NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

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Decision and Reasons for Decision (RfD)

In the matter regarding the

Municipal Tariff Application for the 2026/27 Financial Year

By

Enoch Mgijima Local Municipality

THE DECISION

At its meeting held on 8 May 2026, the Regulator Executive Committee (REC) considered the Enoch Mgijima 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 8 of this document.

Based on the available information and the analysis performed, the REC decided:

1. to approve the tariffs 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. to note the COS study submitted by the municipality;
3. that the municipality must submit a report accounting for all the costs identified in its COS study to enable the National Energy Regulator of South Africa (NERSA) to perform its independent verification or audit process by 31 January 2027; and
4. that the Municipality must submit quarterly progress reports on the efficiency improvement measures taken to reduce high energy losses and deficits to enable NERSA to monitor the implementation by 30 September 2026.

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ABBREVIATIONS AND ACRONYMS

COS	Cost of Supply
D-form	Distribution form
ERTSA	Eskom Retail Tariff Structural Adjustments
FBE	Free Basic Electricity
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 Enoch Mgijima Local Municipality (Enoch Mgijima) is situated in the Eastern Cape. The details regarding customer statistics are highlighted in Table 1 below. Enoch Mgijima offers 50 kWh of Free Basic Electricity (FBE) per month to indigent customers.

Table 1: Customer statistics (data obtained from 2024/25 D-forms)

CONSUMER STATISTICS (OBTAINED FROM 2024-2025 DISTRIBUTION FORMS)			
Consumer Classification	**Sales (KWh)**	**%KWh**	**Number of Consumers**
Domestic (Prepaid)	31 605 027	29,60%	10 248
Domestic (Conventional)	1 524 824	1,43%	4 671
Agriculture	801 854	0,75%	29
Manufacturing / Industrial	35 421 509	33,17%	31
Commercial (Prepaid)	6 931 101	6,49%	896
Commercial (Conventional)	29 476 673	27,60%	742
Electricity Department	358 459	0,34%	4
Inter-Departmental & Street Lighting	665 707	0,62%	11
TOTAL SALES	**106 785 153**	**100%**	**16 632**
Free Basic Electricity (FBE)	**1 092 200**	**3,30%**	**2 889**

1.3 NERSA received Enoch Mgijima's tariff application and its revised cost of supply (COS) study on 31 March 2026. The municipality indicated that the revision was necessitated by Eskom's revised tariff structure for the 2025/26 financial year (FY), which introduced new cost components and reallocated existing charges across energy, network and service-related elements.

1.4 Enoch Mgijima is applying for an average price increase of 12.01% for 2026/27FY, which has been limited to Eskom bulk of 9.01% due to its operational inefficiencies.

1.5 NERSA followed the notice and comment consultation process. On 31 March 2026, NERSA published Enoch Mgijima's tariff application on its website, and notices on social media platforms and in national and local newspapers to solicit written comments from affected parties. No comments were received.

1.6 The Energy Regulator's decision was made on 8 May 2026, considering the the analysis performed by NERSA.

2. LEGAL AND REGULATORY FRAMEWORK

Background

2.1. 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 ('the ERA'), the Promotion of Administrative Justice Act, 2000 (Act No. 3 of 2000) (PAJA) and the Electricity Pricing Policy for the South African Electricity Supply Industry, 2008 (EPP).

2.2. 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).

2.3. 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.

2.4. This section provides the legal and policy context within which the Energy Regulator evaluated and determined the municipal electricity tariff application for the 2026/27 municipal financial year.

NERSA's Statutory Mandate

2.5. NERSA is established as a juristic person in terms of section 3 of 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.

2.6. 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.

2.7. 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.

Tariff Determination Principles under the ERA

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

2.9. 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.

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

Administrative Law Requirements

2.11. The approval of municipal electricity tariffs constitutes administrative action as defined in section 1 of 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.

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

Policy Framework: Electricity Pricing Policy (2008)

2.13. 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.

2.14. 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.

2.15. 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.

Cost of Supply Studies

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

2.17. Paragraph 8.1 of the EPP notes that COS methodologies have historically not been consistently applied across the electricity distribution industry.

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

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

Judicial Oversight of the Tariff Approval Process

2.20. 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.

2.21. In its final judgment delivered on 4 December 2025, the Court held that NERSA's public participation process relating to the 2025/26 municipal tariff approvals did not comply with the procedural requirements of section 4 of PAJA and was therefore unlawful.

2.22. 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.

2.23. NERSA subsequently launched a variation application seeking to vary the timelines set by the Court on 4 December 2025, in light of practical difficulties that arose regarding 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.

Court-Directed Timelines

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

a) Written notice of bulk tariffs must be communicated by 6 March 2026.
b) Municipal tariff applications must be submitted by 31 March 2026.
c) Public participation processes must be concluded by 21 April 2026.
d) NERSA decisions must be published by 11 May 2026.

2.25. Municipal tariff approvals from 2027/28 must comply with the following timelines:

a) Written notice of bulk electricity tariffs must be communicated by 31 January each year.
b) Municipal tariff applications must be submitted to NERSA by 20 March each year.
c) Municipal tariffs and the tariff reasons for decision documents must be approved and published by 5 May of each year.

Conclusion

2.26. The determination of municipal electricity tariffs by the Energy Regulator must 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).

2.27. The reasons that follow in this document demonstrate how the Energy Regulator complied with the legislative, policy and judicial framework in determining the municipal electricity tariff for the 2026/27 municipal financial year.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1 In evaluating the financial and technical performance of Enoch Mgijima LM, NERSA relied on the 2024/25 Distribution forms' (D-forms) information provided in analysing the licensee's tariff application. The D-forms' information was validated by NERSA against the relevant source documents submitted by the municipality

(i.e. the trial balance/annual financial statement). Hence, the information provided on the D-forms is considered reliable for the analysis of the tariffs.

3.2 Enoch Mgijima Local Municipality is experiencing severe financial distress, with its deficit worsening significantly from 40.75% in 2023/24 to 91.61% in 2024/25. This is mainly driven by very high energy losses, bulk purchase costs, including penalties and interest, and bad debts, which together account for 87.60% of total expenditure. Although revenue increased by 16%, expenditure increased by 58%, worsening the municipality's financial position. The municipality needs to improve its declared capacity to avoid NMD penalties. It must also implement urgent, credible corrective actions, particularly around reducing energy losses, managing Eskom debt and controlling costs.

Remedies to Improve Financial Performance

a) The municipality should put the following measures in place to improve its financial and technical status:
   - Devise a financial payment plan and commit to it, to ensure that there is continuous payment of Eskom's debt.
   - Action the developed plan for curbing the accumulating energy losses.

3.3 The municipality indicated that it is struggling to keep up with the payment of Eskom debt despite the payment arrangement in place. It cited the historic debt inherited during the merger with other municipalities that were already in distress. In the 2023/24 financial year, the municipality received the relief funds from the National Treasury.

Table 2: Performance indicators

PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS		
INDICATORS	**2024-25FY (Actuals)**	**2023-24 FY (Approved)**
Percentage Surplus (Deficit)	-91,61%	-40,75%
Percentage Energy Losses	52,88%	44,85%

3.4 Energy losses were reported at 52.88% in 2024/25 financial year (2023/24FY: 44.85%), indicating a deterioration. The losses in electricity sales are due to:

a) electricity theft and meter tampering;
b) incorrect billing and unmetered supplies; and
c) cable theft and vandalism.

Measures in Place to Curb the Losses

a) The physical audit and disconnection of tampering meters.

b) Meter tamper amnesty period campaign for certain periods of electricity meters.
c) Replacement of non-vending meters with new smart meters.
d) Continuous monitoring of consumption patterns of all prepaid meters.
e) Conducting the revenue protection process, and introducing use of RT29 tender to install smart meters.

3.6 Current losses of 52.88% are far above acceptable norms and materially erode financial sustainability. If losses were capped at 12% and 6%, the municipality would have seen a reduction in the deficit from 91.61% to 24.42% and 18.32%, respectively. Thus, improving net revenue by approximately R213.588 million, as shown in Table 3 below.

Table 3: Energy loss analysis

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	201,06		
Sales kWh	106 785 153,20	199 419 537,39	213 016 324,03
Purchases kWh	226 613 110,67	226 613 110,67	226 613 110,67
Losses kWh	119 827 957,47	27 193 573,28	13 596 786,64
Losses percentage	**52,88%**	**12,00%**	**6,00%**
Additional Energy (kWh)		92 634 384,19	106 231 170,83
Additional Revenue (Rands)		186 250 692,85	213 588 392,07
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 344 844 056,64	R 531 094 749,49	R 558 432 448,71
Total Expenses (Rands)	R 660 764 633,49	R 660 764 633,49	R 660 764 633,49
Net Profit (Loss)	R -315 920 576,85	R -129 669 884,00	R -102 332 184,78
Percentage Surplus/Deficit	**-91,61%**	**-24,42%**	**-18,32%**

3.7 Based on the above information, the municipality's electricity business is under severe financial pressure, as evidenced by the operating deficit margin escalating to an unsustainable level of 91.61%. This significant deficit indicates that the current electricity revenue is insufficient to recover the full cost of supply, thereby undermining the financial sustainability of the electricity service. The deteriorating margin exposes the municipality to heightened operational and financial risks, including cash flow constraints, inability to adequately maintain and refurbish infrastructure, growing creditor obligations, and increased dependence on cross-subsidisation or external financial support.

3.8 This level of deficit raises serious concerns regarding the municipality's financial viability, regulatory compliance and ability to maintain efficient service delivery obligations in line with cost-reflective tariff principles.

4. DETERMINATION OF ENOCH MGIJIMA'S TARIFFS BASED ON THE COS STUDY

4.1 The process that the Energy Regulator followed in considering and approving Enoch Mgijima's tariff application was supported by a COS study.

4.2 Enoch Mgijima utilised the COS study model developed by Sustainable Energy Africa (SEA) and various other stakeholders to determine its revenue requirements for the 2026/27 financial year and to apportion costs required to service each customer class in a fair and equitable manner. The study diligently follows the NERSA COS Framework and utilises the latest available audited data, which is based on the 2024/25 financial year.

4.3 The figure below details the five steps considered in the determination of the COS study.

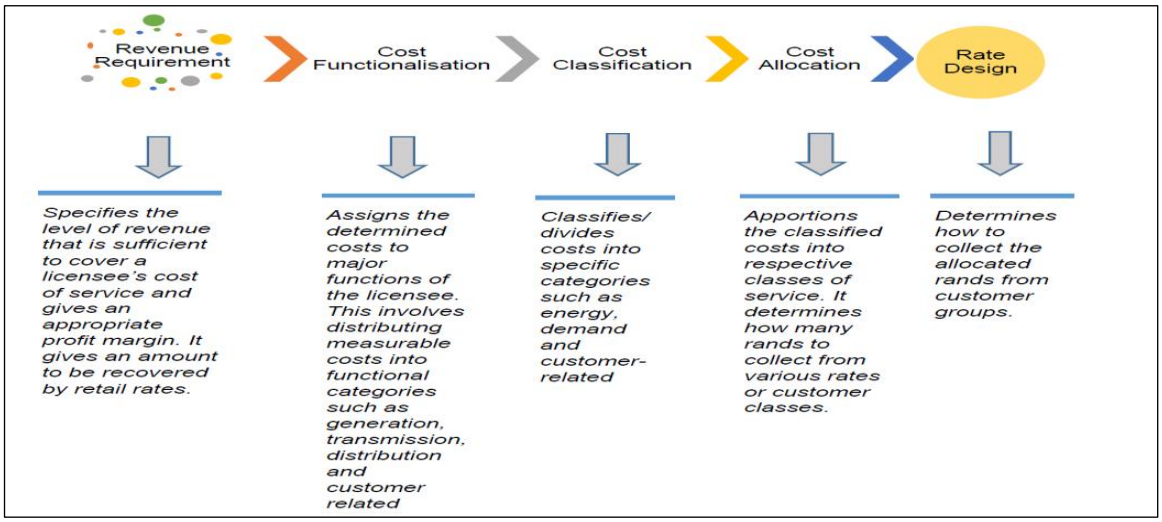


Figure 1: Five steps of COS study

4.4 The following steps are undertaken to analyse the COS study:

Revenue Requirement

4.4.1 In order to be fully cost-reflective, the licensee applied for a revenue requirements are R451.350m for the 2026/27 financial year. This revenue requirement is predominantly Eskom purchases, accounting for 75%, including energy losses

allowance. Operational expenditure accounts for 18% of the overall revenue requirements.

Table 4: Revenue requirement components

	Total cost (R)			
Revenue Requirement components	Wires	Retail	Total	% of Total
Allowable costs	82 588 936	368 761 457	451 350 393	100%
Energy purchases from Eskom - net of cost of losses	-	279 122 264	279 122 264	62%
Energy purchases from Eskom - cost of losses	49 596 653	11 035 007	60 631 660	13%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	25 895 187	45 583 052	71 478 239	16%
Other revenues	- 410 988	- 502 636	- 913 624	0%
Surplus	7 508 085	33 523 769	41 031 854	9%
Not allowable costs	36 299 109	129 210 799	165 509 909	
Cost of losses disallowed	36 299 109	129 210 799	165 509 909	
TOTAL COSTS	118 888 046	497 972 256	616 860 302	
	19%	81%		

4.4.2 The efficiency of the costs in the 2024/25 (base year) financial year has been assessed, as this is the most recent set of actual data. This forms the basis for the projection of costs for the 2026/27 financial year using assumptions to calculate revenue requirements for that year.

4.4.3 Furthermore, NERSA has verified all expense items included in the revenue requirements to ensure that they relate only to the electricity function of the licensee. Where expenses are deemed inflated or unjustified, they have been adjusted accordingly and expanded below.

Bulk Purchases

4.4.4 The licensee applied for a bulk purchase expenditure of R339. 754 million which accounts for 75% of the total costs when including the 12% energy losses allowance. Bulk purchases were verified against the 2024/25 Eskom invoices.

4.4.5 In order to get to the 2026/27 estimation, the 2025/26 COS amount was adjusted by 9.01% in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

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

Operational Expenditure

4.4.7 The municipality applied for a total operational expenditure of R71 478 239 for the 2026/27 financial year, which accounts for 16% of total costs., as shown in Table 4 above.

4.4.8 The approach adopted by the municipality in forecasting operational expenditure is considered reasonable, and the amount is recommended for approval as requested.

Surplus

4.4.9 The licensee applied for a surplus of R41 031 854 calculated using a surplus factor of 9% applied to operating expenditure, inclusive of bulk purchases, for both the wires and retail components of the businesses.

4.4.10 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.

4.4.11 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.

4.4.12 To ensure that the surplus remains modest and commensurate with risk, the exceedance of the NMD, FBE grants 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.

4.4.13 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.

4.4.14 The It is therefore recommended that the Energy Regulator approve the allowable revenue 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.

Cost Functionalisation

4.4.15 The licensee has categorised its revenue requirements of R451 350 million into two main functions: wires (19%) and retail business (81%), which is in line with the NERSA COS Framework, as demonstrated in Figure 2 below.

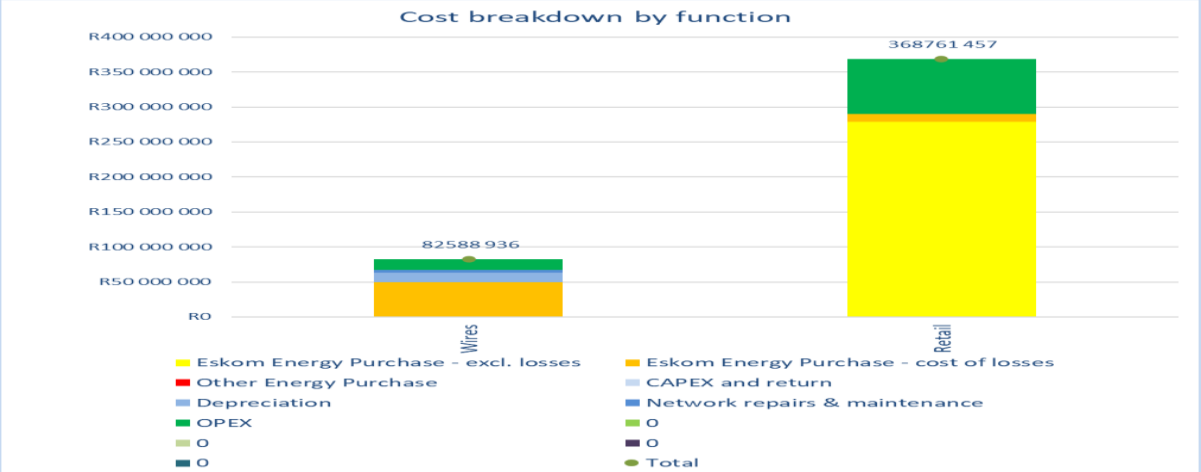


Figure 2: Cost breakdown by functions

4.4.16 These costs align with revenue requirements before adjustments upon verification. Network repairs and maintenance dominate the wires business, while the energy purchases are the primary cost driver for the retail business.

Cost Classification

4.4.17 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.

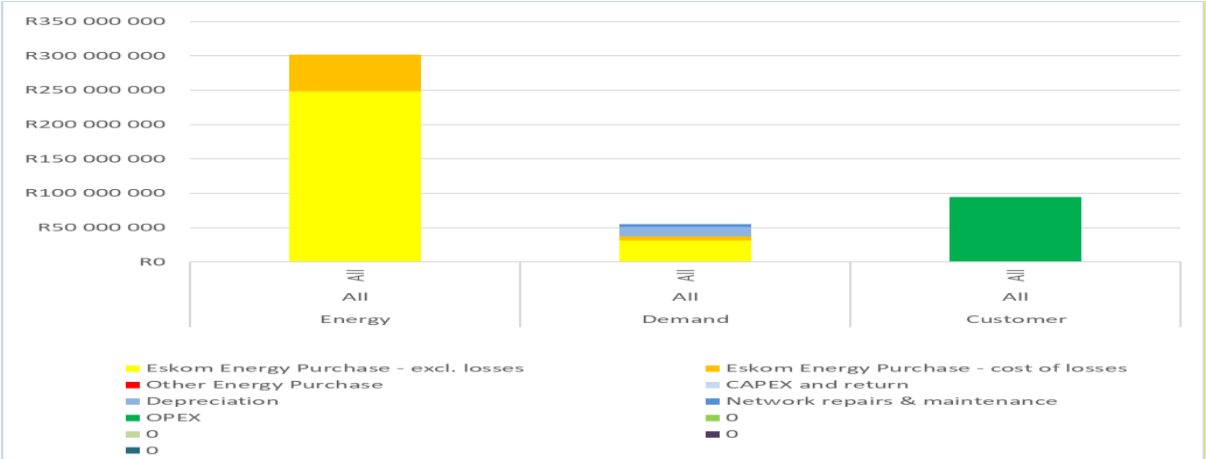


Figure 3: Cost breakdown by cost structure (classification)

4.4.18 Energy purchases constitute energy-driven costs, with the highest expenses occurring during summer under standard time of use, mainly because summer spans a larger portion of the year. Demand-driven costs are also predominantly incurred in summer. Customer-driven costs are primarily attributed to 'Other OPEX', which includes expenses associated with providing electricity distribution services to customers.

Cost Allocation

4.4.19 In this step, the licensee's revenue requirements are allocated between customer categories, in line with the NERSA COS Framework. The costs align with revenue requirements, cost functionalisation and cost classification upon verification. The majority of the costs are allocated for domestic customers (52%), followed by commercial customers (27%).

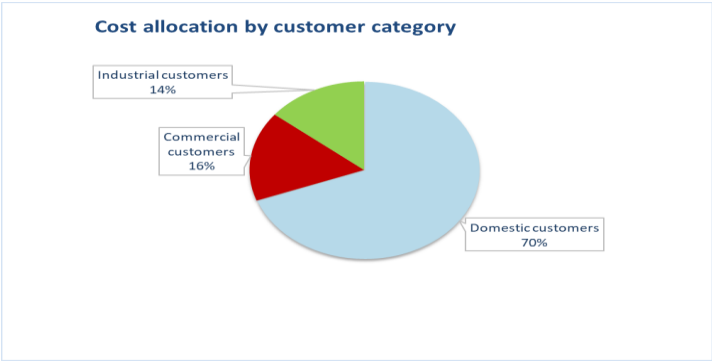


Figure 4: Costs allocated

Rate Design

4.4.20 Figure 5 below demonstrates the outcome of the COS study, showing that certain customer categories should increase, while others should decrease. Comparing these costs to the income per tariff category reveals the over- or under-recovery per tariff category, as shown in

4.4.20 

4.4.20 **Figure 5** below. To achieve full cost reflectivity, the municipality is required to increase tariffs across customer categories, as demonstrated below.

4.4.21 The initial COS results indicated an average increase of 18.2% (R451 350 393) for the municipality to achieve full cost reflectivity. The proposed increase was a 12.01% (R427 794 193), as shown in the first graph of Figure 6. However, after extensive scrutiny of the costs and taking into account inefficiencies such as high energy losses (52,88% in 2024/25) costs related to NMD penalties and interest on Eskom debt charges as well as bad debts the proposed average increase of 12.01% was reduced to 9,01% (aligned with ERTSA) to support funding for bulk purchases while limiting customer bill impacts. This approach protects affordability while placing emphasis on loss-reduction measures to improve future revenue recovery, reflected in the second graph of Figure 7.

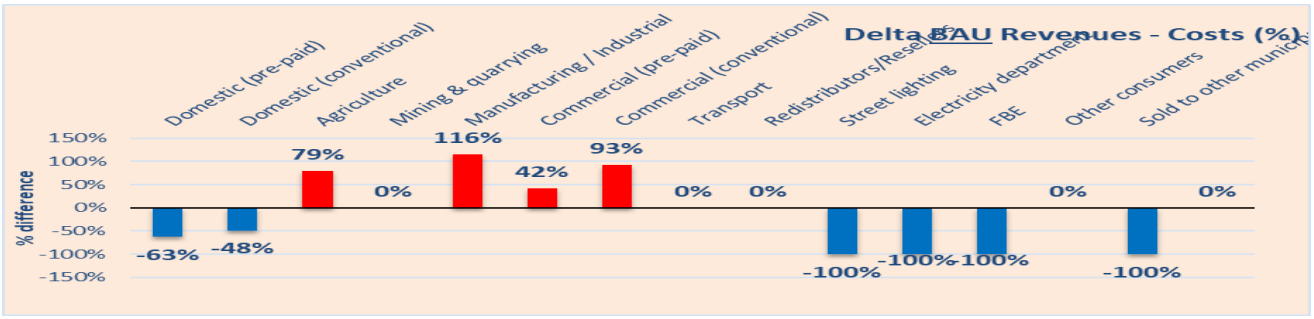




Figure 5: Rate design

5. CONCLUSION ON THE COS STUDY

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6. Old Age Homes	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic Charge (R/month)	1 696,73	12,01%	1900,51	1849,61	9,01%
Energy Charge	115,04	12,01%	128,86	125,41	9,01%
Demand(R/kVA)	315,13	12,01%	352,98	343,52	9,01%

7. Large Power Users: <80kVA	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic Charge (R/month)	2 880,08	12,01%	3225,98	3139,58	9,01%
Energy Charge	191,56	12,01%	214,57	208,82	9,01%
Demand Charge (R/kVA)	524,18	12,01%	587,13	571,41	9,01%
Demand Charge (R/kVA): Where kVA<80 for demand <=80kVA	17 360,96	12,01%	19 446,01	18 925,18	9,01%

8. TOU; T6: TX<100 000kWh/<80kVA	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic Charge (R/month)	1 328,45	12,01%	1488,00	1448,14	9,01%
Demand Charge (R/kVA)	n/a			n/a	
Low Season					
Peak	686,74	12,01%	769,22	748,62	9,01%
Standard	298,61	12,01%	334,47	325,51	9,01%
High	154,26	12,01%	172,79	168,16	9,01%
High Season					
Peak	699,19	12,01%	783,16	762,19	9,01%
Standard	311,01	12,01%	348,36	339,03	9,01%
High	154,26	12,01%	172,79	168,16	9,01%
Reactive Energy	32,35	12,01%	36,24	35,26	9,01%

9. TOU; T7<100 000kWh/>80kVA	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic Charge (R/month)	2 552,54	12,01%	2859,10	2782,52	9,01%
Demand Charge (R/kVA)	210,06	12,01%	235,29	228,99	9,01%
Low Season					
Peak	410,53	12,01%	459,83	447,52	9,01%
Standard	253,77	12,01%	284,25	276,63	9,01%
High	144,38	12,01%	161,72	157,39	9,01%
High Season					
Peak	455,34	12,01%	510,03	496,37	9,01%
Standard	253,77	12,01%	284,25	276,63	9,01%
High	154,26	12,01%	172,79	168,16	9,01%
Demand Charge (R/kVA)	224,47	12,01%	251,43	244,69	9,01%
Reactive Energy	32,35	12,01%	36,24	35,26	9,01%

INKWANCA: NER/D/EC133

1. Domestic Customers: High	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic Charge (R/month)	346,90	12,01%	388,56	378,16	9,01%
Energy Charge	308,59	12,01%	345,65	336,39	9,01%

2. Domestic Prepaid Indigent	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic charge R/Month	339,06	12,01%	379,78	369,61	9,01%
Energy Charge	223,46	12,01%	250,30	243,59	9,01%

3. Commercial Small (Government consumers	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic Charge (R/month)	872,09	12,01%	976,83	950,67	9,01%
Energy Charge	359,26	12,01%	402,41	391,63	9,01%

4. Commercial Large consumers	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic Charge (R/month)	632,07	12,01%	707,98	689,02	9,01%
Energy Charge	135,85	12,01%	152,17	148,09	9,01%
Demand Charge (R/kVA)	294,07	12,01%	329,39	320,57	9,01%

TSOLWANA: NER/D/EC132

1. Domestic Indigent Prepayment	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Energy Charge	265,82	12,01%	297,74	289,77	9,01%

2. Residential Prepaid & Demand 0 - 59 Amp incl. Churches	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Energy Charge	322,27	12,01%	360,97	351,31	9,01%

3. Commercial Credit Meters	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic Charge (R/month)	425,04	12,01%	476,09	463,34	9,01%
Energy Charge	361,45	12,01%	404,86	394,02	9,01%

4. Commercial Bakery	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic Charge (R/month)	397,56	12,01%	445,31	433,38	9,01%
Energy Charge	326,74	12,01%	365,98	356,18	9,01%

5. Commercial Prepaid	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Energy Charge	361,49	12,01%	404,90	394,06	9,01%

6.Commercial: Large Kva(Old Age Home & Abattoir)	2025/26 Approved	% Increase	2026/27 Proposed	2026/27 Recommended	% Increase
	c/kWh	12,01%		c/kWh	9,01%
Basic Charge (R/month)	748,69	12,01%	838,61	816,15	9,01%
Energy Charge	126,86	12,01%	142,09	138,28	9,01%
Demand(R/kVA)	415,46	12,01%	465,35	452,89	9,01%

Analysis and Key Findings

8.4 The municipality's exceptionally high energy losses (52,88% in 2024/25) remain the key driver of affordability and revenue-adequacy risk. Accordingly, the proposed average increase of 12.01% was reduced to 9,01% (aligned with ERTSA) to support funding for bulk purchases while limiting customer bill impacts. This approach protects affordability while placing emphasis on loss-reduction measures to improve future revenue recovery.

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

10.1. The Energy Regulator, having considered Enoch Mgijima's application, supporting information, stakeholder inputs and applicable legal framework, approves the tariff adjustments, as set out in this reasons for decision document.

End.