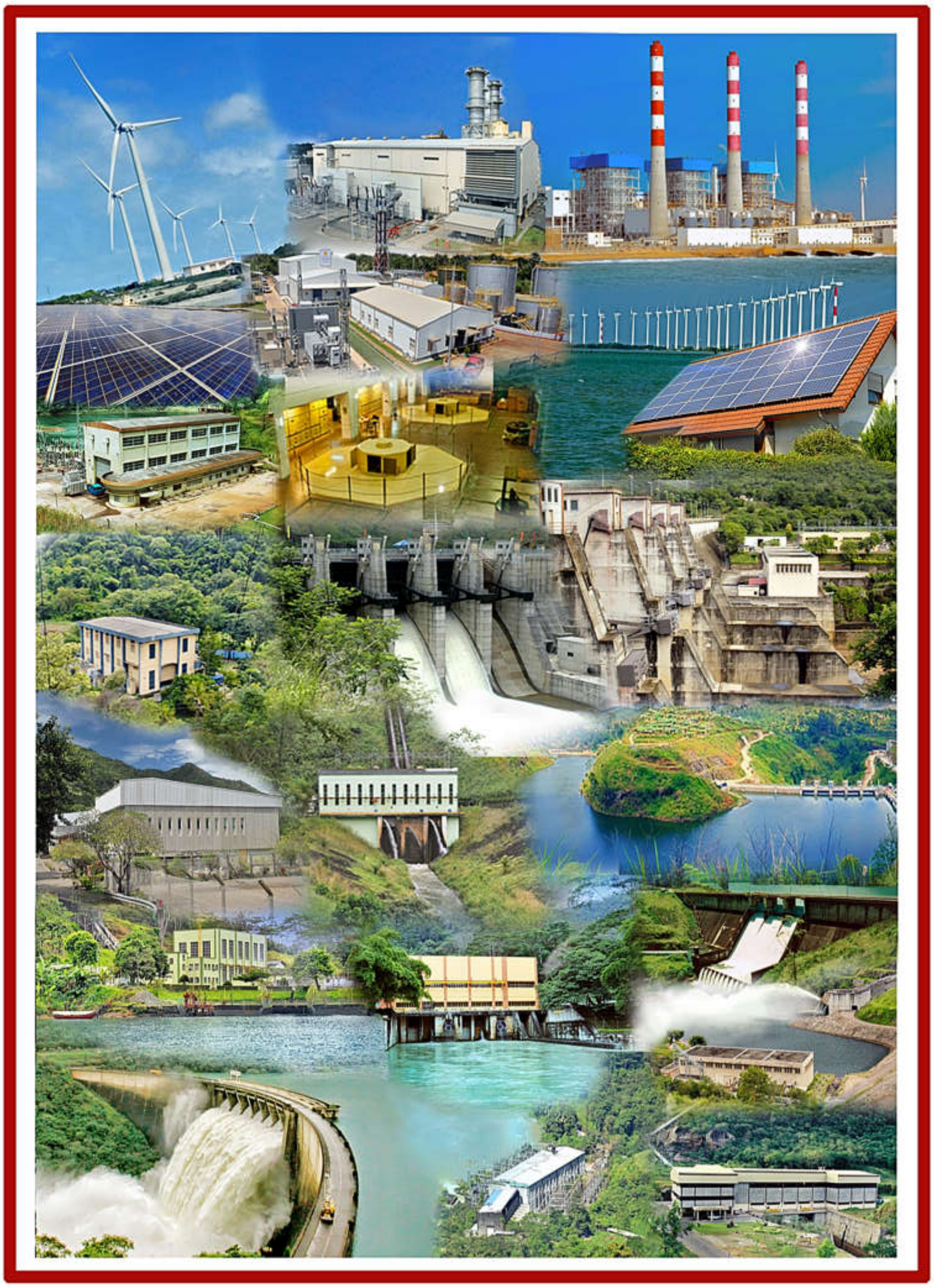
LONG TERM GENERATION EXPANSION PLAN 2020-2039

(DRAFT)



Transmission and Generation Planning Branch
Transmission Division
Ceylon Electricity Board
Sri Lanka
March 2020

CEYLON ELECTRICITY BOARD

LONG TERM GENERATION EXPANSION PLAN

2020-2039

(DRAFT)

Transmission and Generation Planning Branch
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Sri Lanka
March 2020

Long Term Generation Expansion Planning Studies
2020- 2039

Compiled and prepared by
The Generation Planning Unit
Transmission and Generation Planning Branch
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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.

Price Rs. 4000.00

Foreword

The Report on 'Long Term Generation Expansion Planning Studies 2020-2039', 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 2020-2039, and replaces the Long Term Generation Expansion Plan 2018-2037.

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.

March 2020.

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ACRONYMS

ADB	-	Asian Development Bank
API	-	Argus/McCloskey's Coal price Index
bcf	-	Billion Cubic Feet
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
DSM	-	Demand Side Management
DTF	-	Distance to Frontier
EIA	-	Environmental Impact Assessment
ENS	-	Energy Not Served
EOI	-	Expression of Interest
ESP	-	Electrostatic Precipitator
FGD	-	Flue Gas Desulphurization
FOB	-	Free On Board
FOR	-	Forced Outage Rate
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
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
JICA	-	Japan International Cooperation Agency
LKR	-	Sri Lanka Rupees
KPS	-	Kelanatissa 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
LTGEP	-	Long Term Generation Expansion Plan
mscfd	-	Million Standard Cubic Feet per Day
MAED	-	The Model for Analysis of Energy Demand
MMBTU	-	Million British Thermal Units
MTPA	-	Million Tons Per Annum
NDC	-	Nationally Determined Contributions
NEPS	-	National Energy Policy and Strategy
NG	-	Natural Gas
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
PSPP	-	Pumped Storage Power Plant
PV	-	Present Value
RFP	-	Request For Proposals
SAM	-	System Advisor Model
SDDP	-	Stochastic Dual Dynamic Programming
ST	-	Steam Turbine
UNFCCC	-	United Nations Framework Convention on Climate Change
USAID	-	United States Agency for International Development
US$	-	American Dollars
WASP	-	Wien Automatic System Planning Package
WB	-	World Bank
WHO	-	World Health Organization
VSC	-	Voltage Source Converter

Background.

As per section 24(1)(c) of the Sri Lanka Electricity Act no 20 of 2009 (as amended), Ceylon Electricity Board (CEB) as the Transmission Licensee has a statutory duty to ensure that there is sufficient capacity from generation plants to meet reasonable forecast demand for electricity. Additionally, under section 17(c) of the Act, CEB is required to add such capacity on the most economically advantageous terms and in the most transparent manner. CEB prepares Long-Term Generation Expansion Plan (LTGEP) once in every two years for a 20-year period ahead to ensure that the firm capacity technologies that the CEB is required to procure meets the principle of least cost. Hence, this LTGEP serves as the first check of least cost before procurement is carried competitively to further ensure least cost and transparency. In addition, CEB's LTGEPs also provide the capacity additions from "Non-Conventional Renewable Energy" (NCRE) based generating technologies, (termed as Other Renewable Energy - ORE in this report) to supplement firm generating capacity and to maintain renewable share and fuel diversity to meet government policy guidelines.

The specific government policy as applicable to the Electricity Industry is titled the "General Policy Guidelines in Respect of the Electricity Industry" and the methodology to formulate and approve such policy guidelines is stipulated under section 5 of the Sri Lanka Electricity Act no 20 of 2009 (as amended) and under section 30 of the Public Utilities Commission of Sri Lanka (PUCSL) Act no 35 of 2002. The first General Policy Guidelines in respect of the Electricity Industry published after the enactment of the Sri Lanka Electricity Act was in 2009 and remained until April 2019 where an amendment was issued on the 10th April 2019. As the planning studies contained in this LTGEP 2020-2039 has commenced in 2018 and the first draft submission for the approval of the Public Utilities Commission was made in May 2019, the policy guidelines available during the preparation of this report were the guidelines as contained in the original General Policy Guidelines as issued in 2009. However, all possible efforts have been taken to incorporate as much policy changes as contained in the amended policy guideline that was published in April 2019.

This report presents the generation expansion planning studies carried out by the Transmission and Generation Planning Branch of the Ceylon Electricity Board, for the period 2020-2039. The report includes information on the existing generation system, generation planning methodology, system demand forecast, investment and implementation plans for the proposed projects and recommends the most economical sequence of generating capacity additions to meet the least cost and government policies while maintaining the statutory reliability criteria. The final summarized results of the planning studies are presented in the “revised base case plan" as given in Table E.2

Electricity Demand is envisaged to grow at 4.9% annually for the next 20 years

The demand forecasting methodology as used in the planning studies consists of a combination of medium-term forecast and long-term forecasts. Such forecasts also incorporate planned new mega development projects identified by the government. Five-year sales forecasts prepared by the five distribution licensees and time trend analysis of historical demand are used to determine the medium-term forecast. The econometric approach is used to make the long-term forecast. The econometric approach first develops a correlation between past electricity sales and significant independent variables in different sectors and then the projections available for such variables are substituted to forecast future demand.

Even though demand-side management (DSM) is considered as an important tool to conserve and optimize the use of electrical energy at the end-user level, demand reduction due to possible DSM measures are not considered in the forecasts. The responsibility to carry out energy efficiency, energy conservation and demand-side management programs is primarily vested with Sri Lanka Sustainable Energy Authority of Sri Lanka (SLSEA). The Operational Demand Side Management is to be carried out by the Presidential Task Force on Energy Demand Side Management (PTF on EDSM) and guided by a National Steering Committee (NSC). Thus, electrical utilities do not have control over the implementation of DSM programs at present. Further, the DSM forecasts and targets are ambitious and their actual realization is based on many other external factors, including end-user willingness. Therefore, demand reduction due to possible DSM measures are not considered in the forecasts that resulted in the base case plan as presented in this report. However, if any conservation is achieved through DSM activities, actual reductions to demand as a result would be captured and reflected in the demand forecasts of subsequent LTGEPs.

The shape of the daily load profile is expected to change gradually and the growth rate of the day peak shows a higher increase than the growth rate of the night peak. It is estimated that the day peak would surpass the night peak by 2027. The forecasted annual average growth rate of energy demand for the next 20 years is 4.9% and the annual peak demand growth rate is around 4.6%. The load forecast used is given in Table E.1.

National Obligations on Mitigating Global and Local Environmental Implications

Planning Studies as contained in this report are carried out to meet all the environmental and climate change obligations of Sri Lanka during the 20 year planning horizon. Sri Lanka, being a partner to COP21 Paris agreement on mitigation of global climate change induced impacts, presented the Nationally Determined Contributions (NDC) to strengthen global efforts of both mitigation and adaptation. In response to challenges posed by climate change, Sri Lanka has taken several positive steps by introducing national policies, strategies and actions to mitigate climate change induced impacts. According to the ratified NDCs in September 2016 by UNFCCC, among mitigation strategies, Sri Lanka expects a 4% unconditional and 16% conditional reduction of greenhouse gas emissions in the electricity sector. This is incorporated in the LTGEP 2020-2039 by integrating more Other Renewable Energy (ORE) based generation and low carbon thermal generating options to meet the Sri Lanka's obligations in COP21 Paris agreement on mitigation of global climate change induced impacts.

In addition, the latest General Policy Guidelines for Electricity Industry (as issued in April 2019) requires Non-Conventional Renewable Energy (NCRE), (referred to as ORE in this report) to be developed to the optimum levels to diversify generation mix and to minimise dependence on imported resources. It requires ORE resources to be promoted based on a priority order arrived at considering resource potential, economics, the maturity of the technology and quality of supply. First three ORE resources in this priority order are identified as mini-hydro, wind and solar followed by other ORE resources. The policy guidelines also highlight the need to progress with the vision to achieve 50% of electricity generated from renewable sources (under favourable weather conditions) by 2030. In addition, the policy also advocates Other Renewable Energy based generation to be optimally developed to provide 1/3rd of the power demand by 2030. Planning studies as contained in this report has incorporated above policy requirements (though they are issued at the end of the planning studies) as much as possible.

When a major power project is initiated, a detailed environmental impact assessment (EIA) is carried out taking into account the inter-related socio-economic, cultural and human-health impacts and impacts to the ecological systems, both beneficial and adverse. These are performed as location specific studies. Necessary mitigation measures are also identified during such Environmental Impact Assessments and such requisites are included in preparing RFPs of relevant power projects, thereby ensuring environmental commitments during implementation stage as well.

Committed and Candidate Firm Power alternatives for the Growing Electricity Demand

The latest General Policy Guidelines states that; While a high priority is to be given to environmental protection, a suitable generation mix from firm energy sources must be maintained to strengthen the country's economy and energy security. It also stipulates that; to ensure security, availability and reliability of supply, installed firm power capacity (based on firm energy sources such as fossil fuels and storage hydro) shall be there at all time to provide at least a $2/3^{rd}$ of the demand for power. The policy also gives the diversified fuel mix in the installed firm power capacity to be maintained by 2030, namely, 30% based on Liquefied Natural Gas or indigenous Natural Gas, 30% on Coal, 25% on large storage hydro and 15% utilizing furnace oil produced during local refinery process as a by-product and ORE based firm energy sources (such as biomass).

The candidate thermal power plant options considered for the study are; 45 MW gas turbines, 300 MW diesel-fired combined cycle plants, 150 MW, 300 MW & 600 MW natural gas-fired combined cycle plants, 300 MW high efficient and 600 MW supercritical coal-fired steam plants and 15 MW reciprocating engines. Further, the introduction of 600 MW nuclear power plant is also considered in a separate scenario.

3 x 35 MW gas turbines at Kelanitissa as identified in the 2018-2037 LTGEP were considered as a committed project and the same is mentioned as 130 MW capacity in this revised LTGEP 2020-2039 considering updated information available.

A 300 MW dual-fuel (natural gas/auto diesel) fired combined cycle power plant was identified to be commissioned by 2019 in previous LTGEPs (LTGEP 2015-2034 and LTGEP 2018-2037). This power plant was planned to be constructed at Kerawalapitiya. Though the procurement process for the same was initiated, the award could not be made due to legal disputes. Non-implementation of such planned low-cost power capacities necessitated adding supplementary power capacity for shorter/medium terms as stop-gap measures until planned long term capacities are added to ensure reliability and to avoid possible power shortage.

320 MW of furnace oil-fired reciprocating engine based power plants were identified in the LTGEP 2018-2037 to be installed and commissioned by 2018 as short/medium term measures. 170 MW out of this total capacity has been added to the system through the extension of existing IPP contracts. Also, 4 x 24 MW reciprocating engine power plants (at the grid substations of Habarana, Moneragala, Horana and Pallekelle) and a 100 MW reciprocating engine based power plant at Galle as identified in LTGEP 2018-2037 are considered as committed medium-term projects in the preparation of this LTGEP.

The ongoing hydropower projects of 35 MW Broadlands, 122 MW Uma Oya and 31 MW Moragolla are considered as committed power projects. The latest updated commissioning schedules of these hydro projects were used in preparing this revised LTGEP. The proposed 15 MW Thalpitigala hydropower project was considered as a candidate plant for the year 2024, considering the cabinet approvals secured by the Ministry of Irrigation and Water Resource Management. The proposed 24 MW Seethawaka Ganga hydropower project to be developed by Ceylon Electricity Board was considered for the year 2023.

More than 3.5 GW of Renewable Energy Development from Cleaner Indigenous Resources

The 100MW wind farm project that is currently being developed by Ceylon Electricity Board at Mannar was considered as a committed project. One of the main objectives of this large wind farm is to operationally test a novel semi-dispatchable operating strategy, by which more wind resources are expected to be integrated. As the transmission infrastructure has been already developed, the remaining wind potential in Mannar is required to be developed next in phases to meet ORE additions facilitated in this LTGEP to meet government policy targets.

During the planning studies, the contribution from ORE was considered and different ORE technologies were modelled as appropriate. Maximum possible ORE integration has been facilitated in this LTGEP to meet government policies, subjected to the operational constraints. A separate renewable integration study was carried out to identify the year by year renewable resource integration. The operational flexibility, transmission and system constraints were considered in this study. A strong renewable energy development has been facilitated through this plan with a more than fivefold increase to the expected total renewable capacity for the next twenty years as compared to the past two decades. The cumulative ORE capacities envisaged at the end of 20 years are 1,323 MW from wind, 2,210 MW from solar, 654 MW from mini-hydro and 144 MW from biomass. Higher ORE share is expected to maximize the utilization of indigenous natural resources.

With decreasing global price trends due to improvements to solar PV technology and economies of scale during solar photovoltaic production, development of solar PV has been gaining momentum in Sri Lanka. Solar PV additions take place at present under different schemes such as small-scale rooftop, small scale and large scale ground mounted systems. Incentives offered to high end domestic consumers to avoid consumption in higher blocks in the increasing block tariff domestic tariff structure had contributed to higher interest to install domestic solar rooftop systems. Installation of solar PV systems at rooftops helps the country to utilize the otherwise unproductive asset of rooftop area for a productive economic purpose. Government of Sri Lanka (GOSL) launched an accelerated solar development campaign in 2016 to promote rooftop solar installations in the country. The program objective of reaching 200 MW of rooftop solar PV capacity by 2020 has been already achieved and a continuous growth in rooftop capacity is observed.

Procurement work for two directly grid connected ground mounted solar PV projects has been initiated to integrate distributed solar PV schemes at multiple grid locations in sizes of 60 x 1 MW and 90 x 1 MW. Potential large scale solar PV development as concentrated parks too are being studied at few earmarked potential sites such as Pooneryn and Moneragala, which are to be developed in phases. Additional techno/social/environmental feasibility studies are required and securing land is required prior to committing for development of transmission infrastructure to evacuate power from these sites. Ideally, a priority order is preferred to be developed jointly by CEB and SLSEA to phase out the total ORE development during the 20-year period considering the favourability of resource and additional transmission infrastructure development costs.

However, different grid integration strategies such as the geographical distribution of Solar PV installations, curtailment during low demand hours and energy storage systems may be required when penetration of solar PV capacity increases, to reduce adverse implications of large solar PV due to variability, intermittency and resource uncertainty.

Wind Power is another large indigenous clean energy resource in Sri Lanka with a considerable potential for future development. Large scale wind power development in the country is presently focused in main resource areas such as Mannar, Pooneryn, Puttalam and North. Development of wind resources both as distributed and concentrated sites is to be carried out to meet ORE additions planned for the planning period. However, integration of wind resource need to be done giving due considerations to various technical constraints due to its intermittency and strong seasonality. The wind power capacities presented in this report are expected to experience daily and weekly curtailments to overcome technical and operational restrictions, the amount of which is expected to increase gradually over the years with higher penetration. Therefore, features to remotely curtail wind generation (if so required) to meet technical and operational requirements and methods to treat such curtailments need to be incorporated to future contracts, agreements and specifications.

Encouraging the development of other newer forms of clean energy technologies, CEB has called for an Expression of Interest from prospective private developers for the development of geothermal energy conversion, compressed air-based power generation, ocean thermal energy conversion (OTEC), ocean energy conversion (Wave), biogas power generation and other storage applications such as grid-scale battery storages and hybrid systems. Facilitation for similar applications will continue with the progress of commercialization of technologies.

Development of 3 GW of Natural Gas & 2.1 GW of Coal Based Generation Infrastructure to Ensure Reliable and Economic Supply of Electricity

Firm power sources that are available to be dispatched on system requirement and presents an unvarying output while in operation is essential for the proper, reliable and healthy operation of a power system. However continuous delays in implementing the planned low-cost firm power projects have adversely affected the electricity grid as well as the national economy.

Coal power has been identified as one of the most economical generating options to maintain economy/affordability of supply. According to a study conducted by New Energy and Industrial Technology Development (NEDO) - Japan, the Foul point area in Trincomalee was identified as the most promising site to carry out future coal power development, considering attributes such as access to the deep sea. Extension of existing Lakvijaya power station is also considered as a near term coal power development alternative due to the possibility of faster implementation to urgently overcome the firm power capacity deficit at low cost.

In all new planned coal power projects, necessary environmental impact mitigation measures such as strict emission control, indoor coal storages and enclosed coal handling facilities are incorporated along with higher conversion efficiency. Such mitigation measures are incorporated over and above what is required to meet current environmental laws of the country but at an additional capital cost of about 700USD per kW, compared to a conventional coal power plant. Supercritical technology based coal plants have enhanced operating efficiency and reduced coal consumption, which in turn decrease overall emissions. Possibility of introducing such supercritical power plants with larger unit capacities would be evaluated considering other system constraints.

Natural gas (NG), being a low carbon fuel alternative for thermal generation is the next planned fuel addition to the generation mix of the country and the first NG fired power plant was identified in the LTGEP 2015-2034. This LTGEP 2020-2039 has adhered to the government policy on fuel diversification in installed firm capacity and added liquefied natural gas (LNG) based generating capacity to meet government policy targets. 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

Natural gas power generation depends on the availability of natural gas fuel handling infrastructure to import, re-gasify and distribute natural gas. When sourcing LNG for Sri Lanka, a strategically decided mixture of long and medium term LNG contracts along with short term spot market purchases can be adopted to minimize the “take or pay” type contractual risks under fuel price and to significant weather related uncertainties.

Planning studies have considered current fuel price trends of LNG and capital cost recovery of LNG supply infrastructure. Both the floating storage regasification unit (FSRU) and land-based LNG regasification terminal are considered in the studies. Establishing LNG fuel handling and supply infrastructure is important to gain the maximum benefit of LNG based power generation which is much more economical and environmentally friendly than fuel oils. Any delays in establishing LNG infrastructure would cause the LNG power plants to operate on fuel oil, resulting in additional cost on power generation as well as increased environmental emissions.

Main load centres of Sri Lanka are in the Western region of the country. Therefore, locating low carbon natural gas based power plants are recommended to be developed in the Western region to facilitate easy distribution of Natural Gas via pipelines, lower transmission losses while complying with the environmental regulations of the Western region.

Natural gas exploration work is in progress in the Mannar basin and there is a possibility of using such gas in the natural gas-fired power plants when such fuel is commercially available at economically favourable prices.

Key Results of Generation Expansion Planning Study

The optimal expansion plan as contained in this report is derived using planning software OPTGEN, SDDP and WASP. The base case as contained in table E2 includes the yearly generation capacity additions that provide the total lowest present value cost for the period, while meeting the reliability criteria and other constraints. Variations to demand growth and fuel prices are presented under sensitivity analysis. Each plant sequence presented under a given scenario is the least cost plant sequence for the given scenario.

The draft LTGEP 2020-2039 was initially prepared by CEB based on the government policy guidelines, the planning code and the reliability criteria as published in the gazette notification 2019/28 by PUCSL. Upon submitting same to the Board of CEB for approval, the Board requested it to be revised to incorporate a higher reliability criterion than what is published by PUCSL by increasing the lower and upper limits of reserve capacity margin to 10% and 25% respectively from 2.5% to 20% as contained in the PUCSL gazette notification 2019/28.

Accordingly, the base case plan of LTGEP 2020-2039 was changed based on the higher reliability criteria. The Board granted its approval to this base case plan on 22nd April 2019, subject to PUCSL revising the gazette notification to include the enhanced reliability limits proposed by the Board. The Board approved LTGEP 2020-2039 containing the new base case (termed "original base case" hereafter) was submitted to PUCSL approval on 24th May 2019.

The original base case plan prepared based on above enhanced reserve margins and submitted to the Public Utilities Commission of Sri Lanka on 24th May 2019 is given in Table 8.1 of this report. The capacity balance, energy balance and dispatch schedule pertaining to the original base case plan are given in Annex: 8.2, Annex: 8.3 and Annex: 8.4 respectively. All scenario analysis carried out for the original base case plan such as introducing nuclear power and HVDC interconnection to the power system are kept unchanged in this report as an additional reference.

Though Cabinet approval also was received for the enhanced reliability criteria proposed by the Board, PUCSL had not revised the original gazette notification to include the new reliability criteria. After several written clarifications and meetings between PUCSL and CEB, PUCSL finally requested CEB to revise and resubmit the original base case as contained in the draft LTGEP 2020-2039 submitted to PUCSL, to comply with the reliability criteria stipulated in PUCSL gazette 2019/28.

The revised base case plan of the LTGEP 2020-2039 prepared after adopting the gazetted reliability criteria of PUCSL of 2.5% (minimum) and 20% (maximum) reserve margin is presented as an addendum in this draft LTGEP 2020-2039 report and is termed "revised base case plan". This draft LTGEP 2020-2039 had accommodated other observations of the commission such as using economic costs, meeting renewable energy policy target for 2030 and using realistic implementation schedules of the power projects based on the updated project information.

The revised base case plan is given in the Table E.2 and Table Ad.1 of Annex 15 of the Long Term Generation Expansion Plan 2020-2039 report. The capacity balance, energy balance and dispatch schedule of the revised base case plan are given in Tables Ad 6, Ad 7 and Ad 8 of Annex 15 respectively.

It is to be noted that all analysis as contained in this LTGEP 2020-2039 report is same as the original submission made to PUCSL on 24th May 2019, except the following sections that were changed subsequently with the addendum.

- Executive summary
- Base case plan
- Section on externalities
- Contingency analysis

Table E.1 - Base Load Forecast: 2020-2044

Year	Demand		Net Loss*	Net Generation		Peak Demand
	(GWh)	Growth Rate (%)	(%)	(GWh)	Growth Rate (%)	(MW)
2020	16914	7.4%	8.78	18542	7.2%	3050
2021	18194	7.6%	8.62	19910	7.4%	3254
2022	19187	5.5%	8.46	20959	5.3%	3403
2023	20233	5.5%	8.30	22065	5.3%	3561
2024	21337	5.5%	8.15	23230	5.3%	3728
2025	22501	5.5%	8.00	24458	5.3%	3903
2026	23667	5.2%	7.90	25696	5.1%	4079
2027**	24819	4.9%	7.80	26918	4.8%	4241
2028	26025	4.9%	7.70	28195	4.7%	4444
2029	27279	4.8%	7.60	29522	4.7%	4655
2030	28573	4.7%	7.50	30890	4.6%	4872
2031	29917	4.7%	7.45	32325	4.6%	5101
2032	31279	4.6%	7.40	33778	4.5%	5332
2033	32675	4.5%	7.35	35267	4.4%	5569
2034	34119	4.4%	7.30	36806	4.4%	5814
2035	35607	4.4%	7.25	38390	4.3%	6067
2036	37126	4.3%	7.25	40028	4.3%	6328
2037	38692	4.2%	7.25	41716	4.2%	6597
2038	40298	4.2%	7.25	43448	4.2%	6873
2039	41937	4.1%	7.25	45215	4.1%	7155
2040	43623	4.0%	7.25	47033	4.0%	7445
2041	45368	4.0%	7.25	48914	4.0%	7745
2042	47170	4.0%	7.25	50857	4.0%	8054
2043	49037	4.0%	7.25	52870	4.0%	8376
2044	50978	4.0%	7.25	54963	4.0%	8709
5 Year Average Growth	6.0%			5.8%		5.1%
10 Year Average Growth	5.5%			5.3%		4.8%
20 Year Average Growth	4.9%			4.8%		4.6%
25 Year Average Growth	4.7%			4.6%		4.5%

***** Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future.

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

Table E.2 Revised Base Case 2020 - 2039

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP[3] %
2020	Solar 100 MW *(including 35 MW committed)* Wind 20 MW *(2x10 MW Chunnakam Wind)* Mini Hydro 15 MW* Biomass 5 MW*	*200 MW Short Term Basis Supplementary Power Plants* *100 MW Short Term Basis Supplementary Power Plants* **145 MW Reciprocating Engine Power Plants**	6 x 5 MW Northern Power	1.427
2021	Solar 110 MW *(including 70 MW+ 2x10MW committed)* *100 MW Mannar Wind Park* Mini Hydro 20 MW* Biomass 5 MW* *Uma Oya HPP 122 MW* *Broadlands HPP 35 MW*	**395 MW Reciprocating Engine Power Plants** *130 MW Gas Turbine [2]*	100 MW ACE Embilipitiya 20 MW ACE Matara 51 MW Asia Power 200 MW Short Term Basis Supplementary Power Plants 100 MW Short Term Basis Supplementary Power Plants	1.362
2022	Solar 60 MW Wind 150 MW *(including 60 MW committed)* Mini Hydro 20 MW* Biomass 5 MW*	*4 x 24 MW Reciprocating Engine Power Plants* *100 MW Reciprocating Engine Power Plants – Galle* *200 MW Open Cycle Operation of 1 x 300 MW Natural Gas fired Combined Cycle Power Plant – Western Region[2]*	**290 MW Reciprocating Engine Power Plants**	1.424
2023	Solar 60 MW Wind 110 MW Mini Hydro 20 MW* Biomass 5 MW* *Moragolla HPP 31 MW* **Seethawaka HPP 24 MW**	*100 MW Steam Turbine Operation of 1 x 300 MW Natural Gas fired Combined Cycle Power Plant – Western Region[2]* *(Combined Cycle Operation)* (Identified in LTGEP 2015-2034 and LTGEP 2018-2037 to be commissioned by 2019) **300 MW Natural Gas fired Combined Cycle Power Plant – Western Region[2]** (Identified in LTGEP 2018-2037 to be commissioned by 2021) **300 MW Lakvijaya Coal Power Plant Extension** *163 MW Combined Cycle Power Plant (KPS–2)[4]*	**190 MW Reciprocating Engine Power Plants** 4x17 MW Kelanitissa Gas Turbines 115 MW Gas Turbine [1] 4x9 MW Sapugaskanda Diesel Ext. [1] 163 MW Sojitz Kelanitissa Combined Cycle Plant [4]	0.449
2024	Solar 60 MW Wind 90 MW Mini Hydro 20 MW* Biomass 5 MW* **Thalpitigala HPP 15 MW**	**300 MW Natural Gas fired Combined Cycle Power Plant**	4x17 MW Sapugaskanda Diesel[1]	0.345
2025	Solar 80 MW Wind 40 MW Mini Hydro 20 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant**	4x15.6 MW CEB Barge Power Plant[1]	0.331
2026	Solar 90 MW Wind 35 MW Mini Hydro 10 MW* Biomass 5 MW*	**2 x 300 MW New Coal fired Power Plant (Foul Point Phase I)**	**60 MW Reciprocating Engine Power Plants** 4x9 MW Sapugaskanda Diesel Ext. [1]	0.077
2027	Solar 90 MW Wind 50 MW Mini Hydro 10 MW* Biomass 5 MW*	-	-	0.210
2028	Solar 100 MW Wind 40 MW Mini Hydro 10 MW* Biomass 5 MW* **Pumped Storage HPP 200 MW**	-	-	0.152

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP[3] %
2029	Solar 100 MW Wind 40 MW Mini Hydro 10 MW* Biomass 5 MW* **Pumped Storage HPP 200 MW**	-	-	0.121
2030	Solar 100 MW Wind 20 MW Mini Hydro 10 MW* Biomass 5 MW* **Pumped Storage HPP 200 MW**	**300 MW New Coal fired Power Plant** **(Change to Super critical will be evaluated)**	-	0.019
2031	Solar 100 MW Wind 60 MW Mini Hydro 10 MW* Biomass 5 MW*	-	-	0.155
2032	Solar 110 MW Wind 50 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant** **196 MW Reciprocating Engine Power Plants**	*4 x 24 MW Reciprocating Engine Power Plants* *100 MW Reciprocating Engine Power Plants – Galle*	0.128
2033	Solar 110 MW Wind 35 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** **300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2) 3 x 8.93 MW Uthuru Janani Power Plant	0.182
2034	Solar 120 MW Wind 70 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	-	0.105
2035	Solar 120 MW Wind 45 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** **300 MW Natural Gas fired Combined Cycle Power Plant**	300MW West Coast Combined Cycle Power Plant	0.060
2036	Solar 110 MW Wind 50 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.055
2037	Solar 110 MW Wind 50 MW Mini Hydro 10 MW* Biomass 5 MW*	-	-	0.241
2038	Solar 110 MW Wind 70 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	-	0.193
2039	Solar 110 MW Wind 70 MW Mini Hydro 5 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.178
Total PV Cost up to year 2039, **USD 16,555 mil USD** (LKR 2,981.45 billion)				

GENERAL NOTES:

1. Retirement of these plants would be evaluated based on the plant conditions.
2. The plant has dual fuel capability and would be operated with Natural Gas.
3. Refer Contingency Analysis for additional capacity requirements in occurrence of risk events.
4. PPA of Sojitz Kelanitissa is scheduled to be expired in 2023, and will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2023 with the development of LNG based infrastructure.

* Mini-hydro and Biomass annual capacity additions are not restricted to the planned capacities.

- Committed plants are shown in Italics.
- All plant capacities are given in gross values.

- Battery storage is proposed to be added to the system in phase development. (Total 50 MW by 2025 and 100 MW by 2030). Exact capacities and entry years will be evaluated during the detailed design stage of battery storage integration.
- PV cost includes the cost of projected ORE development, USD 2274.04 million based on economic cost. Cost of battery storage is not included in the PV cost.
- Thalpitigala and Gin Ganga multipurpose hydropower plants are proposed and developed by Ministry of Irrigation. As a committed power plant, Thalpitigala is scheduled to begin commercial operation by 2024 while feasibility studies are still being carried out for Gin Ganga project.
- Seethawaka HPP is expected in 2023 while PSPP units are expected in 2028, 2029 and 2030 respectively.
- Refer addendum for the required transmission system reinforcements for the implementation of major power plants in the years up to 2026.

A generation capacity shortage is observed in the short term up to the year 2023 when compared to forecasted demand due to non-implementation of projects identified in previous plans, mainly delays in the implementation of the two 300 MW natural gas-fired combined cycle projects which should have been commissioned in 2019 and 2021 as per previous plans. Therefore, it is necessary to ensure adequate short term capacity additions during the initial years.

The demand forecast as contained in this report (table 3.3) is the results of detailed forecasting studies carried out in 2018, the usual commencement year of the work related to LTGEP 2020-2039. As the consensus with PUCSL to revise the draft plan was reached in January 2020, demand forecasts are not revised performing a complete planning cycle to include the latest demand data, as that would further delay the submission and approval process of the plan. However, as actual sales figures are now available for years 2018 and 2019, those demand figures could be appropriately used in short term studies to revise the short-term capacity requirement identified in this report to determine the actual minimum capacity requirement for initial years. Once the planned low cost long term major plants are commissioned during 2023 – 2025, the majority of short term capacity additions are to be retired as shown in the revised base case.

The capacity share from coal and natural gas as contained in this report are maintained to comply with the fuel diversity requirement of firm capacity as stipulated in the government policy guidelines. Accordingly, by 2025 the firm capacity share of coal power plants is to be 22 % and natural gas power plants to be 38%. By 2030, this share will be 30% from coal and 30% from natural gas, complying exactly with the policy targets.

Implementation of the Plan and Future Work

This plan only stipulates the most economical capacity additions for the future. To implement such plans, the assistance of all stakeholders is required. The National Energy Policy and Strategies as published in the Gazette Extraordinary 2135/61 dated 09th August 2019 states under section 3.9; "Considering limitation to land with specific attributes that are required to develop certain technologies and considering the extensive financial losses incurred in the past owing to shifting of sites to locate power plants, strategic locations to establish future energy infrastructure will be earmarked and secured in advance to ensure timely implementation of such facilities and to minimise adverse social impacts". It is hence of utmost importance to identify and secure land required to locate power capacities as identified in this plan.

It is important to recognise the continuous development of coal as a baseload power generating option, not only to maintain the fuel diversity but also due to unparallel economic advantages that it offers. It was noted during the planning studies that other prominent economies in the region such as India, Indonesia, Vietnam and Bangladesh are continuing the development of coal power plants owing to the economic advantages they offer. Timely implementation of coal plants is considered essential to keep costs of electricity down and thereby making costs of production of Sri Lankan goods low to compete with regional countries.

In order to facilitate the harnessing of indigenous resources and to maintain renewable energy portfolio in the generation mix, a total of 3,495 MW of ORE capacity has been identified to be developed during the planning horizon. Once developed, energy coming from such ORE based power plants are expected to replace the energy that otherwise would have to be generated from thermal power plants. Though ORE based plants, other than biomass and solid waste, do not contribute to installed firm capacity, the energy contribution from such plants reduces the need to install firm capacity in the long run. Thus, unless such ORE capacities identified are not developed, share of thermal firm capacity additions need to be increased in future plans. Responsibility of identifying and preparing renewable resource inventories and maps and managing such renewable energy resources lies with Sri Lanka Sustainable Energy Authority. CEB, through this plan, has facilitated the absorption of ORE based resources. However, for the actual and economical exploitation of such ORE resources, CEB requires the assistance of other agencies.

Introduction of pumped storage power plants as a grid scale energy storage solution is mandatory to enhance the planned ORE absorption and to give operational flexibility. The present high cost of battery energy storage technologies is expected to decline in future with the technology developments, thus making battery energy storage a possible economically viable solution. To facilitate such development and to gain knowledge of such technology, battery storage is facilitated in this report for phased development.

It is important to note that actual energy dispatch in a given future year would depend on the fuel prices prevailing in that year and weather conditions. Based on the fuel price forecasts considered for planning purposes and at average weather conditions coal generation is expected to have a share of 28% by 2025 and 41% by 2030. The Energy contribution from natural gas in 2025 and

2030 would be 29% and 22% respectively. Contribution from renewable energy is going to be over 37% by 2025 and 35% by 2030. Under favourable weather conditions, the latter is expected to go further up. The generating capacity mix identified in this plan is operationally capable of raising the share of generation from cleaner sources, (Natural Gas and renewable energy) up to 70% of total generation.

The total present value of implementing the revised Base Case Plan 2020-2039 in the next 20 years is approximately USD **16,555** million with discount rate of 10%.

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

(i) Reciprocating engine power plants for short term requirement.

The anticipated capacity shortage for the period till 2023 is to be met through the development of reciprocating engine power plants. Development of these power plants expeditiously is essential to increase low reserve capacity margins in the initial years and avoid capacity shortage as a result.

170 MW of extended IPP plants and 300 MW of short-term capacity in operation in 2020 is expected to be retired in 2021. As a result, 395 MW of capacity is seen as required for 2021. This is in addition to another 145 MW required for 2020. If further extension of IPP contracts is expected to be considered along with other competitive capacity procurements, initiation of such capacity additions is recommended to be commenced at earliest upon obtaining approval to this plan.

(ii) Reciprocating engine power plants on medium-term requirement.

Out of 320 MW reciprocating engine capacity identified in LTGEP 2018-2037, following power projects had been identified as medium-term capacity developments. It is essential to fast track the development of these projects and complete the projects by 2022.

a) 4x24 MW Reciprocating engines plants at four grid locations.

b) 100 MW Reciprocating engine based power plant in Galle

(iii) Commissioning of 35 MW Broadlands, 122MW Uma Oya, and 31 MW Moragolla by the year 2021, 2021 and 2023 respectively.

(iv) Commissioning of 100 MW wind farm at Mannar by the year 2021.

The semi dispatchable Mannar wind farm that is expected to generate approximately 337GWh annually need to be expedited. As the transmission infrastructure is already available up to Mannar, additional wind resource at Mannar island needs to be developed next.

(v) Commissioning of Other renewable energy projects

Approximate capacity addition of 1,200 MW of Wind and 2,000 MW of solar is facilitated through this plan for the 20 year planning horizon. It is the responsibility of all agencies including Sustainable Energy Authority to carry out necessary resource availability studies and to come out with suitable locations where such capacities could be developed.

(vi) 130 MW of gas turbines by the year 2021

The power plant is expected to add much needed peaking capacity and reduce the dependency on hydropower.

(vii) Natural gas fired combined cycle power plants and associated LNG import infrastructure.

Two, 300 MW dual fuel combined cycle power plants must be commissioned in western region by 2023. The associated LNG supply infrastructure having sufficient capacity to be developed on a fast track basis to cater to the two new power plants and the existing combined cycles that are to be converted to natural gas.

Two additional 300 MW natural gas fired combined cycle power plants are identified as required for 2024 and 2025. The land acquisition process and all other necessary approvals are required to be obtained immediately to commence the project procurement activities for these two power plants. Development of associated transmission facilities also required to be commenced in parallel to the power plant implementation schedule. Early approval to this LTGEP is essential to commence development work on those two plants.

(viii) Extension of Lakvijaya Power Plant.

The 4th Unit of Lakvijaya coal power plant is planned to be commissioned by 2023. Prompt action is required from all stakeholder authorities to enable timely implementation of the project on the targeted date.

(ix) High efficient coal power plant development

Two, 300 MW High Efficient Coal Power Plants are planned to be commissioned in 2026 at Foul Point in Trincomalee. The land acquisition process and all other necessary approvals are required to be obtained immediately to commence the project procurement activities.

(x) Pumped storage power plant development

Implementation of 3 x 200MW pumped storage power plant has been identified for 2028, 2029 and 2030 respectively. Pumped storage plants with variable speed pumping mechanisms is not only useful as an energy storage method, but also to facilitates absorption of maximum ORE and reduces possible ORE generation curtailments. In addition, this will operate as a peaking power plant by minimizing the high cost thermal generation. It is also identified that such pumped storage hydro plants are required in the future to provide operational flexibility, including fast ramping up/down capability and frequency regulation.

In order to account for the occurrence of risk events, a separate contingency analysis has been carried out as contained under "Contingency Analysis" for the first five year period. Low hydrology than what is planned, increase in demand beyond forecast, delays in implementation of power plants and outage of a major power plant are considered as risk events in the contingency analysis.

CHAPTER 1
INTRODUCTION

1.1 Background

The Electricity sector in Sri Lanka is governed by the Sri Lanka Electricity Act, No. 20 of 2009 amended by Act No. 31 of 2013 [1]. Ceylon Electricity Board (CEB), established by CEB Act No. 17 of 1969 (as amended), is under legal obligation to develop and maintain an efficient, coordinated and economical system of Electricity supply in accordance with Licenses issued. CEB is responsible for most of the generation and distribution licenses while being sole licensee for transmission. CEB has been issued a generation license, a transmission license and four distribution licenses. Lanka Electricity Company (LECO), a subsidiary of CEB is the other distribution licensee and there are several Independent Power Producers, whose production is also purchased by CEB. The Public Utilities Commission of Sri Lanka (PUCSL) is the regulator of the sector and was established by the PUCSL Act No. 35 of 2002 and empowered by the Electricity Act. The Sri Lankan power system has a total installed capacity of approximately 4046 MW by end of year 2018 with a total dispatchable capacity of 3436 MW. The maximum demand recorded in 2018 was 2616 MW and total net generation was 1537GWh.

Generation expansion planning is a part of the process of achieving an efficient and economical electricity supply system to the country. In order to meet the increasing demand for electrical energy, while considering the retirements of existing the thermal plants, new generating stations need to be installed as and when necessary. The planning studies presented in this report are based on the Annual Report 2017 of Central Bank of Sri Lanka [2] and electricity sector data up to 2018. The information presented has been updated to December 2018 unless otherwise stated.

The generating system has to be planned taking into consideration the electricity demand growth, generation technologies, environmental and climate change considerations, fuel diversification mix, prevailing government policies and financial requirements. Evaluation of each type of candidate generating plant technologies, from both renewable and thermal is screened, to select the optimum plant mix schedule in the best interest of the country.

1.2 The Economy

In the last six years (2013-2018), the real GDP growth in the Sri Lanka economy has varied from 5% to 3.2 % in 2018. Details of some demographic and economic indicators are given in Table 1.1.

Table 1.1- Demographic and Economic Indicators of Sri Lanka

	Units	2013	2014	2015	2016	2017	2018
Mid-Year Population	Millions	20.58	20.77	20.97	21.20	21.44	21.67
Population Growth Rate	%	0.8	0.9	0.9	1.1	1.1	1.1
GDP Real Growth Rate	%	3.4	5	5	4.5	3.4	3.2
GDP /Capita (Market prices)	US$	3609	3819	3842	3886	4104	4102
Exchange Rate (Avg.)	LKR/US$	129.11	130.56	135.94	145.60	152.46	162.54
GDP Constant 2010 Prices	Mill LKR	7,846,202	8,235,429	8,647,833	9,034,290	9,344,839	9,644,728

Source: Annual Report 2018, Central Bank of Sri Lanka

1.2.1 Electricity and Economy

Electricity demand growth rate in the past has most of the times revealed a direct correlation with the growth rate of the country's economy. Figure 1.1 shows growth rates of electricity demand and GDP from 1997 to 2018.

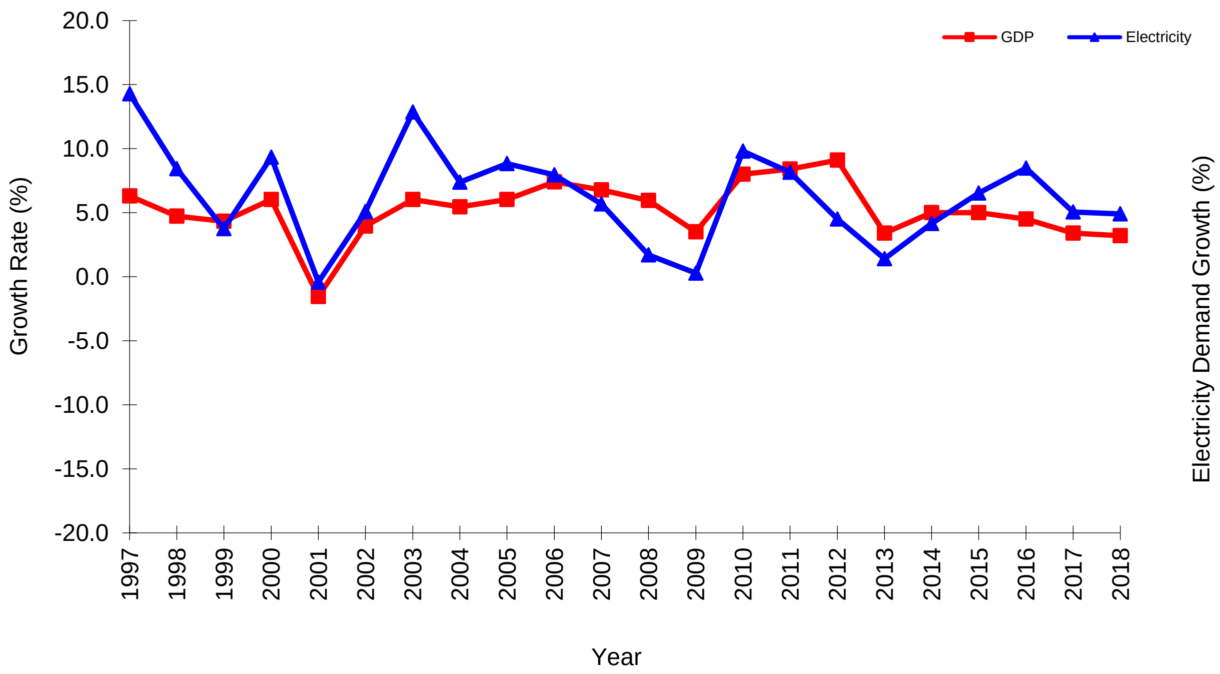


Figure 1.1 - Growth Rates of GDP and Electricity Sales

1.2.2 Economic Projections

The Central Bank of Sri Lanka has forecasted the latest GDP growth rates in real terms for four consecutive years, which is published in Annual Report 2018 of Central Bank of Sri Lanka [2] and Annual Report 2017 of Central Bank of Sri Lanka [3] as depicted in Table 1.2.

Table 1.2 - Forecast of GDP Growth Rate in Real Terms

Year	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*
2017 Forecast	5.0	5.5	60	6.0	6.0	
2018 Forecast		4.0	4.5	5.0	5.0	5.0

Source: Annual Reports 2017 & 2018, Central Bank of Sri Lanka

1.3 Energy Sector

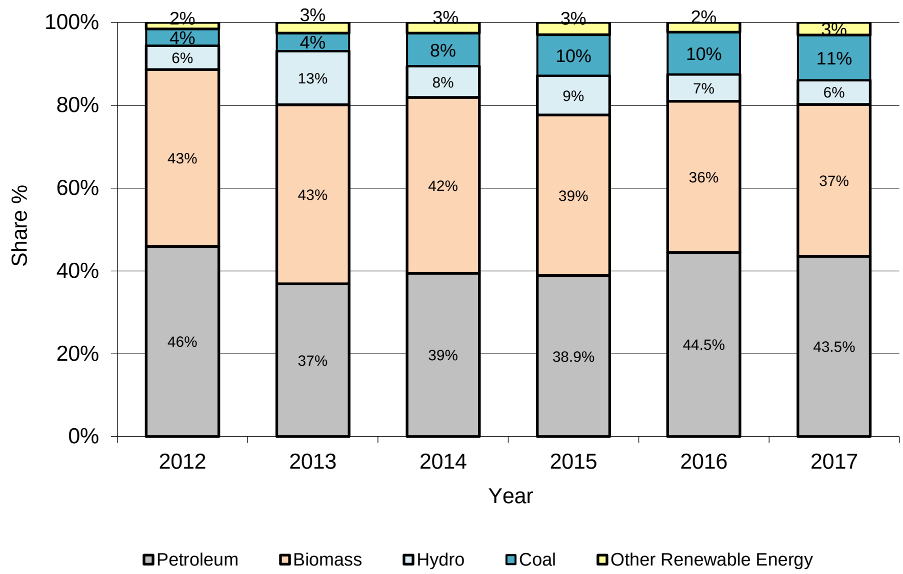
1.3.1 Energy Supply

Biomass or fuel wood, petroleum and hydro are the major primary energy supply sources, which cater the Sri Lankan energy demand. Petroleum turns out to be the major source of commercial energy, which covers more than 40 percent of the energy demand. Biomass or fuel wood, which is mainly a non-commercial fuel, at present also provides approximately 40 percent of the country's total energy requirement.

Although electricity and petroleum products are the major forms of commercial energy, an increasing amount of biomass is also commercially grown and traded. Hydropower which covers 6% of the total primary energy supply is the main indigenous source of primary commercial energy in Sri Lanka. Estimated potential of hydro resource is about 2000MW, of which significant resource has already been harnessed. Further exploitation of hydro resources is becoming increasingly difficult owing to social and/or environmental impacts associated with large-scale development. Apart from these, there is a considerable potential for wind and solar power development. The first commercial wind power plants were established in 2010 and the total capacity of wind power plants by end of 2018 is 128MW. 100MW wind farm at Mannar Island is at the implementation stage. The steps have been initiated to harness the economical wind and solar potential in Sri Lanka in an optimal manner. The first commercial solar power plants were commissioned in year 2016 and the total capacity of commercial solar power plants by end of 2018 was 51MW and nearly 170MW of solar roof tops were also connected by end of 2018. 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. By end of 2018, 37 small scale solar PV parks of 1MW has been awarded to private investors for development and another 90 small scale solar PV parks of 1MW has been under evaluation to award during 2019.

As at present, the total fossil fuel requirement of the country is imported either as crude oil or as refined products and used for transport, power generation, industry and other applications. Apart from this, initiatives have been launched in towards oil exploration with the prime intention of harnessing potential petroleum resources in the Mannar Basin. Exploration license has been awarded to explore for oil and natural gas in the Mannar Basin off the north-west coast and drilling of the test wells has been carried out. At present, natural gas has been discovered in Mannar basin (off shore from Kalpitiya Pennisula) with a potential of 70 mscfd. Discoverable gas amount of this reserve is estimated approximately 300 bcf. This may even extend beyond the potential of 2TCF with daily extraction rates of 100 mscfd but further exploration should be carried out in order to verify these figures.

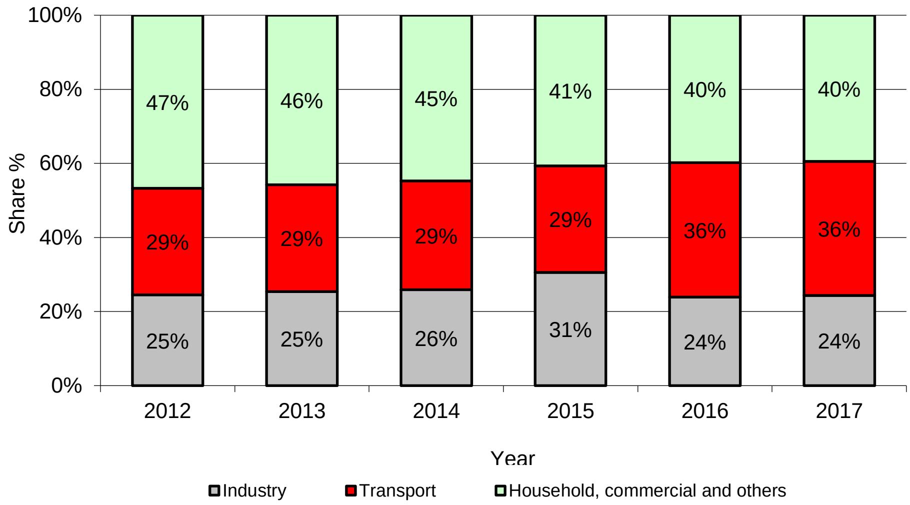
In 2017 the primary energy supply consisted of Biomass (4607 ktoe), Petroleum (5462 ktoe), Coal (1358 ktoe), Hydro (738 ktoe) and other renewable sources (387 ktoe). The share of these in the gross primary energy supply from 2012 to 2017 is shown in Figure 1.2. Hydro electricity is adjusted to reflect the energy input required in a thermal plant to produce the equivalent amount of electricity.



Source: Sri Lanka Sustainable Energy Authority

Figure 1.2 - Share of Gross Primary Energy Supply by Source

1.3.2 Energy Demand



Source: Sri Lanka Sustainable Energy Authority

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

Sectorial energy consumption trend from 2012 to 2017 is shown in Figure 1.3. According to the above chart, household and commercial sector appears to be the largest sector in terms of energy consumption when all the traditional sources of energy are taken into account. Further, it shows a decreasing trend while industry and Transport sector shows an increasing trend.

The consumption for 2017 is made up of biomass (4564 ktoe), petroleum (4364 ktoe), coal (44.2 ktoe) and electricity (1150 ktoe). Due to poor conversion efficiency of biomass, the composition of the net (or useful) energy consumption in the domestic sector could be different from the above. On the other hand, being the cheapest and most easily accessible source of energy, fuel wood still dominates the domestic sector consumption. Even though it is traded in urban and suburban areas fuel wood is still classified as a non-commercial form of energy.

1.3.3 Emissions from Energy Sector

The Total CO_2 Emission levels of Sri Lanka are 20.9 Million tons, which is approximately only 0.06 % of the total CO_2 emissions generated in the World. The absolute emission levels as well as the per capita emission levels are much below compared to many other countries in the world as tabulated in Table 1.3.

Table 1.3 - Comparison of CO_2 Emissions from Fuel Combustion

Country	kg CO_2/2010 US$ of GDP	kg CO_2/2010 US$ of GDP Adjusted to PPP	Tons of CO_2 per Capita	Total CO_2 Emissions (Million tons)
Sri Lanka	**0.26**	**0.09**	**0.99**	**20.9**
Pakistan	0.67	0.17	0.79	153.4
India	0.84	0.269	1.57	2076.8
Indonesia	0.44	0.17	1.74	454.9
Malaysia	0.63	0.28	6.93	216.2
Thailand	0.60	0.23	3.55	244.6
China	0.93	0.46	6.57	9101.5
Japan	0.19	0.24	9.04	1147.1
France	0.10	0.12	4.38	292.9
Denmark	0.10	0.13	5.84	33.5
Germany	0.19	0.21	8.88	731.6
Switzerland	0.06	0.08	4.53	37.9
United Kingdom	0.14	0.15	5.65	371.1
USA	0.2.9	0.29	14.95	4833.1
Canada	0.30	0.35	14.91	540.8
Australia	0.26	0.36	16.0	392.4
Qatar	0.46	0.27	30.77	79.1
Brazil	0.19	0.15	2.01	416.7
World	0.42	0.30	4.35	32314.2

Source: IEA CO_2 Emissions from Fuel Combustion (2018 Edition) [04] -2016 Data

Even though electricity sector is the major contributor for emissions in the world, the transport sector contributes for majority of the emissions in Sri Lanka. The contribution to emissions from electricity sector of recent four years is tabulated in Table 1.4 and sector wise comparison of CO_2 emissions in 2016 is shown in Figure 1.4.

Table 1.4 - CO_2 Emissions in the Recent Past

Year	Sri Lanka 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

Source: IEA CO_2 Emissions from Fuel Combustion (2018 Edition) [04] -2016 Data

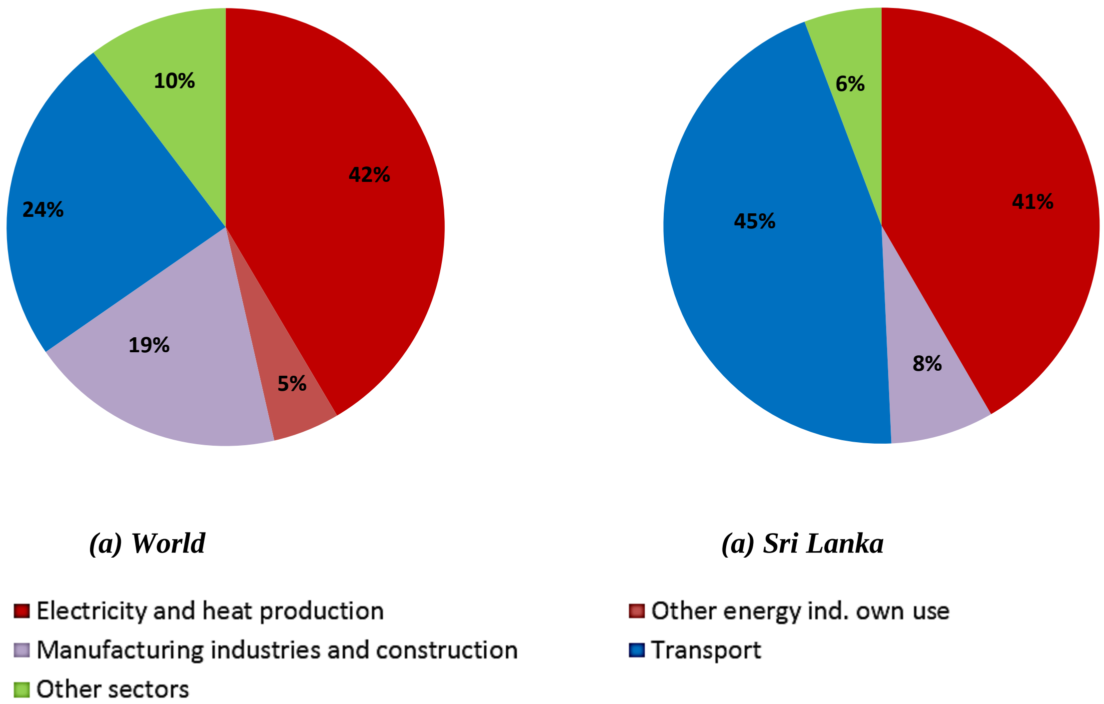


Figure 1.4 - CO_2 Emissions from Fuel Combustion 2016

Source: IEA CO_2 Emissions from Fuel Combustion (2018 Edition) [04] -2016 Data

1.4 Electricity Sector

1.4.1 Ease of Doing Business

The "Ease of Doing Business" index ranks countries based on capability of starting businesses with an overall Distance to Frontier (DTF) score. The score is determined by several factors which includes the subsection of "Getting Electricity". The Getting Electricity index is based on the procedures, time and cost required for a business to obtain a permanent electricity connection for a newly constructed warehouse, while assessing efficiency of connection process, Reliability of supply and transparency of tariff index measures, reliability of power supply and the price of electricity.

The Doing the business 2019 [05] report published by World Bank Group, classified Sri Lanka at an overall Distance to Frontier (DTF) score of 61.22 creating a Ease of Doing Business rank of 100th out of

190 countries, with the subsection of Getting Electricity DTF score of 74.37 which ranked 84th out of all 190 countries.

1.4.2 Access to Electricity

By the end of December, 2018, approximately 99% of the total population had access to electricity from the national electricity grid. Figure 1.5 shows the percentage level of electrification district wise as at end of June 2016.

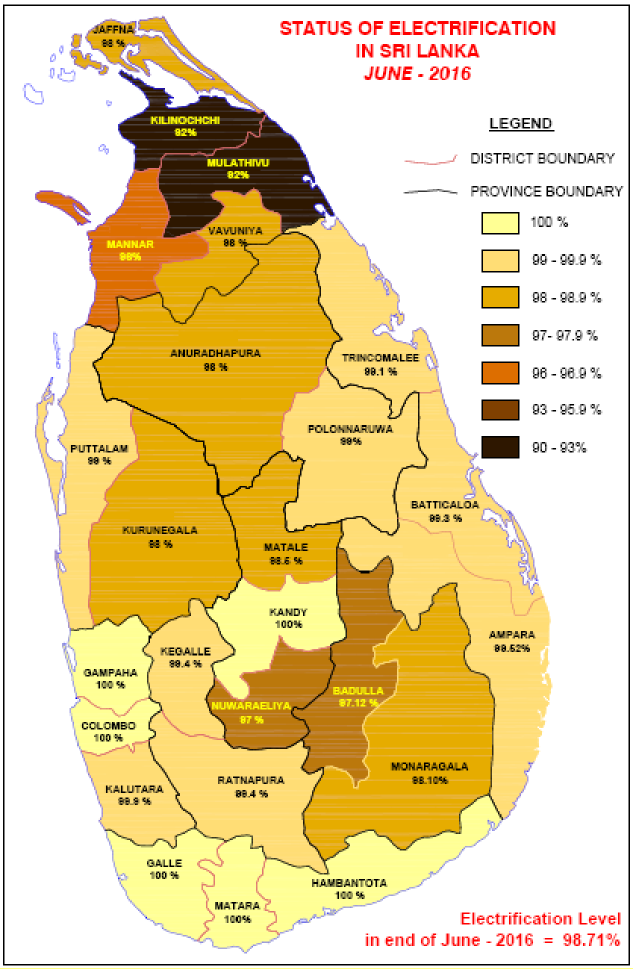


Figure 1.5 - Level of Electrification

1.4.3 Electricity Consumption

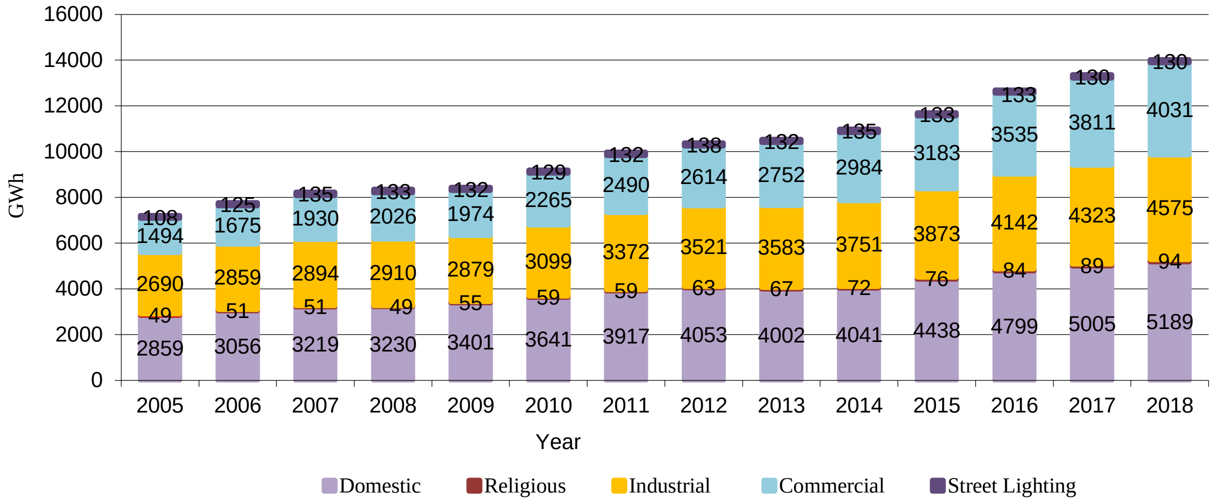


Figure 1.6 - Sectorial Consumption of Electricity (2005 - 2018)

The amount of energy consumed by each sector (i.e. each tariff category) from 2005 to 2018 is shown in Figure 1.6 while Figure 1.7 depicts sectorial electricity consumption share in 2018. These Figures reveal that the industrial and commercial (general purpose, hotel, government) sectors' consumption together is more than the consumption in the domestic sector. This is a pleasing situation for an economy with ambitious GDP growth projections.

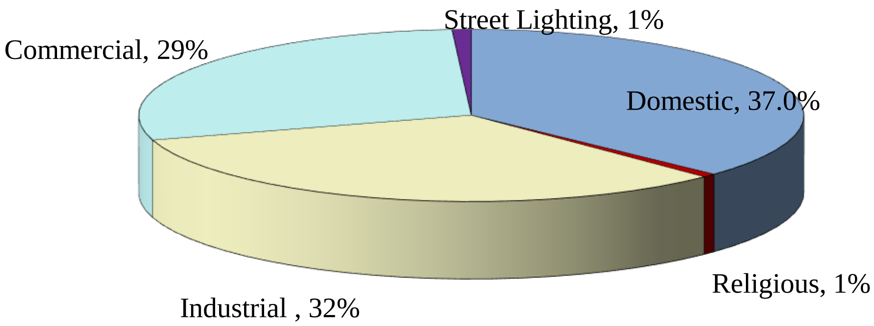


Figure 1.7 - Sectorial Consumption of Electricity (2018)

The average per capita electricity consumption in 2017 and 2018 were 626kWh per person and 650 kWh per person respectively. Generally, it has been rising steadily; however, in the period 2007 – 2009 with the slowing down of the electricity growth, the per capita consumption has stagnated. A similar trend is observed during 2012 to 2013. Figure 1.8 illustrates the trend of per capita electricity consumption of Sri Lanka from 2004 to 2018. It is compared to other Asian countries per capita electricity consumption variation from 2004 to 2013 as depicted in Figure 1.9.

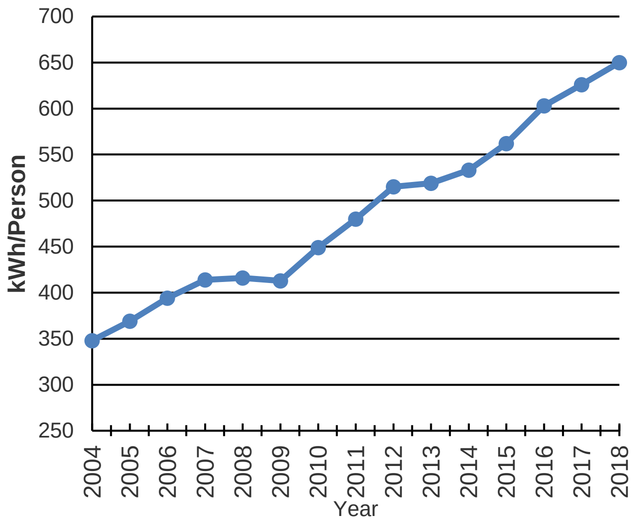


Figure 1.8 – Sri Lanka Per Capita Electricity Consumption (2004-2018)

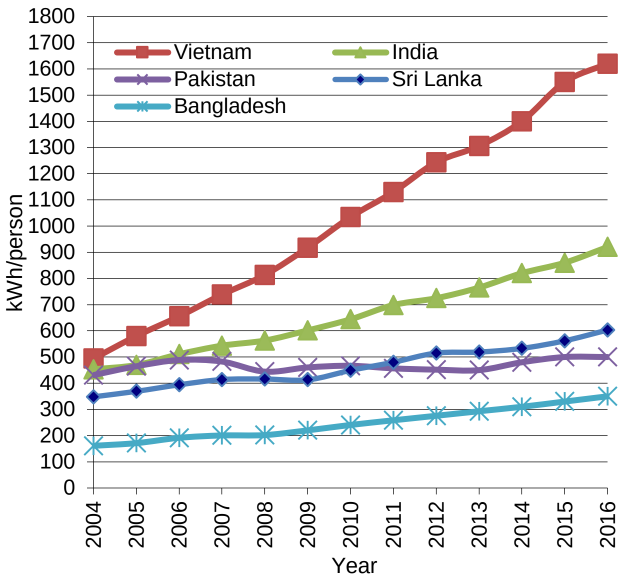


Figure 1.9 – Asian Countries Per Capita Electricity Consumption (2004-2016)

1.4.4 Capacity and Demand

Sri Lanka electricity requirement was growing at an average annual rate of around 5%-6% during the past 20 years, and this trend is expected to continue in the foreseeable future. The total installed capacity peak demand over the last twenty years are given in the Table 1.5 and graphically shown in Figure 1.10. The development of other renewables through the past years is illustrated in Figure 1.11

Table 1.5 - Installed Capacity and Peak Demand

Year	Installed Capacity	Capacity Growth	Peak Demand	Peak Demand Growth
	MW	(%)	MW	(%)
1998	1636	3%	1137	10%
1999	1682	3%	1291	14%
2000	1764	5%	1404	9%
2001	1874	6%	1445	3%
2002	1893	1%	1422	-2%
2003	2180	15%	1516	7%
2004	2280	5%	1563	3%
2005	2411	6%	1748	12%
2006	2434	1%	1893	8%
2007	2444	0.4%	1842	-2.7%
2008	2645	8%	1922	4%
2009	2684	1%	1868	-3%
2010	2818	5%	1955	5%
2011	3141	10%	2163	10%
2012	3312	5%	2146	-1%

Year	Installed Capacity	Capacity Growth	Peak Demand	Peak Demand Growth
	MW	(%)	MW	(%)
2013	3355	1%	2164	1%
2014	3932	17%	2152	-1%
2015	3847	-2%	2283	6%
2016	4018	4%	2453	7%
2017	4060	1%	2523	3%
2018	4046	-0.3	2616	4%
`Last 5 year avg. growth		0.73%		5.01%
Last 10 year avg. growth		4.67%		3.81%
Last 20 year avg. growth		4.73%		3.79%

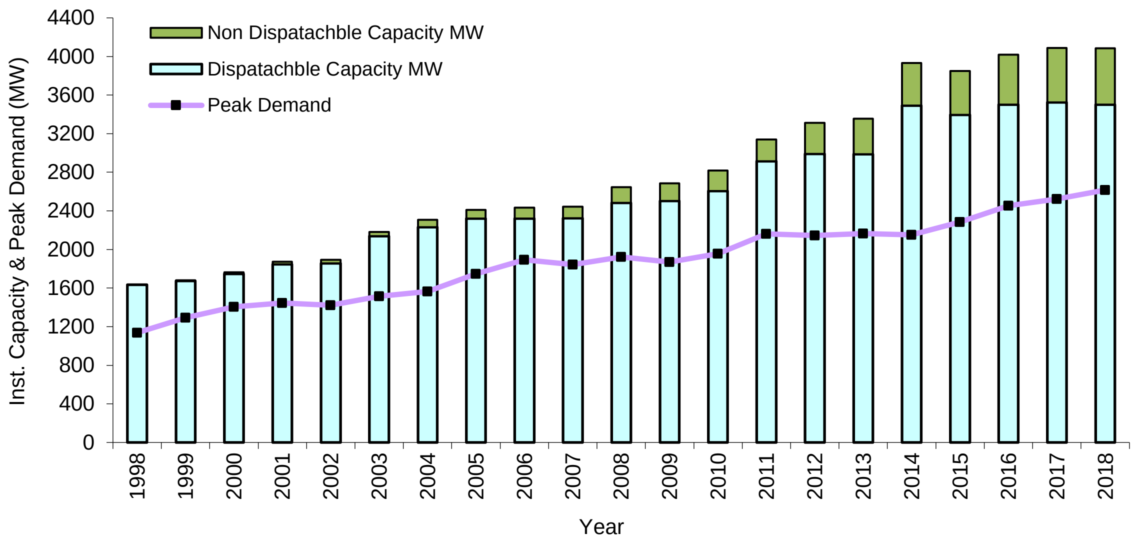


Figure 1.10 – Total Installed Capacity and Peak Demand

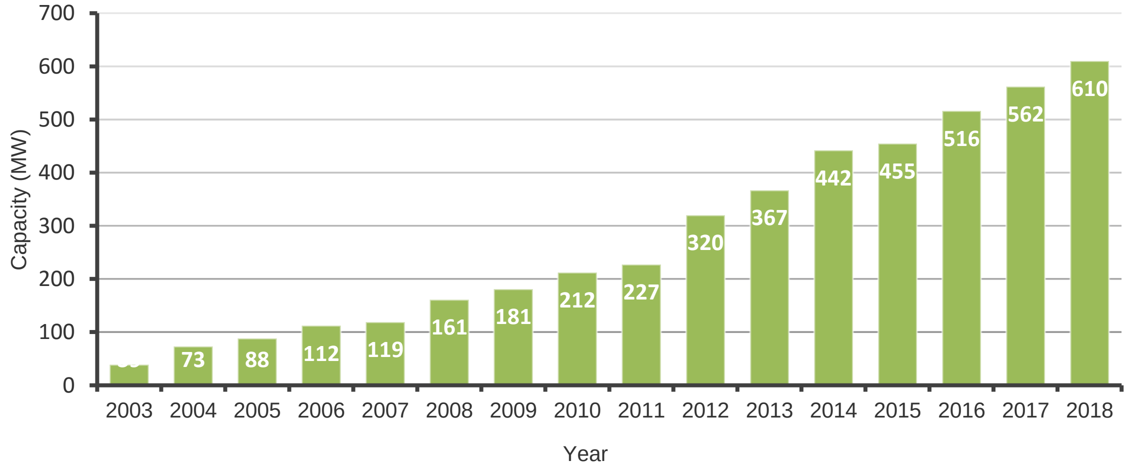


Figure 1.11 – Other Renewable Energy Capacity Development

1.4.5 Generation

In early stages the electricity demand of the country was mainly supplied by hydro generation and the contribution from thermal generation was minimal. With the time, thermal generation has become prominent. At present, thermal generation share is much higher than that of hydro. Further the other renewable energy generation from mini hydro, wind, solar, dendro etc is also increasing. Electricity Generation during the last twenty-five years is summarized in Table 1.6 and graphically shown in Figure 1.12.

Table 1.6 - Electricity Generation 1994-2018

Year	Hydro Generation		Other Renewable		Thermal Generation		Self-Generation		Total
	GWh	%	GWh	%	GWh	%	GWh	%	GWh
1994	4073	93.4	0	0.0	265	6.1	22	0.5	4360
1995	4496	94.2	0	0.0	260	5.5	17	0.4	4774
1996	3233	72.0	3	0.1	1102	24.5	152	3.4	4490
1997	3426	67.1	4	0.1	1441	28.2	235	4.6	5107
1998	3892	69.1	6	0.1	1620	28.8	114	2.0	5632
1999	4135	67.5	21	0.3	1871	30.6	97	1.6	6125
2000	3138	46.3	46	0.7	3437	50.7	158	2.3	6780
2001	3030	46.2	68	1.0	3361	51.2	105	1.6	6564
2002	2575	37.4	107	1.6	4074	59.1	136	2.0	6892
2003	3175	42.0	124	1.6	4263	56.4	0	0.0	7562
2004	2739	33.8	208	2.6	5051	62.3	115	1.4	8113
2005	3158	36.3	282	3.2	5269	60.5	0	0.0	8709
2006	4272	45.9	349	3.7	4694	50.4	0	0.0	9314
2007	3585	36.8	347	3.6	5800	59.6	0	0.0	9733
2008	3683	37.5	438	4.5	5697	58.0	0	0.0	9819
2009	3338	34.0	552	5.6	5914	60.3	0	0.0	9803
2010	4969	46.7	731	6.9	4948	46.5	0	0.0	10649
2011	3999	35.2	725	6.4	6629	58.4	2.9	0.0	11356
2012	2710	23.1	736	6.3	8280	70.6	1.4	0.0	11727
2013	5990	50.3	1179	9.9	4729	39.7	0	0.0	11898
2014	3632	29.5	1217	9.9	7466	60.6	0	0.0	12316
2015	4904	37.5	1467	11.2	6718	51.3	0	0.0	13090
2016	3481	24.6	1160	8.2	9507	67.2	0	0.0	14148
2017	3059	20.8	1464	10.0	10148	69.2	0	0.0	14671
2018	5149	33.8	1715	11.2	8390	55.0	0	0.0	15255
Last 5 year av. Growth	9.12%		8.94 %		2.96%				5.50%
Last 10 year av. Growth	4.94%		13.42%		3.96%				5.04%

The Total Generation and ORE Generation excludes the contribution from Rooftop Solar

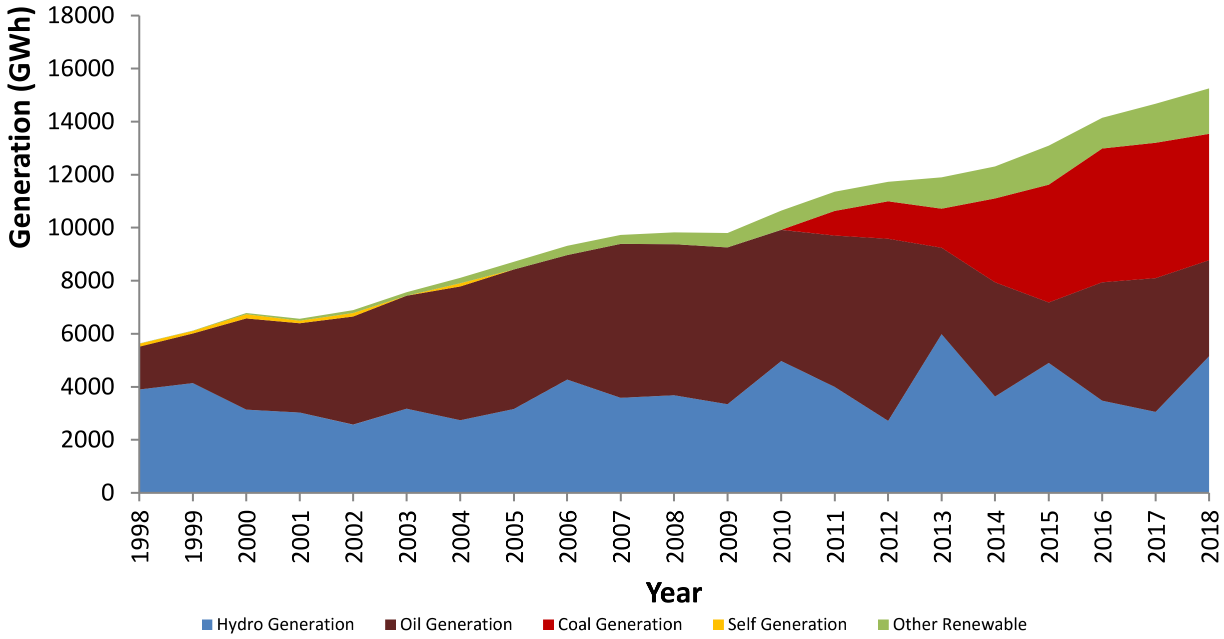


Figure 1.12 - Generation Share in the Recent Past

Sri Lankan Power System has operated maintaining 30%-60% share of renewable energy throughout the recent years. This trend will be continued in the future also with the optimum amount of renewable energy integration to the system. Total renewable energy share over the past ten years are shown in Figure 1.13.

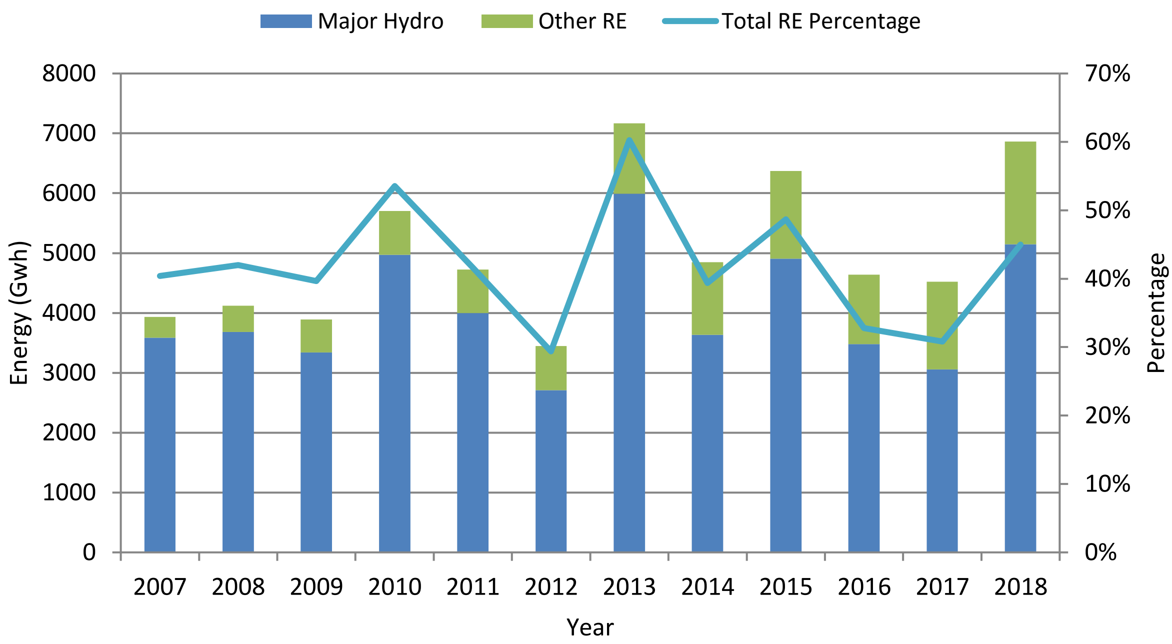


Figure 1.13 – Renewable Share in the Recent Past

In Comparison World Electricity Generation has been mainly depended on Thermal Generation throughout the past two decades. Coal Power Generation is the major source contributing approximately 40% of the World Electricity Generation from 1996 to 2016. Gas power Generation has increased from 15% to 23%, while Oil Power Generation has decreased from 9% to 3% during the past two decades. The total Renewable Generation including Large Hydro power has increased from 20%-23% during the time horizon while Nuclear Power Generation has decreased from 17% to 10%. World Electricity Generation during the last twenty years is summarized in Figure 1.14 and World Electricity Generation by source as a percentage is shown in Figure 1.15

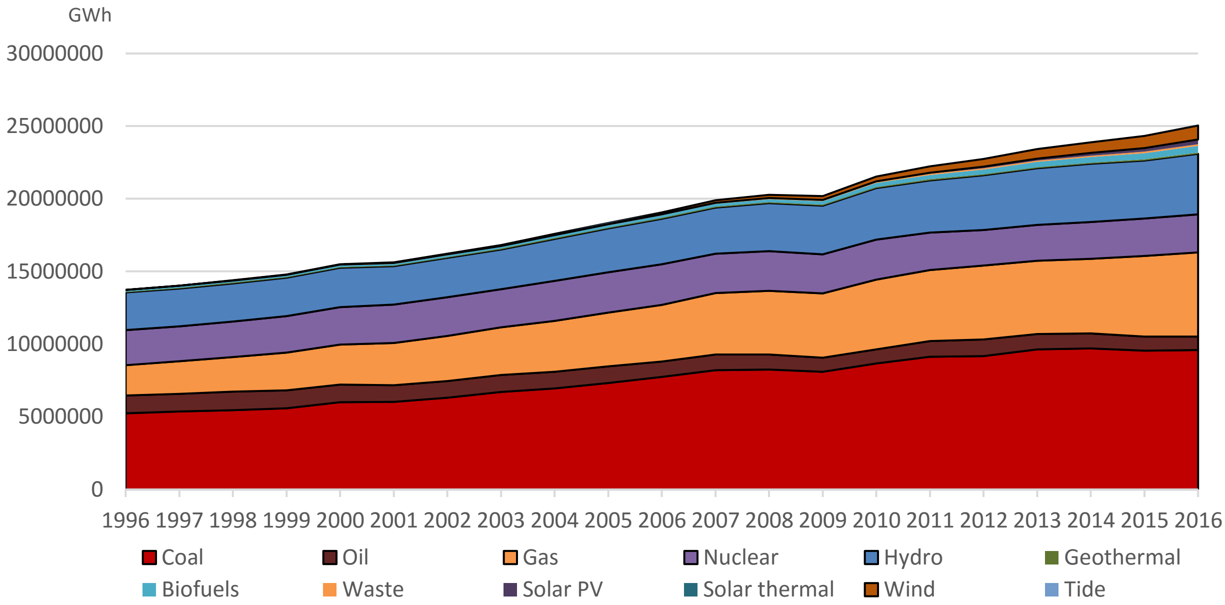


Figure 1.14 – World Electricity Generation(GWh)

Source: International Energy Agency Statistics

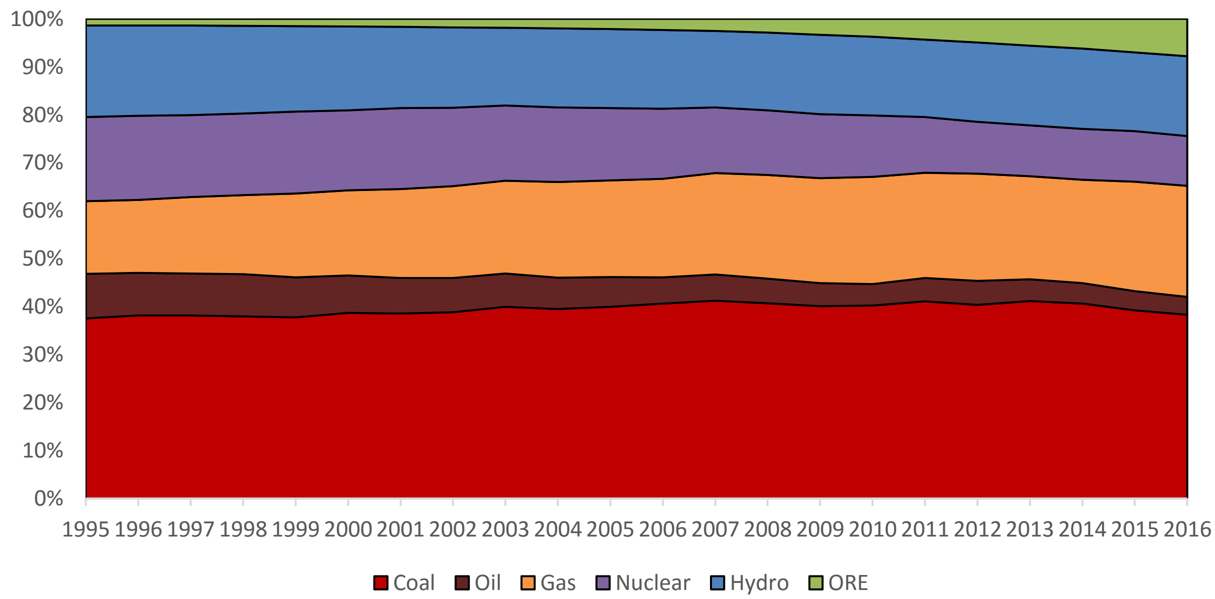


Figure 1.15 – World Electricity Generation by Source as Percentage

Source: International Energy Agency Statistics

1.5 Implementation of Planning cycle

The performance evaluation of previous years indicates that the CEB overall cost at selling point has increased by 5.75 % in 2018 compared to 2016. The Transmission and Distribution losses of CEB has improved from 9.63% in 2016 to 8.34% by 2018.

The previous versions of LTGEP have identified the commissioning of low cost major power plants in the system. The LTGEP 2013-2032, had identified the commissioning of 2x 250 MW Sampoor Coal Power Plant by 2018. The Sampoor Coal Power plant which went through the initial gestation stage, that is finalizing the feasibility studies, EIA, land reservation, and initiating tender procedure, was cancelled in 2015. In LTGEP 2015-2034, a 300 MW Natural Gas Combined Cycle plant was introduced to be commissioned in 2019. After receiving the commission approval for LTGEP 2015-2034 in September 2016, the tender process was initiated by CEB in November 2016. However, the Power Plant has not been awarded and timely implementation of the power plant in 2019 is not achievable.

Due to the non-implementation of low cost power plant as planned in to the system high cost supplementary power needed to be procured to overcome shortages as stop gap measures. Supplementary Power sources of 56MW had provided 37.2 GWh for a period of 7 months in 2018. The PPA of retired IPP, ACE Power Embilipitya was extended and it supplied 362.84 GWh energy in 2018.

1.6 Planning Process

CEB is under a statutory duty to develop and maintain an efficient, co-coordinated and economical system of electricity supply for the whole of Sri Lanka. In order to fulfill the above duty, CEB revises the Long Term Generation Expansion Plan (LTGEP) once in two years complying with Section 43 of Sri Lanka Electricity Act, No 31 of 2013. Intensive studies are conducted by the Transmission and Generation Planning Branch of the CEB in order to prepare this plan. A coordinating committee representing the relevant Branches of CEB meets during the study period to review the study inputs and the findings.

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

1.7 Objectives

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

(a) To determine the Demand Forecast for next 25 years.
(b) To investigate the feasibility of new generating plants for addition to the system in terms of plant and system characteristics.

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

1.8 Structure of the Report

The Long Term Generation Expansion Plan 2020-2039 consists of the following chapters as indicated in the Grid Code.

Chapter 2 Presents the existing and committed generation system of Sri Lanka.
Chapter 3 The past and forecast electricity demand with the forecasting methodology is explained.
Chapter 4 Thermal Generation options for the future system expansions are discussed.
Chapter 5 Renewable Generation options for the future system expansions are discussed.
Chapter 6 Explains the Generation expansion planning guidelines, methodology and the parameters.
Chapter 7 Explains the Development of the Reference Case.
Chapter 8 Describes the Development of the Base Case and Sensitivity Analysis.
Chapter 9 Focuses on Policy and Scenario Analysis.
Chapter 10 Discusses the Environmental implications of the expansion plan.
Chapter 11 Elaborates the Recommendations of the Base Case Plan.
Chapter 12 Based on required implementation schedule and investments for the generation projects.
Chapter 13 Shall concentrate on the contingency analysis on the provided plan.
Chapter 14 Provides a comparison of this year plan with the previous plan.

CHAPTER 2
THE EXISTING AND COMMITTED GENERATING SYSTEM

The existing generating system in the country is mainly owned by CEB with a considerable share owned by the private sector. Until 1996 the total electricity system was owned by CEB. Since 1996, private sector has also participated in power generation. The existing generating system in the country has approximately 4046 MW of installed capacity by 2019 including non-dispatchable plants of capacity 610 MW owned by private sector developers. The majority of dispatchable capacity is owned by CEB (i.e. about 84% of the total dispatchable capacity), which includes 1398.85 MW of hydro and 1504 MW of thermal generation capacity. Balance dispatchable capacity, which is totally thermal plants, is owned by Independent Power Producers (IPPs).

2.1 Hydro and Other Renewable Power Generation

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

2.1.1 CEB Owned Hydro and Other Renewable Power Plants

Most of the comparatively large scale hydro resources in Sri Lanka have been developed by the CEB. At present, hydro projects having capacities below 10MW (termed mini hydro), are allowed to be developed by private sector as run-of river plants and larger hydro plants are to be developed by the CEB. Since these run-of river type mini hydro plants are non-dispatchable, they are modeled differently from CEB owned hydro plants in the generation expansion planning simulations. The operation and maintenance cost of these CEB hydro power plants was taken as 12.24 US$/kW per annum.

(a) Existing System

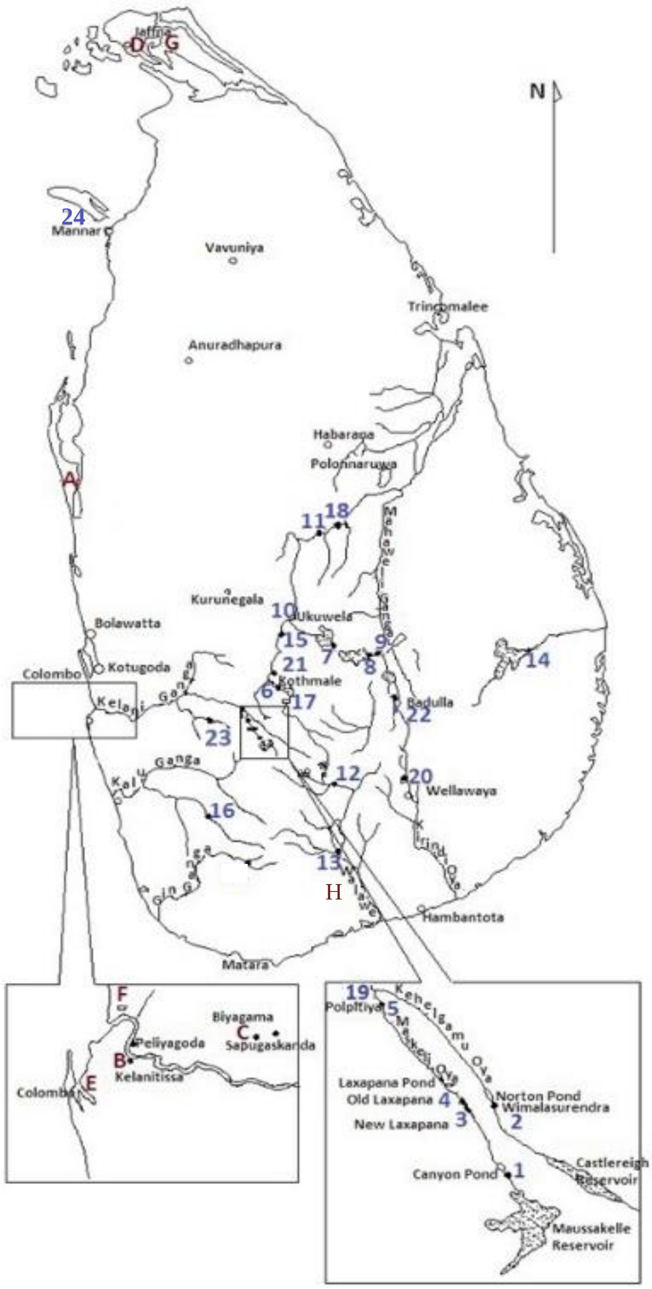
The existing CEB generating system has a substantial share based on hydropower (i.e.1398.85 MW hydro out of 2903 MW of total CEB installed capacity). Approximately 48% of the total existing CEB system capacity is installed in 17 hydro power stations and 32 % of the total energy demand was met by the major hydro plants in 2018. Details of the existing and committed hydro system are given in Table 2.1 and the geographical locations of the Power Stations are shown in the Figure 2.1.

The major hydropower schemes already developed are associated with Kelani and Mahaweli river basins. Five hydro power stations with a total installed capacity of 369.8 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 Maskeliya 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 Moussakelle are the major storage reservoirs in the Laxapana hydropower complex located at main tributaries Kehelgamu Oya and Maskeliya Oya respectively. Castlereigh reservoir with active storage of 52 MCM feeds the Wimalasurendra Power Station of capacity 2 x 25MW at Norton-bridge, while Canyon 2 x 30MW is fed from the Moussakelle reservoir of storage 108 MCM.

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

Plant Name	Units x Capacity	Capacity (MW)	Expected Annual Avg. Energy (GWh)	Active Storage (MCM)	Rated Head (m)	Year of Commissioning
Canyon	2 x 30	60	160	107.9 (Moussakelle)	207.2	1983 - Unit 1 1989 - Unit 2
Wimalasurendra	2 x 25	50	112	52.01 (Castlereigh)	227.38	1965
Old Laxapana	3x 9.6+ 2x12.5	53.8	286	0.245 (Norton)	472.4	1950 1958
New Laxapana	2 x 58	116	552	0.629 (Canyon)	541	Unit 1 1974 Unit 2 1974
Polpitiya	2 x 45	90	453	0.113 (Laxapana)	259	1969
Laxapana Total		**369.8**	**1563**			
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 61.3	122.6	454	462	77.8	1986
Ukuwela	2 x 20	40	154	2.1	75.1	Unit 1&2 – '76
Bowatenna	1 x 40	40	48	23.5	50.9	1981
Rantambe	2 x 25	50	239	3.4	32.7	1990
Nilambe	2 x 1.6	3.2	-	0.005	110	1988
Mahaweli Total		**816.8**	**2667**			
Samanalawewa	2 x 60	120	344	218	320	1992
Kukule	2 x 37.5	75	300	1.67	186.4	2003
Small hydro		17.25				
Samanala Total		**212.25**	**644**			
Existing Total		**1398.85****	**4874**			
Committed						
Broadlands	2x17.5	35	126	0.198	56.9	2020
Moragolla	2x15.1	30.2	97.6	1.98	69	2023
Mannar Wind Park		103.5	337			2020
Multi-Purpose Projects						
Uma Oya	2x61	122	290	0.7	722	2021
Total		**290.7**	**850.6***			

Note: ***** ***According to feasibility studies. ** 3MW wind project at Hambantota not included.***



No.	Power Plant	Capacity MW
	Hydro Power Plants (Existing)	
1	Canyon	60
2	Wimalasurendra	50
3	New Laxapana	116
4	Old Laxapana	53.8
5	Polpitiya	90
6	Kotmale	201
7	Victoria	210.3
8	Randenigala	126.8
9	Rantambe	51.8
10	Ukuwela	38.6
11	Bowatenna	40
12	Samanalawewa	120
13	Udawalawe	6
14	Inginiyagala	11.25
15	Nilambe	3.2
16	Kukule	75
17	Upper Kotmale	150
18	Moragahakanda	25
	Hydro Power Plants (Committed)	
19	Broadlands	35
20	Uma Oya	122
21	Moragolla	30.2
	Hydro Power Plants (Candidate)	
22	Thalpitigala	15
23	Seethawaka	24
	Other Renewable (Committed)	
24	Mannar Wind Park	100
	Thermal Power Plants	
A	Lakvijaya Coal Power Plant	900
B	Kelanithissa PP, Sojitz PP	523
C	Sapugaskanda PP, Asia Power	211
D	Uthuru Janani	27
E	CEB Barge Mounted Plant	60
F	West Coast PP	300
G	Northern Power	38
H	ACE Power Embilipitiya	100

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

The development of the major hydro-power resources under the Mahaweli project added seven hydro power stations (*Ukuwela, Bowatenna, Kotmale, Upper Kotmale, Victoria, Randenigala and Rantambe*) to the national grid with a total installed capacity of 817 MW (58.4% of the total hydropower capacity). Three major reservoirs, *Kotmale, Victoria and Randenigala*, which were built under the accelerated Mahaweli development program, feed the power stations installed with these reservoirs. The latest major power station in this system is 150MW Upper Kotmale hydro power plant.

Polgolla - diversion weir (across Mahaweli Ganga), downstream of Kotmale and upstream of Victoria, diverts Mahaweli waters to irrigation systems via Ukuwela power station (40 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 (40MW) and mainly Mahaweli System-H by means of separate waterways. Water discharged through Bowatenna power station goes to Elahera Ela and is available for diversion to Mahaweli systems D and G.

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

Samanalawewa hydro power plant of capacity 120MW was commissioned in 1992. Samanalawewa reservoir, which is on Walawe River and with active storage of 218 MCM, feeds this power plant. Kukule power project which was commissioned in 2003, is a run-of river type plant located on Kukule Ganga, a tributary of Kalu Ganga. Kukule power plant is 70 MW in capacity and which provides an average of 300 GWh of energy per year under average hydro conditions.

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

(b) Committed Plants

The 35MW Broadlands hydropower project located near Kithulagala on the Maskeliyaoya was considered as a committed plant. The dam site of the project is to be located near Polpitiya power house and in addition to the main dam, there will be a diversion weir across Kehelgamuoya. The project has a 0.198 MCM active storage and it is expected to generate 126GWh energy per annum. It will be added to the system in 2020.

122MW Uma Oya multipurpose hydro power project was considered as a committed plant. Under Uma Oya multipurpose hydro power project, two small reservoirs will be built close to Welimada where the water from these two reservoirs will be diverted through a tunnel to the underground power house located at Randeniya near Wellawaya. It is expected to generate 290 GWh of annual energy and will be added to the system in 2021. 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 2023.

Mannar Wind Park is the first large scale wind power project developed in Sri Lanka. During the 1st stage 103.5 MW of wind power will be developed by CEB in the southern coast of the Mannar Island which would contribute 337 GWh of mean annual energy.

Moragahakanda (25MW) is an Irrigation Project with a power generation component and is developed by Ministry of Mahaweli Development and Environment.

Moragahakanda 25MW hydro power plant is in operation at the present. The Plant was built near the Moragahakanda main dam and the electricity will be generated using four turbines. This will consist of two 7.5 MW and another two 5 MW Turbines.

The water released after operating turbines of 7.5 MW, will be taken to Mahakanadara Reservoir through Ihala Elahera cannel. The water released by operating of turbines of 5 MW will be sent to Ambanganga and then to Giritale, Minneriya, Kavudulla and Kantale reservoirs through old Elahera cannel.

2.1.2 Other Renewable Power Plants Owned by IPPs

Initially, Government of Sri Lanka has taken a policy decision to develop hydropower plants below 10MW 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 recent years, there has been a substantial increase in Wind and Solar additions to the system.

Total capacity of these plants is approximately 610 MW as at 31st December 2018. These plants are mainly connected to 33kV distribution lines. As of 31st December 2018, CEB has signed standard power purchase agreements and issued Letter of Intents for another 539MW of ORE power plants to be developed. The existing Capacity contributions from other renewables as of are tabulated in Table 2.2.

Table 2.2: Existing Other Renewable Energy (ORE) Capacities

Project Type	Number of Projects	Capacity (MW)
Mini Hydro Power	197	393.5
Wind Power	15	128.45
Biomass	12	37.09
Solar Power	8	51.36

In this study, a capacity and energy contributions from these mini hydro and other non-conventional renewable energy plants were considered in the base case as committed and modeled accordingly. The figures were projected based on expected development according to current project pipeline records. The projected committed development used in this study is given and further explained in chapter 5.

In addition, total Rooftop Solar capacity of 170MW (both CEB and LECO) has been integrated to the system by 31st December 2018.

2.1.3 Capability of Existing Hydropower Plants

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

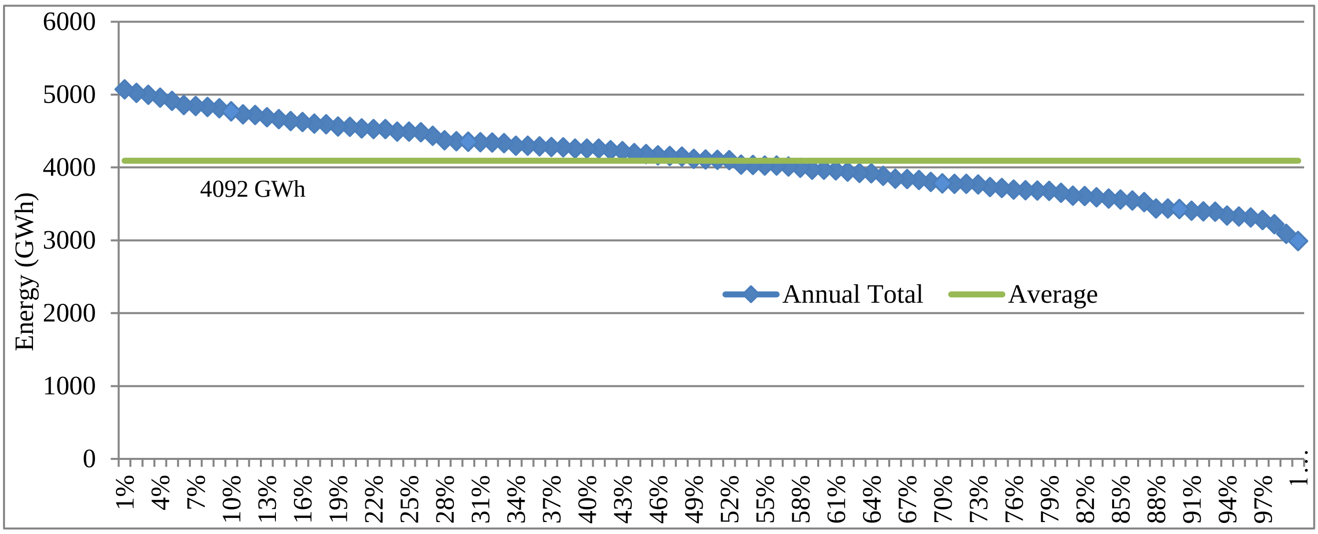


Figure 2.2 - Potential of Hydropower System from Past 35 years Hydrological Data

The annual energy variation of the existing hydro system, using the inflow data from 1979 to 2017 and based on SDDP computer simulation is shown in Figure 2.2. This shows that the capability of the major hydro system (Mahaweli, Laxapana and Samanala) could vary as much as from 2989 GWh to 5072 GWh. The corresponding summary of the hydro potential is given in Table 2.3 with probabilities of 10% (very wet), 20 %(wet), 50% (medium), 15% (dry) and 5% (very dry) hydro conditions.

Table 2.3 – Expected Monthly Hydro Power and Energy Variation of the Existing Hydro Plants for the Selected Hydro Conditions

Month	**Very Wet**		**Wet**		**Medium**		**Dry**		**Very Dry**		**Average**	
	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)
Jan	310.0	838.2	231.2	775.6	231.2	778.6	238.1	784.2	245.0	700.3	241	780.9
Feb	245.5	809.2	221.6	787.3	249.7	790.2	195.5	777.3	196.3	709.1	233	785.5
Mar	254.4	915.9	251.5	914.9	255.5	922.3	227.3	907.5	245.8	882.3	250	916.0
Apr	293.8	840.9	278.7	841.4	223.8	836.0	223.5	825.8	233.6	737.8	242	831.1
May	389.9	980.9	361.0	985.5	282.5	932.9	315.3	940.6	193.2	726.5	309	939.1
Jun	533.2	1082.6	489.2	1084.3	381.3	1034.1	353.2	1019.9	261.7	963.7	408	1043.3
Jul	548.9	1034.7	507.2	1015.1	402.3	968.1	338.6	955.0	275.6	821.1	422	974.8
Aug	406.0	895.0	398.8	905.2	353.4	879.5	295.0	877.6	274.3	775.4	355	880.7
Sep	406.2	879.8	340.2	853.4	317.1	856.7	277.6	841.1	253.6	599.2	322	825.6
Oct	429.0	1017.0	406.1	987.4	380.2	963.9	307.7	927.5	323.3	790.9	377	959.8
Nov	570.2	1109.9	576.2	1103.4	519.5	1079.8	400.9	1058.9	251.1	913.9	505	1076.1
Dec	522.5	1063.5	487.4	1048.6	424.3	1020.3	307.8	1001.8	426.4	1076.9	429	1030.3
Total	4910.		4549		4021		3481		3180		4092	

2.2 Thermal Generation

2.2.1 CEB Thermal Plants

(a) Existing

Majority of the present thermal power generating capacity in the country is owned by CEB with a total capacity of 1504 MW. It is made up of Lakvijaya Coal power plant of 900MW, Kelanitissa Gas Turbines of 195MW, Kelanitissa Combined Cycle plant of 165MW, Sapugaskanda Diesel power plants of 160MW, Uthuru Janani diesel power plant of 24 MW and Barge Mounted Plant of 64MW. The Lakvijaya Coal plant 900MW funded by EXIM Bank China commissioned in 2011 (Phase I) and 2014 (Phase II) was the latest thermal power plant addition to the CEB system.

(b) Plant Retirements

For planning purposes, retirement dates of CEB owned existing thermal power plants are considered as indicated in Table 2.4.

Table 2.4 Plant Retirement Schedule

CEB Power Plants	Year
1. KPS Frame5 GTs all units	2023
2. KPS GT7*	2023
3. Sapugaskanda PS A (4 units)	2024
4. Sapugaskanda PS B (4 Units) (4 Units)	2023 2026
5. Barge Mounted Power Plant	2025
6. Kelanithissa Combined Cycle	2033

* Provision of further extension beyond 2023 will be further studied.

(c) Committed

As a CEB owned committed power plant, only 130 MW Gas Turbine Power Plant at Kelanitissa is proposed to be commissioned by 2021.

Capacity and energy details of the existing and committed thermal plants are shown in Table 2.5.

Technical parameters and cost details of the existing thermal generation plants as input to the 2020 Expansion Planning Studies are summarized in Table 2.6.

Table 2.5 - Details of Existing and Committed Thermal Plants

Plant Name	No of Units x Name Plate Capacity (MW)	No of Units x Capacity used for Studies (MW)	Annual Max. Energy (GWh)	Commissioning
Puttalam Coal Power Plant				
Lakvijaya CPP	3 x 300	3 x 270	5355	2011 & 2014
Puttalam Coal Total	**900**	**810**	**5355**	
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 (JBIC)	1x 165	1 x 161	1196	Aug 2002
Kelanitissa Total	**360**	**344**	**2281**	
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 16	4 x 15.6	515	Acquired in 2015
Existing Total Thermal	**1510.7**	**1383.1**	**9309**	
Committed				
Kelanitissa Gas	3 x 45	130		2021
Committed Total Thermal	**135**			

Table 2.6 - Characteristics of Existing and Committed CEB Owned Thermal Plants

		Kelanitissa			Sapugaskanda		Lakvijaya Coal	Other	
Name of Plant	**Units**	**GT (Old)**	**GT (New)**	**Comb. Cycle (JBIC)**	**Diesel (Station A)**	**Diesel (Ext.) (Station B)**	**Coal (Phase I & II)**	**Uthuru Janani**	**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 12K50MC-S
Input Parameters for Studies									
Number of Units		4	1	1	4	8	3	3	4
Unit Capacity	MW	17	115	161	17	9	270	8.93	15.6
Minimum operating level	MW	17	80	100	17	9	162	8.93	15.6
Calorific Value of the fuel	kCal/kg	10500	10500	10880	10300	10300	6300	10300	10300
Heat Rate at Min. Load	kCal/kWh	4294	3542	2127	2303	2185	Unit 1-2767 Unit 2-2691 Unit 3-2615	2164	2226
Incremental Heat Rate	kCal/kWh	0	2337	1359	0	0	Unit 1-2172 Unit 2-2331 Unit 3-2330	0	0
Heat Rate at Full Load	kCal/kWh	4294	3175	1837	2303	2185	Unit 1-2529 Unit 2-2547 Unit 3-2501	2164	2226
Fuel Cost	USCts/GCal	5168	5168	5295	4274	4274	1680	4274	4274
Full Load Efficiency	%	20	27	47	37	39	Unit 1-31 Unit 2-32 Unit 3-33	40	39
Forced Outage Rate	%	29	19	8	8	17	12	15	2
Scheduled Maintenance	Days/Year	35	52	27	38	28	52	32	24
Fixed O&M Cost	$/kWmonth	3.04	0.17	1.87	8.47	7.76	1.09	1.75	0.92
Variable O&M Cost	$/MWh	0.64	5.04	2.72	5.75	1.70	3.90	8.35	6.21

Note: All costs are in January 2019 US$ 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.

2.2.2 Independent Power Producers (IPPs)

(a) Existing

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

Table 2.7 - Details of Existing and Committed IPP Plants

Plant Name	Name Plate Cap. (MW)	Cap. used for Studies	Min. Guarenteed Ann. Energy (GWh)	Commissioning	Contract Period. (Yrs.)
Independent Power Producers					
Sojitz Kelanitissa (Pvt.) Ltd	163	163	-	GT- March 2003 ST - October 2003	20
ACE Power Embilipitiya Ltd+	100	99.5	697	2005 April	10
West Coast (Pvt) Ltd.	300	270	-	2010 May	25
Existing Total IPP	**563**	**532.5**			
Committed	-	-	-		
Reciprocating Engine Power Plants at the Grid Substations of Habarana, Moneragala, Horana and Pallekelle	4 x 24	4 x 24		2021	
NG fired Combined Cycle Power Plant	300	287		2022	
Committed Total IPP	**396**	**383**	**-**		

Note:

+ The contract of ACE Power Embilipitiya Power Plant which expired was extended on short term basis.

CHAPTER 3
ELECTRICITY DEMAND: PAST AND THE FORECAST

3.1 Past Demand

Demand for electricity in the country during the last fifteen years has been growing at an average rate of about 5.5% per annum while peak demand has been growing at a rate of 3.7% per annum as shown in Table 3.1. However, the peak demand has grown at a rate of 5.0% during the last 5 years and energy demand has been growing at a rate of 6.2% per annum. In 2018, net electricity generated to meet the demand amounted to 15,374GWh (including rooftop solar energy contribution), which had been only 9,803GWh ten years ago. The recorded maximum demand within the year 2018 was 2,616MW, which was 2,523MW in year 2017 and 1,868MW ten years ago.

Table 3.1 - Electricity Demand in Sri Lanka, 2004– 2018

Year	Demand*	Avg. Growth	Trans. & Distribution Losses	Net Generation	Avg. Growth	Load Factor **	Peak	Avg. Growth
	(GWh)	(%)	(%)	(GWh)	(%)	(%)	(MW)	(%)
2004	6667	7.4	15.2	7998	5.8	58.4	1563	3.1
2005	7255	8.8	16.7	8709	8.9	56.9	1748	11.8
2006	7832	8.0	15.9	9314	6.9	56.2	1893	8.3
2007	8276	5.7	15.0	9733	4.5	60.3	1842	-2.7
2008	8417	1.7	14.3	9819	0.9	58.3	1922	4.3
2009	8441	0.3	13.9	9803	-0.2	59.9	1868	-2.8
2010	9268	9.8	13.0	10649	8.6	62.2	1955	4.7
2011	10023	8.2	11.7	11353	6.6	59.9	2163	10.6
2012	10474	4.5	10.7	11725	3.3	62.4	2146	-0.8
2013	10624	1.4	10.7	11898	1.5	62.8	2164	0.8
2014	11063	4.1	10.2	12316	3.5	65.3	2152	-0.6
2015	11786	6.5	10.0	13090	6.3	65.4^{+}	2283	6.1
2016	12785	8.5	9.6	14148	8.1	65.8^{+}	2453	7.4
2017	13431	5.1	8.5	14671	3.7	66.4^{+}	2523	2.9
2018	14091	4.9	8.3[(a)]	15374^{++}	4.8	67.1^{+}	2616	3.7
Last 5 year		6.2%			5.7%			5.0%
Last 10 year		5.9%			5.1%			3.8%
Last 15 year		5.5%			4.8%			3.7%

*Gross units sold excluding Self-Generation component
**Load factor calculated on net Generation
$^{+}$Load Factor includes Other Renewable Energy
$^{++}$Including Rooftop Solar energy contribution
(a) Provisional

Figure 3.1 shows a considerable decrease in percentage of system losses during 2000-2018. The major contribution towards this decrement is the decrease in Transmission & Distribution Losses. Figure 3.2 shows the System Load Factor on net generation which calculated including Other Renewable Energy (Mini hydro, Wind & Solar) component. Overall improvement in the load factor can be observed as shown in Figure 3.2 and in 2018 it was calculated as 67.1% on net generation.

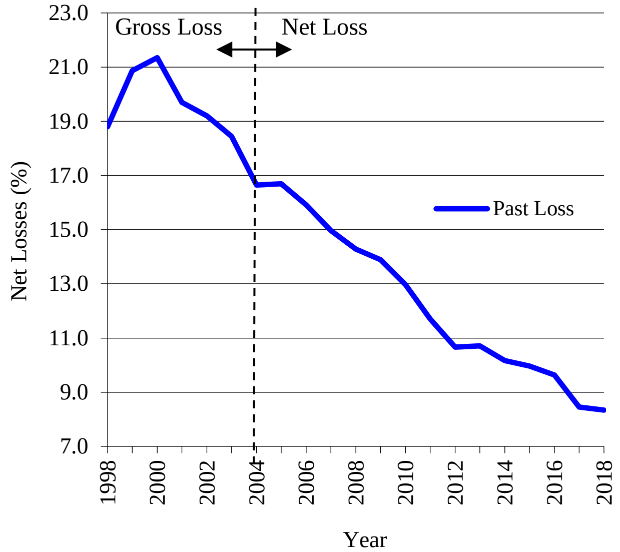


Figure 3.1 - Past System Loss

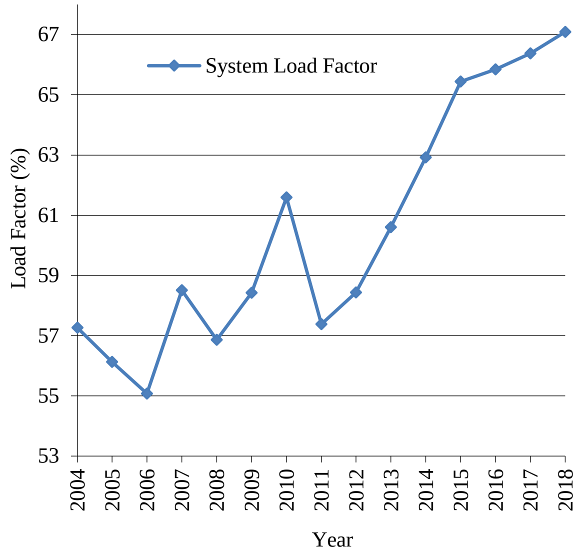


Figure 3.2 – Past Trend in the Load Factor

Figure 3.3 shows the country's daily load curve recorded on the day of annual peak for previous eight years. From the Figure 3.3, it could be observed that the shape of the load curve remain as the same. However, significant growth in the day peak could be seen in last three years (2016, 2017 and 2018) compared to other years. The system peak demand occurred for short period from about 18.30 to 22.00 hours daily. The recorded maximum system peak is 2,523MW in year 2017, while in year 2018 the peak is 2,616MW.

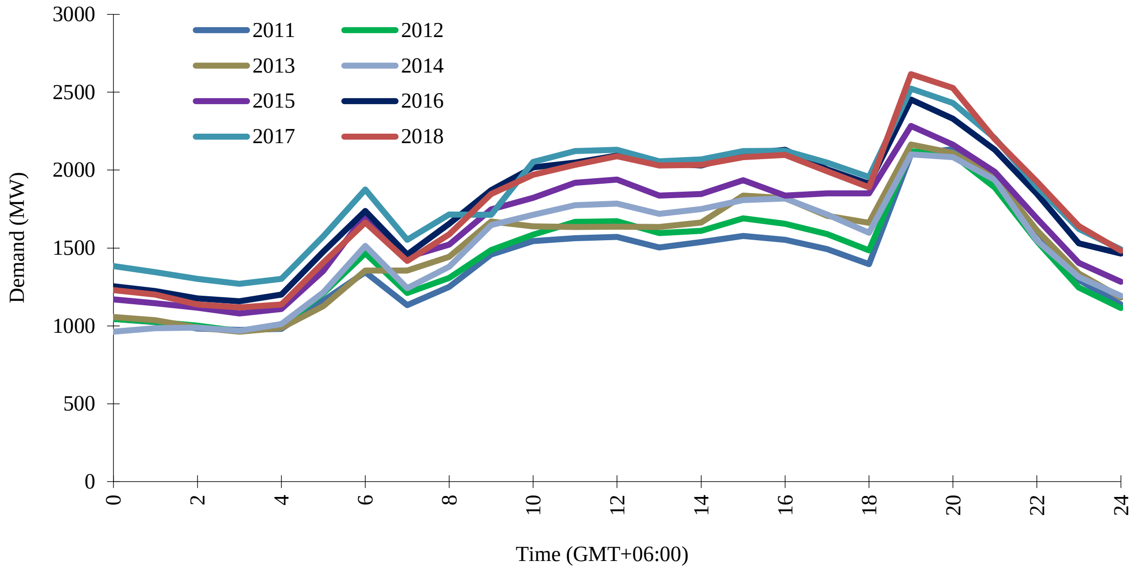


Figure 3.3 - Change in Daily Load Curve over Last Eight Years

Figure 3.4 shows the percentage consumption shares among different consumer categories from 1979 to 2018.In 2018, share of domestic consumption in the total demand was 37% while that of industrial and commercial sectors were 32% and 29% respectively. Religious purpose consumers and street lighting, which is referred as the other category, together accounted only for 2%. Similarly in 2009 (10 years ago), share of domestic, industrial, commercial and religious purpose & street lighting consumptions in the total demand, were 40%, 32%, 26% and 2% respectively.

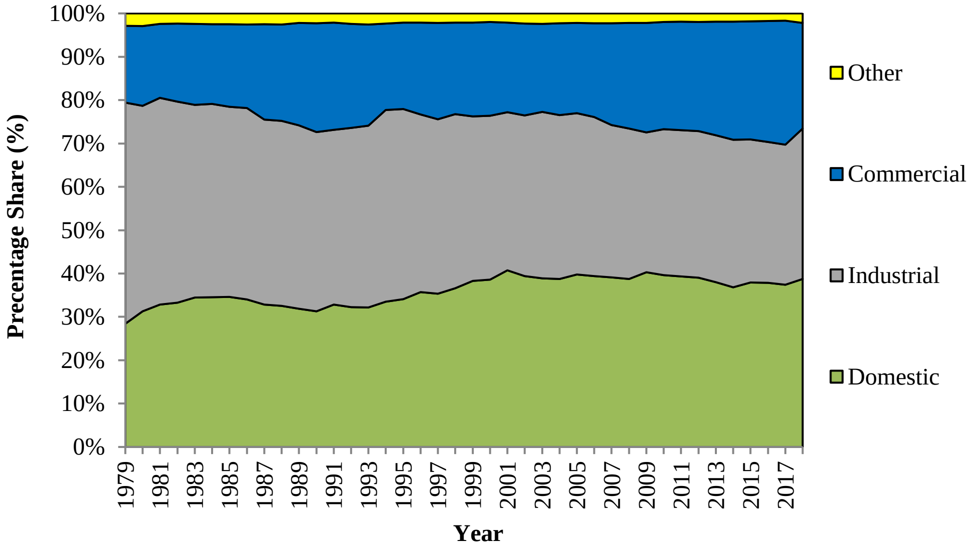


Figure 3.4 - Consumption Share among Different Consumer Categories

3.2 Policies, Guidelines and Future Major Development Projects for Electricity Demand Forecast

3.2.1 Policies and Guidelines

The Electricity Demand Forecast 2020-2044 prepared complying with the following policies and guidelines.

- National Energy Policy and Strategies of Sri Lanka, June 2008 [35]
- General Policy Guidelines on the Electricity Industry for the Public Utilities Commission of Sri Lanka, June 2009 amended in March 2019 under section 5 of Sri Lanka Electricity Act N0 20 of 2009 [37]
- Draft Generation Planning Code in the Draft Grid Code issued by the Transmission Division, Ceylon Electricity Board, August 2015 [34]

3.2.2 Future Major Development Projects

The Government has proposed and planned for large scale development projects, which will lead to increase of electricity demand in the future. The major development plans are mainly identified by Western Region Megapolis Plan and Hambantota Port Development Plan in Southern Region.

The Western Region Megapolis Plan identifies following major areas for the development.

- Multi Model Transport Hub (Pettah)
- Administrative Cities Development Project
- Science and Technology City
- Maritime City Development Project
- Colombo Central Business District
- Housing Development
- Horana & Mirigama Industrial Township
- SME Industry
- Colombo Port City
- Transport
- Tourism

The cumulative electricity demand requirements for the identified projects (Maritime City Development Project, Administrative Cities Development Project, Multi Model Transport Hub (Pettah) and Science and Technology City) under the Capital City and Colombo Commercial City development programs of Ministry of Megapolis and Western Development are indicatively estimated as 121MW for 2018-2022, 399MW for 2023-2026 and 508MW for 2027-2030 period.

The Colombo Port City Development Project is a major development project under the Western Region Megapolis Plan and indicative cumulative electricity demand requirement estimated as 30MW by 2020, 177MW by 2025, 313MW by 2030 and 393MW by 2040. Hambantota Port Development Plan in Southern Region also estimated approximately 400MW electricity demand for the initial stage in the present development plan.

The Electricity Demand Forecast 2020-2044 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 by CEB for the preparation of twenty five year electricity demand forecast. Distribution Divisions five year sales forecast and time trend approach has been considered to determine the medium term forecast. For the long term, econometric approach has been adopted by analysing past electricity sales figures with significant independent variables.

In addition to the above approaches, the End User Approach was adopted separately through MAED model as described in section 3.5.In End user modelling, extensive analysis of end user energy demand considered by identifying technological, social and economic driving factors in Industry, Transportation, Household and Service sectors separately.

3.3.1 Medium Term Demand Forecast (2020-2023)

Five year sales forecasts from the CEB Distribution Divisions and LECO were collected and considered for the medium term demand forecast. Additionally, the Time Trend modelling based on the past five year sales figures has been adopted by capturing recent electricity sales pattern and the growth [6].

3.3.2 Long Term Demand Forecast (2024-2044)

Econometric model was used for Long Term Demand Forecast from 2024-2044, giving due consideration to the energy conservation, electricity consumer tariff categories (multisector) and economic growth of sectors [6]. Separate forecasts were prepared for Domestic, Industry and Commercial sectors to comply with multi sector approach.

In the models, the sales figures of the past were analysed against several independent variables given in Table 3.2 using regression technique. During the process, some of the insignificant independent variables were eliminated.

Table 3.2 – Variables Used for Econometric Modeling

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

According to the Central Bank of Sri Lanka Annual Report 2017 and previous publications, sector wise GDP and its percentage share to the total GDP were analysed for the period from 1978 to 2017. Base year was taken as 2017 and the percentage share for Agriculture, Industry and Services are 6.9%, 26.8% and 56.8% respectively.

The resulting final regression coefficients together with the expected growth of the independent variables (based on the official publications and future assumptions) are then used to project the electricity demand for 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) 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, Previous year Domestic Consumer Accounts and Previous year Electricity Demand in Domestic consumer category were significant independent variables for the domestic sector demand growth.

$$Ddom(t) = 98.14 + 0.43\ GDPPC(t) + 0.27\ CAdom(t-1) + 0.66\ Ddom(t-1)$$

Where,

Ddom (t)	-	Electricity demand in domestic consumer category (GWh)
GDPPC (t)	-	Gross Domestic Product Per Capita ('000s LKR)
CAdom (t-1)	-	Domestic Consumer Accounts in previous year (in '000s)
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 GDP, Industrial consumer accounts and previous year Electricity demand in Industrial consumer category.

$$Di(t) = 89.81 + 0.28\ GDPi(t) + 17.38\ CAi(t) + 0.57\ Di(t-1)$$

Where,

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

Commercial (General Purpose, Hotel and Government) Sector

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

$$Dcom(t) = -265.67 + 0.13\ GDPser(t) + 1.004 CAcom(t) + 0.73\ Dcom(t-1)$$

Where,

Dcom (t)	-	Electricity demand in Commercial consumer categories (GWh)
GDPser	-	Service Sector Gross Domestic Product (in '000 LKR)
CAcom (t)	-	Commercial Consumer Accounts (in '000s)
Dcom (t-1)	-	Previous year Electricity demand in Co mmercial 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.

$$\ln(Dos(t)) = -100.38 + 0.053\ t$$

Where,

Dos (t)	-	Electricity demand in other sector consumer category (GWh)
t	-	Year

Trend Analysis for Long Term Electricity Demand Forecast

To capture the recent trend variation of Domestic, Industrial and Commercial (General Purpose, Hotel and Government) sector demands, each sector has separately analysed based on data from 2010 to 2017 and reflected in long term forecast.

Cumulative Demand

Once the electricity demand forecast was derived based on the econometric approach adjusting with trend analysis for the four sectors separately, they were added together to derive the demand forecast from 2024 to 2044. Total electricity demand forecast 2020-2044 is a combination of medium term and long term approaches as described in section 3.3.

Net Loss Forecast

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

Expected Transmission and Distribution loss of 8.00% in year 2025, 7.50% in year 2030 and 7.25% in year 2035 was used in the studies. Total net energy loss forecast to be achieved throughout the planning period is shown in Figure 3.5 with the expected improvements of the network. However, the actual losses would be vary depend on the generation combination of each year. 2017 system net loss was analysed considering energy contribution from Rooftop Solar PV connections, Self-Generation, Small Island Generation etc. and approximate value of 9.28% was taken for the analysis.

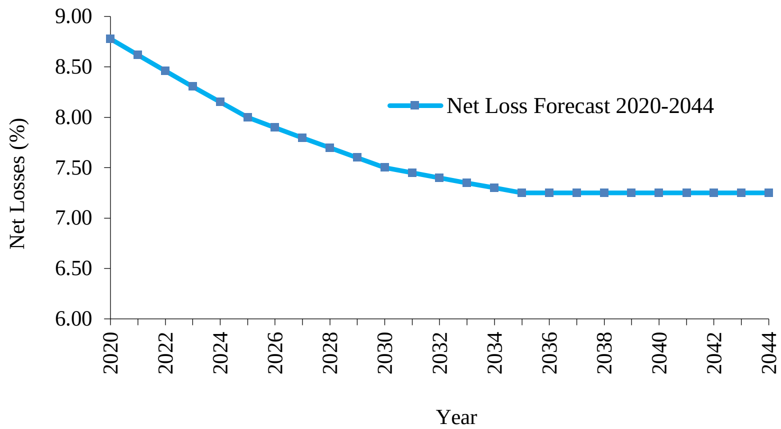


Figure 3.5–Net Loss Forecast 2020-2044

Load Factor and Peak 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 2018 it was 67.1% on net generation.

Separate analysis was carried out by considering actual monthly records of the night peak, day peak and off peak from 2011 to 2017 for the provinces and whole country. It was observed that the night peak, day peak and off peak shows increasing trends as shown in Figure 3.6 (a). However, it could be observed that the growth of day peak is higher than the growth of night peak 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, it has considered the growth of the off peak based on the past growth and trend.

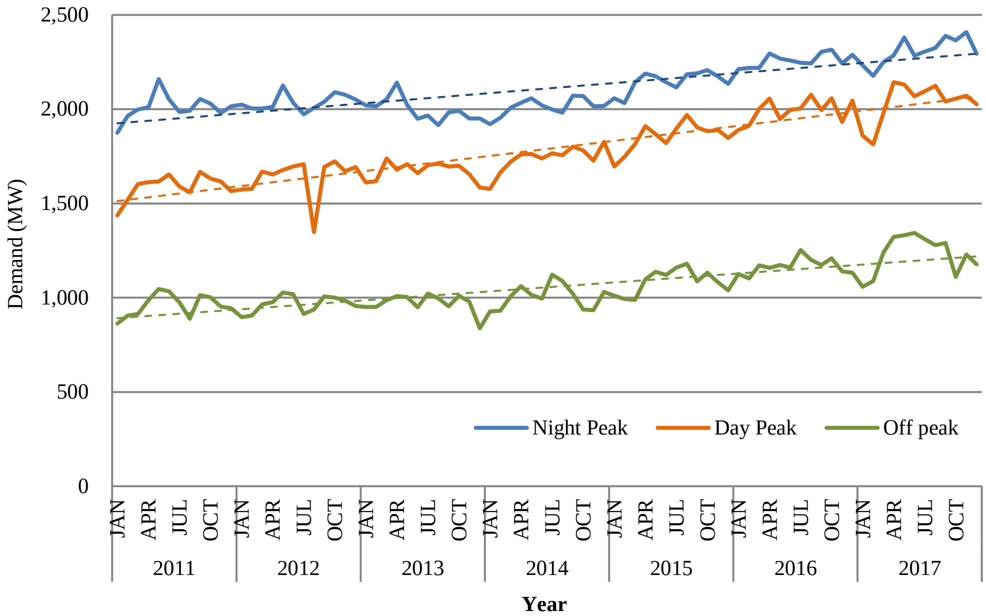


Figure 3.6 (a) – Analysis of Night peak, Day peak and Off peak Trends 2011-2017

According to the above analysis, we have predicted that the crossover of the load profile shape would occur in 2027. 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).

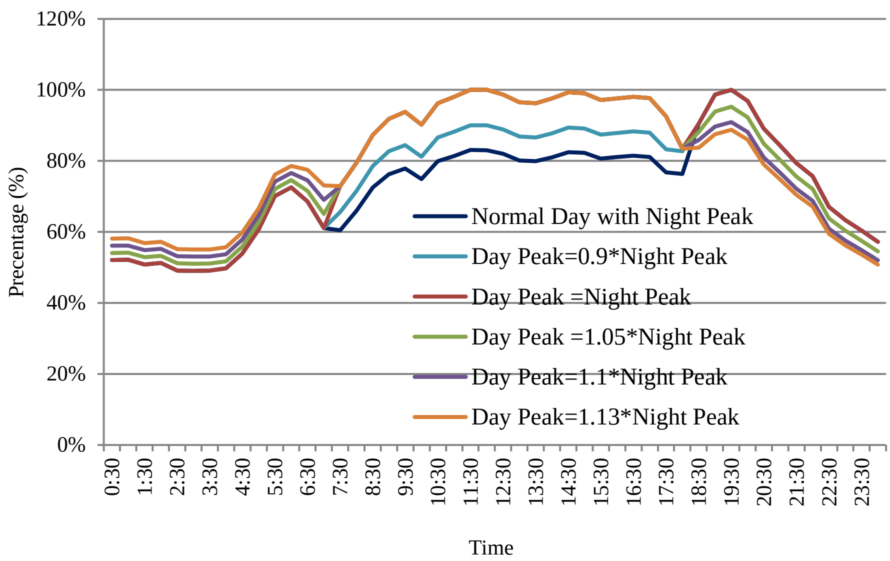


Figure 3.6 (b) – Load Profile Shape Forecast

It is assumed that the load factor become maximum in 2027. The forecast of annual load factor up to 2044 was done based on the relationship between the ratio of the day and night peak demands and the load factor of the peak day. Sales growth variation of the each tariff category could result for the increasing trend of the load factor in future. Accordingly, the system load factor shows the increasing trend with 72.4% by 2027 and Figure 3.7 shows the system load factor forecast for the planning horizon.

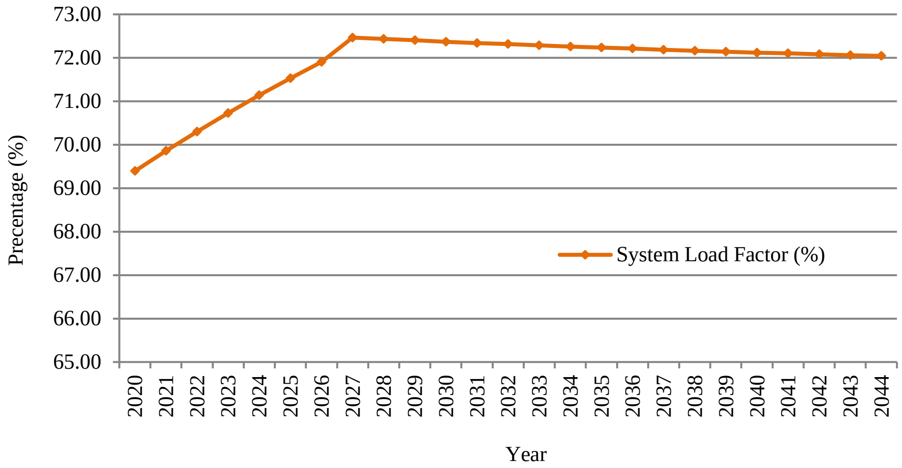


Figure 3.7 – System Load Factor Forecast 2020-2044

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

3.4 Base Demand Forecast 2020-2044

Base demand forecast 2020-2044 was prepared as described in Section 3.3 for the planning horizon. In addition to that a number of demand forecast scenarios are prepared as described in section 3.6.

Table 3.3 shows the 'Base Load Forecast 2020-2044'.

Table 3.3 - Base Load Forecast 2020-2044

Year	Demand		Net Loss*	Net Generation		Peak Demand
	(GWh)	Growth Rate (%)	(%)	(GWh)	Growth Rate (%)	(MW)
2020	16914	7.4%	8.78	18542	7.2%	3050
2021	18194	7.6%	8.62	19910	7.4%	3254
2022	19187	5.5%	8.46	20959	5.3%	3403
2023	20233	5.5%	8.30	22065	5.3%	3561
2024	21337	5.5%	8.15	23230	5.3%	3728
2025	22501	5.5%	8.00	24458	5.3%	3903
2026	23667	5.2%	7.90	25696	5.1%	4079
2027**	24819	4.9%	7.80	26918	4.8%	4241
2028	26025	4.9%	7.70	28195	4.7%	4444
2029	27279	4.8%	7.60	29522	4.7%	4655
2030	28573	4.7%	7.50	30890	4.6%	4872
2031	29917	4.7%	7.45	32325	4.6%	5101
2032	31279	4.6%	7.40	33778	4.5%	5332
2033	32675	4.5%	7.35	35267	4.4%	5569
2034	34119	4.4%	7.30	36806	4.4%	5814
2035	35607	4.4%	7.25	38390	4.3%	6067
2036	37126	4.3%	7.25	40028	4.3%	6328
2037	38692	4.2%	7.25	41716	4.2%	6597
2038	40298	4.2%	7.25	43448	4.2%	6873
2039	41937	4.1%	7.25	45215	4.1%	7155
2040	43623	4.0%	7.25	47033	4.0%	7445
2041	45368	4.0%	7.25	48914	4.0%	7745
2042	47170	4.0%	7.25	50857	4.0%	8054
2043	49037	4.0%	7.25	52870	4.0%	8376
2044	50978	4.0%	7.25	54963	4.0%	8709
5 Year Average Growth	6.0%			5.8%		5.1%
10 Year Average Growth	5.5%			5.3%		4.8%
20 Year Average Growth	4.9%			4.8%		4.6%
25 Year Average Growth	4.7%			4.6%		4.5%

*****Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro 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 END USER Model (MAED) for Load Projection

Model for Analysis of Energy Demand (MAED) developed by International Atomic Energy Agency (IAEA) for Load Projection with Bottom-Up (End User) approach. Energy Demand Calculation module utilize 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 identify 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 Industry, Transportation, Household and Service sectors are considered separately. Secondary electricity demands (net generation) is calculated taking into consideration Transmission & Distribution losses.

Model was developed based on year 2010 as the base year and revised based on the socio-economic data of 2015-2017 period. Planning years from 2020 to 2045 adjusted considering the present situation and future of the economy, demography, energy intensity 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. Peak electricity demand is calculated by the Load Factor % determines from the above load profiles. Also the rural and urban household % share assumed as 75%: 25% in 2020, 70%:30% in 2030 and 60%:40% in 2040.

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

Table 3.4 – Main & Sub Sector Breakdown

<table>
<tr><th>Main Sector</th><th colspan="2">Sub Sectors (Clients)</th></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 rowspan="2">Household</td><td colspan="2">Urban</td></tr>
<tr><td colspan="2">Rural</td></tr>
<tr><td>Transport</td><td colspan="2">Domestic EV Plugin</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 demands for electricity will increase shifting from other energy forms. This assumption is based on that the cost of electricity generation will decrease with the addition of low cost power plants to the system. The demography and the GDP composition remain in line with the Reference Scenario. Electricity use in all the sectors, Industry, Transport, Household and Services will increase compared to the Reference Scenario.

Table 3.5 shows the annual average growth rate of Total Energy Demand and Electricity Demand for 2020-2045 planning horizon for each scenario.

Table 3.5 – Annual Average Growth Rate 2020-2045

Scenario	Total Energy Demand Growth Rate %	Electricity Demand Growth Rate %
Reference	3.9	4.9
Low Economic Growth	3.3	4.2
High Electricity Penetration	4.1	5.2

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

Table 3.6 – MAED Reference Scenario

Sector	Unit	2020	2025	2030	2035	2040	2045
Industry	GWh	5,996	8,086	10,943	14,397	17,925	21,857
Transport	GWh	125	187	242	296	407	525
Households	GWh	6,531	7,614	8,959	10,612	12,592	14,788
Services	GWh	4,929	7,122	9,414	12,238	15,624	19,292
Total	GWh	17,581	23,010	29,558	37,543	46,548	56,462
Industry	%	34.11	35.14	37.02	39.74	38.51	38.71
Transport	%	0.71	0.81	0.82	0.82	0.88	0.93
Households	%	37.15	33.09	30.31	29.29	27.05	26.19
Services	%	28.04	30.95	31.85	33.78	33.57	34.17
Peak	MW	3,038	3,817	4,863	6,141	7,501	9,089
Load Factor	%	66.07%	68.82%	69.38%	69.78%	70.71%	70.71%

Total electricity demand of the MAED reference scenario and Base Demand Forecast 2020-2044 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.

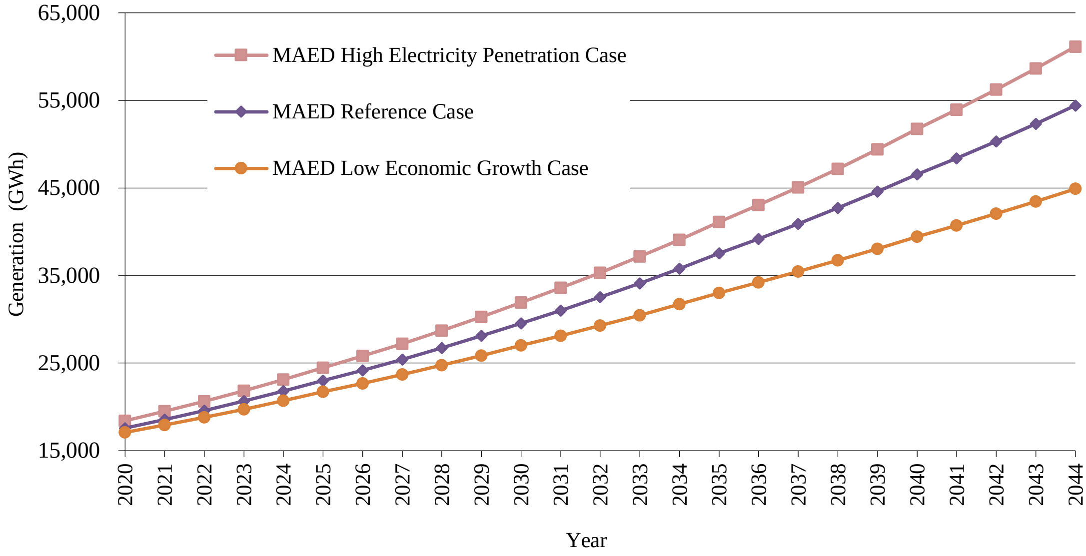


Figure 3.8 - Generation Forecast Comparison

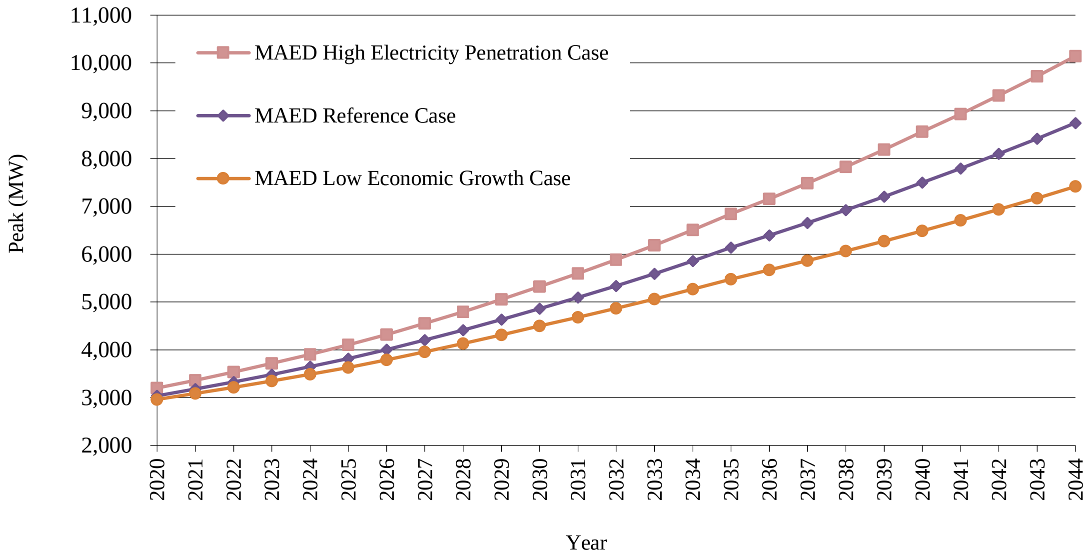


Figure 3.9 – Peak Demand Forecast Comparison

3.6 Demand Forecast Scenarios

Different demand forecast scenarios were prepared considering growth rate variations to the base demand forecast, long term time trend approach, end user approach 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 to 13.

1. **High Load Forecast** - The forecast developed considering 1% higher economic growth of the country beyond 2022 and economic sector change based on higher growth in Industrial and Service sector in future

2. **Low Load Forecast** - The forecast developed considering 1% reduction from the annual growth rate of Base Load Forecast

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 1993

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

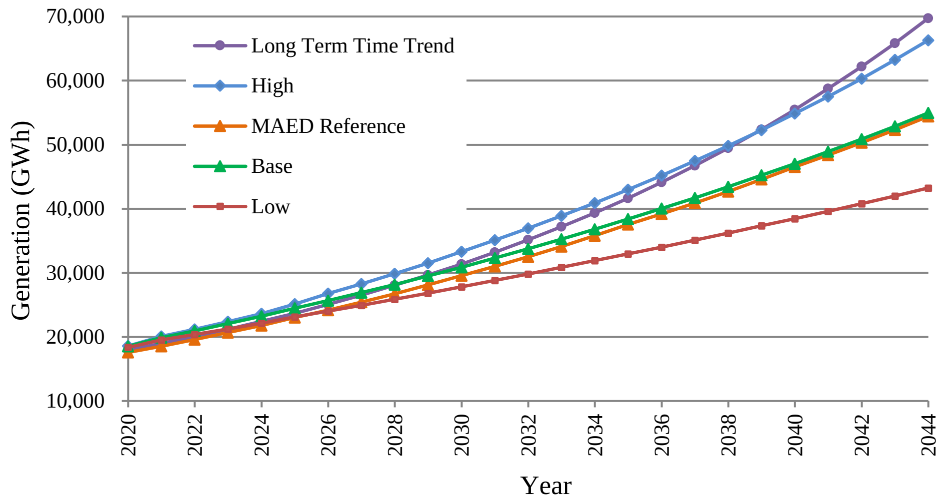


Figure 3.10 - Generation Forecast of Low, High, Long Term Time Trend and MAED with Base

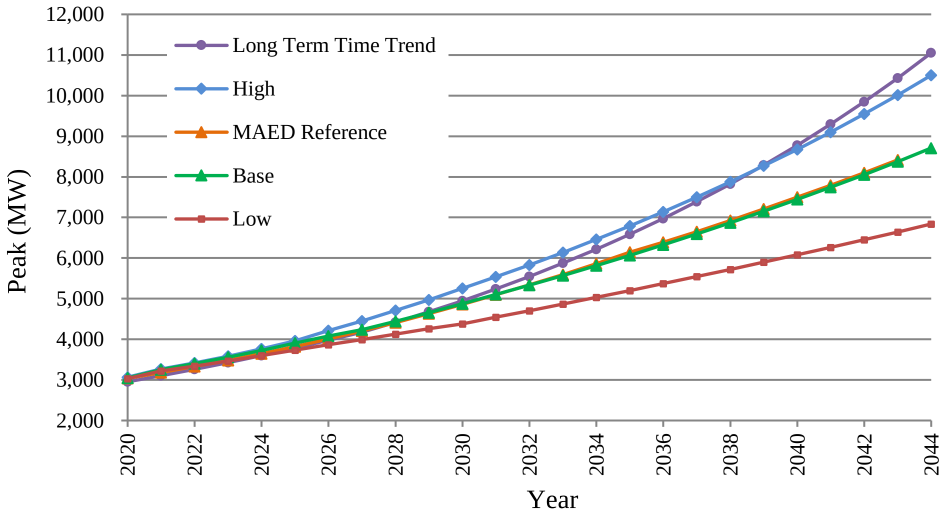


Figure 3.11–Peak Demand Forecast of Low, High, Long Term Time Trend and MAED with Base

3.7 Comparison with Past Forecasts

Demand forecast is reviewed once in two years with the revision of Long Term Generation Expansion Plan. This enables to capture the latest changes in the electricity demand as well as associated socio economic variables. Table 3.7 shows the comparison of past demand forecasts used in the previous expansion plans and their percentage variation against the actual demand. 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 3.7 – Comparison of Past Demand Forecast with Actuals (in GWh)

Year	LTGEP 2011 - 2025	LTGEP 2013 - 2032	LTGEP 2015 - 2034	LTGEP 2018-2037	Actual Demand (GWh)
2011	10036 (+0.1%)				10026
2012	10698 (+2.1%)	10675 (+1.9%)			10475
2013	11402 (+7.3%)	11104 (+4.5%)			10624
2014	12149 (+9.8%)	12072 (+9.1%)			11063
2015	12941 (+9.8%)	12834 (+8.9%)	11516 (-2.3%)		11786
2016	13773 (+7.7%)	13618 (+6.5%)	12015 (-6.0%)		12785
2017	14630 (+8.9%)	14420 (+7.4%)	12842 (-4.4%)	13656 (+1.7%)	13431
2018	15530 (+10.2%)	15240 (+8.2%)	13726 (-2.6%)	14588 (+3.5%)	14091

Note: Within bracket figures indicate the percentage deviation of demand forecast with reference to actual demand

3.8 Electricity Demand Reduction and Demand Side Management

Energy Efficiency Improvement and Conservation (EEI&C) efforts are identified as one of the ten pillars of the draft final version of the new National Energy Policy & Strategies of Sri Lanka. 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 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.

Sri Lanka Sustainable Energy Authority (SEA) has been entrusted the task of implementing the EEI&C programme, named Operation Demand Side Management (Operation DSM). This programme will be carried out by a Presidential Task Force on Energy Demand Side Management (PTF on EDSM) and guided by a National Steering Committee (NSC) and implemented by a Programme Management Unit (PMU) within the SEA.

The main objectives of the Operation DSM programme will be to implement the strategies on:

- The national energy efficiency improvement and conservation programme will be further strengthened 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.
- A home productivity improvement programme, with energy efficiency and conservation as the central theme will be launched to empower women.
- 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 that will enhance the safety of road users, and to contribute to energy conservation with a better aesthetic sense.
- 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.

- Losses incurred in petroleum refining will be reduced by continuous technology infusion with new investments.
- Transport fuel use in petroleum distribution will be reduced by utilising regional storage facilities connected with the rail-based supply network.
- Virtual offices and video/teleconferencing will be promoted by making necessary changes to organisational working culture as a strategy to minimize physical movement.
- Transport energy use will be reduced by undertaking 'avoid, shift and improve' strategies with a strong focus on high quality public transport and intelligent traffic management solutions.
- Economic activities will be developed in dense clusters to benefit from lower logistic costs and improved synergies in special zones identified as smart cities, served by smart grids.
- Sustainable neighbourhoods will be used as a key design element in urban development with the objective of reducing energy demand.
- 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.
- Fuel efficiency of vehicles would be a key consideration in deciding applicable taxes on vehicles to encourage a higher efficiency vehicle fleet.

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 expansive base load generation.

Recently, SEA has done a study on the energy usage pattern, technologies and processes of the household, commercial and industrial sectors. In that study, SEA has identified eleven thrust areas, which can have a deep impact on the energy saving as listed below:

- Efficient Lighting
- Efficient Fans
- Efficient Refrigerators
- Efficient Air Conditioning
- Efficient Pumps
- Efficient Motors
- Eliminating Incandescent Lamps
- Green Buildings
- Energy Management System & Building Management Systems
- Smart Homes
- Power Factor Improvement

Implementation of the programme will be targeted to serve three market segments, i.e. industrial, commercial and residential/SME/Government segments. The first two market segments will served mainly by the utilities, in association with Energy Services Companies (ESCOs), Energy Auditors, Energy Managers and a panel of consultants. The large volume residential/SME/government segment will be served by SEA through an appliance control initiative and an on-site electricity generation facility using Solar PV roof top systems. An approximate estimation of energy savings (kWh) and demand savings (MW) realizable indicates that the programme can save 1,104 GWh by 2020 and differ a 417 MW capacity in generation expansion. Similarly, the Smart Home initiative focusing on Solar PV roof top systems can avoid 139.2GWh by 2020 and differ a 100MW capacity in day time grid generation.

The frontrunner thrust of the Operation DSM programme (elimination of incandescent lamps) is the distribution of ten million LED lamps among low electricity user residences. CEB initiated a bulk procurement programme of the required stock of lamps at nearly 1/3rd the market price of a similar product. Distribution of these lamps on a 24 month hire purchase scheme is expected to be done in 2019. Surveys and research which are required for detailed design of the remaining thrusts are in progress, and are expected to yield valuable insights into electricity demand profiles of different customer groups.

The code of practice on energy efficiency buildings will be implemented on a mandatory basis by 2020, and the necessary legislations are being drafted. As a precursor to this programme, mandatory reporting of energy and operational information on several classes of customers will be made effective within 2019.

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

Renewable energy based power, fossil fuel based thermal power and nuclear-based thermal power is the primary energy options to be considered in meeting the future electricity demand. The predominant thermal energy sources are based on oil, natural gas, coal and nuclear fuel combinations. A large number of factors including cost of development, operation and maintenance costs and environmental effects have to be evaluated in order to consider the suitability of these primary options. Environmental mitigation measures are included in the cost figures given in this report. In addition to these thermal generation options, renewable energy generation options are also considered in order to serve the future electricity demand. Renewable energy generation options are discussed in detail in Chapter 5 and the India-Sri Lanka Electricity Grid Interconnection option is briefly described in latter part of this chapter.

4.1 Thermal Options

4.1.1 Available Studies for Thermal Plants

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

a) Feasibility Study for Trincomalee Coal-Fired Power Station conducted in 1988 [7]: The feasibility study on Trincomalee coal-fired power station considered a site capacity of 900MW when fully developed (3x300MW in a phased development). The investment cost and other relevant parameters were reviewed during the 1995 Thermal Generation Options Study [8].

b) Thermal Generation Options, 1988 [9] and Thermal Generation Options, 1996 [8]

c) Special Assistance for Project Formulation (SAPROF) for Kelanitissa Combined Cycle Power Plant (1996) [10]

d) Review of Least Cost Generation Expansion Studies (1997) [11]

e) Coal Fired Thermal Development Project – West Coast (1998) [12]: Feasibility study and the preparation of contract documents (engineering services) for construction of the first 300MW coal power plant on the West Coast in Kalpitiya in the Puttalam District with the assistance of Japan Bank for International Cooperation . The selected site with an area of 103 ha is suitable to accommodate the entire power plant in its final capacity of 900MW with all auxiliary and ancillary buildings, the coal stockyard, ash disposal area, switchyard etc. and including a 43 ha buffer zone.

f) Feasibility Study for Combined Cycle Power Development Project at Kerawalapitiya -1999 [13]

g) Sri Lanka Electric Power Technology Assessment. Draft Report (Final), (July 2002) [14]

h) Master Plan Study for the Development of Power Generation and Transmission System in Sri Lanka, 2006 [15].

i) Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka, 2010 [16].

j) Energy Diversification and Enhancement Project Phase IIA- Feasibility Study for Introducing LNG to Sri Lanka, 2014 [17]

k) Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka, 2014. [18]

l) Feasibility Study on High Efficiency and Eco-friendly Coal-fired Thermal Power Plant in Sri Lanka, 2015 [19]

m) Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka, 2018. [20]

4.1.2 Thermal Power Candidates

Several power generation technologies were considered in the initial screening of generation options based on the studies listed above. Following are the thermal power generation technologies considered for the initial screening process:

(i) Natural Gas fired Gas Turbine Power Plants
(ii) Diesel fired Combined Cycle Power Plants
(iii) Natural Gas fired Combined Cycle Power Plant
(iv) High Efficient Coal Fired Thermal Power Plant
(v) Super Critical Coal Fired Thermal Power Plant
(vi) Nuclear Power Plant
(vii) Reciprocating Engines

Large number of generation technology alternatives with different capacities cannot be used in the detailed study at once due to practical and computational difficulties. The preliminary screening has to be done in order to reduce the number of alternatives by choosing the most economical optimum set of generation technologies. The Screening Curve Method was used to reduce the number of alternatives. After the initial screening, nine alternative expansion options, which are described in Section 4.1.3, were considered for the detailed planning studies. The results of the screening curve analysis are given in Annex 8.1.

4.1.3 Candidate Thermal Plant Details

Capital costs of projects are shown in two components: The foreign cost and the local cost. During the pre-feasibility and feasibility studies, capital costs have been estimated inclusive of insurance and freight for delivery to site (CIF basis). Local costs, both material and labour, have been converted to their border price equivalents, using standard conversion factors. 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 2019 values.

The thermal plant cost database, which was revised during the Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka, 2018 has been adjusted to accommodate US dollar to SL Rupees exchange rate variations as well as rupee and dollar escalations. No escalation is applied to capital costs during the study period, thus assuming that all capital costs will remain fixed in constant terms throughout the planning horizon.

A summary of the capital costs and economic lifetimes of candidate plants taken as input to the present studies after the preliminary screening is given in Table 4.1. Operating characteristics of these plants are shown in Table 4.2. The detailed characteristics of the candidate thermal plants are given in Annex 4.1.

Table 4.1 - Capital Cost Details of Thermal Expansion Candidates

Plant	***NET Capacity (MW)***	***Pure Unit Construction Cost -NET basis- (US$/kW)***		***Total Unit Cost (US$/ kW)***	***Const: Period (Yrs)***	***IDC at 10% (% of Pure capital cost)***	***Const. Cost Incl. of IDC (US$/kW) -NET basis- (US$/kW)***		***Total Unit Cost Incl. of IDC (Net) (US$/kW)***	***Economic life (Years)***
		Local	Foreign				Local	Foreign		
45MW Gas Turbine-NG	40	100.8	632.6	733.4	1.5	6.51	107.4	673.8	781.1	20
300MW Combined Cycle -Auto Diesel	281	195.3	781.2	976.5	3	13.54	221.7	887	1108.7	30
150MW Combined Cycle –NG	153	207.0	828.0	1035.0	3	13.54	235.0	940.1	1175.1	30
300MW Combined Cycle –NG	290	189.5	757.8	947.2	3	13.54	215.1	860.4	1075.5	30
600MW Combined Cycle –NG	582	156.2	624.8	780.9	3	13.54	177.3	709.3	886.7	30
300MW High Efficient Coal Plant	270	346.4	1458.6	1805.0	4	18.53	410.6	1728.9	2139.5	30
600MW Super Critical Coal Plant	564	330.6	1613.1	1943.7	4	18.53	391.9	1912.0	2303.9	30
600MW Nuclear Power Plant	552	867.7	3781.7	4649.4	5	23.78	1074.1	4680.9	5755.0	60
15MW Reciprocat- -ing Engine	15	174.6	783.7	958.3	1.5	6.51	186.0	834.7	1020.7	20

All costs are in January 2019 border prices. Exchange rate US$ 1 = LKR180.10, IDC = Interest during Construction

Table 4.2 – Characteristics of Candidate Thermal Plants

Plant	NET Capacity (MW)	Heat Rate (kCal/kWh)		Full Load Efficiency (Net,HHV) %	FOR %	Scheduled Maint. Days (Yr)	Fixed O&M Cost ($/kW Month)	Variable O&M Cost (USCts/ kWh)
		At Min. Load	Avg. Incr.					
45MW Gas Turbine-NG	40	3871	2310	31.0	8	30	0.68	0.546
300MW Combined Cycle Plant -Auto Diesel	281	2302	1462	48.0	8	30	0.41	0.355
150MW Combined Cycle Plant- NG	153	2030	1462	49.2	8	30	0.38	0.501
300MW Combined Cycle Plant- NG	290	2247	1462	48.6	8	30	0.38	0.501
600MW Combined Cycle Plant- NG	582	3019	1462	48.9	8	30	0.38	0.501

300MW High Efficient Coal Plant	270	2547	1935	38.4	3	45	4.51	0.589
600MW Super Critical Coal Plant	564	2248	1833	41.3	3	45	4.86	0.589
600MW Nuclear Power Plant	552	2723	2340	32.0	0.5	40	8.33	0.150
15MW Reciprocat- -ing Engine	15	2210	-	38.9	5	60	2.40	0.640

All costs are in January 2019 border prices. Exchange rate US$ 1 = LKR180.10, FOR = Forced Outage Rate
Heat values of petroleum fuel and coal based plants are in HHV

4. 2 Fuel

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. Considering the volatility present in fuel prices, constant fuel prices are mainly used in long term planning studies. Therefore, the fixed prices in constant terms were used for this planning study. The price sensitivity of the plan was tested for fuel price escalation based on International Energy Agency forecast, World Energy Outlook – 2018.

(i) Petroleum Products (Auto Diesel, Fuel oil, Residual Oil, Naphtha):

In the present context, all fossil fuel-based thermal generation in Sri Lanka would continue to depend on imports (However, it should be noted that oil exploration activity is presently on going in the Mannar basin). Ceylon Petroleum Corporation (CPC) presently provides all petroleum products required for thermal power stations. Weighted average of Brent crude oil price for the years 2016 to 2018 of 63.37 US$/bbl was considered for the study and internationally recognized fuel price forecasts by the World Bank and International Monetary Fund (IMF) are shown for comparison in Figure 4.1.

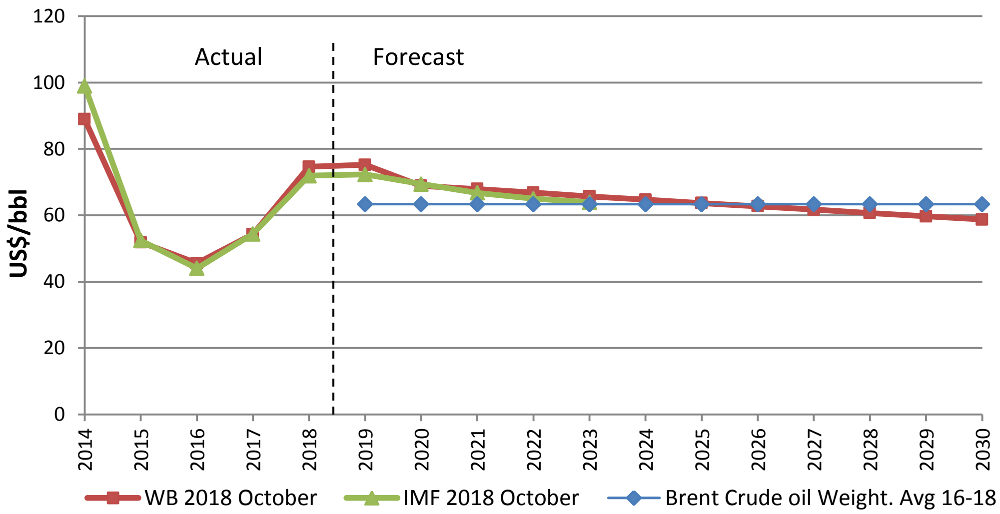


Figure 4.1 – World Bank and IMF Crude Oil Price Forecast

The CIF prices are shown in Table 4.3 with the fuel characteristics and the fuel prices used in the analyses. 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	CIF Price	
			($/bbl)	Rs/l
Auto Diesel	10500	0.84	72.5	82.1
Fuel oil	10300	0.94	65.8	74.5
Residual oil	10300	0.94	65.8	74.5
Naphtha	10880	0.76	68.9	78.0

Source: Oil prices based on Brent Crude Oil Price Index

(ii) Coal

Coal is a commonly used fuel options for electricity generation in the world. CEB identified coal as an economically attractive fuel option for electricity generation in 1980's. But No coal plants were built until 2011 due to several environmental and social issues. At present, 900MW coal power plants are in operation at Puttalam which was built in two stages. It is important to note that the coal prices are not linked with the petroleum prices historically. However, recently coal prices too have shown an increased volatility. 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 6000 kcal/kg on FOB basis from Richards Bay, South Africa. Shipping cost may vary depending on shipping distance and typical values range from 12-13 US$/ton. Further, internationally recognized fuel price forecasts by the World Bank and International Monetary Fund (IMF) are considered for comparison as shown in Figure 4.2. Weighted average coal price used in studies are closer representation to IMF projection which is higher compared with World Bank projections.

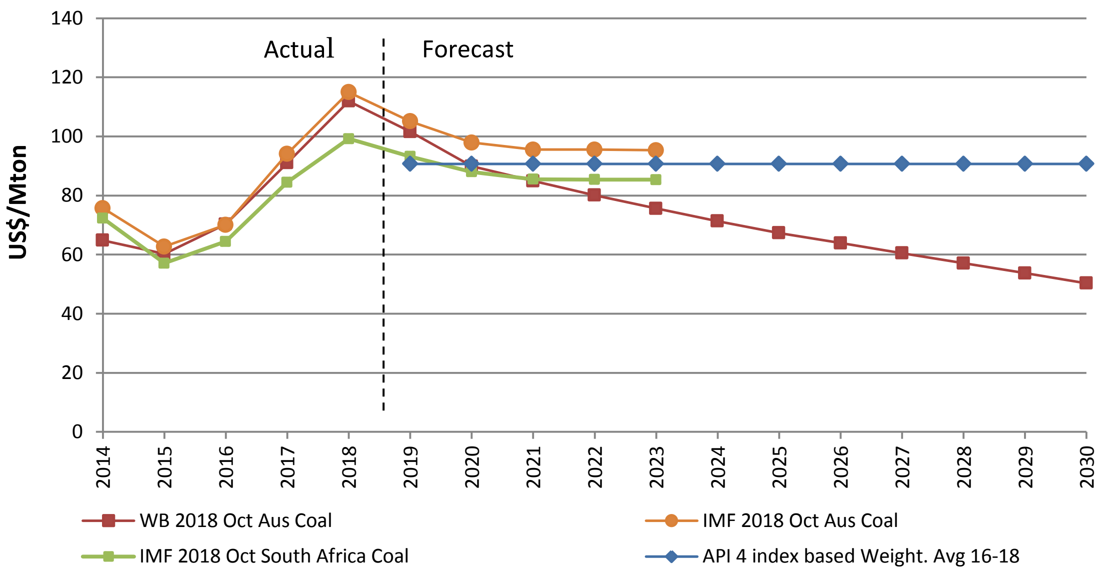


Figure 4.2 – World Bank and IMF Coal Price Forecast

In deriving the appropriate price forecast a weighted average of API 4 index and a typical shipping/handling cost was considered. Two coal types are used based on different handling cost. The values are shown in Table 4.4.

Table 4.4 – Coal Prices and Characteristics for Analysis

Fuel Type	Heat Content (kCal/kg)	Market Price ($/MTon)	Remarks
Coal type1	6300	105.9	High Efficiency Coal Power Plants and Super Critical Coal Power Plants at West Coast
Coal type2	6300	103.6	High Efficiency Coal Power Plants and Super Critical Coal Power Plants at East Coast

Source: Coal prices based on API 4 Index

(iii) Liquefied Natural Gas

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

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

1. Sri Lanka Electric Power Technology Assessment Draft Report (Final), (July 2002) [14]
2. Sri Lanka Natural Gas Options Study, USAID-SARI/Energy Program (Revised June 2003) [21]
3. Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka – 2010 (JICA funded), phase I [16]
4. Energy diversification enhancement by introducing Liquefied Natural Gas operated power generation option in Sri Lanka. –Phase IIA [17]

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

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

According to the "Study for Energy diversification enhancement by introducing LNG Operated Power Generation options in Sri Lanka", there are different LNG pricing mechanisms adopted in different regions of the world and the current LNG pricing system particularly in Asian market is linked with the Japanese average import LNG price (CIF) which is indexed against the Average Japanese imported Crude oil price, i.e. Japanese Crude Oil Cocktail (JCC). The above study suggests that the linkage between 11% to 17% with Japanese Crude Cocktail (JCC) reflects appropriate LNG FOB price for Sri Lanka. Actual price shall vary based on long term contract agreements and minimum order quantity. Platts Japanese Korean Marker (JKM) is another benchmark price for the Asian region and has been comparable to the JCC linked prices in the recent past.

In order to identify a possible rate for LNG supply prices to Sri Lanka it is useful to analyze the Indian, Pakistan and Bangladesh recent scenarios. Even though typical LNG contracts had varied between 11%-17% linkage in the past, recent trends reveal even at low order quantities a lower slope is achievable through good negotiations. Considering most recent oil based contracts and price offers the slope variation between 11.5% to 12.5 % with Brent Crude oil Index, could be considered while the fixed component varies from 0% to 0.5 %, however this range is highly dependable on negotiation.

Internationally recognized fuel price forecasts by the World Bank and International Monetary Fund are considered for comparison with an appropriate price forecast of LNG for Sri Lanka based on weighted average Brent Index from 2016 to 2018 as shown in Figure 4.3.

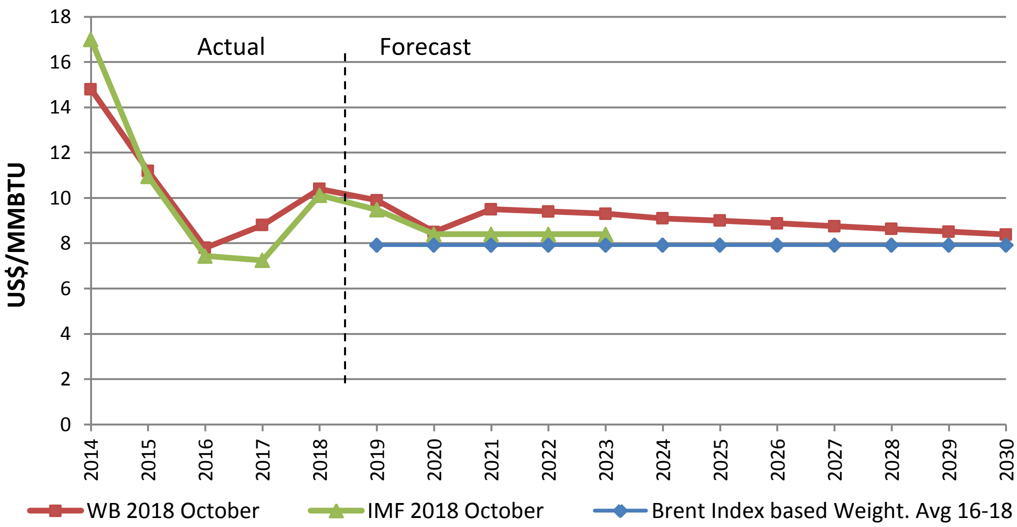


Figure 4.3 – World Bank and IMF Natural Gas Price Forecast

In addition to the CIF price, the price of fuel delivered to the power plant is calculated which includes the handling charge consisting of regasification and transportation of fuel through pipeline network. Accordingly, 12.5% Slope to Brent Crude Oil Index plus a handling fee of 2 US$/MMBtu has been considered. Thus for the long term generation expansion planning study LNG price of 9.92 $/MMBtu is considered based on Brent Crude oil price of 63.37 US$/bbl projected in section 4.2(i).

Table 4.5 illustrates the associated cost for construction and operation of LNG infrastructure.

Table 4.5 – Associated Cost for LNG Development

Land Based Terminal*	**Cost (2014 base prices)**
1 Mtpa Terminal Capital Cost (MUS$)	488
2 Mtpa Terminal Upgrade Cost(MUS$)	206
Fixed O & M Cost(MUS$/ year)	2.1
Variable O & M Cost(MUS$/year)	1.8

Floating Storage Regasification Unit**	**Cost (2019 base prices)**
1 Mtpa Terminal Capital Cost (MUS$)	174
Annual Cost(MUS$/ year)	53

Source: *Energy Diversification Enhancement Project Phase IIA Feasibility Study for Introducing LNG to Sri Lanka
** Study conducted by National Agency for Public Private Partnerships with Navigant Consulting [22]

(iv) Natural Gas

In September 2007, the Petroleum Resources Development Secretariat (PRDS) which was established under the Petroleum Resources Act, N0 26 of 2003 to ensure proper management of the petroleum resources industry in Sri Lanka, launched its first Licensing Round for exploration of oil and gas in the Mannar Basin off the north-west coast and in 2008 exploration activities initiated with the awarding of one exploration block (3000 sqkm) in Mannar Basin. Two wells namely ‘Dorado and ‘Barracuda’ have been drilled, ‘Dorado’ indicates the availability of natural gas and it is estimated to have approximately 300 bcf of recoverable gas reserves. Gas production rate predicted is 70 mscfd. This amount is equivalent to approximately 0.5 mtpa. Based on the above most likely quantity of natural gas, it is estimated that it could cater 1000MW capacity for approximately 15 years with a plant factor of 30-50%.

The volumetric estimate of the technically complex “Barracuda” discovery exceeds 1.8 TCF. In addition to that the Mannar Basin analysis shows a remarkable natural gas potential that is yet to be explored. However exploitation of domestic natural gas adds many economic benefits to the country in terms of direct fiscal gains to state through agreed contractual fiscal terms (tax, royalty, bonus, profit share, other levies, etc.) and value added externalities such as new industry, employment creation and development of local knowledge base and supplier chain. Therefore the effective gas price to the state could be more attractive compared to other imported fuels and energy sources.”

In early 2016 PRDS signed a joint Study agreement with an international oil company and have already selected a seismic contractor to explore two new blocks off the east coast. PRDS has already announced the international marketing campaign to select a suitable operator to appraise and develop the two previous gas discoveries and prospects in the offshore Block in Mannar Basin. It is expected to drill more test wells during 2018 to 2019 depending on the success of the prospects analysis of the exploration program. In support of commercialization of these identified reserves, PRDS has already taken the initiative to recruit a NG consultant and is in the process of preparing a NG policy for Sri Lanka.

(v) Nuclear

Alternative fuel options such as Nuclear Power have to be explored by avoiding excessive dependence of power sector in Sri Lanka on the imported fossil fuel. Nuclear plants are inherently large in capacity compared to other technologies for power generation. From technical point of view, the capacity of the present system is considerably small to accommodate a Nuclear power plant of typical size. However, cabinet approval has been given to consider nuclear as an option to meet the future energy demand and also to consider Nuclear Power in the generation planning exercise and to carry out a pre-feasibility study on the Nuclear Option. Nuclear option was included in this study as a candidate plant from year 2030 onwards.

Ministry of Power, Energy and Business Development requested further assistance from International Atomic Energy Agency (IAEA) for “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. Ministry of Power, Energy and Business Development acts as the Nuclear Energy Programme Implementing Organization (NEPIO). In 2018, Ministry, CEB, Sri Lanka Atomic Energy Board (SLAEB) and Sri Lanka Atomic Energy Regulatory Council (SLAERC) jointly initiated the Nuclear Power Program with the assistance from IAEA. Objective is to prepare a comprehensive report addressing the 19 milestones, according to Phase 1 of the IAEA milestones approach by the end of 2020. Further IAEA assistance is obtained at present 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

Presently the 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.

4.3. Screening of Generation Options

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

The thermal plant cost database, which was revised during the Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka 2018 was extensively used during the current planning study However, adjustments have been made to the cost base to reflect January 2019 values. Whenever feasibility study results are available for any prospective project, such results were used in preference to the above studies.

4.3.1 Thermal Plant Specific Cost Comparison

The specific costs of the selected candidate plants for different plant factors are tabulated in the Table 4.6. These specific costs are derived in the screening curve methodology which considers the capital Investments cost, Operation and Maintenance cost, Fuel cost and economic life time of a given generation alternative. It reveals how different technologies perform at different plant factors. Accordingly, Peak Load Power plants are cost effective at low plant factor operation whereas base load plants such as Coal and Nuclear are attractive options for higher plant factor operations. However, in actual simulations, the size of the generation units are taken into account and it would make a significant effect in the final plant selection.

Table 4.6 - Specific Cost of Candidate Thermal Plants in USCts/kWh (LKR/kWh)

Plant \ Plant Factor	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8
45MW Gas Turbine Natural Gas	22.23 (40.04)	16.85 (30.34)	15.05 (27.11)	14.16 (25.50)	13.62 (24.53)	13.26 (23.88)	13.00 (23.42)	12.81 (23.07)
300MW Combined Cycle Plant Auto Diesel	21.99 (39.61)	15.80 (28.45)	13.73 (24.73)	12.70 (22.87)	12.08 (21.76)	11.67 (21.02)	11.37 (20.48)	11.15 (20.09)
150MW Combined Cycle Plant Natural Gas	20.43 (36.79)	13.90 (25.04)	11.73 (21.12)	10.64 (19.16)	9.99 (17.98)	9.55 (17.20)	9.24 (16.64)	9.01 (16.22)
300MW Combined Cycle Plant Natural Gas	19.45 (35.03)	13.46 (24.24)	11.46 (20.64)	10.46 (18.84)	9.86 (17.76)	9.46 (17.04)	9.17 (16.52)	8.96 (16.14)
600MW Combined Cycle Plant Natural Gas	17.40 (31.34)	12.41 (22.35)	10.75 (19.36)	9.92 (17.86)	9.42 (16.96)	9.08 (16.36)	8.85 (15.93)	8.67 (15.61)
300MW High Efficient Coal Plant	32.32 (58.20)	18.30 (32.95)	13.62 (24.53)	11.29 (20.33)	9.88 (17.80)	8.95 (16.12)	8.28 (14.91)	7.78 (14.01)
600MW Super Critical Coal Plant	34.21 (61.61)	19.11 (34.42)	14.08 (25.36)	11.56 (20.82)	10.05 (18.11)	9.05 (16.29)	8.33 (15.00)	7.79 (14.03)
600MW Nuclear Plant	65.26 (117.53)	32.93 (59.31)	22.15 (39.90)	16.77 (30.19)	13.53 (24.37)	11.38 (20.49)	9.84 (17.72)	8.68 (15.64)
15MW Reciprocating Engines	26.22 (47.23)	18.15 (32.70)	15.47 (27.85)	14.12 (25.43)	13.31 (23.98)	12.78 (23.01)	12.39 (22.32)	12.10 (21.80)

Note: 1 US$ = LKR 180.10

4.4 Current Status of Non-Committed Thermal Projects

(a) **Trincomalee Coal Power Project**

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

Agreements for Power purchase, Implementation, Land Lease, Coal Supply and agreements with Board of Investment were signed and the feasibility study of the project was completed. The Environmental clearance was received subjected to further studies.

The Project had acquired around 500 acres for the implementation and consists of the main power block, coal handling plant, coal storage yard, ash disposal system, sea water cooling system, other building facilities and a green belt.

However, the project was not granted the approval by PUCSL in the Long Term Generation Expansion Plan 2015-2034 [23], indicating the undertaking given to the Supreme Court Case No SCFR 179/2016.

(b) **New Coal fired Power Plant – Foul Point, Trincomalee**

Ceylon Electricity Board completed the Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka with the financial assistance of New Energy and Industrial Technology Development Organization (NEDO) of Japan and the study was carried out by Electric Power Development Co., Ltd. (J-POWER) in 2013 and 2014 [18]. Under the above study, candidate sites were studied from South-West to South Coast Area and in Trincomalee Bay area considering, technical, environmental and social conditions and finally three sites at southern coast, site in Hambantota port area and a site at Sampur area in Trincomalee were selected as the most suitable sites for future coal power development.

In 2014, the Feasibility Study for High Efficient and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka commenced under the same program and the study was conducted for the site in Sampur area in Trincomalee [19]. Basic thermal plant design has been prepared for 1200MW (either 300MW High efficient advanced subcritical power plants or 600MW super critical power plants) development considering technical, geological and environmental considerations. High Efficient and Eco Friendly Coal fired thermal power plant equipped with several emission control technologies to reduce emission levels significantly was studied. The Environmental Impact Assessment of the proposed project was temporarily suspended due to the non-availability of the identified land for the power plant development. However an alternate land at Foul Point area has been identified and process of acquisition is initiated. Necessary feasibility studies for the alternate land are to recommence once the land acquisition is finalized.

(c) **Coal Power Plants in the West Coast – Extension at Norochcholai**

An initial study has been carried out to evaluate the possibility of developing an additional 300MW capacity within the premises of Lakvijaya Coal Power Station. During the study it has been observed that the existing coal yard is sufficient to store coal for an additional generation unit but the coal unloading capacity and the coal conveyer system need to be upgraded to improve reliability and redundancy. It has mentioned that upgrades will be required in some of the auxiliary components of the existing power plant in order to cater for an additional unit. New study has been initiated to implement 2x300 MW high efficient coal power plants within and adjacent to Lakvijaya coal power plant with appropriate transmission infrastructure.

(d) **Coal Power Plants in the Southern Coast**

Southern Coal Power Project: CEB has identified locations near Karagan Lewaya, Mirijjawila, Mirissa and Mawella as prospective sites in Southern coast and Athuruwella in the Western Coast for future Coal fired power plants. Recent Pre-Feasibility Study for High Efficient and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka selected Hambantota port and Mawalla locations as prospective sites in southern coast for coal power development.

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

4.5 India-Sri Lanka Electricity Grid Interconnection

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

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

Various Line route options and connection schemes were analyzed during the pre-feasibility studies. 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 consist of 130km 400kV HVDC overhead line segment from Madurai to Indian sea coast , 120km of 400kV Under-Sea cable from Indian sea coast to Sri Lankan Sea coast, 110km Overhead line segment of 400kV from Sri Lankan sea coast to Anuradhapura and two converter stations at Madurai and Anuradhapura.

During latest working group discussions between countries initiated in year 2017, it was proposed to shift the HVDC station in Sri Lankan side from Anuradhapura to New Habarana. The following alternatives of the interconnection route have been identified:

Option-1: 2x500MW HVDC terminal stations each at Madurai-New (India) and New Habarana (Sri Lanka) along with HVDC bipole line: 410km

– Overhead Line (India): Madurai (New) to Panaikulam: 130km
– Submarine Cable: Panaikulam (India) to Thirukketiswaram (SL): 120km
– Overhead Line (SL): Thirukketiswaram to New Habarana: 160km

Option-2: 2x500MW HVDC terminal stations each at Madurai-New (India) and New Habarana (Sri Lanka) along with HVDC bipole line: 420km

– Overhead Line (India): Madurai (New) to near Dhanushkodi: 180km
– Submarine Cable: Dhanushkodi (India) to Talaimannar (SL): 40km
– Overhead Line (SL): Talaimannar to New Habarana: 200km

Option-3: 2x500MW HVDC terminal stations each at Madurai-New (India) and Thirukketiswaram (Sri Lanka) along with HVDC bipole line: 410km

– Overhead Line (India): Madurai (new) to near Dhanushkodi: 180km
– Submarine Cable: Dhanushkodi (India) to Thirukketiswaram (SL): 70km
– Overhead Line (SL): Thirukketiswaram to New Habarana: 160km

Both HVDC technologies, Conventional Line Commuted Conversion (LCC) and Voltage Source Conversion (VSC) are to be considered in future studies. The interconnection has been envisaged to be implemented with 2x500MW HVDC blocks in two phases.

Phase I : 1 x 500 MW Monopole
Phase II : 2 x 500 MW Bipole

The cost of each alternative for each technology 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 feasibility study is yet to be initiated once the option if finalized.

CHAPTER 5
RENEWABLE GENERATION OPTIONS FOR FUTURE EXPANSION

5.1 Introduction

Owing to its geo-climatic conditions, Sri Lanka is blessed with diverse forms of renewable energy resources. As a developing nation, Sri Lanka has been reaping the benefits from these indigenous renewable energy sources for decades which supported the sustainable economic growth. Country's electricity energy needs were predominantly met by renewable energy sources over decades, with prime contribution from the major hydro power resources. That has enabled the country to maintain green credential with low carbon emissions per capita level in electricity generation throughout the past years. However, the rising economic growth and the energy demand necessitate the development of power generation sources. In a context where global consensus is in place to combat climate change, Sri Lanka is ambitious and progressing towards low carbon pathways through renewable energy development. Substantial increase of the contribution of indigenous renewable energy sources is envisaged in the electricity sector and it will reduce the greenhouse gas emission as well as enhance the energy security aspects.

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, falling water, sea-waves, geothermal heat or biomass into heat or electricity without exhausting the source. The large or regulated hydro power plants which are major renewable energy sources have been the major contributor in the past. However, other technologies such as small hydro, wind, solar, biomass etc. are the leading forms of renewable technologies globally and it is expected to be dominant contributors in the future.

Sri Lanka has harnessed major renewable resources (large hydro) to almost its maximum economical potential. Secondly, as indigenous resources, Other Renewable Energy potentials have become alternate source of energy for the future due to the low impact on environment compared to other fossil fuel based sources of energy. 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 underway at present.

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

Hydro power and biomass power generation are not intermittent in performance. On the other hand, Wind and Solar Photovoltaic sources are highly intermittent and seasonal in nature. These physical characteristics of the resource make the challenges in grid integration and different power systems has different integration capacities based on resource and system characteristics and economic performance. Prior to the preparation of Long Term Generation Expansion Plan, a comprehensive

Renewable Energy Integration Study is carried out in order to optimize the contribution of renewable energy while giving due consideration to technical, operational and economic performance.

Government of Sri Lanka established the Sustainable Energy Authority (SEA) on 1st October 2007, enacting the Sri Lanka Sustainable Energy Authority Act No. 35 of 2007. SEA is expected to develop indigenous renewable energy resources and drive the country towards a new level of sustainability in energy generation and usage; to declare energy development areas; to implement energy efficiency measures and conservation programmes; to promote energy security, reliability and cost effectiveness in energy delivery and information management.

The objective of the SEA is to identify, promote, facilitate, implement and manage energy efficiency improvements and energy conservation programmes in domestic, commercial, agricultural, transport, industrial and any other relevant sector. Also SEA will promote energy security, energy conservation reliability and cost-effectiveness of energy delivery to the country by policy development and analysis and related information management. Further the authority will ensure that adequate funds are available to implement its objects, consistence with minimum economic cost of energy and energy security for the nation, thereby protecting natural, human and economic wealth by embracing best sustainability practices. Relating to power development, SEA will hold two key elements namely declaration of energy development area and on-grid & off-grid renewable energy resources. CEB and SEA jointly play a complementary role to each other in enhancing the contribution of other renewable energy resources. CEB and SEA facilitated the private sector for other renewable energy development and recently CEB also has undertaken the development of large scale renewable energy projects. CEB is in the process of implementation of initial 100MW of Wind Park in Mannar Island.

5.2 Major Renewable Energy 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 [24], 1989. These include 27 sites capable of generating electricity at a long-term average cost of less than 15 USCts/kWh (in 1988 prices) and having a total capacity of approximately 870MW. Portion 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 project 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 [25]. 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 [26 and 27] 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 [28] where the diversion of Uma Oya, a tributary of Mahaweli Ganga was studied. The development proposed in this study was used as a candidate in the present expansion studies. In 2001, SNC Lavalin Inc. of Canada was engaged to conduct the feasibility study on Uma Oya with the assistance of Canadian International Development Agency (CIDA). However, only Phase I of the study was completed by the consultants.

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

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

(e) In October 2013 Sri Lanka Energies (Pvt) Ltd studied two options for Seethawaka Hydro Power Project and CEB had decided to develop the option with a reservoir for maximum use of the river for power generation. In December 2018, the Technical Feasibility Study of the project has been completed by Central Engineering Consultancy Bureau (CECB) of Sri Lanka and CEB acts as the implementing agency of the project.

(f) "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" carried out by JICA funds [29] 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 in March 2018 proposed an alternative location for a Pumped Storage Power Plant considering the existing Victoria reservoir being used as 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 (30MW) 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 construction work and electro mechanical work are in Progress in parallel at Main Dam Site, Main Tunnel, Diversion Tunnel and Power House Site and the project is scheduled to be completed in July 2019.

ii. Moragolla Hydro Power Project

The 30MW Moragolla Hydropower Project located downstream of the Kotmale power station and approximately 3.5 km 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 expectated 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 the project is under pre-construction phase and expected to be operational by December 2022.

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 122MW 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 by December 2020.

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 of the Master Plan Study. (Studies conducted under the Master Plan study were considered to be at pre-feasibility level).

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

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

Following projects are identified as the candidate large scale hydro power projects.

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 is scaled down to a lower capacity hydro power plant. CEB has conducted the initial feasibility studies together with the procurement of consultancy services for Environmental Impact Assessment (EIA) of the project.

A separate Project Management unit was appointed in CEB to implement the project and the detailed feasibility study has been completed in December 2018. 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,

ii. Other Hydro Power Projects

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

The preliminary feasibility studies and EIA studies of the Thalpitigala Hydro Power Project have been finalized and approved. As per the feasibility studies, the power plant is 15MW (2 x 7.5MW) with an estimated annual energy contribution of 52.4GWh.

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

5.2.4 Details of the Candidate Hydro Power Projects

The basic technical data of the selected projects are summarized in Table 5.1 (see Annex 5.1 for further details). A summary of the capital cost is given in Table 5.2.

Table 5.1 - Characteristics of Candidate Hydro Plants

Project	River Basin	Ins. Capacity (MW)	Annu. Energy (GWh)	Storage (MCM)
Seethawaka	Kelani	24	54(@ 27% PF)	3.51
Thalpitigala	Uma Oya	15	52.4(@39% PF)	17.96

Table 5.2 - Capital Cost Details of Hydro Expansion Candidates

Plant	Capacity (MW)	Pure Const. Cost US$/kW		Total Cost (US$/kW)	Const Period (Yrs)	IDC at 10% (% pure costs)	Const. Cost as Input to Analysis incl. IDC (US$/kW)		Total Cost incl. IDC (US$/kW)	Economic Life (Years)
		Local	Foreign				Local	Foreign		
Seethawaka[1]	24	1197.4	2383.5	3580.9	4	18.53	1359.5	2706.2	4065.8	50
Thalpitigala[2]	15	2102.4	5024.2	7126.5	3.5	16	2438.7	5828.1	8266.8	50

Exchange rate US$ 1 = LKR 180.098 , IDC = Interest during Construction

1. Estimated Project cost is extracted from the Seethawaka Ganga Hydropower Project Feasibility Study, December 2018 [30]

2. Detail cost breakdown is not feasible as hydro power is a secondary benefit and developed by Ministry of Irrigation and Water Resource Management. However, for comparison 60% of the total project cost is assumed for Power generation

5.3 Hydro Power Capacity Extensions

The Sri Lankan power system is gradually transforming into a thermal based system. In view of this, it would be pertinent to prepare the hydropower system for peaking duty. This aspect was further studied under the JICA funded "Hydro Power Optimization Study of 2004". Given below is a brief summary of possible expansions of existing hydro stations studied under the "Hydro Power Optimization Study" [25].

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 [31] and had considered three options for the expansion. They are of addition of another power house nearby existing power plant (Base option), addition of a surface type power house 2km downstream of the existing power house (Downstream Option) and using Victoria and Randenigala reservoirs as a pump storage power plant (pump storage option). From the feasibility study, it was concluded that the addition of the new power house closer to the existing power plant is an economically viable option as provisions have already been made for the expansion when the existing power plant was constructed. Under this expansion, two units of 114MW each will be added. This expansion could double the capacity of Victoria while the energy benefits are as follows.

Table 5.3 – Details of Victoria Expansion

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

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

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

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

(c) Kotmale Project:

Provision for capacity expansion has been kept in the existing Kotmale Power Station. At present 3 x 67MW generators are installed in the Kotmale Power Station with an annual average energy output of

455 GWh. The amount of energy could be increased by about 20% by raising the dam crest from elevation 706.5m to 735.0 masl.

5.3.2 Samanala Complex

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

The Stage II Feasibility Study report done by CECB in April 2002 recommends installation of one additional 60MW capacity without developing the Diyawini Oya dam. The major factor in consideration for selecting single unit expansion was the impact on financial revenue caused by decrease of total annual energy due to the head loss occurred by high velocity in existing low pressure tunnel. A summary of expansion details is shown in Table 5.4.

Table 5.4 – Expansion Details of Samanalawewa Power Station

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

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

5.3.3 Laxapana Complex

During the Phase E of the Master Plan for the Electricity Supply in Sri Lanka, 1990 [32], some upgrading measures at Laxapana Complex have been studied. Also, under the Hydro Power Optimization Study further studies were carried out to upgrade Wimalasurendra Power Station, New Laxapana power station & Old Laxapana Power Station. And also for upgrading of the Samanalawewa and Polpitiya Power Stations, studies were carried out during the period of February to June 2010 by POYRY Energt AG, Switzerland. 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 115.2MW. Planned replacement of generator, turbine governor excitation & controls of the old Laxapana Project were completed increasing the plant efficiency and also the plant capacity has been increased from 50MW to 53.5MW.

Expansion of Polpitiya Power Station is currently being implemented and the plant capacity will be increased to 90MW from 75MW from 2019 onwards.

5.4 Other Renewable Energy Development

Growth of other renewable energy sources in Sri Lanka in commercial scale initiated with the development of mini-hydro and wind resources in mid-nineties. The project development was led largely by the private sector with the facilitation of Ceylon Electricity Board and the country's renewable energy industry has been growing continuously over the years with both local and foreign investments. Currently, Ceylon Electricity Board is engaged in developing first large scale renewable energy projects in the country.

Share of Other Renewable Energy based generation at present is 11% of total energy generation in the country and its contribution is expected to increase in the future. At the end of 2018, 610.4 MW of other renewable energy power plants have been connected to the national grid and the total comprises 393.5 MW of mini-hydro, 128.5 MW of wind, 51.4 MW of Solar PV and 37.1 MW of biomass based generation capacities. In addition, the rooftop solar PV capacity with a total of 170MW that are embedded at the consumer end is also achieving notable growth in its contribution.

Table 5.5 shows the growth of the renewable energy capacity and energy contribution compared to the overall capacity and generation for past 15 years in the country. Other renewable energy sources have been under the cost reflective technology specific tariff scheme since 2012 and the tariff is given is given in the Annex 5.2. With the falling technology costs and rising competition in the industry, competitive price setting mechanisms are increasingly being followed at present for the development of new renewable energy projects.

Table 5.5 – Energy and Demand Contribution from Other Renewable Sources

Year	Energy Generation (GWh)		Capacity (MW)	
	Other Renewable	System Total	Other Renewable	Total System Installed Capacity
2004	206	8043	73	2499
2005	280	8769	88	2411
2006	346	9389	112	2434
2007	344	9814	119	2444
2008	433	9901	161	2645
2009	546	9882	181	2684
2010	724	10714	212	2818
2011	722	11528	227	3141
2012	730	11801	320	3312
2013	1178	11962	367	3355
2014	1215	12418	442	3932
2015	1466	13154	455	3850
2016	1160	14148	516	4018
2017	1464	14,671	563	4087
2018	1762	15,305	585	4048

5.4.1 Projected Future Development

Future development of indigenous renewable energy resources is important as it is one of the significant contributors for achieving the nationally determined targets on greenhouse gas emission reduction as well as a key factor in enhancing the national energy security. Ambitious growth in renewable energy sector including wind and solar PV is projected for next 20 year planning period in this long term generation expansion plan 2020-2039.

Being different form of generation technologies, new renewable energy resources has several inherent challenges when developing and integrating into the power system. Therefore, future Other Renewable Energy (ORE) capacity additions are planned in an optimum manner based on the comprehensive grid integration study focusing on the availability of technical potential, resource quality, system stability and reliability, system operational implications, global technology costs, transmission infrastructure development, past experience in project development and economic implications.Projected future development of other renewable energy considered for the long term generation expansion plan for the period of 2020-2039 is given in the Table 5.6 below. Projected capacity additions have been assumed as committed and modelled accordingly. Hence the timely implementation is important to capture the intended benefits. Furthermore, the projected future development of ORE in a low demand and high demand scenario is presented in Annex 5.3

Table 5.6 – Projected Future Development of ORE (Assumed as Committed in Base Case Plan)

Year	Cumulative Mini hydro Capacity (MW)	Cumulative Wind Capacity (MW)	Cumulative Biomass Capacity (MW)	Cumulative Solar Capacity (MW)	Cumulative Total ORE Capacity (MW)	Annual Total ORE Generation (GWh)	Share of ORE from Total Generation %
2020	419	368	49	410	1245	3403	18.4%
2021	439	488	54	470	1450	3970	19.9%
2022	459	558	59	530	1605	4376	20.9%
2023	479	598	64	590	1730	4677	21.2%
2024	499	598	69	650	1815	4863	20.9%
2025	519	638	74	730	1960	5193	21.2%
2026	529	673	79	820	2100	5483	21.3%
2027	539	723	84	910	2255	5819	21.6%
2028	549	763	89	1010	2410	6144	21.8%
2029	559	803	94	1110	2565	6469	21.9%
2030	569	823	99	1210	2700	6738	21.8%
2031	579	883	104	1310	2875	7114	22.0%
2032	589	933	109	1420	3050	7487	22.2%
2033	599	968	114	1530	3210	7801	22.1%
2034	609	1038	119	1650	3415	8244	22.4%
2035	619	1083	124	1770	3595	8613	22.4%
2036	629	1133	129	1880	3770	8985	22.4%
2037	639	1183	134	1990	3945	9357	22.4%
2038	649	1253	139	2100	4140	9786	22.5%
2039	654	1323	144	2210	4330	10198	22.6%

Note: Further additions of Mini-hydro and Biomass capacities could be considered project by project depending on the feasibility and implementation.

At the end of year 2018, the total renewable energy capacity has reached 2009 MW which includes 1399 MW of Major Hydro and 610 MW of other renewable energy capacity. Table 5.7 and Figure 5.1 provides the future increase in planned capacities of other renewable energy technologies. The projected target of total other renewable energy capacity by 2020 is 1245 MW which more than twice of current ORE capacity and aspiring progress in project development and implementation is essential to reach near term targets.

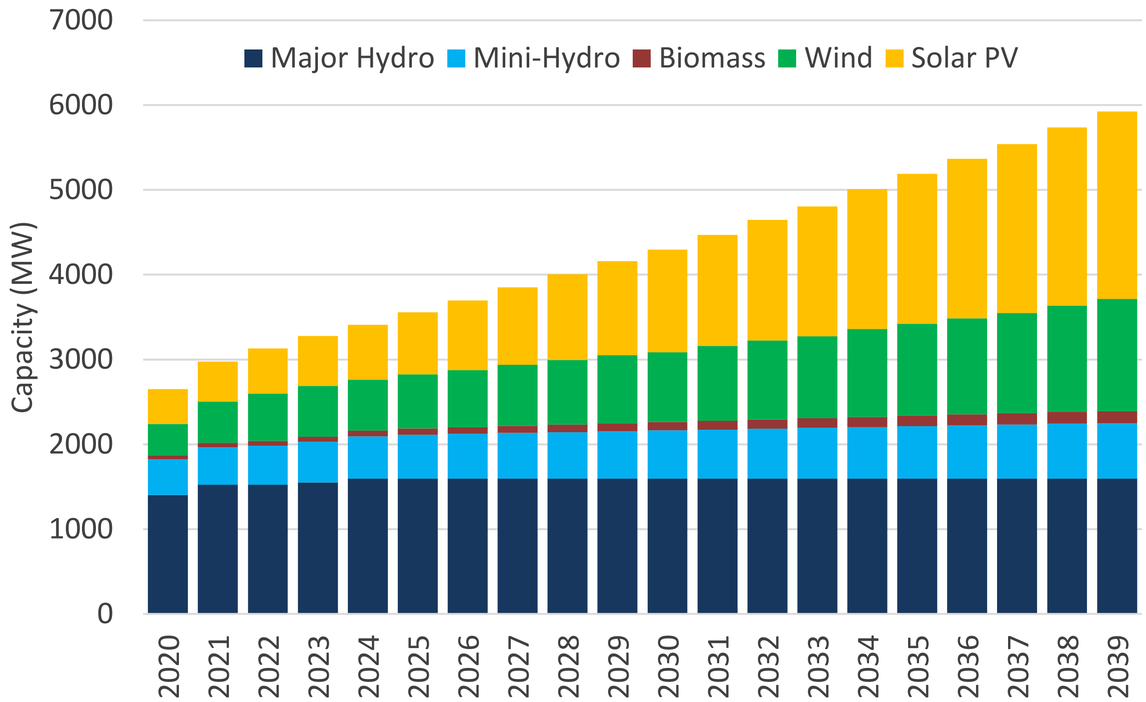


Figure 5.1: Total Renewable Energy Capacity Development

In long term, the total other renewable energy (ORE) capacity is planned to increase from 1245 MW in 2020 to 4330 MW by 2039. Total capacity of major hydro resources is expected to increase first five years by 225 MW with the completion of ongoing hydro power projects and will remain at the same level afterwards. The total planned Other Renewable Energy (ORE) capacity will increase to 2700MW by 2030.

Wind and Solar capacity is the significant contributor to the ORE capacity increase whereas a moderate growth is expected in Mini-hydro and Biomass technologies. Beyond 2023, the major share of the other renewable capacity is mainly by solar power followed by wind power. Other renewable energy segment will become dominant as it will exceed the major hydro capacity by 2022. In long term the total ORE capacity is planned to reach 4330 MW by 2039 which comprises 2210 MW of solar and 1323 MW of wind resources.

Figure 5.2 illustrates the historical ORE capacity additions from 1996 and projected ORE capacity addition for next 20-year period until 2039. Approximately, 170 to 200 MW of ORE capacity is expected to be integrated in to the system annually in this long term generation expansion plan 2020-2039. More than fivefold increase in the annual ORE capacity addition is planned for the next 20 years in comparison to the actual capacity added in past 20 years annually.

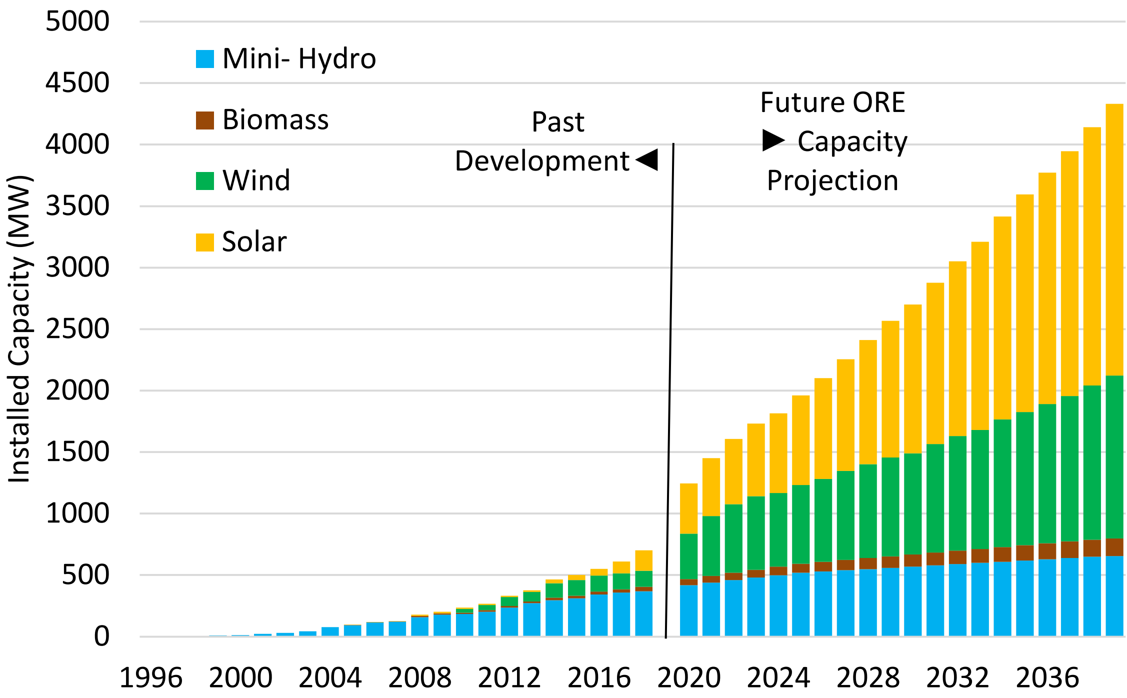


Figure 5.2: Past and Future Other Renewable Energy (ORE) Capacity Development

At present 45% of the total electricity demand is generated by renewable energy resources in average hydrological conditions and the energy share can increase up to 50% in a very wet hydrological condition. Contribution from major hydro resources which has the largest contribution at present will have a stagnated growth due to small capacity additions in forthcoming years. The development of other renewable energy resources will enhance the declining renewable energy share to be maintained above 35-40% during next 20-year period. Figure 5.3 below illustrates the contribution of renewable energy sources and the percentage energy share variation over the next 20-year period.

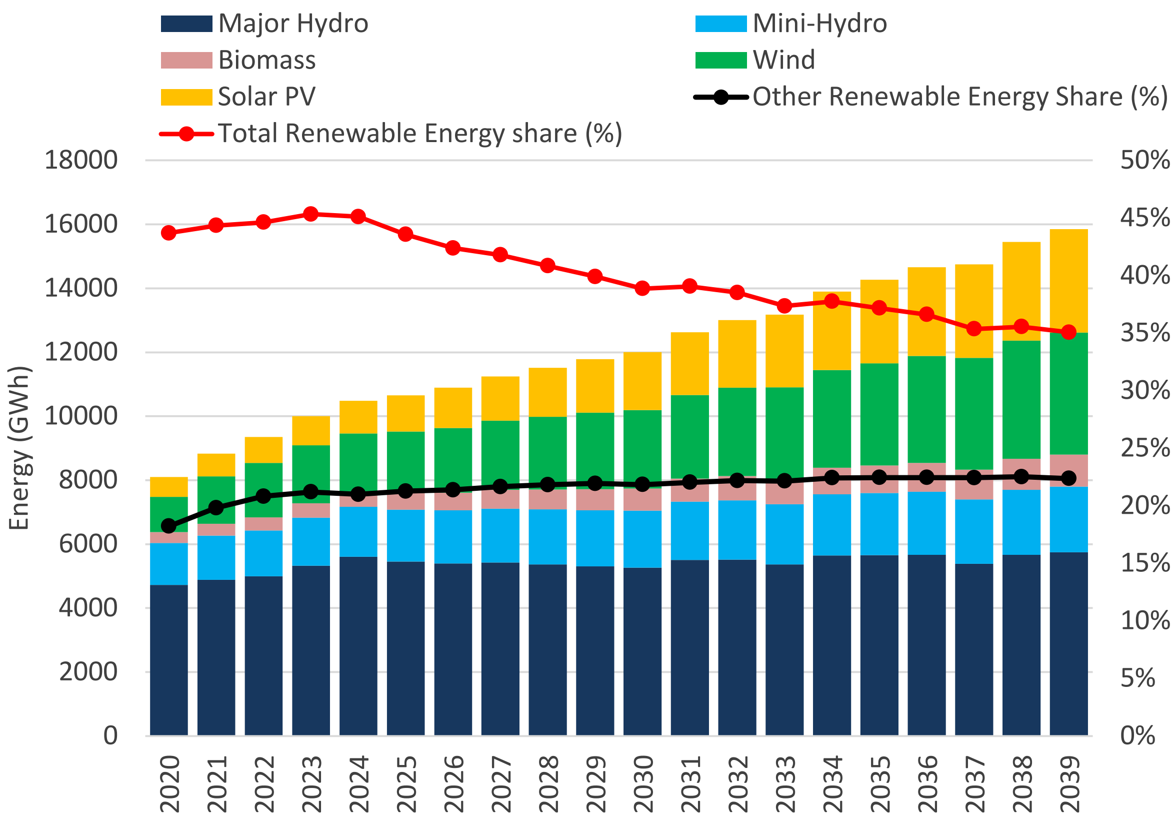


Figure 5.3: Energy Contribution of Renewable Energy Sources and Energy Share for Next 20 Years

The total renewable energy share continues to be significant over the next 20-year period mainly due to scaling up of integration of other renewable energy technologies. ORE contribution increases with the system growth and maintain optimum share of more than 20% energy share beyond 2020. ORE contribution will exceed the major hydro energy production beyond 2025 and will dominate the renewable energy sector. Mini hydro is the largest energy contributor in the other renewable energy sector at present. It will be surpassed by wind in 2021 with the projected development and continue to be the largest contributor in other renewable energy category for the entire planning period. Solar capacity will rapidly grow than wind and its energy contribution will grow steadily over the planning period with the projected development. However, owing to its lower plant factor, its energy share will be lower than mini-hydro and wind in initial 10 years and the subsequently solar will become the second largest energy contributor in ORE category beyond 2030.

5.4.2 Wind Power Development

Sri Lanka is blessed with quality wind resources mainly located in the North-western coastal area, Northern area and central highland area. Mainly greater wind power potential (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 various 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. Harnessing the exploitable wind power potential is then subjected to various technical constraints such as power systems stability, power system operation, seasonality and variability. This technical potential is defined by the renewable energy grid integration study conducted by the Ceylon Electricity Board. In the next 20-year period, Mannar and Northern areas will be focused for wind power development at large scale and the Puttalam, Eastern and central highland areas are will contribute to small to medium scale wind power resource development. Sri Lanka Sustainable Energy Authority has identified resource locations for large scale wind power development in Mannar, Jaffna peninsula, Kokilai and Puttalam areas. Both public and private engagement in developing these resources is taking place and at present competitive pricing mechanisms are increasingly being followed in developing this power projects. Five resource regimes mentioned above have been considered in the detailed study process with actual site characteristics and the expected capacity factors of those wind regimes are given in the table 5.7 below. Additionally, the main results of wind resource modelling results are illustrated in the Annex 5.5.

Table 5.7 – Wind resource regimes and expected annual capacity factors

Wind Regime	Annual Capacity Factor (%)
Northern	34.1
Mannar	36.7
Puttalam	32.1
Eastern	27.3
Central Highland	19.1

5.4.2.1 Development of Mannar Wind Farm Project

Ceylon Electricity Board is currently engaged in developing a large scale wind farm project in the Mannar island located in the northern province. The project is located in the southern coast of the Mannar island and the necessary wind farm infrastructure will be developed under the project. Being one of the attractive wind resources in the country, this 100MW is expected to generate annually around 337GWh.

Ceylon Electricity Board received financial assistance from Asian Development Bank (ADB) for the development of this key project. At present, the feasibility study, Environmental Impact Assessment (EIA) and land procurement process have been finalized and the site construction work commences in the first quarter of 2019. Project completion and commercial operation is expected in the year 2020.

5.4.2.2 Development of Pooneryn Renewable Energy park

Ministry of Power, Energy and Business Development together with Sri Lanka Sustainable Energy Authority and Ceylon Electricity Board have taken the new initiative to develop a large scale renewable energy park at the Pooneryn site located in the northern province. Preliminary studies are currently in progress for both renewable energy park and associated transmission infrastructure. According to the initial assessments, the park will produce 250MW wind power and 150MW of solar PV generation.

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. Exploitation of available resource requires the consideration of competing land uses and availability of transmission and distribution infrastructure.

Solar Photovoltaic development in Sri Lanka has been gaining momentum with the falling technology costs and global trends in the improvement in solar PV technology as a clean form of energy resource. At present, with the facilitation of Ministry of Power, Energy and Business Development (MOPEBD), Ceylon Electricity Board (CEB) and Sri Lanka Sustainable Energy Authority (SLSEA), development of grid scale solar PV power projects, small scale distributed solar PV projects and rooftop solar PV installations are achieving significant growth in commercial scale. Distributed solar PV resource development has its own advantageous and challenges that require careful consideration. 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. Solar PV resource development activities are currently progressing in following areas and novel applications such as floating Solar PV are being evaluated.

Two main solar resource regimes of the country have been considered for the assessment of medium to large scale solar PV applications and multiple resource locations have been considered for assessing small scale distributed solar PV applications. Expected annual capacity factors of resource regimes considered in the planning study are given in the table 5.8 below and an extract of solar PV modelling results is given in Annex 5.6 for illustration purpose

Table 5.8 – Solar resource regimes and average capacity factors

Solar Regime	Average Annual Capacity Factor (%)
Killinochchi (Northern part of the island)	16.0
Hambanthota (Southern part of the island)	16.3
Distributed – (Average of Multiple locations)	17.1

Enhanced capacity factors can be achieved in solar PV projects by employing emerging improvements in applications such as tracking systems, bi-facial type solar modules and other design and operational features.

5.4.3.1 Development of Rooftop Solar PV Installations

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. Rooftop solar PV installations can significantly reduce the land use and environmental concerns particularly in urban and suburban areas with the availability of rooftop spaces. 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 introduced in Sri Lanka in 2010 by the Ministry of Power and Renewable Energy, Ceylon Electricity Boards (CEB) and Lanka Electric Company (LECO). This scheme allows any electricity consumer to participate as a producer to generate electricity with a renewable energy source for own usage as well as to export any excess energy. The installed capacity of the generating facility shall not exceed the contract demand of the customer. The 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. No financial compensation is paid for the excess energy exported by the consumer. The electricity bill is prepared taking into account the difference between the import and the export of energy. At present, country has about 14,700 such installations under Net metering scheme amounting to 106MW of solar power.

In view of further enhancing the renewable energy portfolio in the electricity generation in Sri Lanka, the Government of Sri Lanka (GOSL) has launched accelerated solar development program in 2016 to promote roof top solar installations in the country. The objective of the above program is to reach an installed capacity of roof top solar to 200MW by 2020. In order to support the GOSL's renewable energy promotional drive, the Net Metering Concept was further enhanced by introducing another two schemes.

"Net Accounting" concept is the second scheme initiated. It is an extension to the existing new metering scheme where consumer is compensated for the exported energy with a two tier tariff for 20-year period. The generating capacity of the facility is limited to the contract demand of the consumer and this scheme is limited only to solar power generation. The third scheme is the "Net Plus" scheme where the consumer can install a solar PV generation unit and all the generated energy will be exported to the grid. The installed capacity is limited to the contract demand of the consumer, unlike previous two schemes there is no linkage between the consumption and electricity generation. 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 schemes under Net Accounting and Net plus has reached 63MW at present bringing total rooftop solar PV capacity in the country to 169 MW.

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 under the projected solar capacity additions stipulated in Table 5.7. With the planned growth of rooftop solar PV capacity for future, it is essential to address the main technical challenges encounter by the distribution divisions to streamline the roof top solar PV program and to maintain the quality of the electricity supply to the consumers.

5.4.3.2 Development of Small Scale Distributed Solar PV Project development

Increased penetration level of solar PV generation which is intermittent by nature, introduces more variability into the system starting from finer time scale. One strategy to minimize the inherent variability challenge of solar PV resources is geographical distribution 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 across the system can reduce the overall variability levels experienced by the system. Strategy of geographical distribution is technically advantageous for solar PV grid integration and key study results on this is presented in the Annex 5.6.

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 BOO basis. Extending this initiative, its second phase was launched to develop 90 MW of 1 MW solar PV plants with improved contractual terms to provide more facilitation and flexibility to developers. As a results significant number of bids were attracted during this second phase of 1MW solar development projects. Projects from both phases are currently in progress at various stages in the project development activities. This initiative is expected to continue in future to develop 1 MW and 10 MW solar power plants in the country.

5.4.3.3 Development of large Scale Solar PV Parks

Large scale solar PV part development has its own advantageous in economies of scale and also technical challenges. Large scale solar PV park developments is planned for the future and initial assessments and planning work have been initiated for the Poonyryn, Siyambalanduwa in Moneragala areas. Further, Sri Lanka Sustainable Energy Authority has identified resource locations for large scale development in Trincomalee, Ampara, Monaragala, Hambantota, Kurunegala, and Anuradhapura areas in future years.

5.4.4 Mini-hydro Development

History of small hydro power generation in Sri Lanka spans over 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 until 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, which includes training & capacity building, pre-feasibility studies and resource assessments. The procedure for electricity purchases from Small Power Producers (SPPs) by the CEB was regularized beginning 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. Further National Energy Policy in 2006 has identified fuel diversify and energy security in electricity generation as a strategic objective and development of renewable energy projects was identified as a part of this strategy. In view of above action was taken to introduce a, three-tier tariff instead of avoided cost based tariff with effect from year 2008. All large-scale hydropower generation facilities are to be remaining under Government control for the foreseeable future and small hydro power plants development is carried out by the Private sector. 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 performed by carried out as part of the hydropower component 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 capacity in the country is 873MW. As at end 2018, the total grid connected Mini hydro capacity is 393.5 MW which comprises 368.5 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. The projection of future Mini-hydro capacity additions as per the table 5.7 and further capacity additions shall be considered project by project depending on the feasibility of implementation. Annex 5.6 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 residuals. Growing biomass as a fuel for Dendro power generation gained attention in the recent past and at the end of 2018 total biomass based capacity is 37 MW including both Dendro and agriculture waste based power generation. Evidently, the growth of the biomass capacity in the past has not achieved the planned progress providing firm capacity to. The biomass power plants have been treated as dispatchable power plants in the planning process and expected grow in capacity in the planning period.

Further capacity additions shall be considered project by project depending on the feasibility of implementation.

5.4.6 Municipal Solid Waste Based Power Generation

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

Ceylon Electricity Board and Sustainable Energy Authority have facilitated the development by providing a tariff and several Letters of intent (LOIs) have been issued for future developments. One 10 MW waste to energy project planned in Muthurajawela area has signed the standard power purchase agreement and currently in progress.

5.4.7 Other Forms of Renewable Energy Technologies

CEB has embarked upon developing other forms of new renewable energy sources with the recent initiative by requesting international proposals to develop new renewable technology applications such as Geothermal Energy conversion, Compressed Air based power generation, Ocean Thermal Energy Conversion (OTEC), Ocean Energy (Wave) conversion, Biogas power generation and other storage applications such as grid scale battery storages for energy shifting and hybrid systems consists of wind, solar PV and energy storage. This initiative is titles as Exotic energy development and is expected to bring new technological experience while developing indigenous renewable energy resources. Grid interconnection facilities will be facilitated provided by the Ceylon Electricity Board for above identified technologies. developed for the commercial scale operation.

5.4.8 Renewable Energy Grid Integration Study 2020 - 2030

The transition from a conventional generation technology to a power system with a higher share of variable renewable energy technologies creates new challenges. Assessment of technical, operational, economic aspects and identifying necessary integration measures is the key for enabling the effective utilization of renewable energy sources while maintaining a quality and reliable supply of electricity. The study "Integration of Renewable Based Generation into Sri Lankan Grid 2020-2030" [33] is carried out by Ceylon Electricity Board supplementing the long term expansion planning process mainly to investigate key challenges and to determine the technical and economic optimum levels of renewable energy based generation to the grid.

Non-dispatchable technologies such as wind and solar PV that are variable in nature have notable differences in performance compared to other dispatchable technologies such as Hydro power, and Biomass. Variability and uncertainty of wind and solar PV power generation creates challenges for the reliable operation of power system. Wind and solar PV resources are not contributory to the power system strength in terms of inertia creating power system stability challenges. Therefore, to determine these stability and operational constraints and to determine the necessary countermeasures, a detail and a power system stability analysis and a power system operation analysis were conducted in this renewable energy grid integration study.

The overall scope of the study covers the areas of renewable energy resource estimation, future renewable energy projection with optimized long term generation expansion planning, transmission infrastructure availability and development, system stability and operation, economics of integration. Further, operating reserve requirements and variable renewable energy curtailment requirement for planned ORE integration scenarios is assessed and impact of grid scale storage technologies such as pump storage hydro power on battery energy storages is also studied. WASP (Wien Automatic System Planning), SDDP (Stochastic Dual Dynamic Programming), NCP (Short-term dispatch simulation), SAM (System Advisor Model) and PSSE (Power System Simulation for Engineering) software tools are among the key tools used for performing this grid integration study and the outline of the study methodology is given in the Annex 5.4.

5.4.9 Development of Grid Scale Storage Technologies

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 and Ceylon Electricity Board has identified the requirement of developing the pumped hydro power project as a long term solution to increase power system flexibility and also CEB is currently embarking upon developing grid scale battery energy storages to enhance the quality of the supply of electricity.

5.4.9.1 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. Primarily function of pumped hydro storage was to provide peaking capacity releasing the stored energy and however the technology has now evolved to provide enhanced services to enable flexible grid operation especially with renewable energy integration.

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

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

Mainly load following capability and power plant characteristics, environmental and social considerations and economic aspects of above options were evaluated and the study concluded that the Hydro Plant Capacity Extensions and Pump Storage Hydro Power Plants are the most suitable options for future development. The scope of the Study “Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka” includes the identification of most promising candidate site for the future development of pump storage power plant.

Pumped storage hydro power plant as a large scale storage medium 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 efficient operation of base load power plants in the system. 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 seasonally and intermittency 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 pumped hydro storage project and to employ the adjustable speed type technology to archive 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 Pump Storage Power Plant and all the sites were investigated and ranked in terms of Environmental, Topographical, Geological and Technical aspects. The preliminary screening process identified three promising sites for the detailed site investigations. 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 Pump Storage power plant should be 600MW considering the peaking requirement beyond 2025.The unit capacity of pump storage power plant was determined considering the System limitations in terms of frequency deviations and manufacturing limitations of high head turbines. The study considered 200MW unit size for the baseline case and the final unit size will be decided after further assessments. A 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 new scheme is located in the Kandy district adjacent to the Victoria reservoir. In this newly proposed project, the existing Victoria reservoir serve as the lower pond and an existing irrigation pond located on the eastern side of Victoria reservoir act as the upper pond after expansion. The site has the potential to develop a pumped hydro storage power plant with a total capacity of 1400 MW and staged development is proposed in the study. Figure 5.4 below illustrates the proposed sited under two studies mentioned above and the table 5.9 shows the estimated capital cost of development for proposed sites locations under two studies.

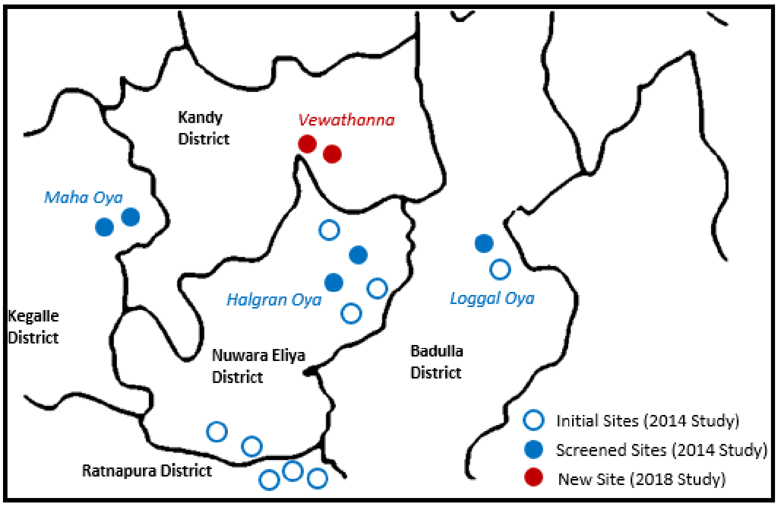


Figure 5.4: Three Selected Sites for PSPP after Preliminary Screening

Table 5.9 – Estimated capital cost of development for proposed PSPP sites locations

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***	***1055.8***	***1306.9***	***5.0***	***50***
Proposed site (2018 study)[2]	***1400***	***649.0***	***803.33***	***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 [29]
2. Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka" carried out by JICA in March 2018 [20]

5.4.9.2 Development of Grid Scale Battery Energy Storages

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 hydro 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 and 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 is currently evaluating the option of introducing the grid scale battery energy storages mainly in the areas of,

- Energy arbitrage services
- Frequency support services
- Ramp Rate Control
- Solar Smoothing,
- Solar Firming
- Solar Shifting

CHAPTER 6
GENERATION EXPANSION PLANNING METHODOLOGY AND PARAMETERS

CEB considers the project options from all possible sources including CEB owned generation developments, large thermal plants from the independent power producers and other renewable energy sources in order to meet the system demand. Several factors are taken in to account in this process of selecting the appropriate power development project. Commercially exploitable potential, technical feasibility studies, operational & dispatch studies, environment impact assessment and economic feasibility are the main factors of this selection process.

Together with these factors, the Draft Grid Code of CEB Transmission Licensee, Planning Guidelines issued by the Ministry of Power and Energy, General Policy Guidelines on the Electricity Industry for the Public Utilities Commission of Sri Lanka, National Energy Policy and Cabinet approval on "Deciding of the Composition of Electricity Generation of Sri Lanka" is taken into consideration in the planning process.

Long Term Generation Expansion Plan is the outcome of the selection process. The methodology adopted in the process is described in this chapter.

6.1. Generation Planning Code

Draft Generation Planning Code in the Grid Code issued by the Transmission Division of CEB (August 2015) [34] is considered in preparing the Long Term Generation Expansion Plan 2020-2039.

6.2. National Energy Policy and Strategies

Ministry of Power and Energy gazette the National Energy Policy & Strategies of Sri Lanka in June 2008 [35]. This document spells out the implementing strategies, specific targets and milestones through which the Government of Sri Lanka and its people would endeavor to develop and manage the energy sector. Specific new initiatives are included in this policy to expand the delivery of affordable energy services to a larger share of the population, to improve energy sector planning, management and regulation.

The "National Energy Policy and Strategies of Sri Lanka" is elaborated in three sections in this policy document as follows:

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

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

- Providing Basic Energy Needs

- Ensuring Energy Security
- Promoting Energy Efficiency and Conservation
- Promoting Indigenous Resources
- Adopting an Appropriate Pricing Policy
- Enhancing Energy Sector Management Capacity
- Consumer Protection and Ensuring a Level Playing Field
- Enhancing the Quality of Energy Services
- Protection from Adverse Environmental Impacts of Energy Facilities

National Energy Policy and Strategies of Sri Lanka should be reviewed and revised after a period of three years. A new 'National Energy Policy and Strategies of Sri Lanka' is being drafted by relevant authorities which further enhances the existing policy guidelines.

The draft final version of new National Energy Policy has elaborated on the following ten pillars , in the broad areas impacting the society, economy and the environment

- 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 Future Energy Infrastructure
- Providing Opportunities for Innovation and Entrepreneurship

During the Preparation of Long Term Generation Expansion Plan 2020-2039, due consideration is given to salient features of new National Energy Policy pillars.

6.3 Policy on Composition of Electricity Generation of Sri Lanka

Considering the importance of Energy security, a joint Cabinet Memorandum was submitted by Minister of Power and Renewable Energy and Minister of Special Assignments Titled "Deciding of the Composition of Electricity Generation of Sri Lanka" and approval of the Cabinet was received on 9th May 2018. The new Government Policy as per the approved Cabinet Decision No 18/0864/727/020 based on nine principals [36].

Subsequently the referring to the new government policy directives, the General Policy Guidelines on the Electricity Industry for the Public Utilities Commission of Sri Lanka was also amended in March 2019 under section 5 of Sri Lanka Electricity Act N0 20 of 2009. [37]

Long Term Generation Expansion Plan 2020-2039 has incorporated the new government policy directives in preparation of the plan.

6.4 Preliminary Screening of Generation Options

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

Details of the screening curve methodology are given in Annex 6.1. The results of the screening curve analysis are explained in section 8.1 in Chapter 8. The detailed planning methodology described in section 6.4 to section 6.7 is used to finalize the Least Cost Generation Expansion Plan.

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

6.5.1 SDDP and NCP Models

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

The potential of hydropower system estimated using SDDP model is used. Hundred scenario outputs of SDDP were rearranged and divided into five hydro conditions, Very Wet, Wet, Average, Dry and Very Dry considering probability levels.

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

6.5.2 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.

6.5.3 WASP Package

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

6.5.4 MESSAGE Software

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

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

6.5.5 OPTGEN Software

Generation Planning Section uses the OPTGEN software developed by PSR (Brazil) as a new long term expansion planning model that determines the least cost sizing and timing decisions for construction, retirement and reinforcement of generation capacities and transmission network. The model optimizes the trade-off between investment costs to build new projects and the expected value of operative costs obtained from SDDP, the transmission constrained stochastic hydrothermal dispatch model, which allows a detailed representation of the system's operation under uncertainty. 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.

6.6 Hydro Power Development

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

6.7 Assessment of Environmental Implications and Financial Scheduling

Though the environmental effects of each thermal and hydro option are considered in the initial selection, overall assessment of environmental implications is carried out for the proposed LTGEP. The plant emissions are assessed after the possible environmental mitigation measures are taken. Other two aspects of the planning process are the implementation and financing. In fact, the total period of implementation of a project including feasibility studies varies approximately from 4 years for a gas turbine, 6 years for a LNG power plant and 8 years for a coal-fired plant. Similarly, implementation period of a hydro plant is in the range of 7 to 8 years. Therefore, implementation scheduling is an important item of the planning process. Furthermore, generation system expansion is highly capital intensive. Therefore, financial schedule is prepared in order to identify the financial requirement which is essential for sourcing of funds and for projecting electricity tariffs.

6.8 Modeling of Other Renewable Energy

According to the Grid Code, only the existing ORE plants are considered as committed in the Reference Case. However, a optimum projected development was considered and incorporated in to the Base Case of the LTGEP. The main technologies of ORE; mini-hydro, wind, solar and dendro were modeled.

A comprehensive ORE integration study was conducted by CEB to determine integration of ORE resources prior to preparation of the LTGEP 2020-2039 as described in chapter 5. Mini hydro, Wind and solar additions were projected annually and taking into account the actual resource profiles of Mini hydro, wind and solar.

Initial screening is done considering the policy directives to incorporate renewable energy targets and system modelling is carried out to considering the economics of dispatching. In final stage renewable additions are verified with transmission network constraints to configure the optimum renewable additions per year.

6.9 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 Softwares. Parameters and constraints given in Grid Code were used in the studies and those are described in detail.

6.9.1 Study Period

The results of Base Case and all sensitivity studies are presented in the report for a period of 20 years (2020-2039). In this regard, the studies were conducted for a period of 25 years (2020-2044).

6.9.2 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 180.10 LKR/USD. This is the average value of December 2018 exchange rates. All costs are based on 1st of January 2019.

6.9.3 Plant Commissioning and Retirements

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

6.9.4 Cost of Energy Not Served (ENS)

The average loss to the economy due to electrical energy not supplied has been estimated as 0.745 USD/kWh (in 2019 prices). This value has been derived by escalating the ENS figure given by PUCSL as 0.5 USD/kWh in 2011.

6.9.5 Reserve Margin

Reserve margin is the a reliability criteria which is the measure of the generation capacity available over and above the amount required to meet the system load requirements.
In preparation of LTGEP, the Reliability criteria of having increased Reserve Margin was considered as per the instructions of Ministry of Power, Energy & Business Development and Decision of CEB Board. Power Plant development is optimized between 10% (Minimum) and 25% (Maximum) Reserve Margin.

The LTGEP is prepared accordingly and shall incorporate instances of which engineering judgements have to be made considering the appropriate unit sizes, optimum usage of available lands, conservation of the environment etc.

6.9.6 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 compatibility of values for Reserve Margin and LOLP are interdependent. The LTGEP is prepared in adherence to maintaining the LOLP values to a maximum of 1.5%. This corresponds to cumulative failure duration of 5.5 days/year for the generating system.

LOLP shall vary with the Hydro conditions, thus maximum LOLP shall be complied during all conditions including the driest hydro conditions in preparation of LTGEP. 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.

6.9.7 Discount Rate

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

6.9.8 Plant Capital Cost Distribution among Construction Years

The distribution of plant capital cost among construction period is carried out by assuming "S" curve function relating expenditure to time based on 10% discount rate. The resultant annual cost distributions for individual power plants are given in the Investment Program shown in Annex 12.1 and Annex 12.2 in Chapter 12. However, optimization process considers only the total cost and is not affected by this cost distribution.

6.9.9 Assumptions and Constraints Applied

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

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

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

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

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

Table 6.1 Committed Power Plants

Power Plant	Capacity (MW)	Year of Operation
Thermal		
LNG operated Combined Cycle Power Plant	300	2022 (Identified in LTGEP 2015-2034 and LTGEP 2018-2037 to be commissioned by 2019)
Furnace Oil based Thermal Power Plant	4x24	2021
Kelanitissa Gas Turbines	130	2021
Hydro		
Uma Oya HPP	122	2021
Broadlands HPP	35	2020
Moragolla HPP	30.2	2023
ORE		
Mannar Wind Power Plant	100	2020

e) As per the approved LTGEP 2018-2037, Cabinet has granted approval for 300 MW LNG Combined Cycle Plant in 2021 to be accommodated from ongoing tender for 300 Duel Fuel Combined Cycle Plant in 2019, subjected to the Attorney Generals clearance. CEB has initiated the studies to commission 300MW High Efficient Coal Power Plants in 2023 as an extension of the Lakvijaya Coal Power Plant.

f) 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)	Year of Operation
Thermal		
Reciprocating Engines	15	2021
Gas Turbine	45	2022
Diesel operated Combined Cycle Plant	300	2023
LNG operated Combined Cycle Plant	150 / 300	2023
High Efficiency Coal Plant	300	2024
Supercritical Coal Plant	600	2030
LNG operated Combined Cycle Plant	600	2030
Nuclear Power Plant	600	2030
Hydro		
Seethawaka Ganga HP	24	2023
Thalpitigala HPP	15	2024
Pumped Storage Power Plant	3x200	2028

g) 5MW Dendro Power Plant is modeled from the data received from Sustainable Energy Authority. The integration capacity of Dendro Power Plants is not limited but could be considered on project by project basis depending on the feasibility.

h) The integration of Mini Hydro capacity is not limited but could be considered on project by project basis depending on the feasibility.

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

j) All new ORE Plants are capable to curtail the generation when necessary.

k) The development of Required LNG Infrastructure will be available by 2021 for importing Natural Gas.

l) Plant Retirements of CEB owned and IPP plants are given in Table 6.3.

Table 6.3 Plant Retirement Schedule

CEB Power Plants	Year	IPP Power Plants	Year
1. Kelanithissa Frame5 GTs *	2023	1. Sojitz Combined Cycle Plant	2023
2. Kelanithissa GT7	2023	2. Kerawalapitiya West CCY Plant	2035
3. Sapugaskanda PS A (4 units)	2024		
4. Sapugaskanda PS B (4 Units) (4 Units)	2023 2026		
5. Barge Mounted Power Plant	2025		
6. Kelanithissa Combined Cycle	2033		

* Retirement year shall be reviewed with the actual implementation year of Kelanitissa New Gas Turbines.

m) The contract of 163 MW Sojitz Power Plant at Kelanitissa will expire in 2023 and it will be operated as a CEB plant until 2033.

n) Provision for further extension beyond 2023 for KPS GT7 will be evaluated based on the extent of refurbishment of existing machine.

o) All alterations conducted to planning parameters in preparation of revised base case plan are described in Addendum (Annex 15)

CHAPTER 7
GENERATION EXPANSION PLANNING STUDY DEVELOPMENT OF THE REFERENCE CASE

This chapter presents the analysis results of the Reference Case for 2020-2039 planning horizon in detail including capacity additions, system energy share, dispatch and annual CO_2 emissions. Reference case implications for climate change mitigation related studies and applications are discussed in detail in Chapter 10.

7.1 Introduction

The Reference Case 2020-2039 was developed by following the Draft Generation Planning Code in the Draft Grid Code issued by the Transmission Licensee for the Long Term Generation Expansion Plan. Accordingly, it exclude any policy guideline on generation technology options that would cause the plan to deviate from least cost. In addition, it considers existing power plants already in operation and the committed renewable energy power plant (Major hydro and ORE) capacities as at 1st January 2019.

7.2 Reference Case Plan

The Reference Case Plan is given in Table 7.1 and The total present value (PV) cost of the Reference Case Plan for the period 2020-2039 is USD 16,284 million (LKR 2,932.67 billion in January 2019 values based on the discount rate of 10%).

Table 7.1: Generation Expansion Planning Study – Reference Case (2020-2039)

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2020	*Wind 100 MW (Mannar Wind Park)* Major Hydro *35 MW (Broadlands HPP)*	*320 MW Reciprocating Engine Power Plants** (Identified in LTGEP 2018-2037 to be commissioned by 2018) **Additional Capacity Requirement from Contingency Analysis = 345 MW Reciprocating Engine Power Plants** (Above capacities include the extension of existing power plants)	6 x 5 MW Northern Power	0.614
2021	Major Hydro *122 MW (Uma Oya HPP)*	*130 MW Gas Turbine* ⁺ **Additional Capacity Requirement from Contingency Analysis = 105 MW Reciprocating Engine Power Plants**	-	0.353
2022	-	*1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region* (Identified in LTGEP 2015-2034 and LTGEP 2018-2037 to be commissioned by 2019) **1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** (Identified in LTGEP 2018-2037 to be commissioned by 2021)	450 MW Reciprocating Engine Power Plants (Includes the expiry of extended power plant contracts)	0.696
2023	Major Hydro *31 MW (Moragolla HPP)*	**2x300 MW New Coal Power Plant (Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2)* •	4x17 MW Kelanitissa Gas Turbines 115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.192
2024	-	**1x300 MW Natural Gas fired Combined Cycle Power Plant** **1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	4x17 MW Sapugaskanda Diesel**	0.038
2025	-	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	4x15.6 MW CEB Barge Power Plant** 220 MW Reciprocating Engine Power Plants *	0.210
2026	-	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	4x9 MW Sapugaskanda Diesel Ext.**	0.218
2027	-	-	-	0.776
2028	-	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	-	0.624
2029	-	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	-	0.563
2030	Major Hydro 200 MW (Pumped Storage Power Plant)	-	-	0.696
2031	-	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	-	0.712
2032	-	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	-	0.777
2033	-	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** **1x150 MW Natural Gas fired Combined Cycle Power Plant** **1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2) 3 x 8.93 MW Uthuru Janani Power Plant	0.688
2034	-	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	-	0.656

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2035	-	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** **1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	300MW West Coast Combined Cycle Power Plant	0.587
2036	-	**1x300 MW Natural Gas fired Combined Cycle Power Plants**	-	0.650
2037	-	**1x300 MW Natural Gas fired Combined Cycle Power Plants**	-	0.738
2038	-	**1x300 MW Natural Gas fired Combined Cycle Power Plants**	-	0.841
2039	-	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	-	0.987
Total PV Cost up to year 2039**, USD 16,283.75 million** [LKR 2,932.67 billion] °				

GENERAL NOTES:

* To meet the demand from year 2020 until major power plants are implemented and out of total 320 MW only 100 MW would continue beyond 2025 as backup power plants to provide the secure supply during the contingency events. As of 2019, 170MW out of 320MW has been added to the system as extension of existing power plants.

** Retirement of these plants would be evaluated based on the plant conditions.

+ The plant has duel fuel capability and would be operated with Natural Gas.

• Sojitz Kelanitissa is scheduled to be retired in 2023 will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2021 with the development of LNG based infrastructure.

° PV cost includes the cost of projected ORE development, USD 325.5 million based on economic cost.

✓ Committed plants are shown in Italics. All plant capacities are given in gross values.

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 is heavily depend on the thermal based generation system with the limitations of renewable based energy to cater the increasing electricity demand over the planning horizon.

Table 7.2: Capacity Additions by Plant Type – Reference Case (2020-2039)

Type of Plant	2020-2024 (MW)	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	Total capacity addition (MW)	%
Major Hydro	188	-	-	-	188	3%
Pumped Hydro	-	-	200	-	200	3%
Gas Turbines	130	-	-	-	130	1%
Coal	900	1200	1200	600	3900	55%
NG CCY	900	-	450	1200	2550	36%
Reciprocating Engine	320*	(-220)	-	-	100	1%
ORE	100	-	-	-	100	1%
Total	**2538**	**980**	**1850**	**1800**	**7168**	**100%**

*This figure represents the net capacity addition for the period

According to the above, Reference Case Plan comprised major thermal power plants including 3900MW of Coal based power plants and 2550MW NG based combined cycle power plants. In the year 2039, the share of Coal based capacity addition is 55% while natural gas based capacity is around 36%. When compared with the Base Case plan, the Reference Case contains additional Coal based power plants to compensate for the energy contribution from 3325MW of ORE plants in the Base Case plan.

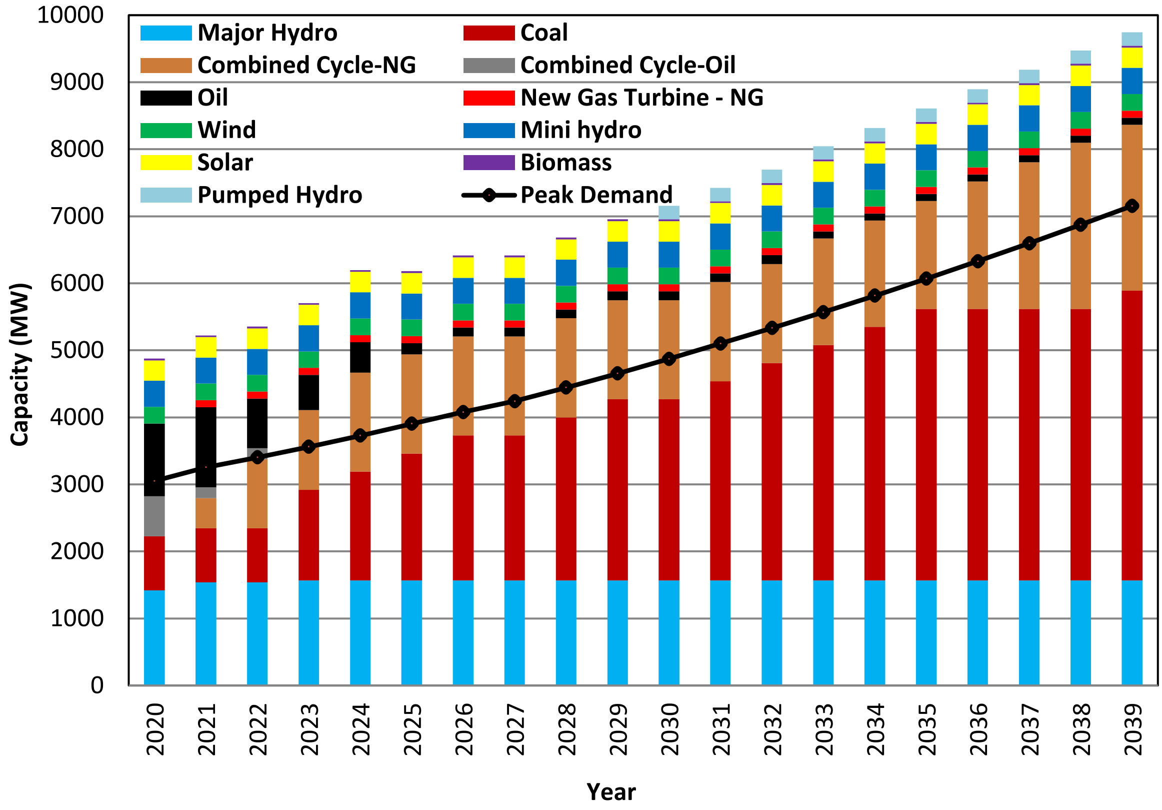


Figure 7.1 - Cumulative Capacity by Plant Type in Reference Case

7.2.2 System Energy Share

Future energy supply mix of the Reference Case is graphically represented in Figure 7.2. The hydro generation share slightly increases with addition of committed hydro power plants during initial four years of the planning period and thereafter continues to contribute at the same level. Energy contribution from ORE also remain at constant over the planning horizon.

With the introduction of Natural Gas fired Combined Cycle power plants to the system in year 2022, Coal and NG share for the energy contribution comes to the same level. Beyond 2023, Coal and NG become the major energy contributors of the system and the Coal energy share gradually increases with the addition of new Coal power plants to cater the increasing national demand. Coal energy share is 22% in 2020 and will gradually increase up to 65% by 2039. NG based Combined Cycle plants contribute to energy share over the planning period with 15% ~ 22% with the addition of power plants over the planning horizon. As shown in the Figure 7.2, other thermal based power generation including combined cycle, gas turbine and other oil power plants decreases to around 1% by 2039.

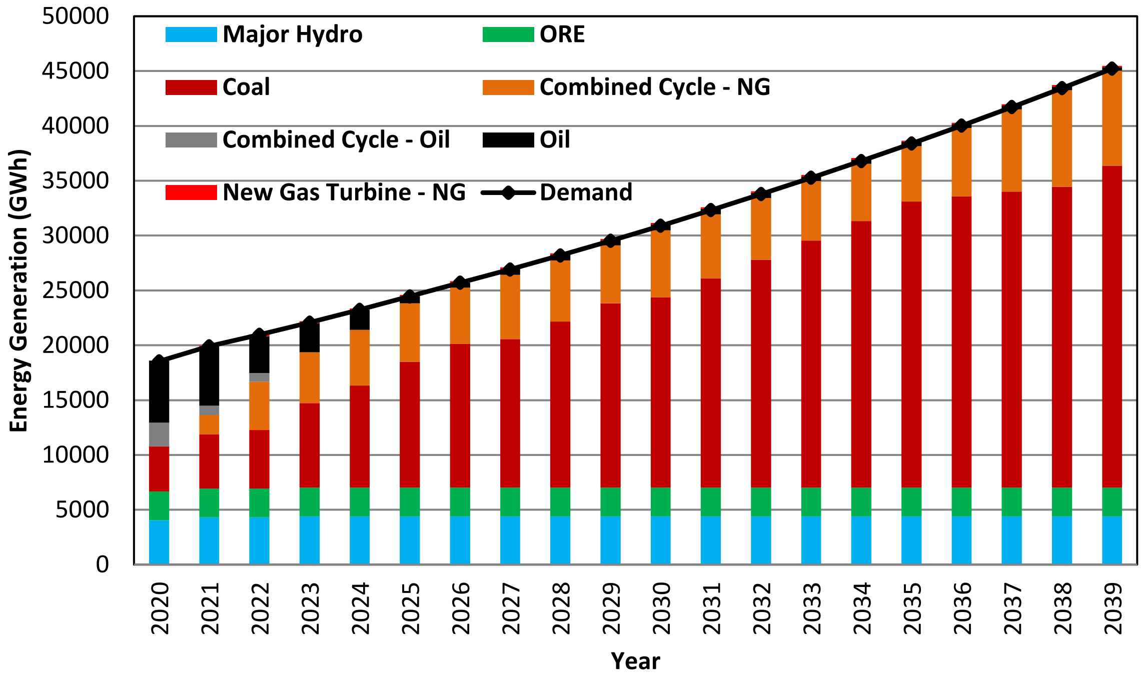


Figure 7.2 – Energy Mix over next 20 years in Reference Case

Compared with the Base Case plan, Reference case shows the USD 391 million PV cost decrement over the planning horizon.

7.2.3 Environmental Emissions and Implications

Reference Case contains additional Coal based power plants to compensate for the contributions from 3325MW ORE, 450MW NG fired Combined Cycle, 400MW Pumped Storage Hydro and 39MW Major Hydro Power Plants in the Base Case plan. Accordingly, the reduction in CO_2 emissions to be achieved with the inclusion of ORE, additional hydro and low emission thermal power plants in the Base Case plan and the expected reduction is presented in Table 7.3.

Table 7.3: Reduction in Annual CO_2 Emissions in Base Case Plan (In CO_2 million tons)

Year/Scenario	2025	2030	2039
Reference Case	14.2	19.6	31.2
Base Case	12.3	15.9	24.4
Difference	**1.9**	**3.7**	**6.7**

Further, the Reference case implications for climate change mitigation related studies and initiatives are discussed in detail in Chapter 10.

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

This chapter presents the results of the Base Case analysis for 2020-2039 planning horizon in detail. Results on Environmental Impacts of Base Case analysis are discussed in the Chapter 10.

8.1 Results of the Preliminary Screening of Generation Options

For the preliminary screening of alternative options, two coal fired steam plant technologies, , one Natural Gas -fired gas turbines, one oil fired combined cycle power plants, three Natural Gas fired combined cycle plants, an oil fired reciprocating engine and a Nuclear Power plant were considered. For evaluating alternative generation technologies with varying capital investments, operational costs, maintenance costs and life time, it is necessary to employ an indicator common for all plants. Specific generation cost expressed in US Cents/ kWh calculated at different plant factors for each plant was used to screen the initial alternatives before carrying out the detailed expansion planning studies. Discount rate of 10%, which is considered as the base discount rate for the National Planning studies, is used for the above screening process and the sensitivity of the preliminary screening is tested for 3% and 15% discount rates. The specific generation costs for selected thermal plants calculated for 10% discount rate is shown in Annex 8.1.
From the screening curve analysis, the following candidate technologies were selected as suitable options for detailed generation expansion planning studies.

- 45MW Natural Gas fired gas turbine
- 300MW Auto Diesel fired combined cycle power plant
- 300MW High Efficient Coal fired thermal power plant
- 600MW Super Critical Coal power plant
- 150MW NG fired combined cycle power plant
- 300MW NG fired combined cycle power plant
- 600MW NG fired combined cycle power plant
- 600MW Nuclear Power plant
- 15MW Furnace oil Reciprocating Engine

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

In addition to the above alternatives derived from the screening analysis, 3x200MW Pump Storage Power Plant (PSPP) was introduced to the system. Introduction of PSPP was based on the results of two studies, “Development Planning on Optimal Power generation for Peak Demand in Sri Lanka” [29] and “Integration of Renewable Based Generation into Sri Lankan Grid” [33]. In the base case plan, PSPP is proposed to be added to the system to enable the storage of surplus renewable energy that would have curtailed due to power system operational limitations, to enable the efficient operation of base load power plants in the system during low load periods and to enable greater utilization of renewable energy resources by using adjustable speed type technology in PSPP.

8.2 Government Policy on Composition of Electricity Generation

When developing the Base Case Plan, special consideration was given to the joint Cabinet Memorandum titled "Deciding of the Composition of Electricity Generation of Sri Lanka" and approved by the Cabinet on 9th May 2018.

The government policy directive based on the above cabinet memorandum contains nine (09) principles regarding the future electricity mix of the country proposed through LTGEP. The energy mix proposed through the Base Case Plan of LTGEP 2020-2039 has considered these principles and aligned the base case along with the salient points included in the 09 principles as indicated below.

1. Giving due consideration for environmental conservation in deciding the energy mix and to have an energy mix comprising of different firm energy sources for strengthening the economy and ensuring energy security.

2. Maintaining electricity generation cost at minimum possible, as it is required to keep the electricity expenses at minimum levels in order for Sri Lanka to compete with the global economy.

3. As it is required to diversify the energy mix to the maximum feasible level adopting sophisticated technologies in the world, to accept in principle the necessity of strategically developing all the practically developable energy sources, and exploiting the non-conventional alternative renewable energy sources such as solar power, wind power, biomass, geothermal, wave and solid waste and high efficient coal power technologies, LNG, indigenously available natural gas and nuclear power in timely and appropriate manner.

4. Considering renewable energy development as a prime policy of the Government, meeting 50% of the electricity requirement on the country using major hydro power plants and non-conventional renewable energy sources under favourable weather conditions

5. Developing the non-conventional renewable energy sources to the maximum feasible level, meeting around 1/3 of the electricity requirement of the country (2,500 MW) using non-conventional renewable energy sources by 2030.

6. As the new technologies like storage of renewable energy are fast developing, planning the future power plants with the goal of realizing self-sufficiency in the electricity sector by 2050.

7. In order to ensure energy security, meeting around 2/3 of the electricity generation using firm power sources such as LNG, coal, fossil fuel and large hydro.

8. As it is essential to maintain the firm power capacity using a practical and a balanced energy mix, the firm power capacity mix to be met by 2030 using 30% LNG or indigenous natural gas, 30% high efficient coal power, 25% large hydro, 15% furnace oil which is a by-product from the refineries in the country and also non-conventional renewable energy sources which can be used for firm power.

9. Accepting minimizing the Carbon Foot Print of the electricity sector through carbon sequestration using reforestation as an important principle in electricity generation.

The base case plan proposes a diversified energy mix with several firm energy sources such as Coal, Natural Gas, Large Hydro, Furnace Oil and Other Renewable Energy (pumped storage, ORE with battery etc.). Development of these different types of sources were optimized and the above diverse firm energy mix consisting of both imported and indigenous resources paves way to ensuring the energy security of the country. Also, the base case plan has been developed under the least cost principles complying with all the duly approved (committed) government policies and Transmission Licensee’s guidelines to conform to the operational requirements of the power system.

Due consideration was given for the environmental conservation while developing the base case plan and it is extensively discussed in Chapter 10 including the reforestation programme to minimize the Carbon footprint of the electricity sector.

Priority was given to developing the maximum feasible renewable energy sources which is explained in detail in Chapter 5. The capacity of ORE in the system by 2030 is 2700 MW (30% of total installed capacity) and this capacity increases up to 4330 MW by 2039. Energy storage options such as pumped storage power plant and battery storage systems are included in the Base Case to ensure the maximum utilization of ORE.

The firm capacity share of the Base Case has been maintained as per the above principles and it is graphically presented in Figure 8.4.

From the perspective of thermal generation options considered in the planning horizon, high efficient coal power technologies, natural gas based power plants and nuclear power technology has been evaluated in Chapter 4.

8.3 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. In this study, committed power plants have been fixed according to the present implementation schedules.

The total present value (PV) cost of the Base Case Plan including the cost of development of ORE for the period 2020-2039 is USD 16,675 million (LKR 3,003.07 billion) in January 2019 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 (e.g. loan repayment of CEB plants or capacity payment to IPP plants) are not reflected in the total least cost of the system (PV) which is the optimized result of expansion studies.

Table 8.1– Generation Expansion Planning Study - Base Case (2020 – 2039)

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2020	Major Hydro *35 MW* *(Broadlands HPP)* *Wind 100 MW (Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 100 MW Biomass 5 MW	*320 MW Reciprocating Engine Power Plants** (Identified in LTGEP 2018-2037 to be commissioned by 2018) **Additional Capacity Requirement from Contingency Analysis = 345 MW Reciprocating Engine Power Plants** (Above capacities include the extension of existing power plants)	6 x 5 MW Northern Power	Refer Contingency Analysis for details
2021	Major Hydro *122 MW* *(Uma Oya HPP)* Mini Hydro 20 MW Wind 120 MW Solar 60 MW Biomass 5 MW	*130 MW Gas Turbine +* **Additional Capacity Requirement from Contingency Analysis = 105 MW Reciprocating Engine Power Plants**	-	
2022	Mini Hydro 20 MW Wind 70 MW Solar 60 MW Biomass 5 MW	*1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region++* (Identified in LTGEP 2015-2034 and LTGEP 2018-2037 to be commissioned by 2019) **1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region++** (Identified in LTGEP 2018-2037 to be commissioned by 2021)	470 MW Reciprocating Engine Power Plants (Includes the expiry of extended power plant contracts)	0.238
2023	Major Hydro *31 MW* *(Moragolla HPP)* **24 MW (Seethawaka HPP)** Mini Hydro 20 MW Wind 40 MW Solar 60 MW Biomass 5 MW	**1x300 MW New Coal Power Plant ++** **(Change to Super critical will be evaluated)** **(Lakvijaya Extension Phase I)** **1x300 MW Natural Gas fired Combined Cycle Power Plant** *163 MW Combined Cycle Power Plant (KPS–2)•*	4x17 MW Kelanitissa Gas Turbines 115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.051
2024	Major Hydro **15 MW (Thalpitigala HPP)** Mini Hydro 20 MW Biomass 5 MW Solar 60 MW	**1x300 MW New Coal Power Plant ++** **(Change to Super critical will be evaluated)** **(Lakvijaya Extension Phase II)**	4x17 MW Sapugaskanda Diesel**	0.045
2025	Mini Hydro 20 MW Wind 40 MW Solar 80 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Lakvijaya Extension Phase II or Foul Point Phase I)** **1x300 MW Natural Gas fired Combined Cycle Power Plant**	4x15.6 MW CEB Barge Power Plant** 200 MW Reciprocating Engine Power Plants *	0.029
2026	Mini Hydro 10 MW Wind 35 MW Solar 90 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	4x9 MW Sapugaskanda Diesel Ext. **	0.025
2027	Mini Hydro 10 MW Wind 50 MW Solar 90 MW Biomass 5 MW		-	0.073
2028	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 40 MW Solar 100 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Foul Point Phase I)**	-	0.009
2029	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 40 MW Solar 100 MW Biomass 5 MW	-	-	0.007
2030	Mini Hydro 10 MW Wind 20 MW Solar 100 MW Biomass 5 MW	-	-	0.031
2031	Mini Hydro 10 MW Wind 60 MW Solar 100 MW Biomass 5 MW	-	-	0.143
2032	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Foul Point Phase II)**	-	0.024

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2033	Mini Hydro 10 MW Wind 35 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** **1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase II)**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2) 3 x 8.93 MW Uthuru Janani Power Plant	0.040
2034	Mini Hydro 10 MW Wind 70 MW Solar 120 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants**	-	0.030
2035	Mini Hydro 10 MW Wind 45 MW Solar 120 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	300MW West Coast Combined Cycle Power Plant	0.096
2036	Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants**	-	0.088
2037	Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase III)**	-	0.083
2038	Mini Hydro 10 MW Wind 70 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.080
2039	Mini Hydro 5 MW Wind 70 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase III)**	-	0.074
Total PV Cost up to year 2039, **USD 16,675 million** (LKR 3,003.07 billion)°				

GENERAL NOTES:

∗ To meet the demand from year 2020 until major power plants are implemented and out of total 320 MW only 100 MW would continue beyond 2025 as backup power plants to provide the secure supply during the contingency events. As of 2019, 170MW out of 320MW has been added to the system as extension of existing power plants.

** Retirement of these plants would be evaluated based on the plant conditions.

\+ The plant has duel fuel capability and would be operated with Natural Gas.

- Sojitz Kelanitissa is scheduled to be retired in 2023 will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2021 with the development of LNG based infrastructure.

° PV cost includes the cost of projected ORE development, USD 2274.04 million based on economic cost. Cost of battery storage is not included in the PV cost.

✓ Committed plants are shown in Italics. All plant capacities are given in gross values.

✓ Thalpitigala and Gin Ganga multipurpose hydro power plants are proposed and developed by Ministry of Irrigation. As a candidate power plant, Thalpitigala is scheduled to begin commercial operation by 2024 while feasibility studies are still being carried out for Gin Ganga project.

✓ Seethawaka HPP and PSPP units are forced in 2023, 2028, 2029 and 2032 respectively.

✓ Battery storage is proposed to be added to the system in phase development. (Total 50 MW by 2025 and 100 MW by 2030). Exact capacities and entry years will be evaluated during the detailed design stage of battery storage integration.

++ Refer Contingency Analysis for the impact from delays in implementation of power plants. The required transmission system reinforcements for the implementation of power plants are as follows:

In 2022, in order to connect first 300 MW Natural Gas fired Combined Cycle Power Plant – Western Region, completion of:

- Kerawalapitiya 220kV Switching Station
- Underground Transmission Network under Greater Colombo Transmission & Distribution Loss Reduction Project
- Rehabilitation of Colombo E and F Grid Substations
- New Polpitiya, Padukka Grid substations and New Polpitiya-Padukka-Pannipitya transmission lines

In 2022, in order to connect second 300 MW Natural Gas fired Combined Cycle Power Plant - Western Region, completion of:

- Kerawalapitiya-Port 2nd 220kV transmission line

- Kirindiwela 220kV/132kV grid substation and 220kV, Veyangoda-Kirindiwela, 400kV, Kirindiwela-Padukka and 220kV Kotmale-New Polpitiya transmission lines

+++ The required transmission system reinforcements for the implementation of 2023 and 2024 Coal power plants are as follows:

In 2023, in order to connect 300 MW New Coal Power Plant (Lakvijaya Extension Phase I), completion of:

- 220kV/132kV New Habarana Grid Substation and 220kV, New Habarana-Veyangoda transmission line
- Upgrading the New Habarana -New Anuradhapura 220kV transmission line

In 2024, in order to connect 300 MW New Coal Power Plant (Lakvijaya Extension Phase II), completion of:

- Wariaypola South 220kV Switching Station
- Transmission line from Lakvijaya New Coal Plant to proposed Wariyapola south switching station

Table 8.2: Generation Expansion Planning Study - Base Case Capacity Additions (2020 – 2039)

Year	Peak Demand (MW)	Capacity Addition (MW)								Existing Plant Retirements	LOLP %
		Gas Turbines	Reciprocating Engines	Coal	LNG	Major Hydro	Pumped Hydro	ORE	Total		
2020	3,050		665			35		340	1040	(30)	-
2021	3,254	130	105			122		205	537		-
2022	3,403		(470)		600			155	285		0.238
2023	3,561			300	300	55		125	780	(219)	0.051
2024	3,728			300		15		85	400	(68)	0.045
2025	3,903		(200)	300	300			145	545	(64)	0.029
2026	4,079				300			140	440	(36)	0.025
2027	4,241							155	155		0.073
2028	4,444			300			200	155	655		0.009
2029	4,655						200	155	355		0.007
2030	4,872							135	135		0.031
2031	5,101							175	175		0.143
2032	5,332			300			200	175	675		0.024
2033	5,569			300	300			160	760	(354)	0.040
2034	5,814				300			205	505		0.030
2035	6,067				300			180	480	(300)	0.096
2036	6,328				300			175	475		0.088
2037	6,597			300				175	475		0.083
2038	6,873				300			195	495		0.080
2039	7,155			300				190	490		0.074
Total		**130**	**100**	**2400**	**3000**	**227**	**600**	**3425**	**9857**	**(1071)**	

8.3.1 System Capacity Distribution

The supply mix of the power sector is moving towards thermal and ORE based generation system with the increase of demand since the total hydro capacity remains nearly the same over the planning horizon in the Base Case scenario. Retirement of existing thermal capacities also necessitates new capacity additions and plant retirement details are given in Table 8.1. In the year 2025, the share of coal based generation capacity is 22% and it remains in the range 22% - 24% throughout the horizon. Current Major Hydro capacity contribution is 28% under average hydro condition where as it will be 22% and 13% in the year 2025 and 2039 respectively. Current share of oil based capacity is 33% and it gradually decreases with the introduction of NG and Coal based thermal power plants in the first half of the planning period and then the capacity share becomes negligible leading up to only 2% in 2039. Pumped Hydro capacity will be introduced to the system in 2028 and its capacity contribution in 2039 is 5%.

Present total installed capacity is 4048 MW and out of that 3463 MW is dispatchable power plants and the Chapter 2 includes the detailed information of the existing generation system. 1070 MW of existing thermal capacity is due to retire during the 20 year planning period and three units of 35 MW gas turbine are added to the system for operational requirements. Future addition of hydro capacity is 227 MW including 188MW of committed plants and 39MW of new hydro power plants as shown in the Table 8.1. 2400 MW of coal power plants are added during the planning period of 2020-2039 and a mix of NG and coal based generation units serve the base load requirement of the system. As shown in the Table 5.6, 3425 MW of ORE capacity additions over the 20 year period is expected and the total ORE capacity increases to 1960 MW in 2025 and 4330 MW in 2039. The first 200MW Pumped Storage Hydro power plant unit is added in 2028 followed by another two units of same capacity in 2029 and 2032. The first phase of Wind Power Park at Mannar with 100MW capacity is expected to be implemented within year 2020.

Capacity additions by plant type are summarised in five year periods in Table 8.3 and graphically represented in Figure 8.1. Capacity balance of the system is presented in Annex 8.2.

Table 8.3: Capacity Additions by Plant Type

Type of Plant	2020-2024 (MW)	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	227	-	-	-	227	3%
Pumped Hydro	-	400	200	-	600	6%
Gas Turbines	130	-	-	-	130	1%
Coal	600	600	600	600	2400	24%
NG CCY	900	600	600	900	3000	30%
Reciprocating Engine	300*	(-200)	-	-	100	1%
ORE	910	750	850	915	3425	35%
Total	**3067**	**2150**	**2250**	**2415**	**9882**	**100.00%**

***** This figure represents the net capacity addition for the period.

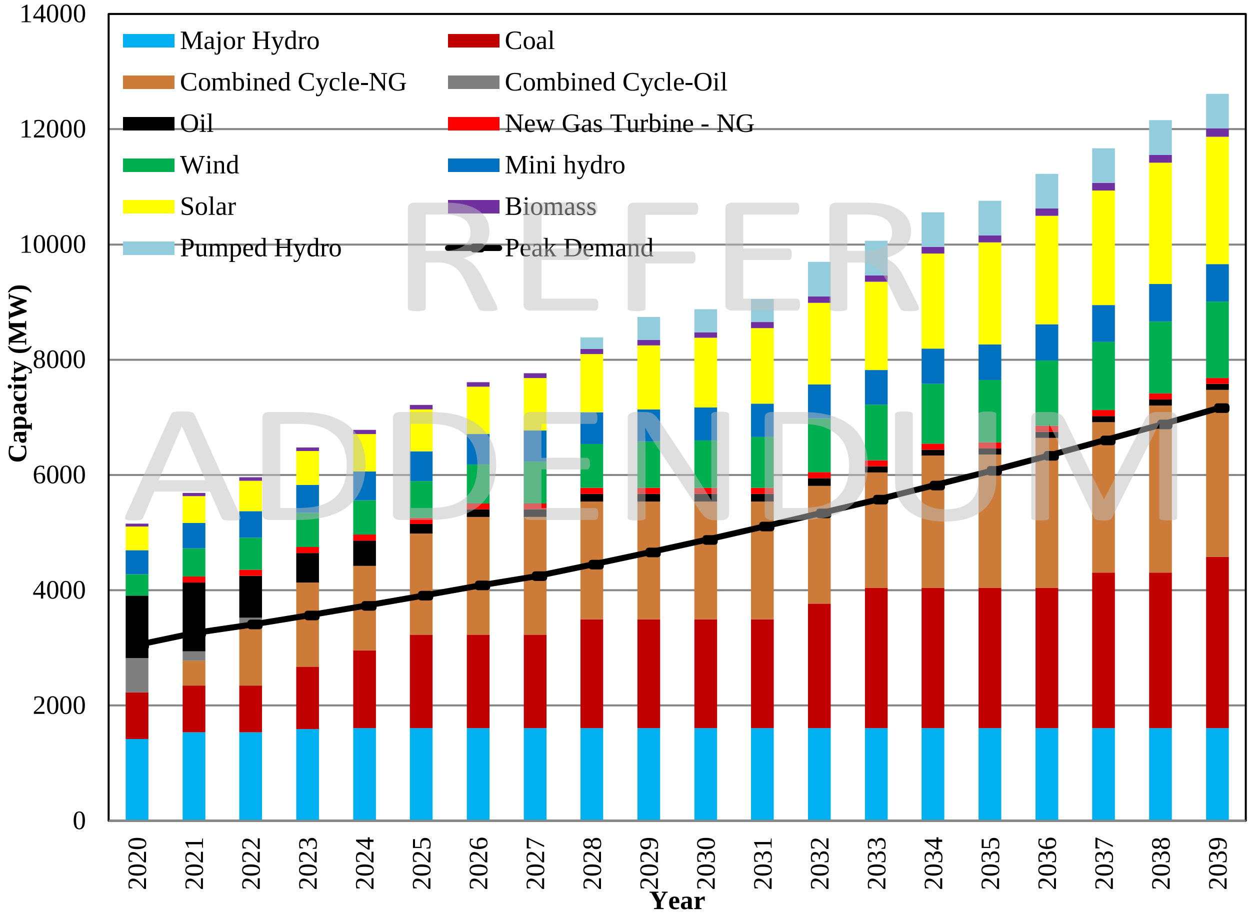


Figure 8.1 –Cumulative Capacity by Plant Type in Base Case

Information on the capacity share is illustrated in the Figure 8.2 and the variation of the total renewable capacity contribution over the years is shown in the Figure 8.3. It is observed that 50% 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.

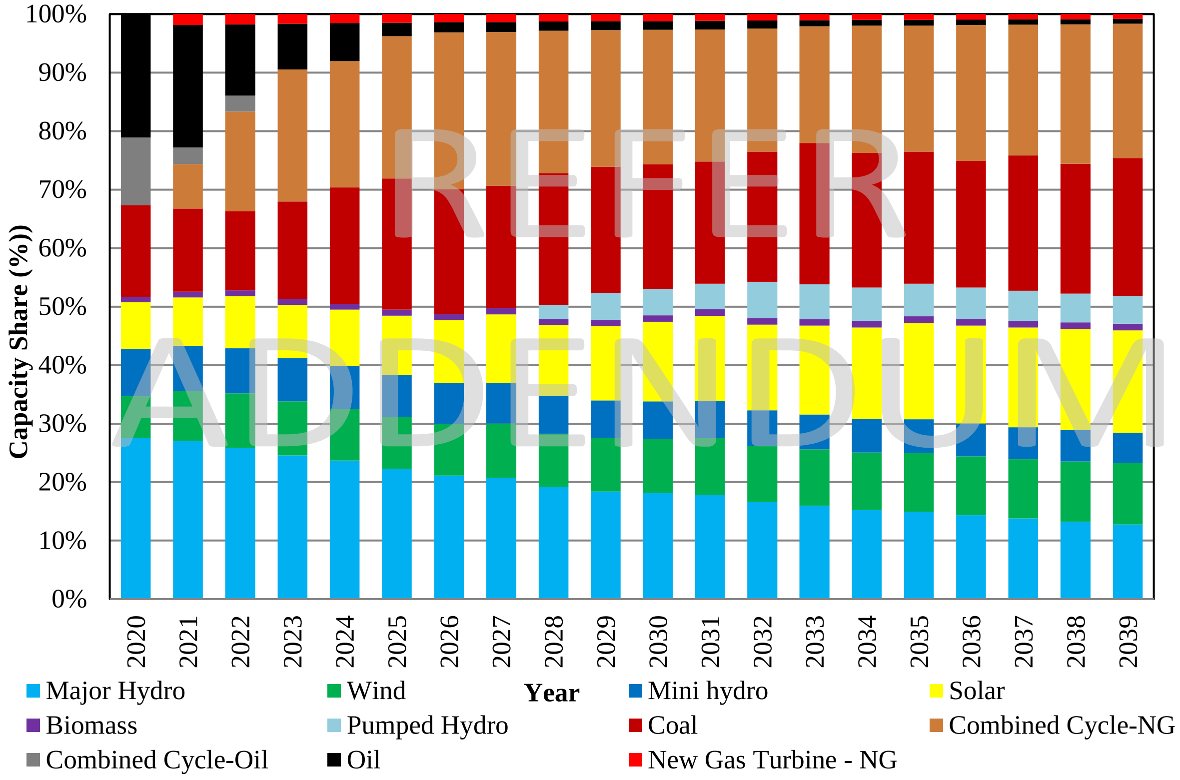


Figure 8.2 – Capacity Mix over next 20 years in Base Case

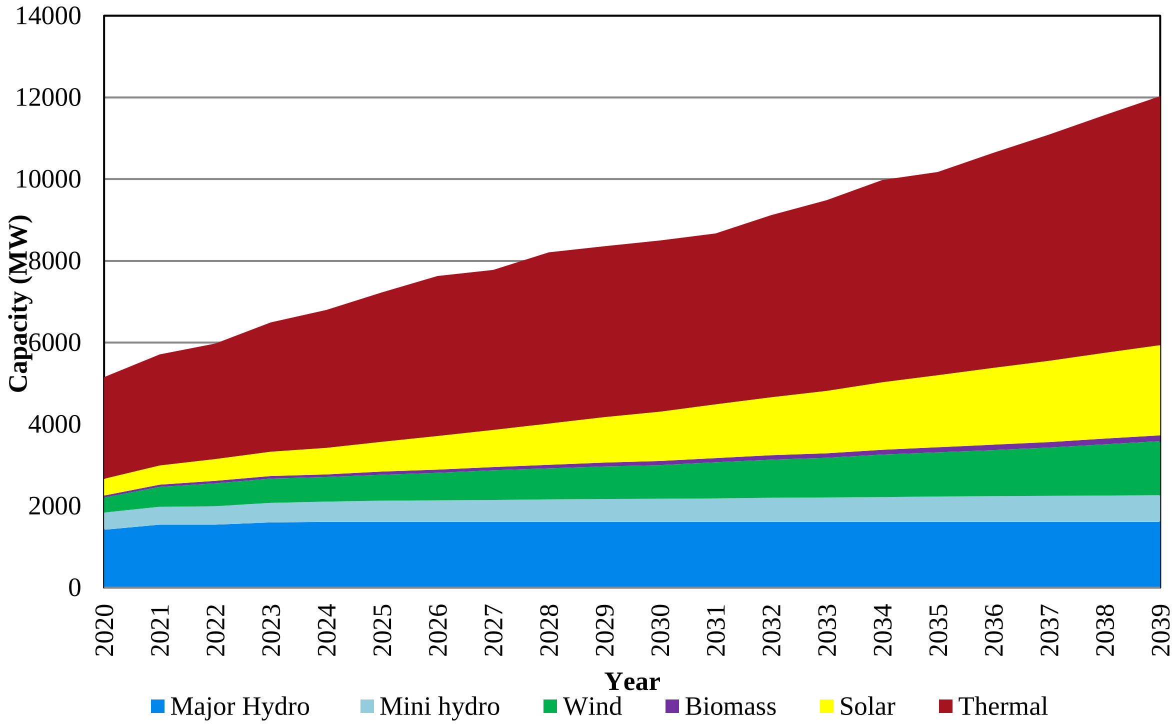


Figure 8.3 – Capacity wise Renewable Contribution over next 20 years

Variation of the firm capacity share over the planning horizon is shown in the figure 8.4. By year 2030, complying with the General Policy Guidelines issued in March 2019, firm capacity share is comprised of 34% Natural Gas, 30% high efficient coal power, 26% large hydro, and 10% other sources. During the entire planning horizon with a high firm capacity share, priority has been given to the introduction of Natural Gas based thermal power plants as major firm thermal energy source.

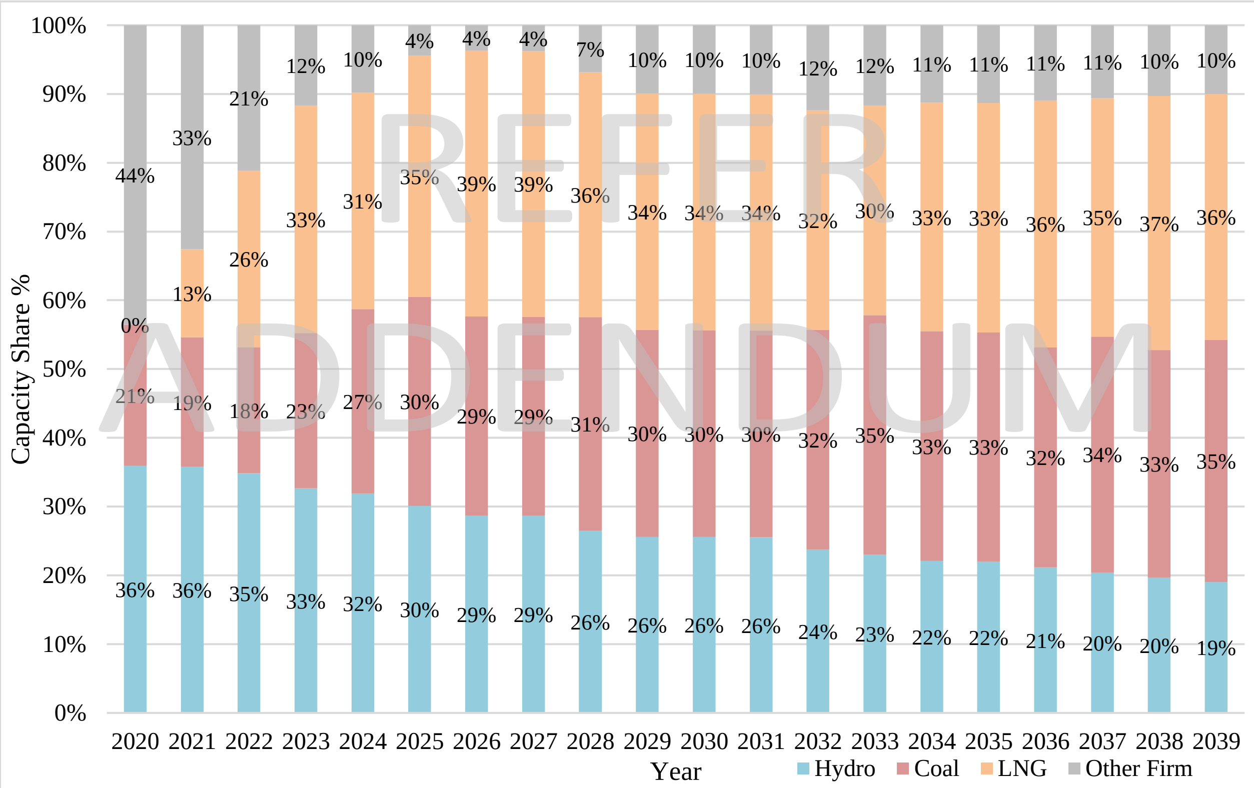


Figure 8.4 – Firm Capacity Share over next 20 years in Base Case

Table 8.4 shows total installed capacity, firm capacity, renewable energy capacity and the peak demand for the years 2025, 2030 and 2039. 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 8.4: Capacity Distribution for Selected Years in Base Case

Year	**2025**	**2030**	**2039**
Total Installed Capacity (MW)	**7,206**	**8,871**	**12,609**
Total Firm Installed Capacity (MW)	5,338	6,288	8,442
Major Hydro Installed Capacity (MW)	1,607	2,007	2,207
ORE Installed Capacity (MW)	1,960	2,700	4,330
Total Renewable Installed Capacity (MW)	**3,567**	**4,707**	**6,537**
Peak Demand (MW)	**3,903**	**4,872**	**7,155**

8.3.2 System Energy Share

In 2018, on average 44% of the total energy demand is met by renewable energy sources whereas 56% is met by thermal generation. Future energy supply scenario of the Base Case Plan is graphically represented in Figure 8.5. The hydro generation share slightly increases with addition of new hydro power plants during the first half of the planning period and thereafter continues to contribute at the same level. Beyond 2023, Coal and NG become the major energy contributors of the system and the energy share gradually increases with the addition of new Coal and NG power plants to cater the increasing national demand. Coal energy share is 21% in 2020 and will gradually increase up to 44% by 2039. As shown in the Figure 8.5, energy share of NG based Combined Cycle plants varies in the range of 20% - 25% over the planning period and the energy contribution from other oil fired power plants including Diesel power plants and IPPs decreases from 29% in 2020 to 1% by 2026 with the gradual retirement of oil plants. Energy contribution from ORE increases from present 11% to 21% by 2020 and thereafter continues to maintain the contribution over the planning period which is the optimum ORE penetration levels to the system. Percentage energy share of each plant type is given in Figure 8.6 and Energy Balance of the system is given in Annex 8.3. The Annual expected generation and plant factors under different hydro conditions for the Base Case Plan are given in Annex 8.4.

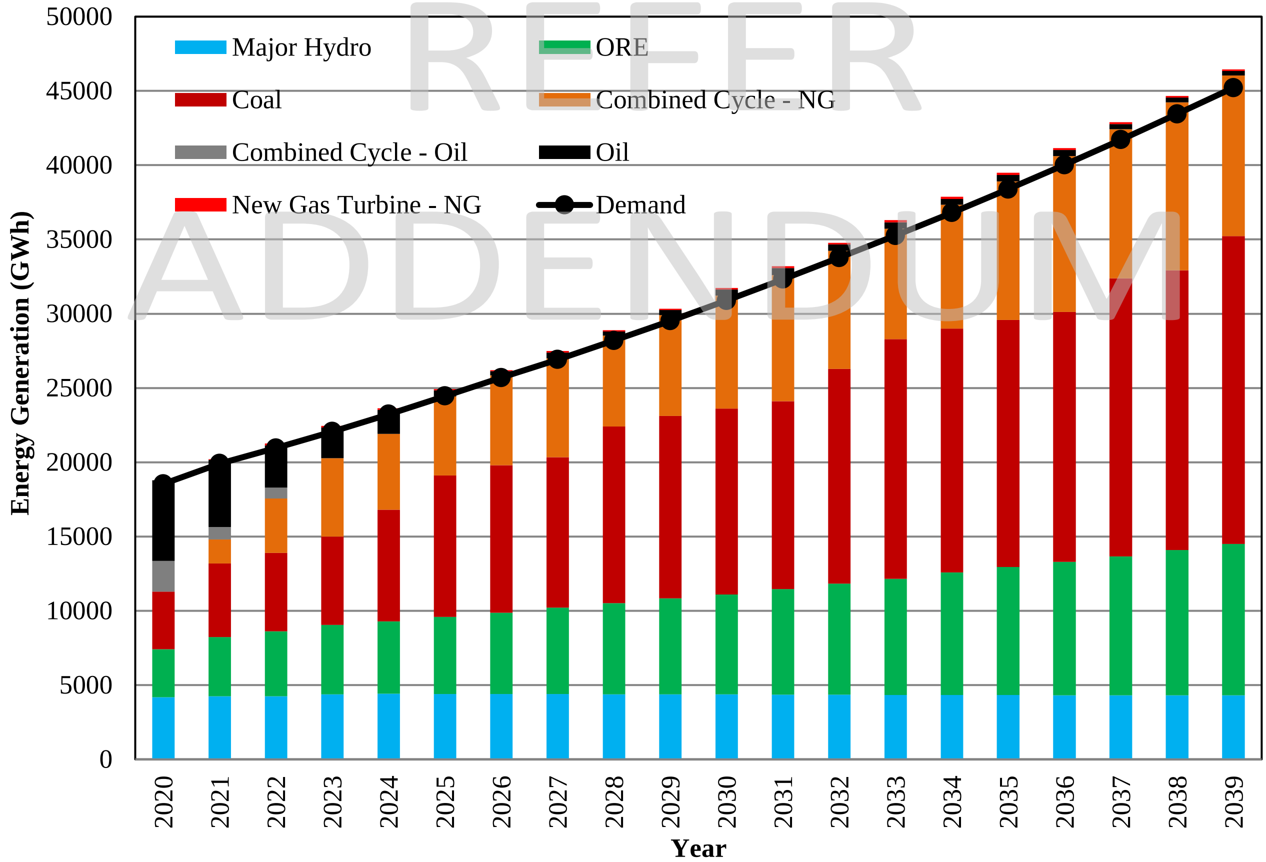


Figure 8.5 – Energy Mix over next 20 years in Base Case

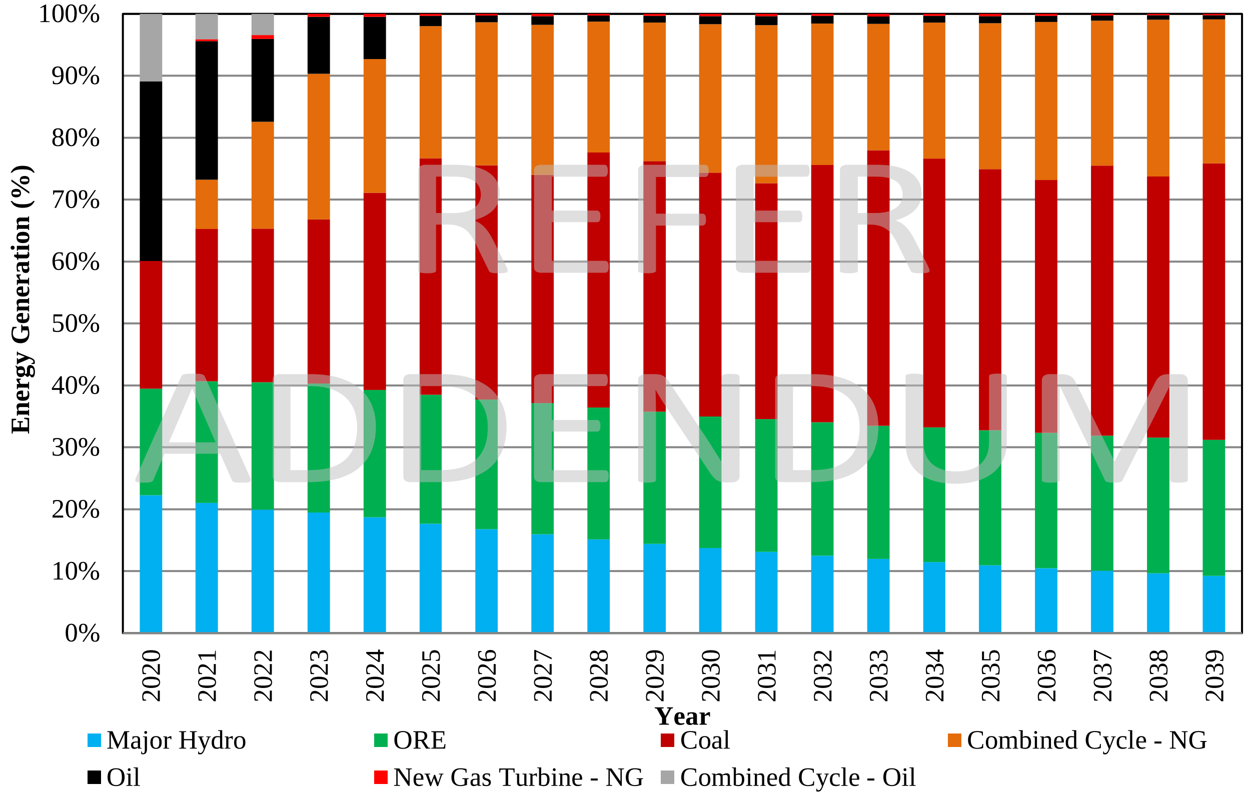


Figure 8.6 – Percentage Share of Energy Mix over next 20 years in Base Case

Contribution from ORE based generation is shown in Figure 8.7 and the Figure 8.8 illustrates the variation of total renewable share in the total system for the 20 year study period. To integrate the optimum amount of ORE based generation, the implementation of proposed thermal power plants and pumped storage power plants 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.

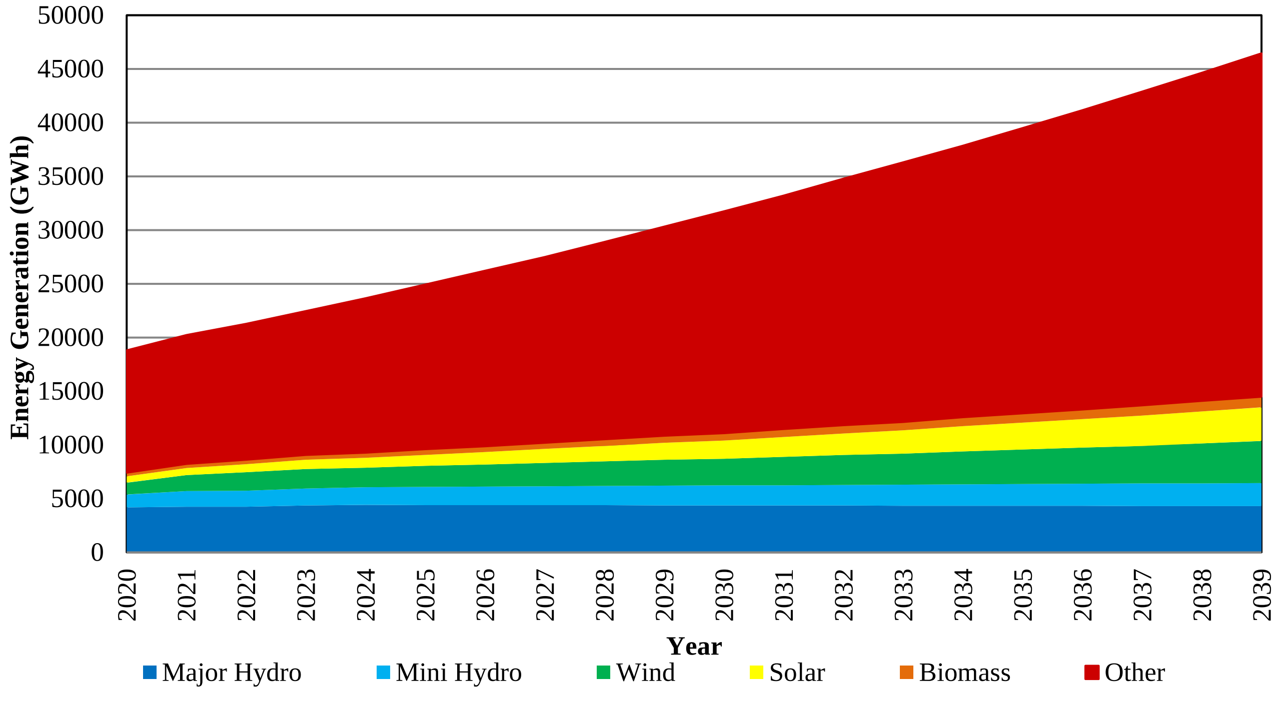


Figure 8.7 –Renewable Contribution over next 20 years based on energy resource

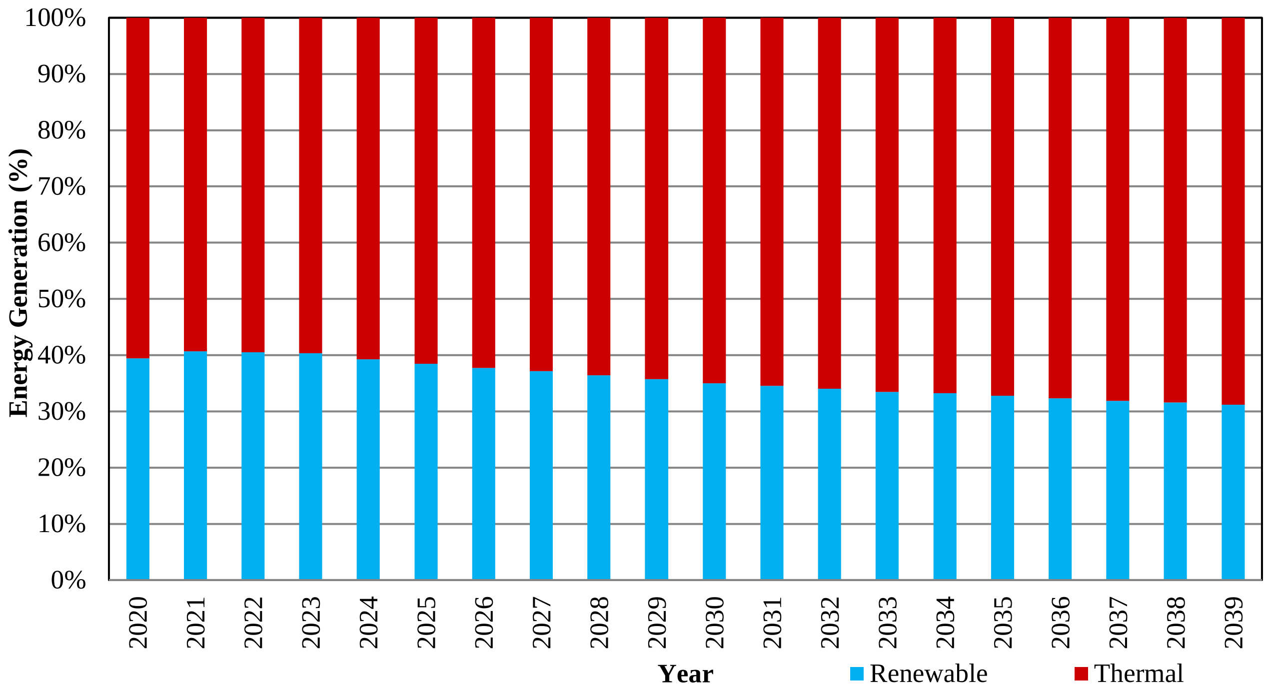


Figure 8.8 - Percentage Share of Renewables over next 20 years in Base Case

8.3.3 Fuel, Operation and Maintenance Cost

Expected expenditure on fuel, operation and maintenance (O&M) of the Generation System from 2020 to 2039 is summarized in Table 8.5 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 8.5. Expected fuel quantities and associated costs of fuel in the Base Case are graphically represented in Figure 8.9 and Figure 8.10 based on the fuel prices indicated in Section 4.2 of Chapter 4.

Table 8.5: Cost of Fuel, Operation and Maintenance of Base Case

Units: million US$

Year	Operation and Maintenance					Fuel
	Hydro	Pumped Hydro	Thermal	ORE	Total	
2020-2024	99.1	0.0	615.4	218.8	933.3	4759.6
2025-2029	104.9	7.3	851.7	282.9	1246.7	5251.5
2030-2034	104.8	31.7	1118.2	347.2	1601.9	6639.3
2035-2039	104.7	36.5	1397.5	419.6	1958.4	8189.8
Total	**413.5**	**75.5**	**3982.8**	**1268.5**	**5740.3**	**24840.2**

Total fixed and variable O&M cost over next 20 years is in the order of about 5,740 million USD and total fuel cost about 24,840 million USD in constant terms.

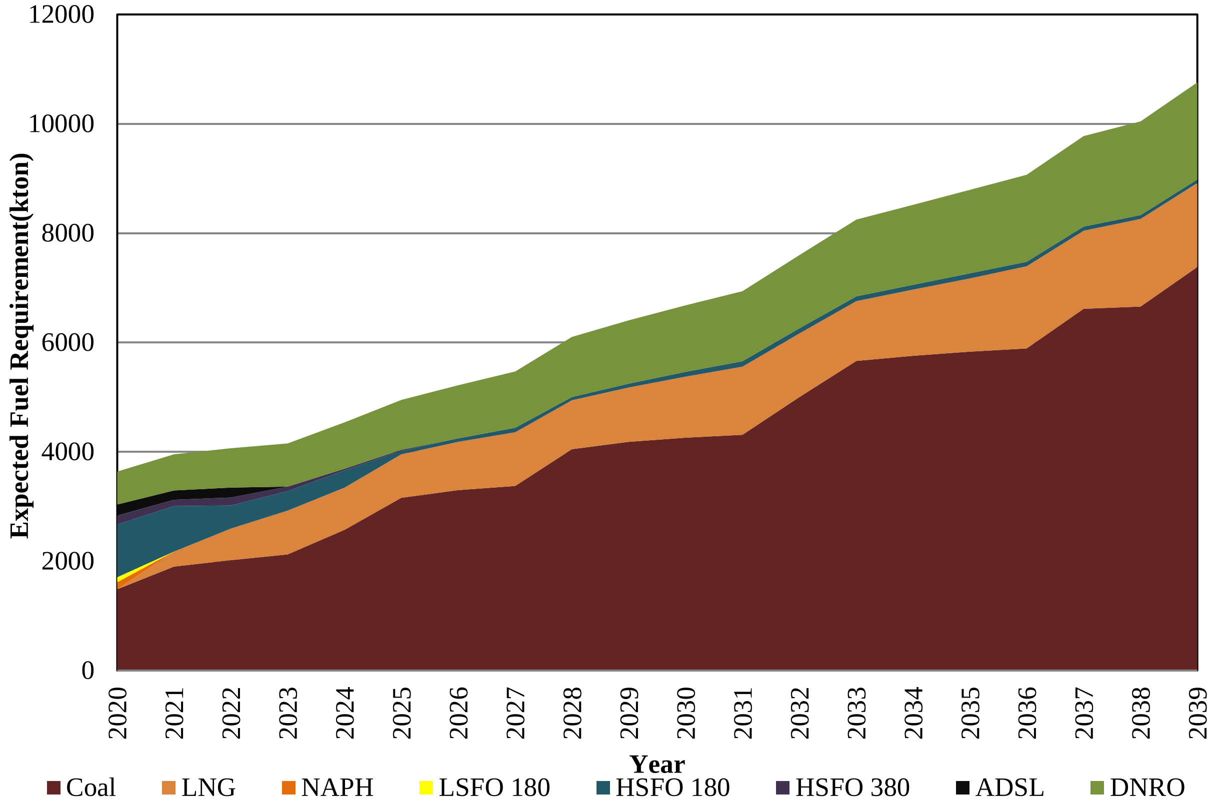


Figure 8.9 - Fuel Requirement of Base Case

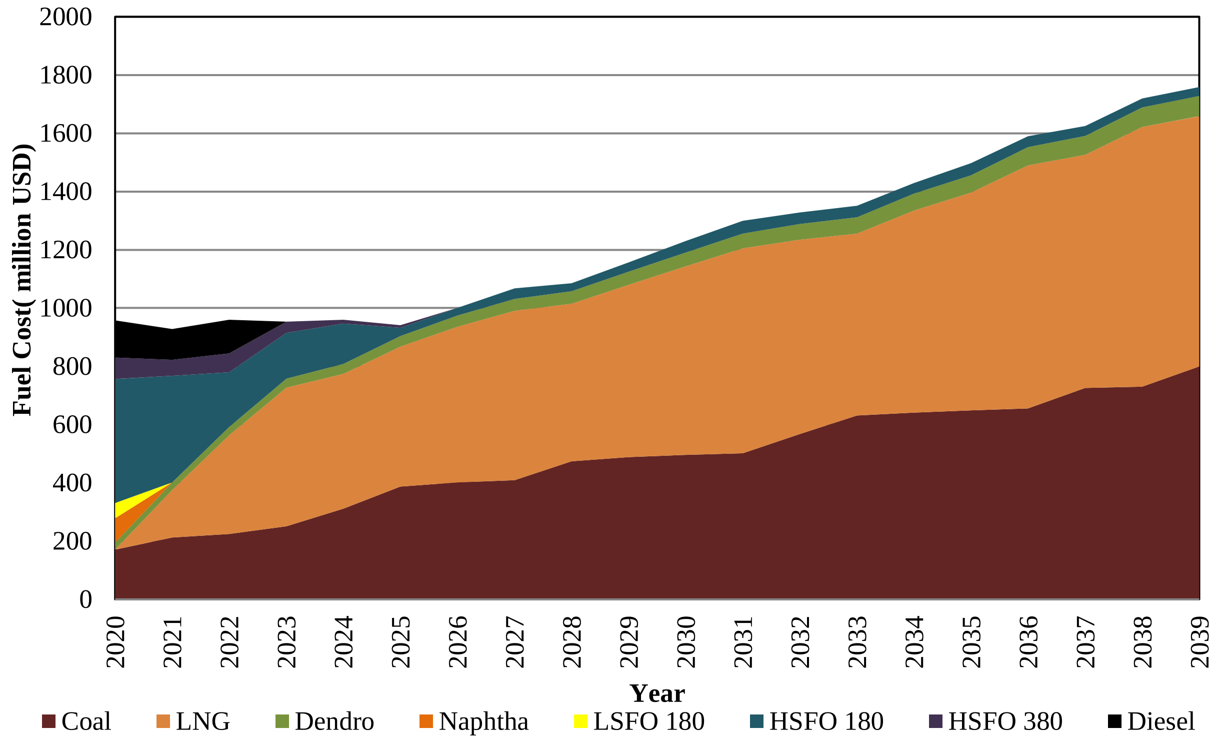


Figure 8.10 - Expected Variation of Fuel Cost of Base Case

In the initial years of the planning period, the oil requirement is relatively high due to contingency requirements with the coal remaining constant and NG requirement increasing gradually. After 2025, the oil quantity requirement becomes negligible with the minimal dispatch of the oil based thermal power plants while the NG and coal requirement increases gradually with the introduction of new NG and coal plants. A coal power plant of capacity 300MW typically consumes approximately 0.8 million tons per annum and a NG Combined Cycle power plant of capacity 300MW typically consumes approximately 0.2 million tonnes per annum at 60% plant factor, however it can vary depending on energy generated, plant characteristics and fuel characteristics.

In year 2020, nearly 1.2 million tons of heavy fuel (residual and furnace oil) will be burnt in oil power stations and this consumption will decrease to 84,830 tons in 2025 in an average hydro condition. Diesel consumption is estimated to be 203,280 tons in 2020 and by 2023 will completely be phased out. 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 coal and NG power plants including the conversion of existing oil power plants to NG.

Expected growth of Biomass plant capacities requires a notable amount of fuel quantity annually due to its own characteristics as a fuel.

The expected annual coal requirement for the existing Lakvijaya Coal Power Plant , the future development of coal plants and the annual NG requirement for the future development of combined cycle power plants as per the Base Case Plan is shown in the Figure 8.11 and details are given in Annex 8.5

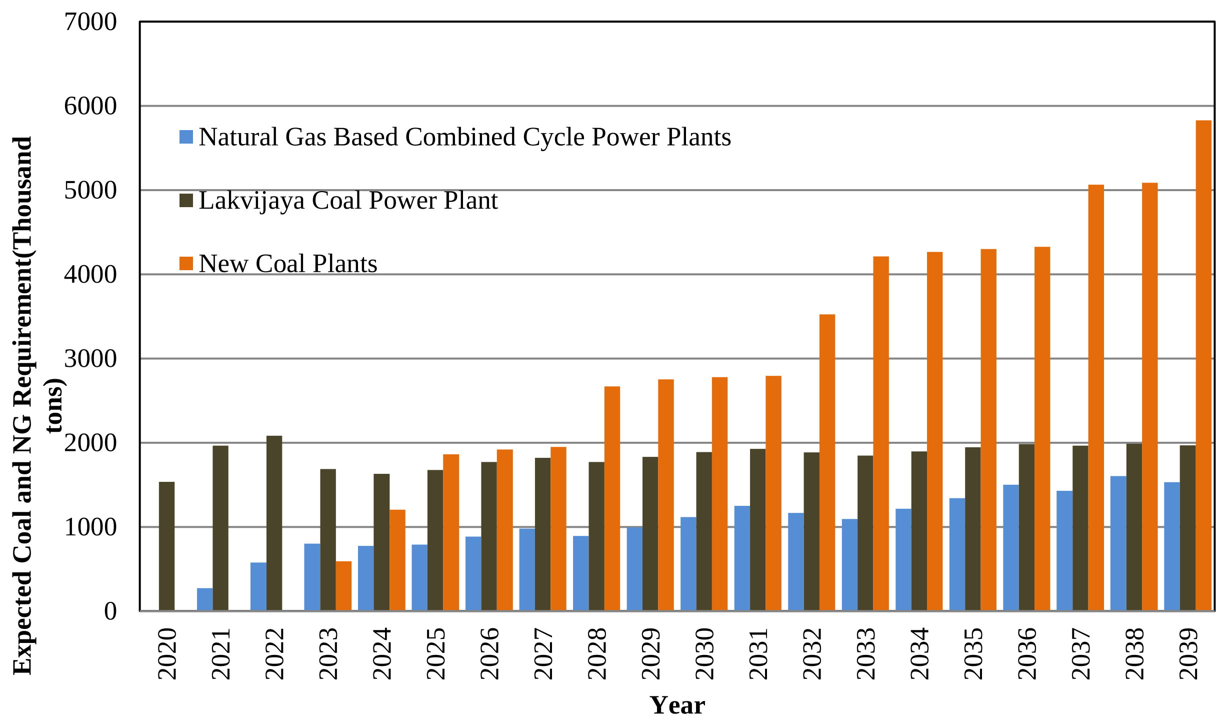


Figure 8.11 - Expected Annual Coal and Natural Gas Requirement of the Base Case

8.3.4 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.

The Base Case plan maintains a Minimum Reserve Margin of 10% and a Maximum Reserve Margin of 25% 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 power plants by contingency capacity additions in this period. Reserve Margin variation with the actual available capacity in the driest period and with the total installed capacity including ORE throughout the 20 year period is shown in the Figure 8.12. System Reserve Margin with total installed capacity including intermittent ORE capacities appears to be higher than the actual available Reserve Margin in the critical hydro condition.

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. The dependency of LOLP value on the Reserve Margin maintained in the planning horizon (inverse relationship) and the relatively high reserve margin ensures the LOLP value is maintained below 1.5% for all hydro conditions thereby ensuring the reliability of the system.

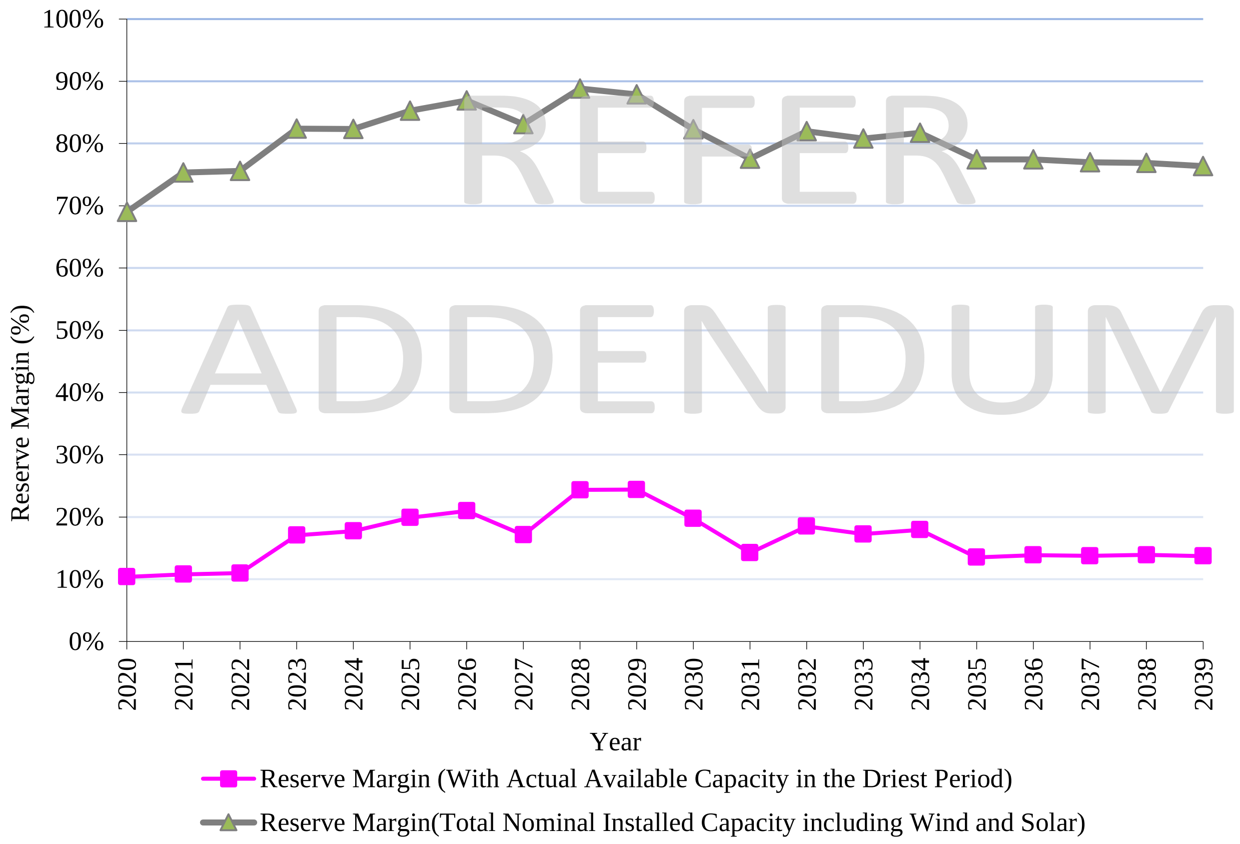


Figure 8.12 – Variation of Reserve Margin in Base Case

8.3.5 Spinning Reserve Requirement

The Spinning Reserve requirement for the system operation is considered in long term expansion planning exercise. A spinning reserve equivalent to the largest unit in operation was kept in previous long term planning studies for contingency purpose. As the Base Case Plan 2020-2039 focuses on higher penetration levels of intermittent ORE capacities; requirement of additional spinning reserve has been considered. With the higher level of variable ORE integration to the system, additional spinning reserves are maintained using the reserve capacity from firm power plants.

8.4 Impact of Demand Variation on Base Case Plan

High Demand and Low Demand cases were analysed in order to identify the demand variation impact on the Base Case Plan 2020-2039. 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 5.7% while Base Demand forecast shows 4.9% average growth rate. This demand increase results an increase of short term and long term power plant capacity additions than identified in Base Case Plan 2020-2039. In addition, High demand case shows 7.6% 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 8.6.

Table 8.6: Capacity Additions by Plant Type – High Demand Case

Type of Plant	2020-2024 (MW)	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	227	-	-	-	227	2%
Pumped Hydro	-	400	200	-	600	5%
Gas Turbines	130	-	-	-	130	1%
Coal	600	600	1200	600	3000	27%
NG CCY	900	600	600	1500	3600	32%
Reciprocating Engine	260*	(160)	-	-	100	1%
ORE	910	750	850	1135	3645	32%
Total	**3027**	**2190**	**2850**	**3235**	**11302**	**100.00%**

***** This figure represents the net capacity addition for the period.

Twenty year average electricity demand growth in low demand forecast is 3.9% which is 1.0% lower than the growth in Base Demand forecast. This demand reduction results to the reduction of short term and long term power plant capacity additions than identified in Base Case Plan 2020-2039. Low demand case shows 11.5% total present worth cost decrement compared to the Base Case Plan 2020-2039. Capacity additions for Low Demand Case by plant type are summarised in five year periods in Table 8.7.

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

Type of Plant	2020-2024 (MW)	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	227	-	-	-	227	3%
Pumped Hydro	-	-	400	-	400	5%
Gas Turbines	130	-	-	-	130	1%
Coal	600	600	300	300	1800	23%
NG CCY	600	600	600	600	2400	32%
Reciprocating Engine	275*	(175)	-	-	100	1%
ORE	910	600	530	625	2665	35%
Total	**2742**	**1625**	**1830**	**1525**	**7722**	**100.00%**

***** This figure represents the net capacity addition for the period.

Overall Thermal and Renewable (mainly on Pumped Hydro and Other Renewable Energy) capacity additions and fuel requirement of High and Low Demand cases will vary over the planning horizon 2020-2039.The resulting plans for the two cases are given in Annex 8.6 and Annex 8.7 respectively.

8.5 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 were 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.

Nevertheless, the government policy directive regarding the future electricity mix of the country should be complied in each of the scenario. Therefore the real impact on cost due to variation of discount rate cannot be analysed.

8.6 Impact of Fuel Price Sensitivity on Base Case Plan

For the Base Case Plan, fuel prices were assumed to be constant throughout the planning horizon. The impact of global fuel price escalations is an important input variable and the sensitivity of the base case to fuel price variations needs to be investigated in the planning process. Therefore, a separate scenario was studied applying the year by year fuel price escalations projected by the International Energy Agency.

World Energy Outlook 2018, published by International Energy Agency announces the latest indicative price variations of Coal, Oil and Gas up to 2040. The IEA's methodology considers the impact of supply demand balance, future energy policies, global economic activities and demographic trends for projecting future fuel prices trajectories. Following fuel prices escalations given in Table 8.8 have been projected under the current policies scenario. According to the IEA forecast oil price escalation is the highest for the period of 2020-2039 while Coal price escalation remains the lowest.

Table 8.8: Fuel Price Escalation percentages (from 2020 prices)

Fuel	2020	2025	2030	2035	2039
Coal	Base	-4.3 %	-0.8%	2.9%	6%
Natural Gas	Base	13.4%	15.6%	17.9%	19.8%
Crude Oil	Base	51.4%	67.6%	85.6%	101.3%

Above fuel price escalations have been used throughout the planning period for the Base Case. It is observed that the plant additions in each year remain unchanged in both cases and the operation cost increases due to the fuel price escalation. The Table 8.9 below includes the costs comparison of simulated scenarios. According to the results, Total PV cost for 2020-2039 period increase by 825 million USD compared to Base Case.

Table 8.9: Cost impact of fuel price escalation of Base case (million US$)

Scenario	Constant Fuel Prices	Fuel Price Escalation	Difference
Base Case	16,675	17,500	825

8.7 Summary

The total present value of cost over the planning horizon for Base Case and Sensitivities studied are summarized in Table 8.10.

Table 8.10: Comparison of the Sensitivities of the Base Case Plan

	Present Value of costs during the planning horizon	Deviation of PV Cost from Base Case	
	(Million USD)	(Million USD)	%
Base Case	16,675	-	-
Sensitivities on Base Case			
Demand Variation			
High Demand	17,944	1,269	7.6
Low Demand	14,763	(1,912)	(11.5)
Fuel Price Escalation	17,500	825	4.9

CHAPTER 9

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 addition to the Reference Case and the Base Case.

To evaluate the impact of implementing the energy policy elements on firm power capacity mix, a scenario was studied with power plant development as equivalent to approved LTGEP 2018-2037.

Considering the energy policy element of diversifying the energy mix to the maximum feasible level, adopting nuclear technology as a potential energy source beyond 2030, Energy Mix with Nuclear Power Development Scenario was considered.

HVDC interconnection with India was studied as a separate scenario to study the impact of the interconnection on the economics and operation of the Sri Lankan power system and how the scenario compares with the Base Case.

9.1 LTGEP 2018-2037 Base Case Equivalent Scenario

A Scenario is studied to analyze the policy cost taken to deviate from the criteria of the base case plan of the approved LTGEP 2018-2037. In order to have a fair comparison the reliability criteria are kept constant with reserve margin of 10% (minimum) and 25% (maximum).

The Scenario is prepared for the same Demand Forecast as described in Table 3.3. The Other Renewable Integration levels were also kept as same as described in Table 5.6 after verifying with operational and transmission network constraints. The short term power plant requirement for implementation delays of Natural Gas Combined Cycle Plants till 2022, were considered the same.

The total PV cost of this scenario is USD 16,643 million and shows a decrement of USD 32 million from the PV cost of Base Case which could be indicated as the policy cost of implementing the policy on electricity generation mix.

The capacity additions by plant type which are summarised in five year periods are shown in Table 9.1 and the plant schedule is presented in Annex 9.1.

Table 9.1: Capacity Additions by Plant Type – Base Case equivalent to LTGEP 2018-2037

Type of Plant	2020-2024 (MW)	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	Total capacity addition (MW)	Total capacity addition %
Major Hydro	227	-	-	-	227	3%
Pumped Hydro	-	400	200	-	600	6%
Gas Turbines	130	-	-	-	130	1%
Coal	900	900	900	900	3600	36%
NG CCY	600	0	600	600	1800	18%
Reciprocating Engine	300*	(-200)	-	-	100	1%
ORE	910	750	850	915	3425	35%
Total	**3067**	**1850**	**2550**	**2415**	**9882**	**100.00%**

***** This figure represents the net capacity addition for the period.

9.2 Energy Mix with Nuclear Power Development Scenario

Energy Mix with Nuclear Power Development scenario was carried out to study the impact of diversification of fuel options in electricity generation mix instead of adhering to conventional thermal energy sources such as Petroleum or Coal in future. The general policy guidelines on future electricity mix also stresses on diversifying the energy mix to the maximum feasible level adopting sophisticated technologies in the world, to accept in principle the necessity of strategically developing all the practically developable energy sources including Nuclear Power. Therefore, this scenario was studied by introducing Nuclear power plants instead of Coal power development beyond 2032.

Nuclear plants are introduced in year 2033 with sufficient lead time to implement a Nuclear Power Program. The first 600MW was selected in 2035 and thereafter another 600MW was added in 2037. Energy Mix with Nuclear Power Development scenario gives a diversified fuel mix including Coal, Natural Gas and Nuclear.

Pre-feasibility for introduction of Nuclear Power Development in Sri Lanka will be further evaluated in the ongoing IAEA assisted study on “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.

The total PV cost of this scenario is USD 17,174 million which and shows an increment of USD 499 million from the PV cost of Base Case Plan.

The capacity additions by plant type which are summarised in five year periods are shown in Table 9.2 and the plant schedule is presented in Annex 9.2. Capacity Share and Energy share in 2039 for this scenario is shown in Figures 9.1 and 9.2 respectively.

Table 9.2: Capacity Additions by Plant Type – Energy Mix with Nuclear Power Development

Type of Plant	2020-2024 (MW)	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	227	-	-	-	227	2%
Pumped Hydro	-	400	200	-	600	6%
Gas Turbines	130	-	-	-	130	1%
Coal	600	600	300	0	1500	15%
NG CCY	900	600	600	900	3000	29%
Nuclear	0	0	0	1200	1200	12%
Reciprocating Engine	300*	(-200)	-	-	100	1%
ORE	910	750	850	915	3425	34%
Total	**3067**	**2150**	**1950**	**3015**	**10182**	**100.00%**

***** This figure represents the net capacity addition for the period.

9.3 HVDC Interconnection Scenario

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 Indian Limited (POWERGRID) jointly for the implementation of 1000MW 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 is not economically or financially viable [38]. Major items which are affecting the project cost are submarine cable and HVDC Technology (Conventional HVDC or VSC based HVDC) selection. Accordingly, as discussed in section 4.5 of chapter 4 latest studies identified alternative route options in order to reduce the cost. Possibility of further reduction of cost would be explored during implementation stage and both India and Sri Lanka must consider the present power situation and carry out further studies on HVDC interconnection feasibility considering economics, power system stability, power quality etc.

In Sri Lanka, renewable development, off peak improvement and coal power development are the important factors when considering HVDC interconnection. A scenario was developed considering the implementation of 500MW HVDC in 2031. Estimated cost of 621 USD million was used for evaluation purpose considering VSC technology in one of the options identified in Chapter 4. Further, landed cost of 8.99 US Cents/kWh [39] which includes marginal cost of Indian system, interconnection transmission charges, reliability support charges, O&M charges etc. was used in the analysis.

In HVDC Interconnection Scenario following assumptions were taken.

(a) 1 x 500MW HVDC Interconnection will be implemented in 2031.

(b) ORE implementation will remain same as Base Case plan and therefore to facilitate the integration of ORE, 200MW Pump Storage Power Plant (PSPP) will be considered in 2028.

(c) Thermal power plants addition will remain as same as Base Case plan up to 2028

(d) Thermal power plants addition will be in compliance to maintain the electricity mix as per the policy guidelines [37]

Due to implementation of HVDC, two units of 200MW PSPP will be replaced compared to Base Case Plan and hence the support functions provided by HVDC to integrate renewable energy should be further reviewed with the proposed ORE capacity additions. It was observed that for the assumed transfer price, the energy imported through the HVDC link is reached a maximum of approximately 40% plant factor during the planning horizon considering dry weather conditions. Therefore, transfer price of electricity, HVDC interconnection technical parameters, amount of energy import & export with annual plant factors, and related costs should also be further reviewed.

The total PV cost of the scenario is USD 16,684 million which indicates a USD 9 million increment from the PV cost of Base Case.

The capacity additions by plant type which are summarised in five year periods are shown in Table 9.3. Power plant sequence of the scenario is given in Annex 9.3. Capacity Share and Energy share in 2039 for this scenario is shown in Figures 9.1 and 9.2 respectively.

Table 9.3: Capacity Additions by Plant Type – HVDC Interconnection Scenario

Type of Plant	2020-2024 (MW)	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	227	-	-	-	227	2%
HVDC Interconnection	-	-	500	-	500	5%
Pumped Hydro	-	200	-	-	200	2%
Gas Turbines	130	-	-	-	130	1%
Coal	600	600	600	600	2400	24%
NG CCY	900	600	600	900	3000	30%
Reciprocating Engine	300*	(-200)	-	-	100	1%
ORE	910	750	850	915	3425	35%
Total	**3067**	**1950**	**2550**	**2415**	**9982**	**100.00%**

***** This figure represents the net capacity addition for the period.

9.4 Comparison of Energy Supply alternatives in 2039

9.4.1 Global Context

Table 9.4 shows the present and projected energy mix in a number of different countries. It could be observed that majority of the countries and regions as whole are projecting a balanced generation mix with considerable contributions from Natural Gas, Coal, 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 a Renewable share between 20% and 40%.

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 49% in 2040.

When considering Asian countries major source of power generation is coal and it remains to be the same in 2040 according to the projections.

Table 9.4: Present & Projected Power Generation Mix in Other Countries

		NG	Coal	Nuclear	Renewable	Other	Source
USA	2017	31%	31%	20%	17%	1%	IEA-World Energy Outlook 2018
	2040	33%	23%	14%	29%	0%	
China	2017	3%	67%	4%	25%	0%	IEA-World Energy Outlook 2018
	2040	9%	51%	9%	31%	0%	
EU	2017	21%	21%	25%	31%	2%	IEA-World Energy Outlook 2018
	2040	23%	9%	18%	49%	0%	
Japan	2017	37%	33%	3%	17%	7%	IEA-World Energy Outlook 2018
	2040	29%	28%	15%	24%	1%	
Russia	2017	47%	16%	19%	17%	1%	IEA-World Energy Outlook 2018
	2040	45%	15%	20%	20%	0%	
India	2017	5%	74%	3%	16%	2%	IEA-World Energy Outlook 2018
	2040	8%	57%	4%	31%	0%	
South East Asia	2016	43%	35%	0%	18%	4%	IEA-South East Asia Energy Outlook 2017
	2040	27%	50%	1%	22%	1%	
Asia Pacific	2017	12%	59%	4%	22%	2%	IEA-World Energy Outlook 2018
	2040	14%	49%	7%	30%	0%	
Vietnam	2015	30%	34%	0%	34%	2%	Vietnam Power Development Plan VII (Revised) - Approved in 2016
	2030	17%	53%	6%	23%	1%	
Indonesia	2018	21%	62%	0%	12%	5%	RUPTL 2018-2027 (Electricity Supply Business Plan)
	2027	21%	59%	0%	20%	0%	

9.4.2 Sri Lankan Context

The Figure 9.1 illustrates the energy mix in different key scenarios considered in 2039. The Base Case Scenario is complied with the National Energy Policy Elements with realistic cohesiveness. Compared with Base Case Scenario, Energy Mix Scenario enhances the energy security policy by diversifying the fuel mix further in to Nuclear Power. In the HVDC interconnection scenario, impact from the interconnection on the operation of the system was identified.

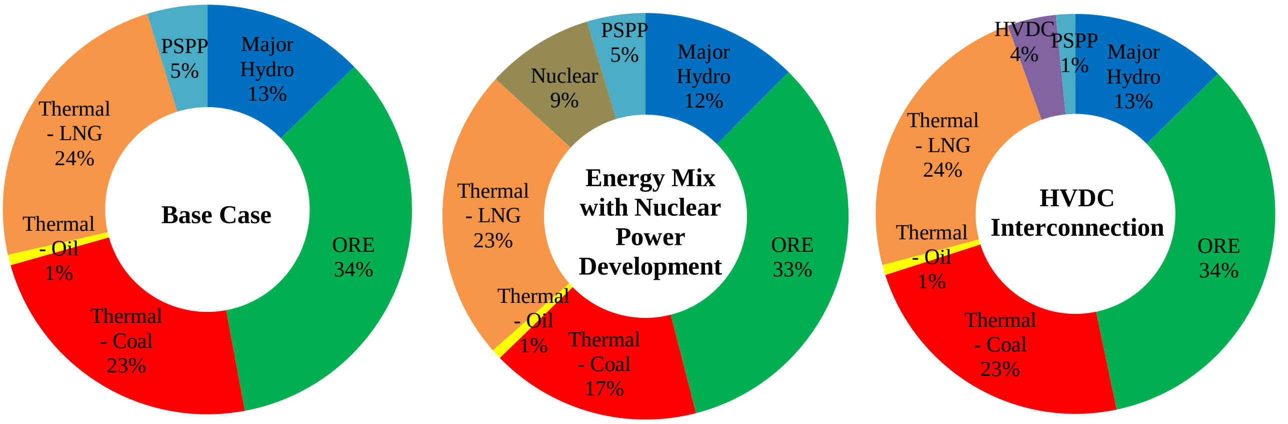


Figure 9.1 – Installed Capacity Share Comparison in 2039

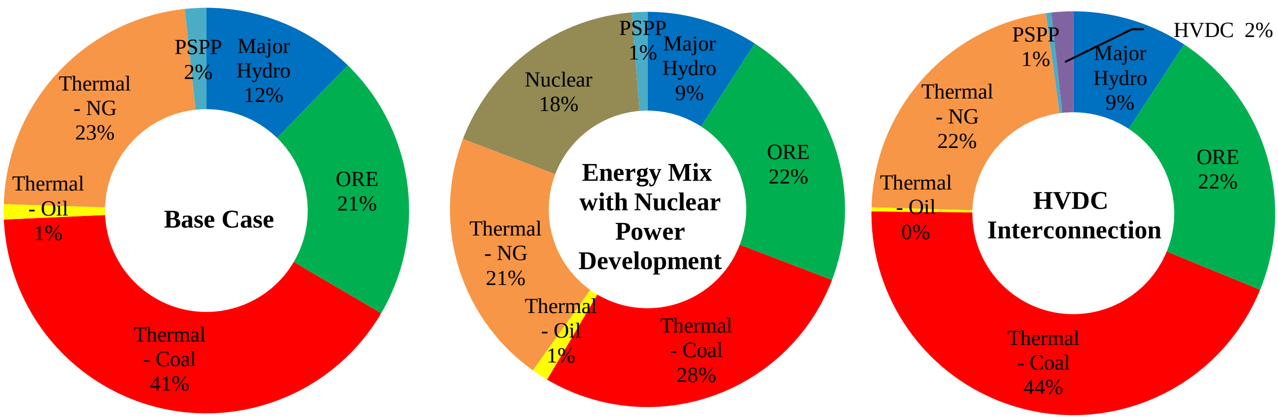


Figure 9.2 –Energy Share Comparison in 2039

CHAPTER 10
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 thermal generation increased only during the drought period and hence the power sector had only minor impact on theenvironment.However,after exploiting most of the major hydro potential,alternative fuel types had to be looked at to cater the growing electricitydemand. Thereafter, fossil fuel was introduced into the power system.At present the main focus is also on power generation using other renewable energy sources such as wind and solar. Even at present, around 50% of renewable energy share is maintained from major hydro and other renewable energy resources.

The impact of electricity generation on the environment could be due to one or several factors including: particulate emissions; gaseous emissions (CO_2, SO_X, NO_X etc.); warm water discharges into lakes, rivers or sea; liquid and solid waste (sludge, ash); inundation (in the case of large reservoirs) and changes of land use. Although many of these are common to any development project, particulate and gaseous emissions are of primary importance in the case of electricity generation using fossil fuels.Further, when developing renewable power plants such as wind and solar due consideration should be given toconflicts with bird migration routes, bird habitats, unique land features such as sand dunes, vegetation, changes in land use, inhabitants and noise pollution.

This chapter describes the environmental impact due toparticulate and gaseous emissions,of the implementation of Base Case Generation Expansion Plan and other selected scenarios.

10.1 Greenhouse Gases

Greenhouse gases are that which 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 gasesin the Earths' atmosphere. There are also anthropogenic greenhouse gases such as Hydrofluorocarbons (HFCs),Perfluorocarbons (PFCs) and Sulphur hexafluoride (SF_6).

10.2 Country Context

10.2.1 Overview of Emissions in Sri Lanka

When considering the greenhouse gases,CO_2 is one of the primary gases which contribute towards warming of earths' atmosphere.Table 10.1 indicate CO_2 emissions from fuel combustion in each sector in Sri Lanka for the year 2016.It could be observed that approximately 41.5% of CO_2 emission from the electricity sector while major contributor for CO_2 emission is the transport sector which account for approximately 44.8%.

Table 10.1 - CO_2 Emissions from fuel combustion

	CO_2 emissions *Million tons of CO_2*	
Total	**20.89**	**100.0%**
Electricity and heat production	8.67	41.5%
Other energy industry own use	0.04	0.2%
Manuf. industries and construction	1.62	7.8%
Transport	9.36	44.8%
Other sectors	1.2	5.7%

Source: IEA CO_2 Emissions from Fuel Combustion (2018 Edition) -2016 data

Further the average emission factor from electricity generation in the past is shown in Figure 10.1

Source: Sustainable Energy Authority

Figure 10.1 –Average Emission Factor

Until thermal generation was introduced to Sri Lankan power system,itonly 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 to reduce GHG emissions and promoted through Government policies.With the focus on increasing renewable energy,more complicated analyses are required to overcome the uncertainties and intermittency in renewable energy generation.

Proposed expansion sequence predicts an increase in the thermal generation and anincrease in the use of fossil fuels in the power sector seems inevitable.In the Base Case Plan 2020-2039, the capacity share from thermal power plants is maintained approximately at 50%and renewable capacity share at 50% in year 2039, having more than 5900MW of total renewable power plants.

10.2.2 Ambient Air Quality & Stack Emission Standards

In 1994, Government of Sri Lanka has approved ambient air quality standards and it was amended in 2008. In June 2019, National Environmental Regulations on Stationary Source Emission Control were introduced. These standards are used as a guide in the EIA process of thermal power plants of Sri Lanka. At present, all thermal power projects have to comply with these standards as shown in Table 10.2.

Table 10.2 - Ambient Air Quality Standards and Proposed Stack Emission Standards of Sri Lanka

Pollutant Type	Ambient Air Quality Std. (µg/m3)				Stack Emission Std. Previous (mg/MJ)		Stack Emission Std. New (mg/Nm3)	
	Annual Level	24 hour level	8 hour Level	1 hour Level	Coal	Liquid Fuel	Coal	Oil
Nitrogen Dioxides (NO_2)	-	100	150	250	300	130	650	450
Sulphur Dioxides (SO_2)	-	80	120	200	520	340	850	850
PM10	50	100	-	-	-	-		
PM2.5	25	50	-	-	-	-		
Total Suspended Particles(TSP)	-	-	-	-	40	40	150	150

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 directingnational 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 10.3 shows a comparison of these standards.

Table10.3 - 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

A comparison of proposed stack emission standards of different countries and organisations for coal power plantsis shown in Table 10.4.

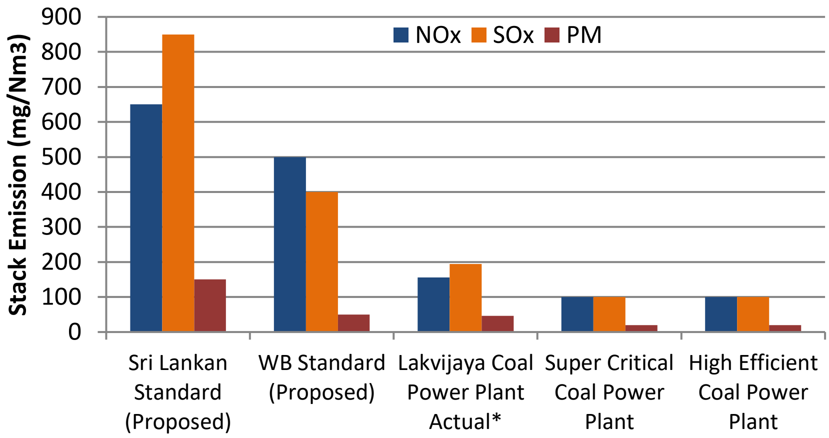
Table 10.4 - Comparison of Emission Standards for Coal Power Plants of Different Countries and Organisations

(All values in mg/Nm^3)

Pollutant	**Sri Lanka**	World Bank (non-degraded airshed,≥50MWth to <600MWth)	India (power plants after 2017)	China (new plants after 2012)	European Union (power plants after 2014>300MW)
Nitrogen Oxides	**650**	500	100	100	150
Sulphur Dioxide	**850**	400	100	100	150
Suspended Particulate	**150**	50	30	30	10

Source: Central Environmental Authority, WB IFC, IEA Clean Coal Center

Figure 10.2compares the stack emission levels of existing and proposed coal power plants in Sri Lanka with the standards. In addition to the low NOxburners used in the proposed coal power plants, they also include Selective Catalytic Reduction (SCR)to achieve very low levels of NOx emissions.



*Note:*LVPS values correspond to actual test results in October 2016*

Figure 10.2- Comparison of Stack Emission of Coal Power Plants

Recent emission measurement values from Lakvijaya power plant also indicated that the stack emission values are complying with the relevant standards.

10.3 Uncontrolled Emission Factors

One of the problems in analysing the environmental implications of electricity generation is correctly assessing the ‘emission coefficients’ or more commonly the ‘emission factors’. Choice of different sources can always lead to overestimation or underestimation of real emissions. Table 10.5 lists the uncontrolled emission factors *(emissions without considering the effect of control technologies in addition to the standard emission control devices used in planning studies)*which arebased on the given calorific values.

Table 10.5 - Uncontrolled Emission Factors (by Plant Technology)

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

Sources: Thermal Generation Options Study [8], 2006 IPCC Guidelines

Basically, CO_2 and SO_2 emission factors are calculated based on the fuel characteristics, while NOx emissions, which depend on the plant technology, are obtained from a single source [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 variousemission control technologies.

10.4 Emission Control Technologies

According to the expansion sequence of Base CasePlan 2020-2039 mentioned in Chapter 8 (Table 8.1), 3650MW of Renewable energy power plants, 3000MW Natural Gas combined cycle power plants, 2400MW of Coal power plants,105MW of Gas Turbines and 100MW furnace oil fired power plants are to be addedin the longer runto the Sri Lankan power system in the next 20 years starting from 2020. The impact on the environment due to particulate and air-emissions from the thermal power plants out of above additions and the effectiveness of using control devices to mitigate those impacts are analysed here. Particulate matter(PM) and three types of gaseous emissions were considered in the analysis, viz. SO_2, NOx and CO_2.

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

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

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

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

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

Table 10.6 shows the abatement factors of typical control technologies available for controlling emissions, during and/or after combustion. The values used in the study are shown shaded.The 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 10.6 - Abatement Factors of Typical Control Devices

(Factors in %)

Device	Sox	NO_X	TSP	PM	CO	CH_4	NMVOC
Fabric Filter			99.5	99.5			
Electro Static Precipitator				99.8			
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 – CCY *		80					

Sources: Decades Manual & Coal feasibility Study Reports

TSP - Total Suspended Particles

FGD - Flue Gas Desulphurisation

NMVOC - Non Methane Volatile Organic Compounds

CCY - Combined Cycle Plants

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

Further, CEB has taken steps to reduce emissions through efficient technologies for coal power plants by introducing high efficient super critical technology instead of subcritical technologies. By introducing high efficient technologies, CO_2 emissions could be reduced by 12%-16% comparatively with subcritical technologies.

10.5 Emission Factors Used

In the present study, emission factors were either calculated based on stoichiometry or taken from the actual measured values or calculated based on design and operational data for candidate plants. Emission factors were chosen from a single source [8] where sufficient data were notavailable.Table 10.7 shows the actual and proposed coal power plant data used in the study. When comparing with the standard values for coal power plants in Table 10.5 it is clear that the performance of the coal power plants in Sri Lanka is much satisfactory.

__Table 10.7 - Emission Factors of the coal power plants__

Plant Type	GCV of coal	GCV of coal	Sulphur	Emission Factor			
			Content	Particulate	CO_2	SO_x	NO_x
	(kcal/kg)	(kJ/kg)	(%)	(mg/MJ)	(g/MJ)	(g/MJ)	(g/MJ)
Candidate - High Efficient Coal Power Plant	6300	26377	0.65	7.00	94.6	0.035	0.035
Candidate - Super Critical Coal Power Plant	6300	26377	0.65	7.00	94.6	0.035	0.035
Coal Steam-Lakvijaya Power Station	6300	26377	0.7	15.00	94.6	0.056	0.260

Taking into consideration the emission factors mentioned in Table 10.5, Table 10.7 and the characteristics of the power plants, emissions per unit of electricity generated is calculated as shown in Table 10.8

__Table 10.8 - Emission Factors per Unit Generation__

__(a) Coal Power Plants__

Plant Type	Fuel Type	GCV	Full Load	Emission Factor			
			Heat Rate	Particulate	CO2	SOx	NOx
		(kcal/kg)	kcal/kWh	kg/kWh	kg/kWh	kg/kWh	kg/kWh
Coal Steam-LakVijaya Power Station (Unit 1,Unit 2, Unit 3)	Coal	6300	U1 - 2529 U2 - 2547 U3 - 2501	0.0002 0.0002 0.0002	1.0017 1.0088 0.9906	0.0006 0.0006 0.0006	0.0028 0.0028 0.0027
Coal Steam-High Efficient Coal Candidate	Coal	6300	2241	0.0001	0.8876	0.0003	0.0003
Coal Steam-Super Critical Coal Candidate	Coal	6300	2082	0.0001	0.8246	0.0003	0.0003

__(b) Other Candidate Power Plants__

Plant Type	Fuel Type	GCV	Full Load	Emission Factor			
			Heat Rate	Particulate	CO_2	SOx	NOx
		(kcal/kg)	kcal/kWh	kg/kWh	kg/kWh	kg/kWh	kg/kWh
35 MW Gas Turbine	Natural Gas	13000	2774	0.0000	0.6516	0.0000	0.0002
300 MW Combined Cycle	Auto Diesel	10500	1790	0.0000	0.5553	0.0034	0.0021
15 MW Reciprocating Engines	Furnace Oil	10300	2210	0.0012	0.7060	0.0158	0.0111
150 MW Combined Cycle	Natural Gas	13000	1830	0.0000	0.4298	0.0000	0.0002
300 MW Combined Cycle	Natural Gas	13000	1768	0.0000	0.4153	0.0000	0.0001
600 MW Combined Cycle	Natural Gas	13000	1758	0.0000	0.4129	0.0000	0.0001
600 MW Nuclear Power	Nuclear	-	-	0.0000	0.0000	0.0000	0.0000
5 MW Dendro Plant	Dendro	3224	5694	0.0061	0.0000	0.0000	0.0048

10.6 Environmental Implications – Base Case

Presented below is a quantitative analysis of the emissions associated with the Base Case generation expansion plan described in Chapter 8. The total particulate and gaseous emissions (controlled) under the Base Case plan are shown in Table 10.9 and Figure 10.3.

Table 10.9 – Air Emissions of Base Case

1000 tons/year

Year	PM	SO2	NOx	CO_2
2020	3	66.3	47.4	9,419
2021	3	57.8	42.4	9,772
2022	3.1	28.4	22	9,906
2023	2.9	23.6	18	10,224
2024	3.1	21.6	16.7	11,261
2025	3.1	7.7	7.2	12,285
2026	3.3	7.4	7.1	12,865
2027	3.4	9	8.4	13,401
2028	3.7	8.2	7.8	14,667
2029	4	9	8.5	15,330
2030	4.2	10	9.3	15,903
2031	4.4	10.6	9.9	16,398
2032	4.7	10.6	10	17,767
2033	4.9	12	11	19,052
2034	5.2	11.5	10.9	19,671
2035	5.5	12.2	11.5	20,202
2036	5.7	11.8	11.4	20,841
2037	6	11.6	11.4	22,303
2038	6.2	11.2	11.3	22,931
2039	6.5	11.6	11.6	24,421

With the introduction of coal and natural gas based generation, CO_2 emission shows a continuous increasing trend. However, the introduction of Natural Gas Combined Cycle power plants to the system reduces theincreasing rate of CO_2 emissions. The higher level of particulate, SO_x and NO_x emissions in the initial years is due to dispatch of furnace oil fired power plantswhich are added to the system on short term basis due to delays in implementation of the power plants identified in LTGEP 2018-2037.Apart from that particulate, SO_x and NO_x has an increasing trend with time.

According to Figure 10.4, SO_x and NO_x emissions per kWh shows a levelised trend while per unit CO_2 emissions has slightly an increasing trend. The higherenergy dispatch of furnace oil fired power plants with heavy SO_x and NO_x pollutants has led to much higherper unit emission levels in the initial years.

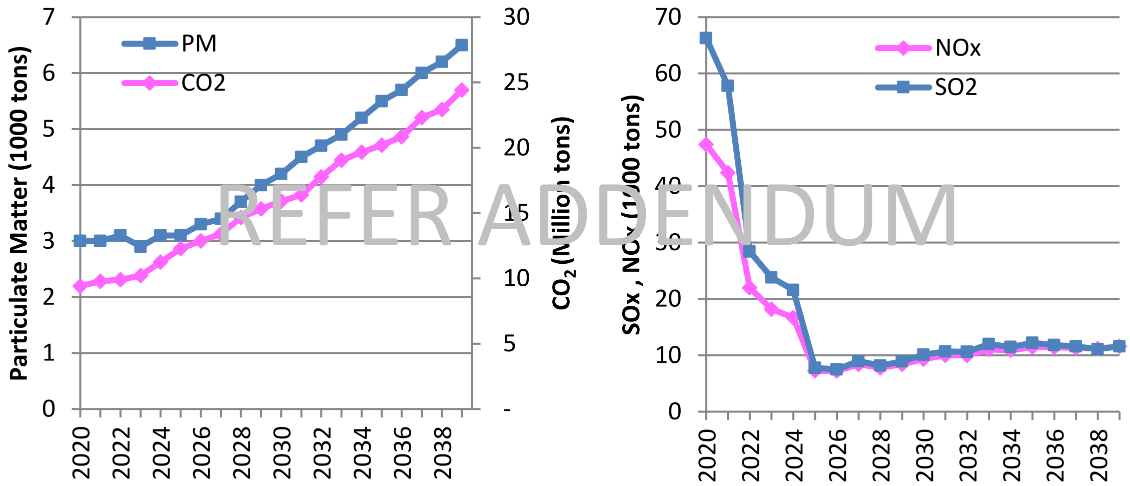


Figure 10.3– PM, SO_2, $NO_x$and CO_2 emissions of Base Scenario

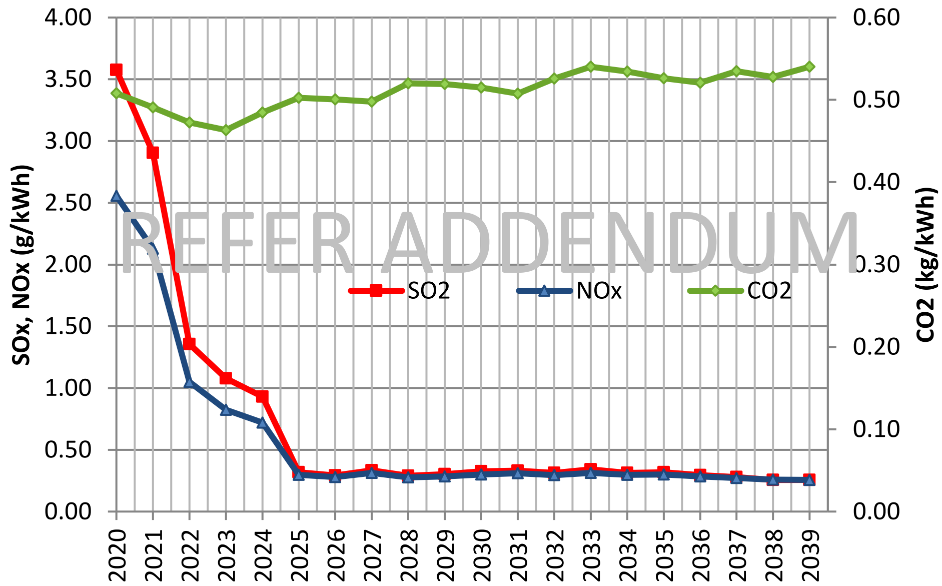


Figure 10.4 – SO_2, NO_x and CO_2 emissions per kWh generated

10.7 Environmental Implications – Other Scenarios

10.7.1 Comparison of Emissions

The effects on emissions under following scenarios were analysed and evaluated against the Base Case emission quantities.

1. Reference Scenario
2. HVDCScenario
3. Energy Mix with Nuclear Scenario

From Figure 10.5 and Figure 10.6 it can be seen that the SO_2 and NOx emissions are higher during the initial years due to the dispatch of furnace oil power plants which are added for short term requirement. After 2025 the SO_2 and NOx emissions have drastically reduced and thereafter the rate of increase is also very low.

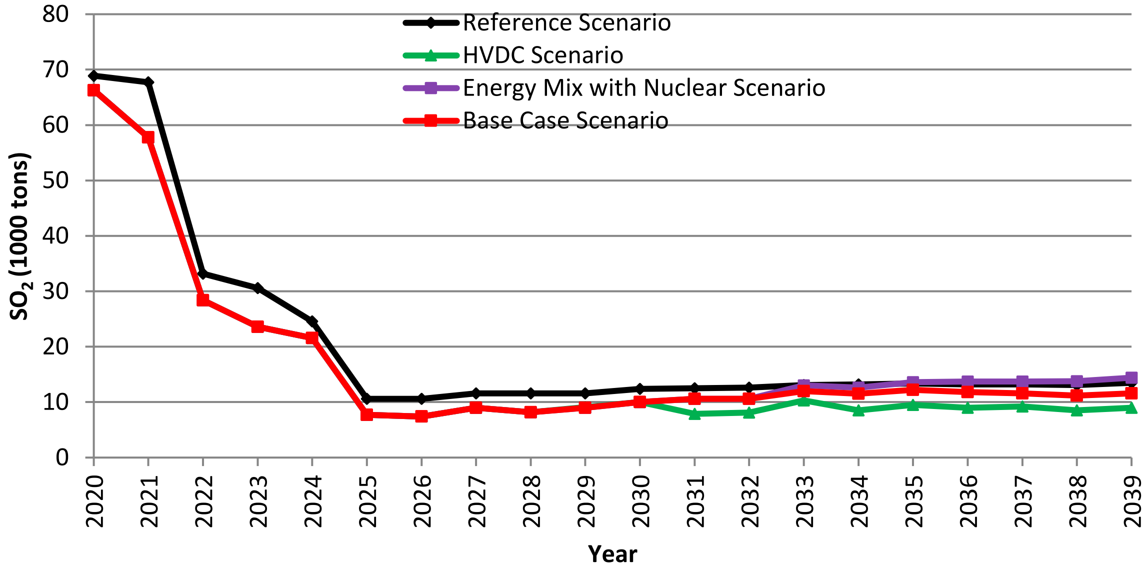


Figure 10.5 – SO_2 Emissions

In the HVDC scenario emissions of the electricity imported will not be accounted and hence this scenario has lowest SO_2 and NOx emissions. (Energy export also not considered for analysis)

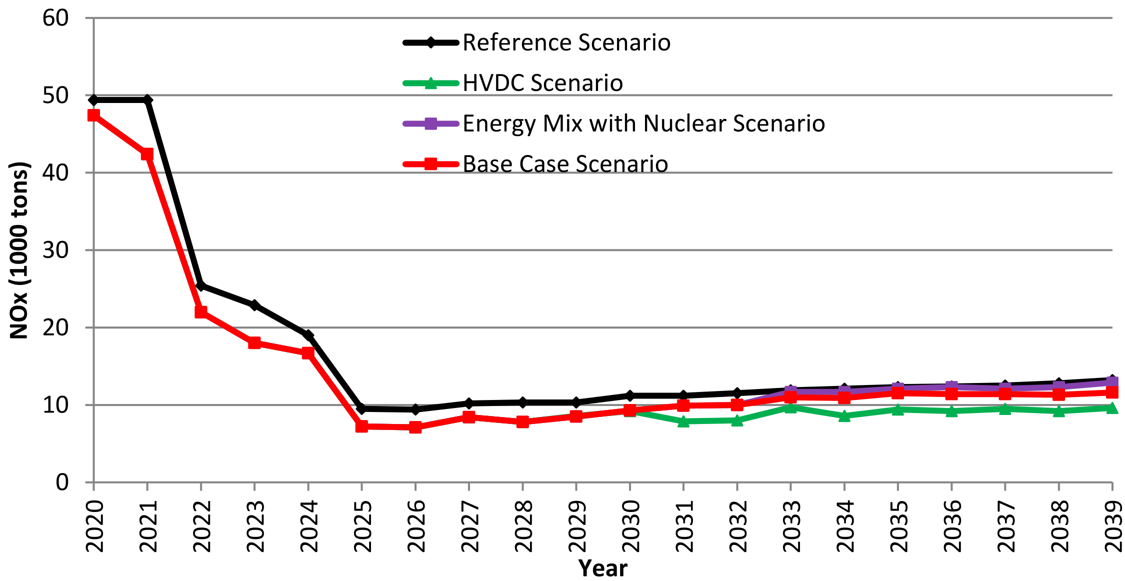


Figure 10.6 – NOx Emissions

Figure 10.7 shows the CO_2 emissions of the scenarios. Reference Scenario has higher CO_2 emissions compared to Base Case Scenario due to non integration of future renewable energy power plantsto the system. The CO_2 emission factors of NG fired combined cycle plants are about 50% less than that of coal fired power plants. Therefore theincreased number of NG fired combined cycle power plants in the Base Case scenario is also contributing towardsthe reduction of CO_2 emissions. HVDC and nuclear scenarios have lower CO_2 emissions after they are introduced to the system.Nuclear scenario has lowest CO_2 emissions due to replacement of coal and NG combined cycle power plants.

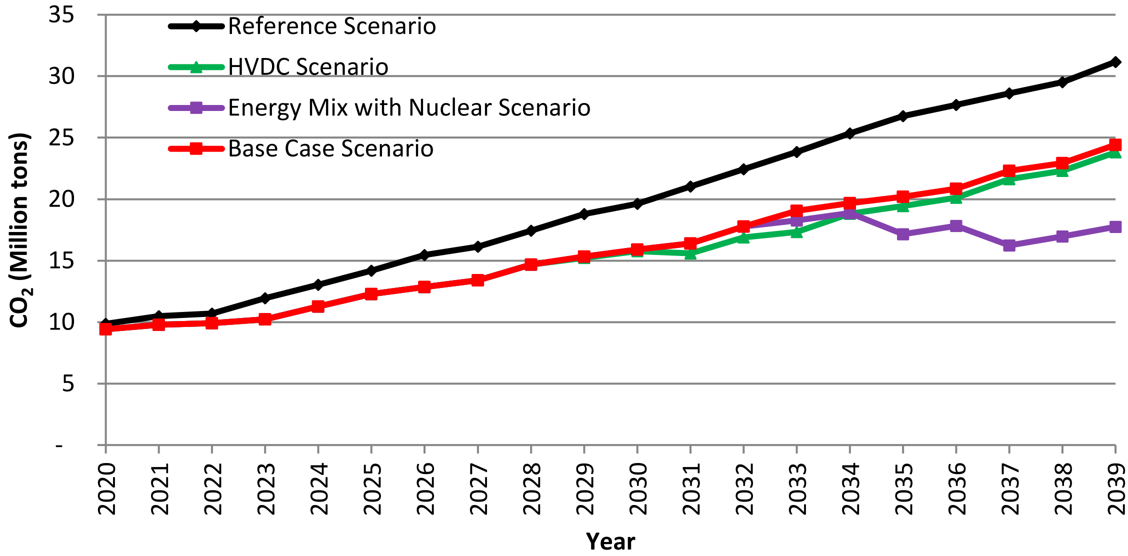


Figure 10.7 – CO_2 Emissions

Similarly particulate emission factors of NG fired combined cycle plants are negligiblecompared to coal fired power plants. Future biomass power plants have contributed mainly towards the particulate emissions compared to Reference case. Figure10.8 shows the comparison of PM emission related to various scenarios.

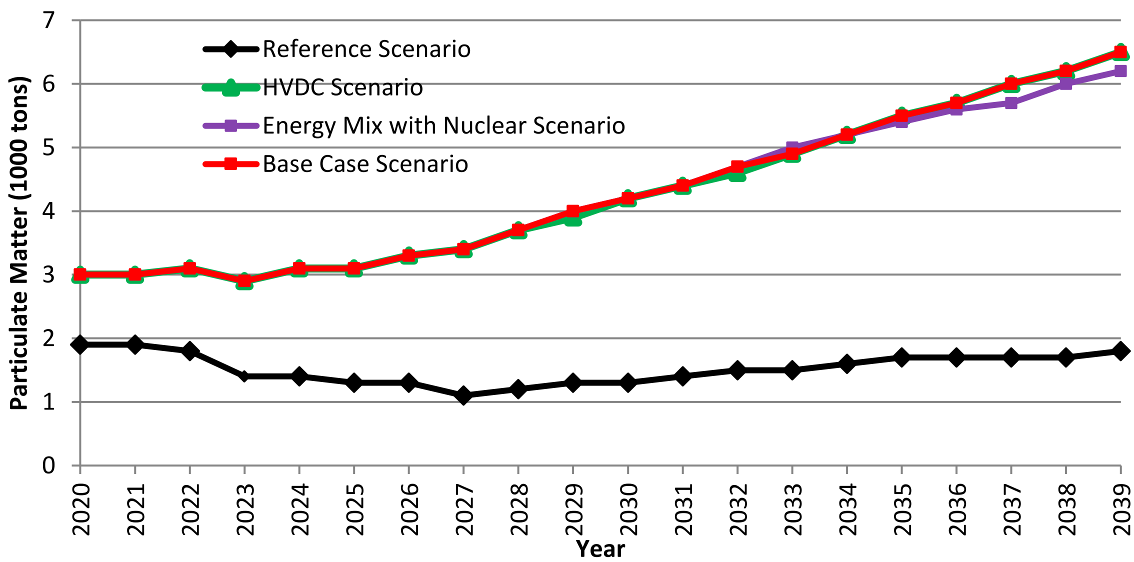


Figure 10.8 – Particulate Matter Emissions

Figure 10.9 shows the past actual and forecast values of average emission factors for the Base Case and the Reference Scenarios. Average emission factor of the Base Case scenario shows a levelized trend in the long term.

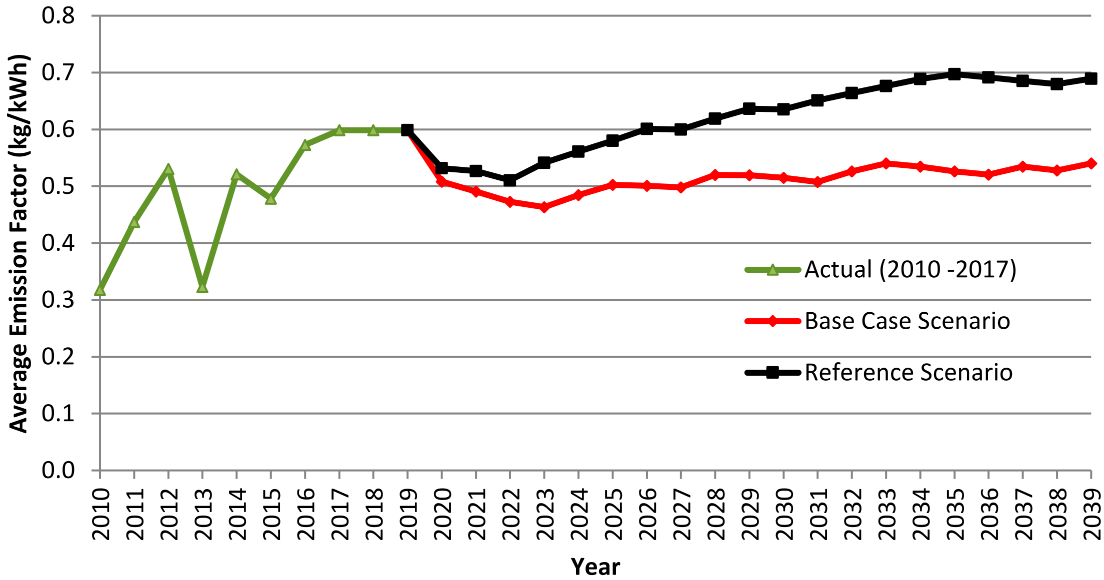


Figure 10.9 – Average Emission Factor Comparison

10.7.2 Cost Impacts of CO_2 Emission Reduction

Comparison of total CO_2 emission with total system cost is shown in Figure 10.10.

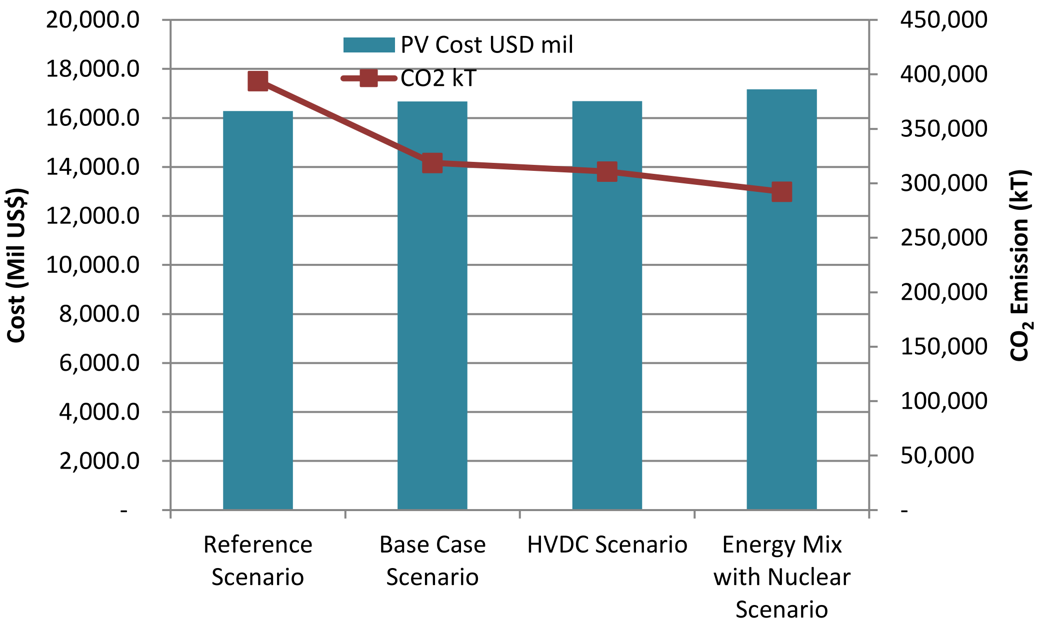


Figure 10.10 – Comparison of System Cost with CO_2 Emissions

Further, the incremental cost of each case was analysed by comparing the cost differences and the reduction of CO_2 emissions in each case compared to Reference Case and shown in Figure 10.11.

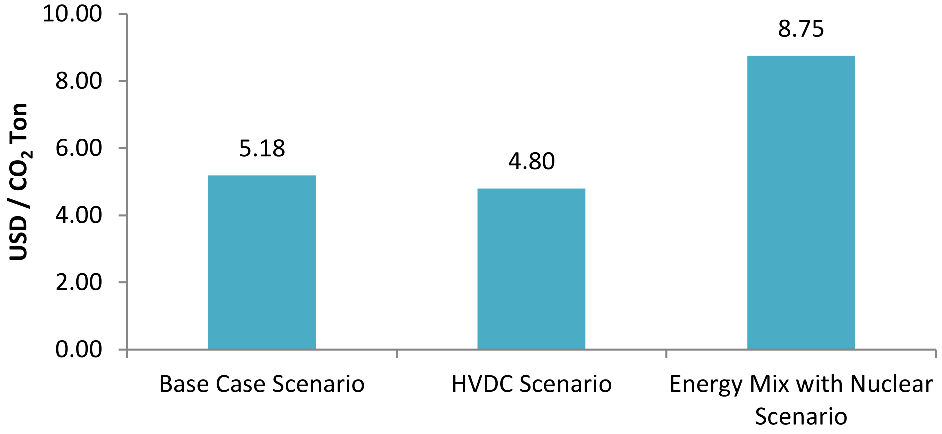


Figure 10.11 – Comparison of Incremental Cost for CO_2 reduction

There are other 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 functionof 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.Therefor it can be a useful analytical tool for Sri Lanka in defining a cost-effective, low carbon investment program for Sri Lanka.

10.8 Climate Change

10.8.1 Background

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

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

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

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

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

Major events and decisions by Conference of Parties are summarized in Table 10.10.

Table 10.10 – 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.

COP	Events and Decisions
COP18/CMP8 Doha, Qatar 2012	Extension of the Kyoto protocol Developed country parties agreed for a second commitment period up to 31.12.2020, a revised list of greenhouse gases and commitment by parties to reduce GHG emission by at least 18% below 1990 levels. However, the expected reductions are comparatively low and there is a significance difference in the parties to the second commitment compared to the previous with parties such as Japan, Canada, and Russia not being included for the second commitment. 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.
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	Governments agreeda 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, since this would significantly reduce risks and the impacts of climate change. Before and during the Paris conference, countries submitted comprehensive national climate action plans (INDCs). This agreement wasopened 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 instrumentsof ratification. On 5 October 2016, the threshold for entry into force of the Paris Agreement was achieved. The Paris Agreement entered into force on 4 November 2016. Sri Lanka ratified in September 2016.
COP22/CMP12/CMA1-1 Marrakech,Morocco 2016	The first session of the Conference of the Parties serving as the Meeting of the Parties to the Paris Agreement (CMA1) took place.The Conference successfully demonstrated to the world that the implementation of the Paris Agreement is underway and the constructive spirit of multilateral cooperation on climate change continues.

COP	Events and Decisions
COP24/CMP14/CMA1-3 Katowice, Poland 2018	“Paris Agreement Rule Book” has been taken up for negotiation and participants from Ministry of Mahaweli Development & Environment have participated from Sri Lanka.

10.8.2 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 importantfor both mitigation and adaptation activities. Massive investment is required in order to reduce greenhouse gases significantly as well as for countries toadapt to the adverse effects andreduce 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 establishedwith 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 entrustedto 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.

10.8.3 Sri Lankan Context

Responding to climate change involves two possible approaches: reducing and stabilizing the levels of heat-trapping greenhouse gases in the atmosphere (“mitigation”) and/or adapting to the climate change already in the pipeline (“adaptation”).

Sri Lanka, being highly vulnerable to climate change impacts 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 GHG 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 countryin 2002.

In order to address the issues in climate change a separate dedicated institution named Climate Change Secretariat was created under the Ministry of Mahaweli Development and Environment in 2008. National Climate Change Adaptation Strategy for Sri Lanka 2011-2016 (NCCAS) was developed in 2010, but mitigation strategies are still being developed. Further 'The National Climate Change Policy of Sri Lanka' has been developed by the Climate Change Secretariat of Sri Lanka under Ministry of Mahaweli Development and Environment.

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 onvarious activities related to mitigation.

Following section further describe the different aspects towards reducing GHG emissions and providing sustainable energy to Sri Lankan consumers.

(a) Amendment ofNational Energy Policy and New Energy Mix

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.

Government of Sri Lanka has given more priority for the Energy sector which is highly dependent on imported fossil fuel which is 55% in 2017 and to reduce the present trend, sustainable energy policies are enforced to absorb more renewable energy to the system.The proposedamendment of the National Energy Policy and Strategies adds further focus into enhancing the share of renewable energy.

The New Government Policy on 'Deciding the Energy Mix for Electricity generation in Sri Lanka' identifies the necessity to diversify the energy mix through integration of more renewable energy by strategically developing alternative renewable energy sources such as wave energy, geothermal, ocean thermal, municipal solid waste in addition to solar, wind, mini hydro and biomass.

(b) Nationally Determined Contributions (NDCs)

In accordance with the LTGEP 2015-2034 Sri Lanka also prepared Intended Nationally Determined Contributions (INDCs) and submitted to UNFCC. Among mitigation strategies, Energy Sector INDCs stated that Sri Lanka expects 4% unconditional and 16% conditional reduction of greenhouse gas emissions with compared to Reference scenario in 2030. After ratification INDCs became NDCs and Sri Lanka has an obligation to achieve the target.

During the preparation of LTGEP a separate scenario was analysed by eliminating the committed power plants such as Uma oya, Broadlands, Moragolla and Mannar wind park from Reference case in order to analyse the respective unconditional emission reduction. Further the reference case was compared against the base case to analyse the conditional emission reduction. Both analyses resulted in thatSri Lanka NDC target of 4% unconditional and 16% conditional can be well achieved through the LTGEP scenarios.

(c) Contribution from Renewable Energy

Even up to mid-nineties the Sri Lankan power sector was mainly hydro based with the contribution being over 90%. With the almost full utilization of the available major hydro power potential, CEB had to turn to thermal power which was mainly oil. The first Coal plant of 300MW capacity was only established in 2011 and subsequently next phase in 2014. In 2017, Sri Lanka has achieved a level of economic development of close to 4000 USD per capita income with a comparatively low effect on the global GHG emission. Therefore, Sri Lanka has a right to utilise available resources in order to continue in the development path with the least economic effect on its people.

The Base Case Plan has been worked out based on the least cost economically optimal plant additions considering the energy mix policy in order to meet the forecast electricity demand. Coal power plantsandNG combined cycle power plants will form the major share of the optimised energy mix in the near future.CEB has also initiated to develop remaining major hydro power projects although they involve higher capital cost.

In the Base Case Plan 2020-2039, Other Renewable Energy share is optimized and maintained more than 20% by 2020 onwards and would result in reduction of emissions from power generation considerably. The total projected Renewable Capacity share is maintained at 50% continuously and more than 35% energy share on average which could have the potential to cater around 50% energy depending on favourable weather conditions.

By comparing Reference Case and Base Case Plan, it could be observed that by introducing 3325MW ORE, 450MW NG fired Combined Cycle, 400MW Pumped Storage Hydro and 39MW Major Hydro Power Plants, several thermal power plant additions were eliminated. This would reduce the CO_2 emissions of Base Case Plan as shown in the Figure 10.12.

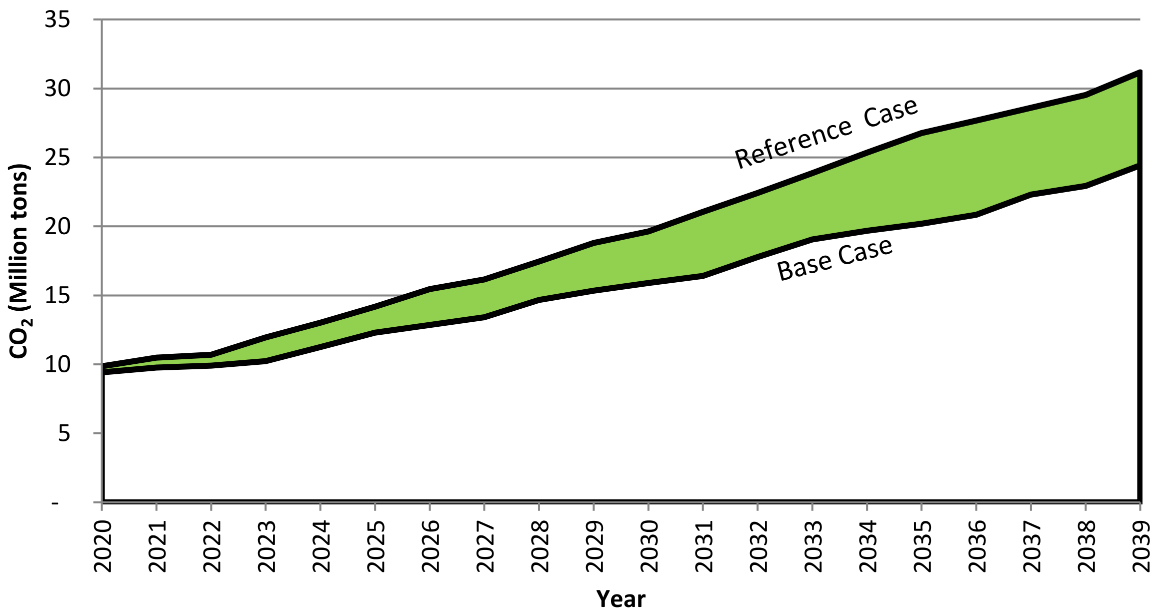


Figure 10.12 – CO_2 Emission Reduction in Base CaseCompared to Reference Case

(d) 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 partof 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.

(e) Carbon Partnership Facility

Sri Lanka has initiated a carbon crediting program with the World Bank where the emission reductions above the NDC targets will be transferred to Carbon Partnership Facility (CPF) of World Bank. CEB act as the trustee and any Private Power Producer who is willing to join the scheme will have to transfer the carbon credits through CEB. Carbon revenue received in this manner may be used to overcome technical and financial barriers for renewable development.

There are different pricing approaches to determine the terms of the carbon finance payment. Diverse country and sectoral context as well as relationship with countries NDC targets also need to be considered during the process of price determination.In the absence of detailed data, price should be determined by negotiation between buyers and sellers taking into account the sellers' Willingness to Accept and Buyers' Willingness to Pay.

In December 2018, theproject was approved for funding and the next step is the negotiation of contract terms including pricing. Internal arrangements for carbon revenue management are also being discussed at present.

(f) Partnership for Market Readiness (PMR)

The Partnership for Market Readiness (PMR) is a grant-based, capacity building trust fund that provides funding and technical assistance for the collective innovation and piloting of carbon-pricing instruments (CPIs) that reduce greenhouse gas (GHG) emissions. 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 have been involved in providing necessary input and feedback to the work carried out under PMR program.

(g) 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.

(h) 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 2017 it has been reduced to approximately 8.45%.

(i) 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.

(j) Tree Planting Program

The New Government Policy on ‘Deciding the Energy Mix for Electricity generation in Sri Lanka’ reflects accepting the minimizing of carbon footprint from the electricity sector, through carbon sequestration using reforestation as an important principle in electricity generation.

Ceylon Electricity Board has identified this as a social responsibility and has carried out numerous tree planting campaigns within last three years. Since 2015, CEB has planted over 17740 trees including over 5000 trees consisting of Kaluwara, Kumbuk,KohombaBamboo, Mango...etc.

Additionally, incommemoration of 50th anniversary of CEB, it is planned to plant 50000 trees in 2019. It is expected to be carried out in areas such asSamanalawewa Dam,Laxapana Dam, Upper Kothmale Dam,Kothmale Power Station, Norochcholei Power Station,NilmabePower Station, Pooneryn Area, KukulegangaReservoir, CastelreighReservoir, IginiyagalaReservoir, UdawalaweReservoir...etc.

10.9 Environmental Impact Mitigation–Renewable Energy Development

The contribution of grid-connected renewable power plants has gradually risen over the last decade. Development of renewable power plants lead to several environmental and social issues. Environmental issues are concerned with conflict with bird migration routes, bird habitats, vegetation and unique land features in the sites where renewable potential is high. Social issues are concerned with inhabitants in the development sites.

Mitigation of such social issues should be involvedwith stakeholder consultations, grievance readiness mechanismsand resettlement. Measures should also be taken to minimize the impact on the environment during the development of renewable power plants.

In view of above, Environmental and Social Management Framework (ESMF) has been developed with the support of international consultants in order to strengthen the legal and regulatory framework,environmental and social screening process and introduce continuous monitoring plan.This would enable the environment and social impact mitigation process to be complied withinternational donor agencies' standards.

The objective of the ESMF is to set out clear guidelines, procedures, and measures that other renewable energy developers can use to facilitate the adequate environmental and social management, including risk management. This will provide guidance to ensure that implementation of renewable projects are carried out in an environmentally and socially sustainable manner, taking into account Sri Lanka's relevant legislation and regulations, as well as the applicable international safeguard policies.

In particular, the ESMF seeks to ensure that:

- The design of other renewable energy projects takes consideration of the potential environmental and social impacts, and ways to minimize, mitigate and/or manage them
- The potential environmental and social implications ofconstruction of power plants or of transmission and distribution lines are taken into account
- Negative impacts during construction and operation are avoided where possible, and where negative impacts are expected, measures to minimize, mitigate and/or manage these impacts are undertaken
- Any losses of assets and/ or means of livelihood resulting from the acquisition of land are compensated for properly
- Environmental and social issues, including gender and health and safety aspects, are integrated into the identification, design, and implementation phases of power plants, depending on the energy technology involved and the local context, and intothemonitoring plans to be prepared
- The contributions of power plants towards the health and well-being of a society are taken into consideration, and affected people have a chance to participate in decisions that directly affect them

The ESMF has been prepared to ensure that the due diligence process is followed by all the entities and agencieswho are involved in providing clearances for the development of renewable power plants, engaged in implementing and monitoring.

10.10 Externalities

Like any other heavy industry, power industry too causes adverse impacts to social and natural environment of varying degrees. Impacts such as releasing of pollutants to local environment, release of waste heat, noise pollution, inundation of lands due to construction of hydro reservoirs etc are local effects, where as the releasing of Green House Gases (GHG) are considered global. Such effects to local and global environment can have directly non quantifiable impacts to climate change, health, society, agriculture and even bio diversity. Such impacts, when expressed in monetary terms, are called Externality Costs. Estimates of such externality costs of different power generating technologies gives 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 where the externality costs vary from study to study by margins of 3 to 6 times.

Environmental and social impacts of development project 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 10.8.3. This LTGEP is prepared complying with all such the international commitments related to climate change mitigation.

10.10.1 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.

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 due to various reasons.

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 adopted to Sri Lanka as coal plants operated in such countries are of much older technology than Lakvijaya Coal power plant operated in Sri Lanka. Therefore, country and location specific studies are required to be done to reasonably estimate the damage cost even though that too can be highly subjective.

10.10.2Global Damage Issues of GHG Emissions

Water vapour (H_2O), Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O) and Atmospheric Octane (O_3) are some of the primary greenhouse gases that are believed to cause global warming and climate change. 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 mine to plant. When total life-cycle emissions, which include emissions at the point of conversion to mining/extraction, transportation, liquefaction and regasification and combustions are considered, the end results are totally different to considering only the effects of releasing GHGs during combustion. For example, when life cycle emissions of natural gas, liquid fuel oils and coal are considered, the equivalent GHG emissions of natural gas (which consists of methane having a GHG causing effect which is 28 times more than CO_2) is more than other liquid fuel oil and are in the same range of coal. Such direct and indirect emissions are present not only in thermal power generating sources but in all types of generating sources including hydro, wind and solar PV. Thus, estimating externality costs of individual power generating technologies and fuels is highly subjective and goes beyond the planning studies conducted by CEB.

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 was required under law. Additional capital costs to do so have already been considered and factored in to capital costs of candidate power plants used in this planning study. Thus, CEB has already considered additional capital costs to bring down externality costs of power generating technologies and hence the costs of externalities have already been factored in to planning studies in the form of additional capital investment.

CHAPTER 11
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.

11.1 Introduction

As discussed in Chapter 8, Base Case Plan is a mix of thermal, hydro and other renewable energy generation technologies. Timely implementation of proposed power plants is crucial to avoid capacity shortages, energy shortages and high cost alternative generation in the future.

Accordingly, the recommendations for the Base Case Plan is given below with special emphasis on the importance of implementation of proposed power projects during the planning horizon.

11.2 Recommendations for the Base Case Plan

Major recommendations for the Base Case Plan are as follows.

11.2.1 Short Term Recommendations for 2020 and 2021

The approved Long Term Generation Expansion Plan 2015-2034 has identified 1x300MW Natural Gas operated Combined Cycle Power Plant to be commissioned by 2019. Furthermore, the approved Long Term Generation Expansion Plan 2018-2037 has identified requirement of having 2x300MW Natural Gas operated Combined Cycle Power Plants to be commissioned by 2019 and 2021.

The Long Term Generation Expansion Plan 2018-2037 has identified 320MW reciprocating engines to be implemented by 2018 and contingency analysis has identified an additional capacity of 150MW for the year 2019 considering simultaneous occurrence of risk events such as implementation delays, very dry hydro conditions , long outages of major power plant etc.

Assuming that 2x300MW Natural Gas operated Combined Cycle Power Plants commissioned by 2022, following capacities are required (Table 11.1) to maintain the stable supply in years 2020 and 2021 in addition to the 470MW requirement identified in year 2019

Table 11.1 – Short Term Power Requirement

Year	Capacity Requirement
2020	195MW
2021	105MW

Timely procurement of short term power requirement would avoid the capacity shortages due to non-implementation of long term power plants in years 2020 and 2021.

11.2.2 Long Term Recommendations

- Thermal Power Plants

Base Case Plan 2020-2039 has identified large-scale thermal power development including 5x300MW Natural Gas Combined Cycle Power Plants, 4x300MW New Coal Power Plants and 3x35MW Gas Turbine up to 2030.

Furthermore, beyond 2030 5x300MW Natural Gas Combined Cycle Power Plants and 4x300MW New Coal Power Plants were identified in the same plan. .

Timely implementations of these firm capacity power plants are very much important to avoid capacity shortages, energy shortages and costly emergency generation in the future. Furthermore, these power plants will reduce the environmental impacts from electricity generation produced from low efficient thermal power generation.

It is also important to implement associated transmission lines for the interconnecting these power plants to the national grid by expediting the ongoing transmission projects and also to initiate other identified transmission line connection.

- Hydro Power Plants

Base Case Plan 2020-2039 has identified committed Hydro Power Plants, i.e. 35MW Broadlands, 122MW Uma Oya and 31MW Moragolla in the years 2020, 2021 and 2023 respectively. Also considered the candidate hydro power developments 24MW Seethawaka by 2023 and 15MW Thalpitigala by 2024.

Timely implementation of all the committed and candidate Hydro Power plants considered in the Base Case Plan is important to avoid power shortages in future.

- Pump Storage Power Plants

Implementation of 3x200MW Pump Storage Power Plant has been identified in 2028, 2029 and 2032 respectively. This is identified as the energy storage technology and facilitate projected variable renewable energy (Wind & Solar) absorption by reducing the curtailments of energy generation. In addition, this will operate as a peaking power plant by minimizing high cost thermal generation.

Therefore, 3x200 MW Pump Storage Power Plant implementation is important to be in line with projected Other Renewable Energy (ORE) development.

- Other Renewable Energy Power Plants

Total capacity addition projected for Other Renewable Energy (ORE) in the Base Case Plan 2020-2039 is a mix of 1175MW Wind, 1900MW Solar, 250MW Mini Hydro and 100MW Biomass.

Timely implementations of these ORE plants as per the schedule is important to avoid energy shortage of power system over the 20 year planning horizon.

- Recommendations for the integration of Variable Renewable Energy (VRE)

Integration of Other Renewable Energy sources in to the Base Case Plan 2020-2039 is considered in an optimum manner based on the study of "Integration of Renewable Based Generation into Sri Lankan Grid 2020-2030".The study revealed that following recommendations are to be fulfilled in order to facilitate the smooth integration of ORE in to the system:

- Day ahead, hourly basis and accurate Wind and Solar PV energy forecasting system should be implemented as early as possible.
- 24 hour (round the clock), renewable energy desk has to be set up and output from each renewable energy sources have to be monitored (if existing plants are not equipped with communication facilities, measures have to be taken to establishing them).
- In order for smooth operation of power system, Variable Renewable Energy (VRE) curtailment rights have to be given to system operator. Feasibility of implementing compensation mechanism has to be studied.
- Planned network strengthening projects must be completed as scheduled.
- Future base load power plants should be designed for cyclic operation in order to keep the VRE curtailment at a minimum level.
- The ORE locations should be prioritized based on the plant factors, land availability and cost of transmission network and developed accordingly.
- If the proposed conventional plants are not commissioned as scheduled, the VRE addition in the plan has to be revised accordingly. Thus it is proposed to review this planning methodology once in two years.

- Availability of Liquefied Natural Gas (LNG)/Natural Gas (NG) and Infrastructure

Natural Gas fired Combined Cycle Power Plants operation will be expect from year 2021 onwards with the basis of NG fuel to be delivered at power plants. Therefore, required LNG infrastructure with associated NG distribution network to be developed in line with this time target considering this as a national priority project.

The LNG procurements contracts should be negotiated to minimize the 'Take or Pay' risks in order not to commit the minimum plant factors. Otherwise, this would lead to curtailment of more ORE sources in order to dispatch the LNG operated power plants.

- Contingency Analysis

As discussed in Chapter 13 Contingency Analysis, timely implementation of planned power plants in the Base Case Plan is very much important. Additional capacities were identified in the Contingency Analysis for the single occurrence and simultaneous occurrence of risk events, which are given below:

- Variation in Hydrology
- Variation in Demand

- Delays in implementation of Power Plants
- Long period outage of a Major Power Plant

- Securing Future Energy Infrastructure

Identification and securing of land for future energy infrastructure development is important for timely implementation of the projects

In the power sector, securing the lands for the future power plants and other related facilities is a crucial issue. Therefore, locations for establishing power generation facilities and related transmission corridors which interconnect such facilities to the national grid should be identified considering this as a national priority. Potential locations identified at present for future power generation projects are given in Table 11.2.

Table 11.2 – Potential Locations for Future Power Generation Projects

Power Project	Identified Location
LNG Projects	Kerawalapitiya / Hambantota
Coal Power Project	Foul Point in Trincomalee
Extension of Coal Power Project	Norachcholai in Puttalam
Pump Storage Power Project	Aranayaka in Kegalle / Victoria-Wewathenna in Kandy
Wind Park Developments	Mannar, Pooneryn, Kalpitiya, Northern & Eastern regions
Solar Park Developments	Siymbalanduwa in Monaragala, Pooneryn, Hambantota, Northern & Eastern regions
Solar/Wind Projects	Puttalam, Welikanda, Northern & Eastern regions

CHAPTER 12
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 2020-2039.

12.1 Committed and Candidate Power Plants in the Base Case Plan

12.1.1 Committed Plants

Following power projects are considered as committed projects in the present study.

- Hydro and Other Renewable Energy (ORE) Power Projects:

  Broadlands (35MW), Uma Oya (122MW), Moragolla (31MW) and Mannar Wind Park (100MW)

- Thermal Power Projects:

  Kelanitissa Gas Turbine (3x35MW), Natural Gas fired Combined Cycle Power Plant (300MW) and Reciprocating Engine Power Plants (4x24MW) at Habarana, Moneragala, Horana and Pallekelle

12.1.2 Present Status of the Committed and Candidate Power Plants

A brief description of the current status of the committed and candidate power projects on which the commitments should be made are given below.

✓ Short Term Power Projects for 2020 and 2021

The Long Term Generation Expansion Plan 2018-2037 has identified 320MW reciprocating engines to be implemented by 2018 and contingency analysis has identified an additional capacity of 150MW for the year 2019. In addition, assuming that 2x300MW Natural Gas operated Combined Cycle Power Plants to be commissioned by 2022, additional capacity requirement of 195MW is identified for the year 2020 and 105MW for the year 2021.

Presently, 170 MW has been added to the system as extension of existing power plants on a short term basis. Tender documents are being prepared for 4x24MW Reciprocating Engine Power Plants (at the Grid Substations of Habarana, Moneragala, Horana and Pallekelle) to be commissioned for the long term operation. For the remaining capacity requirement, several options are under consideration.

✓ Long Term Power Projects – Major Hydro, Other Renewable Energy and Major Thermal

(i) Broadlands Hydro Power Project

China National Electric Equipment Corporation (CNEEC) was selected as the main Contractor for the Broadlands Hydro Power Project and the main construction works were commenced in 2013.

At present, the construction work and electro mechanical work are in Progress in parallel at Main Dam Site, Main Tunnel, Diversion Tunnel and Power House Site and the project is scheduled to be completed by 2020.

(ii) 100MW Mannar Wind Park

Ceylon Electricity Board initiated the first 100MW wind farm in the Mannar Island with the financial assistance of Asian Development Bank (ADB). At present, tender has been awarded and construction work is in progress. Expected date of completion of the project is mid 2020.

(iii) 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 Renewable Energy and Ceylon Electricity Board. The financial assistance for the project is provided by the Government of Iran and currently the project is under construction (civil works, hydro mechanical works and electro mechanical works) and expected to be completed by December 2020.

(iv) 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. Civil works, electro mechanical and hydro mechanical works will commence in 2019 and the power plant is expected to be in operation by December 2022.

(v) Seethawaka Hydro Power Project

CEB has conducted the initial feasibility study together with the procurement of consultancy services for Environmental Impact Assessment (EIA) of the project. A separate Project Management Unit was appointed in CEB to implement the project and the detailed feasibility study has been completed in December 2018. Presently the detail design and EIA is in progress.

(vi) Other Multipurpose 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 and EIA studies of the Thalpitigala Hydro Power Project have been finalized and approved. Thalpitigala hydro power plant is expected to be in operation in 2024.The preliminary feasibility studies for Gin Ganga hydro project is in progress and the parameters of the hydro power plant is yet to be finalized.

(vii) Pumped Storage Power Project

CEB completed the study on “Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka” in 2014, which was conducted with the technical assistance from JICA. This study identified the future options to meet the peak power demand in Sri Lanka. Pumped Storage Power Plant option has been selected as the most suitable option and several sites have been suggested in priority order considering their social, environmental and financial impacts. Pumped storage hydro power plant as a large scale storage medium 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. Moreover, the pumping operation during low load periods enables the efficient operation of base load power plants in the system. Considering those facts, the technical, operational and economic aspects of introducing a pump storage power plant should be further reviewed with a feasibility study. Electricity Sector Master Plan Study 2018 further emphasized Pump Storage Option and identified Victoria-Wewathenna as an alternative location for further studies.

(viii) 3x35MW Kelanitissa Gas Turbine Power Plant

Project Management Unit has been formed within CEB for the implementation of the power plant and RFP (Request for Proposal) is under the preparation process. This is expected to be in operation by 2021.

(ix) 300MW Natural Gas fired Combined Cycle Power Plant

CEB has called for the RFP for the development of a 1x300MW Natural Gas fired Combined Cycle Power Plant at Kerawalapitiya. Presently, awarding of the tender is pending and it is expected to be in operation by 2022.

(x) Coal Power Plants in the West Coast – Extension at Norochcholai

An initial study has been carried out to evaluate the possibility of developing an additional 300MW capacity within the premises of Lakvijaya Coal Power Station as discussed in Section 4.4 of Chapter 4. Project Management Unit has been appointed within CEB to accelerate the implementation and an RFP to be prepared to procure the consultants for the feasibility study for the coal power development within and adjacent to Lakvijaya Coal Power Plant.

(xi) New Coal fired Power Plant – Foul Point, Trincomalee

Pre-feasibility study on High Efficient Coal Fired Thermal Power Plant was initiated in 2013 by the financial assistance from New Energy and Industrial Technology Development Organization (NEDO), Japan. The purpose of the study is to identify a suitable location to implement High-Efficient Coal Fired Thermal Power Plant to Sri Lanka. CEB and Japanese experts identified a land area in Sampur, Trincomalee which is most suitable for 1200 MW (either 300MW High efficient advanced subcritical power plants or 600MW Super critical power plants) coal power development. CEB received the Terms of Reference (TOR) for EIA from Central Environmental Authority in January 2015 and accordingly in May 2015 called for Expression of Interest for Consultancy to carry out the EIA of the project. However, the EIA of the proposed project was temporarily suspended due to the non-availability of the identified land for the power plant development. Presently an alternate land at Foul Point area has been identified and process of land acquisition is initiated. Necessary feasibility studies for the alternate land are to recommence once the land acquisition is finalized.

12.2 Power Plants Identified in the Base Case Plan from 2020 to 2030

The proposed major hydro, thermal and other renewable energy plants up to 2030 according to the Base Case Plan are given below.

Thermal Power Plants:

- 320MW Reciprocating Engine Power Plants in 2020 (Short term basis)
- 345MW Reciprocating Engine Power Plants in 2020 (Short term basis)

- 3x35MW Gas Turbine in 2021
- 105MW Reciprocating Engine Power Plants in 2021
- 2x300MW Natural Gas fired Combined Cycle Power Plants in 2022
- 300MW New Coal Power Plant in 2023 (Lakvijaya Extension Phase I)
- 300MW Natural Gas fired Combined Cycle Power Plant in 2023
- 300MW New Coal Power Plant in 2024 (Lakvijaya Extension Phase II)
- 300MW Natural Gas fired Combined Cycle Power Plant in 2025
- 300MW New Coal Power Plant in 2025 (Lakvijaya Extension Phase II or Foul Point Phase I)
- 300MW Natural Gas fired Combined Cycle Power Plant in 2026
- 300MW New Coal Power Plant in 2028 (Foul Point Phase I)

Major Hydro and Pump Storage Power Plants:

- 35MW Broadlands HPP in 2020
- 122MW Uma Oya HPP in 2021
- 31MW Moragolla HPP in 2023
- 24MW Seethawaka HPP in 2023
- 15MW Thalpitigala HPP in 2024
- 200 MW Pump Storage Power Plant in 2028
- 200 MW Pump Storage Power Plant in 2029

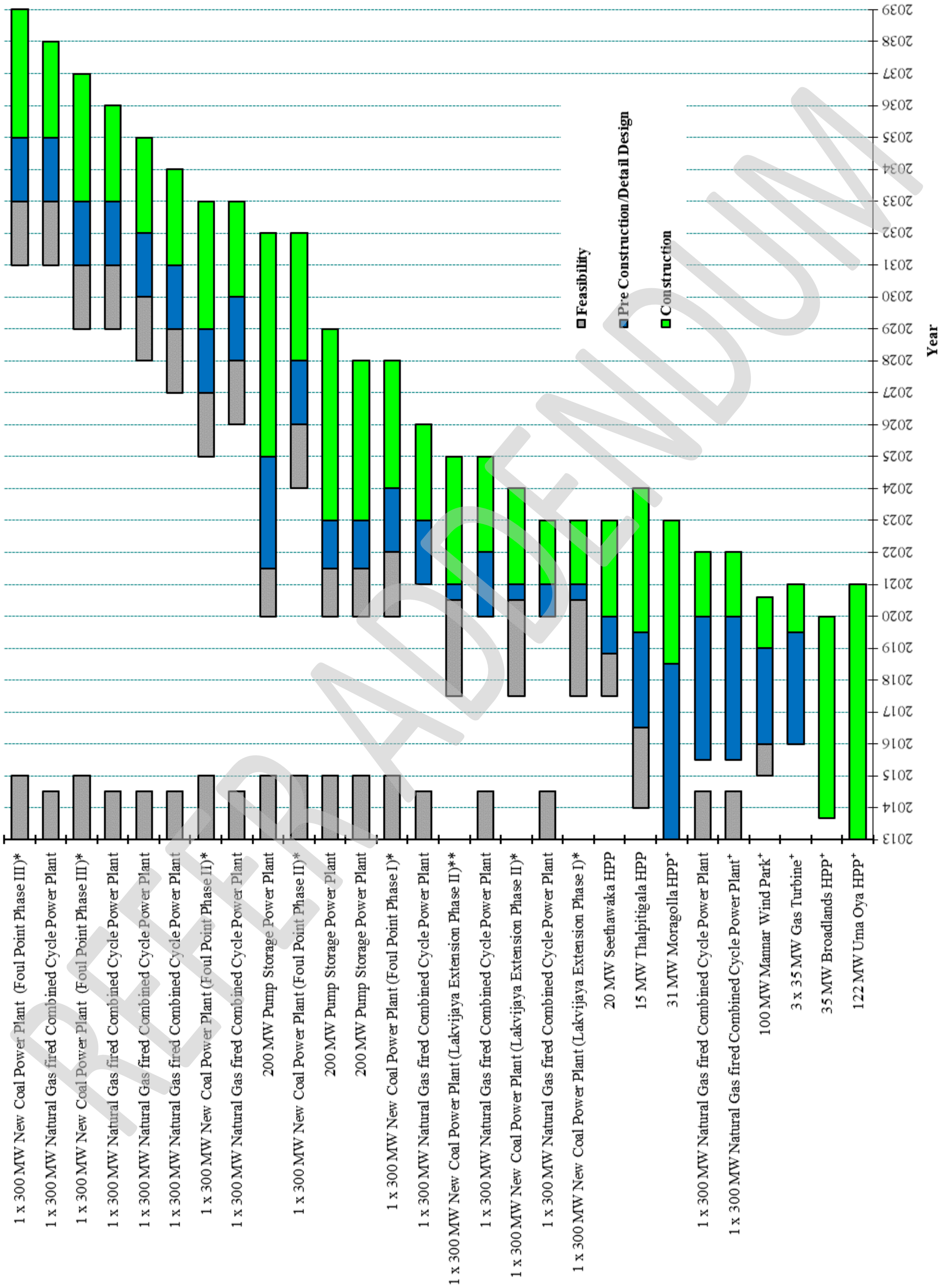
Other Renewable Energy (ORE) Plants:

Table 12.1 – ORE Additions 2020-2030

Year	Mini Hydro	Wind	Solar	Biomass
2020-2030	165MW	675MW	900MW	55MW

12.3 Implementation Schedule

The implementation schedule for both committed and proposed major power plants (hydro and thermal) in the Base Case 2020-2039 is shown in Figure 12.1.



[+]Committed Plants

*Change to super critical will be evaluated

**Lakvijaya Extension Phase II or Foul Point Phase I

Plants assumed as in operation from 1[st] January each year

Implementation of short term thermal power plants are not indicated

Figure 12.1 - Implementation Plan 2020-2039

12.4 Investment Plan for Base Case 2020-2039 and Financial Options

12.4.1 Investment Plan for Base Case Plan 2020-2039

Base Case Plan 2020-2039, annual investment requirement for the twenty-year period is graphically shown in Figure 12.2. The cost details of the investment plan for major hydro & thermal power projects and major wind & solar power developments are given in Annex 12.1 and 12.2 respectively. Tabulated annual investment costs includes only the plant-by-plant pure construction cost and excludes the construction cost for associated other infrastructures (coal jetty, LNG terminal & pipelines etc.).

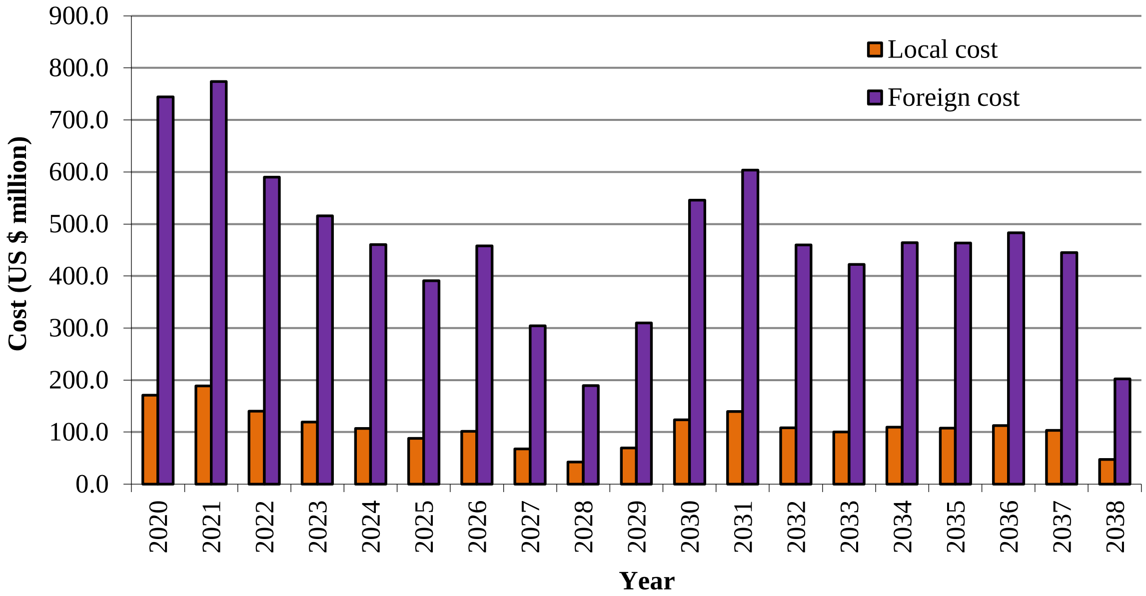


Figure 12.2 - Investment Plan for Base Case 2020 – 2039

12.4.2 Financial Options

Timely investment on the power generation projects are highly important to be in line with the commissioning years of the planned power plant developments.

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, 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 measuring the expected 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 includes,

- 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 the 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 13
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 2020 to 2024 in the Base case. The Contingency Analysis focus to identify the main risk events, which are given below:

(i) Variation in Hydrology
(ii) Variation in Demand
(iii) Delays in implementation of Power Plants
(iv) Long outage period of a Major Power Plant

13.1 Risk Events

13.1.1 Variation in Hydrology

Hydrology is one of the significant risk event that could lead to energy supply shortage, especially when there is delay in implementing major power plant Table 13.1 depicts the annual expected energy output of hydro system for the five hydro conditions, and the difference of energy with respect to the annual weighted average hydro energy of 4,092 GWh. Availability of adequate capacity and energy supply to meet the demand in the driest hydrological condition is important.

Table 13.1 – Expected Annual Energy Output of Five Hydro Conditions and the Difference Compared with Annual Average Hydro Energy

Hydro Condition	Expected Annual Energy (GWh)	Difference of Energy (GWh)
Very dry	3180	-912
Dry	3481	-612
Average	4021	-71
Wet	4549	457
Very wet	4910	817

13.1.2 Variation in Demand

Variation in demand from the base demand projection is considered as an uncertainty. Difference of energy in high demand and low demand scenarios compared to the base demand forecast is shown in figure 13.1 for the five-year period i.e. from 2020 to 2024. Assessment of the adequacy of capacity and energy supply to cater the high demand scenario is an important consideration.

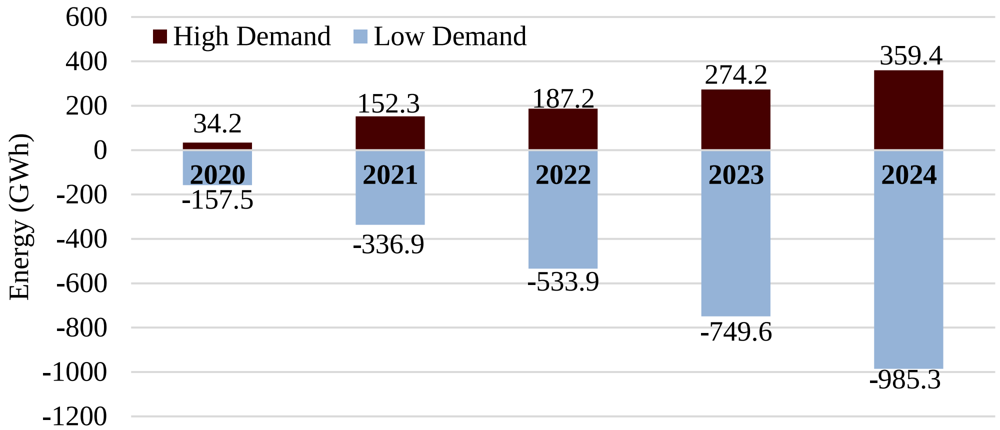


Figure 13.1 – High and Low Energy Demand Variation Compared with the Base Demand

13.1.3 Delays in Implementing Power Plants

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 in this analysis two cases of implementation delays have been considered.

Case 1: Delay in implementaing major thermal plants planned for near term

The approved Long Term Generation Expansion Plan 2015-2034 has identified 1x300MW Natural Gas operated Combined Cycle Power Plant to be commissioned by 2019. Also, the approved Long Term Generation Expansion Plan 2018-2037 has identified requirement of having 2x300MW Natural Gas operated Combined Cycle Power Plants to be commissioned by 2019 and 2021 respectively.

Assuming that 2x300MW Natural Gas operated Combined Cycle Power Plants will be commissioned by 2022, a capacity and energy shortage is enivsaged until these two major thermal plants are commissioned. Table 13.2 shows the considered delays for the case 1 analysis.

Table 13.2 – Implementation Delays of plants –Case 1

Project	**LTGEP 2018-2037**	**Contingency Analysis**
300 MW NG fired Combined Cycle Power Plant	2019 (Simple Cycle) 2020 (Combined Cycle)	2022
300 MW NG fired Combined Cycle Power Plant	2021	2022

Case 2: Delay in implementaing key thermal, hydro and other renewable energy projects

In the case 2, the risk of delaying the implementation of planned major thermal projects, hydro projects and wind power projects is considered. Resulting Capacity and energy shortfall is assessed in section 13.2. Implementations delays considered for the case 2 analysis is given in table 13.3.

Table 13.3 – Implementation Delays of Committed Power Plants

Project	LTGEP 2020-2039	Contingency Analysis
35 MW Broadlands HPP	2020	2021
100 MW Mannar Wind Park Phase I	2020	2021
120 MW Uma Oya HPP	2021	2022
130 Gas Turbines	2021	2022
300 MW NG fired Combined Cycle Power Plant	Contingency Case 1	2022
300 MW NG fired Combined Cycle Power Plant	Contingency Case 1	2022

13.1.4 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 13.4.

Table 13.4 – 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 2020 and 2021
Loss of Capacity	275MW
Loss of Energy	560GWh

13.2 Evaluation of Contingencies

In this contingeny analysis, initially the single occurrence of above mentioned four risk events were considered at first and thereafter, simultatious occurrence of several events were analysed to identify the short term energy and capacity shortage.

13.2.1 Single Occurrence of Risk Events

As mentioned in the 13.1.3, there is a notable risk of capacity and energy shortfall due the delay in implementing major plant. Energy shortfalls expected in the two implementation delay cases is given in table 13.5 and 13.7 below.

Table 13.5 – Estimation of Annual Energy Shortage Risk with Plant Implementation Delay Risk (Case 1) Unit: GWh

Year	2020	2021	2022	2023	2024
Delay in Plant Implementation					
NG fired CCY1 (from 2020 to 2022)	(848)	(1135)			
NG fired CCY2 (from 2021 to 2022)		(1135)			
Loss of Energy	**(848)**	**(2270)**	**-**	**-**	**-**
Energy Shortage Risk	**Yes**	**Yes**	**No**	**No**	**No**

However, due to delay in two major power projects 848GWh and 2270 GWh of energy shortage is estimated for year 2020 and 2021 respectively. The capacity shortage identified to maintain adequate supply capacity is 345 MW and 105 MW for the year 2020 and 2021 respectively. Breakdown of the immediate capacity addition requirement is shown in the Table 13.6.

Table 13.6 – Breakdown of the capacity additions identified for 2019-2021 period

Year	**Capacity addition**
2019	320MW capacity addition identified in LTGEP 2018-2037 and 150 MW capacity addition indentified in the contingency analysis of LTGEP 2018-2037
2020	195 MW capacity addition identified in LTGEP 2020-2039
2021	105 MW capacity addition identified in LTGEP 2020-2039

In the case 2, where implementation delay of major thermal, hydro and wind projects are considered, the expected energy short fall is 1559 GWh, 3397 GWh and 429 GWh in 2020,2021 and 2022 respectively. 390 MW and 105 MW of additional capacity is required in year 2020 and 2021 respectively to avoid the capacity and energy shortfall.

Table 13.7 – Estimation of Annual Energy Shortage Risk with Plant Implementation Delay Risk (Case 2) Unit: GWh

Year	**2020**	**2021**	**2022**	**2023**	**2024**
Delay in Plant Implementation					
Broadlands HPP (from 2020 to 2021)	(124)				
Uma Oya HPP (from 2021 to 2022)		(260)			
130 MW Gas turbines (from 2021 to 2022)		(60)			
NG fired CCY1 (from 2020 to 2022)	(848)	(1135)			
NG fired CCY2 (from 2021 to 2022)		(1135)			
190 MW of the Planned Wind Capacity (from 2020 to 2022)	(587)	(587)			
70 MW of the Planned Wind Capacity (from 2021 to 2023)		(220)	(220)		
70 MW of the Planned Wind Capacity (from 2022 to 2023)			(209)		
Loss of Energy	**(1559)**	**(3397)**	**(429)**	**-**	**-**
Energy Shortage Risk	**Yes**	**Yes**	**No**	**No**	**No**

In the Base Case Plan 2020-2039, major plant implementation delays identified in Case 1 has already been conisdered and resulting capacity addition is 345 MW for year 2020 and and 105 MW for year 2021.

Then the robustness of Base Case analyed to examine the impact of other individual risk events. Possibility of capacity and energy shortage for the Base case of this long term generation expansion plan 2020-2039 is given in Table 13.8 below.

Table 13.8 – Impact of Single Occurrence of Risk Events for the Basecase of LTGEP 2020-2039

Risk Event	Capacity Shortage Risk	Energy Shortage Risk	Remarks on the impact on BaseCase 2020-2039
Hydrology Reduction (Very Dry)	No	No	Energy reduction of 912 GWh could be catered by existing power plants with the Base Case. (Table E.2)
High Demand	Yes	No	45MW in 2020 and 45MW in 2021 of additional thermal capacity identified in High Demand Scenario should be implemented. (Annex 8.6)
Plant Implementation Delay (Case 2)	Yes	Yes	Additional 45MW of capacity is required in year 2020 for the Base Case (Table E.2) to cater implementation delays of case 2
Outage of a Major Power Plant	No	No	Capacity and Energy can be supplied with existing power plants

13.2.2 Simultaneous Occurrence of Several Risk Events

Several contingency events were analysed to identify the severity of these events and mitigation measures were suggested where necessary.

a) Contingency Event 1- Hydrology Reduction and Delays in Power Plant Implementation

The event of worst hydro condition and delays of power plant implementation were taken as the first contingency event. The parameter variations given in (1) and (3) in sectoin 13.1 were taken as the basis for the analysis.

Interms of mitigating this risk, possibility of providing the energy deficit from avalilable power plants was studied. Total annual energy deficit in this contingency event is given in the Table 13.9. Power plant dispatch in the Base Case was taken as the reference. Table 13.10 shows available plant capacities in the critical period having minimum hydro availability with the peak demand.

Table 13.9 – Estimation of Annual Energy Deficit and Energy Shortage Risk

Unit: GWh

Year	2020	2021	2022	2023	2024
Risk 1 :Dry Hydro Condition	**(912)**	**(912)**	**(912)**	**(912)**	**(912)**
Risk 2:Delay in Plant Implementation Case 1					
Broadlands HPP (from 2020 to 2021)	(124)				
Uma Oya HPP (from 2021 to 2022)		(260)			
130 MW Gas turbines (from 2021 to 2022)		(60)			
NG fired CCY1 (from 2020 to 2022)	(848)	(1135)			
NG fired CCY2 (from 2021 to 2022)		(1135)			
190 MW of the Planned Wind Capacity (from 2020 to 2022)	(587)	(587)			
70 MW of the Planned Wind Capacity (from 2021 to 2023)		(220)	(220)		
70 MW of the Planned Wind Capacity (from 2022 to 2023)			(209)		
Sub Total – Risk 2	**(1559)**	**(3397)**	**(429)**		**-**
Total Energy Deficit	**(2,471)**	**(4,309)**	**(1,341)**	**(912)**	**(912)**
Energy Shortage Risk	**Yes**	**Yes**	**No**	**No**	**No**

Table 13.10 – Available Plant Capacities in Critical Period for Each Year

Unit: MW

Available Capacity	2020	2021	2022	2023	2024
Existing Plant Capacity	2,447	2,463	2,465	2,516	2,433
New Major Hydro	0	34	89	118	118
FO Plants (Committed)	320	320	320	320	320
FO Plants (Contingency)	450	675	5	5	5
New Gas Turbine	0	0	105	105	105
LNG CCY Plants	0	0	578	867	867
Coal fired Plant	0	0	0	0	285
ORE	15	16	16	9	10
Total Available Capacity	**3,232**	**3,508**	**3,578**	**3,940**	**4,143**
Peak Demand	**3,050**	**3,254**	**3,403**	**3,561**	**3,728**

This contingency event has a very large impact on the energy supply of the system and it was observed that an annual energy shortage of 2,471 GWh for the year 2020 and a 4,309 GWh shortage for 2021. Additional capacity is required to meet the electricity demand adequately. Capacity requirement to mitigate the risk of both capacity and energy shortage in this contingency event is 450 MW in 2020 and 225 MW in 2021. Installed capacity for this contingency event is shown in the Figure 13.2 with peak demand and Figure 13.3 illustrates the actual available capacity in the critical period of the year with minimum hydro availability.

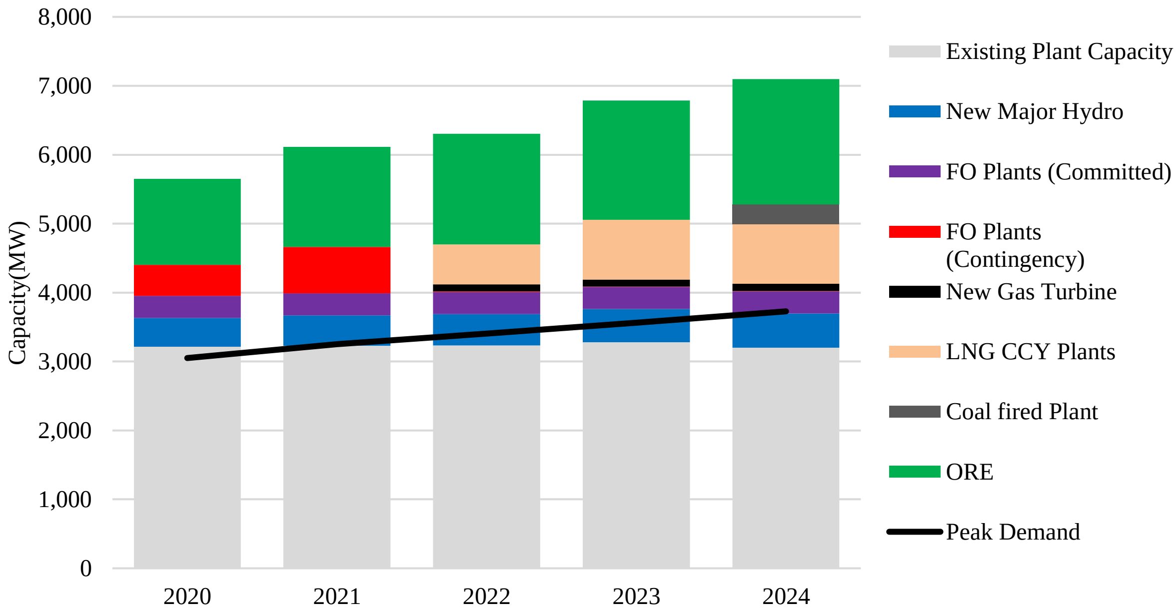


Figure 13.2 – Installed Capacity with Peak Demand (Contingency Event 1)

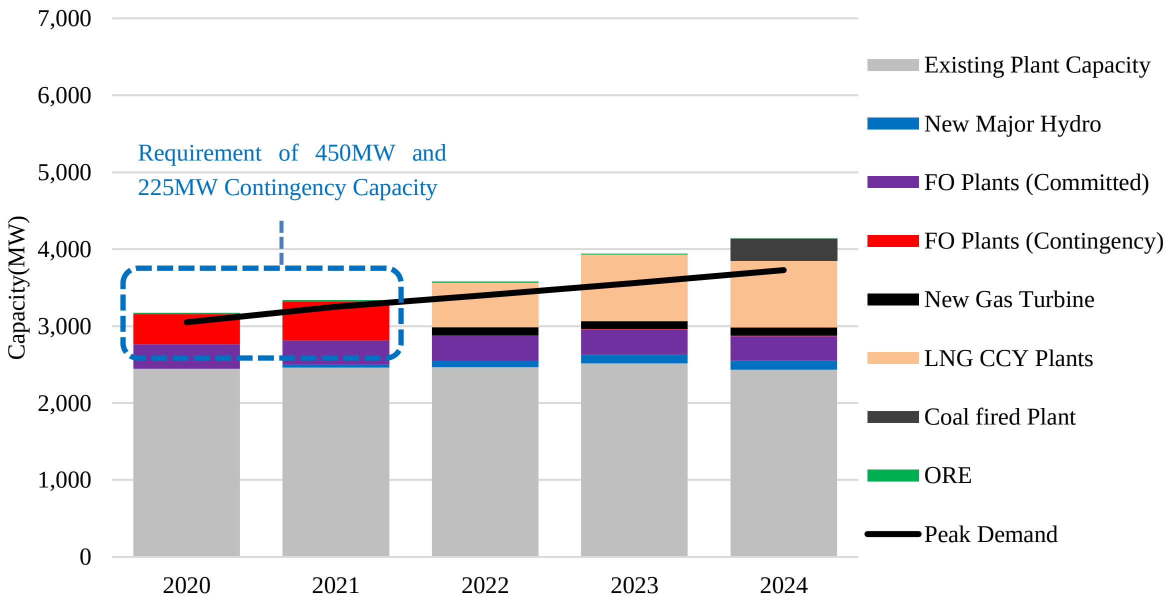


Figure 13.3 - Available Capacity in Critical Period with Peak Demand (Contingency Event 1)

b) Contingency Event 2- Hydrology Reduction, 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 the two risk events of section (a) above is considered for the analysis. The unit outage was assumed to occur in the dry season during first four months of the year. It was observed that both energy and capacity shortage occur in short term in this contingency event. Additional capacity of 525MW in 2020 and 225 MW in 2021 is necessary to mitigate the contengency event. Figure 13.4 below illustrates the availiable capacity in the critical period.

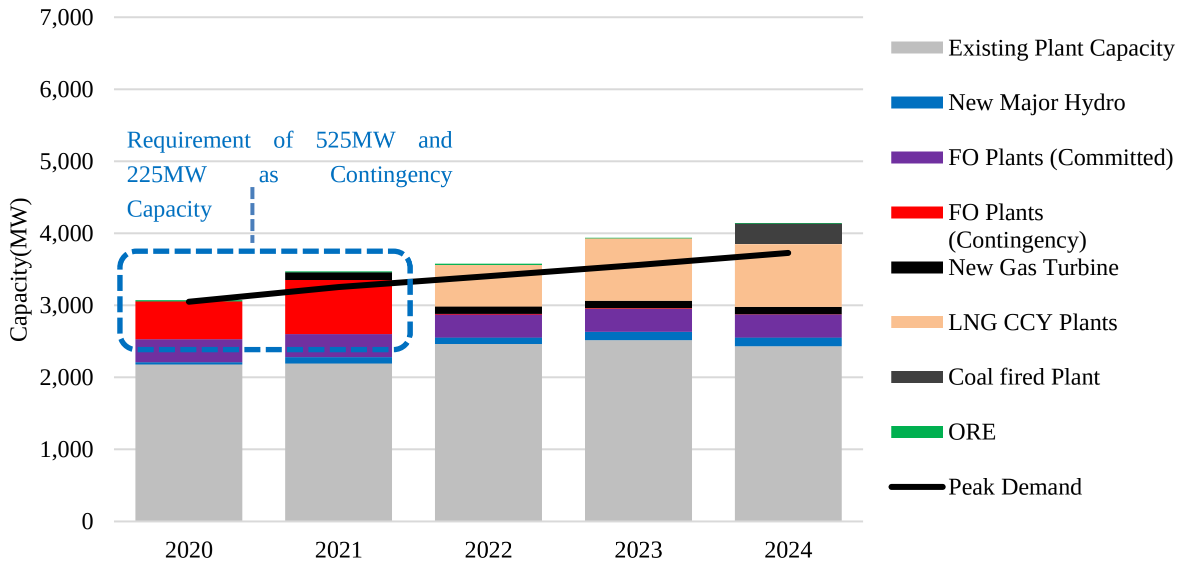


Figure 13.4 - Available Capacity in Critical Period with Peak Demand (Contingency Event 2)

c) Contingency Event 3- High Demand, Hydrology Reduction and Delays in Power Plant Implementaion

The risk event of exceeding base demand projection is considered to occur simultaneously with worst hydro condition and delays in power plant implementation in this contingency event. In this contingency event, additional capacity of 480 MW and 270MW is required in 2020 and 2021. Available plant capacity in critical period is given in the figure 13.5.

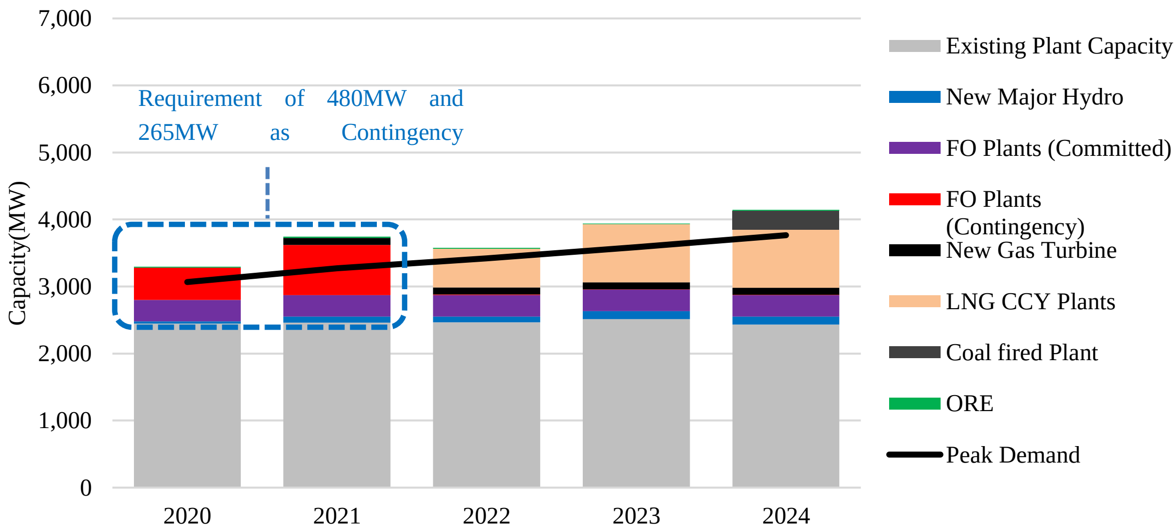


Figure 13.5 - Available Capacity in Critical Period with Peak Demand (Contingency Event 3)

13.3 Conclusion

(1) The implementation delay of two natural gas fired combined cycle plants analyzed in the case 2 has been incorporated into the Base Case 2020-2039 to meet the basic capacity and energy supply requirement during 2020-2021 period. As a result, contingency capacity addition of 345 MW and 105MW are included in the Base Case for the year 2020 and 2021. This identified capacity addition mitigates the risk of capacity and energy shortfall in both dry hydrology and major plant outage events in the Base case. If the implementation delay of thermal, hydro and other renewable plants are considered as in case 2, then the required capacity additions are 390MW in 2020 and 105MW in 2021.

(2) In the contingency event where the dry hydrological condition and the power plant implementation delay occurs, 450 MW and 225 MW is required as capacity addition in the year 2020 and in year 2021 respectively. It is to be nted that 345MW and 105MW of capacities of this amount are already included for year 2020 and 2021 in the Base case plan.

(3) When a major plant outage occurs simultaneously with the dry hydrological condition and also with major thermal, hydro, wind power plant implementation delays, additional capacity of 525MW in 2020 and 225 MW in 2021 is necessary to mitigate the capacity and energy shortage.

(4) In the contingency event where the high demand occurs with dry hydrological condition and major thermal, hydro, wind power plant implementation delays, 480 MW and 270 MW is required as contingency capacity additions in the year 2020 and in year 2021 respectively.

CHAPTER 14
REVISIONS TO PREVIOUS PLAN

This chapter examines the deviations of the results of the present study from the previous generation expansion plan, and to analyse the factors for such deviations. The causes for the differences between the current study (LTGEP 2019 for the period of 2020-2039) and LTGEP 2017 for the period of 2018-2037 are as follows.

- Government Policies
    - Energy Mix
    - Reliability Criteria
- Base Demand Forecast
    - Variation in daily load profile shape with the maximum demand shifting from night peak to day peak, was advanced to an earlier year considering the recent trends.
    - Load Factor variation with load profile change and demand growth trends of each tariff category.
    - Improvement of System Losses Forecast.
- Fuel price variations
- Revised capability of existing hydro power generation potential
- 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 2019-2030"
- Environmental emissions
- Introduction of Battery Storage as an Energy Storage System.

14.1 Government Policies

(a) Energy Mix

The Cabinet Decision on "Deciding the Energy Mix for Electricity Generation in Sri Lanka" approved in May 2018 based on nine principals was considered as a government policy in the preparation of LTGEP 2019. Subsequently the General Policy Guidelines in respect to the Electrical Industry under the section 5 of Sri Lanka Electricity Act was approved by cabinet of Ministers on March 26, 2019.

While considering the objective of maintaining the electricity generation at least cost policy decisions described in chapter 8.2 were also considered and adhered to. Developing the Other Renewable Energy sources to the optimum feasible level and ensuring energy security through fuel diversity of firm capacity sources is compiled as stipulated in government policies.

(b) Reliability Criteria

In preparation of LTGEP 2019, the Reliability criteria of having increased Reserve Margin was considered as per the instructions of Ministry of Power, Energy & Business Development and Decision of CEB Board. Power Plant development is optimized between 10% (Minimum) and 25% (Maximum)

Reserve Margin. The LTGEP 2017 was prepared adhering to reserve margin criteria between 2.5% (Minimum) and 20% (Maximum).

14.2 Demand Forecast

As identified in LTGEP 2018-2037 the night peak, day peak and off peak shows an increasing trend but in particular the growth of day peak is higher than the growth of night peak. Therefore, the shape of the daily load profile will gradually change. However while incorporating the trend of recent years it is estimated that the day peak would exceed the night peak as early as 2027.

Base Demand Forecast 2020-2044 was a combination of Time Trend modelling and Econometric approach as described in section 3.3 of Chapter 3. Twenty-five-year average growth rates of Energy demand and Peak forecasts of LTGEP 2019 are 4.7% and 4.5% while Energy demand and Peak forecast of LTGEP 2017 are 4.8% and 4.4% respectively. Figure 14.1 & 14.2 show the Energy demand and Peak forecast comparison of LTGEP 2017 and LTGEP 2019.

As illustrated in figure 14.1 & 14.2, both the annual energy demand and annual peak demand of LTGEP 2019 is higher than the LTGEP 2017.

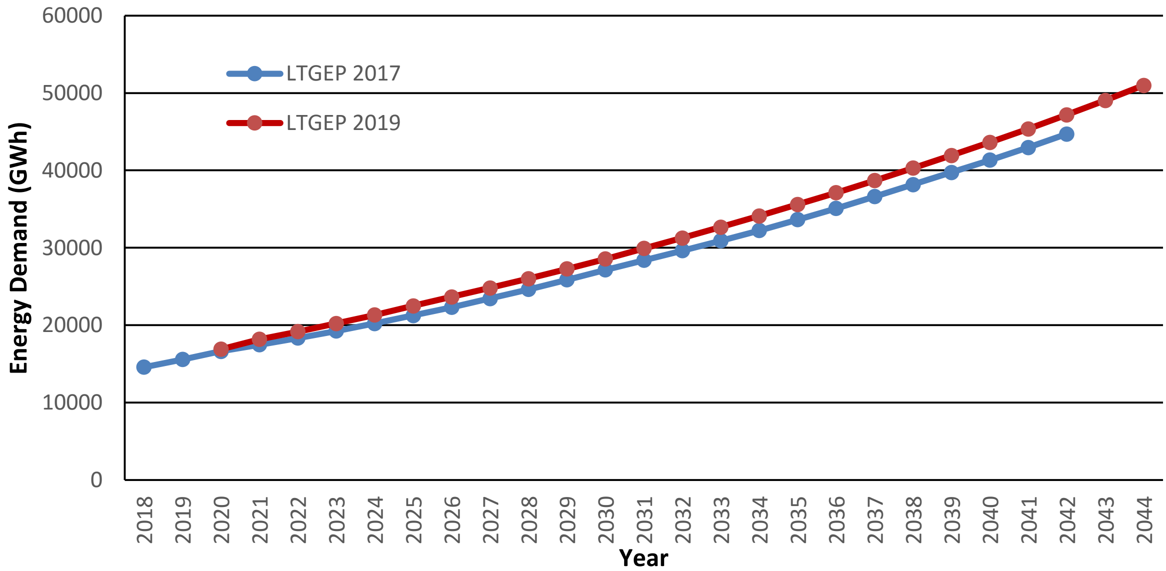


Figure 14.1 - Comparison of 2019 and 2017 Energy Demand Forecasts

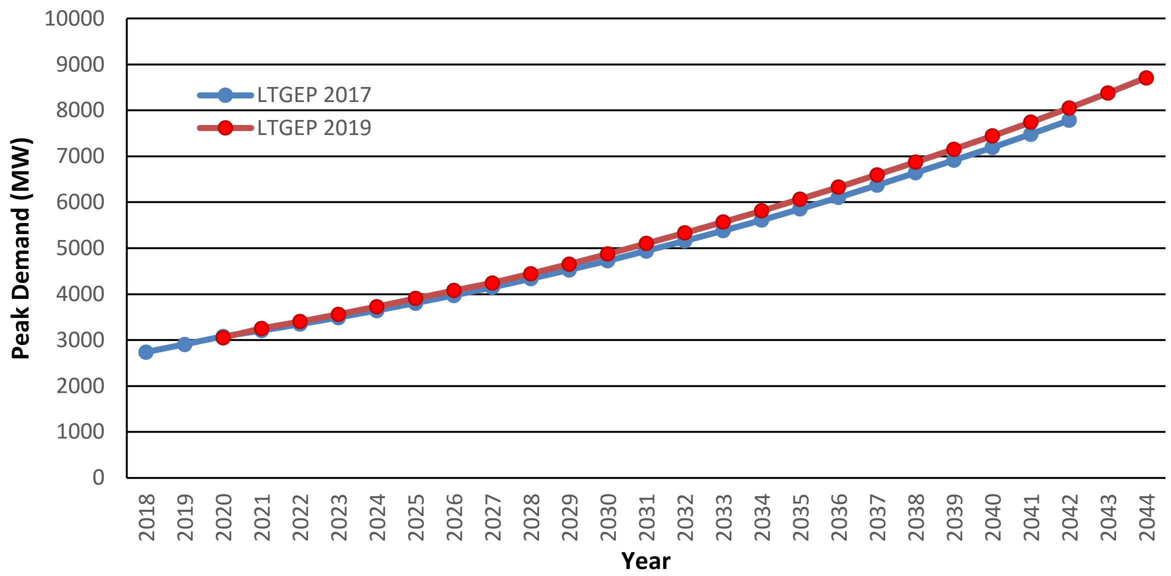


Figure 14.2 - Comparison of 2019 and 2017 Peak Demand Forecasts

14.3 Fuel Prices Variation

Fuel Prices of Coal, Natural Gas and Oil for the present study (LTGEP 2019) were based on historical data of past three year weighted average, which is the most appropriate representation, which was further verified with the World Bank and IMF forecasts as described in Chapter 4. It should be noted that in the present study, all fuel prices are considered as price delivered at power plant exclusive of tax. Fuel prices used in the LTGEP 2019 and LTGEP 2017 are shown in Figure 14.3.

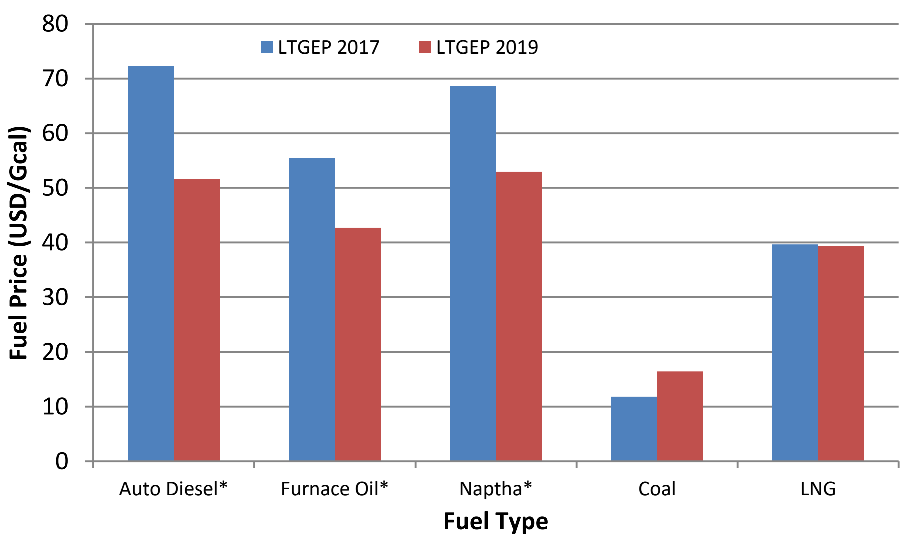


Figure 14.3 – Fuel price variation of LTGEP 2017 and LTGEP 2014

* Prices indicated for Diesel, Furnace Oil and Naphtha in LTGEP 2017 are market prices.

14.4 Revised Capability of Existing Hydro Power Plants

The Annual average energy of existing hydro system estimated as 4092 GWh in comparison to 4050 GWh in LTGEP 2017. The probabilities of hydro conditions were considered the same.

14.5 Integration of Other Renewable Energy (ORE)

Figure 14.4 shows the variation of Other Renewable Energy (ORE) capacity contribution in the selected years 2022, 2027, 2032 & 2037 for both LTGEP 2017 and the LTGEP 2019. The total ORE capacity increases to 3946MW by 2037 in LTGEP 2019 which is 15% higher than LTGEP 2017 total ORE capacity.

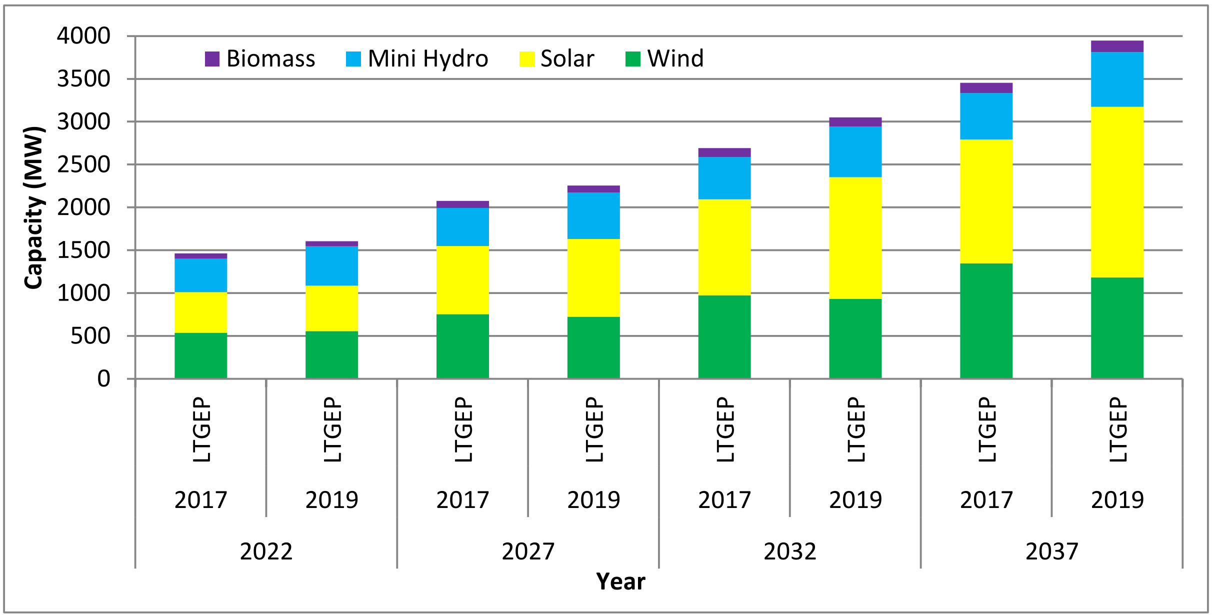


Figure 14.4 – Comparison of ORE Capacity Addition between LTGEP 2019 & LTGEP 2017

The New Government Policy on 'Deciding the Energy Mix for Electricity generation in Sri Lanka' identifies the necessity to diversify the energy mix through integration of more renewable energy by strategically developing alternative renewable energy sources such as wave energy, geothermal, ocean thermal, municipal solid waste in addition to solar, wind, mini hydro and biomass.

14.7 Introduction of Battery Storage as an ESS

Battery storage is proposed to be added to the system in phase development. A cumulative capacity of 50 MW by 2025 and 100 MW by 2030 is expected to be incorporated to the system. Exact capacities and entry years will be evaluated during the detailed design stage of battery storage integration.

14.8 Environmental Emissions

CO_2 and Particulate emissions are lower in LTGEP 2019 than the emission level in the LTGEP 2017. Comparison of CO_2 and Particulate emissions depicts in Figure 14.5. Also SO_x and NO_x emissions LTGEP 2019 compared to LTGEP 2017 is shown in the Figure 14.6. CO_2, SO_x and NO_x emissions have increased in the Initial years, due to non-implementation of natural gas projects in time while continuing to rely on oil power plants.

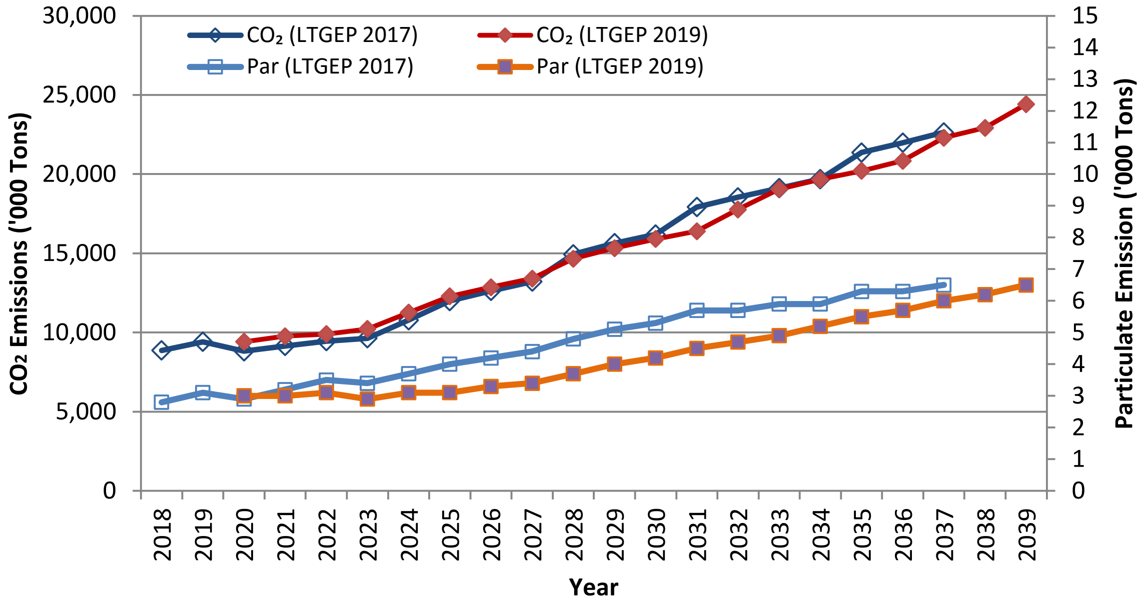


Figure 14.5 - CO_2 and Particulate Emissions

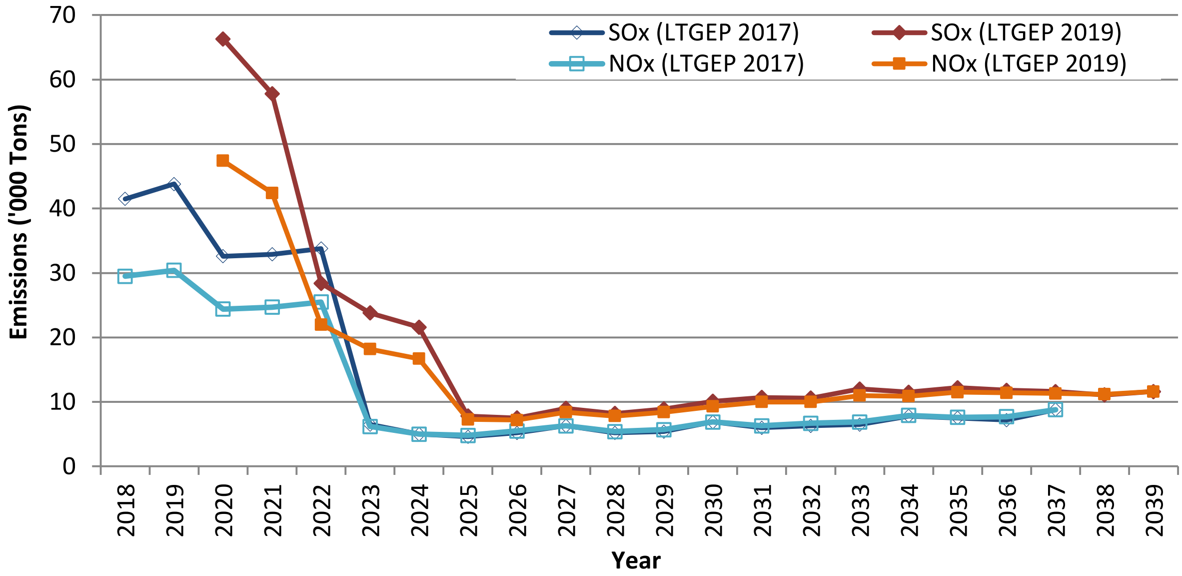


Figure 14.6 – SO_x and NO_x Emissions

14.8 Overall Comparison

The overall comparison of generation expansions proposed by plans for last 20 years and actual implementation is shown in Annex 14.1

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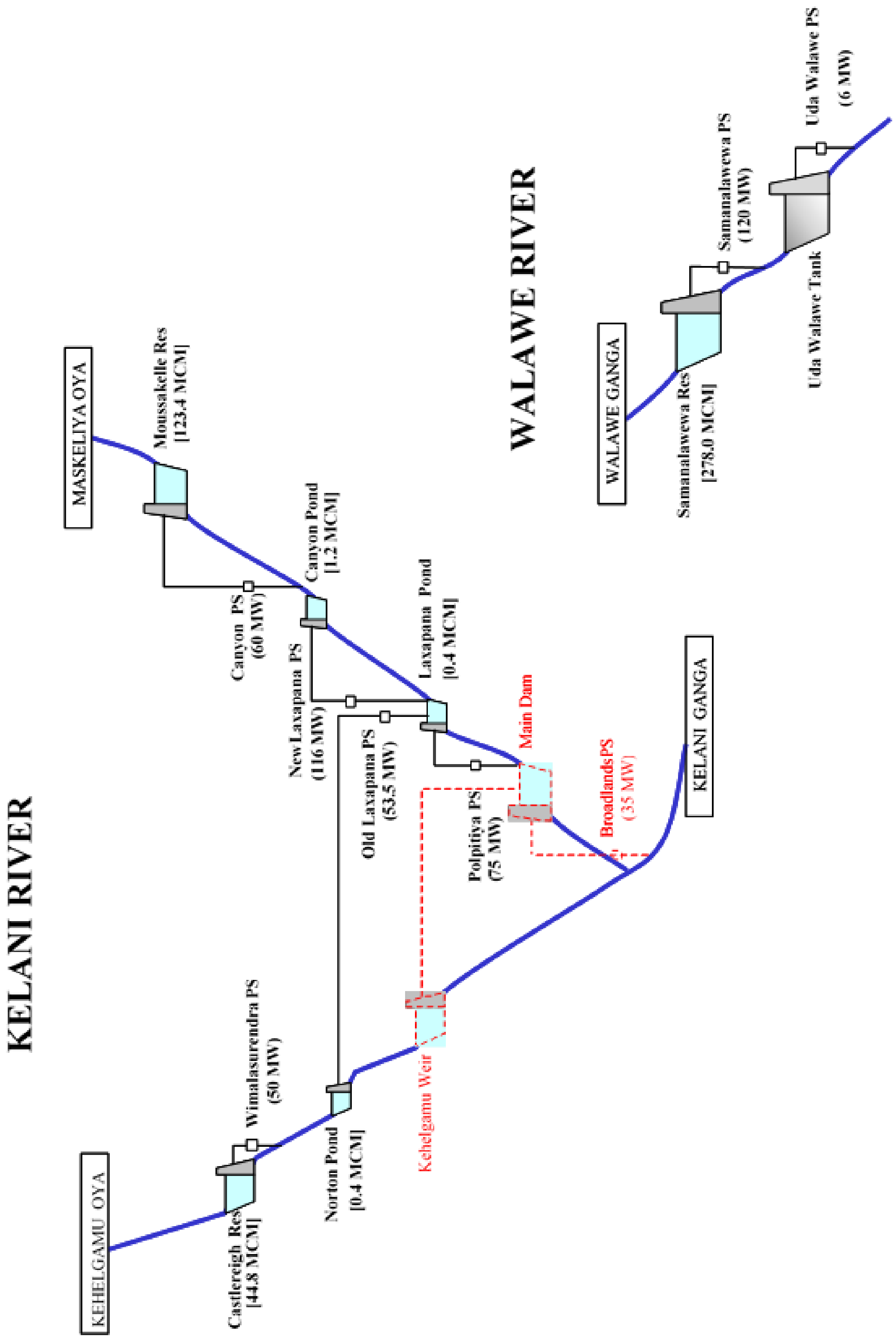
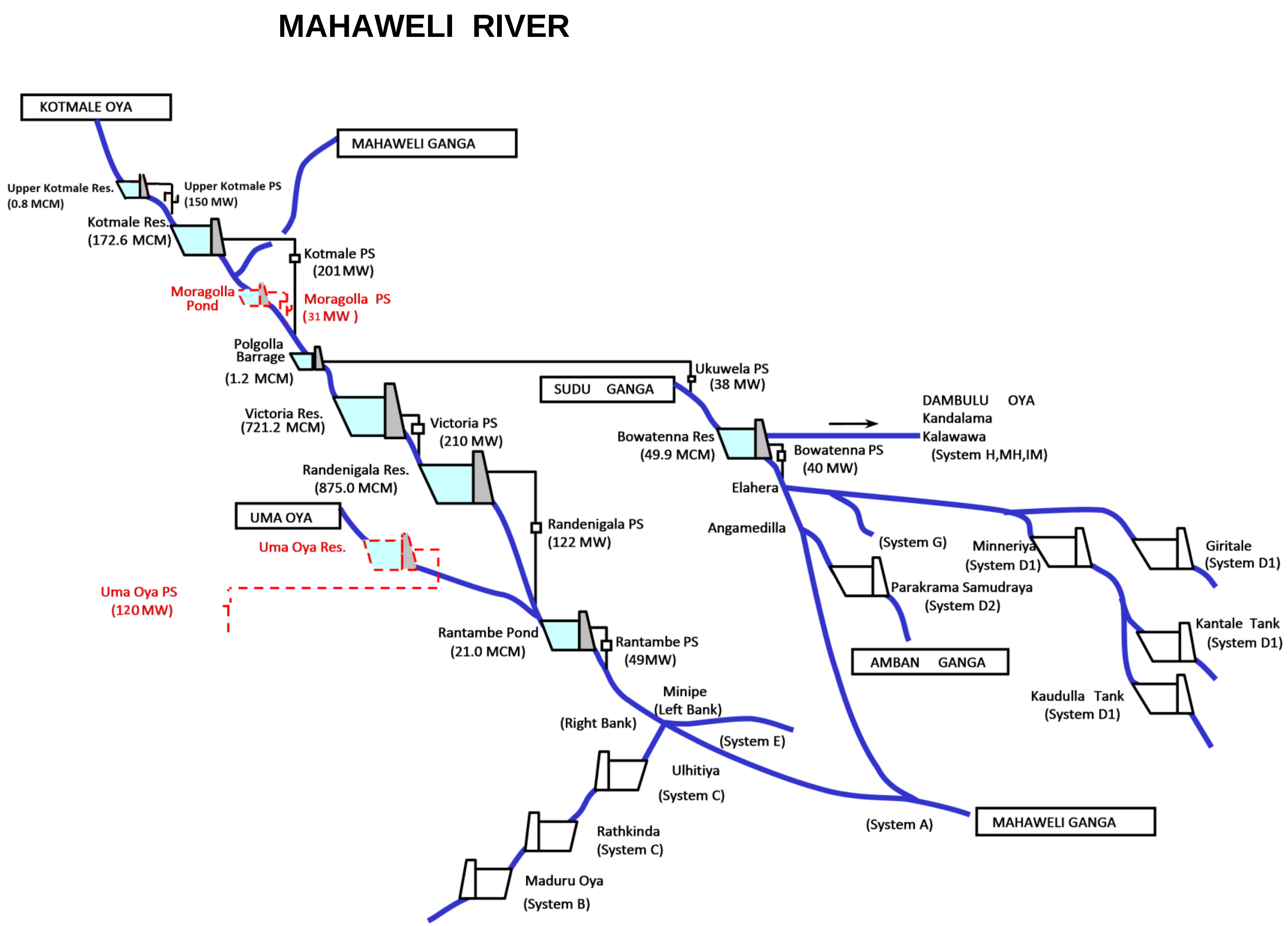
Reservoir Systems in Mahaweli, Kelani and Walawe River Basins

A2.1.1 Reservoir Systems in Kelani and Walawe River Basins



A2.1.2 Reservoir System in Mahaweli River Basin



Annex 3.1

Scenarios of the Demand Forecast

Table A3.1 – High Demand Forecast

Year	Demand (GWh)	Net Losses* (%)	Generation (GWh)	Peak (MW)
2020	16948	8.78	18579	3067
2021	18346	8.62	20076	3272
2022	19374	8.46	21164	3421
2023	20507	8.30	22364	3587
2024	21696	8.15	23622	3766
2025**	23133	8.00	25144	3960
2026	24654	7.90	26768	4218
2027	26054	7.80	28257	4454
2028	27561	7.70	29858	4707
2029	29142	7.60	31538	4973
2030	30795	7.50	33292	5251
2031	32485	7.45	35100	5538
2032	34221	7.40	36955	5833
2033	36022	7.35	38879	6138
2034	37905	7.30	40890	6457
2035	39871	7.25	42988	6790
2036	41905	7.25	45180	7139
2037	44023	7.25	47464	7502
2038	46224	7.25	49837	7879
2039	48500	7.25	52291	8269
2040	50870	7.25	54847	8676
2041	53352	7.25	57522	9101
2042	55942	7.25	60314	9546
2043	58654	7.25	63239	10011
2044	61502	7.25	66310	10500
5 Year Average Growth	6.4%		6.2%	5.3%
10 Year Average Growth	6.2%		6.1%	5.5%
20 Year Average Growth	5.7%		5.6%	5.4%
25 Year Average Growth	5.5%		5.4%	5.3%

*****Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro 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)
2020	16757	8.78	18369	3034
2021	17857	8.62	19541	3223
2022	18653	8.46	20376	3341
2023	19484	8.30	21248	3466
2024	20352	8.15	22158	3596
2025	21258	8.00	23107	3731
2026	22147	7.90	24047	3865
2027	23004	7.80	24949	3992
2028	23892	7.70	25884	4124
2029	24804	7.60	26844	4260
2030**	25733	7.50	27819	4382
2031	26686	7.45	28834	4544
2032	27634	7.40	29842	4704
2033	28591	7.35	30859	4866
2034	29568	7.30	31897	5031
2035	30562	7.25	32951	5199
2036	31560	7.25	34027	5370
2037	32576	7.25	35122	5545
2038	33602	7.25	36229	5721
2039	34633	7.25	37340	5898
2040	35679	7.25	38468	6078
2041	36750	7.25	39622	6262
2042	37842	7.25	40800	6449
2043	38961	7.25	42007	6642
2044	40114	7.25	43249	6840
5 Year Average Growth	5.0%		4.8%	4.3%
10 Year Average Growth	4.5%		4.3%	3.8%
20 Year Average Growth	3.9%		3.8%	3.6%
25 Year Average Growth	3.7%		3.6%	3.4%

*****Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro 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)
2020	16379	8.78	17955	2954
2021	17344	8.62	18979	3101
2022	18365	8.46	20062	3258
2023	19447	8.30	21207	3423
2024	20592	8.15	22419	3598
2025	21805	8.00	23701	3783
2026	23089	7.90	25069	3980
2027	24449	7.80	26516	4178
2028	25889	7.70	28048	4420
2029	27414	7.60	29668	4678
2030	29028	7.50	31382	4950
2031	30738	7.45	33212	5241
2032	32548	7.40	35149	5549
2033	34465	7.35	37199	5875
2034	36495	7.30	39369	6219
2035	38645	7.25	41665	6585
2036	40921	7.25	44119	6975
2037	43331	7.25	46718	7388
2038	45883	7.25	49469	7825
2039	48585	7.25	52383	8289
2040	51447	7.25	55468	8780
2041	54477	7.25	58735	9300
2042	57685	7.25	62194	9850
2043	61083	7.25	65857	10433
2044	64680	7.25	69736	11050
5 Year Average Growth	5.9%		5.7%	5.1%
10 Year Average Growth	5.9%		5.7%	5.2%
20 Year Average Growth	5.9%		5.8%	5.6%
25 Year Average Growth	5.9%		5.8%	5.7%

*****Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future.

Table A3.4 – MAED Load Projection

Year	Demand (GWh)	Net Losses* (%)	Generation (GWh)	Peak (MW)
2020	16033	8.81	17581	3038
2021	16950	8.64	18554	3180
2022	17919	8.48	19579	3328
2023	18944	8.32	20662	3484
2024	20028	8.15	21805	3647
2025	21173	7.98	23010	3817
2026	22278	7.91	24192	4006
2027	23441	7.84	25435	4205
2028	24665	7.76	26741	4414
2029	25953	7.69	28114	4633
2030	27308	7.61	29558	4863
2031	28657	7.58	31006	5096
2032	30073	7.54	32525	5339
2033	31559	7.50	34119	5594
2034	33118	7.47	35790	5861
2035	34754	7.43	37543	6141
2036	36292	7.40	39193	6392
2037	37898	7.37	40915	6653
2038	39575	7.34	42713	6924
2039	41327	7.32	44589	7207
2040	43156	7.29	46548	7501
2041	44881	7.25	48389	7794
2042	46675	7.25	50323	8100
2043	48540	7.25	52335	8417
2044	50481	7.25	54427	8746
5 Year Average Growth	5.7%		5.5%	4.7%
10 Year Average Growth	5.5%		5.4%	4.8%
20 Year Average Growth	5.1%		5.0%	4.7%
25 Year Average Growth	4.9%		4.8%	4.5%

*****Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future.

Candidate Thermal Plant Data Sheets

A4.1.1 Candidate Thermal Power Plant Data

• **Basic data**	**45 MW Gas Turbine+**	**300 MW Diesel Combined Cycle**	**150 MW LNG Combined Cycle**	**300 MW LNG Combined Cycle**
Net capacity (MW)	40	281	153	290
Fuel Type	Duel Fuel Primary:NG Secondary: Auto Diesel	Auto Diesel	Duel Fuel Primary:NG Secondary: Auto Diesel	Duel Fuel Primary:NG Secondary: Auto Diesel
• **Information input to studies**				
Annual fixed O&M cost (US$/kW-month)	0.68	0.41	0.38	0.38
Variable O&M cost (USCts/kWh)	0.546	0.355	0.501	0.501
* Time Availability (Maximum annual PF) (%)	308.2(84.4)	308.2(84.4)	308.2(84.4)	308.2(84.4)
Scheduled annual maintenance duration (days)	30	30	30	30
Forced outage rate (%)	8	8	8	8
Calorific value (kCal/kg)	13000**	10500	13000**	13000**
Minimum operating level (%)	30	39	50	39
Net Heat rate at minimum operating level (kCal/kWh)	3871	2302	2030	2247
Net Heat rate at full load operating level (kCal/kWh)	2774	1790	1746	1768
Capital Cost Incl. IDC (US$/kW) Net Basis	781.1	1108.7	1175.1	1075.5
Construction Period (years)	1.5	3	3	3
Economic Life time (years)	20	30	30	30

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

**Actual values are to be determined

+ The plant has duel fuel capability and would be operated with Natural Gas.

• **Basic data**	**600 MW LNG Combined Cycle**	**300 MW High Efficient Coal Plant**	**600 MW Super Critical Coal Plant**
Net capacity (MW)	582	270	564
Fuel Type	Duel Fuel Primary:NG Secondary: Auto Diesel	Coal	Coal
• **Information input to studies**			
Annual fixed O&M cost (US$/kW-month)	0.38	4.51	4.86
Variable O&M cost (USCts/kWh)	0.501	0.589	0.589
* Time Availability (Maximum annual PF) (%)	308.2(84.4)	310.4(85.0)	310.4(85.0)
Scheduled annual maintenance duration (days)	30	45	45
Forced outage rate (%)	8	3	3
Calorific value (kCal/kg)	13000**	6300	6300
Minimum operating level (%)	19	50	60
Net Heat rate at minimum operating level (kCal/kWh)	3019	2547	2248
Net Heat rate at full load operating level (kCal/kWh)	1758	2241	2082
Capital Cost Incl. IDC (US$/kW) - Net	886.7	2139.5	2303.9
Construction Period (years)	3	4	4
Economic Life time (years)	30	30	30

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

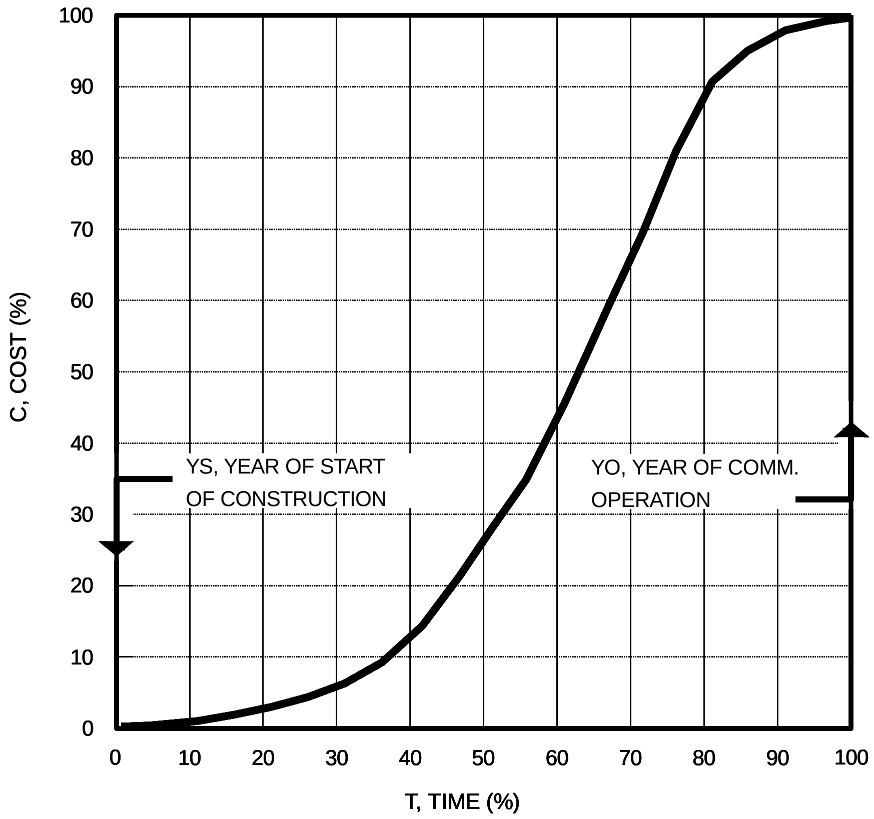
** Actual values are to be determined

• **Basic data**	**600 MW Nuclear**	**15 MW Reciprocating Engine**
Net capacity (MW)	552	15
Fuel Type	Nuclear	Furnace Oil
• **Information input to studies**		
Annual fixed O&M cost (US$/kW-month)	8.33	2.40
Variable O&M cost (USCts/kWh)	0.150	0.640
* Time Availability (Maximum annual PF) (%)	323.4(88.5)	289.7(79.4)
Scheduled annual maintenance duration (days)	40	60
Forced outage rate (%)	0.5	5
Calorific value (kCal/kg)	-	10300
Minimum operating level (%)	90	100
Net Heat rate at minimum operating level (kCal/kWh)	2723	2210
Net Heat rate at full load operating level (kCal/kWh)	2685	2210
Capital Cost Incl. IDC (US$/kW) Net Basis	5755.0	1020.7
Construction Period (years)	5	1.5
Economic Life time (years)	60	20

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

A4.1.2 Power Plant IDC Cost Calculation

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



Plant capital cost distribution against time

Annex 5.1
Candidate Hydro Plant Data Sheets

A 5.1.1 Seethawaka Ganga Hydropower Project

- **General**

Proposed Seethawaka Ganga hydropower project is located within Batangala, Algoda, Dikella, Hinguralakanda East and Hinguralakanda West Grama Niladharai Divisions of Divisional Secretariat area of Dehiowita in Kegalle District, Sabaragamuwa Province.

- **Project Overview**

Province / District	Sabaragamuwa & Kegalle
Catchment	Kelani
Reservoir Full Supply Level (FSL)	70.0 masl
Reservoir Minimum operation level	64.0 masl
Reservoir area at FSL	40 Ha
Reservoir capacity	3.51 MCM
Elevation of the dam crest	74 masl
Max. height of the dam	36 m
Length of the dam	112 m
Spillway Type	Ogee Spill
Length of the headrace tunnel	1.9 km
Length / Diameter Penstock	74 m / 4.6 m
Length Tail Race Channel	60m
Type of Powerhouse	Open-air
Gross Head	45m
Plant Capacity	2 x 12 MW
Average Annual Generation	54 GWh

A 5.1.2 Thalpitigala Hydro Power Project

- **General**

Thalpitigala Hydro Power Project is to be developed by Ministry of Irrigation and Water Resource Management. The envisages the construction of a 49 m high dam across Uma Oya at Thalpitigala and the reservoir will have a capacity of 17.96 MCM.

Project Overview

Province / District	Uva Province
No of Units	2
Plant Capacity	2 x 7.5 MW
Average Annual Generation	52.4 GWh
Design Diversion Discharge	19 m^3/s
Maximum Working Head	108 m
Reservoir Capacity at Normal Storage Level	15.56 MCM

Annex 5.2

Other Renewable Energy Tariff

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

Three-tier Tariff

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

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

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

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

At present competitive bidding process is also being followed for the development of planned ORE projects.

Annex 5.3

Other Renewable Energy Projections for Low & High Demand Scenarios

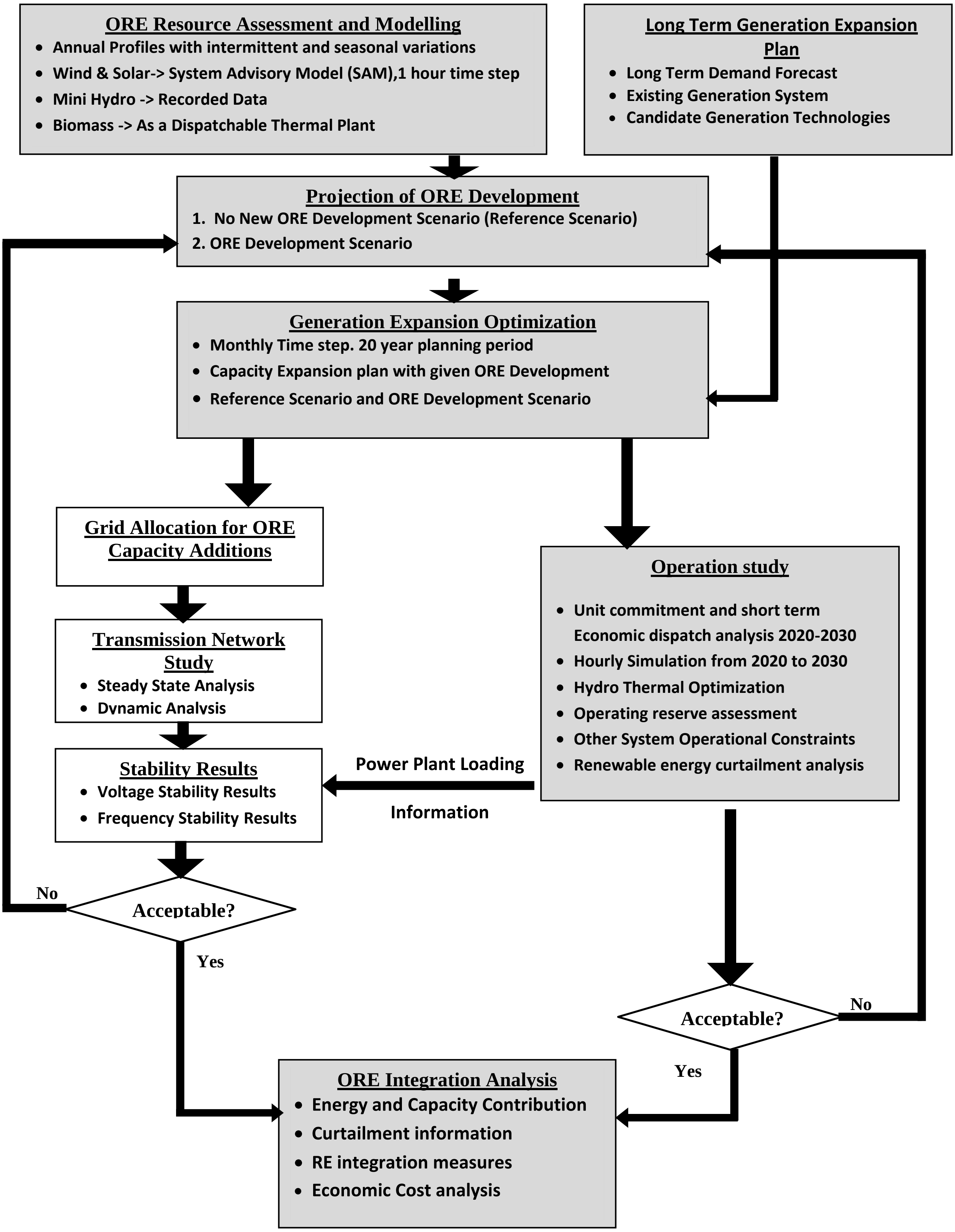
Projected Future Development of ORE for the Low Demand Scenario

Year	Cumulative Mini hydro Capacity (MW)	Cumulative Wind Capacity (MW)	Cumulative Biomass Capacity (MW)	Cumulative Solar Capacity (MW)	Cumulative Total ORE Capacity (MW)	Annual Total ORE Generation (GWh)	Share of ORE from Total Generation (%)
2020	419	368	49	410	1245	3403	18.5%
2021	439	488	54	470	1450	3970	20.3%
2022	459	558	59	530	1605	4376	21.5%
2023	479	598	64	590	1730	4677	22.0%
2024	499	598	69	650	1815	4863	21.9%
2025	519	638	74	730	1960	5193	22.5%
2026	529	673	79	820	2100	5483	22.8%
2027	534	708	84	880	2205	5715	22.9%
2028	539	733	89	950	2310	5937	22.9%
2029	544	758	94	1020	2415	6158	22.9%
2030	549	763	99	1090	2500	6324	22.7%
2031	554	788	104	1160	2605	6536	22.7%
2032	559	803	109	1240	2710	6745	22.6%
2033	564	823	114	1320	2820	6956	22.5%
2034	569	848	119	1410	2945	7207	22.6%
2035	574	868	124	1500	3065	7444	22.6%
2036	579	883	129	1600	3190	7681	22.6%
2037	584	898	134	1700	3315	7919	22.5%
2038	589	918	139	1800	3445	8185	22.6%
2039	594	933	144	1900	3570	8450	22.6%

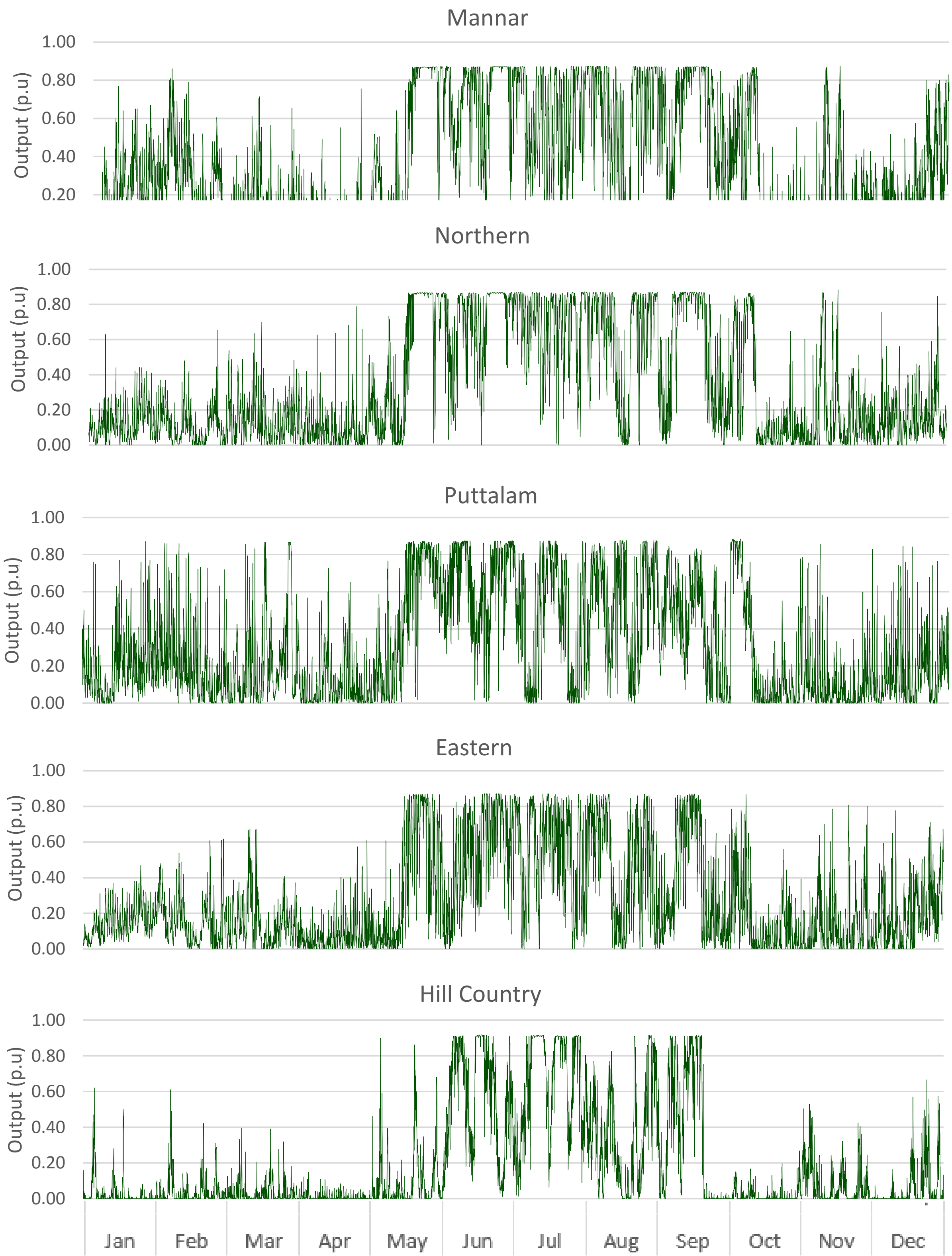
Projected Future Development of ORE for the High Demand Scenario

Year	Cumulative Mini hydro Capacity (MW)	Cumulative Wind Capacity (MW)	Cumulative Biomass Capacity (MW)	Cumulative Solar Capacity (MW)	Cumulative Total ORE Capacity (MW)	Annual Total ORE Generation (GWh)	Share of ORE from Total Generation (%)
2020	419	368	49	410	1245	3403	18.3%
2021	439	488	54	470	1450	3970	19.8%
2022	459	558	59	530	1605	4376	20.7%
2023	479	598	64	590	1730	4677	20.9%
2024	499	598	69	650	1815	4863	20.6%
2025	519	638	74	730	1960	5193	20.7%
2026	529	673	79	820	2100	5483	20.5%
2027	539	723	84	910	2255	5819	20.6%
2028	549	763	89	1010	2410	6144	20.6%
2029	559	803	94	1110	2565	6469	20.5%
2030	569	823	99	1210	2700	6738	20.2%
2031	579	883	104	1310	2875	7114	20.3%
2032	589	933	109	1420	3050	7487	20.3%
2033	599	968	114	1530	3210	7801	20.1%
2034	609	1038	119	1650	3415	8244	20.2%
2035	619	1083	124	1770	3595	8613	20.0%
2036	629	1138	129	1890	3785	9014	20.0%
2037	639	1198	134	2040	4010	9472	20.0%
2038	649	1283	139	2205	4275	10021	20.1%
2039	654	1368	144	2385	4550	10575	20.2%

Methodology of the Renewable Energy Integration Study 2020-2030

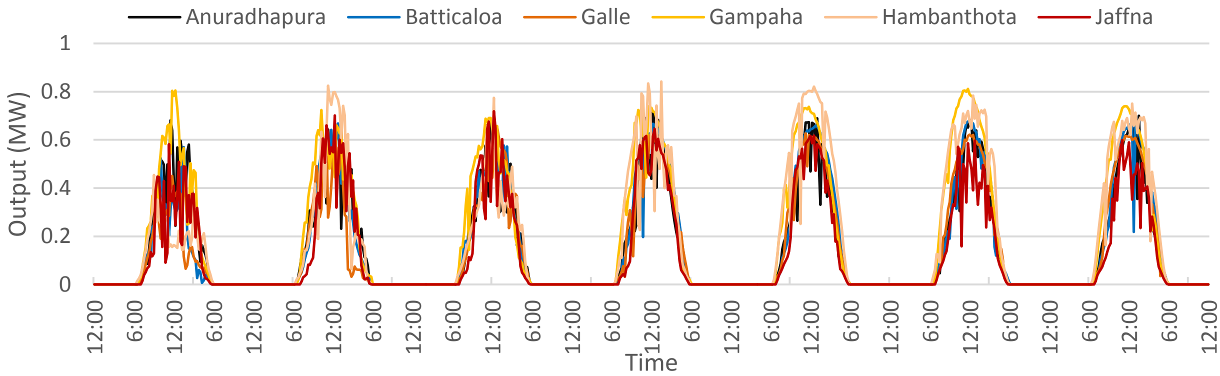


A5.1 Outline of the study methodology of renewable energy integration study 2020-2030

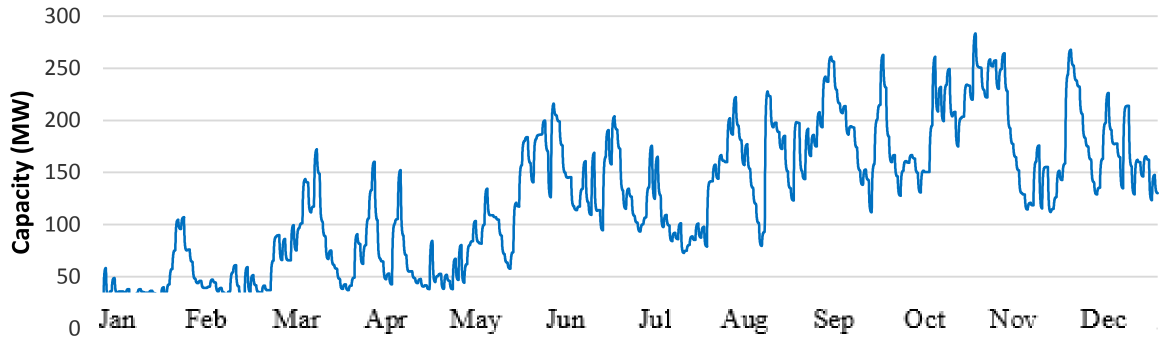


A5.2 Annual variation of wind power production in five wind regimes (Based on 10 min Actual data)

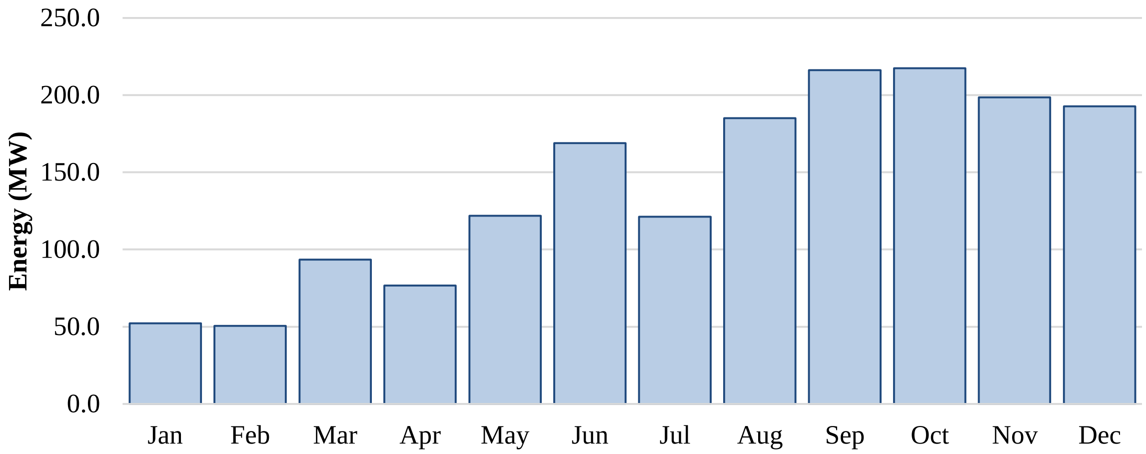
Solar and Mini-Hydro Plant Production Profiles



A5.3 Extract of Solar PV Production based on actual measurement data (15 minute)

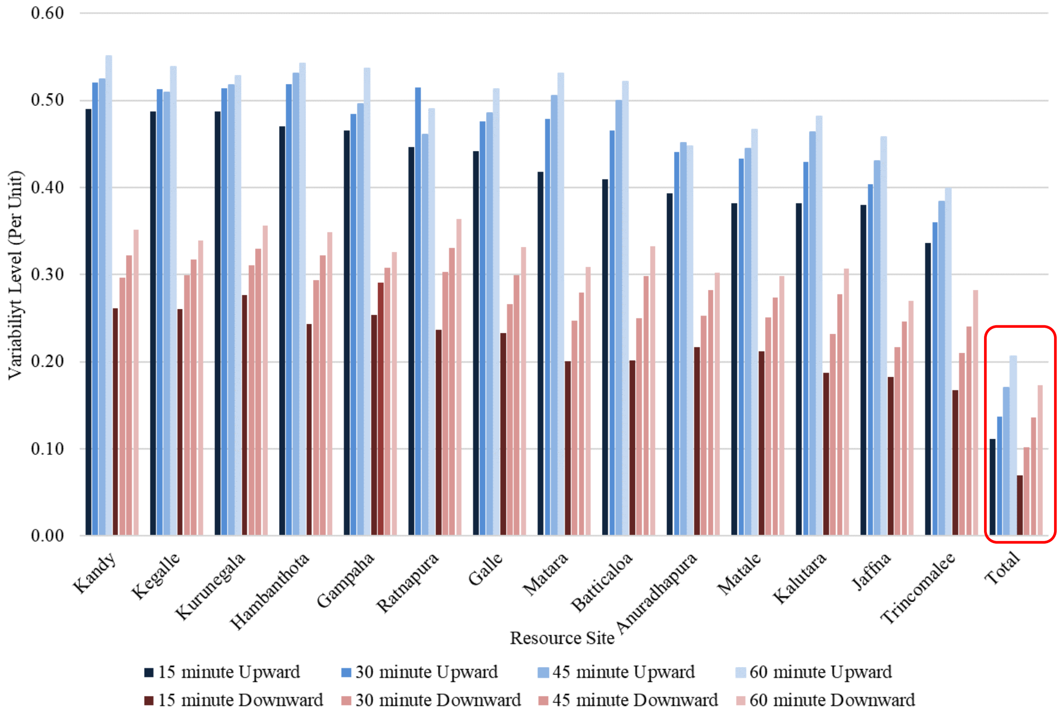


A5.4 Modelled production profile of Minihydro resource based on 2017 data

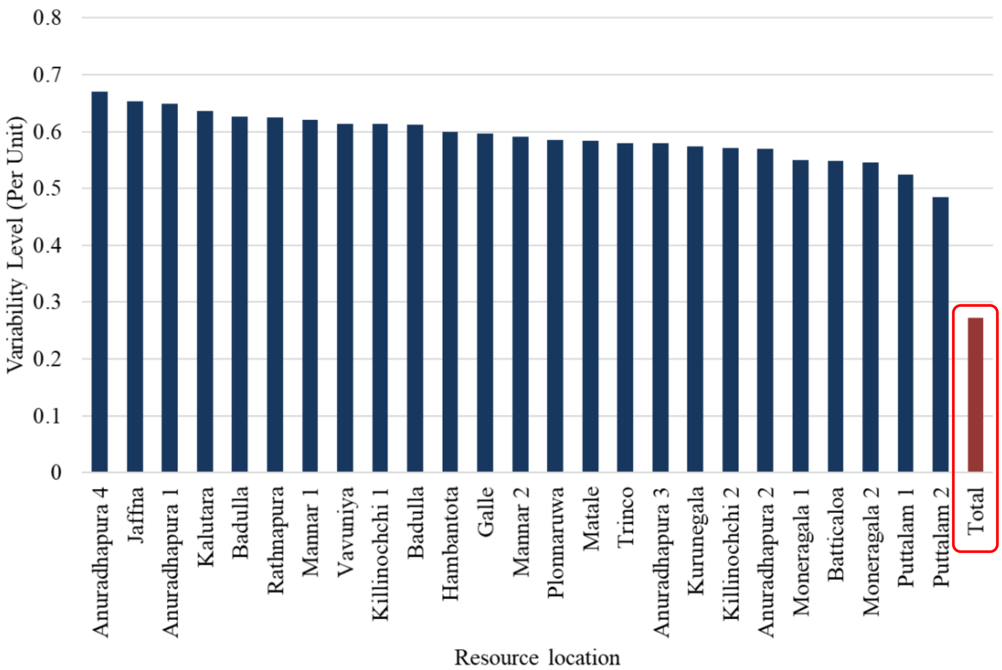


A5.5 Monthly energy production of Minihydro resource based on 2017 data

Figure 5.6 and 5.7 illustrates the variability levels of outputs of solar PV production around the island and the variability of the aggregated output of multiple sites. This indicates that the impact variability on the power system can be mitigated by strategically distributing solar PV development geographically to a certain extent.



A5.6 Solar PV variability levels (15min, 30min, 45min, 60 min) of power outputs of different sites and total power output based actual data covering the country



A5.7 Solar PV variability levels (60 min) of power outputs of different sites and total power output based on satellite data covering the country

Annex 5.7

Cost Details Other Renewable Energy

The Capital Costs of ORE technologies are considered as follows in the generation expansion studies:

- Solar: 1055 USD/kW at the present context and would gradually decline to 900USD /kW by 2025
- Wind: 1400 USD/kW
- Biomass: 1782 USD/kW
- Mini Hydro: 1749 USD/kW

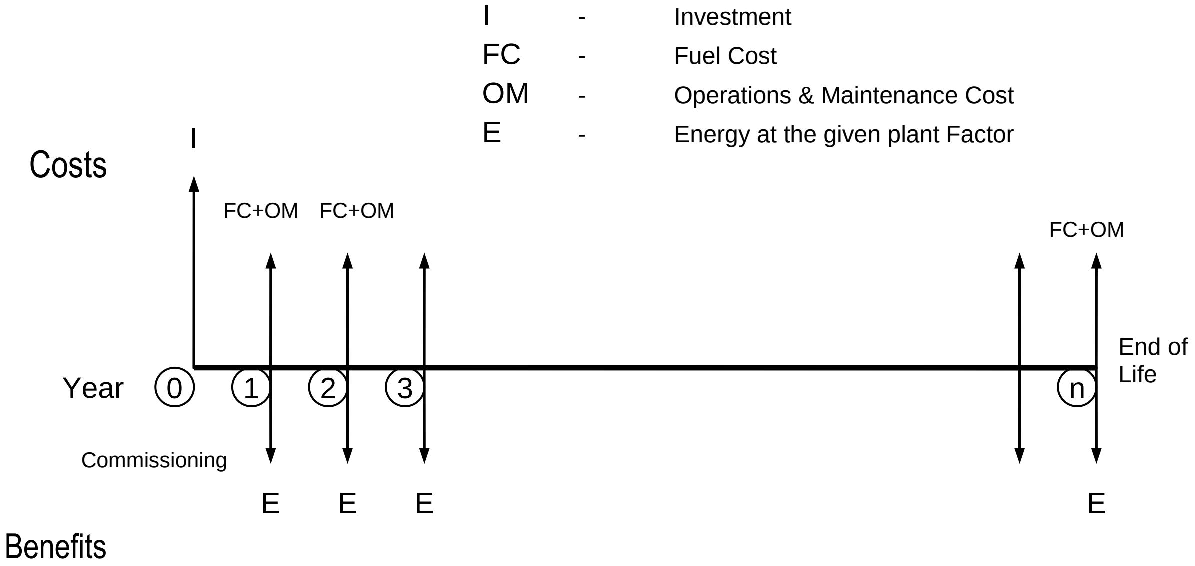
The O & M Costs of these technologies are considered as a percentage of the capital costs and the percentages are as follows:

Fixed O&M Cost	%
Mini Hydro	3
Wind	1.5
Solar	0.9
Biomass	4

Annex 6.1

Methodology of the Screening of Curve

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.



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.

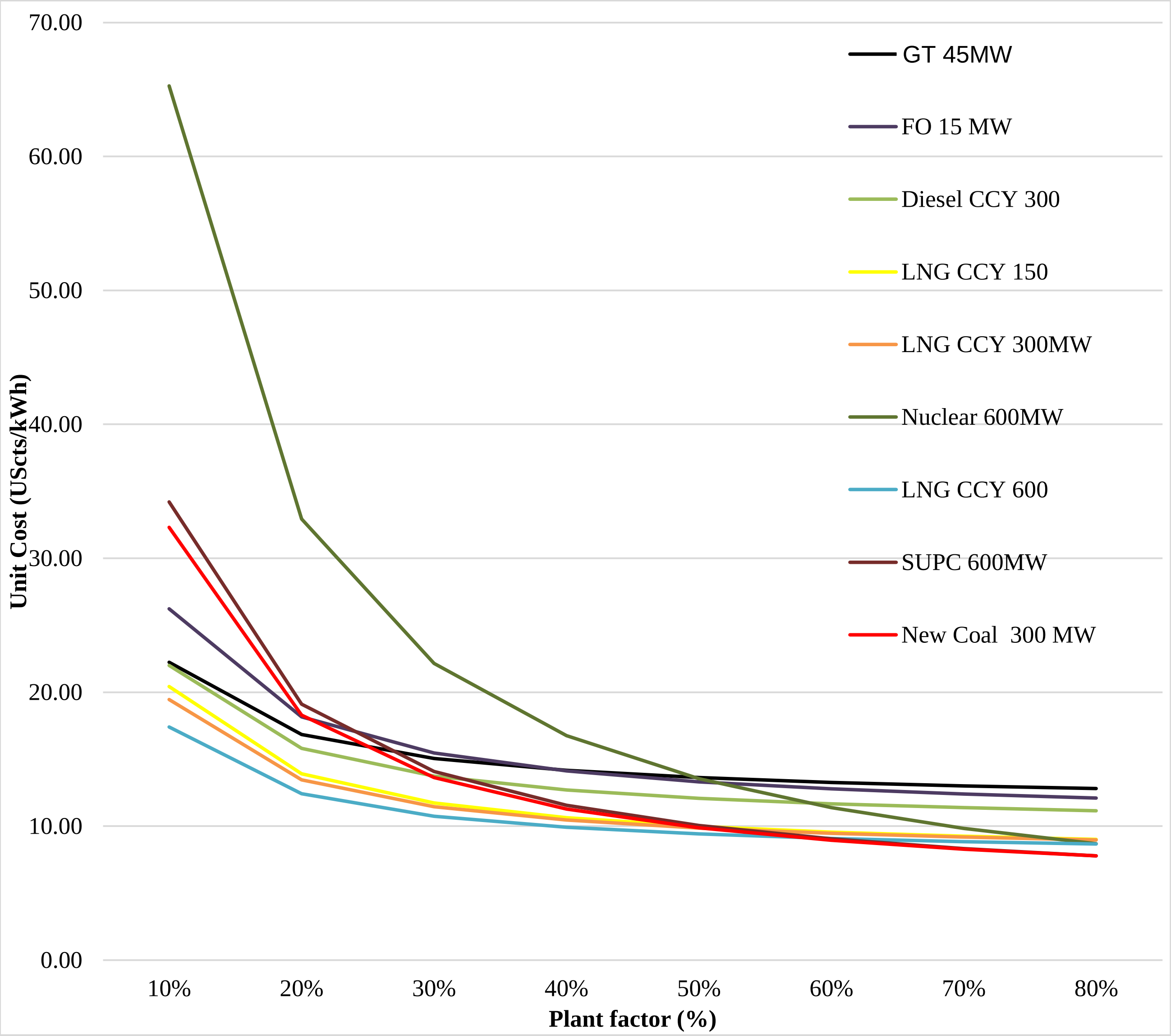
Specific Cost = [I + { Σ Fixed OM + (FC + Var. OM) * E } * PV Factor] / E * PV Factor

Screening of Generation Options

The screening curves were developed for the following Thermal Generation Alternatives

1. GT 45MW - 45MW Natural Gas fired gas turbine
2. CCY 300MW - 300MW Auto Diesel fired combined cycle power plant
3. New Coal 300MW - 300MW High Efficient Coal fired thermal power plant
4. SUPC 600MW - 600MW Super Critical Coal power plant
5. LNG 150MW - 150MW NG fired combined cycle power plant
6. LNG 300MW - 300MW NG fired combined cycle power plant
7. LNG 600MW - 600MW NG fired combined cycle power plant
8. Nuclear 600MW - 600MW Nuclear Power plant
9. FO 15MW - 15MW Furnace oil Reciprocating Engine

A8.1.1 Screening Curves of the Generation Options at 10% Discount Rate



8.1.2 Specific Cost of Screened Candidate Thermal Plants (in LKR)

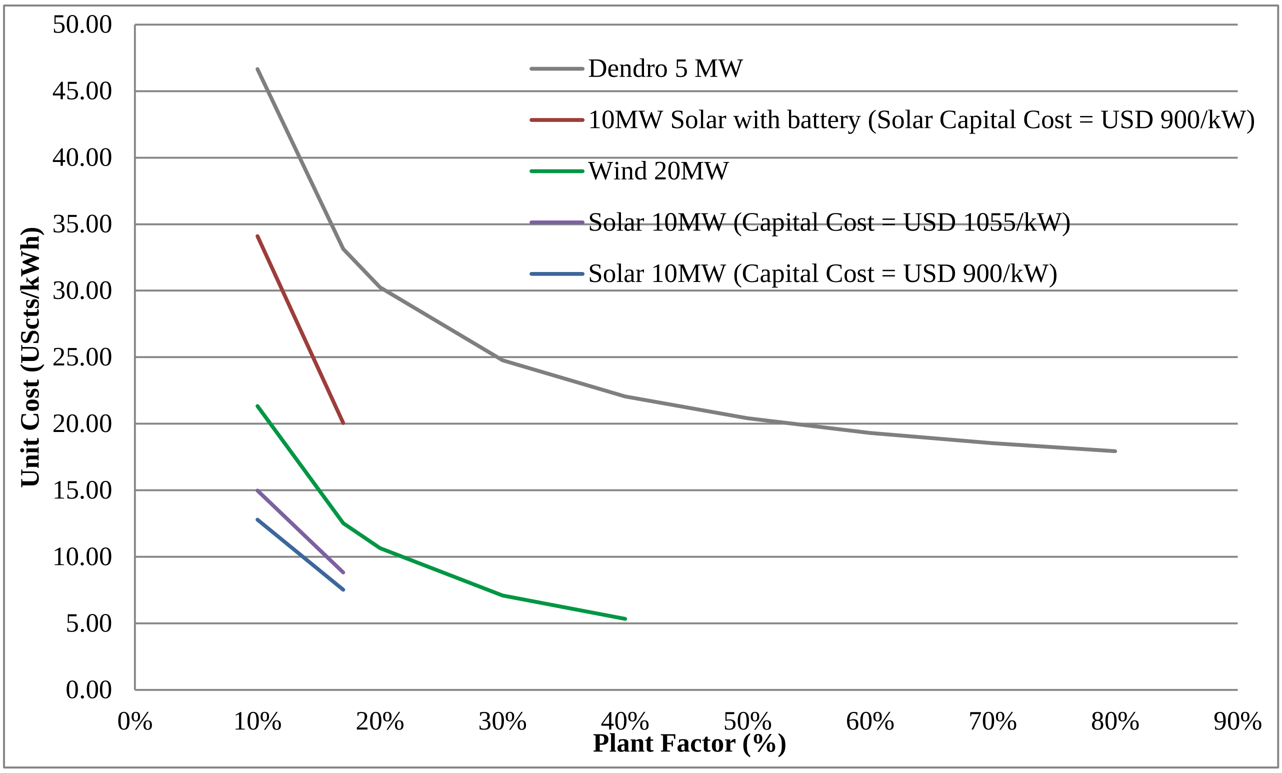
Plant \ Plant Factor	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8
45MW NG fired gas turbine	40.04	30.34	27.11	25.50	24.53	23.88	23.42	23.07
300MW Diesel fired combined cycle power plant	39.61	28.45	24.73	22.87	21.76	21.02	20.48	20.09
300MW Coal fired thermal power plant	58.20	32.95	24.53	20.33	17.80	16.12	14.91	14.01
600MW Super Critical Coal power plant	61.61	34.42	25.36	20.82	18.11	16.29	15.00	14.03
150MW NG fired combined cycle power plant	36.79	25.04	21.12	19.16	17.98	17.20	16.64	16.22
300MW NG fired combined cycle power plant	35.03	24.24	20.64	18.84	17.76	17.04	16.52	16.14
600MW NG fired combined cycle power plant	31.34	22.35	19.36	17.86	16.96	16.36	15.93	15.61
600MW Nuclear Power plant	117.53	59.31	39.90	30.19	24.37	20.49	17.72	15.64
15MW Furnace oil Reciprocating Engine	47.23	32.70	27.85	25.43	23.98	23.01	22.32	21.80

Note: 1 US$ = LKR 180.10

*LNG terminal cost and coal jetty cost is not included in the plant capital cost

The screening curves were developed for the following renewable energy options also.

1. Dendro 5MW - 5MW Biomass power plant
2. Wind 25MW - 20MW Wind power plant
3. Solar 10MW - 10MW Solar power plant
4. Solar 10 MW with Battery - 10 MW Solar power plant with battery storage



Annex 8.2

Capacity Balance for the Base Case 2020 - 2039

Plant Name	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Hydro																				
Existing Major Hydro	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382	1382
New Major Hydro	35	155	155	179	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Pumped Hydro	0	0	0	0	0	0	0	0	200	400	400	400	600	600	600	600	600	600	600	600
Sub Total	**1417**	**1537**	**1537**	**1561**	**1607**	**1607**	**1607**	**1607**	**1807**	**2007**	**2007**	**2007**	**2207**	**2207**	**2207**	**2207**	**2207**	**2207**	**2207**	**2207**
Thermal Existing and Committed																				
Small Gas Turbines	68	68	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	70	70	70	70	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	70	70	70	35	35	35	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
Asia Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa Combined Cycle	161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Combined Cycle	163	163	163	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	270	0	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	810	810
Northern Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Uthurujanani	26	26	26	26	26	26	26	26	26	26	26	26	26	0	0	0	0	0	0	0
CEB Barge Power	62	62	62	62	62	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine Power Plant 320 MW	320	320	300	300	300	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
NG Converted Sojitz Combined Cycle	0	0	0	163	163	163	163	163	163	163	163	163	163	0	0	0	0	0	0	0
NG Converted Kelanitissa Combined Cycle	0	161	161	161	161	161	161	161	161	161	161	161	161	0	0	0	0	0	0	0
NG Converted Kerawalapitiya CCY	0	270	270	270	270	270	270	270	270	270	270	270	270	270	270	0	0	0	0	0
Sub Total	**2,134**	**2,135**	**2,115**	**1,897**	**1,827**	**1,565**	**1,530**	**1,530**	**1,530**	**1,530**	**1,530**	**1,530**	**1,530**	**1,180**	**1,180**	**910**	**910**	**910**	**910**	**910**
New Thermal Plants																				
New Coal	0	0	0	270	540	810	810	810	1,080	1,080	1,080	1,080	1,350	1,620	1,620	1,620	1,620	1,890	1,890	2,160
New Gas Turbine	0	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
New NG Combined Cyle	0	0	579	869	869	1159	1449	1449	1449	1449	1449	1449	1449	1738	2028	2318	2607	2607	2897	2897
Reciprocating Engine Power Plant (Contingency)	345	450	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub Total	**345**	**580**	**709**	**1269**	**1539**	**2099**	**2389**	**2389**	**2659**	**2659**	**2659**	**2659**	**2929**	**3488**	**3778**	**4068**	**4357**	**4627**	**4917**	**5187**
Other Renewable Energy																				
ORE (Minihydro, Wind & Solar)	1197	1397	1547	1667	1747	1887	2022	2172	2322	2472	2602	2772	2942	3097	3297	3472	3642	3812	4002	4187
ORE (Biomass)	49	54	59	64	69	74	79	84	89	94	99	104	109	114	119	124	129	134	139	144
Sub Total	**1245**	**1450**	**1605**	**1730**	**1815**	**1960**	**2100**	**2255**	**2410**	**2565**	**2700**	**2875**	**3050**	**3210**	**3415**	**3595**	**3770**	**3945**	**4140**	**4330**
Total Installed Capacity (A)	**5142**	**5702**	**5966**	**6457**	**6789**	**7231**	**7626**	**7781**	**8406**	**8761**	**8896**	**9071**	**9716**	**10086**	**10580**	**10780**	**11245**	**11690**	**12174**	**12634**
Installed Capacity without ORE (B)	**3896**	**4252**	**4361**	**4727**	**4973**	**5271**	**5526**	**5526**	**5996**	**6196**	**6196**	**6196**	**6666**	**6875**	**7165**	**7185**	**7474**	**7744**	**8034**	**8304**
Peak Demand (C)	**3050**	**3254**	**3403**	**3561**	**3728**	**3903**	**4079**	**4241**	**4444**	**4655**	**4872**	**5101**	**5332**	**5569**	**5814**	**6067**	**6328**	**6597**	**6873**	**7155**
Difference without ORE (B-C)	**846**	**998**	**958**	**1166**	**1245**	**1368**	**1447**	**1285**	**1552**	**1541**	**1324**	**1095**	**1334**	**1306**	**1351**	**1118**	**1146**	**1147**	**1161**	**1149**
Difference (%)	**27.8**	**30.7**	**28.2**	**32.7**	**33.4**	**35.0**	**35.5**	**30.3**	**34.9**	**33.1**	**27.2**	**21.5**	**25.0**	**23.5**	**23.2**	**18.4**	**18.1**	**17.4**	**16.9**	**16.1**

Notes : All the Capacities are in MW

Above total includes ORE plants

Maintenance and FOR outages not considered

Energy Balance for the Base Case 2020 - 2039

Plant Name	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Hydro																				
Existing Major Hydro	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092	4,092
New Major Hydro	52	164	149	286	324	309	301	294	286	279	272	264	256	249	241	234	226	219	212	208
PSPP Generation	0	0	0	0	0	0	0	0	200	400	400	400	600	600	600	597	599	600	600	600
Sub Total	4,144	4,256	4,241	4,378	4,416	4,401	4,393	4,386	4,578	4,771	4,764	4,756	4,948	4,941	4,933	4,923	4,917	4,911	4,904	4,900
Thermal Existing and Committed																				
Small Gas Turbines	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	291	121	262	231	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	479	462	421	169	146	93	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine No7	156	64	180	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa Combined Cycle	749	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Combined Cycle	887	828	732	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	414	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakvijaya Coal	3,891	4,973	5,279	4,273	4,123	4,238	4,482	4,608	4,478	4,638	4,781	4,879	4,766	4,669	4,803	4,925	5,021	4,970	5,030	4,980
Uthurujanani	178	162	146	125	107	67	61	80	62	75	87	98	89	0	0	0	0	0	0	0
CEB Barge Power	296	162	291	251	222	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Furnace Oil fired Reciprocating Engines	3,904	3,549	1,546	1,272	1,138	241	215	307	233	272	326	363	339	428	393	435	400	355	328	321
NG Converted Sojitz Combined Cycle	0	0	0	826	794	681	582	642	577	664	704	728	703	0	0	0	0	0	0	0
NG Converted Kelanitissa Combined Cycle	0	870	700	703	692	620	555	583	554	606	632	663	633	0	0	0	0	0	0	0
NG Converted Kerawalapitiya CCY	0	741	689	699	633	457	381	441	390	440	489	539	500	512	468	0	0	0	0	0
Sub Total	11,246	11,932	10,247	8,550	7,856	6,397	6,275	6,662	6,295	6,694	7,019	7,270	7,029	5,609	5,664	5,360	5,420	5,325	5,357	5,301
New Thermal Plants																				
New Coal	0	0	0	1,686	3,417	5,278	5,439	5,528	7,412	7,647	7,721	7,768	9,682	11,487	11,628	11,724	11,797	13,745	13,810	15,753
New Gas Turbine	0	60	131	106	107	82	68	98	73	89	113	132	119	151	131	154	139	121	106	102
New NG Combined Cyle	0	0	2,273	3,059	2,983	3,573	4,540	4,993	4,582	5,063	5,783	6,561	6,110	6,903	7,865	9,313	10,500	10,026	11,287	10,798
Sub Total	0	60	2,405	4,851	6,507	8,933	10,048	10,619	12,067	12,799	13,617	14,461	15,911	18,541	19,624	21,190	22,436	23,892	25,203	26,653
Other Renewable Energy																				
ORE - Minihydro, Wind & Solar	3,063	3,595	3,966	4,232	4,383	4,678	4,933	5,234	5,524	5,814	6,048	6,388	6,726	7,006	7,414	7,747	8,084	8,422	8,815	9,192
ORE - Biomass (Existing + New)	340	375	410	445	480	515	550	585	620	655	690	725	760	795	830	865	901	936	971	1,006
Sub Total	3,403	3,970	4,376	4,677	4,863	5,193	5,483	5,819	6,144	6,469	6,738	7,114	7,487	7,801	8,244	8,613	8,985	9,357	9,786	10,198
Total Generation (Excluding New Biomass)	**18,575**	**19,942**	**20,975**	**22,070**	**23,217**	**24,442**	**25,680**	**26,901**	**28,464**	**30,078**	**31,447**	**32,875**	**34,614**	**36,096**	**37,634**	**39,220**	**40,858**	**42,550**	**44,280**	**46,047**
System Demand	**18,542**	**19,910**	**20,959**	**22,065**	**23,230**	**24,458**	**25,696**	**26,918**	**28,195**	**29,522**	**30,890**	**32,325**	**33,778**	**35,267**	**36,806**	**38,390**	**40,028**	**41,716**	**43,448**	**45,215**
PSPP Demand	0	0	0	0	0	0	0	0	286	571	571	571	857	857	857	853	856	857	857	857
Unserved Energy	**-33**	**-32**	**-16**	**-5**	**13**	**16**	**16**	**17**	**17**	**16**	**14**	**22**	**21**	**28**	**29**	**22**	**26**	**23**	**25**	**26**

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

Annex 8.4

Annual Energy Generation and Plant Factors

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2020	Major Hydro	1417 MW	2934	4144	5380			
	ORE	1245 MW	2507	3403	4232			
	Kelanitissa Small GTs	4 x 17 MW	7	1	0	1.2	0.3	0.0
	Kelanitissa GT7	1 x 115 MW	342	156	31	34.0	15.5	3.1
	Kelanitissa Combined Cycle	1 x 161 MW	837	749	683	59.4	53.2	48.5
	Sapugaskanda A	4 x 17 MW	407	291	120	68.3	48.9	20.1
	Sapugaskanda B	8 x 9 MW	480	479	472	76.2	76.0	74.8
	Uthuru Janani	3 x 9 MW	183	178	154	77.8	75.7	65.6
	Barge Power Plant	4 x 16 MW	437	296	133	79.9	54.2	24.4
	Lakvijaya Unit 1	270 MW	1474	1308	1309	62.3	55.3	55.3
	Lakvijaya Unit 2	270 MW	1371	1203	1262	58.0	50.8	53.4
	Lakvijaya Unit 3	270 MW	1523	1381	1358	64.4	58.4	57.4
	Sojitz Combined Cycle	1 x 163 MW	977	887	837	68.4	62.1	58.7
	West Coast Combined Cycle	1 x 270 MW	706	414	156	29.9	17.5	6.6
	Reciprocating Engines	665 MW	4555	3904	2700	77.0	66.9	45.7
	Total Renewable Generation		**5441**	**7547**	**9612**			
	Total Thermal Generation		**13299**	**11247**	**9215**			
	Total Generation		**18740**	**18794**	**18827**			
2021	Major Hydro	1537 MW	3058	4256	5785			
	ORE	1450 MW	3031	3970	4839			
	Kelanitissa Small GTs	4 x 17 MW	3	0	0	0.50	0.10	0.00
	Kelanitissa GT7	1 x 115 MW	226	64	1	22.40	6.40	0.10
	Sapugaskanda A	4 x 17 MW	367	121	3	61.50	20.40	0.50
	Sapugaskanda B	8 x 9 MW	480	462	390	76.20	73.30	61.80
	Uthuru Janani	3 x 9 MW	182	162	125	77.70	69.00	53.40
	Barge Power Plant	4 x 16 MW	393	162	5	71.90	29.70	1.00
	Lakvijaya Unit 1	270 MW	1491	1663	1702	63.00	70.30	71.90
	Lakvijaya Unit 2	270 MW	1418	1620	1661	60.00	68.50	70.20
	Lakvijaya Unit 3	270 MW	1520	1690	1732	64.30	71.40	73.20
	Sojitz Combined Cycle	1 x 163 MW	898	828	681	62.90	58.00	47.70
	Kelanitissa CCY(NG Converted)	1 x 161 MW	863	870	987	61.20	61.70	70.00
	West Coast CCY(NG Converted)	1 x 270 MW	929	741	665	39.30	31.30	28.10
	Reciprocating Engines	770 MW	5094	3549	1668	74.60	51.90	24.40
	New Gas Turbines	130 MW	226	60	1	21.30	5.60	0.10
	Total Renewable Generation		**6089**	**8225**	**10623**			
	Total Thermal Generation		**14090**	**11992**	**9621**			
	Total Generation		**20179**	**20217**	**20244**			
2022	Major Hydro	1537 MW	3042	4241	5785			
	ORE	1605 MW	3395	4376	5284			
	Kelanitissa Small GTs	4 x 17 MW	4	1	0	0.7	0.2	0
	Kelanitissa GT7	1 x 115 MW	285	180	64	28.3	17.9	6.4
	Sapugaskanda A	4 x 17 MW	371	262	76	62.3	44	12.8
	Sapugaskanda B	8 x 9 MW	464	421	356	73.6	66.7	56.4
	Uthuru Janani	3 x 9 MW	169	146	116	71.9	62.2	49.4
	Barge Power Plant	4 x 16 MW	394	291	109	72.1	53.2	19.9
	Lakvijaya Unit 1	270 MW	1773	1762	1718	75	74.5	72.6
	Lakvijaya Unit 2	270 MW	1765	1746	1681	74.6	73.8	71.1
	Lakvijaya Unit 3	270 MW	1778	1771	1740	75.2	74.9	73.6
	Sojitz Combined Cycle	1 x 163 MW	860	732	599	60.2	51.2	41.9
	Kelanitissa CCY(NG Converted)	1 x 161 MW	837	700	589	59.3	49.6	41.8
	West Coast CCY(NG Converted)	1 x 270 MW	903	689	568	38.2	29.1	24
	Reciprocating Engines	300 MW	1895	1546	974	68.7	56	35.3
	New Gas Turbines	130 MW	240	131	31	22.6	12.4	2.9
	NG Combined Cycle	2 x 300 MW	3055	2273	1618	60.2	44.8	31.9
	Total Renewable Generation		**6437**	**8617**	**11070**			
	Total Thermal Generation		**14793**	**12651**	**10239**			
	Total Generation		**21230**	**21268**	**21309**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2023	Major Hydro	1561 MW	3125	4378	5990			
	ORE	1730 MW	3653	4677	5626			
	Sapugaskanda A	4 x 17 MW	350	231	109	58.8	38.8	18.3
	Sapugaskanda B	4 x 9 MW	198	169	123	62.7	53.5	38.9
	Uthuru Janani	3 x 9 MW	149	125	88	63.5	53.4	37.3
	Barge Power Plant	4 x 16 MW	364	251	123	66.7	45.9	22.5
	Lakvijaya Unit 1	270 MW	1546	1429	1298	65.4	60.4	54.9
	Lakvijaya Unit 2	270 MW	1510	1349	1200	63.8	57	50.7
	Lakvijaya Unit 3	270 MW	1589	1495	1353	67.2	63.2	57.2
	Kelanitissa CCY(NG Converted)	1 x 161 MW	741	703	615	52.5	49.9	43.6
	Sojitz CCY(NG Converted)	1 x 163 MW	886	826	695	62	57.8	48.7
	West Coast CCY(NG Converted)	1 x 270 MW	752	699	521	31.8	29.6	22
	Reciprocating Engines	300 MW	1722	1272	773	62.4	46.1	28
	New Gas Turbines	130 MW	177	106	37	16.7	10	3.5
	NG Combined Cycle	3 x 300 MW	3878	3059	2388	50.9	40.2	31.4
	New Coal (Lakvijaya Extension)	1 x 300 MW	1794	1686	1538	75.8	71.3	65
	Total Renewable Generation		**6778**	**9055**	**11616**			
	Total Thermal Generation		**15656**	**13400**	**10861**			
	Total Generation		**22434**	**22455**	**22477**			
2024	Major Hydro	1607 MW	3149	4416	6055			
	ORE	1815 MW	3796	4863	5851			
	Sapugaskanda B	4 x 9 MW	192	146	64	60.9	46.4	20.3
	Uthuru Janani	3 x 9 MW	144	107	47	61.3	45.7	19.9
	Barge Power Plant	4 x 16 MW	342	222	57	62.5	40.7	10.5
	Lakvijaya Unit 1	270 MW	1511	1375	1253	63.9	58.1	53
	Lakvijaya Unit 2	270 MW	1483	1304	1192	62.7	55.1	50.4
	Lakvijaya Unit 3	270 MW	1552	1445	1321	65.6	61.1	55.9
	Kelanitissa CCY(NG Converted)	1 x 161 MW	725	692	583	51.4	49.1	41.4
	Sojitz CCY(NG Converted)	1 x 163 MW	879	794	656	61.6	55.6	45.9
	West Coast CCY(NG Converted)	1 x 270 MW	725	633	445	30.7	26.8	18.8
	Reciprocating Engines	300 MW	1634	1138	408	59.2	41.2	14.8
	New Gas Turbines	130 MW	180	107	20	17	10.1	1.9
	NG Combined Cycle	3 x 300 MW	3740	2983	2551	49.1	39.2	33.5
	New Coal (Lakvijaya Extension)	2 x 300 MW	3574	3417	3172	75.6	72.2	67.1
	Total Renewable Generation		**6945**	**9279**	**11906**			
	Total Thermal Generation		**16681**	**14363**	**11769**			
	Total Generation		**23626**	**23642**	**23675**			
2025	Major Hydro	1607 MW	3133	4401	6056			
	ORE	1960 MW	4084	5193	6220			
	Sapugaskanda B	4 x 9 MW	164	93	19	52.1	29.5	5.9
	Uthuru Janani	3 x 9 MW	122	67	13	52	28.7	5.6
	Lakvijaya Unit 1	270 MW	1513	1417	1255	64	59.9	53.1
	Lakvijaya Unit 2	270 MW	1481	1354	1145	62.6	57.3	48.4
	Lakvijaya Unit 3	270 MW	1549	1466	1317	65.5	62	55.7
	Kelanitissa CCY(NG Converted)	1 x 161 MW	708	620	475	50.2	43.9	33.7
	Sojitz CCY(NG Converted)	1 x 163 MW	829	681	412	58	47.7	28.9
	West Coast CCY(NG Converted)	1 x 270 MW	661	457	156	27.9	19.3	6.6
	Reciprocating Engines	100 MW	458	241	20	49.8	26.3	2.2
	New Gas Turbines	130 MW	164	82	4	15.5	7.7	0.3
	NG Combined Cycle	4 x 300 MW	4561	3573	2930	44.9	35.2	28.9
	New Coal (Lakvijaya Extension)	3 x 300 MW	5471	5278	4928	77.1	74.4	69.4
	Total Renewable Generation		**7216**	**9593**	**12276**			
	Total Thermal Generation		**17681**	**15329**	**12674**			
	Total Generation		**24897**	**24922**	**24950**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2026	Major Hydro	1607 MW	3126	4393	6057			
	ORE	2100 MW	4353	5483	6531			
	Uthuru Janani	3 x 9 MW	103	61	21	43.8	26	8.9
	Lakvijaya Unit 1	270 MW	1557	1496	1343	65.8	63.3	56.8
	Lakvijaya Unit 2	270 MW	1530	1458	1267	64.7	61.7	53.5
	Lakvijaya Unit 3	270 MW	1581	1528	1432	66.8	64.6	60.5
	Kelanitissa CCY(NG Converted)	1 x 161 MW	687	555	296	48.7	39.3	21
	Sojitz CCY(NG Converted)	1 x 163 MW	792	582	301	55.5	40.7	21.1
	West Coast CCY(NG Converted)	1 x 270 MW	599	381	114	25.3	16.1	4.8
	Reciprocating Engines	100 MW	391	215	54	42.5	23.4	5.9
	New Gas Turbines	130 MW	142	68	16	13.4	6.4	1.5
	NG Combined Cycle	5 x 300 MW	5709	4540	3620	45	35.8	28.5
	New Coal (Lakvijaya Extension)	3 x 300 MW	5610	5439	5169	79.1	76.7	72.8
	Total Renewable Generation		**7478**	**9876**	**12587**			
	Total Thermal Generation		**18701**	**16323**	**13633**			
	Total Generation		**26179**	**26199**	**26220**			
2027	Major Hydro	1607 MW	3118	4386	6057			
	ORE	2255 MW	4667	5819	6886			
	Uthuru Janani	3 x 9 MW	109	80	24	46.5	34.2	10.4
	Lakvijaya Unit 1	270 MW	1587	1537	1430	67.1	65	60.5
	Lakvijaya Unit 2	270 MW	1564	1506	1378	66.1	63.7	58.3
	Lakvijaya Unit 3	270 MW	1610	1566	1482	68.1	66.2	62.6
	Kelanitissa CCY(NG Converted)	1 x 161 MW	701	583	385	49.7	41.3	27.3
	Sojitz CCY(NG Converted)	1 x 163 MW	810	642	353	56.8	45	24.7
	West Coast CCY(NG Converted)	1 x 270 MW	628	441	189	26.6	18.7	8
	Reciprocating Engines	100 MW	417	307	83	45.3	33.4	9
	New Gas Turbines	130 MW	154	98	20	14.5	9.3	1.8
	NG Combined Cycle	5 x 300 MW	6436	4993	3909	50.7	39.3	30.8
	New Coal (Lakvijaya Extension)	3 x 300 MW	5682	5528	5293	80.1	77.9	74.6
	Total Renewable Generation		**7785**	**10205**	**12943**			
	Total Thermal Generation		**19698**	**17281**	**14546**			
	Total Generation		**27483**	**27486**	**27489**			
2028	Major Hydro	1607 MW	3111	4378	6057			
	ORE	2410 MW	4971	6144	7231			
	Uthuru Janani	3 x 9 MW	105	62	11	44.9	26.5	4.9
	Lakvijaya Unit 1	270 MW	1553	1497	1375	65.7	63.3	58.1
	Lakvijaya Unit 2	270 MW	1528	1454	1304	64.6	61.5	55.1
	Lakvijaya Unit 3	270 MW	1578	1527	1432	66.7	64.6	60.5
	Kelanitissa CCY(NG Converted)	1 x 161 MW	694	554	328	49.2	39.3	23.3
	Sojitz CCY(NG Converted)	1 x 163 MW	806	577	295	56.5	40.4	20.7
	West Coast CCY(NG Converted)	1 x 270 MW	596	390	102	25.2	16.5	4.3
	Reciprocating Engines	100 MW	400	233	46	43.5	25.3	5
	New Gas Turbines	130 MW	144	73	14	13.6	6.8	1.3
	NG Combined Cycle	5 x 300 MW	5786	4582	3636	45.6	36.1	28.7
	New Coal (Lakvijaya Extension)	3 x 300 MW	5617	5446	5153	79.2	76.8	72.6
	New Coal (Foul Point)	1 x 300 MW	1995	1966	1900	84.3	83.1	80.3
	Total Renewable Generation		**8081**	**10522**	**13288**			
	Total Thermal Generation		**20802**	**18361**	**15596**			
	Total Generation		**28883**	**28883**	**28884**			
2029	Major Hydro	1607 MW	3103	4371	6058			
	ORE	2565 MW	5275	6469	7576			
	Uthuru Janani	3 x 9 MW	114	75	21	48.5	31.8	9.1
	Lakvijaya Unit 1	270 MW	1598	1547	1451	67.6	65.4	61.3
	Lakvijaya Unit 2	270 MW	1576	1513	1408	66.6	64	59.5
	Lakvijaya Unit 3	270 MW	1632	1579	1506	69	66.8	63.7
	Kelanitissa CCY(NG Converted)	1 x 161 MW	735	605	392	52.1	42.9	27.8
	Sojitz CCY(NG Converted)	1 x 163 MW	846	664	327	59.3	46.5	22.9
	West Coast CCY(NG Converted)	1 x 270 MW	687	440	144	29	18.6	6.1
	Reciprocating Engines	100 MW	432	271	89	46.9	29.5	9.6
	New Gas Turbines	130 MW	152	89	28	14.4	8.4	2.7
	NG Combined Cycle	5 x 300 MW	6376	5063	3993	50.3	39.9	31.5
	New Coal (Lakvijaya Extension)	3 x 300 MW	5806	5655	5386	81.8	79.7	75.9
	New Coal (Foul Point)	1 x 300 MW	2003	1992	1954	84.7	84.2	82.6
	Total Renewable Generation		**8378**	**10840**	**13634**			
	Total Thermal Generation		**21957**	**19493**	**16699**			
	Total Generation		**30335**	**30333**	**30333**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2030	Major Hydro	1607 MW	3095	4364	6058			
	ORE	2700 MW	5522	6738	7865			
	Uthuru Janani	3 x 9 MW	125	87	32	53.2	37.1	13.7
	Lakvijaya Unit 1	270 MW	1635	1591	1530	69.1	67.3	64.7
	Lakvijaya Unit 2	270 MW	1611	1566	1484	68.1	66.2	62.7
	Lakvijaya Unit 3	270 MW	1668	1624	1557	70.5	68.7	65.8
	Kelanitissa CCY(NG Converted)	1 x 161 MW	760	632	495	53.9	44.8	35.1
	Sojitz CCY(NG Converted)	1 x 163 MW	870	704	474	60.9	49.3	33.2
	West Coast CCY(NG Converted)	1 x 270 MW	689	489	215	29.1	20.7	9.1
	Reciprocating Engines	100 MW	476	326	116	51.8	35.4	12.6
	New Gas Turbines	130 MW	174	113	31	16.4	10.6	3
	NG Combined Cycle	5 x 300 MW	7270	5783	4409	57.3	45.6	34.8
	New Coal (Lakvijaya Extension)	3 x 300 MW	5838	5727	5499	82.3	80.7	77.5
	New Coal (Foul Point)	1 x 300 MW	2001	1994	1973	84.6	84.3	83.4
	Total Renewable Generation		**8617**	**11102**	**13923**			
	Total Thermal Generation		**23117**	**20636**	**17815**			
	Total Generation		**31734**	**31738**	**31738**			
2031	Major Hydro	1607 MW	3088	4356	6058			
	ORE	2875 MW	5876	7114	8260			
	Uthuru Janani	3 x 9 MW	136	98	52	57.9	41.7	22.2
	Lakvijaya Unit 1	270 MW	1668	1629	1558	70.5	68.9	65.9
	Lakvijaya Unit 2	270 MW	1637	1597	1530	69.2	67.5	64.7
	Lakvijaya Unit 3	270 MW	1686	1653	1586	71.3	69.9	67.1
	Kelanitissa CCY(NG Converted)	1 x 161 MW	863	663	514	61.2	47	36.5
	Sojitz CCY(NG Converted)	1 x 163 MW	922	728	565	64.6	51	39.5
	West Coast CCY(NG Converted)	1 x 270 MW	834	539	384	35.3	22.8	16.2
	Reciprocating Engines	100 MW	504	363	183	54.8	39.5	19.9
	New Gas Turbines	130 MW	208	132	56	19.6	12.4	5.2
	NG Combined Cycle	5 x 300 MW	7887	6561	4900	62.2	51.7	38.6
	New Coal (Lakvijaya Extension)	3 x 300 MW	5875	5775	5582	82.8	81.4	78.7
	New Coal (Foul Point)	1 x 300 MW	2002	1993	1974	84.6	84.3	83.5
	Total Renewable Generation		**8964**	**11470**	**14318**			
	Total Thermal Generation		**24222**	**21731**	**18884**			
	Total Generation		**33186**	**33201**	**33202**			
2032	Major Hydro	1607 MW	3080	4348	6057			
	ORE	3050 MW	6228	7487	8653			
	Uthuru Janani	3 x 9 MW	133	89	34	56.8	37.8	14.5
	Lakvijaya Unit 1	270 MW	1635	1587	1498	69.1	67.1	63.3
	Lakvijaya Unit 2	270 MW	1614	1556	1448	68.2	65.8	61.2
	Lakvijaya Unit 3	270 MW	1656	1623	1546	70	68.6	65.4
	Kelanitissa CCY(NG Converted)	1 x 161 MW	797	633	496	56.5	44.8	35.2
	Sojitz CCY(NG Converted)	1 x 163 MW	924	703	498	64.7	49.2	34.9
	West Coast CCY(NG Converted)	1 x 270 MW	776	500	318	32.8	21.1	13.4
	Reciprocating Engines	100 MW	507	339	155	55.1	36.8	16.9
	New Gas Turbines	130 MW	174	119	56	16.4	11.2	5.3
	NG Combined Cycle	5 x 300 MW	7451	6110	4602	58.7	48.2	36.3
	New Coal (Lakvijaya Extension)	3 x 300 MW	5795	5697	5477	81.7	80.3	77.2
	New Coal (Foul Point)	2 x 300 MW	4003	3985	3936	84.6	84.2	83.2
	Total Renewable Generation		**9308**	**11835**	**14710**			
	Total Thermal Generation		**25465**	**22941**	**20064**			
	Total Generation		**34773**	**34776**	**34774**			
2033	Major Hydro	1607 MW	3073	4341	6056			
	ORE	3210 MW	6521	7801	8987			
	Lakvijaya Unit 1	270 MW	1620	1557	1465	68.5	65.8	62
	Lakvijaya Unit 2	270 MW	1606	1523	1426	67.9	64.4	60.3
	Lakvijaya Unit 3	270 MW	1630	1589	1518	68.9	67.2	64.2
	West Coast CCY(NG Converted)	1 x 270 MW	755	512	338	31.9	21.7	14.3
	Reciprocating Engines	100 MW	593	428	150	64.5	46.6	16.4
	New Gas Turbines	130 MW	231	151	58	21.7	14.2	5.5
	NG Combined Cycle	6 x 300 MW	8601	6903	5141	56.5	45.3	33.8
	New Coal (Lakvijaya Extension)	3 x 300 MW	5684	5550	5315	80.1	78.2	74.9
	New Coal (Foul Point)	3 x 300 MW	5975	5936	5838	84.2	83.7	82.3
	Total Renewable Generation		**9594**	**12142**	**15043**			
	Total Thermal Generation		**26695**	**24149**	**21249**			
	Total Generation		**36289**	**36291**	**36292**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2034	Major Hydro	1607 MW	3065	4333	6056			
	ORE	3415 MW	6942	8244	9450			
	Lakvijaya Unit 1	270 MW	1646	1600	1529	69.6	67.6	64.6
	Lakvijaya Unit 2	270 MW	1626	1573	1478	68.8	66.5	62.5
	Lakvijaya Unit 3	270 MW	1664	1630	1559	70.3	68.9	65.9
	West Coast CCY(NG Converted)	1 x 270 MW	623	468	274	26.3	19.8	11.6
	Reciprocating Engines	100 MW	571	393	140	62.1	42.7	15.2
	New Gas Turbines	130 MW	200	131	45	18.8	12.3	4.3
	NG Combined Cycle	7 x 300 MW	9763	7865	5983	55	44.3	33.7
	New Coal (Lakvijaya Extension)	3 x 300 MW	5779	5671	5449	81.4	79.9	76.8
	New Coal (Foul Point)	3 x 300 MW	5985	5957	5903	84.3	83.9	83.2
	Total Renewable Generation		**10008**	**12577**	**15506**			
	Total Thermal Generation		**27857**	**25288**	**22360**			
	Total Generation		**37865**	**37865**	**37866**			
2035	Major Hydro	1607 MW	3057	4326	6058			
	ORE	3595 MW	7290	8613	9838			
	Lakvijaya Unit 1	270 MW	1668	1639	1574	70.5	69.3	66.6
	Lakvijaya Unit 2	270 MW	1650	1622	1555	69.8	68.6	65.7
	Lakvijaya Unit 3	270 MW	1697	1664	1596	71.8	70.3	67.5
	Reciprocating Engines	100 MW	617	435	197	67.1	47.3	21.4
	New Gas Turbines	130 MW	257	153	58	24.2	14.4	5.5
	NG Combined Cycle	8 x 300 MW	11400	9313	7122	56.2	45.9	35.1
	New Coal (Lakvijaya Extension)	3 x 300 MW	5842	5753	5561	82.3	81.1	78.4
	New Coal (Foul Point)	3 x 300 MW	5993	5971	5932	84.5	84.2	83.6
	Total Renewable Generation		**10347**	**12939**	**15896**			
	Total Thermal Generation		**29124**	**26550**	**23595**			
	Total Generation		**39471**	**39489**	**39491**			
2036	Major Hydro	1607 MW	3050	4318	6059			
	ORE	3770 MW	7640	8985	10230			
	Lakvijaya Unit 1	270 MW	1713	1677	1602	72.4	70.9	67.7
	Lakvijaya Unit 2	270 MW	1704	1655	1584	72	70	67
	Lakvijaya Unit 3	270 MW	1720	1689	1625	72.7	71.4	68.7
	Reciprocating Engines	100 MW	596	399	148	64.8	43.4	16.1
	New Gas Turbines	130 MW	230	139	51	21.7	13.1	4.8
	NG Combined Cycle	9 x 300 MW	12613	10500	8257	55.2	46	36.2
	New Coal (Lakvijaya Extension)	3 x 300 MW	5885	5814	5652	82.9	81.9	79.7
	New Coal (Foul Point)	3 x 300 MW	6002	5983	5953	84.6	84.3	83.9
	Total Renewable Generation		**10690**	**13303**	**16289**			
	Total Thermal Generation		**30463**	**27856**	**24872**			
	Total Generation		**41153**	**41159**	**41161**			
2037	Major Hydro	1607 MW	3042	4311	6060			
	ORE	3945 MW	7991	9357	10622			
	Lakvijaya Unit 1	270 MW	1705	1655	1601	72.1	70	67.7
	Lakvijaya Unit 2	270 MW	1684	1637	1568	71.2	69.2	66.3
	Lakvijaya Unit 3	270 MW	1714	1678	1615	72.4	70.9	68.3
	Reciprocating Engines	100 MW	544	355	104	59.2	38.6	11.3
	New Gas Turbines	130 MW	194	121	37	18.3	11.4	3.5
	NG Combined Cycle	9 x 300 MW	12159	10026	7761	53.2	43.9	34
	New Coal (Lakvijaya Extension)	3 x 300 MW	5853	5776	5587	82.5	81.4	78.7
	New Coal (Foul Point)	4 x 300 MW	7993	7969	7932	84.5	84.2	83.8
	Total Renewable Generation		**11034**	**13669**	**16683**			
	Total Thermal Generation		**31846**	**29217**	**26205**			
	Total Generation		**42880**	**42886**	**42888**			
2038	Major Hydro	1607 MW	3035	4304	6061			
	ORE	4140 MW	8399	9786	11071			
	Lakvijaya Unit 1	270 MW	1709	1679	1622	72.3	71	68.6
	Lakvijaya Unit 2	270 MW	1701	1658	1608	71.9	70.1	68
	Lakvijaya Unit 3	270 MW	1724	1692	1636	72.9	71.5	69.2
	Reciprocating Engines	100 MW	505	328	110	54.9	35.6	11.9
	New Gas Turbines	130 MW	181	106	16	17.1	10	1.5
	NG Combined Cycle	10 x 300 MW	13504	11287	8900	53.2	44.5	35.1
	New Coal (Lakvijaya Extension)	3 x 300 MW	5888	5829	5671	83	82.1	79.9
	New Coal (Foul Point)	4 x 300 MW	8001	7981	7956	84.6	84.4	84.1
	Total Renewable Generation		**11434**	**14090**	**17132**			
	Total Thermal Generation		**33213**	**30560**	**27519**			
	Total Generation		**44647**	**44650**	**44651**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2039	Major Hydro	1607 MW	3031	4300	6062			
	ORE	4330 MW	8800	10198	11493			
	Lakvijaya Unit 1	270 MW	1707	1659	1606	72.2	70.1	67.9
	Lakvijaya Unit 2	270 MW	1699	1643	1583	71.8	69.5	66.9
	Lakvijaya Unit 3	270 MW	1714	1678	1620	72.5	70.9	68.5
	Reciprocating Engines	100 MW	479	321	89	52.1	34.9	9.6
	New Gas Turbines	130 MW	164	102	24	15.4	9.6	2.3
	NG Combined Cycle	10 x 300 MW	12976	10798	8423	51.1	42.5	33.2
	New Coal (Lakvijaya Extension)	3 x 300 MW	5881	5782	5614	82.9	81.5	79.1
	New Coal (Foul Point)	5 x 300 MW	9997	9971	9939	84.5	84.3	84.1
	Total Renewable Generation		**11831**	**14498**	**17554**			
	Total Thermal Generation		**34617**	**31954**	**28898**			
	Total Generation		**46448**	**46452**	**46452**			

NOTES:
1. Annual total generation figure does not include operation of PSPP
2. Annual total renewable generation figure includes the generation from new biomass power plants.

Fuel Requirement and Expenditure on Fuel

Base Case 2020 - 2039

Year	Auto Diesel		Furnace Oil (LSFO 180)		Furnace Oil (HSFO 180)		Residual Oil (HSFO 380)		Naphtha		Coal (6300 kcal/kg)		LNG		Dendro	
	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD
2020	203.3	128.0	91.4	52.2	966.6	426.0	159.3	73.4	127.9	84.0	1488.1	170.8			600.3	23.7
2021	167.4	105.2			830.8	366.0	118.7	55.0			1904.8	212.4	271.8	162.9	662.2	26.1
2022	180.8	114.9			425.3	187.6	141.7	65.3			2021.9	224.1	575.2	339.4	724.1	28.5
2023					356.3	157.2	84.5	38.7			2124.6	250.3	801.0	476.6	785.9	31.0
2024					315.4	139.1	29.3	13.7			2573.2	311.3	773.8	462.9	847.8	33.4
2025					66.2	29.2	18.6	8.7			3162.7	386.8	790.7	480.6	909.7	35.8
2026					60.3	26.6					3302.0	401.3	883.4	534.4	971.6	38.3
2027					82.9	36.6					3377.1	409.1	979.3	581.1	1033.5	40.7
2028					62.3	27.5					4049.9	474.2	892.9	540.3	1095.4	43.2
2029					72.3	31.9					4181.7	488.0	994.6	591.6	1157.3	45.6
2030					89.1	39.3					4258.4	495.9	1117.3	647.3	1219.1	48.0
2031					100.0	44.1					4309.4	501.0	1247.4	703.8	1281.0	50.5
2032					91.1	40.2					5000.4	567.8	1167.0	667.3	1342.9	52.9
2033					91.6	40.3					5661.6	631.4	1092.9	624.4	1404.8	55.3
2034					84.2	37.0					5756.0	641.2	1213.4	693.7	1466.7	57.8
2035					93.3	41.1					5832.3	649.0	1339.2	746.8	1528.6	60.2
2036					85.6	37.7					5891.4	655.1	1500.9	834.4	1590.4	62.7
2037					76.2	33.5					6614.9	725.2	1429.6	800.7	1652.3	65.1
2038					69.2	30.5					6658.1	729.6	1601.7	891.9	1714.2	67.5
2039					68.5	30.1					7380.9	799.5	1531.8	859.2	1776.1	70.0

Results of Generation Expansion Planning Studies 2020-2039

High Demand Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2020	Major Hydro 35 MW (Broadlands HPP) *Wind 100 MW (Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 100 MW Biomass 5 MW	*320 MW Reciprocating Engine Power Plants** (Identified in LTGEP 2018-2037 to be commissioned by 2018) **Additional Capacity Requirement from Contingency Analysis = 390 MW Reciprocating Engine Power Plants** (Above capacities include the extension of existing power plants)	6 x 5 MW Northern Power	0.366
2021	Major Hydro *120 MW (Uma Oya HPP)* Mini Hydro 20 MW Wind 120 MW Solar 60 MW Biomass 5 MW	*130 MW Gas Turbine* + **Additional Capacity Requirement from Contingency Analysis = 150 MW Reciprocating Engine Power Plants**	-	0.099
2022	Mini Hydro 20 MW Wind 70 MW Solar 60 MW Biomass 5 MW	*1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region*++ (Identified in LTGEP 2015-2034 and LTGEP 2018-2037 to be commissioned by 2019) **1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**++ (Identified in LTGEP 2018-2037 to be commissioned by 2021) **1x300 MW Natural Gas fired Combined Cycle Power Plant**	600 MW Reciprocating Engine Power Plants (Includes the expiry of extended power plant contracts)	0.084
2023	Major Hydro *31 MW (Moragolla HPP)* **24 MW (Seethawaka HPP)** Mini Hydro 20 MW Wind 40 MW Solar 60 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase I)** *163 MW Combined Cycle Power Plant (KPS–2)*•	4x17 MW Kelanitissa Gas Turbines 115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.104
2024	Major Hydro **15 MW (Thalpitigala HPP)** Mini Hydro 20 MW Biomass 5 MW Solar 60 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase II)**	4x17 MW Sapugaskanda Diesel**	0.087
2025	Mini Hydro 20 MW Wind 40 MW Solar 80 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase II or Foul Point Phase I)** **1x300 MW Natural Gas fired Combined Cycle Power Plant**	4x15.6 MW CEB Barge Power Plant** 160 MW Reciprocating Engine Power Plants *	0.043
2026	Mini Hydro 10 MW Wind 35 MW Solar 90 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	4x9 MW Sapugaskanda Diesel Ext. **	0.053
2027	Mini Hydro 10 MW Wind 50 MW Solar 90 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase I)**	-	0.045
2028	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 40 MW Solar 100 MW Biomass 5 MW	-	-	0.048
2029	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 40 MW Solar 100 MW Biomass 5 MW	-	-	0.059
2030	Mini Hydro 10 MW Wind 20 MW Solar 100 MW Biomass 5 MW	-	-	0.442
2031	Mini Hydro 10 MW Wind 60 MW Solar 100 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase II)**	-	0.540

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2032	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase II)**	-	0.220
2033	Mini Hydro 10 MW Wind 35 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** **1x300 MW Natural Gas fired Combined Cycle Power Plant** **1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase III)**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2) 3 x 8.93 MW Uthuru Janani Power Plant	0.064
2034	Mini Hydro 10 MW Wind 70 MW Solar 120 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase III)**	-	0.096
2035	Mini Hydro 10 MW Wind 45 MW Solar 120 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region** **1x300 MW Natural Gas fired Combined Cycle Power Plant**	300MW West Coast Combined Cycle Power Plant	0.108
2036	Mini Hydro 10 MW Wind 55 MW Solar 120 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	-	0.152
2037	Mini Hydro 10 MW Wind 60 MW Solar 150 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.223
2038	Mini Hydro 10 MW Wind 85 MW Solar 165 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.309
2039	Mini Hydro 5 MW Wind 85 MW Solar 180 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant** **1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	-	0.141
Total PV Cost up to year 2039, **USD 17,944.45 million** (LKR 3,231.76 billion)°				

GENERAL NOTES:

- ∗ To meet the demand from year 2020 until major power plants are implemented and out of total 320 MW only 100 MW would continue beyond 2025 as backup power plants to provide the secure supply during the contingency events. As of 2019, 170MW out of 320MW has been added to the system as extension of existing power plants.
- ** Retirement of these plants would be evaluated based on the plant conditions.
- + The plant has duel fuel capability and would be operated with Natural Gas.
- ++ Refer Contingency Analysis for the impact from delays in implementation of power plants.
- • Sojitz Kelanitissa is scheduled to be retired in 2023 will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2021 with the development of LNG based infrastructure.
- ° PV cost includes the cost of projected ORE development, USD 2,309.9 million based on economic cost. Cost of battery storage is not included in the PV cost.
- ✓ Committed plants are shown in Italics. All plant capacities are given in gross values.
- ✓ Thalpitigala and Gin Ganga multipurpose hydro power plants are proposed and developed by Ministry of Irrigation. As a candidate power plant, Thalpitigala is scheduled to begin commercial operation by 2024 while feasibility studies are still being carried out for Gin Ganga project.
- ✓ Seethawaka HPP and PSPP units are forced in 2023, 2028, 2029 and 2032 respectively.
- ✓ Battery storage is proposed to be added to the system in phase development. (Total 50 MW by 2025 and 100 MW by 2030). Exact capacities and entry years will be evaluated during the detailed design stage of battery storage integration.

Annex 8.7

Results of Generation Expansion Planning Studies 2020-2039

Low Demand Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2020	Major Hydro *35 MW* *(Broadlands HPP)* *Wind* *100 MW* *(Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 100 MW Biomass 5 MW	*320 MW Reciprocating Engine Power Plants** (Identified in LTGEP 2018-2037 to be commissioned by 2018) **Additional Capacity Requirement from Contingency Analysis = 330 MW Reciprocating Engine Power Plants** (Above capacities include the extension of existing power plants)	6 x 5 MW Northern Power	0.335
2021	Major Hydro *120 MW* *(Uma Oya HPP)* Mini Hydro 20 MW Wind 120 MW Solar 60 MW Biomass 5 MW	*130 MW Gas Turbine* ⁺ **Additional Capacity Requirement from Contingency Analysis = 75 MW Reciprocating Engine Power Plants**	-	0.117
2022	Mini Hydro 20 MW Wind 70 MW Solar 60 MW Biomass 5 MW	*1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region* (Identified in LTGEP 2015-2034 and LTGEP 2018-2037 to be commissioned by 2019) **1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** (Identified in LTGEP 2018-2037 to be commissioned by 2021)	450 MW Reciprocating Engine Power Plants (Includes the expiry of extended power plant contracts)	0.148
2023	Major Hydro *31 MW* *(Moragolla HPP)* **24 MW** **(Seethawaka HPP)** Mini Hydro 20 MW Wind 40 MW Solar 60 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase** *163 MW Combined Cycle Power Plant (KPS–2)*•	4x17 MW Kelanitissa Gas Turbines 115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.131
2024	Major Hydro **15 MW** **(Thalpitigala HPP)** Mini Hydro 20 MW Biomass 5 MW Solar 60 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase II)**	4x17 MW Sapugaskanda Diesel**	0.086
2025	Mini Hydro 20 MW Wind 40 MW Solar 80 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	4x15.6 MW CEB Barge Power Plant** 175 MW Reciprocating Engine Power Plants *	0.188
2026	Mini Hydro 10 MW Wind 35 MW Solar 90 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase II or Foul Point Phase I)**	4x9 MW Sapugaskanda Diesel Ext. **	0.111
2027	Mini Hydro 5 MW Wind 35 MW Solar 60 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.056
2028	Mini Hydro 5 MW Wind 25 MW Solar 70 MW Biomass 5 MW	-	-	0.141
2029	Mini Hydro 5 MW Wind 25 MW Solar 70 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase I)**	-	0.073
2030	Mini Hydro 5 MW Wind 5 MW Solar 70 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.031
2031	Mini Hydro 5 MW Wind 25 MW Solar 70 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase II)**	-	0.015
2032	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 5 MW Wind 15 MW Solar 80 MW Biomass 5 MW	-	-	0.008
2033	Major Hydro 200 MW (Pumped Storage	**1x300 MW Natural Gas fired Combined Cycle**	165 MW Combined Cycle Plant	0.009

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
	Mini Hydro 5 MW Power Plant) Solar 80 MW Wind 20 MW Biomass 5 MW	**Power Plant – Western Region**	(KPS) 163 MW Combined Cycle Plant (KPS- 2) 3 x 8.93 MW Uthuru Janani Power Plant	
2034	Mini Hydro 5 MW Wind 25 MW Solar 90 MW Biomass 5 MW	-	-	0.025
2035	Mini Hydro 5 MW Wind 20 MW Solar 90 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	300MW West Coast Combined Cycle Power Plant	0.055
2036	Mini Hydro 5 MW Wind 15 MW Solar 100 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase III)**	-	0.032
2037	Mini Hydro 5 MW Wind 15 MW Solar 100 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.020
2038	Mini Hydro 5 MW Wind 20 MW Solar 100 MW Biomass 5 MW	-	-	0.057
2039	Mini Hydro 5 MW Wind 15 MW Solar 100 MW Biomass 5 MW	-	-	0.162
Total PV Cost up to year 2039, **USD 14,763.27 million** (LKR 2,658.84 billion)°				

GENERAL NOTES:

- * To meet the demand from year 2020 until major power plants are implemented and out of total 320 MW only 100 MW would continue beyond 2025 as backup power plants to provide the secure supply during the contingency events. As of 2019, 170MW out of 320MW has been added to the system as extension of existing power plants.
- ** Retirement of these plants would be evaluated based on the plant conditions.
- \+ The plant has duel fuel capability and would be operated with Natural Gas.
- • Sojitz Kelanitissa is scheduled to be retired in 2023 will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2021 with the development of LNG based infrastructure.
- ° PV cost includes the cost of projected ORE development, USD 2,003.3 million based on economic cost. Cost of battery storage is not included in the PV cost.
- ✓ Committed plants are shown in Italics. All plant capacities are given in gross values.
- ✓ Thalpitigala and Gin Ganga multipurpose hydro power plants are proposed and developed by Ministry of Irrigation. As a candidate power plant, Thalpitigala is scheduled to begin commercial operation by 2024 while feasibility studies are still being carried out for Gin Ganga project.
- ✓ Seethawaka HPP and PSPP two units are forced in 2023, 2032 and 2033 respectively.
- ✓ Battery storage is proposed to be added to the system in phase development. (Total 50 MW by 2025 and 100 MW by 2030). Exact capacities and entry years will be evaluated during the detailed design stage of battery storage integration.

Annex 9.1

Results of Generation Expansion Planning Studies 2020-2039

Base Case equivalent to LTGEP 2018-2037

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2020	Major Hydro *35 MW* *(Broadlands HPP)* *Wind* *100 MW* *(Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 100 MW Biomass 5 MW	*320 MW Reciprocating Engine Power Plants** (Identified in LTGEP 2018-2037 to be commissioned by 2018) **Additional Capacity Requirement from Contingency Analysis = 345 MW Reciprocating Engine Power Plants** (Above capacities include the extension of existing power plants)	6 x 5 MW Northern Power	0.391
2021	Major Hydro *120 MW* *(Uma Oya HPP)* Mini Hydro 20 MW Wind 120 MW Solar 60 MW Biomass 5 MW	*130 MW Gas Turbine ⁺* **Additional Capacity Requirement from Contingency Analysis = 105 MW Reciprocating Engine Power Plants**	-	0.134
2022	Mini Hydro 20 MW Wind 70 MW Solar 60 MW Biomass 5 MW	*1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region⁺⁺* (Identified in LTGEP 2015-2034 and LTGEP 2018-2037 to be commissioned by 2019) **1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region⁺⁺** (Identified in LTGEP 2018-2037 to be commissioned by 2021)	470 MW Reciprocating Engine Power Plants (Includes the expiry of extended power plant contracts)	0.238
2023	Major Hydro *31 MW* *(Moragolla HPP)* **24 MW** **(Seethawaka HPP)** Mini Hydro 20 MW Wind 40 MW Solar 60 MW Biomass 5 MW	**2x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Lakvijaya Extension Phase I)** *163 MW Combined Cycle Power Plant (KPS–2)•*	4x17 MW Kelanitissa Gas Turbines 115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.047
2024	Major Hydro **15 MW** **(Thalpitigala HPP)** Mini Hydro 20 MW Biomass 5 MW Solar 60 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Lakvijaya Extension Phase II or Foul Point Phase I)**	4x17 MW Sapugaskanda Diesel**	0.041
2025	Mini Hydro 20 MW Wind 40 MW Solar 80 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Foul Point Phase I)**	4x15.6 MW CEB Barge Power Plant** 200 MW Reciprocating Engine Power Plants *	0.153
2026	Mini Hydro 10 MW Wind 35 MW Solar 90 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Foul Point Phase II)**	4x9 MW Sapugaskanda Diesel Ext. **	0.125
2027	Mini Hydro 10 MW Wind 50 MW Solar 90 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Foul Point Phase II)**	-	0.065
2028	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 40 MW Solar 100 MW Biomass 5 MW		-	0.045
2029	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 40 MW Solar 100 MW Biomass 5 MW	-	-	0.035
2030	Mini Hydro 10 MW Wind 20 MW Solar 100 MW Biomass 5 MW	-	-	0.255
2031	Mini Hydro 10 MW Wind 60 MW Solar 100 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Foul Point Phase III)**	-	0.139

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2032	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase III)**	-	0.020
2033	Mini Hydro 10 MW Wind 35 MW Solar 110 MW Biomass 5 MW	**2x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS-2) 3 x 8.93 MW Uthuru Janani Power Plant	0.039
2034	Mini Hydro 10 MW Wind 70 MW Solar 120 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Sothern Region)**	-	0.029
2035	Mini Hydro 10 MW Wind 45 MW Solar 120 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	300MW West Coast Combined Cycle Power Plant	0.100
2036	Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Sothern Region)**	-	0.091
2037	Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Sothern Region)**	-	0.085
2038	Mini Hydro 10 MW Wind 70 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Sothern Region)**	-	0.083
2039	Mini Hydro 5 MW Wind 70 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	-	0.076
Total PV Cost up to year 2039, **USD 16,643million** (LKR 2,997,404billion)++				

- * To meet the demand from year 2020 until major power plants are implemented and out of total 320 MW only 100 MW would continue beyond 2025 as backup power plants to provide the secure supply during the contingency events. As of 2019, 170MW out of 320MW has been added to the system as extension of existing power plants.
- ** Retirement of these plants would be evaluated based on the plant conditions.
- \+ The plant has duel fuel capability and would be operated with Natural Gas.
- ++ Refer Contingency Analysis for the impact from delays in implementation of power plants.
- • Sojitz Kelanitissa is scheduled to be retired in 2023 will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2021 with the development of LNG based infrastructure.
- ° PV cost includes the cost of projected ORE development, USD 2274.04 million based on economic cost. Cost of battery storage is not included in the PV cost.
- ✓ Committed plants are shown in Italics. All plant capacities are given in gross values.
- ✓ Thalpitigala and Gin Ganga multipurpose hydro power plants are proposed and developed by Ministry of Irrigation. As a candidate power plant, Thalpitigala is scheduled to begin commercial operation by 2024 while feasibility studies are still being carried out for Gin Ganga project.
- ✓ Seethawaka HPP and PSPP units are forced in 2023, 2028, 2029 and 2032 respectively.
- ✓ Battery storage is proposed to be added to the system in phase development. (Total 50 MW by 2025 and 100 MW by 2030). Exact capacities and entry years will be evaluated during the detailed design stage of battery storage integration.

Results of Generation Expansion Planning Studies 2020-2039

Energy Mix with Nuclear Power Development

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2020	Major Hydro *35 MW* *(Broadlands HPP)* *Wind* *100 MW* *(Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 100 MW Biomass 5 MW	*320 MW Reciprocating Engine Power Plants** (Identified in LTGEP 2018-2037 to be commissioned by 2018) **Additional Capacity Requirement from Contingency Analysis = 345 MW Reciprocating Engine Power Plants** (Above capacities include the extension of existing power plants)	6 x 5 MW Northern Power	0.391
2021	Major Hydro *120 MW* *(Uma Oya HPP)* Mini Hydro 20 MW Wind 120 MW Solar 60 MW Biomass 5 MW	*130 MW Gas Turbine* ⁺ **Additional Capacity Requirement from Contingency Analysis = 105 MW Reciprocating Engine Power Plants**	-	0.134
2022	Mini Hydro 20 MW Wind 70 MW Solar 60 MW Biomass 5 MW	*1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region*⁺⁺ (Identified in LTGEP 2015-2034 and LTGEP 2018-2037 to be commissioned by 2019) **1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**⁺⁺ (Identified in LTGEP 2018-2037 to be commissioned by 2021)	470 MW Reciprocating Engine Power Plants (Includes the expiry of extended power plant contracts)	0.238
2023	Major Hydro *31 MW* *(Moragolla HPP)* **24 MW** **(Seethawaka HPP)** Mini Hydro 20 MW Wind 40 MW Solar 60 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase I)** **1x300 MW Natural Gas fired Combined Cycle Power Plant** *163 MW Combined Cycle Power Plant (KPS–2)*•	4x17 MW Kelanitissa Gas Turbines 115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.051
2024	Major Hydro **15 MW** **(Thalpitigala HPP)** Mini Hydro 20 MW Biomass 5 MW Solar 60 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase II)**	4x17 MW Sapugaskanda Diesel**	0.045
2025	Mini Hydro 20 MW Wind 40 MW Solar 80 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase II or Foul Point Phase I)** **1x300 MW Natural Gas fired Combined Cycle Power Plant**	4x15.6 MW CEB Barge Power Plant** 200 MW Reciprocating Engine Power Plants *	0.029
2026	Mini Hydro 10 MW Wind 35 MW Solar 90 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	4x9 MW Sapugaskanda Diesel Ext. **	0.025
2027	Mini Hydro 10 MW Wind 50 MW Solar 90 MW Biomass 5 MW		-	0.073
2028	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 40 MW Solar 100 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase I)**	-	0.009
2029	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 40 MW Solar 100 MW Biomass 5 MW	-	-	0.007
2030	Mini Hydro 10 MW Wind 20 MW Solar 100 MW Biomass 5 MW	-	-	0.031
2031	Mini Hydro 10 MW Wind 60 MW Solar 100 MW Biomass 5 MW	-	-	0.143

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2032	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase II)**	-	0.024
2033	Mini Hydro 10 MW Wind 35 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2) 3 x 8.93 MW Uthuru Janani Power Plant	0.566
2034	Mini Hydro 10 MW Wind 70 MW Solar 120 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants**	-	0.206
2035	Mini Hydro 10 MW Wind 45 MW Solar 120 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region** **1x600 MW Nuclear Power Plant**	300MW West Coast Combined Cycle Power Plant	0.016
2036	Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants**	-	0.015
2037	Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x600 MW Nuclear Power Plant**	-	0.002
2038	Mini Hydro 10 MW Wind 70 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.002
2039	Mini Hydro 5 MW Wind 70 MW Solar 110 MW Biomass 5 MW	-	-	0.010
Total PV Cost up to year 2039, **USD 17,173.62 million** (LKR 3,092.93 billion)°				

GENERAL NOTES:

∗ To meet the demand from year 2020 until major power plants are implemented and out of total 320 MW only 100 MW would continue beyond 2025 as backup power plants to provide the secure supply during the contingency events. As of 2019, 170MW out of 320MW has been added to the system as extension of existing power plants.

** Retirement of these plants would be evaluated based on the plant conditions.

+ The plant has duel fuel capability and would be operated with Natural Gas.

++ Refer Contingency Analysis for the impact from delays in implementation of power plants.

- Sojitz Kelanitissa is scheduled to be retired in 2023 will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2021 with the development of LNG based infrastructure.

° PV cost includes the cost of projected ORE development, USD 2274.04 million based on economic cost. Cost of battery storage is not included in the PV cost.

✓ Committed plants are shown in Italics. All plant capacities are given in gross values.

✓ Thalpitigala and Gin Ganga multipurpose hydro power plants are proposed and developed by Ministry of Irrigation. As a candidate power plant, Thalpitigala is scheduled to begin commercial operation by 2024 while feasibility studies are still being carried out for Gin Ganga project.

✓ Seethawaka HPP and PSPP units are forced in 2023, 2028, 2029 and 2032 respectively.

✓ Battery storage is proposed to be added to the system in phase development. (Total 50 MW by 2025 and 100 MW by 2030). Exact capacities and entry years will be evaluated during the detailed design stage of battery storage integration.

Annex 9.3

Results of Generation Expansion Planning Studies 2020-2039

India-Sri Lanka HVDC Interconnection Scenario

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2020	Major Hydro *35 MW* *(Broadlands HPP)* *Wind* *100 MW* *(Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 100 MW Biomass 5 MW	*320 MW Reciprocating Engine Power Plants** (Identified in LTGEP 2018-2037 to be commissioned by 2018) **Additional Capacity Requirement from Contingency Analysis = 345 MW Reciprocating Engine Power Plants** (Above capacities include the extension of existing power plants)	6 x 5 MW Northern Power	0.391
2021	Major Hydro *122 MW* *(Uma Oya HPP)* Mini Hydro 20 MW Wind 120 MW Solar 60 MW Biomass 5 MW	*130 MW Gas Turbine* + **Additional Capacity Requirement from Contingency Analysis = 105 MW Reciprocating Engine Power Plants**	-	0.134
2022	Mini Hydro 20 MW Wind 70 MW Solar 60 MW Biomass 5 MW	*1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region*++ (Identified in LTGEP 2015-2034 and LTGEP 2018-2037 to be commissioned by 2019) **1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**++ (Identified in LTGEP 2018-2037 to be commissioned by 2021)	470 MW Reciprocating Engine Power Plants (Includes the expiry of extended power plant contracts)	0.238
2023	Major Hydro *31 MW* *(Moragolla HPP)* **24 MW** **(Seethawaka HPP)** Mini Hydro 20 MW Wind 40 MW Solar 60 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase I)** **1x300 MW Natural Gas fired Combined Cycle Power Plant** *163 MW Combined Cycle Power Plant (KPS–2)*•	4x17 MW Kelanitissa Gas Turbines 115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.051
2024	Major Hydro **15 MW** **(Thalpitigala HPP)** Mini Hydro 20 MW Biomass 5 MW Solar 60 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase II)**	4x17 MW Sapugaskanda Diesel**	0.045
2025	Mini Hydro 20 MW Wind 40 MW Solar 80 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Lakvijaya Extension Phase II or Foul Point Phase I)** **1x300 MW Natural Gas fired Combined Cycle Power Plant**	4x15.6 MW CEB Barge Power Plant** 200 MW Reciprocating Engine Power Plants *	0.029
2026	Mini Hydro 10 MW Wind 35 MW Solar 90 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	4x9 MW Sapugaskanda Diesel Ext. **	0.025
2027	Mini Hydro 10 MW Wind 50 MW Solar 90 MW Biomass 5 MW		-	0.073
2028	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 40 MW Solar 100 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated) (Foul Point Phase I)**	-	0.009
2029	Mini Hydro 10 MW Wind 40 MW Solar 100 MW Biomass 5 MW			0.034
2030	Mini Hydro 10 MW Wind 20 MW Solar 100 MW Biomass 5 MW	-	-	0.132
2031	Mini Hydro 10 MW Wind 60 MW Solar 100 MW Biomass 5 MW	**500MW India-Sri Lanka HVDC Interconnection**	-	0.037

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2032	Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Foul Point Phase II)**	-	0.032
2033	Mini Hydro 10 MW Wind 35 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS-2) 3 x 8.93 MW Uthuru Janani Power Plant	0.188
2034	Mini Hydro 10 MW Wind 70 MW Solar 120 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants** **1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Foul Point Phase II)**	-	0.034
2035	Mini Hydro 10 MW Wind 45 MW Solar 120 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	300MW West Coast Combined Cycle Power Plant	0.098
2036	Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants**	-	0.092
2037	Mini Hydro 10 MW Wind 50 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Foul Point Phase III)**	-	0.087
2038	Mini Hydro 10 MW Wind 70 MW Solar 110 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.079
2039	Mini Hydro 5 MW Wind 70 MW Solar 110 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** **(Foul Point Phase III)**	-	0.073
Total PV Cost up to year 2039, **USD 16,683.47 million** (LKR 3,004.66 billion)++				

* To meet the demand from year 2020 until major power plants are implemented and out of total 320 MW only 100 MW would continue beyond 2025 as backup power plants to provide the secure supply during the contingency events. As of 2019, 170MW out of 320MW has been added to the system as extension of existing power plants.

** Retirement of these plants would be evaluated based on the plant conditions.

\+ The plant has duel fuel capability and would be operated with Natural Gas.

++ Refer Contingency Analysis for the impact from delays in implementation of power plants.

- Sojitz Kelanitissa is scheduled to be retired in 2023 will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2021 with the development of LNG based infrastructure.

° PV cost includes the cost of projected ORE development, USD 2274.04 million based on economic cost. Cost of battery storage is not included in the PV cost.

✓ Committed plants are shown in Italics. All plant capacities are given in gross values.

✓ Thalpitigala and Gin Ganga multipurpose hydro power plants are proposed and developed by Ministry of Irrigation. As a candidate power plant, Thalpitigala is scheduled to begin commercial operation by 2024 while feasibility studies are still being carried out for Gin Ganga project.

✓ Seethawaka HPP is forced in 2023.

✓ 1x200MW PSPP unit is forced in 2028 and the implementation of 500MW HVDC is forced in 2031 for study purpose.

✓ Support functions provided by HVDC to integrate renewable energy should be further reviewed with the proposed ORE capacity additions and operational issues of the power plant sequence must be further studied with respect to renewable energy curtailment

✓ Battery storage is proposed to be added to the system in phase development. (Total 50 MW by 2025 and 100 MW by 2030). Exact capacities and entry years will be evaluated during the detailed design stage of battery storage integration.

Investment Plan for Major Hydro & Thermal Projects (Base Case), 2020-2039

(Costs in million US$, Exch. Rate:180.1 LKR/US$)

YEAR & PLANT	2020		2021		2022		2023		2024		2025		2026		2027		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	
2021 - 35 MW Gas Turbine - 3 units																			
Base Cost	9.6	60.1															**9.6**	**60.1**	**69.7**
Contingencies	1.4	9.0															**1.4**	**9.0**	**10.4**
Port Handling & other charges (5%)		3.5															**0.0**	**3.5**	**3.5**
Total	11.0	72.6															**11.0**	**72.6**	**83.6**
2021 - 100 MW Reciprocating Engine Power Plants																			
Base Cost	11.8	47.4															**11.8**	**47.4**	**59.2**
Contingencies	2.1	8.4															**2.1**	**8.4**	**10.4**
Port Handling & other charges (5%)		2.8															**0.0**	**2.8**	**2.8**
Total	13.9	58.5															**13.9**	**58.5**	**72.5**
2022 - 300 MW Natural Gas Fired Combined Cycle Power Plant - Western Region - 2 units																			
Base Cost	55.9	223.7	30.2	120.6													**86.1**	**344.3**	**430.4**
Contingencies	8.4	33.6	4.5	18.1													**12.9**	**51.7**	**64.6**
Port Handling & other charges (5%)		12.9		6.9													**0.0**	**19.8**	**19.8**
Total	64.3	270.2	34.7	145.6													**99.0**	**415.8**	**514.8**
2023 - 300 MW Natural Gas Fired Combined Cycle Power Plant - 1 unit																			
Base Cost	4.7	18.7	28.0	111.8	15.0	60.3											**47.7**	**190.8**	**238.5**
Contingencies	0.7	2.8	4.2	16.8	2.3	9.1											**7.2**	**28.7**	**35.9**
Port Handling & other charges (5%)		1.1		6.4		3.5											**0.0**	**11.0**	**11.0**
Total	5.4	22.6	32.2	135.0	17.3	72.9											**54.9**	**230.5**	**285.4**
2023 - 300 MW New Coal Power Plant (Change to super critical will be evaluated) (Lakvijaya Extension Phase I) - 1 unit																			
Base Cost	21.3	89.7	39.2	165.0	16.6	70.0											**77.1**	**324.7**	**401.8**
Contingencies	3.2	13.4	5.9	24.7	2.5	10.5											**11.6**	**48.6**	**60.2**
Port Handling & other charges (5%)		5.2		9.5		4.0											**0.0**	**18.7**	**18.7**
Total	24.5	108.3	45.1	199.2	19.1	84.5											**88.7**	**392.0**	**480.7**
2023 - 24 MW Seethawaka Hydro Power Plant																			
Base Cost	2.4	5.1	14.8	30.6	8.0	16.5											**25.2**	**52.2**	**77.4**
Contingencies	0.4	0.8	2.2	4.6	1.2	2.5											**3.8**	**7.9**	**11.7**
Port Handling & other charges (5%)		0.3		1.8		1.0											**0.0**	**3.0**	**3.0**
Total	2.8	6.2	17.0	37.0	9.2	20.0											**29.0**	**63.1**	**92.1**
2024 - 300 MW New Coal Power Plant (Change to super critical will be evaluated) (Lakvijaya Extension Phase II) - 1 unit																			
Base Cost	4.3	17.8	21.3	89.7	39.2	165.0	16.6	70.0									**81.4**	**342.5**	**423.9**
Contingencies	0.6	2.7	3.2	13.4	5.9	24.7	2.5	10.5									**12.2**	**51.3**	**63.5**
Port Handling & other charges (5%)		1.0		5.2		9.5		4.0									**0.0**	**19.7**	**19.7**
Total	4.9	21.5	24.5	108.3	45.1	199.2	19.1	84.5									**93.6**	**413.5**	**507.1**
2025 - 300 MW Natural Gas Fired Combined Cycle Power Plant - 1 unit																			
Base Cost					4.7	18.7	28.0	111.8	15.0	60.3							**47.7**	**190.8**	**238.5**
Contingencies					0.7	2.8	4.2	16.8	2.3	9.1							**7.2**	**28.7**	**35.9**
Port Handling & other charges (5%)						1.1		6.4		3.5							**0.0**	**11.0**	**11.0**
Total					5.4	22.6	32.2	135.0	17.3	72.9							**54.9**	**230.5**	**285.4**
2025 - 300 MW New Coal Power Plant (Change to super critical will be evaluated) (Lakvijaya Extension Phase II or Foul Point Phase I) - 1 unit																			
Base Cost			4.3	17.8	21.3	89.7	39.2	165.0	16.6	70.0							**81.4**	**342.5**	**423.9**
Contingencies			0.6	2.7	3.2	13.4	5.9	24.7	2.5	10.5							**12.2**	**51.3**	**63.5**
Port Handling & other charges (5%)				1.0		5.2		9.5		4.0							**0.0**	**19.7**	**19.7**
Total			4.9	21.5	24.5	108.3	45.1	199.2	19.1	84.5							**93.6**	**413.5**	**507.1**
Annual Total	**126.8**	**559.8**	**158.4**	**646.6**	**120.6**	**507.4**													

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Investment Plan for Major Hydro & Thermal Projects (Base Case), 2020-2039

(Costs in million US$, Exch. Rate:180.1 LKR/US$)

YEAR & PLANT	2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		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**	
2026 - 300 MW Natural Gas Fired Combined Cycle Power Plant - 1 unit																							
Base Cost	4.7	18.7	28.0	111.8	15.0	60.3															**47.7**	**190.8**	**238.5**
Contingencies	0.7	2.8	4.2	16.8	2.3	9.1															**7.2**	**28.7**	**35.9**
Port Handling & other charges (5%)		1.1		6.4		3.5															**0.0**	**11.0**	**11.0**
Total	5.4	22.6	32.2	135.0	17.3	72.9															**54.9**	**230.5**	**285.4**
2028 - 300 MW New Coal Power Plant (Change to super critical will be evaluated) (Foul Point Phase I) - 1 unit																							
Base Cost			4.3	17.8	21.3	89.7	39.2	165.0	16.6	70.0											**81.4**	**342.5**	**423.9**
Contingencies			0.6	2.7	3.2	13.4	5.9	24.7	2.5	10.5											**12.2**	**51.3**	**63.5**
Port Handling & other charges (5%)				1.0		5.2		9.5		4.0											**0.0**	**19.7**	**19.7**
Total			4.9	21.5	24.5	108.3	45.1	199.2	19.1	84.5											**93.6**	**413.5**	**507.1**
2028 - 200 MW Pump Storage Power Plant- 1 unit																							
Base Cost	1.1	5.6	4.8	23.1	10.8	52.1	11.1	54.0	3.6	17.5											**31.4**	**152.3**	**183.7**
Contingencies	0.2	0.8	0.7	3.5	1.6	7.8	1.7	8.1	0.5	2.6											**4.7**	**22.8**	**27.5**
Port Handling & other charges (5%)		0.3		1.3		3.0		3.1		1.0											**0.0**	**8.8**	**8.8**
Total	1.3	6.7	5.5	27.9	12.4	62.9	12.8	65.2	4.1	21.1											**36.1**	**183.9**	**220.0**
2029 - 200 MW Pump Storage Power Plant- 1 unit																							
Base Cost			1.1	5.6	4.8	23.1	10.8	52.1	11.1	54.0	3.6	17.5									**31.4**	**152.3**	**183.7**
Contingencies			0.2	0.8	0.7	3.5	1.6	7.8	1.7	8.1	0.5	2.6									**4.7**	**22.8**	**27.5**
Port Handling & other charges (5%)				0.3		1.3		3.0		3.1		1.0									**0.0**	**8.8**	**8.8**
Total			1.3	6.7	5.5	27.9	12.4	62.9	12.8	65.2	4.1	21.1									**36.1**	**183.9**	**220.0**
2032 - 200 MW Pump Storage Power Plant- 1 unit																							
Base Cost									1.1	5.6	4.8	23.1	10.8	52.1	11.1	54.0	3.6	17.5			**31.4**	**152.3**	**183.7**
Contingencies									0.2	0.8	0.7	3.5	1.6	7.8	1.7	8.1	0.5	2.6			**4.7**	**22.8**	**27.5**
Port Handling & other charges (5%)										0.3		1.3		3.0		3.1		1.0			**0.0**	**8.8**	**8.8**
Total									1.3	6.7	5.5	27.9	12.4	62.9	12.8	65.2	4.1	21.1			**36.1**	**183.9**	**220.0**
2032 - 300 MW New Coal Power Plant (Change to super critical will be evaluated) (Foul Point Phase II) - 1 unit																							
Base Cost											4.3	17.8	21.3	89.7	39.2	165.0	16.6	70.0			**81.4**	**342.5**	**423.9**
Contingencies											0.6	2.7	3.2	13.4	5.9	24.7	2.5	10.5			**12.2**	**51.3**	**63.5**
Port Handling & other charges (5%)												1.0		5.2		9.5		4.0			**0.0**	**19.7**	**19.7**
Total											4.9	21.5	24.5	108.3	45.1	199.2	19.1	84.5			**93.6**	**413.5**	**507.1**
2033 - 300 MW Natural Gas Fired Combined Cycle Power Plant - Western Region - 1 unit																							
Base Cost															4.7	18.7	28.0	111.8	15.0	60.3	**47.7**	**190.8**	**238.5**
Contingencies															0.7	2.8	4.2	16.8	2.3	9.1	**7.2**	**28.7**	**35.9**
Port Handling & other charges (5%)																1.1		6.4		3.5	**0.0**	**11.0**	**11.0**
Total															5.4	22.6	32.2	135.0	17.3	72.9	**54.9**	**230.5**	**285.4**
2033 - 300 MW New Coal Power Plant (Change to super critical will be evaluated) (Foul Point Phase II) - 1 unit																							
Base Cost													4.3	17.8	21.3	89.7	39.2	165.0	16.6	70.0	**81.4**	**342.5**	**423.9**
Contingencies													0.6	2.7	3.2	13.4	5.9	24.7	2.5	10.5	**12.2**	**51.3**	**63.5**
Port Handling & other charges (5%)														1.0		5.2		9.5		4.0	**0.0**	**19.7**	**19.7**
Total													4.9	21.5	24.5	108.3	45.1	199.2	19.1	84.5	**93.6**	**413.5**	**507.1**
Annual Total	**103.1**	**448.0**	**80.3**	**348.6**	**59.7**	**272.0**	**70.3**	**327.3**	**37.3**	**177.6**	**14.5**	**70.6**	**41.8**	**192.7**	**87.8**	**395.2**							

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Investment Plan for Major Hydro & Thermal Projects (Base Case), 2020-2039

(Costs in million US$, Exch. Rate:180.1 LKR/US$)

YEAR & PLANT	2029		2030		2031		2032		2033		2034		2035		2036		2037		2038		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**	
2034 - 300 MW Natural Gas Fired Combined Cycle Power Plant - 1 unit																							
Base Cost					4.7	18.7	28.0	111.8	15.0	60.3											**47.7**	**190.8**	**238.5**
Contingencies					0.7	2.8	4.2	16.8	2.3	9.1											**7.2**	**28.7**	**35.9**
Port Handling & other charges (5%)						1.1		6.4		3.5											**0.0**	**11.0**	**11.0**
Total					5.4	22.6	32.2	135.0	17.3	72.9											**54.9**	**230.5**	**285.4**
2035 - 300 MW Natural Gas Fired Combined Cycle Power Plant - Western Region - 1 unit																							
Base Cost							4.7	18.7	28.0	111.8	15.0	60.3									**47.7**	**190.8**	**238.5**
Contingencies							0.7	2.8	4.2	16.8	2.3	9.1									**7.2**	**28.7**	**35.9**
Port Handling & other charges (5%)								1.1		6.4		3.5									**0.0**	**11.0**	**11.0**
Total							5.4	22.6	32.2	135.0	17.3	72.9									**54.9**	**230.5**	**285.4**
2036 - 300 MW Natural Gas Fired Combined Cycle Power Plant - 1 unit																							
Base Cost									4.7	18.7	28.0	111.8	15.0	60.3							**47.7**	**190.8**	**238.5**
Contingencies									0.7	2.8	4.2	16.8	2.3	9.1							**7.2**	**28.7**	**35.9**
Port Handling & other charges (5%)										1.1		6.4		3.5							**0.0**	**11.0**	**11.0**
Total									5.4	22.6	32.2	135.0	17.3	72.9							**54.9**	**230.5**	**285.4**
2037 - 300 MW New Coal Power Plant (Change to super critical will be evaluated) (Foul Point Phase III) - 1 unit																							
Base Cost									4.3	17.8	21.3	89.7	39.2	165.0	16.6	70.0					**81.4**	**342.5**	**423.9**
Contingencies									0.6	2.7	3.2	13.4	5.9	24.7	2.5	10.5					**12.2**	**51.3**	**63.5**
Port Handling & other charges (5%)										1.0		5.2		9.5		4.0					**0.0**	**19.7**	**19.7**
Total									4.9	21.5	24.5	108.3	45.1	199.2	19.1	84.5					**93.6**	**413.5**	**507.1**
2038 - 300 MW Natural Gas Fired Combined Cycle Power Plant - 1 unit																							
Base Cost													4.7	18.7	28.0	111.8	15.0	60.3			**47.7**	**190.8**	**238.5**
Contingencies													0.7	2.8	4.2	16.8	2.3	9.1			**7.2**	**28.7**	**35.9**
Port Handling & other charges (5%)														1.1		6.4		3.5			**0.0**	**11.0**	**11.0**
Total													5.4	22.6	32.2	135.0	17.3	72.9			**54.9**	**230.5**	**285.4**
2039 - 300 MW New Coal Power Plant (Change to super critical will be evaluated) (Foul Point Phase III) - 1 unit																							
Base Cost													4.3	17.8	21.3	89.7	39.2	165.0	16.6	70.0	**81.4**	**342.5**	**423.9**
Contingencies													0.6	2.7	3.2	13.4	5.9	24.7	2.5	10.5	**12.2**	**51.3**	**63.5**
Port Handling & other charges (5%)														1.0		5.2		9.5		4.0	**0.0**	**19.7**	**19.7**
Total													4.9	21.5	24.5	108.3	45.1	199.2	19.1	84.5	**93.6**	**413.5**	**507.1**
Annual Total					**105.9**	**462.4**	**74.0**	**315.0**	**59.8**	**252.0**	**74.0**	**316.2**	**72.7**	**316.2**	**75.8**	**327.8**	**62.4**	**272.1**	**19.1**	**84.5**			

Note:

(i) Disbursement start from year 2020 onwards.

(ii) Investment plan not included the cost of the Thalpitigal Hydro Power Plant identified by 2024 to be developed by Ministry of Irrigation and Water Resource Management.

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

Investment Plan for Major Wind & Solar Developments (Base Case), 2020-2039

(Costs in million US$, Exch. Rate:180.1 LKR/US$)

YEAR & PLANT	2020		2021		2022		2023		2024		2025		2026		2027		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
2021 - 60 MW Solar Power Development																			
Base Cost	7.1	28.5															**7.1**	**28.5**	**35.7**
Contingencies	1.3	5.0															**1.3**	**5.0**	**6.3**
Port Handling & other charges (5%)		1.7															**0.0**	**1.7**	**1.7**
Total	8.4	35.2															**8.4**	**35.2**	**43.6**
2021 - 120 MW Mannar Wind Park																			
Base Cost	21.2	85.0															**21.2**	**85.0**	**106.2**
Contingencies	3.7	15.0															**3.7**	**15.0**	**18.7**
Port Handling & other charges (5%)		5.0															**0.0**	**5.0**	**5.0**
Total	25.0	105.0															**25.0**	**105.0**	**130.0**
2022 - 60 MW Solar Power Development																			
Base Cost	3.2	12.8	6.9	27.7													**10.1**	**40.5**	**50.6**
Contingencies	0.6	2.3	1.2	4.9													**1.8**	**7.1**	**8.9**
Port Handling & other charges (5%)		0.8		1.6													**0.0**	**2.4**	**2.4**
Total	3.8	15.9	8.1	34.2													**11.9**	**50.0**	**62.0**
2022 - 70 MW Wind Power Development																			
Base Cost	5.8	23.0	12.4	49.6													**18.1**	**72.6**	**90.7**
Contingencies	1.0	4.1	2.2	8.7													**3.2**	**12.8**	**16.0**
Port Handling & other charges (5%)		1.4		2.9													**0.0**	**4.3**	**4.3**
Total	6.8	28.4	14.6	61.2													**21.4**	**89.7**	**111.0**
2023 - 60 MW Solar Power Development																			
Base Cost			3.1	12.4	6.7	26.8											**9.8**	**39.2**	**49.1**
Contingencies			0.5	2.2	1.2	4.7											**1.7**	**6.9**	**8.7**
Port Handling & other charges (5%)				0.7		1.6											**0.0**	**2.3**	**2.3**
Total			3.7	15.4	7.9	33.1											**11.5**	**48.5**	**60.0**
2023 - 40 MW Wind Power Development																			
Base Cost			3.3	13.1	7.1	28.3											**10.4**	**41.5**	**51.9**
Contingencies			0.6	2.3	1.2	5.0											**1.8**	**7.3**	**9.2**
Port Handling & other charges (5%)				0.8		1.7											**0.0**	**2.4**	**2.4**
Total			3.9	16.2	8.3	35.0											**12.2**	**51.2**	**63.4**
2024 - 60 MW Solar Power Development																			
Base Cost					3.0	12.0	6.5	25.9									**9.5**	**38.0**	**47.5**
Contingencies					0.5	2.1	1.1	4.6									**1.7**	**6.7**	**8.4**
Port Handling & other charges (5%)						0.7		1.5									**0.0**	**2.2**	**2.2**
Total					3.5	14.9	7.6	32.0									**11.2**	**46.9**	**58.1**
2025 - 80 MW Solar Power Development																			
Base Cost							3.9	15.5	8.4	33.4							**12.2**	**49.0**	**61.2**
Contingencies							0.7	2.7	1.5	5.9							**2.2**	**8.6**	**10.8**
Port Handling & other charges (5%)								0.9		2.0							**0.0**	**2.9**	**2.9**
Total							4.6	19.2	9.8	41.3							**14.4**	**60.5**	**74.9**
Annual Total	**43.9**	**184.5**	**30.2**	**127.0**	**19.8**	**83.0**													

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Investment Plan for Major Wind & Solar Developments (Base Case), 2020-2039

(Costs in million US$, Exch. Rate:180.1 LKR/US$)

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**
2025 - 40 MW Wind Power Development																			
Base Cost	3.3	13.1	7.1	28.3													**10.4**	**41.5**	**51.9**
Contingencies	0.6	2.3	1.2	5.0													**1.8**	**7.3**	**9.2**
Port Handling & other charges (5%)		0.8		1.7													**0.0**	**2.4**	**2.4**
Total	3.9	16.2	8.3	35.0													**12.2**	**51.2**	**63.4**
2026 - 90 MW Solar Power Development																			
Base Cost			4.4	17.5	9.4	37.6											**13.8**	**55.1**	**68.9**
Contingencies			0.8	3.1	1.7	6.6											**2.4**	**9.7**	**12.2**
Port Handling & other charges (5%)				1.0		2.2											**0.0**	**3.2**	**3.2**
Total			5.1	21.6	11.1	46.5											**16.2**	**68.0**	**84.2**
2026 - 35 MW Wind Power Development																			
Base Cost			2.9	11.5	6.2	24.8											**9.1**	**36.3**	**45.4**
Contingencies			0.5	2.0	1.1	4.4											**1.6**	**6.4**	**8.0**
Port Handling & other charges (5%)				0.7		1.5											**0.0**	**2.1**	**2.1**
Total			3.4	14.2	7.3	30.6											**10.7**	**44.8**	**55.5**
2027 - 90 MW Solar Power Development																			
Base Cost					4.4	17.5	9.4	37.6									**13.8**	**55.1**	**68.9**
Contingencies					0.8	3.1	1.7	6.6									**2.4**	**9.7**	**12.2**
Port Handling & other charges (5%)						1.0		2.2									**0.0**	**3.2**	**3.2**
Total					5.1	21.6	11.1	46.5									**16.2**	**68.0**	**84.2**
2027 - 50 MW Wind Power Development																			
Base Cost					4.1	16.4	8.9	35.4									**13.0**	**51.9**	**64.8**
Contingencies					0.7	2.9	1.6	6.2									**2.3**	**9.2**	**11.4**
Port Handling & other charges (5%)						1.0		2.1									**0.0**	**3.1**	**3.1**
Total					4.8	20.3	10.4	43.7									**15.3**	**64.1**	**79.3**
2028 - 100 MW Solar Power Development																			
Base Cost							4.9	19.4	10.4	41.8							**15.3**	**61.2**	**76.5**
Contingencies							0.9	3.4	1.8	7.4							**2.7**	**10.8**	**13.5**
Port Handling & other charges (5%)								1.1		2.5							**0.0**	**3.6**	**3.6**
Total							5.7	24.0	12.3	51.6							**18.0**	**75.6**	**93.6**
2028 - 40 MW Wind Power Development																			
Base Cost							3.3	13.1	7.1	28.3							**10.4**	**41.5**	**51.9**
Contingencies							0.6	2.3	1.2	5.0							**1.8**	**7.3**	**9.2**
Port Handling & other charges (5%)								0.8		1.7							**0.0**	**2.4**	**2.4**
Total							3.9	16.2	8.3	35.0							**12.2**	**51.2**	**63.4**
Annual Total	**16.1**	**67.5**	**26.7**	**112.1**	**28.3**	**119.0**	**31.1**	**130.4**											

Continued in the next page

Investment Plan for Major Wind & Solar Developments (Base Case), 2020-2039

(Costs in million US$, Exch. Rate:180.1 LKR/US$)

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
2029 - 100 MW Solar Power Development																			
Base Cost	4.9	19.4	10.4	41.8													**15.3**	**61.2**	**76.5**
Contingencies	0.9	3.4	1.8	7.4													**2.7**	**10.8**	**13.5**
Port Handling & other charges (5%)		1.1		2.5													**0.0**	**3.6**	**3.6**
Total	5.7	24.0	12.3	51.6													**18.0**	**75.6**	**93.6**
2029 - 40 MW Wind Power Development																			
Base Cost	3.3	13.1	7.1	28.3													**10.4**	**41.5**	**51.9**
Contingencies	0.6	2.3	1.2	5.0													**1.8**	**7.3**	**9.2**
Port Handling & other charges (5%)		0.8		1.7													**0.0**	**2.4**	**2.4**
Total	3.9	16.2	8.3	35.0													**12.2**	**51.2**	**63.4**
2030 - 100 MW Solar Power Development																			
Base Cost			4.9	19.4	10.4	41.8											**15.3**	**61.2**	**76.5**
Contingencies			0.9	3.4	1.8	7.4											**2.7**	**10.8**	**13.5**
Port Handling & other charges (5%)				1.1		2.5											**0.0**	**3.6**	**3.6**
Total			5.7	24.0	12.3	51.6											**18.0**	**75.6**	**93.6**
2030 - 20 MW Wind Power Development																			
Base Cost			1.6	6.6	3.5	14.2											**5.2**	**20.7**	**25.9**
Contingencies			0.3	1.2	0.6	2.5											**0.9**	**3.7**	**4.6**
Port Handling & other charges (5%)				0.4		0.8											**0.0**	**1.2**	**1.2**
Total			1.9	8.1	4.2	17.5											**6.1**	**25.6**	**31.7**
2031 - 100 MW Solar Power Development																			
Base Cost					4.9	19.4	10.4	41.8									**15.3**	**61.2**	**76.5**
Contingencies					0.9	3.4	1.8	7.4									**2.7**	**10.8**	**13.5**
Port Handling & other charges (5%)						1.1		2.5									**0.0**	**3.6**	**3.6**
Total					5.7	24.0	12.3	51.6									18.0	**75.6**	**93.6**
2031 - 60 MW Wind Power Development																			
Base Cost					4.9	19.7	10.6	42.5									**15.6**	**62.2**	**77.8**
Contingencies					0.9	3.5	1.9	7.5									**2.7**	**11.0**	**13.7**
Port Handling & other charges (5%)						1.2		2.5									**0.0**	**3.7**	**3.7**
Total					5.8	24.4	12.5	52.5									**18.3**	**76.9**	**95.2**
2032 - 110 MW Solar Power Development																			
Base Cost							5.3	21.3	11.5	46.0							**16.8**	**67.3**	**84.2**
Contingencies							0.9	3.8	2.0	8.1							**3.0**	**11.9**	**14.9**
Port Handling & other charges (5%)								1.3		2.7							**0.0**	**4.0**	**4.0**
Total							6.3	26.4	13.5	56.8							**19.8**	**83.2**	**103.0**
2032 - 50 MW Wind Power Development																			
Base Cost							4.1	16.4	8.9	35.4							**13.0**	**51.9**	**64.8**
Contingencies							0.7	2.9	1.6	6.2							**2.3**	**9.2**	**11.4**
Port Handling & other charges (5%)								1.0		2.1							**0.0**	**3.1**	**3.1**
Total							4.8	20.3	10.4	43.7							**15.3**	**64.1**	**79.3**
Annual Total	**30.2**	**126.8**	**28.3**	**118.7**	**28.0**	**117.5**	**35.9**	**150.8**											

Continued in the next page

Investment Plan for Major Wind & Solar Developments (Base Case), 2020-2039

(Costs in million US$, Exch. Rate:180.1 LKR/US$)

YEAR & PLANT	2031		2032		2033		2034		2035		2036		2037		2038		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**	
2033 - 110 MW Solar Power Development																			
Base Cost	5.3	21.3	11.5	46.0													**16.8**	**67.3**	**84.2**
Contingencies	0.9	3.8	2.0	8.1													**3.0**	**11.9**	**14.9**
Port Handling & other charges (5%)		1.3		2.7													**0.0**	**4.0**	**4.0**
Total	6.3	26.4	13.5	56.8													**19.8**	**83.2**	**103.0**
2033 - 35 MW Wind Power Development																			
Base Cost	2.9	11.5	6.2	24.8													**9.1**	**36.3**	**45.4**
Contingencies	0.5	2.0	1.1	4.4													**1.6**	**6.4**	**8.0**
Port Handling & other charges (5%)		0.7		1.5													**0.0**	**2.1**	**2.1**
Total	3.4	14.2	7.3	30.6													**10.7**	**44.8**	**55.5**
2034 - 120 MW Solar Power Development																			
Base Cost			5.8	23.3	12.5	50.2											**18.4**	**73.4**	**91.8**
Contingencies			1.0	4.1	2.2	8.9											**3.2**	**13.0**	**16.2**
Port Handling & other charges (5%)				1.4		3.0											**0.0**	**4.3**	**4.3**
Total			6.8	28.8	14.8	62.0											**21.6**	**90.7**	**112.3**
2034 - 70 MW Wind Power Development																			
Base Cost			5.8	23.0	12.4	49.6											**18.1**	**72.6**	**90.7**
Contingencies			1.0	4.1	2.2	8.7											**3.2**	**12.8**	**16.0**
Port Handling & other charges (5%)				1.4		2.9											**0.0**	**4.3**	**4.3**
Total			6.8	28.4	14.6	61.2											**21.4**	**89.7**	**111.0**
2035 - 120 MW Solar Power Development																			
Base Cost					5.8	23.3	12.5	50.2									**18.4**	**73.4**	**91.8**
Contingencies					1.0	4.1	2.2	8.9									**3.2**	**13.0**	**16.2**
Port Handling & other charges (5%)						1.4		3.0									**0.0**	**4.3**	**4.3**
Total					6.8	28.8	14.8	62.0									21.6	**90.7**	**112.3**
2035 - 45 MW Wind Power Development																			
Base Cost					3.7	14.8	8.0	31.9									**11.7**	**46.7**	**58.3**
Contingencies					0.7	2.6	1.4	5.6									**2.1**	**8.2**	**10.3**
Port Handling & other charges (5%)						0.9		1.9									**0.0**	**2.7**	**2.7**
Total					4.4	18.3	9.4	39.4									**13.7**	**57.6**	**71.4**
2036 - 110 MW Solar Power Development																			
Base Cost							5.3	21.3	11.5	46.0							**16.8**	**67.3**	**84.2**
Contingencies							0.9	3.8	2.0	8.1							**3.0**	**11.9**	**14.9**
Port Handling & other charges (5%)								1.3		2.7							**0.0**	**4.0**	**4.0**
Total							6.3	26.4	13.5	56.8							**19.8**	**83.2**	**103.0**
2036 - 50 MW Wind Power Development																			
Base Cost							4.1	16.4	8.9	35.4							**13.0**	**51.9**	**64.8**
Contingencies							0.7	2.9	1.6	6.2							**2.3**	**9.2**	**11.4**
Port Handling & other charges (5%)								1.0		2.1							**0.0**	**3.1**	**3.1**
Total							4.8	20.3	10.4	43.7							**15.3**	**64.1**	**79.3**
Annual Total	**33.6**	**141.1**	**34.4**	**144.6**	**40.5**	**170.2**	**35.2**	**148.0**											

Continued in the next page

Investment Plan for Major Wind & Solar Developments (Base Case), 2020-2039

(Costs in million US$, Exch. Rate:180.1 LKR/US$)

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
2037 - 110 MW Solar Power Development											
Base Cost	5.3	21.3	11.5	46.0					**16.8**	**67.3**	**84.2**
Contingencies	0.9	3.8	2.0	8.1					**3.0**	**11.9**	**14.9**
Port Handling & other charges (5%)		1.3		2.7					**0.0**	**4.0**	**4.0**
Total	6.3	26.4	13.5	56.8					**19.8**	**83.2**	**103.0**
2037 - 50 MW Wind Power Development											
Base Cost	4.1	16.4	8.9	35.4					**13.0**	**51.9**	**64.8**
Contingencies	0.7	2.9	1.6	6.2					**2.3**	**9.2**	**11.4**
Port Handling & other charges (5%)		1.0		2.1					**0.0**	**3.1**	**3.1**
Total	4.8	20.3	10.4	43.7					**15.3**	**64.1**	**79.3**
2038 - 110 MW Solar Power Development											
Base Cost			5.3	21.3	11.5	46.0			**16.8**	**67.3**	**84.2**
Contingencies			0.9	3.8	2.0	8.1			**3.0**	**11.9**	**14.9**
Port Handling & other charges (5%)				1.3		2.7			**0.0**	**4.0**	**4.0**
Total			6.3	26.4	13.5	56.8			**19.8**	**83.2**	**103.0**
2038 - 70 MW Wind Power Development											
Base Cost			5.8	23.0	12.4	49.6			**18.1**	**72.6**	**90.7**
Contingencies			1.0	4.1	2.2	8.7			**3.2**	**12.8**	**16.0**
Port Handling & other charges (5%)				1.4		2.9			**0.0**	**4.3**	**4.3**
Total			6.8	28.4	14.6	61.2			**21.4**	**89.7**	**111.0**
2039 - 110 MW Solar Power Development											
Base Cost					5.3	21.3	11.5	46.0	**16.8**	**67.3**	**84.2**
Contingencies					0.9	3.8	2.0	8.1	**3.0**	**11.9**	**14.9**
Port Handling & other charges (5%)						1.3		2.7	**0.0**	**4.0**	**4.0**
Total					6.3	26.4	13.5	56.8	19.8	**83.2**	**103.0**
2039 - 70 MW Wind Power Development											
Base Cost					5.8	23.0	12.4	49.6	**18.1**	**72.6**	**90.7**
Contingencies					1.0	4.1	2.2	8.7	**3.2**	**12.8**	**16.0**
Port Handling & other charges (5%)						1.4		2.9	**0.0**	**4.3**	**4.3**
Total					6.8	28.4	14.6	61.2	**21.4**	**89.7**	**111.0**
Annual Total	**35.1**	**147.2**	**37.0**	**155.3**	**41.2**	**172.8**	**28.1**	**118.0**			

Note:

(i) Disbursement start from year 2020 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.

Actual Generation Expansions and the Plans from 1992-2018

Year	Actual Expansions	Long Term Generation Expansion Plan (LTGEP)																
		1992-2006	1993-2007	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
2005	100-HLV 100-ACE	300-CO	44-GT	-	300-CO	-	105-GT	-	-	300-CCY	200-DS	100-HLV 100-ACE	-	-	-	-	-	-
2006	-	-	49-GIN 44-GT 68-CCY	22-GT 49-GIN	-	300-CCY	300-CO	150-UPK	300-CO	-	300-CCY	-	-	-	-	-	-	-
2007	-	-	150-CO 22-GT	300-CO	300-CO	-	-	-	150-UPK	105-GT	-	200-GT PART	-	-	-	-	-	-
2008	-	-	-	66-GT	49-GIN	300-CO	300-CO	300-CO	300-CO	150-UPK 300-CO	300-CO	100-ST PAI 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 10-DS	300-TRNC	300-TRNC	105-GT	300-CO	300-CO	2*285-PUT(ST2) 250-TPCL	-	-	-	-
2014	2*285-PUT 20-Northern 24-CPE	_	_	_	_	_	_	_	210-GT	_	300-CO	300-CO	300-CO	250-TPCL	20-Northern 24-CPE 75-GT 2*315-PUT	20-Northern 24-CPE 300-PUT	-	-
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 2*35-GT
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
2023	_	_	_	_	_	_	_	_	_	_	_	_	_	_	300-CO	2*300-CO	163-AES CCY(LNG) 300-ASC CO	163-AES CCY(LNG) 300-ASC CO
2024	_	_	_	_	_	_	_	_	_	_	_	_	_	_		_	300-ASC CO	300-ASC CO
2025	_	_	_	_	_	_	_	_	_	_	_	_	_	_	2*300-CO	300-CO	_	300-ASC CO

Note: ORE Plants are not indicated

KUK – Kukule hydro power station, BDL – Broadlands hydro power station, UPK – Upper Kotmale hydro power station, GIN – Gin ganga hydro power station, 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

** Approval was not granted by PUCSL

+PPA has extended and procurment of power plants by CEB is under consideration

Annex 15

Addendum

1) Addendum – Revision of the Base Case 2020-2039

I. Background

II. Revised Base Case 2020-2039

III. Existing and Committed System Considered for Revised Base Case

IV. Projected Future Development of ORE for Revised Base Case

V. Capacity Additions by Plant Type for Revised Base Case

VI. Capacity Balance for the Revised Base Case 2020 – 2039

VII. Capacity Mix and Share for Revised Base Case

VIII. Energy Balance for the Revised Base Case 2020 – 2039

IX. Energy Mix and Share for Revised Base Case

X. Firm Capacity Share of Revised Base Case

XI. Annual Energy Generation and Plant Factors of Revised Base Case

XII. Fuel Requirement and Expenditure on Fuel

XIII. Reserve Margin and LOLP of Revised Base Case

XIV. Implementation Plan of Revised Base Case

XV. Emissions of Revised Base Case

XVI. Contingency Analysis of Revised Base Case

XVII. Required Transmission Infrastructure for Major Plants during Initial Years of Revised Base Case

Annex 15

Revision of the Base Case 2020-2039

Background

Transmission Licensee submitted the draft Long Term Generation Expansion Plan (LTGEP) 2020-2039 to the PUCSL on 2019-05-24 and for its approval under Section 43(8) of Sri Lanka Electricity (Amendment) Act No. 31 of 2013. PUCSL conveyed its observations and decisions on the submitted draft LTGEP 2020-2039 on 2019-10-31 through the letter PUC/LI/AP19/01. Transmission Licensee again submitted its detailed comments to the commission observations by way of the letter AGM (CS)/DGM(CSRA)/GEN/4 dated 2019-11-25. Having considered CEB responses, commission gave its decision again requesting the draft LTGEP 2020-2039 to be revised again within 2 months through the letter PUC/LI/AP19/01 dated 2020-01-09.

Following major observations of PUCSL (through letter ref PUC/L1/AP19/01) was considered in revising the Base Case 2020-2039 of draft LTGEP 2020-2039.

1. Compliance to the gazetted reserve margin criteria (minimum: 2.5% & maximum: 20%)

Revised base case plan has been prepared to comply with gazette notification (No. 2019/28 dated 2019-02-08) that states a minimum reserve margin of 2.5% and a maximum of 20%.

2. Incorporating Economic Costs

The draft LTGEP 2020-2039 has been prepared taking all the costs components such as capital costs, fuel costs and operational costs on economic cost basis. An additional description on externalities has been included in the Environmental Implications Chapter (Section 10.10) to describe how externalities has been considered in the preparation of LTGEP 2020-2039,.

3. Complying to General Policy Guidelines (namely to the vision to achieve 50% Renewable energy share by 2030 under favourable **weather** conditions)

The revised base case of draft LTGEP 2020-2039 foresees 44% of electricity generation from renewable energy sources by the year 2030 under favourable **hydro** condition. It is observed that this share could be increased to as much as 46% under favourable **weather** conditions and other technical enhancements such as solar tracking for other RE sources. Future plans in each planning cycle will progressively improved following intergration studies to absorbe a higher share of renewable energy so that the vision to achieve 50% of renewable energy share by 2030 under favourable weather conditions could be realized.

4. Need to comply with realistic project implementation time lines for major power projects to be commissioned in first eight years.

Revised base case plan of draft LTGEP 2020-2039 has been prepared considering the latest updated implementation schedules of major power projects. Projects that are to be commissioned in the first half of an year has been considered as commsioned in that year and projects that are commissioned in the second half has been considered from following year. Accordingly, the commissioning years of commited/candidate projects as considered for planning studies are as follows.

Commssioning years of committed/candidate major power projects as considered for planning studies.

- 35 MW Broadlands Hydro Power Project in 2021
- 100 MW Mannar Wind Power Plant in 2021
- 130 MW Gas Turbine Power Plant in 2021
- 1st 300 MW LNG fired Combined Cycle Power Plant in 2023
  (200 MW Open Cycle Operation in 2022)
- 4x 24 MW Reciprocating Engine Power Plants in 2022
- 100 MW Reciprocating Engine Power plant in Galle in 2022

Candidate Power Projects

- 300 MW Lakvijaya Coal Power Plant Extension in 2023
- 2nd 300 MW LNG Combined Cycle Power Plant in 2023
- 3rd 300 MW LNG Combined Cycle Power Plant in 2024
- 4th 300 MW LNG Combined Cycle Power Plant in 2025
- 300 MW Coal fired Power Plant (Foul Point) in 2026

Table Ad 1: Revised Base Case 2020-2039

<table>
<tr><th>YEAR</th><th>RENEWABLE ADDITIONS</th><th>THERMAL ADDITIONS</th><th>THERMAL RETIREMENTS</th><th>LOLP[3] %</th></tr>
<tr><td>2020</td><td>Solar 100 MW
(including 35 MW committed)

Wind 20 MW
(2x10 MW Chunnakam Wind)

Mini Hydro 15 MW*
Biomass 5 MW*</td><td>200 MW Short Term Basis Supplementary Power Plants
100 MW Short Term Basis Supplementary Power Plants
145 MW Reciprocating Engine Power Plants</td><td>6 x 5 MW Northern Power</td><td>1.427</td></tr>
<tr><td>2021</td><td>Solar 110 MW
(including 70 MW+ 2x10MW committed)

100 MW Mannar Wind Park

Mini Hydro 20 MW*
Biomass 5 MW*

Uma Oya HPP 122 MW
Broadlands HPP 35 MW</td><td>395 MW Reciprocating Engine Power Plants
130 MW Gas Turbine [2]</td><td>100 MW ACE Embilipitiya
20 MW ACE Matara
51 MW Asia Power
200 MW Short Term Basis Supplementary Power Plants
100 MW Short Term Basis Supplementary Power Plants</td><td>1.362</td></tr>
<tr><td>2022</td><td>Solar 60 MW

Wind 150 MW
(including 60 MW committed)

Mini Hydro 20 MW*
Biomass 5 MW*</td><td>4 x 24 MW Reciprocating Engine Power Plants
100 MW Reciprocating Engine Power Plants – Galle

200 MW Open Cycle Operation of 1 x 300 MW Natural Gas fired Combined Cycle Power Plant – Western Region[2]</td><td>290 MW Reciprocating Engine Power Plants</td><td>1.424</td></tr>
<tr><td>2023</td><td>Solar 60 MW
Wind 110 MW
Mini Hydro 20 MW*
Biomass 5 MW*

Moragolla HPP 31 MW
Seethawaka HPP 24 MW</td><td>100 MW Steam Turbine Operation of 1 x 300 MW Natural Gas fired Combined Cycle Power Plant – Western Region[2]
(Combined Cycle Operation)
(Identified in LTGEP 2015-2034 and LTGEP 2018-2037 to be commissioned by 2019)

300 MW Natural Gas fired Combined Cycle Power Plant – Western Region[2]
(Identified in LTGEP 2018-2037 to be commissioned by 2021)

300 MW Lakvijaya Coal Power Plant Extension

163 MW Combined Cycle Power Plant (KPS–2)[4]</td><td>190 MW Reciprocating Engine Power Plants
4x17 MW Kelanitissa Gas Turbines
115 MW Gas Turbine [1]
4x9 MW Sapugaskanda Diesel Ext. [1]
163 MW Sojitz Kelanitissa Combined Cycle Plant [4]</td><td>0.449</td></tr>
<tr><td>2024</td><td>Solar 60 MW
Wind 90 MW
Mini Hydro 20 MW*
Biomass 5 MW*
Thalpitigala HPP 15 MW</td><td>300 MW Natural Gas fired Combined Cycle Power Plant</td><td>4x17 MW Sapugaskanda Diesel[1]</td><td>0.345</td></tr>
<tr><td>2025</td><td>Solar 80 MW
Wind 40 MW
Mini Hydro 20 MW*
Biomass 5 MW*</td><td>300 MW Natural Gas fired Combined Cycle Power Plant</td><td>4x15.6 MW CEB Barge Power Plant[1]</td><td>0.331</td></tr>
<tr><td>2026</td><td>Solar 90 MW
Wind 35 MW
Mini Hydro 10 MW*
Biomass 5 MW*</td><td>2 x 300 MW New Coal fired Power Plant
(Foul Point Phase I)</td><td>60 MW Reciprocating Engine Power Plants
4x9 MW Sapugaskanda Diesel Ext. [1]</td><td>0.077</td></tr>
<tr><td>2027</td><td>Solar 90 MW
Wind 50 MW
Mini Hydro 10 MW*
Biomass 5 MW*</td><td>-</td><td>-</td><td>0.210</td></tr>
<tr><td>2028</td><td>Solar 100 MW
Wind 40 MW
Mini Hydro 10 MW*
Biomass 5 MW*</td><td>-</td><td>-</td><td>0.152</td></tr>
</table>

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP[3] %
	Pumped Storage HPP 200 MW			
2029	Solar 100 MW Wind 40 MW Mini Hydro 10 MW* Biomass 5 MW* **Pumped Storage HPP 200 MW**	-	-	0.121
2030	Solar 100 MW Wind 20 MW Mini Hydro 10 MW* Biomass 5 MW* **Pumped Storage HPP 200 MW**	**300 MW New Coal fired Power Plant** **(Change to Super critical will be evaluated)**	-	0.019
2031	Solar 100 MW Wind 60 MW Mini Hydro 10 MW* Biomass 5 MW*	-	-	0.155
2032	Solar 110 MW Wind 50 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant** **196 MW Reciprocating Engine Power Plants**	*4 x 24 MW Reciprocating Engine Power Plants* *100 MW Reciprocating Engine Power Plants – Galle*	0.128
2033	Solar 110 MW Wind 35 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** **300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2) 3 x 8.93 MW Uthuru Janani Power Plant	0.182
2034	Solar 120 MW Wind 70 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	-	0.105
2035	Solar 120 MW Wind 45 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** **300 MW Natural Gas fired Combined Cycle Power Plant**	300MW West Coast Combined Cycle Power Plant	0.060
2036	Solar 110 MW Wind 50 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.055
2037	Solar 110 MW Wind 50 MW Mini Hydro 10 MW* Biomass 5 MW*	-	-	0.241
2038	Solar 110 MW Wind 70 MW Mini Hydro 10 MW* Biomass 5 MW*	**300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	-	0.193
2039	Solar 110 MW Wind 70 MW Mini Hydro 5 MW* Biomass 5 MW*	**300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.178
Total Present Value Cost up to year 2039, **USD 16,555 mil USD** (LKR 2,981.45 billion)				

GENERAL NOTES:

1. Retirement of these plants would be evaluated based on the plant conditions.
2. The plant has dual fuel capability and would be operated with Natural Gas.
3. Refer Contingency Analysis for additional capacity requirements in the occurrence of risk events.
4. PPA of Sojitz Kelanitissa is scheduled to be expired in 2023, and will be operated as a CEB Natural Gas-fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2023 with the development of LNG based infrastructure.

* Mini-hydro and Biomass annual capacity additions are not restricted to the planned capacities.

- Committed plants are shown in Italics.
- All plant capacities are given in gross values.
- Battery storage is proposed to be added to the system in phase development. (Total 50 MW by 2025 and 100 MW by 2030). Exact capacities and entry years will be evaluated during the detailed design stage of battery storage integration.
- Present Value cost includes the cost of projected ORE development, USD 2,226 million based on economic cost. Cost of battery storage is not included in the Present Value cost.
- Thalpitigala and Gin Ganga multipurpose hydropower plants are proposed and developed by Ministry of Irrigation. As a committed power plant, Thalpitigala is scheduled to begin commercial operation by 2024 while feasibility studies are still being carried out for Gin Ganga project.
- Seethawaka HPP and PSPP units are forced in 2023, 2028, 2029 and 2030 respectively.

Existing and Committed System Considered for Revised Base Case

The details of hydro and thermal plants as contained in Table 2.1 and 2.7 respectively under chapter 2 has been revised as follows.

Table Ad. 2 – Existing and Committed Hydro and Other Renewable Power Plants

Plant Name	Units x Capacity	Capacity (MW)	Expected Annual Avg. Energy (GWh)	Active Storage (MCM)	Rated Head (m)	Year of Commissioning
Canyon	2 x 30	60	160	107.9 (Moussakelle)	207.2	1983 - Unit 1 1989 - Unit 2
Wimalasurendra	2 x 25	50	112	52.01 (Castlereigh)	227.3 8	1965
Old Laxapana	3x 9.6+ 2x12.5	53.8	286	0.245 (Norton)	472.4	1950 1958
New Laxapana	2 x 58	116	552	0.629 (Canyon)	541	Unit 1 1974 Unit 2 1974
Polpitiya	2 x 45	90	453	0.113 (Laxapana)	259	1969
Laxapana Total		**369.8**	**1563**			
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 61.3	122.6	454	462	77.8	1986
Ukuwela	2 x 20	40	154	2.1	75.1	Unit 1&2 – '76
Bowatenna	1 x 40	40	48	23.5	50.9	1981
Rantambe	2 x 25	50	239	3.4	32.7	1990
Nilambe	2 x 1.6	3.2	-	0.005	110	1988
Mahaweli Total		**816.8**	**2667**			
Samanalawewa	2 x 60	120	344	218	320	1992
Kukule	2 x 37.5	75	300	1.67	186.4	2003
Small hydro		17.25				
Samanala Total		**212.25**	**644**			
Existing Total		**1398.85****	**4874**			
Committed						
Broadlands	2x17.5	35	126	0.198	56.9	2021
Moragolla	2x15.1	30.2	97.6	1.98	69	2023
Mannar Wind Park		103.5	337			2021
Multi-Purpose Projects						
Uma Oya	2x61	122	290	0.7	722	2021
Total		**290.7**	**850.6***			

Table Ad. 3- Details of Existing and Committed IPP Plants

Plant Name	Name Plate Cap. (MW)	Cap. used for Studies	Min. Guarenteed Ann. Energy (GWh)	Commissioning	Contract Period. (Yrs.)
Independent Power Producers					
Sojitz Kelanitissa (Pvt.) Ltd	163	163	-	GT- March 2003 ST - October 2003	20
ACE Power Embilipitiya Ltd+	100	99.5	697	2005 April	10
ACE Power Matara+	24.8	20	167	2002 March	10
Asia Power Ltd+	51	50.8	330	1998 June	20
West Coast (Pvt) Ltd.	300	270	-	2010 May	25
Existing Total IPP	**638.8**	**603.3**			
Committed					
Reciprocating Engine Power Plants at the Grid Substations of Habarana, Moneragala, Horana and Pallekelle	4 x 24	4 x 24		2022	
100 MW Reciprocating Engine Power Plants – Galle	100	100		2022	
NG fired Combined Cycle Power Plant	300	287		2022	
Committed Total IPP	**496**	**483**	**-**		

Note:

+ The contract of ACE Power Embilipitiya, Asia Power and ACE Power Matara Power Plants have been extended beyond contract period mentioned here.

Projected Future Development of ORE for Revised Base Case

Table Ad. 4 – Projected Future Development of ORE (Assumed as Committed in Base Case Plan)

Year	Cumulative Mini hydro Capacity (MW)	Cumulative Wind Capacity (MW)	Cumulative Biomass Capacity (MW)	Cumulative Solar Capacity (MW)	Cumulative Total ORE Capacity (MW)	Annual Total ORE Generation (GWh)	Share of ORE from Total Generation %
2020	419	148	49	360	975	2645	14.3%
2021	439	248	54	470	1210	3223	16.2%
2022	459	398	59	530	1445	3879	18.5%
2023	479	508	64	590	1640	4401	19.9%
2024	499	598	69	650	1815	4864	20.9%
2025	519	638	74	730	1960	5194	21.2%
2026	529	673	79	820	2100	5484	21.3%
2027	539	723	84	910	2255	5820	21.6%
2028	549	763	89	1010	2410	6145	21.8%
2029	559	803	94	1110	2565	6470	21.9%
2030	569	823	99	1210	2700	6740	21.8%
2031	579	883	104	1310	2875	7115	22.0%
2032	589	933	109	1420	3050	7488	22.2%
2033	599	968	114	1530	3210	7802	22.1%
2034	609	1038	119	1650	3415	8245	22.4%
2035	619	1083	124	1770	3595	8614	22.4%
2036	629	1133	129	1880	3770	8986	22.4%
2037	639	1183	134	1990	3945	9358	22.4%
2038	649	1253	139	2100	4140	9787	22.5%
2039	654	1323	144	2210	4330	10199	22.6%

Table Ad 5: Capacity Additions by Plant Type for Revised Base Case

Year	Peak Demand (MW)	Capacity Addition (MW)								Retirements	LOLP %
		Gas Turbines	Reciprocating Engines	Coal	NG Combined Cycle	Major Hydro	Pumped Hydro	ORE	Total		
2020	3,050		445			0		140	585	-30	1.427
2021	3,254	130	395			155		235	915	-471	1.362
2022	3,403		196		200			235	631	-290	1.424
2023	3,561			300	400	55		195	950	-409	0.449
2024	3,728				300	15		175	490	-68	0.345
2025	3,903				300			145	445	-64	0.331
2026	4,079			600				140	740	-96	0.077
2027	4,241							155	155		0.210
2028	4,444						200	155	355		0.152
2029	4,655						200	155	355		0.121
2030	4,872			300			200	135	635		0.019
2031	5,101							175	175		0.155
2032	5,332		196		300			175	671	-196	0.128
2033	5,569			300	300			160	760	-354	0.182
2034	5,814			300				205	505		0.105
2035	6,067				600			180	780	-300	0.060
2036	6,328				300			175	475		0.055
2037	6,597							175	175		0.241
2038	6,873			300				195	495		0.193
2039	7,155				300			190	490		0.178
Total		**130**	**1232**	**2100**	**3000**	**225**	**600**	**3495**	**10782**	**-2278**	

Table Ad 6: Capacity Balance for the Revised Base Case 2020 - 2039

Plant Name	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Hydro																				
Existing Major Hydro	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383	1383
New Major Hydro	0	155	155	179	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Pumped Hydro	0	0	0	0	0	0	0	0	200	400	600	600	600	600	600	600	600	600	600	600
Sub Total	**1383**	**1538**	**1538**	**1562**	**1608**	**1608**	**1608**	**1608**	**1808**	**2008**	**2208**	**2208**	**2208**	**2208**	**2208**	**2208**	**2208**	**2208**	**2208**	**2208**
Thermal Existing and Committed																				
Small Gas Turbines	68	68	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	70	70	70	70	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	70	70	70	35	35	35	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
Asia Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa Combined Cycle	161	161	161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Combined Cycle	163	163	163	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	270	270	270	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	810	810
Northern Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Uthurujanani	26	26	26	26	26	26	26	26	26	26	26	26	26	0	0	0	0	0	0	0
CEB Barge Power	62	62	62	62	62	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine Power Plants	0	0	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195
NG Converted Sojitz Combined Cycle	0	0	0	163	163	163	163	163	163	163	163	163	163	0	0	0	0	0	0	0
NG Converted Kelanitissa Combined Cycle	0	0	0	161	161	161	161	161	161	161	161	161	161	0	0	0	0	0	0	0
NG Converted Kerawalapitiya CCY	0	0	0	270	270	270	270	270	270	270	270	270	270	270	270	0	0	0	0	0
Sub Total	**1,814**	**1,814**	**2,009**	**1,792**	**1,722**	**1,660**	**1,625**	**1,625**	**1,625**	**1,625**	**1,625**	**1,625**	**1,625**	**1,275**	**1,275**	**1,005**	**1,005**	**1,005**	**1,005**	**1,005**
New Thermal Plants																				
New Coal	0	0	0	270	270	270	810	810	810	810	1,080	1,080	1,080	1,350	1,620	1,620	1,620	1,620	1,890	1,890
New Gas Turbine	0	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
New NG Combined Cyle	0	0	200	579	869	1159	1159	1159	1159	1159	1159	1159	1449	1738	1738	2318	2607	2607	2607	2897
Reciprocating Engine Power Plant (Short Term)	615	540	255	60	60	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub Total	**615**	**670**	**585**	**1039**	**1329**	**1619**	**2099**	**2099**	**2099**	**2099**	**2369**	**2369**	**2659**	**3218**	**3488**	**4068**	**4357**	**4357**	**4627**	**4917**
Other Renewable Energy																				
ORE (Minihydro, Wind & Solar)	927	1157	1387	1577	1747	1887	2022	2172	2322	2472	2602	2772	2942	3097	3297	3472	3642	3812	4002	4187
ORE (Biomass)	49	54	59	64	69	74	79	84	89	94	99	104	109	114	119	124	129	134	139	144
Sub Total	**975**	**1210**	**1445**	**1640**	**1815**	**1960**	**2100**	**2255**	**2410**	**2565**	**2700**	**2875**	**3050**	**3210**	**3415**	**3595**	**3770**	**3945**	**4140**	**4330**
Total Installed Capacity (A)	**4788**	**5233**	**5578**	**6033**	**6475**	**6847**	**7432**	**7587**	**7942**	**8297**	**8902**	**9077**	**9542**	**9912**	**10386**	**10876**	**11341**	**11516**	**11980**	**12460**
Installed Capacity without ORE (B)	**3812**	**4022**	**4132**	**4393**	**4659**	**4887**	**5332**	**5332**	**5532**	**5732**	**6202**	**6202**	**6492**	**6701**	**6971**	**7281**	**7570**	**7570**	**7840**	**8130**
Peak Demand (C)	**3050**	**3254**	**3403**	**3561**	**3728**	**3903**	**4079**	**4241**	**4444**	**4655**	**4872**	**5101**	**5332**	**5569**	**5814**	**6067**	**6328**	**6597**	**6873**	**7155**
Difference without ORE (B-C)	**762**	**768**	**729**	**832**	**931**	**984**	**1253**	**1091**	**1088**	**1077**	**1330**	**1101**	**1160**	**1132**	**1157**	**1214**	**1242**	**973**	**967**	**975**
Difference (%)	**25.0**	**23.6**	**21.4**	**23.4**	**25.0**	**25.2**	**30.7**	**25.7**	**24.5**	**23.1**	**27.3**	**21.6**	**21.7**	**20.3**	**19.9**	**20.0**	**19.6**	**14.8**	**14.1**	**13.6**

Notes : All the Capacities are in MW
Above total includes ORE plants
Maintenance and FOR outages not considered

Capacity Mix and Share for Revised Base Case

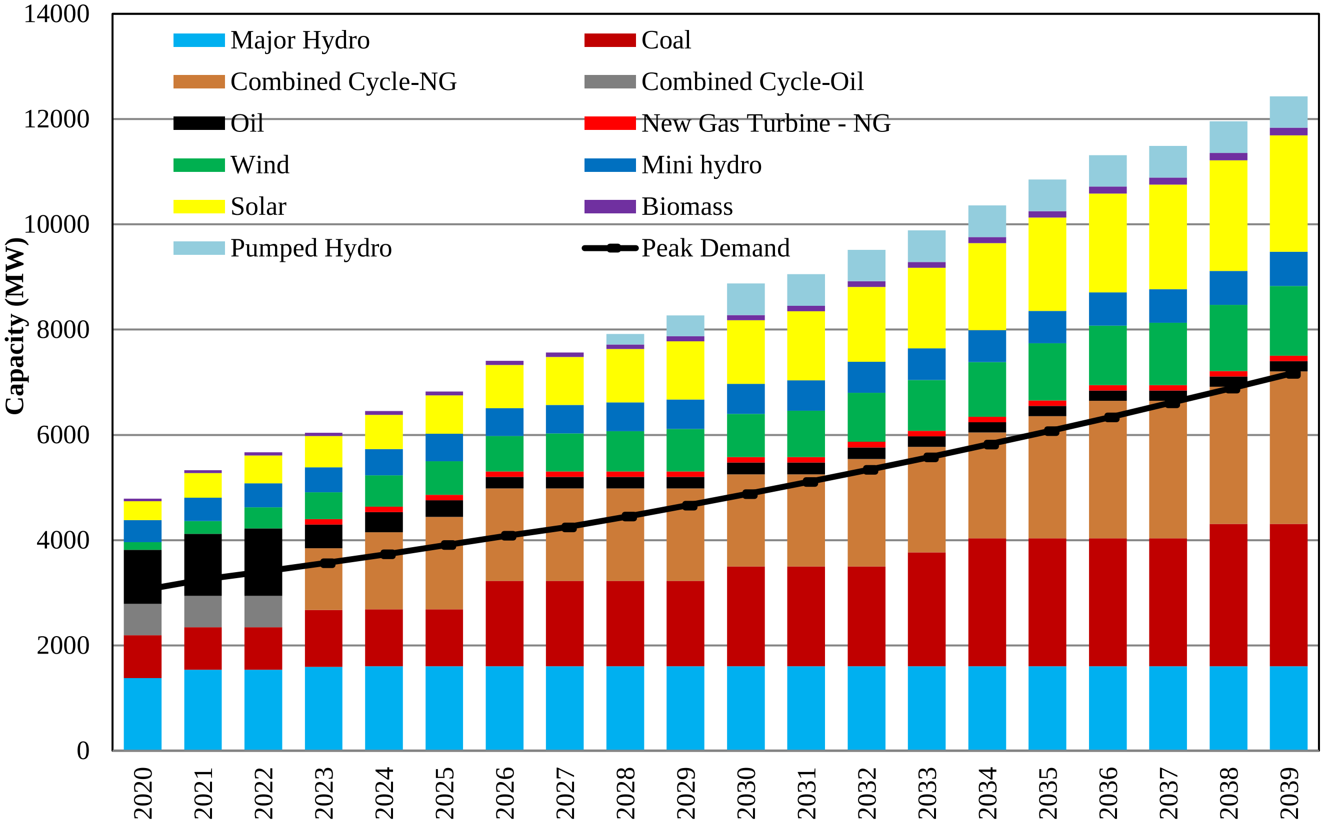


Figure Ad. 1 – Capacity Mix over next 20 years in Revised Base Case

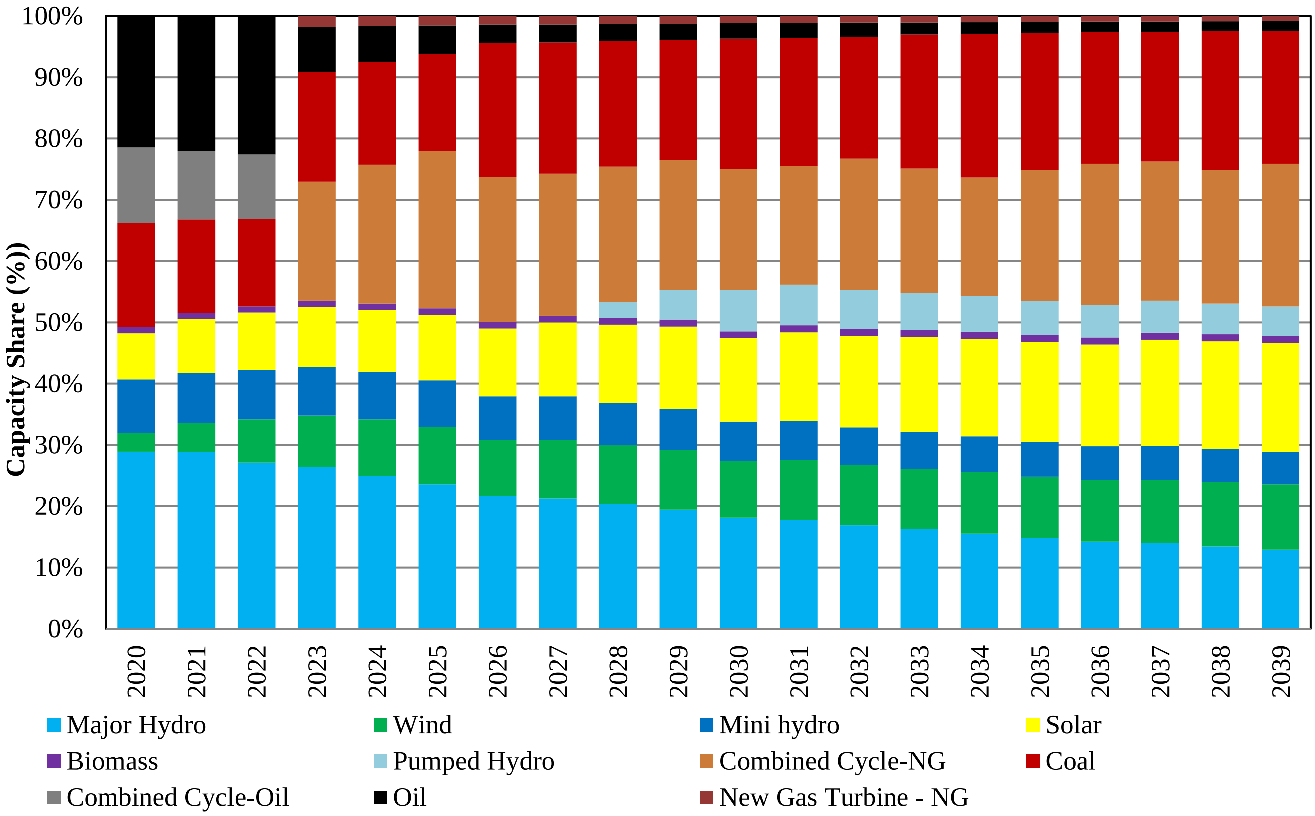


Figure Ad. 2 – Percentage Share of Capacity Mix over next 20 years in Revised Base Case

Table Ad 7: Energy Balance for the Revised Base Case 2020 - 2039

Plant Name	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Hydro																				
Existing Major Hydro	3886	4092	4092	4092	4092	4092	4092	4092	4092	4092	4092	4092	4092	4092	4092	4092	4092	4092	4092	4092
New Major Hydro	0	164	149	286	324	309	301	294	286	279	272	264	256	249	241	234	226	219	212	208
PSPP Generation	0	0	0	0	0	0	0	0	200	400	600	600	600	600	600	599	600	598	599	600
Sub Total	3,886	4,256	4,241	4,378	4,416	4,401	4,393	4,386	4,578	4,771	4,964	4,956	4,948	4,941	4,933	4,925	4,918	4,909	4,903	4,900
Thermal Existing and Committed																				
Small Gas Turbines	8	11	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	367	400	427	263	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	480	480	480	193	169	149	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine No7	264	335	355	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa Combined Cycle	804	875	925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Combined Cycle	968	1,031	1,069	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	578	763	951	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakvijaya Coal	4,169	4,334	4,484	4,559	4,772	4,946	4,535	4,673	4,814	4,982	4,923	4,990	5,059	4,934	4,865	4,968	5,062	5,123	5,076	5,128
Uthurujanani	181	181	181	143	124	111	82	93	99	116	103	120	108	0	0	0	0	0	0	0
CEB Barge Power	393	425	450	300	247	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Furnace Oil fired Reciprocating Engines	3,977	3,559	2,993	1,250	1,025	943	522	628	672	761	700	794	730	905	851	776	712	813	760	729
NG Converted Sojitz Combined Cycle	0	0	0	870	814	767	601	655	702	772	751	801	736	0	0	0	0	0	0	0
NG Converted Kelanitissa Combined Cycle	0	0	0	748	724	690	561	579	646	713	676	735	688	0	0	0	0	0	0	0
NG Converted Kerawalapitiya CCY	0	0	0	791	723	661	430	489	542	621	562	665	608	581	539	0	0	0	0	0
Sub Total	12,190	12,395	12,324	9,117	8,598	8,268	6,731	7,116	7,476	7,964	7,716	8,104	7,928	6,420	6,255	5,744	5,774	5,936	5,837	5,857
New Thermal Plants																				
New Coal	0	0	0	1,911	1,953	1,967	5,719	5,774	5,901	5,975	7,978	7,979	7,970	9,882	11,811	11,875	11,914	11,945	13,916	13,945
New Gas Turbine	0	225	234	138	121	127	85	111	123	139	122	152	139	177	159	142	125	150	137	123
New NG Combined Cyle	0	0	494	2,476	3,680	4,945	3,775	4,280	4,860	5,413	4,905	5,580	6,901	7,670	7,062	8,790	10,044	11,181	10,670	12,027
Sub Total	0	225	728	4,525	5,754	7,039	9,580	10,164	10,884	11,528	13,005	13,711	15,010	17,728	19,032	20,807	22,084	23,277	24,722	26,095
Other Renewable Energy																				
ORE (Minihydro, Wind & Solar)	2,305	2,848	3,469	3,956	4,383	4,678	4,933	5,234	5,524	5,814	6,048	6,388	6,726	7,006	7,414	7,747	8,084	8,422	8,815	9,192
ORE (Biomass)	340	375	410	445	480	515	550	585	620	655	690	725	760	795	830	865	901	936	971	1,006
Sub Total	2,645	3,223	3,879	4,401	4,863	5,193	5,483	5,819	6,144	6,469	6,738	7,114	7,487	7,801	8,244	8,613	8,985	9,357	9,786	10,198
Total Generation (Excluding New Biomass)	**18,521**	**19,881**	**20,928**	**22,048**	**23,214**	**24,440**	**25,679**	**26,900**	**28,463**	**30,077**	**31,733**	**33,160**	**34,613**	**36,095**	**37,633**	**39,223**	**40,860**	**42,545**	**44,277**	**46,045**
System Demand	**18,542**	**19,910**	**20,959**	**22,065**	**23,230**	**24,458**	**25,696**	**26,918**	**28,195**	**29,522**	**30,890**	**32,325**	**33,778**	**35,267**	**36,806**	**38,390**	**40,028**	**41,716**	**43,448**	**45,215**
PSPP Demand	0	0	0	0	0	0	0	0	286	571	857	857	857	857	857	856	857	854	856	857
Unserved Energy	**21**	**29**	**31**	**17**	**16**	**18**	**17**	**18**	**18**	**17**	**14**	**22**	**22**	**30**	**30**	**22**	**25**	**25**	**26**	**27**

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

Energy Mix and Share for Revised Base Case

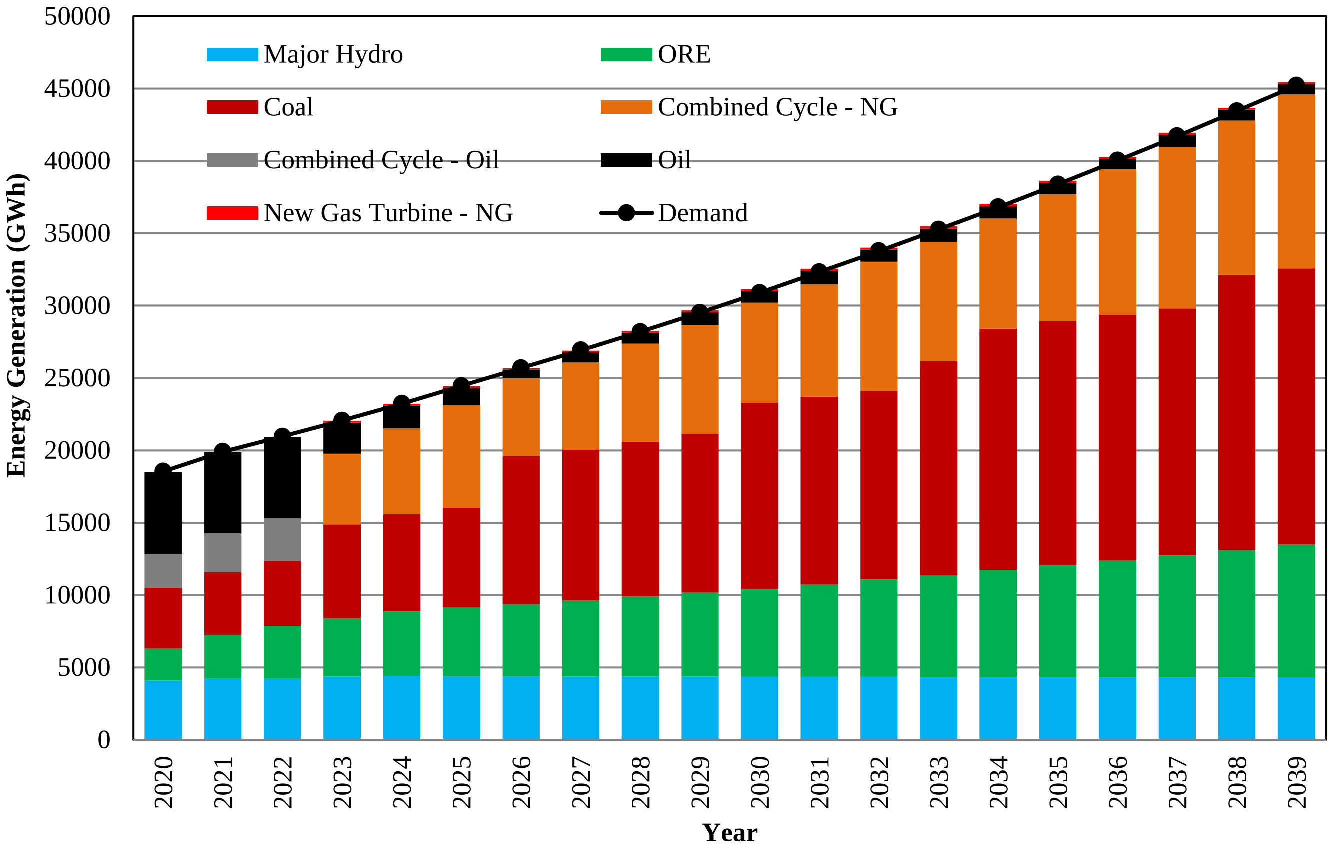


Figure Ad. 3 – Energy Mix over next 20 years in Revised Base Case

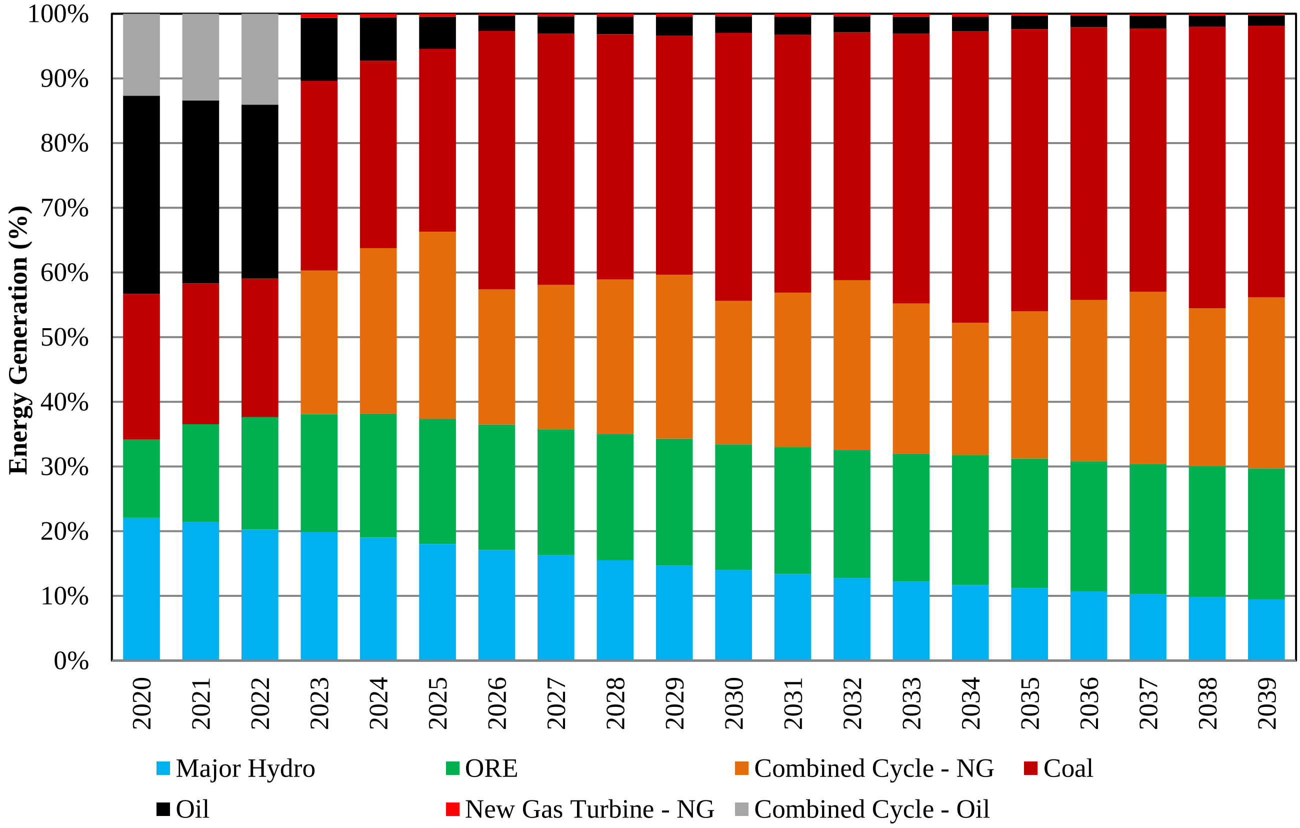


Figure Ad. 4 – Percentage Share of Energy Mix over next 20 years in Revised Base Case

Firm Capacity Share of Revised Base Case

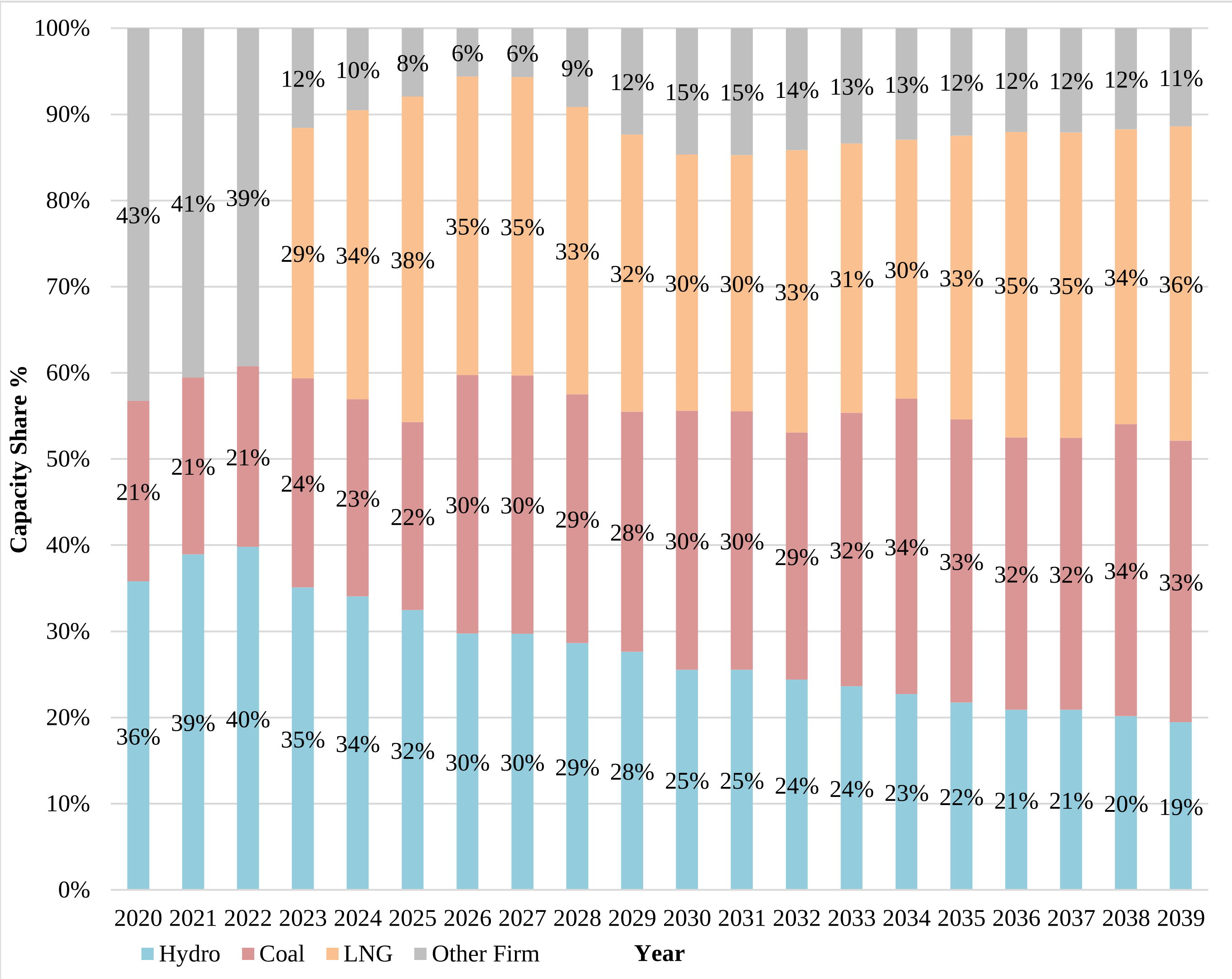


Figure Ad. 5 – Firm Capacity Share over next 20 years in Base Case

Table Ad 8: Annual Energy Generation and Plant Factors of Revised Base Case

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2020	Major Hydro	1383 MW	2835	3886	5225			
	ORE	975 MW	1749	2645	3475			
	Kelanitissa Small GTs	4 x 17 MW	80	8	1	13.4	1.4	0.1
	Kelanitissa GT7	1 x 115 MW	417	264	112	41.3	26.2	11.1
	Kelanitissa Combined Cycle	1 x 161 MW	946	804	724	67.2	57.1	51.4
	Sapugaskanda A	4 x 17 MW	452	367	237	75.8	61.7	39.8
	Sapugaskanda B	8 x 9 MW	480	480	480	76.2	76.2	76.0
	Uthuru Janani	3 x 9 MW	183	181	174	77.8	77.3	74.2
	Barge Power Plant	4 x 16 MW	477	393	256	87.2	71.9	46.9
	Lakvijaya Unit 1	270 MW	1565	1394	1151	66.2	58.9	48.7
	Lakvijaya Unit 2	270 MW	1510	1319	1090	63.8	55.8	46.1
	Lakvijaya Unit 3	270 MW	1601	1456	1198	67.7	61.6	50.6
	Sojitz Combined Cycle	1 x 163 MW	1111	968	867	77.8	67.8	60.7
	West Coast Combined Cycle	1 x 270 MW	995	578	328	42.1	24.4	13.9
	Reciprocating Engines	615 MW	4234	3977	3437	78.6	73.8	63.8
	Total Renewable Generation		**4584**	**6531**	**8699**			
	Total Thermal Generation		**14050**	**12190**	**10055**			
	Total Generation		**18634**	**18721**	**18754**			
2021	Major Hydro	1538 MW	3058	4256	5785			
	ORE	1210 MW	2285	3223	4092			
	Kelanitissa Small GTs	4 x 17 MW	84	11	1	14.1	1.8	0.1
	Kelanitissa GT7	1 x 115 MW	475	335	190	47.2	33.3	18.8
	Sapugaskanda A	4 x 17 MW	475	400	306	79.7	67.2	51.5
	Sapugaskanda B	8 x 9 MW	480	480	478	76.2	76.1	75.8
	Uthuru Janani	3 x 9 MW	183	181	172	77.8	77.2	73.5
	Barge Power Plant	4 x 16 MW	492	425	331	89.9	77.8	60.6
	Lakvijaya Unit 1	270 MW	1598	1450	1175	67.6	61.3	49.7
	Lakvijaya Unit 2	270 MW	1566	1391	1144	66.2	58.8	48.4
	Lakvijaya Unit 3	270 MW	1634	1493	1229	69.1	63.1	52.0
	Sojitz Combined Cycle	1 x 163 MW	1149	1031	881	80.5	72.2	61.7
	Kelanitissa Combined Cycle	1 x 161 MW	1023	875	720	72.6	62.1	51.1
	West Coast Combined Cycle	1 x 270 MW	1223	763	403	51.7	32.3	17.0
	Reciprocating Engines	540 MW	3735	3559	3108	79.0	75.2	65.7
	New Gas Turbines	130 MW	485	225	118	46.6	21.6	11.4
	Total Renewable Generation		**5343**	**7479**	**9877**			
	Total Thermal Generation		**14600**	**12619**	**10259**			
	Total Generation		**19943**	**20098**	**20135**			
2022	Major Hydro	1538 MW	3042	4241	5785			
	ORE	1445 MW	2898	3879	4788			
	Kelanitissa Small GTs	4 x 17 MW	84	10	1	14.1	1.7	0.1
	Kelanitissa GT7	1 x 115 MW	492	355	229	48.9	35.3	22.8
	Sapugaskanda A	4 x 17 MW	481	427	356	80.8	71.7	59.8
	Sapugaskanda B	8 x 9 MW	480	480	476	76.2	76.1	75.5
	Uthuru Janani	3 x 9 MW	183	181	171	77.8	77.0	72.8
	Barge Power Plant	4 x 16 MW	496	450	381	90.7	82.3	69.7
	Lakvijaya Unit 1	270 MW	1618	1492	1232	68.4	63.1	52.1
	Lakvijaya Unit 2	270 MW	1586	1445	1177	67.1	61.1	49.8
	Lakvijaya Unit 3	270 MW	1656	1547	1365	70.0	65.4	57.7
	Sojitz Combined Cycle	1 x 163 MW	1171	1069	906	82.0	74.8	63.5
	Kelanitissa Combined Cycle	1 x 161 MW	1041	925	752	74.0	65.7	53.4
	West Coast Combined Cycle	1 x 270 MW	1338	951	520	56.6	40.2	22.0
	Reciprocating Engines	450 MW	3115	2993	2662	79.0	75.9	67.5
	New Gas Turbines	130 MW	441	234	140	42.3	22.5	13.4
	Open Cycle Operation of NG CCY	200 MW	906	494	266	52.8	28.8	15.5
	Total Renewable Generation		**5940**	**8120**	**10573**			
	Total Thermal Generation		**15086**	**13052**	**10633**			
	Total Generation		**21027**	**21172**	**21207**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2023	Major Hydro	1561 MW	3125	4378	5991			
	ORE	1640 MW	3377	4401	5349			
	Sapugaskanda A	4 x 17 MW	377	263	129	63.3	44.1	21.6
	Sapugaskanda B	4 x 9 MW	222	193	144	70.5	61.3	45.8
	Uthuru Janani	3 x 9 MW	168	143	107	71.6	60.9	45.4
	Barge Power Plant	4 x 16 MW	390	300	163	71.3	54.9	29.9
	Lakvijaya Unit 1	270 MW	1618	1520	1325	68.4	64.3	56.0
	Lakvijaya Unit 2	270 MW	1590	1443	1191	67.2	61.0	50.4
	Lakvijaya Unit 3	270 MW	1649	1596	1554	69.7	67.5	65.7
	Kelanitissa CCY(NG Converted)	1 x 161 MW	926	748	634	65.7	53.0	45.0
	Sojitz CCY(NG Converted)	1 x 163 MW	1003	870	732	70.3	61.0	51.3
	West Coast CCY(NG Converted)	1 x 270 MW	1011	791	547	42.8	33.4	23.1
	Reciprocating Engines	255 MW	1544	1250	912	69.1	56.0	40.8
	New Gas Turbines	130 MW	219	138	53	20.6	13.0	5.0
	NG Combined Cycle	2 x 300 MW	3261	2476	1750	64.3	48.8	34.5
	New Coal (Lakvijaya Extension)	1 x 300 MW	1903	1911	1859	80.5	80.8	78.6
	Total Renewable Generation		**6502**	**8779**	**11341**			
	Total Thermal Generation		**15883**	**13642**	**11101**			
	Total Generation		**22385**	**22421**	**22442**			
2024	Major Hydro	1607 MW	3149	4416	6055			
	ORE	1815 MW	3796	4863	5851			
	Sapugaskanda B	4 x 9 MW	207	169	119	65.7	53.6	37.7
	Uthuru Janani	3 x 9 MW	156	124	84	66.5	52.7	35.8
	Barge Power Plant	4 x 16 MW	376	247	94	68.8	45.1	17.1
	Lakvijaya Unit 1	270 MW	1621	1593	1525	68.5	67.3	64.5
	Lakvijaya Unit 2	270 MW	1593	1510	1376	67.3	63.8	58.2
	Lakvijaya Unit 3	270 MW	1680	1669	1631	71.1	70.6	68.9
	Kelanitissa CCY(NG Converted)	1 x 161 MW	862	724	595	61.1	51.3	42.2
	Sojitz CCY(NG Converted)	1 x 163 MW	963	814	649	67.4	57	45.5
	West Coast CCY(NG Converted)	1 x 270 MW	888	723	491	37.5	30.6	20.8
	Reciprocating Engines	255 MW	1406	1025	508	62.9	45.9	22.8
	New Gas Turbines	130 MW	198	121	34	18.7	11.4	3.2
	NG Combined Cycle	3 x 300 MW	4745	3680	2762	62.3	48.3	36.3
	New Coal (Lakvijaya Extension)	1 x 300 MW	1966	1953	1882	83.1	82.6	79.6
	Total Renewable Generation		**6945**	**9279**	**11906**			
	Total Thermal Generation		**16661**	**14352**	**11750**			
	Total Generation		**23606**	**23631**	**23656**			
2025	Major Hydro	1607 MW	3133	4401	6056			
	ORE	1960 MW	4084	5193	6220			
	Sapugaskanda B	4 x 9 MW	187	149	105	59.4	47.3	33.3
	Uthuru Janani	3 x 9 MW	140	111	75	59.7	47.2	31.8
	Lakvijaya Unit 1	270 MW	1670	1654	1594	70.6	69.9	67.4
	Lakvijaya Unit 2	270 MW	1615	1582	1527	68.3	66.9	64.6
	Lakvijaya Unit 3	270 MW	1734	1710	1654	73.3	72.3	69.9
	Kelanitissa CCY(NG Converted)	1 x 161 MW	829	690	559	58.8	49	39.6
	Sojitz CCY(NG Converted)	1 x 163 MW	937	767	591	65.6	53.7	41.4
	West Coast CCY(NG Converted)	1 x 270 MW	832	661	454	35.2	28	19.2
	Reciprocating Engines	255 MW	1258	943	463	56.3	42.2	20.7
	New Gas Turbines	130 MW	192	127	39	18.1	11.9	3.7
	NG Combined Cycle	4 x 300 MW	6,272	4,945	3674	61.8	48.7	36.2
	New Coal (Lakvijaya Extension)	1 x 300 MW	1,992	1,967	1907	84.2	83.2	80.6
	Total Renewable Generation		**7216**	**9593**	**12276**			
	Total Thermal Generation		**17658**	**15306**	**12642**			
	Total Generation		**24874**	**24899**	**24918**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2026	Major Hydro	1607 MW	3126	4393	6057			
	ORE	2100 MW	4353	5483	6531			
	Uthuru Janani	3 x 9 MW	109	82	24	46.4	35	10.2
	Lakvijaya Unit 1	270 MW	1568	1517	1419	66.3	64.2	60
	Lakvijaya Unit 2	270 MW	1506	1426	1267	63.7	60.3	53.6
	Lakvijaya Unit 3	270 MW	1632	1592	1510	69	67.3	63.8
	Kelanitissa CCY(NG Converted)	1 x 161 MW	680	561	432	48.2	39.8	30.6
	Sojitz CCY(NG Converted)	1 x 163 MW	789	601	301	55.2	42.1	21.1
	West Coast CCY(NG Converted)	1 x 270 MW	600	430	190	25.4	18.2	8.1
	Reciprocating Engines	195 MW	752	522	132	44	30.6	7.7
	New Gas Turbines	130 MW	147	85	9	13.8	8	0.9
	NG Combined Cycle	4 x 300 MW	5,065	3,775	2850	49.9	37.2	28.1
	New Coal (Lakvijaya Extension)	1 x 300 MW	1,892	1,837	1747	80	77.7	73.9
	New Coal (Foul Point)	2 x 300 MW	3,957	3,882	3746	83.7	82.1	79.2
	Total Renewable Generation		**7478**	**9876**	**12587**			
	Total Thermal Generation		**18697**	**16310**	**13627**			
	Total Generation		**26175**	**26186**	**26214**			
2027	Major Hydro	1607 MW	3118	4386	6057			
	ORE	2255 MW	4667	5819	6886			
	Uthuru Janani	3 x 9 MW	124	93	46	52.8	39.4	19.5
	Lakvijaya Unit 1	270 MW	1598	1559	1477	67.6	65.9	62.5
	Lakvijaya Unit 2	270 MW	1553	1493	1351	65.7	63.1	57.1
	Lakvijaya Unit 3	270 MW	1657	1620	1550	70.1	68.5	65.6
	Kelanitissa CCY(NG Converted)	1 x 161 MW	729	579	441	51.7	41	31.2
	Sojitz CCY(NG Converted)	1 x 163 MW	826	655	478	57.9	45.8	33.5
	West Coast CCY(NG Converted)	1 x 270 MW	674	489	264	28.5	20.7	11.2
	Reciprocating Engines	195 MW	808	628	245	47.3	36.7	14.3
	New Gas Turbines	130 MW	160	111	26	15.1	10.4	2.4
	NG Combined Cycle	4 x 300 MW	5,676	4,280	3095	55.9	42.2	30.5
	New Coal (Lakvijaya Extension)	1x 300 MW	1,913	1,866	1783	80.9	78.9	75.4
	New Coal (Foul Point)	2 x 300 MW	3,972	3,907	3788	84	82.6	80.1
	Total Renewable Generation		**7785**	**10205**	**12943**			
	Total Thermal Generation		**19690**	**17280**	**14544**			
	Total Generation		**27475**	**27485**	**27487**			
2028	Major Hydro	1607 MW	3111	4378	6057			
	ORE	2410 MW	4971	6144	7231			
	Uthuru Janani	3 x 9 MW	137	99	47	58.3	42.3	20.1
	Lakvijaya Unit 1	270 MW	1644	1605	1545	69.5	67.9	65.3
	Lakvijaya Unit 2	270 MW	1582	1537	1459	66.9	65	61.7
	Lakvijaya Unit 3	270 MW	1709	1672	1605	72.3	70.7	67.8
	Kelanitissa CCY(NG Converted)	1 x 161 MW	790	646	491	56	45.8	34.8
	Sojitz CCY(NG Converted)	1 x 163 MW	903	702	547	63.2	49.2	38.3
	West Coast CCY(NG Converted)	1 x 270 MW	770	542	360	32.5	22.9	15.2
	Reciprocating Engines	195 MW	920	672	253	53.9	39.4	14.8
	New Gas Turbines	130 MW	172	123	29	16.1	11.6	2.7
	NG Combined Cycle	4x 300 MW	6,195	4,860	3504	61	47.9	34.5
	New Coal (Lakvijaya Extension)	1 x 300 MW	1972	1930	1859	83.4	81.6	78.6
	New Coal (Foul Point)	2 x 300 MW	4001	3971	3898	84.6	83.9	82.4
	Total Renewable Generation		**8081**	**10522**	**13288**			
	Total Thermal Generation		**20795**	**18359**	**15597**			
	Total Generation		**28876**	**28881**	**28885**			
2029	Major Hydro	1607 MW	3103	4371	6058			
	ORE	2565 MW	5275	6469	7576			
	Uthuru Janani	3 x 9 MW	156	116	71	66.3	49.2	30.4
	Lakvijaya Unit 1	270 MW	1702	1670	1608	72	70.6	68
	Lakvijaya Unit 2	270 MW	1636	1593	1539	69.2	67.3	65.1
	Lakvijaya Unit 3	270 MW	1747	1719	1665	73.9	72.7	70.4
	Kelanitissa CCY(NG Converted)	1 x 161 MW	894	713	532	63.4	50.6	37.7
	Sojitz CCY(NG Converted)	1 x 163 MW	973	772	586	68.1	54.1	41
	West Coast CCY(NG Converted)	1 x 270 MW	927	621	468	39.2	26.2	19.8
	Reciprocating Engines	195 MW	1042	761	363	61	44.5	21.2
	New Gas Turbines	130 MW	241	139	31	22.7	13.1	3
	NG Combined Cycle	4x 300 MW	6625	5413	3950	65.3	53.3	38.9
	New Coal (Lakvijaya Extension)	1 x 300 MW	1995	1975	1912	84.4	83.5	80.8
	New Coal (Foul Point)	2 x 300 MW	4011	4000	3976	84.8	84.6	84
	Total Renewable Generation		**8378**	**10840**	**13634**			
	Total Thermal Generation		**21949**	**19492**	**16701**			
	Total Generation		**30327**	**30332**	**30335**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2030	Major Hydro	1607 MW	3095	4364	6058			
	ORE	2700 MW	5522	6738	7865			
	Uthuru Janani	3 x 9 MW	146	103	48	62.4	44	20.3
	Lakvijaya Unit 1	270 MW	1704	1652	1581	72	69.8	66.8
	Lakvijaya Unit 2	270 MW	1622	1562	1517	68.6	66	64.2
	Lakvijaya Unit 3	270 MW	1743	1710	1643	73.7	72.3	69.5
	Kelanitissa CCY(NG Converted)	1 x 161 MW	812	676	523	57.6	48	37.1
	Sojitz CCY(NG Converted)	1 x 163 MW	895	751	544	62.7	52.6	38.1
	West Coast CCY(NG Converted)	1 x 270 MW	805	562	396	34	23.8	16.8
	Reciprocating Engines	195 MW	1037	700	228	60.7	41	13.3
	New Gas Turbines	130 MW	198	122	43	18.6	11.5	4
	NG Combined Cycle	4x 300 MW	6230	4905	3516	61.4	48.3	34.6
	New Coal (Lakvijaya Extension)	1 x 300 MW	1995	1973	1890	84.3	83.4	79.9
	New Coal (Foul Point)	3 x 300 MW	6017	6005	5972	84.8	84.6	84.2
	Total Renewable Generation		**8617**	**11102**	**13923**			
	Total Thermal Generation		**23204**	**20721**	**17901**			
	Total Generation		**31821**	**31823**	**31824**			
2031	Major Hydro	1607 MW	3088	4356	6058			
	ORE	2875 MW	5876	7114	8260			
	Uthuru Janani	3 x 9 MW	158	120	92	67.4	51.2	39.3
	Lakvijaya Unit 1	270 MW	1710	1673	1600	72.3	70.8	67.6
	Lakvijaya Unit 2	270 MW	1646	1596	1538	69.6	67.5	65
	Lakvijaya Unit 3	270 MW	1734	1720	1665	73.3	72.7	70.4
	Kelanitissa CCY(NG Converted)	1 x 161 MW	910	735	548	64.5	52.1	38.8
	Sojitz CCY(NG Converted)	1 x 163 MW	1008	801	606	70.6	56.1	42.5
	West Coast CCY(NG Converted)	1 x 270 MW	1022	664	474	43.2	28.1	20
	Reciprocating Engines	195 MW	1121	794	457	65.6	46.5	26.8
	New Gas Turbines	130 MW	314	152	61	29.6	14.4	5.7
	NG Combined Cycle	4x 300 MW	6656	5580	4064	65.6	55	40
	New Coal (Lakvijaya Extension)	1 x 300 MW	1993	1974	1894	84.3	83.5	80.1
	New Coal (Foul Point)	3 x 300 MW	6016	6004	5970	84.8	84.6	84.1
	Total Renewable Generation		**8964**	**11470**	**14318**			
	Total Thermal Generation		**24288**	**21813**	**18969**			
	Total Generation		**33252**	**33283**	**33287**			
2032	Major Hydro	1607 MW	3080	4348	6057			
	ORE	3050 MW	6228	7487	8653			
	Uthuru Janani	3 x 9 MW	147	108	67	62.8	45.9	28.7
	Lakvijaya Unit 1	270 MW	1715	1689	1628	72.5	71.4	68.8
	Lakvijaya Unit 2	270 MW	1668	1639	1571	70.5	69.3	66.4
	Lakvijaya Unit 3	270 MW	1746	1731	1677	73.8	73.2	70.9
	Kelanitissa CCY(NG Converted)	1 x 161 MW	873	688	515	61.9	48.8	36.5
	Sojitz CCY(NG Converted)	1 x 163 MW	966	736	582	67.6	51.5	40.8
	West Coast CCY(NG Converted)	1 x 270 MW	899	608	468	38	25.7	19.8
	Reciprocating Engines	195 MW	1058	730	406	61.9	42.7	23.8
	New Gas Turbines	130 MW	257	139	54	24.2	13.1	5.1
	NG Combined Cycle	5 x 300 MW	8106	6901	5234	63.9	54.4	41.3
	New Coal (Lakvijaya Extension)	1 x 300 MW	1990	1972	1902	84.1	83.4	80.4
	New Coal (Foul Point)	3 x 300 MW	6014	5998	5961	84.8	84.5	84
	Total Renewable Generation		**9308**	**11835**	**14710**			
	Total Thermal Generation		**25439**	**22939**	**20065**			
	Total Generation		**34747**	**34774**	**34775**			
2033	Major Hydro	1607 MW	3073	4341	6056			
	ORE	3210 MW	6521	7801	8987			
	Lakvijaya Unit 1	270 MW	1680	1648	1585	71	69.7	67
	Lakvijaya Unit 2	270 MW	1645	1605	1524	69.5	67.8	64.4
	Lakvijaya Unit 3	270 MW	1713	1681	1621	72.4	71.1	68.6
	West Coast CCY(NG Converted)	1 x 270 MW	892	581	460	37.7	24.6	19.4
	Reciprocating Engines	195 MW	1148	905	601	67.2	53	35.2
	New Gas Turbines	130 MW	338	176	75	31.9	16.6	7.1
	NG Combined Cycle	6 x 300 MW	9286	7670	5674	61	50.4	37.3
	New Coal (Lakvijaya Extension)	1 x 300 MW	1965	1930	1853	83.1	81.6	78.3
	New Coal (Foul Point)	4 x 300 MW	7993	7952	7856	84.5	84.1	83
	Total Renewable Generation		**9594**	**12142**	**15043**			
	Total Thermal Generation		**26660**	**24148**	**21249**			
	Total Generation		**36254**	**36290**	**36292**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2034	Major Hydro	1607 MW	3065	4333	6056			
	ORE	3415 MW	6942	8244	9450			
	Lakvijaya Unit 1	270 MW	1652	1628	1546	69.8	68.8	65.4
	Lakvijaya Unit 2	270 MW	1623	1574	1480	68.6	66.6	62.6
	Lakvijaya Unit 3	270 MW	1701	1663	1600	71.9	70.3	67.7
	West Coast CCY(NG Converted)	1 x 270 MW	796	539	413	33.7	22.8	17.5
	Reciprocating Engines	195 MW	1106	851	482	64.8	49.8	28.2
	New Gas Turbines	130 MW	262	159	63	24.7	14.9	5.9
	NG Combined Cycle	6 x 300 MW	8802	7062	5158	57.8	46.4	33.9
	New Coal (Lakvijaya Extension)	1 x 300 MW	1937	1898	1828	81.9	80.2	77.3
	New Coal (Foul Point)	5 x 300 MW	9963	9913	9790	84.3	83.8	82.8
	Total Renewable Generation		**10008**	**12577**	**15506**			
	Total Thermal Generation		**27842**	**25287**	**22360**			
	Total Generation		**37850**	**37864**	**37866**			
2035	Major Hydro	1607 MW	3057	4326	6058			
	ORE	3595 MW	7290	8613	9838			
	Lakvijaya Unit 1	270 MW	1699	1658	1588	71.8	70.1	67.1
	Lakvijaya Unit 2	270 MW	1648	1617	1543	69.7	68.4	65.2
	Lakvijaya Unit 3	270 MW	1723	1693	1623	72.9	71.6	68.6
	Reciprocating Engines	195 MW	1095	776	321	64.1	45.4	18.8
	New Gas Turbines	130 MW	213	142	56	20.1	13.4	5.3
	NG Combined Cycle	8 x 300 MW	10815	8790	6755	53.3	43.3	33.3
	New Coal (Lakvijaya Extension)	1 x 300 MW	1960	1933	1858	82.8	81.7	78.6
	New Coal (Foul Point)	5 x 300 MW	9982	9942	9852	84.4	84.1	83.3
	Total Renewable Generation		**10347**	**12939**	**15896**			
	Total Thermal Generation		**29135**	**26551**	**23596**			
	Total Generation		**39482**	**39490**	**39492**			
2036	Major Hydro	1607 MW	3050	4318	6059			
	ORE	3770 MW	7640	8985	10230			
	Lakvijaya Unit 1	270 MW	1721	1691	1619	72.8	71.5	68.5
	Lakvijaya Unit 2	270 MW	1704	1654	1575	72	69.9	66.6
	Lakvijaya Unit 3	270 MW	1737	1717	1659	73.4	72.6	70.1
	Reciprocating Engines	195 MW	1060	712	247	62.1	41.7	14.5
	New Gas Turbines	130 MW	197	125	45	18.6	11.8	4.2
	NG Combined Cycle	9 x 300 MW	12081	10044	7941	52.9	44	34.8
	New Coal (Lakvijaya Extension)	1 x 300 MW	1969	1949	1891	83.3	82.4	79.9
	New Coal (Foul Point)	5 x 300 MW	9997	9965	9896	84.5	84.3	83.7
	Total Renewable Generation		**10690**	**13303**	**16289**			
	Total Thermal Generation		**30466**	**27857**	**24873**			
	Total Generation		**41156**	**41160**	**41162**			
2037	Major Hydro	1607 MW	3042	4311	6060			
	ORE	3945 MW	7991	9357	10622			
	Lakvijaya Unit 1	270 MW	1731	1712	1644	73.2	72.4	69.5
	Lakvijaya Unit 2	270 MW	1718	1678	1613	72.7	70.9	68.2
	Lakvijaya Unit 3	270 MW	1749	1734	1686	74	73.3	71.3
	Reciprocating Engines	195 MW	1139	813	433	66.7	47.6	25.3
	New Gas Turbines	130 MW	286	150	60	26.9	14.2	5.6
	NG Combined Cycle	9 x 300 MW	13204	11181	8906	57.8	49	39
	New Coal (Lakvijaya Extension)	1 x 300 MW	1978	1964	1932	83.6	83	81.7
	New Coal (Foul Point)	5 x 300 MW	10007	9981	9929	84.6	84.4	84
	Total Renewable Generation		**11034**	**13669**	**16683**			
	Total Thermal Generation		**31812**	**29213**	**26203**			
	Total Generation		**42846**	**42882**	**42886**			
2038	Major Hydro	1607 MW	3035	4304	6061			
	ORE	4140 MW	8399	9786	11071			
	Lakvijaya Unit 1	270 MW	1725	1696	1628	72.9	71.7	68.8
	Lakvijaya Unit 2	270 MW	1712	1659	1600	72.4	70.2	67.6
	Lakvijaya Unit 3	270 MW	1740	1721	1668	73.6	72.8	70.5
	Reciprocating Engines	195 MW	1094	760	301	64.1	44.5	17.6
	New Gas Turbines	130 MW	224	137	48	21.1	12.9	4.5
	NG Combined Cycle	9 x 300 MW	12741	10669	8475	55.8	46.7	37.1
	New Coal (Lakvijaya Extension)	1 x 300 MW	1970	1953	1904	83.3	82.6	80.5
	New Coal (Foul Point)	6 x 300 MW	11997	11963	11896	84.5	84.3	83.8
	Total Renewable Generation		**11434**	**14090**	**17132**			
	Total Thermal Generation		**33203**	**30558**	**27520**			
	Total Generation		**44637**	**44648**	**44652**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2039	Major Hydro	1607 MW	3031	4300	6062			
	ORE	4330 MW	8800	10198	11493			
	Lakvijaya Unit 1	270 MW	1735	1714	1658	73.4	72.5	70.1
	Lakvijaya Unit 2	270 MW	1720	1678	1624	72.7	71	68.7
	Lakvijaya Unit 3	270 MW	1751	1736	1690	74	73.4	71.4
	Reciprocating Engines	195 MW	1046	729	276	61.2	42.7	16.2
	New Gas Turbines	130 MW	204	123	44	19.2	11.6	4.2
	NG Combined Cycle	10 x 300 MW	14167	12027	9735	55.8	47.4	38.4
	New Coal (Lakvijaya Extension)	1 x 300 MW	1979	1965	1934	83.7	83.1	81.8
	New Coal (Foul Point)	6 x 300 MW	12009	11980	11936	84.6	84.4	84.1
	Total Renewable Generation		**11831**	**14498**	**17554**			
	Total Thermal Generation		**34611**	**31952**	**28897**			
	Total Generation		**46442**	**46450**	**46451**			

NOTES:

1. Annual total generation figure does not include operation of PSPP
2. Annual total renewable generation figure includes the generation from new biomass power plants.

Table Ad 9: Fuel Requirement and Expenditure on Fuel

Revised Base Case 2020 - 2039

Year	Auto Diesel		Furnace Oil (LSFO 180)		Furnace Oil (HSFO 180)		Residual Oil (HSFO 380)		Naphtha		Coal (6300 kcal/kg)		LNG		Dendro	
	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD
2020	250.2	154.6	126.1	68.9	975.2	429.8	176.1	81.0	136.8	87.9	1597.9	181.8			600.3	23.7
2021	343.8	216.1	166.5	85.2	892.5	393.4	183.3	84.2	148.7	93.0	1661.1	188.1			662.2	26.1
2022	494.0	329.2	207.6	101.1	776.3	342.3	189.0	86.8	157.3	96.6	1718.5	193.8			724.1	28.5
2023					362.3	159.8	95.9	43.9			2304.5	269.1	758.5	435.9	785.9	31.0
2024					298.6	131.8	33.8	15.8			2398.3	278.6	898.0	514.8	847.8	33.4
2025					225.4	99.3	29.9	13.9			2468.8	285.7	1053.0	600.9	909.7	35.8
2026					129.0	56.9					3748.4	409.5	794.8	475.0	971.6	38.3
2027					153.8	67.8					3819.2	416.5	893.0	521.7	1033.5	40.7
2028					164.9	72.7					3916.0	426.1	1003.3	575.3	1095.4	43.2
2029					187.2	82.6					4004.7	434.9	1118.5	629.6	1157.3	45.6
2030					171.5	75.6					4743.2	506.6	1024.4	588.3	1219.1	48.0
2031					195.3	86.1					4768.8	509.1	1160.4	646.8	1281.0	50.5
2032					179.0	78.9					4792.0	511.4	1314.4	730.5	1342.9	52.9
2033					194.2	85.5					5474.0	577.6	1218.4	677.4	1404.8	55.3
2034					182.5	80.3					6183.2	646.4	1121.6	632.9	1466.7	57.8
2035					166.6	73.3					6244.0	652.4	1263.1	709.0	1528.6	60.2
2036					152.9	67.3					6293.3	657.2	1433.1	801.4	1590.4	62.7
2037					174.4	76.8					6327.4	660.6	1598.4	876.4	1652.3	65.1
2038					163.1	71.8					7058.9	731.6	1523.4	841.9	1714.2	67.5
2039					156.5	68.9					7088.6	734.5	1708.5	940.4	1776.1	70.0

Reserve Margin and LOLP of Revised Base Case

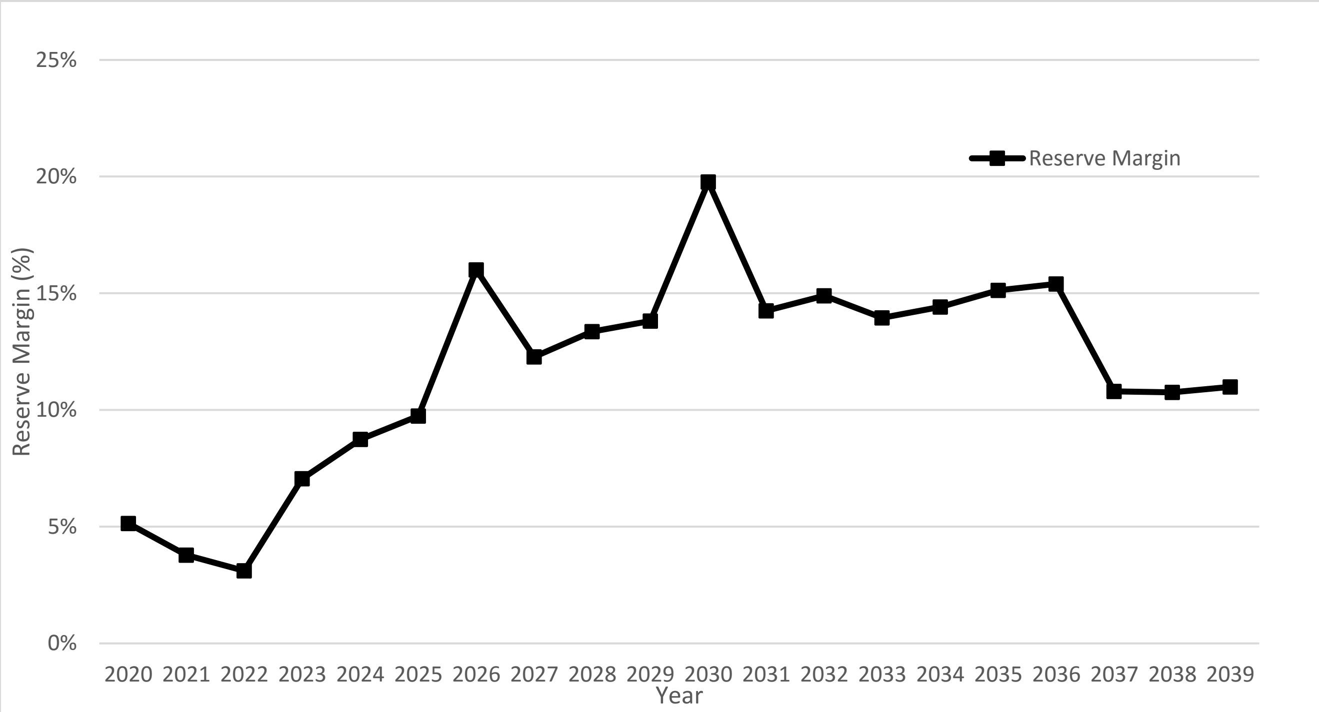


Figure Ad. 6 – Variation of Reserve Margin in Base Case

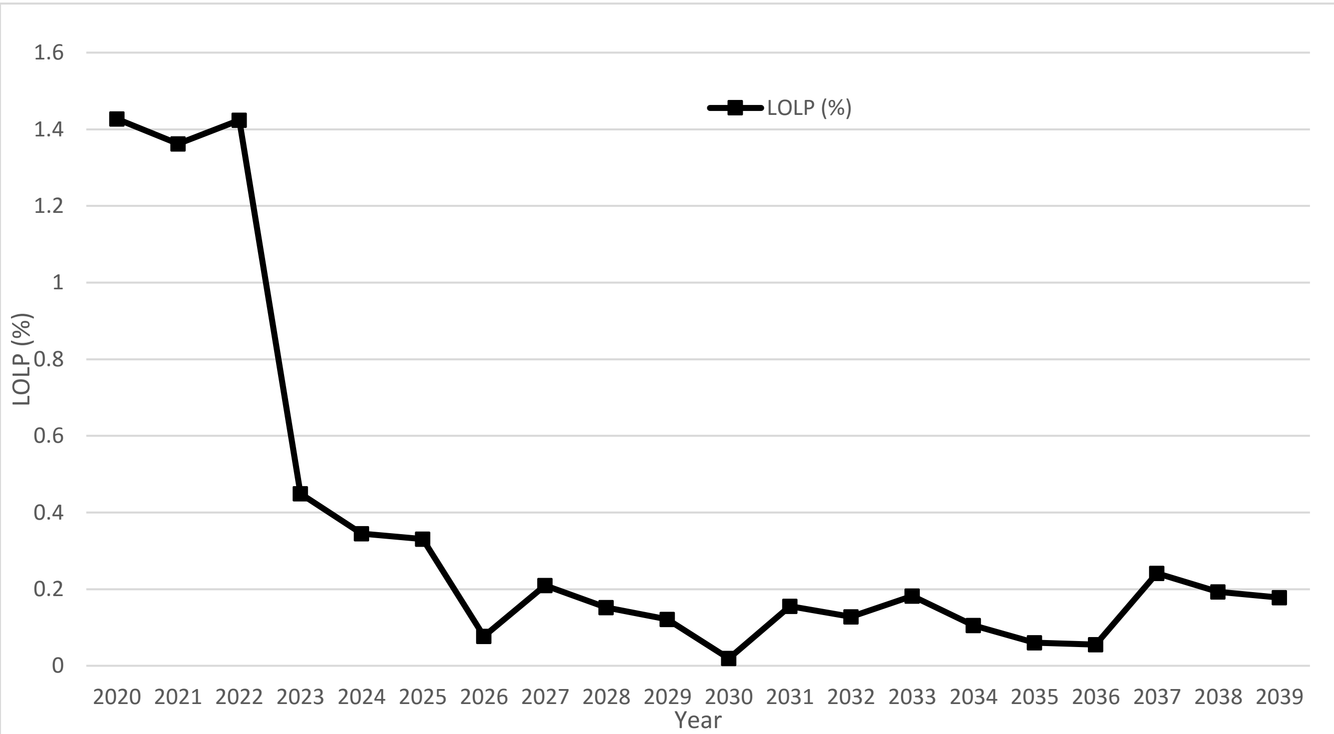
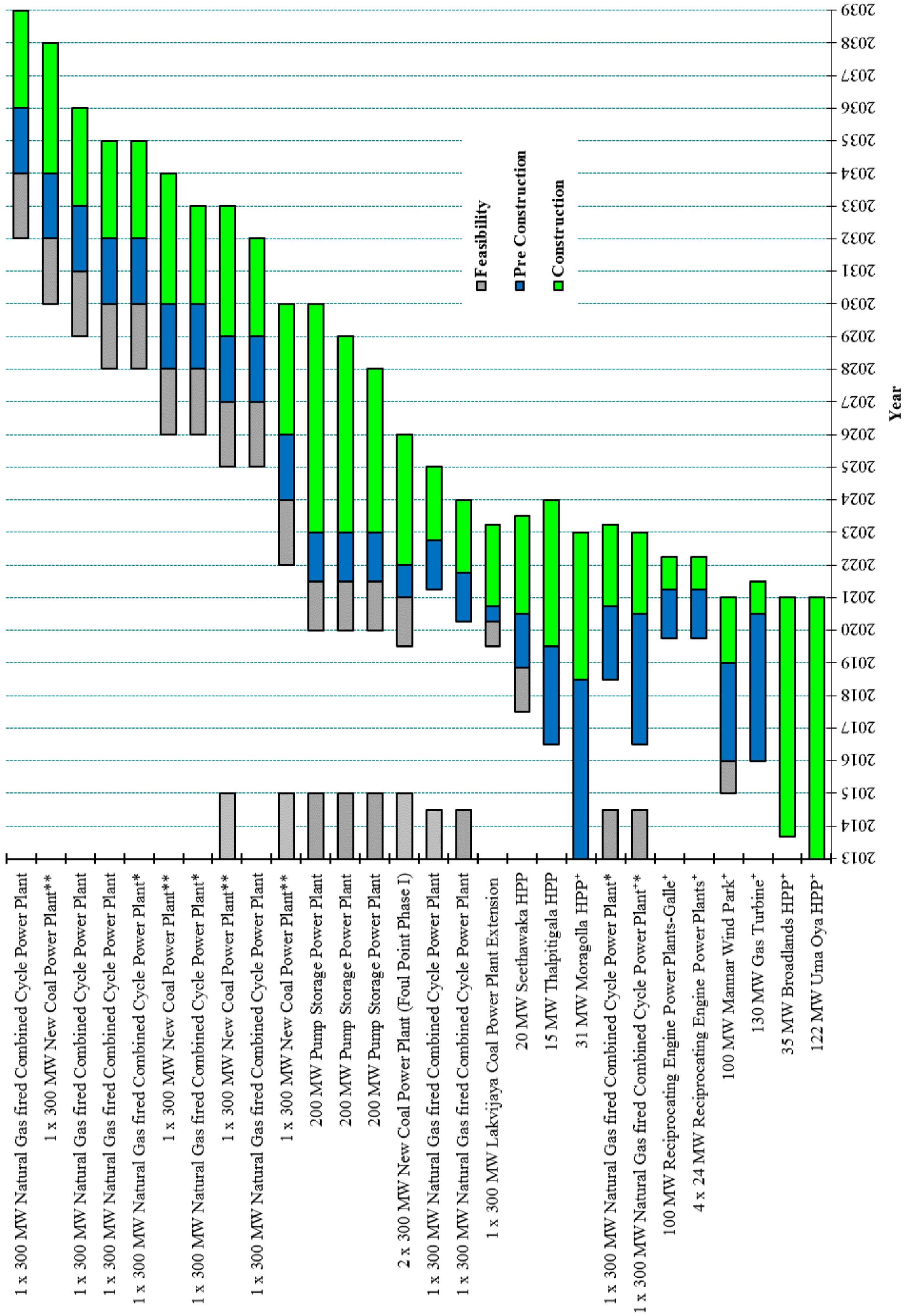


Figure Ad. 7 – Variation of LOLP in Base Case

Implementation Plan of Revised Base Case



+Committed Plants

*Natural Gas fired Combined Cycle Power Plant-Western Region

**Change to super critical will be evaluated

Plants assumed as in operation from 1st January each year

Implementation of short term thermal power plants are not indicated

Emissions of Revised Base Case

Table Ad 10 – Air Emissions of Base Case

1000 tons/year

Year	PM	SO2	NOx	CO_2
2020	3.0	66.9	47.8	10,071
2021	3.3	62.1	43.9	10,492
2022	3.6	56.2	38.6	11,084
2023	3.0	23.7	18.2	10,485
2024	3.1	20.0	15.6	10,757
2025	3.1	18.1	14.6	11,181
2026	3.4	12.3	10.3	13,003
2027	4.0	14.0	11.7	13,530
2028	4.2	14.8	12.4	14,114
2029	4.4	16.3	13.5	14,720
2030	4.7	15.8	13.3	16,151
2031	4.9	17.3	14.5	16,638
2032	5.1	16.3	13.9	17,140
2033	5.5	19.0	15.9	18,470
2034	5.8	18.5	15.6	19,826
2035	6.0	17.5	15.1	20,372
2036	6.2	16.5	14.6	20,993
2037	6.4	18.1	16.0	21,592
2038	6.7	17.7	15.7	23,062
2039	6.9	17.4	15.7	23,697

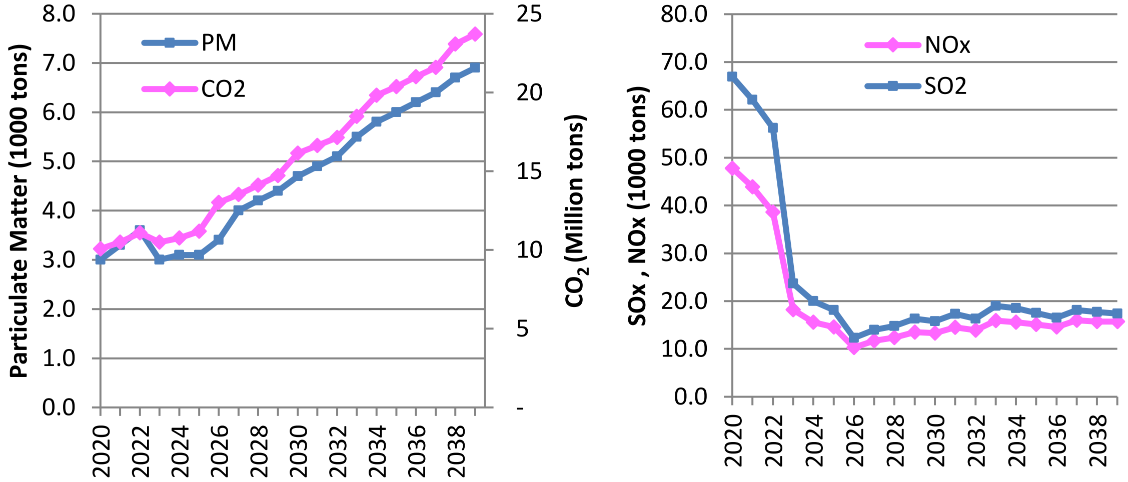


Figure Ad. 8 – PM, SO_2, NO_x and CO_2 emissions of Base Scenario

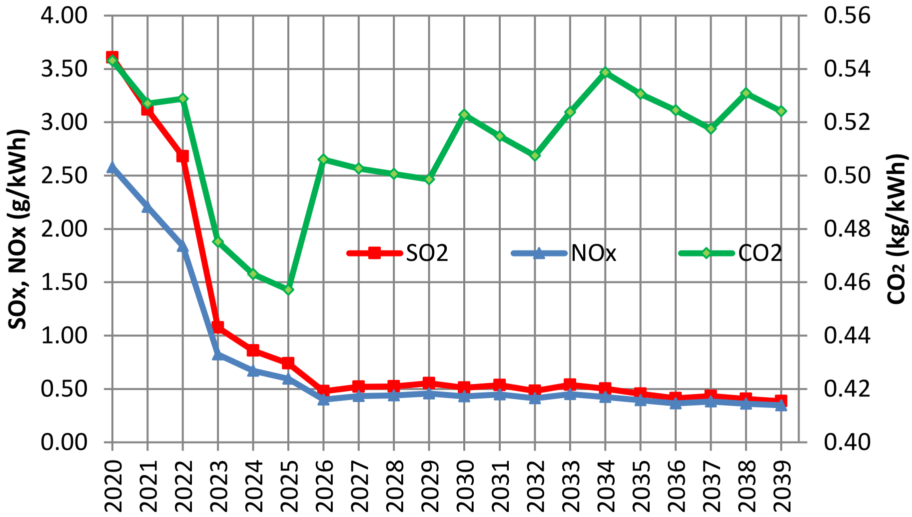


Figure Ad. 9 – SO_2, NO_x and CO_2 emissions per kWh generated

Contingency Analysis of Revised Base Case

Contingency analysis was performed on the revised base case to identify the impacts of different risk events such as hydrological variations, delay in plant implementation, demand variation and long-term outages of major power plants. Following capacities are identified in each year to mitigate the risks to maintain the minimum stipulated reliability criteria as specified in the government gazette notification No 2019/28 dated 8th February 2019.

Table Ad 11 – Capacity Requirement Under Contingency Scenarios

Year	Required Additional Capacity (MW)						
	Single Occurrence of Risk Events				Multiple Occurrence of Risk Events		
	Low Hydro Inflow	High Demand	Major Unit Outage	Plat Delay	Dry Hydro and Plant Delay	Major Unit Outage, Low Hydro Inflow and Plant Delay	High Demand, Low Hydro Inflow and Plant Delay
2020	240	30	105	0	240	315	270
2021	150	30	120	225	465	555	510
2022	210	45	120	195	435	525	480
2023	15	0	0	450	690	765	750
2024	0	0	0	75	285	375	345

Low Hydro Inflow

- Expected annual energy from existing hydro plants reduced to 3180 GWh

High Demand

- Demand growth considered for 1% higher economic growth of the country

Revised commissioning years of committed/candidate major power projects as considered for contingency analysis.

- 122 MW Uma Oya HPP delayed till 2022
- 130 MW Gas turbine delayed till 2022
- Open cycle operation of 1st 300MW NG combined cycle Plant delayed till 2023
- 300 MW Lakvijaya Extension coal power plant delayed till 2024
- 31 MW Moragolla plant delayed till 2024
- 24 MW Seethawaka delayed till 2024
- 2nd 300 MW Natural gas plant delayed till 2024
- 3rd 300 MW Natural gas plant delayed till 2025

Long period outage of a Major Power Plant

- One unit of Lakvijaya coal power station considered on outage for the first four months

Revised Transmission Infrastructure Requirement for Major Plant Additions During Initial Years of Revised Base Case

1st 300 MW Natural Gas fired Combined Cycle Power Plant – Western Region,

- Kerawalapitiya 220kV Switching Station
- Underground Transmission Network under Greater Colombo Transmission & Distribution Loss Reduction Project
- Rehabilitation of Colombo E and F Grid Substations
- New Polpitiya, Padukka Grid substations and New Polpitiya-Padukka-Pannipitya transmission lines

2nd 300 MW Natural Gas fired Combined Cycle Power Plant – Western Region,

- Kerawalapitiya-Port 2nd 220kV transmission line
- Kirindiwela 220kV/132kV grid substation and 220kV, Veyangoda-Kirindiwela, 400kV, Kirindiwela-Padukka and 220kV Kotmale-New Polpitiya transmission lines

300 MW Lakvijaya Coal Power Plant Extension

- 220kV/132kV New Habarana Grid Substation and 220kV, New Habarana-Veyangoda transmission line
- Upgrading the New Habarana -New Anuradhapura 220kV transmission line

3rd 300 MW Natural Gas fired Combined Cycle Power Plant

- Construction of Hambantota 220/132/33kV Switching Station and Construction of New Polpitiya-Hambantota 2xZebra, 220kV, 150km, double circuit transmission line under GPD&EEIP Tranche II
- Construction of Hambantota-Matara 132kV Transmission line included under Power System Reliability Strengthening Project

4th 300 MW Natural Gas fired Combined Cycle Power Plant – Western Region,

- Construction of Kerawalapitiya 400/220kV Switching Station and interconnection from Kerawalapitiya switching station 2
- Construction of Kerawalapitiya-Kirindiwela 400kV transmission line
- Construction of Kirindiwela 400/220kV Switching Station
- Construction of 2nos of transmission line bays at Kirindiwela switching station
- (in 2025, operation will be in 220kV level)

2x 300 MW New Coal Power Plant (Foul Point)

- Sampoor Switching Station (220kV bus arrangement inclu. bus coupler, 6x220kV bus TL bays)
- Construction of Sampoor SS to New Habarana SS 100km, 4*Zebra, 400kV double circuit transmission lines (220kV operation)
- Construction of Sampoor SS to Kappalturai GS 45km, 2*Zebra, 220kV double circuit transmission line