PUBLIC UTILITIES COMMISSION OF SRI LANKA

Decision on Electricity Tariffs

Effective from October 15, 2025

Contents

List of Acronyms

2024H1	Period of January to June in the year 2024
2025H1	Period of January to June in the year 2025
2025H2	Period of July to December in the year 2025
2025Q1	Period of January to March in the year 2025
2025Q2	Period of April to June in the year 2025
AWPLR	Average Weighted Prime Lending Rate
BSOB	Bulk Supply Operations Business
BST	Bulk Supply Tariff
BSTA	Bulk Supply Transaction Account
CAPEX	Capital Expenditure
CBSL	Central Bank of Sri Lanka
CEB	Ceylon Electricity Board
CPC	Ceylon Petroleum Corporation
DL	Distribution Licensee
GDP	Gross Domestic Product
GWh	Giga Watt Hours
HFO	Heavy Fuel Oil
IPP	Independent Power Producers
kWh	Kilo Watt Hour
LECO	Lanka Electricity Company Private Limited
LISS	Licensee Information Submission System
MLKR	Million Sri Lankan Rupees
MoALLI	Ministry of Agriculture, Livestock, Land and Irrigation
MW	Mega Watt
NCRE	Non-Conventional Renewable Energy
O&M	Operation and Maintenance
OD	Overdraft
OND	October, November and December
OPEX	Operational Expenditure
PPA	Power Purchase Agreement
PPIUS	Producer Price Index United States of America
PUCSL	Public Utilities Commission of Sri Lanka
ROA	Return on Assets
ROE	Return on Equity
SESRIP	Supporting Electricity Supply Reliability Improvement Project
SLEA	Sri Lanka Electricity Act No.20 of 2009
TL	Transmission Licensee
ToU	Time of Use
UNT	Uniform National Tariff
UNTA	Uniform National Tariff Adjustment
WIP	Work-in progress

1. Introduction

In terms of the Section 30 of Sri Lanka Electricity Act No. 20 of 2009, General Policy Guidelines for the electricity industry and the Commission approved "Tariff Methodology - 2021", the CEB was directed to submit the tariff proposal for the third tariff revision of 2025. Accordingly, the end user and bulk supply tariff proposals by CEB, considering the quarter starting from October 2025, were received by the Commission on August 27, 2025, for the third tariff revision of 2025. The CEB proposal requests for a tariff increase of 6.8%, effective from October 01, 2025.

In terms of Section 17(b) of PUCSL Act, No. 35 of 2002, and Section 30(3)(b) of Sri Lanka Electricity Act, No. 20 of 2009, the Commission declared open the stakeholder consultation on the tariff revision. The consultation document published includes detailed evaluation on the CEB submission. The consultation sessions were conducted covering all 9 provinces, with the participation of over 300 stakeholders representing various sectors. Summary of comments (oral and written) from stakeholder consultation is given in Annex – 1.

This decision, made on October 13, 2025, as per the powers vested with the Commission, in terms of the Section 30(2) of Sri Lanka Electricity Act No. 20 of 2009, considered the submissions by CEB and LECO, inputs from the other stakeholders, approved Tariff Methodology, other related legal provisions, and General Policy Guidelines. The approved end user tariffs (Annex - 2) are effective from October 15, 2025, (for both CEB and LECO consumers), until next tariff revision.

2. Generation Energy Cost

Electricity generation – Energy cost component is significantly dependent on the forecasted demand, generation mix and fuel prices, for the subjected period. Therefore, these areas are detailed in the sections below.

2.1. Demand Forecast

2.1.1. Licensee Submission and Commission's Observations

The electricity generation demand forecast for the period of October to December 2025 has been submitted by the CEB, considering the forecasted electricity sales for the period and the approved network losses. This generation demand forecast in comparison to the actual demand for the year 2025 is provided below.

Table 1: Generation demand forecast

Description	Unit	Quantity
Generation demand forecast for Oct to Dec 2025	GWh	4,389
Actual generation demand for Oct to Dec 2024	GWh	4,246
Forecasted generation demand growth	%	3.36%

2.1.2. Commission Decision on the Demand Forecast

Demand forecast by CEB is accepted considering the actual demand growth trend observed up to September this year.

2.2. Hydro Generation Forecast

2.2.1. Licensee Submission and Commission's Observations

The Major Hydro generation forecast submitted for the third tariff revision of 2025, in comparison to the actual generation for the same period in previous years is shown in the table below.

Table 2: October to December Hydro generation

Description	Unit	Major Hydro Generation
CEB forecast for Oct-Dec 2025	GWh	1,493
Actual for Oct-Dec 2024	GWh	1,577
Actual for Oct-Dec 2023	GWh	2,026
Actual for Oct-Dec 2022	GWh	1,677
Actual for Oct-Dec 2021	GWh	1,962

*Note: New plant additions increase the generation capacity annually, resulting in more potential for electricity generation compared to the previous year

The CEB has forecasted a total hydro inflow of 1,630.2 GWh for the period from October to December 2025, which is marginally lower than the ten-year average October to December inflow of 1,691.9 GWh. This indicates that the forecasted inflow conditions are slightly below the historical average for the same period.

2.2.2. Commission Decision on the Hydro Generation Forecast

Based on the above comparison, CEB forecast for this year is well below the actual hydro generation in the previous years. However, considering the 'Below Normal' rainfall forecast by Meteorological Department for the period of October to December 2025 (http://meteo.gov.lk/index.php?option=com_content&view=article&id=78&Itemid=290&lang=en), the CEB hydro generation forecast is accepted.

2.3. NCRE Generation Forecast

2.3.1. Licensee Submission and Commission's Observations

The NCRE generation forecasted by the Commission for October to December 2025 is compared below with the CEB submission. The Commission forecast is derived considering the source wise NCRE capacity availability and actual capacity factors yielded by each source, during the last two years.

Table 3: NCRE generation forecasts for October to December

Month	Unit	NCRE Generation Forecast	
		CEB	PUCSL
Oct - 2025	GWh	440	395
Nov - 2025	GWh	372	397
Dec - 2025	GWh	367	372
Total	GWh	1,179	1,164

2.3.2. Commission Decision on the NCRE Generation Forecast

The CEB submitted NCRE generation forecast is in line with the alternative forecast done by the Commission. Hence the CEB forecast is accepted.

2.4. Fuel Prices

2.4.1. Licensee Submission and Commission's Observations

The fuel prices considered for CEB submission are as follows.

Table 4: Fuel price forecast

Fuel Type	Unit	Oct-25	Nov-25	Dec-25
Coal	LKR/kg	42.15	41.19	42.36
Fuel Oil	LKR/Ltr.	177.00	177.00	177.00
Naphtha	LKR/Ltr.	141.00	141.00	141.00
Diesel	LKR/Ltr.	289.00	289.00	289.00

The CEB submission states that the coal prices are based on the actual/forecasted prices. Liquid fuel prices used are as determined by the Ceylon Petroleum Corporation. It should be noted that the CEB is yet to enter into fuel supply agreements for power generation plants, despite directives issued on the matter. The Commission has started the process of issuing an enforcement order regarding this matter and the newspaper notice to inform the affected parties on the same is already published.

2.4.2. Commission Decision on the Fuel Prices

The Commission has received an update from the CEB on the actions taken on entering into the fuel supply agreements and the challenges faced with the existing fuel supplier (Ceylon Petroleum Corporation). However, the Commission is in the process of issuing an enforcement order regarding this matter. Under these circumstances, the Commission decides to proceed with the submitted fuel prices, subject to possible claw backs in the future, based on any variations to the actual fuel prices.

2.5. Commission Decision on the Generation Energy Cost

Considering the above decisions on the constituent elements within the Generation - Energy Cost, the Commission approves the following generation energy cost forecast, submitted by the CEB, for the period of October to December 2025.

Table 5: October to December generation energy cost forecast

Plant/Complex	Unit	Oct-25	Nov-25	Dec-25
Mahaweli/Laxapana/Samanala - Hydro	GWh	575.68	472.74	444.85
	LKR/kWh	-	-	-
Thambapawani – Wind	GWh	21.40	14.33	20.92
	LKR/kWh	-	-	-
Sapugaskanda Old – Furnace Oil	GWh	13.09	26.78	8.50
	LKR/kWh	47.94	45.20	50.37
Sapugaskanda Ext. – Furnace Oil	GWh	24.13	36.94	27.21
	LKR/kWh	42.63	41.65	42.31
Kelanitissa Small GT – Diesel	GWh	-	-	-
	LKR/kWh	-	-	-
Kelanitissa GT7 – Diesel	GWh	-	-	-
	LKR/kWh	-	-	-
Kelanitissa Combined Cycle 1 – Naphtha/Diesel	GWh	67.10	84.53	68.47
	LKR/kWh	39.02	38.85	38.88
Kelanitissa Combined Cycle 2 – Diesel	GWh	-	-	-
	LKR/kWh	-	-	-
Lakvijaya – Coal	GWh	346.84	335.65	520.26
	LKR/kWh	17.93	17.56	17.81
New Chunnakam – Furnace Oil	GWh	6.57	10.11	5.07
	LKR/kWh	41.94	41.19	42.57
Chunnakam & Islands – Diesel	GWh	0.20	0.20	0.20
	LKR/kWh	92.89	92.89	92.89
Barge – Furnace Oil	GWh	18.49	33.05	14.95
	LKR/kWh	43.69	41.87	44.67
30MW Hambantota – Diesel	GWh	-	-	-
	LKR/kWh	-	-	-
20MW Mathugama – Diesel	GWh	-	-	-
	LKR/kWh	-	-	-
Westcoast IPP – Furnace Oil	GWh	36.72	51.18	10.41
	LKR/kWh	49.77	49.33	53.70

Sobadhanavi IPP – Diesel/LNG	GWh	-	-	-
	LKR/kWh	-	-	-
Solar Rooftop Generation	GWh	162.41	145.96	153.53
	LKR/kWh	28.23	28.23	28.23
Other renewable	GWh	226.64	211.88	192.21
	LKR/kWh	17.06	16.92	17.28
Total Generated Energy	GWh	1,499.28	1,423.34	1,466.57
Monthly Energy Cost	MLKR	21,874	23,973	22,623
Total Energy Cost	MLKR			68,469

3. Generation Capacity Cost

3.1. Licensee Submission and Commission's Observations

The CEB submitted Generation capacity cost of each power plant is given below.

Table 6: Generation capacity cost forecast

Plant/Complex	Unit	Oct-25	Nov-25	Dec-25
Mahaweli – Hydro	MLKR	436	436	447
Laxapana – Hydro	MLKR	550	559	559
Samanala – Hydro	MLKR	813	813	813
Thambapawani – Wind	MLKR	560	560	560
Sapugaskanda Old – Furnace Oil	MLKR	61	61	61
Sapugaskanda Ext. – Furnace Oil	MLKR	68	68	72
Kelanitissa Small GT – Diesel	MLKR	46	46	46
Kelanitissa GT7 – Disel	MLKR	82	82	82
Kelanitissa Combined Cycle 1 – Naphtha/Diesel	MLKR	92	92	92
Kelanitissa Combined Cycle 2 – Diesel	MLKR	85	85	85
Lakvijaya – Coal	MLKR	1,128	1,142	1,159
New Chunnakam – Furnace Oil	MLKR	51	51	51
Chunnakam & Islands – Diesel	MLKR	9	9	9
Barge – Furnace Oil	MLKR	51	51	53
30MW Hambantota – Diesel	MLKR	27	27	27
20MW Mathugama – Diesel	MLKR	18	18	18
Westcoast IPP – Furnace Oil	MLKR	1,449	1,407	1,449
Sobadhanavi IPP – Diesel/LNG	MLKR	1,219	1,181	1,219
Rooftop solar	MLKR	-	-	-
Other renewables	MLKR	-	-	-
Total	MLKR	6,745	6,686	6,803
				20,233

The Commission requested clarifications on the inclusion of project delay related payments of USD 5 million (~MLKR 1,500) for Uma Oya power plant, under the Samanala complex, resulting in increasing the capacity costs.

The clarification request was specifically on the inclusion of these costs for the period of October to December, even with an already approved USD 1.6 million of payments, previously submitted by CEB for June – 2025 tariff revision. As per the clarifications received, the Uma Oya project comes under the purview of the Ministry of Agriculture, Livestock, Land and Irrigation (MoALLI), and the same ministry is liable for any project delay related claims from the contractor. However, a decision by Cabinet of Ministers has directed CEB to take up a total of USD 38.6 million payment claim by the

project contractor, owing to the project delays. CEB has already settled USD 19.3 million of these payments by September 01, 2025.

As per the clarifications, the inclusion of USD 5 million for this tariff revision has been initiated with a request from MoALLI, to settle a portion of the dues to contractor, during the last quarter of 2025. Further, the CEB has not submitted a plan for the settlement of the remaining due amount.

This cost item was critically objected by the stakeholders in the consultation sessions, raising concerns on whether it is an efficient cost.

3.2. Commission Decision on the Generation Capacity Cost

The Commission requires standard CEB board approved payment plan to approve any further payments with regard to the Uma Oya delay payment. Accordingly, this item is not approved with this tariff revision. Therefore, MLKR 18,733 of Generation – Capacity Cost is approved.

4. Transmission and Distribution Costs

4.1. Licensee Submission and Commission's Observations

The CEB proposed transmission and distribution costs for the subjected period are as follows.

Table 7: CEB Transmission and Distribution Allowed Revenues

Description	Unit	Forecast for Oct to December 2025
Transmission Allowed Revenue	MLKR	5,593
Distribution Allowed Revenue – CEB DLs	MLKR	23,252

The CEB submitted initial Transmission Allowed Revenue is based on the Commission approved annual Allowed Revenue to the Licensee. However, subsequent to the tariff proposal submission, CEB has also filed an additional cost item of BLKR 2.5 to be paid to the Sojitz Kelanitissa (Pvt) Limited, as an arbitration related payment. This has been requested to be included within the Transmission Licensee's Allowed Revenue.

The Distribution Allowed Revenue submission includes additional cost items over and above the annual approved values. The additional cost items for the period of October to December – 2025 are shown in the table below.

Table 8: Additional cost submitted by CEB DLs for October to December 2025

Additional Cost Item	Unit	DL1	DL2	DL3	DL4	Total
Additional Allowed Revenue required for the Licensee own works	MLKR	788	-	874	-	1,662
Additional Allowed Revenue required for Insurance Reserve Fund	MLKR	212	181	126	103	621
Additional Allowed Revenue required for SESRIP WIP	MLKR	135	118	194	93	540
Additional Allowed Revenue required for SESRIP loan repayment due in Nov-2025	MLKR	287	306	195	100	888
Additional Allowed Revenue required for Insurance Reserve Fund for Common Divisions and Vidulakpaya apportionment for the DLs	MLKR	20	8	5	4	37
Total Additional Allowed Revenue for Quarter 4 of 2025	MLKR	1,442	613	1,395	300	3,749

Clarifications were requested from the CEB on each item above. Key points from the clarifications received are given below.

1. Additional cost for Licensee own works
   - DL1 has not shared the calculation of the additional Allowed revenue amount requested for Licensee own works and merely stated that these costs are requested for material and personnel expenses.
   - DL3 has shared a calculation indicating that an additional MLKR 2,756 of Allowed Revenue is required. Only MLKR 1,000 of this is requested, out of which MLKR 126 is for the insurance reserve fund and the remainder of MLKR 874 is for the Licensee own works. Also, as mentioned in the tariff submission, the DL3 actual Allowed Revenue fund utilization is MLKR 19,755 for year 2024, while the approved Allowed Revenue for 2025 is MLKR 17,761 (before claw-backs). Accordingly, a considerable shortage is observed.

2. Insurance reserve fund
   The insurance reserve fund of CEB has been established in 1971. The contribution to the fund has been through retained earning transfers and interest income from the investments. The fund balance as of August 31, 2025, is BLKR 33.2. The Licensee wise breakdown of contributions to the fund is not submitted.

3. SESRIP related costs
   SESRIP is a project commenced in year 2019, to develop selected critical 33KV tower lines and gantries, as identified under the Medium Voltage Development Plans of CEB DLs from the year 2015. The project was initially planned to be completed by the year 2021. However, the current estimated completion is by the end of year 2025. The project has been delayed due to multiple reasons including the Covid pandemic, economic crisis, approval delays, land clearance delays and technical challenges. The DLs have filed for both WIP related to the project and also for the upcoming project loan repayment.

4. Vidulakpaya cost
   Vidulakpaya is a new building project to locate the offices of CEB Chairman, GM, AGM (DD1), AGM (transmission), AGM (CS), AGM (Projects) and other CEB permanent offices currently rented. The office spaces are to be remapped to the same building following the restructuring process. The total project cost is estimated at BLKR 11.6, and to be expensed until the year 2030. The approval of the Cabinet of Ministers is still pending for the continuation of this project utilizing CEB funds. For this project, the DLs have submitted a cost item of MLKR 36 for the final quarter of 2025.

It is also to be noted that the CEB has requested an additional Allowed Revenue of MLKR 10,600 for its DLs, subsequent to the original tariff submission. This amount has been requested as a measure of reinstating the CEB DL Return on Asset component of the Allowed Revenue, which the CEB has self-curtailed with the proposal submitted for July – 2024 tariff revision. This request has been made with the view of ensuring the financial sustainability of separate entities to be created with the ongoing power sector reform exercise.

4.2. Commission Decision on Transmission and Distribution Costs

The initially submitted Transmission Licensee's Allowed Revenue is accepted as it is in line with the already approved annual Allowed Revenue.

From the extra cost items requested by the CEB DLs, the following costs are not approved due to the reasons given therewith.

1. DL1 additional cost for own Licensee works – The additional cost requirement was not justified.

2. SESRIP WIP – Project is yet to be completed and used. Therefore, the WIP cannot be approved.

3. Vidulakpaya cost – The project cost shall be borne by the Licensees that would utilize the building. Therefore, the cost shall be filed by the corresponding Licensees, subsequent to the restructuring. Further, the approval of the Cabinet of Ministers is yet to be obtained for the project continuation.

4. Additional MLKR 10,600 requested to reinstate RoA – This item would be considered with the Allowed Revenue filing to be carried out by the Licensees, after the restructuring.

Accordingly, the approved additional cost items of DLs are summarized in the table below.

Table 9: Approved additional cost items of CEB DLs

Additional Cost Item		Unit	Submitted Amount	Approved Amount
Additional Allowed Revenue for the Licensee own works	DL1	MLKR	788	-
	DL3	MLKR	874	874
Additional Allowed Revenue for Insurance Reserve Fund		MLKR	621	621
Additional Allowed Revenue for SESRIP WIP		MLKR	540	-
Additional Allowed Revenue for SESRIP loan repayment due in Nov-2025		MLKR	888	888
Additional Allowed Revenue for Insurance Reserve Fund for Common Divisions		MLKR	2	2
Additional Allowed Revenue for Vidulakpaya apportionment		MLKR	36	-
Additional Allowed Revenue for RoA		MLKR	10,600	-
Total Additional Allowed Revenue for Quarter 4 of 2025		MLKR	14,349	2,385

Accordingly, the approved *Allowed Revenues* for the period are given below.

Table 10: Approved Distribution and Transmission Allowed Revenues

Description	Unit	Approved Allowed Revenue for October to December 2025
Transmission Allowed Revenue	MLKR	5,593
Distribution Allowed Revenue - CEB	MLKR	21,888
Distribution Allowed Revenue - LECO	MLKR	2,173

5. Finance Cost

5.1. Licensee Submission and Commission's Observations

A total of MLKR 7,830 has been submitted by CEB as finance costs for the period of October to December 2025. The breakdown of these costs is shown in the table below.

Table 11: Finance cost breakdown

Description	Unit	Oct-25	Nov-25	Dec-25	Total
Interest on term loans	MLKR	512	496	706	1,714
Overdraft Interest	MLKR	213	213	213	638
Debenture Interest Account	MLKR	159	154	159	471
Delay interest on IPP payments	MLKR	7	7	5	18
Delay interest on NCRE payments	MLKR	238	238	208	683
Capital repayment of term loans	MLKR	1,316	1,249	1,741	4,305
Total	MLKR	2,443	2,355	3,031	7,830

The Commission requested further clarifications on the following matters related to finance costs.

1. Increase in NCRE delay interest compared to the amount previously approved for the final quarter of 2025.
2. Not obtaining the total loan amount approved by the Commission to restructure and settle the past unpaid debts (legacy debts).

The key information from the responses received for the above clarification requests is given below.

- The NCRE delay payment increase for this period is due to the passing of previously approved Moragahakanda delay interest payment from June – 2025 to the final quarter of 2025. The approved cost for June – 2025 has not been totally expensed in the month.
- Though the CEB had planned to restructure BLKR 70 of legacy debts, it was able to restructure only BLKR 53.5 of these debts due to the financing limitations with CEB's liquidity constraints and exposure limits imposed by the CBSL.

5.1. Commission Decision on Finance Cost

Considering the clarifications received from the CEB on the concerned items within the Finance Cost submitted, the Commission accepts the submitted Finance Cost.

6. Transmission Licensee Revenue Surplus/Deficit from Past Periods

6.1. Licensee Submission and Commission's Observations

As per the Clause 2.5.3 and 2.5.4 of the 'Tariff Methodology', revenue surplus/deficit of the Transmission Licensee (arising from Bulk Supply and Operation Business) in a period 'p', is to be compensated during the tariff determination for period 'p+2'. Thus, the surplus/deficit of April to June 2025 is applicable to be considered in setting tariffs for October to December 2025 (within the quarterly tariff review framework).

The CEB has submitted an estimated value of MLKR 5,311 as the surplus for April to June 2025, considering the profit reported in CEB provisional income statement for the quarter 2 of the year 2025. It is mentioned that the above amount has been proposed due to the unavailability of data to calculate the surplus/deficit resulting from forecast variations. However, the submitted value is not acceptable, as it has not been calculated in accordance with the calculation method given in the Tariff Methodology and also as it does not align with the principle of surplus/deficit resulting due to forecast variation.

Further to the above, this tariff review requires addressing the treatment of following TL surplus/deficit related adjustments.

1. Surplus/deficit of TL for the first quarter of the year 2025, as this has not been considered in any previous tariff reviews and this will not be relevant in any upcoming tariff reviews too, due to the consideration of 'p - 2' quarter. (This is a result of complete transition to quarterly tariff reviews)
2. Surplus of July to December 2024, compensated during the June – 2025 tariff review has only been partially passed to the consumers, as this surplus was distributed throughout total electricity sales in the period of June to December 2025. The remaining amount of this surplus needs to be considered.
3. As mentioned in the CEB proposal, the surplus/deficit of TL for the year 2024, considered in previous tariff revisions, is based on provisional data. Therefore, adjustment for this too is required with the final verified data.

Considering the above, necessary data to calculate the above items was requested from the Licensees. The calculation of these items is shown below.

6.1.1 Calculation of Revenue Surplus/Deficit of TL for 2025H1

TL's revenue surplus due to Bulk Supply Operation Business is calculated based on the principles explained below.

The revenue surplus from Bulk Supply Operation Business, due to forecasting errors, will be the addition of;

A. Estimated generation cost – actual generation cost = Cost Difference
B. Actual revenue from sales – estimated revenue from sales = Revenue Difference

Accordingly,

Revenue Surplus = Cost Difference + Revenue Difference

Taking;

G_E - Estimated total generation metered at Transmission to Distribution boundary
G_A - Actual total generation metered at Transmission to Distribution boundary
C_E - Estimated unit cost at Transmission to Distribution boundary
C_A - Actual unit cost at Transmission to Distribution boundary
R_E - Estimated unit revenue at Transmission to Distribution boundary
R_A - Actual unit revenue at Transmission to Distribution boundary

Cost Difference = $G_E \times C_E - G_A \times C_A$

Revenue Difference = $G_A \times R_A - G_E \times R_E$

Revenue Surplus = $G_E \times C_E - G_A \times C_A + G_A \times R_A - G_E \times R_E$ …….. (1)

Further, prior to the application of any claw-backs;

1. The estimated revenue is approved for invoicing during the period.
   Therefore, $R_E = R_A$
2. Also, the approved revenue is equal to the estimated cost, to ensure the breakeven.
   Therefore, $C_E = R_A = R_E$

Considering the above;

Revenue Surplus $= G_E \times C_E - G_A \times C_A + G_A \times C_E - G_E \times C_E$

$= G_A \times [C_E - C_A]$ …….. (2)

In the previous tariff revisions, the TL revenue surplus was calculated based on the formula (2) as derived above. This tariff revision requires the consideration of the entire 2025H1 surplus/deficit, to avoid the 2025Q1 period being missed, as explained above.

The Bulk Supply Tariffs approved for the period of January to June – 2025, had to be revised in June – 2025, due to the end user tariff revision in the same month. This unprecedented revision of Bulk Supply Tariffs has complexed the revenue surplus calculation of 2025H1 period, where it is required to consider January to May and June periods separately for the calculations. Further, the extended version of the formula (1), as shown above is required for this calculation. The calculation of TL revenue surplus/deficit due to forecasting errors is shown below.

Table 12: Calculation of TL revenue surplus due to forecast errors

Revenue Surplus from Energy Sales

Description	Unit	Jan - 25 to May - 25	Jun-25
Approved Cost (a)	Rs./kWh	19.94	14.57
Approved Revenue (b)	Rs./kWh	18.85	16.00
Actual Cost (c)	Rs./kWh	18.02	12.19
Actual Revenue (d)	Rs./kWh	18.85	16.00
Approved Energy (e)	GWh	6,925.67	1,383.57
Actual Energy (f)	GWh	6,888.54	1,439.17
Cost Difference [a.e -c.f = g]	MLKR	13,966.49	2,615.22
Revenue Difference [d.f -b.e = h]	MLKR	(700.03)	889.49
TL Revenue Surplus from Energy Sales [g + h]	MLKR	13,266.47	3,504.72
Forecast Cost for Energy [a.e]	MLKR	138,097.91	20,158.68
Forecast Revenue for Energy [b.e]	MLKR	130,548.93	22,137.19
Forecast Surplus/(Deficit) for Energy [Σ b.e - Σ a.e]	MLKR		(5,570.47)

Revenue Surplus from Capacity Sales

Description	Unit	Jan - 25 to May - 25	Jun-25
Approved Cost (a)	Rs./MW	3,082,540.52	4,842,809.12
Approved Revenue (b)	Rs./MW	3,172,266.25	4,085,887.51
Actual Cost (c)	Rs./MW	2,730,660.85	3,105,469.03
Actual Revenue (d)	Rs./MW	3,172,266.25	4,085,887.51
Approved Capacity (e)	MW	2,646.00	2,473.00
Actual Capacity (f)	MW	2,659.00	2,537.92
Cost Difference [n.(a.e -c.f)/10^6 = g]	MLKR	4,477.88	4,094.82
Revenue Difference [n.(d.f -b.e)/10^6 = h]	MLKR	206.20	265.28
TL Revenue Surplus from Capapcity Sales [g + h]	MLKR	4,684.07	4,360.10
Forecast Cost for Capacity [n.a.e /10^6]	MLKR	40,782.01	11,976.27
Forecast Revenue for Capacity [n.b.e/10^6]	MLKR	41,969.08	10,104.40
Forecast Surplus/(Deficit) for Capacity [Σ(n.b.e/10^6) -Σ(n.a.e /10^6)]	MLKR		(684.80)

*Note: 'n' in the table above refers to the number of months

Total Revenue Surplus

Surplus from Energy sales for 2025H1	MLKR	16,771.19
Surplus from Capacity sales for 2025H1	MLKR	9,044.17
TL Revenue from UNT adjustment for 2025H1	MLKR	3,315.00
Total Revenue Surplus for 2025H1	MLKR	29,130.35

However, due to the non-coinciding of the initial forecast periods with the separate periods considered above for calculations, a revenue deficit is shown considering the forecast cost and forecast revenue calculated with the segregated data above. This amounts to MLKR 6,255 *[5,570.47 + 684.80]* of a deficit. Accordingly, the TL revenue surplus of 2025H1 to be considered for claw-back is MLKR 22,875.

6.1.2. Reconciliation of TL Revenue Surplus/Deficit Compensations from 2024

The following TL surplus amounts have been applied as claw-backs in tariff calculations, with regards to the year 2024.

Table 13: TL revenue surplus claw-backs from 2024

Tariff Revision	Claw-back Amount from 2024 (MLKR)
January – 2025 tariff revision	51,098
June – 2025 tariff revision	11,858
Total	62,956

The above claw-back amounts were decided with the provisional data that were available at the time of tariff revision. However, the final data for the year 2024 is available at present. The actual TL revenue surplus as per this data is as follows.

Table 14: Calculation of actual TL revenue surplus for 2024

Item		**Unit**	**Amount**
CEB Revenue	Direct revenue from electricity sales	MLKR	544,803
	Uniform National Tariff revenue adjustment from LECO	MLKR	966
	Revenue surplus brought forward from previous periods	MLKR	-
Generation Cost	Energy Cost	MLKR	(294,858)
	Capacity Cost	MLKR	(52,335)
Transmission Allowed Revenue		MLKR	(22,490)
Distribution Allowed Revenue	CEB Distribution Licensees	MLKR	(90,614)
Finance Cost		MLKR	(25,011)
Revenue Surplus/(Deficit) for 2024		**MLKR**	**60,461**

Accordingly, an excess claw-back of MLKR 2,495, has been applied on the TL, pertaining to the revenue surplus from the year 2024. This amount needs to be included as a negative revenue adjustment.

Further, the MLKR 11,858 of surplus clawed-back with the June – 2025 tariff revision was to be passed to the consumers during the period of June to December -2025. Accordingly, MLKR 5,082 of the above surplus would remain to be considered for the final quarter of 2025, assuming uniform electricity sales pattern for June to December.

6.1. Commission Decision on Revenue Surplus from Past Periods

As calculated above, the following revenue adjustments are approved for the period of October to December – 2025.

Table 15: Approved revenue adjustments for TL surplus/deficit

Description	Unit	Amount
TL revenue surplus of 2025H1	MLKR	22,875
Corrections of excess claw-back for 2024	MLKR	(2,495)
Remaining portion of the claw-back applied in June - 2025	MLKR	5,082
Total Revenue Adjustment	MLKR	25,462

*Note: Due to the complete transition to tariff review interval of 3 months from 6 months, the additional revenue surplus/deficit adjustments pertaining to 2024H2 (partial) and 2025Q1 have also been included in the table above.

The Commission observes that the resulting claw-back above would have a significant impact on the electricity tariffs, as it is an accumulation of surplus/deficit from multiple periods. Accordingly, the application of this claw-back to the final quarter of 2025 will result in significantly reducing the electricity tariffs in this quarter. However, in the next quarter, the tariffs will see a greater rise with the impact of claw-back not being present. Thus, the consideration of total claw-back above in one quarter would introduce a high volatility in the end-user tariffs. The Commission foresees the overarching negative impacts these volatilities can have on the economy of the country.

The maintaining of the tariff stability was a major point highlighted by many stakeholders during the consultation. Considering these facts and with the good faith of establishing the tariff stability, the Commission decides to apply the above claw-back amount in a phased manner. Accordingly, MLKR 8,487, one third of the total revenue adjustment calculated above (25,462/3), would be clawed back during the final quarter of 2025. The remaining revenue surplus of MLKR 16,975 is approved to be considered for claw-back in the next quarterly tariff review. Accordingly, the Transmission Licensee is directed to submit the claw-back amount of MLKR 16,975 for the 2026 first quarter tariff review, along with the calculated revenue surplus/deficit for the quarter 3 of 2025.

The Commission also recognizes the inherent volatility introduced by the quarterly tariff reviews, even before accounting for the impact of claw-backs. This volatility primarily arises from the seasonal variations in Sri Lanka's hydro-thermal power system. Furthermore, such quarterly fluctuations in electricity prices could have adverse implications for the national economy.

7. Electricity Sales Revenue

7.1. Licensee Submission and Commission's Observations

CEB has forecasted sales of 3,964 GWh for the period of October to December 2025. The breakdown of CEB end-user sales and sales to LECO is shown below, as submitted by CEB.

Table 16: CEB submitted sales revenue breakdown

Description	Oct - Dec Forecasted Sales (GWh)	Jun - Dec Forecasted Electricity Sales Revenue (MLKR)
CEB DL End-user sales	3,575	102,155
Sales to LECO	389	10,217
Total CEB Revenue	3,964	112,372

The sales revenue calculation submitted by the CEB was observed to have missed the revenue to CEB from LECO solar prosumer energy related revenue. The CEB was requested to provide a revised sales revenue calculation including the above component. However, CEB has requested the Commission to calculate the particular revenue component, as it does not contain the necessary data for calculating the same.

Accordingly, the calculated total revenue with received end-user sales forecasts for all the DLs is shown in the table below.

Table 17: CEB submitted sales revenue breakdown

Description	Unit	Amount
Revenue of CEB DLs	MLKR	102,155
Revenue of LECO	MLKR	14,483
Total Revenue of All DLs	MLKR	116,638

7.2. Commission Decision on Electricity Sales Revenue

The Commission approves forecast revenue calculated above.

8. Tariff Revision Percentage and Rate Structure

8.1. Licensee Submission and Commission's Observations

The summary of CEB cost/revenue forecasts for the subjected period and the calculation of tariff revision percentage is shown in the table below.

Table 18: Summary of CEB submitted costs/revenue

Description		Unit	Amount
Generation	Energy cost	MLKR	68,469
	Capacity cost	MLKR	20,233
Transmission cost		MLKR	5,593
Distribution cost - CEB		MLKR	23,252
Finance Cost		MLKR	7,830
Total Cost		MLKR	125,377
Estimated Revenue at present tariff		MLKR	112,372
Estimated 2025 2Q profit		MLKR	5,311
Surplus/ (Deficit)		MLKR	(7,694)
Requested tariff revision percentage, to be effective from Oct 1, 2025		%	6.8%

*Note: CEB submission considers LECO as a single consumer. Therefore, end-user revenue of LECO consumers and LECO allowed revenue is not included above. If the CEB proposal is adjusted with LECO allowed revenue, the percentage increase would be 6.72%.

The tariff structure proposed by CEB to enable the above revenue increase provides a uniform 6.8% increase for all consumer categories and subgroups.

However, considering the Commission's decision on all the cost and revenue components above, the tariff revision percentage is calculated as follows.

Table 19: Summary of commission approved costs/revenues

Description		Unit	Amount for Oct-Dec
Generation	Energy cost	MLKR	68,469
	Capacity cost	MLKR	18,733
Transmission cost		MLKR	5,593
Distribution cost	CEB DLs	MLKR	21,888
	LECO	MLKR	2,173
Finance Cost		MLKR	7,830
Total Cost		MLKR	124,686
Estimated Revenue at present tariff		MLKR	116,638
TL revenue surplus adjustment		MLKR	8,487
Surplus/ (Deficit)		MLKR	440
No. of days from Oct 1st, until the revised tariff implemented		Nos.	14
Approved tariff revision percentage		%	-0.44%

Accordingly, the calculation results suggest a minimal reduction in electricity tariffs by 0.44%. However, this value is negligible and within the error margin.

9.2 Commission Decision on the Tariff Revision Percentage and Rate Structure

As per the results above, the Commission approves to continue with the existing electricity tariffs, until the next revision. Further, the Commission decides to maintain the ongoing tariff table. Thus, zero bill increase is ensured for all consumer groups.

The approved tariff table is provided as Annex – 2 and the applicable conditions for the licensees are provided in Annex - 3.

Summary of Comments from the Stakeholder Consultation –Third Electricity Tariff Revision: October 2025

The Public Utilities Commission of Sri Lanka conducted a series of public consultations to obtain feedback from stakeholders on the proposed Third Electricity Tariff Revision for 2025. These consultations were held across all nine provinces, ensuring broad public participation and regional representation.

More than 300 stakeholders attended the sessions, including representatives from industry, commerce, small and medium enterprises, the public sector, consumer associations, religious organizations, and individual consumers. The consultation process provided an open platform for participants to express their views, concerns, and suggestions regarding the proposed tariff structure and its anticipated implications on different consumer categories and the national economy. Stakeholders were consulted on the key topics outlined below. The summary presented below consolidates the key themes and observations expressed during the consultations.

Consultation Category	Number of Stakeholder Mentions	Key Stakeholder Concerns & Comments
1. Forecasted generation mix and costs for the period of October to December 2025 submitted by CEB	60	• Inefficiencies in generation dispatch, unplanned outages, and inaccuracies in forecasting must not be transferred to consumers through higher tariffs. • Deployment of BESS and pumped hydro storage is recommended to enhance system flexibility and reliability. • Inefficiencies and delays in projects such as the Uma Oya, should not be reflected in end user tariffs. • Forecasted generation must be aligned with rainfall data and meteorological predictions, discrepancies in projected renewable energy output. • CEB to study and implement measures to reduce generation costs, Promote public–private participation and cost-efficient generation strategies. Maximize renewable energy and minimize thermal/diesel generation, Optimize the generation mix to lower overall costs.
2. Fuel cost used by CEB	28	• Lack of transparency in fuel procurement and CPC pricing is unfair; CEB should enter into proper Fuel Supply Agreements (FSAs). • Over-reliance on oil and fossil fuels continues; LNG is costly and not clean, and LNG and diesel cost appear unrealistic. • Fuel purchased at CPC retail rates instead of bulk rates, tariff revisions unfairly pass these costs to consumers, Fuel cost data should be made publicly available for transparency and accountability. • Promote NCRE to reduce reliance on costly fuel-based generation.

		• The Commission shall issue an enforcement order directing CEB to finalize FSAs, as CEB has not complied with previous directives. • Call for competitive bidding, public disclosure, and alignment with global fuel trends, as fuel prices used by CEB remain inconsistent with international benchmarks.
3. CEB submitted distribution costs over and above the Commission approved values	33	• Uncapitalize projects loan repayments should not be passed on to consumers, as this violates the approved tariff methodology, Distribution costs not properly justified or audited. • Inefficiencies, unnecessary allowances, high vehicle hiring cost and maintenance costs arising from poor technical leadership should not be transferred to consumers. • Recommendations for forensic audit, internal controls, and improving management of distribution infrastructure & CEB Operation. • Additional revenue beyond the approved amount should be properly monitored, and such inaccuracies must be corrected to prevent unjustified tariff increases. • CEB to manage operational costs more efficiently, Network losses of 8–9% are excessive, certain maintenance responsibilities should be transferred to local authorities to improve efficiency, Street lamp operation and contracted works found inefficient. •Distribution costs include unnecessary infrastructure and "Vidulakapaya" building expenses flagged as inappropriate for tariff recovery.
4. Finance costs for October to December 2025 submitted by CEB	20	• Excessive financial costs, legacy debts, and project delays should not be passed to consumer tariffs. • Why are consumers paying for unknown historic debts? Transparency in finance cost breakdowns requested, independent audits recommended. • NCRE delayed payment interest should not be passed to consumer tariffs; CEB should ensure proper financial management in advance. • CEB's cost accounting and recording standards should be streamlined, with proper audits and improved financial transparency.
5. Revenue Surplus/Deficit of Transmission Licensee	15	• Surpluses are not fully utilized to reduce tariffs, and CEB's revenue management lacks accountability. • Any excess profit or retained earnings should benefit consumers, not only offset CEB losses. • Prior surpluses should be returned to consumers through a proper mechanism; CEB is not adhering to the approved tariff methodology. • CEB is not following the correct clawback mechanism or basic accounting principles.
6. Proposed Tariff Structure by CEB	86	•Strong opposition to the uniform 6.8% increase due to affordability concerns among households, SMEs, agriculture, tourism, and low-income groups

		•Quarterly electricity tariff revisions create economic instability; annual or biannual revisions are preferred. •Changes in bill formats, such as SMS notifications, are inconvenient for consumers; printed bills are preferred. •Lifeline and social subsidy mechanisms should protect low-income users; increase the lifeline limit to 60 per month •Fixed charges and Maximum demand charges for industries are high; relief requested. •Midyear tariff revisions create budgeting issues for government institutions.
7. Commission's analysis on the tariff submission	28	•Strictly enforce cost-reflective principles and adhere to the approved tariff methodology. •Current tariff calculations follow a marginal cost and cost recovery approach rather than a fully cost-reflective method. •Stronger oversight of project delays, loan utilization, and mismanaged funds is required. •Independent verification, audits, and review of unjustified costs are requested •The Commission's independence must be protected
8. Stakeholder proposals to improve costing and efficiency of Licensees	68	•Promote renewable energy, rooftop solar, and energy storage with appropriate financing support. •Strengthen grid infrastructure to accommodate increased renewable integration. •Allow open access for industries to procure power independently and wheel it through the grid • Improve operational efficiency by reducing overstaffing, administrative waste, and ineffective contracts. •Address inefficiencies in generation dispatch and unplanned outages that adversely affect consumers and industries. •Enhance public awareness on energy conservation and demand-side management. •Quarterly tariff revisions are impractical; tariffs should remain stable for a defined period. • Introduce smart meters and improve billing accuracy and efficiency •Improve power quality, reduce supply interruptions, and ensure reliable service • Encourage competition and reduce the monopoly structure within the power sector.

Tariff Table for a 30 Day Billing Cycle

Annex - 2

		Tariff effective until 14th October 2025				Approved Tariff, Effective from 15th October 2025							
		Energy Charge (LKR/kWh)		Fixed Charge (LKR/month)		Energy Charge (LKR/kWh)				Fixed Charge (LKR/month)			
Domestic													
Consumption 0-60 kWh per month													
Block 1 : 0-30 kWh		4.50		80.00		4.50				80.00			
Block 2 : 31-60 kWh		8.00		210.00		8.00				210.00			
Consumption above 60kWh per month													
Block 1 : 0-60 kWh		12.75		-		12.75				-			
Block 2 : 61-90 kWh		18.50		400.00		18.50				400.00			
Block 3 : 91-120 kWh		24.00		1,000.00		24.00				1,000.00			
Block 4 : 121-180 kWh		41.00		1,500.00		41.00				1,500.00			
Block 5 : Above 180 kWh		61.00		2,100.00		61.00				2,100.00			
Domestic Time Of Use													
Peak [18:30 to 22:30]		67.00		2,100.00		67.00				2,100.00			
Day [05:30 to 18:30]		35.00				35.00							
Off Peak [22:30 to 05:30]		21.00				21.00							
Religious & Charitable													
Block 1 : 0-30 kWh		4.50		75.00		4.50				75.00			
Block 2 : 31-90 kWh		4.50		200.00		4.50				200.00			
Block 3 : 91-120 kWh		8.00		350.00		8.00				350.00			
Block 4 : 121-180 kWh		19.00		1,300.00		19.00				1,300.00			
Block 5 : Above 180 kWh		26.00		1,700.00		26.00				1,700.00			
Other Consumers		**Industrial/Hotel**		**General Purpose/Government**		**Industrial**		**Hotel**		**General Purpose**		**Government**	
Volume Differentiated Monthly Consumption (kWh/month)		<300	>300	<180	>180	<300	>300	<300	>300	<180	>180	<180	>180
Supply at 400/230V & Contract Demand<42kVA (1)	Energy Charge (LKR/kWh)	8.00	17.00	25.00	34.00	8.00	17.00	8.00	17.00	25.00	34.00	25.00	34.00
	Fixed Charge (LKR/month)	300.00	800.00	500.00	1,600.00	300.00	800.00	300.00	800.00	500.00	1,600.00	500.00	1,600.00
Supply at 400/230V & Contract Demand >42kVA (2)	Peak [18:30 to 22:30] (LKR/kWh)	28.00		47.00		28.00		28.00		47.00		47.00	
	Day [05:30 to 18:30] (LKR/kWh)	15.00		41.00		15.00		15.00		41.00		41.00	
	Off Peak [22:30 to 05:30] (LKR/kWh)	12.00		31.00		12.00		12.00		31.00		31.00	
	Demand Charge (LKR/kVA)	1,400.00		1,500.00		1,400.00		1,400.00		1,500.00		1,500.00	
	Fixed Charge (LKR/month)	5,000.00		5,000.00		5,000.00		5,000.00		5,000.00		5,000.00	
Supply at 11kV & above (3)	Peak [18:30 to 22:30] (LKR/kWh)	27.00		46.00		27.00		27.00		46.00		46.00	
	Day [05:30 to 18:30] (LKR/kWh)	14.00		39.50		14.00		14.00		39.50		39.50	
	Off Peak [22:30 to 05:30] (LKR/kWh)	11.00		30.00		11.00		11.00		30.00		30.00	
	Demand Charge (LKR/kVA)	1,350.00		1,450.00		1,350.00		1,350.00		1,450.00		1,450.00	
	Fixed Charge (LKR/month)	5,000.00		5,000.00		5,000.00		5,000.00		5,000.00		5,000.00	
Street Lighting													
Energy Charge (LKR/kWh)				50.00							50.00		
Agriculture: Optional Time of Use													
Peak [18:30 to 22:30] (LKR/kWh)				23.00							23.00		
Day [05:30 to 18:30] (LKR/kWh)				13.00							13.00		
Off Peak [22:30 to 05:30] (LKR/kWh)				7.00							7.00		
Fixed Charge (LKR/month)				750.00							750.00		
EV Charging Stations		**DC Fast Charging**		**AC Level 2 Charging**		**DC Fast Charging**				**AC Level 2 Charging**			
Peak (LKR/kWh)		111.00		90.00		111.00				90.00			
Day (LKR/kWh)		87.00		70.00		87.00				70.00			
Off Peak (LKR/kWh)		53.00		40.00		53.00				40.00			

Optional Pre-paid Tariff Scheme (LECO) for Retail Consumers

		Tariff effective until 14th October 2025	Approved Tariff, Effective from 15th October 2025
		Energy Charge (LKR/kWh)	Energy Charge (LKR/kWh)
Domestic	Block 1 : 0-90 kWh/month	16.00	16.00
	Block 2 : Above 90 kWh/month	61.00	61.00
Religious	Block 1 : 0-90 kWh /month	8.00	8.00
	Block 2 : Above 90 kWh/month	28.00	28.00
General (GP-1)		36.00	36.00
Industrial (I-1)		18.00	18.00
Hotel (H-1)		18.00	18.00

Annex - 3

Conditions to the Licensee

	Condition	Deadline
1.	CEB and LECO shall share a plan with timelines to submit quarterly licensee wise cost accounts.	December 31, 2025
2.	CEB and LECO shall share a plan with timelines to perform cost audits of their licensee wise cost accounts.	December 31, 2025
3.	Transmission Licensee shall enter into Power Purchase Agreements (PPA) with the CEB Generation Licensee.	December 31, 2025
4.	Transmission Licensee shall enter into Power Sales Agreements (PSA) with Distribution Licensees.	December 31, 2025
5.	Transmission Licensee shall perform a forensic audit on the expenses and balance of Transmission Licensee's revenue surplus calculated of MLKR 60,461 for the year 2024, and submit the report to the Commission.	December 15, 2025
6.	Transmission Licensee shall identify MLKR 16,975 of surplus amount, pending for claw-back, as a liability of the Transmission Licensee or other succeeding entity (National System Operator) after electricity industry reforms.	October 31, 2025
7.	Transmission Licensee/succeeding entity shall submit the pending claw-back of MLKR 16,975 as part of the entity's revenue surplus, with the submission for next tariff revision.	On the date of next tariff proposal submission