NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

The Decision and Reasons for Decision (RfD)

In the matter regarding the

Municipal Tariff Application for the 2026/27 Financial Year

By

Greater Tzaneen Local Municipality

THE DECISION

1. At its meeting held on 6 May 2026, the Regulator Executive Committee (REC) considered Greater Tzaneen 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 20) 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.

TABLE OF CONTENTS

The Decision 1
Abbreviations 5
1. Introduction 6

2. Legal and Regulatory Framework 7
3. Financial and Technical Performance 11
4. Determination of Polokwane's tariffs based on the COS study 12
4.1. Revenue Requirement 13
4.2. Cost Functionalisation 16
4.3. Cost Classification 16
4.4. Cost Allocation 17
4.5. Rate Design 18
5. Conclusion on the COS 18
6. Public Participation 19
7. The Objectors and other Intervening Parties 20
8. Tariff Analysis: 21
9. Confidentiality 28
10. Conclusion 28

LIST OF TABLES

Table 1: Customer Statistics (Data obtained from 2024/25 D-forms) 6
Table 2: Performance Indicators 12
Table 3: Revenue Requirement Components 13
Table 4: Operational Expenditure 14

LIST OF FIGURES

Figure 1: Fives steps of COS 13
Figure 2: Costs breakdown by Functions ..... **Error! Bookmark not defined.**
Figure 3: Costs breakdown by cost structure (Classification) 17
Figure 4: Costs Allocated 17
Figure 5: Revenue Recovery by Customer Category 18
Figure 6: COS Results 19

ABBREVIATIONS

COS	Cost of Supply
D-form	Distribution form
ERTSA	Eskom's 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. Greater Tzaneen is a medium-sized municipality situated in Limpopo Province. The municipality has a total of 9 379 customers, with the Domestic Customer base accounting for 51,43% of sales, as indicated in Table 2 below. In the 2025/26 financial year the municipality increased the tariffs by 13,8% is proposing an average increase of 8,5% for the 2026/27 financial year. The municipality has confirmed that it does have an indigent register and 23 indigent customers and provides 50kWh free basic electricity per month to the customers.

1.3. Table 1 below highlights statistical data that gives 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)	18 666	8.69	3 756
Domestic (Conventional)	91 822	42.74	4 574
Agriculture	40 265	18.74	149
Manufacturing/Industrial	39 671	18.46	127
Commercial Conventional	24 436	11.37	773
Totals	**214 860**	**100**	**9 379**
[1]Free Basic Electricity (FBE)	185	0.17[2]	23

1.4. NERSA received Greater Tzaneen'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 and the removal of Inclining Block Tariffs (IBT) for the domestic tariffs.

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

[2] This is a percentage of domestic MWh

1.5. The municipality applied the Cost-Plus methodology in developing its COS study. The framework explicitly permits municipalities to determine allowable revenue using prudently incurred costs plus a reasonable surplus.

1.6. In accordance with the NERSA COS framework, the allowable revenue was established through a build-up of costs. These costs were built up from verified bulk purchases (Eskom invoices) and electricity-related operating costs (tested against D-Forms, Trial Balance and audited Annual Financial Statements (AFS).

1.7. An asset value of R1.0 billion with a Depreciation of R92 146 million was extracted from the municipality's AFS for cost verification purposes. The depreciation was included as a proxy for asset consumption and future asset replacement consistent with the cost-plus methodology.

1.8. NERSA followed the notice and comment consultation process. Greater Tzaneen'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 ("EPP") for the South African Electricity Supply Industry, 2008.

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 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 electricity regulatory mandate of the Energy Regulator 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 (ESI).

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 the 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 2026/27 financial year.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In assessing the financial and technical performance of Greater Tzaneen, 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 declining financial sustainability, with the percentage surplus decreasing from 10,97% in 2023/24 financial year to 7,16% in 2024/25 financial year, as reflected in Table 3 below. The reduced surplus may be attributable to a combination of rising bulk purchase and operating costs relative to revenue, lower sales volumes, increased technical and non-technical losses and revenue collection constraints (including billing inefficiencies). A sustained decline in surplus reduces the electricity business' financial buffer and may increase liquidity risk, weaken the municipality's ability to fund the Eskom account, undertake maintenance, place upward pressure on future tariffs to maintain cost recovery and payment sustainability.

3.3. The municipality's account is not in arrears, as confirmed by the absence of interest charges levied by Eskom, indicating that the account is maintained in compliance with agreed credit terms and settled within the prescribed settlement period under an accrual accounting framework.

B. Technical Performance

3.4. The municipality's technical performance remains satisfactory. However, energy losses increased from 10,00% in 2023/24 financial year to 11,08% in 2024/25 financial year (Table 3). Increased electricity losses typically erode the electricity business' financial position, since more energy is purchased than can be billed and collected. However, while the trend is negative, the reported loss level remains below the 12% benchmark referenced in the COS framework.

Table 2: Performance Indicators

PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS		
INDICATORS	**2024-25 FY (Actuals)**	**2023-24 FY (Approved)**
Percentage Surplus (Deficit)%	7,16%	10,97%
Percentage Energy Losses %	11,08%	10,0%

4. DETERMINATION OF GREATER TZANEEN'S TARIFFS BASED ON THE COS STUDY

i. The process that the Energy Regulator followed in considering and approving Greater Tzaneen'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 and the removal of the IBT tariffs for the Domestic Customers.

ii. The revenue requirement for Greater Tzaneen municipality was determined using a cost-plus methodology. The study diligently follows the NERSA COS framework and utilises the latest available audited data which is based on the 2024/25 financial year.

iii. 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).

iv. The analysis applied the relevant adjustment index and treated cost movements as follows:
   a) bulk purchase costs were updated using the approved 9,01% Eskom bulk tariff movements;
   b) controllable electricity OPEX costs were adjusted using CPI-linked assumptions; and
   c) adjustments were supported by source documents and reasonability checks (D-Forms, Trial Balance and AFS).

v. All shared municipal costs were ring-fenced and strictly allocated to the electricity distribution function using the D-Form cost allocation methodology, consistent with the COS requirements. Verification against the Trial Balance and audited AFS confirmed that only electricity-related costs were included in the revenue requirement.

vi. Figure 1 below details the five steps considered in the determination of the COS study.

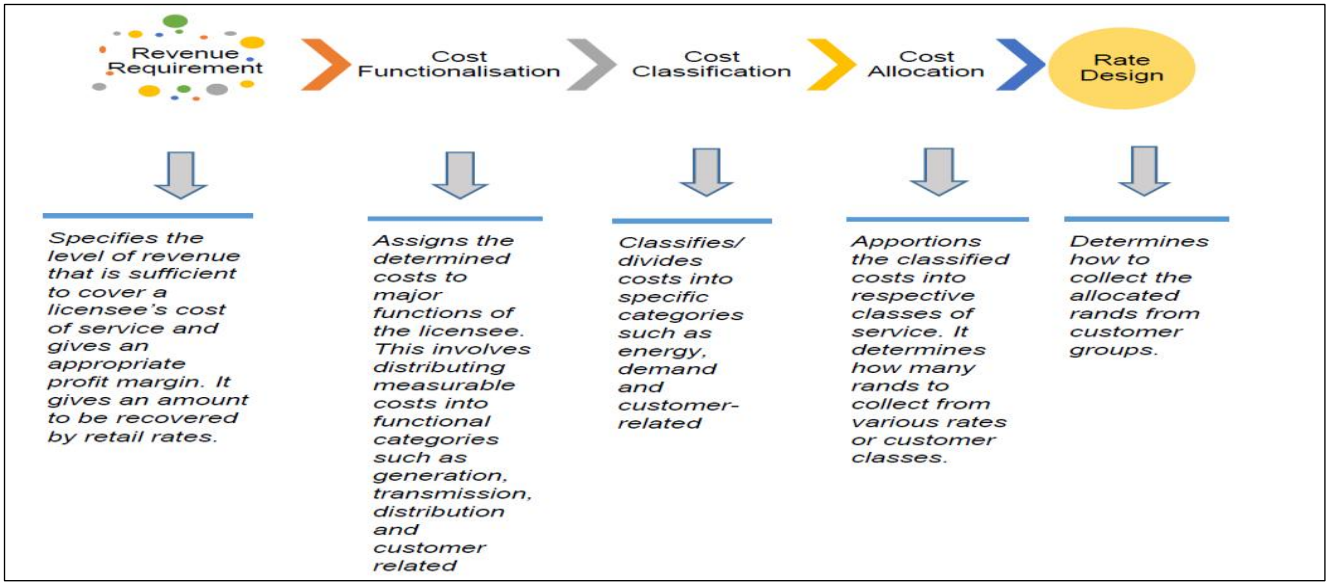


Figure 1: Fives Steps of COS

vii. The following steps are undertaken to analyse the cost of supply study submitted by the municipality:

4.1. Revenue Requirement

To be fully cost reflective, the licensee's revenue requirement is R1,3 billion for the 2026/27 financial year. This revenue requirement is predominantly Eskom purchases accounting for 72% including energy losses allowance. Operational expenditure accounts for 11% of revenue requirement.

Table 3: Revenue Requirement Components

Revenue Requirement components	Wires	Retail	Total	% of Total
Allowable costs	350 189 398	900 421 225	1 250 610 623	100%
Energy purchases from Eskom - net of cost of losses	-	789 781 761	789 781 761	63%
Energy purchases from Eskom - cost of losses	94 042 114	13 042 339	107 084 454	9%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	234 648 284	16 068 250	250 716 534	11%
Other revenues	- 10 336 400	- 327 600	- 10 664 000	-1%
Surplus	31 835 400	81 856 475	113 691 875	9%
Not allowable costs	-	-	-	
Cost of losses disallowed	-	-	-	
TOTAL COSTS	350 189 398	900 421 225	1 250 610 623	
	28%	72%		

4.1.1. The efficiency costs for the 2024/25 financial year have been assessed, as this constitutes the most recent set of actual data. This assessment serves as the baseline for projecting costs for the 2026/27 financial year, applying stated assumptions to determine the revenue requirement for that period.

4.1.2. In line with COS framework requirements, 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, ensuring separation of electricity and non-electricity functions. Any costs not demonstrably related to electricity distribution were adjusted or excluded. This approach ensures compliance with the principle of cost causality and prevents cross-subsidisation between municipal functions.

4.1.3. All expenses included in the revenue requirements have been examined to ensure that they are directly attributable to the electricity distribution function of the licensee. Where costs were identified as inflated, inefficient, or not sufficiently justified, such amounts were adjusted or excluded accordingly. These adjustments are detailed and motivated below.

Bulk Purchases

4.1.4. Greater Tzaneen applied for bulk purchase expenditure amounting to R896 866 million, representing 72% of total costs. The bulk purchase figures were verified against Eskom invoices for the 2024/25 financial year.

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

4.1.6. The methodology applied in forecasting bulk purchase costs is deemed reasonable. Accordingly, the bulk purchase expenditure has been recommended for approval as submitted.

Table 4*:* Operational Expenditure

	Year 0 estimate (Rand)	Year 1 estimate (Rand)	Year 2 estimate (Rand)
General & Other	R 218 018 378	R 238 608 146	R 242 408 329
Salaries and allowances	R 68 073 834	R 71 477 525	R 75 766 177
Materials and supplies	R 20 127 224	R 41 075 481	R 43 129 255
Contracted Services	R 22 934 072	R 25 000 000	R 26 000 000
Payments to consultants (operational work)	R 6 729 618	R 9 200 000	R 9 660 000
Other creditors interests	R 8 007 418	R 5 905 140	R 6 200 397
Current year depreciation	R 92 146 212	R 85 950 000	R 81 652 500
Shared OPEX	R 5 623 709	R 7 979 243	R 8 308 206
Bad debts written-off	R 2 000 000	R 1 750 000	R 1 767 500
General Expenses	R 3 623 709	R 6 229 243	R 6 540 706
Total	**R 223 642 087**	**R 246 587 389**	**R 250 716 534**

4.1.7. The licensee applied for operational expenditure of R250 717 million which accounts for 11% of total costs as reflected in Table 4 above.

4.1.8. The approach adopted by the licensee in forecasting operational expenditure is reasonable and has been approved as applied for. However, no costs were deemed to be inefficient and within the municipality's control from the cost base of the municipality.

Surplus

4.1.9. The licensee applied for a surplus of R113 693 million. In recommending a surplus, NERSA relied on section 15(1)(a) of the Electricity Regulation Act, which provides that tariffs must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return. In applying this provision, together with the COS methodology, NERSA is required to ensure that the licensee recovers efficiently and prudently incurred costs, including a reasonable return, while preventing excessive compensation.

4.1.10. The surplus is not derived from a return on assets, but rather assessed as a margin on total costs, consistent with the Cost of Supply framework.

4.1.11. The applied surplus margin of 9% (as indicated in Table 4 of the RFD) was benchmarked against the established target range of 10–20% on the approved NERSA COS framework, EPP Policy Position 1, D-Form and Trial Balance. The licensee's margin therefore sits below the lower bound of the framework range.

4.1.12. In assessing whether the approved surplus is commensurate with the risk of the licensed activity (section 15(1)(a) of the ERA), NERSA considered both (i) the quantitative reasonableness of the surplus level and (ii) the municipality's risk profile, as evidenced by the information submitted.

4.1.13. Accordingly, the surplus was tested against the municipality's risk profile, considering the following factors:

a) Revenue collection and credit risk: The municipality reported exposure to non-payment and bad debts. For the 2026/27 FY, the municipality budgeted a bad debt write-off of R2 million, which is within the 5% benchmark for bad debts.

b) Operational risk: The municipality's network performance indicates elevated technical and non-technical losses. Energy losses were reported at 11,08% in 2024/25 (up from 10% in 2023/24) but remain within the 12% benchmark referenced in the COS framework.

4.1.14. These risks support the inclusion of a modest surplus to promote revenue sufficiency and continuity of supply. Consistent with the COS framework principle that only efficient and prudently incurred costs may be recovered. These interventions demonstrate that the approved surplus level was moderated to protect consumers and avoid over-compensation.

4.1.15. The decision to approve the revenue requirement as applied for will then be used in the next steps which are Cost Functionalisation, Classification, Allocation and Rate Setting. These steps have been verified and confirmed to align with the revenue requirement. Further details of these steps are discussed below.

4.2. Cost Functionalisation

4.2.1. The licensee has categorised its revenue requirement of R1,3 billion 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.

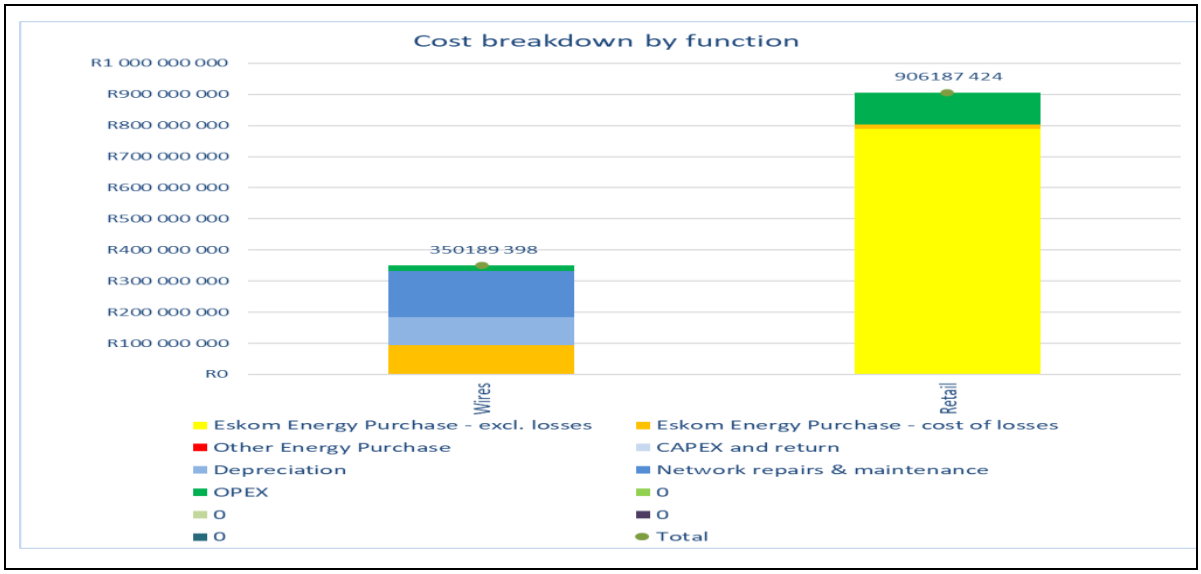


Figure 2: Costs breakdown by Functions

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

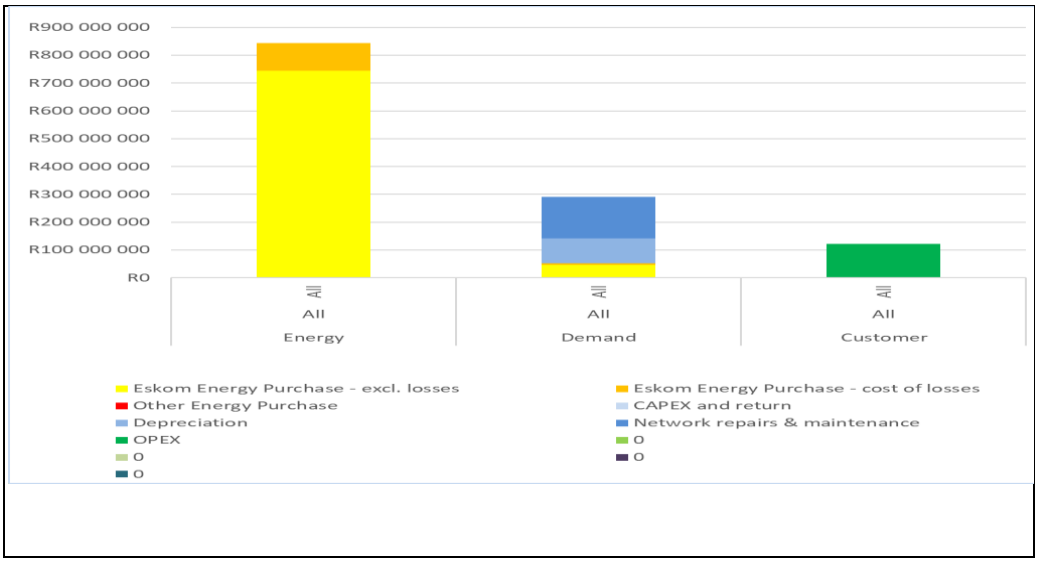


Figure 3: Costs breakdown by cost structure (Classification)

4.3.2. Energy purchases constitute energy-driven costs, with the highest expenditure occurring during summer period under 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 summer period. Customer-driven costs are primarily attributed to "Other OPEX," which encompasses expenses related to the provision of electricity distribution services to customers.

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.

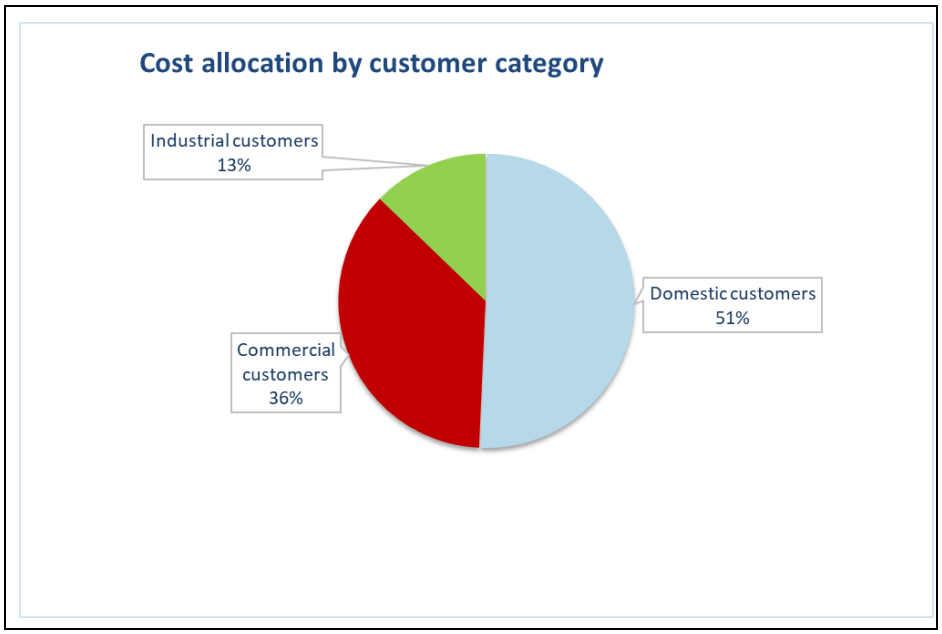


Figure 4: Costs Allocated

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 the revenue generated per tariff category highlights the extent of over- or under-recovery within each tariff 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. Such cross-subsidisation is permitted and expected within municipal tariff structures, particularly to protect vulnerable households. The municipality's commitment to a phased transition to cost-reflective tariffs aligns with NERSA's approach of avoiding tariff shock while improving allocative efficiency over time.

4.5.3. To achieve full cost reflectivity, the municipality would be required to implement differentiated tariff adjustments across the various customer categories. The tariff path reflects a risk-mitigated approach, prioritising affordability, revenue stability, over immediate cost reflectivity.

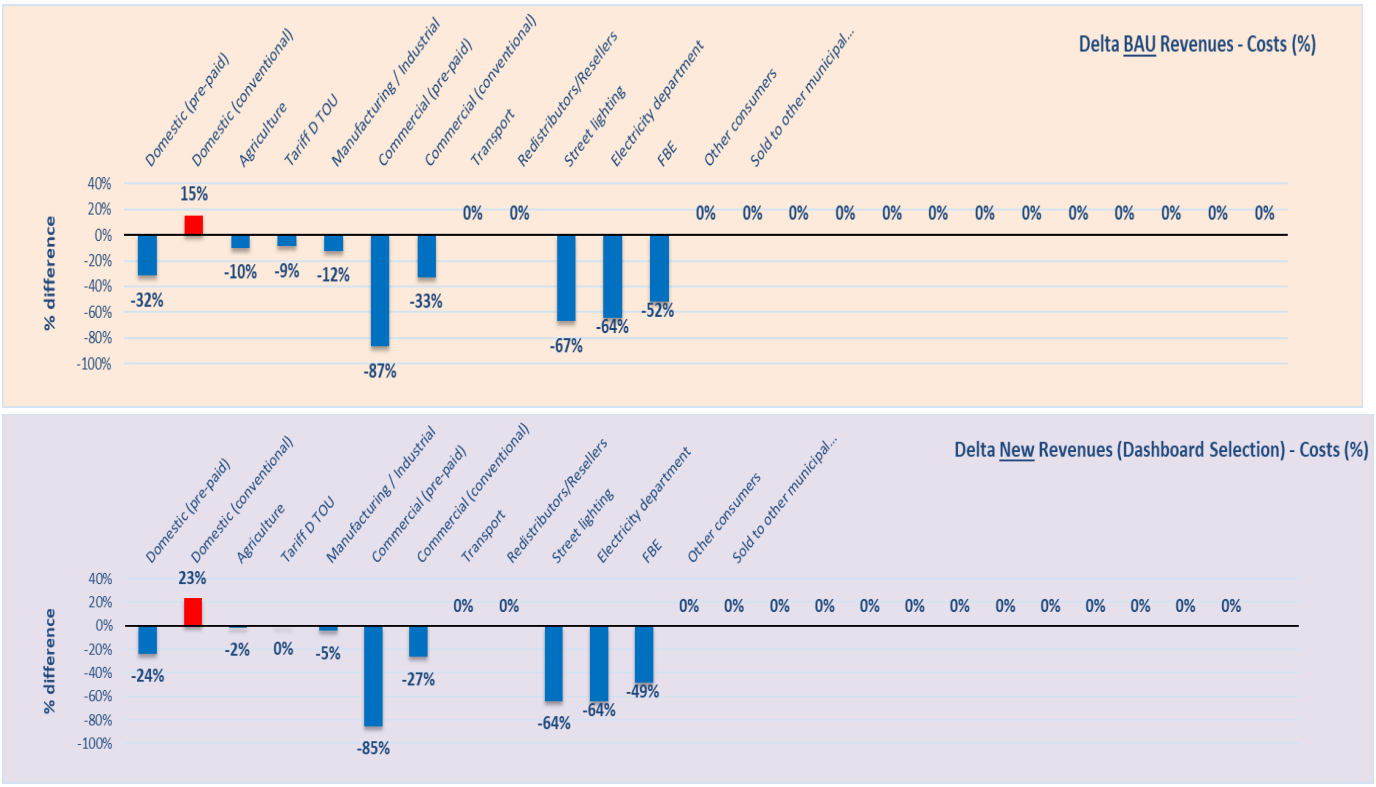


Figure 5: Revenue Recovery by Customer Category

5. CONCLUSION ON THE COS

5.1. The municipality applied the Cost-Plus methodology when developing its COS study. This approach does not have an audited Regulatory Asset Base (RAB) that meets the requirements for a Rate of Return (RoR) determination. Accordingly, no return on assets was calculated and no Weighted Average Cost of Capital (WACC) was applied.

5.2. The COS framework explicitly allows municipalities to determine allowable revenue using

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TARIFF B: DOM / AGRIC CONV

DOM / AGRIC: 16kVA- 1 PHASE	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Energy Charge: c/kWh	*339,93*	*8,52%*	*368,88*	*368,88*	*8,52%*	The approved tariff adjustments reflect a phased move toward cost reflective tariffs.
Basic Charge: R/month	*708,14*	*4,29%*	*738,54*	*738,54*	*4,29%*	
Excess Energy Charge> 1500kWh: c/kWh	*347,00*	*9,50%*	*379,95*	*379,95*	*9,50%*	

DOM / AGRIC: 25kVA- 3 PHASE	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Energy Charge: c/kWh	*282,26*	*8,52*	*306,30*	*306,30*	*8,52*	The approved tariff adjustments reflect a phased move toward cost reflective tariffs.
Basic Charge: R/month	*2 806,22*	*4,29*	*2 926,70*	*2 926,70*	*4,29*	
Excess Energy Charge> 3000kWh: c/kWh	*290,73*	*8,52*	*315,49*	*315,49*	*8,52*	

DOM / AGRIC: 50kVA- 3 PHASE	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Energy Charge: c/kWh	*282,26*	*8,52*	*306,30*	*306,30*	*8,52%*	The tariff adjustments reflect a phased move toward cost reflective tariffs.
Basic Charge: R/month	*3741,63*	*4,29*	*3902,27*	*3902,27*	*4,29%*	
Excess Energy Charge> 3000kWh: c/kWh	*290,73*	*8,52*	*315,49*	*315,49*	*8,52%*	

DOM / AGRIC: 75kVA- 3 PHASE	*2025/26 Approved*	*% Increase*	*2026/27 Proposed*	*2026/27 Recommended*	*Recommended % Increase*	*Analysis & Key findings*
Energy Charge: c/kWh	*282,26*	*8,52%*	*306,30*	*306,30*	*8,52%*	The tariff adjustments reflect a phased move toward cost reflective tariffs.
Basic Charge: R/month	*5 238,29*	*4,29%*	*5 463,19*	*5 463,19*	*4,29%*	
Excess Energy Charge> 3000kWh: c/kWh	*290,73*	*8,52%*	*315,49*	*315,49*	*8,52%*	

COMMERCIAL CONVENTIONAL

BUSINESS MEDIUM 16kVA - Single	*2025/26 Approved*	*% Increase*	*2026/27 Proposed*	*2026/27 Recommended*	*Recommended % Increase*	*Analysis & Key findings*
Energy Charge: c/kWh	*272,55*	*9,10%*	*297,35*	*297,35*	*9,10%*	The municipality applied for a uniform increase for these customers.
Basic Charge: R/month	*2 159,17*	*9,10%*	*2 355,65*	*2 355,65*	*9,10%*	
Excess Energy Charge> 1500kWh: c/kWh	*280,72*	*9,10%*	*306,27*	306,27	9,10%	

BUSINESS MEDIUM 25kVA - 3 Phase	*2025/26 Approved*	*% Increase*	*2026/27 Proposed*	*2026/27 Recommended*	*Recommended % Increase*	*Analysis & Key findings*
Energy Charge: c/kWh	*252,64*	*9,10%*	*275,63*	*275,63*	*9,10%*	The tariff adjustments reflect a uniform increase.
Basic Charge: R/month	*2 789,16*	*9,10%*	*3 042,97*	*3 042,97*	*9,10%*	
Excess Energy Charge> 3000kWh: c/kWh	*260,22*	*9,10%*	*283,90*	*283,90*	*9,10%*	

BUSINESS MEDIUM 50kVA - 3 Phase	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Energy Charge: c/kWh	*252,64*	*9,10%*	*275,63*	*275,63*	*9,10%*	The tariff adjustments reflect a uniform increase.
Basic Charge: R/month	*3 387,39*	*9,10%*	*3 695,64*	*3 695,64*	*9,10%*	
Excess Energy Charge> 3000kWh: c/kWh	*260,22*	*9,10%*	*283,90*	*283,90*	*9,10%*	

BUSINESS MEDIUM 75kVA - 3 Phase	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Energy Charge: c/kWh	*252,64*	*9,10%*	*275,63*	*275,63*	*9,10%*	Tariff adjustments reflect a uniform increase.
Basic Charge: R/month	*4 879,91*	*9,10%*	*5 323,98*	*5 323,98*	*9,10%*	
Excess Energy Charge> 3000kWh: c/kWh	*260,22*	*9,10%*	*283,90*	*283,90*	*9,10%*	

COMMERCIAL PREPAID

BUSINESS MEDIUM 16kVA - Single	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Energy Charge: c/kWh	*350,69*	*9,01%*	*382,30*	*382,30*	*9,01%*	The tariff adjustments reflect a phased move towards cost reflectivity.
Basic Charge: R/month	*1 084,41*	*9,00%*	*1 182,00*	*1 182,00*	*9,00%*	

BUSINESS MEDIUM 25kVA – 3 Phase	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Energy Charge: c/kWh	*350,69*	*9,01%*	*382,30*	*382,30*	*9,01%*	The tariff adjustments reflect a phased move towards cost reflectivity.
Basic Charge: R/month	*1 360,96*	*9,00%*	*1 483,44*	*1 483,44*	*9,00%*	

BUSINESS MEDIUM 50kVA – 3 Phase	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Energy Charge: c/kWh	*350,69*	*9,01%*	*382,30*	*382,30*	*9,01%*	The tariff adjustments reflect a phased move towards cost reflectivity.
Basic Charge: R/month	*1 701,2*	*9,00%*	*1 854,30*	*1 854,30*	*9,00%*	

BUSINESS MEDIUM 75kVA – 3 Phase	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Energy Charge: c/kWh	*350,69*	*9,01%*	*382,30*	*382,30*	*9,01%*	The approved tariff adjustments reflect a phased move toward cost reflective tariffs.
Basic Charge: R/month	*2 466,74*	*9,00%*	*2 688,73*	*2 688,73*	*9,00%*	
STREETLIGHTS	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Energy Charge: c/kWh	*229,50*	*6,00%*	*243,27*	*243,27*	*6,00%*	
Basic Charge: R/month	*362,26*	*6,00%*	*384,00*	*384,00*	*6,00%*	Uniform increase proposed by the municipality.

TARIFF C

BUSINESS HIGH	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Basic Charge (R/month)	*5 054,39*	*9,00%*	*5 509,30*	*5 509,30*	*9,00%*	The approved tariff adjustments reflect a phased move toward cost reflective tariffs.
Demand Charge (R/kVA)						
Network High Demand	*599,61*	*9,00%*	*653,60*	*653,60*	*9,00%*	
Network Low Demand	*224,19*	*9,01%*	*244,40*	*244,40*	*9,01%*	
ENERGY CHARGE						
High Season	*215,85*	*9,01%*	*235,30*	*235,30*	*9,01%*	
Low Season	*159,23*	*9,02%*	*173,60*	*173,60*	*9,02%*	

AGRIC / DOM HIGH	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Basic Charge (R/month)	*4 846,68*	*9,10%*	*5 287,73*	*5 287,73*	*9,10%*	Uniform increase for all tariff components.
Demand Charge (R/kVA)						
Network High Demand	*689,56*	*9,10%*	*752,31*	*752,31*	*9,10%*	
Network Low Demand	*372,67*	*9,10%*	*406,58*	*406,58*	*9,10%*	
ENERGY CHARGE						
High Season	217,56	*9,10%*	*237,36*	*237,36*	*9,10%*	
Low Season	161,22	*9,10%*	*175,89*	*175,89*	*9,10%*	

TARIFF D

BULK METER	***2025/26 Approved***	***% Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***	***Analysis & Key findings***
Basic Charge (R/month)	*20 983,58*	*9,10%*	*22 893,08*	*22 893,08*	*9,10%*	The approved tariff adjustments reflect a phased move toward cost reflective tariffs.
Demand Charge (R/kVA)						
Network High Demand	*130,387*	*9,10%*	*142,25*	*142,25*	*9,10%*	
Network Low Demand	*130,387*	*9,10%*	*142,25*	*142,25*	*9,10%*	
Low Season						
Peak	*252,77*	*9,10%*	*275,77*	*275,77*	*9,10%*	
Standard	*178,664*	*9,10%*	*194,92*	*194,92*	*9,10%*	
Off-Peak	*121,325*	*9,10%*	*132,37*	*132,37*	*9,10%*	
High Season						
Peak	*825,47*	*9,10%*	*900,59*	*900,59*	*9,10%*	
Standard	*238,52*	*9,10%*	*260,23*	*260,23*	*9,10%*	
Off-Peak	*138,69*	*9,10%*	*151,31*	*151,31*	*9,10%*	

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

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