PUBLIC UTILITIES COMMISSION OF SRI LANKA

DECISION ON LEAST COST LONG TERM GENERATION EXPANSION PLAN 2018-2037

This Document contains the decision of the Commission on the Least Cost Long Term Generation Expansion Plan for the period of 2018-2037, prepared by the Ceylon Electricity Board (Transmission Licensee operating under License No EL/T/09-002) in terms of Section 43 of the Sri Lanka Electricity Act No. 20 of 2009 as amended by section 13 of Sri Lanka Electricity (amendment) Act No. 31 of 2013

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DECISION ON LEAST COST LONG TERM GENERATION EXPANSION PLAN 2018-2037

1. Introduction

Section 43 of the Sri Lanka Electricity Act No. 20 of 2009 as amended by section 13 of Sri Lanka Electricity (amendment) Act No. 31 of 2013, requires the Transmission Licensee to prepare and submit the Least Cost Long Term Generation Expansion Plan (LCLTGEP) for approval of the Public Utilities Commission of Sri Lanka (Commission). Accordingly Ceylon Electricity Board has submitted their plan on 5th May 2017. Prior to this the input parameters used in preparation of the draft plan was submitted for Commission's information on 6th February 2017. Those input parameters were published for stakeholder comments from 17th February to 22nd March. Subsequently, the Commission has conducted a wide stakeholder consultation on the submitted LCLTGEP (***Annex***: summary of comments and Commissions response). The draft LCLTGEP was published for stakeholder comments from 9th May 2017 to 15th June 2017 and the oral session for comments was held on 15th June 2017.

2. Generation Planning Code

The Transmission Licensee was required to follow the Least Cost Generation Expansion Planning Code approved and issued by the Commission in April 2011. In preparation of the LCLTGEP, the said planning code was adhered and followed by the Transmission Licensee, except for the following areas;

- Reserve Margin

  The planning code defined 10% - 35% window is replaced with draft Grid Code figures of 2.5% - 20%, which might result in lower reliability levels. However, CEB has violated these new Reserve Margin criteria (upper limit) at all the years (even at the driest period in 2028), in the proposed base case plan sent for approval.

- Loss of Load Probability (LOLP)

  The planning code defined 0.5%-1.5%, and the lower limit of 0.5% is consistently overlooked in the base case that may result in over investment.

- Cost of Energy Not Served

  This is set at 0.5 USD/kWh in the planning code and CEB has escalated this to 0.663 USD/kWh for the proposed plan to accommodate for inflation since 2011.

3. Generation Planning Tool

CEB uses mainly the Wien Automatic System Planning (WASP IV) software to derive the generation plans. This software model uses an objective function to minimize total cost B, where;

$$B_j = \sum_{t=1}^{T}\left(\bar{I}_{j,t} - \bar{S}_{j,t} + \bar{F}_{j,t} + \bar{L}_{j,t} + \bar{M}_{j,t} + \bar{O}_{j,t}\right)$$

I – Capital Investment Costs
S – Salvage Value of Investment costs
F – Fuel Costs
L – Fuel Inventory Costs
M – Non-fuel O & M Costs
O – Cost of Energy Not Served
j – Plant Number
t – Period Number
T - Planning Period

The model has the capability to optimize the selection of future generation plant technologies and plant sizes to meet the projected demand at the lowest cost. One main shortcoming of the software is the inadequate modelling of renewable energy, where CEB has the practice of adjusting the forecast demand to accommodate a pre-planned set of new renewable energy plants (both their energy and peak demand contributions).

As stated above, the WASP model fails to optimize the Renewable Energy technologies, since those are not dispatchable, and CEB shall explore new models to rectify this issue. CEB has already purchased OPTGEN software to rectify this issue, and thus this shortcoming can be rectified in future plans.

4. Demand Forecast

Based on econometric models, CEB has assumed a 5.0% energy demand growth and a 4.5% peak demand growth rate for the period 2018-2037 in the proposed LCLTGEP, while assuming the load factor to increase from current 66.3% to 72.4% by year 2030. As pointed out by few stakeholders, this assumption on load factor improvement resulting off-peak demand increase(45% of peak load in 2017 to 55% of peak demand in 2037), is unrealistic considering the past off-peak demand growth rates (2%-3% during last five years). The assumptions on the off-peak demand is critical if the resulting plan is to add more base load plants like coal power plants to system. With the absorption of Other Renewable Energy (ORE) sources to the system, CEB is assuming the off-peak demand to grow from the 1,100MW (current level) to about 1,700 MW by 2037, which leaves very little room for coal plant additions to the system (Existing coal plant capacity is 900MW). Even with the planned 600MW (2025 to 2027) pumped storage hydro plant, the situation does not improve substantially.

The network losses assumed in the demand forecast are higher than loss targets allowed by the Commission for 2016-2020, as stated in its Decision on Revenue Caps and Bulk Supply Tariff 2016-2020. However, considering its low impact on the generation plan (especially for the next decade), no changes to the demand is considered in the approval process.

5. Candidate Plants Sizes and Technologies

As stated above, the WASP software package used by CEB for the preparation of the plan seems not capable of optimizing the size and timing of ORE plant additions, hence they are added outside the optimization equation, after considering the specific costs, resource potential, development speed and other transmission constraints. Similarly, in case of large hydro plants, they are added to the plan (even when the specific costs are as high as 59.41 LKR/kWh in case of Ging gaga project), considering other economic benefits. CEB has used 150MW, 300MW and 600 MW plant capacity options for base load and intermittent duty needs of the system in future.

Coal fired plants (both subcritical and super critical plants) and Natural Gas (NG) fired combined cycle plants are having fairly close specific costs (Table 1) and thus require close attention. Both coal technologies assume using coal with lower quality (lower quality than that is used in the existing Puttlam coal plant), and thus potentially result in lower efficiencies and relatively higher adverse environmental impacts (high ash content, etc). Out of the two coal technologies, only 600 MW supercritical coal technology was considered after 2028 in the base case plan. This appears to be contradicting the least cost principles (if externality costs are not considered in the plan). One reason for the postponement of the super critical plant is the large unit size (600 MW) of the super critical plant, which may exceed the reserve margin criteria at first few years of the planning period. In addition the pump storage hydro plant is advanced to accommodate all the proposed coal plant developments in the proposed 'base' case.

Table 1: Specific cost at 80% plant factor

	CEB Base Case Prices	2016 Average Prices	2016 Q4 Average Prices
Fuel Price (USD/MMBtu)	10	8.36	9.09
150MW CCP – NG (USCts/kWh)	9.64	8.47	8.99
300MW CCP – NG (USCts/kWh)	9.59	8.42	8.94
Fuel Price (USD/MT)	69.7	80.9	110.5
300MW Coal (USCts/kWh)	7.20	7.62	8.75
600MW Coal (USCts/kWh)	7.31	7.70	8.74

In case of NG plants, only 300MW NG plants are considered for optimization in the 'No future coal power development' case, thus compromising on the least cost principles; considering 150MW NG option could reduce cost.

6. Economic Costs

The provisions of the Sri Lanka Electricity Act require minimization of **Economic Costs** in the planning process. In this context CEB has taken an effort to include border prices in to the planning process (i.e. excluding tax and other levies that distort prices). However, CEB has not considered few critical components of economic costs (most of which are outside the planning boundaries under the Planning Code); such as a) environmental externalities, b) local employment and other economic benefits of some technologies, c) lower currency risks attached to indigenous technologies d) pertinent cost reduction trends on certain ORE technologies e) variances in transmission costs due to locational advantages of certain technologies and f) indigenous sources that improve energy security. Most of these factors are difficult to quantify and thus highly debatable. However, when certain key options are very close and competing in terms of specific costs, these factors have to be considered at least qualitative basis. For example NG options and the subcritical coal options only differ by 0.8 USD Cents/ kWh, and in the planning process WASP starts to shift from coal to NG at about 1.2 USD Cents/kWh as additional externality cost for coal technologies, and thus the externality figures, etc can play a key role to differ the planning decisions.

7. Fuel Costs

CEB has based its fuel cost assumption from Lanka Coal (coal price for Puttlam coal plant), Ceylon Petroleum Corporation (oil prices) and Japanese Crude Cocktail (JCC) basis (NG prices). However, those costs are not fully reflected in the published Platts (Singapore), JCC and NEWC indexes (Australian coal index published by www.Globalcoal.com) at the end of the year 2016. During the presentation on the draft LCLTGEP by CEB, it was revealed that it relied on two year (2015 and 2016) average market prices for fuel cost estimates. Using such long term (2015 and 2016) average, when the current prices are substantially different (Table 2) appears to misrepresent the actual pricing at the time of preparation of the plan. Most notably, they have used the existing market prices for oil products (which is with taxes, etc and excessively higher than the border prices).

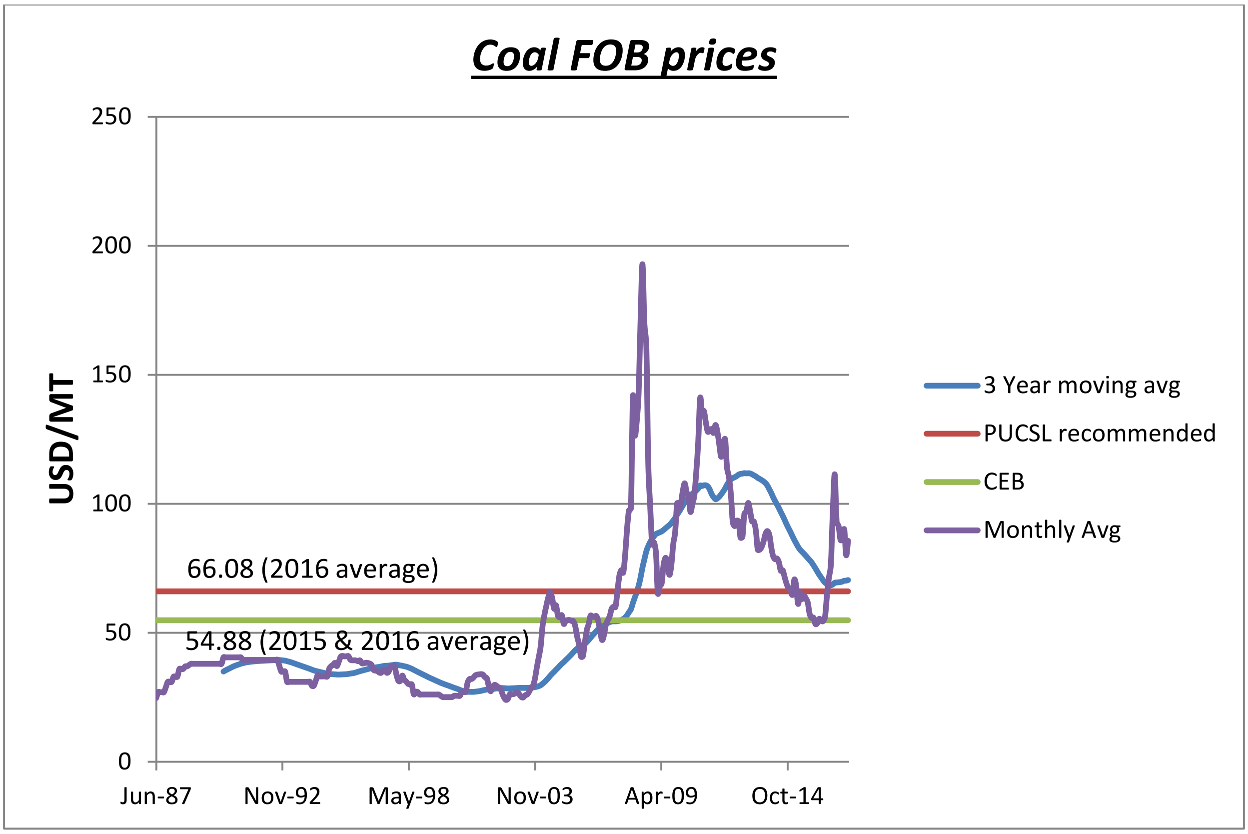
Table 2: Fuel Prices

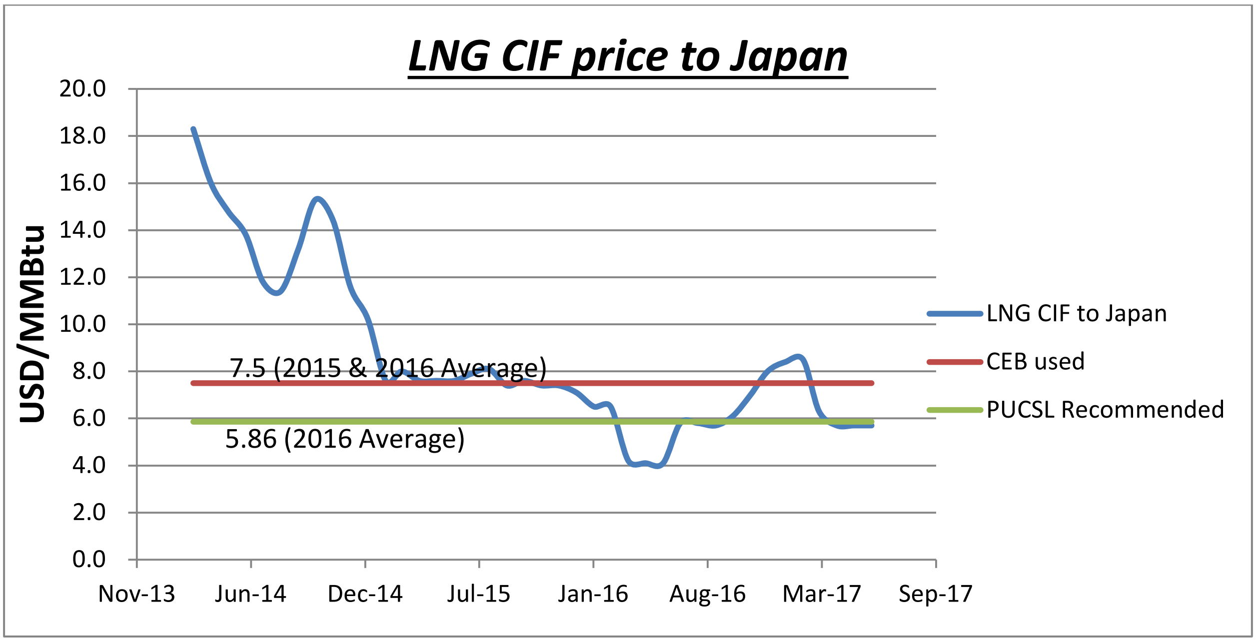
Fuel Cost	Coal $/MT	NG $/MMBtu	Auto Diesel $/bbl	Furnace Oil $/bbl
Value used in CEB draft plan	69.7	10.0	105.3	88.6
***Fuel prices (based on year 2016 average)**	81.0	8.4	53.6	46.5

*Sources for Fuel Costs:

- Coal: NEWC published by Globalcoal.com, unloading costs (14.82 $/MT) from Lanka Coal Ltd.
- Liquefied Natural Gas (LNG): JCC published by http://www.paj.gr.jp – Petroleum Association of Japan(PAJ) , 2.5 $/MMBtu taken as regasification and handling costs
- Oil : PLATTS, handling costs from Ceylon Petroleum Corporation

The PUCSL recommended fuel prices compared to long term price (spot LNG prices for Japan (METI website) and Australian coal prices (www.Indexmundi.com)) trends are shown below. The 2016 average fuel prices were recommended considering the recent step increase in coal prices and the recent gradual reduction in LNG prices. In case of coal; CEB coal price (FOB) assumption is clearly below the current price levels, as opposed to LNG; where CEB price is higher than the current price level. When comparing with the three year moving average prices for coal, assuming a price well below the moving average price (as proposed by CEB) is not recommended. In case of LNG, long term Asian market prices are not available and thus PUCSL recommended price (8.4 $/MMBtu) for NG which is similar to the recommendations made by Petroleum Resource Development Secretariat, (8.3 $/MMBtu) could be used.


Coal FOB prices
USD/MT
250
200
150
100
50
0
66.08 (2016 average)
54.88 (2015 & 2016 average)
Jun-87
Nov-92
May-98
Nov-03
Apr-09
Oct-14
3 Year moving avg
PUCSL recommended
CEB
Monthly Avg


LNG CIF price to Japan
USD/MMBtu
20.0
18.0
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
7.5 (2015 & 2016 Average)
5.86 (2016 Average)
Nov-13
Jun-14
Dec-14
Jul-15
Jan-16
Aug-16
Mar-17
Sep-17
LNG CIF to Japan
CEB used
PUCSL Recommended

8. Externality Cost

CEB has not included any externality cost in their scenarios of the draft LCLTGEP 2018-2037, thus as stressed by many stakeholders, does not reflect the true economic costs of power generation. Ideally, externalities depend heavily on the site specific environmental conditions, plant technology and fuel used. Thus site specific studies are required to reliably determine the figured on externality cost for a particular technology. Lack of such data in Sri Lankan context is a main shortcoming. Yet it is not recommended to fully ignore such costs, just because accurate specific data is not available. Several contemporary international studies are available and could be used in the analysis as scenarios, to arrive at a decision on the ultimate plan. In addition, a breakeven analysis could be carried out to work out the breakeven externality cost figure that would materially change the plant selection options in the software.

As shown in Table 3 below, there is a wide range for the externality costs for each fuel and related technology.

Table 3: Externality Costs

Study	Externality Cost (US Cents/kWh)		
	Coal	**NG**	**Oil**
Environmental Accounting for Pollution in the United States Economy - 2011	2.8	0.85	2.03
Health & Environmental Costs of Electricity Generation in Minnesota - 2010	6	0.8	
INCORPORATING SOCIAL AND ENVIRONMENTAL CONCERNS IN LONG TERM ELECTRICITY GENERATION EXPANSION PLANNING IN SRI LANKA	7.6	2.4	6.8
The True Cost of Electric Power - 2012	0.2-12.6	0.001-0.578	-
Environmental Externalities from Electric Power Generation, The Case of RCREEE Member States – 2013 (mean value**)**	5.4	1.7	5.9

As stated above, it is critical to note that a mere 1.2 US Cents/kWh difference in externality costs is sufficient to tilt a coal dominant generation plan to a NG dominated plan, and all the recent studies reveal higher gaps in externality costs (between coal and NG). CEB was asked to use the

‘Environmental Externalities from Electric Power Generation, The Case of RCREEE Member States – 2013 (**mean value**)’ as externality cost in the scenarios requested by the Commission, those results and the Commissions’ own analysis supports this conclusion. Considering site specific nature of externality costs; national adjustments for population density, national economic conditions, etc were not made.

9. CEB Base case

CEB recommends the following case as the preferred case for Commissions approval;

Table 4: Base Case plan submitted by CEB

YEAR	RENEWABLE ADDITIONS			THERML ADDITIONS	THERMAL RETIREMENTS
2018	Mini Hydro Biomass	15 MW 5 MW	Solar 160 MW	*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *150 MW Furnace Oil fired Power Plant **	**8x6.13 MW Asia Power**
2019	Major Hydro Mini Hydro Solar	*122 MW* 15 MW 95 MW	*(Uma Oya HPP)* Wind 50 MW Biomass 5 MW	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region+*	-
2020	Major Hydro	*35 MW*	*(Broadlands HPP)*	*1x35 MW Gas Turbine*	**6x5 MW Northern Power**
		15 MW	**(Thalpitigala HPP)**		
	Wind	*100 MW*	*(Mannar Wind Park)*		
	Mini Hydro	15 MW	Wind 120 MW		
	Solar	105 MW	Biomass 5 MW		
2021	Mini Hydro Solar	10 MW 55 MW	Wind 75 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	**4x17 MW Kelanitissa Gas Turbines**
	Major Hydro	*30 MW*	*(Moragolla HPP)*		

		20 MW	**(Seethawaka)**		
2022	**HPP)**	**20 MW**	**(Gin Ganga HPP)**		
	Mini Hydro	10 MW	Wind 50 MW		
	Solar	6 MW	Biomass 5 MW		
2023	Mini Hydro Solar	10 MW 55 MW	Wind 60 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2)*	**115 MW Gas Turbine**** **4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant**
2024	Mini Hydro Solar	10 MW 55 MW	Wind 45 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	**4x18 MW Sapugaskanda Diesel**
2025	Major Hydro Mini Hydro Solar	200 MW 10 MW 104 MW	(Pumped Storage Power Plant) Wind 85 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	**4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant**
2026	Major Hydro Mini Hydro Biomass	200 MW 10 MW 5 MW	(Pumped Storage Power Plant) Solar 55 MW	-	-
2027	Major Hydro Mini Hydro Solar	200 MW 10 MW 54 MW	(Pumped Storage Power Plant) Wind 25 MW Biomass 5 MW	-	-
2028	Mini Hydro Solar	10 MW 105 MW	Wind 45 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-

2029	Mini Hydro Solar	10 MW 54 MW	Wind 25 MW Biomass 5 MW	-	-
2030	Mini Hydro Solar	10 MW 55 MW	Wind 70 MW Biomass 5 MW		-
2031	Mini Hydro Solar	10 MW 54 MW	Wind 35 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-
2032	Mini Hydro Solar	10 MW 55 MW	Wind 45 MW	-	-
2033	Mini Hydro Solar	10 MW 54 MW	Wind 70 MW Biomass 5 MW	**2x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	**165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)**
2034	Mini Hydro Solar	10 MW 55 MW	Wind 70 MW		-
2035	Mini Hydro Solar	10 MW 54 MW	Wind 70 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	**300MW West Coast Combined Cycle Power Plant**
2036	Mini Hydro Solar	10 MW 55 MW	Wind 95 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant -Western Region**	-
2037	**Mini Hydro** **Solar**	**10 MW** **104 MW**	**Wind 70 MW** **Biomass 5 MW**	-	-

As indicated by many stakeholders, the amount of renewables included in the plan is inadequate to meet the policy targets set by the Government (latest target is 70% of generation by 2030). As per the generation mix forecast for the period 2018-2037, Renewable energy contribution remains within 40-60% of the total generation, while keeping Other Renewable Energy to 20% in 2020 and beyond. Also few stakeholders have raised the issue of keeping an additional 5% reserve margin to accommodate ORE in future, and thus increasing the Reserve Margin artificially (leading to higher investments), further network studies and use of new planning software is expected to rectify this issue. Overall, the allowed ORE additions (906MW within 2018-2022) in the plan, is high when the current total installation of 544 MW is considered and thus shall be further increased only after carrying out specific network integration studies.

CEB has selected (advanced) the Pumped storage power plant 2025 onwards, overlooking the least cost criterion to accommodate more coal power plants that require running round the clock (i.e. to increase the off peak demand artificially). In addition, the super critical coal technology, which is expensive than the subcritical coal technology is selected after year 2028, overlooking the least cost criterion. There were many stakeholder arguments for and against the predominantly coal based plan proposed by CEB, considering national policy targets, Paris Agreement and NDCs, low cost power to consumers, etc.

Also the LOLP value is well below the minimum requirement set by the planning Code (0.5%) for year 2019 and beyond, which indicates possible overinvestment in the plan.

10. Scenarios

As stated above commission requested several scenarios (fuel prices and externality figures) to check the robustness of the base case plan as submitted by the CEB, while the results show varying fuel and technology selection due to the cost parameter changes, the resent value of the objective function will show the exact difference in costs as a result of the changes in plant selection. Meanwhile, Commission also conducted its own scenario analysis and the results are shown below (Table 5).

The cumulative Present Value (PV) up to year 2037 was checked for the CEB base case plan at revised (2016 year average fuel prices) fuel prices and with externality costs (included as variable O & M cost). In addition a Revised case (at CEB base case demand forecast) that had forced conditions as listed below was studied at CEB proposed fuel prices, with externality costs and with revised fuel prices (both with and without externality costs). The results of the scenario (PV cost up to year 2037) is shown below. The PV cost shown here is excluding the PV cost of Other Renewable Energy which amounts to USD Mn 2,691 over the period 2018-2037.

Table 5: Cumulative PV up to year 2037

(USD Mn)

Scenario	PV Cost at CEB proposed fuel prices	PV Cost at 2016 year average fuel prices
CEB Base Case	11,877	10,900
CEB Base Case with Externalities	15,068	13,961
CEB No Further Coal Development Case	12,422	10,747
Revised Case	-	10,645
Revised Case with Externalities	-	12,833

CEB base case at revised fuel prices has a higher cumulative PV up to year 2037 (USD Mn 10,900) as compared to Revised case (USD Mn 10,645). Revised case contain only Gas Turbine and NG plants as future thermal plant additions, since coal with pumped storage hydro plant combination results in a higher PV.

Forced conditions of the revised case:

- 300MW Coal Plants (Sub Critical) were not considered for the optimization due to low efficiency and high emissions
- 600MW Super Critical Coal Plant option was allowed from 2025 onwards considering a feasible timeframe for implementation and Pump Storage Plant option was forced if Super Critical coal plants are selected
- 35MW Diesel Gas Turbines have been restricted for optimization after 2020 due to emission restrictions in the load centres

Table 6: Externality cost included in the analysis

Fuel	Coal	Natural Gas	Auto Diesel	Furnace Oil
Externality cost (US Cents/kWh)	3	0.49	4	4

Source for externality cost: Environmental Externalities from Electric Power Generation (The Case of RCREEE Member States) – September 2013 (minimum Value)

Considering the close price range and high impact of any externality costs, CEB base case was further analyzed with 2016 average fuel prices and externalities. When the 2016 average fuel prices are used the 'Revised' Case has a lower PV up to 2037 (USD Mn 10,645) as compared to CEB base case with 2016 average fuel prices (USD Mn 10,900), and when externalities are considered, the Revised case is the least cost with PV USD MN 12,833 up to year 2037. Revised case has no further coal plant additions in the planning horizon (2018-2037)

Thus the 'Revised' case (where supercritical coal plants are not selected) is the lowest cost at the recommended fuel prices by the Commission and if externality (damage) costs are included that case clearly have the Least Economic Cost and thus in terms of Section 43 of the Sri Lanka Electricity Act No. 20 of 2009 as amended by section 13 of Sri Lanka Electricity (amendment) Act No. 31 of 2013, 'Revised' case shall be selected.

11. Energy mix considerations

Sri Lanka has built one coal power station (Norachcholai 900 MW) and relies on it to supply about 40% of the current demand. Also Natural Gas deposits have been discovered in the North- Western sea area of the country and any development of that resource would depend heavily on the prospective demand from the power sector. Anyhow, coal is expected to remain a main source of energy till 2030 (where it will still supply about 20% of the demand), even without any further coal plant development. The assumptions on the externality costs shall be further validated with site/ country specific studies as well.

12. Decision on LCLTGEP 2018-2037

Section 43 of the Sri Lanka Electricity Act No. 20 of 2009 as amended by section 13 of Sri Lanka Electricity (amendment) Act No. 31 of 2013, and the current fuel price trends, Commission decided to use one year (2016) average fuel prices and include externality costs (Table 6) in the variable O&M cost of the power plants to arrive at the plan with least economic costs. The approved Generation Expansion plan for the period 2018-2037 is given in ***Table 7***.

The Transmission Licensee (CEB) is hereby directed to commence procurement process as per the provisions of Section 43 of the Sri Lanka Electricity Act No. 20 of 2009 as amended by section 13 of Sri Lanka Electricity (amendment) Act No. 31 of 2013, for the new plants within the period 2018-2028 and to conduct relevant network studies, and to revisit and refine the input parameters including the following, when preparing the LCLTGEP 2020-2039 that is to be submitted for Commissions' approval on or before 30th April 2019.

- Demand forecast (specially the off peak demand and load factor)
- Investment plan with ORE absorption levels to achieve 60% of electricity generation from Renewable energy sources (including Large Hydro plants) by year 2030.
- Externality costs of generating options; country and location specific studies
- Adhering the network loss targets set by the Commission

Table 7: Approved LCLTGEP 2018-2037

YEAR	RENEWABLE ADDITIONS			THERMAL ADDITIONS	THERMAL RETIREMENTS
2018	Mini Hydro Biomass	15 MW 5 MW	Solar 160 MW	_100 MW Furnace Oil fired Power Plant * 70 MW Furnace Oil fired Power Plant * 150 MW Furnace Oil fired Power Plant *_	**8x6.13 MW Asia Power**
2019	Major Hydro Mini Hydro Solar	_122 MW_ 15 MW 95 MW	_(Uma Oya HPP)_ Wind 50 MW Biomass 5 MW	_2x35 MW Gas Turbine_ _1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region_$^{+}$	-
2020	Major Hydro	_35 MW_	_(Broadlands HPP)_	_1x35 MW Gas Turbine_	**6x5 MW Northern Power**
		15 MW	**(Thalpitigala HPP)**		
	Wind	_100 MW_	_(Mannar Wind Park)_		
	Mini Hydro	15 MW	Wind 120 MW		
	Solar	105 MW	Biomass 5 MW		
2021	Mini Hydro Solar	10 MW 55 MW	Wind 75 MW Biomass 5 MW	**1x150 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	**4x17 MW Kelanitissa Gas Turbines**
2022	Major Hydro	_30 MW_	_(Moragolla HPP)_		
		20 MW	**(Seethawaka HPP)**		
		20 MW	**(Gin Ganga HPP)**		
	Mini Hydro	10 MW	Wind 50 MW		

	Solar	6 MW	Biomass 5 MW		
2023	Mini Hydro Solar	10 MW 55 MW	Wind 60 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant** *163 MW Combined Cycle Power Plant (KPS–2)*	**115 MW Gas Turbine**** **4x9 MW Sapugaskanda Diesel Ext.**** **163 MW Sojitz Kelanitissa Combined Cycle Plant**
2024	Mini Hydro Solar	10 MW 55 MW	Wind 45 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	**4x18 MW Sapugaskanda Diesel**
2025	Mini Hydro Solar	10 MW 104 MW	Wind 85 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	**4x9 MW Sapugaskanda Diesel Ext.** **4x15 MW CEB Barge Power Plant**
2026	Mini Hydro Biomass	10 MW 5 MW	Solar 55 MW	**1x150 MW Natural Gas fired Combined Cycle Power Plant**	-
2027	Mini Hydro Solar	10 MW 54 MW	Wind 25 MW Biomass 5 MW	**1x150 MW Natural Gas fired Combined Cycle Power Plant**	-
2028	Mini Hydro Solar	10 MW 105 MW	Wind 45 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-
2029	Mini Hydro Solar	10 MW 54 MW	Wind 25 MW Biomass 5 MW	**1x150 MW Natural Gas fired Combined Cycle Power Plant**	-
2030	Mini Hydro Solar	10 MW 55 MW	Wind 70 MW Biomass 5 MW	**1x150 MW Natural Gas fired Combined Cycle Power Plant**	-
2031	Mini Hydro Solar	10 MW 54 MW	Wind 35 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-
2032	Mini Hydro Solar	10 MW 55 MW	Wind 45 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-

2033	Mini Hydro Solar	10 MW 54 MW	Wind 70 MW Biomass 5 MW	**2x300 MW Natural Gas fired Combined Cycle Power Plants**	**165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)**
2034	Mini Hydro Solar	10 MW 55 MW	Wind 70 MW	**1x150 MW Natural Gas fired Combined Cycle Power Plant**	-
2035	Mini Hydro Solar	10 MW 54 MW	Wind 70 MW Biomass 5 MW	**2x300 MW Natural Gas fired Combined Cycle Power Plant**	**300MW West Coast Combined Cycle Power Plant**
2036	Mini Hydro Solar	10 MW 55 MW	Wind 95 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-
2037	Mini Hydro Solar	10 MW 104 MW	Wind 70 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-

Annexure

Summary of the comments received at Stakeholder Consultations and the Commission's Responses

Dear Stakeholder, we value and appreciate your effort in participating in the public consultation process of Least Cost Long Term Generation Expansion Plan (LCLTGEP 2018-37). We have strongly considered the comments, proposals and suggestions that you have made and revised the submitted plan accommodating major changes given the limited time phase. However, some comments, proposals and suggestions will be incorporated in developing the next LCLTGEP due to time constraints in approving the LCLTGEP 2018-37 for fast implementation.

Summarized Comment	Commenter(s)	Response of the Commission
Share of renewable energy considered in this plan is not adequate **- Non adherence to government policies/ Commitments under Paris Agreement on Climate Change/ targets under Surya Bala Sangramaya**	1. Dr. Anil Cabraal 2. Dr. Janaka Ratnasiri 3. Environmental Foundation Limited 4. Mr. K C Somaratne 5. Ms. Neela Marikkar 6. Mr. Parakrama Jayasinghe 7. Small Hydro Power Developers Association 8. Solar Industries Association 9. Mr. Vidhura Ralapanawa 10. Prof. Praveen Aberatne 11. Mr. Mayura Botheju 12. SLYCAN Trust 13. Mr Gnanalingam 14. Strategic Enterprises Management Agency	The Commission has noted that the total renewable energy share of approved plan (including large hydro) is expected to be within 35 percent to 50 percent (depending on hydro condition) during the planning period of 2018-2037. The Commission has also noted that the plan is not fully complied with the national renewable targets (eg. Paris Agreement and Surya Bala Sangamaya), as other renewable energy (ORE) integration capability of the system is limited by the stability, operational and economic constraints. CEB has projected Other Renewable Energy (ORE) according to the study of "Integration of Renewable Based generation into Sri Lankan Grid 2017-2028". As per the study, optimum ORE capacity has been integrated into the system up to 2028 (20% energy share) and continued throughout the planning horizon. The Commission noted that the set targets under Soorya Bala Sangramaya for the year 2020 (200MW) has been considered in preparing the plan, but the target for

	15. Mr. Clifford Regis 16. Renewable Energy Developers Association (REDA) 17. Mr. Nimal Liyanage	the year 2025 (1000MW) has not been considered in the plan. Therefore the Commission will strictly consider the observation to be incorporated in approving future generation plans.
In order to identify true the economic cost, costs of externalities should also be considered. -Impact of pollutants other than gases also should be considered. -Identify Sri Lanka specific values prior to next planning cycle	1. Dr. Anil Cabraal 2. Mr. Hasala Dharmawardhana 3. Mr. Ranjith Vithanage 4. Environmental Foundation Limited 5. Dr. Janaka Ratnasiri 6. Ms. Neela Marikkar 7. Mr. Parakrama Jayasinghe 8. Prof. Praveen Aberatne 9. Mr. Nimal Liyanage	The Commission noted the comment with appreciation and incorporated in the approved plan. The approved LCLTGEP 2018 -37 considered the externality costs. Reference for costs of externalities: The Case of RCREEE Member States September 2013. At the same time, the Commission agrees that it is required to consider location specific damage costs. But, such studies are not available locally at present and time limitations do not allow the Commission to do fresh studies at this point. Thus, the Commission will discuss with the CEB to develop studies to identify values that are most relevant to Sri Lanka to be incorporated in future LCLTGEPs.
Cost of renewable based generation become low cost compared to imported fuel based generation due to the impact of rupee depreciation	1. Ms. Neela Marikkar 2. Mr. Parakrama Jayasinghe 3. Small Hydro Power Deve. 4. Mr. Vidhura Ralapanawa 5. Mr. Mayura Botheju 6. Mr. Nimal Liyanage	The Commission agrees. The approved plan has not considered the impact of rupee depreciation due to limitation of time as it requires lengthy studies. The Commission has already initiated to revise the planning code and will consider the mentioned comment when revising the code. The future generation plans would be prepared adhering to the new planning code.
WASP is designed for planning base load plants and not suitable to analyze new renewable technologies and hence outdated	1. Dr Anil Cabraal 2. Mr. Parakrama Jayasinghe 3. Mr. Vidhura Ralapanawa 4. Strategic Enterprise Management Agency	The Commission agrees that the present planning software has its own limitations on modelling renewable energy and transmission costs. CEB has already communicated to the Commission that they are in the process of building capacity for the staff to use the OptGen software in next generation planning. The latest software allows CEB in modelling variable renewable energy as

		well as transmission costs. The Commission encourages the licensee to adopt and use the best practices in the world to develop the future LCLTGEPs.
Generation Planning Code in the Grid Code is no longer appropriate in preparing the Long-Term Generation Expansion Plan 2018-2037 as it bound by the limitations of WASP.	1. Dr. Anil Cabraal 2. Mr. Parakrama Jayasinghe 3. Mr. Vidhura Ralapanawa 4. SLYCAN Trust	Noted The Commission has already initiated to revise the planning code and will consider the mentioned comment when revising the code. The future generation plans would be prepared adhering to the new planning code.
Problems in fuel prices used for the preparation of the draft plan. -Different from international price indices -Same reference period should be used for all fuel types	1. SC 2. Mr. Vidura ralapanawa	The Commission agrees with your observation. The approved LCLTGEP considered average fuel prices of the year 2016 from the sources below; -Coal price (81.0 USD/MT); NEWC as published by Globalcoal.com + (shipping+ insurance and lightering costs) as invoiced by Lanka Coal for the respective period -Oil Price(LSFO:46.5USD/bbl, diesel : 53.6USD/bbl); Singapore platts + freight and terminal charges from CPC/CPSTL for the respective period -NG price(8.4 USD/MMBtu); 14% of Petroleum Association of Japan, monthly crude oil import cost for the respective period + USD 2.5/MMBtu terminal costs Fuel prices will be approved by the Commission at input data consultation prior to prepare future generation plans.
Coal is the cheapest option and are required for economic development	1. Eng M V R Perera 2. Mr. W A D R Jayawardene 3. Mr. Gayan Heenatiyana	Noted The approved LCLTGEP 2018 -37 considered the externality costs (social and environment costs) and power plants qualify according to the least cost principals were approved.
Cancellation of Sampur Coal plant is costly and technically unsound	1. Prof. Kumar David	Noted. Cancellation of Sampur Coal power plant was a decision by the Government.

decision. **Propose to go ahead with proposed coal plants but gradually shift to other technologies**		The approved LCLTGEP 2018 -37 considered the externality costs (social and environment costs) and power plants qualify according to the least cost principals were approved.
The plan underestimates the expected cost reductions in renewable technology	1. Dr. Anil Cabraal 2. Mr. Parakrama Jayasinghe 3. Mr. Vidhura Ralapanawa	The approved plan has considered capital cost reduction for solar plants only.(initial 1400USD/KW gradually reduced to 900USD/KW by 2025). The Commission will communicate to CEB to consider cost reduction trends of other renewables technologies also in future generation plans
Consideration of technological advances in renewable technologies in the plan **-smart networks,** **-battery storage systems** **-vehicle charging** **-smart grids to mitigate stability issues**	1. Solar Industries Association 2. Mr. Vidhura Ralapanawa 3. Mr. Mayura Botheju 4. Mr. Gananalingam 5. Mr. Anusha De Silva 6. Dr. Lilantha Samaranayeke 7. Mr. E M Piyasena	Noted The mentioned technologies have not been considered in the present plan other than pump storage hydro power plants. The Commission take the observation into very serious consideration and discuss with CEB on how to incorporate the developing technologies in future generation plans.
Plan has not considered Demand Side Management (DSM) initiatives of the government.	1. Dr. Anil Cabraal 2. Environmental Foundation Limited 3. Mr. Vidhura Ralapanawa 4. Institute of Engineers Sri Lanka 5. Mr Parakrama Jayasinghe 6. Mr. E M Piyasena	Noted The Commission noted that the demand reduction targets based on the Demand Side Management initiatives are currently being identified by the Presidential Task Force and the Sustainable Energy Authority. The Commision will communicate to CEB and SEA to take the required actions to incorporate the impact of DSM in next generation plan.
Consideration of availability of Domestic Natural Gas in the plan	1. Environmental Foundation Limited 2. Petroleum Resources Development Secretariat 3. Mr Gayan Heenatiyana	Noted . The approved plan includes Natural gas fired power plants, hence, the plan provides more opportunity for utilization of domestic natural gas.

		At the same time, Petroleum Resources Development Secretariat pointed out about the availability of domestic natural gas by 2021-23, subjected to finding an investor by 2018 at the public consultation held by the Commission The Commission will communicate to CEB to conduct a scenario analysis considering the availability of domestic natural gas for future generation plans.
If high cost renewables are added instead of low cost power plants, the government should compensate for the additional cost.	1. Mr. Asela Pathberiya 2. Mr. Sampath Thilakarathne	In line with the provision of the Sri Lanka Electricity Act, the Government has the power to decide on the compensation if relevant.
Solar plants generate energy only in day hours and this will cause even more sharp night peak.	Mr. Dammika Kulathilaka	Noted Please note that the day peak demand of the system is increasing at a higher rate than the night peak demand according to the proposed plan. It is expected that the day peak will exceed the night peak in the year 2030. Hence, having more solar plants will provide a larger portion of daily energy requirements, whereas hydro plants can be used for night peak. The battery storage option can also be considered as a solution for sharp night peak resulted by solar generation, in future plans with decreasing costs.
Even though border prices are used for the preparation of the plan, actual dispatch is conducted based on market prices of the fuel	1. Mr. Hasala Dharmawar. 2. Sri Lanka Energy Managers Association	We agree that at present the merit order dispatch is based on the market prices of fuel. The Commission will consider issuing a regulatory tool to ensure that the fuel prices consider in merit order dispatch, do not vary from the border prices of fuel used in preparation of the plan.
Transmission cost also should be considered, when least cost is identified.	1. Dr. Anil Cabraal 2. SC	The plan has not considered the cost of transmission lines due to the limitation of the software that used to develop the plan. However, the Commission encourage CEB to adopt best practices in the world to develop the future plans and the issue will be addressed in the future plans.

Pessimistic Network losses forecast - Network loss in 2016 is 9.64% the forecast for 2042 is 9% -Not complied with loss targets issued by PUCSL until 2020	1. Sri Lanka Energy Managers Association 2. Dr. Tilak Siyamabalapitiya	Noted The Commission has issued loss targets to CEB for next 4 years (7.5% by 2020) but it is noted that it has not been considered. The Commission will strictly consider this in future generation plans.
Sri Lanka being a small country with a high population density, a nuclear plant will not be socially acceptable	1. Dr. Anil Cabraal 2. Dr. Janaka Ratnasiri 3. Mr. Nimal Liyanage	The Commission appreciate these observations. Nuclear power is considered only as a potential thermal generation option in the study. However, base case plan or the approved plan does not include any nuclear power plants.
Milestones to be achieved to develop Nuclear power - No valid logic behind delaying Nuclear plants until 2030	1. Atomic Energy Board 2. Dr. Lilantha Samaranayeke	The Commission appreciate these observations. The decision to proceed with nuclear power plants, will depend on the government policy on Nuclear based generation.
Basis for having 5% amount of extra spinning capacity per MW of ORE, is not clear.	1. Mr. Hasala Dharmawar. 2. Dr. Tilak Siyambalapitiya	Noted. Additional spinning capacity for renewable energy considers in this plan, (5%) was determined based on the outcome of frequency stability studies in Renewable energy integration study “Integration of Renewable Base Generation in to Sri Lankan Grid 2017-2018"
Pollution and adverse effects to biodiversity by Mini-hydro plants, small/mega solar plants and wind plants cannot be ignored.	1. Environmental Foundation Limited 2. Rainforest Protectors of Sri Lanka	Noted. The Commission will communicate with Central Environmental Authority (CEA) and SEA to ensure required EIA is conducted prior to implementation of other renewable plants and also to ensure post monitoring requirements in the EIA are met during the operation of the plant.
The CEB is seeking, Variable Renewable Energy curtailment rights. This is not acceptable	1. Dr. Anil Cabraal 2. Mr. Mayura Botheju	The Commission appreciate these observations. Approved plan will include only least cost plants. LNG plants will provide additional flexibility of operating in lower capacity factor and hence, will reduce the

- due to asymmetry of negotiating power between CEB and the variable renewable energy developers. -Nowhere in the world renewable energy is curtailed to generate from fossil fuel		requirements for renewable curtailments, compared to coal plants. However, when intermittent generation capacity is high, in certain instances it is required to limit the power output of intermittent sources to avoid overloading of the Transmission System. This is an accepted international practice. However, agreements with the power producers and CEB, including terms for procedures and compensation for curtailments will be established prior to exercising any curtailment rights.
Coal plants should not be considered, when Paris Agreement specifically, noted that Sri Lanka cancelled plans to build 4700 MW of coal-fired power generation.	1. Dr. Anil Cabraal 2. Mr. Ranjith Vithanage	The approved LCLTGEP 2018 -37 considered the externality costs (social and environment costs) and power plants qualify according to the least cost principals were approved. Please note that the Paris Agreement specifies that Sri Lanka has taken initiatives to eliminate introducing coal plants from 2030.
Timely implementation of power plants should be ensured.	1. Dr. Tilak Siyamabalapitiya 2. Petroleum Resources Development Secretariat 3. Mr. Dammika Kulathilaka	Noted The Commission will communicate to CEB to submit implementation plans for the first 10 years of the approved plan, with millstones. Please note that CEB has already submitted the plans for the base case in the draft plan. The commission expects to monitor the progress regularly against the submitted milestones and take remedial actions if any delays in implementation are observed.
Coal Jetty, harbour and fuel transport cost should be considered in the plan.	1. Dr. Anil Cabraal 2. Mr. Vidura Ralapanawa	The approved LCLTGEP 2018-37 has considered the costs of coal harbour, jetty and coal transport infrastructure in the decision given.
Slow implementation of government initiatives on solar roof top capacity additions / proposals to	3. Rainforest Protectors of Sri Lanka 4. Mr. Bandula Unamboowa 5. Dr. U Pethiyagoda	Noted. Please note that the CEB and LECO have been already in the process of providing concessionary loans for rooftop solar installation.

expedite rooftop solar plants.		The Commission has issued a directive to CEB, to provide grid connections to rooftop solar in 2 weeks and also the exempted solar rooftop consumers from requiring licensees for selling electricity.
Need to consider the scarcity of land especially in the urban areas, when development of power plants (eg. large scale solar)	Dr. Lalantha Samaranayeke	The Commission agrees. The Commission will consider conducting an independent study in future, regarding land allocation for power projects in long term.
Requirement for proper disposal mechanisms and destinations for thrown out solar panels will have to be planned now.	Dr. Lilantha Samaranayeke	The Commission agrees. The plan has not considered the disposal Requirements of solar plants. The Commission will communicate with SEA and CEA to further study the requirement of a disposal mechanism for solar plants
Consideration procurement of electricity through interconnectors	Mr. Gamini S	Noted Governments of India and Sri Lanka signed a Memorandum of Understanding (MOU) in 2010 to conduct a feasibility study on inter-connection of the electricity grids of the two countries. This feasibility study was carried by CEB jointly with Power Grid Corporation Indian Limited (POWERGRID) with the main objective to provide the necessary recommendations for implementation of the 1000MW HVDC interconnection project. However, this scenario was not considered in the present generation plan as the change in power systems are yet to study. This scenario can be incorporated into future plans, once the feasibility of such option is identified in the updated studies.
Require identification of Policy Cost	Strategic Enterprise Management Agency	Noted The observation will be incorporated for the revised planning code.

Different plan is proposed.	Mr. Imran Ansari	The proposed changes are not considered in the approved plan, as the basis of the changes was not provided.
New technology for wind based energy	Mr. S Karunadasa	The proposed technology is not considered in the approved plan, as sufficient information regarding the technology is not available.
Proposal for LNG supply to Sri Lanka	Brightstar	The proposal is not considered in the approved plan, as this has no direct relevance to the approval process of the plan.

Commenters on Draft Plan

1. Dr. Anil Cabraal
2. Mr. Asela Pathberiya
3. Mr. Dasun Andarage
4. Mr. Hasala Dharmawardene
5. Mr. Imran Ansari
6. Mr. Ranjith Vithanage-National Movement for Consumer Rights Protection
7. Mr. Sampath Thilakarathne
8. SC
9. Sri Lanka Energy Mangers Association
10. Environmental Foundation (Guarantee) Limited (EFL)
11. Dr. Janaka Ratnasiri
12. Mr. K C Somaratne
13. Ms. Neela Marikkar
14. Mr. Parakrama Jayasinghe (Bio -Energy Association)
15. Petroleum Resources Development Secretariat (PRDS)
16. Small Hydro Power Developers Association
17. Solar Industries Association
18. Rainforest Protectors of Sri Lanka
19. Dr. Tilak Siyambalapitiya
20. Mr. Vidhura Ralapanawa
21. Mr. Anusha De Silva
22. Mr. Dhammika Kulathilaka
23. Prof. Praveen Aberatne
24. Dr. Lilantha Samaranayeke
25. Mr. Mayura Botheju
26. SLYCAN Trust
27. Atomic Energy Board
28. Mr. Bandula Unamboowa
29. Mr. Gayan Heenatiyana
30. Mr. W A D R Jayawardene
31. Mr. K.Gnanalingam
32. Mr. S Karunadasa
33. Brightstar
34. Strategic Enterprise Management Agency (SEMA)
35. Institute of Engineers Sri Lanka
36. Mr. E M Piyasena

Commenters on Input Data

1. Dr. Tilak Siyamabalapitiya
2. Gayan Heenatiyana
3. Gamini Samarasinghe
4. Mr. Clifford Regis
5. Prof. Kumar David
6. Dr U.Pethiyagoda.
7. Mr. Anil Cabraal
8. Environmental Foundation (Guarantee) Limited(EFL)
9. Renewable Energy Developers Association (REDA)
10. Nimal Liyanage
11. SC
12. Mr. Vidura Ralapanawe
13. Eng. M V R Perera