NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

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The Decision and Reasons for Decision (RfD)

In the matter regarding the

Municipal Tariff Applications for the 2026/27 Financial Year

By

uMkhanyakude District Municipality (UKDM)

THE DECISION

At its meeting held on 27 May 2026, the Regulator Executive Committee (REC) considered uMkhanyakude District Municipality's tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27FY as set out in section 8 of the tariff analysis on page 24 of the RFD.

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

a) to approve the tariffs that are based on the Cost of Supply (COS) Report as recommended in the tariff analysis section for implementation by the municipality with effect from 1 July 2026;
b) to note the COS Report submitted by the municipality;
c) that the municipality must submit a report accounting for all the costs that have been noted in its COS study by 31 January 2027, to enable NERSA to perform its independent verification/audit process; and
d) 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 thereof 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
UKDM	uMkhanyakude District Municipality
MFMA	Municipal Finance Management Act
NERA	National Electricity Regulation Act
NERSA	National Energy Regulator of South Africa
NMD	Non-Maximum Demand
OPEX	Operating Expenditure
RAB	Regulatory Asset Base
RfD	Reasons for Decision
ROR	Rate of Return
SEA	Sustainable Energy Africa
TOU	Time-of-Use

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 (FY).

1.2. NERSA received uMkhanyakude's tariff application together with its revised COS on 31 March 2026. The municipality revised the COS because of changes in Eskom tariffs.

1.3. Table 1 below shows customer statistics of uMkhanyakude for 2024/25FY. This data is obtained from the latest D-form.

Table 1: Customer statistics (data obtained from the latest D forms – 2024/25FY)

	Sales (MWh)	% MWh	Number of customers
Free Basic Electricity			
Domestic (prepaid)	2 447 070	63%	1920
Domestic (conventional)			
Manufacturing/Industrial	5 214	0.13%	3
Commercial Prepaid			
Commercial (conventional)	1 425 753	37%	39
Total	**3 878 037**	**100%**	**1962**

1.4. NERSA followed the notice and comment consultation process. uMkhanyakude'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.

1.5. NERSA's decision was made on 22 May 2026, considering the written comments received from the affected stakeholders and 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 Proce Determination, and Eskom Retail Tariff and Structural Adjustments (ERTSA) decision and is undertaken annually in order to align with the

municipal budgeting process contemplated in the Municipal Finance Management Act, 2003 (Act No. 56 of 2003; MFMA).

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 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 ERA. The electricity regulatory mandate of the Energy Regulator is therefore primarily governed by ERA. Section 3 of 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 ERA.

2.2.2. In particular:

a) section 4(a)(i) of ERA provides that the Energy Regulator must consider applications for licences and may issue licences subject to conditions;
b) section 4(a)(ii) of ERA provides that the Energy Regulator must regulate prices and tariffs; and
c) section 14(1)(d) of 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 ERA.

2.3. **Tariff Determination Principles under ERA**

2.3.1. When determining or approving electricity tariffs, the Energy Regulator must apply the principles contained in section 15(1) of 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 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 COS methodologies have historically not been consistently applied across the electricity distribution industry.

2.6.3. Policy Position 23 therefore 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.

2.6.4. 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. Having heard NERSA's application, the court 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;
d) NERSA decisions to be published 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 to be communicated by 31 January each year;
b) municipal tariff applications to be submitted to NERSA by 20 March each year;
c) municipal tariff approvals and the tariff reasons for decision document to 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 NERA, ERA, PAJA, the 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 (RfD) 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 evaluating the financial and technical performance of UKDM, the assessment relied on the distribution forms (D-forms) for the 2024/25FY, submitted as part of the municipality's tariff application. The information contained in the D-forms was verified against the supporting source documents provided by the municipality, including the Trial Balance and Annual Financial Statements (AFS). As a result, the data captured in the D-forms is considered reliable for the purposes of the tariff analysis.

3.2. Table 3 below indicates that UKDM's electricity business's percentage deficit worsened from -16.29% in the 2023/24FY to -37,71% in the 2024/25FY. The high deficit is attributed to the low increase in revenue and the increase in OPEX line items i.e., Eskom bulk purchases, repairs and maintenance, materials and supplies and depreciation. The licensee is further experiencing challenges with meter readers. The licensee further recorded a 28% increase in the total expenditure in the 2024/25FY (R55 million) when compared against the (R43 million) recorded in the 2023/24FY. Despite the deficit, the licensee continues to operate its electricity department optimally and maintains its Eskom account.

3.3. The energy losses decreased from 82,57% in the 2023/24FY to 70,76% in the 2024/25FY as indicated in table 2 below. The municipality indicated that the high energy losses are mainly attributable to ageing metering system, electricity meter tampering, ageing distribution system, shortage of conventional meter readers and financial challenges within the municipality.

Table 2: Performance indicators

PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS		
INDICATORS	**2024-25 FY (Actuals)**	**2023-24 FY (Approved)**
Percentage Surplus (Deficit) [%]	-37,71	-16,29
Percentage Energy Losses (%)	70,76	82,57

3.4. Based on the above information provided by the municipality from the D-forms, uMkhanyakude's performance is not satisfactory as evidenced by an increase in the deficit and energy losses**.**

Table 3: Energy Losses Analysis

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	224,99		
Sales kWh	3 881 622,00	11 683 402,72	12 479 998,36
Purchases kWh	13 276 594,00	13 276 594,00	13 276 594,00
Losses kWh	9 394 972,00	1 593 191,28	796 595,64
Losses percentage	**70,76%**	**12,00%**	**6,00%**
Additional Energy (kWh)		7 801 780,72	8 598 376,36
Additional Revenue (Rands)		17 553 366,46	19 345 641,28
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 40 002 533,00	R 57 555 899,46	R 59 348 174,28
Total Expenses (Rands)	R 55 086 749,81	R 55 086 749,81	R 55 086 749,81
Net Profit (Loss)	R -15 084 216,81	R 2 469 149,65	R 4 261 424,47
Percentage Surplus/Deficit	**-37,71%**	**4,29%**	**7,18%**

3.5. The municipality reported electricity energy losses of 9 394 972 kWh, which translates to an excessively high loss level of 70,76% of total bulk energy purchases. The reported losses are significantly above prudent and acceptable industry benchmark levels and indicate severe technical and non-technical inefficiencies within the electricity distribution network.

3.6. The Energy Regulator notes with concern that losses at this level materially undermine the financial sustainability and operational viability of the electricity undertaking. Excessive losses reduce the amount of energy available for sale, weaken revenue recovery and place substantial upward pressure on customer tariffs.

3.7. Should the municipality reduce energy losses to the prudent benchmark level of 12%, the analysis indicates that losses would decrease to approximately 1 593 191.28 kWh. This reduction would make available approximately 7 801 780.72 kWh for additional sales and generate additional revenue of approximately R17 553 366.46.

3.8. Furthermore, should losses be reduced to 6%, energy losses would decrease further to approximately 796 595.64 kWh, resulting in additional energy sales of approximately 8 598 376.36 kWh and additional revenue of approximately R19 345 641.28.

3.9. The Energy Regulator is therefore of the view that the municipality should prioritise urgent corrective interventions aimed at reducing technical and nontechnical losses.

3.10. Such interventions should include:

a) strengthening revenue protection measures;
b) addressing electricity theft and illegal connections;
c) improving metering accuracy and billing systems;
d) enhancing energy balancing and monitoring;
e) refurbishing aging network infrastructure; and
f) improving maintenance and operational efficiency.

3.11. The Energy Regulator further notes that failure to address the municipality's excessive energy losses may continue to weaken revenue recovery, increase financial instability and place additional pressure on future tariff increases.

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

4.1. The process followed in considering and approving UKDM's tariff application was supported by a revised COS study.

4.2. uMkhanyakude utilised the COS model developed by Sustainable Energy Africa (SEA) to determine its revenue requirements for the 2026/27FY and to apportion costs required to service each customer's class in a fair and equitable manner. The municipality applied the cost-plus methodology in conducting its COS study.

4.3. The municipality applied for tariff increases of approximately 12.20% across various customer categories for the 2026/27FY. Following assessment of the COS study, D-forms, financial information and supporting schedules, the Energy Regulator recommend reduced tariff increases of approximately 9.5%.

4.4. The reduction in the approved tariff increase was primarily informed by the municipality's high energy losses and deteriorating financial position. The municipality reported electricity losses significantly above prudent benchmark levels, indicating substantial technical and non-technical inefficiencies within the electricity undertaking. Excessive losses reduce energy available for sale, weaken revenue recovery and place upward pressure on customer tariffs.

4.5. In addition, the municipality's electricity undertaking continues to operate at a significant deficit position, indicating that the expenditure required to operate and maintain the network exceeds the revenue generated from electricity operations. The Energy Regulator noted that a substantial portion of the applied revenue requirement was driven by inefficiencies and financial pressures associated with high losses and weak financial performance.

4.6. The Energy Regulator is of the view that customers should not bear the full burden of inefficient expenditure, excessive losses and financial underperformance through higher electricity tariffs. Accordingly, adjustments were made to remove non-prudent and inefficient costs from the allowable revenue requirement, resulting in the approval of lower tariff increases.

4.7. The recommended increase of approximately 9.5% is considered reasonable and sufficient to enable recovery of prudently incurred costs while balancing customer affordability, economic sustainability and the long-term viability of the electricity undertaking.

4.8. **Error! Reference source not found.** below details the five steps considered in the determination of the COS study.

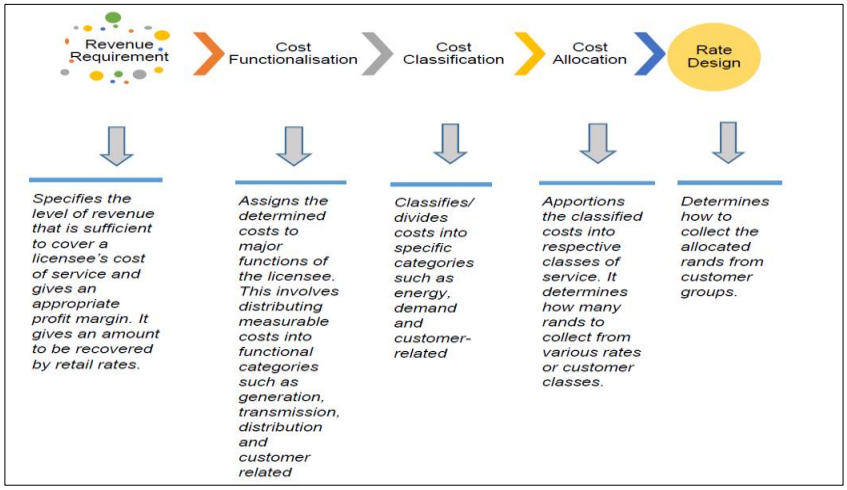


Figure 1: Five steps of COS

4.9. Section 18.7 of the COS Framework requires that tariff adjustments:
- 4.9.1. be informed by COS outcomes;
- 4.9.2. progressively move tariffs towards cost-reflectivity; and
- 4.9.3. be implemented in a structured and transparent manner, including phased adjustments where required.

4.10. Considering the Tariff Application, the licensee has reflected and applied these requirements as follows:
- 4.10.1. The tariff application is based on a COS model incorporating financial, technical, and customer data inputs.
- 4.10.2. Bulk purchase costs were updated using the approved 9.01% Eskom bulk tariff adjustment.
- 4.10.3. Controllable electricity OPEX costs were adjusted using CPI-linked assumptions.
- 4.10.4. Adjustments were supported by source documents and reasonability checks (D-forms, Trial Balance and AFS).

4.11. This ensures that tariff adjustments are grounded in cost-reflective principles.

- 4.11.1. The licensee has proposed a phased implementation over three financial years to achieve full cost recovery.

- 4.11.2. This approach aligns with section 18.7, which allows for gradual tariff realignment to mitigate tariff shocks and maintain affordability for vulnerable customer groups.

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4.12. The following steps were undertaken to analyse the COS study:

Revenue Requirement

4.12.1. The municipality applied for an allowable revenue requirement of R24 857 666 for the 2026/27FY. Following the assessment of the submitted COS information, NERSA identified inefficiencies amounting to R91 797 relating primarily to operational expenditure and surplus adjustments. Consequently, the recommended allowable revenue requirement amounts to R24 765 868.

Table 4: Revenue Requirement Components

	Total cost (R)					
Revenue Requirement components	Wires	Retail	Total	NERSA Adjustment	NERSA Recommendation	% of Total
Allowable costs	9 558 304	15 299 362	24 857 666	(91 797)	24 765 868	100%
Energy purchases from Eskom - net of cost of losses	-	8 521 886	8 521 886		8 521 886	34%
Energy purchases from Eskom - cost of losses	3 580 632	-	3 580 632		3 580 632	14%
Other energy purchases	-	-	-			0%
Capital expenditure	-	-	-			0%
Operational expenditure (incl. Depreciation)	5 693 021	6 454 739	12 147 760	(87 426)	12 060 334	49%
Other revenues	-	-	-			0%
Surplus	284 651	322 737	607 388	(4 371)	603 017	2%
Not allowable costs	4 727 965	13 008 114	17 736 078			
Cost of losses disallowed	4 727 965	13 008 114	17 736 078			
TOTAL COSTS	14 286 269	28 307 475	42 593 744			
	34%	66%				

4.12.2. The municipality applied a cost-plus methodology in the determination of its revenue requirement, as reflected in table 4 of the RfD, and did not utilise a rate of return (ROR) approach. Accordingly, no Regulatory Asset Base (RAB) was determined or applied.

4.12.3. Energy purchases from Eskom, inclusive of the cost of losses, amount to R12 102 518 and represent approximately 48% of the total allowable costs. Of this amount, energy purchases net of losses accounts for R8 521 886, or 34% of the total allowable costs, while the cost of losses accounts for R3 580 632, or 14%.

4.12.4. Operational expenditure, including depreciation, constitutes the largest component of the revenue requirement at R12 147 760, representing approximately 49% of the total allowable costs. Following the assessment of the submitted expenditure, NERSA disallowed inefficient costs amounting to

R87 426. The recommended operational expenditure therefore amounts to R12 060 334.

4.12.5. The municipality further applied for a surplus of R607 388, representing approximately 2% of the total allowable costs. NERSA assessed the proposed surplus against the sustainability requirements of the electricity undertaking and determined that an adjustment of R4 371 was necessary. Consequently, the recommended surplus amounts to R603 017.

4.12.6. NERSA notes that the municipality did not apply for any capital expenditure or other energy purchases within the 2026/27FY. Furthermore, no other revenues were reflected in the revenue requirement calculation.

4.12.7. The analysis also identified non-allowable costs relating to the cost of losses amounting to R17 736 078. These costs were excluded from the allowable cost base in line with the NERSA COS Framework and the principle that only prudently incurred and efficiently justified costs may be recovered through tariffs.

4.12.8. Overall, the assessment indicates that the municipality's revenue requirement is largely driven by operational expenditure and bulk electricity purchases. NERSA is satisfied that, after the adjustments effected, the recommended revenue requirement reflects prudent, efficient, and cost-reflective expenditure necessary for the sustainable provision of electricity services.

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

4.12.10. All expenses included in the revenue requirement have been examined to confirm that they pertain exclusively to the licensee's electricity function. Where any amounts were found to be inflated or insufficiently substantiated, adjustments have been effected accordingly.

Bulk purchases

4.12.11. The municipality applied for bulk electricity purchase costs amounting to R12 102 518 for the 2026/27FY, comprising energy purchases from Eskom net of the cost of losses of R8 521 886 and energy purchases relating to the cost of losses of R3 580 632.

4.12.12. Bulk electricity purchases constitute approximately 48% of the total allowable revenue requirement and remain one of the primary cost drivers within the municipality's electricity business. The analysis indicates that the municipality is significantly dependent on Eskom as its sole bulk electricity supplier, with

no provision made for other energy purchases during the financial year under review.

4.12.13. The municipality's bulk purchase costs are lower than operational expenditure, which indicates that the electricity business is largely driven by operational and administrative costs rather than energy procurement costs. This may be attributable to relatively low electricity sales volumes, limited industrial and commercial demand, and high fixed operating costs associated with maintaining the electricity distribution network.

4.12.14. Furthermore, the municipality appears to have a relatively limited high-consumption industrial and commercial customer base, resulting in lower bulk electricity purchases from Eskom. Reduced electricity demand and lower sales volumes may also be attributable to economic conditions, energy efficiency initiatives, embedded generation, and increased adoption of alternative energy sources such as rooftop solar photovoltaic systems.

4.12.15. UKDM projected its bulk purchases for the 2026/27FY using the 2025/26FY Eskom tariffs as a base and made the following assumptions: sales growth of 0%, and bulk purchase cost increases of 9.01% for the 2026/27FY. These bulk increases are in line with the approved ERTSA.

Operational Expenditure

4.12.16. The municipality applied for Total OPEX of R12 147 760 for the 2026/27FY. Following the assessment of the submitted COS information and supporting schedules, NERSA identified inefficiencies relating to Non-Maximum Demand (NMD) exceedance penalties amounting to R87 426. These costs were deemed avoidable and inefficient and were therefore disallowed from the allowable cost base.

Table 5: Operational Expenditure

Cost drivers	Units	2024/25FY Actuals	2025/26FY Budgeted	2026/27FY Applied	NERSA Adjustments	2026/27FY Recommended
General costs and other	**R**	**18 133 845**	**11 486 033**	**12 147 760**	**(87 426)**	**12 060 335**
Salaries and allowances	R					
Materials and supplies	R	9 904 778	4 693 500	4 928 175	-	4 928 175
Contracted Services	R				-	
Salaries, wages and allowances (exclu. Repa	R	6 732 868	6 064 108	6 367 313	-	6 367 313
Current year depreciation	R	1 496 199	728 425	764 846	-	764 846
NMD exceedance penalties	R			87 426	(87 426)	-
Shared OPEX	**R**	**1 527 518**	**-**	**-**	**-**	**-**
Bad debts written-off	R	1 527 518			-	
Total Opex	**R**	**19 661 363**	**11 486 033**	**12 147 760**	**(87 426)**	**12 060 334**

4.12.17. Accordingly, the recommended Total OPEX for the 2026/27FY amounts to R12 060 334 after the adjustment.

4.12.18. The analysis indicates that General Costs and Other expenses constitute the largest component of operating expenditure. The municipality applied for R12 147 760 under this category, of which R87 426 related to NMD exceedance penalties. Following the disallowance of these penalties, the recommended amount is R12 060 335.

4.12.19. Materials and supplies expenditure increased from R4 693 500 in the 2025/26 budget to R4 928 175 in the 2026/27 application, representing an increase of approximately 5.0%. NERSA assessed the expenditure against historical trends and operational requirements and found the costs to be reasonable and prudently incurred.

4.12.20. Salaries, wages and allowances increased from R6 064 108 in the 2025/26 budget to R6 367 313 in the 2026/27 application, representing an increase of approximately 5.0%. The expenditure was assessed against staff cost trends and was found to be within acceptable limits for the operation of the electricity undertaking.

4.12.21. Current year depreciation increased from R728 425 to R764 846, representing an increase of approximately 5.0%. NERSA found the depreciation expense to be aligned with the municipality's electricity asset base and consistent with prudent accounting treatment.

4.12.22. The municipality further reflected Shared OPEX and bad debts written off amounting to R1 527 518 based on historical actual expenditure. However, no allocation was applied for within the 2026/27FY and consequently no recommendation was made under these categories.

Surplus

4.12.23. The municipality applied for a surplus of R607 388 for the 2026/27FY, representing approximately 2% of the total allowable revenue requirement. Following the assessment of the submitted COS information, NERSA adjusted the proposed surplus downward by R4 371, resulting in a recommended surplus of R603 017.

4.12.24. NERSA notes that the proposed surplus is relatively low when assessed against the operational and financial risks facing the municipality's electricity business. The analysis indicates that the municipality is operating under significant financial pressure, primarily due to high energy losses and an apparent revenue deficit estimated at approximately 37%.

4.12.25. The municipality's projected surplus was assessed as a reasonable and prudent operating margin required to support the long-term financial sustainability of the electricity business. The margin is justified given the municipality's operation within a high-risk electricity network environment that necessitates continuous maintenance, refurbishment and operational enhancements. In addition, the municipality indicated that the margin would

fund initiatives aimed at improving revenue collection, strengthening network reliability, and enhancing the sustainability of service delivery.

4.12.26. Furthermore, the anticipated improvement in the collection rate from 29% to 98% is expected to materially reduce bad debt provisions and improve cash flow management. Accordingly, the projected surplus is not considered excessive, but rather a reasonable operating margin necessary to ensure the continued financial viability and sustainability of the electricity service.

4.12.27. In recommending a surplus, NERSA relied on section 15(1)(a) of ERA under the tariff principles, which specify that the tariffs set by the Regulator must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return.

4.12.28. In applying the Act, NERSA is required to ensure that UKMD recovers efficient costs and a reasonable return, while preventing excessive compensation. The return proposed by uMkhanyakude is considered reasonable, as it falls within the established target range of 10% to 20%. Consequently, the requested amount has been recommended as applied for.

Depreciation

4.12.29. The municipality applied for current year depreciation amounting to R764 846 as part of operational expenditure for the 2026/27FY. The applied depreciation reflects a marginal increase when compared to the 2025/26 budgeted amount of R728 425, while remaining below the 2024/25 actual expenditure of R1 496 199.

4.12.30. The Energy Regulator assessed the depreciation provision against the municipality's asset base, historical expenditure trends and supporting financial information. The assessment confirmed that the applied depreciation is reasonable and prudently incurred for the continued operation of the electricity undertaking. Accordingly, the depreciation amount of R764 846 was allowed in full.

4.12.31. Although the municipality's depreciation provision was found to be reasonable, the Energy Regulator is of the view that continued investment in maintenance and refurbishment remains essential, particularly in light of the municipality's operational and financial challenges.

4.12.32. The municipality is therefore encouraged to strengthen asset management practices and ensure that depreciation provisions remain aligned with future infrastructure replacement and network sustainability requirements.

Cost Functionalisation

4.12.33. The licensee has categorised its revenue requirement of R28.46 million into two primary functional components, namely the wires business (33%) and the retail business (66%), in accordance with the NERSA COS framework,

as illustrated in Figure 2 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

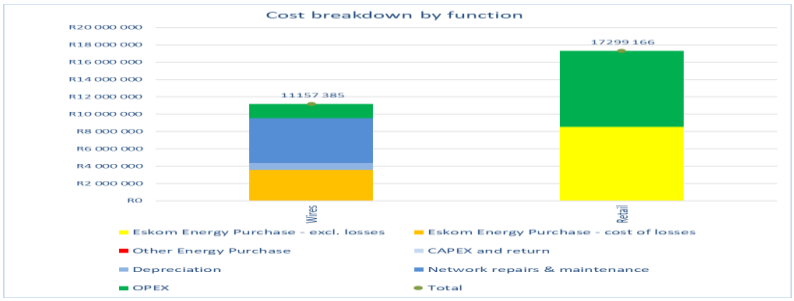


Figure 2: Costs breakdown by function

4.12.34. 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.

4.12.35. The verification of costs included in the COS model was undertaken using both the NERSA D-forms and the municipality's Audited AFS for 2024/25FY.

Cost Classification

4.12.36. The licensee has classified its costs into energy, demand, and customer-related cost components, in accordance with the NERSA COS framework. The costs align with revenue requirements and cost functionalisation upon verification.

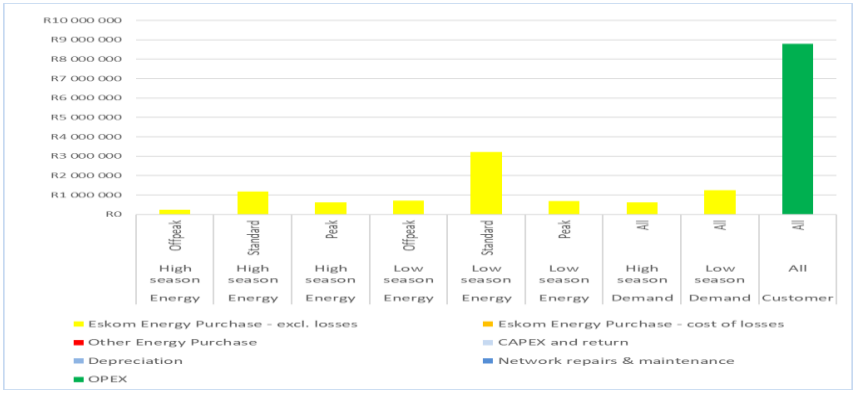


Figure 3: Costs breakdown by cost structure (classification)

4.12.37. Energy purchases constitute energy-driven costs, with the highest expenditure incurred during the summer period under the standard TOU

structure, largely due to the longer duration of the summer season. Demand-driven costs are similarly concentrated in the summer period. Customer-driven costs are primarily associated with 'Other OPEX,' which includes expenses related to the provision of electricity distribution services to customers.

Cost Allocation

4.12.38. In this step, the licensee's revenue requirement is allocated across customer categories, in accordance with the NERSA COS framework. Upon verification, the allocation is found to be consistent with the stated revenue requirement and aligned with the principles of cost allocation.

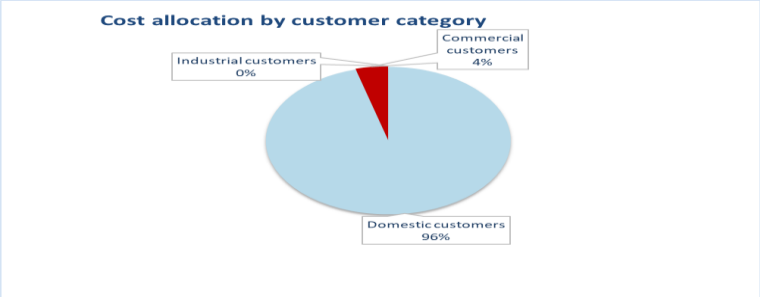


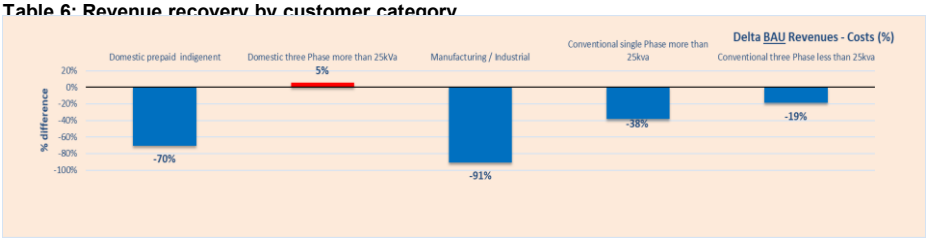
Figure 4: Costs allocated

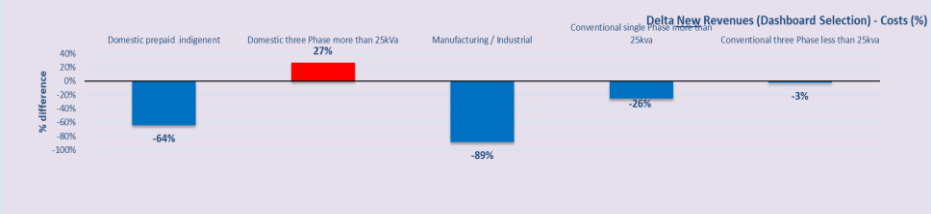
Rate Design

4.12.39. Table 7 below reflects the outcome of the COS study, indicating that certain customer categories require upward adjustments, while others warrant decrease. A comparison between the COS and the revenue generated per tariff category highlights the extent of over- or under-recovery within each category.

4.12.40. To achieve cost reflectivity, UKDM would be required to implement differentiated tariff adjustments across customer categories. Domestic and industrial time of use customer categories require upward adjustments, while commercial customers subsidisation should decrease.

Table 6: Revenue recovery by customer category





4.12.41. The COS study confirms the presence of cross-subsidisation between customer categories. Certain categories are under-recovering (receiving a subsidy), while others are over-recovering (providing the subsidy). Commercial customers are cross-subsidising residential and municipal customer categories, which is consistent with typical municipal tariff structures.

5. CONCLUSION ON THE COS STUDY

5.1. While the outcome of the COS study may indicate an average tariff adjustment of a certain percentage for a licensee to achieve full cost reflectivity, a municipality may elect to implement such adjustments on a phased basis, including applying an increase below the COS-derived level.

5.2. This approach may be informed by a range of considerations, including the need to maintain tariff sustainability to support ongoing demand for electricity services. Excessive tariff increases may adversely affect consumption levels, thereby impacting revenue stability.

5.3. In addition, the licensee may consider its ability to meet financial obligations, including payments to Eskom, as well as the broader affordability constraints faced by customers, in determining the appropriate trajectory for tariff adjustments.

5.4. This approach is intended to safeguard the municipality's revenue base and support its financial sustainability, in line with applicable legislative requirements.

5.5. The COS study is based on forecast assumptions and, as such, does not guarantee that the projected outcomes will materialise. Accordingly, the licensee retains the discretion to review the results and determine its own revenue requirements to ensure financial sustainability. In this regard, the municipality will be required to submit a report accounting for all costs that remain unverified.

5.6. The COS study results indicate a required increase of 123.6%, as illustrated in Figure 5 below. However, in an effort to mitigate the impact on customers, the licensee has proposed a lower increase of 12.20%.

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Commercial						
2.3 Commercial Three phase <_25kVA	**2025/26 approved**	**2026/27 proposed**	***% increase***	***Recommended tariff***	***% increase***	***Key Analysis and Findings***
Energy charge (c/kWh)	286.13	321.04	12.20%	313.31	9.50%	The Energy Regulator noted that the increase will impose additional financial pressure on commercial customers and small businesses. Excessive tariff increases may negatively affect business sustainability, operating costs and economic activity within the municipal area.
Basic Charge (R/month)	219.61	246.40	12.20%	240.47	9.50%	

Commercial						
2.4 Commercial three-phase > 25 kVA	**2025/26 approved**	**2026/27 proposed**	***% increase***	***Recommended tariff***	***% increase***	***Key Analysis and Findings***
Energy charge (c/kWh)	286.13	321.04	12.20%	313.31	9.50%	The municipality's proposed increase exceeded the approved benchmark increase and would have placed additional financial pressure on commercial and medium-scale business customers. Higher electricity tariffs may adversely affect operational costs, profitability and economic competitiveness.
Basic Charge (R/month)	876.88	983.86	12.20%	960.18	9.50%	

3. Industrial	**2025/26 approved**	**2026/27 proposed**	***% increase***	***Recommended tariff***	**% increase**	**Key Analysis and Findings**
Energy charge: c/kWh	130.31	146.21	12.20%	142.69	9.50%	The Energy Regulator is of the view that the approved tariffs are reasonable, cost reflective and aligned with the approved allowable revenue requirement while limiting the impact on industrial and economic activity.
Demand Charge (R/kVA)	415.33	466	12.20%	454.79	9.50%	
Average Tariff (c/kWh)	**272.82**	**306.11**	12.20%	298.74	9.50%	

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

10.1. From an overview of the facts and evidence presented to the REC, it is appropriate to consider the review of uMkhanyakude's tariff application for 2026/27FY.

End.