NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

Decision and Reasons for Decision (RfD)

In the matter regarding the

Municipal Tariff Application for the 2026/27 Financial Year

By

Msunduzi Local Municipality

THE DECISION

At its meeting held on 9 May 2026, the Regulator Executive Committee (REC) considered the Msunduzi Local Municipality's tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year (FY) the decision is set out on the tariff analysis section 8 on page 23 of the RFD Based on the information submitted and the analysis conducted, the REC decided to:

1. The tariffs based on the COS Report are approved as recommended in the tariff analysis section for implementation by the Licensee with effect from 1 July 2026;
2. the Cost of Supply Report submitted by the Licensee be noted;
3. the Licensee is required to submit a report accounting for all costs reflected in its COS study, to enable the Regulator to undertake its independent verification and audit process by 30 September 2026; and
4. that the municipality must submit specific, measurable, achievable, realistic and time-bound (SMART) energy loss reduction progress reports quarterly for NERSA to monitor implementation thereof.

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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. Msunduzi Local Municipality (The Municipality) is situated in the KwaZulu-Natal Province.

Table 1 Customer Statistics (Data obtained from the latest D-forms – 2024/25)

CUSTOMER STATISTICS			
Consumer classification	**Sales (MWh)**	**%MWh**	**Number of consumers**
Domestic (Pre-paid)	48 469	3,86%	43 623
Domestic (Conventional)	217 604	17,34%	40 710
Commercial (Prepaid)	72	0,01%	14
Commercial (Converntional)	115 978	9,24%	7 054
Manufacturing/Industrial	842 030	67,11%	809
Street lighting, own use and sold to other municipal departments	30 589	2,44%	N/A
Totals	**1 254 742**	**100%**	**92 210**
Free Basic Electricity	**15 907**	**1,27%**	**26 512**

1.3. Industrial customers account for 67.11% of total electricity sales followed by domestic customers accounting for 21.21%.

1.4. NERSA received the Municipality's tariff application together with its Cost of Supply (COS) study on 30 March 2026.

1.5. The Municipality implemented a 14.6% average price increase in 2025/26 financial year and is applying for an average price increase of 9.26% for the 2026/27 financial year..

1.6. For this application, the Licensee confirmed that tariffs applied for were authorised by the Municipal Council and it undertook customer consultation during which submissions were received.

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

1.8. NERSA's decision was made on 9 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 Price Determination and Eskom Retail Tariff and Structural Adjustment 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).

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. Statutory Mandate of the Energy Regulator

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, the Energy Regulator exercises this authority through the powers conferred by ERA:

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.

c) Section 14(1)(d) of the ERA authorises the Energy Regulator to impose licence conditions relating to the setting or approval of prices, charges, rates and tariffs charged by Licensees.

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

2.3. Tariff Determination Principles under the ERA

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

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

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

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

2.4. Administrative Law Requirements

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

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

2.5. Policy Framework: Electricity Pricing Policy (2008)

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

2.5.2. Policy Position 1 of the EPP provides that the revenue requirement for a regulated Licensee must be set at a level that covers the full cost of production,

including a reasonable risk-adjusted margin or return on appropriate asset values.

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

2.6. **Cost of Supply Studies**

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

2.6.2. Paragraph 8.1 of the EPP notes that Cost of Supply methodologies have historically been applied inconsistently 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 whenever 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 must be provided 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's decisions must be publicised 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;
c) Municipal tariff approvals and the tariff Reasons for Decision document must be approved and published by 5 May of each year.

2.9. **Conclusion**

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

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

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In evaluating the financial and technical performance of the Municipality, the assessment relied 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 the supporting source documents provided by the Municipality, including the Trial Balance and Annual Financial Statements. As a result, the data captured in the D-forms is considered reliable for the purposes of the tariff analysis.

3.2. The Municipality recorded a percentage deficit of 17.72% in the 2023/24 financial year and improved to 6.01% in the 2024/25 financial year.

3.3. Table 2 below shows that the Municipality recorded energy losses of 18.78% in the 2023/24 financial year and 26.73% in the 2024/25 financial year.

Table 2: Performance indicators

Outputs:	2024/25	2023/24
Percentage Surplus	-6,01%	-17,72%
Percentage Energy Losses:	23,33	18,78

3.4. The percentage energy losses increased from 18.78% in the 2023/24 financial year to 23.33% in the 2024/25 financial year. The Licensee faces significant challenges arising from illegal connections, meter tampering, and vandalism of infrastructure, in which contribute substantially to electricity losses.

3.5. These losses not only reduce revenue but also strain operational resources. The Municipality has identified numerous areas with illegal connections and is actively working to remove them. within addition, faulty metering installations have been identified, requiring audits, replacements, and rewiring where necessary.

3.6. While strategies like recruitment of interns and implementing load reduction plans are in place, there's a need for ongoing review and improvement and minimizing network energy losses. Addressing these issues requires a multi-faceted approach encompassing regulatory compliance, infrastructure maintenance, and enhancements to operational efficiency..

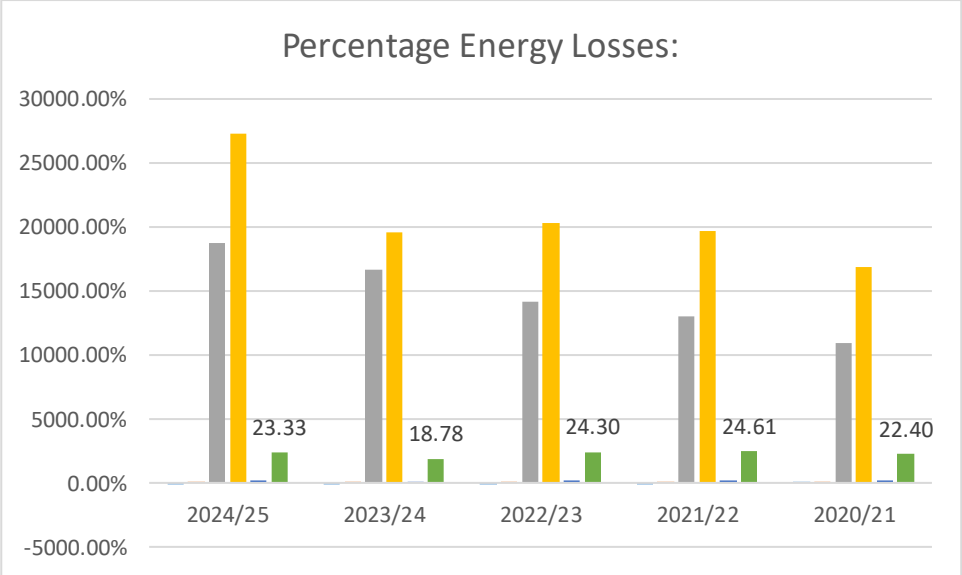


Figure 1: Energy losses trend

2.1.1 Figure 2 above reflects a concerning trend of increasing energy losses for the Licensee over the past five years. Despite intervention plans submitted to the Regulator annually, the losses continued to rise, reaching 23.3% in the latest reporting period 2024/25 financial year.

2.1.2 This upward trajectory indicates that the current strategies and interventions may not be effectively addressing the root causes of energy losses, such as illegal connections, tampering, and

infrastructure vulnerabilities. It suggests that there may be underlying systemic issues that need to be addressed comprehensively.

2.1.3 Further analysis is needed to identify the specific reasons for the inefficiency of the intervention plans and to develop more targeted and robust strategies to curb energy losses effectively. Additionally, there may be a need for closer collaboration between the Licensee, the Regulator, and other stakeholders may be necessary to address this persistent challenge and promote sustainable energy distribution and revenue management

Table 3: Energy losses recovery potential impact

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	272,88		
Sales kWh	1 254 745 635,00	1 440 121 066,56	1 538 311 139,28
Purchases kWh	1 636 501 212,00	1 636 501 212,00	1 636 501 212,00
Losses kWh	381 755 577,00	196 380 145,44	98 190 072,72
Losses percentage	**23,33%**	**12,00%**	**6,00%**
Additional Energy (kWh)		185 375 431,56	283 565 504,28
Additional Revenue (Rands)		505 846 598,68	773 784 555,13
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 3 569 249 901,00	R 4 075 096 499,68	R 4 343 034 456,13
Total Expenses (Rands)	R 3 783 831 782,00	R 3 783 831 782,00	R 3 783 831 782,00
Net Profit (Loss)	R -214 581 881,00	R 291 264 717,68	R 559 202 674,13
Percentage Surplus/Deficit	**-6,01%**	**7,15%**	**12,88%**

3.7. The Licensee has the potential to improve from a deficit of 6.01% to a surplus of 7.15% if energy losses are limited to 12% and the surplus could potentially increase to 12.88% if the energy losses are reduced to 6%.

3.8. Based on the above information, the Municipality's electricity is satisfactory as they are able to generate a surplus and the energy losses are low.

4. DETERMINATION OF MSUNDUZI'S TARIFFS BASED ON THE COST OF SUPPLY STUDY

4.1. The process followed in considering and approving the Municipality's tariff application was supported by a cost of supply study.

4.2. The Municipality utilised the COS study model developed by Sustainable Energy Africa (SEA) to determine its revenue requirements for the 2026/27 financial year and to allocate the costs of providing service each customer category in a fair and equitable manner. The study follows the NERSA COS Framework and utilises the latest available audited data which is based on the 2024/25 financial year

4.3.

4.4. below details the five steps considered in the determination of the COS study.

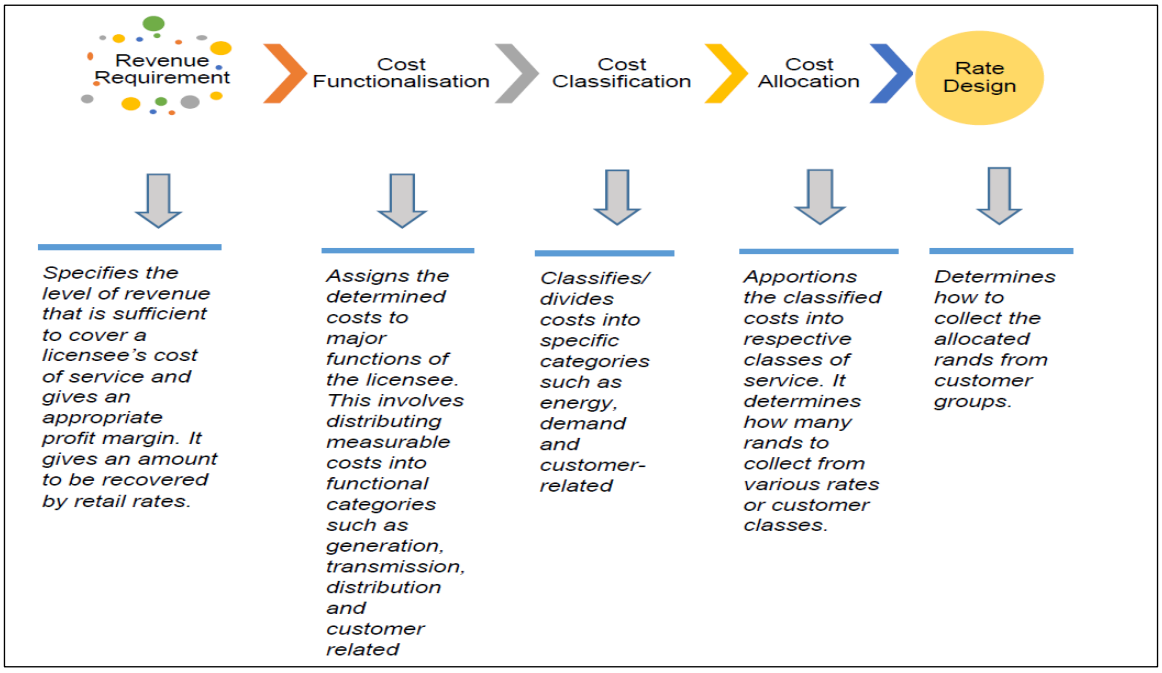


Figure 2: Fives steps of COS

4.5. Section 18.7 of the COS Framework requires that tariff adjustments:

a) be informed by cost-of-supply outcomes;

b) Progressively move tariffs towards cost-reflectivity; and

c) be implemented in a structured and transparent manner, including phased adjustments where required.

4.6. In its tariff application, the Licensee has considered and applied these requirements as follows:

a) The tariff application is based on a COS model incorporating financial, technical, and customer data inputs.

b) Bulk purchase costs were updated using the approved 8.76% Eskom bulk tariff adjustment.

c) Controllable electricity OPEX costs were adjusted using CPI-linked assumptions.

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

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

4.8. The following steps are undertaken to analyse the Cost of Supply study:

Revenue Requirement

4.8.1. The revenue requirement step specifies the level of revenue that is sufficient to cover a Licensee's cost of service and appropriate margin. It is an indication of the amount to be recovered from the approved tariffs.

4.8.2. The Licensee applied a cost-plus methodology in the determination of its revenue requirement and did not utilise a Rate of Return (ROR) approach. Accordingly, no return based on a Regulatory Asset Base (RAB) was determined or applied.

4.8.3. The Municipality submitted a COS, detailing revenue requirements of R4 630 651 913 for the 2026/27 financial year. This revenue requirement is dominantly Eskom purchases accounting for 88% including an energy losses allowance. Operational expenditure accounts for 13%. The recommended revenue requirement is R 4 423 735 109 in line with Table 4 below.

Table 4: Msunduzi Revenue Requirement

	Total cost (R)					
Revenue Requirement components	**Wires**	**Retail**	**Applied for 2026/27**	**NERSA Adjustments**	**NERSA Decision 2026/27**	**% of Total**
Allowable costs	984 332 767	3 646 319 146	4 630 651 913	- 206 916 804	4 423 735 109	100%
Energy purchases from Eskom - net of cost of losses	-	3 282 852 469	3 282 852 469	-	3 282 852 469	71%
Energy purchases from Eskom - cost of losses	389 188 086	124 402 658	513 590 744	-	513 590 744	11%
Other energy purchases	-	-	-	-		0%
Capital expenditure	-	-	-	-		0%
Operational expenditure (incl. Depreciation)	544 944 903	354 910 804	899 855 706	- 188 106 185	711 749 521	19%
Other revenues	**- 3 904 284**	**- 137 579 877**	**- 141 484 161**	-	**- 141 484 161**	-3%
Surplus	54 104 062	21 733 093	75 837 155	- 18 810 619	57 026 536	2%
Not allowable costs	188 717 388	294 762 267	483 479 655	-	483 479 655	
Cost of losses disallowed	188 717 388	294 762 267	483 479 655	-	483 479 655	
TOTAL COSTS	1 173 050 155	3 941 081 413	5 114 131 569	-206 916 804	4 907 214 765	
	23%	77%				

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

4.8.4. 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. In instances where expenses are deemed inflated or unjustified, these have been adjusted accordingly and expanded on below.

Bulk purchases

4.8.5. The Municipality's COS projects a bulk purchase expenditure of R3 796 44 213 which accounts for 86% of total costs when including the 12% energy losses allowance. Bulk purchases were verified against Eskom invoices in the 2024/25 financial year.

4.8.6. The Licensee projected its bulk purchases for the 2026/27 financial year using the 2025/26 financial year Eskom tariffs as a base and made the following assumptions: sales growth of 0%, and a bulk purchase cost increases of 9.01% for the 2026/27 financial year which is in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

Operational Expenditure

4.8.7. The Municipality's COS projects operational expenditure totalling R899 855 706, representing 19% of overall costs. Table 5 below provides a breakdown of this expenditure.

Table 5: Operational expenditure[1]

Cost Drivers	Actual 2024/25	Budget 2025/26	Applied for 2026/27	NERSA Adjustments	NERSA Decision 2026/27
General & Other	R 447 123 825	R 582 414 916	R 605 711 512	-R 188 106 185	R 417 605 327
Salaries and allowances	R 107 861 626	R 107 861 626	R 112 176 091	R 6 281 861	R 118 457 952
Materials and supplies	R 59 692 236	R 71 693 367	R 74 561 102	-R 9 997 979	R 64 563 122
Contracted Services	R 105 193 656	R 108 508 308	R 112 848 640	R -	R 112 848 640
Salaries, wages and allowances (exclu. Rep	R 40 570 500	R 138 238 843	R 143 768 397	-R 99 212 251	R 44 556 146
Payments to consultants (operational wor	R 6 743 032	R 3 580 236	R 3 723 445	R -	R 3 723 445
Eskom debts' interests	R 57 384 031	R 31 426 832	R 32 683 905	-R 32 683 905	R 0
Other creditors interests	R 23 801 123	R 24 753 168	R 25 743 295	R -	R 25 743 295
Current year depreciation	R 45 877 621	R 96 352 536	R 100 206 637	-R 52 493 912	R 47 712 726
NMD exceedance penalties	R -	R -	R -	R -	R -
Shared OPEX	R 271 952 842	R 282 830 956	R 294 144 194	R -	R 294 144 194
Bad debts written-off	R 6 992 210	R 7 271 899	R 7 562 775	R -	R 7 562 775
FBE paid to Eskom	R -	R -	R -	R -	R -
Charges from other Municipal Department	R 39 807 557	R 41 399 859	R 43 055 853	R -	R 43 055 853
General Expenses	R 225 153 075	R 234 159 198	R 243 525 566	R -	R 243 525 566
Total	**R 719 076 668**	**R 865 245 872**	**R 899 855 706**	**-R 188 106 185**	**R 711 749 521**

[1] COS tool Comm & Fin Forecasts. (Year 2)

4.8.8. NERSA recommends an operational expenditure of R711 749 521 as a result of the following:

4.8.8.1. Depreciation has been kept constant compared to the Licensee's 110% growth assumption between 2024/25 and 2025/26. The depreciation value is R47 712 726 in line with table 5.

4.8.8.2. Eskom debt interest has been excluded.

4.8.8.3. Salaries have been increased by 5.6% between 2024/25 and 2025/26 compared to the Licensees 110%.

4.8.8.4. Materials and supplies have been increased by inflation between 2024/25 and 2025/26 compared to the Licensee's 20%

Surplus

4.8.9. The Municipality's revenue requirement includes a surplus of R75 837 155, calculated using a margin of 10% applied to operating expenditure, exclusive of bulk purchases, for both the wires and retail components of the electricity business. This has been adjusted in line with the recommended operational expenditure. The recommended surplus is R57.026 million.

4.8.10. To ensure that the applied surplus is not excessive and remains within acceptable regulatory bounds, the following validation procedures were undertaken:

4.8.10.1. The applied margin of 10% was benchmarked against the 10%–20% range prescribed in the approved NERSA COS framework, as supported by the EPP Policy Position 1.

4.8.10.2. The margin was further assessed against the Municipality's risk profile to ensure alignment with the principle of cost reflectivity and financial sustainability.

4.8.11. Risk factors considered include the following:

a) Revenue collection risk, with current collection levels above 70%, reflecting possible exposure to non-payment.

b) Operational risk, including energy losses; and

c) Financial sustainability requirements, including the need to maintain adequate cash flows for ongoing operations and infrastructure investment.

4.8.12. Based on the above, the applied surplus margin of 10% is considered conservative, justified, and commensurate with the Licensee's risk profile, while remaining within the acceptable parameters of the NERSA COS framework. This approach supports the financial viability of the electricity distribution function without imposing undue burden on consumers.

4.8.13. Furthermore, in recommending a surplus, NERSA relied on section 15(1)(a) of the Electricity Regulation Act under the tariff principles which provides 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.”

4.8.14. In applying the act, NERSA is required to ensure that the Municipality recovers efficient costs and a reasonable return, while preventing excessive compensation.

4.8.15. The recommended revenue requirement will be applied in the subsequent COS steps, namely Cost Functionalisation, Cost Classification, Cost Allocation, and Rate Setting. These steps have been verified and confirmed to align with the approved revenue requirement. Further details on these steps are provided below.

Cost Functionalisation

4.8.16. The Licensee has categorised its revenue requirement into two primary functional components, namely the wires business (20%) and the retail business (80%), 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.

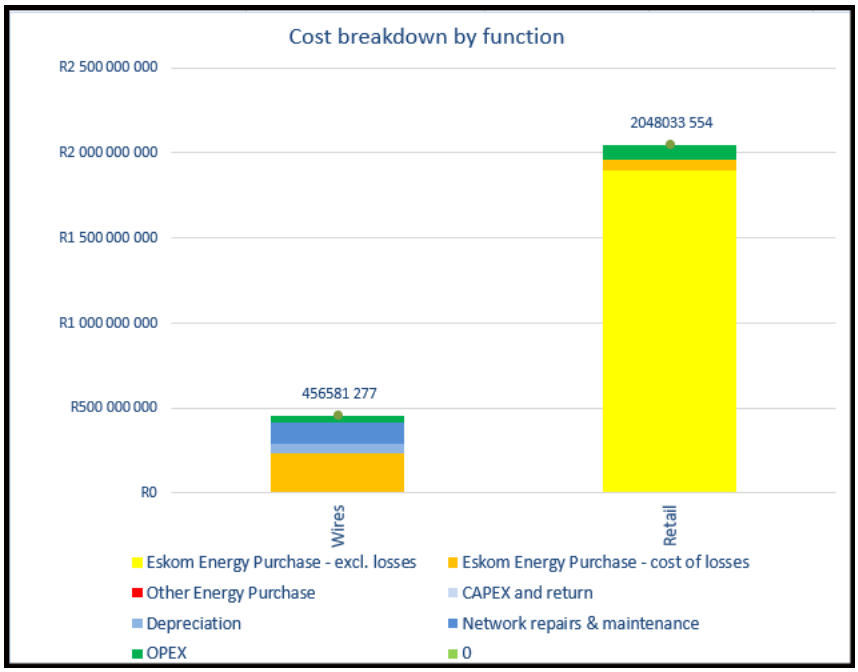


Figure 3: Costs breakdown by Functions

4.8.17. 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

Cost Classification

4.8.18. 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 functionalization upon verification.

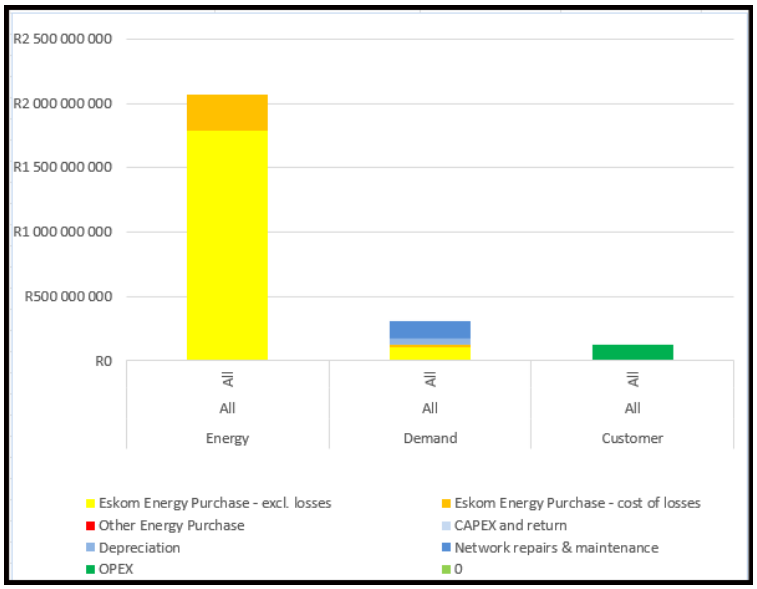


Figure 4: Costs breakdown by cost structure (Classification)

4.8.19. Energy purchases constitute energy-driven costs, with the highest expenditure incurred during the summer period under the standard time-of-use structure, largely due to the longer duration of the summer season as shown in figure 3 above. 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

4.8.20. 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.

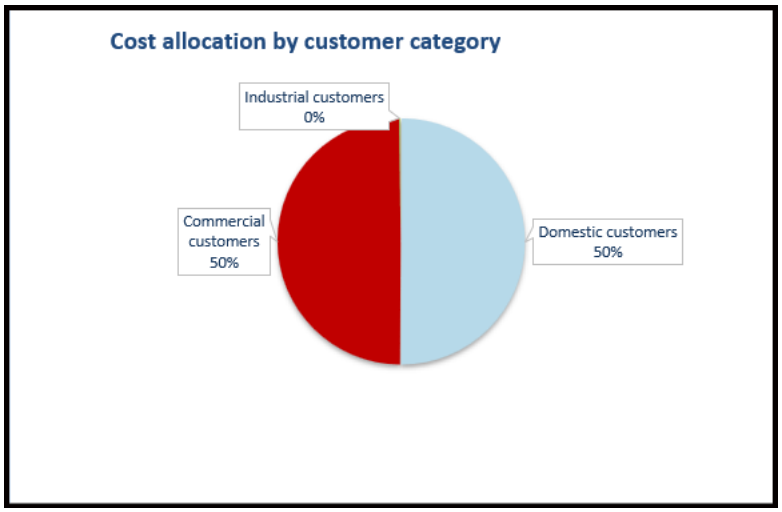


Figure 5: Costs Allocated

Rate Design

4.8.21. Figure 6 below reflects the outcome of the COS study, indicating that certain customer categories require upward adjustments, while others warrant decreases. A comparison between the cost of supply and the revenue generated per tariff category highlights the extent of over- or under-recovery within each category, as illustrated in Table 4 below.

4.8.22. To achieve full cost reflectivity, the Municipality would be required to implement differentiated tariff adjustments across customer categories. However, the Municipality has adopted a less aggressive approach, opting instead for a uniform tariff increase of 9% across all customer categories. The Municipality has cross subsidisation within its tariffs, as a result, the Municipality will be requested to develop a cross-subsidy framework to ensure that there is fairness and transparency in their cross subsidisation.

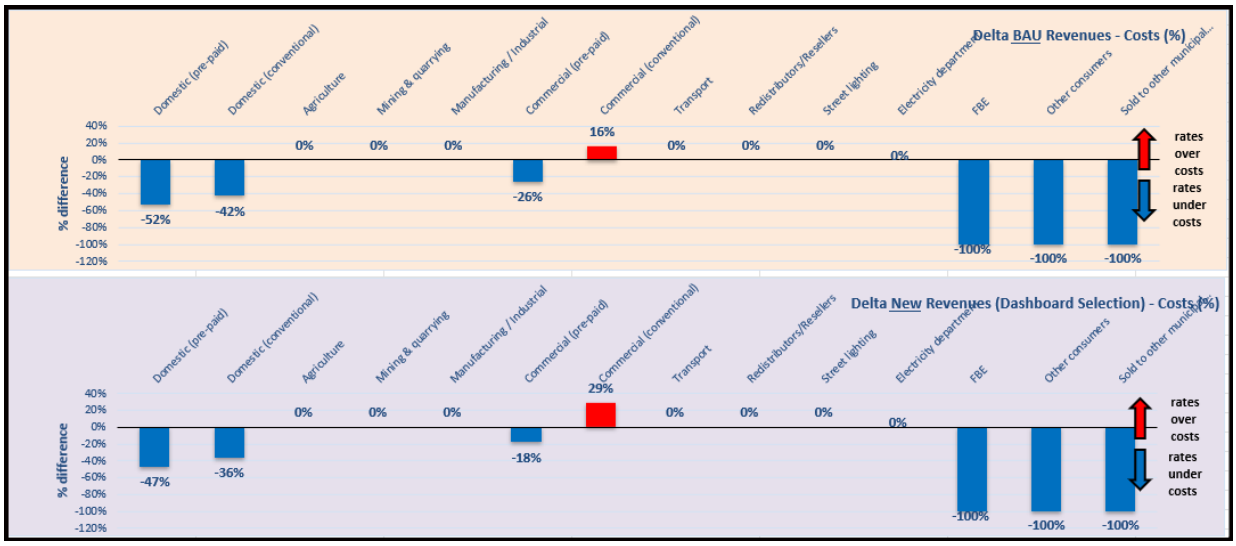


Figure 6: Revenue Recovery by customer category

5. CONCLUSION ON THE COS

5.1.1. 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.

5.1.2. 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.

5.1.3. In addition, the Licensee may take into account 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.

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

5.1.5. 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

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Energy charge (c/kWh)	337,94	369,24	9.26 %	361,26	6.90 %	

S3.2, S3.3&S5 Low end 20Amp	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Energy charge (c/kWh)	385,23	420,90	9.26 %	411,81	6.90 %	
Basic Charge (R/month)	240,58	262,86	9.26 %	257,18	6.90 %	

S3.2/S3.3/S5/ Mid end straightline 60A	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Energy charge (c/kWh)	385,23	420,90	9.26 %	411,81	6.90 %	
Basic Charge (R/month)	300,74	328,59	9.26 %	321,49	6.90 %	

S3.2/S3.3/S5 High end straightline 80A	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Energy charge (c/kWh)	385,23	420,90	9.26 %	411,81	6.90 %	
Basic Charge (R/month)	375,91	410,71	9.26 %	401,84	6.90 %	

S4. 100 A 3phase (low - 20A)	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Energy charge (c/kWh)	385,23	420,90	9.26 %	411,81	6.90 %	
Basic Charge (R/month)	360,86	394,27	9.26 %	385,76	6.90 %	

S4. High end straightline 100 amps 3phase (medium)	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Energy charge (c/kWh)	376,94	411,84	9.26 %	402,94	6.90 %	
Basic Charge (R/month)	706,20	771,59	9.26 %	754,93	6.90 %	

S4. 100 amps 3phase (high)	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Energy charge (c/kWh)	384,96	420,61	9.26 %	411,52	6.90 %	
Basic Charge (R/month)	1127,70	1232,13	9.26 %	1205,52	6.90 %	

TD.1: Domestic Single Phase	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Basic Monthly **(R/month):**	116,61	127,40	9.26 %	124,65	6.90 %	

Low season Energy charges:						
Peak **(c/kWh):**	262,17	286,44	9.26 %	280,26	6.90 %	
Standard (**c/kWh):**	189,09	206,60	9.26 %	202,13	6.90 %	
Off-peak **(c/kWh):**	130,10	142,15	9.26 %	139,08	6.90 %	
High Season energy charges						
Peak **(c/kWh):**	746,44	815,56	9.26 %	797,94	6.90 %	
Standard (**c/kWh):**	244,06	266,66	9.26 %	260,90	6.90 %	
Off-peak **(c/kWh):**	145,93	159,45	9.26 %	156,00	6.90 %	
Demand charge **(R/kVA):**	21,45	23,44	9.26 %	22,93	6.90 %	

TD2: Domestic Three Phase	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Basic Monthly **(R/month):**	181,15	197,93	9.26 %	193,65	6.90 %	
Low season Energy charges:						
Peak **(c/kWh):**	257,32	281,14	9.26 %	275,07	6.90 %	
Standard (**c/kWh):**	185,60	202,78	9.26 %	198,40	6.90 %	
Off-peak **(c/kWh):**	127,69	139,51	9.26 %	136,50	6.90 %	
High Season energy charges						
Peak **(c/kWh):**	746,44	815,56	9.26 %	797,94	6.90 %	
Standard (**c/kWh):**	245,47	268,20	9.26 %	262,41	6.90 %	
Off-peak **(c/kWh):**	145,93	159,45	9.26 %	156,00	6.90 %	
Demand charge **(R/kVA):**	15,50	16,94	9.26 %	16,57	6.90 %	

COMMERCIAL						
B.1 Small power Single phase≤100	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Energy charge (c/kWh)	232,70	254,25	9.26 %	248,76	6.90 %	
Basic Charge (R/month):	148,54	162,29	9.26 %	158,79	6.90 %	
Amp charge (R/Amp):	45,09	49,27	9.26 %	48,20	6.90 %	

B.3: Three phase ≤100 Small Power	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**

Energy charge (c/kWh)	232,70	254,25	9.26 %	248,76	6.90 %	
Basic Charge (R/month):	266,36	291,02	9.26 %	284,74	6.90 %	
Amp charge (R/Amp):	38,02	41,54	9.26 %	40,64	6.90 %	

INDUSTRIAL						
C.1: Three phase <100 Large Power	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Basic charge (R/month)	1 163,64	1271,39	9.26 %	1243,93	6.90 %	
Demand charge (R/kVA)	447,10	488,51	9.26 %	477,95	6.90 %	
Energy charge (c/kWh)	198,25	216,61	9.26 %	211,93	6.90 %	

Scale T1: Large Customer at MV	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Basic Monthly **(R/month):**	5 818,12	6356,88	9.26 %	6219,57	6.90 %	
Low season Energy charges:						
Peak **(c/kWh):**	272,04	297,23	9.26 %	290,81	6.90 %	
Standard (**c/kWh):**	205,63	224,67	9.26 %	219,82	6.90 %	
Off-peak **(c/kWh):**	152,01	166,08	9.26 %	162,50	6.90 %	
High Season energy charges						
Peak **(c/kWh)**	712,30	778,25	9.26 %	761,44	6.90 %	
Standard (**c/kWh)**	256,89	280,67	9.26 %	274,61	6.90 %	
Off-peak **(c/kWh)**	166,42	181,83	9.26 %	177,90	6.90 %	
Demand charge **(R/kVA):**	188,96	206,46	9.26 %	202,00	6.90 %	
Access charge (R/kVA)	84,53	92,35	9.26 %	90,36	6.90 %	

Scale T2: Large User Scale at 400V	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Basic Monthly **(R/month):**	1 083,55	1183,89	9.26 %	1158,32	6.90 %	
Low season Energy charges:						
Peak **(c/kWh):**	285,68	312,13	9.26 %	305,39	6.90 %	
Standard (**c/kWh):**	214,04	233,86	9.26 %	228,81	6.90 %	
Off-peak **(c/kWh):**	159,57	174,34	9.26 %	170,58	6.90 %	

High Season energy charges						
Peak **(c/kWh):**	747,92	817,18	9.26 %	799,53	6.90 %	
Standard (**c/kWh):**	269,74	294,71	9.26 %	288,35	6.90 %	
Off-peak **(c/kWh):**	174,73	190,91	9.26 %	186,78	6.90 %	
Demand charge **(R/kVA):**	207,86	227,11	9.26 %	222,21	6.90 %	
Amp charge **(R/Amp):**	92,98	101,59	9.26 %	99,39	6.90 %	

STREET LIGHTING						
L.1 Whole Night	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Basic charge (R/month)	84,66	92,50	9.26 %	90,50	6.90 %	
Energy charge (c/kWh)	182,82	199,75	9.26 %	195,43	6.90 %	

L2: 24 hour	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Basic charge (R/month)	84,66	92,50	9.26 %	90,50	6.90 %	
Energy charge (c/kWh)	197,65	215,96	9.26 %	211,29	6.90 %	

L.3: Whole Night High Mast	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Basic charge (R/month)	1 693,22	1850,01	9.26 %	1810,05	6.90 %	
Energy charge (c/kWh)	182,82	199,75	9.26 %	195,43	6.90 %	

L4: 24 Hrs Traffic	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Energy charge (c/kWh)	197,65	215,96	9.26 %	211,29	6,90 %	

MEGAFLEX 1 - 132 kV 40MVA AND ABOVE CUSTOMERS	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Service charge **(R/account/day)**	1 135,92	1241,11	9.26 %	1241,11	9.26 %	Increase is in line with the Eskom megaflex
Low season Energy charges:						
Peak **(c/kWh):**	263,47	287,87	9.26 %	287,87	9.26 %	
Standard (**c/kWh):**	148,14	161,86	9.26 %	161,86	9.26 %	

Off-peak **(c/kWh):**	105,81	115,61	9.26 %	115,61	9.26 %	
High Season energy charges						
Peak **(c/kWh):**	634,86	693,65	9.26 %	693,65	9.26 %	
Standard (**c/kWh):**	158,72	173,42	9.26 %	173,42	9.26 %	
Off-peak **(c/kWh):**	105,81	115,61	9.26 %	115,61	9.26 %	
Network Access charge/ capacity charge **(R/kVA)**	16,24	17,74	9.26 %	17,74	9.26 %	
Demand charge **(R/kVA):**	9,60	10,49	9.26 %	10,49	9.26 %	
Ancialliary service charge **(c/kWh)**	0,37	0,40	9.26 %	0,40	9.26 %	
Electrification an rural network subsidy **(c/kWh)**	5,02	5,49	9.26 %	5,49	9.26 %	
Transmission Network Charge **(R/kVA/day)**	9,60	10,49	9.26 %	10,49	9.26 %	
Urban volatage **(R/kVA/m)**	2,23	2,44	9.26 %	2,44	9.26 %	
Administration charge **(R/kVA/day)**	19,67	21,49	9.26 %	21,49	9.26 %	
Reactive service charge **(c/kWh)**	32,20	35,18	9.26 %	35,18	9.26 %	
Legacy charge	20,93	22,87	9.26 %	22,87	9.26 %	
Generation capacity charge	6,46	7,06	9.26 %	7,06	9.26 %	
Municipal Mark Up only for Hulamin as per agreement						

MEGAFLEX 2 - 132 kV UNDER 40MVA CUSTOMERS	2025/26	2026/27 Proposed	% increase	Recommended Tariff	% incrc asc	Key Analysis and Findings
Service charge (R/account/day)	1 135.92	1238.27	9.01 %	1337.33	17.73 %	
Low season Energy charges:						
Peak (c/kWh):	263.47	364.13	38.21 %	307.98	15.27 %	
Standard (c/kWh):	148.14	204.74	38.20 %	173.06	15.27 %	
Off-peak (c/kWh):	105.81	146.24	38.21 %	123.69	15.27 %	
High Season energy charges						
Peak (c/kWh):	634.86	877.43	38.21 %	742.13	16.90 %	
Standard (c/kWh):	158.72	219.37	38.21 %	185.54	16.90 %	
Off-peak (c/kWh):	105.81	146.24	38.21 %	123.69	16.90 %	
Network Access charge/ capacity charge (R/kVA)	16.24	22.60	39.17 %	19.17	18.04 %	

Demand charge (R/kVA):	9.60	13.36	39.14 %	11.30	17.72 %	
Ancialliary service charge (c/kWh)	0.37	0.40	8.12 %	0.43	16.23 %	
Electrification an rural network subsidy (c/kWh)	5.02	6.18	23.11 %	5.91	17.71 %	
Transmission Network Charge (R/kVA/day)	9.60	10.46	8.95 %	11.30	17.70 %	
Urban volatage (R/kVA/m)	2.23	2.43	8.97 %	2.62	17.49 %	
Administration charge (R/kVA/day)	19.67	21.44	9.00 %	23.16	17.74 %	
Reactive service charge (c/kWh)	32.20	39.66	23.18 %	37.91	17.73 %	
Legacy charge	20.93	22.82	9.03 %	24.65	17.77 %	
Generation capacity charge	6.46	9.82	52.01 %	10.61	64.24 %	

Small Scale embedded generation (SSEG)/ embedded generation (EG) - Export tariff	**2025/26**	**2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**% increase**	**Key Analysis and Findings**
Feed-inn Tariff **(c/kWh)**	78,07	85,30	9.26 %	83,46	6.90 %	

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

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

End.