NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

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The Decision and Reasons for Decision

In the matter regarding the

Municipal Tariff Application for the 2026/27 Financial Year

by

Chief Albert Luthuli Local Municipality

THE DECISION

1. At its meeting held on 6 May 2026, the Regulator Executive Committee (REC) considered Chief Albert Luthuli Local Municipality's tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year set out in Section 7 (Page 27) below.

2. Based on the available information and the analysis performed thus far, the Regulator Executive Committee decided to:

   2.1. approve the tariffs that are based on the Cost of Supply (COS) Study as recommended in the tariff analysis section for implementation by the municipality with effect from 1 July 2026;
   2.2. note the COS study submitted by the municipality;
   2.3. that the municipality must submit a report accounting for all the costs that have been noted in its COS study to enable the National Energy Regulator of South Africa to perform its independent verification/audit process by 31 January 2027; and
   2.4. that the municipality must submit a quarterly smart efficiency plan with improvement measures identified in reducing high energy losses and submit by 30 September 2026.

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ABBREVIATIONS

COS	Cost of Supply
D-Form	Distribution Form
ERTSA	Eskom Retail Tariff Structural Adjustments
FBE	Free Basic Electricity
IBT	Inclining Block Tariff
IPP	Independent Power Producer
MFMA	Municipal Finance Management Act
NERA	National Electricity Regulation Act
NERSA	National Energy Regulator of South Africa
OPEX	Operating Expenditure

1. INTRODUCTION

1.1. The National Energy Regulator of South Africa (NERSA) receives and considers tariff applications on a yearly basis, in accordance with the mandate of the Energy Regulator to regulate prices and tariffs. Municipal tariffs must be approved by the Energy Regulator to be implemented on 1 July of each financial year.

1.2. The Chief Albert Luthuli Local Municipality is a small rural municipality situated in Mpumalanga.

1.3. The Municipality has a total of 7,675 customers, with the domestic customer base accounting for 79.90% of sales, as indicated in Table 2 below. In the 2025/26 financial year the municipality increased the tariffs by 11.40% is proposing an average increase of 10.5% for the 2026/27 financial year. The municipality has confirmed that it has an indigent register and provides 50 kWh free basic electricity per month to the 1,546 registered indigent customers.

1.4. Table 1 below highlights statistical data that provide a customer outlook of the Municipality's electricity supply in the region. This information is derived from the 2024/25 D-Form as provided by the licensee.

Table 1: Customer Statistics (Data obtained from 2024/25 D-Forms)

Consumer Classification	MWh	% MWh	Number of Consumers
Domestic (prepaid)	18,620	70.61	7,192
Domestic (conventional)	2,450	9.29	75
Commercial (prepaid)	1,389	5.27	227
Commercial (conventional)	3,312	12.56	179
Industrial	598	2.27	2
Totals	**26,369**	**100%**	**7,675**
[1]Free Basic Electricity (FBE)	7	0.03	1,520

[1] This information is already included in the customer statistics table above under domestic prepaid/conventional category

1.5. NERSA received Chief Albert Luthuli Local Municipality's tariff application, accompanied by a revised Cost of Supply (COS) study, on 31 March 2026 for the 2026/27 financial year. The Municipality attributed the revision of the COS study to Eskom's implementation of approved retail and municipal bulk tariff structural changes, arising from the approved Eskom's Retail Tariff and Structural Adjustment (ERTSA) decision for the 2025/26 FY.

1.6. The methodology used in the COS study for Chief Albert Luthuli Local Municipality is the cost-plus methodology. Aligned to the NERSA COS Framework: costs were built up from verified bulk purchases (Eskom invoices) and verified electricity-related operating costs (tested against D-Forms, Trial Balance and Audited AFS).

1.7. The asset value is estimated as – R365,036 million (AFS); depreciation – R18,153,944 (AFS); and profit margin – R39,460,310 (Table 5 – Revenue Requirement- RR).

1.8. NERSA followed the notice and comment consultation process. Chief Albert Luthuli Local Municipality's tariff application was published on the NERSA website on 31 March 2026, on social media platforms and national and local newspapers to solicit written comments from affected parties.

1.9. NERSA's decision was made on 6 May 2026, considering the analysis performed by NERSA.

2. LEGAL AND REGULATORY FRAMEWORK

2.1. Background

2.1.1. The approval of municipal electricity tariffs constitutes a core regulatory function of the Energy Regulator and must be exercised in accordance with the applicable legislative framework, national policy directives and court orders. The principal legal instruments governing the exercise of this regulatory authority include the National Energy Regulator Act, 2004 (Act No. 40 of 2004) ("NERA"), the Electricity Regulation Act, 2006 (Act No. 4 of 2006) as amended ("ERA"), the Promotion of Administrative Justice Act, 2000 (Act 3 of 2000) ("PAJA"), and the Electricity Pricing Policy for the South African Electricity Supply Industry, 2008 ("EPP").

2.1.2. The approval of municipal electricity tariffs follows the Eskom Multi-year Price Determination and Eskom Retail Tariff and Structural Adjustment decision and is undertaken annually to align with the municipal budgeting process contemplated in the Municipal Finance Management Act, 2003 (Act No. 56 of 2003).

2.1.3. In addition, the municipal tariff approval process has recently been the subject of judicial scrutiny in the High Court of South Africa (Gauteng Division, Pretoria) in AfriForum NPC v National Energy Regulator of South Africa and Others (Case No. 2025/137620), which resulted in structural directives governing the timing and conduct of NERSA's tariff approval process.

2.1.4. This section provides the legal and policy context within which the Energy Regulator evaluated and determined the municipal electricity tariff application for the 2026/2027 municipal financial year.

2.2. **NERSA's Statutory Mandate**

2.2.1. NERSA is established as a juristic person in terms of section 3 of the NERA. In terms of section 4 of NERA, the Energy Regulator, as the decision-making body, must regulate the electricity industry and execute the functions set out in the ERA. The Energy Regulator's electricity regulatory mandate is therefore primarily governed by the ERA. Section 3 of the ERA particularly provides that the Energy Regulator is the custodian and enforcer of the National Electricity Regulatory Framework and exercises regulatory authority over activities regulated under the ERA.

2.2.2. In particular:

a) section 4(a)(i) of the ERA provides that the Energy Regulator must consider applications for licences and may issue licences subject to conditions;
b) section 4(a)(ii) of the ERA provides that the Energy Regulator must regulate prices and tariffs; and
c) section 14(1)(d) of the ERA authorises the Energy Regulator to impose licence conditions relating to the setting or approval of prices, charges, rates and tariffs charged by licensees.

2.2.3. Municipalities distributing electricity do so under electricity distribution licences issued by the Energy Regulator and are therefore subject to the tariff approval framework established under the ERA.

2.3. Tariff Determination Principles under the ERA

2.3.1. When determining or approving electricity tariffs, the Energy Regulator must apply the principles contained in section 15(1) of the ERA.

2.3.2. Section 15(1) provides that the Energy Regulator:

a) must enable an efficient licensee to recover the full cost of the licensed activity;
b) must allow for a reasonable return commensurate with the risk of the licensed activity;
c) may provide incentives for continued improvement of technical and economic efficiency;
d) must avoid undue discrimination between customer categories;
e) may permit cross-subsidies of tariffs to certain classes of customers; and
f) may have regard to the need to ensure security of supply, diversity of supply and the promotion of renewable energy.

2.3.3. These statutory requirements form the core legal principles guiding the determination of electricity tariffs within the South African electricity supply industry.

2.4. Administrative Law Requirements

2.4.1. The approval of municipal electricity tariffs constitutes administrative action as defined in section 1 of the PAJA. Accordingly, the Energy Regulator must ensure that its tariff determinations are lawful, reasonable and procedurally fair as required by sections 3 and 6 of PAJA. Procedural fairness requires that affected parties and the public be afforded a reasonable opportunity to make representations before a final decision is taken.

2.4.2. Public participation processes conducted by the Energy Regulator therefore form an essential component of the municipal tariff approval process and are intended to ensure transparency, accountability and fairness in regulatory decision-making.

2.5. Policy Framework: Electricity Pricing Policy (2008)

2.5.1. In addition to the statutory framework, the Energy Regulator must have regard to the EPP. The EPP establishes national policy principles for electricity tariff setting, including cost reflectivity, transparency, economic efficiency and equity.

2.5.2. Policy Position 1 of the EPP provides that the revenue requirement for a regulated licensee must be set at a level that covers the full cost of production, including a reasonable risk-adjusted margin or return on appropriate asset values.

2.5.3. Policy Position 2 states that electricity tariffs must reflect the efficient cost of rendering electricity services accurately and that the average level of tariffs must be set to recover the approved revenue requirement.

2.6. Cost of Supply Studies

2.6.1. The EPP recognises that cost-reflective tariff structures require a sound understanding of the underlying cost drivers associated with electricity distribution.

2.6.2. Paragraph 8.1 of the EPP notes that cost of supply methodologies have historically not been consistently applied across the electricity distribution industry.

2.6.3. Policy Position 23 therefore requires electricity distributors to undertake cost of supply studies at least every five years, or when significant structural changes occur in the customer base or cost structure.

2.6.4. Such studies must be conducted in accordance with the methodology approved by NERSA and must accompany tariff structure applications submitted to the Energy Regulator.

2.7. Judicial Oversight of the Tariff Approval Process

2.7.1. The municipal tariff approval process administered by NERSA was the subject of litigation in AfriForum NPC v National Energy Regulator of South Africa and Others (Case No. 2025/137620) before the High Court of South Africa, Gauteng Division, Pretoria.

2.7.2. In its final judgment delivered on 4 December 2025, the Court held that NERSA's public participation process relating to the 2025/2026 municipal tariff approvals did not comply with the procedural requirements of section 4 of PAJA and was therefore unlawful.

2.7.3. However, recognising the potentially disruptive consequences of setting aside tariff determinations already implemented by municipalities, the Court declined to invalidate the tariffs. Instead, to assist in the timeous and lawful approval of municipal tariffs, the Court issued a structural interdict regulating the municipal tariff approval process going forward.

2.7.4. NERSA subsequently launched a variation application which sought to vary the timelines which were set by the Court on 4 December 2025, considering the practical difficulties which arose as it relates to NERSA's compliance with the court order. The Court, having heard NERSA's application, granted the variation application in respect of the fixed deadlines for the 2026/27 municipal tariff approvals.

2.8. **Court-directed Timelines**

2.8.1. The timelines below are applicable in respect of the 2026/27 municipal tariff approvals:

a) written notice of bulk tariffs by 6 March 2026;
b) municipal tariff applications to be submitted by 31 March 2026;
c) public participation processes to be concluded by 21 April 2026; and
d) the publication of NERSA decisions by 11 May 2026.

2.8.2. Municipal tariff approvals from 2027/28 are to comply with the following timelines:

a) written notice of bulk electricity tariffs be communicated by 31 January each year;
b) municipal tariff applications be submitted to NERSA by 20 March each year; and
c) municipal tariff approvals and the Tariff Reasons for Decision document, be approved and published by 5 May of each year.

2.9. **Conclusion**

2.9.1. The determination of municipal electricity tariffs by the Energy Regulator must therefore be undertaken within a comprehensive regulatory framework consisting of the NERA, ERA, PAJA, EPP and the binding judicial directives issued by the High Court in AfriForum NPC v NERSA (Case No. 2025/137620).

2.9.2. The reasons that follow in this Reasons for Decision document demonstrate how the Energy Regulator complied with the legislative, policy and judicial framework in determining the municipal electricity tariff for the 2026/2027 municipal financial year.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In assessing the financial and technical performance of Chief Albert Luthuli Local Municipality, the assessment relied primarily on the Distribution Forms (D-Forms) for the 2024/25 financial year submitted as part of the licensee's tariff application. The information contained in the D-Forms was verified against supporting source documents provided by the municipality, including the Trial Balance and Annual Financial Statements. The verified D-Form data set is therefore regarded as sufficiently reliable for purposes of evaluating performance trends that inform the tariff analysis.

A. Financial Performance

3.2. The municipality's electricity business shows weak financial sustainability, evidenced by a percentage deficit of 77.24% (2024/25 FY), although it is an improvement from 106.24% (2023/24 FY). This is indicated in Table 4 below:

3.3. The main drivers of the deficit, as recorded, are:

i) the Notified Maximum Demand (NMD) costs (R3,164,470million) (i.e. penalty paid to Eskom by the Municipality for exceeding its NMD); and
ii) ageing infrastructure contributing to high technical losses and associated cost inefficiencies.

3.4. Although there is an improvement in the financial performance of the Municipality, the current position indicates material inefficiencies and financial risk and supports the need for credible and monitored corrective actions, particularly around the exceedance of the NMD. However, the Municipality has partially completed Phase 1 and Phase 2 of de-loading for purposes of reducing the NMD costs.

Remedies to improve financial performance

3.5. Chief Albert Luthuli Local Municipality needs to put the following measures in place to improve its financial status. Due to financial constraints, the Municipality expects to complete deloading in the next financial year (2026/27). This will reduce the NMD penalty paid to Eskom by the Municipality.

B. Technical Performance

3.6. The Chief Albert Luthuli Local Municipality's technical performance remains critically constrained by high energy losses, which, although improved at 31.28% (2024/25) down from 43.01% (2023/24), as presented in Table 3 below, are still higher than the acceptable range of 12% as indicated in the COS Framework.

3.7. The Municipality's losses are attributed to a combination of:

a) Unaccounted own consumption - there is no difference between purchases for own use and resale.
b) Illegal connections/meter bypass – these are identified through regular meter inspections.
c) The aged infrastructure of the Municipality.

3.8. The Municipality has indicated that it will put the following measures in place to curb the high energy losses:

Table 2: Measures to Curb Energy Losses

Task to be completed	Detailed description of the task
Installation of meters at all municipal buildings and other municipal consumption points.	Municipality to install meters and ensure regular meter readings to keep records of its own consumption.
Installation of prepaid split/smart meters.	Municipality to install prepaid split/smart meters. All meters to be replaced with smart meters.
Upgrade capacity at substations. Building of the new Silobela Substation.	The Municipality to deload Carolina Substation to the newly upgraded Silobela Substation.
Replacing of faulty, aged & vandalised infrastructure(network)	The Municipality to replace aged and vandalised network of underground and overhead.
Metering of public lights	A pilot exercise on metering of public lights to measure own consumption.

3.9. Bulk electricity purchases amounted to R84,459 million (38 MWh), but electricity sales revenue amounted to R47,652 million (26 MWh), which means approximately R36,807 million of the bulk purchase cost was not recovered. This reflects a revenue recovery rate of about 56% (i.e., 44% not recovered) from electricity sales.

The municipality has high energy losses of 31.28%, which significantly undermines financial sustainability.

- If losses were capped at 12%, the Municipality would:

  a) improve net revenue by approximately R16,286 million; and
  b) reduce the deficit from 77.24% to 32.09%.

- If losses were capped at 6%, the Municipality would:

  c) improve net revenue by approximately R21,354 million; and
  d) reduce the deficit from 77.24% to 22.39%.

Table 3: Sensitivity Analysis

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	220,10		
Sales kWh	26 368 575,83	33 768 059,60	36 070 427,30
Purchases kWh	38 372 795,00	38 372 795,00	38 372 795,00
Losses kWh	12 004 219,17	4 604 735,40	2 302 367,70
Losses percentage	**31,28%**	**12,00%**	**6,00%**
Additional Energy (kWh)		7 399 483,77	9 701 851,47
Additional Revenue (Rands)		16 286 263,78	21 353 775,09
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 47 652 233,44	R 63 938 497,22	R 69 006 008,53
Total Expenses (Rands)	R 84 458 746,00	R 84 458 746,00	R 84 458 746,00
Net Profit (Loss)	R -36 806 512,56	R -20 520 248,78	R -15 452 737,47
Percentage Surplus/Deficit	**-77,24%**	**-32,09%**	**-22,39%**

3.10. The Revenue Requirement proposed is R130,558 million with the removal of the NMD (R3,164million) and the costs for the losses (R18,405 million), then RR becomes R112,153 million.

3.11. From a regulatory standpoint, energy loss levels of this magnitude are not consistent with efficient distribution operations and represent a major threat to both revenue sufficiency and security/quality of supply, justifying stronger reporting and oversight conditions.

Table 4: Performance Indicators

PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS		
INDICATORS	**2024-25FY (Actuals)**	**2023-24 FY (Approved)**
Percentage surplus (deficit) %	-77.24%	-106.24%
Percentage energy losses %	31.28%	43.01%

4. DETERMINATION OF CHIEF ALBERT LUTHULI LOCAL MUNICIPALITY'S TARIFFS BASED ON THE COS STUDY

a) The process that the Energy Regulator followed in considering and approving Chief Albert Luthuli Local Municipality's tariff application was supported by a cost of supply study. The revised study aimed to improve cost reflectivity by aligning tariffs with Eskom's unbundled costs.

b) The study diligently follows the NERSA COS Framework and utilises the latest available audited data, which is based on the 2024/25 financial year.

c) The municipality submitted a revised COS and tariff application in which the tariff adjustment was determined in line with the October 2023 NERSA-approved COS Framework (section 18.7).

d) The analysis applied the relevant adjustment index and treated cost movements as follows:
   i) bulk purchase costs were updated using the approved 9,01% Eskom bulk tariff movements; and
   ii) controllable electricity OPEX costs were adjusted using CPI-linked assumptions;

iii) adjustments were supported by source documents and reasonability checks (D-Forms, Trial Balance and AFS).

Figure 1 below details the five steps considered in determining the COS study.

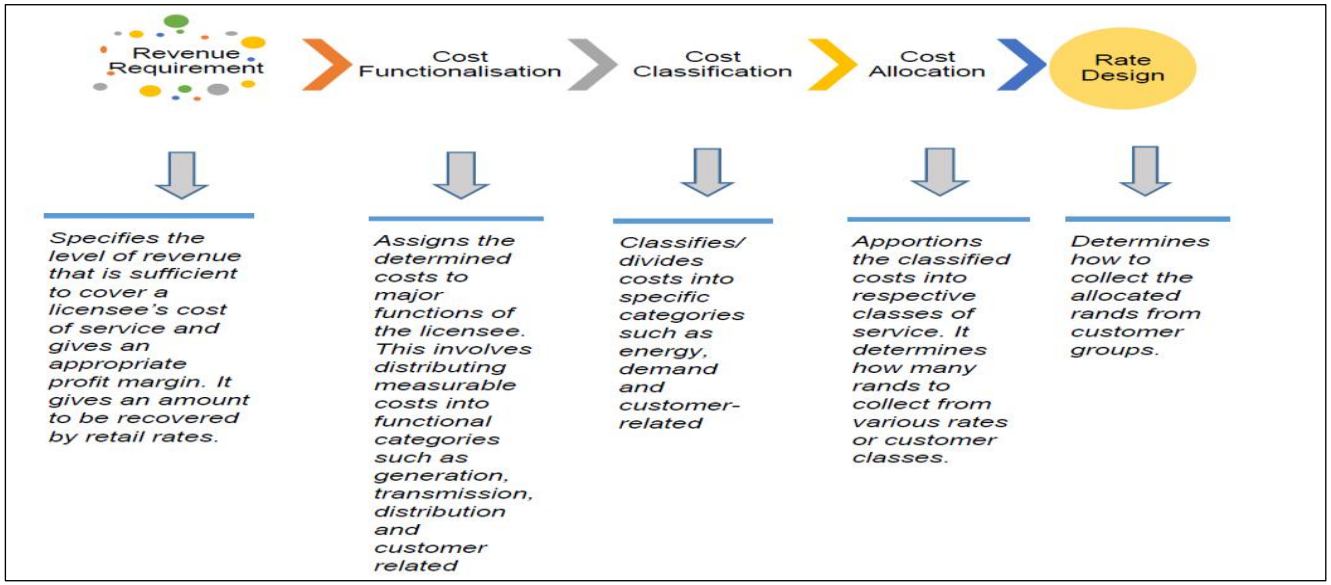


Figure 1: Five Steps of COS

4.1. Revenue Requirement

4.1.1. To be fully cost-reflective, the licensee applied for a revenue requirement of R109,388 million for the 2026/27 financial year. Eskom bulk purchases, inclusive of an allowance for energy losses, account for 84% of the total revenue requirement, while operational expenditure accounts for 22%. After excluding the Notified Maximum Demand (NMD) cost of R3,422 million, the adjusted revenue requirement amounts to R105,966 million.

Table 5: Revenue Requirement Components

Revenue Requirement components	Wires	Retail	Munic Application	NERSA Adjustment	NERSA Recommendation	% of Total
Allowable costs	31 005 769	78 382 657	109 388 426	3 422 691	105 965 735	100%
Energy purchases from Eskom - net of cost of losses	-	79 228 502	79 228 502			72%
Energy purchases from Eskom - cost of losses	13 313 697	-	13 313 697			12%
Other energy purchases	-	-	-			0%
Capital expenditure	-	-	-			0%
Operational expenditure (incl. Depreciation)	16 143 970	7 857 056	24 001 026	3 422 691	20 578 335	22%
Other revenues	- 60 268	- 8 626 006	- 8 686 274			-8%
Surplus	1 608 370	- 76 895	1 531 475			1%
Not allowable costs	8 033 311	10 371 964	18 405 275			
Cost of losses disallowed	8 033 311	10 371 964	18 405 275			
TOTAL COSTS	**39 039 080**	**88 754 621**	**127 793 701**			
	31%	69%				

4.1.2. Efficiency costs for the 2024/25 financial year were assessed as these represent the latest actual data available. This assessment forms the baseline for projecting costs for the 2026/27 financial year, using the stated assumptions to determine the revenue requirement.

4.1.3. In line with the COS Framework, shared municipal costs were ring-fenced and allocated strictly to the electricity business using the D-Form. Cost attribution was verified against the Trial Balance and audited AFS to ensure a clear separation between electricity and non-electricity functions. Any costs not demonstrably related to electricity distribution were adjusted or excluded. This approach supports the principle of cost causality and prevents cross-subsidisation between municipal functions.

4.1.4. All expenses included in the revenue requirement were examined to confirm that they are directly attributable to the licensee's electricity distribution function. Where costs were found to be inflated, inefficient, or insufficiently substantiated, they were adjusted or excluded accordingly. These adjustments are explained below.

Bulk Purchases

4.1.5. Chief Albert Luthuli Local Municipality applied for bulk purchase expenditure of R92,542 million, representing 84% of total costs. The bulk purchase figures were verified against Eskom invoices for the 2024/25 financial year.

4.1.6. To derive the 2026/27 bulk purchase estimate, the 2025/26 Cost of Supply (COS) amount was escalated by 9.01%, in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

4.1.7. The methodology used to forecast bulk purchase costs is considered reasonable. Accordingly, the bulk purchase expenditure is recommended for approval as submitted.

4.1.8. Energy losses above 12%, amounting to R18,405 million, were disallowed on the basis that only efficiently incurred costs, together with a reasonable margin, may be passed through to customers.

Operational expenditure

4.1.9. The licensee applied for operational expenditure of R24,001 million, representing 22% of total costs, as reflected in Table 5 above.

4.1.10. The approach adopted by the licensee in forecasting operational expenditure is considered reasonable and has been approved as applied for. However, costs deemed inefficient and within the municipality's control, such as the Notified Maximum Demand (NMD) penalty of R3,423 million arising from exceedances, were excluded from the municipality's cost base.

Table 6: OPEX Adjustment

Cost Drivers	Units	2026/27	Adjustments	Recommended Opex 2026/27
General Costs & Other	R	**21 589 971**	(3 422 691)	**18 167 280**
Salaries and Allowances	R	5 643 212		5 643 212
Contracted Services	R	2 186 063		2 186 063
Salaries, wages and allowances (excl, R&M)		5 648 638		5 648 638
Payments to consultants (operational work)		809 037		809 037
NMD exceedance penalties	R	3 422 691	(3 422 691)	0
Current year depreciation	R	3 880 330	0	3 880 330
Shared Opex	R	**2 411 055**		**2 411 055**
General Expenses (Travel and subsidies, oil &fuel)	R	2 411 055	0	2 411 055
TOTAL	R	**24 001 026**		**20 578 335**

Surplus

4.1.11. The licensee applied for a surplus of R1,531 million. The applied surplus margin of 1%, as reflected in Table 5 of the revenue requirement, was benchmarked against the target range of 10% to 20% in the approved NERSA COS Framework. The licensee's margin, therefore, falls below the lower end of the benchmark range.

4.1.12. In recommending a surplus, NERSA relied on section 15(1)(a) of the Electricity Regulation Act, which requires tariffs to enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return, in line with Electricity Pricing Policy (EPP) Position 1.

4.1.13. In applying this provision together with the COS methodology, NERSA must ensure that the licensee recovers costs incurred efficiently and prudently, including a reasonable return, while preventing excessive compensation.

4.1.14. To ensure that the surplus remains modest and commensurate with risk, the exceedance of the NMD and the high energy losses were disallowed. NERSA considers it necessary for the Municipality to implement targeted corrective measures. These include reducing energy losses through accelerated metering, network refurbishment, and enforcement against illegal connections; managing notified maximum demand to limit avoidable Eskom-related charges; improving billing, credit control, and revenue collection; ring-fencing and transparently reporting electricity business costs and revenues; and prioritising capital and maintenance expenditure on high-loss and high-failure parts of the network.

4.1.15. From a regulatory perspective, these remedies should be supported by measurable implementation plans and periodic reporting to NERSA so that the Regulator can assess whether the risk profile is improving and whether the surplus allowed in future tariff determinations remains justified.

4.1.16. It is therefore recommended that the Energy Regulator approve the allowable revenue of R106 million, as set out in Table 4 above. This revenue is then used in the subsequent steps of cost functionalisation, classification, allocation, and rate design. These steps were verified to be consistent with the approved revenue requirement and are discussed below.

4.2. Cost Functionalisation

4.2.1. The licensee has categorised its revenue requirement of R106 million into two primary functional components, namely wires and retail business, in accordance with the NERSA COS Framework as demonstrated in Figure 2 below. Upon verification, the allocation of these functional costs was found to be consistent with the stated revenue requirement.

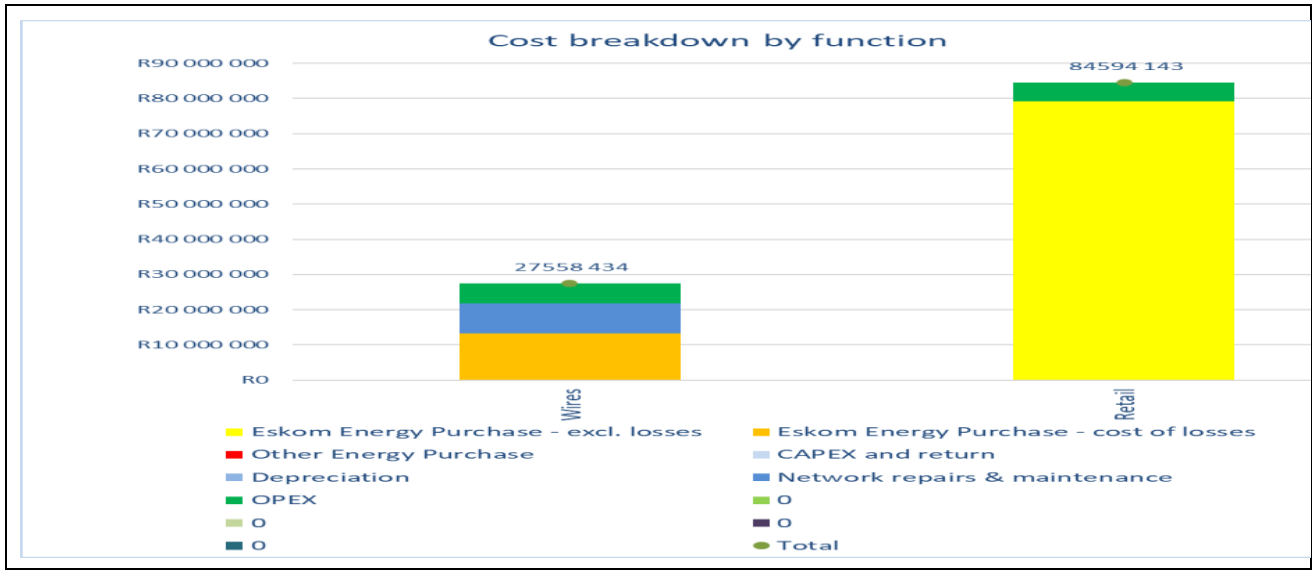


Figure 2: Cost Breakdown by Functions

4.2.2. These costs, upon verification, are consistent with the approved revenue requirements. Network repairs and maintenance are the predominant cost drivers in the wires business, while energy purchases are the primary cost driver in the retail business.

4.3. **Cost Classification**

4.3.1. The licensee classified its costs into energy, demand and customer-related costs, which is in line with the NERSA COS Framework. The costs align with revenue requirements and cost functionalisation upon verification.

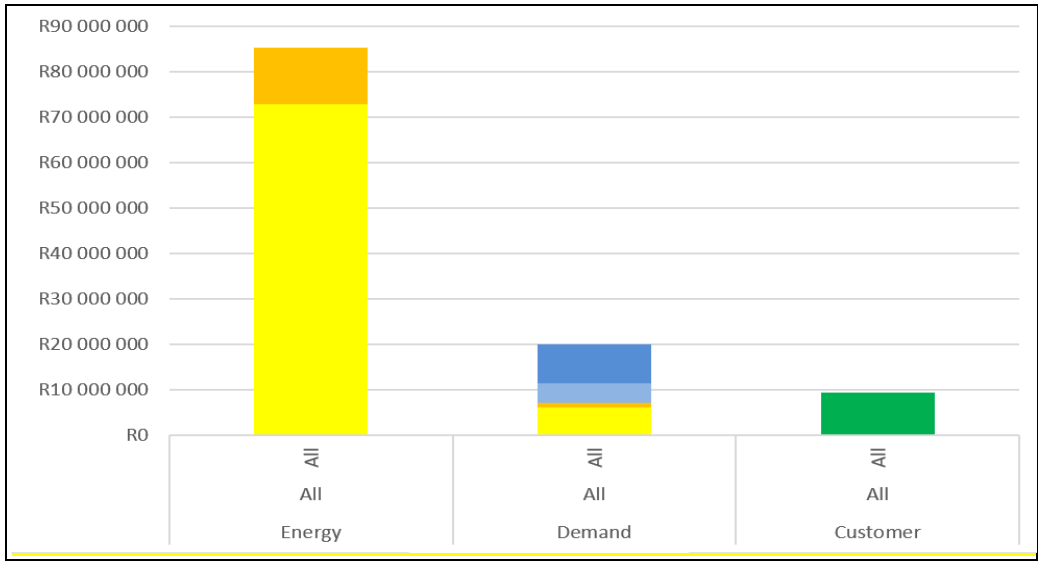


Figure 3: Cost Breakdown by Cost Structure (Classification)

4.3.2. Energy purchases constitute energy-driven costs, with the highest expenditure occurring during summer period under a standard time of use profile, due to the longer duration of the season within the tariff year. Demand-driven costs are likewise predominantly incurred in the summer period. Customer-driven costs are primarily attributed to "Other OPEX," which includes expenses related to providing electricity distribution services to customers.

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4.4. Cost Allocation

4.4.1. In this step, the licensee's revenue requirement is allocated across customer categories, in accordance with the NERSA COS Framework. Upon verification, the allocated costs were found to be consistent with the revenue requirement, cost functionalisation and cost classification outcomes.

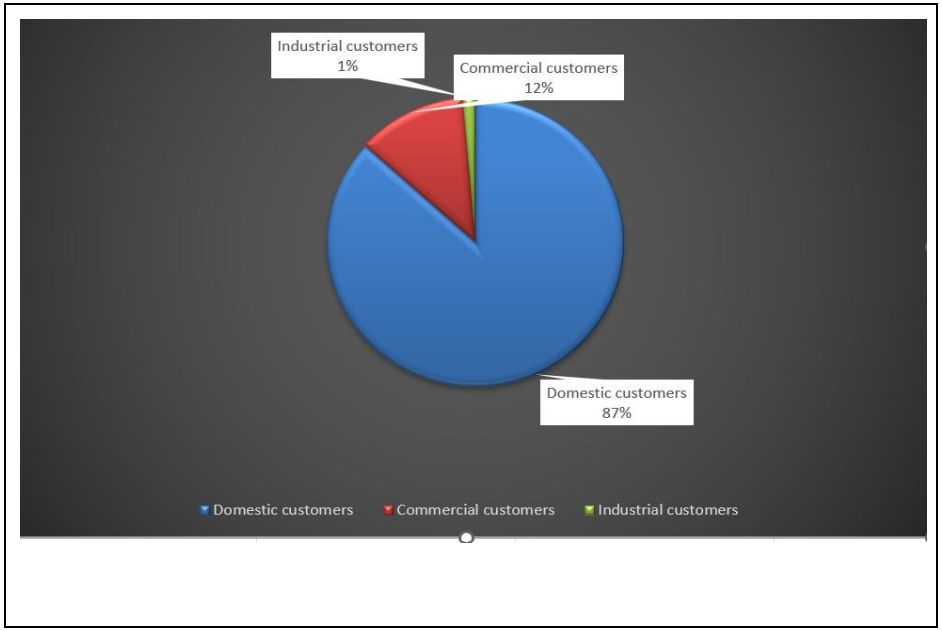


Figure 4: Costs Allocated

4.5. Rate Design

4.5.1. Figure 5 below reflects the outcome of the COS study, indicating that certain customer categories require upward adjustments, while others warrant reductions. A comparison between the COS study and revenue generated by tariff category highlights the extent of over- or under-recovery in each category, as illustrated in Figure 5.

4.5.2. The COS confirms the presence of inter-tariff cross-subsidies, with commercial/industrial customers subsidising residential. The municipality will be requested to develop a cross-subsidy framework that is fair and transparent.

4.5.3. To achieve full cost-reflectivity, the municipality would be required to implement differentiated tariff adjustments across the various customer categories.

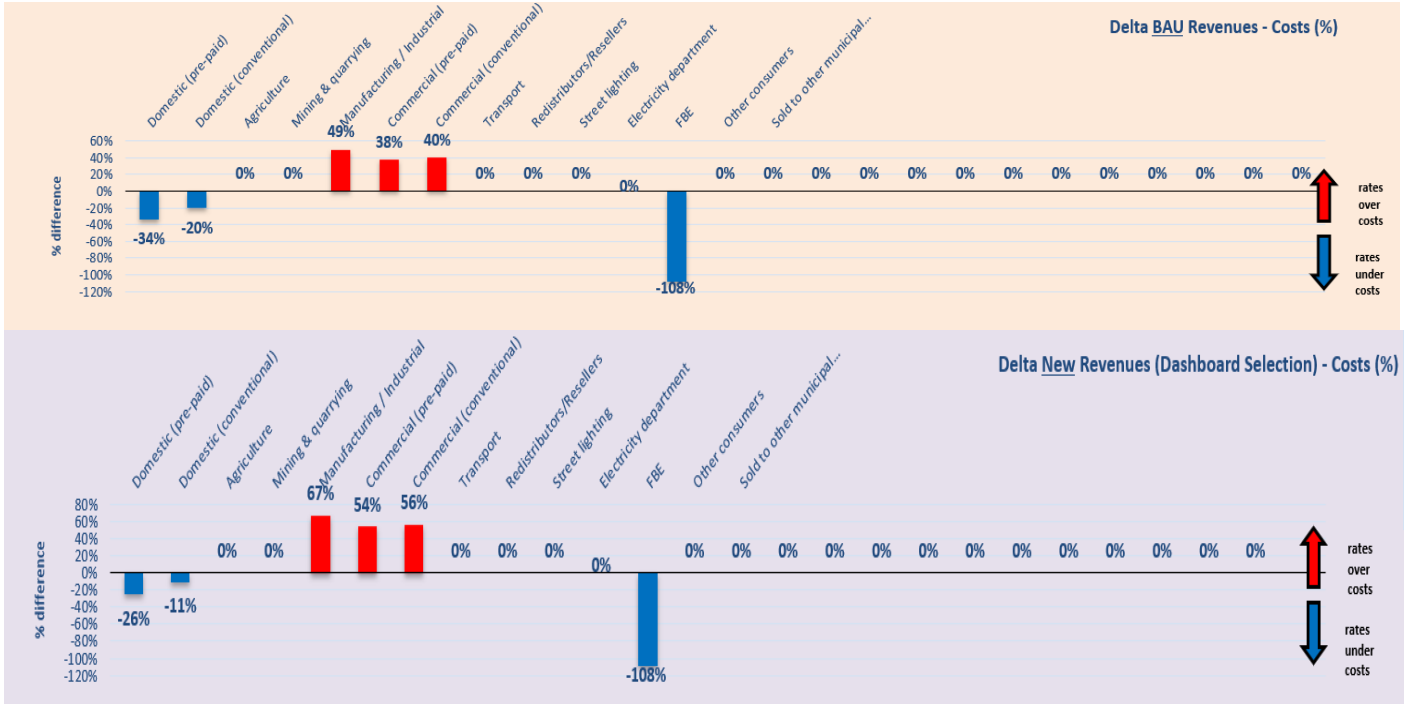


Figure 5: Revenue Recovery by Customer Category

5. CONCLUSION ON THE COS

5.1. Although the COS study indicates that full cost reflectivity would require an average tariff increase of 24.5%, the Municipality adopted a gradualist approach by proposing an average increase of 10.5%. This approach reflects an appropriate balance between revenue adequacy, affordability, and payment risk, particularly given the municipality's customer profile and the high proportion of domestic consumers.

5.2. The COS study submitted by Chief Albert Luthuli Local Municipality for the 2026/27 financial year tariff review is compliant with the NERSA-approved COS Framework and is based on reliable D-Form and audited data. Although the Municipality proposed an average tariff increase of 10.5% across all tariff categories, the COS results indicate that differentiated tariff adjustments are required across customer categories to improve cost reflectivity.

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2. Commercial						
2.1 Prepaid: 1P; 40 A	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic charge: R/month	529.96	10.50%	585.61	585.61	10.50%	Uniform percentage increases across all components, do not fully reflect the COS outcomes, which indicated varying levels of over- and under-recovery by customer segment.
Energy charge: c/kWh - High season	304.41	10.50%	336.37	336.37	10.50%	
Energy charge: c/kWh- low season	276.75	10.50%	305.81	305.81	10.50%	
2.2 41 A to 60 A: 1P	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic charge: R/month	1,152.53	10.50%	1,273.55	1,273.55	10.50%	The Municipality proposed the same increase across the tariff components.
Energy charge: c/kWh - High season	304.41	10.50%	336.37	336.37	10.50%	
Energy charge: c/kWh- low season	276.75	10.50%	305.81	305.81	10.50%	

2.3 61A to 80A: 1P	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic charge: R/month	1,509.08	10.50%	1,667.53	1,667.53	10.50%	The Municipality proposed the same increase across all tariff components.
Energy charge: c/kWh - high season	304.41	10.50%	336.37	336.37	10.50%	
Energy charge: c/kWh- low season	276.75	10.50%	305.81	305.81	10.50%	

2.4 Up to 60 A : 3P	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase	Analysis and key findings
Basic charge: R/month	1,886.94	10.50%	2,085.07	2,085.07	10.50%	All the tariff components are increasing by the same rate of 10.50%.
Energy charge: c/kWh - high season	304.41	10.50%	336.37	336.37	10.50%	
Energy charge: c/kWh- low season	276.75	10.50%	305.81	305.81	10.50%	

2.5 61 to 80 A: 3P	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	Recommended % Increase	Analysis and Key Findings
Basic charge: R/month	2,609.80	10.50%	2,883.83	2,883.83	10.50%	All the tariff components are increasing by the same rate of 10.50%
Energy charge: c/kWh - high season	304.41	10.50%	336.37	336.37	10.50%	
Energy charge: c/kWh- low season	276.75	10,50%	305.81	305.81	10.50%	

Public Benefit Organisations - up to 80 A - (1Phase)	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and key findings**
A) Up to 80 A – 1P						All the tariff components are increasing by the same rate of 10.50%
Basic charge: R/month	475.68	10.50%	525.63	525.63	10.50%	
Energy charge: c/kWh - high season	304.41	10.50%	336.37	336.37	10.50%	
Energy charge: c/kWh- low season	276.75	10.50%	305.81	305.81	10.50%	
Public Benefit Organisations: up to 80 A- 3-phase	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic charge: R/month	638.60	10.50%	705.65	705.65	10.50%	All the tariff components are increasing by the same rate of 10.50%
Energy charge: c/kWh - high season	304.41	10.50%	336.37	336.37	10.50%	
Energy charge: c/kWh- low season	276.75	10.50%	305.81	305.81	10.50%	
Public Benefit Organisations: above 80 A	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic charge: R/month	4,150.33	10.50%	4,586.11	4,586.11	10.50%	All the tariff components are increasing by the same rate of 10.50%
Energy charge: c/kWh - high season	267.07	10.50%	295.11	295.11	10.50%	
Energy charge c/kWh - low season	242.79	10.50%	268.28	268.28	10.50%	

Industrial Tariffs						
up to 60 A - 3P	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic charge: R/month	3,152.97	10.50%	3,484.03	3,484.03	10.50%	All the tariff components are increasing by the same rate of 10.50%
Demand charge: R/kVA	251.88	10.50%	278.32	278.32	10.50%	
Energy charge: c/kWh - high season	277.43	10.50%	306.56	306.56	10.50%	
Energy charge: c/kWh - low season	252.21	10.50%	278.69	278.69	10.50%	
61A up to 80 A 3-phase	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic charge: R/month	3,669.62	10.50%	4,054.93	4,054.93	10.50%	All the tariff components are increasing by the same rate of 10.50%
Demand charge: R/kVA	251.88	10.50%	278.32	278.32	10.50%	
Energy charge: c/kWh - high season	277.43	10.50%	306.56	306.56	10.50%	
Energy charge: c/kWh - low season	252.21	10.50%	278.69	278.69	10.50%	

Up to 80 A - 3P	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic charge: R/month	4,186.30	10.50%	4,625.86	4,625.86	10.50%	All the tariff components are increasing by the same rate of 10.50%
Demand charge: R/kVA	251.88	10.50%	278.32	278.32	10.50%	
Energy charge: c/kWh - high season	277.43	10.50%	306.56	306.56	10.50%	
Energy charge: c/kWh - low season	252,21	10.50%	278.69	278.69	10.50%	
Above 80 A 3-phase	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**Recommended % Increase**	**Analysis and Key Findings**
Basic charge: R/month	8,346.08	10.50%	9,222.42	9,222.42	10.50%	All the tariff components are increasing by the same rate of 10.50%
Demand charge: R/kVA	251.88	10.50%	278.32	278.32	10.50%	
Energy charge: c/kWh - high season	250.98	10.50%	277.34	277.34	10.50%	
Energy charge: c/kWh - low season	228.18	10.50%	252.14	252.14	10.50%	

INDUSTRIAL						
TOU - Low Voltage	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**% Increase**	**Analysis and Key Findings**
Basic charge (R/month)	6,252.40	10.50%	6,908.91	6,908.91	10.50%	All the tariff components are increasing by the same rate of 10.50%
Demand charge (R/kVA)						
Network high demand	153.60	10.50%	169.73	169.73	10.50%	
Network low demand	153.60	10.50%	169.73	169.73	10.50%	
Low Season						
Peak	276.47	10.50%	305.50	305.50	10.50%	
Standard	242.80	10.50%	268.29	268.29	10.50%	
Off-peak	149.76	10.50%	165.48	165.48	10.50%	
High Season						
Peak	279.51	10.50%	308.86	308.86	10.50%	
Standard	245.46	10.50%	271.23	271.23	10.50%	
Off-peak	151.41	10.50%	167.31	167.31	10.50%	

TOU - High Voltage	**2025/26 Approved**	**% Increase**	**2026/27 Proposed**	**2026/27 Recommended**	**% Increase**	**Analysis and Key Findings**
Basic charge (R/month)	6,558.17	10.50%	7,246.78	7,246.78	10.50%	All the tariff components are increasing by the same rate of 10.50%
Demand charge (R/kVA)						
Network high demand	173.37	10.50%	191.58	191.58	10.50%	
Network low demand	173.37	10.50%	191.58	191.58	10.50%	
Low Season						
Peak	299.20	10.50%	330.61	330.61	10.50%	
Standard	262.73	10.50%	290.31	290.31	10.50%	
Off-peak	162.05	10.50%	179.07	179.07	10.50%	
High Season						
Peak	310.72	10.50%	343.34	343.34	10.50%	
Standard	272.85	10.50%	301.50	301.50	10.50%	
Off-peak	168.30	10.50%	185.97	185.97	10.50%	

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

10.1. The Energy Regulator, having considered the Chief Albert Luthuli Local Municipality's application, supporting information, and applicable legal framework, approves the tariff adjustments as set out in the Reasons for Decision document.