CEYLON ELECTRICITY BOARD

LONG TERM GENERATION EXPANSION PLAN

2023-2042

(Draft)

Transmission and Generation Planning Branch
Transmission Division
Ceylon Electricity Board
Sri Lanka
September 2022

Long Term Generation Expansion Planning Studies
2023- 2042

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 biennial 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.

Foreword

The Report on 'Long Term Generation Expansion Planning Studies 2023-2042', 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 2023-2042, and replaces the Long Term Generation Expansion Plan 2022-2041.

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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Transmission and Generation Planning Branch
5th Floor, Head Office Bldg.
Ceylon Electricity Board
Sir Chittampalam A. Gardinar Mw.
Colombo 02

Letters:
Tr. and Generation Planning Branch
5th Floor, Ceylon Electricity Board
P.O. Box 540
Colombo, Sri Lanka

e-mail : cegptgp.tr@ceb.lk
Tel : +94-11-2329812
Fax : +94-11-2434866

Prepared by:

Mr. V.B. Wijekoon
Chief Engineer (Generation Planning)

Electrical Engineers

Mr. R.B. Wijekoon
Mrs. D.C. Hapuarachchi
Mrs. M.D.V. Fernando
Mr. K.H.A. Kaushalya
Mr. K.A.M.N. Pathiratne
Mrs. G.R.A.P. Weerasinghe

Reviewed by:

Mr. P.W. Hendahewa
Additional General Manager (Transmission Non-Wired Operations)

Mr. G.J. Aluthge
Former Additional General Manager (Transmission)

Mr. M.L. Weerasinghe
Deputy General Manager (Transmission & Generation Planning)

Any clarifications sought or request for copies of the report should be sent to the Deputy General Manager (Transmission and Generation Planning) at the address above.

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ACRONYMS

ADB	-	Asian Development Bank
API	-	Argus/McCloskey's Coal price Index
bcf	-	Billion Cubic Feet
BESS	-	Battery Energy Storage System
BOO	-	Build, Own and Operate
BOOT	-	Build, Own, Operate and Transfer
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
CDM	-	Clean Development Mechanism
CER	-	Certified Emission Reduction
COP	-	Conference of Parties
CPC	-	Ceylon Petroleum Cooperation
DSM	-	Demand Side Management
EIA	-	Environmental Impact Assessment
ENS	-	Energy Not Served
EOI	-	Expression of Interest
ESP	-	Electrostatic Precipitator
FACTS	-	Flexible Alternating Current Transmission System
FGD	-	Flue Gas Desulphurization
FO	-	Furnace Oil
FOB	-	Free On Board
FOR	-	Forced Outage Rate
FSRU	-	Floating Storage Regasification Unit
GCV	-	Gross Calorific Value
GDP	-	Gross Domestic Product
GHG	-	Green House Gases
GIS	-	Geographic Information System
GT	-	Gas Turbine
HHV	-	Higher Heating Value
HVDC	-	High Voltage Direct Current
IAEA	-	International Atomic Energy Agency
IC	-	Internal Combustion
IDC	-	Interest During Construction
IEA	-	International Energy Agency
IMF	-	International Monetary Fund
INDC	-	Intended Nationally Determined Contributions
IPCC	-	Inter-Governmental Panel on Climate Change
IPP	-	Independent Power Producer

JBIC	-	Japan Bank for International Cooperation
JCC	-	Japan Crude Oil Cocktail
JICA	-	Japan International Cooperation Agency
JKM	-	Japanese Korean Marker
LKR	-	Sri Lanka Rupees
KPS	-	Kelanithissa Power Station
LCC	-	Line Commutated Converter
LCOE	-	Levelised Cost of Electricity
LDC	-	Load Duration Curve
LF	-	Load Factor
LNG	-	Liquefied Natural Gas
LOLP	-	Loss of Load Probability
LPG	-	Liquefied Petroleum Gas
LTGEP	-	Long Term Generation Expansion Plan
MAED	-	The Model for Analysis of Energy Demand
masl	-	Meters Above Sea Level
MMBTU	-	Million British Thermal Units
MMSCFD	-	Million Standard Cubic Feet per Day
MTPA	-	Million Tons Per Annum
NDC	-	Nationally Determined Contributions
NEPS	-	National Energy Policy and Strategy
NG	-	Natural Gas
NPP	-	Nuclear Power Plant
OECD	-	Organization for Economic Co-operation and Development
OECF	-	Overseas Economic Co-operation Fund
ORE	-	Other Renewable Energy
OTEC	-	Ocean Thermal Energy Conversion
O&M	-	Operation and Maintenance
PF	-	Plant Factor
PM	-	Particulate Matter
PPA	-	Power Purchase Agreement
PRDS	-	Petroleum Resources Development Secretariat
PSPP	-	Pumped Storage Power Plant
PUCSL	-	Public Utilities Commission of Sri Lanka
PV	-	Photovoltaic
RE	-	Renewable Energy
RFP	-	Request For Proposals
SAM	-	System Advisor Model
SCR	-	Selective Catalytic Reduction
SDDP	-	Stochastic Dual Dynamic Programming
SNSP	-	System Non Synchronous Penetration
SPPA	-	Standardized Power Purchase Agreement
ST	-	Steam Turbine
STATCOM	-	Static Synchronous Compensator
TC	-	Technical Cooperation
tcf	-	Trillion Cubic Feet
UNFCCC	-	United Nations Framework Convention on Climate Change

USAID	-	United States Agency for International Development
USD	-	American Dollars
WB	-	World Bank
WHO	-	World Health Organization
VRE	-	Variable Renewable Energy
VSC	-	Voltage Source Converter

INTRODUCTION

The Long-Term Generation Expansion Plan (named as "Least Cost Long Term Generation Expansion Plan" in the Sri Lanka Electricity Act), is a biennial publication prepared by Ceylon Electricity Board, which outlines the generating capacity requirement of the power sector during the two decades ahead, to realise a secure, reliable, economical and sustainable supply of electricity, while adhering to the government policies and environmental obligations of the country. The Long-Term Generation Expansion Plan (LTGEP) covers a planning horizon of 20 years.

LTGEP 2023-2042 presents result of the generation expansion planning studies carried out by the Transmission and Generation Planning Branch of the Ceylon Electricity Board for the period 2023-2042. The report also includes information on the existing generation system, the generation planning methodology, system demand forecast and the investment requirement and implementation plans for the proposed projects. Out of different possible scenarios, the plan recommends the adoption of the most justifiable generation mix for the future (titled the "Base Case" plan) that also comply with the government policy pertaining to the electricity industry. This report also contains results of contingency analysis to prepare for possible contingency events (that are not captured in the Base Case) but having a likelihood to occur in the near term. Key actions required and recommendations are separately presented at the end of this executive summary.

Even though long-term generation plans are to be prepared once in two years, this LTGEP 2023-2042 is the second long term generation plan prepared within a year to meet the request of the Public Utilities Commission of Sri Lanka (PUCSL) as contained in their letter dated 5th October 2021 granting approval to last LTGEP (for the period 2022-2041), that a new generation plan be prepared in alignment with the new government policy. The new government policy was formally issued in January 2022.

LATEST GOVERNMENT POLICY GUIDELINES

As stipulated in the Generation Planning Code (which is a part of the Grid Code), it is mandatory to follow the applicable government policy (which is as issued under Section 5 of Sri Lanka Electricity Act. No, 20 of 2009) when conducting planning studies. The current policy for the electricity industry is contained in the document "The General Policy Guidelines in Respect of the Electricity Industry" as approved by the Cabinet of Ministers in November 2021 and issued by the Ministry of Power in January 2022. The government policy contains 04 clauses that are directly related to the future generating mix as proposed in this LTGEP report. The energy mix proposed through the Base Case Plan of LTGEP 2023-2042 is in alignment to all such policy requirements as indicated below.

1. Achieve 70% of electricity generation in the country using renewable energy (RE) sources by 2030
2. Achieve carbon neutrality in power generation by 2050
3. Cease building of new coal-fired power plants
4. New addition of firm capacity will be from clean energy sources such as regasified liquefied natural gas (RLNG)

This latest general policy guidelines has to be read together with the National Energy Policy and Strategies of Sri Lanka published in 2019.

PLANNING APPROACH

CEB's long term planning approach throughout has been to conduct studies[1] in advance to explore different technological and fuel options available to be considered during planning studies, and to include them to long term generation expansion plans when the time is right, technologically and economically to make the choice.

Previously, the planning strategy has been to plan first with conventional firm generating technologies[2] (thermal and storage hydro) that gives out firm power generating capacity to meet planning criteria (reliability and economics), and to supplement firm capacity with non-conventional renewable energy sources (also termed other renewable energy sources – ORE) that are non-firm, and mostly consisting of inverter based technologies such as wind and solar. In addition, cost of ORE technology based generating sources were high in the past compared to conventional technologies (thermal and storage hydro). As a result, widescale adoption of ORE sources were not facilitated via older generation plans. They were included then mainly to maintain the required diversity and to enhance the share of indigenous technologies, and were used only to supplement conventional firm power generating sources. However, since when ORE costs started falling rapidly due to falling costs worldwide, successive generation plans progressively increased the share of ORE. With the General Policy Guidelines of the Government issued in April 2019, the policy itself suggested a renewable energy target of 50% to be met by 2030. This target was further enhanced to 70% with the 2022 policy. This policy target had effectively taken off subjecting renewable energy sources for any optimisation (as normally done during generation planning). Instead, Renewable energy (RE) is now forced to plans

[1] Following studies are referred: Study for Energy Diversification Enhancement by Introducing LNG Operated Power Generation Option in Sri Lanka 2010, Energy Diversification and Enhancement Project Phase IIA- Feasibility Study for Introducing LNG to Sri Lanka 2014, Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka 2014, Feasibility Study on High Efficiency and Eco-friendly Coal-fired Thermal Power Plant in Sri Lanka 2015, Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka 2018.

[2] Firm generating technologies are those that can provide a firm, non-varying power output at their generating terminals at the level requested by the system operators. Storage hydro power, conventional thermal technologies fall under this category. ORE technologies such as wind and solar outputs vary depending on the resource availability and are unable to be started/stopped, power output raised/lowered on the dispatch instructions of system operators and hence termed non-firm.

as a policy directive; and whatever optimization possible is done within very limited remaining space constrained by policy, (which itself stipulates the preferred fuel for thermal generation and had prohibited considering Coal as a fuel).

Planning approach now is mainly revolved around facilitating the absorption of a high percentage of renewable energy forced now by policy to the system. The basic strategy adopted in the plan to progress for such high renewable target is presented in Figure E1, where gradual increase in RE share during the horizon and the interventions facilitated the RE share increase are indicated in graphical form.

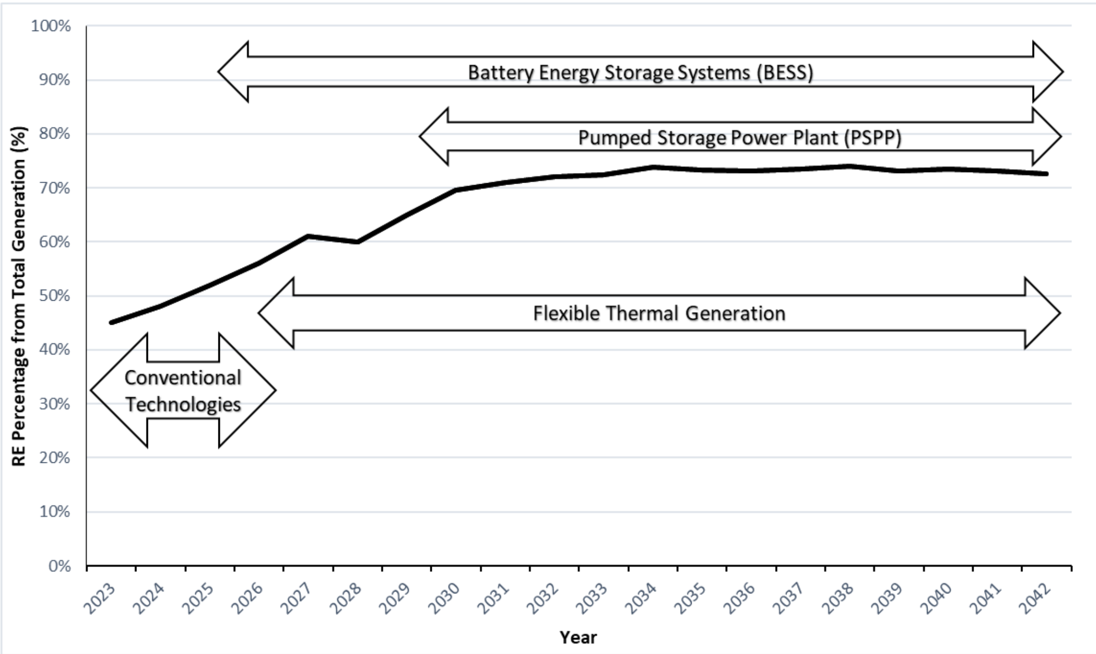


Figure E1 –Achieving 70% RE Target and Proposed Enabling Interventions in Base Case

RESULTS OF THE PLANNING STUDIES

CHANGING ROLES OF FIRM AND NON-FIRM TECHNOLOGIES

The traditional planning approach has been to plan for a sufficient firm generating capacity to meet the demand for electricity and to meet other technical and reliability requirements of the system and, after developing such firm capacity generating base, absorb ORE based generation to the optimum level to supplement firm capacity to maintain other planning considerations such as fuel diversity and economics. However, with the two recent most policy guidelines of the government, CEB was given a renewable energy based generation target to be achieved by year 2030 by the policy itself. As RE share by 2030 is stipulated within the policy document itself, deciding the optimum RE/thermal mix via planning studies had to be replaced by taking the mix declared in the policies directly as input. Accordingly, the 2030 RE milestone target of 70% is now forced in to the plan as input, and the planning studies were conducted to decide the firm capacity and grid support interventions that are required to accommodate the policy target and to address the ensuing technical impacts instead.

However, a minimal synchronous penetration limit has been ensured during operations at all times to maintain the integrity of the generating system.

FLEXIBLE THERMAL GENERATION

The plan proposes natural gas fired Internal Combustion (IC) Engine power plants and Gas Turbine (GT) power plants (simple cycle operation) instead of new Combined Cycle power plants throughout the planning window, except in 2041. These plants provide operational flexibility required to integrate higher proportion of RE. IC engine plants support quick ramping up and ramping down which is a requirement in a system having high amount of variable renewable energy sources. Gas Turbines mainly play the role of peaker plants while providing ancillary services such as frequency regulation capability, maintaining system inertia, etc. IC engine fleet, with their fast start up capability, is also expected to reduce spinning reserve requirement. It is claimed that the latest natural gas driven thermal plants could be configured to operate on blended hydrogen (hydrogen mixed with Natural Gas). With the advancement to technology, such improvements would facilitate the country to progress to carbon neutrality by 2050.

Additionally, the plan also demands all future combined cycle power plants (including the two under procurement), to be *"technically, operationally and contractually capable of being operated regularly between simple cycle and combined cycle operations"*. This is to provide operational flexibility, particularly when solar generation is high.

GRID SUPPORT INTERVENTIONS TO FACILITATE RENEWABLE ENERGY

As demonstrated in Figure E1, reaching 70% RE target by 2030 and maintaining it beyond requires numerous interventions from long term planning perspective to be included in the plan. Apart from introducing flexible thermal generation, the plan also identifies other grid support interventions listed below:

- Implementation of Utility Scale Battery Energy Storage Systems (BESS) primarily for energy shifting purpose which is essential in order to accommodate high level of variable renewable energy in the system. Furthermore, BESS shall be required to provide other ancillary services such as fast frequency response and frequency regulation. BESS are proposed to be developed as standalone systems as well as integrated solutions coupled with large scale fully facilitated solar PV parks. Detailed discussion on the requirement of BESS is presented in Chapter 9 of this report.

- Implementation of Pumped Storage Power Plant (PSPP), which essentially acts as an energy storage providing the same services as BESS. Due to the longer implementation timeline, BESS are introduced in the initial stages of the planning horizon while PSPP is introduced from 2029 onwards in phase development.

- Early introduction of a "Renewable Energy Desk" to the system control centre is mandatory with controlling and monitoring facilities to separately manage RE capacities that are going to be integrated in large proportions. Introduction of solar and wind forecasting too is essential to go with the RE Desk.
- Introduction of demand response schemes and incentives/dis incentives to avoid peak times such as Time of Use (TOU) tariff for all consumer categories, attraction of industries (under preferential tariffs) having flexible loads whose control can be extend to National Control Centre for operations.
- Carrying out necessary amendments to the Grid Code and include requirements for Inverter based generating technologies.

FUEL DIVERSITY

Recommended Base Case scenario of this report facilitates large-scale introduction of renewable energy sources and introduction of natural gas based generation in place of coal, complying with the general policy guidelines. However, with such heavy dependency now placed on natural gas, the strategic diversity in the fuel supply needs to be separately ensured to protect electricity supply against internal and external vulnerabilities in LNG supply chains. The plan recommends that " *all-Natural Gas based power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply*". Furthermore, the LNG procurement contracts should be negotiated to minimize the 'Take or Pay' risks.

DEVELOPMENT OF THE BASE CASE PLAN

DEMAND FORECAST

Electricity demand for the period of 2023-2047 was forecasted considering a combination of medium term and long-term forecasting approaches. Five-year sales forecast of CEB Distribution Divisions and LECO, and time trend approach were used to determine the medium-term forecast. Econometric approach was used for long term forecast. The recovery of the electricity demand growth rate after the impact of the Covid-19 pandemic to the economy has been considered in preparing the forecast.

Table E1 - Base Demand Forecast 2023-2047

Year	Demand		Net Loss*	Net Generation		Peak Demand
	(GWh)	Growth Rate (%)	(%)	(GWh)	Growth Rate (%)	(MW)
2023	16,741	6.4%	7.95	18,186	6.4%	3,021
2024	17,705	5.8%	7.89	19,222	5.7%	3,149
2025	18,725	5.8%	7.83	20,317	5.7%	3,283
2026 **	19,854	6.0%	7.77	21,526	6.0%	3,432
2027	21,124	6.4%	7.70	22,886	6.3%	3,651
2028	22,419	6.1%	7.63	24,272	6.1%	3,890
2029	23,794	6.1%	7.57	25,741	6.1%	4,127
2030	25,253	6.1%	7.50	27,300	6.1%	4,378
2031	26,801	6.1%	7.45	28,958	6.1%	4,645
2032	28,165	5.1%	7.40	30,415	5.0%	4,880
2033	29,601	5.1%	7.35	31,949	5.0%	5,127
2034	31,099	5.1%	7.30	33,548	5.0%	5,385
2035	32,646	5.0%	7.25	35,198	4.9%	5,652
2036	34,241	4.9%	7.25	36,917	4.9%	5,929
2037	35,879	4.8%	7.25	38,684	4.8%	6,214
2038	37,547	4.6%	7.25	40,482	4.6%	6,504
2039	39,253	4.5%	7.25	42,321	4.5%	6,801
2040	41,002	4.5%	7.25	44,207	4.5%	7,106
2041	42,777	4.3%	7.25	46,120	4.3%	7,415
2042	44,584	4.2%	7.25	48,070	4.2%	7,730
2043	46,431	4.1%	7.25	50,061	4.1%	8,051
2044	48,321	4.1%	7.25	52,098	4.1%	8,380
2045	50,259	4.0%	7.25	54,188	4.0%	8,718
2046	52,248	4.0%	7.25	56,332	4.0%	9,064
2047	54,315	4.0%	7.25	58,560	4.0%	9,426
5 Year Average Growth	6.0%			5.9%		4.8%
10 Year Average Growth	6.0%			5.9%		5.5%
20 Year Average Growth	5.3%			5.2%		5.1%
25 Year Average Growth	5.0%			5.0%		4.9%

In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.

* Net losses include losses at the Transmission & Distribution levels. Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depending on the renewable thermal generation mix of the future

** It is expected that day peak would surpass the night peak from this year onwards

Demand for electricity in the country has been growing at an average rate of about 4.4 % per annum during the last fifteen years, while peak demand has been growing at a rate of 3.0 % per annum on average. During year 2020 demand contracted (by 2%, 300 GWh compared to 2019) due to COVID 19 pandemic, but during year 2021 it recovered back to a certain extent indicating a 6.5% growth rate. As per demand projections, the growth is expected to continue at an average rate of 5.3% in the long run. The changes in daily electricity demand pattern reveals the trend of the day time demand is becoming prominent and is anticipated to surpass the night peak and become the dominant peak beyond 2026.

SCENARIOS CONSIDERED IN PLANNING STUDIES

To identify Base Case plan for LTGEP 2023-2042, four specific scenarios were developed within the guidelines specified in the general policy guidelines. The four scenarios developed were:

1. Scenario 1: Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030 and no coal fired plant additions throughout the horizon
2. Scenario 2: Achieving 70 % RE by 2030, attempt to further increasing RE share up to 80% by 2040 and no coal fired plant additions throughout the horizon
3. Scenario 3: Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030, no coal fired plant additions throughout the horizon and considering cross border interconnection with India
4. Scenario 4: Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030, no coal fired plant additions throughout the horizon and considering nuclear power development beyond 2040

All of the above scenarios complied with the general policy guidelines, but Scenario 2, 3 and 4 were specifically developed to evaluate alternative pathways to achieve carbon neutrality in electricity generation by 2050. However, in Scenario 2 significant limitations in achieving 80% RE share by 2040 were observed, especially due to RE spillage reaching uneconomical levels that obstructs RE share reaching 80%. Detailed discussion of all the scenarios is presented in Chapter 10 of this report.

After evaluation of all aforementioned scenarios, Scenario 1 was selected as the Base Case plan as it indicated the lowest present value (PV) cost among the above four scenarios and was technically feasible.

In addition, following scenarios were developed to analyse technical and economic implications of complying with the policy guidelines and to ultimately identify the least cost scenarios unconstrained by policy guidelines.

5. Scenario 5: Achieving 50 % RE by 2030, maintaining 50% RE beyond 2030 and no coal fired plant additions beyond 2030
6. Scenario 6: Achieving 60 % RE by 2030, maintaining 60% RE beyond 2030 and no coal fired plant additions beyond 2030
7. Scenario 7: Achieving 60 % RE by 2030, maintaining 60% RE beyond 2030 and no coal fired plant additions throughout the horizon.

All Scenarios 5, 6 and 7 indicated lower present value cost than the existing policy-based scenarios and Scenario 6 indicated the lowest cost among all six scenarios. Therefore, Scenario 6 was identified as the Reference Case of LTGEP 2023-2042 as it indicated the lowest present value cost unconstrained by policy guidelines and, operationally feasible.

The Table E2 below present the comparison of the long term expansion planning scenarios considered in this LTGEP 2023-2042.

Table E2. Summary of Planning Scenarios and Present Value cost

	Total Present Value Cost (MUSD)	Difference of Present Value Cost compared to Reference scenario (MUSD)
Scenario 1 (Base Case) *70% RE by 2030 and maintaining the same beyond 2030,* *No coal additions in the planning horizon*	18,872	1,365
Scenario 2 *70% RE by 2030 and attempt to reach 80% RE by 2040* *No coal additions in the planning horizon*	*Note 1*	
Scenario 3 *70% RE by 2030 and cross border interconnection with India* *No coal additions in the planning horizon*	18,883	1,376
Scenario 4 *70% RE by 2030 and nuclear power development beyond 2040* *No coal additions in the planning horizon*	18,986	1,479
Scenario 5 *50% RE by 2030 and maintaining the same beyond 2030* *No coal additions beyond 2030*	17,792	285
Scenario 6 (Reference Case) *60% RE by 2030 and maintaining the same beyond 2030* *No coal additions beyond 2030*	17,507	-
Scenario 7 *60% RE by 2030 and maintaining the same beyond 2030* *No coal additions in the planning horizon*	17,855	348

Note 1: The objective of increasing renewable energy share above 70% beyond the year 2030 is not achieved through conventional storage solutions and shall be further evaluated in subsequent planning studies in order to specify cost for the scenario.

The Table E3 below presents the power plant schedule of the base case plan considered in this LTGEP 2023-2042.

Table E3: Proposed Base Case 2023-2042

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [a][b]		THERMAL CAPACITY ADDITIONS and RETIREMENTS [a][c]	
2022	**Uma Oya Hydropower Plant**	**120 MW**		
	Distribution Connected Embedded Solar	160 MW		
	Grid Connected Partially Facilitated Solar	**94 MW**		
	Mini Hydro	20 MW		
	Biomass	10 MW		
2023	Distribution Connected Embedded Solar	160 MW	**Gas Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)**	**235 MW**
	Grid Connected Partially Facilitated Solar [1]	**147 MW**	Short Term Supplementary Power [2]	320 MW
	Wind	**25 MW**	Combined Cycle Power Plant (KPS–2) [3]	163 MW
	Mini Hydro	20 MW	*Retirement of*	
	Biomass	20 MW	*Sojitz Kelanitissa Combined Cycle Plant [3]*	*(163) MW*
2024	**Moragolla Hydropower Plant**	**31 MW**	**New Gas Turbines – Kelanitissa [4]**	**130 MW**
	Distribution Connected Embedded Solar	160 MW	**Steam Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
	Grid Connected Partially Facilitated Solar [1]	223 MW	**Gas Turbine of Second NG Combined Cycle Plant (Kerawalapitiya)**	**235 MW**
	Grid Connected Fully Facilitated Solar	100 MW		
	Wind	**60 MW**	*Retirement of*	
	Mini Hydro	20 MW	*Kelanitissa Gas Turbines [5]*	*(68) MW*
	Biomass	20 MW	*Short Term Supplementary Power*	*(200) MW*
	Standalone Battery Energy Storage	20 MW/50 MWh		
2025	Distribution Connected Embedded Solar	165 MW	**Steam Turbine of Second NG Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
	Grid Connected Partially Facilitated Solar	80 MW		
	Grid Connected Fully Facilitated Solar	260 MW		
	(With Battery Energy Storage)	100 MW/400 MWh		
	Wind (Mannar)[6]	100 MW	*Retirement of*	
	Wind	100 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW	*CEB Barge Power Plant [7]*	*(62) MW*
2026	Distribution Connected Embedded Solar	170 MW	IC Engine Power Plant -Natural Gas (Western Region)	200 MW
	Grid Connected Partially Facilitated Solar	70 MW		
	Grid Connected Fully Facilitated Solar	260 MW	*Retirement of*	
	(With Battery Energy Storage)	100 MW/400 MWh		
	Wind	290 MW	*Gas Turbine (GT7)[8]*	*(115) MW*
	Mini Hydro	25 MW	*4x17 MW Sapugaskande Diesel*	*(68) MW*
	Biomass	20 MW	*8x9 MW Sapugaskande Diesel Ext*	*(72) MW*
	Standalone Battery Energy Storage	80 MW/320 MWh	*Short Term Supplementary Power*	*(120) MW*
2027	Distribution Connected Embedded Solar	170 MW	Gas Turbine -Natural Gas (Western Region)	100 MW
	Grid Connected Partially Facilitated Solar	50 MW		
	Grid Connected Fully Facilitated Solar	280 MW		
	(With Battery Energy Storage)	100 MW/400MWh		
	Wind	250 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh		
2028	Distribution Connected Embedded Solar	170 MW		
	Grid Connected Partially Facilitated Solar	40 MW		
	Grid Connected Fully Facilitated Solar	310 MW		
	(With Battery Energy Storage)	150 MW/600 MWh		
	Wind	200 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW		
	Standalone Battery Energy Storage	200MW/800 MWh		

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a)(b)]		THERMAL CAPACITY ADDITIONS and RETIREMENTS [(a)(c)]	
2029	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 20 MW 350 MW 150 MW/600 MWh 250 MW 25 MW 20 MW 350 MW		
2030	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 250 MW 125 MW/500MWh 200 MW 10 MW 20 MW 350 MW		
2031	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 250 MW 125 MW/500MWh 200 MW 10 MW 20 MW 350 MW	-	
2032	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 250 MW 125 MW/500MWh 150 MW 10 MW 20 MW 350 MW		
2033	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass	170 MW 30 MW 300 MW 150 MW/600MWh 150 MW 10 MW 20 MW	*Retirement of* *Combined Cycle Plant (KPS)* *Combined Cycle Plant (KPS- 2)* *Uthuru Janani Power Plant*	 *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass	180 MW 30 MW 300 MW 150 MW/600MWh 150 MW 10 MW 20 MW	Gas Turbine -Natural Gas	100 MW
2035	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	180 MW 30 MW 300 MW 125MW/500MWh 150 MW 10 MW 10 MW 50MW/200MWh	Gas Turbine -Natural Gas IC Engine Power Plant -Natural Gas *Retirement of* *West Coast Combined Cycle Power Plant*	100 MW 250 MW *(300) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [a][b]		THERMAL CAPACITY ADDITIONS and RETIREMENTS [a][c]	
2036	Distribution Connected Embedded Solar	190 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100MW/400MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100MW/400MWh		
2037	Distribution Connected Embedded Solar	190 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100MW/400MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100MW/400MWh		
2038	Distribution Connected Embedded Solar	200 MW	IC Engine Power Plant -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100MW/400MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100MW/400MWh		
2039	Distribution Connected Embedded Solar	200 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100 MW/400 MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh		
2040	Distribution Connected Embedded Solar	200 MW	IC Engine Power Plant -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	115 MW/460 MWh		
	Wind	150 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh		
2041	Distribution Connected Embedded Solar	200 MW	Gas Turbine -Natural Gas	100 MW
	Grid Connected Partially Facilitated Solar	20 MW	Combined Cycle Power Plant (Natural Gas)	400 MW
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	125 MW/500 MWh		
	Wind	150 MW	*Retirement of*	
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh	*Lakvijaya Coal Power Plant Unit 1*	*(300) MW*
2042	Distribution Connected Embedded Solar	200 MW		
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	125 MW/500 MWh		
	Wind	150 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	150 MW/600 MWh		

GENERAL NOTES

a. All plant capacities (MW) shown are the Gross Capacities. Committed Power Projects are shown in bold text and retiring projects are shown in italics with their capacity in brackets.

b. Mini-hydro and Biomass annual capacity additions are not restricted to the planned capacities mentioned in the table. Higher capacity additions will be evaluated case by case.

   Thalpitigala and Gin Ganga multipurpose hydropower plants are proposed and developed by Ministry of Irrigation and both these plants are considered as candidate power plants with no specific commissioning years at present.

   The capacity addition of battery energy storage devices is mainly to provide energy shifting requirements. Any additional battery storage capacity could be accommodated at detailed studies after evaluating grid support services requirement such as frequency regulation.

   The retirement years of renewable energy capacities are not indicated. However, after the expiry of the PPA, they are expected to be refurbished or replaced with similar capacity from same renewable energy technology.

   The retirement years of battery energy storage systems are not indicated. However, they are expected to be replaced with similar capacity, at the end of their lifetime.

c. With the development of LNG supply infrastructure, the existing 300MW West Coast power plant and 165MW Kelanithissa combined cycle plant are expected to be converted to natural gas in 2025.

   Considering the heavy dependency in future on liquefied natural gas as a fuel for electricity generation, all Natural Gas based power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply.

   All new natural gas fired power plants should have the capability to operate from synthetic fuels such as Hydrogen, to satisfy the policy requirement of achieving carbon neutrality by 2050.

   All new natural gas based Combined Cycle Power plants should be technically, operationally and contractually capable of being operated regularly between simple cycle and combined cycle operations.

   Dates of all plant additions as contained in the table are the dates considered for planning studies, and considered as added at the beginning (as at 1st January) of the respective year. (For example, a generating capacity addition indicated for year 2026 implies that the plant has been considered commissioned from the 1st of January 2026). However, for committed power projects actual commissioning month has been considered based on the present progress of the project.

   Retirement dates of existing firm capacity plants are dates considered as inputs to planning studies. For existing power plants, the actual retirement month/PPA expiry month were considered for studies. However, the ACTUAL retirement of all power plants is to be made after further evaluating the actual plant condition at the time of retirement, (including the availability of useful operating hours beyond the scheduled retirement date), and the implementation progress of planned power plant additions

d. Broadlands Power Plant (35 MW) which is under test running, is not shown in the base case and is considered as an existing plant.

SPECIFIC NOTES

1. It is possible to advance the absorption of Grid connected partially facilitated solar capacity of 147 MW and 223 MW (planned for 2023, 2024 respectively) by one year each, provided the procurement and commissioning is fast tracked for these projects.

2. Technology of supplementary capacity can be opened for both Gas Turbine and IC engine technology. Fuel option can be specified as appropriate at the time of procurement for suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms.

   Short-term supplementary capacity requirement under different contingency events are assessed in the contingency analysis under chapter 14 of the LCLTGEP 2023-2042 report. Such requirements too shall be appropriately considered prior to initiating procurement.

   Extension of the contracts of existing capacities could be considered as appropriate within the legal framework to meet short term requirement.

3. PPA of Sojitz Kelanitissa is scheduled to be expired in 2023, and to be operated as a CEB owned power plant from 2023 to 2033 after conversion to Natural Gas in 2024. It is indicated as " KPS-2" as a capacity addition.

4. This power plant is required to have the special capability to carry out black starts within its limits in the supply restoration exercise, in case of an island wide power failure.

5. Retirement date of the 4 x 17 MW Kelanitissa Gas Turbines are to coincide with the commissioning of the new 130 MW Gas Turbine Plants at the Kelanitissa to comply with local environmental emission regulations.

6. In addition, Mannar Stage II (100 MW) could be accommodated at an earlier year, if development is carried out on fast track basis provided the plant has semi-dispatchable capability with wind forecasting (as in Mannar Stage I).

7. Decision to extend the retirement year of 4 x 15.6 MW Barge Power Plant until the end of year 2026 will be evaluated based on the cost of any refurbishments required for such an extension and the potential benefit of extending beyond the scheduled retirement year.

8. Retirement year of 115 MW Kelanitissa GT7 is extended until the end of 2025 on the basis of carrying out manufacturer recommended major scheduled maintenance work, along with any other essential maintenance required to keep the plant operational.

MEETING ENVIRONMENTAL AND CLIMATE CHANGE OBLIGATIONS

The 20-year development plan presented in this report meets all the environmental and climate change obligations of Sri Lanka during its 20-year planning horizon. In response to the climate change challenges, Sri Lanka too has taken several initiatives by introducing national policies, strategies and actions to mitigate the impacts. Sri Lanka, being a partner to COP21 Paris agreement on mitigation of global climate change induced impacts, presented its 1st Nationally Determined Contributions (NDC) for the electricity sector in September 2016 to strengthen global efforts, expressing a commitment of 4% unconditional and 16% conditional reduction of GHG emissions compared to the business as usual (BAU) scenario of LTGEP 2013-2032. The country further enhanced its commitments through the updated NDC submission for electricity sector in September 2021, by unconditionally reducing GHG emissions by 5% and conditionally by 20% as compared to the BAU. The base case plan, once fully implemented, expects to reduce the GHG emissions beyond 25% and thus fully capable of meeting the enhanced target.

RENEWABLE CAPACITY ADDITIONS

A significant level of RE capacity additions (especially wind and solar PV) is proposed in this plan throughout the planning horizon and with this accelerated development of RE capacities, replacement of conventional technologies need to be made gradually, and proportionately with the introduction of enabling grid support technologies and measures. Hence the generation mix beyond 2030 is expected to change significantly in favour of RE though cannot be perfectly quantified at this stage. The indigenous renewable energy based generation is to dominate in both capacity and energy terms throughout the planning period with 5,646 MW of capacity additions envisaged by during 2023-2030 period and 8,180 MW during 2031-2042 period.

The total renewable energy capacity is planned to be increased from 2,711 MW as at the beginning of 2022 to 8,783 MW by end of 2030 and to 16,963 MW by end of 2042. After the end of plant life/expiry of the PPA of renewable energy plants, they are expected to be refurbished or replaced with similar capacity from same renewable energy technology. As a result, retirement of renewable plants are not indicated separately. The year-by-year renewable energy capacities in the plan are based on the study titled “Integration of Renewable Based Generation into Sri Lankan Grid 2023-2032” conducted by the Ceylon Electricity Board to investigate the technical and economic implications of renewable energy development dictated by the policy and to study the necessary enabling measures required for the successful renewable energy development program. The scale of wind and solar development envisaged in the LTGEP 2023-2042 will elevate the country to the level of nations having high amount of renewable energy generation and hence along with it, the challenge of operating and maintaining such a system remains.

STORAGE HYDRO

Development of major storage hydro capacity is expected to be limited after completing 31 MW Moragolla hydropower plant which is currently in the pipeline.

SOLAR PV

Capacity of Solar PV, is planned to be increased up to 4,659 MW by end of 2030 from a capacity of 615MW (as at end 2021) under a mix of distribution network embedded, partially facilitated grid connected and fully facilitated grid connected developments. It is planned to increase solar capacity to reach 10,739 MW by end of 2042 and is to account for the largest share in the incremental RE capacity additions. Solar PV is expected to retain its dominant share throughout the 20 year planning period.

WIND

Installed wind capacity is planned to be increased up to 1,723 MW by end of 2030 and is expected to grow beyond 2030 at the same rate. Unlike solar PV, only large scale wind projects are expected to dominate the wind development.

MINI HYDRO, BIO MASS

Moderate growth is expected from Mini-hydro and biomass resources within next twenty years. The plan had not placed any restriction to the mini hydro and biomass capacities to be added. Even though mini hydro is a non-firm technology, outputs of mini hydro and biomass plants are not intermittent to the same extent as solar and wind and hence much "grid friendly" than variable renewable energy (VRE) technologies such as solar and wind. Biomass is not a conventional technology but can be considered a firm generating technology. Thus, no restriction to the development of biomass and mini hydro is placed in this plan and hence such capacities could be developed beyond year-by-year capacities mentioned in the plan subjected to any local grid restrictions, if potential exist.

RENEWABLE ENERGY CURTAILMENT

The higher penetration of renewable energy resources which are seasonal in nature contributes to a larger portion of renewable energy being curtailed. The oversupply of VRE Generation is mitigated to a certain extent from storage solutions, however it cannot be completely avoided. Even after the introduction of storage solutions, renewable energy curtailments can be observed in large scale from year 2026 onwards. These mainly occur during the daytime of Sundays throughout the year and daytime of all days of the week during the high wind season. It is mandatory to establish renewable energy curtailment rules in the grid code, such that downward adjustment of power sources is facilitated in a transparent manner. The commercial conditions related to curtailment is required to be included to relevant power purchase agreements appropriately.

THERMAL CAPACITY ADDITIONS

The plan proposes the development of 3,080 MW of Natural Gas based generation to ensure reliable and economic supply of electricity for the 20-year period. They are to come in different technologies such as Gas Turbines, Combined Cycle plants and Internal Combustion Engine (IC) technologies. Complying with the government policy guidelines, no coal power development has been identified throughout the planning horizon.

1,130 MW capacity additions from open cycle gas turbine power plants and 850 MW from Internal Combustion Engine (IC) based power plants s are to be added during the planning horizon. These additions are predominantly to provide system flexibility that is required when operating with higher shares of renewable sources. Furthermore, 1,100 MW capacity of combined cycle power plants are to be added to the system during the planning horizon, 700MW of which is from the two plants under procurement. The existing combined cycle plants that are operating on diesel/naphtha/furnace oil at present are expected to be converted to natural gas once supply of LNG/NG is established.

All future thermal capacity additions, shall have the fuel flexibility to operate in dual fuel mode, and the provision to operate from synthetic fuels, once the technologies become mature.

GRID SUPPORT TECHNOLOGIES

3,365 MW capacity from battery storage (excluding the capacity required for replacement at their end of lifetime) and a further 1,400 MW capacity from pumped storage hydro are planned to be developed throughout the planning horizon to enhance the flexibility of the electricity system to integrate large amount of variable renewable energy sources such as wind and solar PV.

Pumped storage hydro, that typically has lifespans of over 50 years, is considered a long term grid support solution for the country. Battery too is a rapidly establishing technology at grid scale with declining price trends projected. However, current battery technologies need to be replaced in much shorter cycles of 10-15 years which is one drawback compared to the pumped storage hydro.

RECOMEDATIONS AND ACTIONS TO BE TAKEN

Timely implementation of following is mandatory to ensure adequate, economical and reliable supply of electricity in both near and long term. Following are the main recommendations identified from the long term planning studies that need to be addressed by all the stakeholders of the electricity industry. The detailed description of recommendations is provided in Chapter 12.

1. Completion of committed major hydro power plants on time. (Uma Oya, Moragolla)
2. Expedited development of Other Renewable Energy (Solar, Wind, Mini Hydro and Biomass) in prioritized manner with compliance to interconnection codes.
3. Commissioning of two 350 MW natural gas based combined cycle power plants on time.
4. Commissioning of 130 MW New Kelanithissa gas turbine on time.
5. Conversion of fuel capability to natural gas of Kelanithissa combined cycle power plant, Sojitz Kelanithissa and West Coast power plant
6. Ensuring timely availability of Liquefied Natural Gas (LNG)/Natural Gas (NG) and corresponding Infrastructure and minimizing the contractual risk of fuel supply procurement.
7. Development of flexible thermal generation to complement high VRE integration.
8. Development of Battery Energy Storage System (BESS) on time.
9. Development of Pumped Storage Power Plant (PSPP) on time.
10. Contracting supplementary power in near term for capacity shortages.
11. Development of Distribution network embedded energy resources with Supporting Infrastructure and regulations.
12. Establishment of renewable energy desk with resource forecasting system.
13. Development of critical transmission infrastructure on time.
14. Securing of land and transmission line corridors for power projects.
15. Reviewing the interconnection and operating codes, planning codes, policies and regulations.
16. Introducing demand shifting.
17. Introducing demand response schemes and flexible loads.
18. Exploring the possibilities of cross border electricity trade.
19. Exploring the possibilities of green Hydrogen production, storage and usage.
20. Amending power purchase agreements to have curtailments and seasonal tariff adjustments.
21. Conducting further system strengthening studies on maximum capable SNSP levels and requirements to introduce synchronous condensers.

CHAPTER 1
INTRODUCTION

1.1 Background

Ceylon Electricity Board (CEB), established by CEB Act, No. 17 of 1969 (as amended), has a statutory obligation under section 11 of the CEB Act to "*develop and maintain an efficient, coordinated and economical system of electricity supply for the whole of Sri Lanka*." In order to fulfil this obligation, acquiring of generation capacity has to be planned on economical basis. CEB has been preparing Long Term Generation Expansion Plans for nearly four decades to identify the most economical power generation options. Since power generation and transmission projects have long gestation periods, it is important to identify and commence such development activities early in order to cater to the growing demand for electricity considering the retirement of existing generating assets as well. To reflect the developments required in the network assets with the growing electricity demand, Generation Plans are prepared for a 20 year period ahead. They are also updated once in two years to capture any changes in the electricity sector and changes in the socio-economic landscape of the country.

Once the Long-Term Generation Expansion Plan is finalized, a corresponding Long Term Transmission Development Plan is prepared to identify the developments required in the transmission network and to cater to the growing demand of electricity. As the power flow along the transmission lines is dependent both on the location of power plants and geographical spread of load centres, a Long-Term Transmission Development Plan cannot be prepared unless a corresponding Long term generation Plan is prepared first. Thus, the two activities are to be treated as complimentary.

With the enactment of the Sri Lanka Electricity Act, No. 20 of 2009, the electricity sector was brought under the regulatory purview of the Public Utilities Commission of Sri Lanka (PUCSL), established under the Public Utilities Commission of Sri Lanka Act, No. 35 of 2002 and CEB was issued with a generation license, a transmission license and four distribution licenses. As stated in the Electricity Act No. 20 of 2009, CEB is required to 'e*nsure that there is sufficient capacity from generation plant to meet reasonable forecast demand for electricity'.*

In the Sri Lanka Electricity (Amendment) Act, No. 31 issued in August 2013. CEB, as the Transmission licensee, is required to prepare the Long Term Generation Expansion Plan, (referred to in the Act as Least Cost Long Term Generation Expansion Plan), '*indicating the future electricity generating capacity requirements determined on the basis of least economic cost and meeting the technical and reliability requirements of the electricity network',* and submit the same for the approval of PUCSL [1].

Generation expansion planning studies were carried out in order to develop the Long-Term Generation Expansion Plan as contained in this report. The very first exercise of the planning studies is the preparation of demand forecast, which becomes the base for all analysis. Declared sector policies, most suitable candidate generating technologies, environment and climate concerns, International commitments, etc. were also taken into consideration while preparing the Long-Term Generation Expansion Plan.

A typical generation planning exercise strives to add a balance between three main competing objectives, as illustrated in Figure 1.1

I. The security and reliability of electricity supply
II. Sustainability
III. Economics of supply and affordability

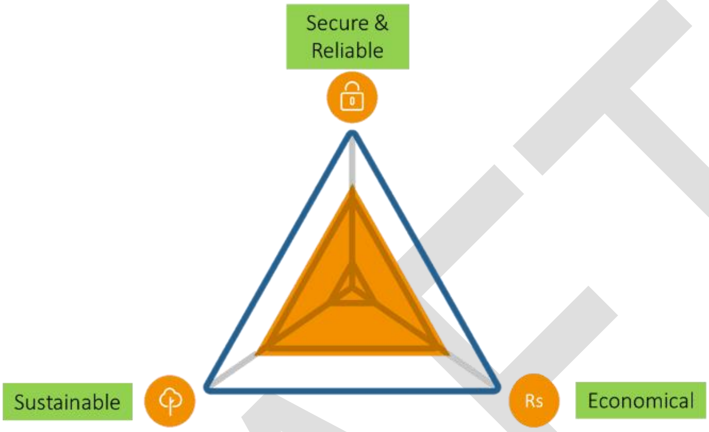


Figure 1.1 – Balance of competing objectives

This generation planning study was conducted to achieve a balance between above three objectives, constrained with the limitations specified by way of policy or through legal and regulatory framework.

The planning studies carried out were based on the reliability criteria as published by the PUCSL in the Government Gazette No 2109/28 dated 2019-02-28 [2], a requirement under section 43(8) of the Electricity Act, and the electricity sector specific government policy applicable as stated under section 5 of the Sri Lanka Electricity Act titled "General Policy Guidelines to be issued by the Minister" [3]. In addition, studies have also considered directions given in the "National Energy Policy and Strategies of Sri Lanka" as published in the Government Gazette No 2135/61 dated 2019-08-09 [4].

A generation planning study typically takes about ten months to complete. Prior to the planning studies, a comprehensive 'Renewable Integration Study' was initiated to foresee the network behaviour with the anticipated addition of relatively high renewable energy share in electricity generation that would reach 70% of total electricity by 2030, as stipulated by the latest General Policy Guideline. This 'Renewable Integration Study' was conducted by a team comprising of engineers from Generation Planning, Transmission Planning, Distribution Planning, System Control, Renewable Energy Development and Research and Development branches of CEB. Results of the study were taken as inputs for preparing this Long Term Generation Expansion Plan 2023-2042.

The planning methodology, planning criteria and policy framework is explained in detail in the chapter 6 of this report. The primary objectives of the generation planning studies conducted by CEB can be summarized into following.

(a) Forecasting of 'National Long Term Electricity Demand' for the next 25 years
(b) Identifying the most suitable generating capacity mix and required grid support interventions to meet the forecasted demand for electricity at lowest economic cost while meeting the reliability requirements and declared sector specific policies of the government as required under law.
(c) Investigating the techno economic feasibility of new alternate generating technologies to expand the generating system
(d) Preparing the capital investment program for the expansion of the generating system
(e) Verifying the robustness of the economically optimum plan by analyzing its sensitivity to changes in the key input parameters.
(f) Conducting scenario analysis to facilitate national level policy making
(g) Conducting contingency analysis to see possible risks in the near term

The data presented in this report has been updated to December 2021 unless otherwise stated. Ongoing project information is updated to the latest information available by April 2022.

1.2 Sri Lanka's Economy

Although Sri Lankan economy has recovered from the contraction recorded in 2020 due to the worldwide impact of Covid-19 pandemic, Sri Lankan economy now is at a fragile state. This was further amplified due to the pressures build up on the exchange rate and depleting of foreign reserves. However, Central Bank of Sri Lanka has forecasted slight growth of Sri Lankan economy in 2022. The economic growth could also affect the forecasts made to electricity demand as contained in this report. Details of some demographic and economic indicators are given in Table 1.1.

Table 1.1- Demographic and Economic Indicators of Sri Lanka

	Units	2017	2018	2019	2020	2021
Mid-Year Population	Millions	21.44	21.67	21.80	21.91	22.15
Population Growth Rate	%	1.1	1.1	0.6	0.5	1.1
GDP Real Growth Rate	%	3.6	3.3	2.3	-3.6	3.7
GDP /Capita (Market prices)	USD	4077	4079	3852	3682	3815
Exchange Rate (Avg.)	LKR/USD	152.46	162.54	178.78	185.52	198.88
GDP Constant 2010 Prices	Mill LKR	9,359,148	9,665,379	9,890,468	9,532,909	9,881,397

Source: Annual Report 2021, Central Bank of Sri Lank

1.2.1 Electricity and Economy

Historical electricity demand growth rate has shown to hold a direct correlation with the growth rate of the country's economy. Figure 1.2 shows the yearly growth rate of electricity demand and that of GDP from 2000 to 2021.

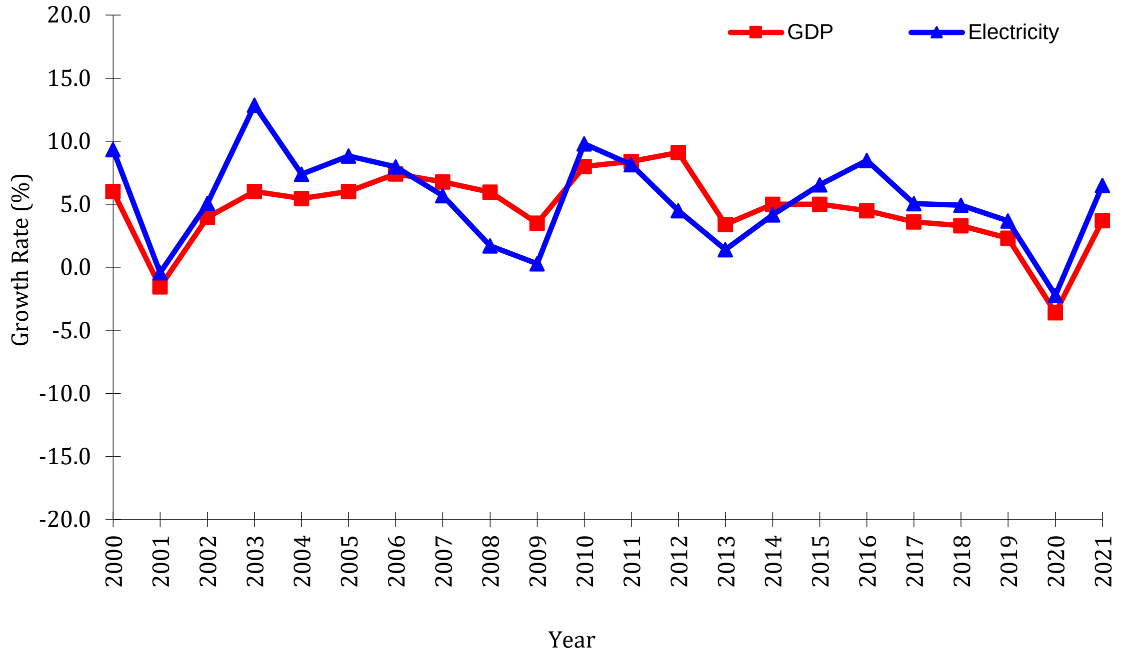


Figure 1.2 - Growth Rates of GDP and Electricity Sales

1.2.2 Economic Projections

The Central Bank of Sri Lanka has forecasted the latest GDP growth rates in real terms for mid and near term, as published in the Annual Report 2019[5], Annual Report 2020[5] and Annual Report 2021[5] as reproduced in Table 1.2.

Table 1.2 - Forecast of GDP Growth Rate in Real Terms

Year	*2021*	*2022*	*2023*	*2024*	*2025*
2019 Forecast	4.5	6.0	6.2	6.5	
2020 Forecast	6.0	5.2	5.8	6.5	7.0
2021 Forecast		1.0	-	-	-

Source: Annual Reports 2019, 2020 and 2021 Central Bank of Sri Lanka

1.3 Sri Lanka's Energy Sector

Overall energy requirement of the country is ensured through primary energy sources such as biomass (fuel wood) and coal, or by secondary sources such as electricity and refined petroleum products. The Energy Flow diagram as published by the Sri Lankan Sustainable Energy Authority is given in Figure 1.3. The energy flow diagram clearly shows the types of primary energy sources entered to the supply chain, their transition to secondary sources such as electricity and finished petroleum products at the middle and how they have ended up at different sectors of the economy.

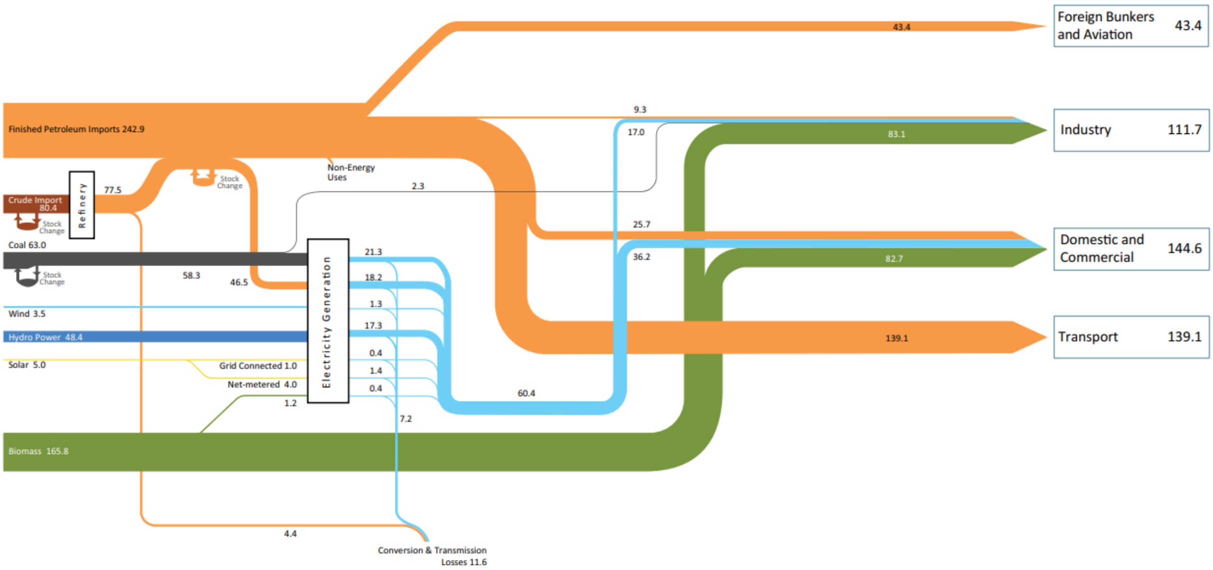


Figure 1.3 – Energy Flow Diagram (2019)

Source: Sri Lanka Sustainable Energy Authority

1.3.1 Energy Supply

The primary energy supply of Sri Lanka is obtained through biomass, petroleum, coal, major hydro and other renewable energy sources. The primary energy supply is dominated by biomass and petroleum.

By end of 2020, petroleum turns out to be the major source of energy supply, which covers a share of 40%. The country's petroleum supply is sourced through direct import of finished products and partly by processing imported crude oil. The only refinery in Sri Lanka, located in Sapugaskanda, converts imported crude oil to refined products to supply approximately half of the petroleum requirement of the country. There are also plans for expanding this refinery capacity.

Apart from this, initiatives have been taken for oil exploration 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 Peninsula). Discoverable gas amount of this reserve is estimated approximately 350 bcf with a potential extraction rate of 70 mscfd. This may even extend beyond the potential of 1.8 tcf with daily extraction rates of 100 mscfd but further exploration should be carried out in order to verify these figures.

Biomass or fuel wood, which is mainly a non-commercial fuel, provided approximately 34% of the country's total energy supply. Biomass is the most widely available source of energy supply in the country. Due to the abundant availability, only a limited portion of the total biomass use is channeled through a commodity market and hence the value of the energy sourced by biomass is not properly accounted.

Coal, which is mainly imported for electricity generation, accounted for 14% of the primary energy supply in year 2020.

Hydro power accounted for 7.8% each from the total primary energy supply in year 2020. Hydropower is the main indigenous source of primary commercial energy in Sri Lanka. Estimated potential of hydro resource is about 2000 MW of which significant portion 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.

Other renewable energy share accounted for 4.2% of total energy supply (wind, solar, biomass, small hydro) in year 2020. There is a considerable potential for wind and solar power development in the country. Steps have been initiated to harness wind and solar potential in Sri Lanka in an optimal manner. The first commercial wind power plants were established in 2010 and the total capacity of wind power plants by end of 2021 was 252 MW. The first large scale wind farm was commissioned in Mannar island in 2020. The first commercial solar power plants were commissioned in year 2016 and the total capacity of commercial solar power plants by end of 2021 was 100 MW and nearly 516 MW of solar roof tops were also connected by end of 2021. Scattered developments of small scale solar power plants have been already initiated and feasibility studies were initiated to develop solar power plants in park concept. A minor portion of the biomass supply is used for power generation thorough dendro, agricultural waste and municipal waste sources.

In 2020 the primary energy supply consisted of Biomass (4108 ktoe), Petroleum (4830 ktoe), Coal (1684 ktoe), Hydro (943 ktoe) and other renewable sources (504 ktoe). The share of these in the gross primary energy supply from 2011 to 2020 is shown in Figure 1.4.

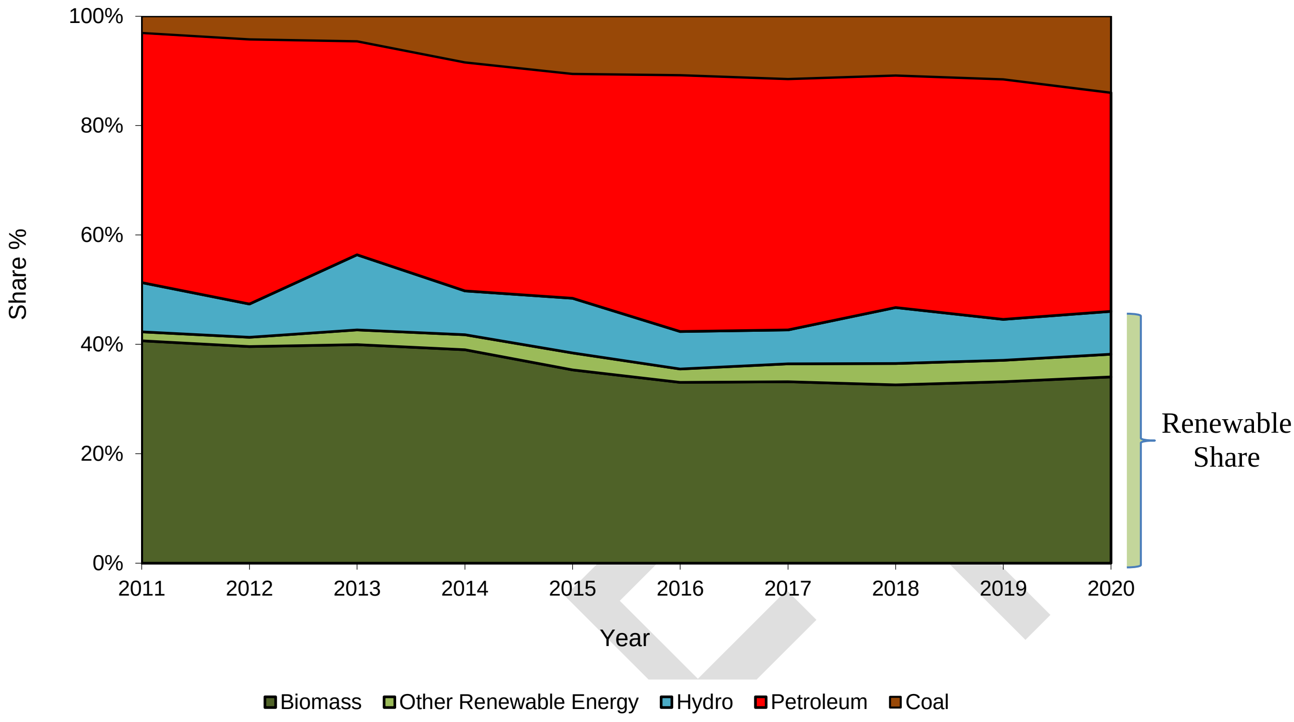


Figure 1.4 - Share of Gross Primary Energy Supply by Source

Source: Sri Lanka Sustainable Energy Authority

1.3.2 Energy Demand

The energy demand is classified based on its energy consumption on Biomass, Petroleum, Electricity and Coal. The largest use of Biomass is in the domestic sector for cooking purposes. The total fossil fuel requirement of the country is for the transport, power generation, industry and other applications. Before commissioning of the coal power plant in Norochcholai, the total demand for coal was only for the industrial sector. But with the commissioning of coal power plants in Norochcholai, 96% of the total coal imports have been used for electricity generation. The total energy consumption by each energy source over the recent past is shown in Table 1.3. The biomass, petroleum and coal usage is shown without considering their usage in the electricity generation.

Table 1.3 – Energy Consumption by Energy Source

Year	Biomass		Petroleum		Electricity		Coal	
	PJ	%	PJ	%	PJ	%	PJ	%
2015	173	46	158.1	42	42.3	11.2	2.3	0.61
2016	166.7	41.9	183.2	46	45.8	11.5	2.1	0.52
2017	163.4	42.4	172.1	44.6	48.3	12.5	1.8	0.48
2018	163.1	42.2	170.0	44	50.8	13.2	2.0	0.51
2019	165.8	41.9	174.3	44	53.2	13.4	2.3	0.58
2020	169.3	44.76	154.8	40.93	52	13.76	2.1	0.55

The main sectors of energy demand can be categorized into industry, transport, household and commercial sector. The sectorial energy consumption trend from 2011 to 2020 is shown in Figure 1.5. Household and commercial sector appear to be the largest sector in terms of energy consumption. However, it is moving through a decreasing trend while the transport sector shows an increasing trend.

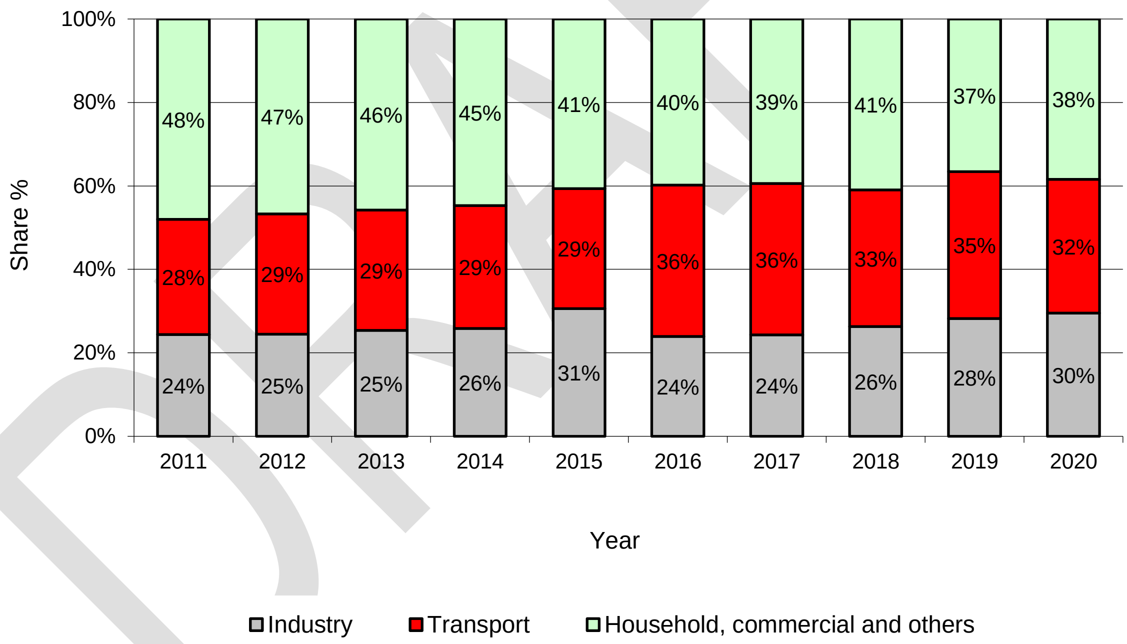


Figure 1.5 - Gross Energy Consumption by Sectors including Non-Commercial Sources

Source: Sri Lanka Sustainable Energy Authority

1.4 Electricity Sector

1.4.1 Global Electricity Sector

The global electricity demand has been growing at an average annual growth rate of approximately 3% during the last two decades. Over the past three decades, worldwide electricity demand has been predominantly supplied by fossil fuel based thermal generation. Contribution from renewable energy was fast expanding, manly driven by the growth in solar PV and Wind resources followed by moderate growths in mini-hydro and biomass generation.

The global electricity demand grew by 6% in 2021 after a small drop in 2020 due to the impact of the Covid-19 pandemic. It was the largest ever annual increase in absolute terms and the largest percentage rise since 2010. Global electricity demand was boosted by a rapid economic recovery. The industrial sector contributed the most to demand growth, followed by the commercial and services sector and the residential sector.

Over the years, coal power generation remained the largest source of electricity generation, contributing to approximately 37% of electricity generated globally. There is an average annual growth of 3% in electricity generated using coal during the past two decades, which is equivalent to the global average annual growth rate for electricity. Natural gas based power generation is the second most predominant energy source at present having a share of 23% out of electricity generated. This share has been increasing from 17% (in 2000) to 23%, (in 2019), with a steady growth during past two decades. In contrast, the global oil based power generation is following a steep decline and the percentage of electricity generation from oil has decreased from 8% (in 2000) to 2.7% (in 2019).

During the same time period the global nuclear power based generation remained at the same level. However, the nuclear energy share has declined from 17% to 10% of total electricity production during past 25 years as the shares of other resources increased. The total renewable energy generation worldwide, including large storage hydro power, has increased from 19% to 27% during the period from 2000-2019. While the hydro energy share has roughly remained constant, the non-hydro renewable share has risen from 1.6% to 10.6%, owing to the rapid growth in solar and wind technologies. The annual electricity produced from solar has risen by 41% in past two decades while wind energy has risen by 22%.

World electricity generation during the last twenty years is summarized in Figure 1.6 and world electricity generation by source as a percentage is shown in Figure 1.7

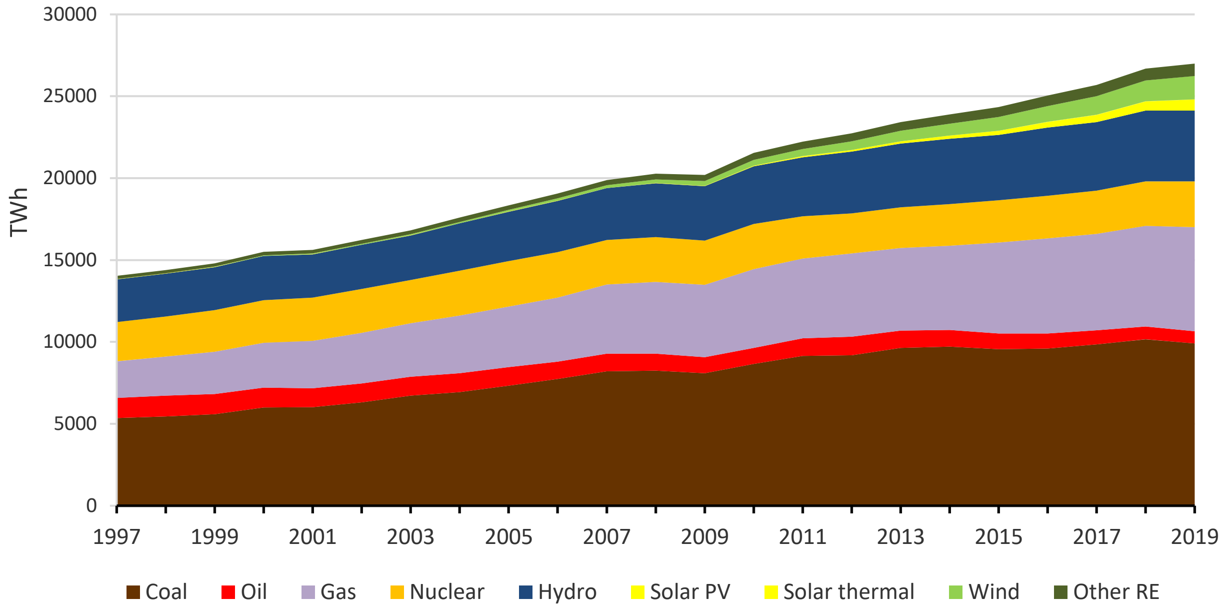


Figure 1.6 – World Electricity Generation (TWh)

Source: International Energy Agency Statistics

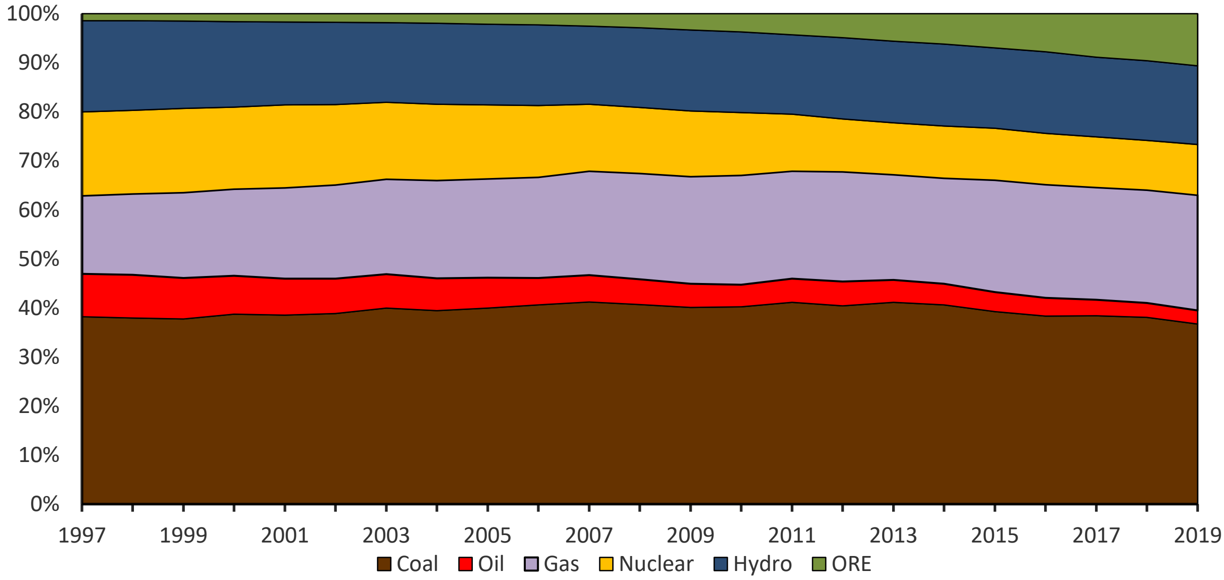


Figure 1.7 – World Electricity Generation by Source as Percentage

Source: International Energy Agency Statistics

1.4.2 Local Electricity Sector

1.4.2.1 Overview

The country's electricity demand has grown at an average rate or 3.2% during last five years. The maximum recorded peak demand was 2802 MW in April 2021. Total net electricity generation in 2021 was 16,716 GWh. At the end of 2021, Sri Lanka had a total installed generating capacity, including rooftop solar, of (approximately) 4,600 MW. This included 2,613 MW of renewable energy based generating capacity and 1,987 MW of thermal capacity.

The renewable energy based generation capacity includes major hydro, mini hydro, solar, wind and biomass technologies and the thermal power generation fleet currently includes reciprocating engines, open cycle and combined cycle turbines and steam plants operated on imported fuel sources of coal and oil. However not all power plants have the capability of providing firm power and hence further sub categorized as dispatchable power plants and non dispatchable power plants. All thermal power plants are capable to operate as dispatchable power plants. The major hydro power plants are dispatchable but with constraints due to hydrological conditions and multipurpose usages while other renewable energy plants are inherently non dispatchable in nature. At present the total dispatchable generation capacity is 3,370 MW while the balance of 1,231 MW from ORE are non dispatchable.

Steps are underway to introduce natural gas to the primary fuel mix in the near future. With the introduction of natural gas, the thermal fuel mix is expected to be diversified even further. Natural gas introduction is through the imported Liquefied Natural Gas (LNG) and establishing the necessary infrastructure is underway. A Floating Storage and Regasification Unit (FSRU) is planned to be established offshore at Kerawalapitiya to provide regasified liquid natural gas to operate power plants at Kerawalapitiya and Kelanithissa.

With the introduction of a very high proportion of renewable energy based generation as included in this report, the fuel mix used for power generation is expected to be further diversified with a major shift from import dependent commercial fuels to indigenous sources.

1.4.2.2 Access to Electricity

The electricity network of Sri Lanka has its transmission and distribution network extended throughout the country, thus providing access to electricity for almost every citizen. The transmission and distribution losses too were brought down gradually from 21.4 % in 2000 to 9.46% in 2021.

The electricity network is required to be expanded continuously to cater to the growing demand for electricity caused by economic growth. In order to facilitate this, grid substations and transmission capacity need to be continuously enhanced and new generating capacity added.

1.4.2.3 Electricity Consumption

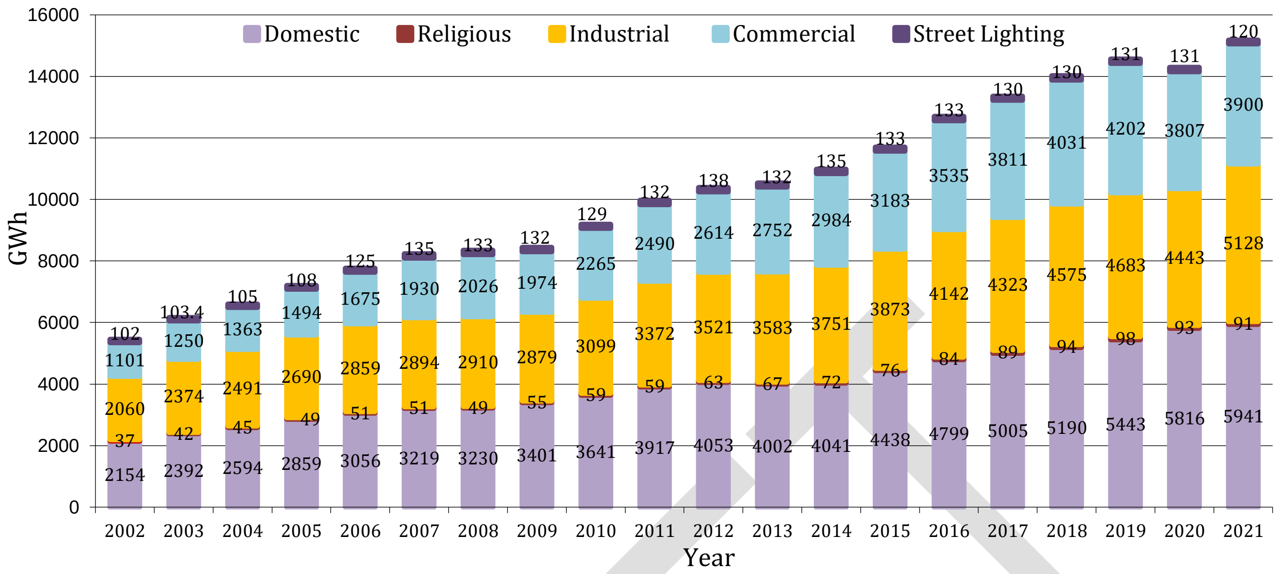


Figure 1.8 - Sectorial Consumption of Electricity (2002 - 2021)

The sectorial electricity consumption (tariff category wise) from 2002 to 2021 is shown in Figure 1.8. Figure 1.9 gives the share of sectorial electricity consumption in 2021. The total consumption of the industrial and commercial sectors (commercial sector consists of General, Hotel and Government tariff categories) is higher than domestic sector consumption, a favorable attribute for an economy with ambitious GDP growth projections. Despite the continuation of COVID-19 pandemic situation in 2021 industrial electricity consumption share has increased while the domestic and commercial sector consumption shares has slightly decreased compared to 2020.

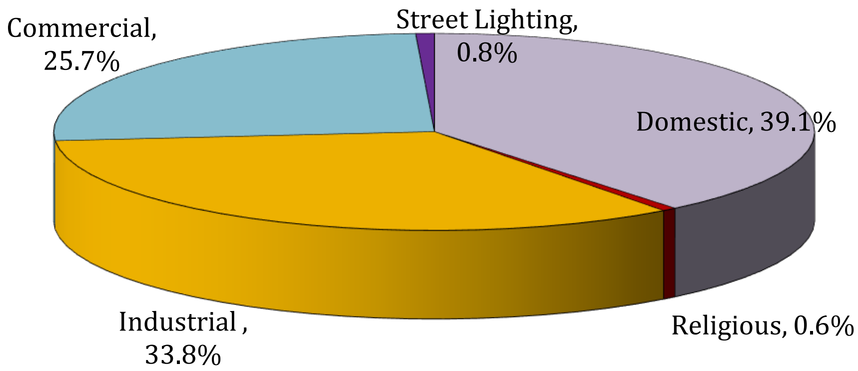


Figure 1.9 - Sectorial Consumption of Electricity (2021)

The average per capita electricity consumption in year 2021, was 694 kWh. This is a considerable increase after a slight drop in 2020. The same has been generally rising steadily; except during the period 2007 to 2009 and during 2012 and 2013. Figure 1.10 illustrates the variation to per capita electricity consumption of Sri Lanka between 2002 to 2021.

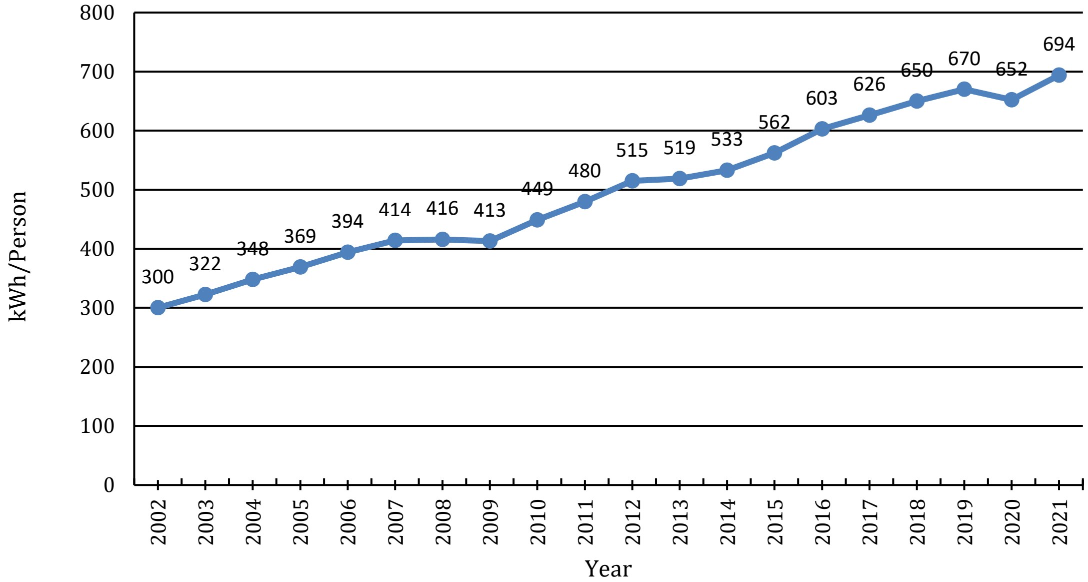


Figure 1.10 – Sri Lanka Per Capita Electricity Consumption (2002-2021)

1.4.2.4 Cost of Electricity

Low electricity price is an essential pre requisite to keep cost of production of both goods and services produced in the country low, and hence be competitive in the local and international market. In order to keep the electricity prices low, it is mandatory to keep the electricity generating cost low. Electricity tariff has to be cost reflective, so that demand management happens at the user's end. Keeping the tariff artificially at low rates can lead to wasteful electricity usage.

Both the fixed cost and the variable cost of producing and supplying a unit of electricity and losses decides the final cost of electricity supplied at end user level. The fixed cost component consists of the fixed generation cost, the costs pertaining to transmission and distribution of electricity, while the variable cost component is mainly determined by the cost of fuel used for thermal generation and variable energy charge paid to renewable sources. Due to different hydrological conditions, the thermal dispatch varies and cost of generating a unit of electricity could significantly vary. This could be heavily impacted when market prices of imported fuels that are used to generate from thermal plants fluctuates. Energy generated through the renewable sources is also dependent on seasonality and variability by nature. To combat these variations in the renewable power generation, grid interventions are needed which involves high capital investment. Generation planning studies are carried out to find the most economical technology mix under various hydrological conditions occurring in different probabilities with varying renewable resource profiles.

Figure 1.11 illustrates how the actual cost of electricity (at selling point) has changed from year 2013 to 2021.

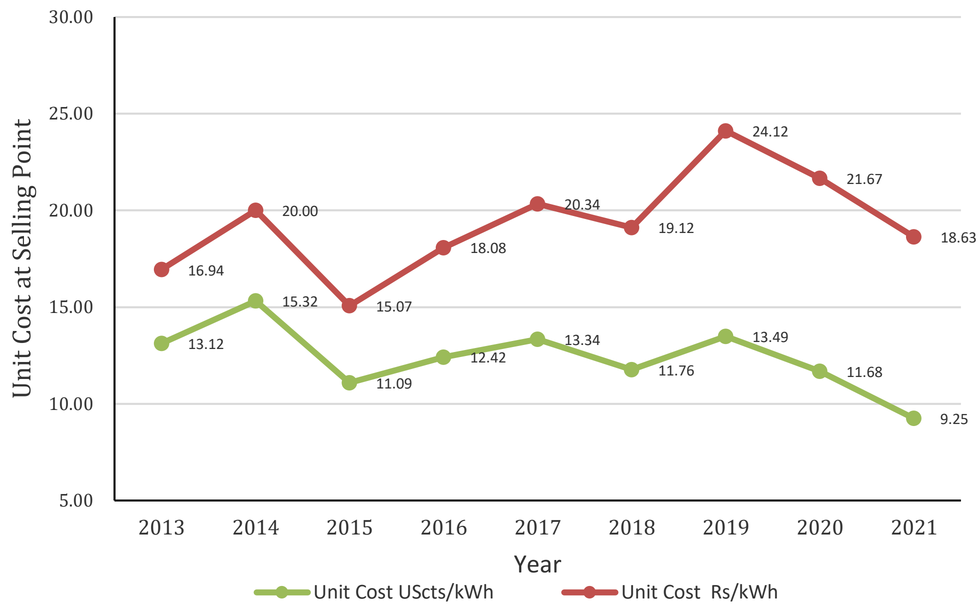


Figure 1.11 – Unit cost of Electricity (2013 -2021)

1.4.2.5 Electricity Demand and Supply

Sri Lanka's peak power demand for electricity has been growing at an average annual rate of around 2.6% during the past 20 years, and this trend is expected to continue in the foreseeable future. Country's daily electricity demand profile has three distinguishable periods classified as the night peak, day peak and off peak. Though the night peak records the highest electricity demand at present, the day time demand is expected to become prominent in years to come. The total installed capacity consists of both dispatchable and non dispatchable forms of generation sources. Ensuring adequate dispatchable capacity is important with the growing peak demand and the firm capacity shortfalls experienced in dry hydrological conditions. By the end of 2021, the total installed capacity was 4184 MW including non dispatchable power plants (small hydro, wind, solar and biomass).

Table 1.4 - Installed Capacity and Peak Demand

Year	Installed Capacity (MW)	Capacity Growth (%)	Peak Demand (MW)	Peak Demand Growth (%)
2002	1,893	1.0%	1,422	-1.6
2003	2,180	13.2%	1,516	6.6
2004	2,280	5.6%	1,563	3.1
2005	2,411	4.2%	1,748	11.8
2006	2,434	0.9%	1,893	8.3
2007	2,444	0.4%	1,842	-2.7
2008	2,645	7.6%	1,922	4.3
2009	2,684	1.5%	1,868	-2.8
2010	2,818	4.8%	1,955	4.7
2011	3,141	10.3%	2,163	10.6
2012	3,312	5.2%	2,146	-0.8
2013	3,355	1.3%	2,164	0.8
2014	3,932	14.7%	2,152	-0.6
2015	3,850	-2.1%	2,283	6.1
2016	4,018	4.2%	2,453	7.4
2017	4,087	1.7%	2,523	2.9
2018	4,046	-1.0%	2,616	3.7
2019	4,217	4.1%	2,668	1.9
2020	4,265	1.1%	2,717	1.8
2021	4,184	-1.9%	2,802	3.1%
`Last 5 year avg. growth		0.59%		2.66%
Last 10 year avg. growth		2.63%		3.01%
Last 20 year avg. growth		4.26%		3.64%

Note: Rooftop solar capacity additions are not considered

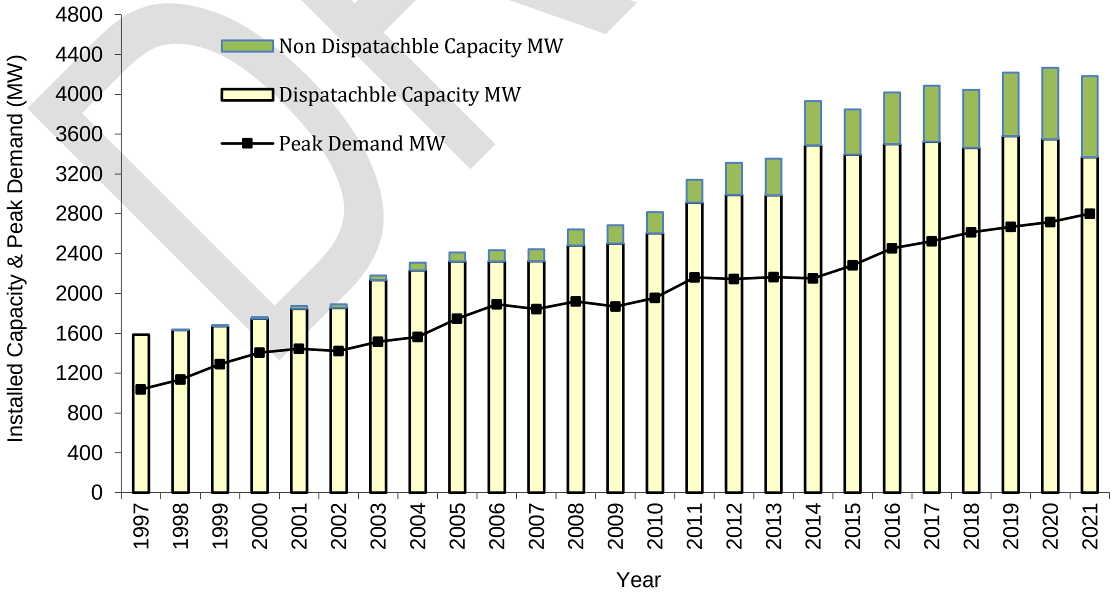


Figure 1.12 – Total Installed Capacity and Peak Demand

Note: Rooftop solar capacity additions are not considered

The Figure 1.13 below illustrates the past development of other renewable energy sources including Mini hydro, Wind, Solar PV and Biomass. Solar PV led the growth in capacity in recent years followed by wind capacities. Moderate growth recoded from Mini-hydro and Biomass Capacities

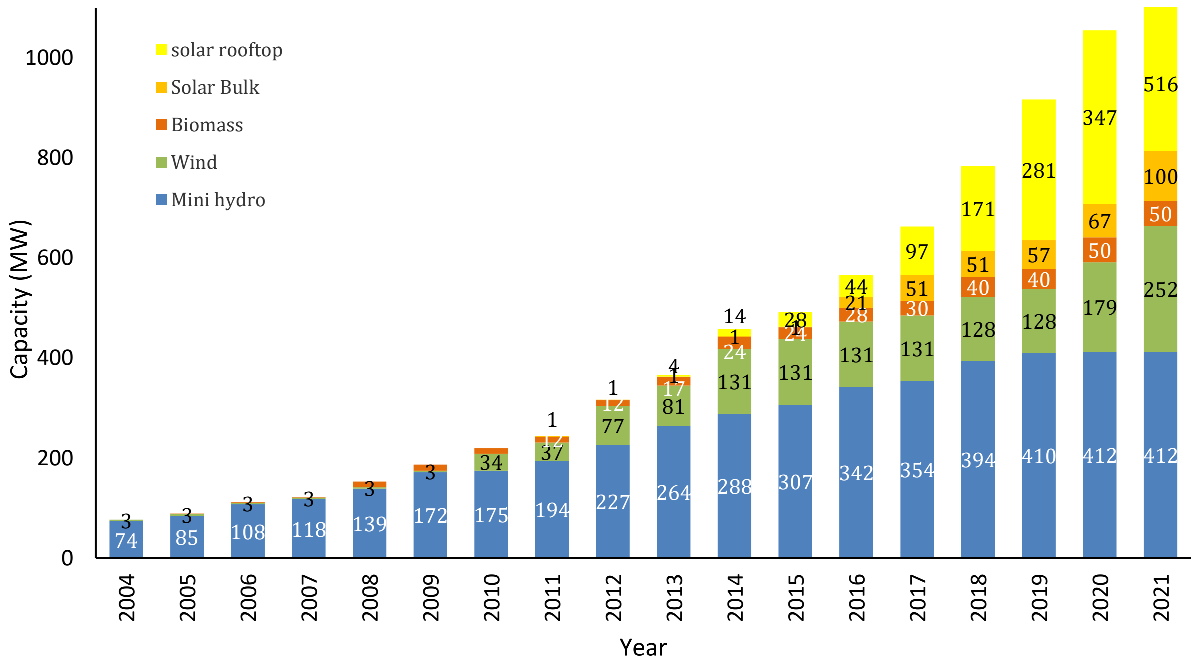


Figure 1.13 – Other Renewable Energy Capacity Development

Electricity generation of the country was predominantly 100% from hydropower until mid-nineties. However, with the growth in electricity demand during the last 20 years and the limited potential to develop new large hydropower resources, the power generation mix in the country has shifted to a mixed hydro-thermal system. Relatively high share of oil based power generation still exists in the present generation mix due to the growing demand, hydrological variations and delays in implementing other major power projects which has a significant impact on the cost of generation. In the year 2021, nearly 33% of the generation share came from coal based generation and another 51% came from renewable energy based generation. Electricity Generation during the last twenty-five years is summarized in Table 1.5 and illustrated in Figure 1.14.

Table 1.5 - Electricity Generation 1997-2021

Year	Hydro Generation		Other Renewable		Thermal Generation		Self-Generation & Small Islands		Total
	GWh	%	GWh	%	GWh	%	GWh	%	GWh
1997	3,426	67.1	4	0.1	1,441	28.2	235	4.6	5,107
1998	3,892	69.1	6	0.1	1,620	28.8	114	2.0	5,632
1999	4,135	67.5	21	0.3	1,871	30.6	97	1.6	6,125
2000	3,138	46.3	46	0.7	3,437	50.7	158	2.3	6,780
2001	3,030	46.2	68	1	3,361	51.2	105	1.6	6,564
2002	2,575	37.4	107	1.6	4,074	59.1	136	2	6,892
2003	3,175	42	124	1.6	4,263	56.4	0	0	7,562
2004	2,739	33.8	208	2.6	5,051	62.3	115	1.4	8,113
2005	3,158	36.3	282	3.2	5,269	60.5	0	0	8,709
2006	4,272	45.9	349	3.7	4,694	50.4	0	0	9,314
2007	3,585	36.8	347	3.6	5,800	59.6	0	0	9,733
2008	3,683	37.5	438	4.5	5,697	58	0	0	9,819
2009	3,338	34	552	5.6	5,914	60.3	0	0	9,803
2010	4,969	46.7	731	6.9	4,948	46.5	0	0	10,649
2011	3,999	35.2	725	6.4	6,629	58.4	2.9	0	11,356
2012	2,710	23.1	736	6.3	8,280	70.6	1.4	0	11,727
2013	5,990	50.3	1,179	9.9	4,729	39.7	0	0	11,898
2014	3,632	29.5	1,217	9.9	7,466	60.6	0	0	12,316
2015	4,904	37.5	1,467	11.2	6,718	51.3	0	0	13,090
2016	3,481	24.6	1,160	8.2	9,507	67.2	0	0	14,148
2017	3,059	20.8	1,464	10	10,148	69.2	0	0	14,671
2018	5,149	33.8	1,715	11.2	8,390	55	2.4	0	15,257
2019	3,784	23.8	1,761	11.1	10,373	65.1	18.7	0.1	15,937
2020	3,911	24.9	1,866	11.9	9,933	63.2	4.2	0	15,714
2021	5,640	33.7	2,922	17.5	8,153	48.8	0	0	16,716
Last 5 year av. Growth			18.9		-5.3				3.3
Last 10 year av. Growth			16.6		-0.2				4.0
Last 20 year av. Growth			19.0		3.7				4.8

Note: Rooftop solar self-consumption is not considered and rooftop solar (export) only considered from year 2019 onwards.

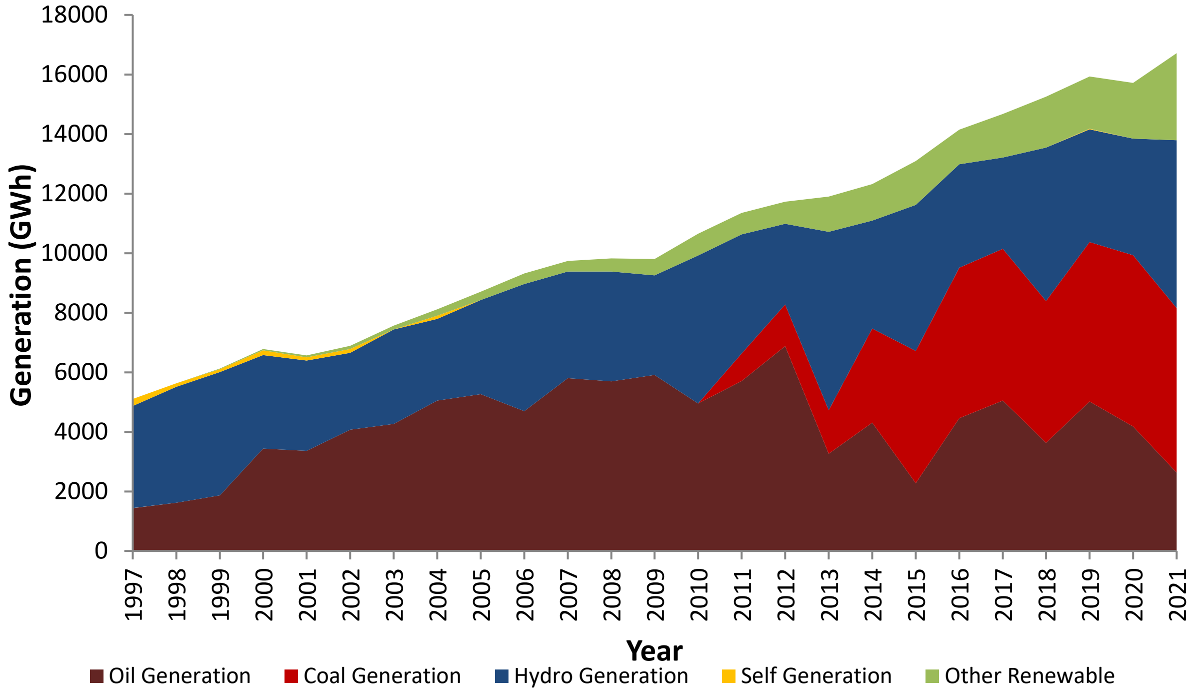


Figure 1.14 - Generation Share in the Recent Past

Sri Lankan electricity system has been maintaining the total renewable energy share between 30% - 60% during the recent past. Major Hydro contribution has varied notably depending on the hydrological conditions and the other renewable energy share has been increasing steadily. The total renewable energy share of the past fifteen years is shown in Figure 1.15.

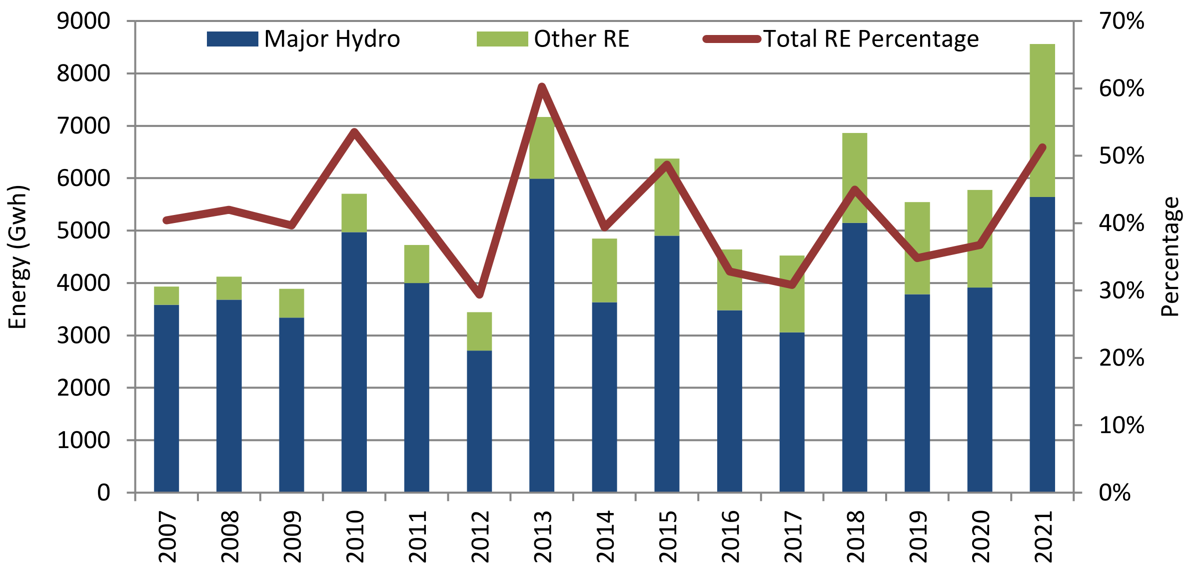


Figure 1.15 – Renewable Share in the Recent Past

1.5 Emissions

The total CO_2 emission of Sri Lanka in 2018 was 20.6 million tons, which is only 0.06% of the total world CO_2 emissions. The absolute emission levels as well as the per capita emission levels of Sri Lanka remains low compared to the overall global average. Emission levels comparison with many regional countries, countries having similar economies and that of developed countries are shown in Table 1.6.

Table 1.6 - Comparison of CO_2 Emissions from Fuel Combustion

Country	kg CO_2/2015USD of GDP	kg CO_2/2015USD of GDP Adjusted to PPP	Tons of CO_2 per Capita	Total CO_2 Emissions (Million tons)
Sri Lanka	**0.23**	**0.07**	**0.95**	**20.6**
Pakistan	0.61	0.17	0.92	194.1
India	0.89	0.23	1.71	2,307.8
Bangladesh	0.34	0.12	0.51	82.0
Indonesia	0.54	0.16	2.03	542.9
Malaysia	0.65	0.24	7.23	228.0
Thailand	0.54	0.19	3.47	241.0
China	0.71	0.40	6.84	9,528.2
Japan	0.23	0.20	8.55	1,080.7
France	0.12	0.11	4.51	303.5
Denmark	0.09	0.11	5.53	32.0
Germany	0.20	0.17	8.40	696.1
Switzerland	0.05	0.06	4.20	35.7
United Kingdom	0.11	0.12	5.30	352.4
Russia	1.12	0.43	10.99	1,587.0
USA	0.25	0.25	15.03	4,921.1
Canada	0.34	0.33	15.25	565.2
Australia	0.29	0.32	15.32	382.9
South Africa	1.31	0.57	7.41	428.0
Qatar	0.51	0.26	30.95	87.0
Egypt	0.59	0.19	2.27	223.6
Brazil	0.23	0.13	1.94	406.3
World	0.41	0.26	4.42	33,513

Source: IEA CO_2 Emissions from Fuel Combustion (2020 Edition) [6] -2018 Data

Globally, electricity sector is the major contributor of CO_2 emissions out of the total energy use or fuel combustion. However, in Sri Lanka, the transport sector is the largest contributor to emissions whereas electricity sector becomes second. Contributions to emissions of Sri Lanka in the recent past is tabulated in Table 1.7 and sector wise comparison of CO_2 emissions of Sri Lanka and the world in 2018 is shown graphically in Figure 1.16.

Table 1.7 – Sri Lanka CO_2 Emissions in the Recent Past

Year	Overall CO_2 Emissions (Million tons)	Electricity Sector CO_2 Emissions (Million tons)
2013	13.74	4.04
2014	16.74	6.79
2015	19.5	6.8
2016	20.9	8.7
2017	23.1	9.9
2018	20.6	8.1

Source: IEA CO_2 Emissions from Fuel Combustion (2020 Edition) [6] -2018 Data

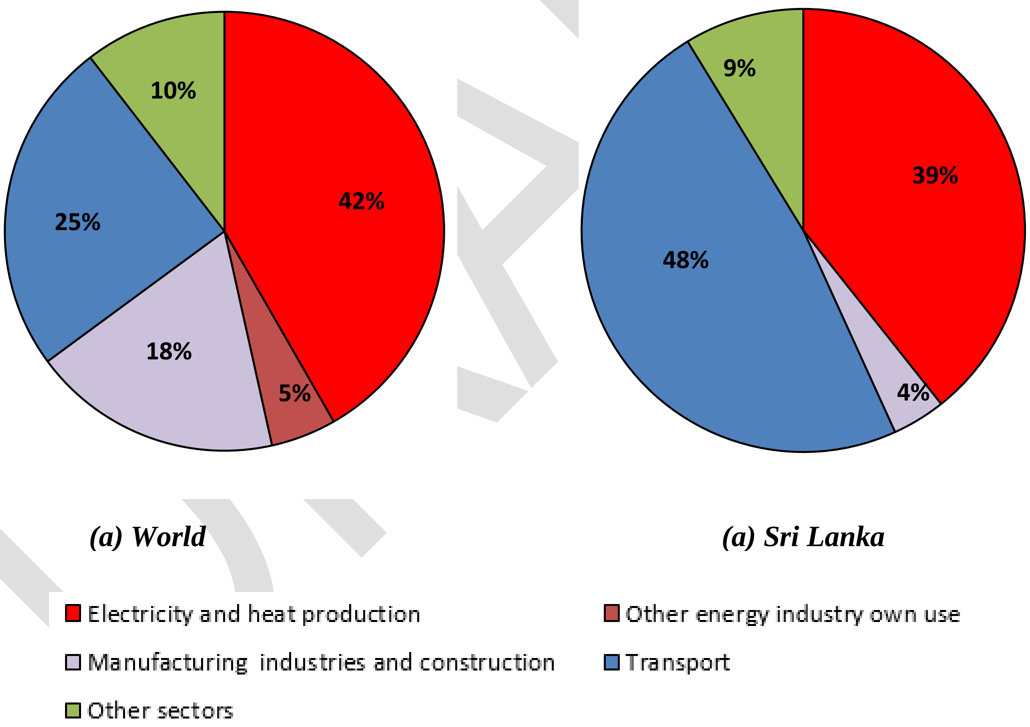


Figure 1.16 - CO_2 Emissions from Fuel Combustion 2020

Source: IEA CO_2 Emissions from Fuel Combustion (2020 Edition) [6] -2018 Data

1.6 Implementation of the Expansion Plan

After a Long Term Generation Expansion Plan (LTGEP) is prepared and approval is received, a corresponding long term transmission development plan is prepared for facilitating the transmission infrastructure for the anticipated generation developments.

The LTGEP that was last submitted to the PUCSL in July 2021 (LTGEP 2022-2041) received a conditional approval, as a new policy target was declared by the government soon after the submission of the LTGEP 2022-2041. Conditional approval was given to all renewable power plants and thermal power plants that would not hinder the commitments made by the latest government policy while implementing the plan.

The new General Policy Guideline was officially published in January 2022 and it envisioned to reach 70% electricity energy generation through renewable sources by 2030 and to have no Coal plant additions, while reaching Carbon Neutrality in 2050. As the conditionally approved LTGEP 2022-2041 was based on the prevailed General Policy Guidelines that targeted to have 50% electricity energy generation through renewable sources by 2030, CEB initiated study work on a new plan to capture the policy elements declared in the new General Policy Guidelines.

This draft LTGEP 2023-2042 is based on the latest General Policy Guidelines. A Long Term Transmission Development Plan (LTTDP) is presently being prepared to facilitate the renewable energy developments envisaged in the LTGEP 2022-2041 and this draft LTGEP 2023-2042. Since transmission developments need lengthy lead times, it is mandatory to have Generation Plans approved timely, as the LTTDP is based on the anticipated generation developments.

Since LTGEPs are prepared once in two years and preparation of a plan itself takes more than ten months, securing the approval within a reasonable time frame is important to ensure a consistent development in the electricity sector.

As per the Sri Lanka Electricity Act, a power plant cannot be added to the system unless the same is identified first in an approved LTGEP. If a power plant that is identified in an approved generation plan is cancelled due to some reason, another power plant cannot be brought to replace it immediately, unless that is included in a new generation plan. Further, as the grace period of large power projects is longer than their construction period, timely implementation of power plant projects as identified in the LTGEPs is important.

Non implementation of expansion plans creates the risk of having undesirable levels of unserved energy with capacity shortfall. To avoid resultant power outages and detrimental impacts on the sector and the economy, procurement of supplementary power is inevitable as short term and medium term measures. Since supplementary power is generally coming with high cost, it is imperative to implement the low cost major power plants identified in the LTGEPs.

1.7 Structure of the Report

The Long Term Generation Expansion Plan 2023-2042 contains following chapters.

Chapter 2 The Existing and Committed Generating Plants
Chapter 3 Electricity Demand: Past and the Future
Chapter 4 Thermal Power Generation Options for the Future Expansion
Chapter 5 Renewable Generation Options for the Future Expansion
Chapter 6 Generation Expansion Planning Methodology and Parameters
Chapter 7 Generation Expansion Planning Study - Development of the Reference Case
Chapter 8 Results of the Generation Expansion Planning Study - Base Case Plan
Chapter 9 Results of the Generation Expansion Planning Study - Operational Analysis of the Base Case Plan
Chapter 10 Results of the Generation Expansion Planning Study - Scenario Analysis
Chapter 11 Environmental implications
Chapter 12 Recommendations of the Base Case Plan
Chapter 13 Implementation and Investment of Generation Projects
Chapter 14 Contingency Analysis
Chapter 15 Revisions to Previous Plan

CHAPTER 2
THE EXISTING AND COMMITTED GENERATING PLANTS

This chapter presents an overview of the existing generating system of the country and the committed generation plants that would be connected to the network in the near future.

A major portion of the existing generating system in the country is owned and operated by CEB with a considerable share of recent additions owned by the private sector. Until 1996 the total electricity system was owned by CEB. Since 1996, private sector has also participated in the power generation business. The existing generating system in the country has approximately 4,184 MW of installed capacity by December 2021 excluding rooftop solar PV installations which amounts to approximately 516 MW. A breakdown of the total installed capacity figure is presented in Table 2.1.

Table 2.1 –Composition of Total Installed Capacity of the System by December 2021

Ownership	Plant Type	Capacity (MW)
CEB	Major Hydro	1,383
	Thermal	1,554
	Renewables (except Major Hydro)	103
Independent Power Producers (IPP)	Thermal	434
	Renewables	710

Apart from above, some power projects which are considered as committed projects are in project development phase including pre-construction and construction activities. Locations of the existing and committed power plants considered in the study are shown in Annex 2.1 and details are discussed in following sections.

2.1 Hydro and Other Renewable Power Generation

Hydropower is the main firm renewable source of generation in the Sri Lankan 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, majority of which are owned by the private sector developers.

2.1.1 Hydro and Other Renewable Power Plants owned by CEB

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

(a) Existing System

The existing CEB generating system has a substantial share based on hydropower (i.e., 1,383 MW from hydro power out of 3,040 MW of total CEB installed capacity). Approximately 45% of the total existing CEB system capacity is installed in 17 hydro power stations and approximately 33.7% of the total energy demand was met by the major hydro plants in 2021. Details of the existing and committed hydro system are given in Table 2.2 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 353.8 MW (26% of the total hydropower capacity) have been built in Laxapana Complex where two cascaded systems are associated with the two main tributaries of Kelani River, Kehelgamu Oya and Maskeli Oya. 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 Maussakelle are the major storage reservoirs in the Laxapana hydropower complex located at main tributaries Kehelgamu Oya and Maskeli Oya respectively. Castlereigh reservoir with active storage of 48 MCM feeds the Wimalasurendra Power Station of capacity 2 x 25 MW at Norton-bridge, while Canyon 2 x 30 MW is fed from the Maussakelle reservoir of storage 108 MCM. Other downstream Power Stations in this cascaded complex are, Old Laxapana, New Laxapana and Samanala (Polpitiya).

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 816MW (59% of the total hydropower capacity). Three major reservoirs*, Kotmale, Victoria and Randenigala*, which were built under the accelerated Mahaweli development program, feed their respective power stations. The latest major power station in this system is 150 MW 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 (38 MW). 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 (40 MW) 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 2.2. Unlike the Laxapana cascade, the Mahaweli system is operated as a multi-purpose system. Hence power generation from the associated power stations is dependent on the down-stream irrigation requirements also. These irrigational requirements being highly seasonal, affects the operation of these power stations during certain periods of the year. It is notable that even in dry seasons where hydrological situation is poor, these power stations are compelled to run for releasing water for irrigational requirements.

Samanalawewa hydro power plant of capacity 120 MW was commissioned in 1992. Samanalawewa reservoir, which is on Walawe River and with active storage of 168 MCM, feeds this power plant.

Kukule Ganga power plant which was commissioned in 2003, is a run-of-the-river type plant located on Kukule Ganga, a tributary of Kalu Ganga. Kukule Ganga power plant is 75 MW in capacity.

The contribution of the three small hydro plants (Inginiyagala – 6.3 MW, Uda Walawe – 6 MW and Nilambe – 3.2 MW) to the National Grid is comparatively small (total 15.5 MW) and is dependent on irrigation water releases from the respective reservoirs.

Mannar Wind Park, erected at the southern coast belt of the Mannar islands, is the first large scale wind power project developed in Sri Lanka. During the first stage, 103.5 MW of wind power was developed. . This plant has 30 wind mills of each having 3.45 MW capacity and it is designed with semi dispatchable model.

Table 2.2 – CEB owned Existing 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 (Maussakelle)	203	1983 - Unit 1 1989 - Unit 2
Wimalasurendra	2 x 25	50	112	47.93 (Castlereigh)	226.1	1965
Old Laxapana	3x 9.6+ 2x12.5	53.8	286	0.245 (Norton)	472.4	1950 1958
New Laxapana	2 x 50	100	552	0.629 (Canyon)	541	Unit 1 1974 Unit 2 1974
Polpitiya	2 x 45	90	453	0.113 (Laxapana)	259	1969
Laxapana Total		**353.8**	**1,563**			
Upper Kotmale	2 x 75	150	409	0.8	473	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	536	77.8	1986
Ukuwela	2 x 19.3	40	154	2.5	75.1	Unit 1&2–'76
Bowatenna	1 x 40	40	48	21.5	50.9	1981
Rantambe	2 x 24.5	50	239	2.8	32.7	1990
Nilambe	2 x 1.61	3.22	-	0.05	110	1988
Mahaweli Total		**816.22**	**2,667**			
Samanalawewa	2 x 60	120	344	168.3	320	1992
Kukule	2 x 37.5	75	300	1.79	186.4	2003
Small hydro		17.25				
Samanala Total		**212.25**	**644**			
Existing Major Hydro total		**1,383**	**4,874**			
Mannar Wind Park		103.5	337			2020
Existing Other Renewable		**103.5**	**337**			
Existing Total		**1,487**	**5,211**			

(b) Committed Plants

The 35 MW Broadlands hydropower plant is the downmost Power plant in the Laxapana Complex and is located near the town Kithulagala. The dam site of the plant is located near Polpitiya power house and in addition to the main dam, there will be a diversion weir across Kehelgamu oya which diverts water in to the main pond. The pond that feeds the plant has 0.198 MCM active storage and the plant is expected to generate 126 GWh energy per annum. It is already grid connected and under commissioning stage.

122 MW Uma Oya hydro power plant is to be operated as a part of the Uma Oya multipurpose hydro power project. Two small reservoirs are built close to Welimada where the water from these two reservoirs are diverted through a tunnel to the underground power house located at Randeniya, near Wellawaya. This Power Plant is expected to generate 290 GWh of energy annually and the plant will be operational in 2022. This project is implemented by the Ministry of Mahaweli Development and Environment.

Moragolla Hydro Power project with a reservoir of 1.98 MCM active storage 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 30.2 MW and 97.6 GWh of mean annual energy. This plant will be added to the system in the latter part of 2023**.**

An extension to the Mannar wind park is being proposed to be developed by CEB, having a total capacity of 50 MW. Initial project work is being carried out at present. Discussions are underway to have another phase of 100 MW wind power plant developed in Silawaturai area by CEB.

Table 2.3 – CEB owned Committed Power Plants

Plant Name	Units x Capacity	Capacity (MW)	Expected Annual Avg. Energy (GWh)	Active Storage (MCM)	Rated Head (m)	Year of Commissioning
Broadlands	2x17.5	35	126	0.198	56.9	2022
Moragolla	2x15.1	30.2	97.6	1.98	69	2024
Uma Oya (Multi-Purpose)	2x61	122	290	0.7	722	2022
Committed Hydro		**187.2**	**513.6**			
Mannar Wind Park Extension		50	163			2024
Committed Other Renewables		**50**	**163**			
Committed Total		**237.2**	**513.6**			

2.1.2 Other Renewable Power Plants Owned by IPPs

a) Existing IPP Plants

Initially, Government of Sri Lanka has taken a policy decision to develop hydropower plants below 10 MW capacities through private sector participation. Many small hydro plants and other renewable power plants have been connected to the system since 1996. Apart from mini hydro power plants, during the recent years, there has been a substantial increase in Wind and Solar additions to the system.

Total capacity of these plants is approximately 710 MW as at 31st December 2021. These plants are mainly connected to 33 kV medium voltage distribution lines. The capacity contributions from other renewable sources are tabulated in Table 2.3.

Table 2.4: Existing IPP owned Other Renewable Energy (ORE) Capacities

Project Type	Number of Projects	Capacity (MW)
Mini Hydro Power	214	414
Wind Power	17	148
Biomass (Dendro,Biomass, Municipal Solid Waste)	16	50
Solar Power (Scattered, ground mounted)	58	100

Addition to above, total Rooftop Solar capacity of approximately 516 MW (both CEB and LECO) has been integrated to the system by 31st December 2021 (both to the MV and LV networks).

(b) Committed IPP Plants

In the recent past CEB has taken timely steps to tender many scattered solar projects and wind projects, of which some are near completion. Also CEB has taken steps to re-tender for the capacities that did not receive offers and for the capacities that project progresses were not shown.

2.1.3. Summary of Renewable Power Generation

A summary of the existing total renewable capacities are summarized in Table 2.4

Table 2.5 – Summary of Existing Network Connected Renewable Capacities as at 31st December 2021

Renewable Source	Capacity (MW)
CEB owned	
Major Hydro	1383
Wind	103.5
Private owned	
Mini Hydro	414
Solar	
Scattered, ground mounted	100
Roof Top facilitated by CEB	416
Roof Top facilitated by LECO	100
Wind	148
Other	
Dendro	27
Biomass	13
Waste to energy	10
Renewables Total	**2,715**

2.2 Thermal Generation

2.2.1 Thermal Plants owned by CEB

(a) Existing

Majority of the present thermal power generating capacity in the country is owned by CEB with a total capacity of 1,554 MW. It is made up of Lakvijaya Coal power plant of 900 MW, Kelanitissa Gas Turbines of 195 MW, Kelanitissa Combined Cycle plant of 165 MW, Sapugaskanda Diesel power plants of 160 MW, Uthuru Janani diesel power plant of 27 MW, Barge Mounted Plant of 64 MW and Containerized Emergency Power Plants of total 50 MW.

Table 2.6 - Details of CEB Owned Existing 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				
Lakvijaya CPP	3x300	3x270	5355	2011 & 2014
Puttalam Coal Total	**900**	**810**	**5,355**	
Kelanitissa Power Station				
Gas turbine (Small GTs)	4 x 20	4 x 17	382	Dec 81, Mar 82, Apr 82,
Gas turbine (GT 7)	1x 115	1 x 115	703	Aug 97
Combined Cycle	1x 165	1 x 161	1196	Aug 2002
Kelanitissa Total	**360**	**344**	**2,281**	
Sapugaskanda Power Station				
Diesel	4 x 20	4 x 17	493	May 84, May 84, Sep 84, Oct 84
Diesel (Ext.)	8 x 10	8 x 9	481	4 Units Sept 97 4 Units Oct 99
Sapugaskanda Total	**160**	**140**	**974**	
Other Thermal Power Plants				
Uthuru Janani	3 x 8.9	3 x 8.9	184	Jan 2013
Barge Mounted Plant	4 x 15.6	4 x 15.6	515	Acquired in 2015
Containerized Emergency Power Plant	50 x 1	50 x 1		2019
Existing Total Thermal	**1,559.1**	**1,433.1**	**9,309**	

Technical parameters and cost details of the existing thermal generation plants as input to the 2022 Expansion Planning Studies are summarized in Table 2.7.

Table 2.7 - Characteristics of Existing CEB Owned Thermal Plants

		Kelanitissa				**Sapugaskanda**		**Lakvijaya Coal**	**Other**	
Name of Plant	**Units**	**GT (Old)**	**GT (New)**	**Comb. Cycle (JBIC)**	**Emergency Plant 50x1**	**Diesel (Station A)**	**Diesel (Ext.) (Station B)**	**Coal (Phase I & II)**	**Uthuru Janani**	**Barge Mounted Plant**
Basic Data										
Engine Type		GE FRAME 5	FIAT (TG 50 D5)	VEGA 109E ALSTHOM		PIELSTIC PC-42	MAN B&W L58/64	-	Wartsila 20V32	Mitsui MAN B&W 12K50 MC-S
Input Parameters for Studies										
Number of Units		4	1	1	50	4	8	3	3	4
Unit Capacity	MW	17	115	161	1	3 x 18 + 16 x 1	9	270	8.93	15.6
Minimum operating level	MW	5	80	120	0.5	11	7	150	2.67	8.5
Calorific Value of the fuel	kCal/kg	10,250	10,250	Naptha-10,800 Diesel-10,925	10,500	D/F - 10,800 H/F - 10,500	D/F - 10,800 H/F - 10,500	5900-6300	10580	10572.8
Heat Rate at Min. Load	kCal/kWh	4,200	2,969	Naptha - 1,974.6 Diesel-2,155.2	2,620	2,276	2,136	Unit 1-3,022 Unit 2-2,767 Unit 3-3,048	2,164	2,132
Incremental Heat Rate	kCal/kWh	0	2,337	Naptha - 1,403.5 Diesel-1,415.4	2,500	2,204	1,889	Unit 1-1,984 Unit 2-2,255 Unit 3-1,973	0	0
Heat Rate at Full Load	kCal/kWh	4,200	2,722	Naptha - 1,818.8 Diesel-1,953.4	2,460	2,248	2,082	Unit 1-2,503 Unit 2-2,511 Unit 3-2,510	2132	2116.5
Fuel Cost	USCts/GCal	5,259	5,259	5,295		3,885	3,885	1,680	3,885	3,885
Full Load Efficiency	%	20	26.5	Naptha - 46.45 Diesel-42.09	35	38	41	Unit 1-38.9 Unit 2-38.9 Unit 3-38.7	44	40
Forced Outage Rate	%	14.67	6.8	8	5.2	9.39	6.92	7.6	5.85	3.76
Fixed O&M Cost	$/kWmonth	3.14	0.18	1.93		2.7	2.7	2.15	1.81	0.95
Variable O&M Cost	$/MWh	0.81	0.75	2.22	8.8	3.466	3.466	2.69	3.48	5.13

Note: All costs are in border prices. Fuel prices are based on Table 4.3 and 4.4 of Chapter 4.
Heat rates and calorific values are given in HHV.

Plant Retirements

For planning studies retirement dates of CEB owned existing thermal power plants are considered as indicated in Table 2.7. However decision on the retirement of power plants will be considered by evaluating the actual plant condition and the implementation progress of planned power plant additions.

Table 2.8: Plant Retirement Schedule

CEB Power Plants	Year of retirement
1. KPS Frame 5 GTs all units	2024
2. KPS GT7	2026
3. Sapugaskanda PS A (4 units)	2026
4. Sapugaskanda PS B (8 Units)	2026
5. Barge Mounted Power Plant*	2025
6. Kelanithissa Combined Cycle Plants	2033

(b) Committed Plants

CEB has taken steps to procure Gas Turbines at Kelanitissa premises, for a capacity of 130 MW. This was awarded in April 2022 and expected operation in 2024.

2.2.2 Thermal plants owned by Independent Power Producers (IPPs)

(a) Existing

Apart from the thermal generating capacity owned by CEB, other thermal Power Plants owned by Independent Power Producers that are connected to the national grid are given in Table 2.8

Table 2.9 - Details of Existing IPP Thermal Power Plants

Plant Name	Capacity used for Studies (MW)	Commissioning	Contract Period (Yrs.)
Sojitz Kelanitissa (Pvt.) Ltd. Combined cycle power plant	163	GT- 2003 March ST –2003 October	20
West Coast (Pvt)Ltd. Combined cycle power plant	270	2010 May	25

(b) Committed

Following power plants are considered as committed power plants in the planning study.

Table 2.10 - Details of Committed IPP Thermal Power Plants

Plant Name	Capacity used for Studies (MW)	Commissioning	Contract Period (Yrs.)
Sobadhanavi Ltd. Combined Cycle Power Plant	350	GT- 2023 ST–2024	20
Combined Cycle Power Plant at Kerawalapitiya	350	GT- 2024 ST–2025	25
Committed Total IPP	**700**		

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 4.4% per annum while peak demand has been growing at a rate of 3% per annum as shown in Table 3.1. The peak demand has grown at a rate of 2.7% during the last 5 years and energy demand has been growing at a rate of 3.2% per annum.

Electricity consumption of Sri Lanka has declined drastically after the national lockdown was enacted in March 2020 due to the COVID-19 pandemic situation. It is observed the demand in 2020 has contracted by 2.2% compared to 2019. However, in 2021 electricity consumption increased by 6.5% and returned to pre-pandemic level mainly due to easing of lockdown curbs. Recovery in electricity demand and consumption in 2021 is mainly due to the surge in economic activities amid easing of lockdown restrictions. Monthly electricity consumption shows positive growth rates in latter part of the year 2021 compared to 2020. In 2021, net electricity generated to meet the demand amounted to 16,716 GWh (including rooftop solar energy contribution), which had been 15,714 GWh in 2020 with 6.4% growth rate and 11,725 GWh ten years ago (in 2012). The recorded maximum demand within the year 2021 was 2,802 MW, which was 2,717 MW in year 2020 and 2146 MW ten years ago (in 2012).

Table 3.1 - Electricity Demand in Sri Lanka, 2007– 2021

Year	Demand* (GWh)	Avg. Growth (%)	T & D Losses (%)	Net Generation (GWh)	Avg. Growth (%)	Load Factor** (%)	Peak (MW)	Avg. Growth (%)
2007	8,276	5.7	15.0	9,733	4.5	60.3	1,842	-2.7
2008	8,417	1.7	14.3	9,819	0.9	58.3	1,922	4.3
2009	8,441	0.3	13.9	9,803	-0.2	59.9	1,868	-2.8
2010	9,268	9.8	13.0	10,649	8.6	62.2	1,955	4.7
2011	10,024	8.2	11.7	11,353	6.6	59.9	2,163	10.6
2012	10,474	4.5	10.7	11,725	3.3	62.4	2,146	-0.8
2013	10,624	1.4	10.7	11,898	1.5	62.8	2,164	0.8
2014	11,063	4.1	10.2	12,316	3.5	65.3	2,152	-0.6
2015	11,786	6.5	10.0	13,090	6.3	65.4	2,283	6.1
2016	12,785	8.5	9.6	14,148	8.1	65.8	2,453	7.4
2017	13,431	5.1	8.5	14,671	3.7	66.4	2,523	2.9
2018	14,091	4.9	8.3	15,374+	4.8	67.1	2,616	3.7
2019	14,611	3.7	8.2	15,922+	3.6	68.1	2,669	2.0
2020	14,286	-2.2	9.1(a)	15,714+	-1.3	65.8	2,717	1.8
2021	15,214	6.5	9.5(a)	16,716+	6.4	68.1	2,802	3.1
Last 5 year		3.2%			3.3%			2.7%
Last 10 year		4.2%			4.0%			3.0%
Last 15 year		4.4%			3.9%			3.0%

Note: *Gross units sold, **Load factor calculated on net Generation,
+Including Rooftop Solar energy contribution, (a) Provisional
Based on the statistical data from CEB Statistical Digests & System Control Centre Annual Reports

Figure 3.1 shows a considerable decrease in percentage of system losses since 2001. Figure 3.2 shows the System Load Factor variation over last 15 years. This was calculated with net generation base. After 2015, adjustment was done for the peak demand by adding respective mini hydro contribution and beyond 2018, net generation adjusted including rooftop solar contribution also. A drop in the load factor could be observed in 2020 (66.02%) which has recovered back to previous levels (68.1%) in 2021.

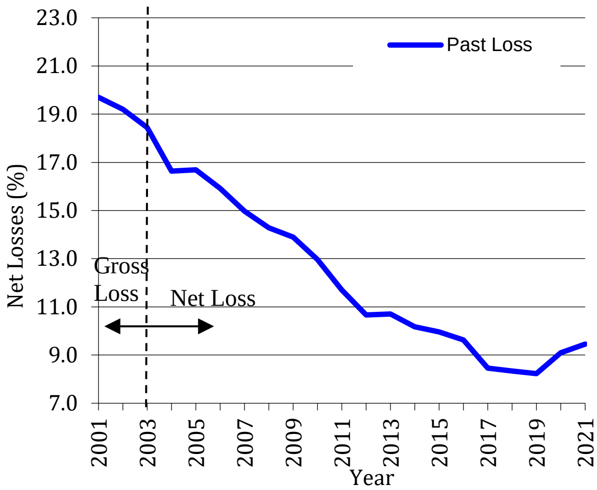


Figure 3.1 - Past System Losses

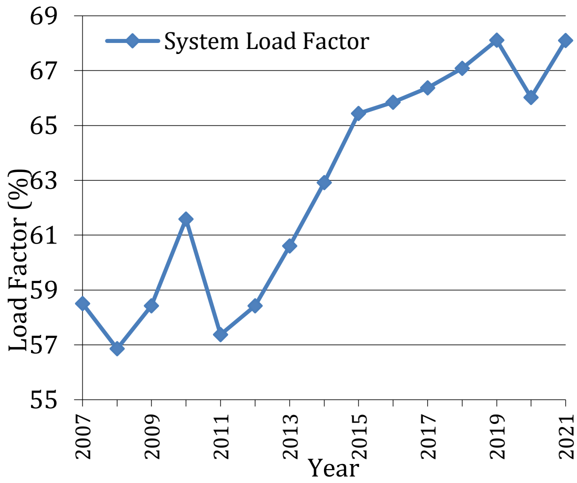


Figure 3.2 – Past Load Factors

Figure 3.3 shows the country's daily load curve recorded on the day of annual peak for previous eight years. It could be observed that the shape of the load curve follows almost a similar pattern. However, significant growth in the day peak could be seen in last six years (2016 to 2021) compared to previous years. The system peak demand occurs generally from about 18.30 to 22.30 hours daily. The recorded maximum system peak was 2,802 MW in year 2021, while in year 2020 the peak was 2,717 MW.

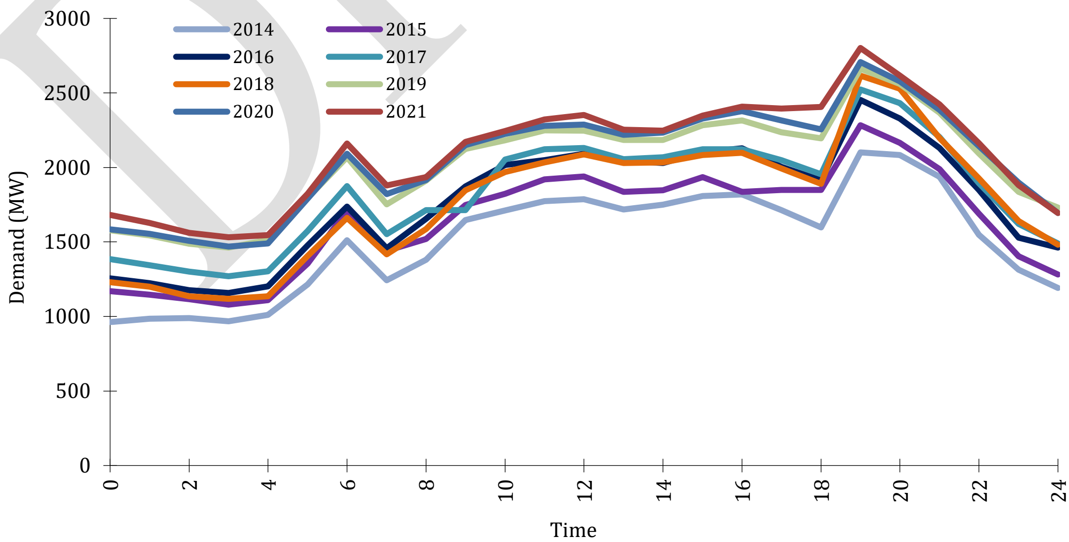


Figure 3.3 - Change in Daily Load Curve over Last Eight Years

Figure 3.4 shows the percentage consumption shares among different consumer categories from 1982 to 2021. In 2021, share of domestic consumption in the total demand was 39% while that of industrial and commercial sectors were 34% and 26% respectively. Religious purpose consumers and street lighting, which is referred as the other category, together accounted only for 1%. Similarly in 2012 (10 years ago), share of domestic, industrial, commercial and religious purpose & street lighting consumptions in the total demand, were 39%, 34%, 25% and 2% respectively.

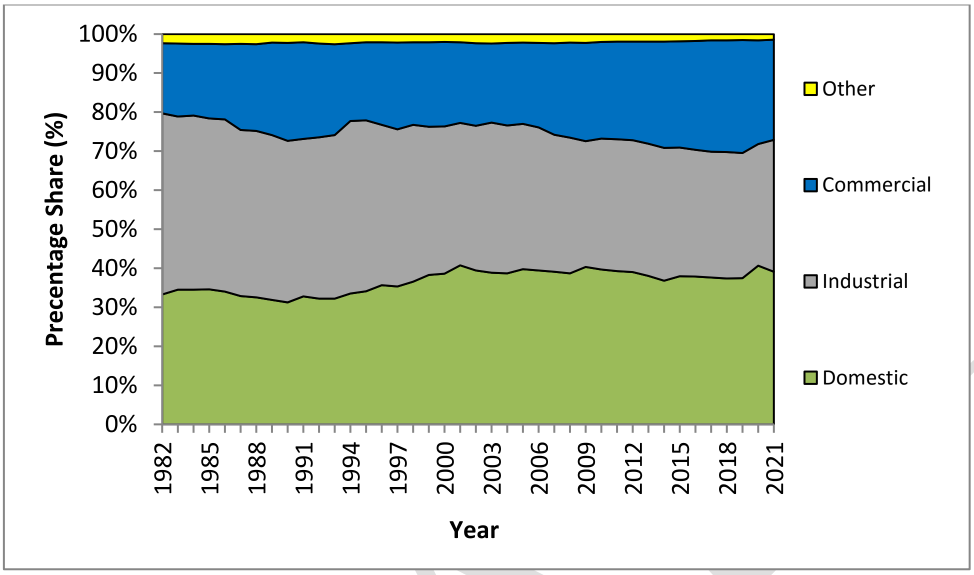


Figure 3.4 - Consumption Share among Different Consumer Categories

3.2 Policies, Guidelines and Information on Future Major Development Projects in Demand Forecasting

3.2.1 Policies and Guidelines

The Electricity Demand Forecast 2023-2047 is prepared complying with the following policies and guidelines.

- National Energy Policy and Strategies of Sri Lanka, August 2019
- General Policy Guidelines on the Electricity Industry for the Public Utilities Commission of Sri Lanka, 2021 issued in January 2022
- Generation Planning Code in the Draft Grid Code issued by the Transmission Division, Ceylon Electricity Board, in October 2018

3.2.2 Information on Future Major Development Projects

Country has planned for large scale developments which will lead to increased electricity demand in the future. In the state sector, the major development projects identified by the Ministry of Urban Development, Water Supply and Housing Facilities can be listed as follows. Currently, these are under different stages of development.

- Colombo Port City Development
- Western Region Light Rail Transit Project
- Solid Waste Management Project
- Metro Colombo Urban Development Project etc.

The Colombo Port City Development Project is a major development project in the load centre. Its cumulative electricity demand requirement is given as 75 MW by 2022, 177 MW by 2025, 313 MW by 2030 and 393 MW by 2040 with phase developments. For the Western Region Light Rail Transit Project, cumulative electricity demand requirement is given as 122 MW by 2022, 131 MW by 2030 and 139 MW by 2035 and beyond.

According to the information by Ministry of Urban Development, Water Supply and Housing Facilities, some of the planned projects were cancelled and some will implement with scope changes. Cumulative electricity demand requirement of other main development projects are indicatively estimated as 118 MW by 2022, 260 MW by 2030 and 290 MW by 2040. In addition, Hambanthota port development has identified approximate power requirement of 500 MW by 2040 and Hambathota BOI zones identified power requirement of 105 MW by 2025.

The Electricity Demand Forecast 2023-2047 was prepared considering the phase development of the above large scale projects. During the detail planning stages, it is required to identify the time based load requirement to determine the load pattern which would impact on actual electricity demand.

3.3 Demand Forecasting Methodology

A combination of medium term and long term forecast approaches has been adopted for the preparation of base demand forecast 2023-2047. Five year sales forecasts of Distribution Divisions and time trend approach are generally considered to determine the medium term forecast. For the long term, econometric approach is adopted by analysing past electricity demand figures with significant independent variables.

For the medium term and long term analysis, past annual electricity demand was considered by adjusting annual electricity sales with power cuts (energy not served) and estimated rooftop solar self consumption.

In addition to the above, a number of demand forecast scenarios and sensitivities were prepared for the planning horizon. Accordingly, the End User Approach was adopted separately through MAED model as described in section 3.5. MAED model analyses the end user energy demand by considering technological, social and economic driving factors in different sectors.

In addition, other demand forecasting scenarios and sensitivities are described in section 3.6.

3.3.1 Medium Term Demand Forecast (2023-2026)

Due to the unusual demand contraction in year 2020 caused by the Corona pandemic, five year time trend modelling was developed based on the electricity demand data from 2015 to 2019. Further, considering the estimated demand for year 2021, it was observed that a lagged time trend would be more appropriate for the medium term forecast. Hence 1 year lag and 2 year lag cases were analysed and two year lag case was considered for the medium term of demand forecast of 2023-2047. [7]

Separate analysis was carried out with the historical electricity sales and growth rates and it was observed that electricity demand bounces back with higher growth rate after the years having unexpected demand drop. Accordingly, medium term demand forecast was developed with trend analysis to reflect this bounce back phenomenon.

3.3.2 Long Term Demand Forecast (2027-2047)

Econometric modelling was used for the long term demand forecasting from 2027 to 2047, giving due consideration to the electricity consumer tariff categories (multisector) and economic growth of sectors [8]. Separate models and forecasts were prepared for three main sectors; Domestic, Industry and Commercial to comply with multi sector approach.

In the models, annual electricity demand (sales figures adjusted with energy not served and estimated rooftop solar self consumption) figures of the past were analysed against several independent variables as given in Table 3.2 using multiple regression technique. Considering the unusual behaviour of socio-economic activities due to COVID-19 pandemic situation in 2020, only data upto 2019 were used in the analysis. During the process, some of the insignificant independent variables were eliminated.

Table 3.2 – Variables Used for Econometric Modeling

Sector	Domestic	Industrial	Commercial	Other
Variables	Gross Domestic Product	Gross Domestic Product	Gross Domestic Product	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 Gross Value Added	Agriculture Sector Gross Value Added	
	Previous year Domestic Consumer Accounts	Industrial Sector Gross Value Added	Industrial Sector Gross Value Added	
		Service Sector Gross Value Added	Service Sector Gross Value Added	
		Industrial Consumer Accounts	Commercial Consumer Accounts	
		Previous year Industrial Consumer Accounts	Previous year Commercial Consumer Accounts	

According to the Central Bank of Sri Lanka Annual Report 2019 and previous publications, sector wise gross value added and its percentage share to the total GDP were analysed for the period from 1978 to 2019. Base year was taken as 2019 and the percentage share for Industry, Services and Agriculture are 26.4%, 57.4% and 7.0% 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 three different sectors.

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) sectors 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 three significant variables. Gross Domestic Product Per Capita, Domestic Consumer Accounts and Previous year Electricity Demand in Domestic consumer category were significant independent variables for the domestic sector demand growth. The econometric model is as follows, where t indicates years:

Ddom (t) = 32.4 + 0.58 GDPPC (t) + 0.16 CAdom (t) + 0.8 Ddom (t-1)

Where,

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

Industrial Sector

The significant variables for electricity demand growth in this sector are Industrial sector Gross Value Added (GVA), Industrial consumer accounts and previous year Electricity demand in Industrial consumer category. The econometric model is as follows, where t indicates years:

Di (t) = 57.86 + 0.26 GVAi (t) + 13.1 CAi (t) + 0.67 Di (t-1)

Where,

Di (t)	-	Electricity demand in Industrial consumer categories (GWh)
GVAi (t)	-	Industrial Sector Gross Value Added ('000 LKR)
CAi (t)	-	Industrial Consumer Accounts ('000s)
Di (t-1)	-	Previous year Electricity demand in Industrial consumer category (GWh)

Commercial Sector (General Purpose, Hotel and Government Sectors)

Significant variables for electricity demand growth in the commercial sector are Service Sector Gross Value Added and previous year Electricity demand in Commercial consumer category. Although there are differences between the identification of Commercial (General Purpose, Hotel & Government) sector in CEB Tariff category and Service sector identified in the statistics of Central Bank of Sri Lanka, Service sector GVA was selected as the most significant variable in regression analysis. The econometric model is as follows, where t indicates years:

Dcom (t) = -76.55 + 0.11 GVAser (t) + 0.93 Dcom (t-1)
Where,
Dcom (t) - Electricity demand in Commercial consumer categories (GWh)
GVAser - Service Sector Gross Value Added ('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 were 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 using logarithm approach was performed to predict the demand in this sector.

ln (Dos (t)) = -97.25 + 0.051t
Where,
Dos (t) - Electricity demand in other sector consumer category (GWh)
t - Year

Forecast of Variables

Due to the impact of COVID-19 on the electricity consumption in 2020, only data upto 2019 was used to derive the above model. But when considering the forecast of variables, 2020 values were considered to obtain more realistic predictions. [8]

3.3.3 Cumulative Electricity Demand Forecast

Once the electricity demand forecast was derived based on the econometric approach, forecasts of four sectors were added together to derive the demand forecast from 2027 to 2047. Cumulative electricity demand forecast 2023-2047 is the combination of medium term and long term approaches as described in section 3.3.

Net Loss Forecast

Estimated total net energy loss (transmission and distribution loss) were added to the total demand forecast in order to derive the net electricity generation forecast.

Expected Transmission and Distribution loss of 7.50% in year 2030 and 7.25% in year 2035 was used in the planning studies. Anticipated reduction of Transmission and Distribution losses with the improvements of the network is shown in Figure 3.5. However, the actual losses would vary depending on the actual generation combination of each year. In 2021, actual loss was 9.46% whereas in 2020 it was 9.08%.

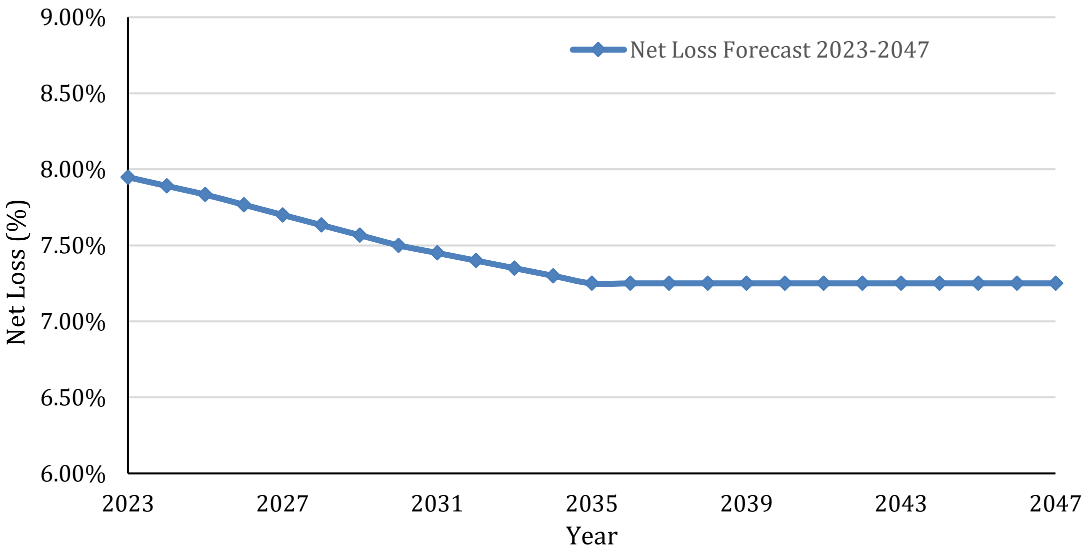


Figure 3.5–Net Loss Forecast 2023-2047

System Load Factor and Peak Demand Forecast

The System Load Factor which is illustrated in Figure 3.2 is calculated by including Other Renewable Energy (Mini hydro, Wind & Solar) in the past fifteen years and in 2021 it was 68.1% on net generation.

According to the analysis carried out by considering actual monthly records of the night peak, day peak and off peak from 2011 to 2020 for the whole country, it was observed that the night peak, day peak and off peak remains its increasing trends as shown in Figure 3.6 (a). It could be observed that the growth of day peak is higher than the growth of night peak specially in the recent six years by resulting in higher growth rate in total energy compared to the peak growth rate. Therefore, in the future more energy will be relatively filled in the daytime of the load profile resulting in the shape of the daily load profile to gradually change and it could be expected that the day peak of the country will become higher than the night peak. In addition, growth of the off peak based on the past growth and trend with assumptions is considered for the future.

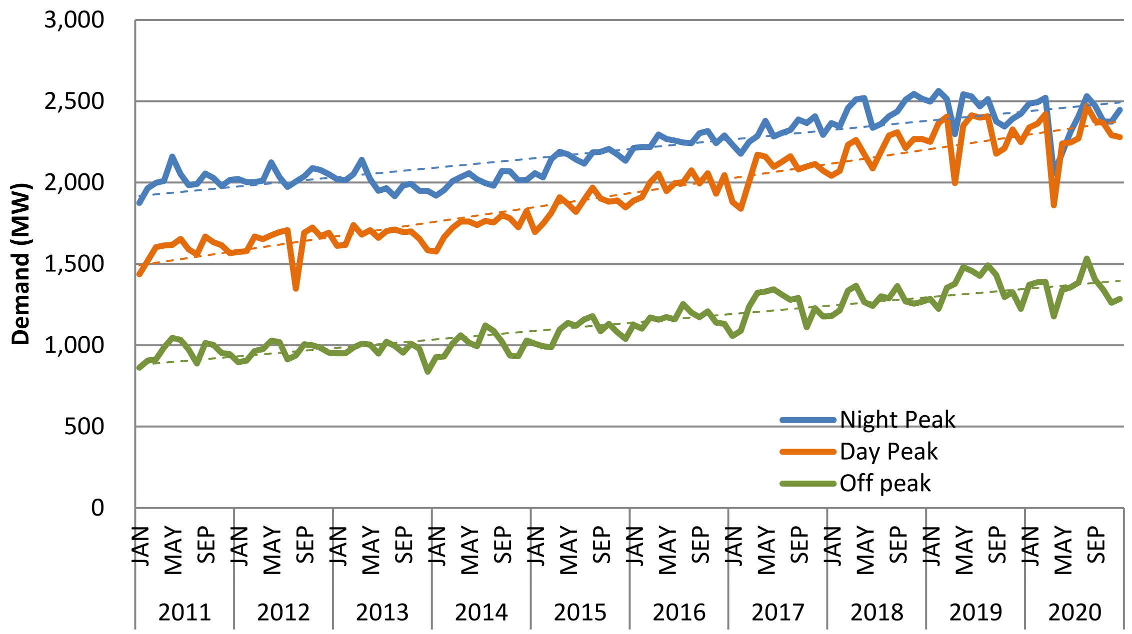


Figure 3.6 (a) – Analysis of Night peak, Day peak and Off peak Trends 2011-2020

According to the trend of peak growth, it is predicted that the night peak and day peak profiles would crossover around 2026. Annual load profiles were determined for each year considering the ratios between peak to off peak, morning peak and night peak. Accordingly, the resultant normalised load profiles are shown in Figure 3.6 (b).

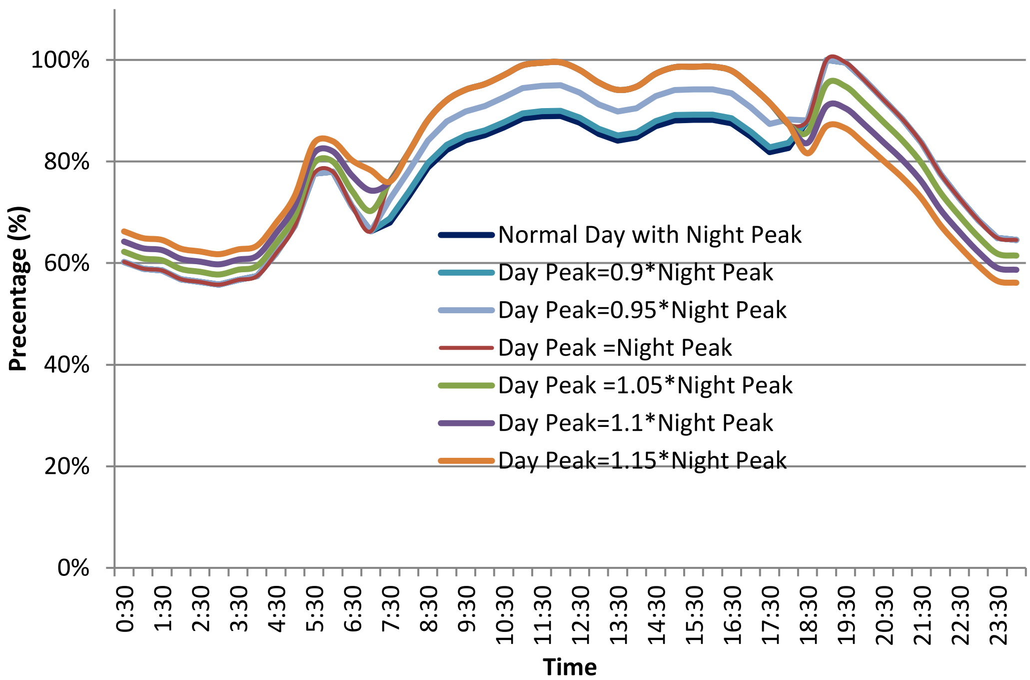


Figure 3.6 (b) – Load Profile Shape Forecast

The forecast of annual load factor up to 2047 was done based on the analysis conducted with normalized load profiles in Figure 3.6 (b) considering the relationship between the ratio of the day and night peak demands and the load factor. In the initial years, load factor improvement is expected due to demand growth of industrial and general purpose (commercial) sectors. Afterwards, it can be seen that the load factor becomes maximum in 2026 when the day peak exceeds night peak and thereafter gradually stabilizes. Figure 3.7 shows the system load factor forecast considered for the planning horizon.

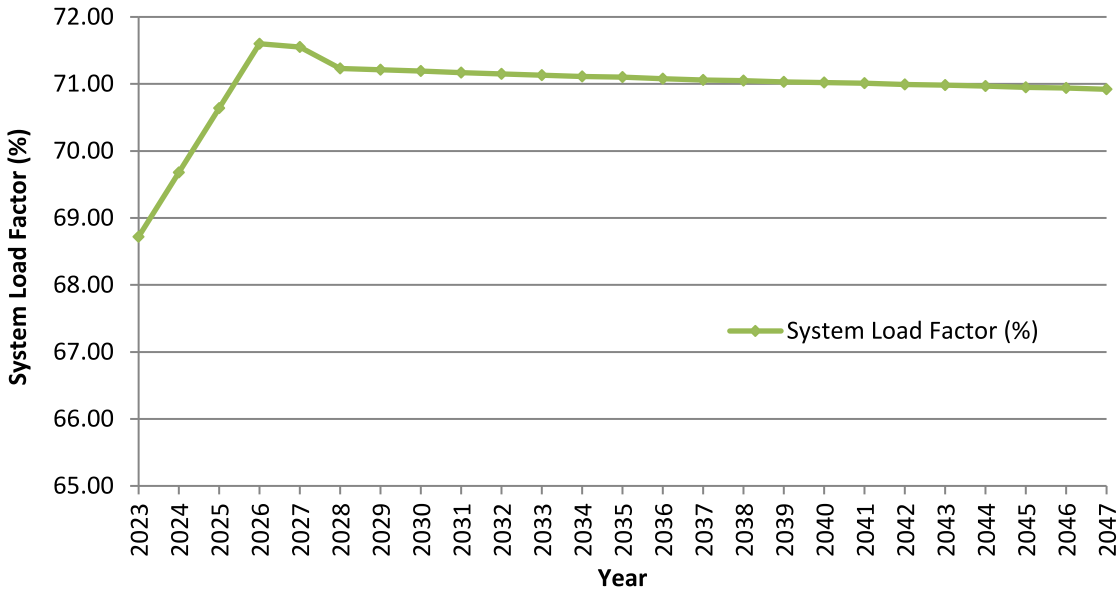


Figure 3.7 – System Load Factor Forecast 2023-2047

Finally, the peak demand forecast was derived using the annual electricity generation forecast and load factor forecast.

3.4 Base Demand Forecast 2023-2047

Base demand forecast 2023-2047 was prepared as per the methodology described in Section 3.3 for the planning horizon. Table 3.3 shows the 'Base Demand Forecast 2023-2047'.

Table 3.3 - Base Demand Forecast 2023-2047

Year	Demand		Net Loss*	Net Generation		Peak Demand
	(GWh)	Growth Rate (%)	(%)	(GWh)	Growth Rate (%)	(MW)
2023	16,741	6.4%	7.95	18,186	6.4%	3,021
2024	17,705	5.8%	7.89	19,222	5.7%	3,149
2025	18,725	5.8%	7.83	20,317	5.7%	3,283
2026**	19,854	6.0%	7.77	21,526	6.0%	3,432
2027	21,124	6.4%	7.70	22,886	6.3%	3,651
2028	22,419	6.1%	7.63	24,272	6.1%	3,890
2029	23,794	6.1%	7.57	25,741	6.1%	4,127
2030	25,253	6.1%	7.50	27,300	6.1%	4,378
2031	26,801	6.1%	7.45	28,958	6.1%	4,645
2032	28,165	5.1%	7.40	30,415	5.0%	4,880
2033	29,601	5.1%	7.35	31,949	5.0%	5,127
2034	31,099	5.1%	7.30	33,548	5.0%	5,385
2035	32,646	5.0%	7.25	35,198	4.9%	5,652
2036	34,241	4.9%	7.25	36,917	4.9%	5,929
2037	35,879	4.8%	7.25	38,684	4.8%	6,214
2038	37,547	4.6%	7.25	40,482	4.6%	6,504
2039	39,253	4.5%	7.25	42,321	4.5%	6,801
2040	41,002	4.5%	7.25	44,207	4.5%	7,106
2041	42,777	4.3%	7.25	46,120	4.3%	7,415
2042	44,584	4.2%	7.25	48,070	4.2%	7,730
2043	46,431	4.1%	7.25	50,061	4.1%	8,051
2044	48,321	4.1%	7.25	52,098	4.1%	8,380
2045	50,259	4.0%	7.25	54,188	4.0%	8,718
2046	52,248	4.0%	7.25	56,332	4.0%	9,064
2047	54,315	4.0%	7.25	58,560	4.0%	9,426
5 Year Average Growth	6.0%			5.9%		4.8%
10 Year Average Growth	6.0%			5.9%		5.5%
20 Year Average Growth	5.3%			5.2%		5.1%
25 Year Average Growth	5.0%			5.0%		4.9%

In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.

* Net losses include losses at the Transmission & Distribution levels, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depending on the renewable thermal generation mix of the future

** It is expected that day peak would surpass the night peak from this year onwards

3.5 Development of Load Projection Scenario based on MAED Model

Model for Analysis of Energy Demand (MAED) was developed by International Atomic Energy Agency (IAEA) for load projection with Bottom-Up (End User) approach. Energy demand calculation module utilizes extensive analysis of end use energy demand data and evaluates future energy demand based on socio-economic, technological and demographic developments of the country.

The model identifies social, economic and technological driving factors and their relations to the identified energy consumer sectors that affect to the final energy demand of each sector.

Final electricity demand projection then separately taken into electric power demand module for further analysis. In that module Household, Industry, Service and Transportation sectors are considered separately. Net generation (referred to as secondary electricity demand in MAED model) is calculated taking into consideration Transmission & Distribution losses (net loss).

Model was developed and revised based on the socio-economic data up to 2020. Planning years from 2023 to 2047 adjusted considering the present situation and future of the economy, demography, sector changes etc. for each 5 year periods. Sub sector wise load profiles are selected based on the clients having the same load profile patterns. Main Sector is represented by the aggregated load profile determined by the model. In addition, peak electricity demand is calculated considering seasonal, daily and hourly variation of the profiles.

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

Table 3.4 – Main & Sub Sector Breakdown for MAED

<table>
<tr><th>Main Sector</th><th colspan="2">Sub Sectors (Clients)</th></tr>
<tr><td rowspan="2">Household</td><td colspan="2">Urban</td></tr>
<tr><td colspan="2">Rural</td></tr>
<tr><td rowspan="5">Industry</td><td colspan="2">Process Industry</td></tr>
<tr><td colspan="2">Petroleum & Gas Industry</td></tr>
<tr><td rowspan="3">Industries with different working patterns</td><td>7 working days with constant load</td></tr>
<tr><td>6 working days with constant load</td></tr>
<tr><td>6 working days with day time operation</td></tr>
<tr><td rowspan="5">Service</td><td colspan="2">Public & Private sector offices</td></tr>
<tr><td colspan="2">Hotel</td></tr>
<tr><td colspan="2">Public & Private Hospital</td></tr>
<tr><td colspan="2">Educational Institutes</td></tr>
<tr><td colspan="2">Marine & Aviation</td></tr>
<tr><td>Transport</td><td colspan="2">Domestic Electric Vehicle Charging pattern</td></tr>
</table>

Three scenarios were developed to analyse the 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 the base demand forecast.

Low Economic Growth Scenario (LEG Scenario)

In this scenario economic growth was reduced 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 demand for electricity will increase with shifting from other energy forms to renewable based electrical energy. This assumption is targeted towards carbon neutrality by 2050. 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, but main focus is given to the transport sector. Electric vehicle penetration was taken into account in this scenario giving due consideration to global EV outlook and country situation. [8]

Table 3.5 shows the annual average growth rate of Net Generation and Peak Demand for 2023-2047 planning horizon for each scenario.

Table 3.5 – Annual Average Growth Rate 2023-2047 of MAED scenarios

Scenario	Total Net Generation Growth Rate %	Peak Demand Growth Rate %
Reference	5.0	4.8
Low Economic Growth	4.6	4.4
High Electricity Penetration	5.2	5.0

Total electricity demand of the MAED reference scenario and Base Demand Forecast 2023-2047 compared in section 3.6 and it was observed that those two are in line for the planning horizon. However, more accurate sector wise end user information is required to capture the real end user impacts for the electricity demand.

Projected final energy demands for Reference, Low Economic Growth and High Electricity Penetration scenarios are given in Figure 3.8 and peak demand projection is given in Figure 3.9.

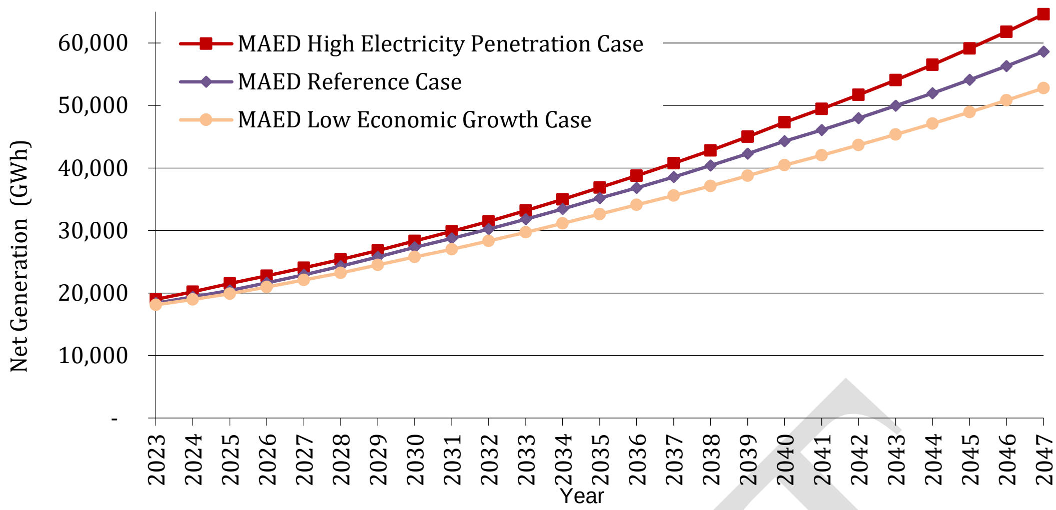


Figure 3.8 - Generation Forecast Comparison - MAED model

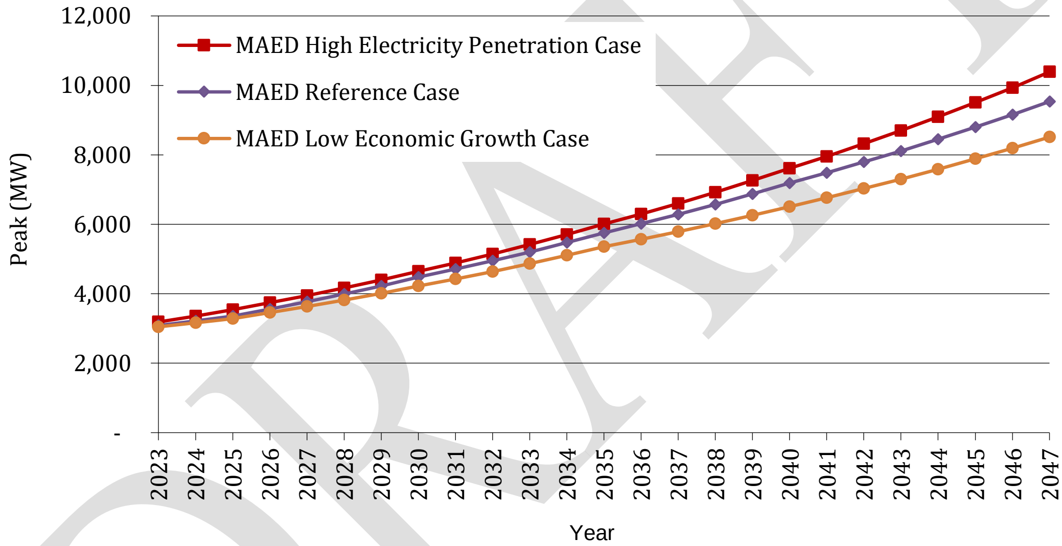


Figure 3.9 – Peak Demand Forecast Comparison - MAED Model

3.6 Demand Forecast Scenarios and Sensitivities

Different demand forecast scenarios and sensitivities were prepared considering variations to the base demand forecast, using long term time trend approach, considering end user approach with MAED model and those are listed below. The effects of the load variation (High and Low load forecast) on the base case generation expansion plan are described in Chapter 8.

1. **High Load Forecast (Econometric)** - The forecast developed considering higher economic growth of the country beyond 2023 and economic sector change based on higher growth in Industrial and Service sector in future.
2. **Low Load Forecast (Econometric)** - The forecast developed considering economic growth rate reduction compared with annual growth rate considered for the base load forecast

(slow recovery of the economy considered for the initial years) and also reduction of other driving factors.

3. **Long Term Time Trend Forecast** - The forecast developed purely based on the time trend approach using the past 25 year electricity demand figures starting from 1996.

4. **MAED Load Projection –** The projection 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.

Annual demand forecast of the above scenarios & sensitivities are presented in Annex 3.1. Figure 3.10 & Figure 3.11 shows graphically, the electricity net generation and peak load forecast for the above four scenarios including Base Load Forecast.

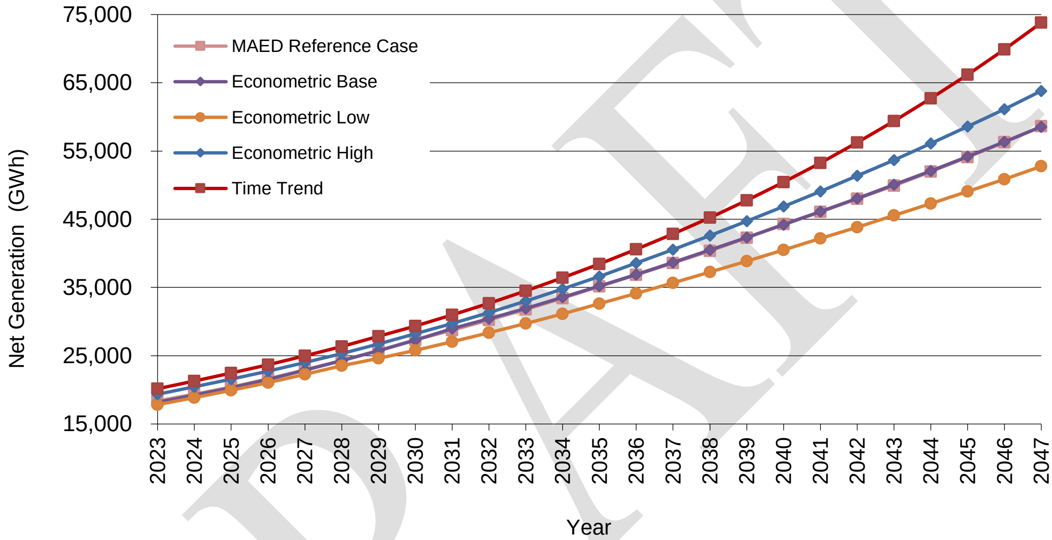


Figure 3.10 - Generation Forecast Comparison - Econometric, Long Term Time Trend and MAED Model

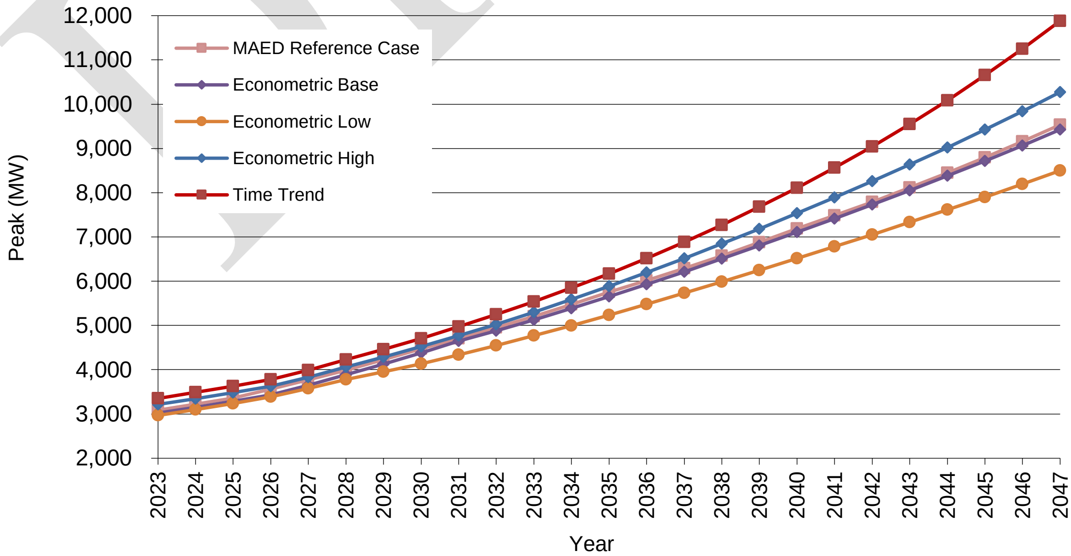


Figure 3.11–Peak Demand Forecast Comparison - Econometric, Long Term Time Trend and MAED Model

3.7 Comparison with Past Forecasts

Electricity 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 associated socio economic factors. Table 3.6 shows the comparison of past demand forecasts used in the previous expansion plans and their percentage variation against the gross energy sold in respective years. Electricity demand forecast is determined based on information considering:

- National economic development,
- National population growth,
- Increase in Electricity tariff consumer account,
- Increase of per capita income, etc.

The under achievement or over achievement of above facts will contribute to negative or positive deviation in actual demand from the forecast.

Table 3.6 – Comparison of Past Demand Forecast with Gross Energy Sold (in GWh)

Year	LTGEP 2011 - 2025	LTGEP 2013 - 2032	LTGEP 2015 - 2034	LTGEP 2018-2037	Gross Energy Sold (GWh)
2012	10,698 (+2.1%)	10,675 (+1.9%)			10,475
2013	11,402 (+7.3%)	11,104 (+4.5%)			10,624
2014	12,149 (+9.8%)	12,072 (+9.1%)			11,063
2015	12,941 (+9.8%)	12,834 (+8.9%)	11,516 (-2.3%)		11,786
2016	13,773 (+7.7%)	13,618 (+6.5%)	12,015 (-6.0%)		12,785
2017	14,630 (+8.9%)	14,420 (+7.4%)	12,842 (-4.4%)		13,431
2018	15,530 (+10.2%)	15,240 (+8.2%)	13,726 (-2.6%)	14,588 (+3.5%)	14,091
2019	16,481 (+12.8%)	16,075 (+10.0%)	14,671 (+0.4%)	15,583 (+6.7%)	14,611
2020	17,489 (+22.4%)	16,937 (+18.6%)	15,681 (+9.8%)	16,646 (+16.5%)	14,286
2021	18,563 (+22.0%)	17,830 (+17.2%)	16,465 (+8.2%)	17,478 (+14.9%)	15,214

Note:

1. Within bracket figures indicate the percentage deviation of demand forecast with reference to gross energy sold
2. Demand forecast represent actual electricity energy demand of the country considering rooftop solar self consumption

3.8 Electricity Demand Reduction and Demand Side Management

Energy demand reduction is taken as a key alternative in the design of energy supply schemes, as it is another way of balancing the energy demand with available supply, as opposed to building new facilities to cater to increasing demand. Demand Side Management (DSM) is a set of activities, which encourage consumers to modify their level and pattern of electricity usage. DSM refers not only to energy reduction but also for load shifting, peak shaving etc. which will help to change load profiles to constant flat load curves by allowing more electricity to be provided by less expensive base load generation. Ultimately, these initiatives will avoid peak demand burden on the network by supporting efficient utilization of available generating options.

Improving Energy Efficiency and Conservation is identified as one of the ten pillars of the National Energy Policy & Strategies (NEPS) of Sri Lanka, 2019. These efforts will reduce the overall cost of energy to the consumer while saving valuable resources of the country and reducing the burden on the environment. Therefore, demand reduction and demand side management will be an important thrust in the foreseeable future. Efficient use of energy will be promoted in all sectors and across the energy value chain, engaging both the suppliers and users, even extending the services to newer markets such as transport and agriculture.

The NEPS identified several strategies on energy demand reduction impacting many sectors in the demand side. Accordingly, identified main strategies which are directly and indirectly related to the power sector are as follows:

- Further strengthening of the national energy efficiency improvement and conservation programme engaging all stakeholders in household, industrial and commercial sectors.
- Energy efficiency improvement and conservation will be promoted through minimum energy performance standards and labelling of appliances, and by introducing green procurement processes in state and private sector organisations.
- Taxation and other incentives and disincentives to support the market for efficient technologies will be introduced.
- Expert energy advisory services will be offered through state and private sector service providers to promote energy efficiency, conservation and energy cost reduction across all end use sectors.
- Water resources will be recognized as a valuable indigenous energy resource. Efficient use of water by competing users at places where there is a high opportunity cost to water will be enhanced.
- Conversion efficiency of power generation facilities will be enhanced.
- A strategic plan for street lighting will be formulated to ensure proper management of street lighting.

- Automated demand response technologies will be considered as a main demand-side management strategy.

- Losses in energy delivery networks will be reduced to optimum levels.

- Virtual offices and video/teleconferencing will be promoted by making necessary changes to organisational working culture as a strategy to minimize physical movement.

- Energy efficiency will be a primary concern in retrofits, and new building designs will be evaluated for their energy performance on a mandatory basis.

- Smart technologies, including smart buildings and complete conversion to smart metering will be ensured to convey price signals to customers, altering the demand profile to reduce the overall cost of supply.

Sustainable Energy Authority (SEA) which carries the responsibility of designing and implementing the energy efficiency improvement & conservation programme, attempted to implement a national programme named Operation Demand Side Management (Operation DSM) under the guidance of a Presidential Task Force on Energy Demand Side Management (PTF on EDSM) with modest success. The programme, launched in 2017 could not amass the financial and human resources as anticipated in the programme design. Eventually, the programme was concluded in 2020, winding up the operations of the Secretariat operated on behalf of the Task Force, due to the want of funds and administrative support for implementation.

Some of the candidate concepts for reducing energy demand identified by the Task Force as ten thrust areas including efficient lighting, efficient refrigerators, efficient chillers, efficient air conditioning, efficient motors & variable speed drives, eliminating incandescent lamps, efficient fans, green buildings, smart homes and power factor improvement continued under the auspices of the SEA.

SEA managed to deploy several major programmes on energy efficiency improvement & conservation. A brief summary of the initiatives taken by SEA is given below:

Financing Energy Efficiency: The Authority managed to successfully approach the Green Climate Fund (GCF) partnering with the World Bank to formulate a financing programme on energy efficiency amounting to USD 108 million. Identified as the Sri Lanka Cooling Project, it is expected that these proceeds will be available in 2023 to improve air-conditioning systems and lighting systems in commercial buildings, identified as two thrust areas under the Task Force. At present, a technical assistance programme is deployed as a project preparatory activity, involving all stakeholders. The World Bank deployed a mission in 2022, to assist the preparation of the credit programme.

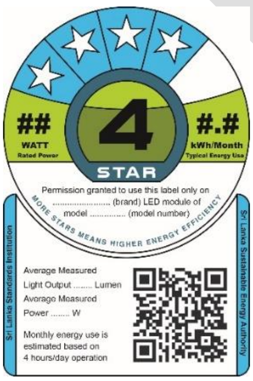
Chiller Survey: A survey has been planned to get a broad picture of the chiller population in the country and to establish a database of their capacities, age, efficiency, etc. With this information, it will be possible to calculate the total energy use of the chiller population and to predict the potential savings which could be achieved by replacing inefficient chillers with modern efficient units. This will be a main item to be considered under the Sri Lanka Cooling Project.

Efficient Refrigerator Programme: This is a scheme of replacing old inefficient refrigerators with efficient Minimum Energy Performance (MEP) labeled refrigerators in households. It is planned conduct a pilot project in the Western Province, where old refrigerators in 1,000 households will be replaced with new MEP labeled refrigerators with a trade in offer, arranged through credit card facilities through participating vendors. Old refrigerators are demolished and refrigerant is collected and handed over to tertiary education institutes. The country-wide energy saving potential in replacing old refrigerators with new ones will be estimated through this pilot project.

Establishment of Energy Consumption Benchmarks: The main target of this project is to facilitate the energy conservation in commercial and industrial sectors through long-term programmes such as Energy Manager programme, Energy Auditor programme, establishing energy consumption benchmarks, etc. Accordingly, a regulation on Energy Consumption Benchmarks is to be enforced. This regulation will be initially applicable for retail and financial sectors as a mandatory energy efficiency improvement programme. This will enable the monitoring of energy consumption levels of above-mentioned sectors and improve energy efficiency.

Enforcing the Code of Practice for Energy Efficient Buildings: The main objective of the Energy Efficiency Building Code (EEBC) is to improve the energy performance of large-scale buildings such as commercial buildings, industrial facilities and large-scale housing establishments. EEBC was finalized by the end of 2021, printed and disseminated among the stakeholders. Draft Regulation approved by the Board has been sent to the Department of Legal Draftsman. Implementation programme for the EEBC will be initiated in 2023.

Energy Labelling Programme for Appliances: Dissemination of energy efficient appliances in the market is very important in order to reduce energy demand in the country. Yet energy efficiency is not an information revealed by the product suppliers and hence customers do not have an opportunity to select energy efficient products during purchasing of energy using appliances. Through appliance energy labelling programme energy labels which display the energy efficiency of products in a simple manner, so that the customers can select energy efficient products during purchasing. At present mandatory energy labelling schemes are in operation for Compact Fluorescent Lamps (CFLs), Ceiling Fans (swept dia: 1400 mm) and LED lamps while voluntary labelling schemes have been introduced for Computers and Refrigerators. It



is planned to extend the energy labelling programme for LED panels, Ceiling Fans (sweep dia: 1200 mm), Televisions, Rice cookers, Water Pumps, Gas stoves, Pedestal Fans, Washing Machines and Irons by preparing and publishing standard by the end of 2024.

Consumer Education: A limited scope advertising campaign was conducted to support the demand management work of CEB, educating the public on energy saving, which was taken down after a brief period. The teaching syllabus of the Science subject which is presently undergoing a vast improvement got the inputs on sustainable energy from the Authority. 101 fun filled student activities were introduced to the curriculum to make sustainable energy, an appealing topic to the students of Grades 7-11. The publication of the quarterly 'Sanraksha' continued amidst the pandemic and other woes covering many important subject areas.

Study on Suitable Technologies for Street Lighting: This programme is designed to improve the street lighting system in Sri Lanka with the coordination of CEB, LECO, urban councils, municipal councils and Pradeshiya Sabhas. It is intended to prepare a set of specifications for street lights as an outcome of this programme. LECO has conducted a survey in the Sri Jayawardenepura Kotte area. Implementation of the project has been started from the Nugegoda Super Market area, and will be continued in this year.

Survey of Household Appliances: The sample survey involving 6,430 households carried out with the support of the Department of Census and Statistics provided some key results in the preliminary data analysis reports, giving a good understanding of the household energy use. The preliminary results are being processed by the Department to generate the national perspective of appliance use in households. It will provide a wealth of information on the load growth trends in the residential sector.

The formidable barriers to implementation of the DSM programme should be further analysed with associated costs, to gain a better understanding of the benefits and costs of the programme. In addition, in the present mode of implementation, utilities do not have a proper control over the implementation of DSM as it will depend on consumer attitudes, best moulded through strict Government policies including fines on wasteful consumption of electricity. With the subsidies given to the electricity sector in different categories, ensuring deterministic demand reduction may not be realistic. Therefore, the DSM forecast having high speculative public response dependent demand reduction should not considered in the determination of the future expansion plan and medium term time trend forecast model will capture the recent year trends including the impact on present DSM activities. On the other hand, interventions with little or no room for human response factors, ranging from automated demand response technologies to large scale plant improvement investments can be taken into future planning exercises, as they are proven to provide very predictable demand reductions and energy savings.

CHAPTER 4
THERMAL POWER GENERATION OPTIONS FOR FUTURE EXPANSION

Power generation options are broadly categorized into 'renewable energy based power generation' and 'thermal energy based power generation'. Thermal energy based power generation technology types are of internal combustion engines, gas turbines, steam turbines and combined cycles utilizing fuel combinations of oil, natural gas and coal. Nuclear power generation also falls into thermal power generation where nuclear fuel is used to operate a steam turbine.

Thermal power generation has its benefits as well as distinct drawbacks compared to its alternative, renewable power generation. Each technology has its specific operational characteristics as well as economics. A large number of factors including cost of development, O&M costs and operational constraints have to be evaluated while adhering to environmental limitations in order to consider the suitability of these primary generation options. The costs of associated environmental mitigation measures of respective generation options are included in the cost figures given in this report.

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

a) Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka, 2010 [9].

b) Energy Diversification and Enhancement Project Phase IIA- Feasibility Study for Introducing LNG to Sri Lanka, 2014 [10]

c) Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka, 2014. [11]

d) Feasibility Study on High Efficiency and Eco-friendly Coal-fired Thermal Power Plant in Sri Lanka, 2015 [12]

e) Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka, 2018. [8]

4.1. Thermal Power Candidate Technologies

4.1.1 Thermal Power Technologies

The main categories for thermal power development technologies are based on Internal combustion engines, gas turbines, steam turbines and combined cycles.

Internal combustion Engines

Internal combustion engines are typically categorized by speed and fuel type. They come in fuel forms of gaseous fuel, liquid fuel, and dual fuel. Due to the possibility of adopting modular sizes of these engine technologies, higher degree of flexibility is seen in operation. In addition, it provides favourable fuel efficiency merits in part load operations with fast start up times. However, the inertia support from internal combustion engines is low.

Simple Cycle Gas Turbines

Gas turbine can operate from both gaseous fuel and liquid fuels. They are classified into two main categories; aero derivative gas turbines and industrial gas turbines. Both of these find application in the power generation industry, for peaking and fast load balancing applications. Simple cycle gas turbines have faster start up times and quick ramping capabilities while aero-derivatives have additional advantages of higher efficiency, no additional cost on O&M for the startup and less maintenance downtime. Gas turbines provide high rotating inertia which is essential for power system stability.

Combined Cycle Gas Turbine

Combined cycle gas turbine plants consist of gas turbine (GT), heat recovery steam generators (HRSG) and steam turbine (ST). There are many different configurations but most common are 1x1x1 and 2x2x1. As common practice, the HRSG is tailored specifically for each gas turbine unit but there are also configurations where 2 or more gas turbines are connected to a single HRSG (2x1x1). Combined cycle plants are often characterized with very high efficiencies designed for baseload and intermediate load operations.

Steam Turbines

Steam turbines are one of the most conventional technologies to produce electricity. Steam is produced by firing boilers, with the help of using fuels such as coal, nuclear and biomass. Steam turbines do not easily adapt to excessive load variations, therefore, are better suited for base load operation. However advanced designs in once through boiler technologies enable certain level of flexibility for operation of coal power plants.

4.1.2 Candidate Thermal Power Plant Specifications

A list of power generation technologies with different fuel configurations were considered as candidate thermal power plants in the planning studies. These were based on prevailing models in the market and previously conducted feasibility studies.

A summary of the capital costs and economic lifetimes of candidate plants taken as input to the present studies is given in Table 4.1. Capital costs of projects are in two components: The foreign cost and the local cost. During the prefeasibility 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. 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 2022 values. 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.

Table 4.1 - Cost Details of Thermal Expansion Candidates

Plant	***Net Capacity (MW)***	***Pure unit cost (USD/ kW)***	***Const: Period (Years)***	***Total unit cost with IDC at 10% (net) (USD/kW)***	***Economic life (Years)***	***Fixed O&M cost (USD/kW Month)***	***Variable O&M cost (USD/ MWh)***
15 MW NG IC Engine	16.62	1,064	1.5	1,134	20	2.99	5.80
15 MW FO IC Engine	16.62	1,064	1.5	1,134	20	2.99	5.80
15 MW Diesel IC Engine	17.1	1,064	1.5	1,134	20	2.99	5.80
200 MW NG IC Engine Plant	208	646	1.5	734	20	2.99	5.80
250 MW NG IC Engine Plant	256	646	1.5	734	20	2.99	5.80
40 MW NG Gas Turbine	40.2	579	1.5	618	20	0.59	4.59
40 MW NG Gas Turbine (Aero Derivative)	41.1	754	1.5	804	20	1.36	4.79
100 MW NG Gas Turbine	106.4	406	1.5	432	20	0.59	4.59
200 MW NG Gas Turbine	191.8	352	1.5	375	20	0.59	4.59
300 MW NG Combined Cycle	288.5	940	3	1,068	30	1.04	2.60
400 MW NG Combined Cycle	419	890	3	991	30	1.04	2.60
300 MW High Efficient Coal Plant	270	1,900	4	2,252	30	3.45	4.59
600 MW Super Critical Coal Plant	564	2,044	4	2,423	30	3.45	4.59
600 MW Nuclear Power Plant	552	4,892	5	6,056	60	10.28	2.42

All costs are in December 2020 border prices, IDC = Interest during Construction

Operating characteristics of these plants are shown in Table 4.2.

Table 4.2 – Characteristics of Candidate Thermal Plants

Plant	Net Capacity (MW)	Min Load (MW)	Heat Rate (kcal/kWh) Full. Load	Heat Rate (kcal/kWh) Avg. Incr.	Full Load Efficiency (Net,HHV) %	FOR
15 MW NG IC Engine	16.62	1.6	2,021	1,797	42.6	10
15 MW FOIC Engine	16.62	1.6	2,074	1,844	41.5	10
15 MW Diesel IC Engine	17.1	1.7	1,943	1,727	44	10
200 MW NG IC Engine	208	1.6	2,021	1,797	42.6	10
250 MW NG IC Engine	256	1.6	2,021	1,797	42.6	10
40 MW NG Gas Turbine	40.2	20.1	2,911	2,038	29.6	8
40 MW NG Gas Turbine (Aero Derivative)	41.1	20.5	2,315	1,621	37.2	8
100 MW NG Gas Turbine	106.4	53.2	2,548	1,784	33.8	8
200 MW NG Gas Turbine	191.8	95.9	2,568	1,798	33.5	8
300 MW NG Combined Cycle	288.5	112.5	1,919	1,428	44.9	8
400 MW NG Combined Cycle	419	167.6	1,757	1,288	49	8
300 MW High Efficient Coal Plant	270	135	2,241	1,935	38.4	3
600 MW Super Critical Coal Plant	564	338.4	2,082	1,833	41.4	3
600 MW Nuclear Power Plant	552	496.8	2,685	2,343	32.1	0.5

Heat values of petroleum fuel and coal based plants are in HHV; FOR = Forced Outage Rate

4. 2 Fuel Types & Fuel Prices Considered for Analysis

Petroleum based fuels, coal, natural gas being the primary sources of fuel, were considered for this long term power generation expansion plan. Additionally, nuclear fuel was considered under the present context considering technical constraints. Hydrogen is also emerging as a clean fuel technology which can be used to operate thermal plants. Considering the high volatility present in fuel prices, constant fuel prices are mainly used in long term planning studies. Therefore, the fixed prices in constant terms based on average of recent years and near future projections by World Bank were used for this planning study. The price sensitivity of the plan was tested for fuel price escalation based on International Energy Agency forecast in World Energy Outlook – 2021. All fuel prices considered are in economic terms, exclusive of taxes.

4.2.1 Liquid Petroleum Products (Auto Diesel, Fuel oil, Naphtha):

In the present context, all fossil fuel based thermal generation in Sri Lanka would continue to depend on imports. Ceylon Petroleum Corporation (CPC) presently provides all petroleum products required for thermal power stations. Furthermore, oil exploration activity is presently ongoing in the Mannar basin.

Weighted average of crude oil CIF price to Sri Lanka from year 2018 to 2021 is 60.74 USD/bbl which is in line with the Brent Crude Oil index for the same period. However, during initial four months of the year 2022, a rapid increase of crude oil price is observed at 100.6 USD/bbl due to global economic factors.

The comparison of crude oil prices with World Bank fuel price forecast (April, 2022) is shown in Figure 4.1. Due to high uncertainty in predicting future fuel prices, weighted average of last three-year prices and future three-year projections by the World Bank was considered as the basis of deciding the crude oil price considered for LTGEP 2023-2042. The crude oil price based on this basis is 69.6 USD/bbl. A fuel price sensitivity scenario is modelled in Section 10.3 to capture the implications of long term international price forecasts.

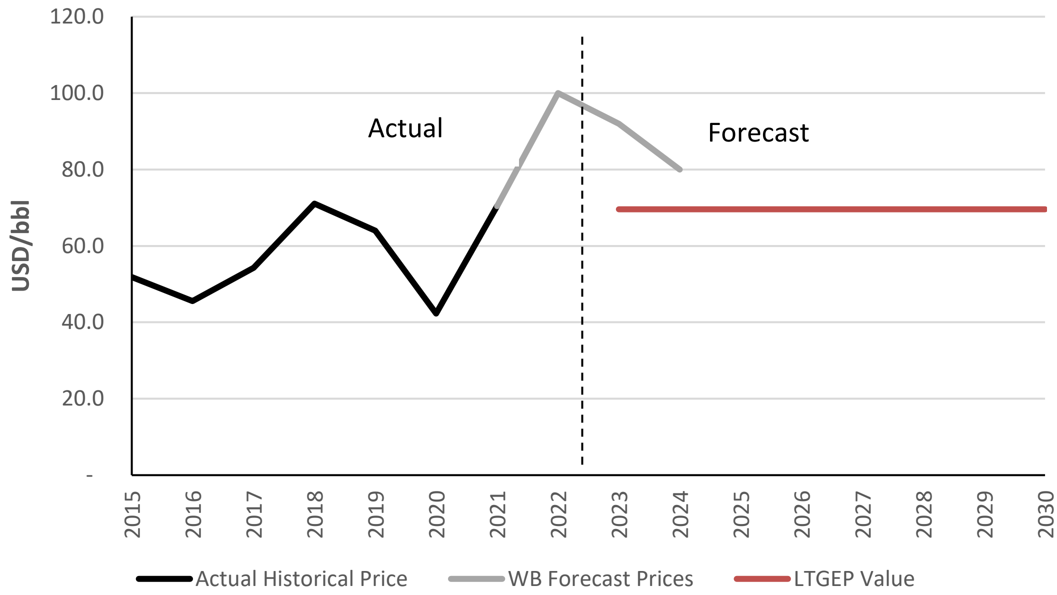


Figure 4.1 –Crude Oil Price Estimation for Analysis in LTGEP

Based on this projected crude oil price and weighted average value of the economic prices provided by the CPC, the fuel prices for diesel, fuel oil and naphtha are derived for LTGEP 2023-2042. The CIF prices are shown in Table 4.3 with the fuel characteristics and the fuel prices used in the analysis. For each fuel type, the applicable local cost were separately added. Further, all the heat contents given are based on Higher Heating Value (HHV).

Table 4.3 – Oil Prices and Characteristics for Analysis

Fuel Type	Heat Content (kcal/kg)	Specific Gravity (kg/l)	CIF Price ($/bbl)
Auto Diesel	10,500	0.84	75.4
Fuel oil	10,300	0.94	82.4
Naphtha	10,880	0.76	59.1

Source: Oil prices based on Ceylon Petroleum Corporation

4.2.2 Coal

Coal is a common fuel option for electricity generation in the world. Coal prices vary with the specific calorific value of coal and other specific parameters of the coal quality such as Ash content, Sulphur amount and volatility. Coal procured to Sri Lanka at present is based on the API 4 index from Argus which is correlated to the coal of net heat value of 6,000 kcal/kg on FOB basis from Richards Bay, South Africa. Shipping cost may vary depending on shipping distance and typical values range from 12-15 USD/MT.

The weighted average of coal prices based on API 4 index from year 2018 to 2021 including handling charge is 114.23 USD/MT. However, during initial four months of the year 2022 a rapid increase of coal prices is observed up to 240 USD/MT due to global economic factors.

The comparison with World Bank fuel price forecast (April, 2022) which is based on coal from New castle, Australia is shown in Figure 4.2. Due to high uncertainty in predicting future coal prices, weighted average of last three-year prices and future three-year projections by the World Bank was considered in deriving coal price for LTGEP 2023-2042. A fuel price sensitivity scenario is modelled in Section 10.3 to capture the implications of long-term international price forecasts.

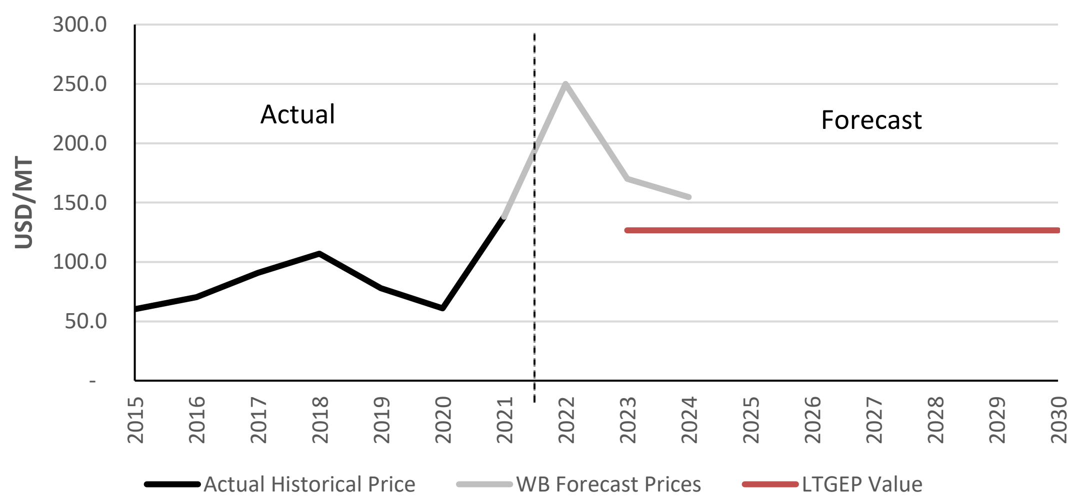


Figure 4.2 –Coal Price Estimation for Analysis in LTGEP

Two coal types are used in planning studies based on different handling costs associated with potential locations. The values are shown in Table 4.4.

Table 4.4 – Coal Prices and Characteristics for Analysis

Fuel Type	Net Heat Content (kcal/kg)	Market Price (USD/MT)	Remarks
Coal type 1	6,000	141	Coal Power Plants at Norochcholai
Coal type 2	6,000	138	High Efficiency Coal Power Plants and Super Critical Coal Power Plants at East Coast (Not used in the base case)

Source: Coal prices based on API 4 Index

4.2.3 Natural Gas

Natural gas would add diversification to the country's fuel mix. There is no commercially developed gas field in Sri Lanka though discoverable gas reserves have been identified. Natural Gas as a fuel for Gas Engines, Gas Turbine and Combined Cycle plants is an attractive option from environmental perspective as it is having relatively low carbon emission.

(a) Regasified Liquefied Natural Gas

Feasibility study for introducing LNG to Sri Lanka that was conducted in year 2014, has identified the Colombo North Port as the best site for development of a LNG terminal out of several promising candidate sites including Hambantota and Trincomalee. LNG requirement of the country was determined considering the fuel 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 NG fired power plants by considering the technical, economic, social and environmental aspects. As identified therein, LNG facility suitable for Sri Lanka would have a land based storage, regasification unit and necessary piping structures with a properly established LNG importing mechanism (via tanker ships).

The recent development of Floating Storage and Regasification Unit (FSRU) which can be moored in the sea has faster implementation possibility than a land based storage structure and is found to be less capital intensive. Considering the initial requirements identified in previous planning studies, CEB has initiated procurement process for the deployment of a FSRU and mooring system, offshore of Kerawalapitiya with a regasification capacity of 375 MMSCFD and LNG storage capacity of minimum 156,000 m3. The terminal is expected to operate for a period of 10 years on BOO basis whereas the Mooring System on BOOT basis. Pipeline infrastructure up to the boundaries of the power plants will be established by Ceylon Petroleum Corporation on BOOT basis.

LNG prices are categorized based on long term contracts, medium term contracts and short term spot prices. There are different LNG pricing mechanisms adopted in different regions of the world. The long term contracts are often linked with oil price and in the Asian market, Japanese Crude Oil Cocktail (JCC) and Brent Crude Oil Index is used for this purpose. Platts Japanese Korean Marker (JKM) is another benchmark price for the Asian region. In addition, LNG contracts based on Henry Hub prices are also considered for Long Term and Medium Term Contracts.

The LNG price from year 2018 to 2021 based on Brent Crude Oil Index is, 7.53 USD/MMBtu (weighted average value with 12.5% proportional linkage to Brent Crude Oil Index). The Henry Hub Index based weighted average LNG Price for the same period is 7.45 USD/MMBtu (linked to Henry Hub Crude Oil Index with formula 1.15%*HH+ 4). It is observed that during initial four months of the year 2022, Asian Natural gas prices have increased up to 15.99USD/ MMBtu due to global economic factors.

The actual and the forecast of World Bank fuel price (April, 2022) which is based LNG import price in Japan, is shown in Figure 4.3. Due to the high uncertainty in predicting future gas prices, weighted average of last three-year actual prices and future three-year projections by the World Bank was considered for LTGEP 2023-2042. The CIF price of LNG, based on this basis is 11.6 USD/MMBtu.

A fuel price sensitivity scenario is modelled in Section 10.3 to capture the implications of long term fluctuations of international LNG price.

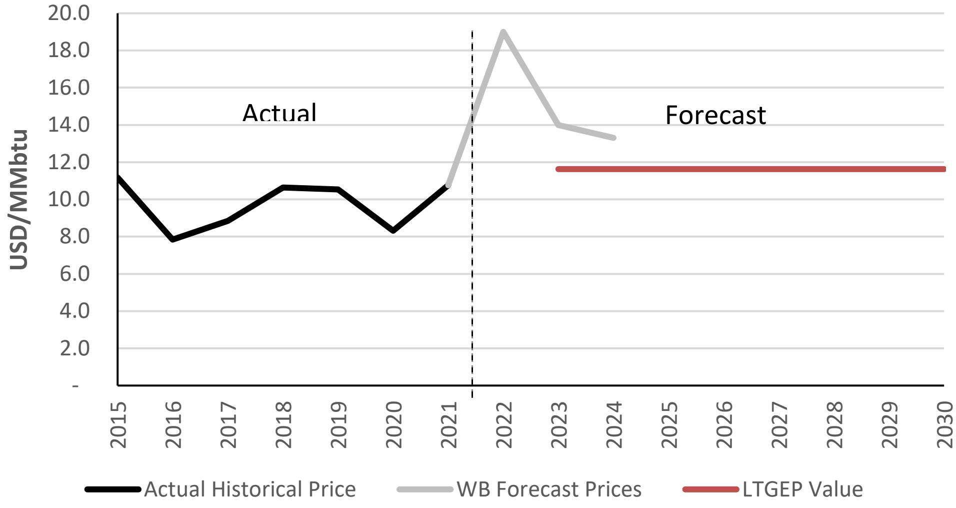


Figure 4.3 –Natural Gas Price Estimation for Analysis in LTGEP

In addition to the CIF price, the price of fuel delivered to the power plant is calculated with an estimated handling charge of 2 USD/MMBtu, which relates to the cost of regasification and transportation of fuel through pipeline network. Hence, price of regasified LNG delivered to the power plant terminal is taken as 13.6 USD/MMBtu in the analysis.

(b) Local Natural Gas

The Petroleum Resources Development Secretariat (PRDS) which was established under the Petroleum Resources Act, No. 26 of 2003, launched its first licensing round for exploration of oil and gas in the Mannar Basin, off North-West coast in 2007. Exploration activities initiated with the awarding of one exploration block with an extent of 3,000 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 350 bcf of recoverable gas reserves. Gas production rate predicted is 70 MMSCFD. The volumetric estimate of the technically complex "Barracuda" discovery exceeds 1.8 tcf. The gas potential in the wider Mannar Basin based on current data and models is estimated to be 9 tcf. PRDS is currently engaged in joint studies with international oil companies to explore additional oil and gas prospectively.

The price of local natural gas depends on factors such as commercially exploitable quantity, contractual fiscal terms, government tax policy, off take options, delivery options for locations, socio-economic concerns, exploration risk capital, development and operating & maintenance costs, etc. Most of these factors are market sensitive. Hence, it is difficult to make accurate predictions on the gas price and the estimated values based on volatile assumptions. The PRDS estimate on local gas price excluding the tax components, is in the range of 7– 10.5 USD/MMBtu.

4.2.4 Liquefied Petroleum Gas

LPG based power generation has only emerged recently, mainly as an environmentally friendly alternative to oil based power generation. Countries which have plans to develop natural gas power plants in the future have developed LPG based power plants in the short term, with the longer term plan to convert to natural gas once the gas is available. The fuel quality used for the power generation has to have high propane content in contrast to the LPG used for residential applications.

4.2.5 Hydrogen

Hydrogen has recently emerged in the global market as a clean fuel that is capable of operating thermal power plants. Many thermal power plant manufacturers have designed their future plants to operate by blending natural gas with synthetic fuels such as hydrogen. Hydrogen is produced by electrolysis or by splitting natural gas through steam methane reforming (SMR). SMR requires carbon capture and storage (CCS) technologies to be in place, as CO2 is produced during the process. Hydrogen production cost from natural gas ranges from 0.5-1.7 USD/kg. Use of CCS technologies to reduce the CO2 emissions from hydrogen production increases this cost of production up to 1-2 USD/kg. At present, utilizing renewable electricity to produce hydrogen through electrolysis costs around 3-8 USD/kg and it is proven as the cleanest method of producing hydrogen[13].Various other hydrogen production technologies have emerged compromising the cost of production with CO2 emission during production. However, the production cost of Hydrogen is expected to decrease with the global trends on clean energy and associated decarbonization goals.

4.2.6 Nuclear

Nuclear power has been considered to be explored as an alternative thermal generation option to avoid excessive dependency on imported fossil fuels for power sector in Sri Lanka. A cabinet approval has been received on 8th September 2010 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.

Accordingly, Sri Lankan government requested and subsequently received International Atomic Energy agency (IAEA) assistance through the technical cooperation programs as follows;

- IAEA TC Project SRL/2/008 (2012/2013 period): Supporting Energy Planning and Pre-Feasibility Study for Nuclear Power and Human Resources Development in Nuclear Power Engineering

- IAEA TC Project SRL/2/010 (2018/2020 Period): Establishing a Roadmap for Nuclear Power Program in Sri Lanka

Under the purview of Ministry of Power; Ceylon Electricity Board (CEB), Sri Lanka Atomic Energy Board (SLAEB) and Sri Lanka Atomic Energy Regulatory Council (SLAERC) contributed as the leading institutions for the project “Establishing a Roadmap for the Nuclear Power Programme in Sri Lanka” with the objective of providing a strong technological, financial, environmental and social understanding for policy makers to take firm decision on the Nuclear Power Development in Sri Lanka. Project Management Unit “To Study the Nuclear Power Option in Sri Lanka” under the Ministry of Power, acted as the Nuclear Energy Programme Implementing Organization (NEPIO). The main task of the project was to prepare a comprehensive report addressing the 19 milestones, according to Phase 1 of the IAEA milestones approach. IAEA assistance was obtained on nine major areas to prepare the comprehensive report covering the 19 milestones for Nuclear Power Development. The nine major areas are as follows.

- Legal and regulatory
- Communications and Human Resource
- Policy
- Electricity market and generation mix
- Nuclear Power Technology
- Siting of NPPs/Nuclear facilities
- Economics and Finance
- Localization Assessment
- Safety and Security

During the project period, a Steering Committee, Program Management Unit and Working Groups have been formed and several IAEA expert missions have been conducted with the participation of stakeholder organizations.

A draft Comprehensive Report on Nuclear Power Study and Planning Programme of Sri Lanka was prepared in 2020 and the same has been reviewed by International Atomic Energy Agency (IAEA) leading to the final report dated March 2021. This comprehensive report is scheduled to be submitted to the Government of Sri Lanka following the Integrated Nuclear Infrastructure Review (INIR) Phase1Mission which is currently undertaken by IAEA.

The capacity of proven and widely adopted nuclear power plant designs are in the range of 600 MW to 1,650 M. Accommodating a nuclear power unit above 600 MW to the Sri Lankan network will be technically challenging with the network condition which depends on the anticipated demand growth and the generation mix which is expected to be dominated by variable renewable energy sources. This technical limitation should be further analysed with scenarios containing the development of cross-border interconnection with India and the planned energy storage additions including pumped storage hydro and battery storage.

Alternative small scale nuclear power plants such as Small Modular Reactors (SMR) are globally still under research level and those can become a proven technology in future.

4.3. Thermal Plant Specific Cost Comparison

The specific costs of the selected candidate plants for different plant factors are tabulated in the Table 4.5. These specific costs are derived by the calculation methodology described in section 6.4 which considers the capital investments cost, operation and maintenance cost, fuel cost and economic life time of a given generation alternative. The specific cost curves reveal how different technologies perform at different plant factors. Power plants which are cost effective at low plant factors are operated as peak load power plants whereas power plants which have lower specific cost at higher plant factors are operated as base load power plants. However, in actual simulations, the size of the generation units is taken into account and it would make a significant effect in the final plant selection. The specific cost curves for the candidate thermal power plants are given in Annex 4.1. Full load heat rates are considered in deriving the specific costs.

Table 4.5 - Specific Cost of Candidate Thermal Plants in USCts/kWh (LKR/kWh)

Power Plant	Plant Factor							
	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8
15 MW NG IC Engine	26.58 (53.56)	17.40 (35.06)	14.34 (28.90)	12.81 (25.81)	11.89 (23.96)	11.28 (22.73)	10.84 (21.85)	10.51 (21.19)
15 MW FOIC Engine	28.70 (57.84)	19.52 (39.34)	16.46 (33.17)	14.93 (30.09)	14.01 (28.24)	13.40 (27.00)	12.96 (26.12)	12.64 (25.46)
15 MW Diesel IC Engine	27.87 (56.15)	18.68 (37.65)	15.62 (31.48)	14.09 (28.40)	13.18 (26.55)	12.56 (25.32)	12.13 (24.43)	11.80 (23.77)
200 MW NG IC Engine	21.94 (44.22)	15.08 (30.39)	12.79 (25.78)	11.65 (23.48)	10.96 (22.09)	10.51 (21.17)	10.18 (20.51)	9.93 (20.02)
250 MW NG IC Engine	21.76 (43.85)	14.99 (30.21)	12.73 (25.66)	11.60 (23.38)	10.93 (22.02)	10.48 (21.11)	10.15 (20.46)	9.91 (19.97)
40 MW NG Gas Turbine	20.03 (40.37)	15.75 (31.73)	14.32 (28.85)	13.60 (27.41)	13.17 (26.55)	12.89 (25.97)	12.69 (25.56)	12.53 (25.25)
40 MW NG Gas Turbine (Aero Derivative)	21.59 (43.50)	15.60 (31.43)	13.60 (27.41)	12.61 (25.40)	12.01 (24.20)	11.61 (23.39)	11.32 (22.82)	11.11 (22.39)
100 MW NG Gas Turbine	16.34 (32.93)	13.21 (26.63)	12.17 (24.53)	11.65 (23.48)	11.34 (22.85)	11.13 (22.43)	10.98 (22.13)	10.87 (21.90)
200 MW NG Gas Turbine	15.69 (31.62)	12.93 (26.05)	12.01 (24.19)	11.55 (23.27)	11.27 (22.71)	11.09 (22.34)	10.95 (22.07)	10.86 (21.87)
300 MW NG Combined Cycle	20.95 (42.21)	14.23 (28.68)	11.99 (24.16)	10.87 (21.91)	10.20 (20.55)	9.75 (19.65)	9.43 (19.01)	9.19 (18.52)
400 MW NG Combined Cycle	19.64 (39.58)	13.32 (26.84)	11.09 (22.35)	10.16 (20.48)	9.53 (19.21)	9.11 (18.36)	8.81 (17.75)	8.58 (17.30)
300 MW High Efficient Coal Plant	32.93 (66.35)	18.73 (37.73)	13.99 (28.19)	11.62 (23.42)	10.20 (20.56)	9.26 (18.65)	8.58 (17.29)	8.07 (16.27)
600 MW Super Critical Coal Plant	33.71 (67.93)	18.97 (38.23)	14.06 (28.33)	11.60 (23.38)	10.13 (20.41)	9.15 (18.43)	8.45 (17.02)	7.92 (15.96)
600 MW Nuclear Power Plant	70.80 (142.67)	35.75 (72.03)	24.06 (48.49)	18.22 (36.71)	14.71 (29.65)	12.38 (24.94)	10.71 (21.58)	9.46 (19.05)

Note: 1 USD = LKR 201.5

4.4 Current Status of Non-Committed Thermal Projects

(a) Coal Power Projects

500 MW coal fired power plant was identified to be developed by the joint venture company Trincomalee Power Company Limited (TPCL) between Ceylon Electricity Board and National Thermal Power Corporation Ltd. of India. The project was not granted the approval by PUCSL in the Long Term Generation Expansion Plan 2015-2034, indicating the undertaking given to the Supreme Court Case No SCFR 179/2016.

Considering the 'General Policy Guidelines for Electricity Industry 2021' the development of all non-committed coal power plants identified in previous planning cycles as mentioned below were discontinued.

i. High Efficient and Eco Friendly Coal fired thermal power plant 1200 MW (either 300 MW High efficient advanced subcritical power plants or 600 MW super critical power plants) at Foul Point, Trincomalee.

ii. 300 MW coal power plant as an extension to Lakvijaya Power Plant, Norochchole.

(b) Natural Gas Power Plants in the West Coast – Kerawalapitiya

Land area of 100-acre in Muthurajawela has been identified for the development of natural gas based power generation in the Western region. Cabinet approval has been granted for this development and EIA for land reclamation is in progress by the Sri Lanka Land Development Corporation (SLLDC).

4.5 India-Sri Lanka Electricity Grid Interconnection

In 2002, NEXANT with the assistance of United States Agency for International Development (USAID) carried out the Pre-feasibility study for Electricity Grid Interconnection between India and Sri Lanka. It was a first step in developing the project concept and was expected to serve as the basis for future technical and economic analysis. In 2006, POWERGRID, India reviewed and updated the study with USAID assistance.

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 out jointly by CEB and Power Grid Corporation Indian Limited (POWERGRID) with the main objective to provide the necessary recommendations for implementation of 1,000MW HVDC interconnection project. Various Line route options and connection schemes were analysed during the pre-feasibility studies. Technical, economical, legal, regulatory and commercial aspects in trading electricity between India and Sri Lanka have also been considered. Consequently, the route option was selected for the initial feasibility study consisting of 130 km 400 kV HVDC overhead line segment from Madurai to Indian sea coast, 120 km of 400 kV Under-Sea cable from Indian sea coast to Sri Lankan Sea coast, 110 km Overhead line segment of 400 kV from Sri Lankan sea coast to Anuradhapura and two converter stations at Madurai and Anuradhapura.

During the India-Sri Lanka Joint Technical Team studies initiated in year 2017, it was proposed to shift the HVDC station in Sri Lankan side from Anuradhapura to New Habarana. Further, after site survey it has been found that overhead interconnection is feasible without any submarine cable. Both synchronous (AC) and asynchronous (DC) options have been studied and the asynchronous interconnection option (DC) has been found desirable. Asynchronous interconnection (overhead) through 2x500 MW Madurai-New to New Habarana along with 500 MW terminals at both ends has been identified as the preferred option in stage I. Both HVDC converter technologies, Conventional Line Commuted Conversion (LCC) and Voltage Source Conversion (VSC) are to be considered in future studies.

The cost of each alternative for combined stage I and II development has been estimated and power flow studies have been conducted from Indian and Sri Lankan side during the latest studies. The financial feasibility study is yet to be initiated.

CHAPTER 5
RENEWABLE GENERATION OPTIONS FOR FUTURE EXPANSION

5.1 Introduction

Sri Lanka being a tropical country is blessed with indigenous renewable energy resources and these indigenous resources have underpinned the economic growth for decades. Country's electricity needs were predominantly met by renewable energy sources in nineties, with prime contribution from the major hydro power resources. That has enabled the country to maintain green credential with per capita low carbon emissions level in electricity generation throughout the past years. The rising economic growth and the energy demand led the expansion of other renewable energy sector as well as thermal based resources. Though the large hydro resources played a major role in renewable energy share in the past, variable forms renewable resources such as wind and solar are becoming dominant contributors in the future. In line with the global efforts to mitigate climate change implications, Sri Lanka has progressively enhanced its ambitious targets and development activities on renewable energy development. Accordingly, a substantial growth in the indigenous wind and solar resource development is envisaged as the country is moving forward on a low carbon pathway in meeting its future electricity requirement.

Renewable energy sources encompass a broad range of continuously replenishing natural energy resources and technologies. A renewable energy system converts the energy in sunlight, wind, stored water, sea-waves, geothermal heat or biomass into heat or electricity without exhausting the source. Sri Lanka has harnessed major renewable resources (large hydro) to almost its maximum economical potential. Sri Lanka has a history of enabling the development of distributed renewable energy resources in the electricity sector and continues to scale up the renewable energy contribution as the electricity demand grows. Developing and harnessing the energy from following renewable energy forms are progressing at present.

- Hydro power
- Wind Power
- Solar Power
- Biomass Power
- Power from Municipal Solid Waste

Hydro power and biomass power generation are not intermittent whereas wind and solar photovoltaic sources are highly intermittent and seasonal in nature. These inherent physical characteristics of the resources cause challenges in grid integration and different power systems have different capability for grid integration based on system characteristics as well as resource characteristics. Prior to the preparation of Long Term Generation Expansion Plan, a comprehensive Renewable Energy Grid Integration Study is conducted to investigate the grid integration challenges and to explore necessary interventions to facilitate higher levels of intermittent renewable energy penetration.

5.2 Major Hydro Development

Sri Lanka was a Hydro Power dependent nation till the late 1990s in which majority of the power requirement was met from hydro power plants. The hydro power potential in the country has been vastly exploited and only a limited amount of generation projects remains in the pipeline. Several prospective candidate hydro projects have been identified in the Master Plan Study [14], 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 870 MW. A part of this hydro potential has been already exploited under the Upper Kotmale Hydro Power Project, which is the latest addition to large scale hydro power projects in Sri Lanka.

5.2.1 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 [15]. 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 [16 and 17] 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 [18] 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, 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.

(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. In December 2018, the Technical Feasibility Study of the project has been completed by Central Engineering Consultancy Bureau (CECB) of Sri Lanka.

(f) "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" carried out by JICA funds [19] 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.

(g) "Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka" carried out by JICA Funds in March 2018 [8] proposed an alternative location for a Pumped Storage Power Plant considering the existing Victoria reservoir being used for the lower pond and an existing irrigation pond located on the eastern side of Victoria Lake being used for the upper pond by expanding the pond.

5.2.2 Committed Hydro Power Projects

Some major hydro projects identified in the Master Plan Study as Broadlands (35MW) and Moragolla (30.2MW) which are under development by CEB and is considered as committed power plants in this study. Ministry of Irrigation and Water Management is developing the Uma Oya Multipurpose project which shall include the construction of a 122MW Hydro Power Plant within its scope.

i. Broadlands Hydro Power Project

The Broadlands Hydropower Project is a run-of-river type project planned to build in the Kelani River. It is expected to generate 126GWh of electrical energy annually. The Broadlands Hydropower Project is the first large scale hydropower plant which has obtained Carbon Development Mechanism registration in Sri Lanka in December 2012. Concurrence has been established to maintain a firm water release to safeguard White Water Rafting sport in Kithulgala area and as a result there will be a reduction in the annual energy generation. China National Electric Equipment Corporation (CNEEC) was selected as the main Contractor of the project. The total project cost is USD 82 million. The 85% of funding is provided by Industrial & Commercial Bank of China (ICBC) and the balance was obtained from Hatton National Bank. The project is already grid connected and under commissioning stage.

ii. Moragolla Hydro Power Project

The 30.2 MW Moragolla Hydropower Project located downstream of the Kotmale power station and approximately 3.5km downstream from the confluence of the Mahaweli Ganga with the Kotmale Oya. Total storage capacity of the reservoir is 4.66 MCM and the annual mean energy expected is 97.6 GWh. The Moragolla Hydropower Project was first identified in "Report on a Survey of Resources of the Mahaweli Ganga Basin, Ceylon, Hunting Survey Corporation, 1962." prepared in cooperation with the Survey General of Ceylon. The location was highlighted as one of potential hydropower sites in "Master Plan for the Electricity Supply of Sri Lanka, German Agency of Technical Cooperation, 1988". Central Engineering Consultancy Bureau of Sri Lanka (CECB) in association with Al-Habshi Consultants with the finance of the Kuwait Fund for Arab Economic Development in 2009. Nippon Koei Co., Ltd. in joint venture with Nippon Koei India Pvt. Ltd. to conducted a review of the Feasibility Study and detailed design work in 2012. At present site preparatory works are being carried out and detailed designs are developed. The power plant is expected to be operational by the latter part of 2023.

iii. Uma Oya Multipurpose Project

Uma Oya Hydro Power project is one of the largest remaining sites of hydro potential. The project is a Multipurpose Development project and it will transfer water from Uma Oya to Kirindi Oya in order to develop hydropower and to irrigate the dry and less developed south-eastern region of the central highlands. The project is implemented by the Ministry of Mahaweli Development & Environment in coordination with the Ministry of Power & Energy and Ceylon Electricity Board. The total capacity is 122 MW and expected annual energy is 290 GWh. The financial assistance for the project is provided by the Government of Iran and currently the project is under construction and expected to be completed in 2022.

5.2.3 Candidate Hydro Power Projects

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 in 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.

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

Following projects were identified in previous plans as the candidate large scale hydro power projects but are on hold at present.

i. Seethawaka Hydro Power Project

Seethawaka River project was identified in the Master Plan produced by CEB in 1989 as Sita014. The project was on the Seethawaka Ganga which is an upper tributary of the Kelani River and was initially identified as a 30MW capacity producing 123 GWh per year. However, due to Social and Environmental considerations, the project was scaled down to a lower capacity. CEB has conducted the initial feasibility studies together with the procurement of consultancy services for Environmental Impact Assessment (EIA) of the project.

A detailed feasibility study has been carried out by CEB and completed in December 2018 in addition to the EIA which was completed in May 2020. As per the feasibility study, a reservoir with a 3.51 MCM capacity is to be impounded to facilitate regulation of flow mainly for generating hydro energy during daily peak demand of electricity. Installed capacity of the power house is 24 MW with an expected annual power generation about 54 GWh (at 27% plant factor).The Project had received the EIA approval from the CEA. However due to high investment cost and the failure of securing funding for the project as a CEB implemented project; the project is on hold at present.

ii. Other Hydro Power Projects

Multipurpose hydro projects such as Thalpitigala and Gin Gaga are identified to be developed by the Ministry of Irrigation and Water Resource Management.

The preliminary feasibility studies and EIA studies of the Thalpitigala Hydro Power Project in Uma Oya basin have been finalized. As per the feasibility studies, the power plant is 15MW (2 x 7.5MW) with an estimated annual energy contribution of 52.4GWh (at 39% plant factor). Storage capacity of the reservoir is 17.96 MCM. However due to difficulties in securing project finances, the project is on hold at present.

The preliminary feasibility studies for Gin Ganga hydro project are in progress and the parameters of the hydro power plant are yet to be finalized.

5.2.4 Capability of Hydro Power Plants

Sri Lankan power system has a fairly large portion of installed hydropower capacity. As hydro generation makes a considerable impact on the dispatch of high cost thermal power, 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 are 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.

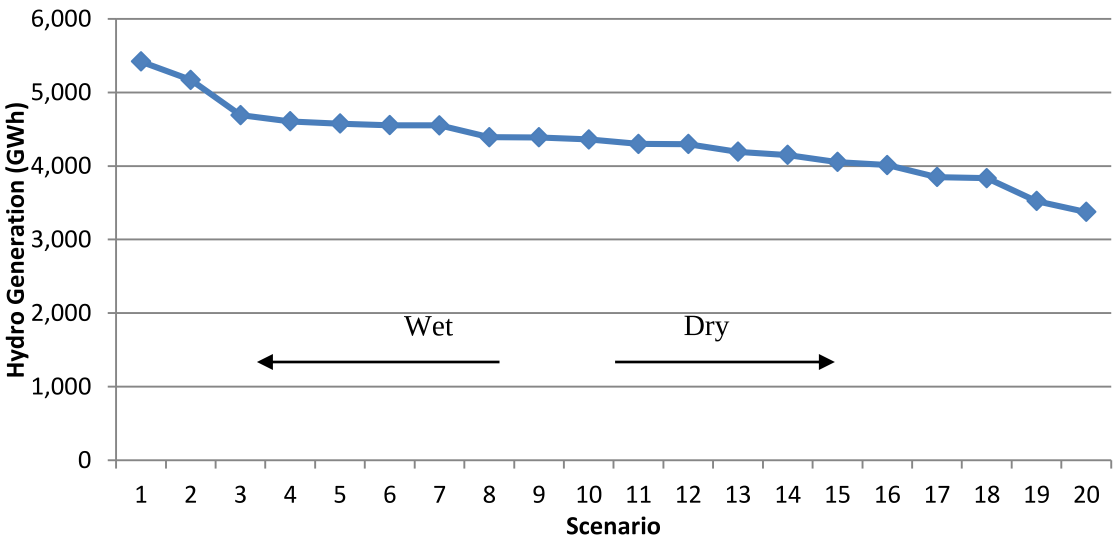


Figure 5.1 - Potential of Hydropower Energy from Past Hydrological Data

The annual energy variation of the hydro system was evaluated using the Stochastic Dual Dynamic Programming (SDDP) model which is a hydrothermal dispatch model used for short, medium and long term operation studies. As inputs for the model, inflow data for past 20 years and the operational details of hydro plants were entered and the model allows a more detailed representation of the uncertainty of future inflows through the use of multiple scenarios in the time-coupled optimization. Based on SDDP simulation outputs, hydro generation figures for the existing plus new hydro plants are obtained and average annual hydro generation figures for 20 scenarios is shown in Figure 5.1. This shows that the capability of the major hydro system

(Mahaweli, Laxapana and Samanala) together with new hydro power plants could vary as much as from around 3,100 GWh to 5,500 GWh. Long term planning exercise has been carried out using 10 scenarios while for short term operational studies up to 100 hydro scenarios have been simulated.

5.3 Hydro Power Capacity Extensions

The capability of providing peak power support from hydro power was studied under the JICA funded "Hydro Power Optimization Study of 2004". Given below is a brief summary of expansions of existing hydro stations studied under the "Hydro Power Optimization Study" [15].

5.3.1 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 as a priority.

(a) Victoria Power Station

(i) Victoria Expansion:

CEB has identified expansion of Victoria Hydro Power Plant as an option to meet the peak power demand. A feasibility study for expansion of Victoria Hydro Power station has been done in 2009 [20] and had considered three options for the expansion. Those were; addition of another power house nearby the existing power plant (base option), addition of a surface type power house 2km downstream of the existing power house (downstream option) and using of Victoria and Randenigala reservoirs as a pumped storage power plant (pumped 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 114 MW each will be added. This expansion could double the capacity of Victoria while the energy benefits are as follows.

Table 5.1 – 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 USD 222 million for implementation. Further analysis of the project is required before incorporating into the Long Term Generation Expansion Plan.

(ii) Victoria Upgradation:

An alternate proposal has been proposed by the Generation Division of CEB to upgrade the existing capacity of Generation units installed in Victoria. The proposal elaborates on rehabilitation works on the turbine and generator while upgrading the capacity of a single unit from 70MW to 92.8 MW by increasing the turbine discharge to 52.8m^3/s. The total output from the Victoria Power Station is expected to be 273 MW. It shall enable usage of excess water in high inflow seasons and also enhance the operating flexibility of the Victoria power station for system frequency controlling requirements.

According to the ongoing study by 'Mahaweli Water Security Investment Program' under the Ministry of Mahaweli Development and Environment, it has been proposed to transfer water from the Randenigala reservoir to Kaluganga reservoir to meet the water demand requirements of North Central Province. This will impact the water availability and operation of the reservoirs of the Mahaweli complex. Therefore, the feasibility of Victoria expansion and upgradation should be further reviewed based on the study outcome of Mahaweli Water Security Investment Program before incorporating into the Long Term Generation Expansion Plan.

(b) Upper Kotmale Diversion:

Diversion of Pundalu Oya and Pundalu 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.

5.3.2 Samanala Complex

Samanalawewa hydropower scheme has envisaged the development of the potential in two stages during initial studies. The existing Samanalawewa power station which was developed under stage I has two generators rated at 60MW each. Stage II of the scheme envisaged the development of Diyawini Oya reservoir and further two units of 60MW each aimed at providing the needs of additional peaking capacity in future. During construction stage of Samanalawewa, provisions such as a bifurcation with bulk head gate in the penstock and a space for an addition of two 60MW units have been made to extend the capacity of the power plant to 240MW.

Stage II of the project was reviewed by CECB in 2000. "Samanalawewa Hydropower Project - Feasibility of the development of stage II" report by CECB concludes that the development of Diyawini Oya is not economical and recommends installation of one additional 60MW capacity with provisions to add the next unit of similar capacity in future.

The stage II development was again reviewed during "The Study of Hydropower Optimization in Sri Lanka" in February 2004. Referring the previous study, the development of Diyawini reservoir is excluded from the analysis but considered the addition of 1 unit as well as 2 units for evaluation. A summary of expansion details according to this report is shown in Table 5.2. Overall evaluation in this study suggested that further investigations and studies are required.

Table 5.2 – 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

5.3.3 Laxapana Complex

During the Phase E of the Master Plan for the Electricity Supply in Sri Lanka, 1990 [21], 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 Polpitiya Power Stations, studies have been carried out. 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 has been increased from 100MW to 116MW. Planned replacement of generator, turbine governor excitation & controls of the Old Laxapana Station were completed increasing the plant capacity (from 50 MW to 53.8 MW) and efficiency.

Expansion of Polpitiya Power Station has been implemented and the plant capacity has been increased to 90MW from 75MW from 2019 onwards.

5.4 Other Renewable Energy Development

As the large hydro resource of the country have been largely developed over the past decades, the other renewable energy sources, mainly small hydro, wind, biomass and solar resources remain as the main potential indigenous resources for future development. The tropical climate of the country influenced by monsoon winds characterizes these resources and distinct seasonality exists in hydro and wind resources.

The grid connected small renewable energy resource development was first initiated in 1997 through the regularization of small renewable energy power producers by Ceylon Electricity Board with the publication of standardized power purchase agreement (SPPA). The growth of other renewable energy sources in Sri Lanka in commercial scale commenced with the development of mini-hydro resources in 1997 and it continued under feed-in tariff system. The introduction of cost reflective, technology specific feed-in tariff in 2007 paved the way for the development of wind resources and considerable growth was achieved in local wind resource development. With the introduction of roof top solar Net Metering facility in the country in 2009 followed by the rapid technology cost decline and rapid growth in the global solar PV industry after 2010, solar resource development gained steep growth over the past years. Subsequent introduction of Net Metering, Net Accounting and Net Plus schemes stimulated the growth of domestic and industrial customers' rooftop solar schemes. Grid scale solar PV developments also started growing at different scales. The other renewable energy project development was led largely by the private sector with the facilitation of Ceylon Electricity Board and the Sri Lanka Sustainable Energy Authority and the first large scale renewable energy project of the country, the 100 MW wind farm in Mannar island was developed by the Ceylon Electricity Board. The renewable energy projects have been successful in attracting investment and the renewable energy industry has been growing continuously over the years. The figure 5.2 below illustrates the growth of other renewable energy capacity over the last two decades.

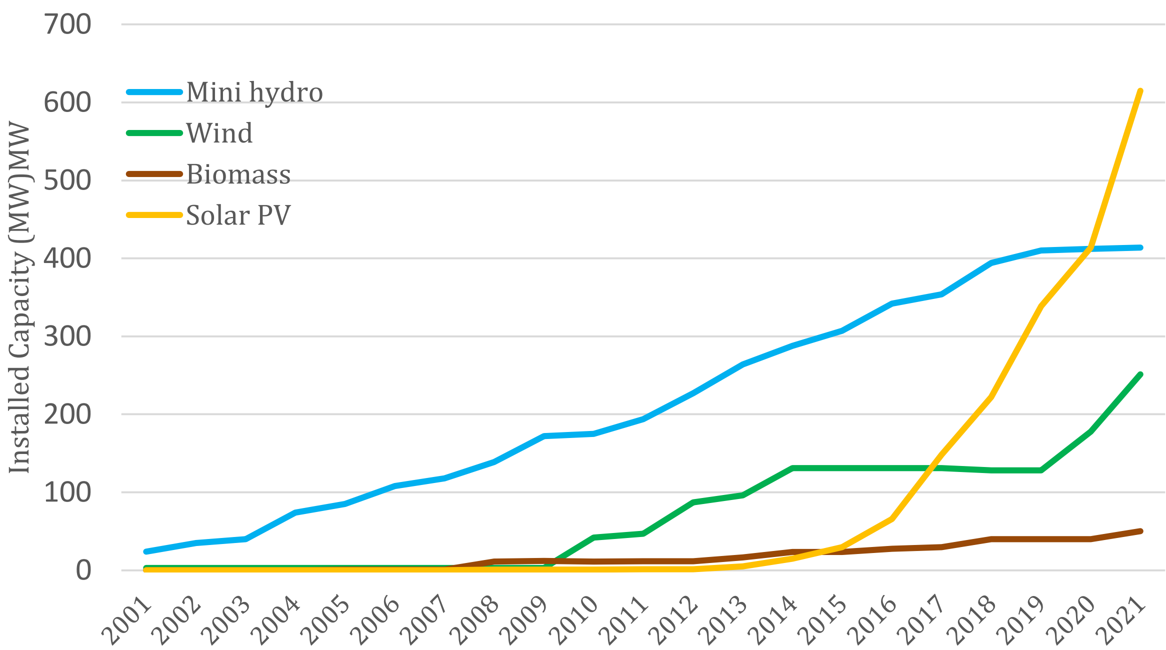


Figure 5.2: Other Renewable Installed Capacity by source 2001-2021

Share of Other Renewable Energy based generation at present is 17.5% of total energy generation in the country and its contribution is expected to increase in the future. At the end of 2021, 1330 MW of other renewable energy power plants have been connected to the national grid and the total comprises 414 MW of mini-hydro, 251 MW of wind, 100 MW of Solar PV (without roof top solar) and 50 MW of biomass based generation capacities. In addition, the rooftop solar PV capacity with a total of approximately 516 MW embedded at the consumer end (both CEB and LECO) is growing steadily.

Other renewable energy sources have been under the cost reflective technology specific tariff scheme since 2012 and with the falling technology costs and rising competition in the industry, competitive bidding process is increasingly being followed at present for the development of renewable energy projects. Table 5.3 shows the growth of the renewable energy capacity and energy contribution (at end of each year) compared to the overall capacity and generation for past 15 years in the country.

Table 5.3 – Energy and Capacity Contribution from Other Renewable Sources

Year	Energy Generation* (GWh)		Capacity** (MW)	
	Other Renewable	System Total	Other Renewable	Total System Installed Capacity
2007	344	9,814	119	2,444
2008	433	9,901	161	2,645
2009	546	9,882	181	2,684
2010	724	10,714	212	2,818
2011	722	11,528	227	3,141
2012	730	11,801	320	3,312
2013	1,178	11,962	367	3,355
2014	1,215	12,418	442	3,932
2015	1,466	13,154	455	3,850
2016	1,160	14,148	516	4,018
2017	1,464	14,671	562	4,087
2018	1,714	15,914	573	4,048
2019	1,761	15,922	915	4,499
2020	1,866	15,714	1,064	4,615
2021	2,922	16,716	1,331	4,700

*Rooftop Solar PV energy exported to the grid is included from year 2019 onwards but self-consumption is not accounted

**Includes rooftop solar PV installations (CEB & LECO) from 2019 onwards

5.4.1 Renewable Energy Grid Integration Study 2023-2032

5.4.1.1 Background & Methodology

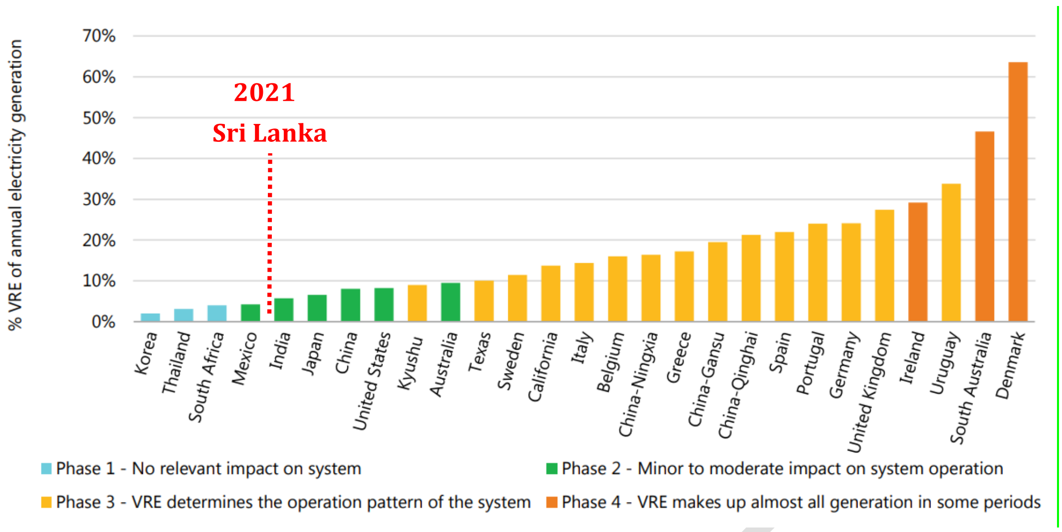
As the country is moving forward with an ambitious program for developing indigenous renewable energy resources towards enhancing its energy security in a low carbon future, substantial growth in indigenous renewable energy development is expected. Developing indigenous renewable energy resources including intermittent resources such as wind and solar at large scale creates growing concerns of their impact on the planning and operation of the power system. The 'General Policy Guidelines on the Electricity Industry for the Public Utilities Commission' which provides the specific government policy guidelines applicable to the Electricity Industry issued in January 2022, stipulates the target of achieving 70% of electricity generation from renewable sources by 2030. With the scale of wind and solar resource development required to achieve that target, Sri Lanka is expected to move to challenging phases of renewable energy integration.

Ceylon Electricity Board (CEB) as the Transmission Licensee having a statutory duty to develop and maintain an efficient, coordinated and economical system of Electricity Supply, conducts a comprehensive Renewable Energy Grid Integration Study specifically designed to identify and address the grid integration challenges related to introducing large amount of renewable energy sources. Almost all potential large hydro resources of Sri Lanka have been already tapped. Moderate growth is expected from the mini-hydro resources, considering the remaining economical resource potential. However, the addition of Mini-hydro and biomass resource is not restricted and will be assessed case by case for future development. Both wind and solar resources being variable renewable energy sources (VRE), introduce range of challenges in reliable and economic operation of power system as well as transmission network expansion. Therefore, assessment of technical, operational, economic aspects and identifying necessary integration measures through a proper grid integration study is the key for enabling the effective utilization of renewable energy sources for maintaining a quality and reliable electricity supply.

Supplementing the long term generation expansion planning studies, the grid integration study serves as a comprehensive examination of the challenges and necessary interventions associated with integrating higher levels of intermittent renewable energy generation in the electricity grid. The future development of the other renewable energy resources included in the Base Case of this LTGEP 2023-2042 is based on the study 'Integration of Renewable Based Generation into Sri Lankan Grid 2023-2032' [22]. The objective of the study is to investigate the most effective and efficient pathway with effective grid integration measures for Sri Lankan Power system for the goal of achieving a total renewable energy share of 70% from the total electricity generation by 2030.

The scale of wind and solar resource development currently being envisaged to meet the government policy targets will move the country's power system to phases where the integration challenges become much more significant requiring special operational, policy and investment based interventions.

According to the classification defined by International Energy Agency (IEA), key characteristics and challenges experienced by different countries with their present wind and solar penetration levels (Annual share of VRE generation), six different phases have been defined ranging from no impact to severe impact of VRE. The 4th phase is the highest phase reached by countries at present as shown in Figure 5.3. Sri Lanka with its present wind and solar development is at the beginning of phase 2 and expected to move to a higher phase with the significant growth of renewable energy in future.



Source: International Energy Agency

Figure 5.3: Classification of phases based on variable renewable integration challenges

As the major portion of the potential renewable additions is comprised of VRE, this study evaluates implications of VRE in different time frames covering capacity adequacy, transmission infrastructure development, system operational flexibility and system stability & reliability aspects of the power system. Therefore, this study is designed with an integrated approach combining resource assessment, capacity expansion planning, system operation analysis and transmission network analysis study components. Then the study recommends the key integration measures to be implemented at the grid level and at plant level (both dispatchable and non dispatchable). An outline of the study methodology is shown in the Annex 5.1.

5.4.1.2 Classification of RE Zones

Assessing resource potential for future development is a key step in the study process. Remaining major hydro and mini-hydro resource potential were considered in the study. The total exploitable wind and solar PV resource locations are based on the resource potentials identified by Sri Lanka Sustainable Energy Authority, assessed considering multiple factors such as the resource potential, local climate, land use and reservations, coastal reservations, access to resource locations, housing density, local climate and distance to transmission infrastructure, etc. The identified resources potentials for each type are planned to be developed following an economic order based on the resources quality (energy yield, geographical staggering due to variability etc.) and infrastructure requirement (land, transmission infrastructure, access roads etc).

Therefore, all wind and solar resources were classified in to seven renewable energy zones where each zone has a specific topographical and resource characteristic. All seven renewable energy zones have substantial potential for solar power, but the wind power is limited to renewable energy zones in Northern, North-western and North Central zones. The classification of zones considered in this study is shown in Annex 5.2. Cost details considered for each technology type and specific cost at certain plant factors are given in Annex 5.3.

5.4.1.3 Operational Study

Sri Lankan power system, being a small isolated power system, its ability to integrate more variable renewable energy that is intermittent in its nature, significantly depends on the stability and operational flexibility of the system. A system operation study was performed under the renewable energy grid integration study to investigate the implication on system operation to identify challenging operating conditions and potential solutions to mitigate the implications of renewable generation. Dispatchable power plants (both Major Hydro and Thermal plants) complement the non-dispatchable generation in meeting the electricity demand while maintaining the balance between supply and demand. Under high penetration levels of variable renewable energy, the dispatchable power plants are required to follow more cyclic operation and to provide fast ramping more regularly. Therefore, the technical constraints of the dispatchable power plants as well as the system flexibility level governs the ability of the system to operate under higher VRE penetration levels reliably.

Operation constraints are prominent specially during low load period such as weekends with large amount of wind, mini-hydro and solar PV generation. During such constrained periods the large thermal units have to lower their output to a minimum or consider shutting down depending on network requirement and the start-up costs etc. Beyond such levels a surplus generation exists in renewable which has to be either curtailed or stored to maintain the supply demand balance of the system. According to the study results, the curtailment magnitude is likely to increase year by year to significant levels with the addition of the planned renewable energy capacities. The most severe impact on operation is observed during periods where low demand coincides with high renewable periods. Therefore, it is crucial that the system operator has adequate measures such as flexible generation, VRE curtailment and energy storage to maintain the supply demand balance throughout the year. The study has recommended adopting improved flexibility performance in both technical and contractual terms for thermal plants, introducing plants with the capability of fast ramping and frequent cycling and the introduction of battery energy storage systems and pumped storage power plant as a long term energy storage measure to enhance system flexibility.

High shares of inverter based non-synchronous renewable energy generation challenges the stable operation of the power system. As the inverter based generation does not actively contribute to the synchronous inertia or to the system strength, high instantaneous penetration levels of inverter based generation lowers the system's ability to withstand sudden imbalances and disturbances that can potentially lead to system failures. The grid integration study evaluates the transmission infrastructure development and the impacts of VRE integration on the stability and security of the transmission network under different operating conditions. The study has proposed the required Transmission system development and strengthening measures for large scale renewable energy development. In addition to the storage requirement, batteries are proposed to provide fast responses required to manage the frequency under high penetration levels of variable renewable energy sources. Exact battery capacity that is required for this purpose will be evaluated through transmission planning studies.

5.4.2 Wind Resource Development

Sri Lanka is blessed with quality wind resources mainly located in the North-western coastal area, Northern area and central highland area. The wind resource patterns are mainly characterized by the Asian monsoon wind system and mainly the richest wind power potential of the island (Class 4 and above) is available in the areas that are exposed to southwest monsoon. Only a portion of the total available potential is economically exploitable due to reasons such as competing land uses, accessibility and environmentally sensitive concerns. Ceylon Electricity Board has identified these exploitable wind resource potentials and prioritized their development activities together with the expansion of transmission infrastructure. Annex 5.4 illustrates the prominent seasonality characteristics of different wind regimes of the island.

The economically exploitable wind power potential identified in the preliminary resource potential assessment was mainly concentrated on Northern and North Western coastal line of the country. The North Eastern coast and the central hills also hold certain amount of wind resources but not prioritized for the immediate development in large scale due to development constraints. The Mannar area, Northern area and Puttalam area are priority resource area to develop wind power compared to other regions of the country. In recent studies, new resource areas for wind power development in north central region have been identified by the Sustainable Energy Authority. However, only preliminary assessment is available without any resource measurement data at present.

The large potential for offshore wind power development in north western and south eastern regions have been identified by initial assessments in World Bank Group studies. However, there is lack of any detailed studies at present and the Sustainable Energy Authority shall engage in further studies to evaluate its potential. The capital cost of offshore wind power development is nearly 3-4 times higher than onshore wind power development; hence detailed studies are essential if development of such resources are to be embarked in future.

Both public and private sector participation in developing these resources is taking place and at present competitive mechanisms are being followed in developing projects. The first ever largest wind farm of the country, the 100 MW Thambapavani Wind Farm has been developed by Ceylon Electricity Board with financial assistance from Asian Development Bank (ADB) in the Southern coast of the Mannar island and further extension to the farm is being considered. Sri Lanka Sustainable Energy Authority had identified further wind resource development zones in Mannar island, Silawathura and Pooneryn area in which land area have been earmarked and gazetted.

5.4.3 Solar Power Development

Sri Lanka, being located within the equatorial belt, has substantial potential in solar resource. Solar resource maps of the country indicate the existence of higher solar resource potentials in the Northern half, Eastern and Southern parts of the country. Resource potential in other areas including mountainous regions is mainly characterized by climatic and geographical features. The cost of solar PV technology is becoming increasingly competitive and a steady and strong growth is expected to continue for both rooftop and ground mounted applications in commercial scale. The local solar power industry gained significant momentum over the past years due to number of support schemes and development initiatives of the Ministry of Power, State Ministry of Solar, Wind and Hydro Power Generation Projects Development, Ceylon Electricity Board and the Sri Lanka Sustainable Energy Authority.

Similar to the wind resource, the technical potential of integrating solar PV resources into the power system is assessed by the renewable energy grid integration study conducted by Ceylon Electricity Board. Both large scale and small scale development is planned for the next twenty years as solar PV is the main form of renewable energy source that indicates the highest growth for long term.

The Solar potential identified in the country can be classified in to following categories of development and are implemented through several configurations appropriately.

1. Grid connected fully facilitated Solar Park (Medium to large scale, 10-100 MW)
    a. Ground Mounted Solar
    b. Floating Solar
2. Grid connected partially facilitated Solar Park (less than 10 MW)
    a. Ground Mounted Solar
    b. Floating Solar
3. Distribution network connected Embedded Solar
    a. Rooftop (Net Metering, Net Accounting, Net Plus)
    b. Ground Mounted

5.4.3.1 Grid connected fully facilitated Solar Park (Medium to large scale, 10-100 MW)

Large scale solar PV park development has its own advantages in economies of scale and also the technical challenges in grid integration. Large scale solar PV parks in the scale of 100 MW are planned for future development in Northern, Southern and Eastern areas. The Sri Lanka Sustainable Energy Authority has identified potential resource locations for large scale development in Trincomalee, Hambantota, Monaragala, Ampara, , Batticaloa, , Kurunegala, Puttalam and Mathale areas to support a longer term large scale development plan. Potential resource locations for the development of medium scale ground mounted PV capacities above 10 MW and below 100 MW have also been identified around the island. Prioritizing the development of large scale resources depending on the resource quality and associated development cost is important for achieving the economic efficiency of the long term renewable energy development program.

The Ground mounted, Grid connected fully facilitated Solar Parks have been modelled based on single axis tracking mode. Almost all these projects are expected to be connected with Storage for energy shifting purposes.

Floating solar technology alternative has the potential to resolve the land limitation issues for developing solar power plants. In this, solar panels are usually mounted upon a floating structure to keep its location fixed. The floating structure is anchored and moored. Direct advantages of floating solar technologies are,

- Higher gains in energy production due to lower PV array temperature
- Minimal Land requirement compared to ground-mounted solar PV
- Reduction in water evaporation of reservoirs
- Possibility of sharing existing electrical infrastructure

A Floating solar power plant with a capacity of 42 kW was installed at the University of Jaffna in 2020 marking the country's first such project as a pilot project. Moreover, the Sri Lanka Sustainable Energy Authority has identified multiple potential reservoir locations to develop large scale floating solar projects and detailed techno-economic assessments for each resource sites are required for long term investment decisions.

5.4.3.2 Grid connected partially facilitated Solar Park (less than 10 MW)

One strategy to minimize the inherent variability challenge of solar PV resources is geographical scattering of solar PV installations as there is a greater diversity in variability characteristics in smallest time scales. Studies conducted by Ceylon Electricity Board have identified that the geographical distribution of solar PV projects can reduce the overall variability levels experienced by the system notably.

A cumulative capacity of 51 MW was connected to the grid from the feed in tariff system by year 2017. In line with the second phase of the accelerated solar development program of the government, Ceylon Electricity Board initiated the development of 60MW with 1MW Solar PV projects at 20 selected Grid substations through international competitive bidding process under Build, Own & Operate (BOO) basis. Subsequently several phases of the same scheme were launched to develop 1 MW x 90, 1 MW x150 solar PV plants with improved contractual terms to provide more facilitation and flexibility to developers. In addition, procurement of several projects of 10 MW capacity have also been awarded after selection through competitive tendering process. It is expected to commission a cumulative capacity of 94 MW by 2023 and another 147 MW by year 2024 from these projects.

Further 223 MW of Grid connected partially facilitated Solar Parks are expected to be opened up for investments in near future based on the availability of existing grid substations.

5.4.3.3 Distribution network connected Embedded Solar

Distribution network connected Embedded Solar is mainly classified in to two subcategories of rooftop solar and small-scale ground mounted solar.

The roof top solar systems are starting to play a prominent role in providing energy needs of the electricity consumers and it is an effective form of embedded generation located at the end user. Since these solar PV installations utilize the available rooftop spaces, those have less impact to the environment caused by land use. Several schemes are adopted worldwide to create an enabling environment for small scale and roof top PV penetration. The ''Energy Banking Facility' for such micro-scale generating facilities, commonly known as the 'Net Energy Metering Facility' for electricity consumers was first introduced in Sri Lanka in 2010 by the Ministry of Power and Renewable Energy through the power utilities Ceylon Electricity Boards (CEB) and Lanka Electric Company (LECO). Subsequently, the Government of Sri Lanka (GOSL) launched accelerated solar development program in 2016 to promote roof top solar installations in the country. In order to support the GOSL's renewable energy promotional drive, the Net Metering Concept was further enhanced by introducing another two schemes. Following are the three schemes under this program.

- Net Metering - Consumer is not paid for the export of energy, but is given credit (in kWh) for consumption of same amount of energy for subsequent billing periods
- Net Accounting - Consumer is compensated for the exported energy with a two tier tariff for 20-year period
- Net Plus -Consumer can install a solar PV generation unit and all the generated energy will be exported to the grid. Unlike previous two schemes there is no linkage between the consumption and electricity generation

The generating capacity of the facility is limited to the contract demand of the consumer in all three schemes. Solar PV installations for above three schemes are restricted to roof top type installations and to be connected to the low voltage distribution network. The total installed capacity of rooftop solar PV under three schemes has reached 516 MW (both CEB and LECO) by the end of 2021 surpassing the program's goal of reaching an installed roof top solar PV capacity of 200 MW by 2020.

These three schemes change the role of the traditional electricity consumer to a consumer and producer. Roof top capacity is expected to grow further in the forthcoming years. With the planned growth of rooftop solar PV capacity for future, it is essential to address the main technical challenges encountered at the distribution level to streamline the roof top solar PV program and to maintain the quality of the electricity supply to the consumers.

A new initiative was taken to develop ground mounted solar PV plants in the distribution system in small scale distributed manner to facilitate rapid uptake of solar PV utilizing the existing network infrastructure. It is expected to be connected to low voltage network, each with 75kW capacity on Build, Own & Operate (BOO) basis. These schemes are planned to be developed within 500 m radius of pre-identified distribution substations, mainly in rural locations and in areas that have less potential for rooftop solar installations.

5.4.4 Mini-hydro Development

History of small hydro power generation in Sri Lanka spans over a century and it is mainly associated with the power generation for the large scale tea plantations in the colonial era. Since then, the small hydro capacity grew gradually until 1960s when the electricity grid was extended to provide supply of electricity. In 1990s, CEB's assistance was provided for the development of the Mini hydropower sector with the required assistance to the private sector. The procedure for electricity purchases from Small Power Producers (SPPs) by the CEB was regularized beginning in 1997 with the publication of a standardized power purchase agreement (SPPA) which included a scheme for calculating the purchase price based on the avoided cost principle. Instead of avoided cost based tariff, a three-tier tariff was introduced with effect from year 2008. Currently the technology specific cost reflective tariff introduced in 2012 is in force.

The geo-climatic condition in Sri Lanka is favourable for the mini hydro development and several past studies have assessed the potential for the development of mini-hydro resources. A comprehensive study has been carried out as part of the Dam Safety and Water Resources Planning project (DSWRP) of the Ministry of Irrigation and Water Resources, focusing on 13 river basins of the country, and the study has concluded that the total Mini-hydro potential in the country as 873MW. As at the end of 2021, the total grid connected Mini hydro capacity is 412MW which comprises 387 MW developed by the private sector and 25 MW under the Moragahakanda Kaluganga Development multi-purpose development project by the Ministry of Mahaweli Development and Environment with the Mahaweli Authority of Sri Lanka. In this long term generation expansion plan, the Mini-hydro capacity is expected to grow moderately within next twenty years as most of the attractive resources and sites have been already developed. Therefore, future capacity additions are not restricted and shall be considered case by case, depending on the feasibility of implementation. Annex 5.5 illustrates the characteristics of annual mini-hydro production pattern.

5.4.5 Biomass Power Development

Biomass is a renewable resource that is primarily based on organic matter as a fuel related to plants, vegetation and waste that generates from agricultural and industrial process as a by-product or residue. Growing biomass as a fuel for Dendro power generation gained attention in the recent past and at the end of 2021 total biomass based capacity was 40 MW including both dendro and agricultural waste based power generation. Evidently, the growth of the biomass capacity in the past has not achieved the expected progress primarily due to the factors associated with biomass fuel supply mechanisms and only a moderate growth is expected in future. However, being a non-intermittent form of generation, the capacity additions are not strictly limited to the planned capacities and further capacity additions shall be considered depending on the feasibility and success of implementation.

5.4.6 Municipal Solid Waste Based Power Generation

Developments of grid scale waste-to-energy projects is identified as sustainable and timely solution for the solid waste management problems in the urban areas. As large amount of solid waste is accumulated throughout the country, converting Municipal Solid Waste to energy has a tremendous potential in waste management, reducing the negative social, health and environmental effects. Different technologies are available for the energy conversion process and the composition and characteristics of accumulated waste as a fuel is an important factor when utilizing for power generation purpose.

Sri Lanka's first Waste-to-Energy Power project was developed and commissioned in Kerawalapitiya area. The 10 MW project is able to convert 700 tons of solid waste, nearly 20% of the household waste to electricity each day. The project was developed with private sector investment with the facilitation of Ceylon Electricity Board and Sustainable Energy Authority. Further, CEB has already signed SPPA to develop 10 MW Municipal solid waste power plants at Karadiyana and several projects at LOI stage at Muthurajawela.

5.4.7 Other Forms of Renewable Energy Technologies

Although CEB has provided opportunity for the development of other forms of new renewable energy sources by requesting international proposals to develop new renewable technology applications by calling proposals (in 2018), no satisfactory proposals have been received. It is expected that such technologies will get attractive after having reached their commercial capability beyond present research level.

5.5 Development of Grid Scale Energy Storages

Integrating variable renewable energy at grid scale as well as end-use sectors while providing reliable supply of electricity has brought much significance to the potential energy storage applications. Storage technologies are diverse and their applications are rapidly expanding globally. Their applications in power systems are growing and can range from energy shifting, frequency controlling, and renewable energy fluctuation controlling. The economic value of different technologies varies depending on the type of application, amount of energy required, amount of power required and the location of the application.

High Energy density storage systems are suitable for performing energy shifting function in system operation whereas high power density storage technologies are suitable to provide fast power to manage instantaneous and momentary supply demand unbalances. Battery energy storages and pumped hydro energy storages are two major storage technologies applicable to power systems today. Ceylon Electricity Board has identified the requirement of developing the pumped hydro power project as a long term solution to increase power system flexibility. CEB is also currently embarking upon developing grid scale battery energy storages for the purpose of energy shifting as well as enhance the quality of the supply of electricity.

Considering the complexity of integrating higher levels of VRE to the system with inherent seasonality characteristics, it is becoming important to evaluate the possibilities of seasonal storage. The development of Hydrogen storage is emerging as a new technology to perform energy shifting through seasons.

5.5.1 Grid Scale Battery Energy Storage Development

Battery energy storage applications in power systems are expanding globally and the technology costs are declining notably. Even though the scale of battery energy storages applications in power systems are small compared to pumped storages, battery energy storages have a wide array of applications in all generation, transmission distribution and consumer end points. Given the range of applications, battery energy storages are employed to enhance the quality and reliability of supply of electricity.

The battery storage systems provide services in different time frames ranging from fast frequency support to energy arbitrage with economic dispatch. Also it provides various support services for renewable energy grid integration. Lithium-ion type of batteries in power system applications are growing at present than the other forms of chemical batteries such as Flow batteries, Lead-based batteries and Sodium Sulphur batteries. Techno-economic assessment of the type of battery storage application and the type of battery technology is essential to identify effective storage solutions.

Ceylon Electricity Board in its latest renewable energy grid integration study has assessed the requirement of grid side application of battery energy storages with the introduction of large amount of intermittent and non-synchronous generation in to the power system. Table 5.4 shows the details of battery energy storage considered for the planning studies.

Table 5.4 – Details of BESS

Capacity, Energy (MW, MWh)	*Capital Cost Pure ($/kW)*	*Capital Cost with IDC ($/kW)*	*Construction Period (Years)*	*Economic Life (Years)*
1 MW/4 MWh	***1330.0***	***1416.0***	***1.5***	***10***

Source : NREL, Cost Projections for Utility-Scale Battery Storage: 2021 Update

5.5.2 Pumped Storage Hydro Power Development

Being a matured technology, pumped hydro storage currently accounts for nearly 97% of the storage applications in power systems worldwide. Primary function of pumped hydro storage was to provide peaking capacity releasing the stored energy. However, the technology has now evolved to provide enhanced services to enable flexible grid operation specially with renewable energy integration.

CEB conducted the study in 2014 on exploring peak power generation options including pumped storage hydro power plant. The study titled "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" was done with the technical assistance from JICA. During the study, all the possible peaking options were evaluated and following options were identified as feasible options.

Hydro Power Plant Capacity Extension
Pumped 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 pumped storage power plants are the most suitable options for future development. 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 pumped storage power plant.

Pumped storage hydro power plant as a large scale storage medium that is able to serve several important secondary purposes other than providing the peaking power. Pumping operation of off-peak period enables the storage of surplus renewable energy that otherwise would have curtailed due to power system operational limitations. The new adjustable speed technology enables greater flexibility for pumping operation and it enables the frequency regulation functions and stability improvement by fast reaction to system supply and demand fluctuations. Moreover, the pumping operation during low load periods enables the operation of base load power plants in the system at their most efficient operating points. The renewable energy grid integration study identifies significant renewable energy curtailment requirement with planned renewable energy capacities. The curtailments are mainly due to the demand pattern of the country and seasonality and variability of variable renewable energy sources. A large scale pumped hydro storage will enable greater utilization of renewable energy resources while alleviating system operational challenges. Therefore, this long term generation expansion plan proposes the development of a pumped hydro storage project having variable speed type technology to achieve required flexibility to the Sri Lankan island power system.

At the initial stage, the study conducted by JICA and CEB identified 11 potential sites for the development of 600MW pumped 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. According to the ranking, Halgran Oya, Maha Oya and Loggal Oya which were located in Nuwara Eliya, Kegalle and Badulla districts were selected as the most suitable sites for future development.

After the detail site investigations carried out for the above three sites, the study concluded that the Maha Oya site location 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 pumped storage power plant should be 600MW considering the peaking requirement beyond 2025.The unit capacity of the power plant was determined considering the system limitations in terms of frequency deviations and manufacturing limitations of high head turbines. Another new site location for the PSPP plant was proposed by the Electricity Sector Master Plan Study completed in 2018 with the assistance of JICA. The proposed site is located in the Kandy district adjacent to the Victoria reservoir. This scheme will utilize the existing Victoria reservoir as the lower pond and an existing irrigation pond located at Wewathenna (on the eastern side of Victoria reservoir) as the upper pond, after expansion. The site has the potential to develop a pumped hydro storage power plant with a total capacity of 1,400 MW (4 x 350 MW) and staged development is proposed in the study.

Figure 5.4 below illustrates the proposed site under two studies mentioned above and the table 5.5 shows the estimated capital cost of development for proposed sites locations under two studies. Consultancy procurement process has been initiated to study both sites and to conduct the detailed feasibility studies for the most promising site. For the base case in planning studies 350 MW unit size has been considered and the final unit size will be decided after the conclusions of the consultancy study.

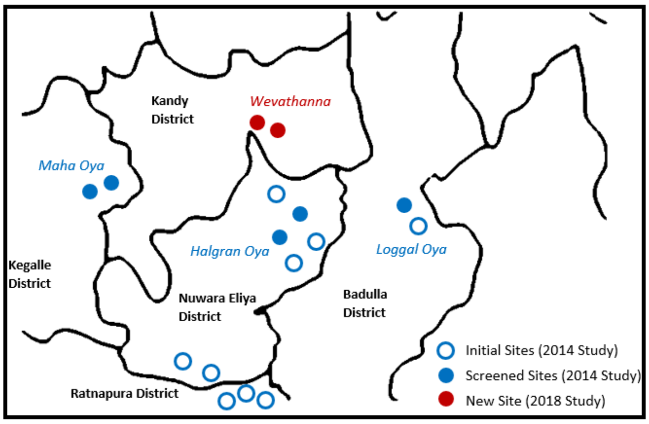


Figure 5.4: Three Selected Sites for PSPP after Preliminary Screening

Table 5.5 – Details of proposed PSPP Sites

Proposed Project	*Capacity (MW)*	*Capital Cost Pure ($/kW)*	*Capital Cost with IDC ($/kW)*	*Construction Period (Years)*	*Economic Plant Life (Years)*
Proposed site (2014 study)[1]	***600***	***1076.3***	***1332.2***	***5.0***	***50***
Proposed site (2018 study)[2]	***1400***	***661.6***	***818.9***	***5.0***	***50***

1. Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" carried out by JICA funds in February 2015 [19]
2. Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka" carried out by JICA in March 2018 [8]

CHAPTER 6
GENERATION EXPANSION PLANNING METHODOLOGY AND PARAMETERS

The long term generation planning exercise investigates avenues to develop the electricity generation system to meet the future electricity demand by considering all potential and proven sources of thermal and renewable energy generation. Several factors are taken into account in this process of evaluating and selecting the most suitable power generating options. Policy targets of the government, technical and economic characteristics of generating technologies, requirements of the network in terms of system security and system operation, exploitable renewable energy resource potentials, environmental obligations as well as transition strategy towards carbon neutrality are among several factors considered in this exercise.

The policies and guidelines relevant to power sector such as “The National Energy Policy and Strategies of Sri Lanka” [4], “General Policy Guidelines on the Electricity Industry” [3] and “Draft Grid Code of CEB Transmission Licensee” [23], are taken into consideration in the planning process.

The Long Term Generation Expansion Plan is the outcome of the optimization process constrained with above mentioned factors. The policies and guidelines that were considered and methodology adopted in the process is described in this Chapter and depicted in Annex 6.1.

6.1. Generation Planning Code

The Least Cost Generation Expansion Planning Code was published in April 2011, to act as basis for conducting generation planning activities. The code represents objectives, planning period, frequency of update, planning boundaries, planning criteria, establishment of economic parameters, the development of base case with sensitivity analysis and other policy and scenario analysis to be considered when preparation of the Least Cost Generation Expansion Plan.

All elements of the Least Cost Generation Expansion Planning Code are contained in the Draft Generation Planning Code under the Grid Code issued by the Transmission Licensee in October 2018, which has been updated from the Grid Code issued by PUCSL in March 2014.

6.2. National Energy Policy and Strategies

Ministry of Power and Energy updated the National Energy Policy & Strategies of Sri Lanka in the Gazette Extraordinary No. 2135/61 dated 2019-08-19 after reviewing and revising the National Energy Policy and Strategies of Sri Lanka published in 2008. The main objective of the National Energy Policy and Strategies declared is to ensure convenient and affordable energy services are available for equitable development of Sri Lanka using clean, safe, sustainable, reliable and economically feasible energy supply. This Policy is formulated in alignment with the future goals of Sri Lanka, current global trends in energy and the Goal 7 of the Sustainable Development Goals of the United Nations. This policy is expected to pave the way to realize the vision of Sri Lanka in achieving carbon neutrality by 2050.

The “National Energy Policy and Strategies of Sri Lanka” is elaborated in three sections as follows:

- **The National Energy Policy,** stating the ten pillars of the policy framework
- **Implementing Strategies,** describing the specific strategies to implement the policy
- **The Results Delivery Framework,** elaborating the specific actions, milestones and the institutions responsible

The National energy policy stands on following ten pillars, rooted in the broad areas impacting the society, economy and the environment to counter balance the forces through enhanced equity, security and sustainability.

- Assuring Energy Security
- Providing Access to Energy Services
- Providing Energy Services at the Optimum Cost to the National Economy
- Improving Energy Efficiency and Conservation
- Enhancing Self Reliance
- Caring for the Environment
- Enhancing the Share of Renewable Energy
- Strengthening the Governance in the Energy Sector
- Securing Land for Future Energy Infrastructure
- Providing Opportunities for Innovation and Entrepreneurship

During the Preparation of Long Term Generation Expansion Plan 2023-2042, due consideration is given to salient features of the National Energy Policy pillars considering the Implementing Strategies and specific milestones as follows .

Assuring Energy Security

1. Diversity of energy resources is met by introducing natural gas to the existing mix of coal, hydro, furnace oil and other renewable resources. Constrained with the Policy Guidelines, coal and furnace oil/diesel will be phased out leaving natural gas and renewables to be the main resources. As the renewable resource becomes dominant in the future, achieving energy security through renewable resources will be looked at with a different perspective.

2. A liquefied natural gas (LNG) terminal of optimum size and technology would be established at the west coast, being the most suitable location. Considering the impact to the country’s energy security, operation of the first terminal and LNG procurement shall be kept under state control.

3. Percentage of installed power generation capacity from a single imported fuel shall not exceed 50% of the total installed firm capacity to safeguard against geopolitical uncertainties and fuel price shocks.

4. National requirements of electricity will be met with proven generation technologies and fuel sources.

Enhancing Self Reliance

1. Indigenous oil and natural gas resources will be explored. Commercial scale exploitation will be strategically phased, giving due consideration to higher future value and possible use in the future as a locally available fuel source to derive cleaner futuristic energy sources such as hydrogen.

2. Renewable energy resources will be exploited based on a priority order arrived at, considering economics, technology and quality of each resource.

3. Wind and solar is identified as the most promising renewable energy resources after hydropower and highest priority is given to develop wind and solar in future years.

Caring for the Environment

1. Energy supply from cleaner sources and technologies will be encouraged to minimize harm to the local and global environment, while taking into consideration both the impacts on the national economy and the long-term environmental benefits.

2. Nationally Determined Contributions (NDCs) to global emission reduction goals will be made to meet the National emission reduction obligations as agreed.

Enhancing the Share of Renewable Energy

1. Energy supply from renewable energy resources in the country's energy mix will be increased to reduce pressure on foreign exchange, as a means of engaging the local community in the energy industry and to attain sustainability.

2. Research will be conducted to overcome adverse impacts of renewable energy absorption to the power system from intermittent sources such as wind and solar energy.

3. Effective forecasting technologies for renewable resources will be introduced so that optimum use of the resource could be realised.

4. Energy storage solutions will be encouraged for firming intermittent renewable sources, voltage and frequency regulation, local grid support, peak shaving and improving grid resilience.

Securing Land for Future Energy Infrastructure

1. Suitable sites to locate future energy infrastructure (power plants, refineries, terminals) will be strategically earmarked in advance following preliminary feasibility studies, so that the public can avoid using such sites, resulting in minimal relocation and social impacts at the time of actual development.

2. Best sites to locate large scale renewable energy infrastructure such as wind and solar farms would be identified in advance and marked on a master plan so that they can be developed as large concentrated facilities in phases.

6.3 General Policy Guidelines on the Electricity Industry for the PUCSL

Section 5 of Sri Lanka Electricity Act, No 20 of 2009 defines Minister of Power has the power to formulate the General Policy Guidelines on Electricity sector for the Public Utilities commission. The General Policy Guidelines on the Electricity Industry 2021 (issued in January 2022), read together with the National Energy Policy and Strategies of Sri Lanka (gazetted in 2019) is taken as the applicable policy guidelines in preparation of LTGEP 2023-2042.

Long Term Generation Expansion Plan 2023-2042 has incorporated the instructions given in the General Policy Guidelines on the Electricity Industry, with emphasis given on following clauses.

Clause 8

The GOSL has long recognized the need for transforming the country's electricity sector from its traditional centralized and vertically integrated structure relying on a few relatively large capacity thermal power plants and collection of storage hydropower plants to one made up of numerous independent operators producing electricity including variable renewable energy (VRE). Several policies have been implemented by the GOSL towards achieving this objective. High integration of renewable energy and achieving a clean and carbon reduced energy economy are priority policy objectives for GOSL.

Clause 9

The GOSL has set the targets of achieving 70% of electricity generation in the country using renewable energy sources by 2030 and carbon neutrality in power generation by 2050, and has decided to cease building of new coal-fired power plants. The Cabinet of Ministers has approved these two policy elements that shall form the basis of Sri Lanka's future electricity capacity expansion planning. Further, new addition of firm capacity will be from clean energy sources such as regasified liquefied natural gas (RLNG).

Clause 15

Addition of new generation facilities and expansion of existing generation facilities will be carried out according to the Least Cost Long Term Generation Expansion Plan (LTLGEP) approved by the PUCSL in accordance with the provisions of Section 43 of the Sri Lanka Electricity Act. LCLTGEP recognizes the need to add adequate generation capacity to meet the growing electricity demand of the country while ensuring reliability and quality of electricity supply as determined by the PUCSL from time to time in consultation with the licensees.

Clause 16

Considering the major policy target of producing electricity using indigenous VRE resources energy storage options such as Pumped Hydroelectric Energy Storage (PHES) and Battery Energy Storage Systems (BESS) will be introduced to ensure reliability and quality of electricity supply.

Clause 23

Electricity generation using renewable resources such as solar and wind does not result in emission of greenhouse gases or local air pollution. The GOSL will give priority to developing renewable energy that is both indigenous and environmentally friendly to achieve its target of 70% renewable based electricity production by 2030. The planned future renewable energy portfolio will include onshore and offshore wind power, land based and floating solar PV as well as rooftop solar PV, micro hydro and biomass.

6.4 Thermal Power Plant Specific Cost Calculation

In the specific cost calculation methodology, investment cost is assumed as an overnight cost to occur at the beginning of the commissioning year and annual costs such as fixed and variable operation, maintenance and repair costs and fuel costs are discounted to the beginning of the commissioning year. Energy is calculated for each year of operation over the life time for various plant factors. Present value of specific energy cost of thermal plants is calculated for a range of plant factors. The specific cost curves reveal how different technologies perform at different plant factors. Specific cost calculation methodology is given in Annex 6.2.

6.5. 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 OPTGEN software tools developed by PSR (Brazil) were extensively used in conducting the system expansion planning studies to determine optimal Long Term Generation Expansion Plan. Model for Analysis of Energy Demand (MAED) developed by International Atomic Energy Agency (IAEA) was used to develop a demand forecast scenario by end user approach.

6.5.1 Stochastic Dual Dynamic Programming (SDDP)

Stochastic Dual Dynamic Programming (SDDP) model is an operation planning tool developed by PSR (Brazil) which simulates the hydro and thermal generation system to optimize the operation of hydro system. 20 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 modelling and reservoir level detail modelling has been done to accurately represent the actual operation. Maximum of hundred scenario simulations could be considered in the model to represent the stochastic nature of hydrological conditions. To observe the operational patterns of the future generation system and to identify any operational issues, SDDP was used to simulate the hourly operation considering the least-cost stochastic operating policy of the hydrothermal system of the country, taking into account the following main inputs:

1. Operational details of hydro plants (water balance, limits on storage and turbine outflow, spillage, etc.)

2. Detailed thermal plant modelling (unit commitment, fuel contracts, efficiency curves, fuel consumption constraints, multiple fuels, etc.)

3. Renewable resource profiles and associated renewable generation plant modelling

4. Modelling of energy storage devices connected to the grid considering hourly time steps

5. Operational constraints of the system

6. Hourly Load variation levels

The modelling and simulation is performed to identify the operating patterns of the conventional power plants, system flexibility issues and the implications of variable renewable energy on the operation of conventional plants including energy storage solutions such as pumped hydro storage and battery energy storage in hourly resolution.

6.5.2 OPTGEN Software

OPTGEN software with the in-built SDDP module, developed by PSR (Brazil) is a long term expansion planning model which is used to determine the least cost sizing and timing decisions for construction and reinforcement of generation capacities and transmission network. OPTGEN optimizes the trade-off between investment costs to build new projects and the expected value of operative costs obtained from SDDP, the stochastic dispatch model. The Software is capable of modelling Other Renewable Energy Sources and is considered for optimization. In order to solve the expansion problem, OPTGEN model uses advanced optimization techniques of mixed-integer programming.

6.5.3 MAED Model

The Model for Analysis of Energy Demand (MAED) relies upon the end use demand projection methodology that was originally developed at IAEA 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.

6.6 Modelling of Hydropower Development

Hydro resource is one of the main indigenous sources of energy and lifetime of a hydropower plant is longer compared to the other alternative sources. Sri Lanka has already developed almost all of the economically feasible hydro power projects in the country and few minor projects remain at their initial feasibility study level due to the inability to justify economically. 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. 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. At present only Broadlands hydropower project, Uma Oya hydropower project and the Moragolla hydropower project are considered as committed.

6.7 Modelling of Other Renewable Energy

The LTGEP 2023-2042 includes a significant amount of renewable energy resource development including wind and solar resources. Therefore, accurate representation of the important characteristics of each renewable energy resources is very important in the planning process. The OPTGEN and SDDP Software packages used in this planning exercise are developed to capture the characteristics of renewable energy resources in the capacity expansion planning exercise in a more effective manner.

The main ORE technologies of mini-hydro, wind, solar and biomass were modelled based on actual resource characteristics as applicable for the generation planning exercise. As the major portion of the future renewable additions is comprising of variable renewable energy sources such as wind and solar PV, the modelling work has captured the variability, uncertainty and seasonality characteristics. Moreover, as explained in the Chapter 5 of this report, a comprehensive renewable energy grid integration study is conducted by CEB parallel to the generation expansion planning exercise which includes detailed analysis using resource modelling.

6.8 Modelling of Energy Storage Systems

Due to the policy requirement of achieving 70% renewable energy by 2030 and carbon neutrality in power sector by 2050, large scale energy storage systems are required to be added to the system. Two major types of storage systems modelled in the planning studies are pumped hydro storage hydro power plant and battery energy storage systems.

SDDP allows the modelling of pumped storage hydro power plant with turbining and pumping operations considering its upper and lower reservoir characteristics. Battery energy storage systems are modelled in SDDP with their capacity and energy characteristics. Detailed characteristics such as state of charge, maximum depth of discharge, charging and discharging efficiencies and regulation time is considered in modelling. Energy storage is mainly utilized for time shifting of excess generation from renewable energy sources in low load periods instead of curtailing the excess generation. In addition, energy storage will also be utilized to provide other services such as ramp support/frequency regulation, renewable capacity firming, etc.

6.9 Assessment of System Operational Capability

It is essential that the proposed development plan provides operational capability to the System Control Centre, to operate the power system in a secure and economical manner, in both normal and contingency situations. In order to operate a stable power system in a high VRE system, a minimum synchronous generation penetration limit is required to be assessed. For long term planning studies a maximum allowable limit of 65% of System Non-Synchronous Penetration has been considered during this planning horizon.

As the system is transitioning towards higher shares of non-dispatchable intermittent variable renewable energy sources with higher degree of variability and uncertainty, ensuring the adequate operational flexibility is essential for the normal system operation to meet the dynamically varying demand of the system. The conventional generation technologies are increasingly required to provide more cyclic operation with faster ramping and frequent start-ups. Therefore, the generation planning exercise has decided the firm capacity mix in each year to facilitate the necessary flexibility requirements. Designing and developing a stable and a resilient power system is essential to withstand both internal and external disturbances to the operation. Important attributes such as adequate synchronous inertia, frequency/voltage control capabilities and power failure restoration capabilities have been considered in preparing the development plan.,

It should be noted that operational studies pertaining to long term planning have been conducted at minimum resolution of hourly timestep. Hence, the exact additional interventions required to operate the power system in shorter timespans preserving system stability are required to be assessed separately. Therefore, the associated cost of these additional interventions has not been considered.

6.10 Assessment of Environmental Implications

The environmental effects of each thermal options are considered in the initial selection of a candidate power plant in the planning process. All thermal power plants are required to adhere to the approved 'National Environmental (Ambient Air Quality) Regulations published in 2008 and the National Environmental (Stationary Sources Emission Control) Regulations published in 2019. Any additional costs to comply with the environmental regulations are considered in the capital cost of the respective power project. During project preconstruction phase, a detailed EIA shall be conducted to address and explore methods to mitigate all localised adverse environmental impacts.

The greenhouse gas emissions that impact the global environment is assessed for each planning scenario as presented in the Chapter 10. The GHG emission levels are analysed to ensure that the climate obligations of Sri Lanka to the UNFCC under the Nationally Determined Commitments (NDCs) are complied as well as to explore further opportunities to reduce greenhouse gas emissions.

6.11 Assessment of Implementation Time and Financial Scheduling

The implementation and financing of the planned power projects are two important aspects in planning and developing an electricity supply system. In fact, the total period of implementation of a project including feasibility studies varies depending on the type, technology and the location of the power project. Typical duration required for generation projects, including the period taken for preplanning activities, is shown below.

1.	Internal Combustion Engine	4 years
2.	Gas Turbine	4 years
3.	Combined Cycle Plant	6 years
4.	Coal Plant	7- 8 years
5.	Nuclear Plant	12- 15 years
6.	Hydropower Plant/Pumped Storage Power Plant	7 - 8 years
7.	Large scale solar park	4 – 6 years
8.	Large scale wind park	4 – 6 years
9.	Battery Energy Storage Systems	3 - 5 years

Developing the electricity generation system is often a highly capital intensive activity in the economy, hence funding and financing power sector projects remains as a critical challenge affecting the timely implementation of projects. An investment schedule of the Base Case scenario is presented to identify the necessary funding and financing requirement as well as for preparing future projections on electricity tariff system.

6.12 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 Generation Planning Software. Parameters and constraints given in Grid Code were used in the studies and those are described in detail.

6.12.1 Study Period

Generation Expansion Panning studies are conducted for a period of 25 years (2023-2047) and the results of Base Case and all sensitivity studies are presented in the report for a period of 20 years (2023-2042). The consideration of additional years in the planning exercise is to enhance the accuracy of the solution to the optimization problem.

6.12.2 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 201.5 LKR/USD. This is the average value of December 2021 exchange rates. All costs are based on 1st of January 2022.

6.12.3 Plant Commissioning and Retirements

It is assumed that the power plants are commissioned or retired at the beginning of each year. However, in actual terms, CEB owned power plants are expected to be retired considering their remaining operable hours and actual implementation progress of new power projects. IPP power plants are to be retired according to the expiry dates of Power Purchase Agreements.

6.12.4 Cost of Energy Not Served (ENS)

The average loss to the economy due to electrical energy not supplied has been estimated as 0.810 USD/kWh (in 2022 prices). This value has been derived by escalating the ENS figure given by PUCSL as 0.5 USD/kWh in 2011.

6.12.5 Reliability Criteria

As per the provisions stipulated in Sri Lanka Electricity Act Section 43(8) and Clause 15 of The General Policy Guidelines on the Electricity Industry issued on 2021, the PUCSL has to publish the reliability criteria for electricity network in consultation with the relevant licensees. "The technical and reliability requirements of electricity network of Sri Lanka" was published in Gazette Extraordinary No. 2109/28 dated 2019-02-08 by the PUCSL [2].

Reserve Margin

Reserve margin is the measure of firm generation capacity available over and above the amount required to meet the system load requirements. When preparing the LTGEP, reserve margin values are maintained between 2.5% (minimum) and 20% (maximum) as published in Gazette Extraordinary No. 2109/28 dated 2019-02-08. The Reserve Margin level is maintained between stipulated limits and necessary reserve margins, in each year, is maintained considering factors such as largest unit sizes, optimum usage of earmarked lands and stability of the network.

Loss of Load Probability (LOLP)

LOLP is another 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.

The association between Reserve Margin and LOLP indices are interrelated and the exact values depend on the approach and the complexity of the adopted methodology. The LTGEP 2023-2042 is prepared maintaining the LOLP values within the stipulated maximum limit of 1.5% as stipulated in the Grid Code and published in Gazette Extraordinary No. 2109/28 dated 2019-02-08.

Transmission License shall prepare the Plan maintaining LOLP values at optimum levels with the mandate on flexibility to adjust the values providing sufficient justification, considering the aforementioned restrictions.

6.12.6 Discount Rate

The discount rate is used in order to analyse 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 analysed by applying lower and higher discount rates.

6.12.7 Plant Capital Cost Distribution among Construction Years

The distribution of plant capital cost during the construction period is carried out by adopting "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 Annex 12.1 and Annex 12.2 and discussed in Chapter 12.

6.12.8 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) The planning process considers the cost to the economy in broader terms. Hence the financial cost associated with taxation, cost of capital, etc.... are not considered.

c) All fuel prices assumed to remain constant as of the reference date, and expressed in economic terms (border prices) as stipulated in the Grid code.

d) All generating plants performance degradation throughout its lifetime has not been considered and accounted for during the studies.

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

f) Committed Power Plants are shown in the Table 6.1 below.

Table 6.1 Committed Power Plants

Power Plant	Capacity (MW)	Year of Operation
Solar		
Grid connected partially facilitated solar	94	2022
	147	2023
Wind		
Mannar	15	2023
Trincomalee	10	2023
Bolawatta	10	2024
Mannar Wind Park Extension	50	2024
Thermal		
Kelanithissa Gas Turbines	130	2024

Power Plant	Capacity (MW)	Year of Operation
Natural Gas Combined Cycle Power Plant I (Sobadhanavi Ltd)	350	2023 – Open Cycle 2024 – Combined Cycle
Natural Gas Combined Cycle Power Plant II	350	2024 – Open Cycle 2025 – Combined Cycle
Hydro		
Uma Oya Hydropower Plant	122	2022
Broadlands Hydropower Plant	35	2022
Moragolla Hydropower Plant	30.2	2024

g) The Candidate Power Plants with earliest possible commissioning year are depicted in the Table 6.2 below.

Table 6.2 Candidate Power Plants

Power Plant	Capacity (MW)	Earliest Year of Operation
Thermal		
IC Engines (Diesel / FO / NG)	15 /200 /250	2026
Gas Turbine (NG)	40 /100 /200	2026
Combined Cycle Power Plant (NG)	300 / 400	2028
Coal Plant (High Efficient /Supercritical)	300 / 600	2028
Nuclear Power Plant	600	2037
Storage		
Battery Energy Storage System		2024
Pumped Storage Power Plant	3x200 / 4x350	2029

h) The integration capacity of biomass and mini hydro power plants is not limited but could be considered on project by project basis depending on the feasibility.

i) All large-scale solar parks have been modelled based on PV plants with single axis tracking.

j) Future large scale wind parks are to be developed as Semi-dispatchable power plants.

k) All new wind and solar PV plants are capable to curtail the generation when necessary.

l) The development of required LNG infrastructure will be available by 2025 for importing natural gas.

m) Plant retirements of CEB owned plants and IPP plants are given in Table 6.3. The power plant retirements are assumed to be at the beginning of each year. However, the actual retirement of CEB owned power plants are to be made after further evaluating the actual plant condition at the time of retirement (including the availability of useful operating hours beyond the scheduled retirement date), and the implementation progress of planned power plant additions.

Table 6.3 Plant Retirement Schedule

CEB Power Plant Retirement	Year	IPP Power Plants' PPA expiry	Year
1. Kelanithissa Frame5 GTs	2024	1. Sojitz Combined Cycle plant	2023
2. Barge mounted power plant	2025	2. Westcoast Combined Cycle plant	2035
3. Sapugaskanda PS A (4 units)	2026		
4. Sapugaskanda PS B (8 Units)	2026		
5. Kelanithissa GT7	2026		
6. Kelanithissa Combined Cycle plant	2033		
7. Uthuru Janani power plant	2033		
8. Lakvijaya coal plant unit 1	2041		

- The contract of 163 MW Sojitz Combined Cycle plant at Kelanithissa will expire in October, 2023 and it will be operated as a CEB plant until 2033.

- Retirement year of Kelanithissa Frame 5 GTs shall be reviewed with the actual implementation year of Kelanithissa New Gas Turbines as constrained by local environmental emission regulations.

- Retirement year of 115 MW Kelanithissa GT7 is extended until beginning of 2026 on the basis of carrying out manufacturer recommended major scheduled maintenance work, along with any other essential maintenance required to keep the plant operational.

- Retirement of BESS after 10 years is considered in the planning horizon and the retired capacities are replaced with similar capacity new BESS.

- Retirement of existing ORE power plants are modelled based on the expiry of their PPA, and is modelled with replacement with similar capacity new power plant of the same technology.

CHAPTER 7
GENERATION EXPANSION PLANNING STUDY DEVELOPMENT OF THE REFERENCE CASE

This chapter presents the analysis results of the reference case for 2023-2042 planning horizon in detail including capacity additions, system energy share, dispatch and cost comparison with base case. The reference case plan is the unconstrained least cost plan and the total cost of reference case demonstrates the total present value cost of generation expansion for the planning horizon unconstrained by policies. This case indicates the least cost development pathway as well as provides a basis for comparison to other scenarios that are constrained by policies.

7.1 Introduction

To develop the reference case 2023-2042, the Draft Generation Planning Code in the Draft Grid Code [23] issued by the Transmission Licensee was used as a guideline. As per the grid code, the reference case should be developed with exclusion of any policy guidelines on generation technology options that would cause the plan to deviate from least cost. In addition, candidate non-dispatchable power plants required to be included owing to policy guidelines issued by the commission or any of the Transmission Licensee's own policies, are not included in the reference case, unless the Transmission Licensee can demonstrate that such power plant costs shall not violate the least-cost objective of developing the reference case.

Accordingly, as the first step of developing the reference case, a case with ORE power plants already in operation as at 1st January 2021 and the committed renewable energy plants was considered. When the case was analysed, it was observed that further cost reductions could be expected by incorporating candidate ORE additions to the plan to a certain extent. Several scenarios were evaluated with varying candidate ORE additions throughout the planning horizon which do not require substantial investments in network or operational reinforcements. The evaluated scenarios are as follows:

1. Achieving 50 % RE by 2030, maintaining 50% RE beyond 2030 and no coal fired plant additions beyond 2030
2. Achieving 60 % RE by 2030, maintaining 60% RE beyond 2030 and no coal fired plant additions beyond 2030
3. Achieving 60 % RE by 2030, maintaining 60% RE beyond 2030 and no coal fired plant additions throughout the horizon.

All the above scenarios indicated lower present value costs than the existing policy-based scenarios and 2nd scenario which achieved 60% RE by 2030, maintained 60% RE beyond 2030 and added no coal fired power plants beyond 2030 indicated the lowest cost among all three scenarios. Therefore, 2nd scenario was identified as the Reference Case of LTGEP 2023-2042 as it indicated the lowest present value cost unconstrained by policy guidelines and, operationally feasible.

7.2 Reference Case Plan

The reference case plan is given in Table 7.1 and the total present value cost of the Reference Case Plan for the period 2023-2042 is USD 17,507 million (LKR 3,527.66 billion) in January 2022 values based on the discount rate of 10%).

Table 7.1: Generation Expansion Planning Study – Reference Case (2023-2042)

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS		THERMAL CAPACITY ADDITIONS and RETIREMENTS	
2022	**Uma Oya Hydropower Plant**	**120 MW**		
	Distribution Connected Embedded Solar	160 MW		
	Grid Connected Partially Facilitated Solar	**94 MW**		
	Mini Hydro	20 MW		
	Biomass	10 MW		
2023	Distribution Connected Embedded Solar	160 MW	**Gas Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)**	**235 MW**
	Grid Connected Partially Facilitated Solar	**147 MW**	Short Term Supplementary Power	320 MW
	Wind	**25 MW**	Combined Cycle Power Plant (KPS–2)	163 MW
	Mini Hydro	20 MW	*Retirement of*	
	Biomass	20 MW	*Sojitz Kelanitissa Combined Cycle Plant*	*(163) MW*
2024	**Moragolla Hydropower Plant**	**31 MW**	**New Gas Turbines – Kelanitissa**	**130 MW**
	Distribution Connected Embedded Solar	160 MW	**Steam Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
	Grid Connected Partially Facilitated Solar	223 MW	**Gas Turbine of Second NG Combined Cycle Plant (Kerawalapitiya)**	**235 MW**
	Grid Connected Fully Facilitated Solar	100 MW	*Retirement of*	
	Wind	**60 MW**	*Kelanitissa Gas Turbines*	*(68) MW*
	Mini Hydro	20 MW	*Short Term Supplementary Power*	*(200) MW*
	Biomass	20 MW		
	Standalone Battery Energy Storage	20 MW/50 MWh		
2025	Distribution Connected Embedded Solar	165 MW	**Steam Turbine of Second NG Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
	Grid Connected Partially Facilitated Solar	80 MW	*Retirement of*	
	Grid Connected Fully Facilitated Solar	160 MW	*CEB Barge Power Plant*	*(62) MW*
	Wind (Mannar)	100 MW		
	Wind	100 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW		
2026	Distribution Connected Embedded Solar	170 MW	IC Engine Power Plant -Natural Gas (Western Region)	200 MW
	Grid Connected Partially Facilitated Solar	70 MW	New Coal Power Plant	300 MW
	Grid Connected Fully Facilitated Solar	100 MW	*Retirement of*	
	Wind	150 MW	*Gas Turbine (GT7)*	*(115) MW*
	Mini Hydro	25 MW	*4x17 MW Sapugaskande Diesel*	*(68) MW*
	Biomass	20 MW	*8x9 MW Sapugaskande Diesel Ext*	*(72) MW*
	Standalone Battery Energy Storage	80 MW/320 MWh	*Short Term Supplementary Power*	*(120) MW*
2027	Distribution Connected Embedded Solar	170 MW		
	Grid Connected Partially Facilitated Solar	50 MW		
	Grid Connected Fully Facilitated Solar	180 MW		
	Wind	100 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW		

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS		THERMAL CAPACITY ADDITIONS and RETIREMENTS	
2028	Distribution Connected Embedded Solar	170 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	40 MW		
	Grid Connected Fully Facilitated Solar	250 MW		
	Wind	100 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW		
2029	Distribution Connected Embedded Solar	170 MW	Gas Turbine -Natural Gas	100 MW
	Grid Connected Partially Facilitated Solar	20 MW	Gas Turbine -Natural Gas	100 MW
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100 MW/400 MWh		
	Wind	200 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW		
	Pumped Storage Hydropower	350 MW		
2030	Distribution Connected Embedded Solar	170 MW		
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	150 MW		
	Wind	200 MW		
	Mini Hydro	10 MW		
	Biomass	20 MW		
	Pumped Storage Hydropower	350 MW		
2031	Distribution Connected Embedded Solar	170 MW	-	
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	100 MW		
	Wind	100 MW		
	Mini Hydro	10 MW		
	Biomass	20 MW		
2032	Distribution Connected Embedded Solar	170 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	100 MW		
	Mini Hydro	10 MW		
	Biomass	20 MW		
2033	Distribution Connected Embedded Solar	170 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW	Combined Cycle Power Plant (Natural Gas)	400 MW
	Grid Connected Fully Facilitated Solar	100 MW		
	Wind	100 MW	*Retirement of*	
	Mini Hydro	10 MW		
	Biomass	20 MW	*Combined Cycle Plant (KPS)*	*(165) MW*
			Combined Cycle Plant (KPS- 2)	*(163) MW*
			Uthuru Janani Power Plant	*(26.7) MW*
2034	Distribution Connected Embedded Solar	180 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	100 MW		
	Wind	100 MW		
	Mini Hydro	10 MW		
	Biomass	20 MW		
2035	Distribution Connected Embedded Solar	180 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Fully Facilitated Solar	250 MW	IC Engine Power Plant -Natural Gas	250 MW
	Wind	100 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW	*Retirement of*	
			West Coast Combined Cycle Power Plant	*(300) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS		THERMAL CAPACITY ADDITIONS and RETIREMENTS	
2036	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass	190 MW 30 MW 200 MW 100 MW 10 MW 10 MW	Gas Turbine -Natural Gas	200 MW
2037	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass	190 MW 30 MW 300 MW 100 MW 10 MW 10 MW	Gas Turbine -Natural Gas IC Engine Power Plant -Natural Gas	100 MW 200 MW
2038	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass Standalone Battery Energy Storage	200 MW 30 MW 300 MW 100 MW 10 MW 10 MW 100MW/400MWh	Gas Turbine -Natural Gas IC Engine Power Plant -Natural Gas	100 MW 200 MW
2039	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass Standalone Battery Energy Storage	200 MW 30 MW 300 MW 100 MW 10 MW 10 MW 100 MW/400 MWh	Gas Turbine -Natural Gas	200 MW
2040	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Biomass	200 MW 20 MW 230 MW 100 MW 10 MW	IC Engine Power Plant -Natural Gas	250 MW
2041	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Biomass Pumped Storage Hydropower	200 MW 20 MW 250 MW 100 MW 10 MW 350 MW	Gas Turbine -Natural Gas Gas Turbine -Natural Gas Gas Turbine -Natural Gas *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	200 MW 200 MW 200 MW *(300) MW*
2042	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Biomass	200 MW 20 MW 250 MW 100 MW 10 MW		

7.2.1 System Capacity Distribution

Reference case capacity additions by plant type are summarised in five-year periods in the Table 7.2 and graphically represents in Figure 7.1. The supply mix heavily depends on the thermal based generation system with limited contribution from the renewable based energy.

Table 7.2: Capacity Additions by Plant Type – Reference Case (2023-2042)

Type of Plant	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	2038-2042 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	31	-	-	-	31	0%
Pumped Hydro	-	700	-	350	1,050	6%
Battery Storage	100	100	-	200	400	2%
Gas Turbines	130	600	1,100	900	2,730	15%
Coal	300	-	-	-	300	2%
Combined Cycle	700	-	400	-	1,100	6%
IC Engines	200	-	450	450	1,100	6%
ORE	2,685	2,680	2,630	3,020	11,015	63%
Total	**4,146**	**4,080**	**4,580**	**4,920**	**17,726**	**100%**

According to the above, reference case plan is comprised of a mix of thermal and renewable power plants. Major hydro and ORE additions amount to 63% of the total capacity additions in the planning horizon while thermal capacity additions include 6% of coal based power plants 27% of natural gas based combined cycles/gas turbines/gas engines. 6% capacity addition of pumped hydro power plant and 2% from battery storage are also included in the reference case. When compared with the base case plan, the reference case contains 3,945 MW less capacity additions mainly due the reduction in ORE and energy storage capacities in the planning horizon.

With regard to energy storage additions, it could be observed that the Base Case contains 3,365 MW of battery storage and 1,400 MW of pumped storage while the reference case contains only 400 MW of battery storage and 1,050 MW of pumped storage. This aspect mainly contributes to the cost difference between the two cases.

Future capacity mix of the reference case is graphically represented in Figure 7.2

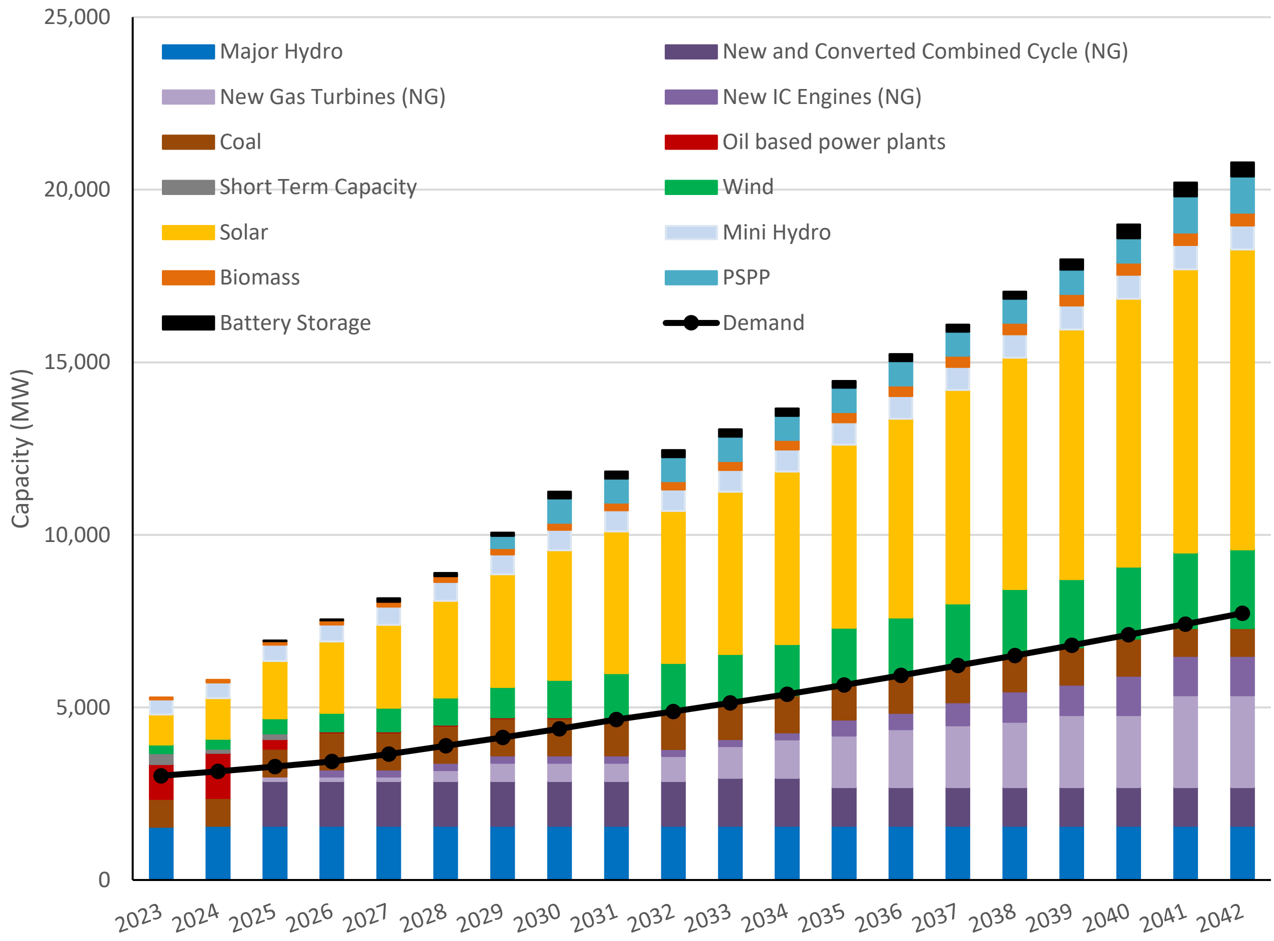


Figure 7.1 - Cumulative Capacity by Plant Type in Reference Case

7.2.2 System Energy Share

Future energy supply mix of the reference case is graphically represented in Figure 7.2.

As for renewables, the hydro generation share gradually decreases throughout the planning horizon starting from 24% in 2023 to 10% in 2042. Energy contribution from ORE reaches 44% in 2030 and continues around 46%-48% throughout the horizon beyond. Consequently, RE share reaches 60% by 2030 and maintains around 60% beyond 2030.

As for thermal power plants, during initial 3 years of the planning horizon major energy contribution comes from oil and coal based thermal generation, and beyond 2025, NG and Coal based power plants become the major thermal energy contributors of the system. The NG based energy share starts at 17% in 2025, fluctuates along the time horizon and reaches 27% by 2042. Coal based energy share decreases gradually throughout the horizon, starting at 31% in 2023 and reaching 11% by 2042. The energy contribution from oil-fired power plants reduces from 23% in 2023 to 0.1% by 2025 with the gradual retirement of oil plants and thereafter becomes negligible.

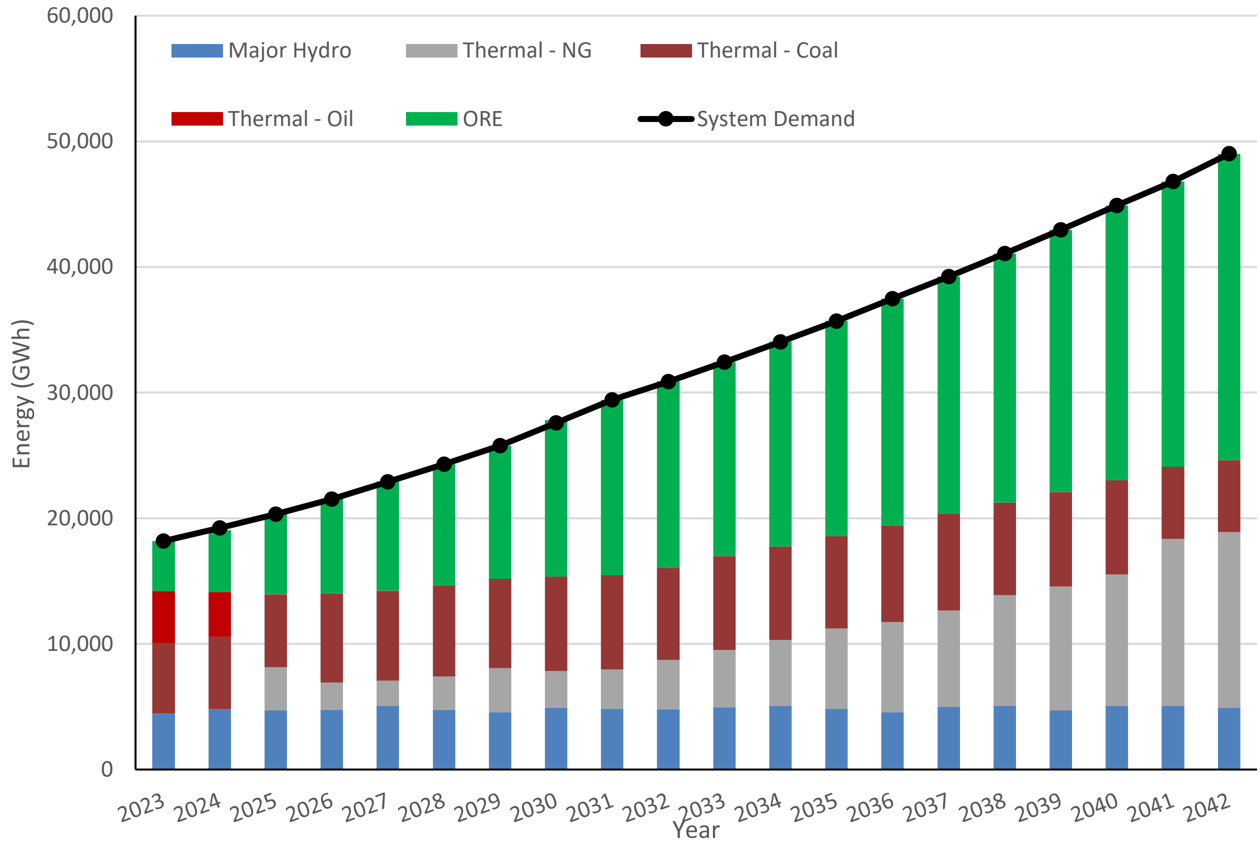


Figure 7.2 – Energy Mix over next 20 years in Reference Case

7.2.3 Cost Comparison with Base Case

Compared with the base case plan, reference case shows the USD 1,365 million (LKR 275 Billion) present value cost decrement over the planning horizon.

Reference case reaches 60% RE by 2030 and maintains the same share throughout the horizon complying with the least cost principles whereas in the Base Case, the policy target of 70% RE has to be met with adding substantial capacity of energy storage. As a result, a considerable increase of investment cost is observed in the base case compared to the reference case. In contrast, the base case considers much higher contribution from renewable energy sources so that the operation cost significantly reducing compared to the reference case. However, the investment cost increase of Base Case compared to Reference Case is much higher than the operation cost decrease achieved in the Base Case, thus the reference case indicates a substantially low total cost compared to the Base Case. All the cost comparisons are presented in Table 7.3.

Table 7.3: Present Value Cost Comparison between Reference Case and Base Case (in million USD)

Cost Type/Scenario	Investment Cost	Operation Cost	Total Cost
Reference Case	7,946	9,561	17,507
Base Case	10,119	8,753	18,872
Difference	(2,173)	808	(1,365)

CHAPTER 8
RESULTS OF GENERATION EXPANSION PLANNING STUDY – BASE CASE PLAN

This chapter presents the results of the base case analysis for 2023-2042 planning horizon in detail which includes capacity balance, energy balance, fuel requirement, operational and maintenance cost, reliability indices and sensitivities of the base case. Results on operational analysis of base case are discussed in chapter 9 and results on environmental impacts of base case analysis are discussed in the Chapter 11.

8.1 Government Policy on Composition of Electricity Generation

When developing the Base Case Plan, special consideration was given to the "General Policy Guidelines for the Electricity Industry'' as stipulated in the Section 5 of Sri Lanka Electricity Act no 20 of 2009 (as amended) and in the Section 30 of the Public Utilities Commission of Sri Lanka (PUCSL) Act no 35 of 2002. This policy guideline was approved by the Cabinet of Ministers in November 2021 and issued by the Ministry of Power in January 2022. The government policy directive based on the above policy guidelines contains 04 clauses directly related to the future electricity mix of the country proposed through LTGEP. The energy mix proposed through the Base Case Plan of LTGEP 2023-2042 has considered these clauses and aligned the Base Case along with the salient points included in the 04 specific clauses as indicated below.

1. Achieve 70% of electricity generation in the country using renewable energy sources by 2030
2. Achieve carbon neutrality in power generation by 2050
3. Cease building of new coal-fired power plants
4. New addition of firm capacity will be from clean energy sources such as regasified liquefied natural gas (RLNG)

Priority was given to achieving 70% of electricity generation using renewable energy sources by 2030 and beyond. The renewable energy share in the system reaches 70% by 2030 and this share is maintained around 70% - 73% beyond 2030 until the end of the planning horizon. Energy storage options such as pumped storage power plant and battery storage systems were included in the base case for energy shifting purpose to ensure the 70% RE share is maintained throughout the horizon. Graphical representation of energy share of the base case is presented in figures 8.5 to 8.7.

As the planning horizon for this plan ends at 2042, achieving carbon neutrality in power generation by 2050 has not been indicated in LTGEP 2023-2042. However, limitations in reaching carbon neutrality were explored through a separate scenario and the resultant conclusions are presented in Chapter 10. It should be highlighted that achieving Carbon neutrality should be a collective attempt and has to be further explored with the advancement of technologies. Plant mix in the proposed base case supports this attempt to some extent (dual fuel capability of proposed thermal power plants with hydrogen blended fuels). Also, carbon sequestration programmes could be promoted, in view of achieving Carbon neutrality by 2050. Depending on the progress and responsiveness of all the stakeholders, these pathways could be further explored in subsequent planning cycles.

Thermal plant additions of the base case plan have been carried out complying with the two policy directives which prohibits adding new coal fired power plants and allows only RLNG as the fuel option for all future firm capacity additions. Accordingly, all the future thermal additions in the base case plan except for the short-term supplementary capacity requirement have been proposed as RLNG fired power plants.

In addition to the above policy directives, as per the "The technical and reliability requirements of electricity network of Sri Lanka" which was published in Gazette Extraordinary No. 2109/28 dated 2019-02-08 by the PUCSL, the Base Case plan has maintained reserve capacity that could be served on demand, within the stipulated limits of 2.5% to 20% over the peak demand throughout the planning horizon.

To identify Base Case plan for LTGEP 2023-2042, four specific scenarios were developed within the guidelines specified in the general policy guidelines. The four scenarios developed were:

1. Scenario 1: Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030 and no coal fired plant additions throughout the horizon
2. Scenario 2: Achieving 70 % RE by 2030, attempt to further increasing RE share up to 80% by 2040 and no coal fired plant additions throughout the horizon
3. Scenario 3: Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030, no coal fired plant additions throughout the horizon and considering cross border interconnection with India
4. Scenario 4: Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030, no coal fired plant additions throughout the horizon and considering nuclear power development beyond 2040

All of the above scenarios complied with the general policy guidelines, but Scenario 2, 3 and 4 were specifically developed to evaluate alternative pathways to achieve carbon neutrality in electricity generation by 2050. However, in Scenario 2 significant limitations in achieving 80% RE share by 2040 were observed, especially due to RE spillage reaching uneconomical levels that obstructs RE share reaching 80%. Detailed discussion of all the scenarios is presented in Chapter 10 of this report.

After evaluation of all aforementioned scenarios, Scenario 1 was selected as the Base Case plan as it indicated the lowest present value cost among the above four scenarios and was technically feasible.

In addition, following scenarios were developed to analyse technical and economic implications of complying with the policy guidelines and to ultimately identify the least cost scenario unconstrained by policy guidelines.

5. Scenario 5: Achieving 50 % RE by 2030, maintaining 50% RE beyond 2030 and no coal fired plant additions beyond 2030
6. Scenario 6: Achieving 60 % RE by 2030, maintaining 60% RE beyond 2030 and no coal fired plant additions beyond 2030
7. Scenario 7: Achieving 60 % RE by 2030, maintaining 60% RE beyond 2030 and no coal fired plant additions throughout the horizon.

All Scenarios 5, 6 and 7 indicated lower present value cost than the existing policy-based scenarios and Scenario 6 indicated the lowest cost among all six scenarios. Therefore, Scenario 6 was identified as the Reference Case of LTGEP 2023-2042 as it indicated the lowest present value cost unconstrained by policy guidelines and, operationally feasible.

Results pertaining to the scenarios other than base case are presented in chapter 10.

8.2 Base Case Plan

The Base Case Plan is given in Table 8.1 and corresponding annual capacity additions are given in the Table 8.2. Table 8.3 presents the cumulative ORE capacity breakdown considered for the Base Case. In this study, commissioning years of committed power plants have been fixed according to the present implementation schedules.

The total present value cost of the Base Case Plan for the period 2023-2042 is USD 18,872 million (LKR 3,802.7 billion) in January 2022 values based on the discount rate of 10%.

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 are not reflected in the total cost of the system (present value) which is the optimized result of expansion studies. Furthermore, the cost to be incurred for developing corresponding transmission infrastructure which is essential for the development of each project would be considered in the transmission planning studies related to this generation expansion plan.

It should also be noted that, the planning process considers the cost to the economy in broader terms in the proposed investment decisions and various business models which could be deployed in implementing the proposed power plants are not taken in to account.

Table 8.1– Generation Expansion Planning Study - Base Case (2023 – 2042)

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a)(b)]	THERMAL CAPACITY ADDITIONS and RETIREMENTS [(a)(c)]
2022	**Uma Oya Hydropower Plant 120 MW** Distribution Connected Embedded Solar 160 MW **Grid Connected Partially Facilitated Solar 94 MW** Mini Hydro 20 MW Biomass 10 MW	
2023	Distribution Connected Embedded Solar 160 MW **Grid Connected Partially Facilitated Solar [1] 147 MW** **Wind 25 MW** Mini Hydro 20 MW Biomass 20 MW	**Gas Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya) 235 MW** Short Term Supplementary Power [2] 320 MW Combined Cycle Power Plant (KPS–2) [3] 163 MW *Retirement of* *Sojitz Kelanitissa Combined Cycle Plant [3] (163) MW*
2024	**Moragolla Hydropower Plant 31 MW** Distribution Connected Embedded Solar 160 MW Grid Connected Partially Facilitated Solar [1] 223 MW Grid Connected Fully Facilitated Solar 100 MW **Wind 60 MW** Mini Hydro 20 MW Biomass 20 MW Standalone Battery Energy Storage 20 MW/50 MWh	**New Gas Turbines – Kelanitissa [4] 130 MW** **Steam Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya) 115 MW** **Gas Turbine of Second NG Combined Cycle Plant (Kerawalapitiya) 235 MW** *Retirement of* *Kelanitissa Gas Turbines [5] (68) MW* *Short Term Supplementary Power (200) MW*
2025	Distribution Connected Embedded Solar 165 MW Grid Connected Partially Facilitated Solar 80 MW Grid Connected Fully Facilitated Solar 260 MW (With Battery Energy Storage) 100 MW/400 MWh Wind (Mannar)[6] 100 MW Wind 100 MW Mini Hydro 25 MW Biomass 20 MW	**Steam Turbine of Second NG Combined Cycle Plant (Kerawalapitiya) 115 MW** *Retirement of* *CEB Barge Power Plant [7] (62) MW*
2026	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 70 MW Grid Connected Fully Facilitated Solar 260 MW (With Battery Energy Storage) 100 MW/400 MWh Wind 290 MW Mini Hydro 25 MW Biomass 20 MW Standalone Battery Energy Storage 80 MW/320 MWh	IC Engine Power Plant -Natural Gas (Western Region) 200 MW *Retirement of* *Gas Turbine (GT7)[8] (115) MW* *4x17 MW Sapugaskande Diesel (68) MW* *8x9 MW Sapugaskande Diesel Ext (72) MW* *Short Term Supplementary Power (120) MW*
2027	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 50 MW Grid Connected Fully Facilitated Solar 280 MW (With Battery Energy Storage) 100 MW/400MWh Wind 250 MW Mini Hydro 25 MW Biomass 20 MW Standalone Battery Energy Storage 100 MW/400 MWh	Gas Turbine -Natural Gas (Western Region) 100 MW
2028	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 40 MW Grid Connected Fully Facilitated Solar 310 MW (With Battery Energy Storage) 150 MW/600 MWh Wind 200 MW Mini Hydro 25 MW Biomass 20 MW Standalone Battery Energy Storage 200MW/800 MWh	

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [a][b]		THERMAL CAPACITY ADDITIONS and RETIREMENTS [a][c]	
2029	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 20 MW 350 MW 150 MW/600 MWh 250 MW 25 MW 20 MW 350 MW		
2030	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 250 MW 125 MW/500MWh 200 MW 10 MW 20 MW 350 MW		
2031	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 250 MW 125 MW/500MWh 200 MW 10 MW 20 MW 350 MW	-	
2032	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 250 MW 125 MW/500MWh 150 MW 10 MW 20 MW 350 MW		
2033	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass	170 MW 30 MW 300 MW 150 MW/600MWh 150 MW 10 MW 20 MW	*Retirement of* *Combined Cycle Plant (KPS)* *Combined Cycle Plant (KPS- 2)* *Uthuru Janani Power Plant*	 *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass	180 MW 30 MW 300 MW 150 MW/600MWh 150 MW 10 MW 20 MW	Gas Turbine -Natural Gas	100 MW
2035	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	180 MW 30 MW 300 MW 125MW/500MWh 150 MW 10 MW 10 MW 50MW/200MWh	Gas Turbine -Natural Gas IC Engine Power Plant -Natural Gas *Retirement of* *West Coast Combined Cycle Power Plant*	100 MW 250 MW *(300) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS (a)(b)		THERMAL CAPACITY ADDITIONS and RETIREMENTS (a)(c)	
2036	Distribution Connected Embedded Solar	190 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100MW/400MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100MW/400MWh		
2037	Distribution Connected Embedded Solar	190 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100MW/400MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100MW/400MWh		
2038	Distribution Connected Embedded Solar	200 MW	IC Engine Power Plant -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100MW/400MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100MW/400MWh		
2039	Distribution Connected Embedded Solar	200 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100 MW/400 MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh		
2040	Distribution Connected Embedded Solar	200 MW	IC Engine Power Plant -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	115 MW/460 MWh		
	Wind	150 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh		
2041	Distribution Connected Embedded Solar	200 MW	Gas Turbine -Natural Gas	100 MW
	Grid Connected Partially Facilitated Solar	20 MW	Combined Cycle Power Plant (Natural Gas)	400 MW
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	125 MW/500 MWh		
	Wind	150 MW	*Retirement of*	
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh	*Lakvijaya Coal Power Plant Unit 1*	*(300) MW*
2042	Distribution Connected Embedded Solar	200 MW		
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	125 MW/500 MWh		
	Wind	150 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	150 MW/600 MWh		

GENERAL NOTES

a. All plant capacities (MW) shown are the Gross Capacities. Committed Power Projects are shown in bold text and retiring projects are shown in italics with their capacity in brackets.

b. Mini-hydro and Biomass annual capacity additions are not restricted to the planned capacities mentioned in the table. Higher capacity additions will be evaluated case by case.

   Thalpitigala and Gin Ganga multipurpose hydropower plants are proposed and developed by Ministry of Irrigation and both these plants are considered as candidate power plants with no specific commissioning years at present.
   The capacity addition of battery energy storage devices is mainly to provide energy shifting requirements. Any additional battery storage capacity could be accommodated at detailed studies after evaluating grid support services requirement such as frequency regulation.

   The retirement years of renewable energy capacities are not indicated. However, after the expiry of the PPA, they are expected to be refurbished or replaced with similar capacity from same renewable energy technology.

   The retirement years of battery energy storage systems are not indicated. However, they are expected to be replaced with similar capacity, at the end of their lifetime.

c. With the development of LNG supply infrastructure, the existing 300MW West Coast power plant and 165MW Kelanithissa combined cycle plant are expected to be converted to natural gas in 2025.

   Considering the heavy dependency in future on liquefied natural gas as a fuel for electricity generation, all Natural Gas based power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply.

   All new natural gas fired power plants should have the capability to operate from synthetic fuels such as Hydrogen, to satisfy the policy requirement of achieving carbon neutrality by 2050.

   All new natural gas based Combined Cycle Power plants should be technically, operationally and contractually capable of being operated regularly between simple cycle and combined cycle operations.

   Dates of all plant additions as contained in the table are the dates considered for planning studies, and considered as added at the beginning (as at 1st January) of the respective year. (For example, a generating capacity addition indicated for year 2026 implies that the plant has been considered commissioned from the 1st of January 2026). However, for committed power projects actual commissioning month has been considered based on the present progress of the project.

   Retirement dates of existing firm capacity plants are dates considered as inputs to planning studies. For existing power plants, the actual retirement month/PPA expiry month were considered for studies. However, the ACTUAL retirement of all power plants is to be made after further evaluating the actual plant condition at the time of retirement, (including the availability of useful operating hours beyond the scheduled retirement date), and the implementation progress of planned power plant additions

d. Broadlands Power Plant (35 MW) which is under test running, is not shown in the base case and is considered as an existing plant.

SPECIFIC NOTES

1. It is possible to advance the absorption of Grid connected partially facilitated solar capacity of 147 MW and 223 MW (planned for 2023, 2024 respectively) by one year each, provided the procurement and commissioning is fast tracked for these projects.

2. Technology of supplementary capacity can be opened for both Gas Turbine and IC engine technology. Fuel option can be specified as appropriate at the time of procurement for suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms.

   Short-term supplementary capacity requirement under different contingency events are assessed in the contingency analysis under chapter 14 of the LCLTGEP 2023-2042 report. Such requirements too shall be appropriately considered prior to initiating procurement.

   Extension of the contracts of existing capacities could be considered as appropriate within the legal framework to meet short term requirement.

3. PPA of Sojitz Kelanitissa is scheduled to be expired in 2023, and to be operated as a CEB owned power plant from 2023 to 2033 after conversion to Natural Gas in 2024. It is indicated as " KPS-2" as a capacity addition.

4. This power plant is required to have the special capability to carry out black starts within its limits in the supply restoration exercise, in case of an island wide power failure.

5. Retirement date of the 4 x 17 MW Kelanitissa Gas Turbines are to coincide with the commissioning of the new 130 MW Gas Turbine Plants at the Kelanitissa to comply with local environmental emission regulations.

6. In addition, Mannar Stage II (100 MW) could be accommodated at an earlier year, if development is carried out on fast track basis provided the plant has semi-dispatchable capability with wind forecasting (as in Mannar Stage I).

7. Decision to extend the retirement year of 4 x 15.6 MW Barge Power Plant until the end of year 2026 will be evaluated based on the cost of any refurbishments required for such an extension and the potential benefit of extending beyond the scheduled retirement year.

8. Retirement year of 115 MW Kelanitissa GT7 is extended until the end of 2025 on the basis of carrying out manufacturer recommended major scheduled maintenance work, along with any other essential maintenance required to keep the plant operational.

Table 8.2: Generation Expansion Planning Study - Base Case Capacity Additions (2023 – 2042)

Year	Gross Capacity Addition (MW)										
	Gas Turbines	IC Engines	Coal	Combined Cycle	Major Hydro	Battery Storage*	Pumped Hydro	Short Term	ORE*	Existing Plant Retirements	Battery Storage Retirements
2022					120				284		
2023				235 (GT)				320	372		
2024	130			350 (ST+GT)	31	20		(200)	583	(68)	
2025				115 (ST)		100			750	(62)	
2026		200				180		(120)	835	(255)	
2027	100					200			795		
2028						350			775	(10)	
2029						150	350		835		
2030						125	350		711	(31)	
2031						125	350		692	(12)	
2032						125	350		660	(30)	
2033						150			694	(369)	
2034	100					170			737	(47)	(20)
2035	100	250				275			705	(325)	(100)
2036	200					380			730	(40)	(180)
2037	200					400			775	(85)	(200)
2038		200				550			785	(85)	(350)
2039	200					350			820	(120)	(150)
2040		200				340			793	(113)	(125)
2041	100			400		350			958	(578)	(125)
2042						400			964	(284)	(125)
Total	**1,130**	**850**	**0**	**1,100**	**31**	**4,740**	**1,400**	**0**	**14,969**	**(2,514)**	**(1,375)**

*ORE and Battery Storage capacity additions include the annual capacities added to compensate for the retired capacities during the study horizon

Table 8.3: Projected Cumulative ORE Capacities (2023 – 2042)

Year	Cumulative Mini hydro Capacity (MW)	Cumulative Wind Capacity (MW)	Cumulative Biomass Capacity (MW)	Cumulative Solar Capacity (MW)	Cumulative Total ORE Capacity (MW)
2023	455	333	80	1,161	2,029
2024	475	433	100	1,644	2,652
2025	500	533	120	2,149	3,302
2026	525	823	140	2,649	4,137
2027	550	1,073	160	3,149	4,932
2028	575	1,273	180	3,669	5,697
2029	600	1,523	200	4,209	6,532
2030	610	1,723	220	4,659	7,212
2031	620	1,923	240	5,109	7,892
2032	630	2,073	260	5,559	8,522
2033	640	2,223	280	6,059	9,202
2034	650	2,373	300	6,569	9,892
2035	660	2,523	310	7,079	10,572
2036	670	2,673	320	7,599	11,262
2037	680	2,823	330	8,119	11,952
2038	690	2,973	340	8,649	12,652
2039	700	3,123	350	9,179	13,352
2040	700	3,273	360	9,699	14,032
2041	700	3,423	370	10,219	14,712
2042	700	3,573	380	10,739	15,392

* Cumulative capacity indicates the allowed cumulative capacity for the respective year.

* Further addition of Mini-hydro and Biomass capacities are not limited to above planned values and will be considered case by case depending on the technical feasibility

8.2.1 System Capacity Distribution

Complying with the general policy guidelines, power sector is moving towards increased share in ORE based generation and energy storage to satisfy the rising demand. Retirement of generation and storage capacities also necessitates new capacity additions. Plant/storage retirement details are given in Tables 8.1 and 8.2. In the year 2023, the share of coal based generation capacity is 14% and it gradually decreases to 2% by the end of planning horizon due to no new coal based power generation plants been added to the system in the whole horizon. Major Hydro capacity contribution is 26% by 2023 whereas it will be 12% and 6% in the years 2030 and 2042 respectively due to limited availability of new capacities to cater the increasing demand. Current share of oil based capacity is 23% and it gradually decreases with the introduction of natural gas based thermal power plants in the first half of the planning period and then the oil based capacity share becomes negligible and reaches zero by 2033.

Present total installed capacity is 4,184 MW (excluding rooftop solar) and out of that 3,371 MW is dispatchable power plants. Chapter 2 includes the detailed information of the existing generation system. A total of 1,340 MW of existing thermal capacity is due to retire during the 20 year planning period. Future addition of hydro capacity is 31 MW including committed plants as shown in the Table 8.1. 1,100 MW of natural gas based combined cycle power plants are added during the planning period of 2023-2042. In addition, 850 MW of natural gas based IC engines and 1,130 MW natural gas based gas turbines are introduced to the system to serve the operational requirements of the system, due to high integration of variable renewable energy sources.

As shown in the Table 8.2, 14,289 MW of ORE capacity additions over the 20-year period is expected which is a 118% increase from the total ORE additions envisaged in the previous LTGEP 2022-2041.

Energy storage solutions such as, pumped storage hydro and grid scale battery storage have been proposed. The first 350 MW Pumped Storage Hydro power plant unit is added in 2029 followed by another three units of same capacity in 2030, 2031 and 2032. Grid scale battery storage systems are added in phase development starting with 20 MW in 2024. The cumulative capacities of battery storage will be 1,125 MW by 2030 and 3,365 MW in 2042. Battery storage requirement beyond 2030 however will be revaluated based on the exact system requirement as well as the progress of the variable renewable energy development.

Capacity additions by plant type are summarised in five year periods in Table 8.4 and graphically represented in Figure 8.1. Capacity balance of the system is presented in Annex 8.1.

Table 8.4: Capacity Additions by Plant Type

Type of Plant	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	2038-2042 (MW)	Total capacity addition (MW)	Total capacity addition %
Major Hydro	31	-	-	-	31	0%
Pumped Hydro	-	1,400	-	-	1,400	6%
Battery Storage	500	875	875	1,115	3,365	16%
Gas Turbines	230	-	600	300	1,130	5%
Coal	-	-	-	-	-	-
Combined Cycle	700	-	-	400	1,100	5%
IC Engines	200	-	250	400	850	4%
ORE	3,335	3,590	3,430	3,440	13,795	64%
Total	**4,996**	**5,865**	**5,155**	**5,655**	**21,671**	**100%**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included

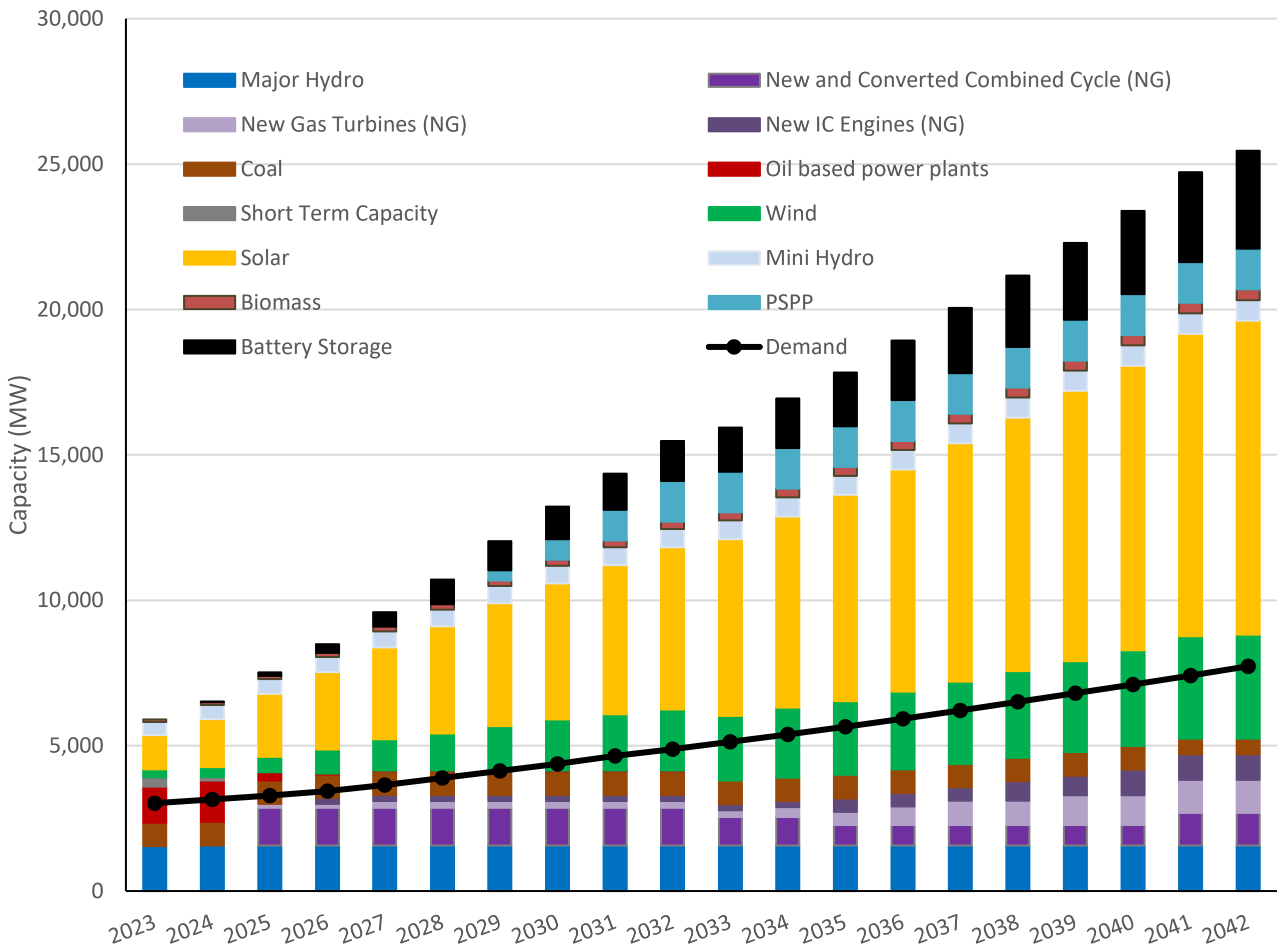


Figure 8.1 –Cumulative Capacity by Plant Type in Base Case

Information on the capacity share is illustrated in the Figure 8.2 and the variation of the total renewable capacity with thermal capacity contribution over the years is shown in the Figure 8.3. It is observed that over 65% of capacity share is maintained by renewable sources throughout the planning horizon complying with development of renewable energy as a prime policy of the government.

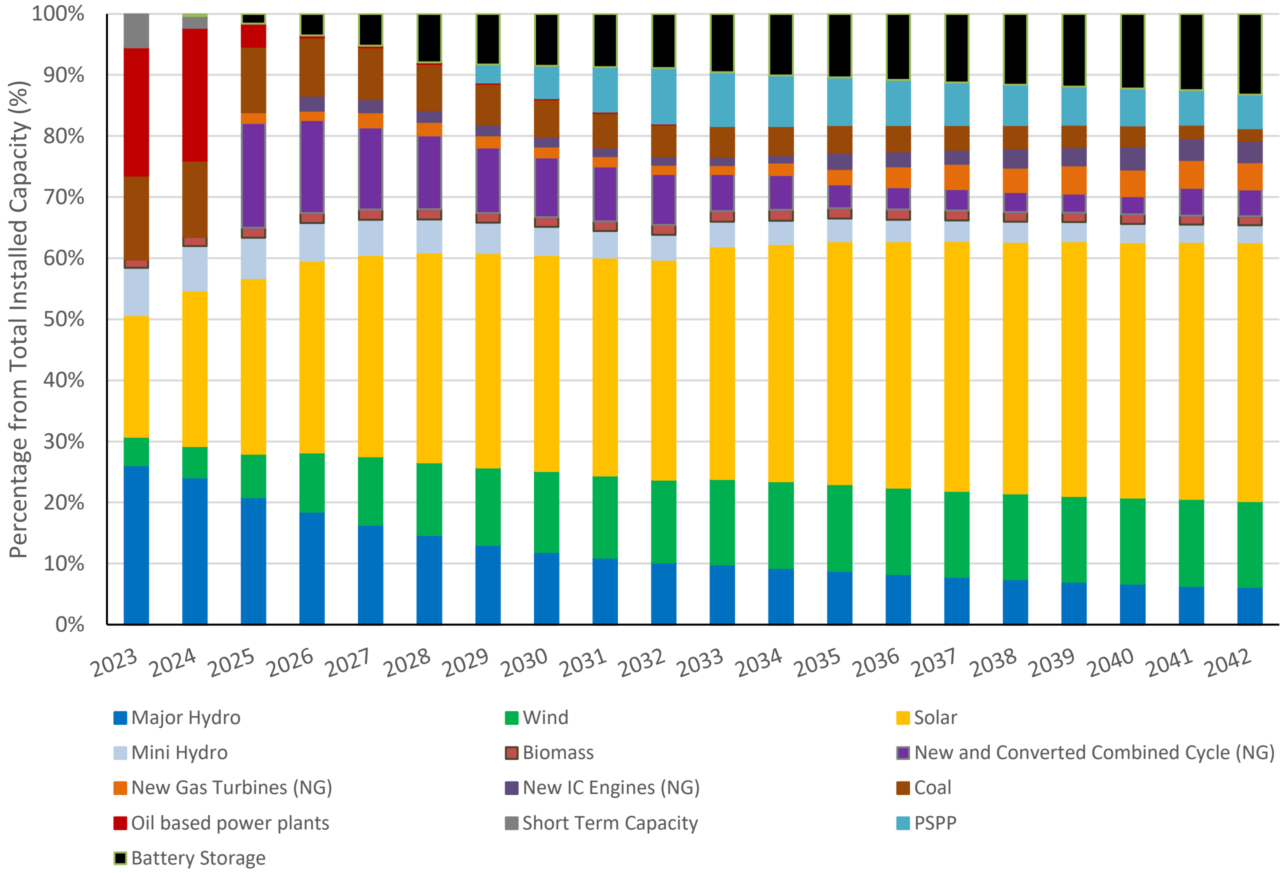


Figure 8.2 – Capacity Mix over next 20 years in Base Case

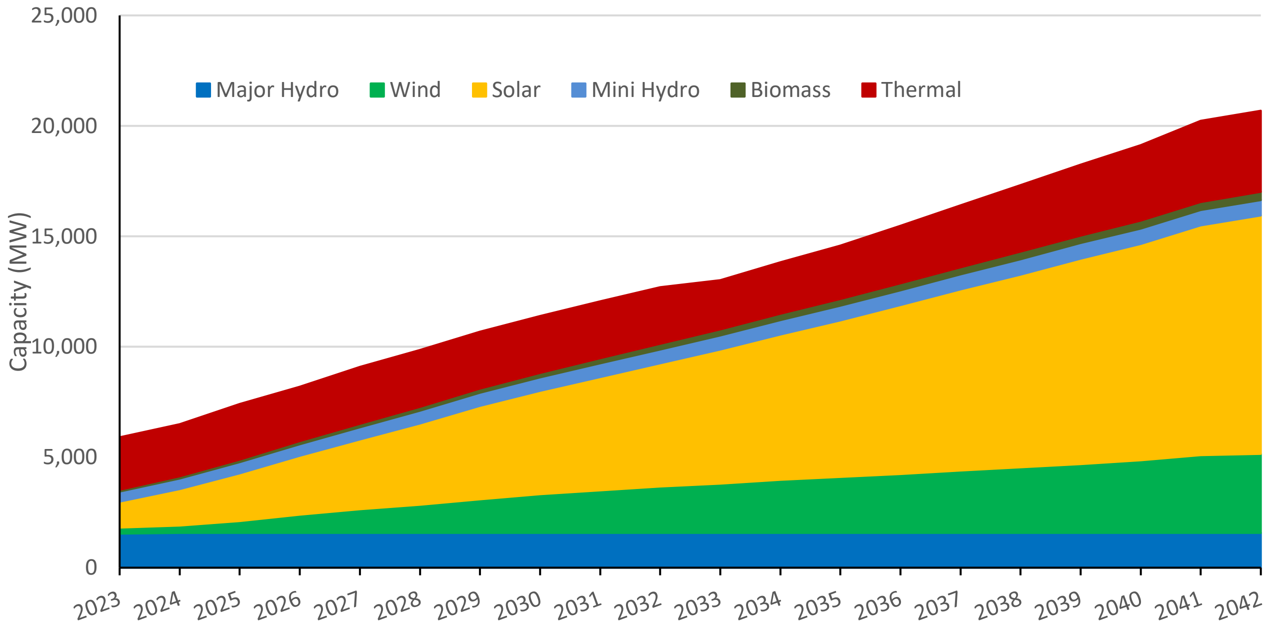


Figure 8.3 – Source wise Capacity Contribution over next 20 years

Variation of the firm capacity share over the planning horizon is shown in the figure 8.4. By year 2030, firm capacity share is comprised of 29% Natural Gas, 13% coal power, 26% large hydro, 27% energy storage, 5% ORE and 1% other firm. For the whole planning horizon and especially beyond 2030, Natural Gas based thermal power plants and energy storage dominate the capacity share as the major firm energy sources.

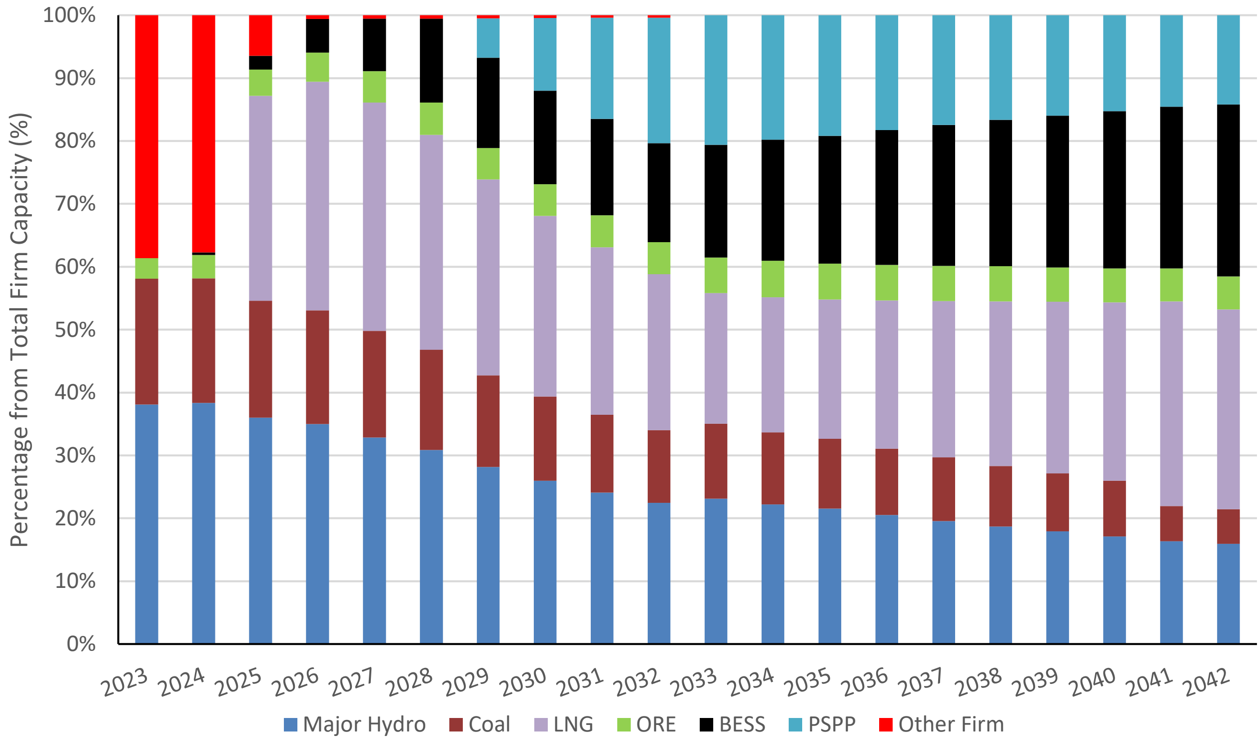


Figure 8.4 – Firm Capacity Share over next 20 years in Base Case

Table 8.5 shows total installed capacity, firm capacity, renewable energy capacity and the peak demand for the years 2030, 2035 and 2042. It is observed that the firm capacity share and the renewable energy share with regard to the total installed capacity and peak demand comply with the government policy on future electricity generation mix.

Table 8.5: Capacity Distribution for Selected Years in Base Case

Year	**2030**	**2035**	**2042**
Major Hydro Installed Capacity (MW)	1,571	1,571	1,571
ORE Installed Capacity (MW)	7,248	10,587	15,446
Total Renewable Installed Capacity (MW)	**8,819**	**12,159**	**17,017**
Total Thermal Installed Capacity (MW)	2,575	2,423	3,670
Total Energy Storage Installed Capacity (MW)	1,825	3,250	4,765
Total Installed Capacity (MW)	**13,219**	**17,832**	**25,452**
Total Firm Installed Capacity (MW)	6,052	7,291	9,847
Peak Demand (MW)	**4,378**	**5,652**	**7,730**

8.2.2 System Energy Share

In 2021, on average 51% of the total energy demand was met by renewable energy sources (34% major hydro and 17% ORE) whereas 49% was met by thermal generation. Future energy supply scenario of the Base Case Plan from 2023 onwards is graphically represented in Figure 8.5. The percentage contribution from different generating sources to the energy mix is shown in Figure 8.6.

As for renewables, the hydro generation share gradually decreases throughout the planning horizon starting from 25% in 2023 to 18% in 2030 and to 10% in 2042. Energy contribution from ORE gradually increases throughout the planning horizon from 22% in 2023 to 52% in 2030 and to 59% by 2042 which adds up to maintaining of 70% RE generation share by 2030 and onwards.

As for thermal power plants, during initial 3 years of the planning horizon major energy contribution comes from oil and coal based thermal generation, but beyond 2025, NG become the major thermal energy contributor to the system and the energy share gradually increases with the addition of new NG power plants to cater the increasing national demand and to improve system operational capabilities. Coal energy share is 31% in 2023 and will gradually decrease up to 7% by 2042. The energy contribution from other oil-fired power plants decreases from 22% in 2023 to 0.1% by 2025 with the gradual retirement of oil plants and thereafter becomes negligible. As shown in the Figure 8.6, energy share of natural gas based power plants gradually increases in the planning horizon, staring from 18% in 2025 to 22% in 2042. Percentage energy share of each plant type is given in Figure 8.6 and Energy Balance of the system is given in Annex 8.2. The Annual expected generation and plant factors under different hydro conditions for the Base Case Plan are given in Annex 8.3.

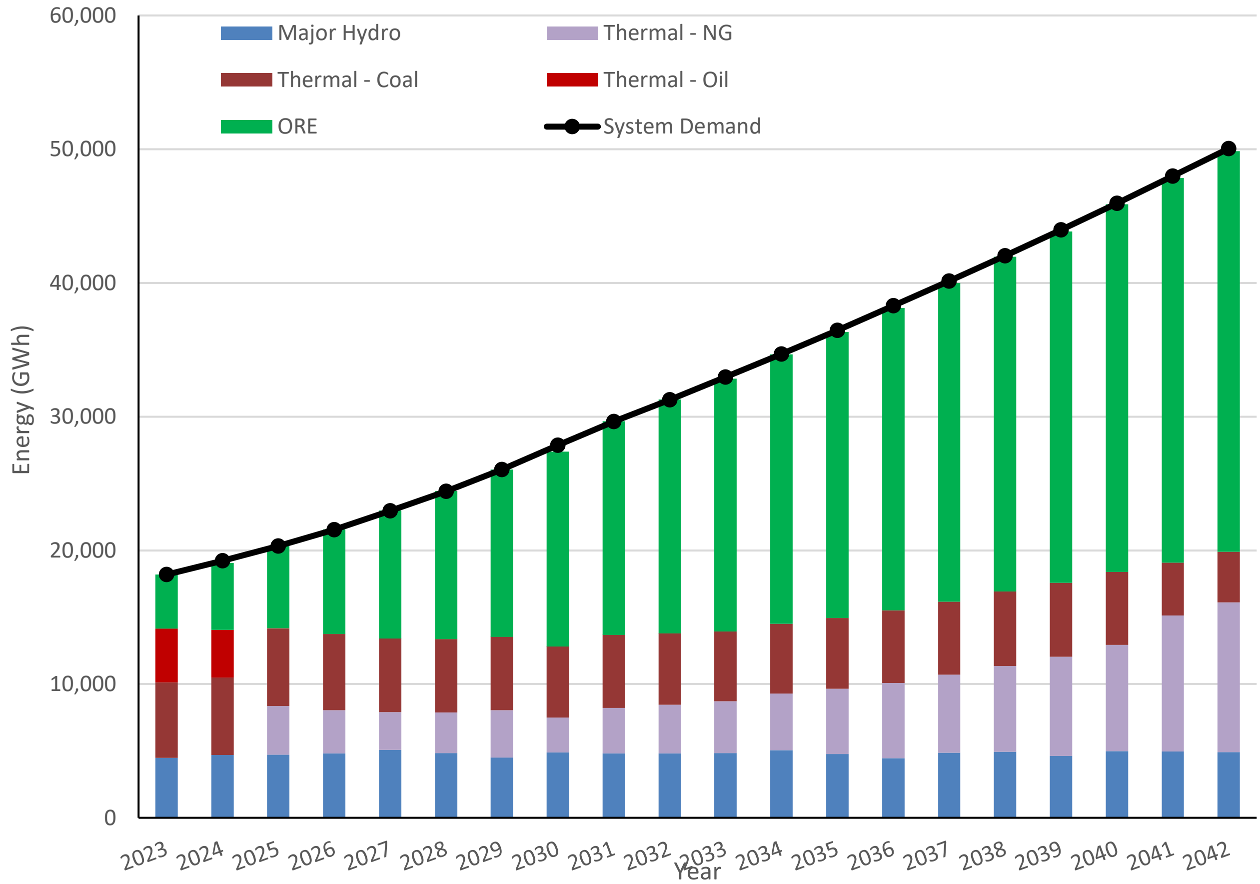


Figure 8.5 – Energy Mix over next 20 years in Base Case

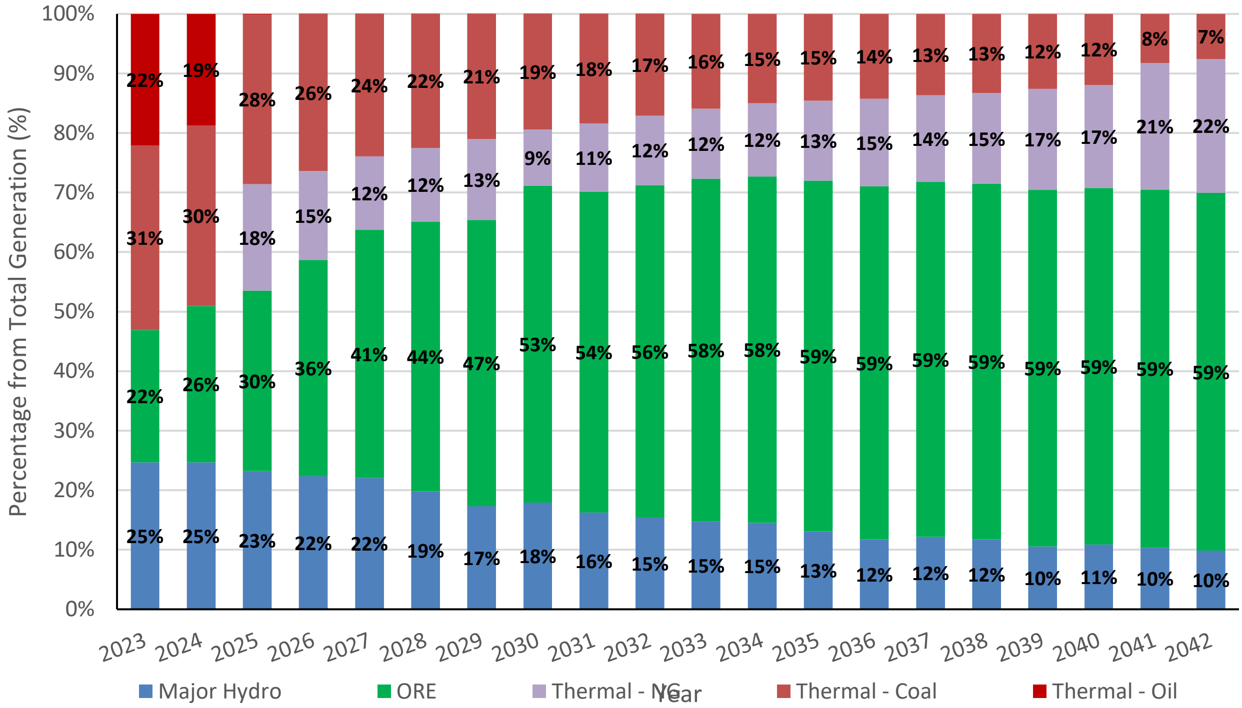


Figure 8.6 – Percentage Share of Energy Mix over next 20 years in Base Case

Breakdown of RE based generation for the 20-year study period is shown in Figure 8.7. 70% RE share is reached by 2030 and maintained up to 2042. With the substantial RE based generation in the system, the implementation of proposed flexible thermal power plants and energy storage capacity as scheduled is imperative in order to maintain the reliability criterion of the power system and to minimize the ORE curtailments during off peak and seasonal resource variations.

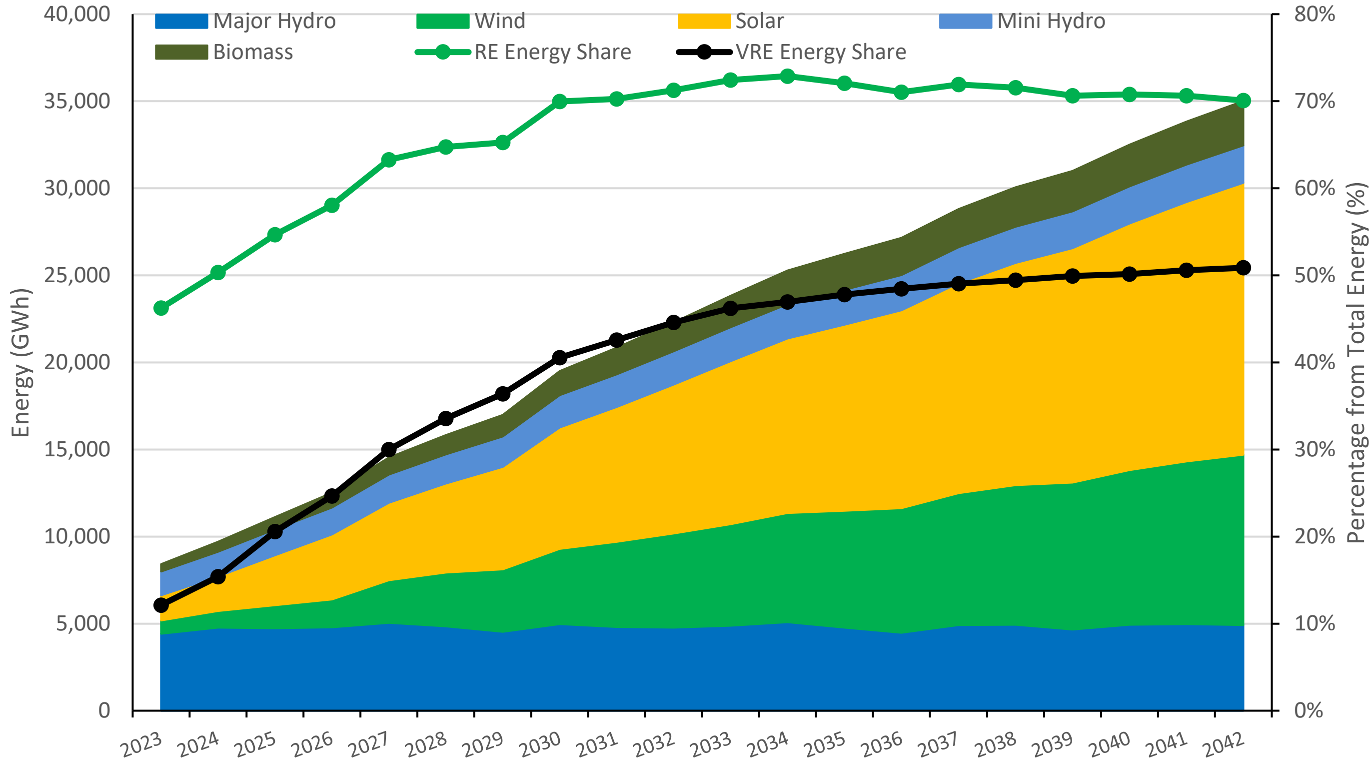


Figure 8.7 – Energy from Renewables and Percentage Share of RE and VRE over next 20 years in Base Case

8.2.3 Fuel, Operation and Maintenance Cost

Expected expenditure on fuel, operation and maintenance (O&M) of the Generation System from 2023 to 2042 for the plants in the Base Case is summarized in Table 8.6 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 8.4. Expected fuel quantities and associated costs of fuel in the Base Case are graphically represented in Figure 8.8 and Figure 8.9 based on the fuel prices indicated in Section 4.2 of Chapter 4.

Table 8.6: Cost of Operation, Maintenance and Fuel

Units: million USD

Year	Operation and Maintenance						Fuel
	Hydro	Thermal	Pumped Hydro	Battery Storage	ORE	Total	
2023-2027	100	370	-	9	332	812	3,648
2028-2032	101	371	45	56	615	1,188	3,667
2033-2037	101	412	90	94	851	1,547	4,578
2038-2042	101	579	90	144	1,074	1,988	6,622
Total	**402**	**1,732**	**224**	**303**	**2,872**	**5,534**	**18,515**

Total fixed and variable O&M cost over next 20 years is in the order of about 5,534 million USD and total fuel cost is about 18,515 million USD in constant terms.

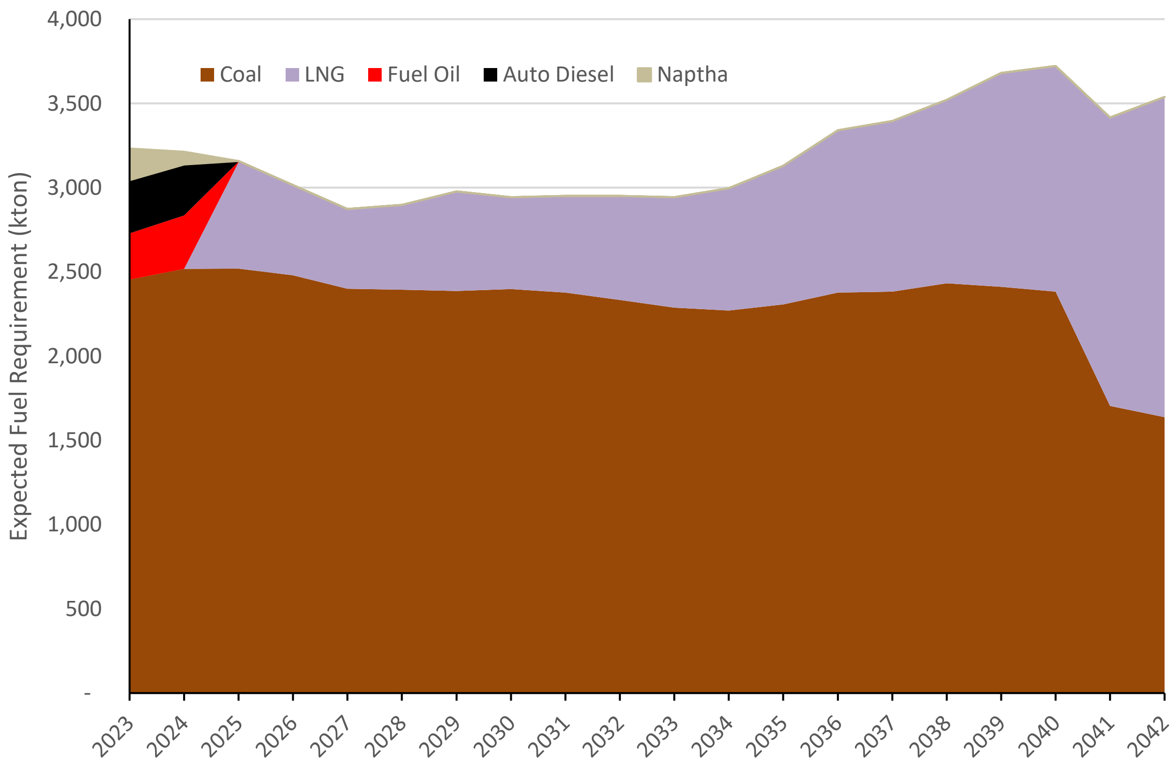


Figure 8.8 - Fuel Requirement of Base Case

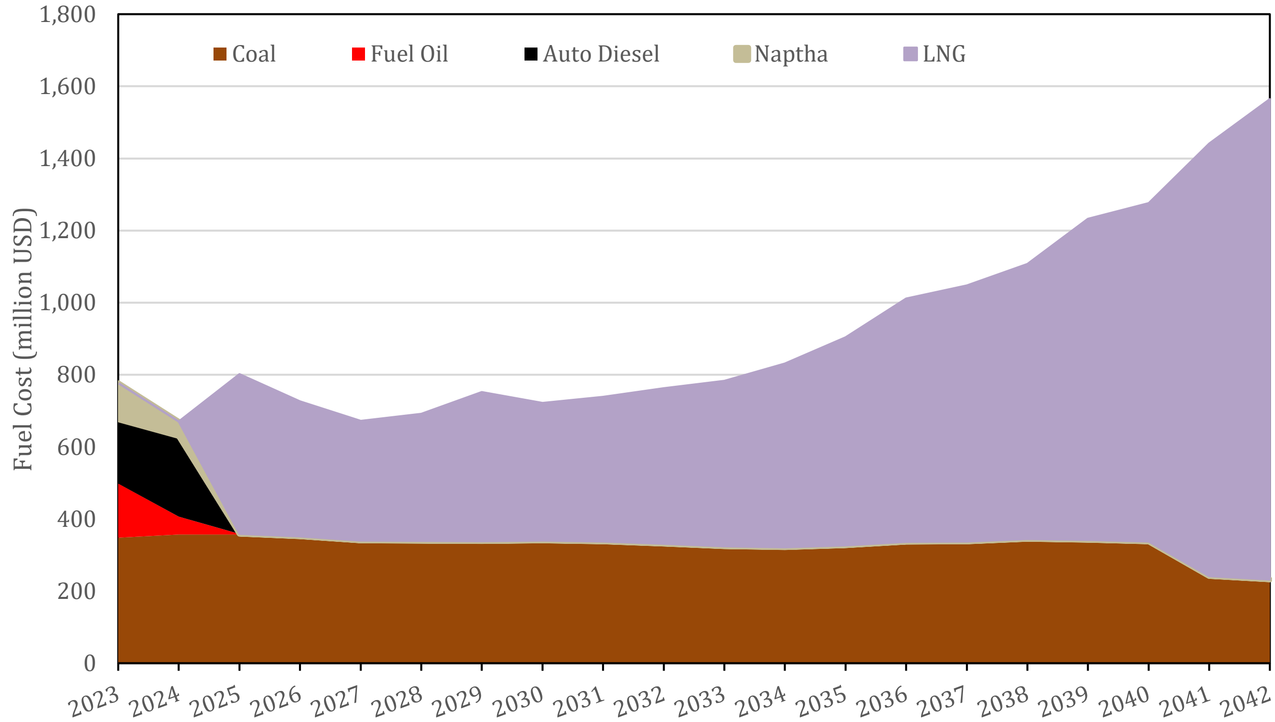


Figure 8.9 - Fuel Cost of Base Case

In the initial years of the planning period, the oil requirement is relatively high due to short term capacity requirements and the coal remains constant while LNG requirement is increasing gradually. After 2025, the oil quantity requirement becomes negligible with the retirement of existing oil based power plants and the minimal dispatch of the oil based thermal power plants, while the NG requirement increases gradually with the introduction of new natural gas based plants.

In the year 2023, nearly 0.8 million tons of fuel oil, diesel and naphtha will be burnt in oil power stations and this consumption will decrease significantly to 0.006 million tons in 2025 and will completely be phased out by 2033. The total consumption of oil decreases within the first 10 years to a minimal value with the phasing out of oil plants and introduction of natural gas based power plants including the conversion of existing oil power plants to natural gas.

As natural gas becomes the dominant fuel in the planning horizon, the expected annual fuel requirement for the future development of natural gas based power plants in average, dry and wet hydro scenarios as per the Base Case Plan, is shown in the Figure 8.10.

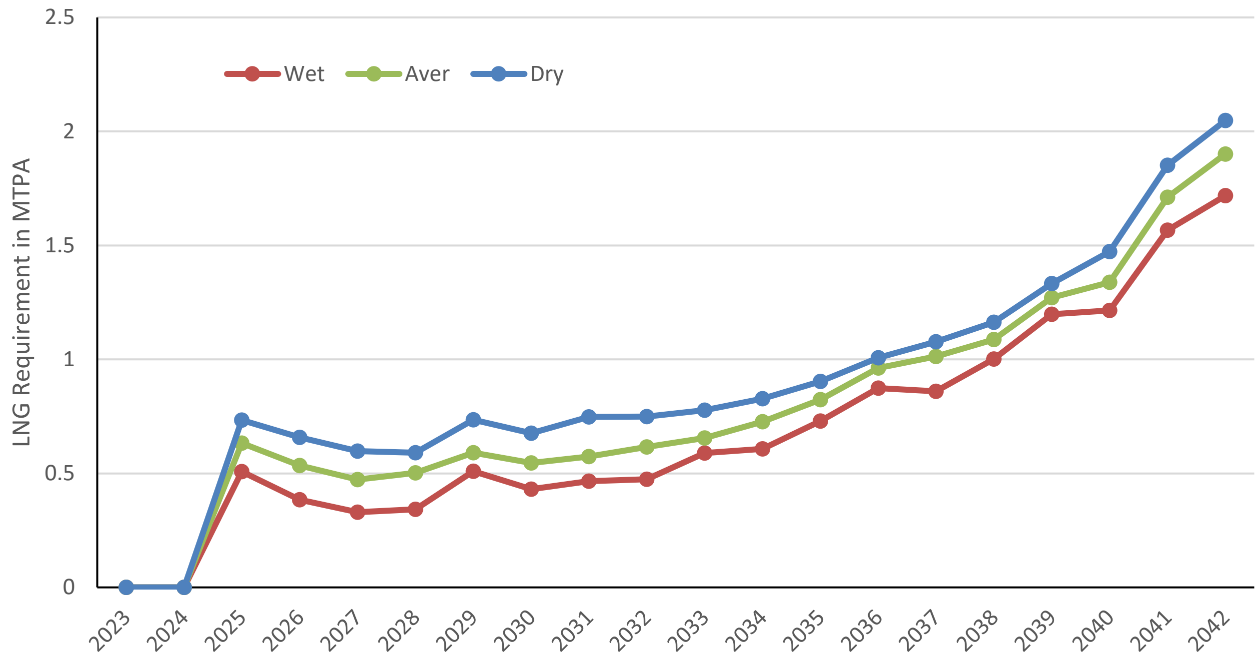


Figure 8.10 - Expected Annual Natural Gas Requirement of the Base Case in Different Hydro Scenarios

8.2.4 Reserve Margin and LOLP

The Base Case plan complies with the stipulated values for Loss of Load Probability and Reserve Margin, for all the hydro conditions in accordance with "The technical and reliability requirements of electricity network of Sri Lanka" which was published in Gazette Extraordinary No. 2109/28 dated 2019-02-08 by the PUCSL.

The Base Case plan maintains available firm capacity share within the minimum Reserve Margin of 2.5% and maximum Reserve Margin of 20% at the critical period for each year (Generally the month with the driest hydro condition). Reserve Capacity in the worst hydro condition is maintained within the stipulated limits even during the initial years of the planning period despite the retirement of several thermal power plants in this period. Reserve Margin and Loss of Load Probability variation during the driest period throughout the 20-year period, considering the available firm capacity during the critical period of each year is shown in the Figure 8.12.

Base Case plan maintains the annual LOLP value below the Maximum LOLP value of 1.5%, which should be complied during all conditions including the driest hydro conditions as shown in Figure 8.11.

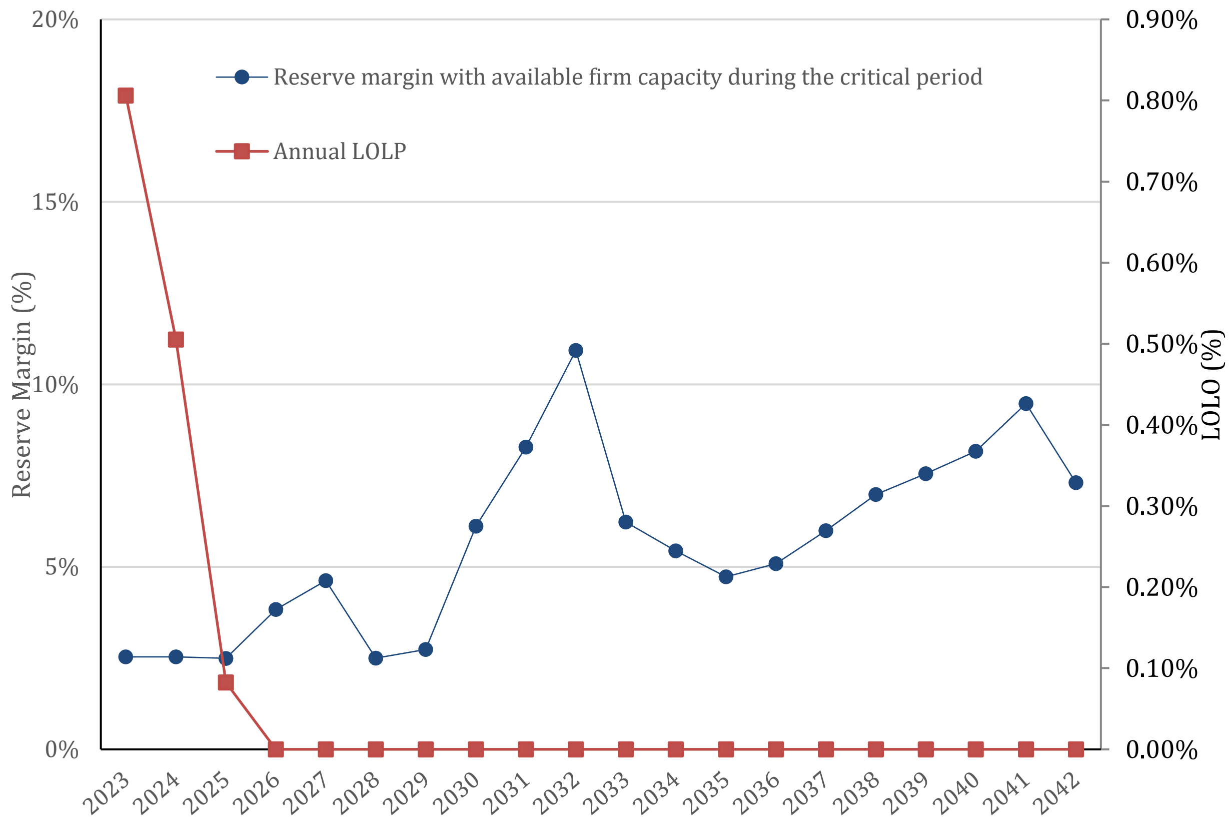


Figure 8.11 – Variation of Reserve Margin and LOLP in Base Case

8.3 Impact of Demand Variation on Base Case Plan

High Demand and Low Demand cases were analysed in order to identify the impact of the demand variation on the Base Case Plan 2023-2042. The demand forecasts used for these two cases are shown in Annex 3.1.

High demand forecast average electricity demand growth rate for twenty-year planning horizon is 5.3%. In order to achieve 70% electricity generation by 2030 with the high demand forecast, solar parks and some wind parks identified under the Base Case Plan 2023-2042 need to be advanced. Due to this increase of power plant capacity additions than that identified in the Base Case Plan, high demand case shows 9.8% increment in the total present worth cost compared to the Base Case over the planning horizon. Capacity additions for High Demand Case by plant type are summarised in five year periods in Table 8.7.

Table 8.7: Capacity Additions by Plant Type – High Demand Case

Type of Plant	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	2038-2042 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	31	-	-	-	31	0%
Pumped Hydro	-	1,400	-	-	1,400	6%
Battery Storage	555	950	925	1,140	3,570	16%
Gas Turbines	330	100	200	800	1,430	7%
Coal	-	-	-	-	-	-
Combined Cycle	700	-	-	400	1,100	5%
IC Engines	200	-	500	-	700	3%
ORE	3,535	3,908	3,153	3,050	13,646	62%
Total	**5,351**	**6,358**	**4,778**	**5,390**	**21,877**	**100%**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included.

Twenty-year average electricity demand growth in low demand forecast is 4.9%. Even with a delayed development of some solar and wind parks identified under the Base Case Plan 2023-2042, 70% electricity generation could be achieved by 2030 with the low demand forecast. Due to this reduction of power plant capacity additions than identified in Base Case Plan 2023-2042, low demand case shows 8.7% total present worth cost decrement compared to the Base Case Plan 2023-2042. Capacity additions for Low Demand Case by plant type are summarised in five year periods in Table 8.8.

Table 8.8: Capacity Additions by Plant Type – Low Demand Case

Type of Plant	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	2038-2042 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	31	-	-	-	31	0%
Pumped Hydro	-	1,400	-	-	1,400	8%
Battery Storage	500	800	550	900	2,750	15%
Gas Turbines	130	100	600	-	830	5%
Coal	-	-	-	-	-	-
Combined Cycle	700	-	-	400	1,100	6%
IC Engines	200	-	-	700	900	5%
ORE	3,185	2,910	2,719	2,599	11,412	62%
Total	**4,746**	**5,210**	**3,869**	**4,599**	**18,423**	**100%**

Above figures represent net capacity additions. Replacements for retiring ORE and Storage capacities not included

The resulting plans for the two cases are given in Annex 8.5 and Annex 8.6 respectively.

8.4 Impact of Discount Rate Variation on Base Case Plan

The discount rate is a crucial component of a discounted cash flow valuation. The discount rate can have a considerable impact on the valuation and hence the selection of power plants in the expansion plan. To study the effect of discount rate on Base Case Plan, analysis was carried out for high and low discount rates compared to 10% used in the Base Case Plan. For low discount rate analysis 3% was used and 15% used for high discount rate.

Low discount rate scenario was carried out to investigate whether high capital cost plants are selected at lower discount rate. In this scenario power plants with comparatively high capital cost were advanced. In the high discount rate analysis, it was observed that the selection of high capital cost power plants was delayed. Therefore, it should be noted that when financing high capital cost power plants, it is required to attract low interest finances in order to be comparatively viable.

8.5 Impact of Delayed Implementation of VRE and Storage Projects on Base Case Plan

As the base case plan of LTGEP 2023-2042 proposes a plant line up dominated by VRE capacity additions and battery storage additions coupled with large scale solar parks, it is important to evaluate the impact on the base case if these VRE and coupled storage projects get delayed. This evaluation is required mainly due to the fact that the VRE capacity additions coupled with storage directly replaces firm base load capacity additions and the other firm capacity additions consisting of flexible thermal generation and peaking thermal plants. Therefore, in the event of delayed implementation of VRE capacity additions coupled with storage, these flexible/peaking thermal generation gets dispatched regularly leading to economically sub optimal operation of the system.

This notion was evaluated by the development of this specific sensitivity on the base case by delaying all major solar parks, wind parks and associated battery projects by 2 years and keeping all other plant additions as it is. As per the results, approximately USD 1 billion increase in the operational cost was indicated in the delayed implementation case compared to base case and it proved that delayed implementation of VRE capacity additions coupled with storage leads to uneconomical operation of the system. Table 8.9 represents above two analysis.

8.6 Impact of Fuel Price Variations on Base Case Plan

As base case has been developed using fixed fuel prices and as fuel prices in international market displays high degree of volatility, it is imperative to develop sensitivities of fuel prices on the base case. For this planning study, sensitivities of fuel prices on all the scenarios including base case have been carried out and the results and discussion are presented in Chapter 10.

8.7 Summary

The total present value of cost over the planning horizon for Base Case and Sensitivities studied are summarized in Table 8.9.

Table 8.9: Comparison of the Sensitivities of the Base Case Plan

	Present Value of costs during the planning horizon	Deviation of Present Value Cost from Base Case	
	(Million USD)	(Million USD)	%
Base Case	18,872	-	-
Sensitivities on Base Case			
Demand Variation			
High Demand	20,584	1,712	9.8
Low Demand	17,228	(1,644)	(8.7)
VRE and Storage Delay (by 2 years)	19,054	182	1

CHAPTER 9
RESULTS OF GENERATION EXPANSION PLANNING STUDY – OPERATIONAL ANALYSIS OF THE BASE CASE PLAN

This chapter presents the summary of operational analysis aspects of the Base Case plan for the period of 2023-2042.

9.1 Background

Traditionally long-term planning of power systems was mainly based on meeting the projected demand at minimum cost. Sri Lanka also being a country having a large hydro and thermal based power system has been carrying out long term generation planning based on conventional long term planning concepts. During the last decade, increasing amounts of Wind and Solar power (termed as Variable Renewable Energy – VRE) has been integrated to the system. The present trend is to aggressively add VRE to the system to meet the government's policy targets set to reduce dependency on fossil fuels and to promote indigenous resources, resulting in reduced environment impacts and reduced expenditure on fossil fuel. Furthermore, diminishing capital cost of VRE technologies has encouraged this. These developments together with other various advancements in power systems such as increased reliability requirements, increased use of novel technologies etc., have prompted to incorporate operational planning aspects to long term planning to evaluate the flexibility and resilience of the power system.

The addition of VRE sources to the system and the increase in share of VRE throughout the planning horizon is illustrated in Figure 9.1. It is observed that VRE share which is currently at less than 10%, increases rapidly during the planning period reaching 40% by 2030 and 50% by 2042. As shown in Figure 5.3 of Chapter 5, Sri Lanka moves from Phase 2 to Phase 4 on the classification defined by International Energy Agency (IEA) based wind and solar penetration levels.

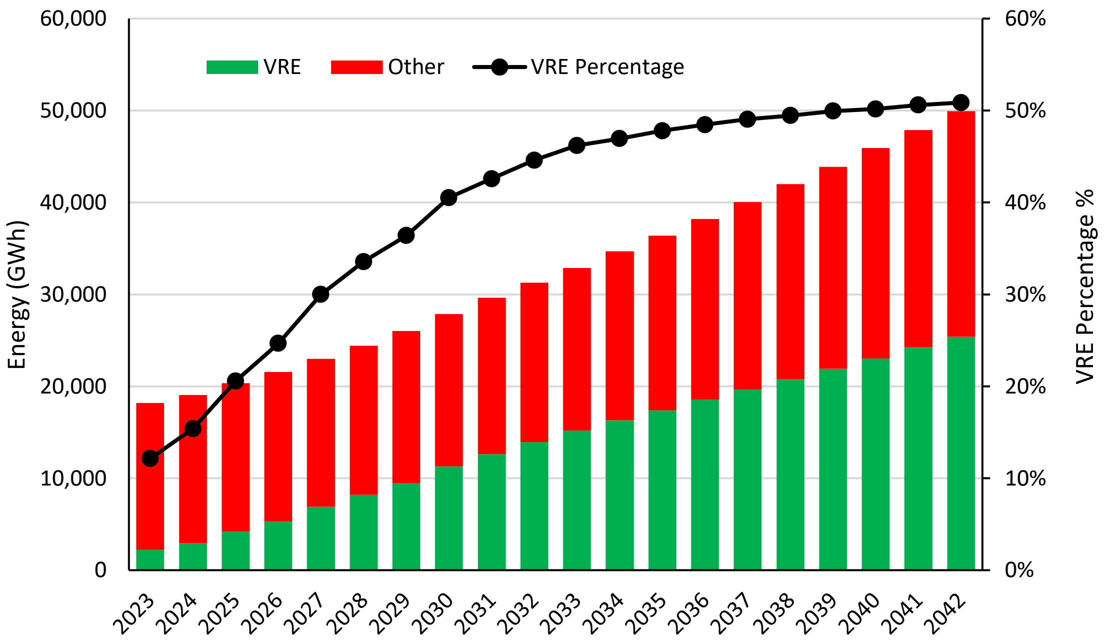


Figure 9.1 – VRE Energy Share in the Base Case

Some of the notable drawbacks in VRE are intermittency of the resource and low inertial support to the system. To overcome these system-wide impacts of VRE, sufficient system inertia and high ramping requirements of conventional power plants is demanded. The intermittency of VRE would cause the conventional power plants having comparatively higher unit costs to start up and ramp up more frequently. Different forms of energy storage and mechanisms such as demand response will become increasingly relevant to aid in the shaping of supply and demand to match one another at all time points of the load curve.

With the above operational considerations, long term generation planning evolves steadily. In the past, many operational constraints were simplified, to keep the planning models computationally small. However, with the ever-increasing demand for operational flexibility of power systems, it is vital to evaluate the projected operational aspects of the system such as power system stability, sufficient ramping capability, sufficient reserve availability, behaviour of energy storage in the system, etc.

The long-term generation planning tools used by CEB offer the capability to carry out hourly simulations of the generation system which enables to capture some of the operational characteristics of the projected power system. This section summarizes the results of the operational analysis carried out for milestone years of the planning horizon in the long-term generation planning exercise. The operational features which were checked using the SDDP hourly simulations are listed below:

1. The worst anticipated hourly and daily ramping event originated from VRE sources.

2. Sufficient generation capacity to provide required operating reserves and the designated power plants providing primary and secondary reserve requirement.

   The primary reserve responds to varying frequency signals, stabilizing the system frequency by compensating imbalances. The purpose of the secondary reserve is to restore power balance and relieve the primary reserve.

3. Sufficient Power plants with fast ramp up and ramp down capability.

4. Standby generation capacity reserve requirement for releasing a major power plant for planned maintenance or forced outages.

5. Sufficient generating capacity (having black start/line charging) capability to restore island wide supply in case of a total system failure, under the standard total failure restoration.

9.2 Non-Synchronous Generation Penetration Limits

Due to the increasing integration of renewable energy sources such as wind as solar, more power is injected to the grid, through power electronic inverters. The System Non-Synchronous Penetration (SNSP) refers to the instantaneous measure of the percentage of generation that comes from non-synchronous sources, such as wind, solar, battery storage and HVDC interconnector imports, relative to the system demand.

The detailed operational analysis for Base Case plan has been conducted considering the maximum allowable System Non-Synchronous Penetration (SNSP) limit to 65%. The remaining 35% of the demand is expected to be provided from synchronous generation that provides the required mechanical inertia to the system. This proportion of Non-Synchronous penetration to Synchronous penetration is presently considered based on the practices followed in other countries that adopt very high VRE penetration. However, it is mandatory to conduct detailed studies to evaluate the impact on the Sri Lankan power system to gradually achieve this target phase by phase. The SNSP distribution simulated during the planning horizon of the base case is depicted in figure 9.2.

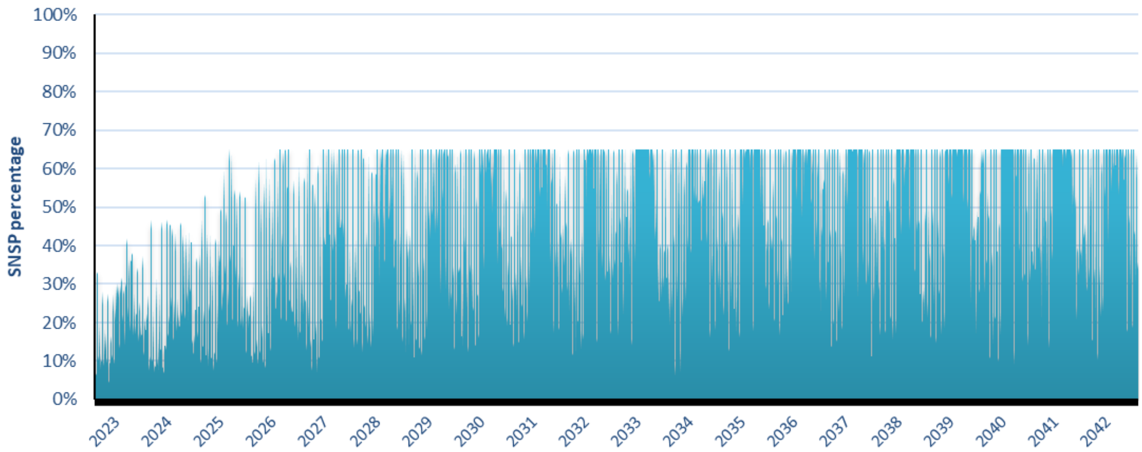


Figure 9.2 – Distribution of SNSP from 2023-2042

The present maximum SNSP level of our network is around 20-25%. With the anticipated VRE additions, the instances surpassing allowable limit of SNSP level of 65% is reached as early as 2026 and maintained the same up to 2042 during simulations. However, it is observed, as the VRE integration level increases throughout the planning horizon, the actual SNSP level tend to exceed the 65% given limit and even reaches up to 80% in years beyond 2030. The countries which plan very high renewable energy targets plan to increase their SNSP limits up to 75% or higher. Increasing the SNSP further for Sri Lanka power system is to be evaluated through comprehensive studies with necessary system reinforcements.

The instantaneous penetration level of VRE sources (prior to storage and curtailment) respective to the forecasted demand for year 2030, is depicted in figure 9.3. Furthermore, the distribution of SNSP of the total system in year 2030 after introducing storage and curtailment, is depicted in figure 9.4.

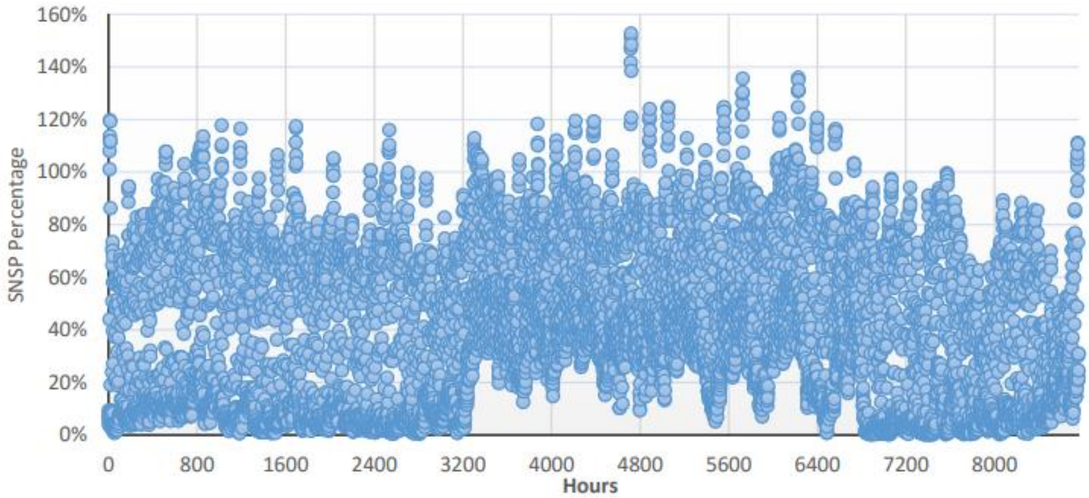


Figure 9.3 – SNSP without Storage & Curtailment in 2030

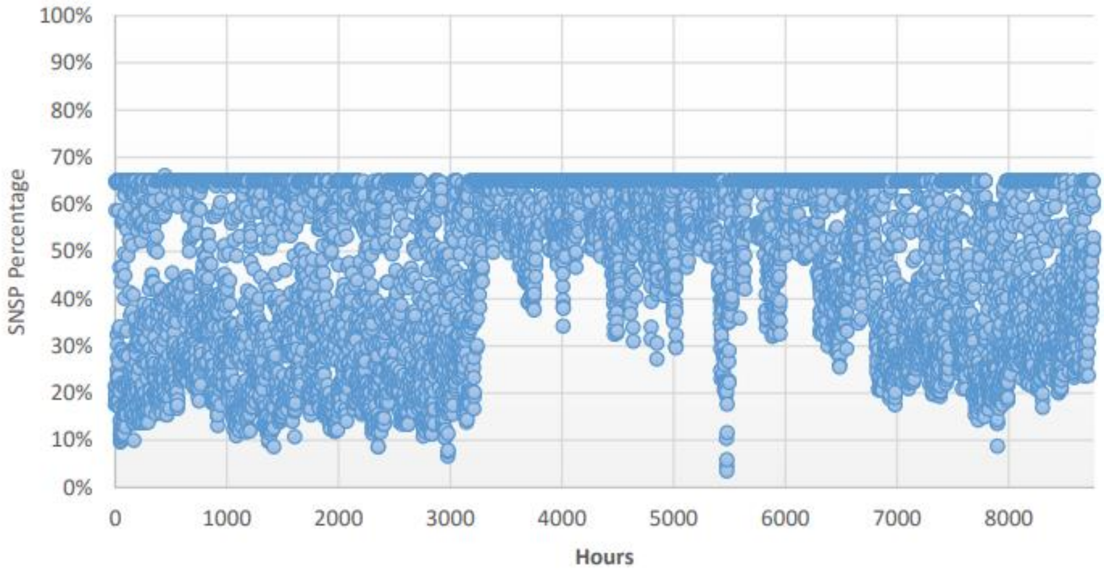


Figure 9.4 – SNSP Constrained with 65% Limit with Storage & Curtailment in 2030

After limiting Non Synchronous Penetration Level at 65%, the SNSP has reached 65% for a total period of 3105 hours in 2030. Also, it goes above 50% for 4727 hours. This shows that in year 2030, approximately 35% - 55% of the duration the power system operates with very high amount of inverter-based generation. Therefore, it is critical that necessary system reinforcements are established to ensure that power system can operate without any failure during a contingency event.

9.3 Dispatch Patterns in weekly load curve

An extract of sample weekly system dispatch patterns during different seasons of targeted policy year 2030 are summarized as follows. It can be seen that each season has unique characteristics driven by weather dependent events.

Dry Season

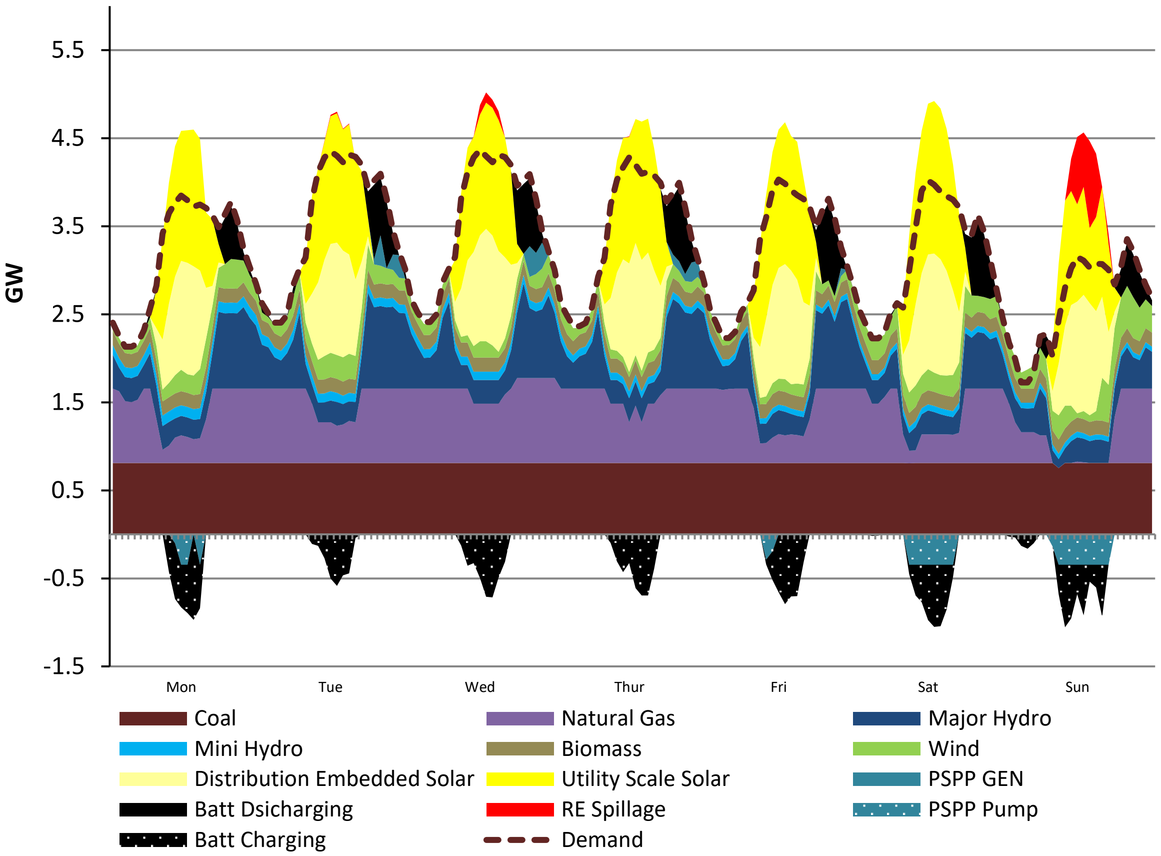


Figure 9.5 – Sample Weekly Dispatch during Dry Season – March 2030

Salient Features

1. Base load operation of Coal Power plants and Base / Intermediate operation of Combined Cycle Power Plants.

2. Solar energy production dominant during daytime, and excess energy discharged through Battery Storage and Pumped Hydro Storage during night Peak.

3. Wind energy production is low, and Major Hydro is dispatched during night peak and off peak.

4. Curtailments observed mainly during Sunday daytime, and occasionally during weekday daytime.

High Wind Season

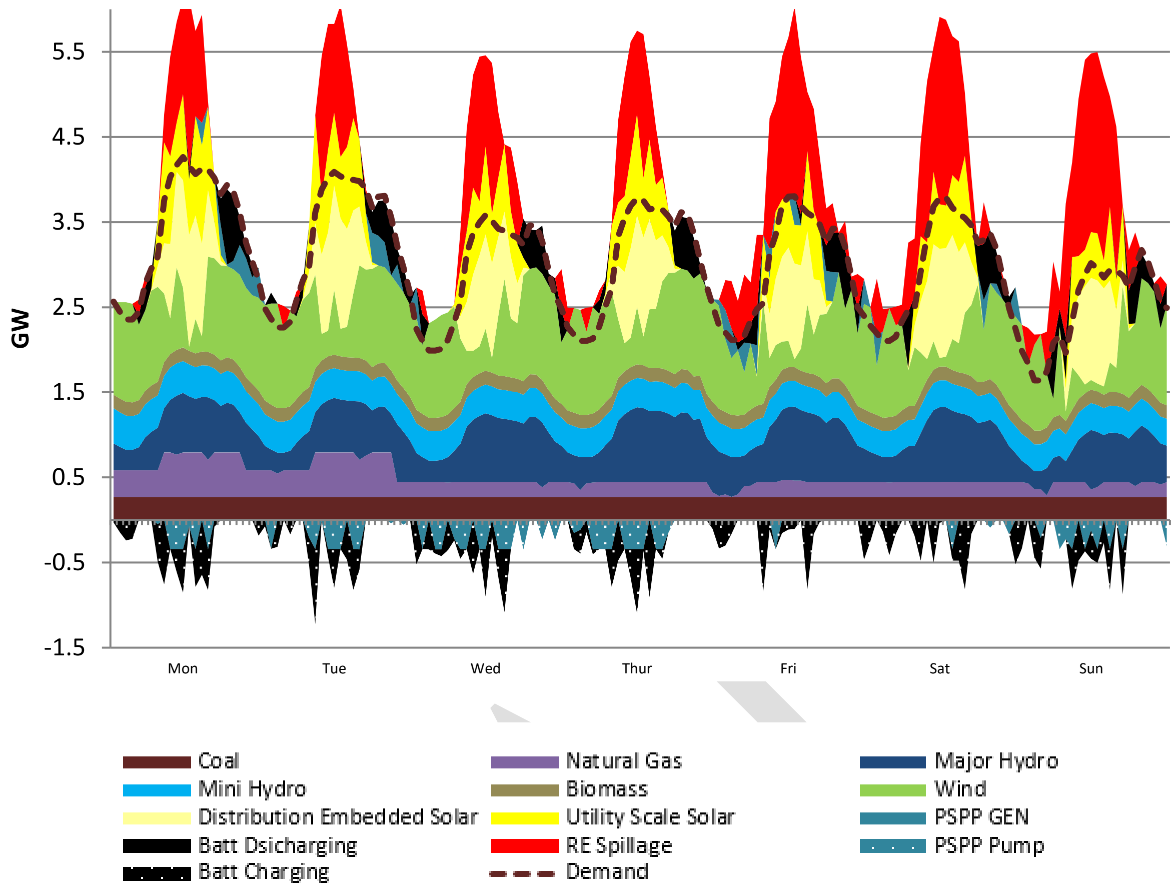


Figure 9.6 – Sample Weekly Dispatch during High Wind Season – September 2030

Salient Features

1. At least one coal power plant expected to be on maintenance while the remaining shall operate on base load. Combined Cycle Power Plants operation shall be limited. However flexible power plants such as Gas Engines and Gas Turbines shall be dispatched in cyclic operation.

2. Wind energy production is high, and dispatch from hydro is also considerable due to active south west monsoon. Average solar energy production can be expected during daytime. Hence months from May to September will have very high share of renewable energy generation

3. Battery Energy Storage and Pumped Hydro Storage units can be expected to operate thought the day providing energy shifting and frequency regulation.

4. Curtailments can be observed both in weekdays and weekends, in both daytime and off peak time.

Wet Season

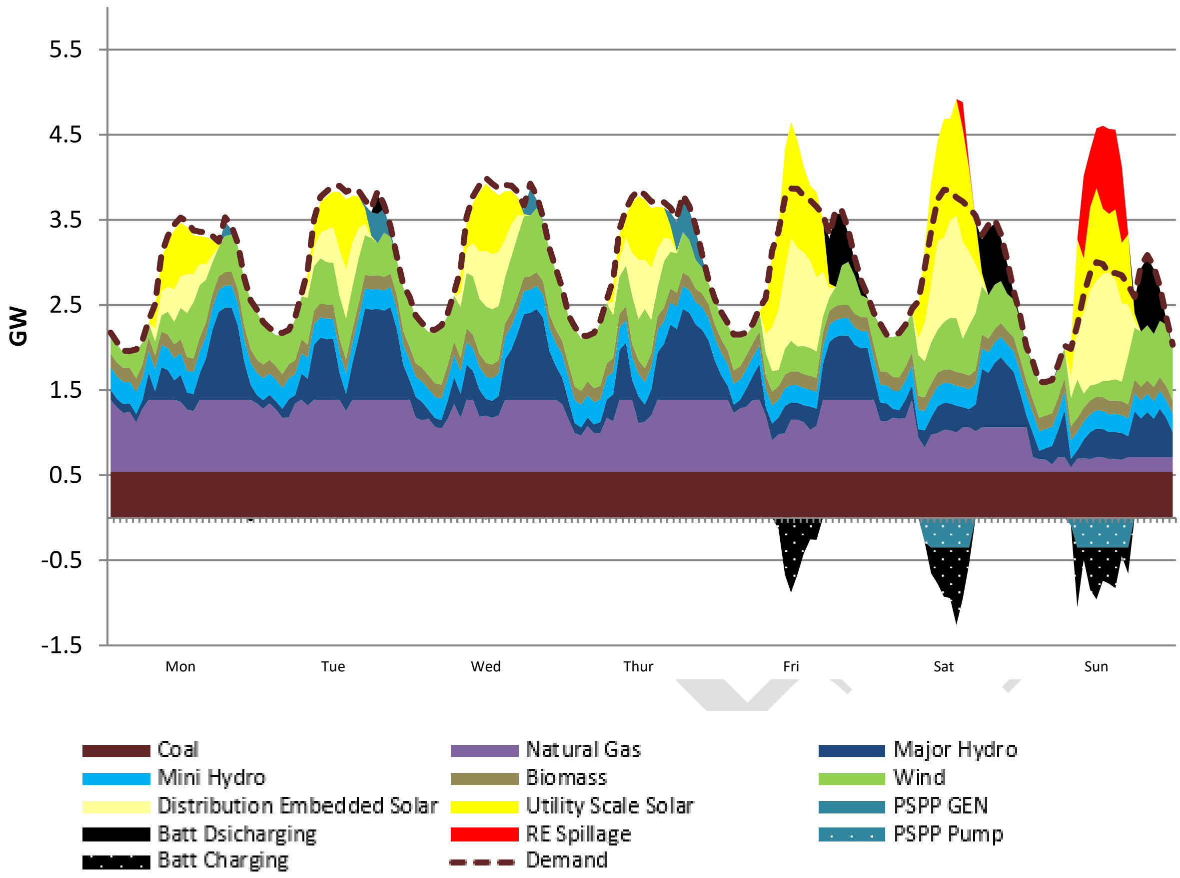


Figure 9.7 – Sample Weekly Dispatch during Wet Season – December 2030

Salient Features

1. Base load operation of Coal Power plants and Base / Intermediate operation of Combined Cycle Power Plants. Peaking thermal power plants to operate during days solar energy production is low. A major thermal power plant could be considered for maintenance during this season due to high availability of renewable energy resources during this season.

2. Solar energy production could decrease in certain days and wind energy production remains average. Northeast monsoon and Inter monsoon could increase the hydro inflows and Major Hydro could be dispatched appropriately during night peak and off peak.

3. Storage is utilized for energy shifting during days in which solar energy production is in excess.

4. Curtailments observed mainly during Sunday daytime, and occasionally during weekday daytime.

As explained in chapter 3, the growth of day peak is higher compared to night peak, hence the capability to absorb higher share of solar PV penetration is expected to increase with time in the planning horizon. However, the severity of risk events in drastic weather conditions is also increased as the system is much more dependent on weather dependent renewable resources. Sample weekly dispatch during dry season, high wind season and wet season of years 2024, 2036 and 2042 are depicted in Annex 9.1, Annex 9.2 and Annex 9.3 respectively.

9.4 Renewable Energy Curtailments

Curtailment of renewable energy resources can occur due to transmission congestion or excess generation during low load periods. The excess generation mainly occurs due to the seasonality effects of VRE Generation, being incompatible with the demand. The excess energy produced during certain time periods has to be curtailed to maintain system frequency. As the penetration of from variable renewable energy sources increases, the capability to absorb all the VRE produced also decreases. The oversupply of VRE Generation can be solved to a certain extent from storage solutions, however it cannot be completely mitigated.

The severity of Renewable Energy curtailments of the Base case plan can be observed throughout the time horizon as illustrated in figure 9.8. Table 9.1 depicts the magnitude of renewable energy curtailments observed in each year for the planning horizon from 2023 to 2042.

Table 9.1: Renewable Energy Curtailment details

Year	Maximum Observed Renewable Energy Curtailment Event (MW)	Average Annual Cumulative Renewable Energy Curtailment (GWh)	Renewable Energy Curtailment from RE Generation (%)	Renewable Energy Curtailment from Total Generation %
2023	47	0	0.0%	0.0%
2024	82	1	0.0%	0.0%
2025	377	11	0.1%	0.1%
2026	1,073	86	0.7%	0.4%
2027	1,600	335	2.3%	1.5%
2028	2,290	670	4.2%	2.7%
2029	3,092	887	5.2%	3.4%
2030	3,455	815	4.3%	2.9%
2031	3,818	791	3.8%	2.7%
2032	4,289	788	3.5%	2.5%
2033	4,588	776	3.3%	2.4%
2034	5,011	1,022	4.0%	2.9%
2035	5,477	1,250	4.8%	3.4%
2036	6,355	1,563	5.8%	4.1%
2037	6,625	1,830	6.4%	4.6%
2038	7,389	2,129	7.1%	5.1%
2039	8,151	2,422	7.8%	5.5%
2040	9,064	2,734	8.4%	6.0%
2041	9,694	2,919	8.6%	6.1%
2042	10,344	3,119	8.9%	6.2%

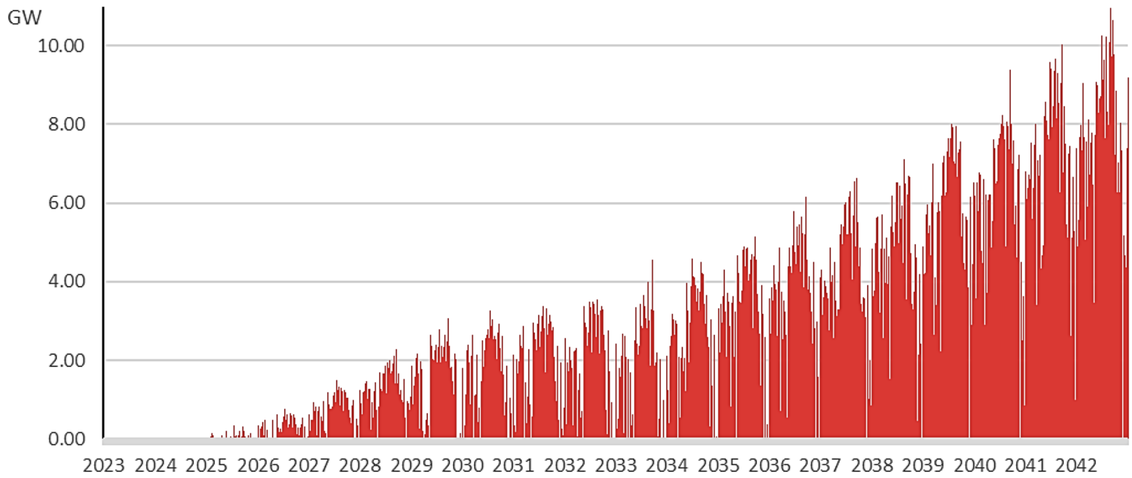


Figure 9.8 – Renewable Energy Curtailments 2023-2042

Even though minor scale Renewable Energy curtailments can be observed from 2023 onwards, the curtailments become distinct only after 2026. The introduction of large-scale Battery Energy storage devices to the system from 2025 onwards is essential to avoid further curtailments than depicted. With the introduction of pumped storage hydro power plants, the curtailments reduce to a certain extent from year 2030 onwards. However, as the share of VRE sources increase rapidly, the renewable energy curtailments tend to rise drastically beyond 2033 as shown in the Figure 9.8. Additional interventions beyond conventional storage solutions are required to mitigate this spillage of surplus energy.

It is also mandatory to establish renewable energy curtailment rules in the grid code, such that downward adjustment of power sources is facilitated in a transparent manner. The conditions related to curtailment is required to be mandated in relevant power purchase agreements appropriately.

Curtailments can be practiced through online and offline modes. During offline mode, where remote controlling is not possible, curtailments are done on day ahead instructions based on weather forecasts. However, in such instances curtailments can be excessive, because of the prediction error. On the other hand, in online mode where remote controlling and monitoring is enabled, it is possible to curtail the amount that is exactly required corresponding to the actual demand.

The renewable energy curtailment results in varying hydro conditions for policy target year of 2030 illustrates a curtailment level of 770-850 GWh per year. The annual curtailment pattern of year 2030 is illustrated in Figure 9.9 and the average weekly curtailment pattern and average daily curtailment pattern of year 2030 are illustrated in figure 9.10.

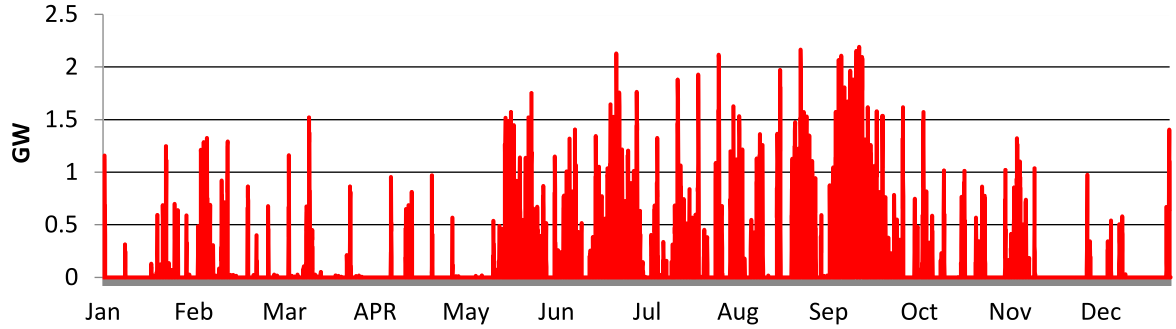


Figure 9.9 - Annual curtailment pattern of Year 2030

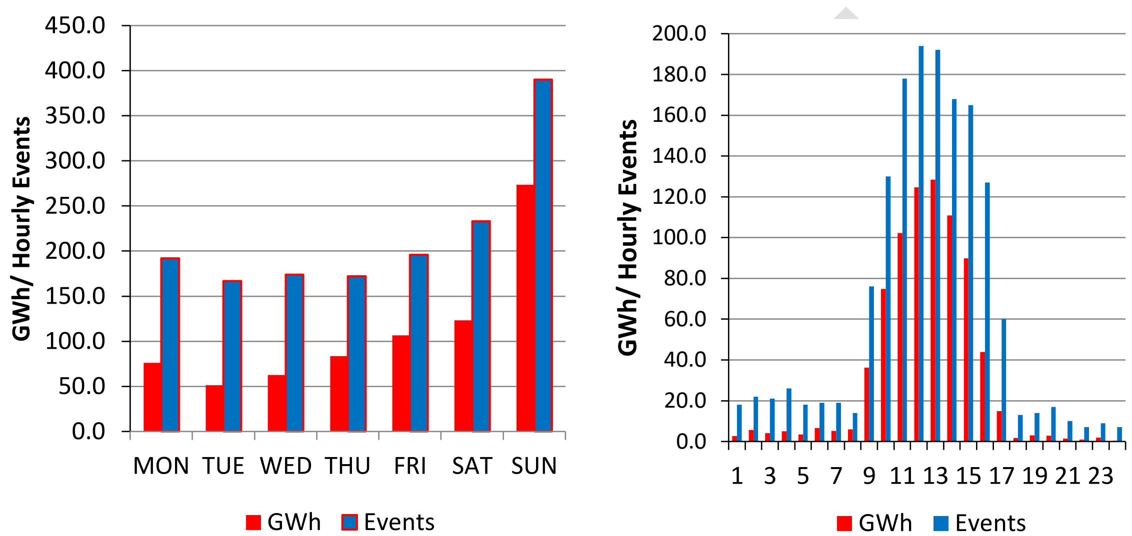


Figure 9.10 - Average weekly curtailment pattern and Average daily curtailment of Year 2030

The major observations on curtailment pattern are as follows.

1. Curtailment during the dry season (January to April) is relatively low and occurs mainly during daytime in Sundays, where the demand is comparatively low.
2. Highest Curtailment during the year is observed during the High Wind Season (May-September). The curtailment is mostly during daytime in which solar production and wind production overlap. There can be occasional curtailments during off-peak times during this season where wind production is very high. Curtailment can be observed in both weekdays and weekends.
3. Curtailment during the wet season (October-December) is also relatively low with curtailment mainly observed during daytime in Sundays, where demand is comparatively low.

9.5 Thermal Power Plant Operations

The performance patterns of thermal power plants are altered significantly with the rapidly rising VRE Generation. Conventional operating patterns from base load to peak load operation of the thermal power plants have to be adjusted for more flexible operating patterns. The key features of high ramping capabilities, lower minimum load operating capability, higher number of start stop cycles, lower uptime and downtime requirements are essential requirements for thermal power plants operating in a high VRE system. However, limited amount from either coal or combined cycle power plants shall continue to operate on baseload to provide necessary system strength.

A sample of the operating pattern of thermal power plants in year 2030, is depicted in figure 9.11.

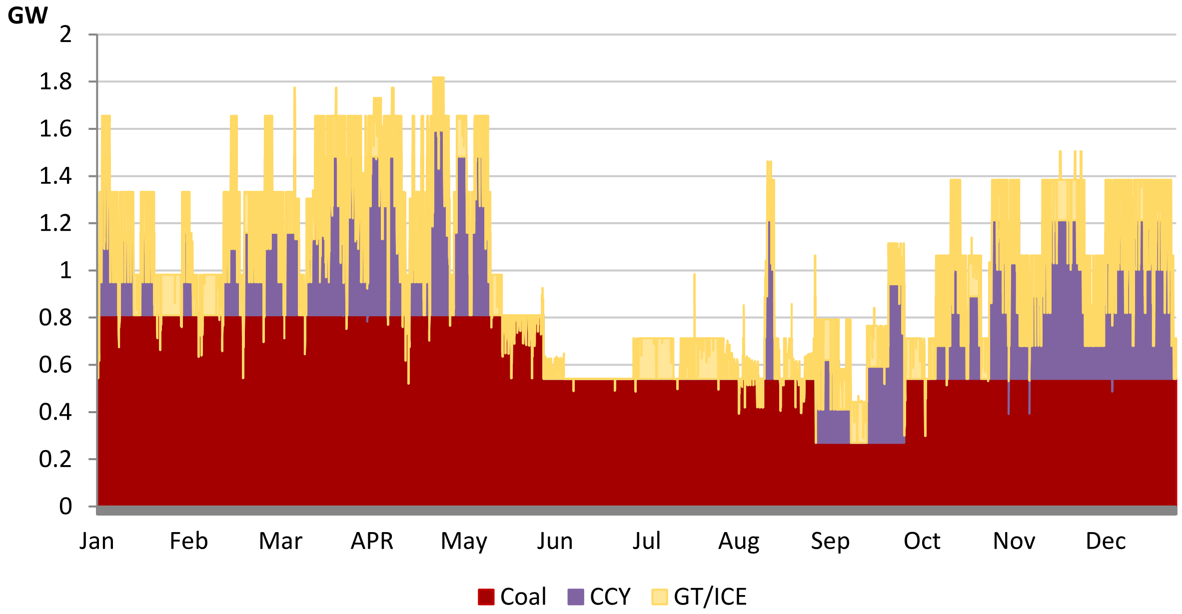


Figure 9.11 – Sample of Thermal plant operating pattern of Year 2030

It can be observed that the operation of combined cycle power plants have been limited to dry season and wet season, while the more flexible thermal generation sources such as gas engines and gas turbines have operated throughout the year.

9.6 Operation of Energy Storage

The Battery Energy Storage and Pumped Hydro Storage are integral developments for the future power system which provide the most essential services to keep the system running. The services of providing frequency regulation and energy shifting are the most critical aspects identified in the generation planning studies and the storage systems are expected to provide these services.

A sample of the operating pattern of Pumped Hydro Storage in year 2030 is depicted in figure 9.12 and Battery Energy Storage in year 2030 is depicted in figure 9.13.

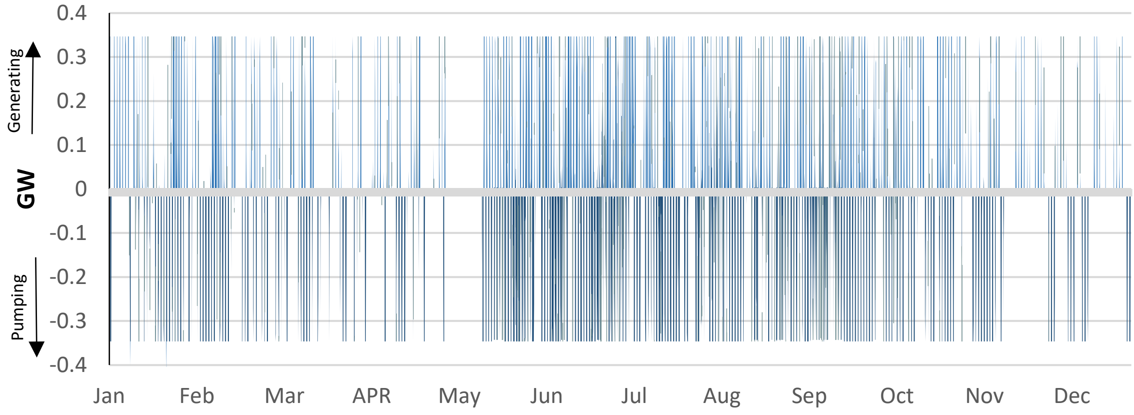


Figure 9.12 – Sample of Pumped Hydro Storage plant operating pattern of Year 2030

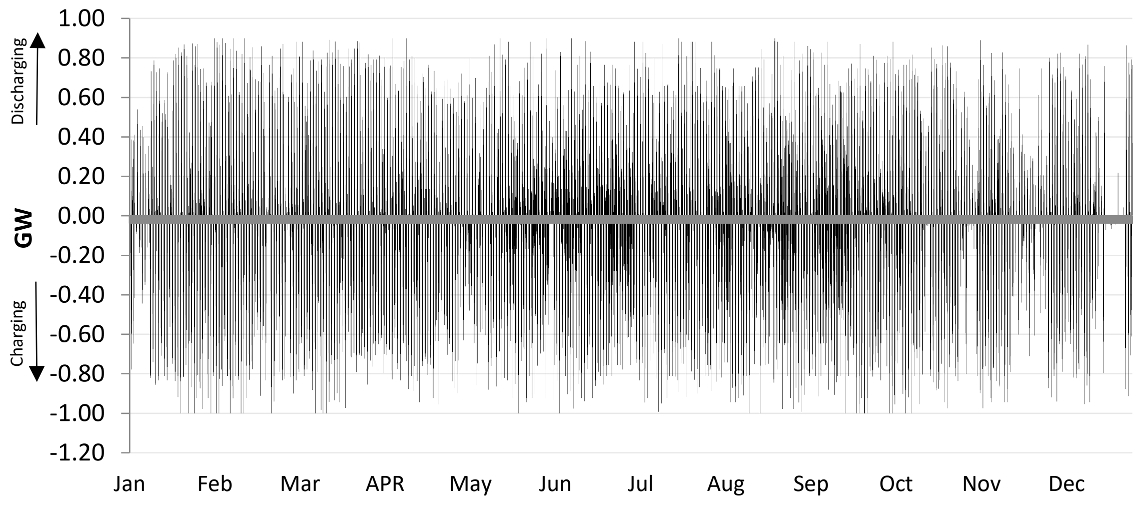


Figure 9.13 – Sample of Battery Energy Storage plant operating pattern of Year 2030

The operation of the pumped hydro storage is expected approximately with 43% of annual duration, with pumping plant factor of 21% and Generation Plant factor of 15% in year 2030. The operation of the Battery Energy Storage is expected approximately with 71% of annual duration, with charging plant factor of 13% and discharging plant factor of 11% in year 2030. For simulations, BESS operation duration is higher due to its higher efficiency compared to PSPP. However, in actual operation, very long lifetime capability of pumped hydro storage needs to be considered in contrast to the limited life cycle of battery storage which would definitely alter the operation pattern of the storage assets.

9.7 Ramping Requirements

The daily ramp up events of large magnitude of VRE generation is mainly caused by the rise in solar PV generation in the morning half of the day and ramp down events at the evening portion. Such events have the possibility of creating hourly ramp of VRE generation (after curtailment) exceeding 1,600 MW in the year 2030. The daily ramp events reach approximately 2,700 MW in some days of the year. Figure 9.14 illustrates the change in VRE in hourly resolution in a dry season week of the year 2030.

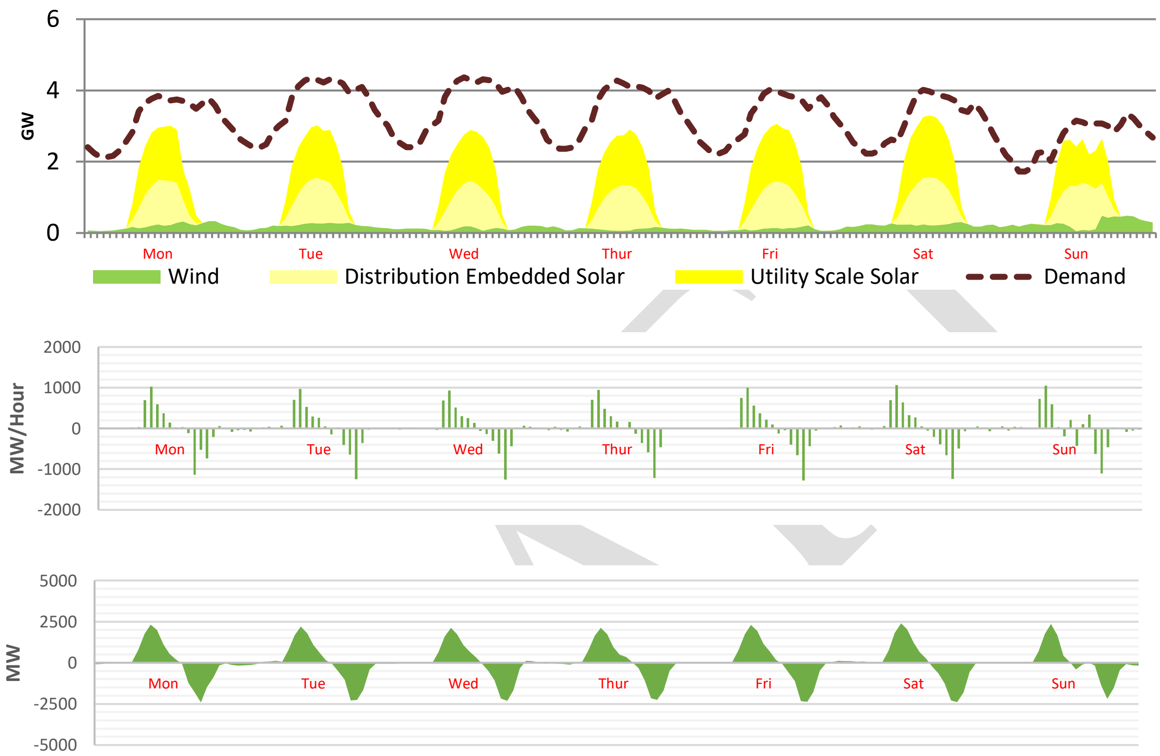


Figure 9.14–Generation, Hourly Ramping & Daily Ramping of VRE - Dry Season Week 2030

The VRE ramp in hourly resolution during morning and evening is much lower in high wind season and wet season, due to the capability of utilizing wind during sunrise and sunset periods. However, further extensive studies are required in intra hourly time scale to depict the effect of VRE variations.

The effect of ramping events considering changes in both VRE generation and load change have to be addressed by the system operator. These large changes take place in the evening reflecting the “Duck Curve” effect for the net demand requiring the ramping up of flexible generation to meet the sharp evening peak appearing in the net load. Since this is much of a predictable situation, system operator can plan ahead by having sufficient power plants capable of ramping during that time. This sharp peak in the net load that reaches up to 2,500 MW in the year 2030 requires the operation of peaking capacities. The flexible capacity required to adjust the output to maintain the supply demand balance in the hour-to-hour basis can reach up to 1,500 MW by 2030.

The figure 9.15 and figure 9.16 illustrates the variation in the net load in dry season and high wind season due to the variabilities in the VRE generation and the demand.

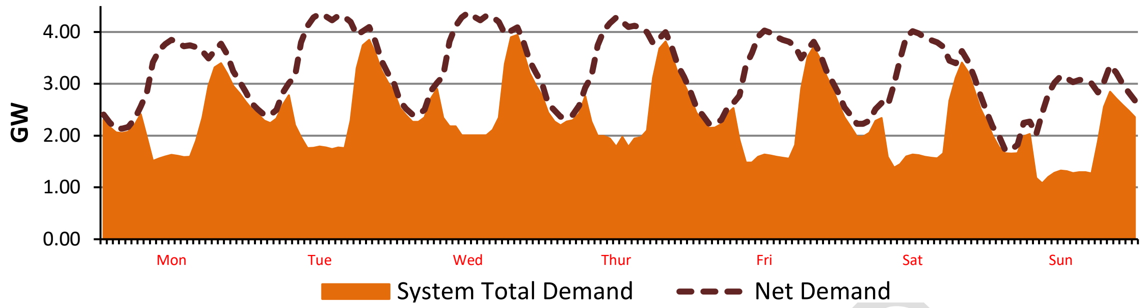


Figure 9.15–Net Demand of Dry Season Week in 2030

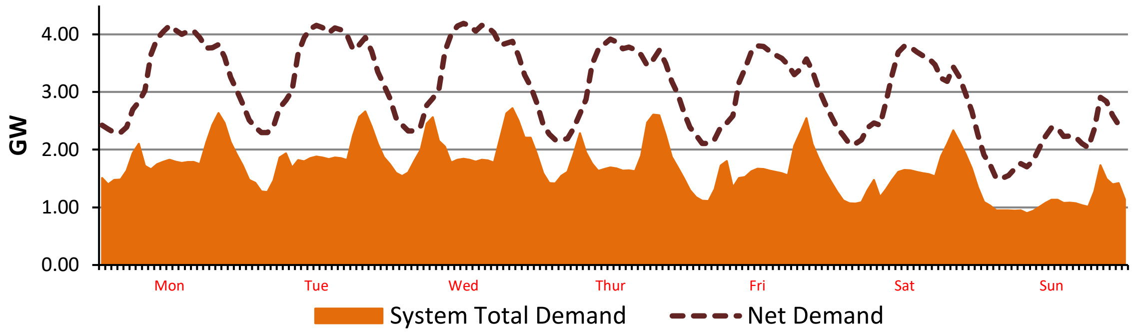


Figure 9.16–Net Demand of High Wind Season Week in 2030

Geographical staggering of wind and solar PV resources will support to lower this hour-to-hour flexible capacity requirement.

9.8 Summary of Operational Planning results

The results of the operational analysis carried out are summarized in Table 9.2 and the results are presented for the milestone years of the planning horizon which are 2024, 2030, 2036 and 2042.

Table 9.2: Results of the Operational Analysis

No.	Operational Feature	Results			
		2024	**2030**	**2036**	**2042**
1	Largest anticipated hourly ramp event from total VRE Generation (MW/hour)	550	1,600	2,700	5,600
2	largest anticipated daily ramp event from total VRE Generation (MW)	750	2,700	4,450	7,000
3	Largest anticipated hourly ramp of the net load (MW/hour)	700	1,500	2,900	5,500
4	Largest anticipated daily ramp of the net load (MW)	1,000	2,500	4,000	6,500
5	Power Plant capability to provide primary operating reserves and secondary operating reserves	• Major Hydro • 130 MW Gas Turbine • 460 MW Open Cycle Mode from 700 MW CCY	• 1,000 MW BESS • 350 MW PSPP • Major Hydro • 230 MW Gas Turbines • 200 MW Gas Engines • 460 MW Open Cycle mode of 700 MW CCY	• 1,850 MW BESS • 1,400 MW PSPP • Major Hydro • 630 MW Gas Turbines • 450 MW Gas Engines • 460 MW Open Cycle mode of 700 MW CCY	• 3,200 MW BESS • 1,400 MW PSPP • Major Hydro • 1,130 MW Gas Turbines • 850 MW Gas Engines • 690 MW Open Cycle mode of 1,100 MW CCY

No.	Operational Feature	Results			
		2024	**2030**	**2036**	**2042**
6	Power plant with fastest ramp up and down capability and the ramp rate	130 MW New GTs	1,000 MW BESS	1,850 MW BESS	3,200 MW BESS
		30 (MW/ min)	Approx. 100 %	Approx. 100 %	Approx. 100 %
7	Standby generation capacity reserve requirement to release a major power plant for maintenance	Reserve firm capacity has been maintained in each year throughout the planning horizon to compensate for the outage of the largest unit of the system. Adequate firm capacity need to be maintained to compensate for reduced renewable energy generation during extreme weather events.			
8	Power plants with the capability to initiate restoration island wide supply in case of a total system failure	Major Hydros[1] 130 MW New GTs[1]	Major Hydros[1] 130 MW New GTs[1]	Major Hydros[1] 130 MW New GTs[1]	Major Hydros[1] 130 MW New GTs[1]

1. In addition to these plants, if further capacity is required to have the capability to restore the grid after a system failure, it would be assessed in future with further transmission related studies and included in the specifications of the new plant additions accordingly.

9.9 Power System Stability

Transmission Planning studies were carried out to complement the generation planning studies, covering critical scenarios of system dispatch. Accordingly, scenarios consisting Night Peak, Day Peak, Off Peak during weekdays and weekends of Dry season, High Wind Season and Wet Season were considered for transmission system stability studies. Following system studies are carried out for these scenarios adhering to the planning criteria,

a. Load flow studies
   i. Normal operation condition
   ii. Single contingency situation
b. Transient Stability Studies
   i. Short Term Frequency Stability analysis
   ii. Frequency and rotor angle stability analysis
   iii. Voltage stability analysis
c. Short Circuit Analysis

The load flow studies carried out and all the scenarios were within the planning criteria for both normal operating condition and single contingency condition for the year 2030. However, it is observed that there is a trend for transmission voltage profile to be increased, and therefore it may be required to introduce interventions for over voltage conditions with higher RE penetration.

Further, introduction of large-scale Battery Energy Storage Systems (BESS) proposed in the LTGEP, is a significant challenge to model in the system for transient stability analysis as the existing models lacks the intended capabilities. Therefore, it is prudent to wait till a proper transient stability analysis to be carried out with the intended BESS capacities of the system. This will be carried out with the Long-Term Transmission Planning Study by making the solutions for the issues arise due to the large-scale BESS additions.

Following are the salient points which have come across during the transmission planning studies for the year 2030,

i. Grid Code has to be strengthened to absorb the 70% RE penetration to the network.
ii. System interventions to manage high voltage trend.
   a. Introducing reactors etc.
iii. System spinning reserves to manage the short-term frequency variation and stability by introducing,
   a. BESS (for frequency control)
   b. Pump Storage Hydro Power Plants (Frequency control)

    c. Synchronous Condensers to improve system inertia

iv. Technical interventions to mitigate transmission congestions when integrating RE at remote areas to better utilize transmission infrastructure like,

    a. Using of BESS.

    b. Using of phase shifters, FACTS devices (UPFC, Smart Wires, etc.) to control power flow.

v. Technical Interventions to increase Short Circuit Ratio (SCR) at the Point of Common Coupling (PCC) of large scale RE integration like,

    a. Increase of voltage levels (400kV)

    b. Introducing parallel transmission circuits

    c. Introducing Synchronous Condensers, STATCOM, VSC, etc. to strengthen the PCC

In conclusion, above requirements will be studied in detail in Long-Term Transmission Plan 2023-2032, with the solutions for the issues arise due to the large-scale BESS additions.

CHAPTER 10
RESULTS OF GENERATION EXPANSION PLANNING STUDY – SCENARIO ANALYSIS

This chapter presents the analysis of the different scenarios considered in the generation expansion planning studies in determination of the Base Case and the Reference case.

The current policy for the sector is stipulated through General Policy Guidelines in Respect of The Electricity Industry as issued in January 2022 which was considered during the preparation of the Base Case Plan. Nevertheless, planning studies were conducted under several generation expansion scenarios to analyse pathways to achieve carbon neutrality and to evaluate the technical and economic implications of complying with the policy guideline.

Section 10.1 describes the scenarios analysed within the stipulated policy guidelines in order to achieve 70% renewable energy by 2030 and in view of achieving carbon neutrality beyond the planning horizon by means such as increasing renewable energy share over 70%, cross border interconnection with India and adopting nuclear power technology.

Section 10.2 describes the scenarios analysed in order to determine the least cost scenario in a policy unconstrained environment and a comparison of these scenarios with Base Case.

Sensitivity on fuel price variation for these scenarios is discussed in section 10.3 and a comparison provided in section 10.4.

10.1 Policy Constrained Scenarios

Scenario 1:

Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030 and no coal fired plant additions throughout the horizon

After evaluation of all policy constrained scenarios described below, this scenario was selected as Base Case plan as it indicated the lowest present value cost among the four policy constrained scenarios and was technically feasible. The total present value cost of this scenario is USD 18,872 million. The capacity additions by plant type which are summarised in five-year periods are shown in Table 8.4 of Chapter 8 along with detailed analysis of the Base Case Plan.

Scenario 2:

Achieving 70 % RE by 2030, attempt to further increasing RE share up to 80% by 2040 and no coal fired plant additions throughout the horizon

This scenario was developed complying with the General policy Guidelines to achieve 70% of electricity from renewable sources by 2030 and further increase the renewable energy share during the planning horizon. Although the planning cycle ends at 2042, this scenario was explored as a pathway to achieve carbon neutrality by 2050 which is another major element in the current policy.

The scenario was developed for the demand forecast as described in Table 3.3. ORE integration schedule is as same as in Base Case Plan up to year 2032, but increasing the renewable energy and storage capacities from 2033 to 2042.

The capacity additions by plant type which are summarised in five-year periods are shown in Table 10.1.

Table 10.1: Capacity Additions by Plant Type: Scenario 2

Type of Plant	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	2038-2042 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	31	-	-	-	31	0%
Pumped Hydro	-	1,400	-	-	1,400	6%
Battery Storage	500	975	1,375	1,565	4,415	19%
Gas Turbines	230	-	400	100	730	3%
Coal	-	-	-	-	-	-
Combined Cycle	700	-	-	400	1,100	5%
IC Engines	200	-	250	400	850	3%
ORE	3,335	3,641	3,930	4,420	15,326	64%
Total	**4,996**	**6,016**	**5,955**	**6,885**	**23,852**	**100%**

Above figures represent net capacity additions, replacements for retiring ORE and storage capacities not included

The renewable energy capacity additions have been increased by 1,480MW (22%) and storage capacity additions by 950 MW (48%) for the period from 2033-2042 compared to the Base Case plan. Although it was intended to increase the renewable energy generation share from 70% to 82% during the planning horizon, in actual case the renewable energy share increases only upto 73% by 2042, while a considerable amount of renewable energy generation being curtailed. This is illustrated in figure 10.1. Main reason for this curtailment is the inability of the forecasted demand profile to absorb renewable energy generation that is discrete in nature. Although there is a considerable increase of the investment cost of scenario 2 compared to scenario 1 (Base Case), the operational cost of scenario 2 has not decreased substantially due to higher curtailment.

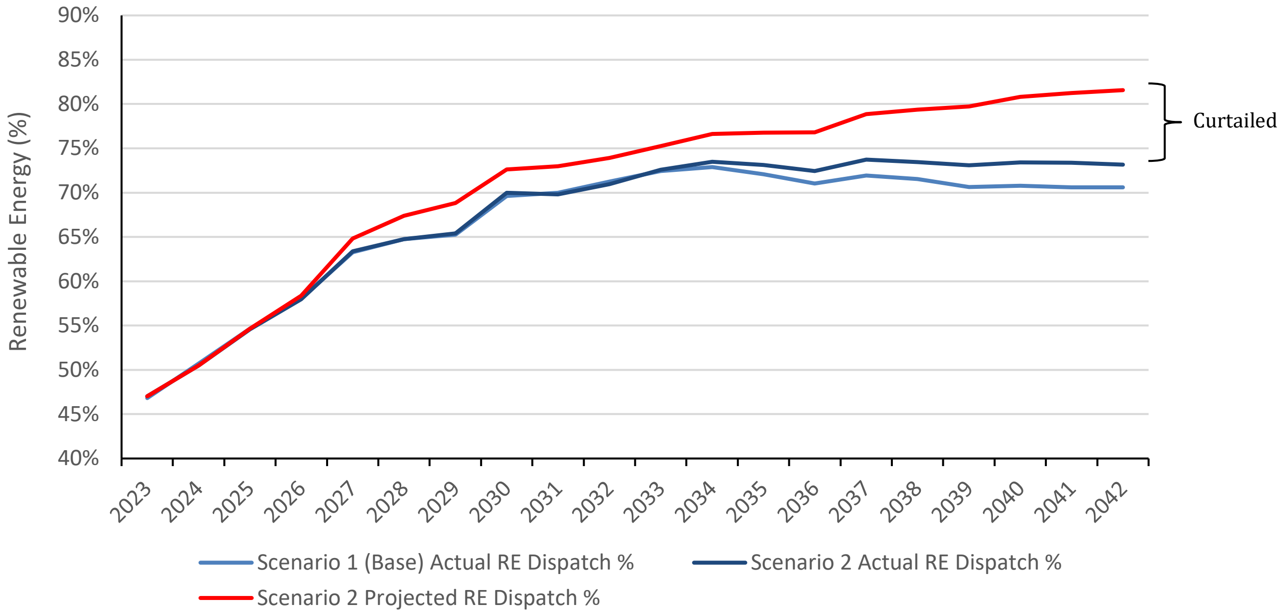


Figure 10.1 – Renewable Energy Share Comparison (2023-2042)

Conventional storage solutions such as Battery Energy Storage and Pumped Hydro Storage are not capable to facilitate this requirement due to limited storage capacity. Possible interventions that require further detailed studies to resolve these are as follows.

1. Longer duration storage is required other than the conventional storages to shift the energy from one season to the other. Hydrogen storage is emerging as a possible candidate option for this requirement and detailed studies are required to be conducted on the same.
2. Introducing demand response schemes with load management strategies and investigating the possibility of introducing flexible loads such as electric vehicles, desalination plants, etc.
3. Possibilities of cross border electricity trade should be analyzed, to export excess generation and to import our demand requirement as necessary. The seasonal/daily trends of supply demand balancing in both countries need to be evaluated to assess the viability of this solution.

Hence, achieving the government policy target of carbon neutrality by 2050 by increasing the renewable energy share would require more detailed studies. Since this requirement is considered for beyond year 2030, initial actions are required with detailed assessments for identifying the correct pathway with above interventions. Hence, the task of increasing renewable energy share above 70% beyond the year 2030 shall be evaluated in subsequent planning studies by identifying the appropriate capacity mix of renewable and new storage technologies.

In addition to the above, other possible options including carbon sequestration are required to be evaluated in order to achieve carbon neutrality by 2050 (Further discussed in chapter 11).

Scenario 3:

Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030, no coal fired plant additions throughout the horizon and considering cross border interconnection with India

Importance of regional integration is increasingly being recognized due to its economic and reliability benefits. Cross border interconnections in South Asian region offers new opportunities to greater use of cheaper and cleaner resources as there is a diversity in natural resources, daily and seasonal electricity demand patterns between countries. Interconnection between India-Sri Lanka is being studied with the support of two governments.

According to the Memorandum of Understanding (MOU) signed between Governments of India and Sri Lanka in 2010, a feasibility study was carried by CEB and Power Grid Corporation India Limited (POWERGRID) jointly for the implementation of 1000 MW HVDC interconnection project. The feasibility study has considered the technical, economical, legal, regulatory and commercial aspects in trading electricity between India and Sri Lanka. According to the initial proposals on feasibility study and also with the economic & financial analysis, the project was not economically or financially viable [24]. Major items which were affecting the project cost were submarine cable and HVDC Technology (Conventional HVDC or VSC based HVDC) selection. During the India-Sri Lanka Joint Technical Team studies initiated in year 2017, it has been found that overhead interconnection is feasible without any submarine cable. Asynchronous interconnection (overhead) through 2x500 MW Madurai-New to New Habarana along with 500 MW terminals at both ends has been identified as the preferred option in stage I. Both HVDC converter technologies, Conventional Line Commuted Conversion (LCC) and Voltage Source Conversion (VSC) are to be considered in future studies. As the technical studies are nearing completion, detailed economic and financial feasibility assessment to assess the financial viability of the project will be caried out in the near future.

In Sri Lanka, the very ambitious renewable energy development program, changing electricity demand pattern, future requirement of ancillary services are the important factors when considering HVDC interconnection. In the Long Term Generation Expansion Planning studies for the period of 2023-2042, a scenario was developed considering the implementation of 500 MW HVDC in the year 2034. Estimated investment cost of 687 USD million was used for evaluation purpose considering the project alternative mentioned in Chapter 4. Further, landed cost of 10 US Cents/kWh is considered based on a previous study [25] which includes marginal cost of Indian system, interconnection transmission charges, reliability support charges, O&M charges etc. and the same is used in the analysis. Given the uncertainty of the transfer price at this initial stage, a sensitivity analysis was performed for the study purpose to examine its impact on the utilization of the interconnection.

Following assumptions were made regarding the HVDC Interconnection Scenario

(a) 1 × 500 MW HVDC Interconnection is schedule for operation by 2034.

(b) Transfer price of 10 US Cents/kWh is considered. (A ± 20% variation of the transfer price was evaluated separately as a sensitivity).

(c) ORE implementation will remain same as Base Case plan and the energy storage additions are also considered as planned in this scenario.

(d) Thermal power plants addition will remain as same as Base Case plan up to 2034.

The Indian and Sri Lankan systems were considered as coordinated systems in the simulation and the energy exchange opportunity was assessed for the 500 MW HVDC link. The HVDC interconnection scenario developed based on the above assumptions has a total present value cost of 18,883 million USD and it is expensive than the Base Case of the LTGEP 2023-2042 with a marginal difference of 11 Million USD. It was observed that the average utilization of the interconnection for all the considered transfer prices are high due to the high renewable integration to the system. The total present value costs vary considerably with the transfer price as shown in the Table 10.2 below.

Table 10.2 – Sensitivity analysis for the transfer price of the HVDC interconnection

Scenario/Sensitivity	**Total Present Value Cost 2023-2042 (mill USD)**
500 MW HVDC Interconnection (10 Uscts/kWh)	18,883
500 MW HVDC Interconnection (8 Uscts/kWh)	17,795
500 MW HVDC Interconnection (12 Uscts/kWh)	19,024

Capacity additions by plant type are summarised in five year periods in Table 10.3 below. Power plant sequence of the scenario is given in Annex 10.1.

Table 10.3: Capacity Additions by Plant Type: Scenario 3

Type of Plant	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	2038-2042 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	31	-	-	-	31	0%
Pumped Hydro	-	1,400	-	-	1,400	6%
Battery Storage	500	875	875	1,115	3,365	15%
Gas Turbines	230	-	200	300	730	5%
Coal	-	-	-	-	-	-
Combined Cycle	700	-	-	400	1,100	5%
IC Engines	200	-	250	400	850	4%
HVDC Interconnection	-	-	500	-	500	2%
ORE	3,335	3,590	3,430	3,440	13,795	63%
Total	**4,996**	**5,865**	**5,255**	**5,655**	**21,771**	**100%**

Above figures represent net capacity additions, replacements for retiring ORE and storage capacities not included

It is observed that the integrated operation of two systems primarily provides import opportunities for Sri Lanka with minimal or no export opportunities in the studied scenario. The total present value cost of the alternative can vary depending on the exact investment cost, pricing and trading arrangements possible between India and Sri Lanka. Further the presence of the Indian power exchange provides an expanded market space allowing the energy exchanges to be based on the requirements of the producers and buyers.

It should be reviewed in detail whether the design and terms of operation of 500 MW HVDC interconnection has the potential to enhance the system flexibility to integrate a large amount of renewable energy in long term. In addition to that the development policies of power sectors both in India and Sri Lanka will have a significant impact on applicability of the HVDC interconnection alternative between two countries.

Considering these factors, it is important to conduct detailed feasibility studies reviewing technical and economic parameters to further investigate the exchange opportunities between India and Sri Lanka and to establish the techno economic viability of the cross border interconnection.

Scenario 4:

Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030, no coal fired plant additions throughout the horizon and considering nuclear power development beyond 2040

Nuclear power is the second-largest source of low-carbon electricity today and it is regarded as one of the technologies having large potential to combat climate change. Despite the declining investment on nuclear power on advanced countries, several new comer countries are exploring the possibility of introducing nuclear power mainly driven by energy security concerns. This scenario was analysed as an optional pathway in view of achieving carbon neutrality in power generation in 2050 as stipulated in the policy guidelines.

Nuclear power is widely regarded as a generation option which requires special consideration when introduced and operated in a power system. Unlike other conventional thermal generation alternatives, Nuclear power facility and the electric grid have a tight inter-dependency that is very important for the safe and economic operation of the nuclear power plant. The electric grid expects the nuclear power facility to provide reliable power similar to any other large thermal power plant but unlike other power plants the nuclear unit requires the grid to support the nuclear facility in normal operation and during start-up, shut down and outage periods for safe operation. In addition to that it is important that the electric grid to provide voltage, frequency and supply continuity at safer and standard level for safe and economic operation of the nuclear facility. In this background, the International Atomic Energy Agency (IAEA) highlights the importance of considering aspects such as overall Grid Studies, Grid reliability and performance, Unit Size, NPP Operating characteristics, Site Assessment and grid connection, Power system standards, Grid control and communication, Interface between nuclear power plant and the system operator when evaluating the nuclear power option. The electric grid infrastructure was assessed under the study "Establishing a Roadmap for Nuclear Power Program in Sri Lanka" with the assistance of IAEA, developing a comprehensive report with the objective of providing a strong technological, financial, environmental and social understanding for policy makers to take firm decision on the Nuclear Power Development in Sri Lanka. The main findings and the conclusion made under the study is outlined below and they are intended to support the decision making on the nuclear power program of the country.

1. The upfront investment cost of nuclear power is very high compared to other alternatives even without considering additional investments required for necessary transmission network reinforcements. Therefore, the nuclear power can possibly come in to the mix when the development of other cheaper thermal sources is restricted or strictly decided based on policy to enhance energy security through fuel diversification or to meet long term carbon emission reduction targets rather than for pure economic reasons.

2. Evaluation of the performance of the grid at present reveals that the improvements are required in frequency and voltage performance to match the industry criteria/guidelines for integrating a nuclear power unit to the Grid, safely and reliably.

3. The relatively large unit size of NPP continues to be the biggest technical challenge for the Sri Lankan system. The maximum unit size of a nuclear power unit with current grid characteristics is calculated to be in the range of 440 MW - 490 MW by 2040 and calculation based on an industry thumb rule, the possible size of a nuclear power unit turns out to be 370 MW for the year 2040 and 540 MW for the year 2050. This indicates the limited capability of the Sri Lankan power system to integrate a large nuclear power unit as an isolated system.

4. The development of cross-border interconnection and pumped storage hydro units in future are most likely change the system characteristics drastically allowing large units to be connected to the system. The HVDC interconnection between India and Sri Lanka which is being studied at present for feasibility can well be a prerequisite to integrate a large nuclear power unit to the system in future provided that the terms of operation of the interconnection are set in favour of the NPP operation. Therefore, introduction of the interconnection as well as the pumped storage hydro plant will create significant milestone in making the Sri Lanka system capable to integrate a Large Nuclear power unit and that should be studied in detail.

5. The recent policies of the electricity sector tend to focus more in the direction of enhancing the contribution of variable renewable energy resources which will lead to more decentralized power system. Given the system wide implications caused by variable renewable energy (VRE) technologies such as wind and solar, it is important to recognize the challenges it creates in terms of system stability, security and operation flexibility for the safe and economic operation of a nuclear power unit. Therefore, the future design of the power system is a major factor which will determine the country's ability to accommodate a nuclear power unit in safe and economic manner. It is important to establish and prioritize the long term energy strategy of the country and then to design and develop the power system for the future needs. Such considerations are necessary if the country is to decide on pursuing a nuclear power development program.

Based on the aforementioned findings, it was concluded that integrating a conventional nuclear plant to the system is a severe challenge during this planning horizon. However, developments in small scale modular reactor nuclear power plants (SMRs) in commercial scale in future and the advancements of grid enhancement technologies will provide future prospects for Sri Lankan system to integrate a nuclear power unit.

Considering these above factors only an illustrative scenario was developed considering the available options for development of nuclear power plant after 2040. However, it should be noted that much detailed studies and technological interventions are required in pursuant of this scenario as a long term solution. Total present value cost of this scenario is USD 18,986 million.

The capacity additions by plant type which are summarised in five-year periods are shown in Table 10.4 and the plant schedule is presented in Annex 10.2.

Table 10.4: Capacity Additions by Plant Type: Scenario 4

Type of Plant	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	2038-2042 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	31	-	-	-	31	0%
Pumped Hydro	-	1,400	-	-	1,400	6%
Battery Storage	500	875	875	1,115	3,365	15%
Gas Turbines	230	-	600	200	1,030	5%
Coal	-	-	-	-	-	0%
Combined Cycle	700	-	-	-	700	3%
Nuclear	-	-	-	600	600	3%
IC Engines	200	-	250	400	850	4%
ORE	3,335	3,590	3,430	3,440	13,795	63%
Total	**4,996**	**5,865**	**5,155**	**5,755**	**21,771**	**100%**

Above figures represent net capacity additions, Replacements for retiring ORE and Storage capacities not included

10.2 Policy Unconstrained Scenarios

Following scenarios were developed to identify the least cost generation expansion planning scenarios unconstrained by policy guidelines.

Scenario 5:

Achieving 50% RE by 2030, maintaining 50% RE beyond 2030 and no coal fired plant additions beyond 2030

This scenario was formulated by considering the vision of achieving 50% electricity from renewable sources by 2030 according to the previous policy guidelines (issued in April 2019) in order to identify the cost impact of increasing the renewable energy target to 70% by 2030.

The scenario was developed for the demand forecast as described in Table 3.3. The renewable integration level was considered to achieve 50% from renewable generation by 2030 progressively and coal power development was restricted after 2030.The operational and transmission network requirement to achieve a higher level of renewable (which is 70% renewable by 2030) has been already evaluated through the Base Case plan.

The total present value cost of this scenario is USD 17,792 million and shows a lower cost compared to the Base Case. Approximately USD 1 billion increment from 50% RE to 70% RE by 2030 can be identified as the policy cost of increasing RE target through the latest policy guidelines.

The capacity additions by plant type which are summarised in five-year periods are shown in Table 10.5 and the plant schedule is presented in Annex 10.3.

Table 10.5: Capacity Additions by Plant Type: Scenario 5

Type of Plant	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	2038-2042 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	31	-	-	-	31	0%
Pumped Hydro	-	700	-	-	700	4%
Battery Storage	150	60	40	100	350	2%
Gas Turbines	130	400	1,500	700	2,730	16%
Coal	300	300	-	-	600	4%
Combined Cycle	700	-	-	400	1,100	7%
IC Engines	200	-	450	650	1,300	8%
ORE	2,330	2,260	2,560	2,947	10,097	60%
Total	**3,841**	**3,720**	**4,550**	**4,797**	**16,908**	**100%**

Above figures represent net capacity additions, replacements for retiring ORE and storage capacities not included

Scenario 6:

Achieving 60 % RE by 2030, maintaining 60% RE beyond 2030 and no coal fired plant additions beyond 2030

This scenario was developed in order to investigate a possible lowest cost scenario with varying level of renewable energy (between 50% RE and 70% RE by 2030) target by 2030.

This case was formulated using the same demand forecast as in Base Case. The lowest cost scenario was obtained at a RE integration level of 60% by 2030.

The total present value cost of this scenario is USD 17,507 million and showed the lowest cost when compared with all other scenarios. Hence this scenario is considered as the Reference Case.

The capacity additions by plant type which are summarised in five-year periods are shown in Table 7.2 of Chapter 7 along with other detailed analysis.

Scenario 7:

Achieving 60 % RE by 2030, maintaining 60% RE beyond 2030 and no coal fired plant additions throughout the horizon

This scenario was also developed similar to scenario 6 but with restriction of coal power development throughout the planning horizon.

The total present value cost of this scenario is USD 17,855 million. The capacity additions by plant type which are summarised in five-year periods are shown in Table 10.6 and the plant schedule is presented in Annex 10.4.

Table 10.6: Capacity Additions by Plant Type: Scenario 7

Type of Plant	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	2038-2042 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	31	-	-	-	31	0%
Pumped Hydro	-	700	-	350	1,050	6%
Battery Storage	100	100	-	200	400	2%
Gas Turbines	330	600	1,100	1000	3,030	17%
Coal	-	-	-	-	-	0%
Combined Cycle	700	-	400	-	1,100	6%
IC Engines	200	-	450	450	1,100	6%
ORE	2,685	2,680	2,630	3,070	11,065	62%
Total	**4,046**	**4,080**	**4,580**	**5,070**	**17,776**	**100%**

Above figures represent net capacity additions, Replacements for retiring ORE and Storage capacities not included

10.3 Scenario Sensitivities

10.3.1 Comparison with Base Case and Impact of Fuel Price Sensitivity

Historical fuel price variations show that high volatility in global LNG prices and relatively low level of volatility in international coal prices. However due to global economic crisis in the recent past, even the coal prices have soared drastically. Considering both the extent of volatility and the likelihood of volatility of LNG and coal prices, it is important to examine the potential impact on these scenarios.

The long term planning studies considers the constant fuel prices throughout the planning horizon and the impact of the fuel price volatility and variation is separately investigated as a sensitivity analysis in the planning process. The impact of long term global fuel price escalations and short term fuel price volatility are important considerations in terms of electricity system security. Table 10.7 summarizes the fuel price sensitivities considered and the cost of each fuel types considered for the planning horizon of scenarios pertaining to varying renewable energy shares.

Table 10.7: Fuel Price Projections for Fuel Price Sensitivities

Fuel Price Sensitivity	Coal (USD/Mton)	LNG (USD/MMBtu)	Crude Oil (USD/bbl)
Base Based on weighted average of actual fuel prices (From year 2019-2021) & World Bank Forecast (April ,2022)	141	13.6	69.6
High Based on actual fuel prices (Jan-Apr, 2022)	255	14.3	100.9
Low Based on weighted average of actual fuel prices (From year 2018-2021)	114	9.5	60.7

Variation in the fuel prices was applied to the scenarios to assess the degree of impact on the operation cost of each scenario. The results provide an indication of the robustness of each scenario against fuel price variations as presented in Table 10.8.

Table 10.8: Present Value of costs of Scenarios for Fuel Price Sensitivities

	Base Fuel Price Total Cost (MUSD)	High Fuel Price Total Cost (MUSD)	Difference of Cost to Base Fuel Prices (MUSD)	Low Fuel Price Total Cost (MUSD)	Difference of Cost to Base Fuel Prices (MUSD)
Base Case (70%RE)	18,872	22,088	+ 3,216	17,187	-1,685
Scenario 5 (50% RE)	17,792	21,825	+ 4,033	15,544	-2,248
Scenario 6 (60%RE)	17,507	21,047	+ 3,540	15,442	-2,065

According to the results, it is observed that Base Case has lowered the import dependence by indigenous renewable resource development, and is more robust to fuel price hikes. However, even under extreme fuel price variations the least cost scenario remains as Scenario 6, targeting a 60% renewable energy share. From all considered fuel price sensitivity scenarios, Base Case, which considers 70% renewable energy share remains as the most expensive scenario. The large investment cost for the Base case scenario is the main cause for its higher cost.

The increased reliance on the natural gas based capacities in all scenarios can lead to higher impact of gas prices fluctuations. It is important to adopt available measures to minimize the risk of imported natural gas price fluctuations. In the event where the local natural gas is available in future, country will have the opportunity to lower the dependency on imported liquid natural gas.

10.3.2 Impact of Cost Projection Sensitivity on Scenarios

The long term planning studies have been conducted considering constant capital and operating costs throughout the planning horizon. The importance of considering the capital cost projections in conjunction with operational cost reduction projections is necessary to evaluate the robustness of planning scenarios.

The capital cost of renewable energy and storage technologies have fallen rapidly in recent years, and is expected to continue declining in the future. The capital cost reduction during the past decade of solar PV and wind has been considerable and is expected to decline further in the next decade. As many countries gear up for higher renewable shares, the accelerated requirement of battery storage systems is also expected to bring down their costs. Therefore, it is necessary to consider projections for capital cost reduction in long term studies, to evaluate the robustness of selecting an optimum planning scenario. The cost projection for renewable energy and storage technologies has been derived for sensitivity studies based on forecast of National Renewable Energy Laboratory as depicted in figure 10.2. [26]

The World Bank Commodity Price forecast (April, 2022) is a short term forecast for a period of three years. In contrast, the World Energy Outlook 2021 published by International Energy Agency (IEA) announces the latest indicative long term price variations of coal, oil and gas up to 2040. The IEA's methodology considers the impact of supply demand balance, current and future energy policies, global economic activities and demographic trends for projecting future fuel prices trajectories. The fuel prices escalations for sensitivity of cost projections as given in figure 10.3 have been derived based on both short term forecast by World Bank Commodity Price forecast and long term forecast by the International Energy Agency (stated policies scenario).

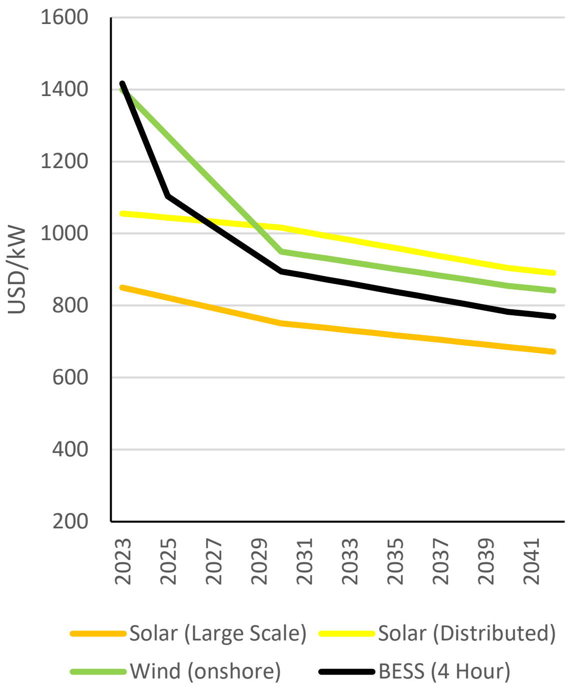


Figure 10.2 – Capital Cost Projections for Renewable Energy and Storage

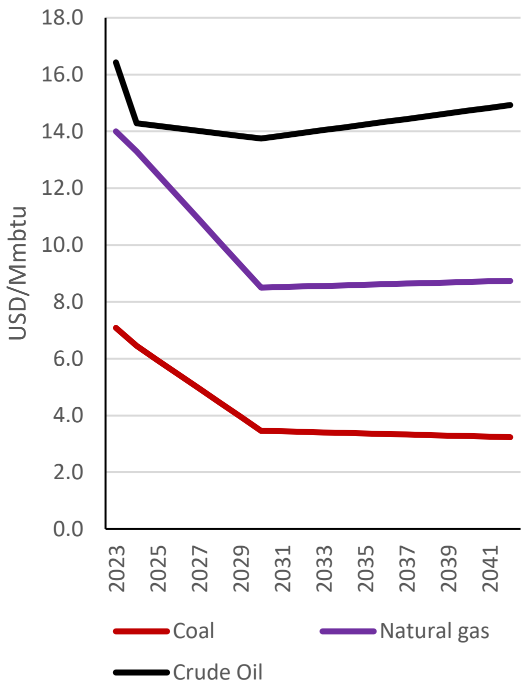


Figure 10.3 –Cost Projections for Fuel Prices

The main scenario studies have different Renewable energy mixes and firm capacity mixes having different degree of impact from potential fuel price escalation and fluctuations. The present value cost of the cost projection of key scenarios are presented in Table 10.9.

Table 10.9: Sensitivity of Cost Projections for key scenarios

Scenario	**Cost**		
	Investment Cost (MUSD)	Operational Cost (MUSD)	Total Cost (MUSD)
Base Case (70%RE)	8,940	7,314	16,254
Scenario 5 (50% RE)	7,123	8,324	15,457
Scenario 6 (60%RE)	7,411	7,889	15,300

As per the results, it is observed that even with cost projections, Scenario 6 (considering 60% share in renewable resources by 2030), is showing the lowest cost. Base Case consisting of 70% renewable energy share by 2030 is the most expensive with total present value cost difference of 954 million USD compared to Scenario 6 (Reference case).

10.4 Comparison of Future Energy Supply alternatives

10.4.1 Global Context

Table 10.10 shows the present and projected energy mix in a number of different countries. It could be observed that majority of the countries are focusing on reducing coal power generation significantly from the generation mix with increased contribution from low carbon or zero carbon generation sources such as Natural Gas, Nuclear and Renewables. Another important observation is that most of the countries and regions are thriving to increase the renewable share in the energy mix by projecting higher renewable shares.

Especially, European Union (EU) energy mix mainly consists of renewable energy since the power grid is interconnected among EU countries and hence the technical limitations of absorbing renewable energy are less. Renewable energy share is projected to be maintained at 75% in 2050.

Table 10.10: Present & Projected Power Generation Mix in Other Countries and Regions

		NG	Coal	Nuclear	Renewable	Other
USA	2020	40%	20%	19%	20%	1%
	2050	30%	1%	10%	59%	0%
China	2020	3%	64%	5%	29%	0%
	2050	4%	25%	9%	61%	0%
EU	2020	20%	14%	25%	39%	2%
	2050	10%	0%	15%	75%	0%
Japan	2020	37%	32%	4%	23%	4%
	2050	13%	6%	18%	56%	6%
Russia	2020	45%	16%	20%	18%	1%
	2050	44%	9%	18%	29%	0%
India	2020	4.3%	70.0%	2.9%	22.4%	0.4%
	2050	3.4%	18.9%	5.8%	71.7%	0%
Middle East	2020	71%	0%	1%	2%	26%
	2050	57%	1%	3%	32%	7%
Asia Pacific	2020	11%	57%	5%	25%	1%
	2050	10%	23%	8%	60%	0%
Sri Lanka	**2020**	0%	36.6%	0%	36.8%	26.6%
	2042	22%	8%	0%	70%	0%

Source: IEA-World Energy Outlook 2021, Draft LTGEP 2023-2042

10.4.2 Sri Lankan Context

The Base Case Scenario is complied with the government policy of achieving 70% of renewable generation by 2030. The HVDC interconnection scenario and Nuclear scenario is expected to consist of same energy and capacity share in 2030 as Base case scenario. The Figure 10.4 and Figure 10.5 illustrates the projected energy mix and capacity mix in 2042 for all scenarios considered.

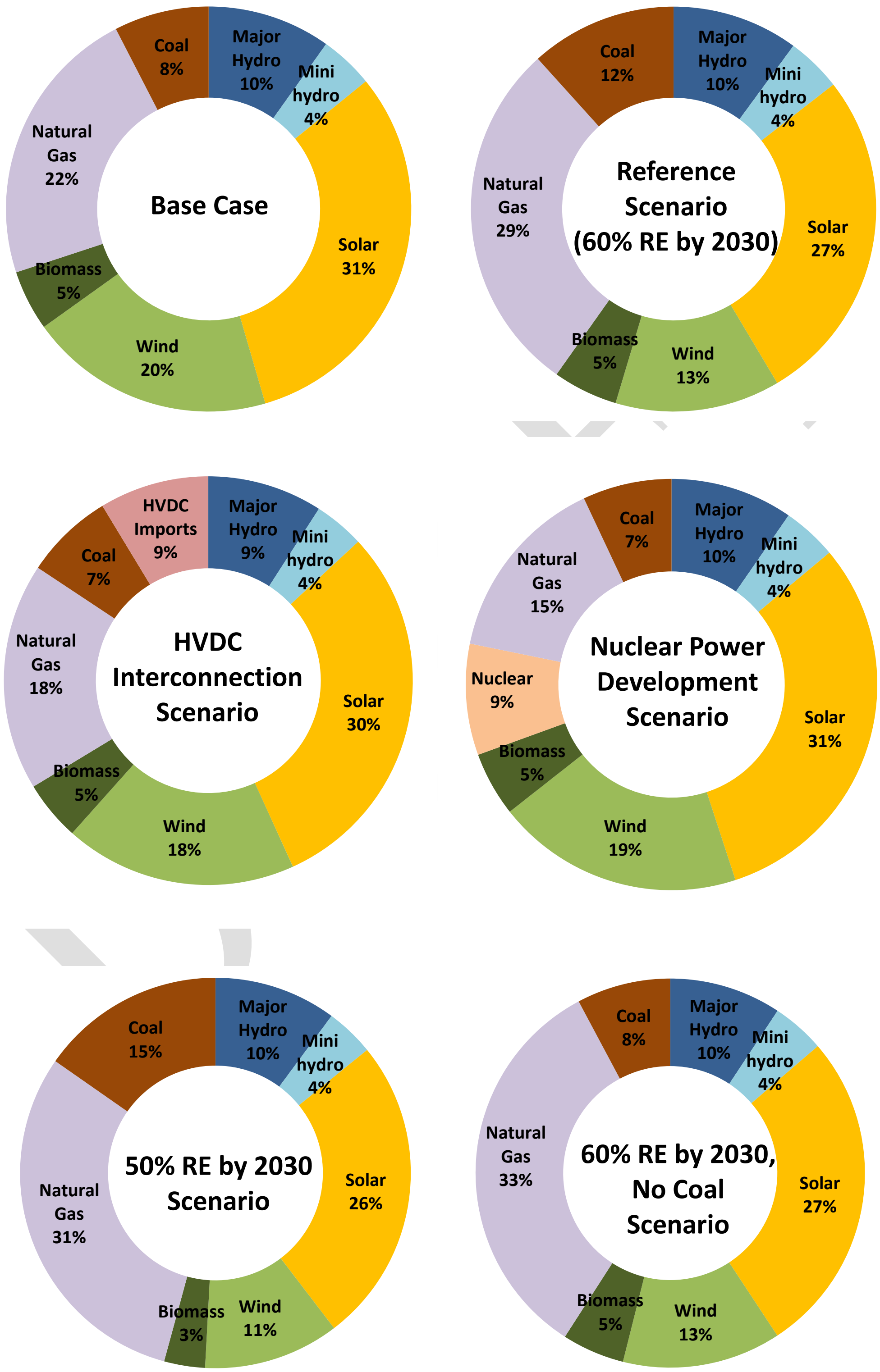


Figure 10.4 –Energy Share Comparison in 2042

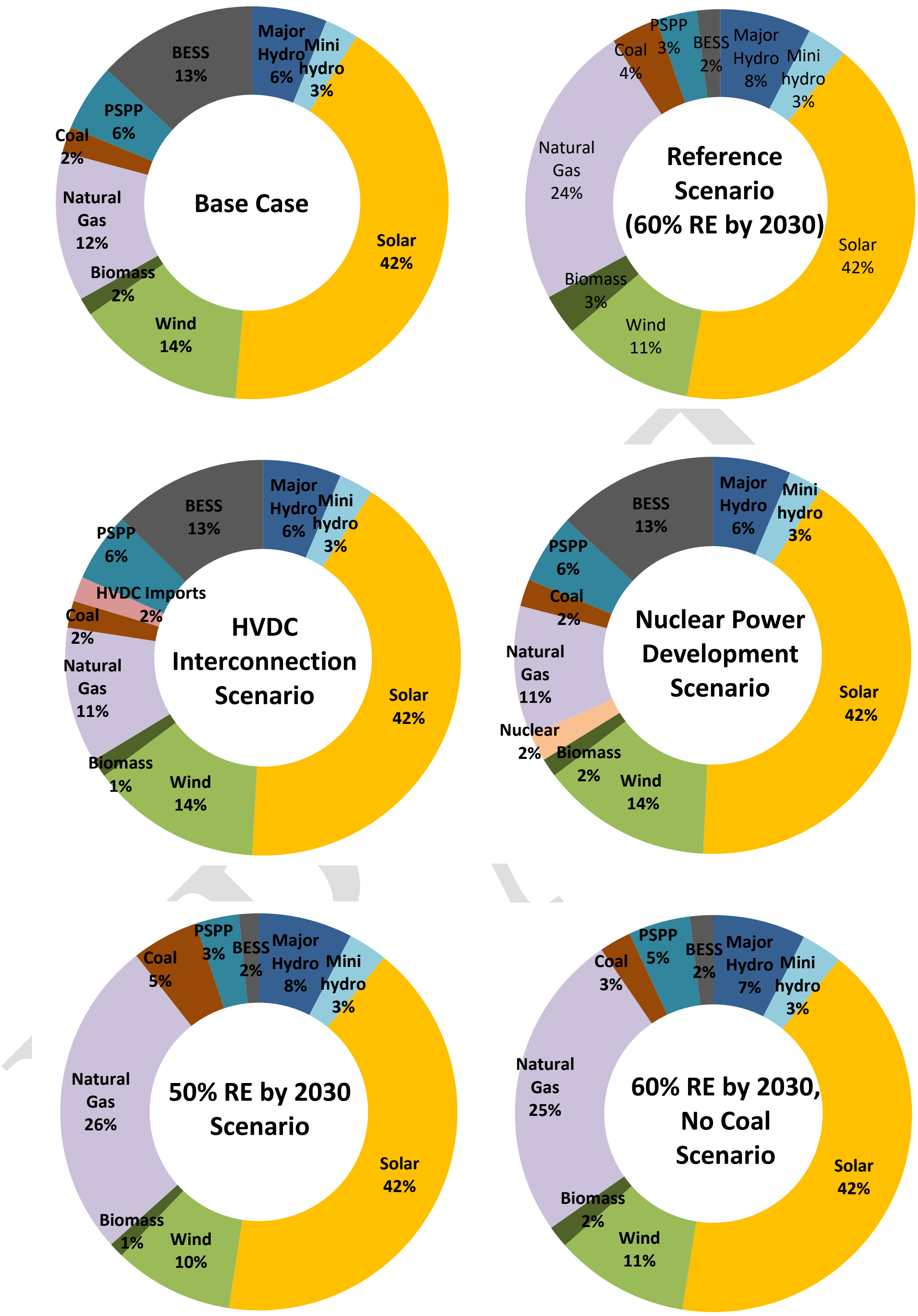


Figure 10.5 – Installed Capacity Share Comparison in 2042

A comparison of present value costs of scenarios, with the Base Case plan is summarized in Table 10.11.

Table 10.11: Summary of Present Value cost of the scenarios

Scenario	Incremental Capacity Additions between 2023-2042		Total Present Value Cost (MUSD)	Difference of present value cost compared to Base Case (MUSD)
Scenario1 Base Case Scenario	Renewables Natural Gas Coal BESS PSPP	13,826 MW 3,080 MW - 3,365 MW 1,400 MW	18,872	-
Scenario 3 HVDC Interconnection	Renewables Natural Gas Coal BESS PSPP HVDC	13,826 MW 2,680 MW - 3,365 MW 1,400 MW 500 MW	18,883	+11
Scenario 4 Nuclear Power Development	Renewables Natural Gas Coal BESS PSPP Nuclear	13,826 MW 2,580 MW - 3,365 MW 1,400 MW 600 MW	18,986	+114
Scenario 5 50% RE by 2030 Scenario	Renewables Natural Gas Coal BESS PSPP	10,128 MW 5,130 MW 600 MW 350 MW 700 MW	17,792	- 1,079
Scenario 6 Reference Scenario (60% RE by 2030)	Renewables Natural Gas Coal BESS PSPP	11,046 MW 4,930 MW 300 MW 400 MW 1,050 MW	17,507	- 1,365
Scenario 7 60% RE by 2030 and no coal	Renewables Natural Gas Coal BESS PSPP	11,096 MW 5,230 MW - 400 MW 1,050 MW	17,855	-1,017

CHAPTER 11
ENVIRONMENTAL IMPLICATIONS

Sri Lankan power system until mid-nineties, was a 100% renewable system with only hydro power catering the country's' power demand. Share of fossil fuel thermal generation was increased only during the drought period; hence the power sector had only a minor impact on the environment. However, after exploiting most of the major hydro potential, fossil fuel based power plants were introduced into the power system to cater the growing electricity demand.

Presently, around 50% of the power generation in Sri Lanka, is based on renewable energy sources including major hydro. The balance is generated from fossil fuel power plants. In many instances, electricity generation causes environmental drawbacks. The impact of electricity generation on the environment could be due to one or several factors including particulate emissions, gaseous emissions (CO_2, SO_2, NO_X etc.), warm water discharges into water bodies, liquid and solid waste (sludge, ash), inundation (in the case of large reservoirs), noise pollution 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. Further, when developing renewable power plants such as wind and solar, due consideration should be given to localised issues such as conflicts with bird migration routes, bird habitats, water habitats (in case of floating solar), unique land features such as sand dunes, vegetation, changes in land use, inhabitants and noise pollution.

This chapter describes an overview of environmental commitments related to the electricity sector and the impacts due to particulate and gaseous emissions, by the implementation of Base Case Generation Expansion Plan and other selected scenarios.

11.1 Climate Change

11.1.1 Greenhouse Gases

Greenhouse gases are gases that absorb and emit thermal infrared radiation which causes the gradual heating of Earths' atmosphere which is known as the greenhouse effect. There are natural as well as anthropogenic compounds which contribute to this effect. Water vapour (H_2O), Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O) and Atmospheric Octane (O_3) (though present only in very minute quantities) are primary greenhouse gases in the Earths' atmosphere. There are also anthropogenic greenhouse gases such as Hydrofluorocarbons (HFCs), Perfluorocarbons (PFCs) and Sulphur Hexafluoride (SF_6). For each greenhouse gas, a Global Warming Potential (GWP) has been calculated to reflect how long it remains in the atmosphere and how strongly it absorbs energy.

Table 11.1 – Global Warming Potential of Greenhouse Gases

Greenhouse Gas	GWP values for 100 year time horizon
Carbon Dioxide	1
Methane	25
Nitrous Oxide	298
Hydrofluorocarbons	14,800
Perfluorocarbons	22,800

Source: The Fourth Assessment Report of the United Nations Intergovernmental Panel on Climate Change

11.1.2 GHG Emission Reduction Protocols

The effects of global warming have directly caused concern for the adoption of proper management in climate change. Due to the increasing global concern on climate change, the United Nations Environment Programme and the World Meteorological Organisation jointly established the Intergovernmental Panel on Climate Change (IPCC) in 1988 with a directive to assess the best scientific options on climate change, its potential impacts, and possible response strategies. 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. Major events and decisions by Conference of Parties are summarized in Table 11.2.

(a) The Kyoto Protocol

During the COP3 meeting in 1997 at Kyoto, Japan, the Kyoto Protocol was accepted. It sets binding targets for 37 industrialised counties and the European Community for reducing GHG emissions. It will amount to an average of 5% against 1990 levels over the five-year period 2008-2012. 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 entered in to force on 16th February 2005. Under the Kyoto Protocol, Annex I countries must meet their targets primarily through national measures with support from additional market based mechanisms.

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

Under the Protocol, country’s 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.

During COP 18 at Doha Qatar in 2012, developed country parties agreed for a second commitment period up to 31.12.2020, with 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 significant 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.

(b) The Paris Agreement

In 2015, the COP21 meeting was held in Paris, where the Paris agreement was introduced in which governments agreed a long-term goal of keeping the increase in global average temperature to well below 2°C above pre-industrial levels and to aim to limit the increase to 1.5°C. Under the Paris Agreement both developed and developing countries must determine, plan, and regularly report on the contribution that it undertakes to mitigate global warming.

No mechanism forces a country to set a specific emissions target by a specific date, but each target should go beyond previously set targets. Many countries submitted comprehensive national climate action plans as Intended Nationally Determined Contributions (INDCs). This agreement was opened for signature for one year from 22 April 2016. This was to enter into force after 55 countries that account for at least 55% of global emissions have deposited their instruments of ratification. Sri Lanka ratified its Nationally Determined Contributions (NDC) in September 2016 [27]. On 5 October 2016, the threshold for entry into force of the Paris Agreement was achieved and was entered into force on November 2016.

Table 11.2– Summary of Major COP Decisions

COP	Events and Decisions
COP 3 Kyoto, Japan 1997	Kyoto protocol was accepted.
COP13 Bali, Indonesia 2007	Adoption of Bali Road Map which included, – Launching of Adaptation Fund – A review of Kyoto Protocol – Decisions on Technology transfer and Reducing Deforestation related emissions – Ad-Hoc Working Group (AWG) negotiations on a Long Term Corporative Agreement (LCA) and Kyoto Protocol (KP)
COP17/CMP7 Durban, South Africa 2011	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.
COP18/CMP8 Doha, Qatar 2012	Extension of the Kyoto protocol adopted. As a part of negotiations pursuant to the Bali Action Plan, developing country Parties agreed to take Nationally Appropriate Mitigation Actions (NAMAs) in the context of sustainable development.

COP	Events and Decisions
COP19/CMP9 Warsaw, Poland 2013	Governments advanced the timeline for the development of the 2015 agreement 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.
COP21/CMP11 Paris, France 2015	Paris Agreement was introduced. Before and during the Paris conference, countries submitted comprehensive national climate action plans (INDCs).
COP24/CMP14/CMA1-3 Katowice, Poland 2018	"Paris Agreement Rule Book" has been taken up for negotiation which is to come into force in 2020.
COP 26/CMP16/CMA3 Glasgow, UK 2021	Nations adopted the Glasgow Climate Pact. Decisions include strengthening efforts to build resilience to climate change, to curb greenhouse gas emissions and to provide the necessary finance for both. Nations also completed the Paris Agreement's rulebook.

11.1.3 Climate Finance

Climate finance refers to local, national or transnational financing, which may be drawn from public, private and alternative sources of financing. Climate finance is equally important for both mitigation and adaptation activities. Massive investment is required in order to reduce greenhouse gases significantly as well as for countries to adapt to the adverse effects and reduce the impacts of climate change.

At COP 16, parties decided to establish the Standing Committee on Finance to assist the COP in exercising its functions in relation to the Financial Mechanism of the Convention. This was established with the aim of assisting the COP, with regards to, transparency, efficiency, and effectiveness in the delivery of climate finance. Furthermore, the Standing Committee on Finance is designed to improve the linkages and to promote the coordination with climate finance related actors and initiatives within and outside the Convention. The Convention, under its Article 11, states that the operation of the Financial Mechanism is entrusted to one or more existing international entities. The operation of the Financial Mechanism is partly entrusted to the Global Environment Facility (GEF). In addition to providing guidance to the GEF, Parties have established four special funds: the Special Climate Change Fund (SCCF), the Least Developed Countries Fund (LDCF), both managed by the GEF, and the Green Climate Fund (GCF) under the Convention; and the Adaptation Fund (AF) under the Kyoto Protocol. The Financial Mechanism is accountable to the COP, which decides on its climate change policies, programme priorities and eligibility criteria for funding.

11. 2 Country Context

11.2.1 Overview of Emissions in Sri Lanka

When considering the greenhouse gases, CO_2 is one of the primary gases which contribute towards warming of earth's atmosphere. Table 11.3 indicates Sri Lanka's CO_2 emissions from fuel combustion in each sector for the year 2018. It could be observed that approximately 39% of CO_2 emission is from the electricity sector while major contributor for CO_2 emission is the transport sector which accounts for approximately 48%.

Table 11.3 - CO_2 Emissions from fuel combustion

	CO_2 emissions *Million tons of CO_2*	
Total	**20.60**	**100.0%**
Electricity and heat production	8.1	39%
Manuf. industries and construction	0.80	4%
Transport	9.9	48%
Other sectors	1.8	9%

Source: IEA CO_2 Emissions from Fuel Combustion (2020 Edition) -2018 Data [28]

The average CO_2 emission factor from electricity generation in the past is shown in Figure 11.1

Source: Sustainable Energy Authority

Figure 11.1 – Average CO_2 Emission Factor

Until large thermal plants were introduced to Sri Lankan power system, the power sector only contributed very little to GHG emissions. However, at present the focus is on reducing GHG emissions by integrating more renewable energy in to the power system. In global context, renewable energy resources are playing vital role in reducing GHG emissions and promoted through Government policies. With the focus on increasing renewable energy, more complicated analysis is required to overcome the uncertainties and intermittency which is inherent to renewable energy generation.

11.2.2 Role of Sri Lanka on Climate Change Mitigation

Responding to climate change involves two possible approaches: reducing and stabilizing the levels of heat-trapping greenhouse gases in the atmosphere ("mitigation") and adjustment to consequences of climate change that cannot be avoided ("adaptation").

Sri Lanka has adopted many policy measures that would result in climate change adaptation and mitigation although emission levels are much less than the global values. It is estimated that the total emission contribution of CO_2 emissions from Sri Lanka is as minute as 0.05% of the global total. Even though Kyoto Protocol has not imposed any obligation for non-Annex I countries, Sri Lanka also ratified the Kyoto Protocol as a non-Annex I country in 2002.

In order to address the issues in climate change, a separate dedicated institution named Climate Change Secretariat was formed under the Ministry of Mahaweli Development and Environment, in 2008. National Adaptation Plan for Climate Change Impacts in Sri Lanka 2016-2025 (NCCAS) was developed in 2016. Further, 'The National Climate Change Policy of Sri Lanka' has been developed by the Climate Change Secretariat of Sri Lanka under the Ministry of Mahaweli Development and Environment. Sri Lanka ratified its Nationally Determined Contributions (NDC) in September 2016 in accordance to the Paris agreement through the Climate Change Secretariat of Sri Lanka.

Energy sector is mainly involved in mitigation aspects of climate change and CEB actively participated in developing a 'Low Carbon Development Strategy' (mitigation strategy) which was carried out by Climate Change Secretariat. Further, CEB is an active member of the National Expert Committee on Climate Change Mitigation which provides consultation on various activities related to mitigation.

Following section further describes the different aspects towards reducing GHG emissions and providing sustainable energy to Sri Lankan consumers.

(a) Amendment of National Energy Policy and New Energy Mix

Government of Sri Lanka has given priority in the power sector which is presently dependent on imported fossil fuel, to reduce the present trend by enforcing sustainable energy policies for absorbing more renewable energy into the system.

The National Energy Policy and Strategies of Sri Lanka (2008) stated 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. This target was successfully achieved. The subsequent National Energy Policy and Strategies of Sri Lanka (2019) [4] has increased the milestone to realize a minimum 20% share of electricity generated from renewable energy sources excluding major hydro, by 2022. Further Sri Lanka commits for carbon neutrality by 2050 for the first time through this policy.

The General Policy Guidelines in Respect of the Electricity Industry (2019) has given guideline to progress with the vision to achieve 50% of electricity generation from renewable energy sources by 2030 under favourable weather conditions. The latest General Policy Guidelines in Respect of the Electricity Industry (2021) [3] has set the targets of achieving 70% of electricity generation by renewable sources by 2030, carbon neutrality in power generation by 2050 and to cease building new coal power plants. This amendment was primarily based on the commitment given through the updated NDC in July 2021. Further, new addition of firm power plants will be from regasified liquefied natural gas (R-LNG).

(b) Clean Development Mechanism

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."*

The CDM allows emission reduction projects in developing countries to earn Certified Emission Reduction (CER) credits, which can be traded and used by industrialized countries to meet part of their emission reduction targets under the Kyoto Protocol. 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. CEB has undertaken one of the large scale projects which is Broadlands Hydro Power Project. The estimated emission reduction from the project is approximately 83 kilo tonnes of CO_2 equivalent per annum.

(c) Partnership for Market Readiness (PMR)

The Partnership for Market Readiness (PMR) is a grant-based, multilateral trust fund administered by the World Bank which provides support to countries to prepare and implement climate change mitigation policies, including carbon pricing instruments (CPI), to scale up greenhouse gas (GHG) emission reductions. The PMR brings together developed and developing countries, as well as other key experts and stakeholders, in order to provide a platform for technical discussions on CPIs, collective innovation for pilot efforts and the implementation and scale up of financial flows. Basic elements in implementing CPI is to build market readiness capacity, such as measurement, reporting and verification (MRV) systems, data collection, baseline setting, and establishing regulatory institutions etc. Climate Change Secretariat under the purview of Ministry of Mahaweli Development and Environment is the implementing entity and CEB as a major stakeholder has been involved in providing necessary input and feedback to the work carried out under PMR program. Project was concluded in February 2021. Major activities performed during the project period are as follows.

Implemented by World Bank

1. Exploring the role of carbon pricing instruments (CPIs) in decarbonizing the power and transport sectors
2. Development of integrated MRV and National Registry System (Needs assessment, functional and technical specifications)
3. Sri Lanka Carbon Crediting Scheme (SLCCS) strategy and design study (assessment of the supply and demand and the existing institutional, legal and technical framework for implementation of an enhanced SLCCS)

Implemented by Ministry of Environment

1. Evaluation of overall policy coherence and recommendation on designing and implementing policy package for MRV, registry and SLCCS implementation
2. Deployment of IT infrastructure for MRV and registry
3. Development and implementation of a national climate change data sharing network
4. Road map for new Carbon Pricing Instruments (CPIs)
5. Communication, Capacity Building, Stakeholder Consultation and General Outreach

(d) Fuel Quality Road Map

An action plan has been developed for fuel quality road map by the Air Resource Management & National Ozone Unit of Ministry of Mahaweli Development & Environment. Introduction of low sulphur Diesel, switching to alternative fuels for transport such as biofuel, railway electrification, promoting electric vehicles, development of fuel quality standards and introducing LNG as a cleaner fuel are some of the activities identified in the fuel quality road map.

(e) Loss Reduction

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 2021 it has been reduced to approximately 9.46%.

(f) Demand Side Management & Energy Conservation

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 results in reduction of GHG emissions.

(g) Tree Planting Program

The General Policy Guidelines in Respect of the Electricity Industry (2021), givens directives to introduce counter balancing interventions such as carbon sequestration plantations to reduce carbon footprint of electricity due to power generation.

Ceylon Electricity Board has identified this as a social responsibility and has carried out numerous tree planting campaigns. Since 2015, CEB has planted over 50,000 trees consisting of tree types of Kaluwara, Kumbuk, Kohomba, Bamboo, Mango, etc. in power plant locations, catchment areas and public places.

11.2.3 Nationally Determined Contributions (NDCs) of Sri Lanka

With signing of the Paris Agreement (COP 21) most countries pledged to reduce green house gas emissions as well as to adapt to the impacts of climate change. By scaling up renewable energy, countries can sharply reduce the electricity related CO_2 emissions. Nationally Determined Contributions (NDCs) quantify the commitment of each Party (or signatory that has ratified the Paris Agreement) to reduce CO_2 and other greenhouse gas emissions.

Sri Lanka submitted its first Nationally Determined Contributions in September 2016, in accordance with Decision of COP 21 of the UNFCCC. Base year 2013 was considered as the Business-As-Usual scenario and target period of emission reduction is 2021-2030. The scope of NDC comprised of four areas on mitigation, adaptation, loss and damage and means of implementation. Under the scope of mitigation, reducing GHG emissions was focused on five sectors as follows.

1. Energy sector has a 20% GHG emission reduction target in the NDCs, which amounts to 39,383 Gg of the total GHG emissions (196,915 Gg for the period 2020-2030 as per the BAU scenario of the Long Term Generation Expansion Plan 2013-2032 published in October 2013). The reduction of emissions includes 4% unconditional and 16% conditional reduction.

2. The sectors of transport, waste, industry and forestry aims to reduce 10% of its GHG emissions from the BAU scenarios by 2030. This will be 3% unconditional and 7% conditional. However, at the time of submission, BAU emission scenarios were to be estimated in detail and detailed emission reduction plans for these sectors were yet to be developed.

All countries were expected to revise and submit stronger, more ambitious national climate action plans in 2021 to achieve the Paris Agreement goal. Sri Lanka submitted the updated NDC commitments in July 2021 followed by an amendment submission in September 2021 [28].

Mitigation component of the updated NDC submission comprised of six sectors. The revised more ambitious targets for NDC in Electricity sector are as follows.

Target:

A GHG reduction of 25% in the electricity sector is envisaged (5% unconditionally and 20% conditionally) equivalent to an estimated mitigation level of 9,819,000 MT unconditionally and 39,274,000 MT conditionally (total of 49,093,000 MT) of carbon dioxide equivalent during the period of 2021-2030. (Compared to the BAU scenario of the Long-Term Generation Expansion Plan 2013-2032 of Ceylon Electricity Board published in October 2013).

Actions:

1. Enhance renewable energy contribution to the national electricity generation mix by increasing Solar PV, Wind, Hydro and Sustainable Biomass based electricity generations (Target: Develop an additional capacity of 3,867 MW renewable energy over the RE capacity considered in Business-As-Usual scenario, out of which approximately 950 MW are on an unconditional basis and 2,917 MW on a conditional basis)

2. Implement Demand Side Management (DSM) measures by promoting energy-efficient equipment, technologies, and system improvements in a national energy efficiency improvement and conservation(EEI&C) programme

3. Conversion of existing fuel oil-based combined cycle power plants to Natural Gas (NG) and establishment of new NG plants as conditional measures (once the necessary infrastructure is available)

4. Transmission and distribution network efficiency improvements (Loss reduction of 0.5% compared with BAU by 2030) as an unconditional measure (Target: Approximately 1,848 GWh energy savings)

5. Conduct R&D activities to implement pilot scale projects for NCRE sources that have not yet reached commercial maturity and develop other grid supporting infrastructures as conditional measures

Other sectors namely, transport, waste, industry, forestry and agriculture (newly included) have declared separate unconditional and conditional targets sector-wise in detail. Furthermore, Sri Lanka committed for the following.

- To achieve 70% renewable energy in electricity generation by 2030
- To achieve Carbon Neutrality by 2050 in electricity generation
- No capacity addition of Coal power plants

Compatibility with Base Case Plan

The Base Case plan of LTGEP 2023-2042 complies with the NDC commitment, with more than 25% reduction in GHG emissions for the period from 2023-2030, compared to the BAU scenario of LTGEP 2013-2032. Since the demand forecast of LTGEP 2013-2032 was higher than the demand forecast in LTGEP 2023-2042, a separate scenario with the plant schedule of BAU scenario of LTGEP 2013-2032 is worked out using the demand forecast of LTGEP 2023-2042 to see even with the reduced demand, still the Base Case plan of LTGEP 2023-2042 complies with the NDC commitment due to the addition of significant amount of renewable energy. It has more than 25% reduction in GHG emissions for the period from 2023-2030. Figure 11.2 illustrates the compatibility of Base Case Plan to Sri Lanka's NDC commitments in electricity sector.

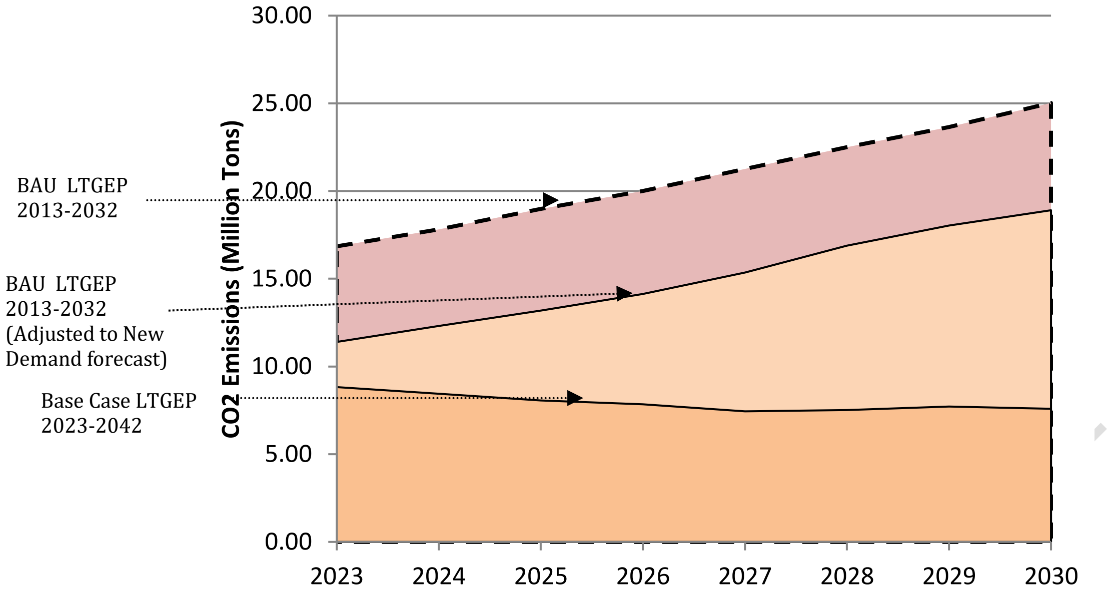


Figure 11.2 – Expected Emission reduction of Base Case compared to NDC - BAU

When achieving the NDC activities, the unconditional targets have been declared based on the financial and technical capability already available in the country. Targets that require external financial and technical support to supplement the domestic capacity are declared as conditional targets.

Conditional development includes the technical and financial support for development of 2,917 MW of renewable energy, for conversion of generators to NG, establishment of natural gas power plants and for development of other grid supporting infrastructures such as storage.

However, it should be noted that non implementation of these conditional targets on time will significantly impact on the level of emission reductions stipulated in the above. Hence, actual emission reductions achievable should be tracked with the implementation progress of the power projects.

11.2.4 Ambient Air Quality & Stack Emission Standards

In 1994, Government of Sri Lanka has approved The National Environmental (Ambient Air Quality) Regulations which was amended through extraordinary gazette No. 1562/22 in August 2008 [29]. The National Environmental (Stationary Sources Emission Control) Regulations, No. 01 of 2019 was published through extraordinary gazette No. 2126/36 in June 2019 which stipulates the stack emission standards for stationary sources [30]. The regulation enforces minimum stack height as well as stack emission limits for thermal power plants.

All thermal power plants are required to comply with the standards of these regulations, as shown in Table 11.4 and Table 11.5.

Table 11.4 - Ambient Air Quality Standards of Sri Lanka

Pollutant Type	Annual Level ($\mu g/m^3$)	24 hour level ($\mu g/m^3$)	8 hour Level ($\mu g/m^3$)	1 hour Level ($\mu g/m^3$)
Nitrogen Dioxides (NO_2)	-	100	150	250
Sulphur Dioxides (SO_2)	-	80	120	200
PM10	50	100	-	-
PM2.5	25	50	-	-

Source: Central Environmental Authority

Table 11.5 - Stack Emission Standards of Sri Lanka

Pollutant Type	Oil > 100 MW	Natural Gas >100 MW	Coal > 50 MW
Nitrogen Dioxides (NO_2) (mg/Nm^3)	500 (Steam Turbine) 450 (Gas Turbine / CCY) 650 (IC Reciprocating Engine)	300 (Steam Turbine) 200 (Gas Turbine / CCY) 350 (IC Reciprocating Engine)	650
Sulphur Dioxides (SO_2) (mg/Nm^3)	850	75	850
PM10 (mg/Nm^3)	150	75	150
Smoke (Opacity)	20%	-	15%

Source: Central Environmental Authority

In 2006, World Health Organization (WHO) released a set of guidelines that would address all regions of the world and provide uniform targets for air quality known as the Air Quality Guidelines (AQG), with the purpose of directing national policymakers to create acceptable air quality standards. WHO also created the WHO-Interim Targets to provide flexibility for developing countries to move towards more stringent standards at their own pace. Sri Lankan ambient air quality standards are mostly in line with the WHO interim targets. Most Asian countries based their standards on the WHO AQG and United States Environment Protection Agency (US EPA) National Ambient Air Quality Standards (NAAQS). Table 11.6 shows a comparison of air quality standards adopted by various countries.

Table 11.6 - Comparison of Ambient Air Quality Standards of Different Countries & Organisation

(All values in mg/m3)

Pollutant	Averaging time	WHO Guideline (Interim target-1, Interim target-2)	US EPA NAAQS	India	Indonesia	Thailand	Pakistan	**Sri Lanka**
Nitrogen Dioxide (NO_2)	Annual	0.04	0.1	0.04	0.1	0.057	0.04	**-**
	24 hours	-		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	-		0.05	0.06	0.1	0.08	**-**
	24 hours	0.02(0.125, 0.05)		0.08	0.365	0.3	0.12	**0.08**
	8 hour						-	**0.12**
	1 hour				0.9	0.78	-	**0.2**
	3 hour		1.3					
	10 minute	0.5		-			-	**-**
PM 10	Annual	0.02 (0.07, 0.05)		0.06		0.05	0.12	**0.05**
	24 hours	0.05 (0.15,0.1)	0.15	0.1	0.15	0.12	0.15	**0.1**
PM 2.5	Annual	0.01 (0.035, 0.025)	0.015	0.04		0.025	0.015	**0.025**
	24 hours	0.025 (0.075, 0.05)	0.035	0.06		0.05	0.035	**0.05**
Suspended Particulate	Annual	-		-	0.09	0.1	0.36	**-**
	24 hours	-		-	0.23	0.33	0.5	**-**

Source: World Wide Web, Central Environmental Authority

11.3 Emission Factors

11.3.1 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 11.7 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 11.7 - Uncontrolled Emission Factors (by Plant Technology)

Plant Type	Fuel Type	GCV	GCV	Sulphur	Emission Factor			
				Content	Particulate	CO_2	SO_2	NOx
		(kcal/kg)	(kJ/kg)	(%)	(mg/MJ)	(g/MJ)	(g/MJ)	(g/MJ)
Internal Combustion Engine	Fuel Oil	10,300	43,124	2-3.5	13.0	76.3	1.709	1.2
	Residual FO	10,300	43,124	2-3.5	13.0	77.4	1.639	1.2
	Auto Diesel	10,500	43,961	1.0	5.0	74.1	0.453	1.2
Gas Turbine	Auto Diesel	10,500	43,961	1.0	5.0	74.1	0.453	0.28
	Natural Gas	13,000	54,428	0	0.0	56.1	0.0	0.1
Comb. Cycle	Auto Diesel	10,500	43,961	1.0	5.0	74.1	0.453	0.28
	Naphtha	10,880	45,552	0	0.0	73.3	0	0.28
	Natural Gas	13,000	54,428	0	0.0	56.1	0.0	0.1
Coal Steam	Coal	6,300	26,377	0.6	40.0	94.6	0.455	0.3
Dendro	Dendro	3,224	13,498	0	255.10	0.0	0.0	0.2

Sources: Thermal Generation Options Study [8], 2006 IPCC Guidelines

Basically, CO_2 and SO_2 emission factors are calculated based on the fuel characteristics, while NO_x emissions, which depend on the plant technology, are obtained from a single source [8]. Generally, particulate emissions depend both on the plant technology and the type of fuel burned. Therefore, the emissions could be controlled by varying the fuel characteristics and by adopting various emission control technologies.

11.3.2 Emission Control Technologies

According to the expansion sequence of Base Case Plan 2023-2042 mentioned in Chapter 8 (Table 8.1), 14,289 MW of Renewable energy power plants, 2,230 MW Natural Gas fired open cycle and combined cycle gas turbine power plants and 850 MW of Natural Gas fired IC Engine power plants along with short term supplementary power plants are to be added to the Sri Lankan power system during the planning horizon. The impact on the environment due to particulate and air-emissions from the thermal power plants out of above additions with that of existing power plants and the effectiveness of using control devices to mitigate those impacts are analysed here. Particulate matter (PM) and gaseous emissions of SO_2, NO_x and CO_2 were considered in the analysis.

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_2 emissions to levels below the standard, but 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 SO_2 emissions and an Electrostatic Precipitator (ESP) for control of PM.

Hence, in the present study, control technologies considered in the proposed coal plants (coal plants not considered for the base Case plan, but in other scenarios) are as follows; ESPs for the control of particulate emissions, sea water FGD for control of SO_2 and low NO_x burners and two stage combustion for the control of NO_x. Coal power plants operating 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 NO_x. Indoor coal storages or silos will be proposed in new coal power plants in order to curb pollution due to coal dust. The Low-NO_x burners are an integrated part of most of the commercially available combined cycle plants, which are capable of reducing NO_x 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 deposits it, preventing the release into the atmosphere. With the rising global energy consumption, technologies such as CCS becomes inevitable to avoid atmospheric greenhouse gas emissions and related climate consequences. Nevertheless, the technology is still being developed and improved.

Table 11.8 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 stricter the emission standards and environmental regulations are, higher the cost it has to be incurred to incorporate mitigation measures. Such costs of the control technologies considered are included in the project costs of candidate plants of the Long Term Generation Expansion Plan which is also a part of the environmental damage mitigation cost.

Table 11.8 - Abatement Factors (%) of Typical Control Devices

Device	SO_2	NO_X	TSP	PM	CO	CH_4	NMVOC
Fabric Filter			99.5	99.5			
Electro Static Precipitator				99.8			
Selective Catalytic Reduction		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 – GT/ CCY *		80					

Sources: Decades Manual & Coal feasibility Study Reports

TSP - Total Suspended Particles

NMVOC - Non Methane Volatile Organic Compounds

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

11.3.3 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 [8] where sufficient data were not available. Table 11.9 shows the actual coal power plant data used in the study.

Table 11.9 - Emission Factors of Existing coal power plant

GCV of coal (kcal/kg)	Sulphur Content (%)	Emission Factor			
		Particulate (mg/MJ)	CO_2 (g/MJ)	SO2 (g/MJ)	NO_x (g/MJ)
6,300	0.7	15.00	94.6	0.056	0.260

Taking into consideration the emission factors mentioned in Table 11.7, Table 11.9 and the characteristics of the power plants, emissions per unit of electricity generated from candidate power plants are calculated as shown in Table 11.10

Table 11.10 Emission Factors of Candidate Power Plants

Plant Type	Fuel Type	Full Load Heat Rate kcal/kWh	Emission Factor			
			Particulate tons/GWh	CO_2 tons/GWh	SO_2 tons/GWh	NOx tons/GWh
15 MW IC Engines	Furnace Oil	2,210	0.1	706.0	15.8	11.1
15 MW IC Engines	Auto Diesel	1,943	0.04	602.8	3.7	9.8
15 MW IC Engines	Natural Gas	2,021	0.0	474.7	0.0	2.0
200 MW IC Engines	Natural Gas	2,021	0.0	474.7	0.0	2.0
250 MW IC Engines	Natural Gas	2,021	0.0	474.7	0.0	2.0
40 MW Gas Turbine	Natural Gas	2,911	0.0	683.7	0.0	0.2
40 MW Gas Turbine (AERO)	Natural Gas	2,315	0.0	543.7	0.0	0.2
100 MW Gas Turbine	Natural Gas	2,548	0.0	598.5	0.0	0.2
200 MW Gas Turbine	Natural Gas	2,568	0.0	603.2	0.0	0.2
300 MW Combined Cycle	Natural Gas	1,919	0.0	450.7	0.0	0.2
400 MW Combined Cycle	Natural Gas	1,757	0.0	412.7	0.0	0.1
300 MW High Efficient Coal	Coal	2,241	0.1	887.6	0.3	0.3
600 MW Supercritical Coal	Coal	2,082	0.1	824.6	0.3	0.3
600 MW Nuclear Power	Nuclear	2,685	0.0	0.0	0.0	0.0
5 MW Dendro Plant	Dendro	5,694	6.1	0.0	0.0	4.8

10.4 Environmental Implications – Base Case

Presented below is a quantitative analysis of the emissions associated with the Base Case generation expansion plan described in Chapter 8. The total particulate and gaseous emissions (controlled) under the Base Case plan are shown in Table 11.11 and Figure 11.3.

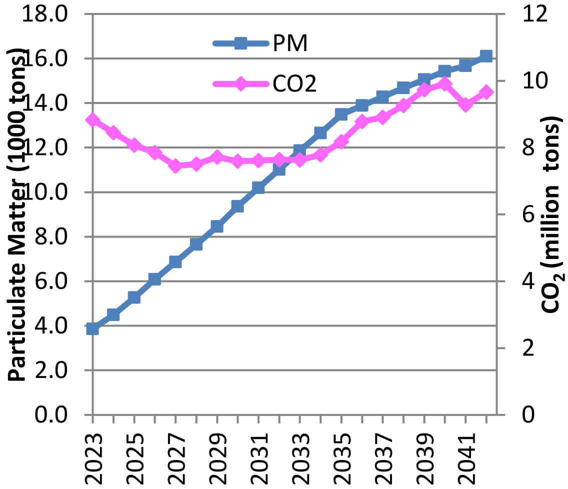
Table 11.11 – Air Emissions of Base Case

1000 tons/year

Year	PM	SO_2	NO_x	CO_2
2023	3.9	53.4	42.9	8824
2024	4.5	15.4	24.0	8445
2025	5.3	4.1	19.2	8071
2026	6.1	3.6	19.4	7848
2027	6.9	3.4	18.8	7452
2028	7.7	3.4	18.7	7510
2029	8.5	3.3	18.9	7719
2030	9.4	3.4	18.7	7595
2031	10.2	3.3	18.7	7608
2032	11.0	3.3	18.5	7641
2033	11.9	3.2	18.2	7630
2034	12.6	3.2	18.0	7780
2035	13.5	3.2	20.2	8178
2036	13.9	3.3	21.0	8784
2037	14.3	3.3	21.2	8903
2038	14.7	3.4	23.1	9254
2039	15.0	3.4	24.0	9731
2040	15.4	3.3	25.3	9906
2041	15.7	2.4	21.4	9277
2042	16.1	2.3	21.4	9664

With the aggressive development of renewable energy power plants to meet the increasing demand, emission levels of CO_2 shows a continuous decreasing trend until around 2034. However, afterwards even with the introduction of significant amount of battery energy storage, the level of renewable curtailment increases due to the nature of the demand pattern and hence increasing the thermal generation by natural gas based power plants. Therefore, after 2034 there is a slight increase of CO_2 emissions. Although the energy contribution is low from biomass plants, it is the major contributor to the increasing trend of the PM emissions during the planning horizon.

The higher level of particulate, SO_2 and NO_x emissions in the initial years is due to dispatch of oil fired power plants which are added to the system on short term basis due to delays in implementation of the power plants identified in previous plans. The SO_2 and NO_x levels are maintained at a steady level after the oil fired plants are retired and renewable power plants are commissioned. But the NO_x levels slightly increases after 2034 due to the increased dispatch of natural gas based power plants.



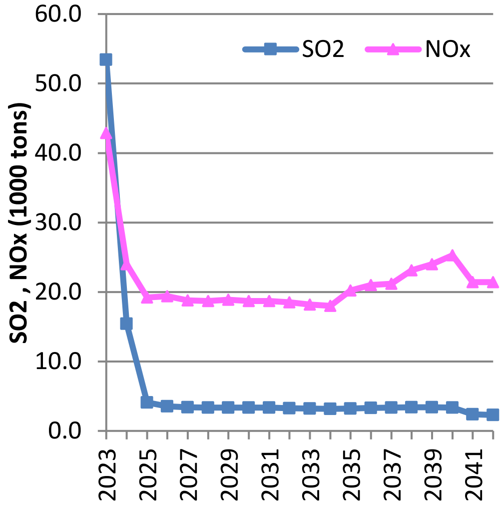


Figure 11.3 – CO_2, PM, SO_2 and NO_x emissions of Base Scenario

According to Figure 11.4, SO_2 and NO_x emissions per kWh shows a levelised trend. The higher energy dispatch of furnace oil fired power plants with heavy SO2 and NO_x pollutants has led to much higher per unit emission levels in the initial years. Per unit CO_2 emissions shows a continuous decreasing trend.

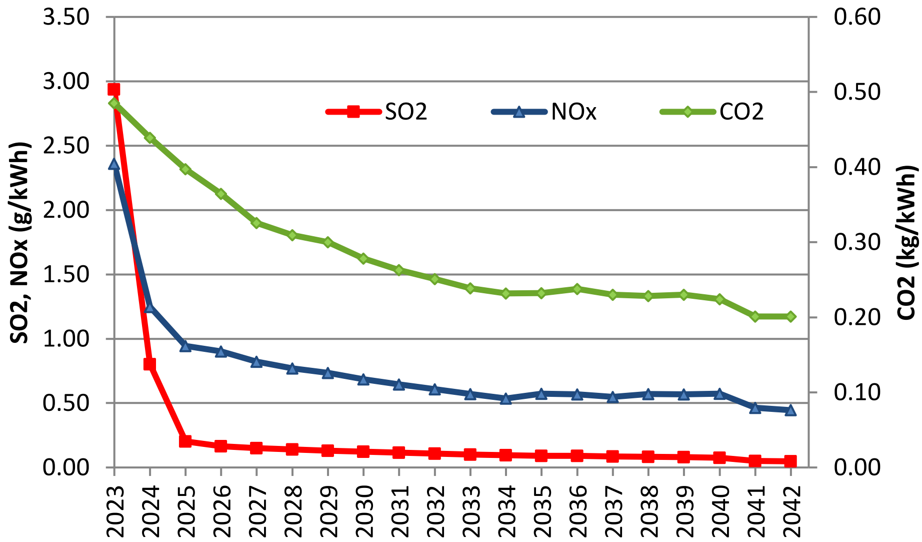


Figure 11.4 – SO_2, NO_x and CO_2 emissions per kWh generated

Figure 11.5 shows the past actual and forecast values of Average CO_2 emission factors for the Base Case. Average CO_2 emission factor of the Base Case scenario shows a decreasing trend in the long term.

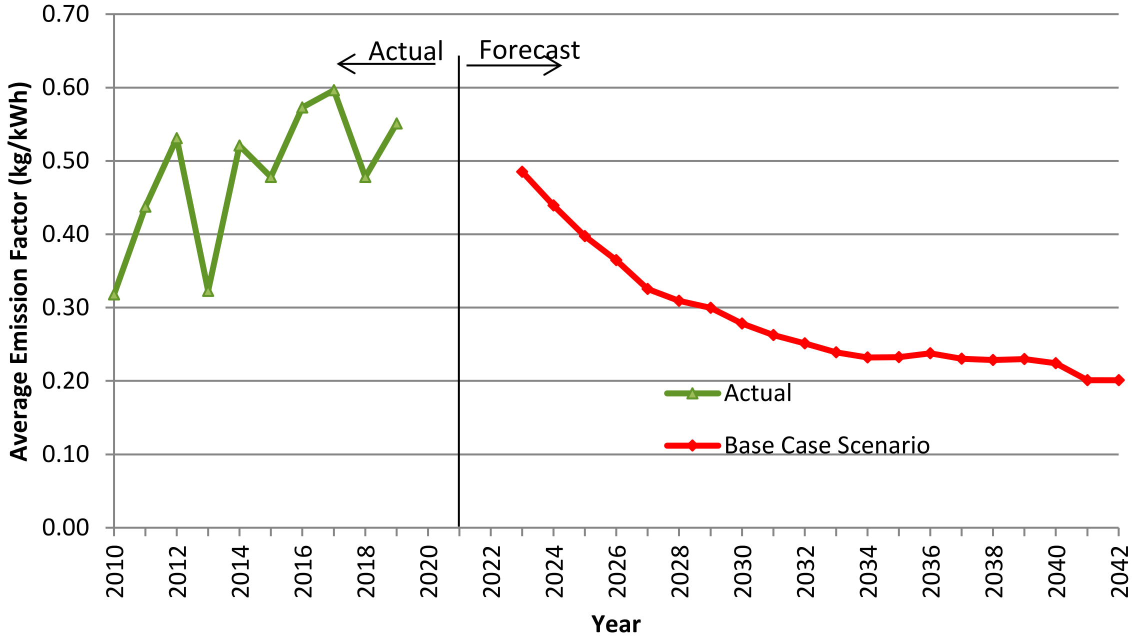


Figure 11.5 – Average CO_2 Emission Factor Comparison

11.5 Environmental Implications – Other Scenarios

11.5.1 Comparison of Emissions

The effects on emissions under following scenarios were analysed and evaluated against the Base Case emission quantities.

1. Reference Scenario
2. HVDC Interconnection Scenario
3. Nuclear Power Development Scenario
4. 50% RE by 2030 Scenario

In the HVDC scenario, emissions of the electricity imported will not be accounted and hence this scenario shows lower emissions compared to base case (Energy export also not considered for analysis).

Figure 11.6 depicts the SO_2 emissions for the planning horizon for above scenarios. It can be seen that the SO_2 are higher during the initial years due to the dispatch of oil power plants. After 2025 the SO_2 emissions have drastically reduced.

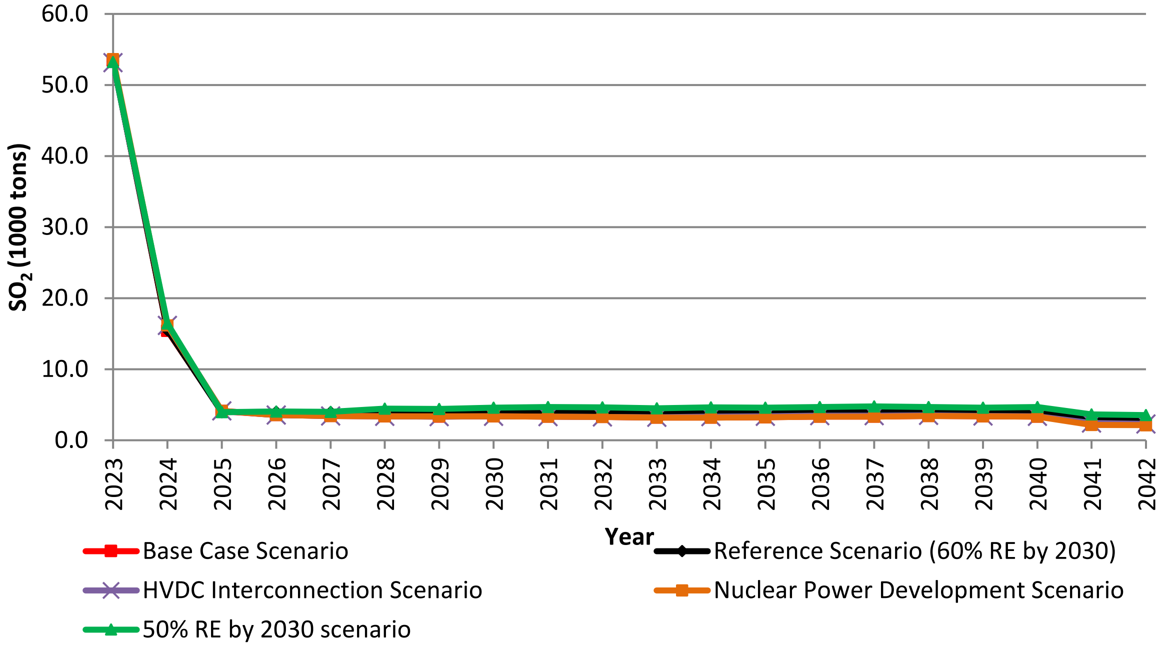


Figure 11.6 – SO_2 Emissions

Figure 11.7 illustrates the NO_x emissions during planning horizon for all scenarios. The higher amount of NO_x emissions would be reduced with the retirement of oil power plants but would gradually increase during the horizon in all scenarios due to the introduction of natural gas based power plants,

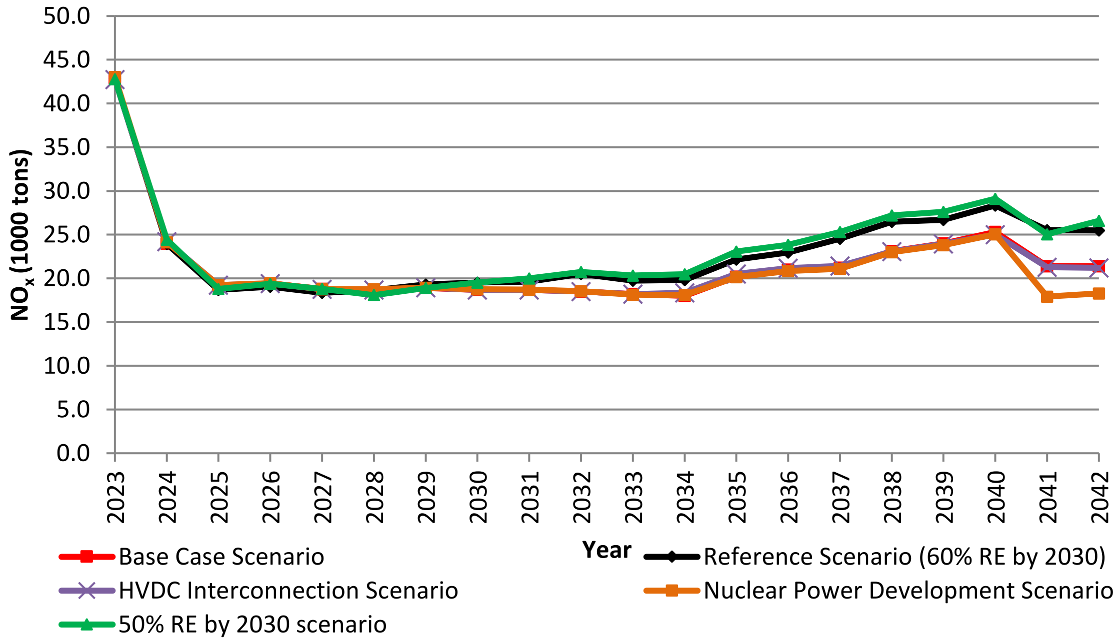


Figure 11.7 – NO_x Emissions

Figure 11.8 shows the CO_2 emissions of the scenarios. Reference Scenario has higher CO_2 emissions compared to Base Case Scenario due to lower share of new renewable energy power plants. 50% RE Scenario has the highest CO_2 emissions. As mentioned above, HVDC scenario has lower CO_2 emissions compared to Base Case Scenario since emissions from energy imports are not considered. Nuclear power development scenario has reduced CO_2 emissions drastically after introduction of the power plant towards the latter part of the planning horizon.

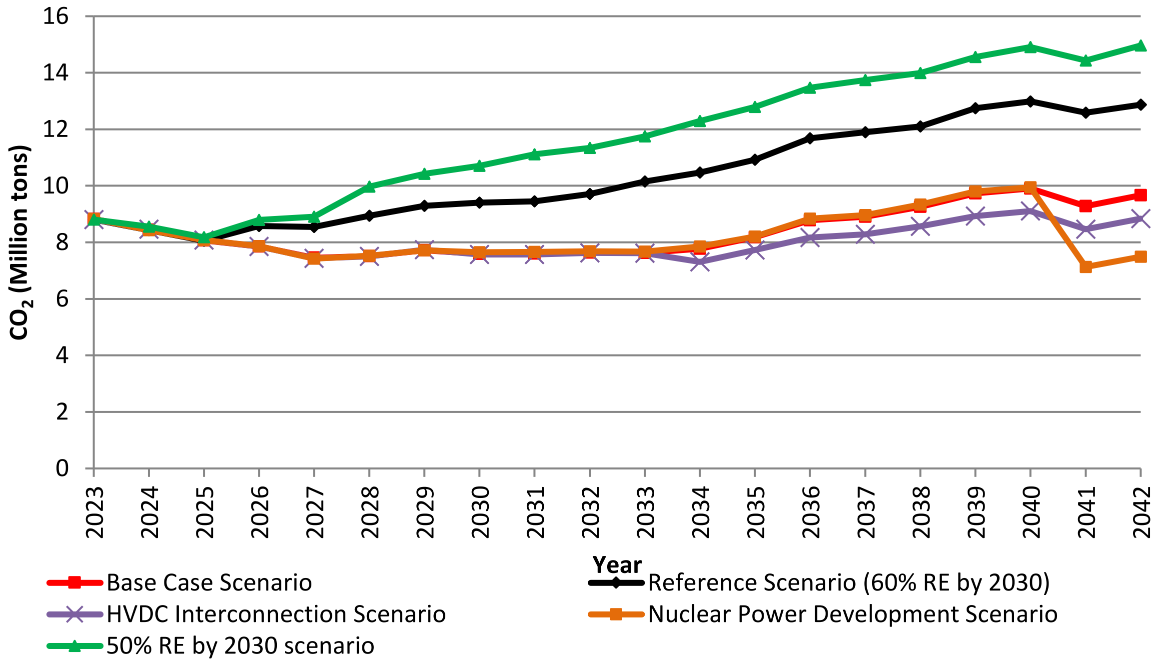


Figure 11.8 – CO_2 Emissions

Figure 11.9 shows the comparison of PM emission related to various scenarios. Future biomass power plants have contributed mainly towards the increase in PM emissions.

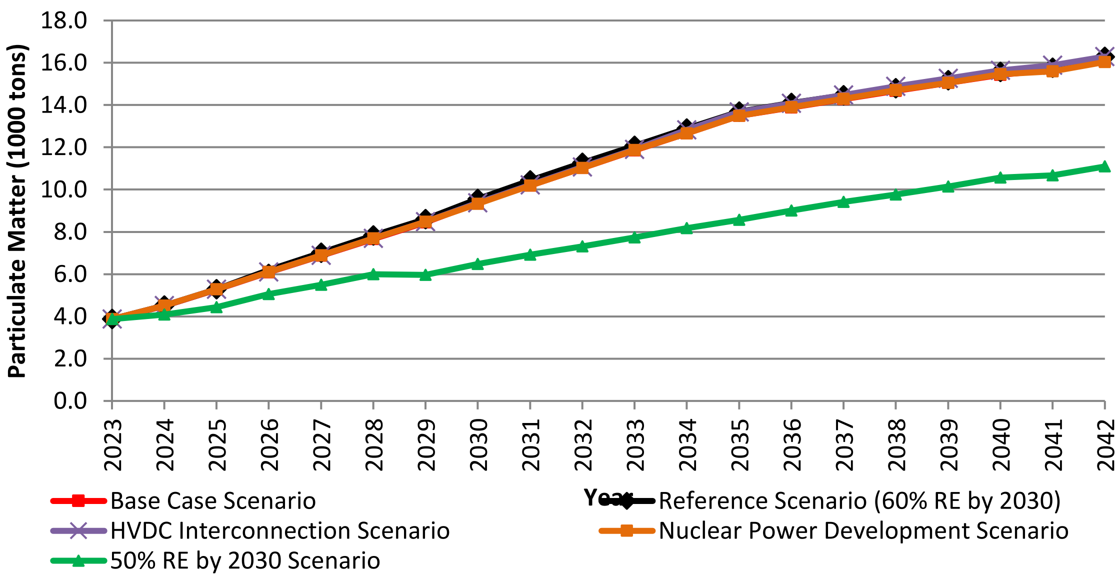


Figure 11.9 – Particulate Matter Emissions

11.5.2 Cost Impacts of CO_2 Emission Reduction

There are tools and techniques developed in order to identify the cost effectiveness of different mitigation options. Marginal Abatement Cost Curve (MACC) is a technique developed to identify the cheapest abatement options among several techniques and in which order they should be prioritised. It is a visual representation showing GHG abatement potentials of various abatement options as a function of GHG abatement costs, and placing these mitigation measures in ascending order of cost-effectiveness. This could be useful in identifying the price of carbon for different GHG emission reduction options and also the overall cost to the economy of meeting specific emission targets. Therefore, it can be a useful analytical tool in defining a cost-effective investment program for Sri Lanka in the pathway for carbon neutrality.

Comparison of total CO_2 emission with total system cost is shown in Figure 11.10. HVDC scenario does not reflect the actual CO_2 emission due to not considering the emission factor for energy imported.

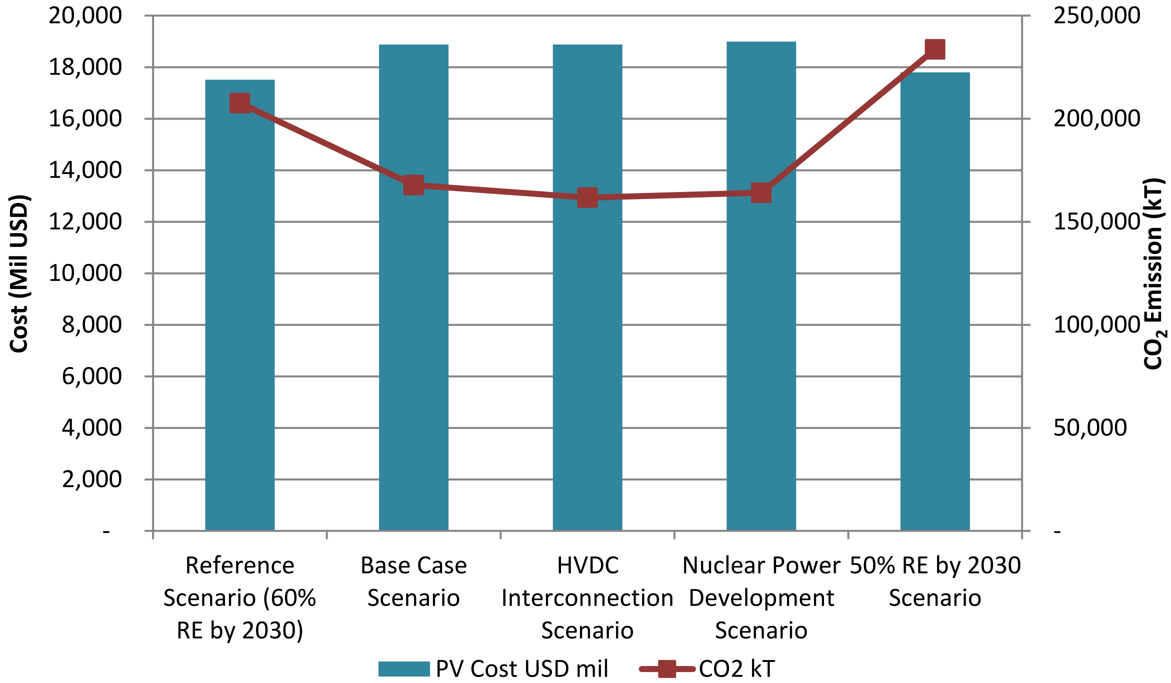


Figure 11.10 – Comparison of System Cost with CO_2 Emissions

Further, the incremental cost of each case is shown in Figure 11.11 by comparing the cost differences and the reduction of CO_2 emissions in each case compared to Reference Case.

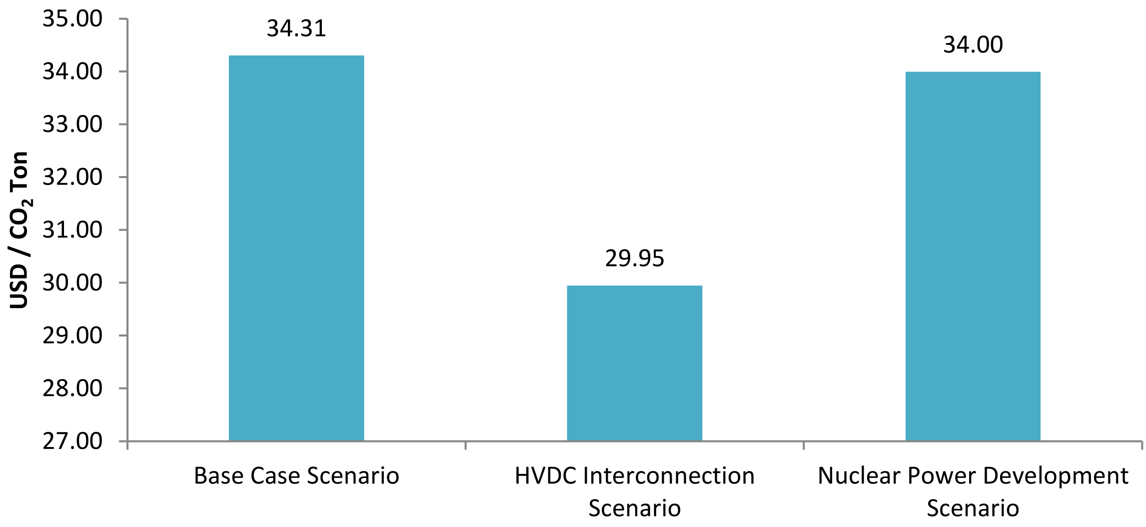


Figure 11.11 – Comparison of Incremental Cost for CO_2 reduction

11.6 Externalities

Externalities as discussed in generation planning are the consequences of a generation activity which indirectly affects other parties without being reflected in market prices. Externalities can be either a positive benefit or negative cost with relation to power generation.

Like any other heavy industry, power industry too causes negative impacts on the social and natural environment in varying degrees. The negative impacts at local level include, releasing of pollutants to local environment, release of waste heat, noise pollution, inundation of lands due to construction of hydro reservoirs, disruption of bird routes by wind plants, etc. The global level impacts are mainly caused with releasing of Green House Gases (GHG). These negative externalities could have non quantifiable impacts to climate change, health, society, agriculture and even bio diversity.

As for the positive impacts, technologies that are capable of generating low cost electricity shall increase the domestic production capabilities contributing to increase the country's GDP. Furthermore, power generation can produce by-products that could be used in manufacturing industries. For example, power generation through coal produces by-products that are used in cement industry and brick manufacturing industry.

Such impacts, when expressed in monetary terms, are called externalities. Estimates of such externalities of different power generating technologies give policy makers a valuable input to decide countries energy policy, generating/fuel mix, future power sector strategies, etc.

As the environmental impacts are a combined effect of all industries, estimating externality costs of specific power generating technology/fuel is a challenge and can be highly subjective due to the difficulty in isolating the contribution of power industry from the impacts from all other industries. Further, as electricity accounts for a less than 12% share of the total energy usage in the country, isolating the impacts of power industry from the balance 88% is very difficult. Thus, expressing the externality costs in monetary terms is a highly subjective exercise as seen from results of studies done in other countries.

Environmental and social impacts of development projects cannot be completely eliminated but can only be contained within ''acceptable limits". Such limits are stipulated in the environmental laws, regulations and standards of a country. This Long-Term Generation Expansion Plan is prepared meeting all such laws and standards. When it comes to reducing GHG emissions, Sri Lanka has obligations under Nationally Determined Contributions (NDC) to reduce emissions unconditionally as well as conditionally, depending on availability of carbon finance as discussed in section 10.1.3. This LTGEP is prepared complying with all such the international commitments related to climate change mitigation.

11.6.1 Local Environmental Damage Issues

Local impacts to social and natural environment can arise due to many causes such as,

1. Local Air pollution as a result of fuel combustion.
2. Pollutants released including waste heat and effluents.
3. Disposal of residual waste products such as ash.
4. Noise emanating from thermal power plants and wind turbines.
5. Effects due to hydro reservoirs.
6. Effects on bird migratory routes and other eco systems

Such localized impacts can have adverse social, environmental and health related issues. However, externality costs of such local impacts cannot be generalised by power generating technology and be adopted to Sri Lanka using studies done in other countries.

It is well known that damage costs are a function of income level of a country, population density around power plants and the specifications of each power plant. Sri Lanka being an island, the localized effects would be entirely different to that of other countries where plants are located inland and therefore health damage issues associated with air pollutants and thermal discharges need to be evaluated in Sri Lanka specific studies. Studies done in other countries for certain generating technologies such as coal power plants cannot be straightaway adopted to Sri Lanka as coal plants operated in such countries are of much older technologies compared with the existing and future coal plants of Sri Lanka. Therefore, country and location specific studies are required to be done to reasonably estimate the damage costs even though that too can be highly subjective.

11.6.2 Global Damage Issues of GHG Emissions

Global impacts of power generation are primarily due to release of CO_2 during combustion process. However, such global impacts of power generation are not only limited to the impacts due to conversion of fuels to electricity at the point of power generation, but also includes the impacts during the total supply chain of the fuel from the mine to the plant. When the total life-cycle emissions of LNG, which include emissions at the point of mining/extraction, liquefaction, transportation, regasification and combustion are considered, the results are totally contrast to the emission of GHGs during combustion only. Global studies have been conducted to prove that when life cycle emissions of natural gas, liquid fuel oils and coal are considered, the equivalent GHG emission of natural gas (which consists of methane having a GHG effect 28 times than CO_2) is more than that of other liquid fuel oils and are somewhat in the same range of coal. Such indirect emissions are present not only in thermal power generating sources but are common to any other type of generating source including hydro, wind and solar PV. Disposal of solar PV panels after de-commissioning has raised a huge global environment concern and re-cycling technologies are yet emerging. Thus, estimating the global impact of GHGs as a part of externalities is highly subjective and is beyond the scope of economic planning.

However, CEB had enhanced the operational specifications of future candidate power generating technologies to further reduce the environmental impacts of such technologies over and above what is stipulated under law. Additional costs to do so have already been considered and factored in to the capital costs of candidate thermal power plants in this planning study. Thus, CEB has already considered additional costs to bring down externality costs of power generating technologies, to be well below the threshold values of environmental regulations and hence the costs of externalities have been internalized in to the planning studies in the form of additional capital investment.

11.7 Pathway to Carbon Neutrality

Carbon neutrality is a state of net-zero carbon emissions achieved by a balance between emitting carbon and absorbing carbon (from the carbon sinks) in the atmosphere. Reaching global carbon neutrality by mid-century and keeping global warming below 1.5 ˚C was one of the main objectives of COP 26. Pledges for carbon neutrality by country parties increased with COP 26. Some countries have put a target year on their policies or laws to achieve this.

Bhutan and Suriname have already achieved carbon neutrality and are the only two countries that are carbon negative. Finland is leading the path to net zero by committing to achieve carbon neutrality by 2035. The majority of countries are aiming for a zero-carbon economy by 2050 including Sri Lanka. Few countries including major emitters such as China and India have carbon neutrality pledges beyond 2050.

With regard to the pathways in achieving carbon neutrality, reduction of greenhouse gas emissions plays a vital role but is not the only key option. Offsetting carbon emissions (in addition to avoidance and reduction) through artificial or natural carbon sinks is also an important factor in reaching this goal. Carbon sinks are systems that absorb more carbon than they emit, such as forests, soils and oceans.

Carbon Sequestration refers to the process of removing carbon from the atmosphere and depositing it in a reservoir (carbon sinks) for a longer period of time. This process is a promising approach to remove CO2 emissions from the atmosphere. Major types of carbon sequestration are biological, geological and technological.

Biologic carbon sequestration refers to storage of atmospheric carbon in vegetation, soils and aquatic environments. Therefore, reforestation (planting trees in a forest where the number of trees has been decreasing) and afforestation (creating new forest) becomes important as they are natural sinks. This will require active participation from forestry sector of the country.

Geologic carbon sequestration is the process of storing CO2 in underground geologic formations. The CO2 is usually pressurized until it becomes a liquid, and then injected into porous rock formations in geologic basins.

New ways to remove and store carbon from the atmosphere using innovative technologies are being explored at global level and these methods are known as technological sequestration. Artificial trees are a means by which carbon is directly captured from the air. However, this process is energy intensive and expensive. Furthermore, ways to use CO2 as a resource (for example in Graphene production) are also being explored globally.

In the pathway to carbon neutrality, possibility of green hydrogen production, storage and usage is also becoming important. Hydrogen can be made from several abundant sources such as natural gas or water. The process and energy used determine whether the hydrogen produced is 'low-carbon' or not. Hydrogen made from fossil fuel such as natural gas must incorporate carbon capture, utilization and storage (CCUS) into the process to be low-carbon. When hydrogen is made from water via electrolysis, the process must be powered by a low-carbon source such as renewable energy to be a low-carbon process. This process is commonly referred to as 'green hydrogen'. This could be used as a seasonal storage to increase the renewable absorption (by reducing curtailments in RE generation) and further be utilized to operate natural gas driven thermal plants on blended hydrogen (hydrogen mixed with natural gas). A key barrier for low-carbon hydrogen is the cost gap with hydrogen from unabated fossil fuels. But with the declining cost of renewable energy this could be a promising technology in the future.

Reaching carbon neutrality cannot be looked upon through the electricity sector alone and emission goals of the other sectors need to be aligned with it. Conservation of natural habitats, developing technology to draw greenhouse gases from the atmosphere as well as reducing the overall carbon emissions as a country are all important factors in the path to carbon neutrality. Activities such as green hydrogen production, EV charging for effective RE utilization, etc. will need the participation of many entities, including that of policy making. Chapter 10 of this LTGEP discusses different pathways for Sri Lanka to achieve carbon neutrality in power sector by increasing renewable energy share, cross-border interconnection and nuclear power development.

CHAPTER 12
RECOMMENDATIONS OF THE BASE CASE PLAN

This chapter elaborates the recommendations for the Base Case Plan by emphasizing the importance of implementation of proposed power projects identified in the planning horizon.

12.1 Introduction

As discussed in Chapter 8, Base Case Plan is developed to achieve 70% of renewable generation by 2030 with a mix of thermal generation technologies and storage options to complement renewables. Timely implementation of proposed power plants is crucial to avoid capacity shortages, energy shortages and high cost alternative generation in the future.

Economies of renewable energy and advancement in renewable and storage technologies are evolving rapidly around the world. The rolling generation expansion plans prepared by CEB once in two years are intended to capture such changes in subsequent planning cycles. The generation expansion envisioned for the last ten years in the planning window is relied on the present up-to-date information whereas such can undergo changes in the future, with the advancement of technologies.

Accordingly, the recommendations for the Base Case Plan, pertaining particularly to the first ten years of the planning horizon are given below with special emphasis on the importance of timely implementation of power plant projects to secure, affordable and reliable supply of electricity.

12.2 Recommendations for the Base Case Plan

Major recommendations for the Base Case Plan are as follows.

1. Development of Renewable Energy

   Base Case Plan 2023-2042 has identified a cumulative capacity of 6,925 MW of ORE to be developed within the first ten years of the planning horizon. This includes development of 4,705 MW of solar, 1,825 MW of wind, 195 MW of mini hydro and 200 MW of biomass power capacities in the first ten years. Timely implementation of projects to achieve these ORE capacities as per the schedule is important to cater to the growing demand while achieving policy targets and climate change obligations. The locations of ORE power plants should be prioritized based on the plant factors, land availability and cost of transmission network. During initial years priority shall be given to locations in which resource potential and grid interconnection capability are available. Formalities and procedures related to land acquisition, environment clearance, etc. have to be reviewed in order to expedite the implementation of ORE projects. It is recommended to streamline renewable energy development procedures to ensure faster implementation as well as strict compliance to interconnection codes. All new medium to large scale ORE power plants should have the operational, technical and contractual capability for curtailment when necessary.

2. Completion of committed Major Hydro power plants on time

Base Case Plan 2023-2042 has identified committed Hydro power plants of 122 MW Uma Oya to be commissioned by 2022 and 31 MW Moragolla to be made available by 2024. Timely implementation of all these committed Hydro power plants is important to avoid power shortages in future.

3. Commissioning of Natural gas based Combined Cycle power plants on time

The first two 350 MW Natural gas based Combined Cycle power plants which are at the construction phase and project development phase should be commissioned to operate on combined cycle mode by the years 2024 and 2025 respectively. These Power plants shall be technically, operationally and contractually capable of being operated regularly between open cycle and combined cycle modes. It is required that the second combined cycle power plant have lower minimum load level capabilities, higher ramp rates and shorter start up time in par with present industry performance levels.

4. Conversion of fuel capability to Natural gas of Kelanithissa Combined Cycle Power Plant, Sojitz Kelanithissa and West Coast Power Plant

The existing 270 MW West Coast power plant, 165 MW Kelanithissa Combined Cycle power plant and 163 MW Sojitz Kelanithissa Combined Cycle power plant are expected to be converted to operate on natural gas by **2025.** Hence all activities that are required to enable the conversion of fuel on time should be initiated immediately.

5. Availability of Liquefied Natural Gas (LNG)/Natural Gas (NG) and Infrastructure

Natural gas based Power plants will operate initially on diesel until year 2025 and the operation from natural gas is expected from year 2025 onwards with the basis of natural gas delivered to power plants through necessary infrastructure. Therefore, required LNG infrastructure with associated natural gas distribution network should be developed in line with this time target considering it as a national priority project.

It is required to ensure that LNG procurement contracts are made to minimize the 'Take or Pay' risks because such commitments can influence the dispatch decisions which will result in low economic benefits and inability to meet the national RE targets.

6. Commissioning of New Kelanithissa Gas Turbine

The 130 MW New Kelanithissa Gas Turbines, are expected to be commissioned in year 2024. It is critical to have this power plant commissioned to facilitate quick supply restoration in case of an island wide power failure. In addition, the power plant shall provide necessary flexible generation requirement and peak power requirement of the system in the future.

7. Development of Flexible Firm Generation to Complement High VRE Integration

Due to the intermittent and variable nature of VRE, the power system needs to have sufficient flexible power sources to ensure system stability and reliability. These flexible power plants should possess the fast startup, fast ramping and deloading capabilities to support the power system to manage the daily net load fluctuations typically seen with high VRE levels.

IC Engine power plant proposed for year 2026, gas turbine power plant proposed for year 2027 and all the Gas Turbine and IC Engine power plants proposed beyond 2030 have been included in the base case plan to fulfil this specific flexibility requirement of the system. Therefore, these proposed power plants should have superior operational flexibility with capability of multiple start-stops without sacrificing their equivalent running hours. Also these plants will provide the requirement of spinning and non-spinning reserves of the system. These power plants should also have high part load efficiencies and should have minimum start up and shut down times (comparable with latest industry standard for IC Engine and Gas Turbine power plants).

8. Development of Pumped Storage Power Plant

Implementation of the planned 4 x 350 MW pumped storage hydro plant is critical as a long term measure to enhance the flexibility and security of the system with high shares of renewable energy technologies. This energy storage technology shall facilitate projected variable renewable energy (wind & solar) absorption by reducing the curtailments of energy generation. The variable speed pumping capability will provide network support for smoothening the variabilities in VRE. In addition, this will operate as a peaking power plant by minimizing high-cost thermal generation. The first unit of the PSPP is expected to be commissioned during 2029. It is necessary to complete the detailed feasibility study by end of 2023 and secure funding and finance for the project by year 2025 such that power plant could be commissioned on time.

9. Development of Battery Energy Storage System (BESS)

With the high penetration of variable renewable energy, battery energy storage capacities are introduced for the purpose of energy shifting, frequency regulation as well as to provide grid level support for renewable energy integration. As first step, a 20 MW capacity is planned to be commissioned by year 2024. The battery capacity is planned to gradually increase up to 1125 MW by 2030. This capacity will be developed as a mix of standalone utility scale BESS and large scale solar parks integrated with BESS. The BESS utilized for energy shifting would require to have minimum 4-hour duration storage, and the possibility of stacking up with other ancillary services to the same are to be evaluated.

10. Supplementary power for capacity shortages

Due to the already delayed implementation of major power projects, a capacity shortage is visualized during the period from 2023 to 2025. A supplementary power capacity ranging from 320 MW to 120 MW is required to maintain the minimum reliability criteria during this period.

Technology for procurement of supplementary capacity can be opened for both Gas turbine and IC engine technology primarily to ensure the most economic terms for the short term requirement from the available alternatives in the market. The fuel option can be specified as appropriate at the time of procurement from suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms. Further, the possibility of utilizing the operational generating capacities with lapsed contracts as well as other short term alternatives shall be explored as appropriately to meet the short term requirement in most economically advantageous terms for the country, within proper legal framework.

11. Fuel flexibility for thermal power plants

Considering the heavy dependency in future on imported LNG as a fuel for electricity generation, all natural gas based power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply. The choice of secondary fuel shall be decided at procurement stage from suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms. Furthermore, considering the policy requirement on carbon neutrality goals, all future power plants should have the capability to operate from synthetic fuels such as hydrogen.

12. Establishment of Renewable Energy Desk with Resource Forecasting System

The early introduction of a "Renewable Energy Desk" to the National System Control Centre is essential to separately manage renewable energy capacities that are going to be integrated in large proportions. The Renewable Energy Desk shall have main functions to cater the following.

- The monitoring and supervisory controlling facilities of renewable energy plants and storage facilities are to be provided to the National System Control Centre.
- Establishing renewable energy forecasting system at the “Renewable Energy Desk” in intra-hour, intra-day and day-ahead timeframes which is vital to manage the uncertainty in maintaining supply and demand balance.

The development of Renewable energy desk is expected phase by phase and major components are required to be completed by year 2026 to ensure that system is capable to operate with high VRE integration levels.

13. Development of Transmission Infrastructure

It is mandatory to have critical transmission infrastructure identified for each project to be implemented in parallel, to ensure evacuation of power from the power plants with the expected reliability. Securing funding and timely implementation of these critical transmission infrastructure projects is essential for commissioning of power projects. The major developments identified for transmission infrastructure to evacuate power from power projects is summarized in Table 12.1.

Table 12.1 – Essential Transmission Development Infrastructure *

Power Project	Required Completion time	Required Major Transmission Development
100 MW Siyambalanduwa Solar Park	2024	1. Construction of Siyambalanduwa- Monaragala 132kV Tr Line 2. Construction of Siyambalanduwa 132 kV Collector station 3. Reconstruction of Medagama - Ampara 132 kV Transmission line
350 MW Natural Gas Combined Cycle Power Plants (Kerawalapitiya) 1	2024	1. Construction of Veyangoda-Kirindiwela-Padukka 220 kV Transmission line 2. Construction of Kotmale-New Polpitiya 220 kV transmission line 3. Construction of Kerawalapitiya 220 kV switching station 4. Construction of Kirindiwela 220 kV GSS switching station
350 MW Natural Gas Combined Cycle Power Plants (Kerawalapitiya) 2	2025	1. Construction of Kerawalapitiya - Port 2nd 220kV Cable
200 MW Natural Gas IC Engine Power Plant (Muthurajawela)	2026	1. Construction of Muthurajawela 220 kV grid substation 2. Contruction of Kerawalapitiya – Muthurajawela 220 kV interconnection
100 MW Pooneryn Development (Wind)	2026	1. Construction of Pooneryn – Kilinochchi 220kV Tr Line (132kV Operation) 2. Construction of Pooneryn Collector station
Mannar Development Phase I (Wind) – 150 MW	2024/ 2025	1. Augmentation of Nadakuda 220 kV grid substation (3x63MVA, 220/33kV transformers)
Mannar Development Phase II (Wind)	2026/2027	1. Upgrade of Mannar – Vauniya with a high capacity conductor 2. Construction of transmission line from Mannar to Vauniya (Voltage and conductor type will be decided with the final generation capacity at Mannar) 3. Construction of Mannar collector station
Southern Renewable Energy Zone Development (Hambantota / Suriyawewa)	2025/2026	1. Augmentation of Hambantota 220 kV grid substation (2x63MVA, 220/33kV transformers) 2. Construction of Hambantota – Suriyawewa 220 kV Transmission line 3. Construction of Suriyawewa 220 kV Collector station 4. Construction of Matara – Hambantota 132 kV Transmission line
North Eastern Renewable Energy Zone Development Phase I -50 MW (Trincomalee / Sampur)	2026	1. Construction of Kapplturei – Sampoor 220 kV Transmission line (132kV Operation)
North Eastern Renewable Energy Zone Development Phase II (Trincomalee / Sampur)	2027	1. Construction of New Habarana – Kappalturei 220 kV Transmission line 2. Construction of Sampoor 220 kV Collector station 3. Construction of Kappalturei – Trinco 2 Deve 220kV Transmission line 4. Construction of Trinco 2 Deve 220 kV Collector station

Power Project	Required Completion time	Required Major Transmission Development
Northern Renewable Energy Zone Development (Murikandy, Iranamadu tank, Point Pedro, Pooneryn)	2028	1. Construction of New Habarana – Vauniya – N Collector 400 kV Transmission line 2. Construction of N Collector, Vauniya and New Habarana 400 kV switching station 3. Construction of Pooneryn , Murikandy, Point Pedro and Iranamadu Collector stations 4. Constrction of N Collector – Collector stations 220kV transmission lines 5. Construction of New Habarana – Victoria – Kirindiwela 400 kV Transmission Line Construction of Victoria 400 kV Switching station
Eastern Renewable Energy Zone Development (Valaichenai/ Vavunativu)	2029	1. Construction of New Habarana – Valachchenai 220 kV Transmission Line 2. Construction of Valachchenai 220 kV Collector station
Pumped Hydro Storage Development	2029/2030	1. Information included above

* Information provided above are based on initial projections and exact transmission infrastructure requirement shall be decided after finalizing locations of all power projects.

14. Development of Distributed Energy Resources

Integration of large capacities of Distributed Energy Resources (DER), mainly through rooftop solar PV schemes shall be an integral requirement to achieve government policy targets. It is necessary to enable proper mechanisms to facilitate accelerated growth of DER while minimizing adverse effects on the network. Following recommendations have been identified by the renewable integration study teams in distribution sector.

(i) It is considered to mandate operation of all future and existing (if possible) Solar PV Inverters of MV and LV connected schemes to operate on Voltage Control Mode.
(ii) Reviewing and amending distribution planning criteria with regard to voltage rise in MV and LV distribution network for accepting future Solar PV systems.
(iii) Evaluating the capability of installing on-load tap changers for the existing distribution transformers with two tap positions to avoid overvoltage during daytime and undervoltage during night time as an interim measure.
(iv) Deploying of smart meters for solar PV connections and installation of communication system to provide comprehensive visibility at Distribution Control Centres and aggregate clusters visibility at National System Control Centre is also recommended.
(v) Development of geospatial feeder wise Hosting Capacity Map, to concentrate investments at correct locations, to be in par with distribution network expansions.

15. Securing of Land and Transmission Line Corridors

In the power sector, identification and securing of the lands for future power plants and associated infrastructure is crucial. Therefore, locations for establishing power generation facilities and related transmission corridors which interconnect such facilities to the national grid should be identified in advance and secured considering this as a national priority. Potential locations identified at present for future power generation projects are given in Table 12.2.

Table 12.2 – Potential Locations for Future Power Generation Projects

Power Project	**Identified Potential Locations**
Solar Park Developments (Ground Mounted / Floating)	Southern, North Eastern, Northern and Eastern regions (Hambantota, Trincomalee, Monaragala, Valaichenai, Iranamadu, Kilinochchi, Pooneryn)
Wind Park Developments	Northern & North Western Regions (Mannar, Pooneryn, Puttalam, Anuradhapura)
Pumped Storage Power Projects	Victoria-Wewathenna in Kandy, Maha Oya -Aranayaka in Kegalle
Natural Gas Power Projects	Kerawalapitiya , Muthurajawela
Battery Energy Storage	Integrated with large solar parks, Standalone Utility Scale

16. Review of Interconnection and operating codes, planning codes, policies and regulations

It is recommended to periodically review and upgrade the existing interconnection and operating codes, planning codes and regulations based on detailed studies and up-to-date industry practices. It is essential to complete the first iteration of reviewed codes by year 2023/2024, such that necessary pathway to operate a power system with high VRE integrations is established. Specific attributes that require reviewing are as follows.

(i) Reviewing the present operating reserve policy of system operation, with dynamic upward and downward requirements that provide additional regulation for the planned renewable energy capacities is required.

(ii) Enhancing the grid support features of variable renewable energy projects including enhanced Ride through capabilities, Ramp Rate Control functions, active power control, etc. through codes and regulations is mandatory to proceed with the planned renewable energy development program.

(iii) Formulation of curtailment policies and contracts that facilitate necessary mechanisms to optimally operate the power system.

(iv) Reviewing the planning codes, and establish suitable parameters and matrices to be adopted for reliability criteria that reflect operation of a high VRE integrated systems.

17. Introducing Demand Shifting

Since majority of renewable energy is curtailed during Sundays, it is necessary to formulate a mechanism to shift certain weekday demands to Sundays. This can be done at minimum cost by introducing necessary tariff structures to promote industries and commercial establishments to operate in Sundays and reduce the demand on weekdays. A rotational mechanism for each consumer could be proposed for selection of the weekday for demand shifting, such that demand reduction is evenly distributed within all weekdays.

Further, introducing a Time of Use (TOU) cost reflective tariff shall also encourage the customers to shift their night loads to the daytime, thus, reducing curtailments during daytime and preventing high cost generation during the night peak.

The necessary background studies for these demand shifting strategies need to be conducted and such need to be introduced by year 2025 to mitigate excess renewable energy curtailments.

18. Introducing Demand response schemes and flexible loads

Introducing demand response methods and conducting studies for finding load management strategies and investigating the possibility of introducing flexible loads such as electric vehicles, desalination plants, hydrogen production, ammonia production, etc., in view of altering the demand profiles as required for maximum utilization of renewable energy and for ensuring system stability.

19. Exploring the possibilities of cross border electricity trade

As the renewable energy integration levels exceed the demand requirements in certain periods in the latter part of the planning horizon, it is necessary to explore the possibilities of cross border electricity trade between Sri Lanka and India. It is essential to conduct detail studies prior to committing in such large-scale infrastructure. Assessment is required on potential power trade options bilateral or multilateral, in the future market with supply demand balance considering seasonal/daily load trends of both countries.

20. Exploring the possibilities of Green Hydrogen Production, Storage and Usage

Since majority of renewable energy is curtailed with seasonal patterns, new storage solutions other than conventional storage solutions have to be considered beyond year 2030. Green Hydrogen production is emerging as a promising technology, which requires detailed feasibility studies to be conducted on its production patterns, storage mechanisms and potential applications to Sri Lanka including power generation and production of ammonia as a fertilizer.

21. Power Purchase Agreement for Biomass with Seasonal tariff adjustment

The development of biomass power plants as expected in the Base case plan shall pay a major role in achieving the envisioned renewable energy targets. However, since the limited availability of biomass resource can be observed, it is beneficial to utilize the resource, during the periods its most essential. It is proposed to introduce a seasonal tariff adjustment for biomass resource such that, the maximum generation is encouraged during dry season and limited generation can be expected during high wind season, to minimize curtailment of VRE generation.

22. Conducting System Strengthening Studies

Conducting studies for necessary grid interventions such as introducing synchronous condensers for maintaining inertia of the network with high non-synchronous penetration, introducing reactive power compensators, etc.

Conducting further studies to investigate the necessity of system non-synchronous penetration (SNSP) limits considering targeted years to achieve smooth operation of the power system. Such studies need to be periodically reviewed with the actual progression of the power system SNSP limits.

CHAPTER 13
IMPLEMENTATION AND INVESTMENT OF GENERATION PROJECTS

This chapter elaborates on the required implementation and the investment plan for the generation projects identified in the Base Case Plan 2023-2042.

13.1 Present Status of Power Plants in the Base Case Plan

13.1.1 Present Status of the Committed Plants

A brief description of the current status of power projects that were considered as committed projects in the present study are given below.

Renewable Energy Power Projects:

(i) Broadlands Hydro Power Project

Main construction works were commenced in 2013. At present, the power plant is at commissioning stage.

(ii) Uma Oya Multipurpose Project

This is a multipurpose development project and it is implemented by the Ministry of Mahaweli Development and Environment in coordination with the Ministry of Power and Ceylon Electricity Board. The financial assistance for the project is provided by the Government of Iran and currently the project is under final stages of construction and expected to be completed within year 2022.

(iii) Moragolla Hydro Power Project

Review of feasibility study and detail design has been completed in 2014 by Nippon Koei, joint venture with Nippon Koei India Pvt Ltd. Preconstruction work including detailed design and tendering commenced in July 2014. Funds from ADB were obtained for implementation of this project. The power plant is expected to be in operation by 2024.

(iv) Solar Power Development

CEB initiated the procurement of small scale scattered solar power projects from private sector under the second phase of the accelerated solar development program of the government. Solar power projects of 1 MW x 60, 1 MW x 90 and 1 MW x150 were tendered through international competitive bidding process for selected grid substations. By 31st December 2021, 49 MW capacity have been developed. It is expected to commission a cumulative capacity of 94 MW by 2023 and another 147 MW by year 2024 from these projects.

Further 223 MW of Grid connected partially facilitated Solar projects are expected to be opened up for investments in near future, where capacity absorption is possible from existing grid substations.

In addition to this, Solar PV systems of 75 kW capacities are planned within 500 m of identified distribution substations where there is less potential for rooftop solar installations. A total of 7000 distribution substations have been identified for phased development under this programme to contribute a cumulative capacity of 525 MW.

(v) Wind Power Development

The extension of Mannar Wind Plant by 50 MW is being implemented by CEB. The capacity enhancement would increase the total capacity of the power plant to 150 MW.

Furthermore, CEB had called for bids of 60 MW wind power development from private sector, in which 3 projects has been already committed to be developed in Trincomalee (10 MW), Madampe (10 MW) and Mannar (15 MW) which are expected during the period 2023 to 2024.

<u>Thermal Power Projects:</u>

(i) Kelanithissa New Gas Turbines (130 MW)

CEB has called for bids under the international competitive bidding scheme to design, manufacture, supply, installation and commissioning of 130 MW Gas Turbines at the Kelanithissa Power Station. This power plant is required to have the capability to support restoration of supply in case of an island wide power failure. The power plant is expected to be operational by 2024.

(ii) 1st Natural gas fired Combined Cycle Power Plant (350 MW)

Construction has initiated for the development of 350 MW Natural Gas fired Combined Cycle Power Plant with dual fuel capability on BOOT basis at Kerawalapitiya. The Power plant is expected to be commissioned in 2023 in open cycle operation and in 2024 as combined cycle operation.

(iii) 2nd Natural gas fired Combined Cycle Power Plant (350 MW)

CEB has initiated procurement process for development of 350 MW Natural Gas fired Combined Cycle Power Plant with dual fuel capability on BOOT basis at Kerawalapitiya. The project is expected to be commissioned in 2024 in open cycle operation and in 2025 as combined cycle operation.

13.1.2 Present Status of the Candidate Power Plants

A brief description of the current status of the candidate power projects on which the initial project activities were commenced are given below.

Renewable Energy Power Projects:

(i) Other Multipurpose Hydro Power Projects (Gin Ganga, Thalpitigala)

Gin Gaga and Thalpitigala Hydro power projects are to be developed by Ministry of Irrigation and Water Resource Management. The preliminary feasibility studies for Gin Ganga hydro project are in progress and the parameters of the hydro power plant are yet to be finalized. The preliminary feasibility studies and EIA studies of the Thalpitigala Hydro Power Project have been finalized and approved. However due to difficulties in securing project finances, the project is on hold at present.

(ii) Solar Power Development

The SEA and CEB has conducted initial studies to identify potential locations to develop large scale solar parks in the country. These include 100 MW ground mounted solar parks and floating solar power plants. As first phase, large scale solar power parks are planned to be developed in Siyambalanduwa, Hambantota and Trincomalee. The land acquisition and initial prefeasibility studies for these projects are being carried out by SEA.

(iii) Wind Power Development

The resources identification for wind power projects has recognized high potential wind power capacity in North western and Northern region of the country. As first phase, large scale on-shore wind power parks are planned to be established in Mannar and Pooneryn. Studies are being carried out by CEB to develop 100 MW in Silawathura. Studies to develop 100 MW in Mannar island and 240 MW in Pooneryn area are conducted by SEA. Furthermore, new wind power development projects are focused on Anuradhapura, Veravill and Puttalam areas.

Thermal Power Projects:

(i) Natural Gas based Gas Turbine/IC Engine Power Plants – West Coast

It has been identified that locating power plants near the load centres of the country has significant economic benefits. Thus, with the establishment of FSRU facilities in Kerawalapitiya (off-shore), Muthurajawela and Kelanitissa have been identified as potential locations for the next natural gas power plants.

Energy Storage Projects:

(i) Pumped Storage Power Project

Pumped Storage Power Plants are to be used as a grid level energy storage and frequency controlling option in future. The JICA assisted study, 'Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka' (2015) identified a site at Aranayaka in the Maha Oya basin as the most suitable site to locate the first pumped storage hydropower project in Sri Lanka. A prefeasibility level study has been completed for this location. Subsequently, 'Electricity Sector Master Plan Study' (2018) identified Wewathenna-Victoria as an alternative location for pumped storage option.

At present consultancy procurement process is ongoing for the selection of the site and detailed feasibility study for the first pumped storage power plant in Sri Lanka. The first phase of this study is to conduct a prefeasibility on Wewathenna-Victoria site and evaluate the both options, Aranayaka and Wewathenna- Victoria, to find out the best site to construct the first pumped storage power plant in Sri Lanka. The second phase of the study shall conduct a detailed feasibility study for the identified most promising location in the first phase. The feasibility study is financed through the Asian Development Bank (ADB).

(ii) Battery Energy Storage (BESS) Projects

Consultancy procurement process has been initiated by CEB for the site selection and RFP preparation for the first BESS in pilot scale. Accordingly, 20 MW/50MWh BESS is proposed to be developed by 2025. This is to be developed as 10 MW for the purpose of energy shifting and 10 MW for the purpose of frequency regulation or as 20MW single capacity serving both requirements.

From year 2025 onwards, large scale Battery Energy Storage projects are proposed to be developed as standalone systems as well as integrated solutions coupled with large scale fully facilitated solar PV parks.

13.2 Power Plants Identified in the Base Case Plan from 2023 to 2032

The proposed major hydro, thermal and other renewable energy plants up to 2032 according to the Base Case Plan are given below.

Renewable Energy Power Plants

(i) Uma Oya Hydro Power Plant (122 MW) in 2022
(ii) Moragolla Hydro Power Plant (31 MW) in 2024
(iii) Other Renewable Energy additions (2023-2032)
   a. Solar (4,705 MW)
      - Distribution Connected Embedded Solar
      - Grid Connected Partially Facilitated Solar
      - Grid Connected Fully Facilitated Solar (with BESS)
   b. Wind (1,825 MW)
   c. Mini Hydro (195 MW)
   d. Biomass (200 MW)

Thermal Power Plants:

(i) Kelanithissa New Gas Turbines (130 MW) in 2024
(ii) 1st Natural gas fired Combined Cycle Power Plant (350 MW) in 2023/2024
(iii) 2nd Natural gas fired Combined Cycle Power Plant (350 MW) in 2024/2025
(iv) Natural gas fired Gas Engines (200 MW) in 2026
(v) Natural gas fired Open cycle gas turbine (100 MW) in 2027

Energy Storage Power Plants:

(i) Battery Energy Storage Pilot Project (20 MW) in 2024
(ii) Standalone Battery Energy Storage Power Plant (80 MW) in 2026
(iii) Standalone Battery Energy Storage Power Plant (100 MW) in 2027
(iv) Standalone Battery Energy Storage Power Plant (200 MW) in 2028
(v) Pumped Storage Power Plant (350 MW) in 2029
(vi) Pumped Storage Power Plant (350 MW) in 2030
(vii) Pumped Storage Power Plant (350 MW) in 2031
(viii) Pumped Storage Power Plant (350 MW) in 2032

13.3 Implementation Schedule

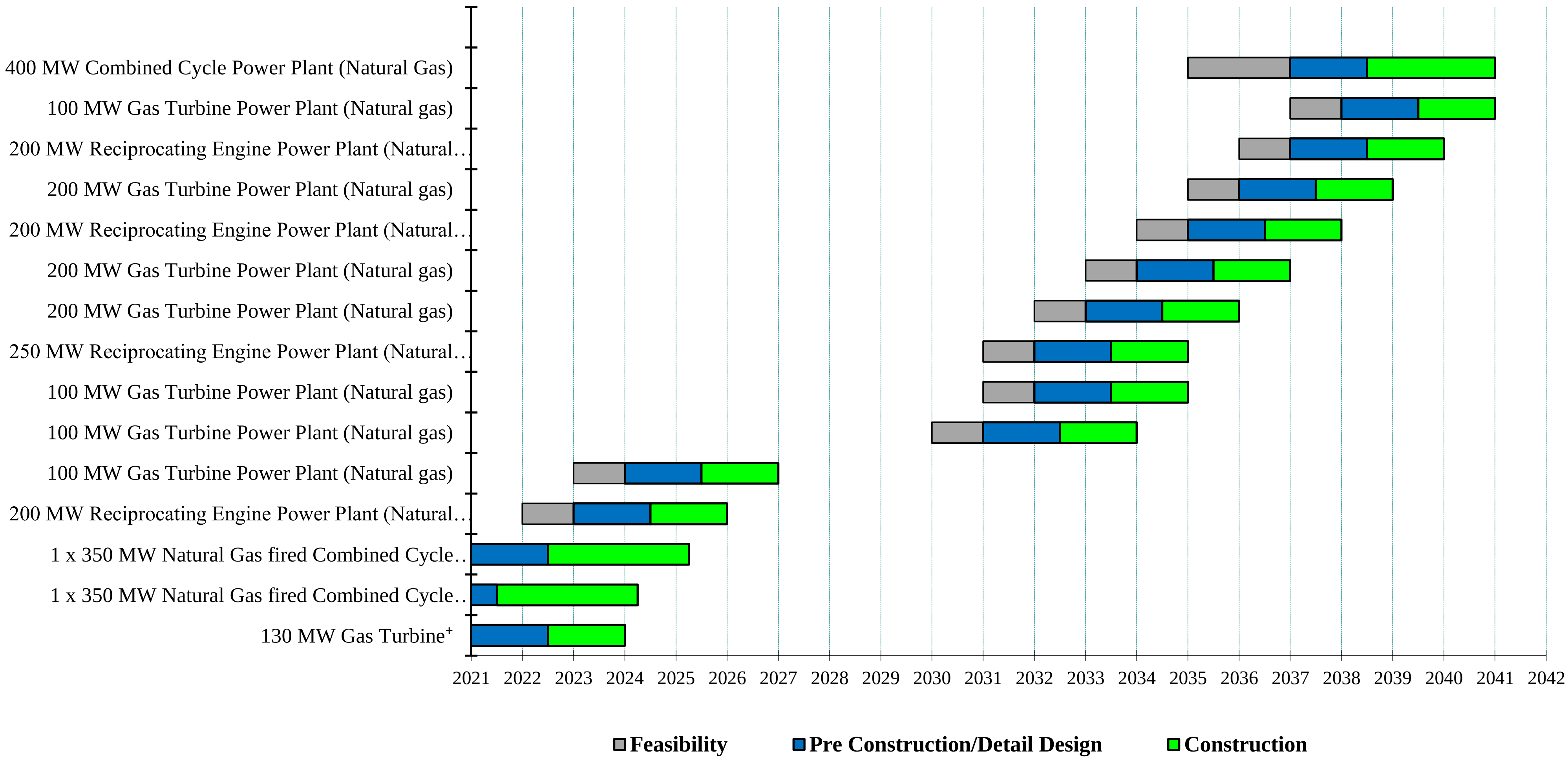
The implementation of power projects consists of three phases; feasibility, pre-construction and construction phase. Some sub activities during these phases include land identification and allocation, obtaining environmental approvals, procurement procedures and securing of funding and finances. In order to implement a project on time, it is necessary to have support from all relevant government institutions and other involved public stakeholders.

It is mandatory to have critical transmission infrastructure identified for each project to be implemented in parallel, to ensure evacuation of power from the power plant and reliability during operation and maintenance. The implementation schedule for committed and proposed major thermal power plants in the Base Case 2023-2042 are shown in Figure 13.1. The implementation schedule for committed and proposed major renewable energy and storage projects in the Base Case 2023-2042 are shown in and Figure 13.2.

Considering the long list of other renewable energy including many small scale development, following project categories are not included in the Figure 13.2.

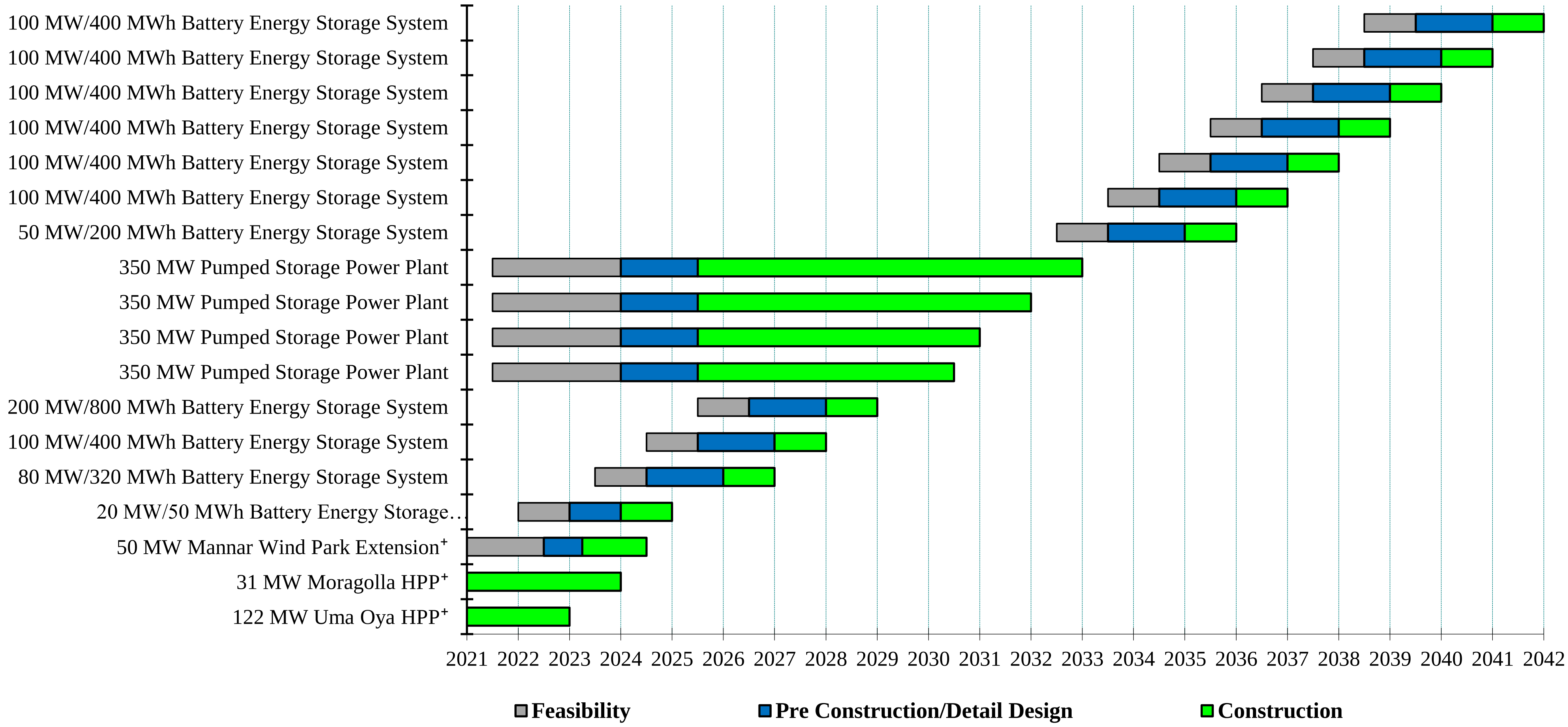
- Distribution Connected Embedded Solar
- Grid Connected Partially Facilitated Solar
- Grid Connected Fully Facilitated Solar (With Battery Energy Storage)
- Wind Parks
- Mini hydro
- Biomass

A Renewable Energy Development Master Action Plan (REDMAP) is being prepared by CEB in collaboration with SEA in order to identify the activity plan and corresponding responsible agencies to make the renewable energy development realizable.



+ Committed Plants

Figure 13.1 - Implementation Plan of Thermal Power Projects 2023-2042



+ Committed Plants

Figure 13.2 - Implementation Plan of Major Renewable Energy and Storage Projects 2023-2042

Note: Only standalone BESS are shown here. The remaining BESS capacity will be implemented coupled with large scale solar parks as identified in the Base Case plan.

13.4 Investment Plan for Base Case 2023-2042 and Financial Options

13.4.1 Investment Plan for Base Case Plan 2023-2042

Annual investment requirement for the Base Case Plan 2023-2042 is graphically shown in Figure 13.3. The cost details of the investment plan for major hydro & thermal power projects and major wind, solar and BESS developments are given in Annex 13.1 and 13.2 respectively. Tabulated annual investment costs include only the plant-by-plant pure construction cost and excludes the construction cost for associated other infrastructures (eg: coal jetty, LNG terminal & pipelines, etc.). Figure 13.4 shows the technology-wise investment cost breakdown.

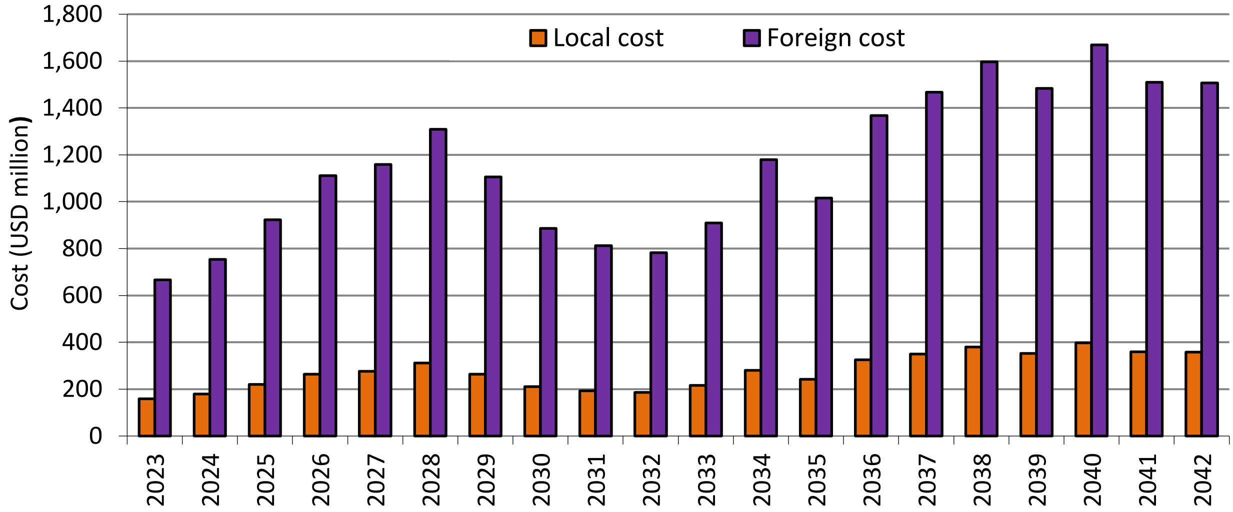


Figure 13.3 - Investment Plan for Base Case 2023 – 2042

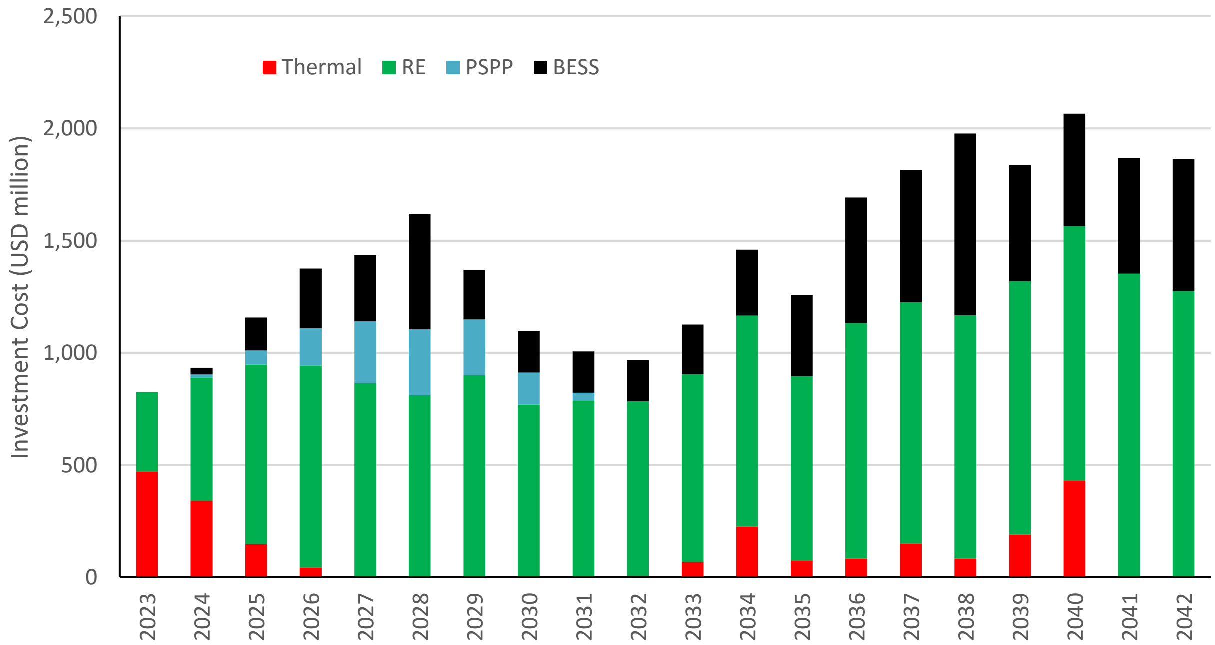


Figure 13.4 – Technology Wise Investment Plan for Base Case 2023 –2042

13.4.2 Financial Options

Timely investment on the power generation projects is highly important to be in line with the commissioning years of the planned power plant developments, although this may be challenging due to the economic situation of the country at present.

Capital investment required for the new power generation facilities could be considered in the form of GOSL/CEB funds, Private funds (such as Independent Power Producers - IPP and Joint Ventures - JV) and Public and Private Partnerships (PPP). The funding could be obtained through sources such as Official Development Assistance (ODA), Export credit, Local Commercial Loans, Concessionary loans, issuance of Green Bonds, Grants by other countries and Government to Government facilities.

The financial terms such as interest rate, commitment fee, exposure fee, grace period and loan repayment period of these funding options would be determined based on,

- Financial performance of the country
- Financial performance of the utility
- Granting of government guarantee
- Credit risk ratings
- Government to Government Concessions, etc.

Most favourable scheme out of above funding options should be selected based on the financial evaluation.

Financial evaluation aims at evaluating the return on investment from a viewpoint of an implementing agency. Financial evaluation of individual projects shall be performed considering financial indicators, which determine the viability of individual project. The financial indicators include,

- Internal Rate of Return (IRR)
- Financial Internal Rate of Return (FIRR)
- Return on Equity (RoE)
- Weighted Average Cost of Capital (WACC)
- Levelised Cost of Energy (LCOE)

IRR & FIRR should be compared with prevailing financial market rates in order to evaluate the viability of the project. RoE is an indicator of the equity providers' expectation on return.

The WACC is an estimation of the expected costs of a projects' all financing sources. This indicates the rate that a project/company is expected to pay on average to all its capital sources including required rate of return demanded by equity holders (cost of equity financing) and debt obligations (cost of debt financing).

LCOE is a useful indicator to determine whether to invest for a power generation project. This will vary depending on the type of project and it is usually taken as a representation for the average price that the generating asset must receive in a market to break even over its lifetime.

CHAPTER 14
CONTINGENCY ANALYSIS

This chapter analyses the impact of both controllable and uncontrollable risk events, which could lead to inadequacy of supply to meet the capacity and energy demand in the immediate future years from 2023 to 2027 in the Base Case. The Contingency Analysis focuses on identifying the main risk events, which are given below:

1. Variation in hydrology
2. Variation in demand
3. Delays in implementation of power plants
4. Long outage period of a major power plant
5. Restriction of fuel supply

14.1 Risk Events

14.1.1 Variation in Hydrology

Hydrology is one of the significant risk events that could lead to energy supply shortage. Table 14.1 depicts the annual expected energy output of hydro system for the five hydro conditions, availability of adequate capacity and energy supply to meet the demand in the driest hydrological condition is important.

Table 14.1 – Expected Annual Major Hydro Energy Output range of Five Hydro Conditions

Hydro Condition	Expected Annual Energy (GWh)
Very dry	3,100- 3,700
Dry	3,700- 4,400
Average	4,400-5,000
Wet	5,000-5,500
Very wet	5,500-6,000

14.1.2 Variation in Demand

Variation in demand from the base demand projection is considered as an uncertainty. Difference of annual energy and peak demand from 2023 to 2027, for both high demand and low demand scenarios compared to the base demand forecast is shown in figure 14.1 and figure 14.2. Assessment of the adequacy of capacity and energy supply to cater the high demand scenario is an important consideration.

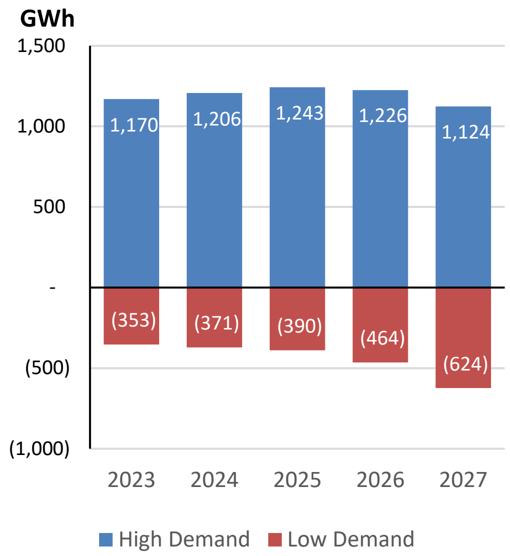


Figure 14.1 –Annual energy demand differences of high and low demand projections relative to base demand forecast

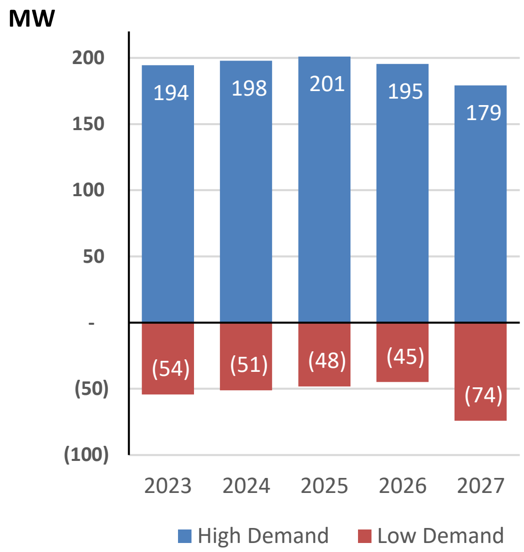


Figure 14.2 –Annual Peak demand differences of high and low demand projections relative to base demand forecast

14.1.3 Delays in Implementing Power Plants

Timely implementation of committed power plants on schedule is critical to avoid capacity and energy shortfalls in short term. However, unexpected deviations can occur in power project implementation phase and the consequences of such implementation delays on the capacity and energy requirement is considered in this analysis. Possibility of a one year delay is considered for each major pipeline project under seven different implementation delay cases. Major thermal power projects, renewable power projects and storage power projects are considerd with one year implementation delay for evaluation of contingencies. The implementation delay cases as depicted in table 14.2 are evaluated to capture most probabiistic implementation delayes in future.

As described in chapter 6, the retirement year of the 4 x 17 MW Kelanitissa Gas Turbines, is to be considered with the actual implementation of Kelanithissa New Gas Turbines. Hence during the contingency analysis it is assumed the 4 x 17 MW Kelanitissa Gas Turbines are available until the New Gas Turbines are commissioned at the Kelanithissa power station.

Table 14.2 – Implementation Delay Cases for Major Pipeline Projects

Delay Case	Major Pipeline Project							
	130 MW New GT	GT of 1st 350 MW NG CCY	(GT+ST) of 1st 350 MW NG CCY	GT of 2nd 350 MW NG CCY	(GT+ST) of 2nd 350 MW NG CCY	Gas Enigine 200 MW	Solar 260 MW & BESS 100 MW	Wind 200 MW
Base Case	**2024**	**2023**	**2024**	**2024**	**2025**	**2026**	**2025**	**2025**
Case 1	2025	2023	2024	2024	2025	2026	2025	2025
Case 2	2024	2024	2025	2024	2025	2026	2025	2025
Case 3	2024	2024	2025	2025	2026	2026	2025	2025
Case 4	2025	2024	2025	2025	2026	2026	2025	2025
Case 5	2024	2023	2024	2025	2026	2027	2025	2025
Case 6	2024	2023	2024	2024	2025	2026	2026	2026
Case 7	2025	2024	2025	2025	2026	2027	2026	2026

14.1.4 Long Period Outage of a Major Power Plant

Outage of a major power plant for a prolonged time period during dry season is also considered as a major risk event. For the contingency analysis, outage of one unit of Lakvijaya Coal Power Plant during the dry season in first four months from January to April was considered. Details of this risk event is given in Table 14.3.

Table 14.3 – Details of Risk Event Outage of a Major Power Plant

Risk Event	One unit outage of Lakvijaya coal power plant
Period	Four months (January – April) in each year
Loss of Capacity	275 MW
Loss of Energy	560 GWh per year

14.1.5 Restriction of fuel supply

There has been an increased risk of supply of fuel to major thermal power plants in the recent past due to the prevaling foreign currency shoratge. Considering any disruptions that could affect supply chains, the worst case scenario of restriction of fuel to all oil, gas and coal plants are considered for contingncy analysis.

For contingency analysis, limits were imposed on the amount of fuel that can be supplied for the operation of thermal power plants as given in Table 14.4. For evaluation of contingencies, two cases were evaluated considering restriction of the supply of oil and gas only and restriction of the supply of oil, gas and coal.

Case 1: Restriction on oil and gas, responsding to simultaenous occurance of evetns 1,2 and 3 in the Table 14.4.

Case 2: Restriction on all fuels of oil, gas and coal responding to simultaenous occurance of events of 1,2,3 and 4 in the Table 14.4.

Table 14.4 – Details of Risk Event Restriction of fuel supply

Event	Fuel	Fuel Supply Limit
1	Fuel Supply limit (Diesel)	280 Barrels per month (20% Reduction)
2	Fuel Supply limit (Furnace Oil)	125 Barrels per month (20% Reduction)
3	Fuel Supply limit (Natural Gas)	0.4 Million tons per year (20% Reduction)
4	Fuel Supply limit (Coal)	2.25 Million tons per year (10% Reduction)

During contingency analysis related to restriction of fuel supply, it has been assumed that KCCP shall also operate from Diesel.

14.2 Evaluation of Contingencies

In this contingeny analysis, initially the single occurrence of above mentioned five risk events were considered at first and thereafter, simultatious occurrence of several events were analysed to identify the short term energy and capacity shortage. The capacity requirement identified in this contingency analysis is in addtion to the short term supplementary power capacity identified in the Base Case plan shown in Table 8.1 of Chapter 8.

The firm capacity during the critical period of each year in the Base Case as shown in the table 14.5 is taken as the reference for the contingency events. Critical period is the period where the difference between peak demand and the firm capacity becomes minimum.

Table 14.5 –Firm Capacities in Critical Period as in the Base Case

Firm Capacity	2023	2024	2025	2026	2027
Major Hydro Capacity (MW)	888	906	906	906	906
Thermal Capacity (MW)	1,846	2,143	2,255	2,498	2,605
Supplementary Power (MW)	320	120	120	0	0
ORE with Storage (MW)	49	53	73	159	309
Total Firm Capacity (Critical Period)	**3,103**	**3,222**	**3,354**	**3,563**	**3,820**
Peak Demand (Critical Period)	**3,021**	**3,149**	**3,283**	**3,422**	**3,641**

Capacity deficit risk is the inability of firm capacity to meet the peak demand in the critical period with minimum reliability requirement. The Energy Deficit risk is the possibilty that the avaible plants will not be able to provide the total energy requirement.

14.2.1 Single Occurrence of Risk Events

The five risk events have potential to cause inadequate supply capability of the system. Though the variation of hydrology is significant, since capacity expansion is optimized considering the driest hydro contition, impact of the hydrology variation is already taken in to account in preparation of the Base Case. Secondly, the variation in demand is also performed as a sensitivity (under Chapter 8). Thirdly, the event of power plant implementation delays has a major impact on the Base Case and likelihood of occuring implementation delay risk event is also high. Table 14.7 shows the capacity deficit observed under implementation delay cases as well as the risk of energy deficit due to the delayed power projects that are planned in the Base Case. The outage of a largest unit during critical periods can further aggravate the situation. The restriction of fuel supply during the crtitical months of the year is the most severe risk event which poses substantial energy deficit risks.

The base case has already identified the short term capacity requirement of 320 MW for year 2023 and 120 MW for the years 2024 and 2025 under the driest hydro condition. The summary of impact of other single occurance of risk events is shown in Table 14.6 below.

Table 14.6 – Impact of Single Occurrence of Risk Events

	Risk Event	Capacity Deficit Risk	Energy Deficit Risk	Remarks
1	Dry Hydro Condition	No	Low	No capacity deficit with the planned capacity addition of the Base Case. Energy requirement in the very dry hydro condition can be catered with the planned capacities in the Base Case (Table 8.1 of Chapter 8)
2	High Demand	High	Low	Additional capacity in the range of 40 MW - 200 MW is required within first five years to maintain the minimum reliability requirment in case of high demand (Annex 8.5)
3	Plant Implementation Delay	High	Low	Refer Table 14.7
4	Outage of a Major Power Plant	High	Low	Outage of largest unit can lead to capacity deficit in the driest month of each year during period of 2023 to 2027. The capacity identified in the Base Case plan is adequate to resolve occurance of any severe energy deficit.
5	Restriction of fuel supply	High	High	Restriction of fuel supply poses a severe risk of energy deficit mainly during the months from February to May. The monthly energy deficit in Case 1 (restriction of oil and gas supply), can reach upto 15% of monthly energy demand. This can further aggrevate upto 30% in Case 2 (restriction of oil, gas and coal supply)

The detailed Energy Deficit Risk in monthly resolution is presented in Annex 14.1 It should be noted that majoirty of the risk occurs during the months from February to April of the year, and appropriate early action should be taken by considering these patterns.

Table 14.7 –Additional short term capacity requirement and the risk of energy deficit under implementation delay cases compared to the Base Case

Delay Case (as in Table 14.2)		2023	2024	2025	2026
Base Case	Capacity Deficit [Energy Deficit Risk]	N/A	N/A	N/A	N/A
Case 1	Capacity Deficit [Energy Deficit Risk]	N/A	61 MW [Low]	N/A	N/A
Case 2	Capacity Deficit [Energy Deficit Risk]	-	234 MW [Low]	-	N/A
Case 3	Capacity Deficit [Energy Deficit Risk]	-	234 MW [Low]	-	N/A
Case 4	Capacity Deficit [Energy Deficit Risk]	-	296 MW [Low]	-	N/A
Case 5	Capacity Deficit [Energy Deficit Risk]	N/A	N/A	N/A	143 MW [Low]
Case 6	Capacity Deficit [Energy Deficit Risk]	N/A	N/A	-	16 MW [Low]
Case 7	Capacity Deficit [Energy Deficit Risk]	-	296 MW [Low]	-	224 MW [Low]

14.2.2 Simultaneous Occurrence of Several Risk Events

Several contingency events are analysed to identify the severity of simultanious occurance of these events for period from 2023 to 2026 and mitigation measures are suggested where necessary. (Contingency events for year 2027 are not indicated as occurance of delay events in year 2027 has not been considered).

a) Contingency Event 1 - Dry Hydro Condition and Delays in Power Plant Implementation

The both events of worst hydro condition and the power plant implementation delays were taken as the first contingency event. The parameter variations given in section 14.1.1 and 14.1.3 were taken as the basis for the analysis. In terms of mitigating this risk, possibility of providing the energy deficit from avalilable power plants was studied relative to the Base case. The additional capacity deficit and the risk of energy deficit compared to the Base case is indicated in the Table 14.8 below.

Table 14.8 – Assessment of the additional capacity deficit and the risk of energy deficit compared to the Base Case due to Contingency Event 1

	2023	2024	2025	2026
Risk 1: Dry Hydro Condition				
Risk 3: Delay in Plant Implementation (Delay Case 7 in Table 14.2)				
Capacity Deficit [Energy Deficit Risk]	- [Low]	296 MW [Low]	- [Low]	224 MW [Low]

This contingency event has a very large impact on the adequate supply capacity of the system. Likelihood of occurring this contingency event is high. Additional capacity is required to meet the electricity demand adequately while maintaining the minimum relaibility level. Therefore, timely implementation of the pipeline major projects is crucial to avoid additional capacity and energy deficit.

b) Contingency Event 2 - Dry Hydro Condition, Delays in Power Plant Implementation and Outage of one Unit of Lakvijaya Coal Power Plant

An adverse contingency event with the loss of one unit of Lakvijaya Coal Power Plant simultaniously with other two risk events of section (a) above is considered for the analysis. The unit outage is assumed to occur in the dry season during first four months of the year. It is observed that both energy and capacity deficit can occur for a short period under this contingency event. The capacity deficit and the risk of energy deficit compared to the Base case is indicated in the Table 14.9 below.

Table 14.9 – Assessment of the additional-capacity deficit and the risk of energy deficit compared to the Base Case under Contingency Event 2

	2023	2024	2025	2026
Risk 1: Dry Hydro Condition				
Risk 3: Delay in Plant Implementation (Delay Case 7 in Table 14.2)				
Risk 4: Major Unit Outage (Outage of one unit of Lakvijaya Power Plant in Jan- April)				
Capacity Deficit [Energy Deficit Risk]	265 MW [Low]	566 MW [Low]	270 MW [Low]	460 MW [Low]

c) **Contingency Event 3 – Dry Hydro Condition, Delays in Power Plant Implementaion and Restricted Fuel Supply**

The events of dry hydro condition, power plant implementation delays and restriction of fuel supply were taken as the third contingency event. This is an adverse contingency event, that has a likelihood of occuring conisdering the current economic crisis of the country. Only the major implementation delay cases have been conisdered for analysis, and fuel supply restriction is conisdered only for oil and gas based power plants.

The capacity deficit and the risk of energy deficit of contingency event 3 compared to the Base case is indicated in the Table 14.10 below.

Table 14.10– Assessment of the additional-capacity deficit and the risk of energy deficit compared to the Base Case under Contingency event 3

	2023	**2024**	**2025**	**2026**
Risk 1: Dry Hydro Condition				
Risk 3: Delay in Plant Implementation (Delay Case 7 in Table 14.2)				
Risk 5: Restricted Fuel Supply (Case 1 – Restriction on oil and gas)				
Capacity Deficit* [Energy Deficit Risk]	- [High]	296 MW [High]	- [High]	224 MW [High]

*****_Capacity Deficit Risk will be even higher due to fuel shortage as it cannot be precisely quantified._

d) **Contingency Event 4 - High Demand, Dry Hydro Condition, Delays in Power Plant Implementaion and Restricted Fuel Supply**

The risk event considers the possibility of a demand increase beyond the base demand projection under worst hydro condition with delays in power plant implementation and fuel supply been restricted. The demand increase beyond the base demand projection has a relatively low likelihood due to the unexpected economic situation of the country but the level of uncertainty related to the demand is very high. The capacity deficit and the risk of energy deficit compared to the Base case is indicated in the Table 14.11 below.

Table 14.11– Assessment of the additional-capacity deficit and the risk of energy deficit compared to the Base Case under Contingency event 4

	2023	**2024**	**2025**	**2026**
Risk 1: Dry Hydro Condition				
Risk 2: High Demand				
Risk 3: Delay in Plant Implementation (Delay Case 7 in Table 14.2)				
Risk 5: Restricted Fuel Supply (Case 1 – Restriction on oil and gas)				
Capacity Deficit* [Energy Deficit Risk]	196 MW [High]	505 MW [High]	136 MW [High]	435 MW [High]

*****_Capacity Deficit Risk will be even higher due to fuel shortage as it cannot be precisely quantified._

14.3 Conclusion

(1) The individual risk events have varying impacts on the Base Case. The driest hydrology condition has already been captured in the preparation of the Base Case in the planning studies. The variation in demand is also performed as a sensitivity (presented in Chapter 8). The possibility of demand increase beyond the base demand projection is relatively low due to the present economic situation of the country, but the level of uncertainty related to the demand is very high. Thirdly, the power plant implemnetation delays pose major risk and likelihood of occuring is high. Outage of a largest unit during critical periods of the year can further aggravate this situation. The restriction of fuel supply during the crtitical months of the year is the most severe risk event which poses significant energy deficit risks and should be avoided.

(2) In the case of simultaneous occurrence of contingency events, the likelihood of contingency event 1 (dry hydro condition and delays in power plant implementation) is high. Implementation delays in the planned 130 MW Gas Turbines, Natural gas Combined Cycle Plants at Kerawalapitiya (2 x 350 MW), 200 MW Gas Engines and large scale renewable projects with storage can lead to capacity and energy deficit durung 2023 to 2026 period.

(3) The likelihood of contingency event 2 (dry hydro condition, delays in power plant implementation and outage of one unit of Lakvijaya Coal plant) is moderate but the impact can be very high if a major unit outage takes place during the driest period when the project implementation is delayed. Therefore, it is important to ensure the timely implementation of the planned projects as well as the availability of the major thermal power plants in operation.

(4) The likelihood of contingency event 3 (dry hydro condition, delays in power plant implementation and restricted fuel supply) is moderate but the impact can be severe if fuel supply restrictions takes place during the driest period when the planned project implementation is delayed. Therefore, it is important to ensure the availability of fuel as well as timely implementtaion of the planned projects.

(5) The likelihood of contingency event 4 (dry hydro condition, high demand, delays in power plant implementation and restricted fuel supply) is relatively low as demand increase beyond the base demand projection in the initial years is low. But in the event of demand increase takes place while power plant implementation delays and fuel shortages are present, severe capacity and energy deficits can be experienced during 2023 to 2026 period.

(6) Implementation delays of only major renewable energy projects have been considered in this contingency analysis. However, delays in implementation of smaller scale renewable projects would further aggravate the situation. it is important to monitor and ensure the timely implementation of all large scale and small-scale renewable energy projects to obtain the expected energy contribution.

(7) The short term capacity deficits identified in the tables 14.8, 14.9, 14.10 and 14.11 are based on inputs used for the planning studies and the exact capacity requirement and the period shall be determined at the time of procurement of such capacity, through detailed short term analysis, taking into consideration the prevailing system situation at that time.

(8) The possibility of utilizing the available generating capacities with lapsed contracts as well as other short term alternatives shall be considered as appropriately to meet short term requirement in most economically advantageous terms within the legal framework of the country.

(9) It is recommended to fast track the procurement and commissioning of Grid connected partially facilitated solar capacity of 147 MW and 223 MW (planned for 2023, 2024 respectively) in which grid capacity is already available, to reduce any energy shortage risk from contingency events. In addition, fast track procurement and commissioning of Mannar Stage II (100 MW) park with semi dispatchable capability at an earlier year can reduce the energy shortage risk for all contingencies.

(10) The impact of the above contingency events on the cost of generation as well as on the economy as a whole is high because short term capacity deficits are avoided using short term alternatives, that are expensive. Therefore, it is a nationally important task to implement the planned pipeline projects as well as the planned transmission development on time to ensure reliable and economic supply of electricity.

CHAPTER 15
REVISIONS TO PREVIOUS PLAN

This chapter examines the deviations of the results of the present study (LTGEP 2023-2042) from that of the previous generation expansion plan (LTGEP 2022-2041), and analyses the factors for such deviations.

This chapter focuses on the main differences from the previous plan under following areas.

- Government Policies
- Base Demand Forecast
- Fuel price variations
- Higher capacity integration of Other Renewable Energy (ORE) based on the results of the study "Integration of Renewable Based Generation in to Sri Lankan Grid 2023-2032"
- Introduction of relatively large capacity of Battery Storage as an Energy Storage System
- Capacity share and Energy share
- Environmental emissions

15.1 Government Policies

The General Policy Guidelines on the Electricity Industry initially issued in 2009 was replaced with the Policy Guidelines issued in April 2019. Another new General Policy Guideline was issued in January 2022, repealing the previous guidelines. This latest "General Policy Guidelines on the Electricity Industry 2021" has to be read together with the "National Energy Policies and Strategies of Sri Lanka", published in 2019.

The policy aims to achieve 70% of electricity generation by 2030 from renewable sources and carbon neutrality in power generation by 2050.

15.2 Demand Forecast

As depicted in the demand forecast study done for LTGEP 2023-2042, the night peak, day peak and off peak shows an increasing trend but in particular, the growth of the day peak was higher than the growth of night peak. It is estimated that the day peak would surpass night peak in 2026. The shape of the daily load profile also undergoes gradual changes.

Base Demand Forecast of LTGEP is a combination of Time Trend modelling and Econometric approach as described in Chapter 3. Twenty five year average growth rates of Energy demand and Peak demand forecasts done for LTGEP 2023-2042 are respectively 5.0% and 4.9% (similar to the growth rates in LTGEP 2022-2041). Figure 15.1 & 15.2 shows the Energy demand and Peak forecast comparison of two LTGEPs.

As illustrated in figure 15.1 & 15.2, both the annual energy demand and annual peak demand of LTGEP 2023-2042 are slightly lower than the LTGEP 2022-2041 in initial years, and this gap is maintained throughout the horizon.

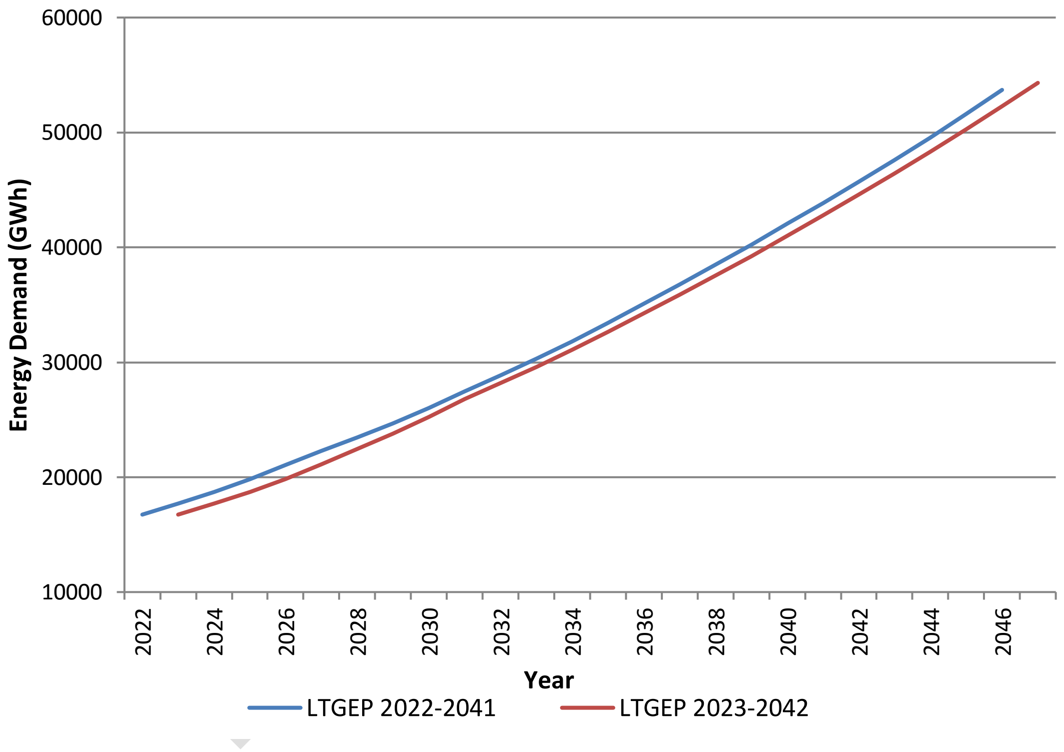


Figure 15.1 - Comparison of Energy Demand Forecasts used in LTGEP 2022-2041 and LTGEP 2023-2042

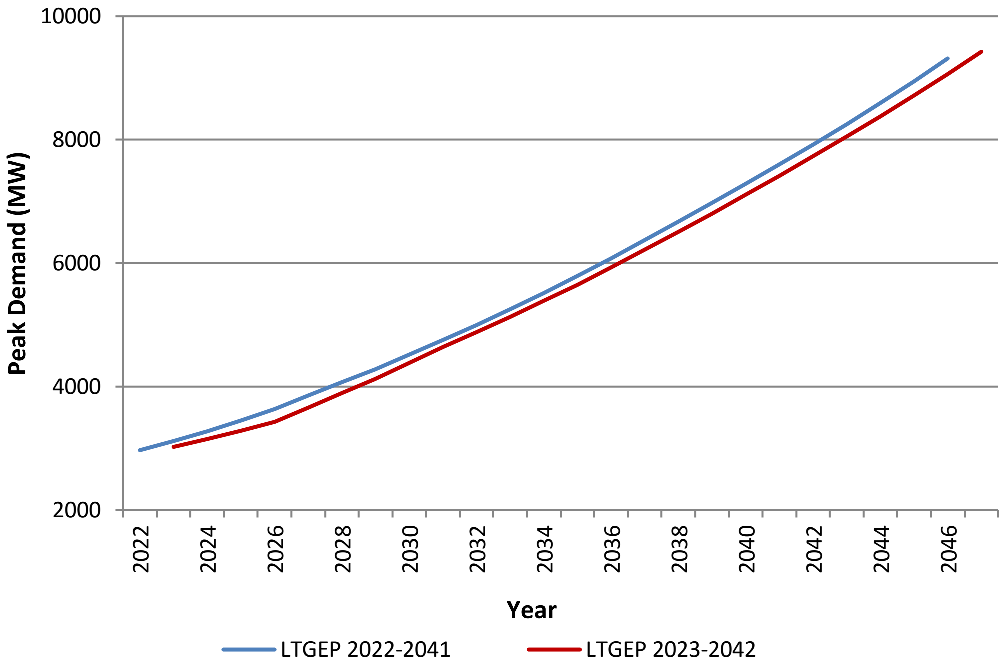


Figure 15.2 - Comparison of Peak Demand Forecasts used in LTGEP 2022-2041 and LTGEP 2023-2042

15.3 Fuel Prices used for Planning Studies

A fixed fuel price is considered throughout the planning horizon. Fuel Prices of Coal, Natural Gas and Oil for the present study (LTGEP 2023-2042) were based on the weighted average of last three-year prices and future three-year projections done by the World Bank. All fuel prices are considered in economic terms (as the price delivered at the power plant exclusive of tax). A comparison of fuel prices used in the LTGEP 2023-2042 and LTGEP 2022-2041 are shown in Figure 15.3.

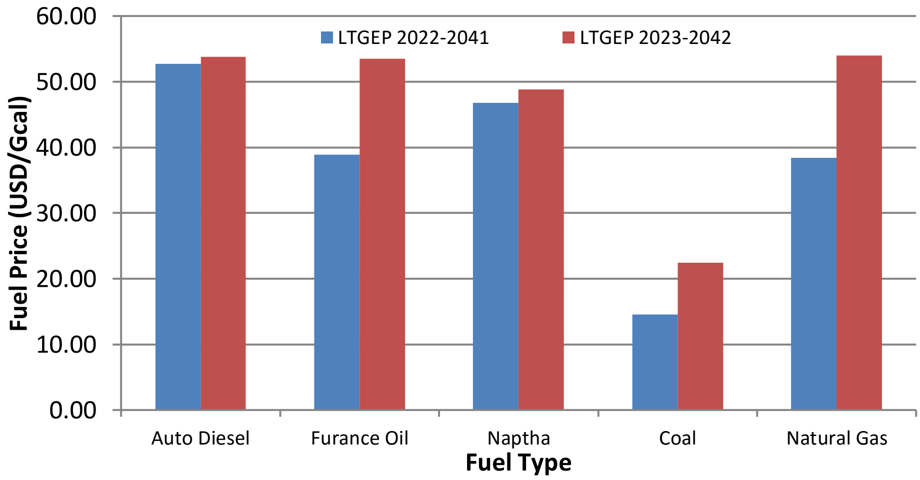


Figure 15.3 – Fuel prices used for LTGEP 2022-2041 and LTGEP 2023-2042

15.4 Integration of Other Renewable Energy Sources

Figure 15.4 shows a comparison of Other Renewable Energy (ORE) capacity contribution in the years of 2025, 2030 and 2035 with respect to LTGEP 2022-2041 and the LTGEP 2023-2042 by different sources. The total ORE capacity increases to 11,962 MW by 2041 in LTGEP 2023-2042 which is 49% higher than in LTGEP 2022-2041.

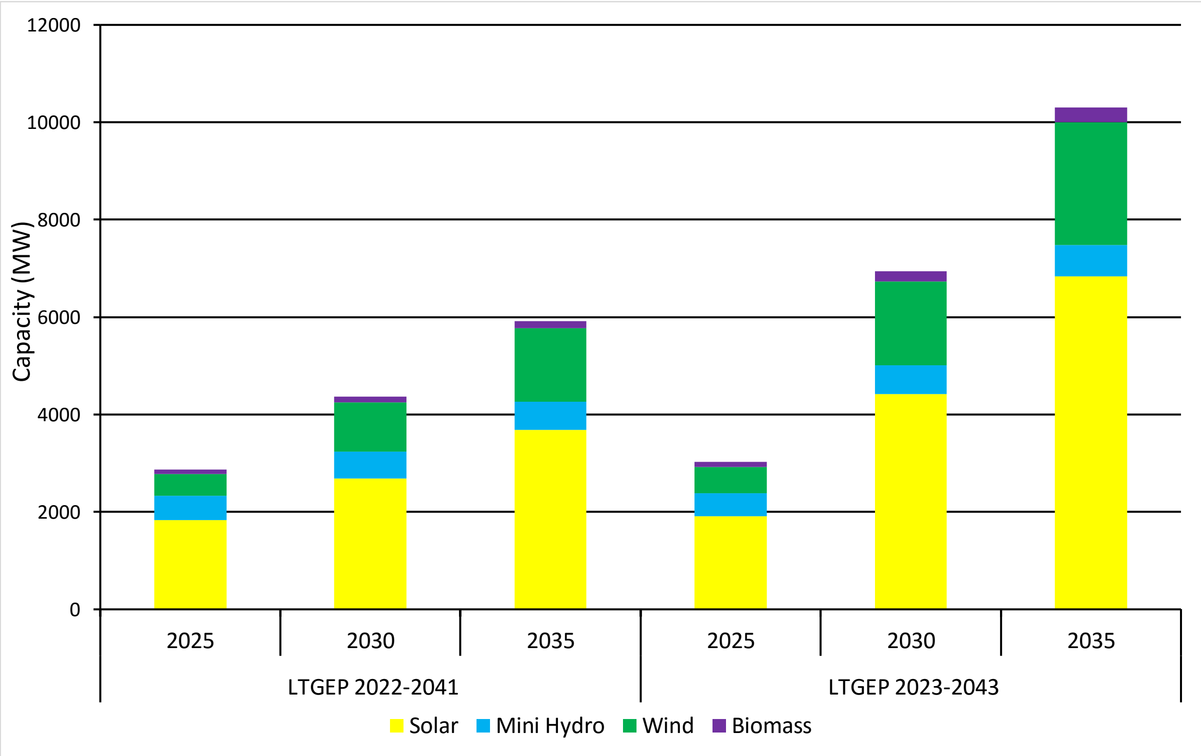


Figure 15.4 – Comparison of ORE Capacities in LTGEP 2022-2041 & LTGEP 2023-2042

15.5 Introduction of Battery Storage

Battery storage is proposed to be added to the system in phase development. A cumulative capacity of 20 MW in 2024 and 1125 MW by 2030 is expected to be incorporated to the network. Capacities beyond 2030 are to be re-evaluated in future planning cycles based on the outcome of the Renewable Energy Integration Studies as well as on the progress of the renewable energy development.

15.6 Capacity Share and Energy Share

In LTGEP 2023-2042, the capacity shares in 2030 of other renewable energy based power plants and Battery Storage have increased by 10.7 % and 7.5 % respectively compared to LTGEP 2022-2041. However, the capacity share of coal based power plants has decreased by 7.5% and that of oil based power plants remain almost same in year 2030. Capacity share of Natural Gas based power plants have dropped in the LTGEP 2023-2042 as a result of the 70% renewable generation target by 2030. A comparison of capacity shares between LTGEP 2023-2042 and LTGEP 2022-2041 is illustrated in Figure 15.5

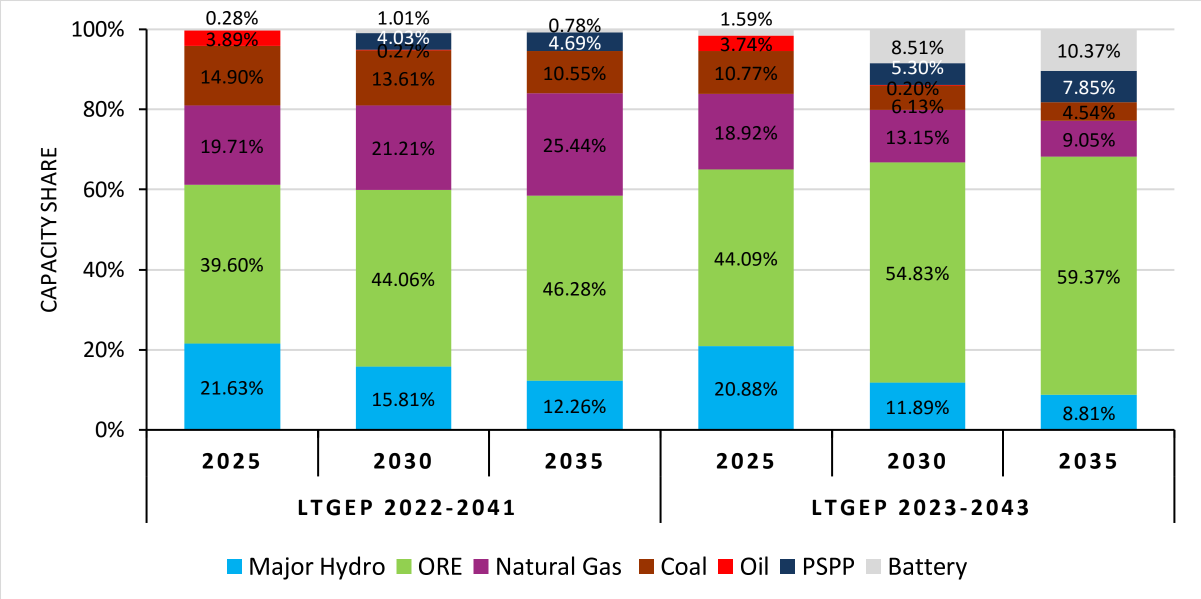


Figure 15.5 – Capacity Share Comparison between LTGEP 2022-2041 & LTGEP 2023-2042

Correspondingly in LTGEP 2023-2042, the energy share of other renewable energy based power plants in year 2030 has increased by 16.4% compared to LTGEP 2022-2041. The main decrease in energy share is from coal based power plants with a reduction of 13.4%. The energy share from natural gas based power plants shows a slight decrease while oil based power plants cease their generation by 2030. A comparison of energy shares between LTGEP 2023-2042 and LTGEP 2022-2041 is illustrated in Figure 15.6.

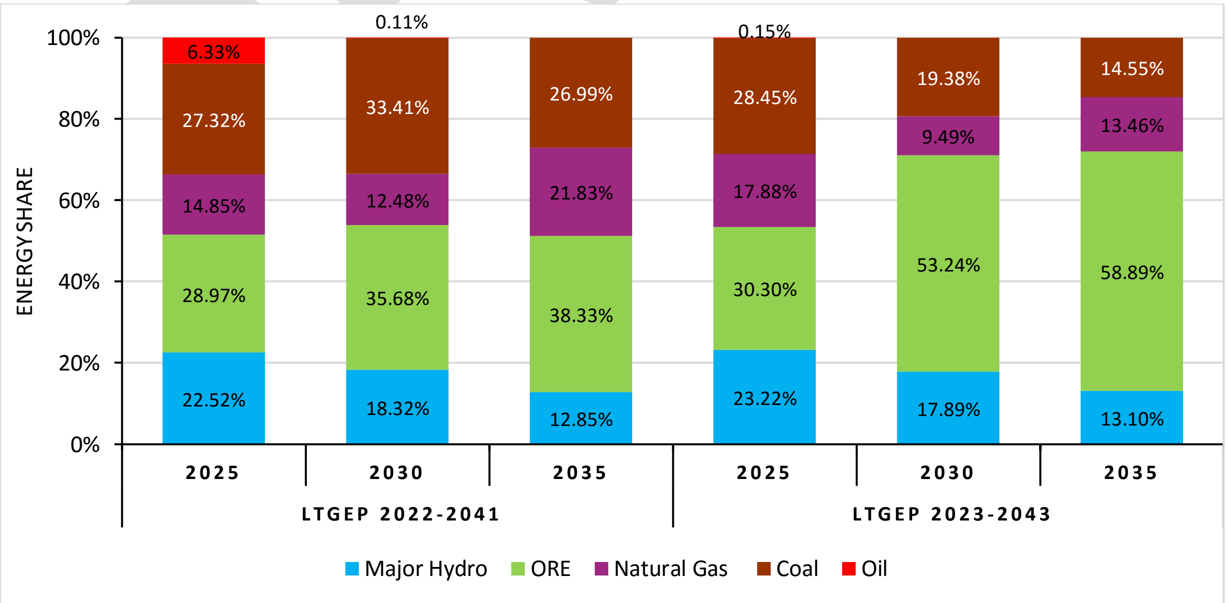


Figure 15.6 – Energy Share Comparison between LTGEP 2022-2041 & LTGEP 2023-2042

15.7 Environmental Emissions

CO_2 emissions are lower in LTGEP 2023-2042 than the CO_2 emissions level in the LTGEP 2022-2041. An increasing trend of particulate matter (PM) emissions is observed in LTGEP 2023-2042 due to the anticipated higher implementation of biomass plants. Also, SO_2 emissions have increased in the initial years, due to dependency on thermal oil plants caused by non-implementation of natural gas projects on time. However, increase of NO_x could be observed with adoption of higher share of reciprocating engines to allow operational flexibility to the system. NO_x emissions could be reduced through various mitigating technologies. Comparison of these environmental emissions are shown in Figure 15.7 and Figure 15.8.

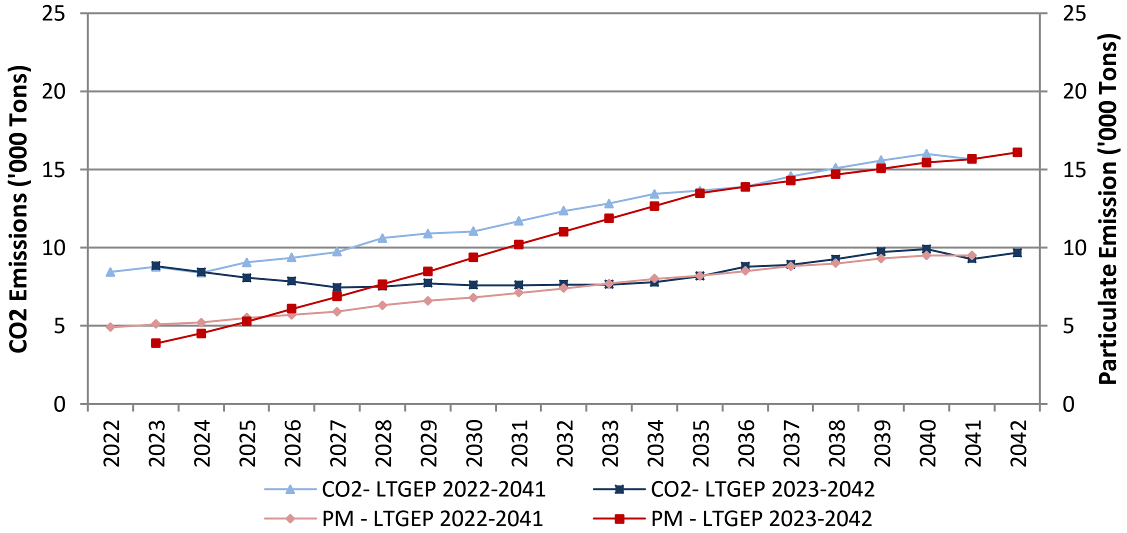


Figure 15.7 - CO_2 and PM Emissions Comparison Between LTGEP 2022-2041 & LTGEP 2023-2042

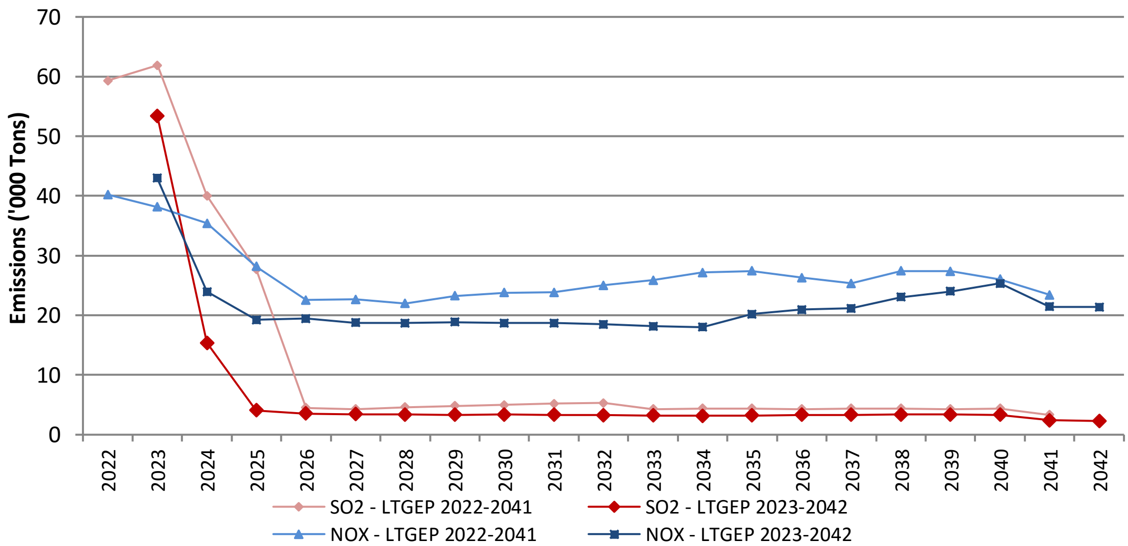


Figure 15.8 – SO_2 and NO_x Emissions Comparison Between LTGEP 2022-2041 & LTGEP 2023-2042

15.8 Overall Comparison

The overall comparison of generation expansions proposed by plans for last 20 years and actual implementation is shown in Annex 15.1

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[17] Broadlands Hydro Electric Project, Central Engineering Consultancy Bureau Communication dated 21st October 1991

[18] Pre-feasibility Study on Uma Oya Multi-purpose Project, Central Engineering Consultancy Bureau, July 1991

[19] Development Planning on Optimal Power generation for Peak Demand in Sri Lanka, Feb 2015, JICA

[20] Feasibility study for expansion of Victoria Hydro Power Station in Sri Lanka, June 2009. JICA

[21] Phase E Report-Master Plan for the Electricity Supply of Sri Lanka, July 1990.

[22] Integration of Renewable Based Generation into Sri Lankan Grid 2023-2032, CEB

[23] Grid Code, Transmission Division, Ceylon Electricity Board (October 2018)

[24] Supplementary Studies for the Feasibility Study on India-Sri Lanka Grid Interconnection Project, December 2011" by Institute of Policy Studies (IPS) in association with Resource Management Associates (RMA) & Tiruchelvam Associates (TA)

[25] Study conducted by ADB - South Asia Subregional Economic Cooperation (SASEC), 2018

[26] National Renewable Energy Laboratory, USA. Annual Technology Baseline (2022)

[27] Nationally Determined Contributions (NDC), Ministry of Mahaweli Development and Environment Sri Lanka, September 2016

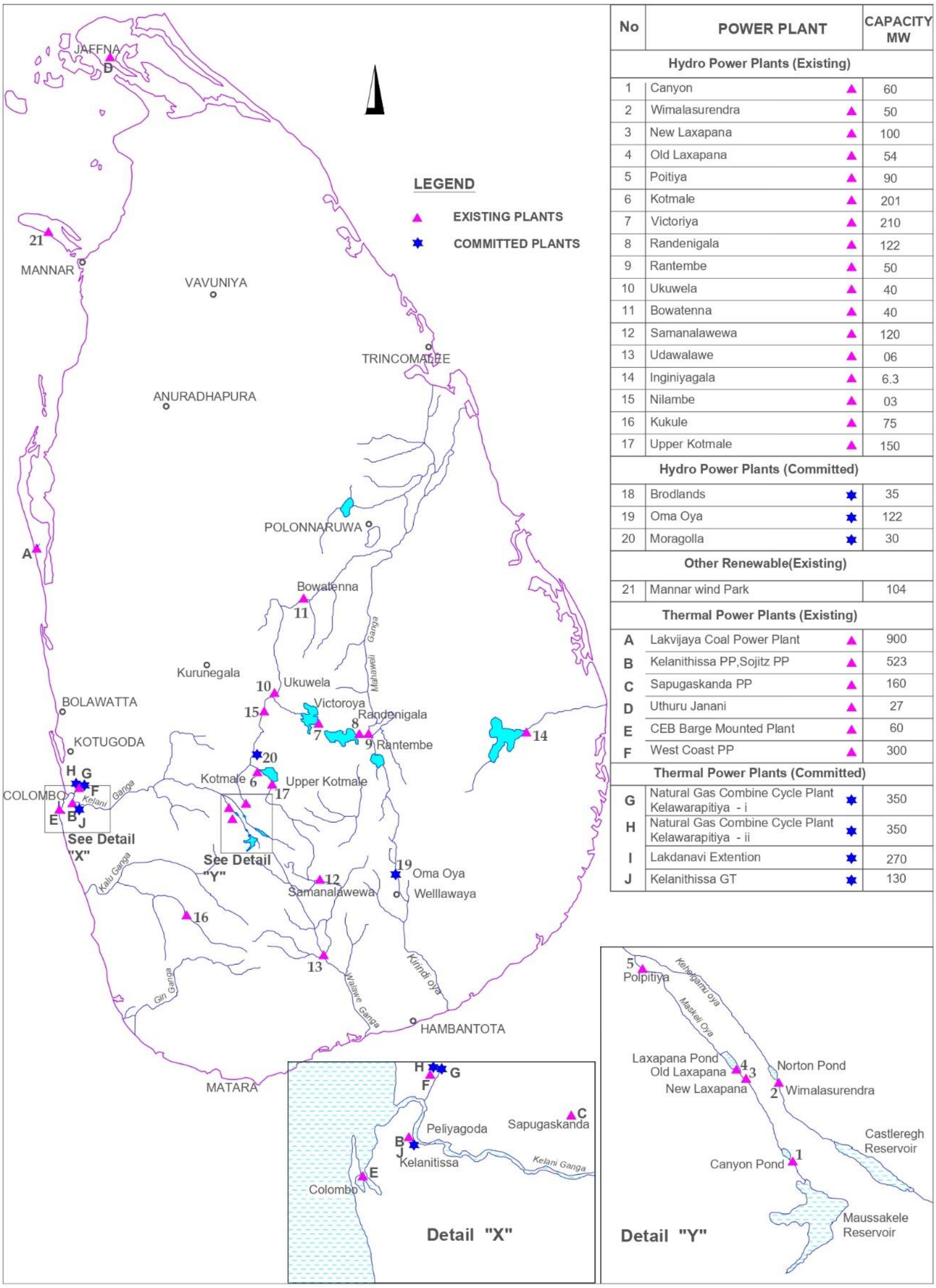
[28] Updated Nationally Determined Contributions (NDC), Ministry of Mahaweli Development and Environment Sri Lanka, September 2021

[29] The National Environmental (Ambient Air Quality) Regulations, August 2008

[30] The National Environmental (Stationary Sources Emission Control) Regulations, June 2019

Annex 2.1

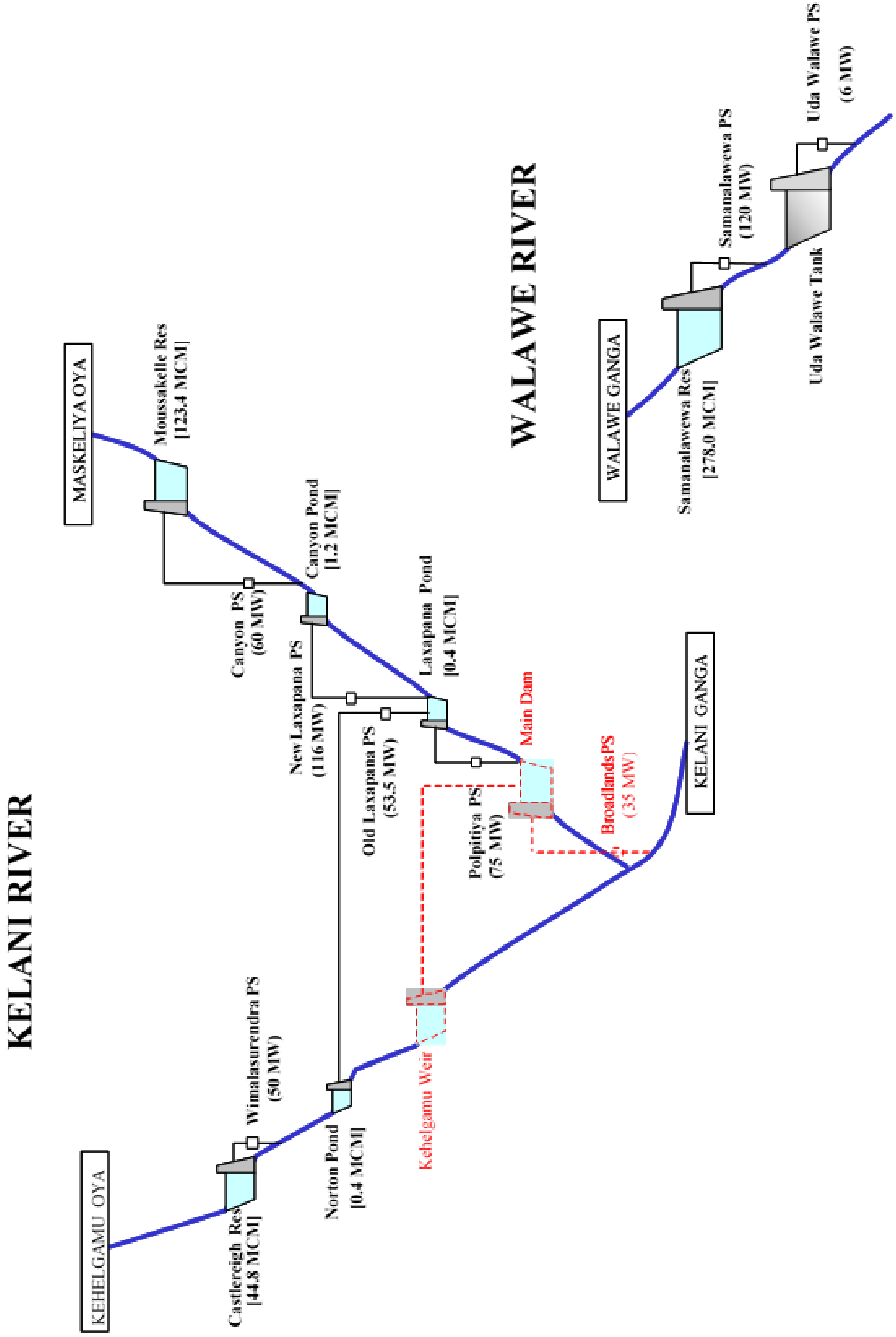
Location of Existing, Committed and Candidate Power Stations



No	POWER PLANT		CAPACITY MW
	Hydro Power Plants (Existing)		
1	Canyon	▲	60
2	Wimalasurendra	▲	50
3	New Laxapana	▲	100
4	Old Laxapana	▲	54
5	Poitiya	▲	90
6	Kotmale	▲	201
7	Victoriya	▲	210
8	Randenigala	▲	122
9	Rantembe	▲	50
10	Ukuwela	▲	40
11	Bowatenna	▲	40
12	Samanalawewa	▲	120
13	Udawalawe	▲	06
14	Inginiyagala	▲	6.3
15	Nilambe	▲	03
16	Kukule	▲	75
17	Upper Kotmale	▲	150
	Hydro Power Plants (Committed)		
18	Brodlands	✱	35
19	Oma Oya	✱	122
20	Moragolla	✱	30
	Other Renewable(Existing)		
21	Mannar wind Park		104
	Thermal Power Plants (Existing)		
A	Lakvijaya Coal Power Plant	▲	900
B	Kelanithissa PP,Sojitz PP	▲	523
C	Sapugaskanda PP	▲	160
D	Uthuru Janani	▲	27
E	CEB Barge Mounted Plant	▲	60
F	West Coast PP	▲	300
	Thermal Power Plants (Committed)		
G	Natural Gas Combine Cycle Plant Kelawarapitiya - i	✱	350
H	Natural Gas Combine Cycle Plant Kelawarapitiya - ii	✱	350
I	Lakdanavi Extention	✱	270
J	Kelanithissa GT	✱	130

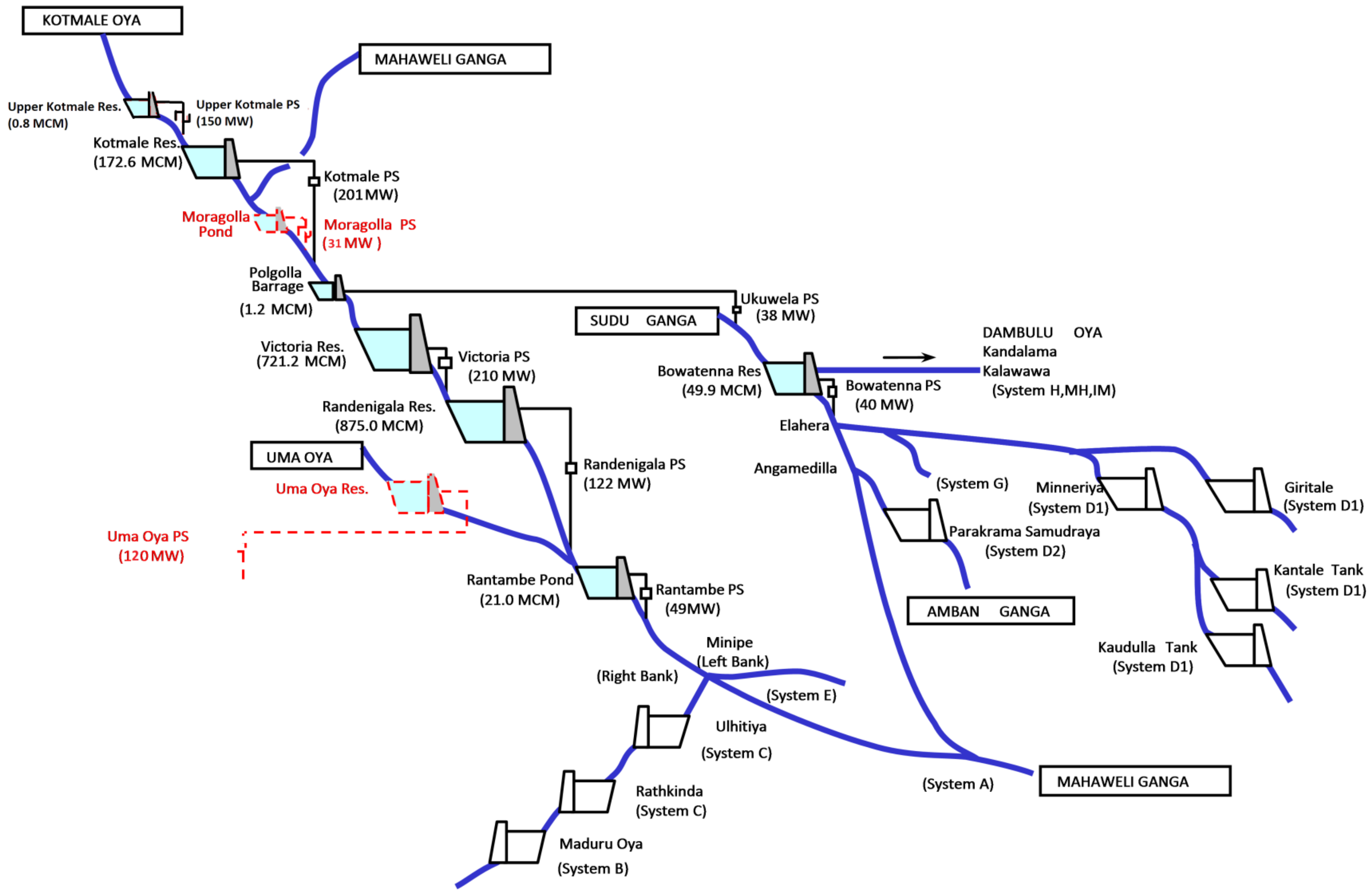
Reservoir Systems in Mahaweli, Kelani and Walawe River Basins

A2.1.1 Reservoir Systems in Kelani and Walawe River Basins



A2.1.2 Reservoir System in MahaweliRiver Basin

MAHAWELIRIVER



Annex 3.1

Scenarios and Sensitivities of the Demand Forecast

Table A3.1 – High Demand Forecast

Year	Demand (GWh)	Net Losses*(%)	Generation (GWh)	Peak (MW)
2023	17818	7.95	19356	3216
2024	18816	7.89	20428	3347
2025	19871	7.83	21560	3484
2026 **	20985	7.77	22752	3627
2027	22161	7.7	24010	3830
2028	23403	7.63	25337	4061
2029	24715	7.57	26738	4286
2030	26100	7.5	28216	4525
2031	27508	7.45	29722	4768
2032	29005	7.4	31323	5026
2033	30590	7.35	33017	5299
2034	32252	7.3	34792	5585
2035	33979	7.25	36635	5882
2036	35769	7.25	38565	6194
2037	37619	7.25	40559	6515
2038	39514	7.25	42603	6845
2039	41464	7.25	44705	7184
2040	43476	7.25	46875	7535
2041	45531	7.25	49089	7892
2042	47636	7.25	51360	8259
2043	49800	7.25	53693	8635
2044	52028	7.25	56095	9023
2045	54325	7.25	58571	9423
2046	56695	7.25	61127	9836
2047	59190	7.25	63816	10272
5 Year Average Growth	5.6%		5.5%	4.5%
10 Year Average Growth	5.6%		5.5%	5.1%
20 Year Average Growth	5.3%		5.3%	5.1%
25 Year Average Growth	5.1%		5.1%	5.0%

In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.

***Net** losses include losses at the Transmission & Distribution levels, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the renewable thermal generation mix of the future.

**It is expected that day peak would surpass the night peak from this year onwards

Table A3.2 – Low Demand Forecast

Year	Demand (GWh)	Net Losses*(%)	Generation (GWh)	Peak (MW)
2023	16416	7.95	17833	2967
2024	17363	7.89	18851	3098
2025	18366	7.83	19927	3235
2026	19426	7.77	21062	3387
2027	20548	7.7	22262	3577
2028	21734	7.63	23530	3777
2029 **	22774	7.57	24638	3951
2030	23871	7.5	25806	4133
2031	25029	7.45	27043	4334
2032	26252	7.4	28349	4545
2033	27537	7.35	29721	4767
2034	28873	7.3	31146	4997
2035	30248	7.25	32612	5234
2036	31659	7.25	34134	5480
2037	33104	7.25	35691	5732
2038	34567	7.25	37269	5988
2039	36057	7.25	38876	6248
2040	37578	7.25	40516	6514
2041	39114	7.25	42172	6782
2042	40671	7.25	43851	7054
2043	42255	7.25	45557	7331
2044	43867	7.25	47296	7612
2045	45513	7.25	49070	7900
2046	47193	7.25	50882	8194
2047	48936	7.25	52761	8498
5 Year Average Growth	5.8%		5.7%	4.8%
10 Year Average Growth	5.4%		5.3%	4.9%
20 Year Average Growth	4.9%		4.8%	4.7%
25 Year Average Growth	4.7%		4.6%	4.5%

In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.

*Net losses include losses at the Transmission & Distribution levels, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the renewable thermal generation mix of the future.

**It is expected that day peak would surpass the night peak from this year onwards

Table A3.3- Long Term Time Trend Demand Forecast

Year	Demand (GWh)	Net Losses* (%)	Generation (GWh)	Peak (MW)
2023	18562	7.95	20165	3350
2024	19599	7.89	21278	3486
2025	20695	7.83	22453	3628
2026	21851	7.77	23692	3777
2027	23072	7.7	24997	3988
2028	24362	7.63	26374	4227
2029	25723	7.57	27830	4461
2030	27161	7.5	29363	4708
2031	28679	7.45	30987	4970
2032	30281	7.4	32701	5247
2033	31974	7.35	34510	5538
2034	33760	7.3	36419	5846
2035	35647	7.25	38434	6171
2036	37639	7.25	40581	6517
2037	39743	7.25	42849	6884
2038	41964	7.25	45244	7269
2039	44309	7.25	47772	7678
2040	46785	7.25	50442	8108
2041	49400	7.25	53261	8562
2042	52160	7.25	56238	9043
2043	55075	7.25	59380	9550
2044	58153	7.25	62699	10085
2045	61403	7.25	66203	10652
2046	64834	7.25	69902	11249
2047	68458	7.25	73809	11881
5 Year Average Growth	5.6%		5.5%	4.5%
10 Year Average Growth	5.6%		5.5%	5.1%
20 Year Average Growth	5.6%		5.5%	5.4%
25 Year Average Growth	5.6%		5.6%	5.4%

In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.

*Net losses include losses at the Transmission & Distribution levels, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the renewable thermal generation mix of the future.

Table A3.4 –MAED Load Projection

Year	Demand (GWh)	Net Losses*(%)	Generation (GWh)	Peak (MW)
2023	16893	8.06	18373	3086
2024	17864	7.71	19356	3220
2025	18891	7.36	20392	3360
2026	20038	7.31	21619	3559
2027	21255	7.27	22921	3769
2028	22546	7.22	24300	3991
2029	23915	7.17	25763	4227
2030	25367	7.13	27314	4477
2031	26685	7.12	28730	4707
2032	28072	7.10	30219	4949
2033	29530	7.10	31786	5203
2034	31065	7.09	33434	5471
2035	32679	7.07	35167	5752
2036	34223	7.07	36827	6014
2037	35840	7.07	38565	6288
2038	37534	7.06	40386	6575
2039	39308	7.06	42292	6875
2040	41165	7.05	44288	7188
2041	42869	7.00	46098	7484
2042	44644	6.96	47982	7792
2043	46492	6.91	49943	8113
2044	48417	6.86	51984	8447
2045	50421	6.82	54109	8795
2046	52508	6.77	56320	9157
2047	54682	6.72	58622	9534
5 Year Average Growth	5.9%		5.7%	5.1%
10 Year Average Growth	5.8%		5.7%	5.4%
20 Year Average Growth	5.2%		5.2%	5.0%
25 Year Average Growth	5.0%		5.0%	4.8%

In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.

*****Net losses include losses at the Transmission & Distribution levels, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the renewable thermal generation mix of the future.

Annex 4.1
Specific Cost Curves of Thermal Generation Options

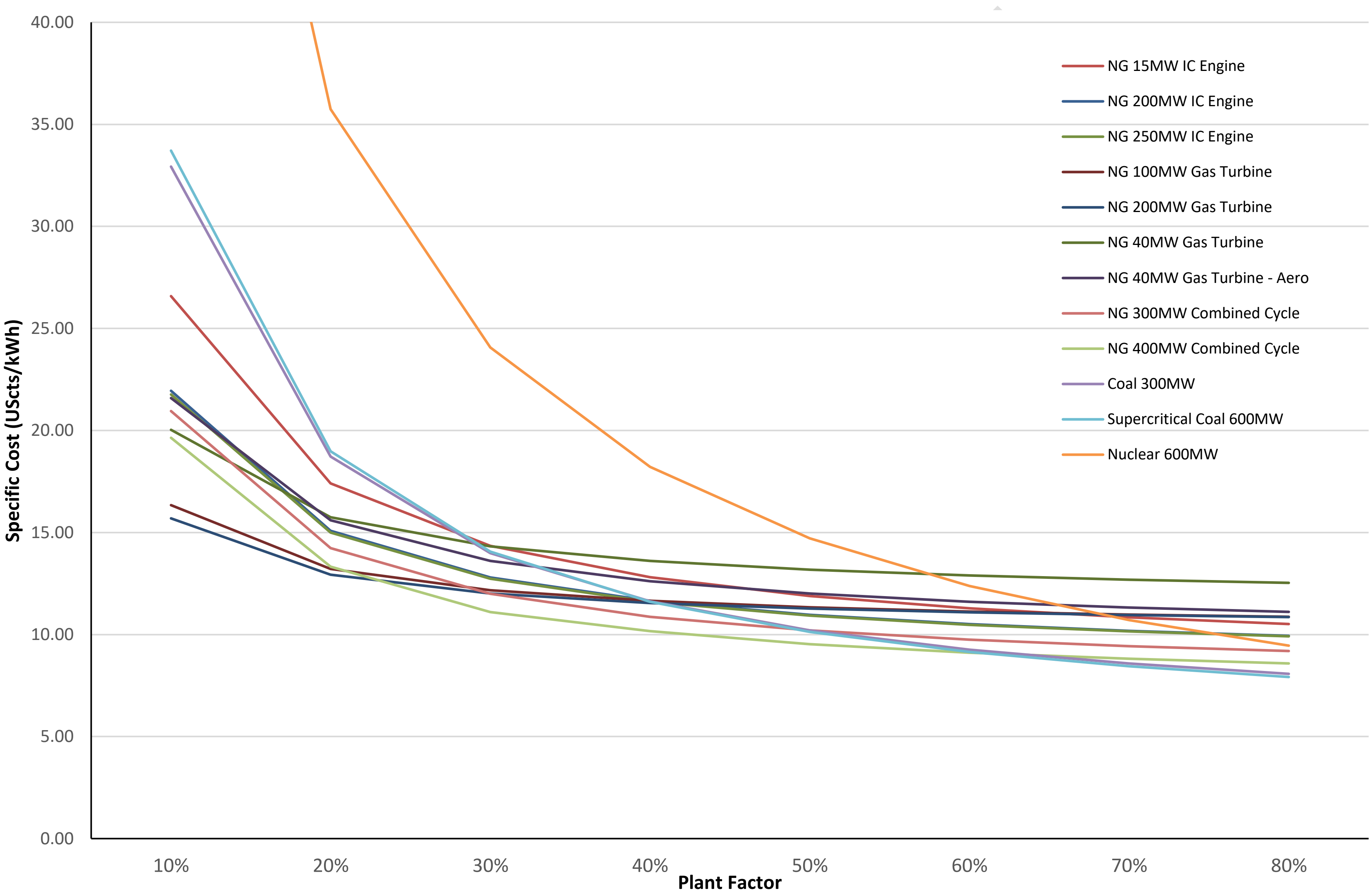
The specific cost and corresponding curves for the candidate thermal generation options are mentioned below.

A4.1 Specific Cost of Candidate Thermal Plants in US cents/kWh (in LKR/kWh)

Power Plant	Plant Factor							
	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8
15 MW NG IC Engine	26.58 (53.56)	17.40 (35.06)	14.34 (28.90)	12.81 (25.81)	11.89 (23.96)	11.28 (22.73)	10.84 (21.85)	10.51 (21.19)
15 MW FOIC Engine	28.70 (57.84)	19.52 (39.34)	16.46 (33.17)	14.93 (30.09)	14.01 (28.24)	13.40 (27.00)	12.96 (26.12)	12.64 (25.46)
15 MW Diesel IC Engine	27.87 (56.15)	18.68 (37.65)	15.62 (31.48)	14.09 (28.40)	13.18 (26.55)	12.56 (25.32)	12.13 (24.43)	11.80 (23.77)
200 MW NG IC Engine	21.94 (44.22)	15.08 (30.39)	12.79 (25.78)	11.65 (23.48)	10.96 (22.09)	10.51 (21.17)	10.18 (20.51)	9.93 (20.02)
250 MW NG IC Engine	21.76 (43.85)	14.99 (30.21)	12.73 (25.66)	11.60 (23.38)	10.93 (22.02)	10.48 (21.11)	10.15 (20.46)	9.91 (19.97)
40 MW NG Gas Turbine	20.03 (40.37)	15.75 (31.73)	14.32 (28.85)	13.60 (27.41)	13.17 (26.55)	12.89 (25.97)	12.69 (25.56)	12.53 (25.25)
40 MW NG Gas Turbine (Aero Derivative)	21.59 (43.50)	15.60 (31.43)	13.60 (27.41)	12.61 (25.40)	12.01 (24.20)	11.61 (23.39)	11.32 (22.82)	11.11 (22.39)
100 MW NG Gas Turbine	16.34 (32.93)	13.21 (26.63)	12.17 (24.53)	11.65 (23.48)	11.34 (22.85)	11.13 (22.43)	10.98 (22.13)	10.87 (21.90)
200 MW NG Gas Turbine	15.69 (31.62)	12.93 (26.05)	12.01 (24.19)	11.55 (23.27)	11.27 (22.71)	11.09 (22.34)	10.95 (22.07)	10.86 (21.87)
300 MW NG Combined Cycle	20.95 (42.21)	14.23 (28.68)	11.99 (24.16)	10.87 (21.91)	10.20 (20.55)	9.75 (19.65)	9.43 (19.01)	9.19 (18.52)
400 MW NG Combined Cycle	19.64 (39.58)	13.32 (26.84)	11.09 (22.35)	10.16 (20.48)	9.53 (19.21)	9.11 (18.36)	8.81 (17.75)	8.58 (17.30)
300 MW High Efficient Coal Plant	32.93 (66.35)	18.73 (37.73)	13.99 (28.19)	11.62 (23.42)	10.20 (20.56)	9.26 (18.65)	8.58 (17.29)	8.07 (16.27)
600 MW Super Critical Coal Plant	33.71 (67.93)	18.97 (38.23)	14.06 (28.33)	11.60 (23.38)	10.13 (20.41)	9.15 (18.43)	8.45 (17.02)	7.92 (15.96)
600 MW Nuclear Power Plant	70.80 (142.67)	35.75 (72.03)	24.06 (48.49)	18.22 (36.71)	14.71 (29.65)	12.38 (24.94)	10.71 (21.58)	9.46 (19.05)

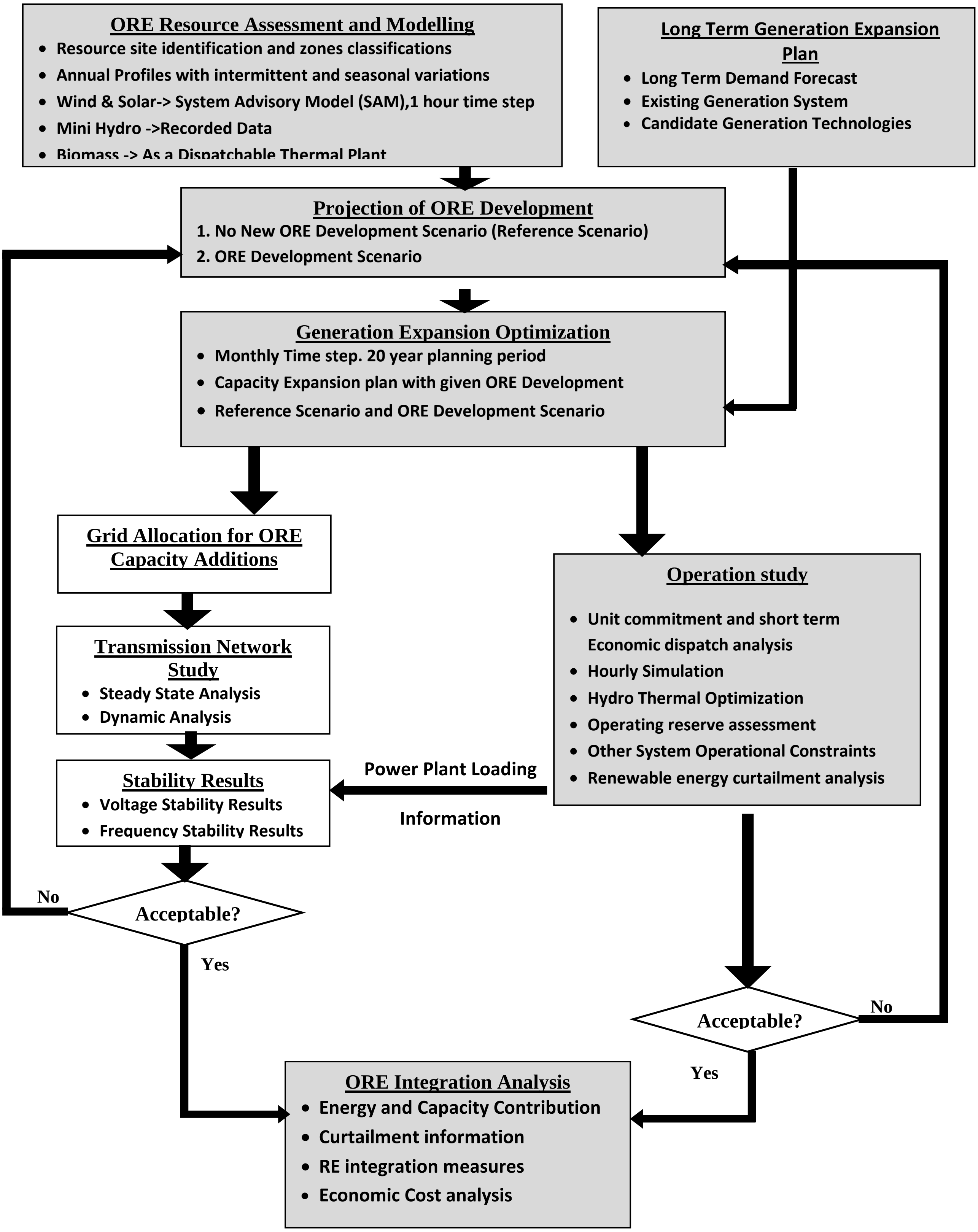
Note: 1 US$ = LKR 201.5

A4.2 Specific Cost Curves of the Generation Options at 10% Discount Rate



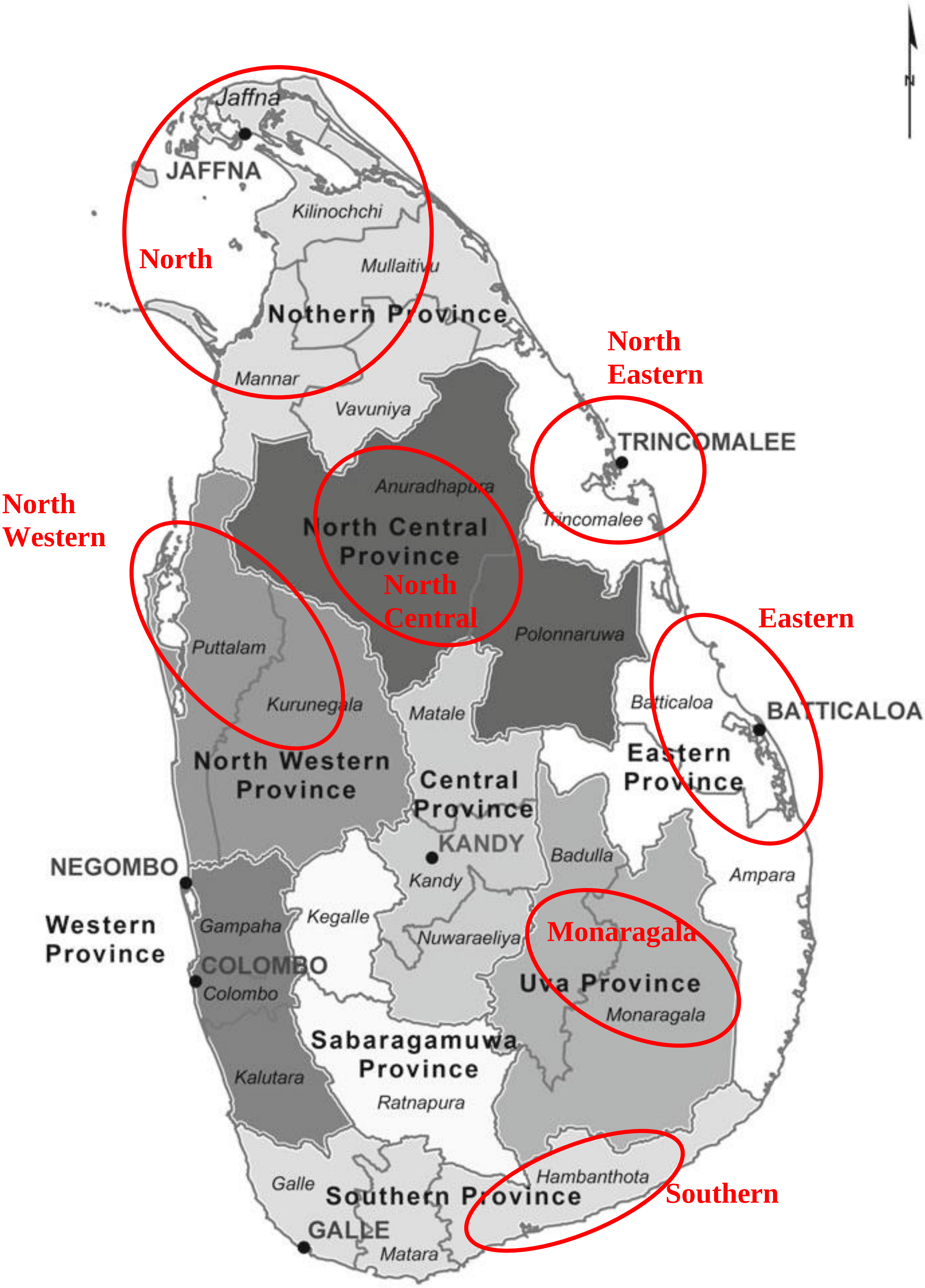
Annex 5.1

Methodology of the Renewable Energy Integration Study 2023-2032



A5.1 Outline of the study methodology of renewable energy integration study 2023-2032

Classification of Renewable Energy Zones



A5.2 Classification of Renewable Energy Zones

Annex 5.3

Cost Details of Other Renewable Energy

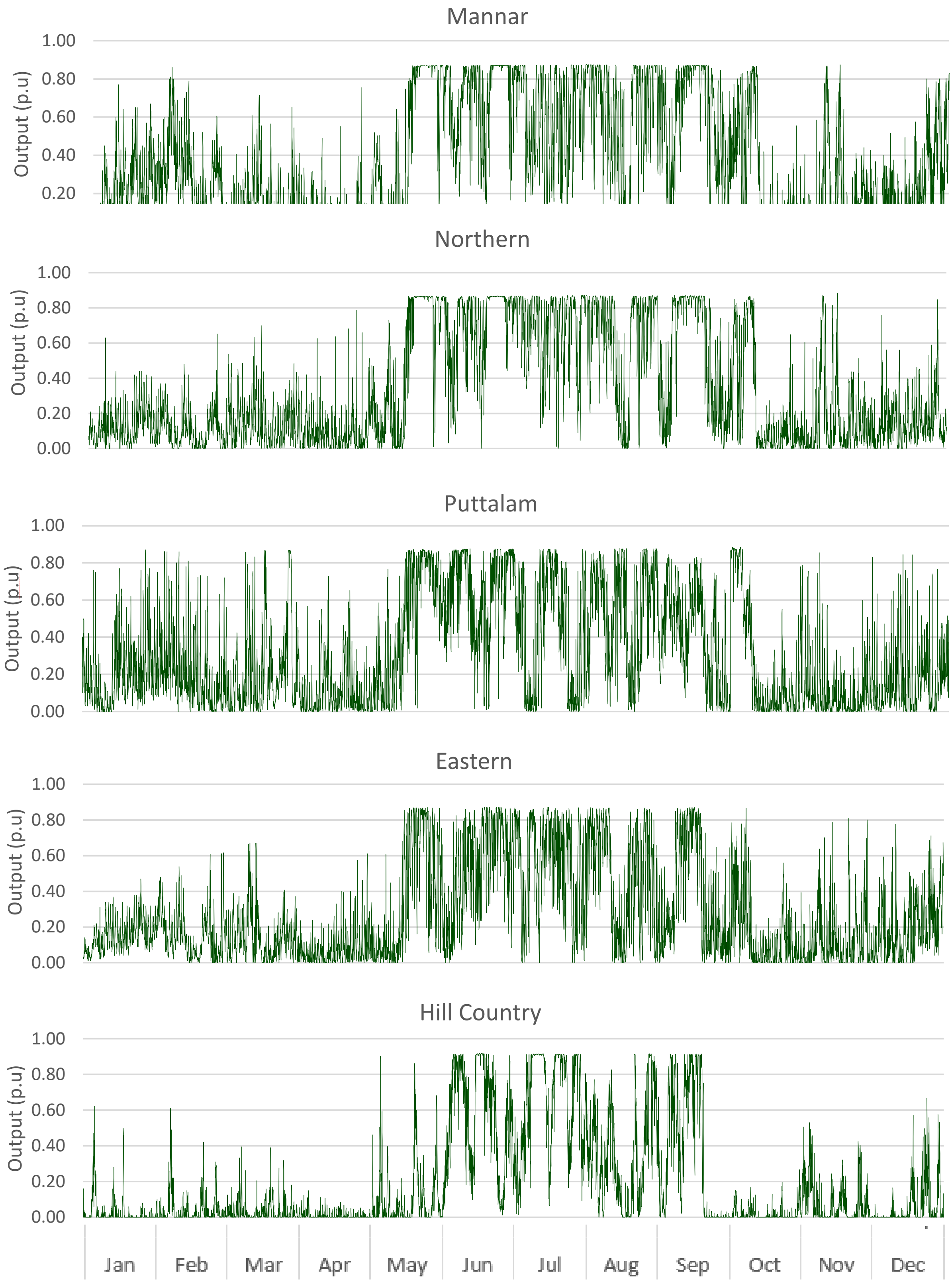
ORE Technology	Pure Capital Cost (USD/kW)	Capital Cost with IDC (USD/kW)	Fixed O&M Cost (% of the capital cost)	Construction years
Solar (Large Scale)	798	850	0.9	1.5
Solar (Distributed)	1012	1055	0.9	1
Floating solar	1221	1300	0.9	1.5
Wind	1314	1400	1.5	1.5
Off-shore wind	2817	3000	1.5	1.5
Biomass	1623	1729	4	1.5
Mini hydro	1675	1784	3	1.5

A5.7 Capital and Fixed O&M Cost of ORE Technologies

Technology		Plant Factor (Apprx.)	Specific Cost UScts/kWh	Specific Cost LKR/kWh
Solar (Large Scale)		20%	5.76	11.61
Solar (Distributed)		17%	8.59	17.31
Floating solar		19%	9.28	18.70
Wind	Hill country	19%	10.46	21.08
	Eastern	27%	7.36	14.83
	Puttalam	32%	6.21	12.51
	Northern	34%	5.84	11.77
	Mannar	40%	4.97	10.01
Off-shore wind		40%	10.65	21.46
Biomass		80%	3.65	7.35
Mini hydro		37%	7.62	15.35

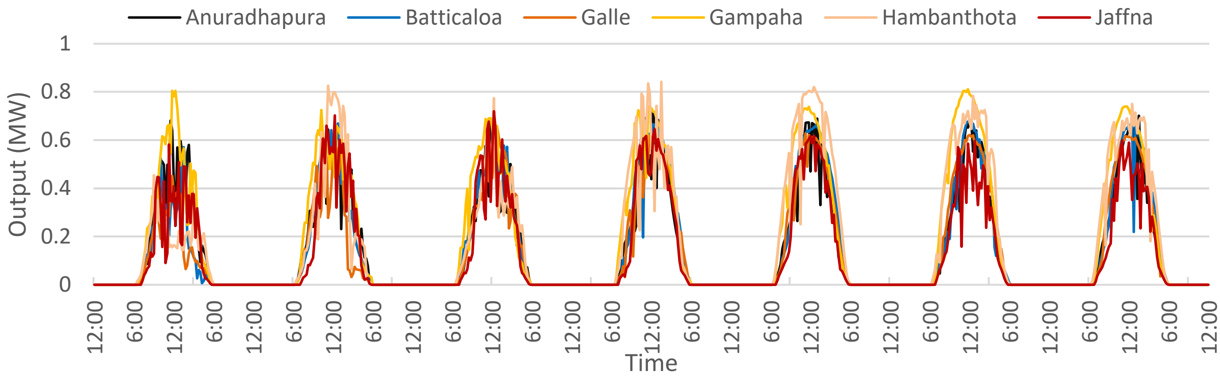
Note: 1 USD = LKR 201.5

A5.8 Specific Cost of ORE Technologies

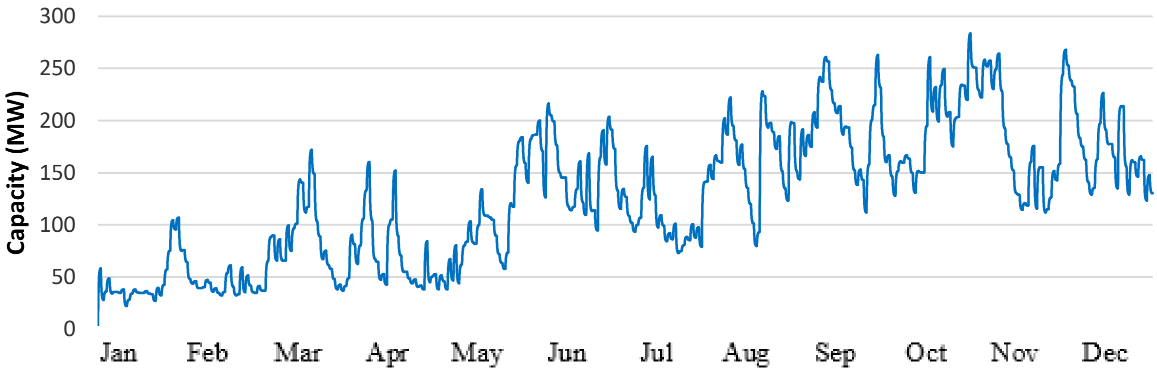


A5.3 Annual variation of wind power production in different regions (Based on 10 min Actual data)

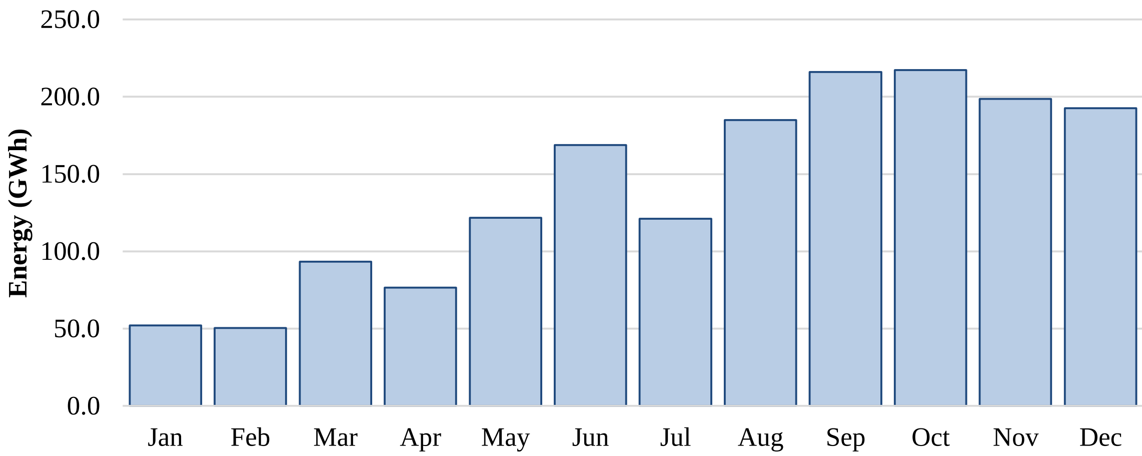
Solar and Mini-Hydro Plant Production Profiles



A5.4 Extract of Solar PV Production based on actual measurement data (15 minute)



A5.5Modelled production profile of Mini-hydro resource

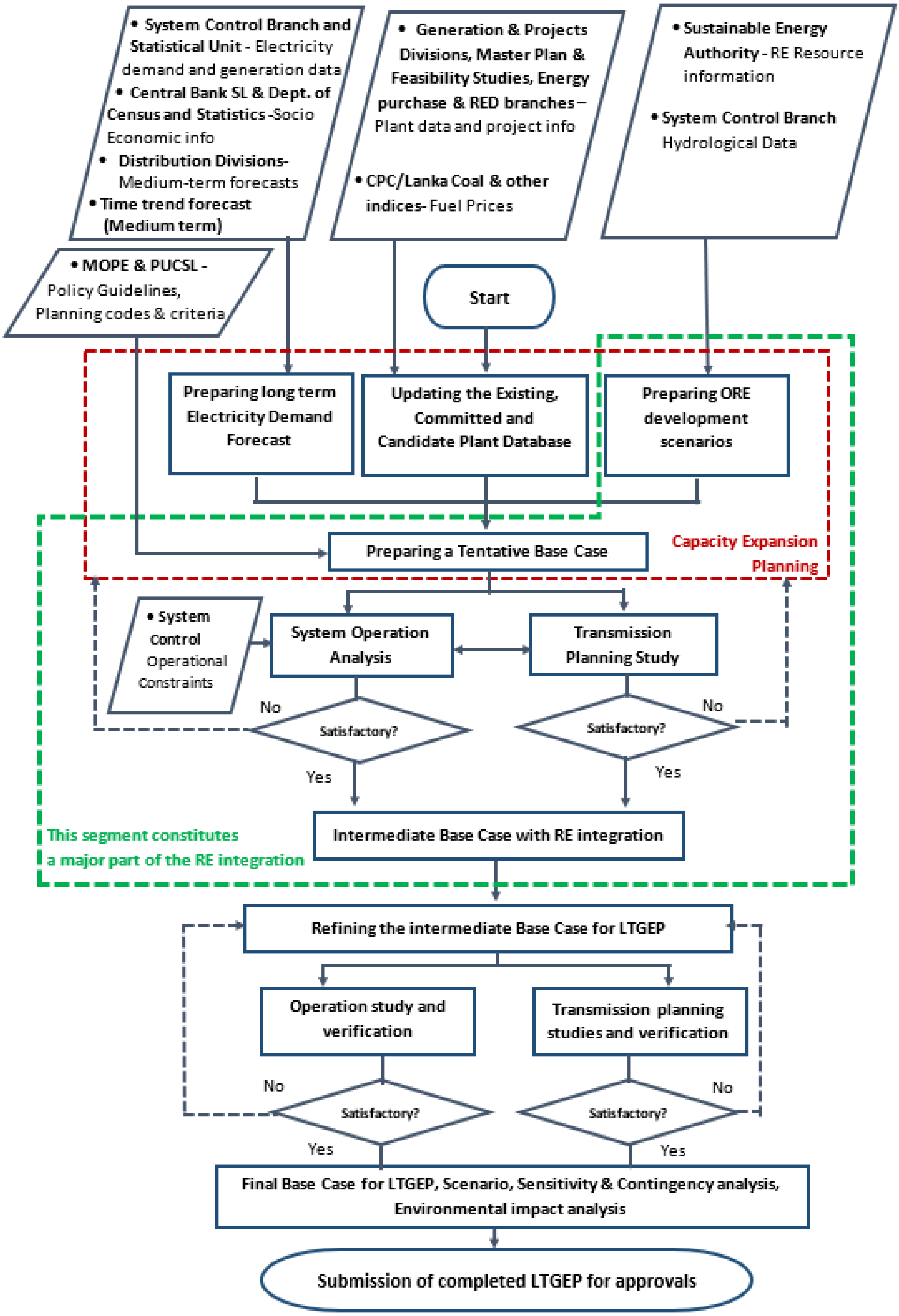


A5.6 Monthly energy production of Mini-hydro resource

Annex 6.1

Generation Expansion Planning Methodology

Flow diagram of the generation expansion planning methodology is shown below.

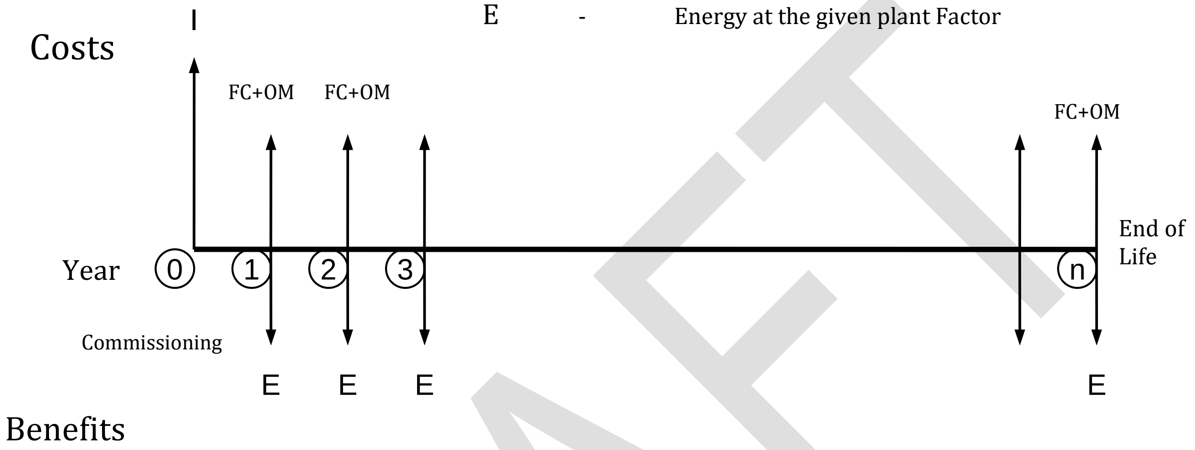


Annex 6.2

Methodology of the Specific Cost Calculation

Present value of specific energy cost of thermal plants is calculated for a range of plant factors, in order to mimic the procedure adopted in the planning software's used for the expansion studies.

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



Investment cost assumed as an overnight cost 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.

Specific Cost = [I + { Σ Fixed OM + (FC + Var. OM) * E } * Present Value Factor] / E * Present Value Factor

Annex 8.1

Capacity Balance for Base Case Plan of LTGEP 2023-2042

Plant Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Hydro																				
Major Hydro	1541	1571	1571	1571	1571	1571	1571	1571	1571	1571	1571	1571	1571	1571	1571	1571	1571	1571	1571	1571
PSPP	0	0	0	0	0	0	350	700	1,050	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Sub Total	1,541	1,571	1,571	1,571	1,571	1,571	1,921	2,271	2,621	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971
Thermal Existing and Committed																				
Small Gas Turbines	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	68	68	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	72	72	72	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine No7	115	115	115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa Combined Cycle	161	163	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Combined Cycle	163	161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	270	270	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakvijaya Coal	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	540	540
Uthurujanani	27	27	27	27	27	27	27	27	27	27	0	0	0	0	0	0	0	0	0	0
CEB Barge Power	62	62	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short Term Supplimentary Power Plants	320	120	120	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG Converted Sojitz Combined Cycle	0	0	163	163	163	163	163	163	163	163	0	0	0	0	0	0	0	0	0	0
NG Converted Kelanitissa Combined Cycle	0	0	161	161	161	161	161	161	161	161	0	0	0	0	0	0	0	0	0	0
NG Converted Kerawalapitiya CCY	0	0	270	270	270	270	270	270	270	270	270	270	0	0	0	0	0	0	0	0
Sub Total	2,136	1,868	1,805	1,430	1,430	1,430	1,430	1,430	1,430	1,430	1,080	1,080	810	810	810	810	810	810	540	540
New Thermal Plants																				
New Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa New Gas Turbines*	0	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
New Gas Engines	0	0	0	208	208	208	208	208	208	208	208	208	464	464	464	672	672	880	880	880
New Gas Turbines	0	0	0	0	106	106	106	106	106	106	106	213	319	511	703	703	895	895	1,001	1,001
New NG Combined Cyle*	235	593	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	1,119	1,119
Sub Total	235	723	830	1,038	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,251	1,613	1,805	1,997	2,205	2,397	2,605	3,130	3,130
Other Renewable Energy																				
Mini Hydro	455	475	500	525	550	575	600	610	620	630	640	650	660	670	680	690	700	700	700	700
Biomass	80	100	120	140	160	180	190	210	231	250	275	297	300	314	322	341	343	360	363	373
Wind	273	333	533	823	1,073	1,273	1,523	1,754	1,933	2,103	2,228	2,403	2,533	2,673	2,823	2,973	3,123	3,293	3,523	3,573
Solar	1,176	1,659	2,164	2,664	3,164	3,684	4,224	4,674	5,126	5,574	6,078	6,579	7,094	7,636	8,203	8,724	9,297	9,784	10,398	10,800
Sub Total	1,984	2,567	3,317	4,152	4,947	5,712	6,537	7,248	7,909	8,557	9,221	9,929	10,587	11,293	12,028	12,728	13,463	14,137	14,984	15,446

BESS	**-**	**20**	**120**	**300**	**500**	**850**	**1,000**	**1,125**	**1,250**	**1,375**	**1,525**	**1,705**	**1,850**	**2,050**	**2,250**	**2,450**	**2,650**	**2,865**	**3,090**	**3,365**

Installed Capacity	**5,896**	**6,749**	**7,644**	**8,492**	**9,593**	**10,708**	**12,033**	**13,219**	**14,355**	**15,478**	**15,942**	**16,936**	**17,832**	**18,930**	**20,056**	**21,164**	**22,291**	**23,388**	**24,715**	**25,452**
System Demand	**3,021**	**3,149**	**3,283**	**3,432**	**3,651**	**3,890**	**4,127**	**4,378**	**4,645**	**4,880**	**5,127**	**5,385**	**5,652**	**5,929**	**6,214**	**6,504**	**6,801**	**7,106**	**7,415**	**7,730**

Notes : All the Capacities are in MW (net)
Maintenance and forced outages are not considered.
* Initial two years (2023 and 2024) will be operated by oil.

Annex 8.2

Energy Balance for Base Case Plan of LTGEP 2023-2042

Plant Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Hydro																				
Major Hydro	4,488	4,703	4,721	4,826	5,072	4,841	4,513	4,999	4,814	4,808	4,848	5,044	4,761	4,466	4,870	4,935	4,624	4,978	4,949	4,908
Sub Total	4,488	4,703	4,721	4,826	5,072	4,841	4,513	4,999	4,814	4,808	4,848	5,044	4,761	4,466	4,870	4,935	4,624	4,978	4,949	4,908
Thermal Existing and Committed																				
Small Gas Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	94	38	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	461	127	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine No7	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa Combined Cycle	1,162	621	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Combined Cycle	636	412	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	229	249	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakvijaya Coal	5,639	5,774	5,785	5,689	5,493	5,498	5,479	5,534	5,449	5,347	5,230	5,207	5,287	5,440	5,462	5,578	5,517	5,470	3,931	3,773
Uthurujanani	144	39	7	5	3	2	0	1	1	1	0	0	0	0	0	0	0	0	0	0
CEB Barge Power	403	118	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short Term Supplimentary Power Plants	876	116	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG Converted Sojitz Combined Cycle	0	0	307	14	42	19	65	38	107	127	0	0	0	0	0	0	0	0	0	0
NG Converted Kelanitissa Combined Cycle	0	0	323	56	61	61	112	116	159	196	0	0	0	0	0	0	0	0	0	0
NG Converted Kerawalapitiya CCY	0	0	264	44	46	25	56	75	149	191	420	493	0	0	0	0	0	0	0	0
Sub Total	9,647	7,496	6,708	5,807	5,646	5,605	5,712	5,763	5,864	5,861	5,650	5,700	5,287	5,440	5,462	5,578	5,517	5,470	3,931	3,773
New Thermal Plants																				
New Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa New Gas Turbines*	0	442	78	39	43	47	52	80	77	91	155	174	207	272	270	222	254	211	215	242
New Gas Engines	0	0	0	743	738	764	848	577	705	705	823	801	1,911	1,915	1,999	2,797	3,263	4,025	4,355	4,463
New Gas Turbines	0	0	0	0	10	6	2	5	7	9	46	123	316	684	876	708	993	869	938	1,263
New NG Combined Cyle*	11	1,593	2,663	2,323	1,901	2,104	2,402	2,045	2,200	2,327	2,420	2,666	2,456	2,732	2,686	2,679	2,921	2,840	4,682	5,248
Sub Total	11	2,034	2,741	3,104	2,692	2,922	3,304	2,707	2,990	3,132	3,444	3,764	4,891	5,604	5,831	6,405	7,432	7,946	10,189	11,215
Other Renewable Energy																				
Mini Hydro	1,373	1,435	1,499	1,568	1,626	1,687	1,759	1,829	1,877	1,913	1,949	1,975	2,000	2,026	2,054	2,079	2,107	2,135	2,137	2,142
Biomass	432	572	712	849	983	1,113	1,177	1,316	1,459	1,599	1,742	1,876	1,999	2,065	2,128	2,195	2,253	2,321	2,401	2,408
Wind	765	949	1,023	1,642	2,467	3,117	3,625	4,309	4,889	5,426	5,847	6,295	6,725	7,156	7,589	8,008	8,449	8,868	9,352	9,781
Solar	1,481	2,045	2,926	3,766	4,495	5,157	5,960	6,851	7,753	8,538	9,353	10,008	10,676	11,360	12,053	12,754	13,455	14,158	14,888	15,629
Sub Total	4,051	5,001	6,160	7,825	9,571	11,073	12,521	14,304	15,977	17,477	18,891	20,153	21,399	22,606	23,824	25,036	26,265	27,482	28,778	29,959

Total Generation	**18,196**	**19,234**	**20,330**	**21,563**	**22,980**	**24,441**	**26,050**	**27,774**	**29,646**	**31,277**	**32,833**	**34,661**	**36,338**	**38,116**	**39,987**	**41,954**	**43,838**	**45,875**	**47,847**	**49,855**
System Demand	**18,186**	**19,222**	**20,317**	**21,526**	**22,886**	**24,272**	**25,741**	**27,300**	**28,958**	**30,415**	**31,949**	**33,548**	**35,198**	**36,917**	**38,684**	**40,482**	**42,321**	**44,207**	**46,120**	**48,070**
PSPP and BESS Net Generation	**0**	**0**	**-5**	**-28**	**-84**	**-157**	**-296**	**-450**	**-675**	**-851**	**-1,027**	**-1,161**	**-1,268**	**-1,381**	**-1,473**	**-1,572**	**-1,673**	**-1,775**	**-1,892**	**-1,984**

Notes - Numbers may not add exactly due to rounding off and net generation figures have deviation from demand forecast figures as energy balance is developed based on simulation results.
Aggregation of hydro dispatches for individual plant is not possible owing to integrated operation and dispatch of hydro energy
All energy figures are shown for weighted average hydrological condition in GWh.

* Initial two years (2023 and 2024) will be operated by oil.

Annual Energy Generation and Plant Factors

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2023	Major Hydro	1541 MW	3842	4488	5020			
	ORE	1984 MW	4051	4051	4051			
	Kelanitissa Small GTs	4 x 17 MW	0	0	0	0%	0%	0%
	Sapugaskanda A	4 x 17 MW	96	94	95	16%	16%	16%
	Sapugaskanda B	8 x 9 MW	483	461	447	77%	73%	71%
	Kelanitissa GT7	1 x 115 MW	4	3	1	0%	0%	0%
	Kelanitissa Combined Cycle	1 x 161 MW	1181	1162	1147	84%	83%	81%
	Sojitz Combined Cycle	1 x 163 MW	851	636	460	60%	45%	32%
	West Coast Combined Cycle	1 x 270 MW	249	226	135	11%	10%	6%
	Lakvijaya Unit 1	300 MW	1639	1639	1639	69%	69%	69%
	Lakvijaya Unit 2	300 MW	2002	2002	2002	85%	85%	85%
	Lakvijaya Unit 3	300 MW	1997	1997	1996	84%	84%	84%
	Uthuru Janani	3 x 9 MW	177	144	130	76%	62%	56%
	Barge Power Plant	4 x 16 MW	457	403	393	84%	74%	72%
	Short Term Supplimentary Power Plants	320 MW	1157	876	664	41%	31%	24%
	New NG Combined Cycles (Open Cycle)	235 MW	10	11	15	1%	1%	1%
	Total Renewable Generation		**7893**	**8539**	**9071**			
	Total Thermal Generation		**10294**	**9644**	**9109**			
	Total Generation		**18187**	**18183**	**18180**			
2024	Major Hydro	1571 MW	3947	4703	5532			
	ORE	2567 MW	5002	5001	5002			
	Sapugaskanda A	4 x 17 MW	54	38	49	9%	6%	8%
	Sapugaskanda B	8 x 9 MW	134	127	135	21%	20%	21%
	Kelanitissa GT7	1 x 115 MW	2	2	1	0%	0%	0%
	Kelanitissa Combined Cycle	1 x 161 MW	734	636	534	52%	45%	38%
	Sojitz Combined Cycle	1 x 163 MW	461	396	326	32%	28%	23%
	West Coast Combined Cycle	1 x 270 MW	406	249	168	17%	11%	7%
	Lakvijaya Unit 1	300 MW	2003	1999	1993	85%	85%	84%
	Lakvijaya Unit 2	300 MW	1814	1804	1772	77%	76%	75%
	Lakvijaya Unit 3	300 MW	1987	1971	1910	84%	83%	81%
	Uthuru Janani	3 x 9 MW	50	39	48	21%	17%	20%
	Barge Power Plant	4 x 16 MW	130	118	128	24%	22%	23%
	Short Term Supplimentary Power Plants	120 MW	165	116	136	16%	11%	13%
	Kelanitissa New Gas Turbines	130 MW	491	442	399	43%	39%	35%
	New NG Combined Cycles	1 x 350 MW + 243 MW	1614	1412	910	53%	46%	30%
	Total Renewable Generation		**8949**	**9704**	**10534**			
	Total Thermal Generation		**10045**	**9349**	**8508**			
	Total Generation		**18994**	**19053**	**19042**			
2025	Major Hydro	1571 MW	4104	4721	5598			
	ORE	3317 MW	6160	6160	6160			
	Sapugaskanda A	4 x 17 MW	1	1	2	0%	0%	0%
	Sapugaskanda B	8 x 9 MW	5	8	8	1%	1%	1%
	Kelanitissa GT7	1 x 115 MW	0	0	1	0%	0%	0%
	Lakvijaya Unit 1	300 MW	2003	1996	1941	85%	84%	82%
	Lakvijaya Unit 2	300 MW	1997	1992	1965	84%	84%	83%
	Lakvijaya Unit 3	300 MW	1807	1797	1737	76%	76%	73%
	Uthuru Janani	3 x 9 MW	6	7	8	2%	3%	3%
	Short Term Supplimentary Power Plants	120 MW	11	13	11	1%	1%	1%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	443	307	203	31%	22%	14%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	360	323	281	26%	23%	20%
	NG Converted West Coast Combined Cycle	1 x 270 MW	271	264	213	11%	11%	9%
	Kelanitissa New Gas Turbines	130 MW	83	78	79	7%	7%	7%
	New NG Combined Cycles	2 x 350 MW	3083	2663	2121	50%	43%	35%
	Total Renewable Generation		**10264**	**10881**	**11758**			
	Total Thermal Generation		**10069**	**9449**	**8569**			
	Total Generation		**20332**	**20330**	**20327**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2026	Major Hydro	1571 MW	3967	4826	5801			
	ORE	4152 MW	7830	7825	7807			
	Lakvijaya Unit 1	300 MW	1817	1792	1692	77%	76%	72%
	Lakvijaya Unit 2	300 MW	1994	1962	1865	84%	83%	79%
	Lakvijaya Unit 3	300 MW	1981	1935	1755	84%	82%	74%
	Uthuru Janani	3 x 9 MW	4	5	6	2%	2%	3%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	19	14	1	1%	1%	0%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	60	56	55	4%	4%	4%
	NG Converted West Coast Combined Cycle	1 x 270 MW	60	44	36	3%	2%	2%
	New Gas Engines	200 MW	946	743	563	52%	41%	31%
	Kelanitissa New Gas Turbines	130 MW	41	39	42	4%	3%	4%
	New NG Combined Cycles	2 x 350 MW	2845	2323	1944	46%	38%	32%
	Total Renewable Generation		**11797**	**12651**	**13608**			
	Total Thermal Generation		**9766**	**8912**	**7959**			
	Total Generation		**21563**	**21563**	**21567**			
2027	Major Hydro	1571 MW	4241	5072	5838			
	ORE	4947 MW	9574	9571	9568			
	Lakvijaya Unit 1	300 MW	1995	1968	1951	84%	83%	82%
	Lakvijaya Unit 2	300 MW	1621	1592	1565	69%	67%	66%
	Lakvijaya Unit 3	300 MW	1972	1932	1879	83%	82%	79%
	Uthuru Janani	3 x 9 MW	3	3	3	1%	1%	1%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	73	42	37	1%	3%	3%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	111	61	35	4%	4%	2%
	NG Converted West Coast Combined Cycle	1 x 270 MW	105	46	32	3%	2%	1%
	New Gas Engines	200 MW	803	738	543	44%	40%	30%
	Kelanitissa New Gas Turbines	130 MW	75	43	40	7%	4%	3%
	New Gas Turbines	100 MW	11	10	12	1%	1%	1%
	New NG Combined Cycles	2 x 350 MW	2398	1901	1480	39%	31%	24%
	Total Renewable Generation		**13815**	**14643**	**15406**			
	Total Thermal Generation		**9166**	**8337**	**7576**			
	Total Generation		**22981**	**22980**	**22982**			
2028	Major Hydro	1571 MW	4207	4841	5675			
	ORE	5712 MW	11073	11073	11071			
	Lakvijaya Unit 1	300 MW	1998	1979	1862	84%	84%	79%
	Lakvijaya Unit 2	300 MW	1972	1962	1896	83%	83%	80%
	Lakvijaya Unit 3	300 MW	1606	1558	1416	68%	66%	60%
	Uthuru Janani	3 x 9 MW	1	2	2	1%	1%	1%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	15	19	0	1%	1%	0%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	58	61	60	4%	4%	4%
	NG Converted West Coast Combined Cycle	1 x 270 MW	32	25	20	1%	1%	1%
	New Gas Engines	200 MW	936	764	583	51%	42%	32%
	Kelanitissa New Gas Turbines	130 MW	46	47	64	4%	4%	6%
	New Gas Turbines	100 MW	6	6	11	1%	1%	1%
	New NG Combined Cycles	2 x 350 MW	2488	2104	1783	41%	34%	29%
	Total Renewable Generation		**15280**	**15914**	**16746**			
	Total Thermal Generation		**9159**	**8527**	**7697**			
	Total Generation		**24439**	**24441**	**24444**			
2029	Major Hydro	1571 MW	3531	4513	5209			
	ORE	6537 MW	12542	12521	12513			
	Lakvijaya Unit 1	300 MW	1635	1620	1579	69%	69%	67%
	Lakvijaya Unit 2	300 MW	1989	1966	1905	84%	83%	81%
	Lakvijaya Unit 3	300 MW	1974	1893	1764	83%	80%	75%
	Uthuru Janani	3 x 9 MW	0	0	0	0%	0%	0%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	166	65	0	12%	5%	3%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	187	112	40	13%	8%	1%
	NG Converted West Coast Combined Cycle	1 x 270 MW	112	56	23	5%	2%	44%
	New Gas Engines	200 MW	1045	848	805	57%	47%	3%
	Kelanitissa New Gas Turbines	130 MW	74	52	32	7%	5%	0%
	New Gas Turbines	100 MW	1	2	3	0%	0%	35%
	New NG Combined Cycles	2 x 350 MW	2816	2402	2165	46%	39%	
	Total Renewable Generation		**16073**	**17034**	**17722**			
	Total Thermal Generation		**9999**	**9016**	**8317**			
	Total Generation		**26072**	**26050**	**26039**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2030	Major Hydro	1571 MW	3705	4999	5379			
	ORE	7248 MW	14571	14304	14578			
	Lakvijaya Unit 1	300 MW	1992	1966	1971	84%	83%	83%
	Lakvijaya Unit 2	300 MW	1776	1757	1725	75%	74%	73%
	Lakvijaya Unit 3	300 MW	1815	1811	1613	77%	77%	68%
	Uthuru Janani	3 x 9 MW	0	1	0	0%	0%	0%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	119	38	0	8%	3%	0%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	214	116	28	15%	8%	2%
	NG Converted West Coast Combined Cycle	1 x 270 MW	175	75	0	7%	3%	0%
	New Gas Engines	200 MW	821	577	706	45%	32%	39%
	Kelanitissa New Gas Turbines	130 MW	87	80	26	8%	7%	2%
	New Gas Turbines	100 MW	4	5	0	0%	1%	0%
	New NG Combined Cycles	2 x 350 MW	2581	2045	1839	42%	33%	30%
	Total Renewable Generation		**18276**	**19303**	**19957**			
	Total Thermal Generation		**9584**	**8470**	**7905**			
	Total Generation		**27861**	**27773**	**27862**			
2031	Major Hydro	1571 MW	3490	4814	5502			
	ORE	7909 MW	16116	15977	15916			
	Lakvijaya Unit 1	300 MW	1989	1951	1946	84%	82%	82%
	Lakvijaya Unit 2	300 MW	1963	1913	1903	83%	81%	80%
	Lakvijaya Unit 3	300 MW	1736	1585	1576	73%	67%	67%
	Uthuru Janani	3 x 9 MW	2	1	1	1%	0%	0%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	214	107	59	15%	8%	4%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	311	159	95	22%	11%	7%
	NG Converted West Coast Combined Cycle	1 x 270 MW	326	149	85	14%	6%	4%
	New Gas Engines	200 MW	772	705	600	42%	39%	33%
	Kelanitissa New Gas Turbines	130 MW	139	77	54	12%	7%	5%
	New Gas Turbines	100 MW	19	7	8	2%	1%	1%
	New NG Combined Cycles	2 x 350 MW	2602	2200	1888	42%	36%	31%
	Total Renewable Generation		**19606**	**20792**	**21418**			
	Total Thermal Generation		**10073**	**8854**	**8213**			
	Total Generation		**29679**	**29646**	**29631**			
2032	Major Hydro	1571 MW	3971	4808	5470			
	ORE	8557 MW	17421	17477	17619			
	Lakvijaya Unit 1	300 MW	1741	1738	1757	74%	73%	74%
	Lakvijaya Unit 2	300 MW	1916	1885	1888	81%	80%	80%
	Lakvijaya Unit 3	300 MW	1819	1724	1739	77%	73%	74%
	Uthuru Janani	3 x 9 MW	3	1	0	1%	1%	0%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	231	127	28	16%	9%	2%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	269	196	85	19%	14%	6%
	NG Converted West Coast Combined Cycle	1 x 270 MW	344	191	72	15%	8%	3%
	New Gas Engines	200 MW	789	705	681	43%	39%	37%
	Kelanitissa New Gas Turbines	130 MW	142	91	58	12%	8%	5%
	New Gas Turbines	100 MW	20	9	3	2%	1%	0%
	New NG Combined Cycles	2 x 350 MW	2589	2327	1904	42%	38%	31%
	Total Renewable Generation		**21392**	**22285**	**23089**			
	Total Thermal Generation		**9865**	**8993**	**8216**			
	Total Generation		**31257**	**31277**	**31305**			
2033	Major Hydro	1571 MW	3916	4848	5232			
	ORE	9221 MW	18839	18891	19025			
	Lakvijaya Unit 1	300 MW	1946	1881	1699	82%	80%	72%
	Lakvijaya Unit 2	300 MW	1553	1536	1497	66%	65%	63%
	Lakvijaya Unit 3	300 MW	1932	1813	1588	82%	77%	67%
	NG Converted West Coast Combined Cycle	1 x 270 MW	523	420	402	22%	18%	17%
	New Gas Engines	200 MW	947	823	870	52%	45%	48%
	Kelanitissa New Gas Turbines	130 MW	210	155	184	18%	14%	16%
	New Gas Turbines	100 MW	87	46	23	9%	5%	2%
	New NG Combined Cycles	2 x 350 MW	2814	2420	2376	46%	39%	39%
	Total Renewable Generation		**22755**	**23739**	**24257**			
	Total Thermal Generation		**10012**	**9094**	**8638**			
	Total Generation		**32766**	**32833**	**32895**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2034	Major Hydro	1571 MW	4209	5044	5567			
	ORE	9929 MW	20093	20153	20078			
	Lakvijaya Unit 1	300 MW	1954	1866	1786	83%	79%	76%
	Lakvijaya Unit 2	300 MW	1934	1890	1860	82%	80%	79%
	Lakvijaya Unit 3	300 MW	1567	1450	1417	66%	61%	60%
	NG Converted West Coast Combined Cycle	1 x 270 MW	584	493	497	25%	21%	21%
	New Gas Engines	200 MW	921	801	681	51%	44%	37%
	Kelanitissa New Gas Turbines	130 MW	193	174	195	17%	15%	17%
	New Gas Turbines	2 x 100 MW	154	123	144	8%	7%	8%
	New NG Combined Cycles	2 x 350 MW	2995	2666	2433	49%	43%	40%
	Total Renewable Generation		**24302**	**25198**	**25645**			
	Total Thermal Generation		**10303**	**9463**	**9012**			
	Total Generation		**34605**	**34661**	**34657**			
2035	Major Hydro	1571 MW	4211	4761	5435			
	ORE	10587 MW	21338	21399	21555			
	Lakvijaya Unit 1	300 MW	1585	1580	1581	67%	67%	67%
	Lakvijaya Unit 2	300 MW	1945	1914	1903	82%	81%	80%
	Lakvijaya Unit 3	300 MW	1856	1792	1620	78%	76%	69%
	New Gas Engines	450 MW	1905	1911	1851	47%	47%	46%
	Kelanitissa New Gas Turbines	130 MW	260	207	156	23%	18%	14%
	New Gas Turbines	3 x 100 MW	452	316	195	16%	11%	7%
	New NG Combined Cycles	2 x 350 MW	2723	2456	2169	44%	40%	35%
	Total Renewable Generation		**25549**	**26161**	**26990**			
	Total Thermal Generation		**10724**	**10177**	**9475**			
	Total Generation		**36274**	**36338**	**36464**			
2036	Major Hydro	1571 MW	4105	4466	5196			
	ORE	11293 MW	22541	22606	22528			
	Lakvijaya Unit 1	300 MW	1923	1901	1743	81%	80%	74%
	Lakvijaya Unit 2	300 MW	1756	1731	1700	74%	73%	72%
	Lakvijaya Unit 3	300 MW	1904	1807	1465	81%	76%	62%
	New Gas Engines	450 MW	2015	1915	1848	50%	47%	45%
	Kelanitissa New Gas Turbines	130 MW	280	272	245	25%	24%	22%
	New Gas Turbines	3 x 100 MW + 1 x 200 MW	734	684	675	16%	15%	15%
	New NG Combined Cycles	2 x 350 MW	2836	2732	2646	46%	45%	43%
	Total Renewable Generation		**26646**	**27072**	**27724**			
	Total Thermal Generation		**11448**	**11043**	**10322**			
	Total Generation		**38095**	**38116**	**38045**			
2037	Major Hydro	1571 MW	3507	4870	5417			
	ORE	12028 MW	23760	23824	23761			
	Lakvijaya Unit 1	300 MW	1961	1907	1846	83%	81%	78%
	Lakvijaya Unit 2	300 MW	1954	1925	1899	83%	81%	80%
	Lakvijaya Unit 3	300 MW	1725	1631	1536	73%	69%	65%
	New Gas Engines	450 MW	2282	1999	1994	56%	49%	49%
	Kelanitissa New Gas Turbines	130 MW	353	270	227	31%	24%	20%
	New Gas Turbines	3 x 100 MW + 2 x 200 MW	1268	876	678	21%	14%	11%
	New NG Combined Cycles	2 x 350 MW	2967	2686	2630	48%	44%	43%
	Total Renewable Generation		**27267**	**28694**	**29178**			
	Total Thermal Generation		**12510**	**11293**	**10809**			
	Total Generation		**39777**	**39987**	**39988**			
2038	Major Hydro	1571 MW	4566	4935	5318			
	ORE	12728 MW	24957	25036	24947			
	Lakvijaya Unit 1	300 MW	1770	1757	1755	75%	74%	74%
	Lakvijaya Unit 2	300 MW	1942	1935	1915	82%	82%	81%
	Lakvijaya Unit 3	300 MW	1921	1886	1871	81%	80%	79%
	New Gas Engines	650 MW	2910	2797	2653	49%	48%	45%
	Kelanitissa New Gas Turbines	130 MW	237	222	193	21%	20%	17%
	New Gas Turbines	3 x 100 MW + 2 x 200 MW	802	708	633	13%	11%	10%
	New NG Combined Cycles	2 x 350 MW	2813	2679	2661	46%	44%	43%
	Total Renewable Generation		**29523**	**29971**	**30265**			
	Total Thermal Generation		**12395**	**11983**	**11681**			
	Total Generation		**41918**	**41954**	**41946**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2039	Major Hydro	1571 MW	4267	4624	4935			
	ORE	13463 MW	26205	26265	26183			
	Lakvijaya Unit 1	300 MW	1969	1966	1964	83%	83%	83%
	Lakvijaya Unit 2	300 MW	1602	1599	1594	68%	68%	67%
	Lakvijaya Unit 3	300 MW	1950	1953	1951	82%	83%	82%
	New Gas Engines	650 MW	3294	3263	3048	56%	55%	52%
	Kelanitissa New Gas Turbines	130 MW	272	254	254	24%	22%	22%
	New Gas Turbines	3 x 100 MW + 3 x 200 MW	1094	993	933	14%	13%	12%
	New NG Combined Cycles	2 x 350 MW	3104	2921	2946	51%	48%	48%
	Total Renewable Generation		**30472**	**30889**	**31118**			
	Total Thermal Generation		**13285**	**12949**	**12690**			
	Total Generation		**43757**	**43838**	**43807**			
2040	Major Hydro	1571 MW	4228	4978	5368			
	ORE	14137 MW	27409	27482	27659			
	Lakvijaya Unit 1	300 MW	1957	1952	1966	83%	83%	83%
	Lakvijaya Unit 2	300 MW	1944	1940	1948	82%	82%	82%
	Lakvijaya Unit 3	300 MW	1578	1578	1589	67%	67%	67%
	New Gas Engines	850 MW	4059	4025	4011	53%	52%	52%
	Kelanitissa New Gas Turbines	130 MW	276	211	169	24%	19%	15%
	New Gas Turbines	3 x 100 MW + 3 x 200 MW	1244	869	679	16%	11%	9%
	New NG Combined Cycles	2 x 350 MW	3053	2840	2588	50%	46%	42%
	Total Renewable Generation		**31637**	**32460**	**33027**			
	Total Thermal Generation		**14111**	**13415**	**12949**			
	Total Generation		**45748**	**45875**	**45976**			
2041	Major Hydro	1571 MW	4198	4949	5264			
	ORE	14984 MW	28713	28778	28702			
	Lakvijaya Unit 2	300 MW	1978	1974	1961	84%	83%	83%
	Lakvijaya Unit 3	300 MW	1965	1956	1941	83%	83%	82%
	New Gas Engines	850 MW	4477	4355	4194	58%	56%	54%
	Kelanitissa New Gas Turbines	130 MW	268	215	201	24%	19%	18%
	New Gas Turbines	4 x 100 MW + 3 x 200 MW	1222	938	932	14%	11%	11%
	New NG Combined Cycles	2 x 350 MW + 1 x 400 MW	4979	4682	4645	51%	48%	47%
	Total Renewable Generation		**32911**	**33727**	**33966**			
	Total Thermal Generation		**14889**	**14120**	**13874**			
	Total Generation		**47800**	**47847**	**47840**			
2042	Major Hydro	1571 MW	4058	4908	5468			
	ORE	15446 MW	29891	29959	29877			
	Lakvijaya Unit 2	300 MW	1802	1801	1798	76%	76%	76%
	Lakvijaya Unit 3	300 MW	1977	1973	1972	84%	83%	83%
	New Gas Engines	850 MW	4823	4463	4336	63%	58%	56%
	Kelanitissa New Gas Turbines	130 MW	293	242	204	26%	21%	18%
	New Gas Turbines	4 x 100 MW + 3 x 200 MW	1490	1263	1114	17%	14%	13%
	New NG Combined Cycles	2 x 350 MW + 1 x 400 MW	5429	5248	5052	55%	54%	52%
	Total Renewable Generation		**33949**	**34868**	**35345**			
	Total Thermal Generation		**15813**	**14988**	**14476**			
	Total Generation		**49762**	**49855**	**49821**			

NOTES:

1. Annual total generation figure does not include operation of PSPP and BESS

Fuel Requirement and Expenditure on Fuel

Base Case 2023-2042

Year	Auto Diesel		Fuel Oil		Naphtha		Coal		LNG	
	1000 MT	million USD	1000 MT	million USD	1000 MT	million USD	1000 MT	million USD	1000 MT	million USD
2023	316.3	177.4	274.4	150.6	186.6	101.3	2,454.4	347.8	-	-
2024	303.0	223.4	316.7	49.6	74.7	40.5	2,518.3	356.8	-	-
2025	2.7	0.1	3.6	1.8	-	-	2,519.3	357.0	632.1	443.1
2026	-	-	1.2	0.6	-	-	2,479.8	351.4	534.5	374.7
2027	-	-	0.7	0.4	-	-	2,399.8	340.0	473.0	331.6
2028	-	-	0.4	0.2	-	-	2,394.8	339.3	502.0	351.9
2029	-	-	0.1	0.0	-	-	2,387.0	338.2	590.5	414.0
2030	-	-	0.1	0.0	-	-	2,398.1	339.8	545.3	382.3
2031	-	-	0.2	0.1	-	-	2,377.4	336.9	573.2	401.8
2032	-	-	0.3	0.1	-	-	2,334.2	330.8	616.1	431.9
2033	-	-	-	-	-	-	2,288.2	324.2	654.5	458.9
2034	-	-	-	-	-	-	2,270.5	321.7	726.9	509.6
2035	-	-	-	-	-	-	2,306.0	326.8	823.0	577.0
2036	-	-	-	-	-	-	2,376.8	336.8	962.9	675.0
2037	-	-	-	-	-	-	2,382.3	337.6	1,013.0	710.2
2038	-	-	-	-	-	-	2,433.0	344.8	1,087.5	762.4
2039	-	-	-	-	-	-	2,410.3	341.5	1,270.6	890.8
2040	-	-	-	-	-	-	2,383.6	337.8	1,338.6	938.4
2041	-	-	-	-	-	-	1,704.4	241.5	1,711.9	1,200.1
2042	-	-	-	-	-	-	1,637.3	232.0	1,901.0	1,332.6

Annex 8.5

Results of Generation Expansion Planning Studies 2023-2042

High Demand Case

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]	THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]
2022	**Uma Oya Hydropower Plant — 120 MW** Distribution Connected Embedded Solar — 160 MW **Grid Connected Partially Facilitated Solar — 94 MW** Mini Hydro — 20 MW Biomass — 10 MW	
2023	Distribution Connected Embedded Solar — 160 MW **Grid Connected Partially Facilitated Solar [1] — 147 MW** **Wind — 25 MW** Mini Hydro — 20 MW Biomass — 20 MW	**Gas Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya) — 235 MW** Short Term Supplementary Power [2] — 520 MW Combined Cycle Power Plant (KPS–2) [3] — 163 MW *Retirement of* *Sojitz Kelanitissa Combined Cycle Plant [3] — (163) MW*
2024	**Moragolla Hydropower Plant — 31 MW** Distribution Connected Embedded Solar — 160 MW Grid Connected Partially Facilitated Solar [1] — 223 MW Grid Connected Fully Facilitated Solar — 100 MW **Wind — 60 MW** Mini Hydro — 20 MW Biomass — 20 MW Standalone Battery Energy Storage — 75 MW/300MWh	**New Gas Turbines – Kelanitissa [4] — 130 MW** **Steam Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya) — 115 MW** **Gas Turbine of Second NG Combined Cycle Plant(Kerawalapitiya) — 235 MW** *Retirement of* *Kelanitissa Gas Turbines[5] — (68) MW* *Short Term Supplementary Power — (200) MW*
2025	Distribution Connected Embedded Solar — 165 MW Grid Connected Partially Facilitated Solar — 80 MW Grid Connected Fully Facilitated Solar — 260 MW (With Battery Energy Storage) — 100MW/400 MWh Wind (Mannar) [6] — 100 MW Wind — 100 MW Mini Hydro — 25 MW Biomass — 20 MW	**Steam Turbine of Second NG Combined Cycle Plant(Kerawalapitiya) — 115 MW** *Retirement of* *CEB Barge Power Plant [7] — (62) MW* *Short Term Supplementary Power — (200) MW*
2026	Distribution Connected Embedded Solar — 170 MW Grid Connected Partially Facilitated Solar — 70 MW Grid Connected Fully Facilitated Solar — 260 MW (With Battery Energy Storage) — 100MW/400 MWh Wind — 290 MW Mini Hydro — 25 MW Biomass — 20 MW Standalone Battery Energy Storage — 80 MW/320 MWh	IC Engine Power Plant -Natural Gas (Western Region) — 200 MW Gas Turbine -Natural Gas — 200 MW *Retirement of* *Gas Turbine (GT7)[8] — (115) MW* *4x17 MW Sapugaskande Diesel — (68) MW* *8x9 MW Sapugaskande Diesel Ext — (72) MW* *Short Term Supplementary Power — (120) MW*
2027	Distribution Connected Embedded Solar — 170 MW Grid Connected Partially Facilitated Solar — 50 MW Grid Connected Fully Facilitated Solar — 380 MW (With Battery Energy Storage) — 100 MW/400MWh Wind — 350 MW Mini Hydro — 25 MW Biomass — 20 MW Standalone Battery Energy Storage — 100 MW/400 MWh	

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]	THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]
2028	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 40 MW Grid Connected Fully Facilitated Solar 310 MW (With Battery Energy Storage) 150 MW/600 MWh Wind 350 MW Mini Hydro 25 MW Biomass 10 MW Standalone Battery Energy Storage 225MW/900 MWh	Gas Turbine -Natural Gas 100 MW
2029	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 20 MW Grid Connected Fully Facilitated Solar 500 MW (With Battery Energy Storage) 175 MW/700 MWh Wind 250 MW Mini Hydro 25 MW Biomass 20 MW Pumped Storage Hydropower 350 MW	
2030	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 400 MW (With Battery Energy Storage) 125 MW/500MWh Wind 170 MW Mini Hydro 10 MW Biomass 20 MW Pumped Storage Hydropower 350 MW	
2031	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 200 MW (With Battery Energy Storage) 125 MW/500MWh Wind 140 MW Mini Hydro 10 MW Biomass 20 MW Pumped Storage Hydropower 350 MW	-
2032	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 300 MW (With Battery Energy Storage) 150 MW/600MWh Wind 120 MW Mini Hydro 10 MW Biomass 20 MW Pumped Storage Hydropower 350 MW	
2033	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 400 MW (With Battery Energy Storage) 150 MW/600MWh Wind 145 MW Mini Hydro 10 MW Biomass 15 MW	*Retirement of* *Combined Cycle Plant (KPS) (165) MW* *Combined Cycle Plant (KPS- 2) (163) MW* *Uthuru Janani Power Plant (26.7) MW*
2034	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 250 MW (With Battery Energy Storage) 125 MW/500MWh Wind 70 MW Mini Hydro 10 MW Biomass 13 MW Standalone Battery Energy Storage 50 MW/200MWh	

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]		THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]	
2035	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	185 MW 30 MW 250 MW 100MW/400MWh 90 MW 10 MW 10 MW 100MW/400MWh	IC Engine Power Plant -Natural Gas *Retirement of* *West Coast Combined Cycle Power Plant*	500 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	194 MW 5 MW 300 MW 150MW/600MWh 150 MW 10 MW 6 MW 50MW/200MWh		
2037	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	177 MW 5 MW 250 MW 100MW/400MWh 150 MW 10 MW 8 MW 100MW/400MWh	Gas Turbine -Natural Gas	200 MW
2038	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Standalone Battery Energy Storage	166 MW 40 MW 250 MW 100MW/400MWh 150 MW 10 MW 100MW/400MWh	Gas Turbine -Natural Gas	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	149 MW 34 MW 300 MW 150 MW/600 MWh 150 MW 10 MW 7 MW 65 MW/260 MWh	Gas Turbine -Natural Gas	200 MW
2040	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Standalone Battery Energy Storage	215 MW 12 MW 300 MW 125 MW/500 MWh 130 MW 100 MW/400 MWh	Gas Turbine -Natural Gas	200 MW
2041	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Biomass Standalone Battery Energy Storage	127 MW 10 MW 350 MW 175 MW/700 MWh 50 MW 10 MW 50 MW/200 MWh	Combined Cycle Power Plant (Natural Gas) *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	400 MW *(300) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]		THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]	
2042	Distribution Connected Embedded Solar	150 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	175 MW/700MWh		
	Wind	100 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400MWh		

Annex 8.6

Results of Generation Expansion Planning Studies 2023-2042

Low Demand Case

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]	THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]
2022	**Uma Oya Hydropower Plant 120 MW** Distribution Connected Embedded Solar 160 MW **Grid Connected Partially Facilitated Solar 94 MW** Mini Hydro 20 MW Biomass 10 MW	
2023	Distribution Connected Embedded Solar 160 MW **Grid Connected Partially Facilitated Solar [1] 147 MW** **Wind 25 MW** Mini Hydro 20 MW Biomass 20 MW	**Gas Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya) 235 MW** Short Term Supplementary Power [2] 260 MW Combined Cycle Power Plant (KPS–2) [3] 163 MW *Retirement of* *Sojitz Kelanitissa Combined Cycle Plant [3] (163) MW*
2024	**Moragolla Hydropower Plant 31 MW** Distribution Connected Embedded Solar 160 MW Grid Connected Partially Facilitated Solar [1] 223 MW Grid Connected Fully Facilitated Solar 100 MW **Wind 60 MW** Mini Hydro 20 MW Biomass 20 MW Standalone Battery Energy Storage 20 MW/50 MWh	**New Gas Turbines – Kelanitissa [4] 130 MW** **Steam Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya) 115 MW** **Gas Turbine of Second NG Combined Cycle Plant(Kerawalapitiya) 235 MW** *Retirement of* *Kelanitissa Gas Turbines[5] (68) MW* *Short Term Supplementary Power (190) MW*
2025	Distribution Connected Embedded Solar 165 MW Grid Connected Partially Facilitated Solar 80 MW Grid Connected Fully Facilitated Solar 200 MW (With Battery Energy Storage) 100MW/400 MWh Wind (Mannar) [6] 100 MW Wind 100 MW Mini Hydro 25 MW Biomass 20 MW	**Steam Turbine of Second NG Combined Cycle Plant(Kerawalapitiya) 115 MW** *Retirement of* *CEB Barge Power Plant [7] (62) MW* *Short Term Supplementary Power (70) MW*
2026	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 70 MW Grid Connected Fully Facilitated Solar 320 MW (With Battery Energy Storage) 100MW/400 MWh Wind 240 MW Mini Hydro 25 MW Biomass 20 MW Standalone Battery Energy Storage 80 MW/320 MWh	IC Engine Power Plant -Natural Gas (Western Region) 200 MW *Retirement of* *Gas Turbine (GT7)[8] (115) MW* *4x17 MW Sapugaskande Diesel (68) MW* *8x9 MW Sapugaskande Diesel Ext (72) MW*
2027	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 50 MW Grid Connected Fully Facilitated Solar 230 MW (With Battery Energy Storage) 100 MW/400MWh Wind 200 MW Mini Hydro 25 MW Biomass 20 MW Standalone Battery Energy Storage 100 MW/400 MWh	

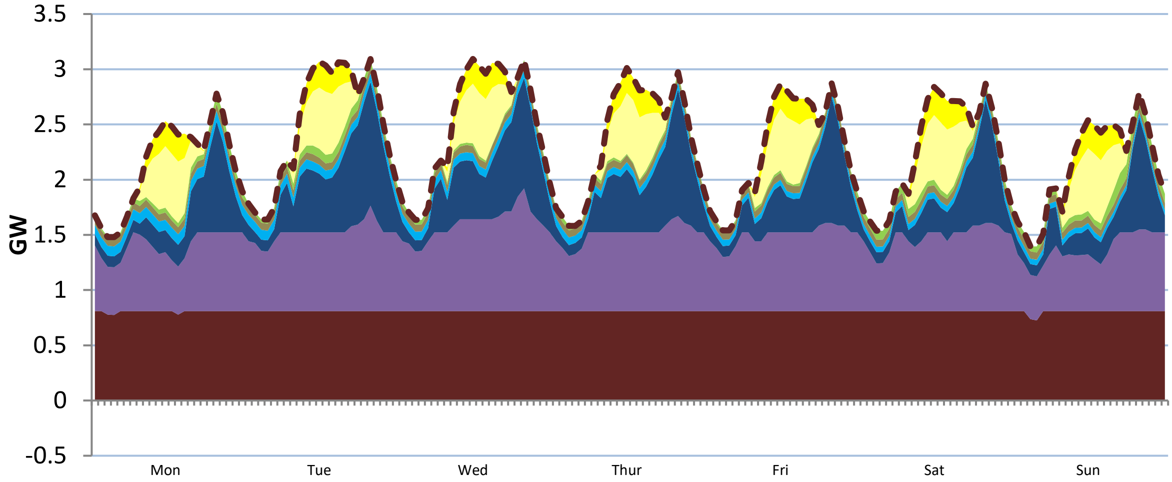
YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS(b)		THERMAL CAPACITY ADDITIONS and RETIREMENTS(a) (c)	
2028	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	170 MW 40 MW 310 MW 150 MW/600 MWh 200 MW 25 MW 10 MW 200MW/800 MWh	Gas Turbine -Natural Gas (Western Region)	100 MW
2029	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 20 MW 250 MW 150 MW/600 MWh 250 MW 25 MW 20 MW 350 MW		
2030	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 200 MW 100 MW/400MWh 70 MW 10 MW 20 MW 350 MW		
2031	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower Standalone Battery Energy Storage	170 MW 30 MW 100 MW 50 MW/200MWh 90 MW 10 MW 20 MW 350 MW 50 MW/200MWh	-	
2032	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 200 MW 100 MW/400MWh 70 MW 10 MW 20 MW 350 MW		
2033	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass	166 MW 30 MW 200 MW 100 MW/400MWh 145 MW 10 MW 15 MW	*Retirement of* *Combined Cycle Plant (KPS)* *Combined Cycle Plant (KPS- 2)* *Uthuru Janani Power Plant*	 *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass	170 MW 30 MW 200 MW 100 MW/400MWh 120 MW 10 MW 13 MW		

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]	THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]
2035	Distribution Connected Embedded Solar 165 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 200 MW (With Battery Energy Storage) 100 MW/400MWh Wind 140 MW Mini Hydro 10 MW Biomass 10 MW	Gas Turbine -Natural Gas 200 MW *Retirement of* *West Coast Combined Cycle Power Plant (300) MW*
2036	Distribution Connected Embedded Solar 174 MW Grid Connected Partially Facilitated Solar 5 MW Grid Connected Fully Facilitated Solar 200 MW (With Battery Energy Storage) 100 MW/400MWh Wind 150 MW Mini Hydro 10 MW Biomass 6 MW Standalone Battery Energy Storage 25MW/100MWh	Gas Turbine -Natural Gas 200 MW
2037	Distribution Connected Embedded Solar 137 MW Grid Connected Partially Facilitated Solar 5 MW Grid Connected Fully Facilitated Solar 200 MW (With Battery Energy Storage) 100MW/400MWh Wind 150 MW Mini Hydro 10 MW Biomass 8 MW Standalone Battery Energy Storage 25MW/100MWh	Gas Turbine -Natural Gas 200 MW
2038	Distribution Connected Embedded Solar 126 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 250 MW (With Battery Energy Storage) 100MW/400MWh Wind 200 MW Mini Hydro 10 MW Standalone Battery Energy Storage 50MW/200MWh	IC Engine Power Plant -Natural Gas 250 MW
2039	Distribution Connected Embedded Solar 89 MW Grid Connected Partially Facilitated Solar 24 MW Grid Connected Fully Facilitated Solar 200 MW (With Battery Energy Storage) 100 MW/400 MWh Wind 200 MW Mini Hydro 10 MW Biomass 7 MW Standalone Battery Energy Storage 50 MW/200 MWh	IC Engine Power Plant -Natural Gas 200 MW
2040	Distribution Connected Embedded Solar 135 MW Grid Connected Partially Facilitated Solar 2 MW Grid Connected Fully Facilitated Solar 300 MW (With Battery Energy Storage) 150 MW/600 MWh Wind 80 MW Standalone Battery Energy Storage 50 MW/200 MWh	
2041	Distribution Connected Embedded Solar 47 MW Grid Connected Partially Facilitated Solar 10 MW Grid Connected Fully Facilitated Solar 300 MW (With Battery Energy Storage) 150 MW/600 MWh Wind 50 MW Biomass 10 MW Standalone Battery Energy Storage 50 MW/200 MWh	Combined Cycle Power Plant (Natural Gas) 400 MW *Retirement of* *Lakvijaya Coal Power Plant Unit 1 (300) MW*

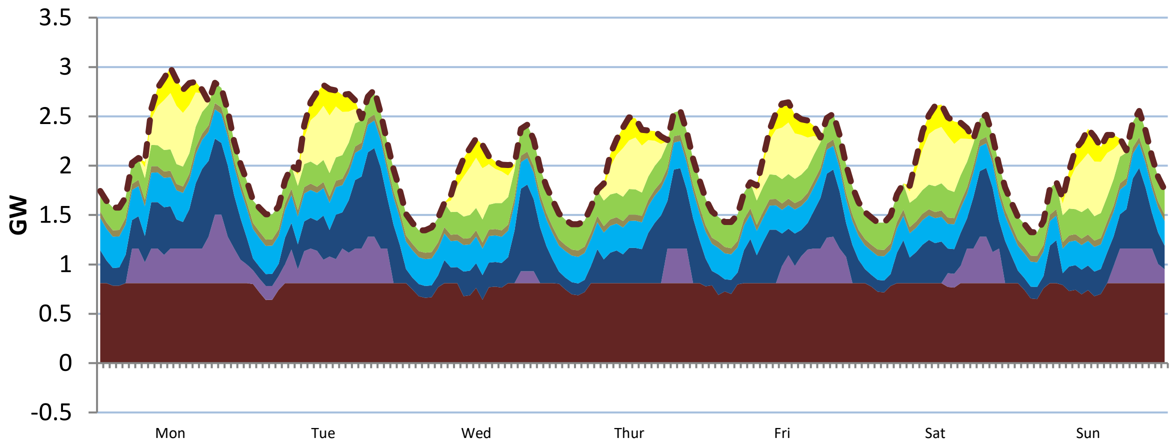
YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]		THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]	
2042	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Biomass Standalone Battery Energy Storage	150 MW 10 MW 300 MW 150 MW/600 MWh 50 MW 10 MW 50 MW/200 MWh	IC Engine Power Plant -Natural Gas	250 MW

Annex 9.1

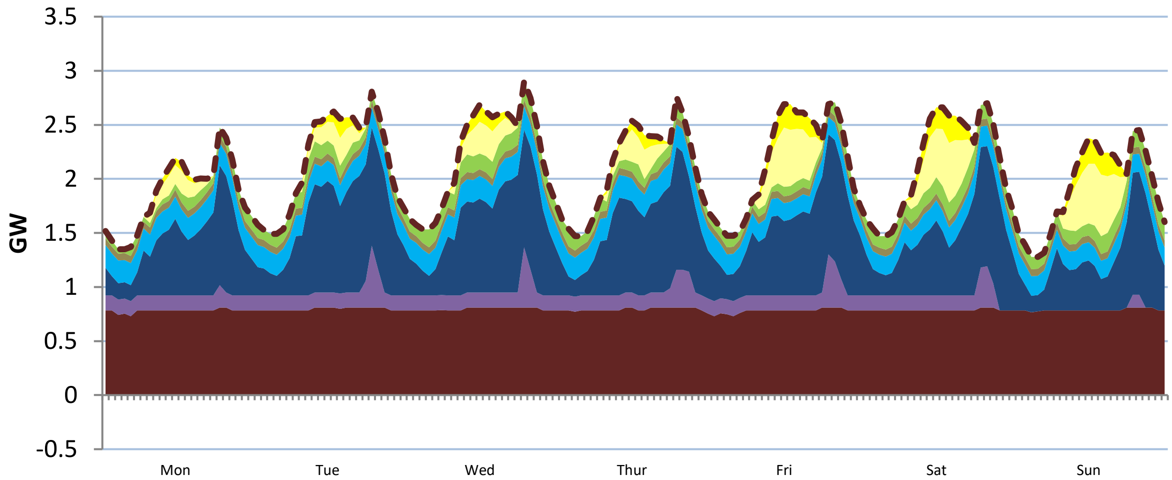
Weekly System Dispatch 2024



Weekly Dispatch Profile of Dry Season in Year 2024

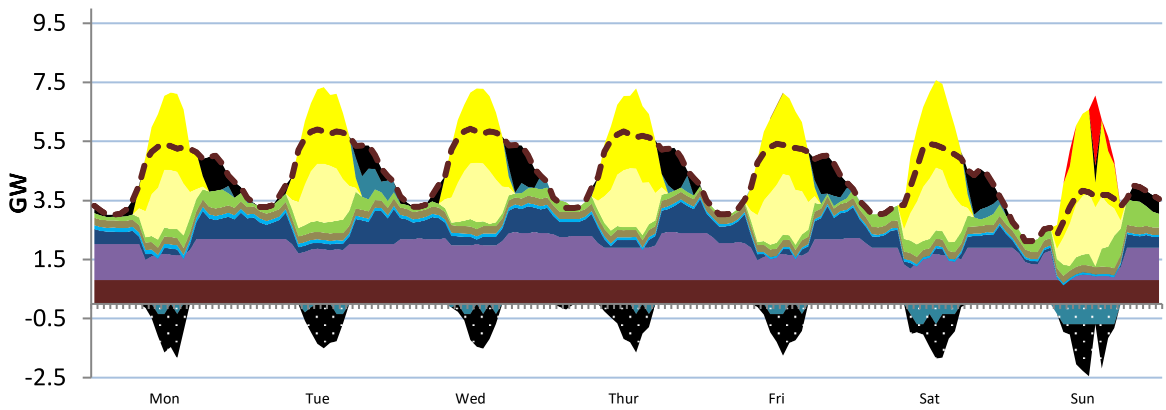


Dispatch Profile of High Wind Season in Year 2024

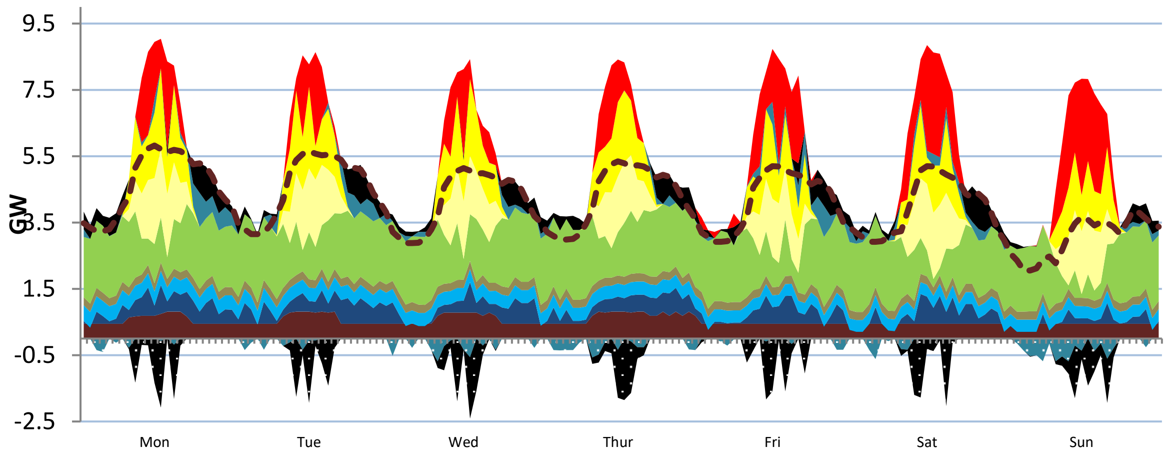


Dispatch Profile of Wet Season in Year 2024

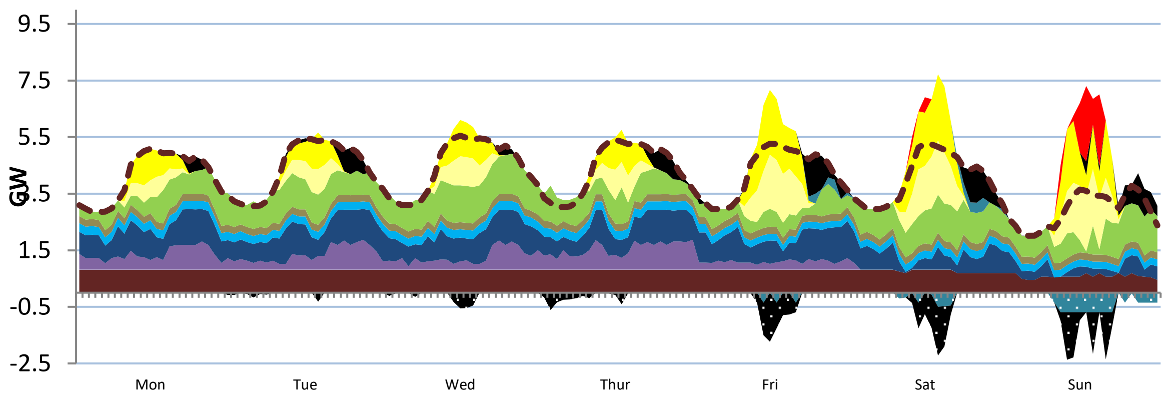
Weekly System Dispatch 2036



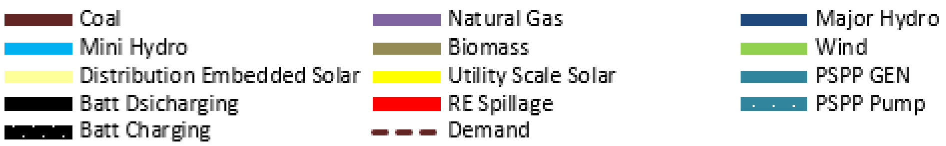
Dispatch Profile of Dry Season in Year 2036



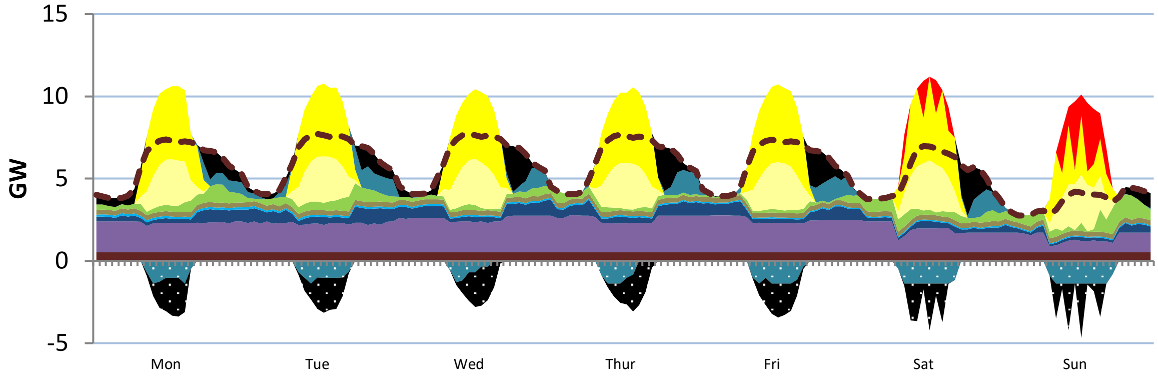
Dispatch Profile of High Wind Season in Year 2036



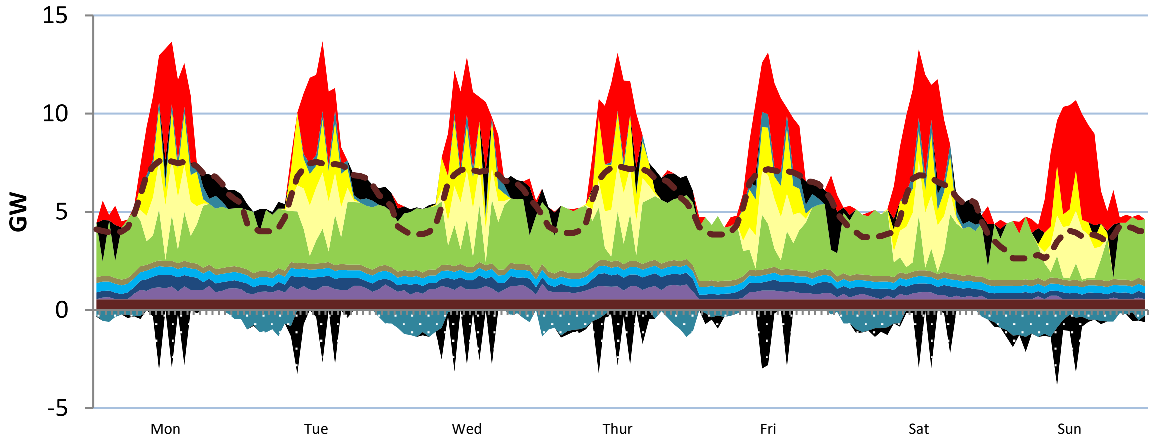
Dispatch Profile of Wet Season in Year 2036



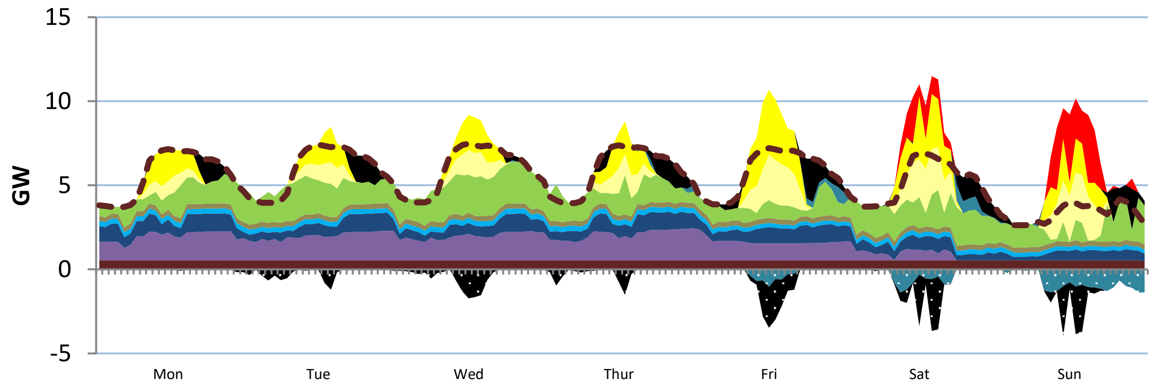
Weekly System Dispatch 2042



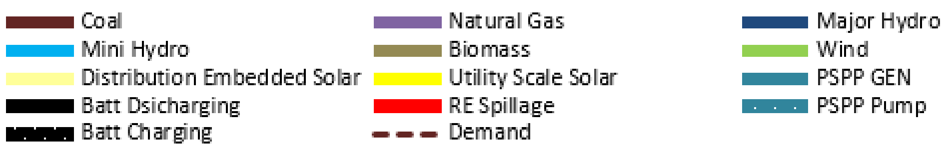
Weekly Dispatch Profile of Dry Season in Year 2042



Dispatch Profile of High Wind Season in Year 2042



Dispatch Profile of Wet Season in Year 2042



Annex 10.1

Results of Generation Expansion Planning Studies 2023-2042

Scenario 3: Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030, no coal fired plant additions throughout the horizon and considering cross border interconnection with India

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a)(b)]		THERMAL CAPACITY ADDITIONS and RETIREMENTS [(a)(c)]	
2022	**Uma Oya Hydropower Plant**	**120 MW**		
	Distribution Connected Embedded Solar	160 MW		
	Grid Connected Partially Facilitated Solar	**94 MW**		
	Mini Hydro	20 MW		
	Biomass	10 MW		
2023	Distribution Connected Embedded Solar	160 MW	**Gas Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)**	**235 MW**
	Grid Connected Partially Facilitated Solar [1]	**147 MW**	Short Term Supplementary Power [2]	320 MW
	Wind	**25 MW**	Combined Cycle Power Plant (KPS–2) [3]	163 MW
	Mini Hydro	20 MW	*Retirement of*	
	Biomass	20 MW	*Sojitz Kelanitissa Combined Cycle Plant* [3]	*(163) MW*
2024	**Moragolla Hydropower Plant**	**31 MW**	**New Gas Turbines – Kelanitissa** [4]	**130 MW**
	Distribution Connected Embedded Solar	160 MW	**Steam Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
	Grid Connected Partially Facilitated Solar [1]	223 MW	**Gas Turbine of Second NG Combined Cycle Plant (Kerawalapitiya)**	**235 MW**
	Grid Connected Fully Facilitated Solar	100 MW		
	Wind	**60 MW**	*Retirement of*	
	Mini Hydro	20 MW	*Kelanitissa Gas Turbines* [5]	*(68) MW*
	Biomass	20 MW	*Short Term Supplementary Power*	*(200) MW*
	Standalone Battery Energy Storage	20 MW/50 MWh		
2025	Distribution Connected Embedded Solar	165 MW	**Steam Turbine of Second NG Combined Cycle Plant (Kerawalapitiya)**	**115 MW**
	Grid Connected Partially Facilitated Solar	80 MW		
	Grid Connected Fully Facilitated Solar	260 MW		
	(With Battery Energy Storage)	100 MW/400 MWh	*Retirement of*	
	Wind (Mannar) [6]	100 MW	*CEB Barge Power Plant* [7]	*(62) MW*
	Wind	100 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW		
2026	Distribution Connected Embedded Solar	170 MW	IC Engine Power Plant -Natural Gas (Western Region)	200 MW
	Grid Connected Partially Facilitated Solar	70 MW		
	Grid Connected Fully Facilitated Solar	260 MW	*Retirement of*	
	(With Battery Energy Storage)	100 MW/400 MWh	*Gas Turbine (GT7)* [8]	*(115) MW*
	Wind	290 MW	*4x17 MW Sapugaskande Diesel*	*(68) MW*
	Mini Hydro	25 MW	*8x9 MW Sapugaskande Diesel Ext*	*(72) MW*
	Biomass	20 MW	*Short Term Supplementary Power*	*(120) MW*
	Standalone Battery Energy Storage	80 MW/320 MWh		
2027	Distribution Connected Embedded Solar	170 MW	Gas Turbine -Natural Gas (Western Region)	100 MW
	Grid Connected Partially Facilitated Solar	50 MW		
	Grid Connected Fully Facilitated Solar	280 MW		
	(With Battery Energy Storage)	100 MW/400MWh		
	Wind	250 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh		

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a)(b)]		THERMAL CAPACITY ADDITIONS and RETIREMENTS [(a)(c)]	
2028	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	170 MW 40 MW 310 MW 150 MW/600 MWh 200 MW 25 MW 20 MW 200MW/800 MWh		
2029	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 20 MW 350 MW 150 MW/600 MWh 250 MW 25 MW 20 MW 350 MW		
2030	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 250 MW 125 MW/500MWh 200 MW 10 MW 20 MW 350 MW		
2031	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 250 MW 125 MW/500MWh 200 MW 10 MW 20 MW 350 MW	-	
2032	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 30 MW 250 MW 125 MW/500MWh 150 MW 10 MW 20 MW 350 MW		
2033	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass	170 MW 30 MW 300 MW 150 MW/600MWh 150 MW 10 MW 20 MW	*Retirement of* *Combined Cycle Plant (KPS)* *Combined Cycle Plant (KPS- 2)* *Uthuru Janani Power Plant*	 *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass	180 MW 30 MW 300 MW 150 MW/600MWh 150 MW 10 MW 20 MW	HVDC interconnection	500 MW
2035	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	180 MW 30 MW 300 MW 125MW/500MWh 150 MW 10 MW 10 MW 50MW/200MWh	IC Engine Power Plant -Natural Gas *Retirement of* *West Coast Combined Cycle Power Plant*	250 MW *(300) MW*

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a)(b)]		THERMAL CAPACITY ADDITIONS and RETIREMENTS [(a)(c)]	
2036	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	190 MW 30 MW 300 MW 100MW/400MWh 150 MW 10 MW 10 MW 100MW/400MWh		
2037	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	190 MW 30 MW 300 MW 100MW/400MWh 150 MW 10 MW 10 MW 100MW/400MWh	Gas Turbine -Natural Gas	200 MW
2038	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	200 MW 30 MW 300 MW 100MW/400MWh 150 MW 10 MW 10 MW 100MW/400MWh	IC Engine Power Plant -Natural Gas	200 MW
2039	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	200 MW 30 MW 300 MW 100 MW/400 MWh 150 MW 10 MW 10 MW 100 MW/400 MWh	Gas Turbine -Natural Gas	200 MW
2040	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Biomass Standalone Battery Energy Storage	200 MW 20 MW 300 MW 115 MW/460 MWh 150 MW 10 MW 100 MW/400 MWh	IC Engine Power Plant -Natural Gas	200 MW
2041	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Biomass Standalone Battery Energy Storage	200 MW 20 MW 300 MW 125 MW/500 MWh 150 MW 10 MW 100 MW/400 MWh	Gas Turbine -Natural Gas Combined Cycle Power Plant (Natural Gas) *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	100 MW 400 MW *(300) MW*
2042	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Biomass Standalone Battery Energy Storage	200 MW 20 MW 300 MW 125 MW/500 MWh 150 MW 10 MW 150 MW/600 MWh		

Annex 10.2

Results of Generation Expansion Planning Studies 2023-2042

Scenario 4: Achieving 70 % RE by 2030, maintaining 70% RE beyond 2030, no coal fired plant additions throughout the horizon and considering nuclear power development beyond 2040

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a)(b)]		THERMAL CAPACITY ADDITIONS and RETIREMENTS [(a)(c)]	
2022	**Uma Oya Hydropower Plant** Distribution Connected Embedded Solar **Grid Connected Partially Facilitated Solar** Mini Hydro Biomass	**120 MW** 160 MW **94 MW** 20 MW 10 MW		
2023	Distribution Connected Embedded Solar **Grid Connected Partially Facilitated Solar [1]** **Wind** Mini Hydro Biomass	160 MW **147 MW** **25 MW** 20 MW 20 MW	**Gas Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)** Short Term Supplementary Power [2] Combined Cycle Power Plant (KPS–2) [3] *Retirement of* *Sojitz Kelanitissa Combined Cycle Plant [3]*	**235 MW** 320 MW 163 MW *(163) MW*
2024	**Moragolla Hydropower Plant** Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar [1] Grid Connected Fully Facilitated Solar **Wind** Mini Hydro Biomass Standalone Battery Energy Storage	**31 MW** 160 MW 223 MW 100 MW **60 MW** 20 MW 20 MW 20 MW/50 MWh	**New Gas Turbines – Kelanitissa [4]** **Steam Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)** **Gas Turbine of Second NG Combined Cycle Plant (Kerawalapitiya)** *Retirement of* *Kelanitissa Gas Turbines [5]* *Short Term Supplementary Power*	**130 MW** **115 MW** **235 MW** *(68) MW* *(200) MW*
2025	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind (Mannar)[6] Wind Mini Hydro Biomass	165 MW 80 MW 260 MW 100 MW/400 MWh 100 MW 100 MW 25 MW 20 MW	**Steam Turbine of Second NG Combined Cycle Plant (Kerawalapitiya**) *Retirement of* *CEB Barge Power Plant [7]*	**115 MW** *(62) MW*
2026	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	170 MW 70 MW 260 MW 100 MW/400 MWh 290 MW 25 MW 20 MW 80 MW/320 MWh	IC Engine Power Plant -Natural Gas (Western Region) *Retirement of* *Gas Turbine (GT7)[8]* *4x17 MW Sapugaskande Diesel* *8x9 MW Sapugaskande Diesel Ext* *Short Term Supplementary Power*	200 MW *(115) MW* *(68) MW* *(72) MW* *(120) MW*
2027	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	170 MW 50 MW 280 MW 100 MW/400MWh 250 MW 25 MW 20 MW 100 MW/400 MWh	Gas Turbine -Natural Gas (Western Region)	100 MW

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a)(b)]		THERMAL CAPACITY ADDITIONS and RETIREMENTS [(a)(c)]	
2028	Distribution Connected Embedded Solar	170 MW		
	Grid Connected Partially Facilitated Solar	40 MW		
	Grid Connected Fully Facilitated Solar	310 MW		
	(With Battery Energy Storage)	150 MW/600 MWh		
	Wind	200 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW		
	Standalone Battery Energy Storage	200MW/800 MWh		
2029	Distribution Connected Embedded Solar	170 MW		
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	350 MW		
	(With Battery Energy Storage)	150 MW/600 MWh		
	Wind	250 MW		
	Mini Hydro	25 MW		
	Biomass	20 MW		
	Pumped Storage Hydropower	350 MW		
2030	Distribution Connected Embedded Solar	170 MW		
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	250 MW		
	(With Battery Energy Storage)	125 MW/500MWh		
	Wind	200 MW		
	Mini Hydro	10 MW		
	Biomass	20 MW		
	Pumped Storage Hydropower	350 MW		
2031	Distribution Connected Embedded Solar	170 MW	-	
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	250 MW		
	(With Battery Energy Storage)	125 MW/500MWh		
	Wind	200 MW		
	Mini Hydro	10 MW		
	Biomass	20 MW		
	Pumped Storage Hydropower	350 MW		
2032	Distribution Connected Embedded Solar	170 MW		
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	250 MW		
	(With Battery Energy Storage)	125 MW/500MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	20 MW		
	Pumped Storage Hydropower	350 MW		
2033	Distribution Connected Embedded Solar	170 MW		
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW	*Retirement of*	
	(With Battery Energy Storage)	150 MW/600MWh		
	Wind	150 MW	*Combined Cycle Plant (KPS)*	*(165) MW*
	Mini Hydro	10 MW	*Combined Cycle Plant (KPS- 2)*	*(163) MW*
	Biomass	20 MW	*Uthuru Janani Power Plant*	*(26.7) MW*
2034	Distribution Connected Embedded Solar	180 MW	Gas Turbine -Natural Gas	100 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	150 MW/600MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	20 MW		

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS [(a)(b)]		THERMAL CAPACITY ADDITIONS and RETIREMENTS [(a)(c)]	
2035	Distribution Connected Embedded Solar	180 MW	Gas Turbine -Natural Gas	100 MW
	Grid Connected Partially Facilitated Solar	30 MW	IC Engine Power Plant -Natural Gas	250 MW
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	125MW/500MWh		
	Wind	150 MW	*Retirement of*	
	Mini Hydro	10 MW		
	Biomass	10 MW	*West Coast Combined Cycle Power Plant*	*(300) MW*
	Standalone Battery Energy Storage	50MW/200MWh		
2036	Distribution Connected Embedded Solar	190 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100MW/400MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100MW/400MWh		
2037	Distribution Connected Embedded Solar	190 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100MW/400MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100MW/400MWh		
2038	Distribution Connected Embedded Solar	200 MW	IC Engine Power Plant -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100MW/400MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100MW/400MWh		
2039	Distribution Connected Embedded Solar	200 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	100 MW/400 MWh		
	Wind	150 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh		
2040	Distribution Connected Embedded Solar	200 MW	IC Engine Power Plant -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	115 MW/460 MWh		
	Wind	150 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh		
2041	Distribution Connected Embedded Solar	200 MW	Nuclear Power Plant	600 MW
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	125 MW/500 MWh		
	Wind	150 MW	*Retirement of*	
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh	*Lakvijaya Coal Power Plant Unit 1*	*(300) MW*
2042	Distribution Connected Embedded Solar	200 MW		
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	(With Battery Energy Storage)	125 MW/500 MWh		
	Wind	150 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	150 MW/600 MWh		

Annex 10.3

Results of Generation Expansion Planning Studies 2023-2042

Scenario 5: Achieving 50% RE by 2030, maintaining 50% RE beyond 2030 and no coal fired plant additions beyond 2030

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]		THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]	
2022	**Uma Oya Hydropower Plant** Distribution Connected Embedded Solar **Grid Connected Partially Facilitated Solar** Mini Hydro Biomass	**120 MW** 150 MW **94 MW** 15 MW 10 MW		
2023	Distribution Connected Embedded Solar **Grid Connected Partially Facilitated Solar [1]** **Wind** Mini Hydro Biomass	150 MW **147 MW** **25 MW** 15 MW 10 MW	**Gas Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)** Short Term Supplementary Power [2] *Retirement of* *Sojitz Kelanitissa Combined Cycle Plant [3]*	**235 MW** 320 MW *(163) MW*
2024	**Moragolla Hydropower Plant** Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar [1] Grid Connected Fully Facilitated Solar **Wind** Mini Hydro Biomass Standalone Battery Energy Storage	**31 MW** 150 MW 223 MW 100 MW **60 MW** 15 MW 10 MW 20 MW/50 MWh	**New Gas Turbines – Kelanitissa [4]** **Steam Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)** **Gas Turbine of Second NG Combined Cycle Plant(Kerawalapitiya)** *Retirement of* *Kelanitissa Gas Turbines[5]* *Short Term Supplementary Power*	**130 MW** **115 MW** **235 MW** *(68) MW* *(200) MW*
2025	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind (Mannar) [6] Wind Mini Hydro Biomass	150 MW 80 MW 100 MW 100 MW 100 MW 15 MW 10 MW	**Steam Turbine of Second NG Combined Cycle Plant(Kerawalapitiya***)* *Retirement of* *CEB Barge Power Plant [7]*	**115 MW** *(62) MW*
2026	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass Standalone Battery Energy Storage	150 MW 70 MW 100 MW 50MW/200 MWh 100 MW 15 MW 10 MW 80 MW/320 MWh	IC Engine Power Plant -Natural Gas Coal Power Plant *Retirement of* *Gas Turbine (GT7)[8]* *4x17 MW Sapugaskande Diesel* *8x9 MW Sapugaskande Diesel Ext* *Short Term Supplementary Power*	200 MW 300 MW *(115) MW* *(68)* *MW(72)* *MW* *(120) MW*
2027	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass	150 MW 20 MW 130 MW 100 MW 15 MW 10 MW		
2028	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro	150 MW 20 MW 200 MW 100 MW 15 MW	Coal Power Plant	300 MW

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]		THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]	
2029	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass Pumped Storage Hydropower	150 MW 20 MW 300 MW 100 MW 15 MW 10 MW 350 MW	Gas Turbine -Natural Gas	200 MW
2030	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass Pumped Storage Hydropower	170 MW 20 MW 150 MW 100 MW 10 MW 10 MW 350 MW		
2031	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass	170 MW 20 MW 100 MW 60 MW/240MWh 100 MW 10 MW 10 MW	-	
2032	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Mini Hydro Biomass	170 MW 20 MW 100 MW 10 MW 10 MW	Gas Turbine -Natural Gas	200 MW
2033	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass	170 MW 20 MW 100 MW 100 MW 10 MW 10 MW	Gas Turbine -Natural Gas *Retirement of* *Combined Cycle Plant (KPS)* *Combined Cycle Plant (KPS- 2)* *Uthuru Janani Power Plant*	600 MW *(165) MW* *(163) MW* *(26.7) MW*
2034	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass	180 MW 20 MW 100 MW 100 MW 10 MW 10 MW	Gas Turbine -Natural Gas	200 MW
2035	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass	180 MW 20 MW 250 MW 100 MW 10 MW 10 MW	Gas Turbine -Natural Gas IC Engine Power Plant -Natural Gas *Retirement of* *West Coast Combined Cycle Power Plant*	300 MW 250 MW *(300) MW*
2036	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar (With Battery Energy Storage) Wind Mini Hydro Biomass	190 MW 20 MW 200 MW 40MW/160MWh 100 MW 10 MW 10 MW	Gas Turbine -Natural Gas	300 MW
2037	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass	190 MW 20 MW 300 MW 100 MW 10 MW 10 MW	Gas Turbine -Natural Gas IC Engine Power Plant -Natural Gas	100 MW 200 MW

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]		THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]	
2038	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass	200 MW 20 MW 300 MW 100 MW 10 MW 10 MW	Gas Turbine -Natural Gas IC Engine Power Plant -Natural Gas	100 MW 200 MW
2039	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass Standalone Battery Energy Storage	200 MW 20 MW 300 MW 100 MW 10 MW 10 MW 100 MW/400 MWh	Gas Turbine -Natural Gas	300 MW
2040	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Biomass	200 MW 20 MW 230 MW 100 MW 7 MW	IC Engine Power Plant -Natural Gas	250 MW
2041	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Biomass	200 MW 20 MW 250 MW 10 MW	Gas Turbine -Natural Gas Combined Cycle Power Plant (Natural Gas) *Retirement of* *Lakvijaya Coal Power Plant Unit 1*	200 MW 400 MW *(300) MW*
2042	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Biomass	200 MW 20 MW 300 MW 100 MW 10 MW	Gas Turbine -Natural Gas IC Engine Power Plant -Natural Gas	100 MW 200 MW

Annex 10.4

Results of Generation Expansion Planning Studies 2023-2042

Scenario 7: Achieving 60 % RE by 2030, maintaining 60% RE beyond 2030 and no coal fired plant additions throughout the horizon

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS(b)		THERMAL CAPACITY ADDITIONS and RETIREMENTS(a) (c)	
2022	**Uma Oya Hydropower Plant** Distribution Connected Embedded Solar **Grid Connected Partially Facilitated Solar** Mini Hydro Biomass	**120 MW** 160 MW **94 MW** 20 MW 10 MW		
2023	Distribution Connected Embedded Solar **Grid Connected Partially Facilitated Solar [1]** **Wind** Mini Hydro Biomass	160 MW **147 MW** **25 MW** 20 MW 20 MW	**Gas Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)** Short Term Supplementary Power [2] *Retirement of* *Sojitz Kelanitissa Combined Cycle Plant [3]*	**235 MW** 320 MW *(163) MW*
2024	**Moragolla Hydropower Plant** Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar [1] Grid Connected Fully Facilitated Solar **Wind** Mini Hydro Biomass Standalone Battery Energy Storage	**31 MW** 160 MW 223 MW 100 MW **60 MW** 20 MW 20 MW 20 MW/50 MWh	**New Gas Turbines – Kelanitissa [4]** **Steam Turbine of Sobadhanvi NG Combined Cycle Plant (Kerawalapitiya)** **Gas Turbine of Second NG Combined Cycle Plant(Kerawalapitiya)** *Retirement of* *Kelanitissa Gas Turbines[5]* *Short Term Supplementary Power*	**130 MW** **115 MW** **235 MW** *(68) MW* *(200) MW*
2025	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind (Mannar) [6] Wind Mini Hydro Biomass	165 MW 80 MW 160 MW 100 MW 100 MW 25 MW 20 MW	**Steam Turbine of Second NG Combined Cycle Plant(Kerawalapitiya)** *Retirement of* *CEB Barge Power Plant [7]*	**115 MW** *(62) MW*
2026	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass Standalone Battery Energy Storage	170 MW 70 MW 100 MW 150 MW 25 MW 20 MW 80 MW/320 MWh	Gas Turbine -Natural Gas IC Engine Power Plant -Natural Gas *Retirement of* *Gas Turbine (GT7)[8]* *4x17 MW Sapugaskande Diesel* *8x9 MW Sapugaskande Diesel Ext* *Short Term Supplementary Power*	100 MW 200 MW *(115) MW* *(68) MW* *(72) MW* *(120) MW*
2027	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass	170 MW 50 MW 180 MW 100 MW 25 MW 20 MW	Gas Turbine -Natural Gas	100 MW
2028	Distribution Connected Embedded Solar Grid Connected Partially Facilitated Solar Grid Connected Fully Facilitated Solar Wind Mini Hydro Biomass	170 MW 40 MW 250 MW 100 MW 25 MW 20 MW	Gas Turbine -Natural Gas	300 MW

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]	THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]
2029	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 20 MW Grid Connected Fully Facilitated Solar 300 MW Wind 200 MW Mini Hydro 25 MW Biomass 20 MW Pumped Storage Hydropower 350 MW	Gas Turbine -Natural Gas 200 MW
2030	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 150 MW (With Battery Energy Storage) 100 MW/400 MWh Wind 200 MW Mini Hydro 10 MW Biomass 20 MW Pumped Storage Hydropower 350 MW	
2031	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 100 MW Wind 100 MW Mini Hydro 10 MW Biomass 20 MW	-
2032	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 100 MW Mini Hydro 10 MW Biomass 20 MW	Gas Turbine -Natural Gas 100 MW
2033	Distribution Connected Embedded Solar 170 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 100 MW Wind 100 MW Mini Hydro 10 MW Biomass 20 MW	Gas Turbine -Natural Gas 200 MW Combined Cycle Power Plant (Natural Gas) 400 MW *Retirement of* *Combined Cycle Plant (KPS) (165) MW* *Combined Cycle Plant (KPS- 2) (163) MW* *Uthuru Janani Power Plant (26.7) MW*
2034	Distribution Connected Embedded Solar 180 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 100 MW Wind 100 MW Mini Hydro 10 MW Biomass 20 MW	Gas Turbine -Natural Gas 300 MW
2035	Distribution Connected Embedded Solar 180 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 250 MW Wind 100 MW Mini Hydro 10 MW Biomass 10 MW	Gas Turbine -Natural Gas 300 MW IC Engine Power Plant -Natural Gas 250 MW *Retirement of* *West Coast Combined Cycle Power Plant (300) MW*
2036	Distribution Connected Embedded Solar 190 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 200 MW Wind 100 MW Mini Hydro 10 MW Biomass 10 MW	Gas Turbine -Natural Gas 200 MW
2037	Distribution Connected Embedded Solar 190 MW Grid Connected Partially Facilitated Solar 30 MW Grid Connected Fully Facilitated Solar 300 MW Wind 100 MW Mini Hydro 10 MW Biomass 10 MW	Gas Turbine -Natural Gas 100 MW IC Engine Power Plant -Natural Gas 200 MW

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS AND RETIREMENTS[b]		THERMAL CAPACITY ADDITIONS and RETIREMENTS[a] [c]	
2038	Distribution Connected Embedded Solar	200 MW	Gas Turbine -Natural Gas	100 MW
	Grid Connected Partially Facilitated Solar	30 MW	IC Engine Power Plant -Natural Gas	200 MW
	Grid Connected Fully Facilitated Solar	300 MW		
	Wind	100 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh		
2039	Distribution Connected Embedded Solar	200 MW	Gas Turbine -Natural Gas	200 MW
	Grid Connected Partially Facilitated Solar	30 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	Wind	100 MW		
	Mini Hydro	10 MW		
	Biomass	10 MW		
	Standalone Battery Energy Storage	100 MW/400 MWh		
2040	Distribution Connected Embedded Solar	200 MW	IC Engine Power Plant -Natural Gas	250 MW
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	230 MW		
	Wind	100 MW		
	Biomass	10 MW		
2041	Distribution Connected Embedded Solar	200 MW	Gas Turbine -Natural Gas	600 MW
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	250 MW		
	Wind	100 MW		
	Biomass	10 MW	*Retirement of*	
	Pumped Storage Hydropower	350 MW		
			Lakvijaya Coal Power Plant Unit 1	*(300) MW*
2042	Distribution Connected Embedded Solar	200 MW	Gas Turbine -Natural Gas	100 MW
	Grid Connected Partially Facilitated Solar	20 MW		
	Grid Connected Fully Facilitated Solar	300 MW		
	Wind	100 MW		
	Biomass	10 MW		

Investment Plan for Major Hydro & Thermal Projects (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2023		2024		2025		2026		2027		2028		2029		2030		2031		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	**L.C**	**F.C**	**Total**
2024 - 130 MW New Gas Turbines - Kelanitissa																					
Base Cost	19.1	76.4																	**19.1**	**76.4**	**95.5**
Contingencies	1.9	7.6																	**1.9**	**7.6**	**9.5**
Port Handling & other charges (5%)		4.2																	**0.0**	**4.2**	**4.2**
Total	21.0	88.2																	**21.0**	**88.2**	**109.2**
2024 -Moragolla HPP																					
Base Cost	2.3	9.1																	**2.3**	**9.1**	**11.4**
Contingencies	0.2	0.9																	**0.2**	**0.9**	**1.1**
Port Handling & other charges (5%)		0.5																	**0.0**	**0.5**	**0.5**
Total	2.5	10.5																	**2.5**	**10.5**	**13.0**
2024 - 350 MW Sobadhanavi NG Combined Cycle Plant (Kerawalapitiya)																					
Base Cost	56.7	226.9																	**56.7**	**226.9**	**283.7**
Contingencies	5.7	22.7																	**5.7**	**22.7**	**28.4**
Port Handling & other charges (5%)		12.5																	**0.0**	**12.5**	**12.5**
Total	62.4	262.1																	**62.4**	**262.1**	**324.5**
2025 - 350 MW Second NG Combined Cycle Plant (Kerawalapitiya)																					
Base Cost	6.3	25.3	56.7	226.9															**63.1**	**252.3**	**315.3**
Contingencies	0.6	2.5	5.7	22.7															**6.3**	**25.2**	**31.5**
Port Handling & other charges (5%)		1.4		12.5															**0.0**	**13.9**	**13.9**
Total	7.0	29.3	62.4	262.1															**69.4**	**291.4**	**360.7**
2026 - 200 MW IC Engine Power Plant - Natural Gas (Western Region)																					
Base Cost			2.8	11.1	25.0	99.9													**27.8**	**111.0**	**138.8**
Contingencies			0.3	1.1	2.5	10.0													**2.8**	**11.1**	**13.9**
Port Handling & other charges (5%)				0.6		5.5													**0.0**	**6.1**	**6.1**
Total			3.1	12.9	27.5	115.4													**30.5**	**128.2**	**158.8**
2027 - 100 MW Gas Turbine - Natural Gas																					
Base Cost					0.8	3.4	7.5	30.1											**8.4**	**33.4**	**41.8**
Contingencies					0.1	0.3	0.8	3.0											**0.8**	**3.3**	**4.2**
Port Handling & other charges (5%)						0.2		1.7											**0.0**	**1.8**	**1.8**
Total					0.9	3.9	8.3	34.7											**9.2**	**38.6**	**47.8**
2029 - 350 MW Pumped Storage Hydropower																					
Base Cost			2.7	10.8	8.1	32.5	18.4	73.6	18.9	75.7	6.0	23.8							**54.1**	**216.4**	**270.5**
Contingencies			0.3	1.1	0.8	3.2	1.8	7.4	1.9	7.6	0.6	2.4							**5.4**	**21.6**	**27.0**
Port Handling & other charges (5%)				0.6		1.8		4.0		4.2		1.3							**0.0**	**11.9**	**11.9**
Total			3.0	12.5	8.9	37.5	20.2	85.0	20.8	87.5	6.5	27.5							**59.5**	**249.9**	**309.4**
2030 - 350 MW Pumped Storage Hydropower																					
Base Cost					2.7	10.8	8.1	32.5	18.4	73.6	18.9	75.7	6.0	23.8					**54.1**	**216.4**	**270.5**
Contingencies					0.3	1.1	0.8	3.2	1.8	7.4	1.9	7.6	0.6	2.4					**5.4**	**21.6**	**27.0**
Port Handling & other charges (5%)					0.0	0.6	0.0	1.8	0.0	4.0	0.0	4.2	0.0	1.3					**0.0**	**11.9**	**11.9**
Total					3.0	12.5	8.9	37.5	20.2	85.0	20.8	87.5	6.5	27.5					**59.5**	**249.9**	**309.4**
Annual Total	**92.9**	**390.1**	**68.4**	**287.5**	**37.3**	**156.7**															

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Investment Plan for Major Hydro & Thermal Projects (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2026		2027		2028		2029		2030		2031		2032		2033		2034		2035		Total		Grand Total
	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	L.C	F.C	L.C	F.C	
2031 - 350 MW Pumped Storage Hydropower																							
Base Cost	2.7	10.8	8.1	32.5	18.4	73.6	18.9	75.7	6.0	23.8											**54.1**	**216.4**	**270.5**
Contingencies	0.3	1.1	0.8	3.2	1.8	7.4	1.9	7.6	0.6	2.4											**5.4**	**21.6**	**27.0**
Port Handling & other charges (5%)	0.0	0.6	0.0	1.8	0.0	4.0	0.0	4.2	0.0	1.3											**0.0**	**11.9**	**11.9**
Total	3.0	12.5	8.9	37.5	20.2	85.0	20.8	87.5	6.5	27.5											**59.5**	**249.9**	**309.4**
2032 - 350 MW Pumped Storage Hydropower																							
Base Cost			2.7	10.8	8.1	32.5	18.4	73.6	18.9	75.7	6.0	23.8									**54.1**	**216.4**	**270.5**
Contingencies			0.3	1.1	0.8	3.2	1.8	7.4	1.9	7.6	0.6	2.4									**5.4**	**21.6**	**27.0**
Port Handling & other charges (5%)			0.0	0.6	0.0	1.8	0.0	4.0	0.0	4.2	0.0	1.3									**0.0**	**11.9**	**11.9**
Total			3.0	12.5	8.9	37.5	20.2	85.0	20.8	87.5	6.5	27.5									**59.5**	**249.9**	**309.4**
2034 - 100 MW Gas Turbine - Natural Gas																							
Base Cost													0.8	3.4	7.5	30.1					**8.4**	**33.4**	**41.8**
Contingencies													0.1	0.3	0.8	3.0					**0.8**	**3.3**	**4.2**
Port Handling & other charges (5%)													0.0	0.2	0.0	1.7					**0.0**	**1.8**	**1.8**
Total													0.9	3.9	8.3	34.7					**9.2**	**38.6**	**47.8**
2035 - 100 MW Gas Turbine - Natural Gas																							
Base Cost															0.8	3.4	7.5	30.1			**8.4**	**33.4**	**41.8**
Contingencies															0.1	0.3	0.8	3.0			**0.8**	**3.3**	**4.2**
Port Handling & other charges (5%)															0.0	0.2	0.0	1.7			**0.0**	**1.8**	**1.8**
Total															0.9	3.9	8.3	34.7			**9.2**	**38.6**	**47.8**
2035 - 250 MW IC Engine Power Plant - Natural Gas																							
Base Cost															3.4	13.7	30.7	122.9			**34.2**	**136.7**	**170.8**
Contingencies															0.3	1.4	3.1	12.3			**3.4**	**13.7**	**17.1**
Port Handling & other charges (5%)																0.8		6.8			**0.0**	**7.5**	**7.5**
Total															3.8	15.8	33.8	142.0			**37.6**	**157.8**	**195.4**
2036 - 200 MW Gas Turbine - Natural Gas																							
Base Cost																	1.3	5.3	11.8	47.1	**13.1**	**52.3**	**65.4**
Contingencies																	0.1	0.5	1.2	4.7	**1.3**	**5.2**	**6.5**
Port Handling & other charges (5%)																		0.3		2.6	**0.0**	**2.9**	**2.9**
Total																	1.4	6.1	12.9	54.4	**14.4**	**60.4**	**74.8**
Annual Total	**40.4**	**169.7**	**53.0**	**222.4**	**56.5**	**237.4**	**47.6**	**199.9**	**27.4**	**115.0**	**6.5**	**27.5**	**0.9**	**3.9**	**13.0**	**54.5**	**43.5**	**182.8**					

Continued in the next page

Investment Plan for Major Hydro & Thermal Projects (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2035		2036		2037		2038		2039		2040		2041		2042		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
2037 - 200 MW Gas Turbine - Natural Gas																			
Base Cost	1.3	5.3	11.8	47.1													**13.1**	**52.3**	**65.4**
Contingencies	0.1	0.5	1.2	4.7													**1.3**	**5.2**	**6.5**
Port Handling & other charges (5%)	0.0	0.3	0.0	2.6													**0.0**	**2.9**	**2.9**
Total	1.4	6.1	12.9	54.4													**14.4**	**60.4**	**74.8**
2038 - 200 MW IC Engine Power Plant - Natural Gas																			
Base Cost			2.8	11.1	25.0	99.9											**27.8**	**111.0**	**138.8**
Contingencies			0.3	1.1	2.5	10.0											**2.8**	**11.1**	**13.9**
Port Handling & other charges (5%)			0.0	0.6	0.0	5.5											**0.0**	**6.1**	**6.1**
Total			3.1	12.9	27.5	115.4											**30.5**	**128.2**	**158.8**
2039 - 200 MW Gas Turbine - Natural Gas																			
Base Cost					1.3	5.3	11.8	47.1									**13.1**	**52.3**	**65.4**
Contingencies					0.1	0.5	1.2	4.7									**1.3**	**5.2**	**6.5**
Port Handling & other charges (5%)					0.0	0.3	0.0	2.6									**0.0**	**2.9**	**2.9**
Total					1.4	6.1	12.9	54.4									**14.4**	**60.4**	**74.8**
2040 - 200 MW IC Engine Power Plant - Natural Gas																			
Base Cost							2.8	11.1	25.0	99.9							**27.8**	**111.0**	**138.8**
Contingencies							0.3	1.1	2.5	10.0							**2.8**	**11.1**	**13.9**
Port Handling & other charges (5%)							0.0	0.6	0.0	5.5							**0.0**	**6.1**	**6.1**
Total							3.1	12.9	27.5	115.4							**30.5**	**128.2**	**158.8**
2041 - 100 MW Gas Turbine - Natural Gas																			
Base Cost									0.8	3.4	7.5	30.1					**8.4**	**33.4**	**41.8**
Contingencies									0.1	0.3	0.8	3.0					**0.8**	**3.3**	**4.2**
Port Handling & other charges (5%)									0.0	0.2	0.0	1.7					**0.0**	**1.8**	**1.8**
Total									0.9	3.9	8.3	34.7					**9.2**	**38.6**	**47.8**
2041 - 400 MW Combined Cycle Power Plant (Natural Gas)																			
Base Cost									7.6	30.3	67.9	271.7					**75.5**	**302.0**	**377.5**
Contingencies									0.8	3.0	6.8	27.2					**7.5**	**30.2**	**37.7**
Port Handling & other charges (5%)										1.7		14.9					**0.0**	**16.6**	**16.6**
Total									8.3	35.0	74.7	313.8					**83.0**	**348.8**	**431.8**
Annual Total	**14.4**	**60.4**	**16.0**	**67.2**	**28.9**	**121.4**	**16.0**	**67.2**	**36.7**	**154.3**	**83.0**	**348.5**							

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Investment Plan for Major Wind, Solar and BESS Developments (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2023		2024		2025		2026		2027		2028		2029		2030		**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**
2023 - 160 MW Distribution Connected Solar																			
Base Cost	30.7	122.8															**30.7**	**122.8**	**153.5**
Contingencies	3.1	12.3															**3.1**	**12.3**	**15.3**
Port Handling & other charges (5%)		6.8															**0.0**	**6.8**	**6.8**
Total	33.8	141.8															**33.8**	**141.8**	**175.6**
2023 - 147 MW Grid Connected Partially Facilitated Solar																			
Base Cost	22.7	90.9															**22.7**	**90.9**	**113.6**
Contingencies	2.3	9.1															**2.3**	**9.1**	**11.4**
Port Handling & other charges (5%)		5.0															**0.0**	**5.0**	**5.0**
Total	25.0	105.0															**25.0**	**105.0**	**129.9**
2023 -25 MW Wind																			
Base Cost	6.4	25.5															**6.4**	**25.5**	**31.8**
Contingencies	0.6	2.5															**0.6**	**2.5**	**3.2**
Port Handling & other charges (5%)		1.4															**0.0**	**1.4**	**1.4**
Total	7.0	29.4															**7.0**	**29.4**	**36.4**
2024 - 160 MW Distribution Connected Solar																			
Base Cost			30.7	122.8													**30.7**	**122.8**	**153.5**
Contingencies			3.1	12.3													**3.1**	**12.3**	**15.3**
Port Handling & other charges (5%)			0.0	6.8													**0.0**	**6.8**	**6.8**
Total			33.8	141.8													**33.8**	**141.8**	**175.6**
2024 - 223 MW Grid Connected Partially Facilitated Solar																			
Base Cost			34.5	137.9													**34.5**	**137.9**	**172.3**
Contingencies			3.4	13.8													**3.4**	**13.8**	**17.2**
Port Handling & other charges (5%)				7.6													**0.0**	**7.6**	**7.6**
Total			37.9	159.2													**37.9**	**159.2**	**197.1**
2024 - 100 MW Grid Connected Fully Facilitated Solar																			
Base Cost			15.5	61.8													**15.5**	**61.8**	**77.3**
Contingencies			1.5	6.2													**1.5**	**6.2**	**7.7**
Port Handling & other charges (5%)				3.4													**0.0**	**3.4**	**3.4**
Total			17.0	71.4													**17.0**	**71.4**	**88.4**
2024 - 60 MW Wind																			
Base Cost			15.3	61.1													**15.3**	**61.1**	**76.4**
Contingencies			1.5	6.1													**1.5**	**6.1**	**7.6**
Port Handling & other charges (5%)				3.4													**0.0**	**3.4**	**3.4**
Total			16.8	70.6													**16.8**	**70.6**	**87.4**
2024 - 20MW/50 MWh BESS																			
Base Cost			5.1	20.6													**5.1**	**20.6**	**25.7**
Contingencies			0.5	2.1													**0.5**	**2.1**	**2.6**
Port Handling & other charges (5%)				1.1													**0.0**	**1.1**	**1.1**
Total			5.7	23.8													**5.7**	**23.8**	**29.5**
2025 - 165 MW Distribution Connected Solar																			
Base Cost					31.7	126.6											**31.7**	**126.6**	**158.3**
Contingencies					3.2	12.7											**3.2**	**12.7**	**15.8**
Port Handling & other charges (5%)						7.0											**0.0**	**7.0**	**7.0**
Total					34.8	146.2											**34.8**	**146.2**	**181.0**
2025 - 80 MW Grid Connected Partially Facilitated Solar																			
Base Cost					12.4	49.5											**12.4**	**49.5**	**61.8**
Contingencies					1.2	4.9											**1.2**	**4.9**	**6.2**
Port Handling & other charges (5%)						2.7											**0.0**	**2.7**	**2.7**
Total					13.6	57.1											**13.6**	**57.1**	**70.7**
Annual Total	**65.8**	**276.2**	**111.1**	**466.8**															

Continued in the next page

Investment Plan for Major Wind, Solar and BESS Developments (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	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**	**Total**
2025 - 260 MW Grid Connected Fully Facilitated Solar											
Base Cost	45.1	180.4							**45.1**	**180.4**	**225.5**
Contingencies	4.5	18.0							**4.5**	**18.0**	**22.5**
Port Handling & other charges (5%)		9.9							**0.0**	**9.9**	**9.9**
Total	49.6	208.3							**49.6**	**208.3**	**257.9**
2025 - 200 MW Wind											
Base Cost	50.9	203.6							**50.9**	**203.6**	**254.5**
Contingencies	5.1	20.4							**5.1**	**20.4**	**25.5**
Port Handling & other charges (5%)		11.2							**0.0**	**11.2**	**11.2**
Total	56.0	235.2							**56.0**	**235.2**	**291.2**
2025 - 100 MW/400 MWh BESS											
Base Cost	25.7	103.0							**25.7**	**103.0**	**128.7**
Contingencies	2.6	10.3							**2.6**	**10.3**	**12.9**
Port Handling & other charges (5%)		5.7							**0.0**	**5.7**	**5.7**
Total	28.3	118.9							**28.3**	**118.9**	**147.3**
2026 - 170 MW Distribution Connected Solar											
Base Cost			32.6	130.4					**32.6**	**130.4**	**163.0**
Contingencies			3.3	13.0					**3.3**	**13.0**	**16.3**
Port Handling & other charges (5%)				7.2					**0.0**	**7.2**	**7.2**
Total			35.9	150.7					**35.9**	**150.7**	**186.5**
2026 - 70 MW Grid Connected Partially Facilitated Solar											
Base Cost			10.8	43.3					**10.8**	**43.3**	**54.1**
Contingencies			1.1	4.3					**1.1**	**4.3**	**5.4**
Port Handling & other charges (5%)				2.4					**0.0**	**2.4**	**2.4**
Total			11.9	50.0					**11.9**	**50.0**	**61.9**
2026 - 260 MW Grid Connected Fully Facilitated Solar											
Base Cost			40.2	160.7					**40.2**	**160.7**	**200.9**
Contingencies			4.0	16.1					**4.0**	**16.1**	**20.1**
Port Handling & other charges (5%)				8.8					**0.0**	**8.8**	**8.8**
Total			44.2	185.6					**44.2**	**185.6**	**229.8**
2026 - 290 MW Wind											
Base Cost			73.8	295.3					**73.8**	**295.3**	**369.1**
Contingencies			7.4	29.5					**7.4**	**29.5**	**36.9**
Port Handling & other charges (5%)				16.2					**0.0**	**16.2**	**16.2**
Total			81.2	341.0					**81.2**	**341.0**	**422.2**
2026 - 180 MW/720 MWh BESS											
Base Cost			46.3	185.4					**46.3**	**185.4**	**231.7**
Contingencies			4.6	18.5					**4.6**	**18.5**	**23.2**
Port Handling & other charges (5%)				10.2					**0.0**	**10.2**	**10.2**
Total			51.0	214.1					**51.0**	**214.1**	**265.1**
2027 - 170 MW Distribution Connected Solar											
Base Cost					32.6	130.4			**32.6**	**130.4**	**163.0**
Contingencies					3.3	13.0			**3.3**	**13.0**	**16.3**
Port Handling & other charges (5%)						7.2			**0.0**	**7.2**	**7.2**
Total					35.9	150.7			**35.9**	**150.7**	**186.5**
2027 - 50 MW Grid Connected Partially Facilitated Solar											
Base Cost					7.7	30.9			**7.7**	**30.9**	**38.6**
Contingencies					0.8	3.1			**0.8**	**3.1**	**3.9**
Port Handling & other charges (5%)						1.7			**0.0**	**1.7**	**1.7**
Total					8.5	35.7			**8.5**	**35.7**	**44.2**
Annual Total	**182.3**	**765.8**	**224.1**	**941.4**							

Continued in the next page

Investment Plan for Major Wind, Solar and BESS Developments (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2027		2028		2029		2030		2031		2032		2033		2034		**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**
2027 - 280 MW Grid Connected Fully Facilitated Solar																			
Base Cost	47.4	189.5															**47.4**	**189.5**	**236.8**
Contingencies	4.7	18.9															**4.7**	**18.9**	**23.7**
Port Handling & other charges (5%)		10.4															**0.0**	**10.4**	**10.4**
Total	52.1	218.8															**52.1**	**218.8**	**270.9**
2027 - 250 MW Wind																			
Base Cost	63.6	254.5															**63.6**	**254.5**	**318.2**
Contingencies	6.4	25.5															**6.4**	**25.5**	**31.8**
Port Handling & other charges (5%)		14.0															**0.0**	**14.0**	**14.0**
Total	70.0	294.0															**70.0**	**294.0**	**364.0**
2027 - 200 MW/800 MWh BESS																			
Base Cost	51.5	206.0															**51.5**	**206.0**	**257.5**
Contingencies	5.1	20.6															**5.1**	**20.6**	**25.7**
Port Handling & other charges (5%)		11.3															**0.0**	**11.3**	**11.3**
Total	56.6	237.9															**56.6**	**237.9**	**294.5**
2028 - 170 MW Distribution Connected Solar																			
Base Cost			32.6	130.4													**32.6**	**130.4**	**163.0**
Contingencies			3.3	13.0													**3.3**	**13.0**	**16.3**
Port Handling & other charges (5%)				7.2													**0.0**	**7.2**	**7.2**
Total			35.9	150.7													**35.9**	**150.7**	**186.5**
2028 - 40 MW Grid Connected Partially Facilitated Solar																			
Base Cost			6.2	24.7													**6.2**	**24.7**	**30.9**
Contingencies			0.6	2.5													**0.6**	**2.5**	**3.1**
Port Handling & other charges (5%)				1.4													**0.0**	**1.4**	**1.4**
Total			6.8	28.6													**6.8**	**28.6**	**35.4**
2028 - 310 MW Grid Connected Fully Facilitated Solar																			
Base Cost			52.0	208.0													**52.0**	**208.0**	**260.0**
Contingencies			5.2	20.8													**5.2**	**20.8**	**26.0**
Port Handling & other charges (5%)				11.4													**0.0**	**11.4**	**11.4**
Total			57.2	240.2													**57.2**	**240.2**	**297.4**
2028 - 200 MW Wind																			
Base Cost			50.9	203.6													**50.9**	**203.6**	**254.5**
Contingencies			5.1	20.4													**5.1**	**20.4**	**25.5**
Port Handling & other charges (5%)				11.2													**0.0**	**11.2**	**11.2**
Total			56.0	235.2													**56.0**	**235.2**	**291.2**
2028 - 350 MW/1400 MWh BESS																			
Base Cost			90.1	360.4													**90.1**	**360.4**	**450.5**
Contingencies			9.0	36.0													**9.0**	**36.0**	**45.1**
Port Handling & other charges (5%)				19.8													**0.0**	**19.8**	**19.8**
Total			99.1	416.3													**99.1**	**416.3**	**515.4**
2029 - 170 MW Distribution Connected Solar																			
Base Cost					32.6	130.4											**32.6**	**130.4**	**163.0**
Contingencies					3.3	13.0											**3.3**	**13.0**	**16.3**
Port Handling & other charges (5%)						7.2											**0.0**	**7.2**	**7.2**
Total					35.9	150.7											**35.9**	**150.7**	**186.5**
2029 - 20 MW Grid Connected Partially Facilitated Solar																			
Base Cost					3.1	12.4											**3.1**	**12.4**	**15.5**
Contingencies					0.3	1.2											**0.3**	**1.2**	**1.5**
Port Handling & other charges (5%)						0.7											**0.0**	**0.7**	**0.7**
Total					3.4	14.3											**3.4**	**14.3**	**17.7**
2029 - 350 MW Grid Connected Fully Facilitated Solar																			
Base Cost					58.2	232.7											**58.2**	**232.7**	**290.9**
Contingencies					5.8	23.3											**5.8**	**23.3**	**29.1**
Port Handling & other charges (5%)						12.8											**0.0**	**12.8**	**12.8**
Total					64.0	268.8											**64.0**	**268.8**	**332.8**
Annual Total	**223.1**	**937.1**	**255.0**	**1071.0**															

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Investment Plan for Major Wind, Solar and BESS Developments (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2029		2030		2031		2032		2033		2034		2035		2036		**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**
2029 - 250 MW Wind																			
Base Cost	63.6	254.5															**63.6**	**254.5**	**318.2**
Contingencies	6.4	25.5															**6.4**	**25.5**	**31.8**
Port Handling & other charges (5%)		14.0															**0.0**	**14.0**	**14.0**
Total	70.0	294.0															**70.0**	**294.0**	**364.0**
2029 - 150 MW/600 MWh BESS																			
Base Cost	38.6	154.5															**38.6**	**154.5**	**193.1**
Contingencies	3.9	15.4															**3.9**	**15.4**	**19.3**
Port Handling & other charges (5%)		8.5															**0.0**	**8.5**	**8.5**
Total	42.5	178.4															**42.5**	**178.4**	**220.9**
2030 - 170 MW Distribution Connected Solar																			
Base Cost			32.6	130.4													**32.6**	**130.4**	**163.0**
Contingencies			3.3	13.0													**3.3**	**13.0**	**16.3**
Port Handling & other charges (5%)				7.2													**0.0**	**7.2**	**7.2**
Total			35.9	150.7													**35.9**	**150.7**	**186.5**
2030 - 30 MW Grid Connected Partially Facilitated Solar																			
Base Cost			4.6	18.5													**4.6**	**18.5**	**23.2**
Contingencies			0.5	1.9													**0.5**	**1.9**	**2.3**
Port Handling & other charges (5%)				1.0													**0.0**	**1.0**	**1.0**
Total			5.1	21.4													**5.1**	**21.4**	**26.5**
2030 - 250 MW Grid Connected Fully Facilitated Solar																			
Base Cost			38.6	154.5													**38.6**	**154.5**	**193.2**
Contingencies			3.9	15.5													**3.9**	**15.5**	**19.3**
Port Handling & other charges (5%)				8.5													**0.0**	**8.5**	**8.5**
Total			42.5	178.5													**42.5**	**178.5**	**221.0**
2030 - 230 MW Wind																			
Base Cost			58.8	235.0													**58.8**	**235.0**	**293.8**
Contingencies			5.9	23.5													**5.9**	**23.5**	**29.4**
Port Handling & other charges (5%)				12.9													**0.0**	**12.9**	**12.9**
Total			64.6	271.5													**64.6**	**271.5**	**336.1**
2030 - 125 MW/500 MWh BESS																			
Base Cost			32.2	128.7													**32.2**	**128.7**	**160.9**
Contingencies			3.2	12.9													**3.2**	**12.9**	**16.1**
Port Handling & other charges (5%)				7.1													**0.0**	**7.1**	**7.1**
Total			35.4	148.7													**35.4**	**148.7**	**184.1**
2031 - 170 MW Distribution Connected Solar																			
Base Cost					32.6	130.4											**32.6**	**130.4**	**163.0**
Contingencies					3.3	13.0											**3.3**	**13.0**	**16.3**
Port Handling & other charges (5%)						7.2											**0.0**	**7.2**	**7.2**
Total					35.9	150.7											**35.9**	**150.7**	**186.5**
2031 - 31 MW Grid Connected Partially Facilitated Solar																			
Base Cost					4.8	19.4											**4.8**	**19.4**	**24.2**
Contingencies					0.5	1.9											**0.5**	**1.9**	**2.4**
Port Handling & other charges (5%)						1.1											**0.0**	**1.1**	**1.1**
Total					5.3	22.4											**5.3**	**22.4**	**27.7**
2031 - 250 MW Grid Connected Fully Facilitated Solar																			
Base Cost					46.8	187.3											**46.8**	**187.3**	**234.1**
Contingencies					4.7	18.7											**4.7**	**18.7**	**23.4**
Port Handling & other charges (5%)						10.3											**0.0**	**10.3**	**10.3**
Total					51.5	216.3											**51.5**	**216.3**	**267.8**
2031 - 210 MW Wind																			
Base Cost					53.5	213.8											**53.5**	**213.8**	**267.3**
Contingencies					5.3	21.4											**5.3**	**21.4**	**26.7**
Port Handling & other charges (5%)						11.8											**0.0**	**11.8**	**11.8**
Total					58.8	247.0											**58.8**	**247.0**	**305.8**
Annual Total	**215.8**	**906.2**	**183.5**	**770.7**															

Continued in the next page

Investment Plan for Major Wind, Solar and BESS Developments (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2031		2032		2033		2034		**Total**		**Grand**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	**Total**
2031 - 125 MW/500 MWh BESS											
Base Cost	32.2	128.7							**32.2**	**128.7**	**160.9**
Contingencies	3.2	12.9							**3.2**	**12.9**	**16.1**
Port Handling & other charges (5%)		7.1							**0.0**	**7.1**	**7.1**
Total	35.4	148.7							**35.4**	**148.7**	**184.1**
2032 - 170 MW Distribution Connected Solar											
Base Cost			32.6	130.4					**32.6**	**130.4**	**163.0**
Contingencies			3.3	13.0					**3.3**	**13.0**	**16.3**
Port Handling & other charges (5%)				7.2					**0.0**	**7.2**	**7.2**
Total			35.9	150.7					**35.9**	**150.7**	**186.5**
2032 - 30 MW Grid Connected Partially Facilitated Solar											
Base Cost			4.6	18.5					**4.6**	**18.5**	**23.2**
Contingencies			0.5	1.9					**0.5**	**1.9**	**2.3**
Port Handling & other charges (5%)				1.0					**0.0**	**1.0**	**1.0**
Total			5.1	21.4					**5.1**	**21.4**	**26.5**
2032 - 250 MW Grid Connected Fully Facilitated Solar											
Base Cost			38.6	154.5					**38.6**	**154.5**	**193.2**
Contingencies			3.9	15.5					**3.9**	**15.5**	**19.3**
Port Handling & other charges (5%)				8.5					**0.0**	**8.5**	**8.5**
Total			42.5	178.5					**42.5**	**178.5**	**221.0**
2032 - 180 MW Wind											
Base Cost			60.3	241.3					**60.3**	**241.3**	**301.6**
Contingencies			6.0	24.1					**6.0**	**24.1**	**30.2**
Port Handling & other charges (5%)				13.3					**0.0**	**13.3**	**13.3**
Total			66.3	278.6					**66.3**	**278.6**	**345.0**
2032 - 125 MW/500 MWh BESS											
Base Cost			32.2	128.7					**32.2**	**128.7**	**160.9**
Contingencies			3.2	12.9					**3.2**	**12.9**	**16.1**
Port Handling & other charges (5%)				7.1					**0.0**	**7.1**	**7.1**
Total			35.4	148.7					**35.4**	**148.7**	**184.1**
2033 - 174 MW Distribution Connected Solar											
Base Cost					33.4	133.5			**33.4**	**133.5**	**166.9**
Contingencies					3.3	13.4			**3.3**	**13.4**	**16.7**
Port Handling & other charges (5%)						7.3			**0.0**	**7.3**	**7.3**
Total					36.7	154.2			**36.7**	**154.2**	**190.9**
2033 - 30 MW Grid Connected Partially Facilitated Solar											
Base Cost					4.6	18.5			**4.6**	**18.5**	**23.2**
Contingencies					0.5	1.9			**0.5**	**1.9**	**2.3**
Port Handling & other charges (5%)						1.0			**0.0**	**1.0**	**1.0**
Total					5.1	21.4			**5.1**	**21.4**	**26.5**
2033 - 300 MW Grid Connected Fully Facilitated Solar											
Base Cost					54.5	218.2			**54.5**	**218.2**	**272.7**
Contingencies					5.5	21.8			**5.5**	**21.8**	**27.3**
Port Handling & other charges (5%)						12.0			**0.0**	**12.0**	**12.0**
Total					60.0	252.0			**60.0**	**252.0**	**312.0**
2033 - 155 MW Wind											
Base Cost					53.9	215.8			**53.9**	**215.8**	**269.7**
Contingencies					5.4	21.6			**5.4**	**21.6**	**27.0**
Port Handling & other charges (5%)						11.9			**0.0**	**11.9**	**11.9**
Total					59.3	249.2			**59.3**	**249.2**	**308.6**
Annual Total	**186.9**	**785.0**	**185.2**	**777.9**							

Continued in the next page

Investment Plan for Major Wind, Solar and BESS Developments (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2033		2034		2035		2036		**Total**		**Grand**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	**Total**
2033 - 150 MW/600 MWh BESS											
Base Cost	38.6	154.5							**38.6**	**154.5**	**193.1**
Contingencies	3.9	15.4							**3.9**	**15.4**	**19.3**
Port Handling & other charges (5%)		8.5							**0.0**	**8.5**	**8.5**
Total	42.5	178.4							**42.5**	**178.4**	**220.9**
2034 - 190 MW Distribution Connected Solar											
Base Cost			36.4	145.8					**36.4**	**145.8**	**182.2**
Contingencies			3.6	14.6					**3.6**	**14.6**	**18.2**
Port Handling & other charges (5%)				8.0					**0.0**	**8.0**	**8.0**
Total			40.1	168.4					**40.1**	**168.4**	**208.5**
2034 - 30 MW Grid Connected Partially Facilitated Solar											
Base Cost			4.6	18.5					**4.6**	**18.5**	**23.2**
Contingencies			0.5	1.9					**0.5**	**1.9**	**2.3**
Port Handling & other charges (5%)				1.0					**0.0**	**1.0**	**1.0**
Total			5.1	21.4					**5.1**	**21.4**	**26.5**
2034 - 300 MW Grid Connected Fully Facilitated Solar											
Base Cost			62.7	250.9					**62.7**	**250.9**	**313.6**
Contingencies			6.3	25.1					**6.3**	**25.1**	**31.4**
Port Handling & other charges (5%)				13.8					**0.0**	**13.8**	**13.8**
Total			69.0	289.8					**69.0**	**289.8**	**358.8**
2034 - 180 MW Wind											
Base Cost			60.4	241.5					**60.4**	**241.5**	**301.8**
Contingencies			6.0	24.1					**6.0**	**24.1**	**30.2**
Port Handling & other charges (5%)				13.3					**0.0**	**13.3**	**13.3**
Total			66.4	278.9					**66.4**	**278.9**	**345.3**
2034 - 200 MW/800MWh BESS											
Base Cost			51.5	205.9					**51.5**	**205.9**	**257.4**
Contingencies			5.1	20.6					**5.1**	**20.6**	**25.7**
Port Handling & other charges (5%)				11.3					**0.0**	**11.3**	**11.3**
Total			56.6	237.8					**56.6**	**237.8**	**294.4**
2035 - 195 MW Distribution Connected Solar											
Base Cost					37.4	149.6			**37.4**	**149.6**	**187.0**
Contingencies					3.7	15.0			**3.7**	**15.0**	**18.7**
Port Handling & other charges (5%)						8.2			**0.0**	**8.2**	**8.2**
Total					41.1	172.8			**41.1**	**172.8**	**214.0**
2035 - 30 MW Grid Connected Partially Facilitated Solar											
Base Cost					4.6	18.5			**4.6**	**18.5**	**23.2**
Contingencies					0.5	1.9			**0.5**	**1.9**	**2.3**
Port Handling & other charges (5%)						1.0			**0.0**	**1.0**	**1.0**
Total					5.1	21.4			**5.1**	**21.4**	**26.5**
2035 - 300 MW Grid Connected Fully Facilitated Solar											
Base Cost					46.4	185.5			**46.4**	**185.5**	**231.8**
Contingencies					4.6	18.5			**4.6**	**18.5**	**23.2**
Port Handling & other charges (5%)						10.2			**0.0**	**10.2**	**10.2**
Total					51.0	214.2			**51.0**	**214.2**	**265.2**
2035 - 160 MW Wind											
Base Cost					55.3	221.1			**55.3**	**221.1**	**276.4**
Contingencies					5.5	22.1			**5.5**	**22.1**	**27.6**
Port Handling & other charges (5%)						12.2			**0.0**	**12.2**	**12.2**
Total					60.8	255.4			**60.8**	**255.4**	**316.2**
Annual Total	**203.6**	**855.3**	**237.2**	**996.3**							

Continued in the next page

Investment Plan for Major Wind, Solar and BESS Developments (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2035		2036		2037		2038		**Total**		**Grand**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	**Total**
2035 - 245 MW/980 MWh BESS											
Base Cost	63.1	252.4							**63.1**	**252.4**	**315.5**
Contingencies	6.3	25.2							**6.3**	**25.2**	**31.5**
Port Handling & other charges (5%)		13.9							**0.0**	**13.9**	**13.9**
Total	69.4	291.5							**69.4**	**291.5**	**360.9**
2036 - 206 MW Distribution Connected Solar											
Base Cost			39.5	158.1					**39.5**	**158.1**	**197.6**
Contingencies			4.0	15.8					**4.0**	**15.8**	**19.8**
Port Handling & other charges (5%)				8.7					**0.0**	**8.7**	**8.7**
Total			43.5	182.6					**43.5**	**182.6**	**226.0**
2036 - 50 MW Grid Connected Partially Facilitated Solar											
Base Cost			7.7	30.9					**7.7**	**30.9**	**38.6**
Contingencies			0.8	3.1					**0.8**	**3.1**	**3.9**
Port Handling & other charges (5%)				1.7					**0.0**	**1.7**	**1.7**
Total			8.5	35.7					**8.5**	**35.7**	**44.2**
2036 - 300 MW Grid Connected Fully Facilitated Solar											
Base Cost			54.5	218.2					**54.5**	**218.2**	**272.7**
Contingencies			5.5	21.8					**5.5**	**21.8**	**27.3**
Port Handling & other charges (5%)				12.0					**0.0**	**12.0**	**12.0**
Total			60.0	252.0					**60.0**	**252.0**	**312.0**
2036 - 150 MW Wind											
Base Cost			81.8	327.3					**81.8**	**327.3**	**409.1**
Contingencies			8.2	32.7					**8.2**	**32.7**	**40.9**
Port Handling & other charges (5%)				18.0					**0.0**	**18.0**	**18.0**
Total			90.0	378.0					**90.0**	**378.0**	**468.0**
2036 - 380 MW/1520 MWh BESS											
Base Cost			97.8	391.3					**97.8**	**391.3**	**489.2**
Contingencies			9.8	39.1					**9.8**	**39.1**	**48.9**
Port Handling & other charges (5%)				21.5					**0.0**	**21.5**	**21.5**
Total			107.6	452.0					**107.6**	**452.0**	**559.6**
2037 - 243 MW Distribution Connected Solar											
Base Cost					46.6	186.4			**46.6**	**186.4**	**233.1**
Contingencies					4.7	18.6			**4.7**	**18.6**	**23.3**
Port Handling & other charges (5%)						10.3			**0.0**	**10.3**	**10.3**
Total					51.3	215.3			**51.3**	**215.3**	**266.6**
2037 - 60 MW Grid Connected Partially Facilitated Solar											
Base Cost					9.3	37.1			**9.3**	**37.1**	**46.4**
Contingencies					0.9	3.7			**0.9**	**3.7**	**4.6**
Port Handling & other charges (5%)						2.0			**0.0**	**2.0**	**2.0**
Total					10.2	42.8			**10.2**	**42.8**	**53.0**
2037 - 300 MW Grid Connected Fully Facilitated Solar											
Base Cost					50.5	201.8			**50.5**	**201.8**	**252.3**
Contingencies					5.0	20.2			**5.0**	**20.2**	**25.2**
Port Handling & other charges (5%)						11.1			**0.0**	**11.1**	**11.1**
Total					55.5	233.1			**55.5**	**233.1**	**288.6**
2037 - 150 MW Wind											
Base Cost					81.8	327.3			**81.8**	**327.3**	**409.1**
Contingencies					8.2	32.7			**8.2**	**32.7**	**40.9**
Port Handling & other charges (5%)						18.0			**0.0**	**18.0**	**18.0**
Total					90.0	378.0			**90.0**	**378.0**	**468.0**
Annual Total	**227.5**	**955.3**	**309.6**	**1300.2**							

Continued in the next page

Investment Plan for Major Wind, Solar and BESS Developments (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2037		2038		2039		2040		**Total**		**Grand**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	**Total**
2037 - 400 MW/1600 MWh BESS											
Base Cost	103.0	411.9							**103.0**	**411.9**	**514.9**
Contingencies	10.3	41.2							**10.3**	**41.2**	**51.5**
Port Handling & other charges (5%)		22.7							**0.0**	**22.7**	**22.7**
Total	113.3	475.8							**113.3**	**475.8**	**589.1**
2038 - 274 MW Distribution Connected Solar											
Base Cost			52.6	210.2					**52.6**	**210.2**	**262.8**
Contingencies			5.3	21.0					**5.3**	**21.0**	**26.3**
Port Handling & other charges (5%)				11.6					**0.0**	**11.6**	**11.6**
Total			57.8	242.8					**57.8**	**242.8**	**300.6**
2038 - 30 MW Grid Connected Partially Facilitated Solar											
Base Cost			4.6	18.5					**4.6**	**18.5**	**23.2**
Contingencies			0.5	1.9					**0.5**	**1.9**	**2.3**
Port Handling & other charges (5%)				1.0					**0.0**	**1.0**	**1.0**
Total			5.1	21.4					**5.1**	**21.4**	**26.5**
2038 - 300 MW Grid Connected Fully Facilitated Solar											
Base Cost			50.5	201.8					**50.5**	**201.8**	**252.3**
Contingencies			5.0	20.2					**5.0**	**20.2**	**25.2**
Port Handling & other charges (5%)				11.1					**0.0**	**11.1**	**11.1**
Total			55.5	233.1					**55.5**	**233.1**	**288.6**
2038 - 150 MW Wind											
Base Cost			81.8	327.3					**81.8**	**327.3**	**409.1**
Contingencies			8.2	32.7					**8.2**	**32.7**	**40.9**
Port Handling & other charges (5%)				18.0					**0.0**	**18.0**	**18.0**
Total			90.0	378.0					**90.0**	**378.0**	**468.0**
2038 - 550 MW/2200 MWh BESS											
Base Cost			141.6	566.4					**141.6**	**566.4**	**708.0**
Contingencies			14.2	56.6					**14.2**	**56.6**	**70.8**
Port Handling & other charges (5%)				31.2					**0.0**	**31.2**	**31.2**
Total			155.8	654.2					**155.8**	**654.2**	**810.0**
2039 - 311 MW Distribution Connected Solar											
Base Cost					59.7	238.6			**59.7**	**238.6**	**298.3**
Contingencies					6.0	23.9			**6.0**	**23.9**	**29.8**
Port Handling & other charges (5%)						13.1			**0.0**	**13.1**	**13.1**
Total					65.6	275.6			**65.6**	**275.6**	**341.2**
2039 - 36 MW Grid Connected Partially Facilitated Solar											
Base Cost					5.6	22.3			**5.6**	**22.3**	**27.8**
Contingencies					0.6	2.2			**0.6**	**2.2**	**2.8**
Port Handling & other charges (5%)						1.2			**0.0**	**1.2**	**1.2**
Total					6.1	25.7			**6.1**	**25.7**	**31.8**
2039 - 300 MW Grid Connected Fully Facilitated Solar											
Base Cost					50.5	201.8			**50.5**	**201.8**	**252.3**
Contingencies					5.0	20.2			**5.0**	**20.2**	**25.2**
Port Handling & other charges (5%)						11.1			**0.0**	**11.1**	**11.1**
Total					55.5	233.1			**55.5**	**233.1**	**288.6**
2039 - 150 MW Wind											
Base Cost					81.8	327.3			**81.8**	**327.3**	**409.1**
Contingencies					8.2	32.7			**8.2**	**32.7**	**40.9**
Port Handling & other charges (5%)						18.0			**0.0**	**18.0**	**18.0**
Total					90.0	378.0			**90.0**	**378.0**	**468.0**
Annual Total	**320.3**	**1345.1**	**364.2**	**1529.5**							

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Investment Plan for Major Wind, Solar and BESS Developments (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2039 L.C	2039 F.C	2040 L.C	2040 F.C	2041 L.C	2041 F.C	2042 L.C	2042 F.C	Total L.C	Total F.C	Grand Total
2039 - 350 MW/1400 MWh BESS											
Base Cost	90.1	360.4							**90.1**	**360.4**	**450.5**
Contingencies	9.0	36.0							**9.0**	**36.0**	**45.1**
Port Handling & other charges (5%)		19.8							**0.0**	**19.8**	**19.8**
Total	99.1	416.3							**99.1**	**416.3**	**515.4**
2040 - 265 MW Distribution Connected Solar											
Base Cost			50.8	203.3					**50.8**	**203.3**	**254.2**
Contingencies			5.1	20.3					**5.1**	**20.3**	**25.4**
Port Handling & other charges (5%)				11.2					**0.0**	**11.2**	**11.2**
Total			55.9	234.8					**55.9**	**234.8**	**290.8**
2040 - 38 MW Grid Connected Partially Facilitated Solar											
Base Cost			5.9	23.5					**5.9**	**23.5**	**29.4**
Contingencies			0.6	2.3					**0.6**	**2.3**	**2.9**
Port Handling & other charges (5%)				1.3					**0.0**	**1.3**	**1.3**
Total			6.5	27.1					**6.5**	**27.1**	**33.6**
2040 - 300 MW Grid Connected Fully Facilitated Solar											
Base Cost			54.5	218.2					**54.5**	**218.2**	**272.7**
Contingencies			5.5	21.8					**5.5**	**21.8**	**27.3**
Port Handling & other charges (5%)				12.0					**0.0**	**12.0**	**12.0**
Total			60.0	252.0					**60.0**	**252.0**	**312.0**
2040 - 170 MW Wind											
Base Cost			86.9	347.6					**86.9**	**347.6**	**434.5**
Contingencies			8.7	34.8					**8.7**	**34.8**	**43.5**
Port Handling & other charges (5%)				19.1					**0.0**	**19.1**	**19.1**
Total			95.6	401.5					**95.6**	**401.5**	**497.1**
2040 - 340 MW/1360 MWh BESS											
Base Cost			87.5	350.1					**87.5**	**350.1**	**437.7**
Contingencies			8.8	35.0					**8.8**	**35.0**	**43.8**
Port Handling & other charges (5%)				19.3					**0.0**	**19.3**	**19.3**
Total			96.3	404.4					**96.3**	**404.4**	**500.7**
2041 - 353 MW Distribution Connected Solar											
Base Cost					67.7	270.8			**67.7**	**270.8**	**338.6**
Contingencies					6.8	27.1			**6.8**	**27.1**	**33.9**
Port Handling & other charges (5%)						14.9			**0.0**	**14.9**	**14.9**
Total					74.5	312.8			**74.5**	**312.8**	**387.3**
2041 - 45 MW Grid Connected Partially Facilitated Solar											
Base Cost					7.0	27.8			**7.0**	**27.8**	**34.8**
Contingencies					0.7	2.8			**0.7**	**2.8**	**3.5**
Port Handling & other charges (5%)						1.5			**0.0**	**1.5**	**1.5**
Total					7.7	32.1			**7.7**	**32.1**	**39.8**
2041 - 300 MW Grid Connected Fully Facilitated Solar											
Base Cost					54.5	218.2			**54.5**	**218.2**	**272.7**
Contingencies					5.5	21.8			**5.5**	**21.8**	**27.3**
Port Handling & other charges (5%)						12.0			**0.0**	**12.0**	**12.0**
Total					60.0	252.0			**60.0**	**252.0**	**312.0**
2041 - 250 MW Wind											
Base Cost					107.3	429.1			**107.3**	**429.1**	**536.4**
Contingencies					10.7	42.9			**10.7**	**42.9**	**53.6**
Port Handling & other charges (5%)						23.6			**0.0**	**23.6**	**23.6**
Total					118.0	495.6			**118.0**	**495.6**	**613.6**
2041 - 350 MW/1400 MWh BESS											
Base Cost					90.1	360.4			**90.1**	**360.4**	**450.5**
Contingencies					9.0	36.0			**9.0**	**36.0**	**45.1**
Port Handling & other charges (5%)						19.8			**0.0**	**19.8**	**19.8**
Total					99.1	416.3			**99.1**	**416.3**	**515.4**
Annual Total	**316.4**	**1328.7**	**314.3**	**1319.9**	**359.3**	**1508.9**					

Investment Plan for Major Wind, Solar and BESS Developments (Base Case), 2023-2042

(Costs in million US$, Exch. Rate:201.5 LKR/US$)

YEAR & PLANT	2042 L.C	2042 F.C	Total L.C	Total F.C	Grand Total
2042 - 360 MW Distribution Connected Solar					
Base Cost	69.1	276.2	**69.1**	**276.2**	**345.3**
Contingencies	6.9	27.6	**6.9**	**27.6**	**34.5**
Port Handling & other charges (5%)		15.2	**0.0**	**15.2**	**15.2**
Total	76.0	319.0	**76.0**	**319.0**	**395.0**
2042 - 114 MW Grid Connected Partially Facilitated Solar					
Base Cost	17.6	70.5	**17.6**	**70.5**	**88.1**
Contingencies	1.8	7.0	**1.8**	**7.0**	**8.8**
Port Handling & other charges (5%)		3.9	**0.0**	**3.9**	**3.9**
Total	19.4	81.4	**19.4**	**81.4**	**100.8**
2042 - 300 MW Grid Connected Fully Facilitated Solar					
Base Cost	54.5	218.2	**54.5**	**218.2**	**272.7**
Contingencies	5.5	21.8	**5.5**	**21.8**	**27.3**
Port Handling & other charges (5%)		12.0	**0.0**	**12.0**	**12.0**
Total	60.0	252.0	**60.0**	**252.0**	**312.0**
2042 - 150 MW Wind					
Base Cost	81.8	327.3	**81.8**	**327.3**	**409.1**
Contingencies	8.2	32.7	**8.2**	**32.7**	**40.9**
Port Handling & other charges (5%)		18.0	**0.0**	**18.0**	**18.0**
Total	90.0	378.0	**90.0**	**378.0**	**468.0**
2042 - 400 MW/1600 MWh BESS					
Base Cost	103.0	411.9	**103.0**	**411.9**	**514.9**
Contingencies	10.3	41.2	**10.3**	**41.2**	**51.5**
Port Handling & other charges (5%)		22.7	**0.0**	**22.7**	**22.7**
Total	113.3	475.8	**113.3**	**475.8**	**589.1**
Annual Total	**358.6**	**1506.2**			

Note:

(i) Disbursement start from year 2023 onwards.

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

(iii) Cost for each year includes the investment cost required to construct the capacity to compensate for the retired capacities in the respective year.

Energy Deficit Risk Percentage

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Dry Hydro Condition	2023	0.01%	0.05%	0.05%	0.01%	0.02%	0.00%	0.02%	0.05%	0.02%	0.03%	0.03%	0.02%
	2024	0.08%	0.05%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%
	2025	0.03%	0.02%	0.03%	0.05%	0.03%	0.07%	0.03%	0.02%	0.07%	0.08%	0.02%	0.06%
	2026	0.05%	0.04%	0.04%	0.04%	0.01%	0.02%	0.06%	0.03%	0.04%	0.03%	0.03%	0.09%
	2027	0.07%	0.06%	0.01%	0.01%	0.02%	0.06%	0.00%	0.03%	0.02%	0.04%	0.02%	0.04%
High Demand	2023	0.01%	0.08%	0.23%	0.01%	0.02%	0.03%	0.03%	0.04%	0.02%	0.04%	0.11%	0.06%
	2024	0.04%	0.07%	0.04%	0.01%	0.01%	0.00%	0.00%	0.00%	0.01%	0.01%	0.02%	0.01%
	2025	0.01%	0.04%	0.05%	0.02%	0.03%	0.04%	0.02%	0.02%	0.02%	0.05%	0.05%	0.03%
	2026	0.03%	0.02%	0.01%	0.01%	0.02%	0.03%	0.02%	0.01%	0.02%	0.06%	0.03%	0.04%
	2027	0.02%	0.01%	0.01%	0.01%	0.23%	0.02%	0.01%	0.02%	0.01%	0.02%	0.03%	0.03%
Long Outage of Major Plant	2023	0.01%	0.14%	0.54%	0.01%	0.02%	0.00%	0.02%	0.02%	0.02%	0.04%	0.04%	0.04%
	2024	0.06%	0.10%	0.04%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.01%
	2025	0.01%	0.06%	0.10%	0.02%	0.03%	0.04%	0.02%	0.02%	0.03%	0.04%	0.05%	0.06%
	2026	0.03%	0.04%	0.02%	0.02%	0.01%	0.03%	0.03%	0.02%	0.02%	0.03%	0.03%	0.05%
	2027	0.03%	0.02%	0.01%	0.01%	0.01%	0.02%	0.01%	0.02%	0.01%	0.02%	0.05%	0.03%
Restricted Fuel Supply Case 1	2023	0.15%	5.97%	17.30%	13.46%	5.73%	1.47%	0.89%	0.00%	2.51%	4.39%	0.47%	0.26%
	2024	2.95%	11.37%	19.88%	12.05%	3.70%	0.00%	0.00%	0.00%	0.00%	0.09%	0.05%	6.25%
	2025	0.46%	8.06%	16.73%	6.71%	1.13%	0.07%	0.03%	0.02%	0.07%	0.26%	3.40%	0.00%
	2026	0.24%	7.31%	20.57%	13.38%	1.65%	0.02%	0.06%	0.03%	0.04%	2.76%	4.51%	0.66%
	2027	0.70%	4.24%	15.46%	3.62%	10.56%	0.06%	0.00%	0.03%	0.02%	0.04%	0.02%	0.04%
Restricted Fuel Supply Case 2	2023	9.64%	15.17%	30.20%	18.47%	14.54%	6.97%	9.04%	5.90%	5.05%	4.68%	1.28%	2.37%
	2024	10.48%	20.62%	28.13%	15.24%	6.56%	2.48%	6.05%	3.84%	0.30%	2.05%	1.88%	4.93%
	2025	5.41%	11.88%	28.48%	8.50%	4.85%	0.85%	1.29%	0.62%	0.56%	2.61%	4.86%	3.70%
	2026	11.21%	16.69%	26.31%	12.30%	9.77%	0.88%	4.22%	2.60%	2.83%	4.70%	6.42%	2.90%
	2027	6.56%	11.97%	22.41%	10.27%	10.10%	0.02%	0.00%	0.03%	0.02%	0.04%	19.40%	12.03%
Implementation Delay Case 7	2023	N/A				0.01%	0.02%	0.00%	0.02%	0.02%	0.03%	0.05%	0.04%
	2024	0.05%	0.04%	0.10%	0.05%	0.02%	0.02%	0.02%	0.02%	0.01%	0.02%	0.03%	0.10%
	2025	0.03%	0.03%	0.03%	0.03%	0.01%	0.03%	0.02%	0.02%	0.01%	0.01%	0.03%	0.06%
	2026	0.02%	0.02%	0.05%	0.03%	0.03%	0.02%	0.02%	0.02%	0.02%	0.02%	0.17%	0.05%
	2027	N/A											

Note : "Energy Deficit Risk Percentage" is indicated as a possibility of monthly energy deficit respective to the monthly energy demand.

Annex 15.1

Actual Generation Expansions and the Plans from 1993-2022

Year	Actual Expansions	Long Term Generation Expansion Plan (LTGEP)																
		1994-2008	1995-2009	1996-2010	1998-2012	1999-2013	2000-2014	2002-2016	2003-2017	2005-2019	2006-2020	2009-2022	2011-2025	2013-2032	2015-2034	2018-2037	2022-2041	2023-2042
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	180-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	270-CCY	-	-	-	-	-	-
2011	285-PUT	-	-	-	300-TRNC	-	300-TRNC	-	300-CO	300-CO	2*300-CO 150-UPK	285-PUT	315-PUT	-	-	-	-	-
2012	150-UPK	-	-	-	210-GT	300-TRNC	105-GT	300-CO	300-CO	300-CO	300-CO	150-UPK	150-UPK	-	-	-	-	-
2013	-	-	-	-	-	105-GT	300-TRNC	300-TRNC	105-GT	300-CO	300-CO	2*285-	-	-	-	-	-	-
2014	2*285-PUT 20-Northern	–	–	–	–	–	210-GT	–	300-CO	300-CO	300-CO	250-TPCL	20-Northern 24-CPE	20-Northern 24-CPE	-	-	-	-
2015	60-Col(CEB)	–	–	–	–	–	–	300-TRNC	300-CO 210-GT	285-GT	300-CO	300-CO	2*35-GT	300-PUT 3*75-GT	60-Col(CEB)		-	-
2016	–	–	–	–	–	–	–	175-GT	300-CO	300-CO	300-CO	–	35-BDL 120-Uma Oya	35-BDL 120-Uma Oya	-		-	-
2017	100-ACE+ 20-ACE+	–	–	–	–	–		–	210-GT	300-CO	300-CO	300-CO	2*250-TPCL	105-GT	170-FO		-	-
2018	–	–	–	–	–	–	–	–	–	300-CO 180-GT	300-CO	300-CO	49-GIN 250-TPCL	27-Moragolla 2*250-TPCL	35-BDL 120-Uma Oya 2*35-GT	320-FO	-	-
2019	–	–	–	–	–	–	–	–	–	420-GT	300-CO	–	250-TPCL	2*300-CO	35-GT 300-LNG	300-LNG 120-Uma Oya	-	-
2020	–	–	–	–	–	–	–	–	–	–	105-GT 300-CO	300-CO	–	–	15-THAL	35-BDL 15-THAL 35-GT	-	-
2021	–	–	–	–	–	–	–	–	–	–	–	300-CO	2*300-CO	300-CO	250-TPCL**	300-LNG	-	-
2022	–	–	–	–	–	–	–	–	–	–	–	300-CO	300-CO	300-CO 49-GIN	31-Moragolla 20-SEETHA 20-GIN 250-TPCL**	31-Moragolla 20-SEETHA 20-GIN	35-BDL 120-Uma Oya	120-Uma Oya
2023	–	–	–	–	–	–	–	–	–	–	–	–	300-CO	2*300-CO	163-AES CCY(LNG) 300-ASC CO	163-AES CCY(LNG) 300-ASC CO	130 GT	235-CCY (Natural Gas)
2024	–	–	–	–	–	–	–	–	–	–	–	–	–	–	300-ASC CO	300-ASC CO	31-Moragolla 350-CCY LNG	31- Moragolla 130 GT 350 CCY (Natural Gas)
2025	–	–	–	–	–	–	–	–	–	–	–	–	2*300-CO	300-CO	200 PSPP	300-ASC CO 200 PSPP	350-CCY LNG 300 Coal LVPS	115 CCY (Natural Gas)
2026	–	–	–	–	–	–	–	–	–	–	–	–	–	–	200 PSPP	200 PSPP	250 Gas Engine LNG	200 Gas Engine (Natural Gas)
2027	–	–	–	–	–	–	–	–	–	–	–	–		300- CO	300- ASC CO	200 PSPP	400 CCY LNG	100 GT (Natural Gas)
2028	–	–	–	–	–	–	–	–	–	–	–	–		300- CO	–	600 - ASC CO	300 Coal	

Note: ORE Plants are not indicated ** Approval was not granted by PUCSL +PPA has extended and procurment of power plants by CEB is under consideration

KUK – Kukule hydro power station, BDL – Broadlands hydro power station, UPK – Upper Kotmale hydro power station, GIN – Gin ganga hydro power station, THAL - Thalpitigala, SEETHA - Seethawaka

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, TPCL-Trincomalee Power Company Coal Power Plant, FO-Furnace Oil power plant, LNG - Natural Gas fired Combined Cycle Power Plant (Western Region), ASC CO-Advanced Sub Critical Coal Power Plant, AES CCY(LNG)-AES Kelanitissa Convertion to LNG, Col(CEB)-CEB Colombo Power Plant, PSPP - Pumped storage power plant

Annex 15.1

Actual ORE Generation Expansions and the Plans from 2015-2023

Year	Actual Expansions	Long Term Generation Expansion Plan (LTGEP)			
		2015-2034	2018-2037	2022-2041	2023-2042
2011	S-1 W-3 MH-19 B-1	-	-	-	-
2012	S-0 W-40 MH-33 B-0	-	-	-	-
2013	S-4 W-5 MH-37 B-0	-	-	-	-
2014	S-10 W-50 MH-24 B-7	-	-	-	-
2015	S-15 W-0 MH-19 B-0	-		-	-
2016	S-36 W-0 MH-35 B-4	S-15 W-0 MH-20 B-10		-	-
2017	S-83 W-0 MH-12 B-2	S-15 W-20 MH-25 B-15		-	-
2018	S-74 W-0 MH-40 B-10	S-15 W-100 MH-25 B-25	S-160 W-0 MH-15 B-5	-	-
2019	S-117 W-0 MH-16 B-0	S-15 W-10 MH-25 B-25	S-95 W-50 MH-15 B-5	-	-
2020	S-75 W-51 MH-2 B-10	S-20 W-100 MH-25 B-25	S-105 W-220 MH-15 B-5	-	-
2021	S-202 W-73 MH-0 B-0	S-10 W-50 MH-25 B-5	S-55 W-75 MH-15 B-14	-	-
2022	–	S-10 W-50 MH-20 B-0	S-6 W-50 MH-10 B-5	S-340 W-20 MH-15 B-14	
2023	–	S-10 W-45 MH-15 B-5	S-55 W-60 MH-10 B-5	S-260 W-35 MH-20 B-4	S-307 W-25 MH-20 B-20
2024	–	S-15 W-45 MH-10 B-10	S-55 W-45 MH-10 B-5	S-270 W-40 MH-10 B-5	S-483 W-60 MH-20 B-20
2025	–	S-10 W-45 MH-10 B-5	S-104 W-85 MH-0 B-5	S-260 W-100 MH-10 B-5	S-505 W-200 MH-25 B-20
2026	–	S-10 W-10 MH-15 B-5	S-55 W-0 MH-10 B-5	S-195 W-100 MH-10 B-5	S-500 W-290 MH-25 B-20
2027	–	S-10 W-20 MH-35 B-10	S-54 W-25 MH-10 B-5	S-160 W-120 MH-10 B-5	S-500 W-250 MH-25 B-20
2028	–	S-10 W-0 MH-35 B-10	S-105 W-45 MH-10 B-5	S-170 W-120 MH-10 B-5	S-520 W-200 MH-25 B-20

Note: S - Solar, W - Wind, MH - Mini Hydro, B - Bio Mass