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CEYLON ELECTRICITY BOARD

PUBLIC UTILITIES COMMISSION OF SRI LANKA
22 NOV 2024
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Your ref: PUC/LIC/2024/CEB/38 My Ref: GP/CE/EXPAN-2023 Date: November 21, 2024

The Director General
Public Utilities Commission of Sri Lanka
6th Floor, BOC Merchant Tower
No.28, St, Michael's Road,
Colombo 3.

Submission of the Draft Long Term Generation Expansion Plan 2025-2044

We write in reference to your letter No. PUC/LIC/2024/CEB/38 dated November 13, 2024, requesting information/clarifications on the Draft Long Term Generation Expansion Plan 2025-2044.

Accordingly, kindly note that the requested information/clarifications in the above referred letter is attached herewith (Annex 1).

Eng. K. G. R. F. Comester
General Manager

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General Manager
Ceylon Electricity Board

Authorized officer for Licenses EL/T/09-002

Annex 1

1. **Reason for using capital and O&M costs for candidate thermal and ORE technologies different to the input submitted to the Commission with the letter (Ref: GP/CE/EXPAN-2023) dated 17 November 2023. Provide the economic indicators/factors considered if these costs have been escalated.**

According to the Grid Code all costs & prices used in planning studies shall reflect the economic conditions as on 1st January of the current year. For LTGEP 2025 2044 the current year is 2024 but the time of submitting input data the latest data available was for year 2021/2022. Hence it is required to escalate the costs to reflect 2024 (2023 end) values.

As already informed in the letter GP/CE/EXPAN-2023 dated 17 November 2023, the costs were escalated based on local & foreign economic indicators shown below.

Assumption: Local to foreign portion of the cost is 20%:80%

Indicator	Value
CCPI 2023	17.4
CCPI 2022	46.4
Exchange Rate 2023	326.74
Exchange Rate 2022	363.16
Exchange Rate 2021	201.4
GDP Deflator – Advanced Economies 2023	3.9
GDP Deflator – Advanced Economies 2022	5.4

2. **Reason for using higher capital cost for Battery Energy Storage Systems (BESS) compared to the cost applied in the previous plan (LTGEP 2023-2042) despite the global downward trend in BESS prices.**

In LTGEP 2023 2042 BESS costs were derived based on 2021 Annual Technology Baseline (ATB), National Renewable Energy Laboratory. For LTGEP 2025 2044 the source was changed to GenCost 2022-23, Final Report, Australia's National Science Agency, CSIRO, July 2023.

Following is the comparison of the capital cost of BESS in publications of GenCost 2022-23 and the parallel ATB report, 2023 ATB.

BESS Type	2023 ATB (US$/kW)	GenCost 2022-23 (US$/kW)
2 hr	1,060	875
4 hr	1,784	1,420
8 hr	3,232	2,523

It can be observed that 2023 ATB values for 4 hr BESS is 34% higher than the LTGEP 2023-2042 value of 1330 $/kW, which is a significant increase. Furthermore, ATB costs are approximately 21-28% higher than the respective GenCost costs. Hence, we have taken the GenCost 2022-23 data for LTGEP 2025-2044 which only indicates a 7% increase from the previous LTGEP value and escalated the value for year 2024.

Hence ,it is evident at the time of preparation of the plan, the available published sources had an increase in the capital cost of BESS systems. The same is reflected in LTGEP 2025-2044.

3. **Reason for the delay in commission the first Pumped Storage Power Plant from 2029 to 2034, as compared to the plant schedule of the LTGEP 2023-2042.**

The Detailed feasibility study of the most promising candidate site (Maha Oya Project) was concluded in year 2024. Given the time frame for next pre construction activities including funding and financing , environmental and other approvals, resettlement plans the project will have high lead time. Furthermore, the planned construction time period is 5 years. Considering the required pre construction and construction activities, the most optimistic earliest availability of the PSPP shall be beyond year 2032.

In addition, due to the substantial demand drop after the economic recession in recent years, there is a 4-year lag in demand compared to the previous LTGEP. Hence the renewable energy additions and their corresponding curtailments are reduced which results in PSPP requirement being less viable before 2034.

4. **Reason for exclusion of the Wewathenna Pumped Storage (2 x 350MW) from the base case which was included in the plant schedule of the LTGEP 2023-2042.**

In LTGEP 2023-2042, pumped storage power plant candidate details were based on data available from "Development Planning on Optimal Power Generation for Peak power Demand in Sri Lanka (2015)" & Project on Electricity Sector Master Plan Study (2018). However, to select the most promising site for first development, both sites were evaluated with detailed prefeasibility study in 2023 with ADB assistance. Subsequently, during the pre-feasibility study on pumped storage hydropower project (2023), Wewatenna potential was reduced from 1400 MW to 700 MW and considering the actual geological conditions at the project site. Hence the construction cost (USD/kW) had also increased, which resulted in lower priority among available sites. Therefore 600 MW Maha site was selected as the first site to develop a PSPP in Sri Lanka and a feasibility study (2024) was carried out on the site.

The Wewathenna Pumped Storage (2 x 350 MW) has been considered as candidate for selection in the base case after the development of (3 x 200 MW) Maha Oya Pumped Storage but is not selected due to the higher cost compared with other alternative options.

5. **Reason for the significant increase in the capital costs of the Wewathenna and Maha Oya Pumped Storage Plants, with increments of 167% and 33% respectively compared to the cost applied in the LTGEP 2023-2042.**

As explained in clarification 4, the cost figures were updated in the recently completed pre-feasibility study with ADB assistance for both sites and respective cost have increased pertaining to updated site conditions and global equipment and labor prices.

6. **Reason for the delay in implementing the HVDC interconnection from 2034 to 2039, as compared to the schedule in the HVDC Interconnection scenario in the LTGEP 2023-2042.**

During the recent DPR study conducted with POWER GRID India, the previous overhead sea cable design was changed to underground sea cable design, which contributed to a high increase in capital cost. Hence the capital cost of the project has increased to 1,225 million USD. Due to the high investment requirement the project is pushed to later part of the horizon.

Since the development of BESS and PSPP (Maha) provides sufficient storage requirements to satisfy the policy targets, further large-scale investment on energy storage or power exchange are not required to cater the projected demand up to year 2039. However, the proposed interconnection at a cost of 1,225 million USD becomes more viable than developing the alternate PSPP site (Wewatenna) or BESS as evident in Scenario 1 and 2. An advancement of the HVDC interconnection is observed up to year 2037 if renewable energy absorption is increased above 70% as observed in scenario 4, however this scenario is expensive than the base case scenario.

7. Has the capital cost for the LNG infrastructure been included in the capital cost of the natural gas candidate technologies?

No. It is included as capital cost to be incurred in the middle of year 2027 for all scenarios.

The cost details related to LNG Infrastructure with the escalations are as follows. CEB shall take necessary action to include this in chapter 4 of the amended report.

	CAPEX (2024 base) (Million USD) ***Used in the Plan***
FSRU	250
Mooring Facility	34
Pipeline (offshore and Onshore)	40
Total	324

8. What is the basis for the net generation forecast of 21,444 GWh in 2025 and the forecasted 5-year average net generation growth rate of 5.3%, as per the time trend demand forecast (Table A3.3), given the negative average net generation growth rates of -3.2% and -0.4% for the last 3 and 5 years, respectively (Table 3.1)?

Long Term Time Trend models generally assume constant growth rate which smooths out data over time. However, external factors such as the pandemic and economic downturns have indeed caused irregularities in recent years.

Model is derived based on following equation

Demand = a (1+g)^t

Where

a : Initial value or the base demand at the starting time. It represents the demand level when t=0.

g : Constant growth rate which reflects the average annual growth in demand over the period of the data set assuming that demand grows at a fixed percentage each year

t : time in years

For the linearized equation:

$$Ln(Demand) = Ln\ (a) + t\ .\ Ln(1+g)$$

Using demand data from 1998 to 2022 (25 years), a constant growth rate (g) of 5.3% is derived, through the regression of the natural log of demand (dependent variable) on time (independent variable). This linearized form allows the growth rate to be estimated more accurately, considering historical trends that are relatively free of random fluctuations or anomalies such as pandemic and economic downturn.

Hence as explained above random variations such as the reduction in the demand in the recent years have been smoothen out from this model.

Please also note that, Table 3.1 depicts the electricity sales excluding self-consumption and energy not served. However, in the demand forecasting process adjusted demand is considered.

9. What are the identified six candidate sites for the nuclear power plant?

According to the latest update by the time LTGEP 2025 – 2044 submitted; six sites were identified as most suitable sites for nuclear power development. However, as per the latest developments of the studies the number of potential sites has been reduced to three after further screening. Presently finalized sites are

i. Pullmoddai
ii. Mullativu site-near Phara ship
iii. Kal-Aru site near Mannar

Please note that this will be updated in LTGEP as appropriately.

10. Is the implementation of HVDC interconnection between India - Sri Lanka and Pumped Storage Power Plant a mandatory prerequisite before the integration of the nuclear power plant?

Yes, it is mandatory to have the HVDC interconnection as well as the pumped storage units implanted to allow safe operation particularly during off-peak conditions. In addition to the to operate in high inverter based periods, synchronous condensers and fast frequency response services shall be required.

11. Reason for not considering the integrated storage solution coupled with large scale fully facilitated solar PV parks (Grid Connected Fully Facilitated Solar with BESS), which was included in the plant schedule of the LTGEP 2023-2042.

In this iteration there is no restriction imposed on the development of BESS as either stand alone or coupled with solar parks. It is to be decided at the procurement stage depending on the viability of site conditions and system requirements. The co-location of BESS with solar parks can have capital cost savings.

However, it is important to unbundle the operation of BESS from the operation of solar parks. All BESS facilities are required to operate separately on dispatch instructions as requested from National System Control Centre. They are required to supply energy in any timeslots as requested by the dispatch instructions in addition to providing fast frequency response services throughout the life cycles.

12. **What Demand Side Management (DSM) measures are recommended for implementation by the distribution licensees as per the DSM implementation plan?**

Implementation of DSM measures mainly depends on the customer and the utility has minimal control over it. Initiatives in the DSM implementation plan are mainly managed by the SEA as the agency responsible for DSM implementation. How ever the cooperation of utility is provided as and when required by SEA and there is no stringent plan on this. The following are examples of the DSM initiatives to which utility can contribute,

i. Introducing demand response schemes
   - Offer a kW and/or kWh-based incentives to customers who are willing to participate in Automated demand response schemes
   - Manual load deferment using automatic time-based switching operation for water pumping, conveyor equipment etc

ii. BESS assisted load management
   - Designing ToU tariffs to open a window of opportunity for BESS to be viable

iii. Customer education and information campaigns.

13. **Reason for limiting the extension of the retirement year for Sapugaskanda A, Sapugaskanda B, and the Barge power plants to only 5 years after their refurbishments**

It is to be noted that the extension of these power plants is required due to reserve margin shortage from year 2026-2027, provided the other power plants are implemented on time. Furthermore, there are economic benefits of operating the furnace oil power plants until the natural gas infrastructure is made available in the country.

In order to continue the operation of these power plants beyond 2026, they are required to be refurbished. Once these refurbishments are completed the power plant can operate for further five years. However, it is to be noted that these plants are inflexible and as more VRE is integrated to the system, operation of such inflexible plants are required to be replaced with flexible generation. If the LNG infrastructure and power plants as base case are implemented on time, there shall be no requirement to further extend these power plants beyond year 2030. However, this can be further validated, in subsequent planning cycles based on the requirement and plant condition.

14. **Does the estimated local gas price (8.5 to 10 USD per MMBtu) by PDASL include the handling charges? If not, what is the estimated handling fee per MMBtu?**

The price estimated by the PDASL refers to the gas delivery price to Norochcholai area, which is in close proximity to the Mannar gas basin. The local gas available at the Mannar basin is in gaseous form and there is no requirement to be converted to LNG. Hence there is no requirement of establishing a FSRU. The only cost associated with the handling charge is for the development of offshore pipeline from Mannar basin to western region. An approximate cost figure is used as capital cost in planning studies as mentioned in section 10.21 in chapter 10

15. What are the estimated plant factors and the specific costs of the candidate ORE technologies?

In this iteration of planning studies VRE plant technologies were allowed to have stochastic variation based on historical data, which results in a range of annual plant factors. Furthermore, for wind plants the plant factors depend on the selection of wind turbine and appropriate hub height for each specific location. The estimated plant factors and respective specific cost of candidate ORE technologies are as follows.

Technology		Plant Factor (Apprx.)	Specific Cost UScts/kWh
Solar (Large Scale)		20%-23%	5.58-6.42
Solar (Distributed)		16%-18%	7.87-8.86
Floating solar		19%	9.9
On Shore Wind	Mannar	38%-44%	5.32- 6.16
	Northern	34%-37%	6.33-6.89
	Puttalam	32%-35%	7.32-6.69
	Eastern	27%	8.67
Off-shore wind	Fixed	45%-50%	12.73-14.14
	Floating	45%-50%	17.63-19.59
Biomass		50%	6.41
Mini hydro		37%	8.09

16. Why wasn't a cost variation trajectory not used for ORE technologies over the planning period?

As stipulated in Grid Code constant prices are been utilized to derive the main planning scenarios. Hence cost variations with time are not considered in developing main scenarios. However, CEB does acknowledge the importance of considering the cost projection, hence have conducted sensitivities of cost variation with time for projected generation technologies and fuel as published by the IEA. These results are already published in section 8.4.2. of LTGEP 2025-2044