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

Nquthu Local Municipality

THE DECISION

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1. At its meeting held on 8 May 2026, the Regulator Executive Committee (REC) considered Nquthu 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) set out in section 8 of the RFD.

2. Based on the available information and the analysis performed thus far, the REC decided:
   2.1. to approve the tariffs that are based on the COS Report as recommended in the tariff analysis section for implementation by the municipality with effect from 1 July 2026;
   2.2. to note the Cost of Supply Report submitted by the municipality;
   2.3. that the municipality must submit a report accounting for all the costs that have been noted in its COS study, to enable NERSA to perform its independent verification/audit process; and
   2.4. that the municipality must submit quarterly Specific Measurable Achievable Realistic and Time-bound (SMART) energy losses reduction progress reports to NERSA to monitor the implementation thereof.

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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
IBT	Inclining Block Tariff
IPP	Independent Power Producer
NLM	Nquthu Local Municipality
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 its mandate to regulate prices and tariffs. Municipal tariffs must be approved by NERSA to be implemented on 1 July of each financial year.

1.2. NERSA received Nquthu Local Municipality's tariff application together with its Cost of Supply (COS) study on 31 March 2026. The municipality revised the COS study because of changes in Eskom tariffs.

1.3. The table below shows the customer statistics of Nquthu for the 2024/25 financial year (FY). This data is obtained from the latest Distribution Forms (D-Forms).

Table 1: Customer Statistics

CUSTOMER STATISTICS			
Consumer classification	(MWh)	%MWh	Number of consumers
Domestic (Pre-paid)	3 701	22,51%	2 492
Domestic (Conventional)	17	0,10%	11
Commercial (Pre-paid)	604	3,67%	383
Commercial (Converntional)	518	3,15%	47
Manufacturing/Industrial	11 490	69,89%	21
Street lighting and own use	110	0,67%	
Totals	16 440	100%	2 954
Free Basic Electricity	1 090	29,44%	1817

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

1.5. NERSA's decision was made on 8 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 NERSA 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 No. 3 of 2000) ('PAJA') and

the Electricity Pricing Policy for the South African Electricity Supply Industry, 2008 ('EPP').

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

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

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

2.2. NERSA's Statutory Mandate

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

2.2.2. In particular:

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

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

2.3. Tariff Determination Principles under the ERA

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

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

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

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

2.4. Administrative Law Requirements

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

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

2.5. Policy Framework: Electricity Pricing Policy (2008)

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

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

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

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

2.6. Cost of Supply Studies

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

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

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

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

2.7. Judicial Oversight of the Tariff Approval Process

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

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

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

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

2.8. **Court-Directed Timelines**

2.8.1. The following timelines 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 must be submitted by 31 March 2026
c) Public participation processes must be concluded by 21 April 2026
d) The publication of NERSA decisions by 11 May 2026.

2.8.2. 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 tariff approvals and the tariff reasons for the 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 NERSA 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 NERSA 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 Nquthu, the assessment relied on the D-Forms for the 2024/25 FY 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. Nquthu's percentage deficit deteriorated from -5.84% in the 2023/24 FY to a deficit of -44.50% in the 2024/25 FY. The decline in financial performance can mainly be attributed to the increase in bulk purchases, lack of improvement in electricity revenue generation and higher spending on repairs and maintenance.

3.3. Table 2: Performance Indicators below shows that Nquthu's energy losses increased from 17.81% in 2023/24 FY to 20.71% in the 2024/25 FY. The municipality indicated that this is mainly due to the lack of technical internal expertise, inaccurate billing and illegal disconnections. The municipality has put in place the following measures to reduce high energy losses: the appointment of a panel of service providers, improved reporting channels for faulty billing and the roll-out of the programme to disconnect illegal electricity meters.

Table 2: Performance Indicators

Indicators	**2023-24**	**2024-25**
Percentage Deficit/Surplus	-5.84%	-44.50%
Percentage Energy Losses	17.81%	20.71%

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

Table 3: Revenue Analysis

	D-Form Input	**Energy Loss@12%**	**Energy Loss@6%**
Average Selling Price	199,85		
Sales kWh	16 441 348,00	18 247 535,68	19 491 685,84
Purchases kWh	20 735 836,00	20 735 836,00	20 735 836,00
Losses kWh	4 294 488,00	2 488 300,32	1 244 150,16
Losses percentage	**20,71%**	**12,00%**	**6,00%**
Additional Energy (kWh)		1 806 187,68	3 050 337,84
Additional Revenue (Rands)		3 609 625,21	6 096 031,16
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 38 185 083,00	R 41 794 708,21	R 44 281 114,16
Total Expenses (Rands)	R 55 176 514,00	R 55 176 514,00	R 55 176 514,00
Net Profit (Loss)	R -16 991 431,00	R -13 381 805,79	R -10 895 399,84
Percentage Surplus/Deficit	**-44,50%**	**-32,02%**	**-24,61%**

3.5. The licensee has the potential to improve the deficit to -32.02% if energy losses are limited to 12%, and the deficit could potentially improve to -24.61% if the energy losses are reduced to 6%.

4. DETERMINATION OF NQUTHU LOCAL MUNICIPALITY'S TARIFFS BASED ON THE COST OF SUPPLY STUDY

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

4.2. Nquthu utilised the COS model developed by Sustainable Energy Africa (SEA) to determine its revenue requirements for the 2026/27 FY 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. The COS study was submitted to NERSA for the 2024/25 FY and was based on audited financial statements for the 2024/25 FY. The study follows the NERSA COS framework and utilises the latest available audited data, which is based on the 2024/25 FY. The asset value is R205 796 554 (2024/25FY D-Form and AFS), Depreciation is R1 733 255 (2026/27FY Budget) and the Profit Margin/Surplus is R4 987 647 (2026/27FY Budget). The depreciation and surplus are highlighted in Figure 2 and Table 5 below.

4.3.

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

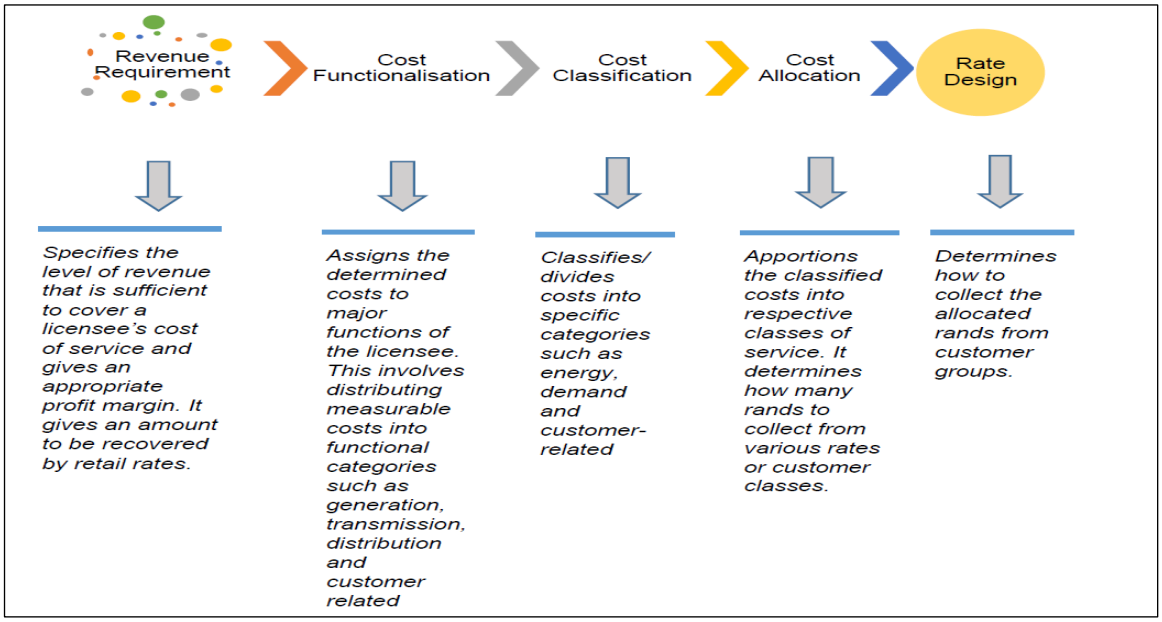


Figure 1: Five Steps of COS

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

4.5.1. be informed by cost of supply outcomes;

4.5.2. progressively move tariffs towards cost-reflectivity; and

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

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

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

4.6.2. Bulk purchase costs were updated using the approved 9.01% Eskom bulk tariff adjustment.

4.6.3. Controllable electricity Operating Expenditure (OPEX) costs were adjusted using CPI-linked assumptions.
4.6.4. 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.
4.7.1. The licensee has proposed a phased implementation over three financial years to achieve full cost recovery.
4.7.2. This approach aligns with section 18.7 of the COS Study, which allows for gradual tariff realignment to mitigate tariff shocks and maintain affordability for vulnerable customer groups.

4.8. The following steps are undertaken to analyse the cost of the supply study:

4.8.1. **Revenue Requirement**

4.8.1.1. 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.

4.8.1.2. The municipality applied a cost-plus methodology in the determination of its revenue requirement, as reflected in Table 4 of the Reasons for Decision document, and did not utilise a Rate of Return (ROR) approach. Accordingly, no Regulatory Asset Base (RAB) was determined or applied.

4.8.1.3. Under the cost-plus framework, the allowable revenue comprises the following:
4.8.1.3.1. Efficient and prudent OPEX of R5 967 067 before surplus
4.8.1.3.2. Depreciation, as a proxy for asset consumption and future asset replacement of R1 733 255
4.8.1.3.3. A reasonable surplus margin applied to the total cost of R4 987 647.

4.8.1.4. To ensure that the applied surplus is not excessive and remains within acceptable regulatory bounds, the following validation procedures were undertaken:
4.8.1.4.1. The applied surplus margin of 9% was benchmarked against the 10 to 20% range prescribed in the approved NERSA COS framework, as supported by the EPP policy position 1, D-Forms and Trial Balance.
4.8.1.4.2. The margin was further assessed against the municipality's risk profile to ensure alignment with the principle of cost reflectivity and financial sustainability.

4.8.1.5. Risk factors considered include the following:

4.8.1.5.1. Revenue collection risk, with current collection levels at approximately 80%, reflecting exposure to non-payment and indigents

4.8.1.5.2. Operational risk, including energy losses of approximately 11% and ageing network infrastructure

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

4.8.1.6. Based on the above, the applied surplus margin of 9% is considered conservative, justified and commensurate with the municipality'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.

4.8.1.7. Nquthu submitted a COS detailing a revenue requirement of R54.86 million for the 2026/27 FY. This revenue requirement is based mainly on Eskom purchases, which account for 70%, while operational expenditure accounts for 11%.

	Total cost (R)			
Revenue Requirement components	**Wires**	**Retail**	**Total**	**% of Total**
Allowable costs	9 741 478	45 122 637	54 864 115	100%
Energy purchases from Eskom - net of cost of losses	-	38 131 757	38 131 757	70%
Energy purchases from Eskom - cost of losses	2 888 822	2 888 822	5 777 644	11%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	5 967 067	-	5 967 067	11%
Other revenues	-	-	-	**0%**
Surplus	885 589	4 102 058	4 987 647	9%
Not allowable costs	2 118 817	2 118 817	4 237 634	
Cost of losses disallowed	2 118 817	2 118 817	4 237 634	
TOTAL COSTS	**11 860 295**	**47 241 454**	**59 101 750**	
	20%	80%		

Figure 2: Revenue Requirement Components

4.8.1.8. The efficiency of costs for the 2024/25 FY 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 FY, applying stated assumptions to determine the revenue requirement for that period.

4.8.1.9. 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, as detailed below.

Bulk purchases

4.8.1.10. Nquthu's COS study projects a bulk purchase expenditure of R38.13 million, which accounts for 70% of total costs when excluding the 12% energy losses allowance. Bulk purchases were verified against Eskom invoices in the 2024/25 FY.

4.8.1.11. The licensee projected its bulk purchases for the 2026/27 FY using the 2025/26 FY Eskom tariffs as a base and made the following assumptions: sales growth of 4% and a bulk purchase cost increase of 9.01% for the 2026/27 FY, which is in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

Operational Expenditure

4.8.1.12. Nquthu's COS study projects operational expenditure totalling R5.97 million, representing 70% of overall costs. Table 4 below provides a breakdown of this expenditure.

Table 4: Operational Expenditure

Functions	Total Opex	Wires	Retail
Depreciation	1 733 255	1 733 255	-
Network and repairs	4 233 812	4 233 812	-
Total	**5 967 067**	**5 967 067**	

4.8.1.13. Only the portion of shared costs directly attributable to the electricity service was allocated to the revenue requirement. This ensures that electricity consumption is charged solely for costs associated with the provision of electricity services.

4.8.1.14. Inefficient cost components – such as NMD exceedance penalties and interest incurred on Eskom-related debt – have been excluded from the total, as these items fall within the control of the municipality. The municipality's accounts with Eskom are up to date with no exceedance recorded under the NMD for the 2024/25 FY.

4.8.1.15. All the other expenses have been grouped under 'Other expenses'. The other operating expenses, including charges from other municipal departments,

have been checked to ensure that they relate only to the electricity function; furthermore, all these expenses have been projected to grow in line with inflation.

Surplus

4.8.1.16. Nquthu's revenue requirement includes a surplus of R4.99 million, calculated using a surplus factor of 9% applied to operating expenditure, inclusive of bulk purchases, for both the wires and retail components of the electricity business. This figure excludes inefficient or non-allowable costs, interest on Eskom-related debt (as the municipality is currently not in arrears on its bulk electricity account) and penalties arising from NMD exceedances. These exclusions were verified against Eskom invoices.

4.8.1.17. The applied surplus margin of 9% was benchmarked against the established target range of 10–20% on the approved NERSA COS framework, EPP policy position 1, D-Form and Trial Balance.

4.8.1.18. To ensure that the profit margin commensurate with the risk, risk considerations were incorporated qualitatively, including the following:

4.8.1.18.1. Revenue collection risks (non-payment, indigent levels, bad debts). The municipality has budgeted to write off bad debt of R0 for the 2026/27 FY.

4.8.1.18.2. Operational risks remain a concern, particularly in relation to energy losses and ageing infrastructure. For the 2026/27 FY, municipal energy losses are projected at 11.00%.

4.8.1.18.3. Financial sustainability requirements.

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

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

4.8.1.21. 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 of these steps are provided below.

4.8.2. Cost Functionalisation

4.8.2.1. The licensee has categorised its revenue requirement of R54.86 million 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. On verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

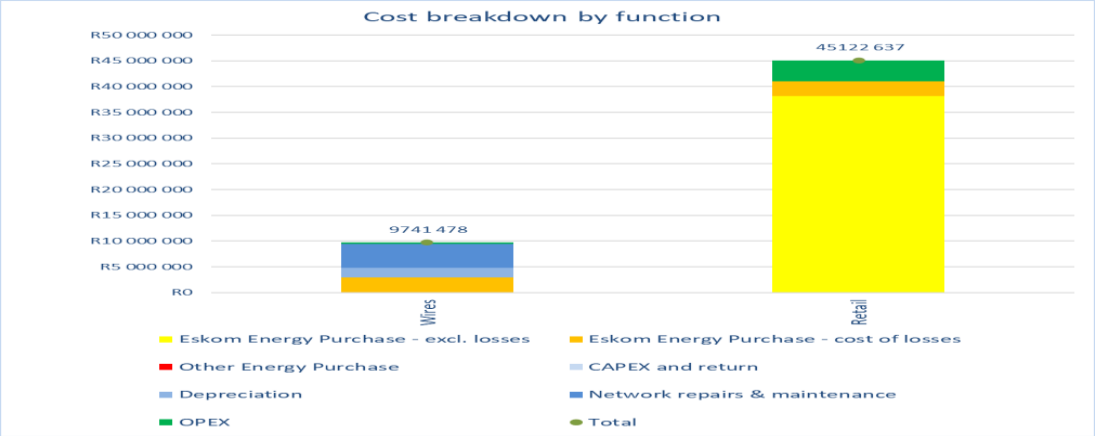


Figure 3: Cost Breakdown by Functions

4.8.2.2. These costs, on 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.

4.8.2.3. The verification of costs included in the COS model was undertaken using both the NERSA D-Forms and the municipality's audited AFS for the 2022/23 FY.

4.8.3. Cost Classification

4.8.3.1. 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 on verification.

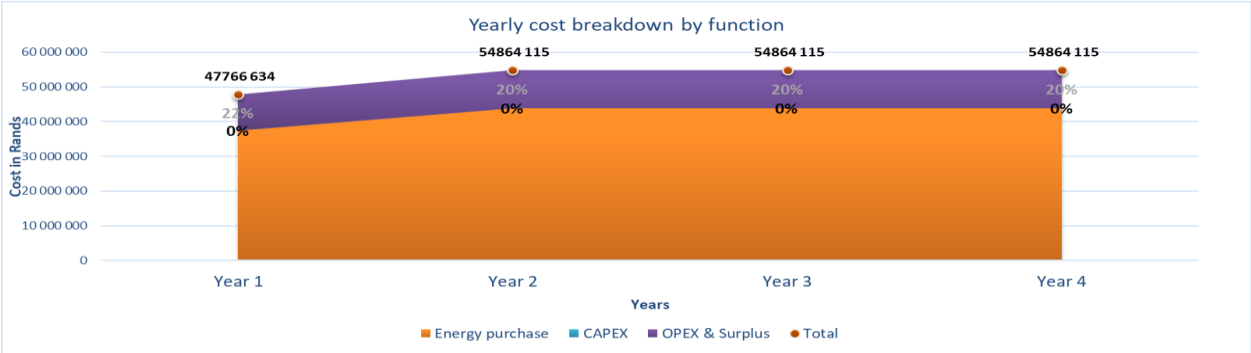


Figure 4: Cost Breakdown by Cost Structure (Classification)

4.8.3.2. 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. 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.

4.8.4. Cost Allocation

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

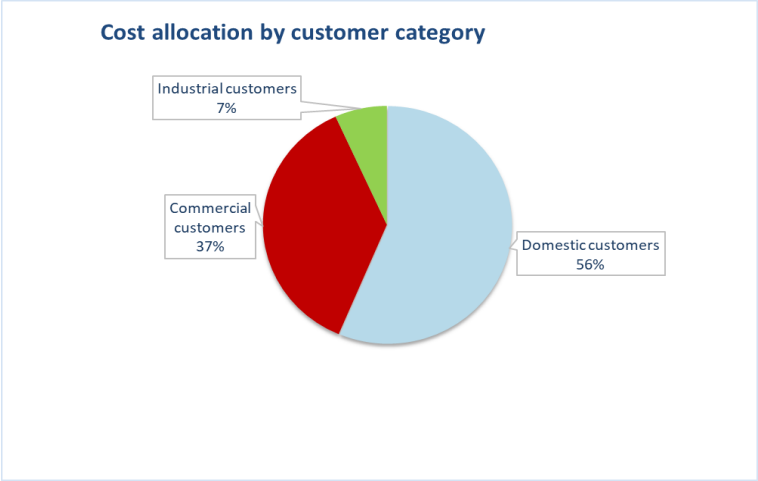


Figure 5: Costs Allocated

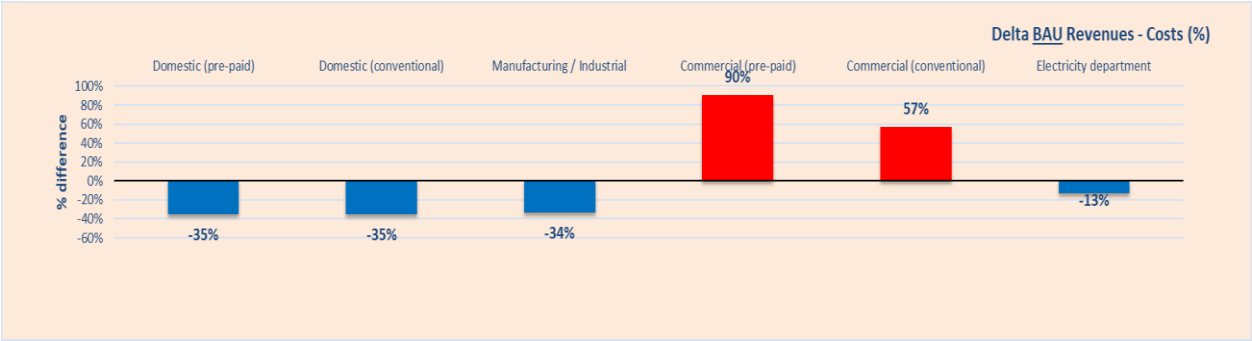
4.8.5. Rate Design

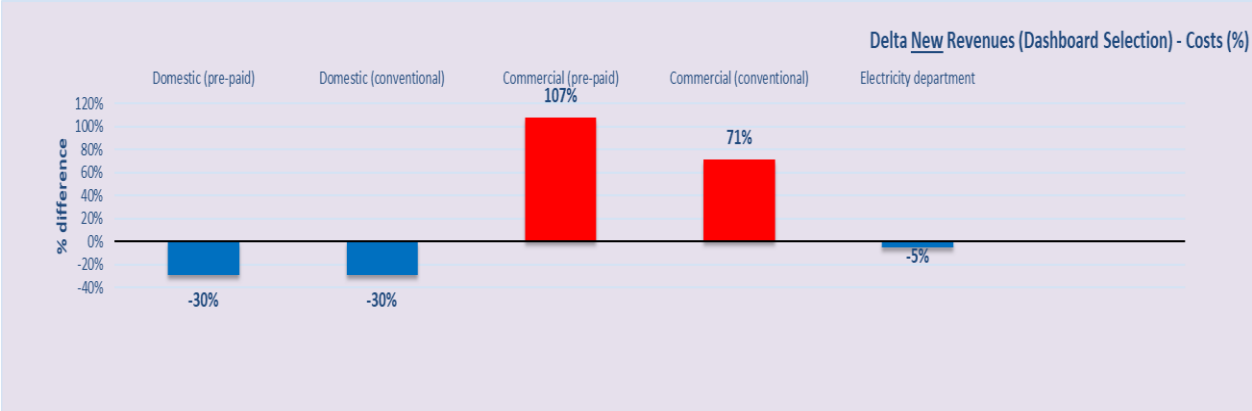
4.8.5.1. Table 4 below reflects the outcome of the COS study, indicating that certain customer categories require upward adjustments, while others warrant a decrease. A comparison between the cost of supply and the

revenue generated per tariff category highlights the extent of over- or under-recovery within each category, as illustrated in Table 4 below.

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

Table 5: Revenue Recovery by Customer Category





4.8.5.3. 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.

4.8.5.4. Based on the revenue outputs of the COS main model, a tariff increase of 9% is required by the municipality. However, the municipality has resolved to implement differentiated tariff increases of 9% for domestic customers and 15% for commercial and industrial customers. This approach seeks to enhance revenue collection while minimising the financial impact on customers, particularly indigent households and low-income households. This approach ensures that cross-subsidies are not removed abruptly, thereby avoiding undue tariff shocks and mitigating adverse impacts on vulnerable consumers. At the same

time, it facilitates a managed, transparent and gradual transition towards tariffs that are cost-reflective, equitable and aligned with the NERSA principles.

5. CONCLUSION ON THE COS

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 36.50% to reach the overall cost-reflectivity, as illustrated in Figure 6 below. The licensee has proposed an average increase of 11.18% to ensure customer protection and municipal sustainability. Based on the available information, the municipality is expected to remain financially sustainable under the recommended tariff increases of 9% and 15%, respectively.

5.7. The outcome of the COS study indicates that the municipality requires a tariff increase of 36.50% to achieve efficient cost reflectivity, as shown in Figure 6 below.

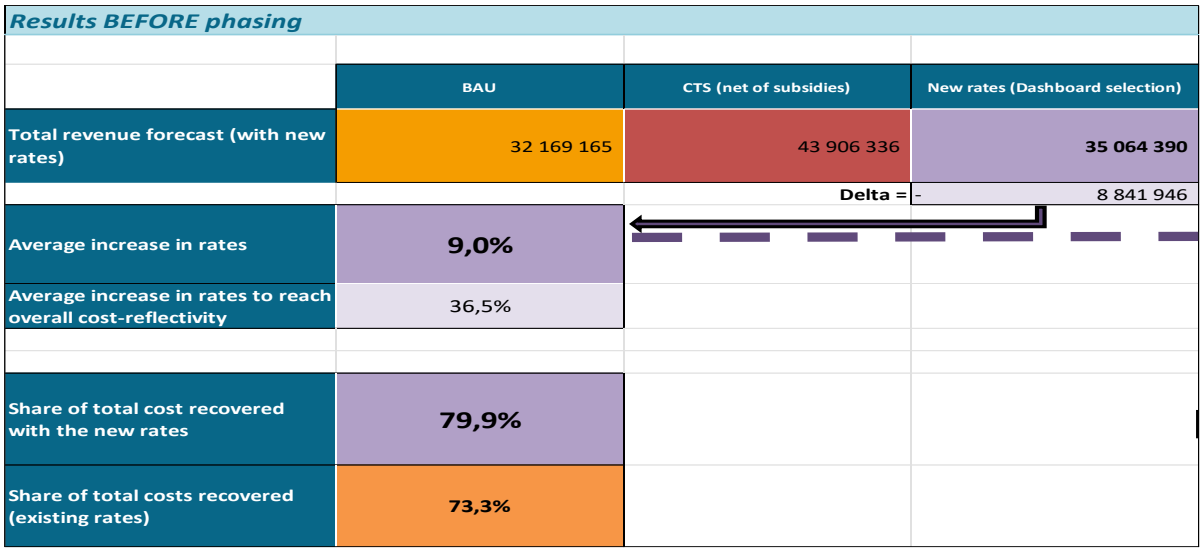


Figure 6: Rate of Design

5.8. The licensee has applied for a 9.00% and a 15.00% tariff increase, respectively, which is below the increases required for full cost reflectivity. NERSA performed an analysis and recommended the applied tariff increase of 9.01% across tariff categories in line with Eskom's ERTSA in order to ensure customer protection and municipal financial sustainability. NERSA's analysis indicates that the recommended tariff increase is sustainable for the Nquthu Local Municipality.

5.9. While the COS study outcome reflected an average tariff increase of 36.50% for the licensee to achieve full cost reflectivity, the municipality adopted a phased-in approach to implement tariff increases below the COS study outcomes. Some of the considerations for this decision include the licensee's requirement to maintain a sustainable tariff level to drive the demand for its electricity services. Significantly higher tariffs could negatively impact the licensee by reducing customer demand and sales. The licensee also considered the ability to service its Eskom account and broader affordability impact on customers in determining the pace of its tariff adjustments.

5.10. This approach will help protect the licensee's revenue base and support its financial sustainability, as required by legislation.

5.11. The COS study is based on forecast values; therefore, until such a time that audited actual figures are available, the true requirement for cost reflectivity cannot be determined with 100% certainty. It is for this reason that the municipality will be requested to submit a report accounting for all the costs that have been noted in its COS study, to enable NERSA to perform its independent verification/audit process.

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9. CONFIDENTIALITY

None.

10. CONCLUSION

From a conspectus of the facts and evidence presented to the REC, it is appropriate to consider the review of Nquthu's tariff application for the 2026/27 financial year.

10.2. All tariffs shall be limited to 9.01% as per the COS study for customer protection and municipal financial sustainability.

End.