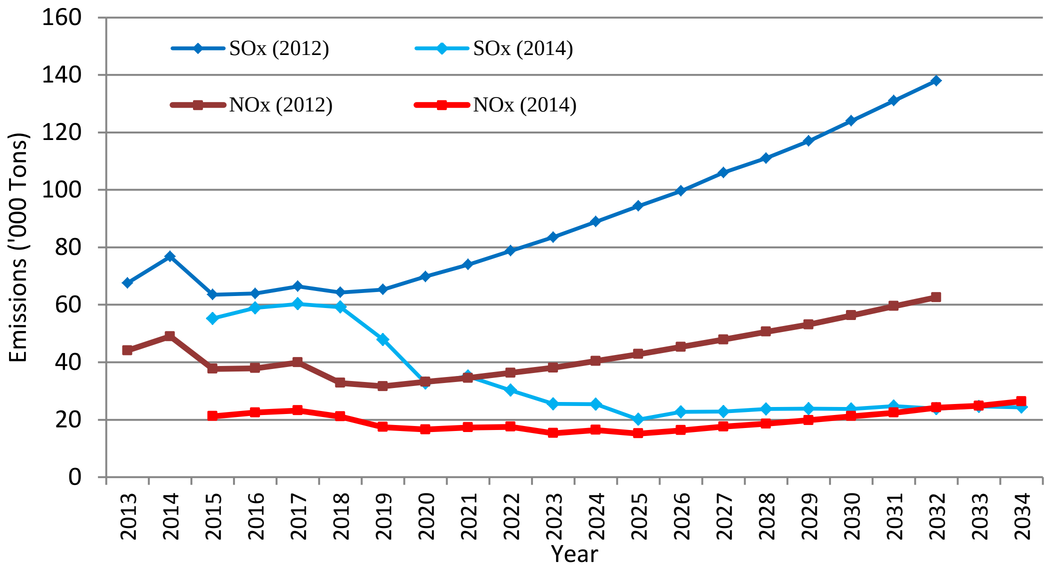
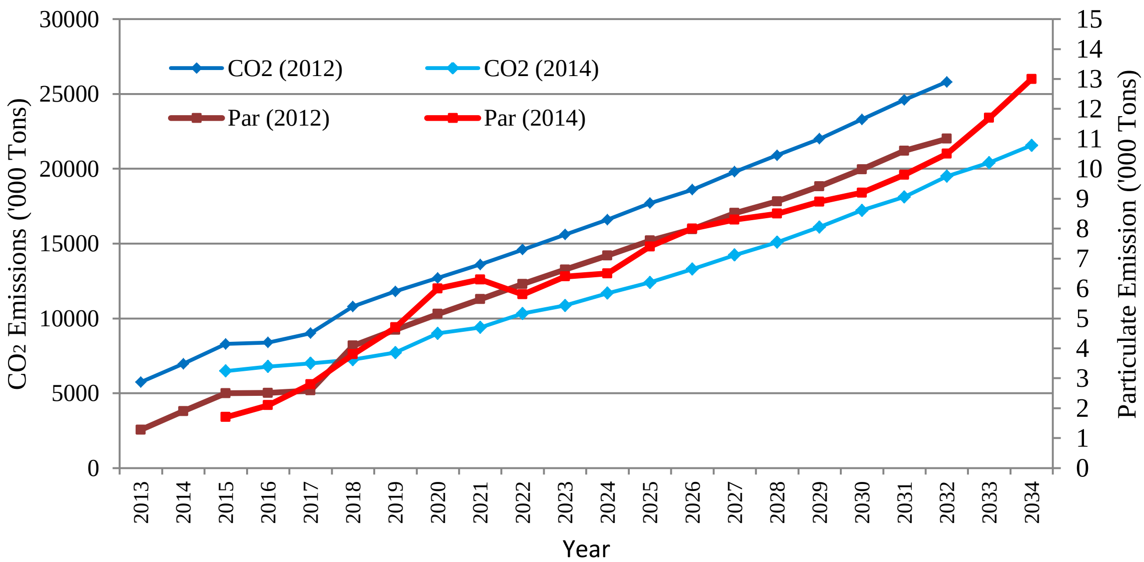


Figure 10.5 - SO_x and NO_x Emissions



Note: Particulate Matter emission from Biomass Plants is considered for LTGEP 2015-2034.

Figure 10.6 – CO_2 and Particulate Emissions

10.3 Fuel Prices

Prices of coal for the present study were obtained from the Lanka Coal Company while oil prices were obtained from Ceylon Petroleum Corporation. Fuel prices used in the respective studies are shown in Figure 10.7. Coal Prices show a significant reduction while oil prices have minor reduction. Figure 10.8 shows the fuel quantities expected to be consumed according to two Base Case Plans (Revised Base Case in 2012 Plan) in LTGEP 2012 and LTGEP 2014.

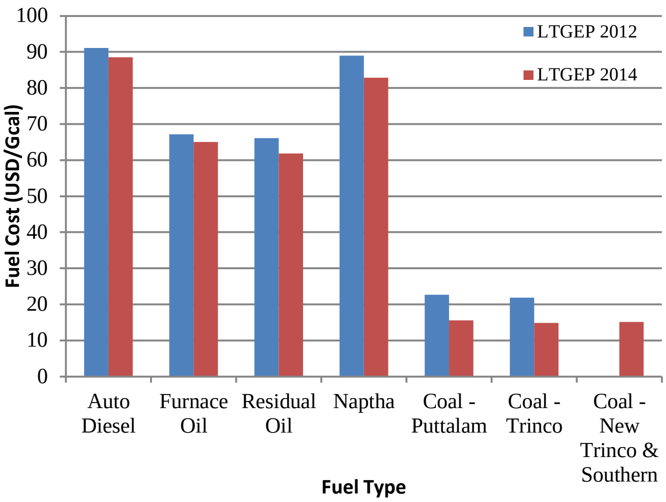


Figure 10.7 - Review of Fuel Prices

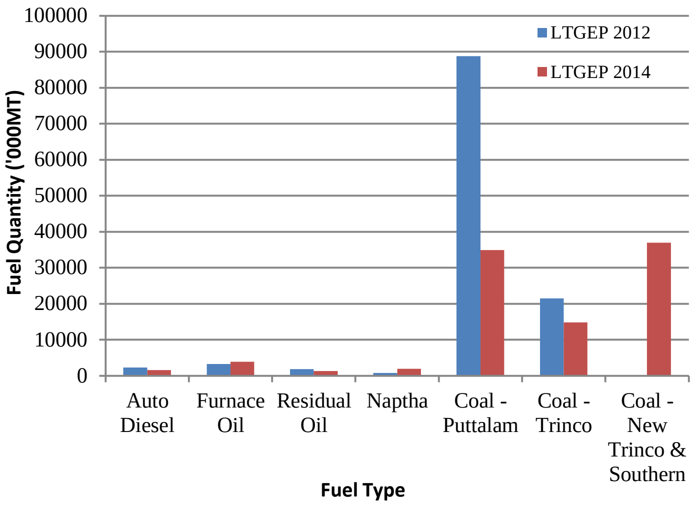


Figure 10.8 Review of Fuel Quantities

10.4 Status of the Last Year Base Case Plan

The total system cost of the Revised Base Plan of LTGEP 2012 for 2013-2032 is 14,049 USD million in 2012 price, whereas the cost of the Base Plan of LTGEP 2014 for 2015-2034 is 12,960 USD million in 2014 price. A brief description is provided in Table 10.1, indicating the present status of each of the power project proposed in the previous study in LTGEP 2012.

Table 10.1 – Comparison with LTGEP 2012- Revised Base Case

Project pipelined in LTGEP – 2012	For Year	Present Status and LTGEP 2014 Recommendations
1x300MW Puttalam Coal (Stage II) 3x75MW Gas Turbine	2015	60MW Colombo Power Plant retired and will operate as CEB owned plant. Puttalam Coal Stage II completed in 2014. 3x75MW Gas Turbine not implemented.

Project pipelined in LTGEP – 2012	For Year	Present Status and LTGEP 2014 Recommendations
35MW Broadlands and 120MW Uma Oya Hydro Power Plants.	2016	35MW Broadlands and 120MW Uma Oya Hydro Power Plants delayed to 2017 due to implementation delays.
1x105MW Gas Turbine	2017	35MW Broadlands and 120MW Uma Oya Hydro Power Plants to be commissioned. 1x105MW Gas Turbine not implemented.
27MW Moragolla Hydro Power Plant 2x250MW Trincomalee Coal Power Plant	2018	2x35MW Gas Turbines to be commissioned. 100MW Mannar Wind Park Phase I to be commissioned. Moragolla HPP delayed till 2020 due to implementation delays. 2x250MW Trincomalee Coal Plant delayed to 2020 due to implementation delays.
2x300MW Coal Plant	2019	1x35MW Gas Turbines to be commissioned.
-	2020	31MW Moragolla and 15MW Thalpitigala Hydro Power Plants to be commissioned. 100MW Mannar Wind Park Phase II to be commissioned. 2x250MW Coal Power Plant Trincomalee Power Company Limited to be commissioned.
1x300MW Coal Plant	2021	50MW Mannar Wind Park Phase II to be commissioned.
49MW Gin Ganga Hydro Power Plant 1x300MW Coal Plant	2022	20MW Seethawaka and 20MW Gin Ganga Hydro Power Plants to be commissioned. 50MW Mannar Wind Park Phase III to be commissioned. 2x300MW New Coal Power Plants, Trincomalee-2 Phase I to be commissioned.

Project pipelined in LTGEP – 2012	For Year	Present Status and LTGEP 2014 Recommendations
2x300MW Coal Plant	2023	163MW AES Kelanithissa Plant to be transferred and operated by CEB. 25MW Mannar Wind Park Phase III to be commissioned.
-	2024	1x300MW New Coal Plant – Southern Region to be commissioned. 25MW Mannar Wind Park Phase III to be commissioned.
1x300MW Coal Plant	2025	1x200MW Pumped Storage Hydro Power Plant to be commissioned. 25MW Mannar Wind Park Phase III to be commissioned.
-	2026	2x200MW Pumped Storage Hydro Power Plant to be commissioned.
1x300MW Coal Plant	2027	1x300MW New Coal Plant – Southern Region to be commissioned.
1x300MW Coal Plant	2028	-
-	2029	1x300MW New Coal Power Plants, Trincomalee-2 Phase II to be commissioned.
1x300MW Coal Plant	2030	1x300MW New Coal Power Plants, Trincomalee-2 Phase II to be commissioned.
1x300MW Coal Plant	2031	-
1x300MW Coal Plant	2032	2x300MW New Coal Plant – Southern Region to be commissioned.

All plants are assumed to be commissioned at the beginning of the year.

10.5 Overall Comparison

The overall comparison of generation expansions proposed by plans for last 20 years and actual expansion took place is shown in Annex 10.1

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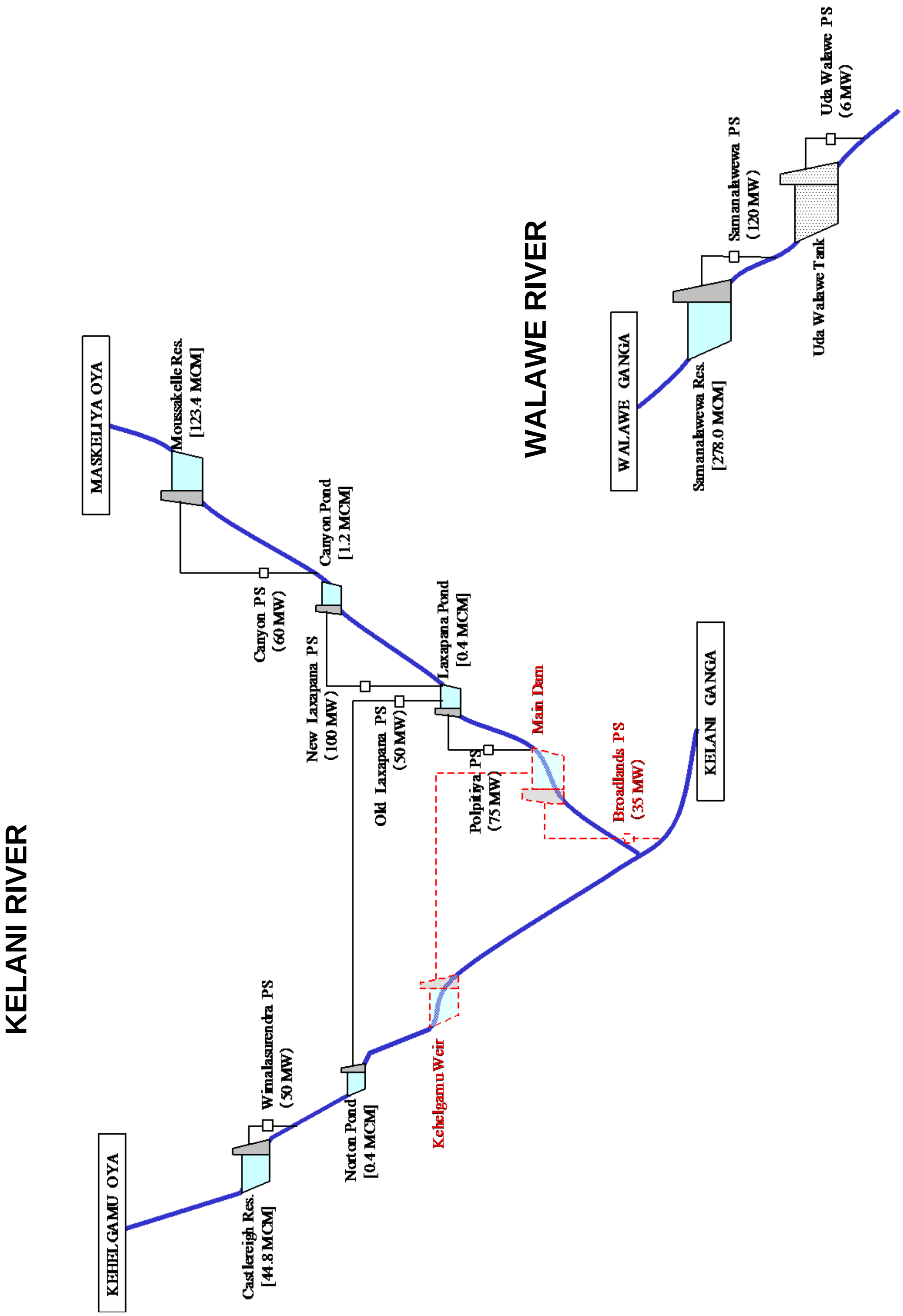
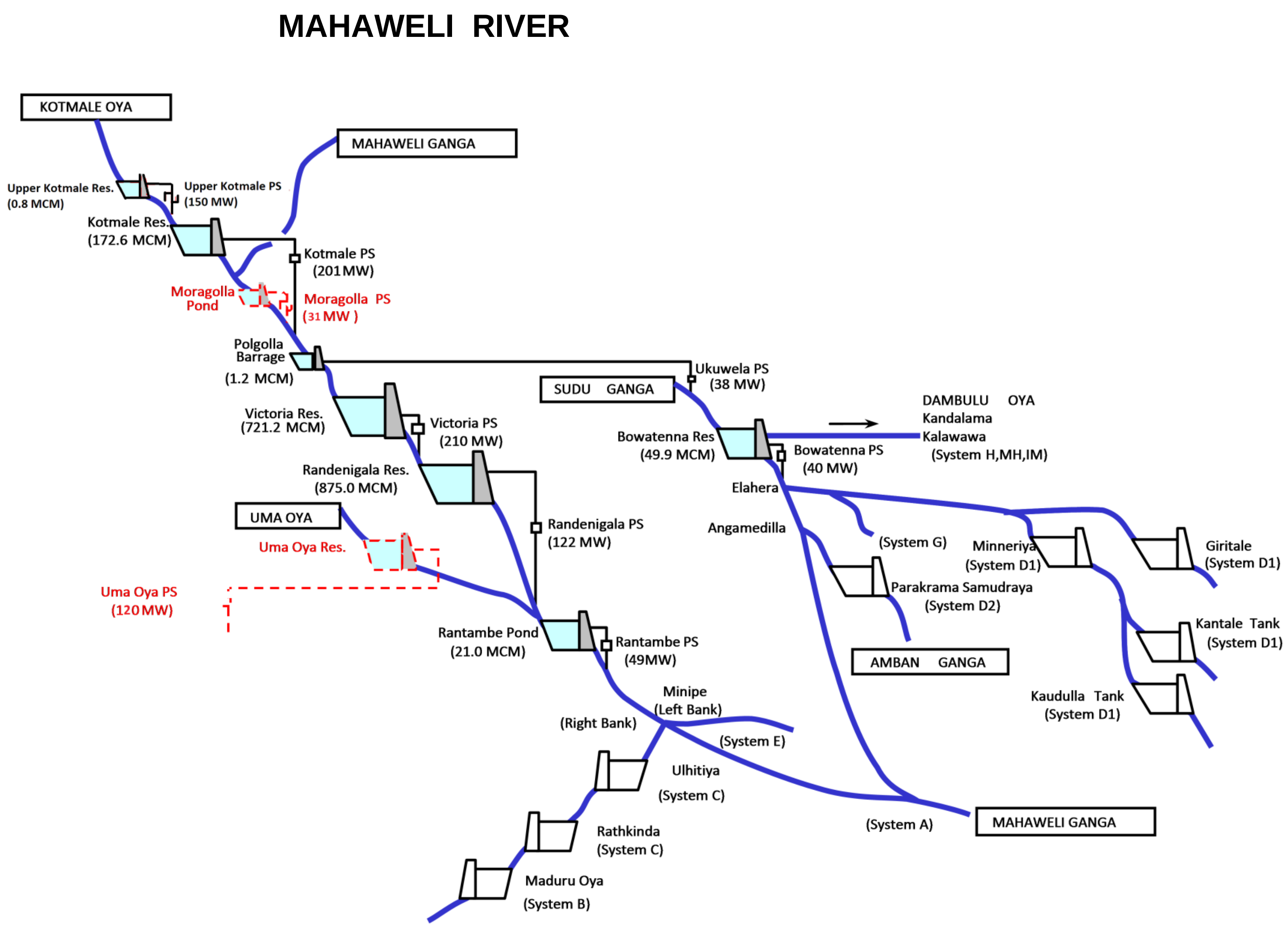
Reservoir Systems in Mahaweli, Kelani and Walawe River Basins

A2.1.1 Reservoir Systems in Kelani and Walawe River Basins



A2.1.2 Reservoir System in Mahaweli River Basin



Annex 3.1

Sensitivities of Demand Forecast

Table A3.1 - Low Demand Forecast

Year	Ene. Dem. (GWh)	Losses (%)	Ene. Gen. (GWh)	Peak (MW)
2015	11516	10.73	12901*	2401
2016	12015	10.68	13451*	2483
2017	12611	10.62	14110	2584
2018	13237	10.57	14801	2689
2019	13894	10.51	15526	2798
2020	14583	10.46	16286	2912
2021	15133	10.40	16889	2996
2022	15699	10.35	17511	3082
2023	16286	10.29	18154	3170
2024	16891	10.23	18816	3261
2025	17521	10.18	19507	3355
2026	18174	10.12	20221	3466
2027	18855	10.07	20966	3582
2028	19549	10.01	21724	3699
2029	20251	9.96	22490	3816
2030	20961	9.90	23264	3934
2031	21674	9.84	24041	4054
2032	22390	9.79	24819	4173
2033	23120	9.73	25613	4294
2034	23868	9.68	26426	4417
2035	24638	9.62	27262	4543
2036	25431	9.57	28122	4673
2037	26248	9.51	29007	4806
2038	27091	9.46	29920	4943
2039	27961	9.40	30862	5084
5 Year Average Growth	4.8%		4.7%	3.9%
10 Year Average Growth	4.3%		4.3%	3.5%
20 Year Average Growth	3.9%		3.8%	3.3%
25 Year Average Growth	3.8%		3.7%	3.2%

* Generation fixed for Energy Marketing Branch Energy Demand Forecast 2015-2016, prepared based on values provided by each Distribution Divisions.

Table A3.2 – High Demand Forecast

Year	Ene. Dem. (GWh)	Losses (%)	Ene. Gen. (GWh)	Peak (MW)
2015	12185	10.73	13651	2541
2016	12921	10.68	14465	2670
2017	13734	10.62	15366	2814
2018	14534	10.57	16252	2952
2019	15363	10.51	17167	3094
2020	16234	10.46	18130	3241
2021	17157	10.40	19149	3396
2022	18138	10.35	20231	3561
2023	19183	10.29	21383	3734
2024	20295	10.23	22609	3918
2025	21482	10.18	23916	4113
2026	22747	10.12	25308	4338
2027	24096	10.07	26793	4577
2028	25518	10.01	28357	4828
2029	27009	9.96	29995	5090
2030	28567	9.90	31706	5362
2031	30189	9.84	33485	5646
2032	31873	9.79	35332	5940
2033	33643	9.73	37271	6248
2034	35508	9.68	39312	6571
2035	37476	9.62	41466	6910
2036	39555	9.57	43740	7268
2037	41753	9.51	46141	7645
2038	44076	9.46	48679	8042
2039	46534	9.40	51362	8461
5 Year Average Growth	6.0%		5.9%	5.0%
10 Year Average Growth	5.8%		5.8%	4.9%
20 Year Average Growth	5.8%		5.7%	5.1%
25 Year Average Growth	5.7%		5.7%	5.1%

Table A3.3 – Demand Forecast with DSM Measures

Year	Ene. Dem. (GWh)	Losses (%)	Ene. Gen. (GWh)	Peak (MW)
2015	11230	10.73	12580	2342
2016	11516	10.68	12893	2380
2017	12120	10.62	13561	2483
2018	12707	10.57	14208	2581
2019	13255	10.51	14812	2669
2020	13786	10.46	15396	2752
2021	14055	10.40	15687	2782
2022	14412	10.35	16075	2829
2023	14801	10.29	16499	2881
2024	15249	10.23	16988	2944
2025	15873	10.18	17672	3039
2026	16473	10.12	18328	3141
2027	17181	10.07	19104	3263
2028	17953	10.01	19950	3397
2029	18789	9.96	20866	3541
2030	19684	9.90	21847	3695
2031	20633	9.84	22886	3859
2032	21635	9.79	23983	4032
2033	22707	9.73	25156	4217
2034	23857	9.68	26413	4415
2035	25090	9.62	27761	4626
2036	26409	9.57	29203	4853
2037	27818	9.51	30742	5094
2038	29322	9.46	32384	5350
2039	30925	9.40	34134	5623
5 Year Average Growth	4.2%		4.2%	3.3%
10 Year Average Growth	3.5%		3.4%	2.6%
20 Year Average Growth	4.0%		4.0%	3.4%
25 Year Average Growth	4.3%		4.2%	3.7%

Table A3.4- 25 Year Time Trend Demand Forecast

Year	Ene. Dem. (GWh)	Losses (%)	Ene. Gen. (GWh)	Peak (MW)
2015	12014	10.73	13458	2505
2016	13177	10.68	14752	2723
2017	14452	10.62	16170	2961
2018	15851	10.57	17724	3220
2019	16881	10.51	18864	3399
2020	17978	10.46	20078	3589
2021	19147	10.40	21369	3790
2022	20391	10.35	22744	4003
2023	21716	10.29	24207	4227
2024	23127	10.23	25764	4465
2025	24630	10.18	27421	4716
2026	26230	10.12	29185	5002
2027	27935	10.07	31062	5306
2028	29750	10.01	33060	5629
2029	31683	9.96	35187	5971
2030	33742	9.90	37450	6333
2031	35935	9.84	39859	6721
2032	38270	9.79	42423	7132
2033	40757	9.73	45152	7569
2034	43406	9.68	48056	8032
2035	46226	9.62	51148	8524
2036	49230	9.57	54438	9046
2037	52429	9.51	57940	9600
2038	55836	9.46	61667	10188
2039	59465	9.40	65634	10812
5 Year Average Growth	8.9%		8.8%	7.9%
10 Year Average Growth	7.5%		7.5%	6.6%
20 Year Average Growth	7.0%		6.9%	6.3%
25 Year Average Growth	6.9%		6.8%	6.3%

Table A3.5 – End User(MAED) Load Projection

Year	Ene. Dem. (GWh)	Losses (%)	Ene. Gen. (GWh)	Peak (MW)
2015	13003	11.35	14668	2604
2016	13730	11.09	15442	2734
2017	14497	10.83	16258	2870
2018	15307	10.57	17116	3013
2019	16162	10.31	18020	3163
2020	17066	10.04	18971	3321
2021	17902	9.90	19869	3471
2022	18779	9.76	20810	3627
2023	19699	9.62	21795	3790
2024	20664	9.48	22827	3961
2025	21677	9.33	23908	4139
2026	22677	9.32	25007	4317
2027	23723	9.30	26156	4503
2028	24817	9.29	27358	4697
2029	25962	9.27	28616	4899
2030	27160	9.26	29931	5110
2031	28340	9.25	31228	5324
2032	29571	9.24	32580	5547
2033	30855	9.23	33991	5780
2034	32195	9.22	35463	6022
2035	33593	9.21	36999	6274
5 Year Average Growth	5.6%		5.3%	5.0%
10 Year Average Growth	5.3%		5.0%	4.8%
20 Year Average Growth	4.9%		4.7%	4.5%

Annex 4.1
Candidate Hydro Plant Data Sheets

A4.1.1 Seethawaka Hydro Power Project

- **General**

Seethawaka river is originated from the upper parts of Horton Plains mountainous range in Nuwara Eliya District. The proposed power project is to be located in the Rue-castle/ Hinguralakanda villages in Dehiovita Divisional Secretariat Division in Kegalle District.

- **Project Overview**

Project Code	Sita 014
Province / District	Sabaragamuwa / Kegalle
Catchment	Seethawaka
Reservoir Full Supply Level at Flooding	67 msl
Reservoir Full Supply Level at Dry Period	68.4 msl
Pond Area	31 ha
Pond Capacity	8 MCM
Weir/Barrage Height	27 m
Weir Top level elevation above MSL	67 m
Weir length	105 m
Spillway Type	Radial Gates
Length / Diameter Penstock	1470 m / 4.5 m
Length Tail Race Channel	20 m
Type of Powerhouse	Open-air
Gross Head	42 m
Plant Capacity	20MW
Average Annual Generation	47.6GWh
Island Area Inundated	0.25 ha
Land Area Inundated	6 ha

Cost Calculations of Candidate Hydro Plants

Hydro Plant Basic Costs

Plant	Capacity (MW)	Construction Cost* (US $ million)		Cost Basis	Exchange Rate (LKR/US$)
		Foreign	Local		
Seethawaka	20	28.42	13.81	2015	131.55

*Value estimated by the Generation Development Studies Branch of CEB for carry out initial project planning requirements.

Hydro Plant costs used for the 2015 Expansion Planning

Plant	Capacity (MW)	Pure Const. Cost US$/kW		Total Cost (US$/kW)	Const Period (Yrs)	IDC at 10% (% pure costs)	Const. Cost as Input to Analysis incl. IDC (US$/kW)		Total Cost incl. IDC (US$/kW)
		Local	Foreign				Local	Foreign	
Seethawaka	20	690.5	1420.9	2111.4	4	18.53	818.5	1684.2	2502.7

* All costs in Jan 2015 prices

Annex 4.3

Candidate Thermal Plant Data Sheets

• **Basic data**	**LNG**	**LNG with terminal**	**Dendro**	**Nuclear**
Installed capacity (MW) - Gross	300	300	5	600
Net capacity (MW)	286.9	286.9	5	552
Fuel Type	LNG/NG	LNG/NG	Bio-mass	Nuclear
• **Information input to studies**				
Annual fixed O&M cost (US$/kW-month)	0.38	0.38	2.75	7.62
Variable O&M cost (USCts/kWh)	0.497	0.497	0.504	1.76
*Available Days per year (Maximum annual PF %)	308.2(84.4)	308.2(84.4)	285.18(78.1)	323.4(88.6)
Scheduled annual maintenance duration (days)	30	30	74	40
Forced outage rate (%)	8	8	2	0.5
Calorific value (kCal/kg)	13000**	13000**	3224	-
Minimum operating level (%)	33	33	100	90
Net Heat rate at minimum operating level (kCal/kWh)	2457	2457	5694	2723
Net Heat rate at full load operating level (kCal/kWh)	1793	1793	5694	2684
Capital Cost Incl. IDC (US$/kW) - Net	1259.0	3421.3	1835.0	5705.2
Construction Period (years)	3	4.5	1.5	5
Economic Life time (years)	30	30	30	60

*Time Availability = (Total Time - Sche. Annual Maint.) x (1-FOR)

**LNG values were used for NG and actual values for NG to be determined

• **Basic data**	**Gas Turbine**	**Gas Turbine**	**Combined Cycle**	**Combined Cycle**
Installed capacity (MW)- Gross	35	105	150	300
Net capacity (MW)	35	105	144	288
Fuel Type	Auto Diesel	Auto Diesel	Auto Diesel	Auto Diesel
• **Information input to studies**				
Annual fixed O&M cost (US$/kW-month)	0.69	0.53	0.55	0.41
Variable O&M cost (USCts/kWh)	0.557	0.417	0.47	0.355
Time Availability * (Maximum annual PF) (%)	308.2(84.4)	308.2(84.4)	308.2(84.4)	308.2(84.4)
Scheduled annual maintenance duration (days)	30	30	30	30
Forced outage rate (%)	8	8	8	8
Calorific value (kCal/kg)	10500	10500	10500	10500
Minimum operating level (%)	100	30	33.3	33.3
Net Heat rate at minimum operating level (kCal/kWh)	3060	4134	2614	2457
Net Heat rate at full load operating level (kCal/kWh)	3060	2857	1842	1785
Capital Cost Incl. IDC (US$/kW) Net Basis	784.9	533.8	1198.6	969.4
Construction Period (years)	1.5	1.5	3	3
Economic Life time (years)	30	30	30	30

• **Basic data**	**Coal Plant Trincomalee PCL**	**New Coal Plant**	**Super Critical Coal Plant**
Installed capacity (MW)	250	300	600
New Capacity (MW)	227	270	564
Fuel Type	Coal	Coal	Coal
• **Information input to studies**			
Annual fixed O&M cost (US$/kW-month)	2.92	4.47	4.50
Variable O&M cost (USCts/kWh)	0.56	0.59	0.59
Time Availability * (Maximum annual PF) (%)	305.75(84.58)	310.7(85.0)	310.7(85.0)
Scheduled annual maintenance duration (days)	40	45	45
Forced outage rate (%)	5	3	3
Calorific value (kCal/kg)	5500	5900	6300
Minimum operating level (%)	60	35	60
Heat rate at minimum operating level (kCal/kWh)	2895	2810	2248
Heat rate at full load operating level (kCal/kWh)	2600	2241	2082
Capital Cost Incl. IDC (US$/kW)- Net basis	1385.6	2119.4	2269.7
Construction Period (years)	4	4	4
Economic Life time (years)	30	30	30

- Time Availability = (Total Time - Sche. Annual Maint.) x (1-FOR)

NCRE Tariff Effective From 01/01/2012

Non-Conventional Renewable Energy Tariff Announcement

Purchase of Electricity to the National Grid under Standardized Power Purchase Agreements (SPPA)

The Ceylon Electricity Board is pleased to announce the new tariff for purchase electricity from Non-Conventional Renewable Energy (NCRE) Sources according to the Cabinet Approval dated 07/03/2014. The SPPA will continue for NCRE projects with a capacity up to 10 MW. The tariff will be three-tire-tariff and effective from 01/01/2012 until further notice.

Three-tier Tariff

All prices are in Sri Lanka Rupees per kilowatt-hour (LKR/kWh)

This will consist of a fixed rate, operations and maintenance (O&M) rate and a fuel rate.

Technology/ Source	Escalable Base O&M Rate (year 1-20)	Escalable Base Fuel Rate (year 1-20)	Non-escalable (fixed rate)		
			Tier 1: Years 1-8	Tier 2: Years 9-15	Tier 3: Year 16-20
Mini-hydro	1.83	None	15.56	5.98	3.40
Mini-hydro-local	1.88	None	15.97	6.14	3.49
Wind	1.30	None	22.05	8.48	4.82
Wind-local	1.33	None	22.60	8.69	4.94
Biomass	1.52	12.25	9.67	3.72	2.11
Biomass 16yr onwards	1.90				
Agro & Industrial waste	1.52	6.13	9.65	3.71	2.11
Agro & Indus 16yr onwards	1.90				
Waste Heat	0.48	None	9.14	3.52	2.00
Escalation rate for year 2013	5.16%	3.44%			

Any other renewable energy technology other than those specified above would be offered a flat tariff of Rs. 23.10 / kWh (non-escalable for 20 years).

Annex 5.2

NCRE Additions for Low Demand Case

Year	Cumulative mini hydro addition (MW)	Cumulative Wind addition* (MW)	Cumulative biomass addition (MW)	Cumulative solar addition (MW)	Cumulative Total NCRE Capacity (MW)	Annual Total NCRE Generation (GWh)	Share of NCRE from Total Generation %
2015	293	124	24	1	442	1516	11.7%
2016	313	124	34	16	487	1677	12.5%
2017	338	144	49	31	562	1945	13.8%
2018	363	244	74	46	727	2561	17.3%
2019	388	254	99	61	802	2872	18.5%
2020	413	304	124	81	922	3329	20.4%
2021	438	304	129	91	962	3464	20.5%
2022	458	304	129	101	992	3548	20.3%
2023	473	349	134	111	1067	3788	20.9%
2024	483	369	144	121	1117	3963	21.1%
2025	493	414	149	131	1187	4187	21.5%
2026	508	439	154	131	1232	4356	21.5%
2027	543	439	164	141	1287	4561	21.8%
2028	578	439	174	141	1332	4750	21.9%
2029	618	439	184	151	1392	4972	22.1%
2030	653	464	194	151	1462	5245	22.5%
2031	658	494	194	161	1507	5361	22.3%
2032	663	539	204	161	1567	5587	22.5%
2033	668	559	214	171	1612	5746	22.4%
2034	673	604	214	181	1672	5917	22.4%

Note: Plant factors- Mini Hydro- 39%, Biomass-80%, Solar-17% and Wind (Mannar)-38%, Wind (Hill Country and Other) - 32%

* Location Based Wind Additions:

	Wind			
Year	Puttalam (MW)	Northern (MW)	Mannar (MW)	Hill Country (MW)
2015	123.9	0	0	0
2016	123.9	0	0	0
2017	143.9	0	0	0
2018	143.9	0	100	0
2019	143.9	0	100	10
2020	143.9	0	150	10
2021	143.9	0	150	10
2022	143.9	0	150	10
2023	163.9	0	175	10
2024	183.9	0	175	10

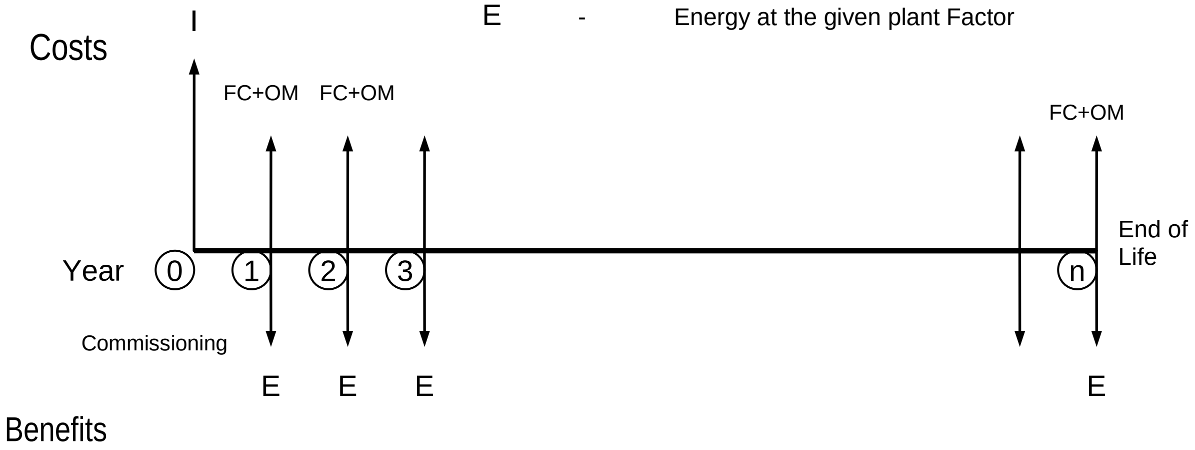
	Wind			
Year	Puttalam (MW)	Northern (MW)	Mannar (MW)	Hill Country (MW)
2025	203.9	0	200	10
2026	203.9	0	225	10
2027	203.9	0	225	10
2028	203.9	0	225	10
2029	203.9	0	225	10
2030	203.9	0	250	10
2031	223.9	0	250	20
2032	243.9	0	275	20
2033	263.9	0	275	20
2034	283.9	0	300	20

Annex 6.1

Methodology of the Screening of Curve

Present value of specific energy cost of thermal plants is calculated for a range of discount rates and plant factors, in order to mimic the procedure adopted in the WASP planning package used for the expansion studies.

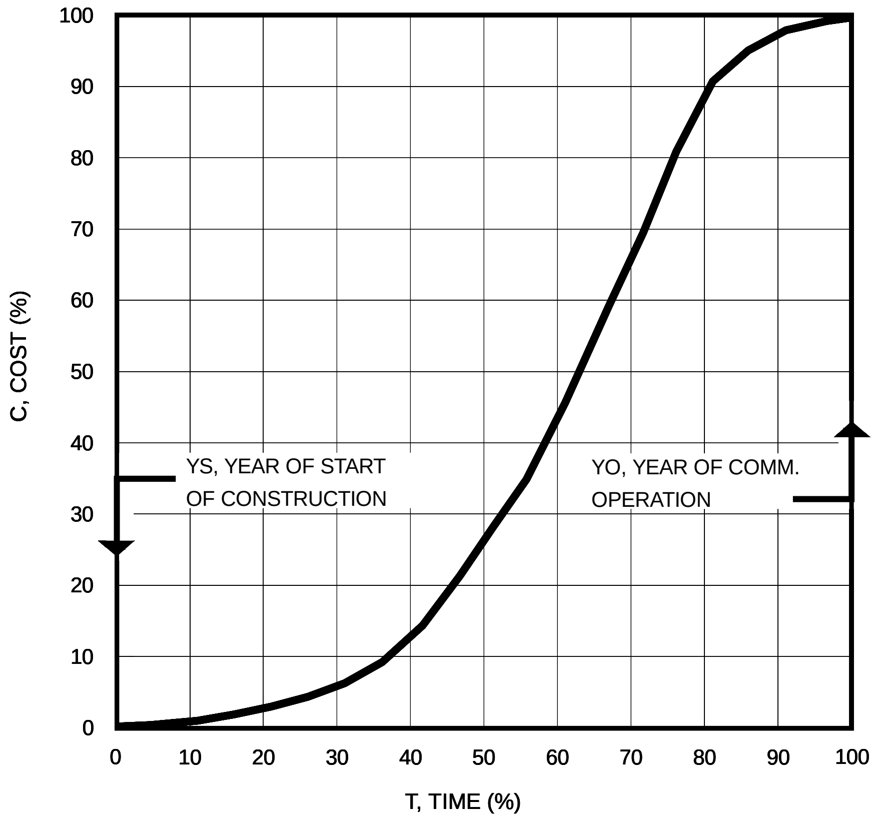
I	-	Investment
FC	-	Fuel Cost
OM	-	Operations & Maintenance Cost
E	-	Energy at the given plant Factor



Investment cost with interest during construction is assumed to occur at the beginning of the commissioning year as presented in above figure. Yearly fixed and variable operation, maintenance and repair costs are discounted to the beginning of the commissioning year while annual fuel costs are also discounted considering the fuel escalation rates. Energy is calculated for each year of operation over the life time for various plant factors.

$$\text{Specific Cost} = [\, I + \{ \Sigma \text{ Fixed OM} + (FC + \text{Var. OM}) * E \} * \text{PV Factor}] / E * \text{PV Factor}$$

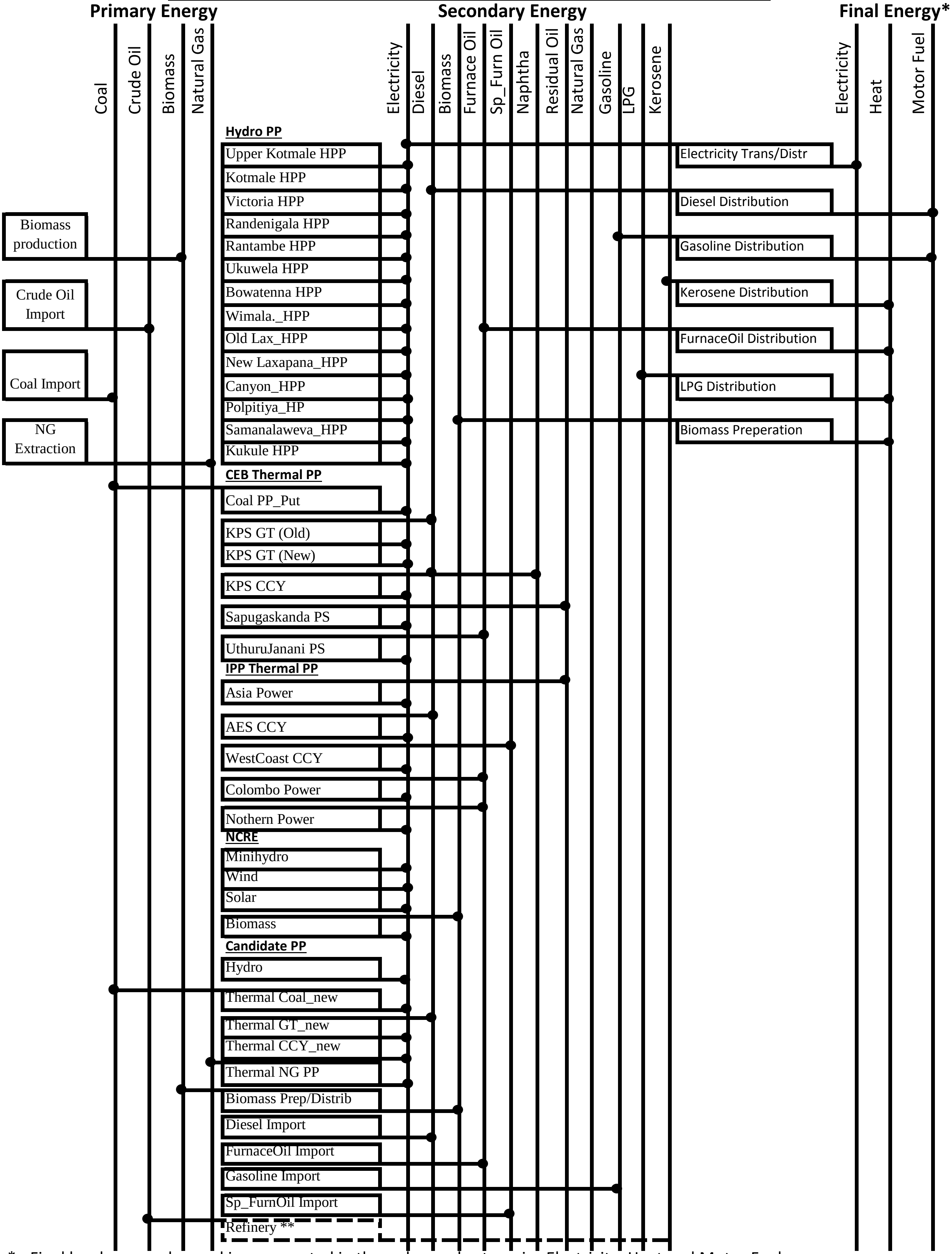
Interest during construction (IDC) is calculated assuming "S" curve shape cost distribution during the construction period which is shown in the figure below.



Plant capital cost distribution against time

Source: Wien Automatic System Planning Package (WASP), Version WASP-IV, User Mannual, 2000

Energy Flow Chart of the Electricity System



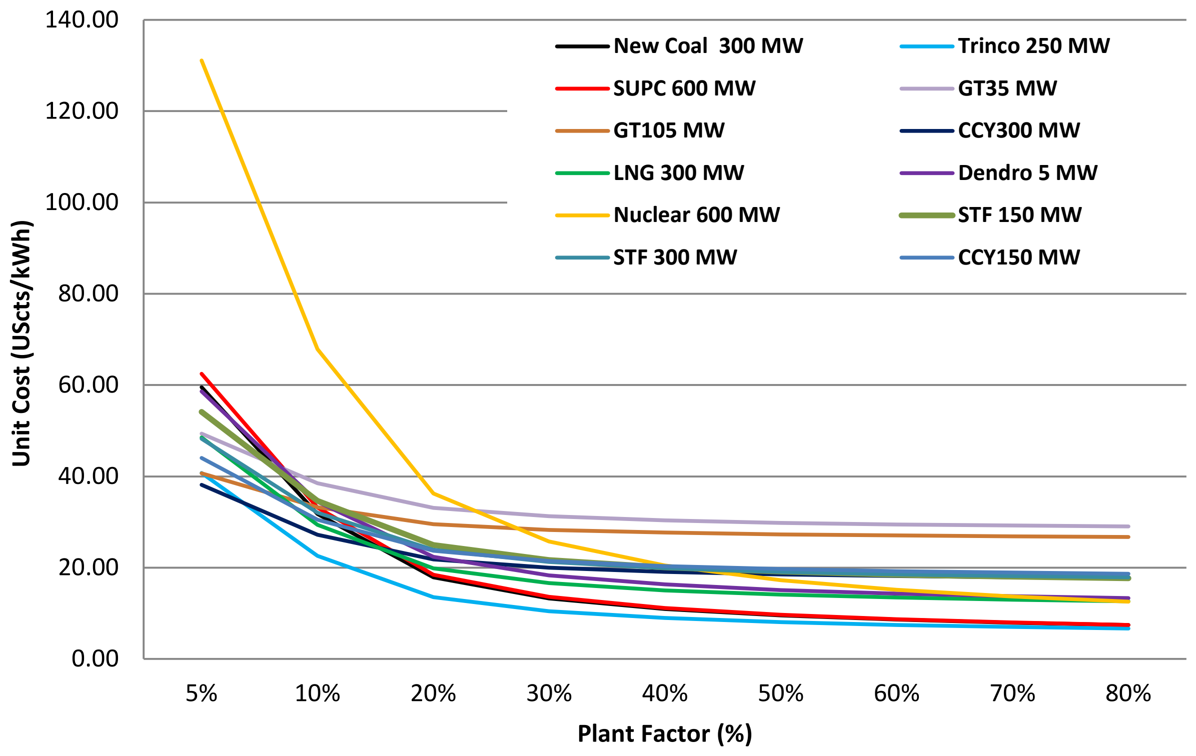
* - Final level energy demand is represented in three demand categories Electricity, Heat and Motor Fuel.
** - Refinery which has secondary level Oil outputs is shown indicatively

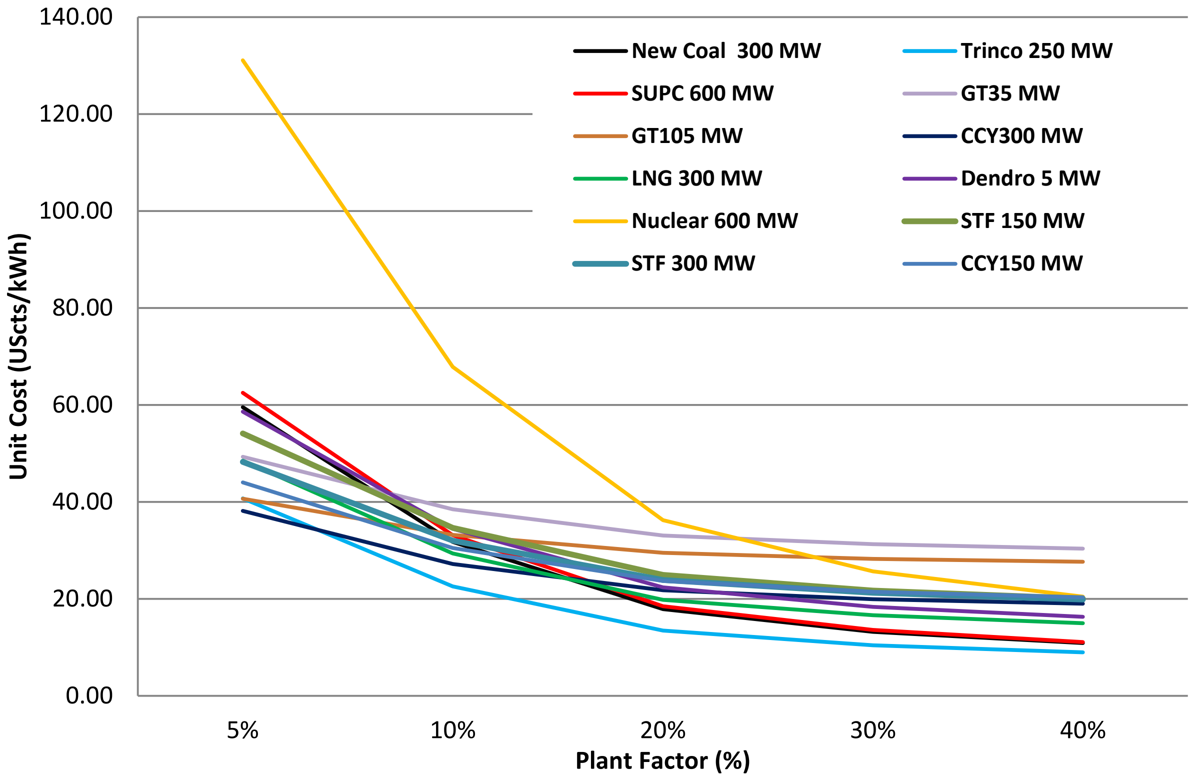
Screening of Generation Options

The screening curves were developed for the following Generation Alternatives

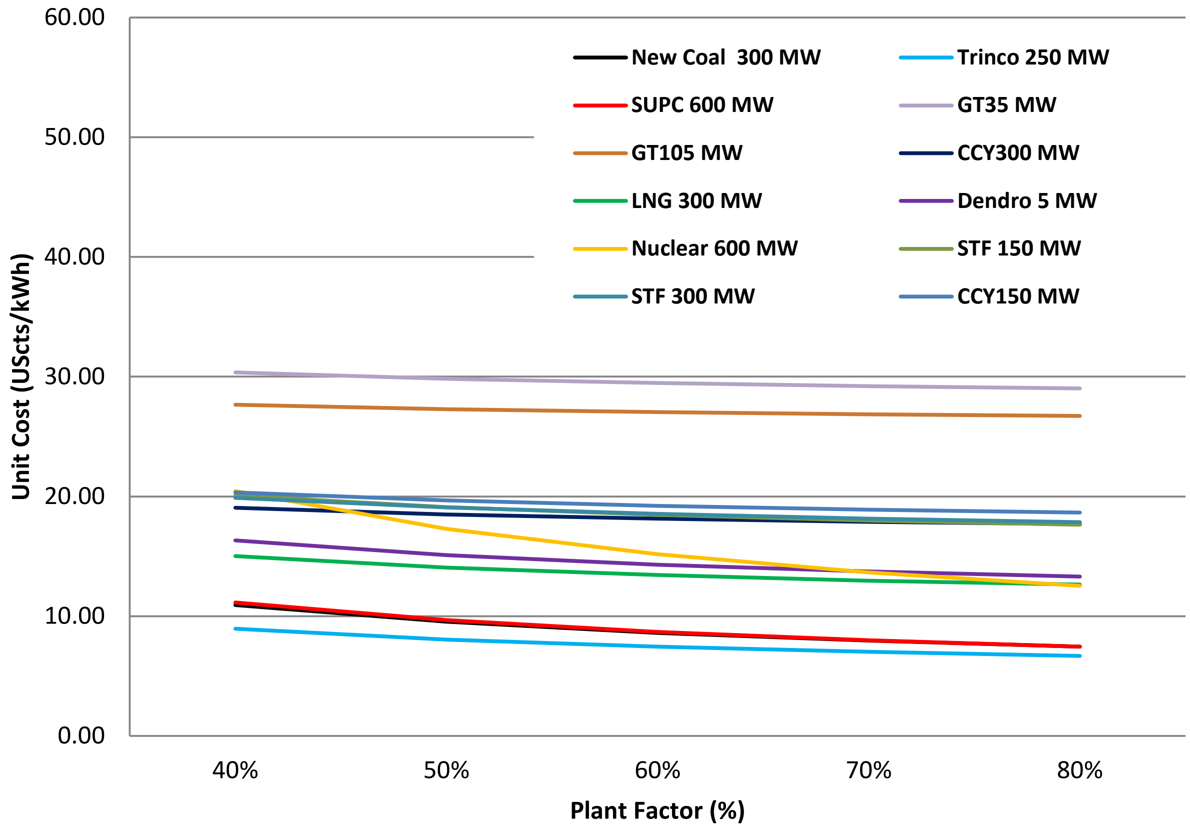
1. STF 150MW - 150 MW Furnace oil fired steam power plant
2. STF 300MW - 300 MW Furnace oil fired steam power plant
3. Trinco 250MW - 250 MW Trincomalee Power Company Limited
4. New Coal 300MW- 300 MW Coal fired steam power plant
5. SUPC 600MW - 600 MW Super Critical type Coal fired steam power plant
6. GT 35MW - 35 MW Auto diesel fired gas turbine
7. GT105MW - 105 MW Auto diesel fired gas turbine
8. CCY 150MW - 150 MW Auto diesel fired combined cycle power plant
9. CCY 300MW - 300 MW Auto diesel fired combined cycle power plant
10. LNG 300MW - 300 MW Natural gas fired combine cycle power plant
11. Nuclear 600MW - Nuclear 600 - 600MW Nuclear Power Plant
12. Dendro 5MW - 5MW Fuel Wood Based Biomass Power Plant

A7.1.1 Screening Curves of the Generation Options at 10% Discount Rate



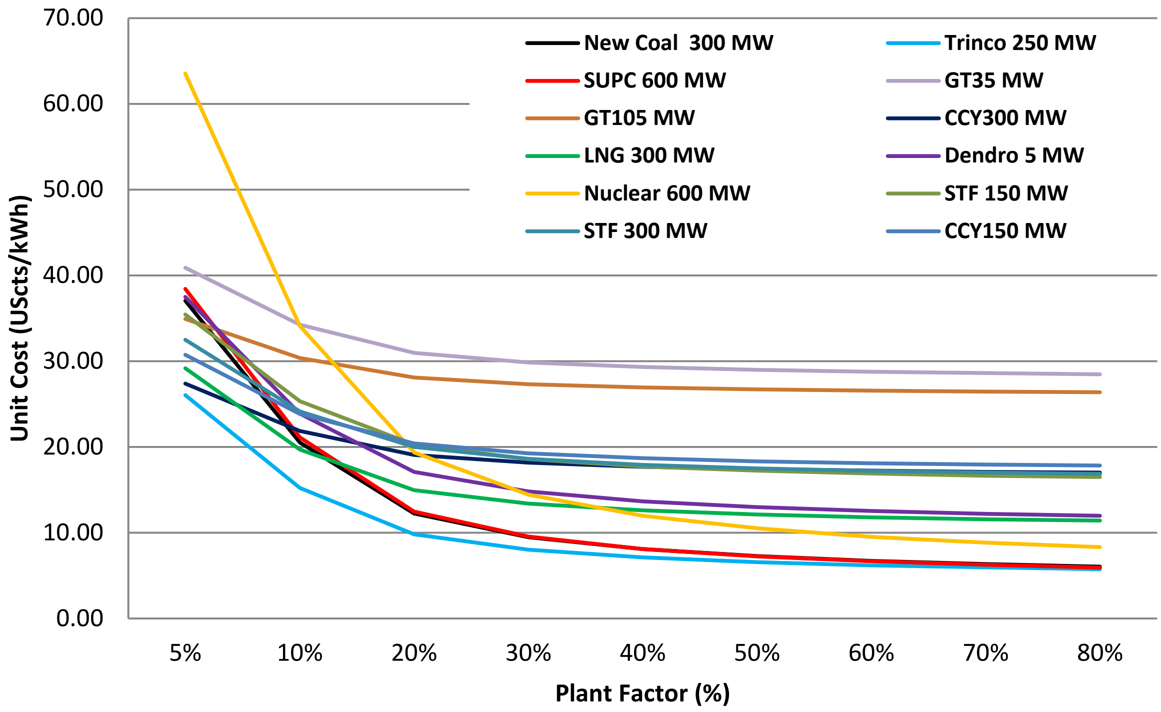


140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Unit Cost (UScts/kWh)
New Coal 300 MW
Trinco 250 MW
SUPC 600 MW
GT35 MW
GT105 MW
CCY300 MW
LNG 300 MW
Dendro 5 MW
Nuclear 600 MW
STF 150 MW
STF 300 MW
CCY150 MW
5%
10%
20%
30%
40%
Plant Factor (%)

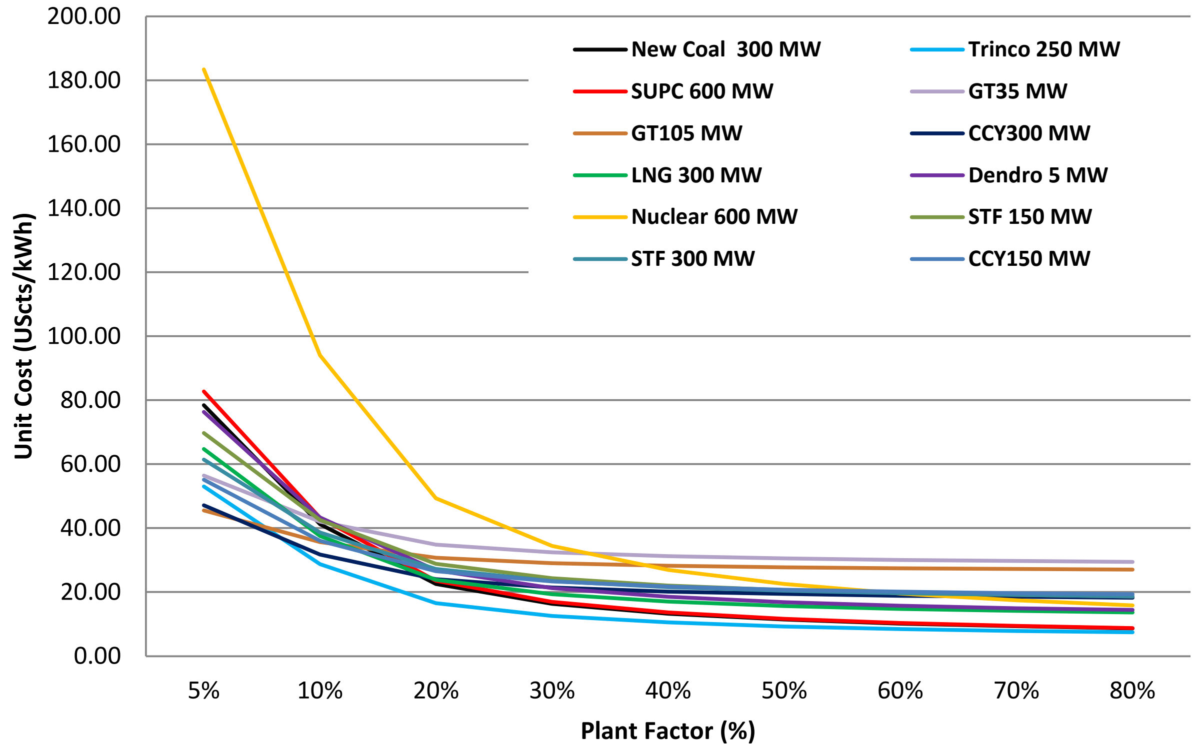


60.00
50.00
40.00
30.00
20.00
10.00
0.00
Unit Cost (UScts/kWh)
New Coal 300 MW
Trinco 250 MW
SUPC 600 MW
GT35 MW
GT105 MW
CCY300 MW
LNG 300 MW
Dendro 5 MW
Nuclear 600 MW
STF 150 MW
STF 300 MW
CCY150 MW
40%
50%
60%
70%
80%
Plant Factor (%)

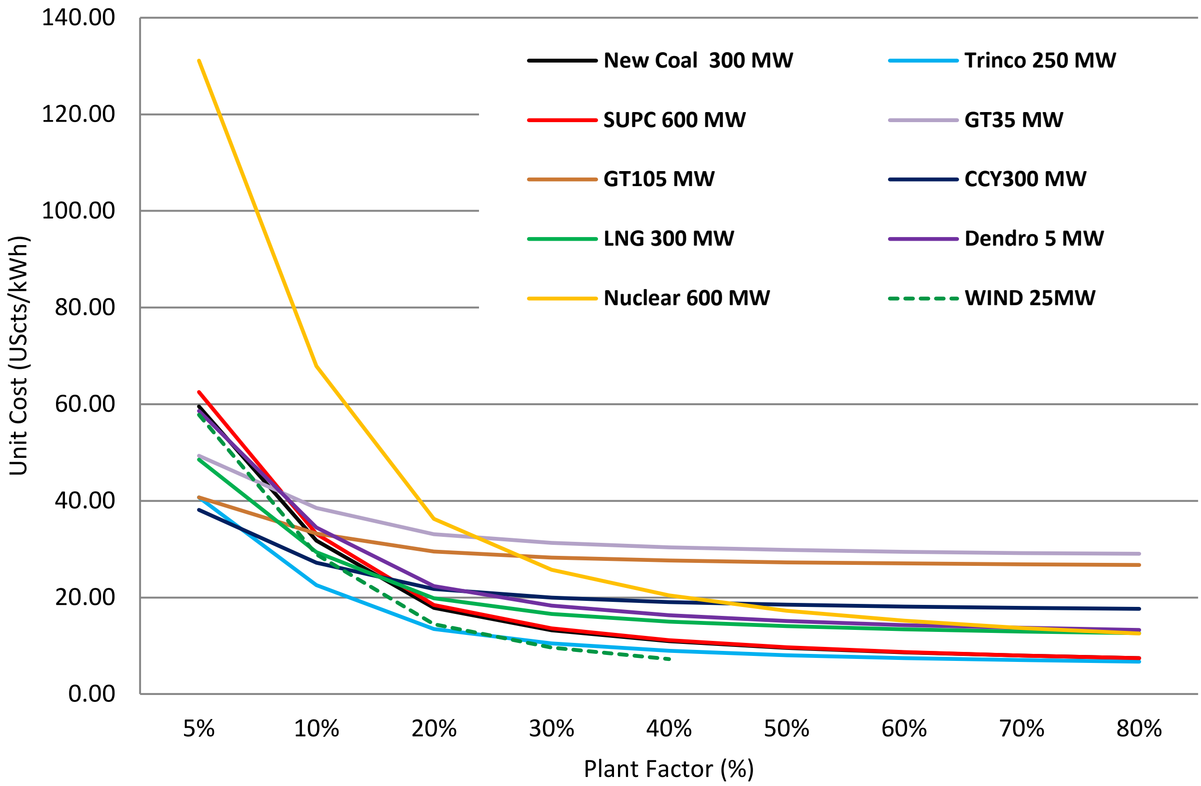
A7.1.2 Screening Curves of the Generation Options at 3% Discount Rate



7.1.3 Screening Curves of the Generation Options at 15% Discount Rate



7.1.4 Screened Generation Options including Wind Plant



7.1.5 Specific Cost of Screened Candidate Thermal Plants

Plant / Plan	*0.1*	*0.2*	*0.3*	*0.4*	*0.5*	*0.6*	*0.7*	*0.8*
35MW Gas Turbine	38.50	33.08	31.27	30.37	29.83	29.47	29.21	29.02
105MW Gas Turbine	33.24	29.52	28.28	27.66	27.29	27.04	26.87	26.73
150MW Combined Cycle Plant	30.50	23.73	21.48	20.35	19.67	19.22	18.90	18.66
300MW Combined Cycle Plant	27.23	21.77	19.96	19.05	18.50	18.14	17.88	17.68
300MW Coal Plant-Trinco	22.58	13.50	10.47	8.96	8.05	7.45	7.02	6.69
300MW New Coal Plant	31.76	17.87	13.24	10.93	9.54	8.61	7.95	7.46
600MW Super Critical Coal Plant	33.15	18.48	13.58	11.14	9.67	8.69	7.99	7.47
300MW LNG plant (Incl: apportioned terminal cost*)	29.38	19.81	16.62	15.03	14.07	13.43	12.97	12.63
600MW Nuclear Plant	67.87	36.25	25.71	20.44	17.28	15.17	13.67	12.54
5MW Dendro Plant	34.45	22.36	18.33	16.32	15.11	14.30	13.73	13.30

Note: 1 US$ = LKR 131.55

*LNG terminal cost is apportioned appropriately and included in the plant capital cost

Annex 7.2

Capacity Balance for the Base Case – 2015

Plant Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Hydro																				
Existing Major Hydro	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335
New Major Hydro	0	0	155	155	155	201	201	241	241	241	241	241	241	241	241	241	241	241	241	241
Pumped Hydro	0	0	0	0	0	0	0	0	0	0	200	600	600	600	600	600	600	600	600	600
Sub Total	**1335**	**1335**	**1490**	**1490**	**1490**	**1536**	**1536**	**1576**	**1576**	**1576**	**1776**	**2176**	**2176**	**2176**	**2176**	**2176**	**2176**	**2176**	**2176**	**2176**
Thermal Existing and Committed																				
Small Gas Turbines	65	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	70	70	70	70	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	70	70	70	70	70	70	70	70	35	35	0	0	0	0	0	0	0	0	0	0
Gas Turbine No7	113	113	113	113	113	113	113	113	0	0	0	0	0	0	0	0	0	0	0	0
Asia Power	51	51	51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KPS Combined Cycle	161	161	161	161	161	161	161	161	161	161	161	161	161	161	161	161	161	161	0	0
AES Combined Cycle	163	163	163	163	163	163	163	163	0	0	0	0	0	0	0	0	0	0	0	0
Colombo Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270
Puttalum Coal	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825
Northern Power	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Uthurujanani	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
KPS Combined Cycle 2	0	0	0	0	0	0	0	0	163	163	163	163	163	163	163	163	163	163	0	0
CEB Barge Power	60	60	60	60	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub Total	**1,903**	**1,903**	**1,838**	**1,787**	**1,717**	**1,627**	**1,627**	**1,627**	**1,480**	**1,480**	**1,445**	**1,445**	**1,445**	**1,445**	**1,445**	**1,445**	**1,445**	**1,445**	**1,121**	**1,121**
New Thermal Plants																				
New Coal	0	0	0	0	0	0	0	540	540	810	810	810	1,080	1,080	1,350	1,620	1,620	2,160	2,160	2,430
Gas Turbine 35 MW	0	0	0	70	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
Coal TPCL	0	0	0	0	0	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454
Sub Total	**0**	**0**	**0**	**70**	**105**	**559**	**559**	**1099**	**1099**	**1369**	**1369**	**1369**	**1639**	**1639**	**1909**	**2179**	**2179**	**2719**	**2719**	**2989**
Non Conventional Renewable Energy																				
Total NCRE (Minihydro, Wind & Solar)	418	453	513	653	703	848	933	1013	1083	1153	1218	1253	1318	1363	1433	1478	1513	1548	1583	1618
Total NCRE (Biomass - Existing)	24	24	24	24	24	24	24	24	24	24	24	24	24	11	11	11	11	11	11	11
Total NCRE (Biomass - New)	0	10	25	50	75	100	105	105	110	120	125	130	140	150	160	170	180	200	225	255
Sub Total	**442**	**487**	**562**	**727**	**802**	**972**	**1062**	**1142**	**1217**	**1297**	**1367**	**1407**	**1482**	**1524**	**1604**	**1659**	**1704**	**1759**	**1819**	**1884**
Total Installed Capacity (A)	**3680**	**3725**	**3889**	**4074**	**4114**	**4694**	**4784**	**5444**	**5371**	**5721**	**5956**	**6396**	**6741**	**6783**	**7133**	**7458**	**7503**	**8098**	**7835**	**8170**
Installed Capacity without NCRE (B)	**3238**	**3238**	**3328**	**3347**	**3312**	**3722**	**3722**	**4302**	**4155**	**4425**	**4590**	**4990**	**5260**	**5260**	**5530**	**5800**	**5800**	**6340**	**6016**	**6286**
Peak Demand (C)	**2401**	**2483**	**2631**	**2788**	**2954**	**3131**	**3259**	**3394**	**3534**	**3681**	**3836**	**4014**	**4203**	**4398**	**4599**	**4805**	**5018**	**5235**	**5459**	**5692**
Difference without NCRE (B-C)	**837**	**755**	**697**	**559**	**358**	**592**	**463**	**909**	**620**	**743**	**754**	**975**	**1057**	**862**	**931**	**995**	**782**	**1105**	**557**	**594**
Difference (%)	**34.8**	**30.4**	**26.5**	**20.1**	**12.1**	**18.9**	**14.2**	**26.8**	**17.6**	**20.2**	**19.7**	**24.3**	**25.2**	**19.6**	**20.3**	**20.7**	**15.6**	**21.1**	**10.2**	**10.4**

Note : All the Capacities are in MW; Above total includes NCRE plants; Maintenance and FOR outages not considered; Operational aspects not reflected.

Annex 7.3 Energy Balance for the Base Case – 2015

Plant Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Hydro																				
Existing Major Hydro	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374	4374
New Major Hydro	0	0	365	365	365	517	517	633	633	633	633	633	633	633	633	633	633	633	633	633
PSPP Generation	0	0	0	0	0	0	0	0	0	0	200	573	533	563	548	560	586	573	570	573
Sub Total	4374	4374	4739	4739	4739	4891	4891	5006	5006	5006	5206	5580	5539	5569	5555	5566	5592	5579	5576	5579
Thermal Existing and Committed																				
Small Gas Turbines	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	407	425	427	427	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	459	472	469	471	482	425	440	393	212	207	0	0	0	0	0	0	0	0	0	0
Gas Turbine No7	68	94	112	142	194	210	228	188	0	0	0	0	0	0	0	0	0	0	0	0
Asia Power	275	294	291	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KPS Combined Cycle	438	492	528	634	819	561	641	493	572	553	642	709	700	733	717	702	741	691	0	0
AES Combined Cycle	190	234	261	346	526	314	365	298	0	0	0	0	0	0	0	0	0	0	0	0
CEB Barge Power Plant	293	310	317	354	383	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	360	431	500	634	947	525	624	447	529	513	607	706	690	724	712	694	730	670	767	728
Puttalum Coal	4,371	4,478	4,595	4,815	5,145	4,853	4,992	4,315	4,583	4,373	4,574	4,705	4,495	4,769	4,604	4,497	4,743	4,350	4,729	4,648
Northern Power	43	54	63	77	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Uthurujanani	160	169	172	173	186	159	166	148	160	159	180	194	195	197	196	194	197	192	195	192
KPS 2 Combined Cycle (CEB)	0	0	0	0	0	0	0	0	346	348	415	506	504	516	514	492	509	450	0	0
Sub Total	7,062	7,453	7,733	8,072	8,783	7,047	7,456	6,281	6,401	6,154	6,419	6,820	6,583	6,938	6,742	6,578	6,920	6,352	5,691	5,567
New Thermal Plants																				
New Coal	0	0	0	0	0	0	0	2,219	2,663	3,734	4,149	4,760	5,963	6,583	7,883	9,229	9,923	11,851	13,447	14,856
Gas Turbine 35 MW	0	0	0	2	29	2	3	0	1	0	0	0	0	0	0	0	0	0	12	3
Gas Turbine 105 MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal TPCL	0	0	0	0	0	2,163	2,288	1,846	1,963	1,900	2,043	2,130	2,062	2,212	2,107	2,058	2,212	2,010	2,229	2,143
Sub Total	0	0	0	2	29	2165	2291	4065	4627	5635	6191	6890	8025	8795	9990	11286	12135	13862	15688	17001
Non Conventional Renewable Energy																				
Total NCRE (Minihy, Wind & Solar)	1314	1401	1579	2052	2179	2658	2938	3201	3411	3611	3823	3910	4108	4238	4436	4566	4649	4754	4838	4942
Total NCRE (Biomass - Existing)	150	154	153	154	156	144	147	136	141	138	151	160	159	72	72	71	72	70	71	70
Total NCRE (Biomass - New)	0	65	163	327	496	608	653	596	656	701	801	882	948	1020	1087	1143	1222	1338	1515	1712
Sub Total	1464	1620	1894	2532	2831	3410	3737	3933	4207	4451	4775	4951	5215	5330	5595	5780	5943	6162	6424	6725

Total Generation	**12900**	**13446**	**14366**	**15345**	**16381**	**17512**	**18375**	**19285**	**20242**	**21246**	**22591**	**24240**	**25362**	**26632**	**27882**	**29211**	**30591**	**31954**	**33380**	**34873**
System Demand	12901	13451	14368	15348	16394	17512	18376	19283	20238	21243	22303	23421	24601	25829	27100	28410	29756	31135	32565	34055
PSPP Demand	0	0	0	0	0	0	0	0	0	0	286	819	761	804	783	800	837	818	814	819
Unserved Energy	**1**	**5**	**2**	**3**	**13**	**0**	**1**	**-2**	**-4**	**-3**	**-3**	**0**	**0**	**1**	**1**	**0**	**3**	**-1**	**0**	**1**

Note:- 1. Numbers may not add exactly due to rounding off.
2. Aggregation of hydro dispatches for individual plant is not possible owing to integrated operation and dispatch of hydro energy
3. All energy figures are shown for weighted average hydrological condition in GWh.

Annual Energy Generation and Plant Factors

Base Case 2015-2034

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2015												
4x20MW Kelanitissa Gas Turbines	0	0	0	0	1	0	0.0	0.0	0.0	0.1	0.2	0.1
4x20MW Sapugaskanda Diesel Plant	199	370	433	462	470	407	32.7	60.6	71.0	75.8	77.0	66.7
8x10MW Sapugaskanda Diesel Ext.	281	436	480	503	506	459	46.1	71.5	78.8	82.4	82.9	75.2
115MW Kelanitissa Gas Turbine	3	25	61	118	145	68	0.3	2.5	6.2	11.9	14.6	6.8
165 MW Kelanitissa CCY Plant	150	262	446	623	678	438	10.7	18.6	31.7	44.2	48.2	31.1
300MW LVPS coal plant (3 units)	4,020	4,248	4,350	4,517	4,758	4,371	55.6	58.8	60.2	62.5	65.8	60.5
24MW Uthurujanani diesel Plant	72	129	175	190	193	160	31.4	56.6	76.8	83.4	84.8	70.3
51MW Asia Power Plant	128	192	305	336	343	274	28.7	43.1	68.5	75.5	77.1	61.7
163MW AES CCY Plant	33	94	154	328	406	190	2.3	6.6	10.8	23.0	28.5	13.3
30MW Nothern Power Plant	12	16	45	62	79	43	4.4	6.2	17.0	23.7	30.0	16.2
270MW Kerawalapitiya CCY Plant	110	171	356	549	629	360	4.6	7.2	15.1	23.2	26.6	15.2
10.5 MW of Dendro plants	45	64	70	72	72	67	48.8	69.1	76.2	78.5	78.6	72.7
13MW Agricultaral Biomass plant	62	79	85	89	89	83	54.1	69.6	75.0	77.8	77.9	72.7
60MW Barge power plant CEB	123	164	333	378	389	293	23.5	31.2	63.3	72.0	74.0	55.7
Total hydro	7,314	6,302	5,257	4,324	3,792	5,339						
Total thermal	5,237	6,249	7,293	8,227	8,757	7,212						
Total generation	12,551	12,551	12,551	12,550	12,549	12,550						
Total demand	12,552	12,552	12,552	12,552	12,552	12,552						
Deficit	1	1	1	2	3	2						
2016												
4x20MW Kelanitissa Gas Turbines	0	0	0	1	2	1	0.0	0.0	0.1	0.2	0.3	0.1
4x20MW Sapugaskanda Diesel Plant	266	398	444	467	473	425	43.6	65.3	72.8	76.6	77.6	69.6
8x10MW Sapugaskanda Diesel Ext.	358	447	487	505	506	472	58.8	73.4	79.8	82.8	83.0	77.3
115MW Kelanitissa Gas Turbine	21	50	95	140	161	94	2.1	5.1	9.6	14.1	16.3	9.5
165 MW Kelanitissa CCY Plant	161	299	531	655	724	492	11.4	21.3	37.7	46.5	51.4	34.9
300MW LVPS coal plant (3 units)	4,080	4,298	4,421	4,707	5,005	4,478	56.5	59.5	61.2	65.1	69.3	62.0
24MW Uthurujanani diesel Plant	85	153	180	192	195	169	37.3	67.2	79.0	84.4	85.7	74.2
51MW Asia Power Plant	142	255	315	342	348	294	31.9	57.2	70.7	76.9	78.2	66.1
163MW AES CCY Plant	50	104	213	394	441	234	3.5	7.3	14.9	27.6	30.9	16.4
30MW Nothern Power Plant	13	34	50	82	95	54	4.9	13.1	19.2	31.3	36.3	20.7
270MW Kerawalapitiya CCY Plant	144	224	449	617	685	431	6.1	9.5	19.0	26.1	29.0	18.2
10.5 MW of Dendro plants	58	67	71	72	72	69	63.4	73.1	76.9	78.6	78.6	75.3
13MW Agricultaral Biomass plant	73	82	87	89	89	85	64.5	71.9	76.1	77.9	77.9	74.7
60MW Barge power plant CEB	115	207	350	389	395	310	21.8	39.3	66.6	74.0	75.2	59.0
5MW Dendro Plant	55	63	67	68	68	65	62.8	71.4	76.1	77.8	77.8	74.3
Total hydro	7,455	6,396	5,318	4,355	3,813	5,404						
Total thermal	5,622	6,681	7,759	8,720	9,261	7,672						
Total generation	13,077	13,077	13,077	13,076	13,074	13,076						
Total demand	13,079	13,079	13,079	13,079	13,079	13,079						
Deficit	1	1	2	3	5	2						

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2017												
4x20MW Sapugaskanda Diesel Plant	248	401	449	472	475	427	40.7	65.8	73.7	77.4	77.9	70.0
8x10MW Sapugaskanda Diesel Ext.	324	449	487	506	506	469	53.2	73.7	79.9	82.9	83.1	76.9
115MW Kelanitissa Gas Turbine	16	67	124	140	192	112	1.6	6.8	12.5	14.1	19.4	11.3
165 MW Kelanitissa CCY Plant	197	329	546	709	819	528	14.0	23.4	38.8	50.3	58.2	37.5
300MW LVPS coal plant (3 units)	4,065	4,340	4,543	4,936	5,159	4,595	56.2	60.1	62.9	68.3	71.4	63.6
24MW Uthurujanani diesel Plant	93	155	183	195	197	172	40.7	68.2	80.3	85.4	86.3	75.6
51MW Asia Power Plant	153	241	306	348	351	291	34.3	54.2	68.9	78.2	78.8	65.3
163MW AES CCY Plant	77	119	255	416	442	261	5.4	8.4	17.8	29.1	30.9	18.3
30MW Nothern Power Plant	14	35	69	85	100	63	5.2	13.1	26.1	32.3	38.2	23.9
270MW Kerawalapitiya CCY Plant	159	282	522	675	841	500	6.7	11.9	22.0	28.5	35.6	21.1
10.5 MW of Dendro plants	53	66	70	72	72	68	58.0	71.9	76.5	78.6	78.6	74.3
13MW Agricultaral Biomass plant	70	81	88	89	89	85	61.3	71.5	76.9	77.9	77.9	74.5
60MW Barge power plant CEB	153	235	337	397	404	317	29.2	44.8	64.0	75.6	76.8	60.3
5MW Dendro Plant	131	158	167	170	170	163	59.9	72.1	76.2	77.8	77.8	74.2
Total hydro	8,149	6,942	5,755	4,690	4,080	5,851						
Total thermal	5,752	6,960	8,146	9,209	9,817	8,049						
Total generation	13,901	13,901	13,901	13,899	13,897	13,900						
Total demand	13,903	13,903	13,903	13,903	13,903	13,903						
Deficit	1	1	2	3	6	2						
2018												
4x20MW Sapugaskanda Diesel Plant	296	387	447	467	473	427	48.5	63.5	73.4	76.7	77.7	70.0
8x10MW Sapugaskanda Diesel Ext.	380	435	486	503	506	470	62.3	71.3	79.7	82.5	83.0	77.2
115MW Kelanitissa Gas Turbine	55	85	152	185	215	142	5.5	8.6	15.4	18.6	21.7	14.3
165 MW Kelanitissa CCY Plant	280	451	619	869	943	634	19.9	32.0	44.0	61.7	66.9	45.0
300MW LVPS coal plant (3 units)	4,074	4,456	4,839	5,220	5,371	4,815	56.4	61.7	67.0	72.2	74.3	66.6
24MW Uthurujanani diesel Plant	108	155	183	192	196	173	47.4	68.1	80.5	84.5	86.0	76.1
163MW AES CCY Plant	103	227	349	465	577	346	7.2	15.9	24.4	32.5	40.4	24.2
30MW Nothern Power Plant	37	53	77	98	117	76	14.1	20.1	29.5	37.2	44.4	29.1
270MW Kerawalapitiya CCY Plant	231	393	639	851	1,061	634	9.8	16.6	27.0	36.0	44.9	26.8
10.5 MW of Dendro plants	54	66	70	72	72	68	58.9	71.5	76.2	78.4	78.6	74.2
13MW Agricultaral Biomass plant	77	84	87	89	89	86	67.4	73.6	76.6	77.8	77.9	75.5
60MW Barge power plant CEB	200	319	373	401	410	354	38.0	60.8	71.1	76.2	77.9	67.4
35MW Gas Turbine (2 units)	0	0	1	3	6	2	0.0	0.1	0.2	0.5	0.9	0.3
5MW Dendro Plant	269	319	334	341	341	327	61.3	72.7	76.3	77.8	77.9	74.6
Total hydro	8,326	7,060	5,830	4,730	4,106	5,933						
Total thermal	6,164	7,429	8,658	9,756	10,376	8,554						
Total generation	14,490	14,489	14,488	14,486	14,482	14,487						
Total demand	14,490	14,490	14,490	14,490	14,490	14,490						
Deficit	1	1	2	5	8	3						
2019												
8x10MW Sapugaskanda Diesel Ext.	394	467	494	506	506	482	64.6	76.5	81.0	82.9	83.1	79.1
115MW Kelanitissa Gas Turbine	98	153	183	254	298	194	9.9	15.4	18.5	25.6	30.1	19.6
165 MW Kelanitissa CCY Plant	461	631	857	996	1,050	819	32.7	44.8	60.8	70.7	74.5	58.2
300MW LVPS coal plant	4,377	4,813	5,221	5,488	5,582	5,145	60.6	66.6	72.3	75.9	77.2	71.2
24MW Uthurujanani diesel Plant	149	175	191	197	198	186	65.4	76.9	83.9	86.6	87.0	81.5
163MW AES CCY Plant	194	329	509	726	920	526	13.6	23.0	35.7	50.8	64.4	36.8
30MW Nothern Power Plant	55	79	99	124	149	101	21.0	30.1	37.6	47.2	56.6	38.3
270MW Kerawalapitiya CCY Plant	400	674	952	1,281	1,355	947	16.9	28.5	40.3	54.2	57.3	40.0
10.5 MW of Dendro plants	62	69	71	72	72	70	67.8	75.1	77.1	78.6	78.6	76.2
13MW Agricultaral Biomass plant	72	84	88	89	89	86	63.5	74.1	77.5	77.9	77.9	75.5
60MW Barge power plant CEB	301	346	399	414	418	383	57.3	65.8	75.8	78.7	79.5	72.9
35MW Gas Turbine	1	3	7	46	160	29	0.1	0.3	0.8	5.0	17.4	3.1
5MW Dendro Plant	423	487	507	512	512	496	64.3	74.1	77.1	77.9	77.9	75.5
Total hydro	8,503	7,178	5,905	4,770	4,132	6,015						
Total thermal	6,987	8,310	9,578	10,703	11,307	9,463						
Total generation	15,489	15,488	15,484	15,473	15,440	15,479						
Total demand	15,491	15,491	15,491	15,491	15,491	15,491						
Deficit	2	3	7	18	51	12						

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2020												
8x10MW Sapugaskanda Diesel Ext.	262	377	446	479	491	425	43.0	61.8	73.2	78.6	80.5	69.7
115MW Kelanitissa Gas Turbine	70	117	230	281	310	210	7.1	11.8	23.2	28.4	31.3	21.2
165 MW Kelanitissa CCY Plant	245	422	575	712	794	561	17.4	30.0	40.8	50.6	56.4	39.8
300MW LVPS coal plant (3 units)	4,223	4,532	4,866	5,221	5,335	4,853	58.4	62.7	67.3	72.2	73.8	67.2
24MW Uthurujanani diesel Plant	85	138	168	184	189	159	37.2	60.6	73.8	80.7	83.2	69.8
163MW AES CCY Plant	101	174	344	427	462	314	7.1	12.2	24.1	29.9	32.3	22.0
270MW Kerawalapitiya CCY Plant	180	399	520	682	828	525	7.6	16.9	22.0	28.8	35.0	22.2
10.5 MW of Dendro plants	42	56	66	70	71	63	45.9	61.3	71.6	76.3	76.8	68.4
13MW Agricultaral Biomass plant	62	75	85	87	88	81	54.8	66.0	74.2	76.3	77.1	71.3
35MW Gas Turbine	0	0	1	3	5	2	0.0	0.0	0.1	0.3	0.6	0.2
250MW Trincomalee Coal Plant (2 units)	1,635	1,887	2,149	2,464	2,701	2,163	41.1	47.5	54.0	61.9	67.9	54.4
5MW Dendro Plant	430	565	630	662	673	608	49.1	64.5	71.9	75.6	76.8	69.4
Total hydro	8,878	7,471	6,133	4,940	4,263	6,249						
Total thermal	7,336	8,743	10,080	11,272	11,947	9,963						
Total generation	16,214	16,214	16,213	16,212	16,209	16,213						
Total demand	16,214	16,214	16,214	16,214	16,214	16,214						
Deficit	0	0	1	2	4	1						
2021												
8x10MW Sapugaskanda Diesel Ext.	312	401	455	483	496	439	51.2	65.8	74.6	79.2	81.3	72.1
115MW Kelanitissa Gas Turbine	77	151	246	294	324	228	7.8	15.3	24.9	29.7	32.7	23.0
165 MW Kelanitissa CCY Plant	290	488	656	814	897	641	20.6	34.7	46.6	57.8	63.7	45.5
300MW LVPS coal plant (3 units)	4,349	4,639	5,056	5,323	5,418	4,992	60.2	64.2	70.0	73.7	75.0	69.1
24MW Uthurujanani diesel Plant	104	151	173	186	192	166	45.6	66.2	75.9	81.8	84.2	72.9
163MW AES CCY Plant	135	250	380	460	570	365	9.5	17.5	26.6	32.2	39.9	25.5
270MW Kerawalapitiya CCY Plant	241	448	596	864	997	624	10.2	19.0	25.2	36.5	42.2	26.4
10.5 MW of Dendro plants	44	59	67	70	71	64	47.8	64.5	73.2	75.9	77.1	69.8
13MW Agricultaral Biomass plant	67	78	85	87	88	82	59.2	68.1	74.7	76.0	77.3	72.3
35MW Gas Turbine (3 units)	0	1	2	6	10	3	0.0	0.1	0.3	0.7	1.1	0.4
250MW Trincomalee Coal Plant (2 units)	1,694	2,013	2,280	2,614	2,810	2,288	42.6	50.6	57.3	65.7	70.7	57.5
5MW Dendro Plant	512	611	673	696	708	653	55.6	66.4	73.2	75.7	77.0	71.0
Total hydro	9,054	7,589	6,208	4,980	4,289	6,331						
Total thermal	7,826	9,291	10,670	11,895	12,581	10,546						
Total generation	16,880	16,880	16,878	16,875	16,870	16,877						
Total demand	16,880	16,880	16,880	16,880	16,880	16,880						
Deficit	0	0	2	5	10	3						
2022												
8x10MW Sapugaskanda Diesel Ext.	242	320	413	457	472	392	39.7	52.4	67.7	74.9	77.4	64.3
115MW Kelanitissa Gas Turbine	67	88	203	265	295	188	6.8	8.9	20.5	26.8	29.8	19.0
165 MW Kelanitissa CCY Plant	230	412	508	600	644	493	16.3	29.2	36.1	42.6	45.7	35.0
300MW LVPS coal plant (3 units)	3,971	4,192	4,299	4,470	4,653	4,315	55.0	58.0	59.5	61.8	64.4	59.7
24MW Uthurujanani diesel Plant	86	120	156	173	181	148	37.6	52.6	68.5	76.0	79.5	64.8
163MW AES CCY Plant	96	192	323	393	425	298	6.7	13.5	22.6	27.5	29.8	20.9
270MW Kerawalapitiya CCY Plant	157	346	466	569	615	447	6.6	14.6	19.7	24.1	26.0	18.9
10.5 MW of Dendro plants	37	49	60	67	69	58	39.8	53.6	65.6	73.1	74.5	63.0
13MW Agricultaral Biomass plant	58	70	80	86	86	78	51.2	61.8	70.3	75.7	75.8	68.3
35MW Gas Turbine (3 units)	0	0	0	0	1	0	0.0	0.0	0.0	0.0	0.1	0.0
250MW Trincomalee Coal Plant (2 units)	1,403	1,741	1,884	1,995	2,052	1,846	35.3	43.8	47.4	50.2	51.6	46.4
5MW Dendro Plant	415	513	618	678	687	596	45.1	55.8	67.2	73.7	74.7	64.8
300MW New Coal Power Plant (2 units)	1,493	1,732	2,192	2,725	3,014	2,219	31.6	36.6	46.3	57.6	63.7	46.9
Total hydro	9,335	7,814	6,387	5,110	4,396	6,513						
Total thermal	8,255	9,776	11,203	12,479	13,193	11,077						
Total generation	17,590	17,590	17,590	17,590	17,589	17,590						
Total demand	17,590	17,590	17,590	17,590	17,590	17,590						
Deficit	0	0	0	0	0	0						

Year / Plant	Annual Energy (GWh) Hydrology condition						Annual Plant Factor (%) Hydrology condition					
	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2023												
8x10MW Sapugaskanda Diesel Ext.	149	187	218	238	243	212	48.9	61.5	71.6	77.9	79.7	69.4
165 MW Kelanitissa CCY Plant	352	487	583	662	742	572	25.0	34.6	41.4	47.0	52.7	40.6
300MW LVPS coal plant (3 units)	4,040	4,333	4,559	4,898	5,087	4,583	55.9	60.0	63.1	67.8	70.4	63.4
24MW Uthurujanani diesel Plant	99	136	168	183	189	160	43.5	59.7	73.6	80.3	82.8	70.1
270MW Kerawalapitiya CCY Plant	290	425	555	618	697	529	12.3	18.0	23.4	26.1	29.5	22.4
10.5 MW of Dendro plants	46	55	63	69	70	62	49.5	60.0	68.5	75.3	75.6	67.0
13MW Agricultaral Biomass plant	61	74	81	87	87	79	53.7	64.7	71.2	76.0	76.6	69.7
163MW KCCP 2 CCY plant CEB	139	279	362	426	466	346	9.7	19.5	25.4	29.8	32.6	24.3
35MW Gas Turbine (3 units)	0	0	1	2	3	1	0.0	0.0	0.1	0.2	0.3	0.1
250MW Trincomalee Coal Plant (2 units)	1,536	1,799	1,939	2,190	2,365	1,963	38.6	45.2	48.8	55.1	59.5	49.4
5MW Dendro Plant	483	603	672	726	729	656	50.2	62.6	69.8	75.3	75.7	68.1
300MW New Coal Power Plant (2 units)	1,752	2,124	2,755	3,154	3,296	2,662	37.0	44.9	58.2	66.7	69.7	56.3
Total hydro	9,441	7,885	6,432	5,134	4,412	6,562						
Total thermal	8,947	10,503	11,955	13,252	13,973	11,825						
Total generation	18,388	18,387	18,387	18,386	18,385	18,387						
Total demand	18,388	18,388	18,388	18,388	18,388	18,388						
Deficit	0	0	0	1	3	1						
2024												
8x10MW Sapugaskanda Diesel Ext.	143	188	213	232	240	207	47.0	61.5	69.8	76.0	78.6	68.0
165 MW Kelanitissa CCY Plant	412	461	564	629	682	553	29.3	32.7	40.0	44.7	48.4	39.3
300MW LVPS coal plant (3 units)	3,985	4,196	4,342	4,587	4,813	4,373	55.1	58.0	60.1	63.5	66.6	60.5
24MW Uthurujanani diesel Plant	110	144	163	179	186	159	48.3	63.1	71.6	78.4	81.6	69.9
270MW Kerawalapitiya CCY Plant	306	417	537	601	641	513	12.9	17.6	22.7	25.4	27.1	21.7
10.5 MW of Dendro plants	41	54	61	67	69	60	44.7	59.2	66.7	72.7	74.7	65.0
13MW Agricultaral Biomass plant	56	73	80	86	87	78	49.0	63.9	70.6	75.5	76.4	68.7
163MW KCCP 2 CCY plant CEB	125	311	360	423	448	348	8.8	21.8	25.2	29.6	31.4	24.4
35MW Gas Turbine (3 units)	0	0	0	1	1	0	0.0	0.0	0.0	0.1	0.2	0.0
250MW Trincomalee Coal Plant (2 units)	1,534	1,785	1,927	2,022	2,145	1,900	38.6	44.9	48.5	50.8	53.9	47.8
5MW Dendro Plant	516	643	717	776	791	701	49.1	61.1	68.2	73.8	75.2	66.7
300MW New Coal Power Plant (3 units)	2,483	3,020	3,796	4,470	4,697	3,734	35.0	42.6	53.5	63.0	66.2	52.6
Total hydro	9,511	7,932	6,462	5,150	4,422	6,595						
Total thermal	9,711	11,291	12,761	14,072	14,800	12,628						
Total generation	19,223	19,223	19,223	19,222	19,222	19,223						
Total demand	19,223	19,223	19,223	19,223	19,223	19,223						
Deficit	0	0	0	1	1	0						
2025												
165 MW Kelanitissa CCY Plant	462	560	661	707	783	642	32.8	39.7	47.0	50.2	55.6	45.6
300MW LVPS coal plant (3 units)	4,198	4,338	4,527	4,849	5,061	4,574	58.1	60.0	62.6	67.1	70.0	63.3
24MW Uthurujanani diesel Plant	128	162	191	197	197	180	56.1	71.0	83.6	86.3	86.4	79.2
270MW Kerawalapitiya CCY Plant	400	520	620	702	740	607	16.9	22.0	26.2	29.7	31.3	25.6
10.5 MW of Dendro plants	48	60	70	72	72	66	51.7	65.4	75.7	78.1	78.1	72.0
13MW Agricultaral Biomass plant	70	82	88	89	89	85	61.7	72.0	77.3	77.7	77.8	74.8
163MW KCCP 2 CCY plant CEB	255	343	430	489	512	415	17.9	24.0	30.1	34.2	35.8	29.1
35MW Gas Turbine (3 units)	0	0	0	0	1	0	0.0	0.0	0.0	0.0	0.1	0.0
250MW Trincomalee Coal Plant (2 units)	1,717	1,964	2,012	2,193	2,346	2,043	43.2	49.4	50.6	55.2	59.0	51.4
5MW Dendro Plant	623	748	835	849	850	801	56.9	68.3	76.2	77.6	77.6	73.1
300MW New Coal Power Plant (3 units)	2,706	3,434	4,263	4,878	5,105	4,149	38.1	48.4	60.1	68.7	71.9	58.5
Total hydro	9,782	8,179	6,692	5,366	4,628	6,827						
Total thermal	10,608	12,210	13,698	15,023	15,755	13,562						
Total generation	20,390	20,390	20,390	20,389	20,383	20,389						
Total demand	20,104	20,104	20,104	20,104	20,104	20,104						
Deficit	-286	-286	-286	-285	-279	-285						

Year / *Plant*	*Annual Energy (GWh)* — *Hydrology condition* 1	2	3	4	5	Avg.	*Annual Plant Factor (%)* — *Hydrology condition* 1	2	3	4	5	Avg.
2026												
165 MW Kelanitissa CCY Plant	526	715	717	725	815	709	37.3	50.8	50.9	51.5	57.9	50.3
300MW LVPS coal plant (3 units)	4,272	4,402	4,658	5,033	5,274	4,705	59.1	60.9	64.5	69.6	73.0	65.1
24MW Uthurujanani diesel Plant	160	198	198	198	198	194	70.3	86.9	87.0	87.0	87.0	85.3
270MW Kerawalapitiya CCY Plant	489	700	724	725	820	706	20.7	29.6	30.6	30.7	34.7	29.8
10.5 MW of Dendro plants	62	72	72	72	72	71	67.2	78.5	78.6	78.6	78.6	77.4
13MW Agricultaral Biomass plant	85	89	89	89	89	88	74.6	77.9	77.9	77.9	77.9	77.6
163MW KCCP 2 CCY plant CEB	354	476	535	537	537	506	24.8	33.3	37.5	37.6	37.6	35.4
35MW Gas Turbine (3 units)	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
250MW Trincomalee Coal Power Plant	1,981	2,015	2,040	2,321	2,487	2,130	49.8	50.7	51.3	58.4	62.5	53.6
5MW Dendro Plant	841	886	886	886	886	882	73.8	77.8	77.8	77.8	77.8	77.4
300MW New Coal Power Plant (3 units)	2,965	3,829	4,962	5,658	5,812	4,760	41.8	54.0	69.9	79.7	81.9	67.1
Total hydro	10,250	8,635	7,092	5,782	5,048	7,250						
Total thermal	11,734	13,382	14,882	16,245	16,991	14,751						
Total generation	21,984	22,017	21,974	22,027	22,039	22,001						
Total demand	21,182	21,182	21,182	21,182	21,182	21,182						
Deficit	-802	-835	-793	-845	-857	-819						
2027												
165 MW Kelanitissa CCY Plant	540	704	717	717	745	700	38.4	50.0	50.9	50.9	52.9	49.7
300MW LVPS coal plant(3 units)	4,271	4,273	4,405	4,766	4,979	4,495	59.1	59.1	61.0	65.9	68.9	62.2
24MW Uthurujanani diesel Plant	171	198	198	198	198	195	74.9	86.7	87.0	87.0	87.0	85.7
270MW Kerawalapitiya CCY Plant	471	678	723	725	726	690	19.9	28.7	30.6	30.7	30.7	29.2
10.5 MW of Dendro plants	59	72	72	72	72	71	64.5	78.5	78.6	78.6	78.6	77.1
13MW Agricultaral Biomass plant	85	89	89	89	89	88	74.6	77.8	77.9	77.9	77.9	77.6
163MW KCCP 2 CCY plant CEB	354	467	534	536	537	503	24.8	32.7	37.4	37.6	37.6	35.3
35MW Gas Turbine (3 units)	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
250MW Trincomalee Coal Plant (2 units)	1,983	2,015	2,016	2,108	2,329	2,062	49.9	50.7	50.7	53.0	58.6	51.8
5MW Dendro Plant	883	954	955	955	955	948	72.0	77.8	77.9	77.9	77.9	77.3
300MW New Coal Power Plant (4 units)	3,772	4,859	6,129	7,108	7,411	5,963	39.9	51.4	64.8	75.1	78.3	63.0
Total hydro	10,511	8,787	7,114	5,817	5,063	7,324						
Total thermal	12,589	14,308	15,838	17,277	18,042	15,715						
Total generation	23,100	23,095	22,952	23,093	23,105	23,039						
Total demand	22,278	22,278	22,278	22,278	22,278	22,278						
Deficit	-822	-816	-674	-815	-827	-761						
2028												
165 MW Kelanitissa CCY Plant	631	715	718	761	873	733	44.8	50.8	50.9	54.0	62.0	52.0
300MW LVPS coal plant (3 units)	4,273	4,435	4,751	5,139	5,267	4,769	59.1	61.4	65.7	71.1	72.9	66.0
24MW Uthurujanani diesel Plant	185	198	198	198	198	197	81.3	86.8	87.0	87.0	87.0	86.4
270MW Kerawalapitiya CCY Plant	577	709	725	732	880	724	24.4	30.0	30.6	31.0	37.2	30.6
10.5 MW of Dendro plants	68	72	72	72	72	72	73.4	78.4	78.6	78.6	78.6	78.0
163MW KCCP 2 CCY plant CEB	373	505	536	537	556	516	26.2	35.4	37.5	37.6	38.9	36.1
35MW Gas Turbine (3 units)	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
250MW Trincomalee Coal Plant (2 units)	2,002	2,016	2,120	2,484	2,639	2,212	50.3	50.7	53.3	62.5	66.4	55.6
5MW Dendro Plant	993	1,022	1,023	1,023	1,023	1,020	75.6	77.8	77.9	77.9	77.9	77.6
300MW New Coal Power Plant (4 units)	4,440	5,662	6,839	7,498	7,716	6,583	46.9	59.8	72.3	79.3	81.6	69.6
Total hydro	10,730	8,904	7,307	5,902	5,121	7,469						
Total thermal	13,541	15,333	16,981	18,445	19,226	16,825						
Total generation	24,272	24,237	24,288	24,347	24,347	24,294						
Total demand	23,490	23,490	23,490	23,490	23,490	23,490						
Deficit	-782	-748	-798	-857	-857	-804						

Plant (2 units)

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2029												
165 MW Kelanitissa CCY Plant	606	713	717	728	807	717	43.0	50.7	50.9	51.7	57.3	50.9
300MW LVPS coal plant (3 units)	4,272	4,311	4,524	4,967	5,115	4,604	59.1	59.7	62.6	68.7	70.8	63.7
24MW Uthurujanani diesel Plant	177	198	198	198	198	196	77.9	86.8	87.0	87.0	87.0	86.1
270MW Kerawalapitiya CCY Plant	579	707	725	726	777	712	24.5	29.9	30.6	30.7	32.8	30.1
10.5 MW of Dendro plants	66	72	72	72	72	72	71.4	78.5	78.6	78.6	78.6	77.8
163MW KCCP 2 CCY plant CEB	385	498	536	537	537	514	27.0	34.9	37.5	37.6	37.6	36.0
35MW Gas Turbine (3 units)	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
250MW Trincomalee Coal Plant (2 units)	1,996	2,015	2,016	2,255	2,473	2,107	50.2	50.7	50.7	56.7	62.2	53.0
5MW Dendro Plant	1,057	1,090	1,091	1,091	1,091	1,087	75.4	77.8	77.8	77.8	77.8	77.6
300MW New Coal Power Plant (5 units)	5,329	6,747	8,169	9,005	9,317	7,883	45.1	57.1	69.1	76.2	78.8	66.7
Total hydro	11,021	9,104	7,389	5,954	5,162	7,586						
Total thermal	14,466	16,353	18,048	19,580	20,389	17,891						
Total generation	25,487	25,458	25,437	25,534	25,551	25,477						
Total demand	24,694	24,694	24,694	24,694	24,694	24,694						
Deficit	-793	-764	-744	-840	-857	-783						
2030												
165 MW Kelanitissa CCY Plant	546	715	717	718	738	702	38.8	50.7	50.9	51.0	52.4	49.8
300MW LVPS coal plant (3 units)	4,271	4,273	4,363	4,838	5,023	4,497	59.1	59.1	60.4	66.9	69.5	62.2
24MW Uthurujanani diesel Plant	156	197	198	198	198	194	68.5	86.7	87.0	87.0	87.0	85.1
270MW Kerawalapitiya CCY Plant	512	676	724	726	726	694	21.6	28.6	30.6	30.7	30.7	29.3
10.5 MW of Dendro plants	58	72	72	72	72	71	63.2	78.2	78.6	78.6	78.6	77.0
163MW KCCP 2 CCY plant CEB	300	438	533	537	537	492	21.0	30.7	37.3	37.6	37.6	34.5
35MW Gas Turbine (3 units)	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
250MW Trincomalee Coal Plant (2 units)	1,976	2,015	2,016	2,085	2,334	2,058	49.7	50.7	50.7	52.4	58.7	51.7
5MW Dendro Plant	1,000	1,157	1,160	1,160	1,160	1,143	67.2	77.7	77.9	77.9	77.9	76.8
300MW New Coal Power Plant (6 units)	6,714	7,957	9,461	10,482	10,853	9,229	47.3	56.1	66.7	73.9	76.5	65.0
Total hydro	11,313	9,306	7,504	5,998	5,181	7,712						
Total thermal	15,534	17,500	19,244	20,816	21,642	19,078						
Total generation	26,848	26,806	26,748	26,814	26,823	26,790						
Total demand	25,990	25,990	25,990	25,990	25,990	25,990						
Deficit	-857	-816	-758	-824	-833	-800						
2031												
165 MW Kelanitissa CCY Plant	652	716	720	792	864	741	46.3	50.9	51.1	56.2	61.4	52.6
300MW LVPS coal plant (3 units)	4,273	4,398	4,747	5,103	5,169	4,743	59.1	60.9	65.7	70.6	71.5	65.6
24MW Uthurujanani diesel Plant	186	198	198	198	198	197	81.8	86.8	87.0	87.0	87.0	86.5
270MW Kerawalapitiya CCY Plant	557	704	725	751	929	730	23.6	29.8	30.7	31.8	39.3	30.9
10.5 MW of Dendro plants	69	72	72	72	72	72	75.2	78.4	78.6	78.6	78.6	78.2
163MW KCCP 2 CCY plant CEB	374	474	536	538	546	508	26.2	33.2	37.5	37.7	38.2	35.6
35MW Gas Turbine (3 units)	0	0	0	0	1	0	0.0	0.0	0.0	0.1	0.1	0.0
250MW Trincomalee Coal Plant (2 units)	2,011	2,016	2,104	2,491	2,678	2,212	50.6	50.7	52.9	62.6	67.3	55.6
5MW Dendro Plant	1,173	1,227	1,228	1,228	1,228	1,222	74.4	77.8	77.9	77.9	77.9	77.5
300MW New Coal Power Plant (6 units)	7,477	8,934	10,203	10,920	11,235	9,923	52.7	63.0	71.9	76.9	79.2	69.9
Total hydro	11,345	9,297	7,586	6,029	5,203	7,754						
Total thermal	16,774	18,739	20,533	22,094	22,920	20,349						
Total generation	28,118	28,036	28,119	28,123	28,123	28,103						
Total demand	27,267	27,267	27,267	27,267	27,267	27,267						
Deficit	-852	-769	-852	-857	-856	-837						

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2032												
165 MW Kelanitissa CCY Plant	531	676	717	718	718	691	37.7	48.0	50.9	50.9	51.0	49.0
300MW LVPS coal plant (3 units)	4,271	4,272	4,273	4,429	4,732	4,350	59.1	59.1	59.1	61.3	65.5	60.2
24MW Uthurujanani diesel Plant	149	191	198	198	198	192	65.2	83.7	87.0	87.0	87.0	84.2
270MW Kerawalapitiya CCY Plant	418	609	721	725	726	670	17.7	25.8	30.5	30.6	30.7	28.3
10.5 MW of Dendro plants	56	69	72	72	72	70	61.2	75.4	78.6	78.6	78.6	76.2
163MW KCCP 2 CCY plant CEB	233	352	488	536	536	450	16.3	24.7	34.2	37.5	37.6	31.5
35MW Gas Turbine (3 units)	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
250MW Trincomalee Coal Plant (2 units)	1,926	2,014	2,015	2,017	2,053	2,010	48.4	50.6	50.7	50.7	51.6	50.5
5MW Dendro Plant	1,124	1,352	1,364	1,364	1,364	1,338	64.2	77.2	77.9	77.9	77.9	76.4
300MW New Coal Power Plant (8 units)	9,326	10,500	11,942	13,312	13,797	11,851	49.3	55.5	63.1	70.3	72.9	62.6
Total hydro	11,384	9,382	7,553	6,016	5,182	7,757						
Total thermal	18,034	20,036	21,792	23,371	24,198	21,621						
Total generation	29,418	29,418	29,344	29,387	29,380	29,378						
Total demand	28,561	28,561	28,561	28,561	28,561	28,561						
Deficit	-857	-857	-784	-826	-820	-818						
2033												
300MW LVPS coal plant(3 units)	4,273	4,379	4,743	5,078	5,133	4,729	59.1	60.6	65.6	70.3	71.0	65.4
24MW Uthurujanani diesel Plant	165	197	198	198	198	195	72.3	86.5	87.0	87.0	87.0	85.4
270MW Kerawalapitiya CCY Plant	595	719	727	851	1,029	767	25.1	30.4	30.7	36.0	43.5	32.4
10.5 MW of Dendro plants	62	72	72	72	72	71	67.5	78.1	78.6	78.6	78.6	77.4
35MW Gas Turbine (3 units)	0	0	1	6	105	12	0.0	0.0	0.1	0.7	11.4	1.3
250MW Trincomalee Coal Plant (2 units)	2,008	2,017	2,140	2,511	2,672	2,229	50.5	50.7	53.8	63.1	67.2	56.1
5MW Dendro Plant	1,345	1,531	1,535	1,535	1,535	1,515	68.2	77.7	77.9	77.9	77.9	76.8
300MW New Coal Power Plant (8 units)	10,906	12,424	13,733	14,482	14,818	13,447	57.6	65.7	72.6	76.5	78.3	71.1
Total hydro	11,401	9,321	7,591	6,045	5,214	7,771						
Total thermal	19,354	21,339	23,148	24,733	25,562	22,965						
Total generation	30,754	30,660	30,739	30,778	30,776	30,736						
Total demand	29,923	29,923	29,923	29,923	29,923	29,923						
Deficit	-831	-737	-816	-855	-853	-813						
2034												
300MW LVPS coal plant(3 units)	4,273	4,324	4,607	5,027	5,072	4,648	59.1	59.8	63.8	69.6	70.2	64.3
24MW Uthurujanani diesel Plant	152	189	198	198	198	192	66.6	82.9	86.9	87.0	87.0	84.1
270MW Kerawalapitiya CCY Plant	545	682	725	775	923	728	23.0	28.9	30.6	32.8	39.0	30.8
10.5 MW of Dendro plants	55	71	72	72	72	70	60.1	77.4	78.5	78.6	78.6	76.5
35MW Gas Turbine (3 units)	0	0	0	2	24	3	0.0	0.0	0.1	0.2	2.6	0.3
250MW Trincomalee Coal Plant (2 units)	1,980	2,015	2,049	2,318	2,586	2,143	49.8	50.7	51.5	58.3	65.0	53.9
5MW Dendro Plant	1,488	1,730	1,739	1,739	1,739	1,712	66.6	77.5	77.8	77.9	77.9	76.7
300MW New Coal Power Plant(9 units)	12,235	13,716	15,139	15,995	16,345	14,856	57.5	64.4	71.1	75.1	76.8	69.8
Total hydro	11,454	9,374	7,594	6,053	5,219	7,790						
Total thermal	20,727	22,729	24,529	26,127	26,959	24,351						
Total generation	32,181	32,103	32,124	32,180	32,178	32,142						
Total demand	31,324	31,324	31,324	31,324	31,324	31,324						
Deficit	-857	-778	-799	-855	-854	-818						

Fuel Requirement and Expenditure on Fuel

Base Case 2015 - 2034

Year	Auto Diesel		Furnace Oil (LSFO 180)		Furnace Oil (HSFO 180)		Residual Oil (HSFO 360)		Naphtha		Coal (6300 kcal/kg)		Coal (5500 kcal/kg)		Coal (5900 kcal/kg)		Dendro	
	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD
2015	52.9	64.3	78.6	75.4	107.2	71.0	237.2	151.4	76.4	81.7	1649.6	161.4					264.3	10.6
2016	68.2	82.1	94.0	89.3	115.3	76.4	247.9	158.2	85.7	91.1	1690.1	165.4					387.5	17.3
2017	77.7	93.3	109.1	102.2	119.3	79.0	247.1	157.7	92.0	96.7	1734.2	169.7					557.7	26.7
2018	101.7	120.6	138.2	123.5	130.6	86.6	185.1	117.9	110.6	112.7	1817.3	177.8					849.1	42.7
2019	156.5	172.3	206.6	168.1	144.7	95.9	94.3	60.1	142.9	139.7	1941.7	190.0					1151.5	59.4
2020	114.4	133.3	114.6	107.3	33.6	22.5	83.1	53.0	97.8	103.3	1831.5	179.2	1022.6	83.5			1328.2	69.4
2021	129.0	149.1	136.2	122.9	35.1	23.5	86.0	54.8	111.8	114.6	1883.9	184.3	1081.6	88.3			1412.0	74.0
2022	105.3	123.5	97.4	94.0	31.2	20.9	76.7	48.9	86.0	92.6	1628.4	159.3	872.8	71.3	842.9	75.3	1291.9	67.6
2023	63.0	83.8	115.4	110.7	33.8	22.6	41.4	26.4	99.8	106.5	1729.6	169.2	928.2	75.8	1011.4	90.4	1407.3	73.9
2024	63.2	84.2	111.9	107.9	33.7	22.6	40.5	25.8	96.4	103.7	1650.4	161.5	898.2	73.4	1418.6	126.8	1482.4	78.1
2025	75.3	100.5	132.3	127.4	38.1	25.6			112.0	120.1	1726.4	168.9	965.6	78.9	1575.9	140.9	1681.1	88.7
2026	91.6	122.3	153.9	147.8	41.1	27.6			123.6	132.4	1775.8	173.7	1006.9	82.2	1808.2	161.6	1839.1	97.3
2027	91.2	121.8	150.4	145.3	41.3	27.7			122.0	131.3	1696.4	166.0	974.8	79.6	2265.2	202.5	1954.8	103.7
2028	93.4	124.5	157.9	150.9	41.6	27.9			127.8	135.8	1799.9	176.1	1045.7	85.4	2500.7	223.5	1927.9	106.5
2029	93.0	124.2	155.3	149.5	41.5	27.8			124.9	133.8	1737.6	170.0	996.2	81.4	2994.5	267.7	2046.9	113.1
2030	89.1	119.0	151.3	146.2	41.0	27.5			122.3	131.7	1697.2	166.0	972.6	79.4	3505.7	313.4	2144.2	118.5
2031	92.1	122.9	159.2	151.3	41.7	27.9			129.3	137.0	1790.3	175.2	1045.6	85.4	3769.5	336.9	2285.1	126.3
2032	81.4	108.8	146.1	141.1	40.5	27.2			120.4	129.8	1641.8	160.6	950.3	77.6	4502.0	402.4	2486.5	137.4
2033	3.5	3.3	167.3	156.2	41.2	27.6					1784.9	174.6	1053.9	86.1	5108.0	456.6	2800.9	154.8
2034	0.8	0.8	158.9	150.5	40.5	27.2					1754.1	171.6	1012.9	82.7	5643.3	504.4	3148.1	174.0

Annex 7.6

Results of Generation Expansion Planning Studies - 2015

Reference Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.169
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.251
2018	-	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.802
2019*****	-	**3x35 MW Gas Turbine** **1x105 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.127
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP****	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.277
2021	-	-	-	0.733
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP****	**2x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.047
2023	-	*163 MW Combined Cycle Plant (KPS – 2)++* **1x300 MW New Coal plant – Southern Region**	163 MW AES Kelanitissa Combined Cycle Plant++ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.047
2024	-	-	-	0.167
2025	**1x200 MW PSPP*****	-	4x9 MW Sapugaskanda Diesel Ext.	0.146
2026	**2x200 MW PSPP*****	-	-	0.019
2027	-	**1x300 MW New Coal plant – Southern Region**	-	0.014
2028	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.012
2029	-	-	-	0.072
2030	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.059
2031	-	**1x300 MW New Coal plant – Southern Region**	-	0.054
2032	-	**1x300 MW New Coal plant – Southern Region**	-	0.052
2033	-	**2x300 MW New Coal plant – Southern Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant KPS2)	0.078
2034	-	**1x300 MW New Coal plant – Southern Region**	-	0.081
Total PV Cost up to year 2034, **US$ 12,892.07 million** [LKR 1,695.95 billion]				

Notes:

1. Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
2. All additions/retirements are carried out at the beginning of each year
3. Committed plants are shown in Italics. All plant capacities are given in gross values..
4. Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively

* In year 2019, Minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2025 and 2026 respectively.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

Results of Generation Expansion Planning Studies - 2014

High Demand Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.253
2016	-	-	-	0.635
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	**1x35 MW Gas Turbine**	4x17 MW Kelanitissa Gas Turbines	0.547
2018	**100 MW Mannar Wind Park Phase I**	**1x35 MW Gas Turbine** **1x105 MW Gas Turbine**	8x6.13 MW Asia Power	0.495
2019	-	**1x150 MW Combined Cycle Plant**	4x18 MW Sapugaskanda diesel	0.705
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.089
2021	**50 MW Mannar Wind Park Phase II**	-	-	0.250
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**2x300 MW New Coal Plant –Trincomalee -2, Phase – I**	-	0.013
2023	**25 MW Mannar Wind Park Phase III**	**1x300 MW New Coal plant – Southern Region** *163 MW Combined Cycle Plant (KPS – 2)+*	163 MW AES Kelanitissa Combined Cycle Plant+ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.015
2024	**25 MW Mannar Wind Park Phase III**	-	-	0.062
2025	**1x200 MW PSPP***** **25 MW Mannar Wind Park Phase III**	-	4x9 MW Sapugaskanda Diesel Ext.	0.062
2026	**2x200 MW PSPP*****	-	-	0.011
2027	-	**1x300 MW New Coal plant – Southern Region**	-	0.010
2028	-	**1x300 MW New Coal plant – Trincomalee -2, Phase - II**	-	0.013
2029	-	**1x300 MW New Coal plant – Trincomalee -2, Phase - II**	-	0.015
2030	-	**2x300 MW New Coal plant – Southern Region**	-	0.003
2031	-	**1x300 MW New Coal plant – Southern Region**	-	0.004
2032	-	**1x300 MW New Coal plant – Southern Region**	-	0.007
2033	-	-	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS-2)	0.319
2034	-	**1x300 MW New Coal plant – Southern Region**	-	0.467
Total PV Cost up to year 2034, **US$ 15,049.49 million** [LKR 1,979.76 billion]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values
- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.
- PV cost includes the cost of Projected Committed NCRE, US$ 1527.8 million based on economic cost, and additional 10% Spinning Reserve requirement from NCRE capacity is kept considering the intermittency of NCRE plants with a cost of US$ 721.9 million.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2025 and 2026 respectively.

\+ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

Results of Generation Expansion Planning Studies - 2014

Low Demand Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.118
2018		**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.134
2019	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	0.341
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP****	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.031
2021	-	-	-	0.065
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP****	-	-	0.109
2023	-	**1x300 MW New Coal plant – Trincomalee -2, Phase - I** *163 MW Combined Cycle Plant (KPS – 2)*+	163 MW AES Kelanitissa Combined Cycle Plant+ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.057
2024	-	**1x300 MW New Coal plant – Trincomalee -2, Phase - I**	-	0.014
2025	-	-	4x9 MW Sapugaskanda Diesel Ext.	0.039
2026	-	-	-	0.090
2027	-	-	-	0.203
2028	-	**1x300 MW New Coal plant – Southern Region**	-	0.079
2029	-	-	-	0.176
2030	-	-	-	0.347
2031	-	**1x300 MW New Coal plant – Southern Region**	-	0.144
2032	**1x200 MW PSPP*****	-	-	0.060
2033	**1x200 MW PSPP*****	-	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS–2)	0.976
2034	-	**1x300 MW New Coal plant – Trincomalee -2, Phase - II**	-	0.097
Total PV Cost up to year 2034, **US$ 10,906.67 million** [LKR 1,434.77 billion]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.
- PV cost includes the cost of Projected Committed NCRE, **US$ 1,320.2 million** based on economic cost, and additional 10% Spinning Reserve requirement from NCRE capacity is kept considering the intermittency of NCRE plants with a cost of US$ 234.9 million.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2032 and 2033 respectively.

\+ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.
- Mannar Wind & other NCRE addition capacities as per the Annex 5.2, throughout the planning horizon.

Results of Generation Expansion Planning Studies - 2014

High Discount Rate (15%) Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*		4x17 MW Kelanitissa Gas Turbines	0.175
2018	**100 MW Mannar Wind Park Phase I**	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.299
2019*****	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.140
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100 MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.164
2021	**50 MW Mannar Wind Park Phase II**	-	-	0.360
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**1x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.114
2023	**25 MW Mannar Wind Park Phase III**	*163 MW Combined Cycle Plant (KPS – 2)*+ **1x300 MW New Coal Plant – Trincomalee -2, Phase – I**	163 MW AES Kelanitissa Combined Cycle Plant++ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.096
2024	**25 MW Mannar Wind Park Phase III**		-	0.253
2025	**25 MW Mannar Wind Park Phase III**	**1x300 MW New Coal plant – Southern Region**	4x9 MW Sapugaskanda Diesel Ext.	0.156
2026	-	**1x300 MW New Coal plant – Southern Region**	-	0.095
2027	-		-	0.316
2028	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.233
2029	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.162
2030	-		-	0.544
2031	**1x200 MW PSPP*****	-	-	0.507
2032	-	**1x300 MW New Coal plant – Southern Region**	-	0.398
2033	**1x200 MW PSPP*****	**1x300 MW New Coal plant – Southern Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS – 2)	0.578
2034	-	**1x300 MW New Coal plant – Southern Region**	-	0.420
Total PV Cost up to year 2034, **US$ 9,752.75 million** [LKR 1,282.97 billion]+				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.

\+ PV cost includes the cost of Projected Committed NCRE, **US$ 1527.9 million** based on economic cost, and an additional Spinning Reserve requirement is kept considering the intermittency of NCRE plants with a cost of **US$ 224.95 million**.

***** In year 2019, minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP is forced in 2022.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

Results of Generation Expansion Planning Studies - 2014

Low Discount Rate (3%) Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.175
2018	**100 MW Mannar Wind Park Phase I**	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.299
2019*****	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.140
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100 MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.164
2021	**50 MW Mannar Wind Park Phase II**	-	-	0.360
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**2x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.015
2023	**25 MW Mannar Wind Park Phase III**	*163 MW Combined Cycle Plant (KPS – 2)*$^{+}$ **1x300 MW New Coal plant – Southern Region**	163 MW AES Kelanitissa Combined Cycle Plant^{++} 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.013
2024	**25 MW Mannar Wind Park Phase III**	-	-	0.040
2025	**1x200 MW PSPP***** **25 MW Mannar Wind Park Phase III**	-	4x9 MW Sapugaskanda Diesel Ext.	0.028
2026	**2x200 MW PSPP*****	-	-	0.003
2027	-	**1x300 MW New Coal plant – Southern Region**	-	0.002
2028	-	-	-	0.010
2029	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.007
2030	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.005
2031	-	**1x300 MW New Coal plant – Southern Region**	-	0.004
2032	-	**1x300 MW New Coal plant – Southern Region**	-	0.003
2033	-	-	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS – 2)	0.142
2034	-	**1x300 MW New Coal plant – Southern Region**	-	0.118
Total PV Cost up to year 2034, **US$ 21,452.70 million** [LKR 2,822.10 billion]$^{+}$				

Notes:

- Discount rate 3%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.

\+ PV cost includes the cost of Projected Committed NCRE, **US$ 1527.9 million** based on economic cost, and an additional Spinning Reserve requirement is kept considering the intermittency of NCRE plants with a cost of **US$ 1,218.51 million**.

***** In year 2019, minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2025 and 2026 respectively.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

Results of Generation Expansion Planning Studies - 2014

Coal Price 50% High Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.175
2018	**100 MW Mannar Wind Park Phase I**	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.299
2019*****	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.140
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100 MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.164
2021	**50 MW Mannar Wind Park Phase II**	-	-	0.360
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**1x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.114
2023	**25 MW Mannar Wind Park Phase III**	**1x300 MW New Coal Plant – Trincomalee -2, Phase – I** *163 MW Combined Cycle Plant (KPS – 2)*++	163 MW AES Kelanitissa Combined Cycle Plant++ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.096
2024	**25 MW Mannar Wind Park Phase III**	-	-	0.253
2025	**1x200 MW PSPP***** **25 MW Mannar Wind Park Phase III**	-	4x9 MW Sapugaskanda Diesel Ext.	0.186
2026	**2x200 MW PSPP*****	-	-	0.025
2027	-	**1x300 MW New Coal plant – Southern Region**	-	0.014
2028	-	**1x300 MW New Coal plant – Southern Region**	-	0.010
2029	-	-	-	0.061
2030	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.036
2031	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.029
2032	-	-	-	0.123
2033	-	**2x300 MW New Coal plant – Southern Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS-2)	0.142
2034	-	**1x300 MW New Coal plant – Southern Region**	-	0.118
Total PV Cost up to year 2034, **US$ 14,243.42 million** [LKR 1,873.72 billion]+				

Notes:
- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.

\+ PV cost includes the cost of Projected Committed NCRE, **US$ 1527.9 million** based on economic cost, and an additional Spinning Reserve requirement is kept considering the intermittency of NCRE plants with a cost of **US$ 279.7 million**.

***** In year 2019, minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2025 and 2026 respectively.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

Results of Generation Expansion Planning Studies - 2014

Coal and Oil Price 50% High Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.175
2018	**100 MW Mannar Wind Park Phase I**	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.299
2019*****	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.140
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100 MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.164
2021	**50 MW Mannar Wind Park Phase II**	-	-	0.360
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**2x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.015
2023	**25 MW Mannar Wind Park Phase III**	**1x300 MW New Coal plant – Southern Region** *163 MW Combined Cycle Plant (KPS – 2)*++	163 MW AES Kelanitissa Combined Cycle Plant++ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.013
2024	**25 MW Mannar Wind Park Phase III**	-	-	0.040
2025	**1x200 MW PSPP***** **25 MW Mannar Wind Park Phase III**	-	4x9 MW Sapugaskanda Diesel Ext.	0.028
2026	**2x200 MW PSPP*****	-	-	0.003
2027	-	**1x300 MW New Coal plant – Southern Region**	-	0.002
2028	-	-	-	0.010
2029	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.007
2030	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.005
2031	-	**1x300 MW New Coal plant – Southern Region**	-	0.004
2032	-	**1x300 MW New Coal plant – Southern Region**	-	0.003
2033	-	-	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS – 2)	0.142
2034	-	**1x300 MW New Coal plant – Southern Region**	-	0.118
Total PV Cost up to year 2034, **US$ 16,506.34 million** [LKR 2,171.41 billion]+				

Notes:
- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.

\+ PV cost includes the cost of Projected Committed NCRE, **US$ 1527.9 million** based on economic cost, and an additional Spinning Reserve requirement is kept considering the intermittency of NCRE plants with a cost of **US$ 717.4 million**.

***** In year 2019, minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2025 and 2026 respectively.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

Results of Generation Expansion Planning Studies - 2014

Energy Mix with Nuclear Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.175
2018	**100 MW Mannar Wind Park Phase I**	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.299
2019*****	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.140
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100 MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.164
2021	**50 MW Mannar Wind Park Phase II**	-	-	0.360
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**2x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.015
2023	**25 MW Mannar Wind Park Phase III**	*163 MW Combined Cycle Plant (KPS – 2)*$^{+}$	163 MW AES Kelanitissa Combined Cycle Plant^{++} 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.096
2024	**25 MW Mannar Wind Park Phase III**	**1x300 MW LNG Plant with Terminal – North Colombo**	-	0.034
2025	**25 MW Mannar Wind Park Phase III**	-	4x9 MW Sapugaskanda Diesel Ext.	0.124
2026	-	-	-	0.385
2027	-	**1x300 MW New Coal plant**	-	0.244
2028	-	**1x300 MW LNG Plant**	-	0.185
2029		-	-	0.532
2030	**3x200 MW PSPP*****	**1x600 MW Nuclear Plant**	-	0.001
2031	-	-	-	0.003
2032	-	-	-	0.015
2033	-	**1x300 MW New Coal plant**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS – 2)	0.089
2034	-	-	-	0.506
Total PV Cost up to year 2034, **US$ 13,034.16 million** [LKR 1,714.65 billion]$^{+}$				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.

+ PV cost includes the cost of Projected Committed NCRE, **US$ 1527.9 million** based on economic cost, and an additional Spinning Reserve requirement is kept considering the intermittency of NCRE plants with a cost of **US$ 222.7 million**.

***** In year 2019, minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2030 respectively.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.
- KPS, KPS – 2 and West-Coast Combined Cycle Plants are converted to LNG fuel option by 2024.

Results of Generation Expansion Planning Studies - 2015

Coal Restricted Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.175
2018	**100 MW Mannar Wind Park Phase I**	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.299
2019*****	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.140
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100 MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.134
2021	**50 MW Mannar Wind Park Phase II**	-	-	0.298
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**2x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.012
2023	**25 MW Mannar Wind Park Phase III**	*163 MW Combined Cycle Plant* *(KPS – 2)*+	163 MW AES Kelanitissa Combined Cycle Plant++ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.096
2024	**25 MW Mannar Wind Park Phase III**	**1x300 MW New Coal plant – Southern Region**	-	0.040
2025	**1x200 MW PSPP***** **25 MW Mannar Wind Park Phase III**	-	4x9 MW Sapugaskanda Diesel Ext.	0.028
2026	**2x200 MW PSPP*****	-	-	0.003
2027	-	**1x300 MW New Coal plant – Southern Region**	-	0.002
2028	-	-	-	0.010
2029	-	-	-	0.061
2030	-	-	-	1.147
2031	-	**1x300 MW LNG Plant with Terminal – North Colombo**	-	0.453
2032	-	**1x300 MW LNG Plant**	-	0.128
2033	-	**2x35 MW Gas Turbine** **1x300 MW LNG Plant**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS–2)	1.179
2034	-	**1x300 MW LNG Plant**	-	0.546
Total PV Cost up to year 2034, **US$ 12,971.65 million** [LKR 1,706.42 billion]+				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.

\+ PV cost includes the cost of Projected Committed NCRE, **US$ 1527.9 million** based on economic cost, and an additional Spinning Reserve requirement is kept considering the intermittency of NCRE plants with a cost of **US$ 361.65 million**.

***** In year 2019, Minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2025 and 2026 respectively.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

Results of Generation Expansion Planning Studies - 2014

Natural Gas Average Penetration Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.175
2018	**100 MW Mannar Wind Park Phase I**	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.299
2019*****	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.140
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100 MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.164
2021	**50 MW Mannar Wind Park Phase II**	165 MW Natural Gas Combined Cycle Plant (KPS) 300 MW West Coast NG Combined Cycle PP	165 MW Combined Cycle Plant (KPS) +++ 300MW West Coast Combined Cycle PP+++	0.258
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**1x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.085
2023	**25 MW Mannar Wind Park Phase III**	163 MW Natural Gas Combined Cycle Plant **1x300 MW NG Combined Cycle Plant**	163 MW AES Kelanitissa Combined Cycle Plant++ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.079
2024	**25 MW Mannar Wind Park Phase III**	-	-	0.199
2025	**1x200 MW PSPP***** **25 MW Mannar Wind Park Phase III**	-	4x9 MW Sapugaskanda Diesel Ext.	0.148
2026	**2x200 MW PSPP*****	-	-	0.021
2027	-	-	-	0.276
2028	-	**1x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.058
2029	-	**1x300 MW New Coal plant – Southern Region**	-	0.040
2030	-		-	0.487
2031	-	**1x300 MW New Coal plant – Southern Region**	-	0.123
2032	-	**1x300 MW New Coal plant – Trincomalee -2, Phase – II**	-	0.095
2033		**1x300 MW New Coal plant – Trincomalee -2, Phase – II** **1x300 MW NG Combined Cycle Plant**	165MW NG Combined Cycle Plant -KPS 163 MW NG Combined Cycle Plant	0.111
2034	-	-	-	0.727
Total PV Cost up to year 2034, **US$ 11,891.84 million** [LKR 1,564.37 billion]+				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.

\+ PV cost includes the cost of Projected Committed NCRE, **US$ 1527.9 million** based on economic cost, and an additional Spinning Reserve requirement is kept considering the intermittency of NCRE plants with a cost of **US$ 93.25 million**. Further it includes an estimated equipment cost of **US$ 5.52 million** for conversion of existing combined cycle plants to Natural Gas.

***** In year 2019,minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2025 and 2026 respectively.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be converted to Natural Gas (NG) Power Plant

Results of Generation Expansion Planning Studies - 2014

Natural Gas High Penetration Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.175
2018	**100 MW Mannar Wind Park Phase I**	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.299
2019*****	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.140
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100 MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.164
2021	**50 MW Mannar Wind Park Phase II**	165 MW Natural Gas Combined Cycle Plant (KPS) 300MW West Coast NG Combined Cycle PP	165 MW Combined Cycle Plant (KPS) +++ 300MW West Coast Combined Cycle PP+++	0.258
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**1x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.085
2023	**25 MW Mannar Wind Park Phase III**	163 MW Natural Gas Combined Cycle Plant **1x300 MW NG Combined Cycle Plant**	163 MW AES Kelanitissa Combined Cycle Plant++ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.079
2024	**25 MW Mannar Wind Park Phase III**	**-**	-	0.199
2025	**1x200 MW PSPP***** **25 MW Mannar Wind Park Phase III**	-	4x9 MW Sapugaskanda Diesel Ext.	0.148
2026	**2x200 MW PSPP*****	-	-	0.021
2027	-	-	-	0.276
2028	-	**1x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.058
2029	-	**1x300 MW New Coal plant – Southern Region**	-	0.040
2030	-		-	0.487
2031		**1x300 MW NG Combined Cycle Plant**	-	0.125
2032	-	**1x300 MW New Coal plant – Southern Region**	-	0.097
2033		**1x300 MW New Coal plant – Trincomalee -2, Phase – II** **1x300 MW NG Combined Cycle Plant**	165 MW NG Combined Cycle Plant (KPS) 163 MW NG Combined Cycle Plant	0.113
2034	-	-	-	0.660
Total PV Cost up to year 2034, **US$ 11,902.65 million** [LKR 1,565.79 billion]+				

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.

\+ PV cost includes the cost of Projected Committed NCRE, **US$ 1527.9 million** based on economic cost, and an additional Spinning Reserve requirement is kept considering the intermittency of NCRE plants with a cost of **US$ 88.90 million**. Further it includes an estimated equipment cost of **US$ 5.52 million** for conversion of existing combined cycle plants to Natural Gas

***** In 2019,minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, & minimum RM is kept at-.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2025 and 2026 respectively.

++ IPP AES Kelanitissa scheduled to retire in 2023 will be converted to Natural Gas (NG) Power Plant

+++ 165 MW Combined Cycle Plant (KPS) and 270MW West Coast Combined Cycle PP are converted to NG Power Plants in 2021, latter with a capacity enhancement.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

Results of Generation Expansion Planning Studies - 2014

HVDC Interconnection Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.175
2018	**100 MW Mannar Wind Park Phase I**	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.299
2019*	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	1.140
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP**** **100 MW Mannar Wind Park Phase II**	**2x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.164
2021	**50 MW Mannar Wind Park Phase II**	-	-	0.360
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP**** **50 MW Mannar Wind Park Phase III**	**2x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.015
2023	**25 MW Mannar Wind Park Phase III**	*163 MW Combined Cycle Plant (KPS – 2)*+	163 MW AES Kelanitissa Combined Cycle Plant+ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.096
2024	**25 MW Mannar Wind Park Phase III**	-	-	0.253
2025	**25 MW Mannar Wind Park Phase III**	**1x500 MW Indu Lanka HVDC Interconnection**++	4x9 MW Sapugaskanda Diesel Ext.	0.056
2026	-	**1x300 MW New Coal plant – Southern Region**	-	0.035
2027	-	**1x300 MW New Coal plant – Southern Region**	-	0.022
2028	-	**1x300 MW New Coal plant – Trincomalee -2, Phase - II**	-	0.016
2029	-	**1x300 MW New Coal plant – Trincomalee -2, Phase - II**	-	0.011
2030	-	-	-	0.043
2031	-	-	-	0.150
2032	-	**1x300 MW New Coal plant – Southern Region**	-	0.119
2033	-	**1x300 MW New Coal plant – Southern Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS–2)	0.477
2034	-	**2x35 MW Gas Turbine**	-	0.930
Total PV Cost up to year 2034, **US$ 12,760.51 million** [LKR 1,678.64 billion]				

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- PV cost includes the cost of Projected Committed NCRE, **US$ 1527.8 million** based on economic cost, and additional 10% Spinning Reserve requirement from NCRE capacity is kept considering the intermittency of NCRE plants with a cost of US$ **574.1 million**.

* In year 2019, minimum Reserve Margin criteria of 2.5% is violated due to generation capacity limitation, and the minimum RM is kept at -1.3%.

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP is forced in 2022.

\+ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

++ HVDC Interconnection costs are based on draft final report of Supplementary Studies for the Feasibility Study on India-Sri Lanka Grid Interconnection Project, November 2011 and need further review. The plant schedule must be further study with operational issues with respect to the curtailments of NCRE, available Coal plants and HVDC Interconnection.

Results of Generation Expansion Planning Studies - 2014

Demand Side Management (DSM) Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15 MW CEB Barge Power Plant	4x15 MW Colombo Power Plant 14x7.11 MW ACE Power Embilipitiya	0.044
2016	-	-	-	0.060
2017	*35 MW Broadlands HPP* *120 MW Uma Oya HPP*	-	4x17 MW Kelanitissa Gas Turbines	0.047
2018	-	**2x35 MW Gas Turbine**	8x6.13 MW Asia Power	0.051
2019	-	**1x35 MW Gas Turbine**	4x18 MW Sapugaskanda diesel	0.121
2020	*31 MW Moragolla HPP* **15 MW Thalpitigala HPP****	**1x250 MW Coal Power Plants Trincomalee Power Company Limited**	4x15 MW CEB Barge Power Plant 6x5 MW Northern Power	0.043
2021	-	-	-	0.056
2022	**20 MW Seethawaka HPP***** **20 MW Gin Ganga HPP****	**1x250 MW Coal Power Plants Trincomalee Power Company Limited**	-	0.011
2023	-	*163 MW Combined Cycle Plant (KPS – 2)*+	163 MW AES Kelanitissa Combined Cycle Plant+ 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.036
2024	-	-	-	0.059
2025	-	-	4x9 MW Sapugaskanda Diesel Ext.	0.155
2026	-	**1x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.042
2027	-	-	-	0.109
2028	-	**1x300 MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.046
2029	-	-	-	0.134
2030	-	**1x300 MW New Coal plant – Southern Region**	-	0.059
2031	-	-	-	0.197
2032	-	**1x300 MW New Coal plant – Southern Region**	-	0.105
2033	**1x200 MW PSPP*****	**1x300 MW New Coal plant – Trincomalee -2, Phase - II**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS – 2)	0.115
2034	**1x200 MW PSPP*****	-	-	0.095
Total PV Cost up to year 2034, **US$ 10,759.16 million** [LKR 1,415.37 billion]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2015 (US$ 1 = LKR. 131.55)
- PV cost includes the cost of Projected Committed NCRE, US$ **1320.2 million** based on economic cost, cost for Demand Side Management activities given by SEA, US$ 892.93 million, and additional 10% Spinning Reserve requirement from NCRE capacity is kept considering the intermittency of NCRE plants with a cost of US$ **138.7 million.**

** Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

*** Seethawaka HPP and PSPP units are forced in 2022, 2033 and 2034 respectively.

\+ IPP AES Kelanitissa scheduled to retire in 2023 will be operated as a CEB power plant from 2023 to 2033.

- Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.
- Mannar Wind & other NCRE addition capacities as per the Annex 5.2, throughout the planning horizon

Annex 10.1

Actual Generation Expansions and the Plans from 2000-2015

Year	Actual expansions	1989-2002	1991-2005	1992-2006	1993-2007	1994-2008	1995-2009	1996-2010	1998-2012	1999-2013	2000-2014	2002-2016	2003-2017	2005-2019	2006-2020	2008-2022	2011-2025	2013-2032
2000	40-DS	150-CO	64-UPK 40-DS 22-GT	-	150-CO 123-UPK	123-UPK	70-KUK	150-CCY	105-GT 50-CCY	40-DS 60-Col	60-Col	-	-	-	-	-	-	-
2001	60-Col	300-CO 136-CC	40-BDL 60-DS 44-GT	150-CO	150-CO	150-CO	150-CO 150-UPK	-	300-CCY	100-CCY 150-CCY	40-DS	-	-	-	-	-	-	-
2002	20-ACE	300-CO	49-GIN 22-GT	150-CO	300-CO	150-CO	22-GT	150-CO 70-KUK	70-KUK	50-CCY	100-CCY 100-AES	20-ACE 109-AES	-	-	-	-	-	-
2003	20-ACE 165-CCY	-	150-CO	60-GT (Refurbish)	60-GT (Refurbish)	60-GT (Refurbish)	150-CO 60-GT (Refurbish)	150-CO 60-GT (Refurbish)	-	70-KUK 150-CCY	50-CCY 50-AES	61-CCY 54-AES 20-ACE 22-DS	20-ACE	-	-	-	-	-
2004	70-KUK 163-AES	-	150-CO	150-CO 60-GT (Refurbish)	300-CO 60-GT (Refurbish)	300-CO 60-GT (Refurbish)	60-GT (Refurbish)	300-CO 60-GT (Refurbish)	300-CO	300-CO	70-KUK 150-CCY	70-KUK	70-KUK 163-AES	-	-	-	-	-
2005	100-HLV 100-ACE	-	22-GT	300-CO	44-GT	-	300-CO	-	105-GT	-	-	300-CCY	200-DS	100-HLV 100-ACE	-	-	-	-
2006	-	-	-	-	49-GIN 44-GT 68-CCY	22-GT 49-GIN	-	300-CCY	300-CO	150-UPK	300-CO	-	300-CCY	-	-	-	-	-
2007	-	-	-	-	150-CO 22-GT	300-CO	300-CO	-	-	-	150-UPK	105-GT	-	200-GT PART	-	-	-	-
2008	-	-	-	-	-	66-GT	49-GIN	300-CO	300-CO	300-CO	300-CO	150-UPK 300-CO	300-CO	100-ST PART 105-GT	200-GT PART	-	-	-
2009	-	-	-	-	-	-	300-TRNC	300-CO	300-TRNC	105-GT	35-GT	-	150-UPK	140-GT	100-ST PART 2*105-GT 35-GT	200-GT PART	-	-
2010	270-WC CCY	-	-	-	-	-	-	300-CO	105-GT	300-CO	300-CO	300-CO	-	300-CO 150-UPK	75-GT 2*105-GT	300-CCY 200-GS	-	-
2011	285-PUT	-	-	-	-	-	-	-	300-TRNC	-	300-TRNC	-	300-CO	300-CO	2*300-CO 150-UPK	325-GT	285-PUT	-
2012	150-UPK	-	-	-	-	-	-	-	210-GT	300-TRNC	105-GT	300-CO	300-CO	300-CO	300-CO	285-PUT 150-UPK	75-GT 150-UPK	-
2013	-	-	-	-	-	-	-	-	-	105-GT 10-DS	300-TRNC	300-TRNC	105-GT	300-CO	300-CO	285-PUT(ST2) 2*250-TRNC	20-Northern 24-CPE 35-GT	-
2014	2*285-PUT 20-Northern 24-CPE	_	_	_	_	_	_	_	_	_	210-GT	_	300-CO	300-CO	300-CO	285-PUT(ST2)	2*285-PUT	20-Northern 24-CPE 285-PUT
2015	_	_	_	_	_	_	_	_	_	_	_	300-TRNC	300-CO 210-GT	285-GT	300-CO	2*250-TRNC 300-CO	35-BDL 120-Uma Oya 49-GIN	285-PUT 3*75-GT
2016	_	_	_	_	_	_	_	_	_	_	_	175-GT	300-CO	300-CO	300-CO	300-CO	_	35-BDL 120-Uma Oya
2017	_	_	_	_	_	_	_	_	_	_		_	210-GT	300-CO	300-CO	300-CO	2*250-TRNC	105-GT
2018	_	_	_	_	_	_	_	_	_	_	_	_	_	300-CO 180-GT	300-CO	300-CO	250-TRNC	27-Moragolla 2*250-TRNC
2019	_	_	_	_	_	_	_	_	_	_	_	_	_	420-GT	300-CO	300-CO	250-TRNC	2*300-CO
2020	_	_	_	_	_	_	_	_	_	_	_	_	_	_	105-GT 300-CO	300-CO	_	_

Note: NCRE Plants are not indicated

KUK – Kukule hydro power station, BDL – Broadlands hydro power station, UPK – Upper Kotmale hydro power station, GIN – Gin ganga hydro power station, MAD – Madulu oya hydro power station

ST – Steam plant, DS – Diesel plant, CPE-Chunnakum Power Extension, CCY – Combined cycle plant, CO – Coal fired steam plant, GT – Gas turbine, LKV – Lakdanavi power plant, Asia – Asia power plant, Col – Colombo power plant, ACE – ACE power plant,HLV-Heladanavi power station, TRNC-Trinco Coal Power Plant, Northern-Northern power plant, PUT-Puttalam Coal Power Plant