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

Newcastle Local Municipality

THE DECISION

At its meeting held on 8 May 2026, the Regulator Executive Committee (REC) considered the Newcastle 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 21 of the RFD Based on the information submitted and the analysis conducted, the REC decided to:

1. approve the tariffs that are based on the COS report as recommended in the tariff analysis section for implementation by the licensee with effect from 1 July 2026.
2. note the COS report submitted by the licensee; and
3. that the licensee must submit a report accounting for all the costs that have been noted in its COS study to enable the National Energy Regulator of South Africa to perform its independent verification/audit process by 30 September 2026.

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ABBREVIATIONS AND ACRONYMS

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 its mandate to regulate prices and tariffs. Municipal tariffs must be approved by the Energy Regulator to be implemented on 1 July of each financial year.

1.2. The Newcastle Local Municipality is in KwaZulu-Natal, and is one of the three municipalities that form the Amajuba District.

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)	27 576,00	7,61%	5 539
Domestic (Conventional)	67 179,00	18,54%	9 059
Commercial (Converntional)	52 150,00	14,39%	2 908
Manufacturing/Industrial	212 649,00	58,70%	264
Street Lighting,Own use and other departments	2 731,00	0,75%	N/A
Totals	362 285	100%	17 770
Free Basic Electricity	1 518	1,60%	2530

1.3. Industrial customers account for 58.7% of the total electricity sales, followed by domestic customers accounting for 26.15%.

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

1.5. Newcastle implemented a 13% average price increase in the 2025/26 financial year (FY) and is applying for an average price increase of 9% for the 2026/27FY.

1.6. For this application, the licensee confirmed that the tariffs applied for are authorised by the Municipal Council, and it undertook customer consultation with no comments received.

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

1.8. 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

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 ('the 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 (MYPD) and Eskom Retail Tariff and Structural Adjustment (ERTSA) decision and is undertaken annually to align with the municipal budgeting process contemplated in the Municipal Finance Management Act, 2003 (Act No. 56 of 2003).

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

2.1.4. This section provides the legal and policy context within which the Energy Regulator evaluated and determined the municipal electricity tariff application for the 2026/2027 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 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 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. EPP 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 (COS) methodologies have historically not been consistently applied across the electricity distribution industry.

2.6.3. EPP 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 NERSA.

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 seeking to vary the timelines set by the Court on 4 December 2025, considering the practical difficulties arising from 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 communicated by 6 March 2026.
b) Municipal tariff applications must be submitted by 31 March 2026.
c) Public participation processes must be concluded by 21 April 2026.
d) 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 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 contained in this document demonstrate how the Energy Regulator complied with the legislative, policy and judicial framework in determining the municipal electricity tariff for the 2026/27 municipal financial year.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In evaluating the financial and technical performance of Newcastle, 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 (AFS). As a result, the data captured in the D-forms is considered reliable for purposes of the tariff analysis.

3.2. Newcastle recorded a percentage surplus of 8.58% in the 2023/24 financial year, which has improved to 10.5% in the 2024/25 financial year.

3.3. Table 2 below shows that Newcastle recorded energy losses of 9.82% in the 2023/24 financial year and 10.71% in the 2024/25 financial year.

Table 2: Performance indicators

Outputs:	2024/25	2023/24
Percentage Surplus	4,48%	0,20%
Energy Losses:	10,71	9,82

3.4. 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 NEWCASTLE'S TARIFFS BASED ON THE COST OF SUPPLY STUDY

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

4.2. Newcastle utilised the COS study model developed by Sustainable Energy Africa (SEA) to determine its revenue requirements for the 2026/27 financial year and to apportion costs required to service each customer's class 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.

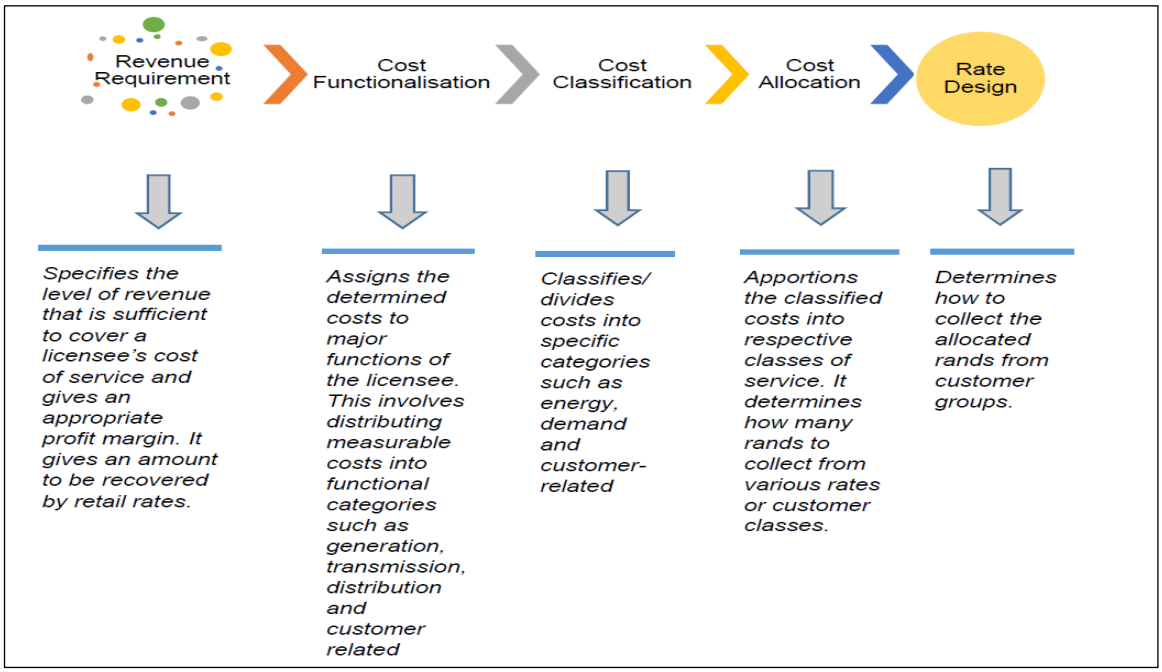


Figure 1: Five steps of COS study

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 its tariff application, the licensee 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 8.76% Eskom bulk tariff adjustment.

4.6.3. Controllable electricity OPEX was 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.

4.8. The following steps are undertaken to analyse the COS 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. Newcastle submitted a COS detailing revenue requirements of R1 110 253 880 for the 2026/27 financial year. As shown in Table 3 below, this revenue requirement is dominated by Eskom purchases accounting for 72%, including an energy losses allowance. Operational expenditure accounts for 26%.

Table 3: Newcastle revenue requirement

Revenue Requirement components	Total cost (R) Wires	Retail	Applied For 2026/27	NERSA Adjustments	NERSA Decision 2026/27	% of Total
Allowable costs	157 399 861	952 854 019	1 110 253 880	-	1 110 253 880	100%
Energy purchases from Eskom - net of cost of losses	-	703 001 524	703 001 524	-	703 001 524	63%
Energy purchases from Eskom - cost of losses	47 151 485	47 323 320	94 474 805	-	94 474 805	9%
Other energy purchases	-	-	-		-	0%
Operational expenditure (incl. Depreciation)	101 362 295	189 196 043	290 558 338	-	290 558 338	26%
Other revenues	- 1 136 498	- 5 078 611	- 6 215 109	-	- 6 215 109	-1%
Surplus	10 022 580	18 411 743	28 434 323	-	28 434 323	3%
Not allowable costs	-	-	-	-		
Cost of losses disallowed	-	-	-	-		
TOTAL COSTS	157 399 861	952 854 019	1 110 253 880	-	1 110 253 880	
	14%	86%				

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 requirement 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. Newcastle's COS projects a bulk purchase expenditure of R797 476 329, which accounts for 72% of total costs when including the 12% energy losses allowance. Bulk purchases were verified against the 2024/25 Eskom invoices.

4.8.6. The licensee projected its bulk purchases for the 2026/27 financial year using the 2025/26 Eskom tariffs as a base and made the following assumptions: sales growth of 0%, and a bulk purchase cost increase 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. Newcastle's COS study projects operational expenditure totalling R290 558 338, representing 26% of overall costs. Table below provides a breakdown of this expenditure.

Table 4: Operational expenditure[1]

Cost Drivers	Actual 2024/25	Budget 2025/26	Applied for 2026/27	NERSA Adjustments	NERSA Decision 2026/27
General & Other	R 137 959 486	R 80 301 359	R 99 385 765	R -	R 99 385 765
Salaries and allowances	R 31 083 007	R 20 851 055	R 36 368 442	R -	R 36 368 442
Materials and supplies	R 9 015	R 14 418	R 15 283	R -	R 15 283
Contracted Services	R 20 380 902	R 11 904 577	R 12 618 852	R -	R 12 618 852
Salaries, wages and allowances (exclu. Repairs and Maintenance)				R -	R -
Payments to consultants (operational work)	R 154 413	R 100 000	R 106 000	R -	R 106 000
Eskom debts' interests	R 35 960 100	R -	R -		
Other creditors interests	R -	R -	R -		
Current year depreciation	R 50 372 049	R 47 431 309	R 50 277 188	R -	R 50 277 188
NMD exceedance penalties	R -	R -	R -		
Shared OPEX	R 54 112 874	R 187 703 351	R 191 172 573	-R 98 322 891	R 92 849 682
Bad debts written-off	R 4 995 629	R 153 835 585	R 153 835 585	-R 98 322 891	R 55 512 694
FBE paid to Eskom	R 3 341 885	R 4 476 679	R 4 745 280	R -	R 4 745 280
Charges from other Municipal Departments	R 42 195 453	R 28 743 130	R 31 904 874	R -	R 31 904 874
General Expenses	R 3 579 907	R 647 957	R 686 834	R -	R 686 834
Total	**R 192 072 360**	**R 268 004 710**	**R 290 558 338**	**-R 98 322 891**	**R 192 235 447**

4.8.8. The operating expenditure comprises:

4.8.8.1. depreciation, as a proxy for asset consumption and future asset replacement of R50 277 188;

4.8.8.2. efficient (as evidenced by low energy losses) network repairs and maintenance of R34.736 million; and

4.8.8.3. all the other efficient expenses of R205.544 million have been grouped under 'OPEX'. This includes bad debts, which have been tested to ensure that they are below the NERSA 5% threshold.

4.8.9. The approach adopted by Newcastle in forecasting operational expenditure is considered reasonable, and the amount has therefore been recommended as requested. Furthermore, the licensee is not incurring inefficient costs such as Notified Maximum Demand (NMD) exceedance penalties and interest incurred on Eskom-related debt.

Surplus

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

4.8.10. Newcastle's revenue requirement includes a surplus of R28.434 million, calculated using a surplus factor of 10% applied to operating expenditure, exclusive of bulk purchases, for both the wires and retail components of the electricity business.

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

4.8.11.1. The applied surplus 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.

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

4.8.12. Risk factors considered include the following:

4.8.12.1. Revenue collection risk, with current collection levels above 89%, reflecting minimum exposure to non-payment.

4.8.12.2. Operational risk, including energy losses of approximately 10.71%, signifying a well-maintained network infrastructure.

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

4.8.13. 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.

4.8.14. Furthermore, 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'.

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

4.8.16. 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

4.8.17. The licensee has categorised its revenue requirement of R153.4 million into two primary functional components, namely the wires business (14%) and the retail business (86%), 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.

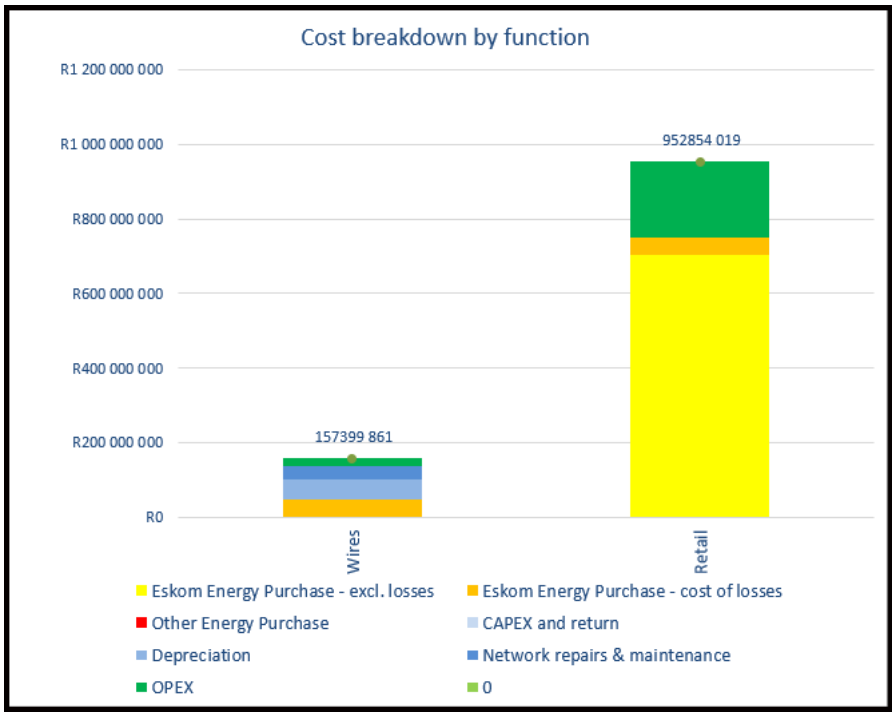


Figure 2*:* Cost breakdown by functions

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

Cost Classification

4.8.19. 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.

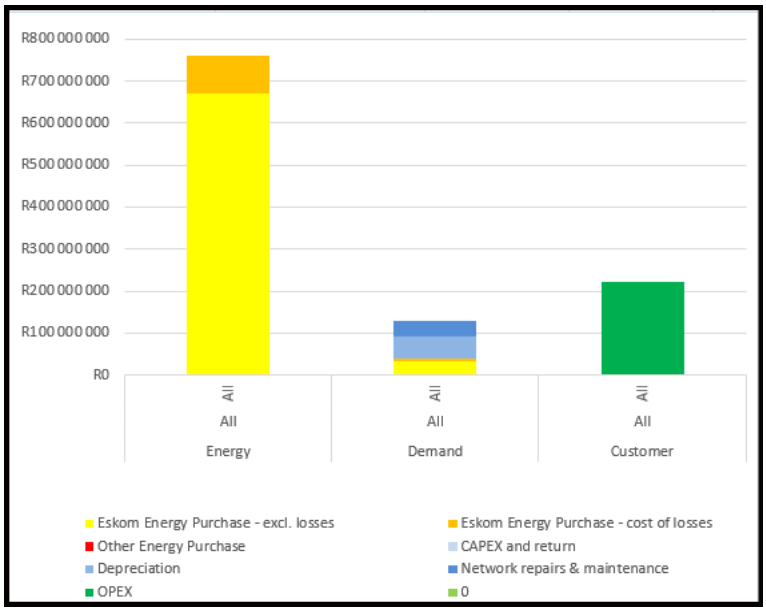


Figure 3*:* Cost breakdown by cost structure (classification)

4.8.20. 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

4.8.21. 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.

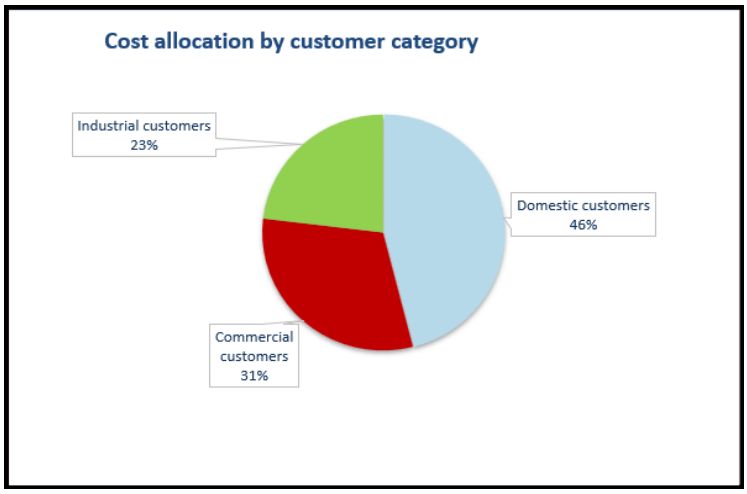


Figure 4: Costs allocated

Rate Design

4.8.22. Table 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 6 below.

4.8.23. 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 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 its cross-subsidisation is fair and transparent.

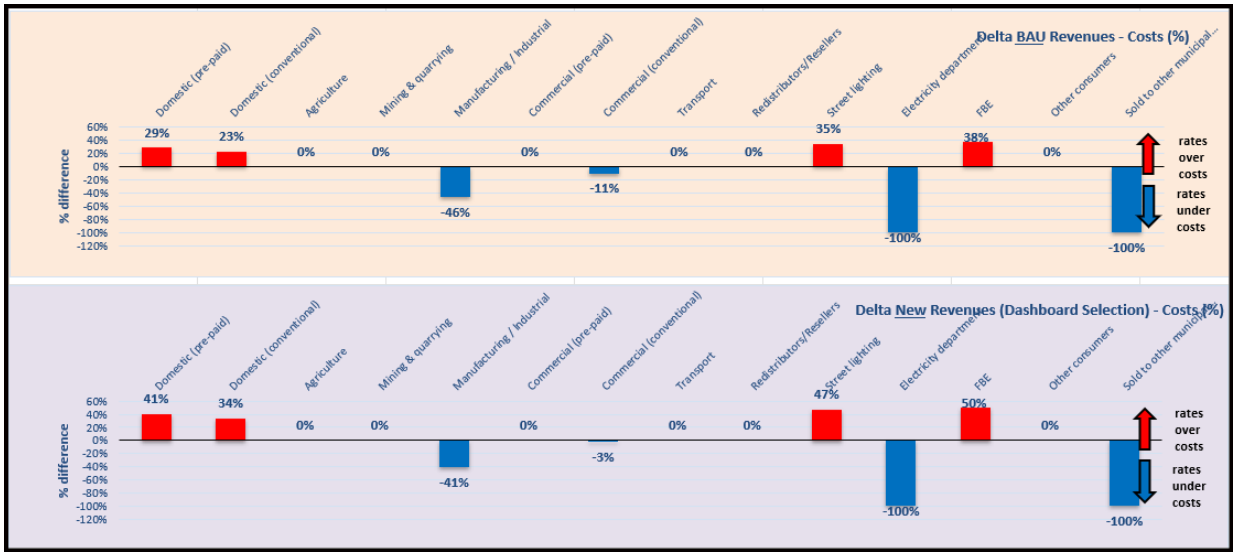


Figure 5: Revenue recovery by customer category

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 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.

5.4. This approach is intended to safeguard the licensee'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 8% after NERSA adjustments, as illustrated in Figure 6 below. This increase which is in line with the application is recommended for approval.

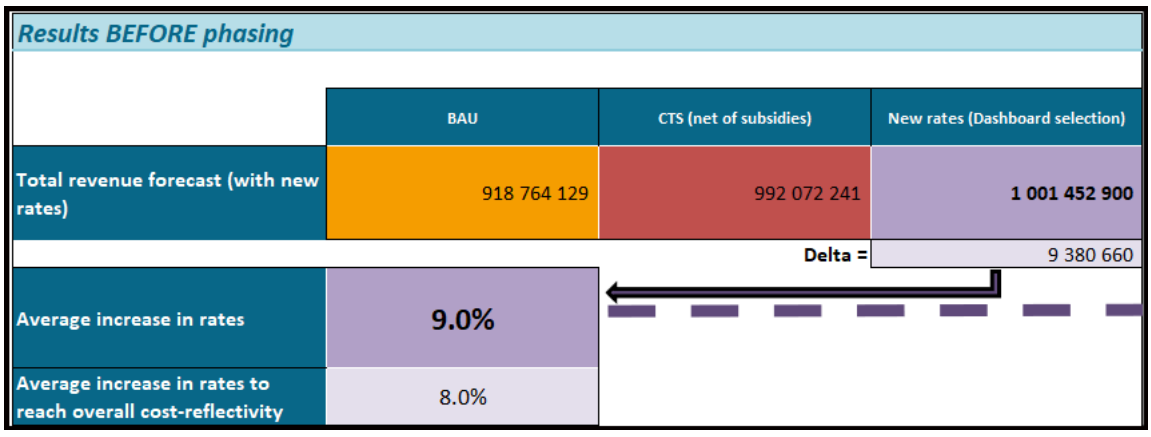


Figure 5: Rate design

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Scale 2 : 60A domestic supplies (Vacant lot)	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Analysis and Key Findings
Basic Charge (R/month)	410,38	435,01	6,00%	435,01	6,00%	

Scale 2 : 60A domestic supplies (Time of use)	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Analysis and Key Findings
Basic charge (R/month)	422,23	447,57	6,00%	447,57	6,00%	
Energy Low season						
Peak (c/kWh)	407,27	443,93	9,00%	443,93	9,00%	
Standard (c/kWh)	212,58	231,71	9,00%	231,71	9,00%	
Off-peak (c/kWh)	115,76	126,18	9,00%	126,18	9,00%	
Energy High season						
Peak (c/kWh)	671,74	732,20	9,00%	732,20	9,00%	
Standard (c/kWh)	257,79	280,99	9,00%	280,99	9,00%	
Off-peak (c/kWh)	152,57	166,30	9,00%	166,30	9,00%	

Scale 3 : Large domestic supplies and small business premises	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Analysis and Key Findings
Basic charge (R/month)	1167,64	1237,70	6,00%	1237,70	6,00%	
Energy charge (c/kWh)	273,03	297,61	9,00%	297,61	9,00%	

Scale 3 : Large domestic supplies and small business premises (Vacant business stand)	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Analysis and Key Findings
Basic charge (R/month)	1164,66	1234,54	6,00%	1234,54	6,00%	

Scale 3 : Large domestic supplies and small business premises (Time of Use)	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Analysis and Key Findings
Basic charge (R/month)	1167,64	1237,70	6,00%	1237,70	6,00%	
Energy Low SSason						
Peak (c/kWh)	301,33	301,33	0,00%	301,33	0,00%	
Standard (c/kWh)	191,75	191,75	0,00%	191,75	0,00%	
Off-peak (c/kWh)	99,36	99,36	0,00%	99,36	0,00%	
Energy High season						
Peak (c/kWh)	520,28	520,28	0,00%	520,28	0,00%	
Standard (c/kWh)	221,85	221,85	0,00%	221,85	0,00%	
Off-peak (c/kWh)	107,70	107,70	0,00%	107,70	0,00%	

Scale 4 : Medium business and industrial premises (Vacant Stand)	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Analysis and Key Findings
Basic charge (R/month)	1164,76	1234,65	6,00%	1234,65	6,00%	

Scale 4 : Medium business and industrial premises (Standard)	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Analysis and Key Findings
Basic charge (R/month)	2511,53	2662,22	6,00%	2662,22	6,00%	
Energy charges (c/kWh)	148,03	161,35	9,00%	161,35	9,00%	
Network demand charge (R/kVA)	261,78	285,34	9,00%	285,34	9,00%	
Network capacity charge (R/kVA)	227,04	247,48	9,00%	247,48	9,00%	

Scale 4 : Medium business and industrial premises (Time of Use)	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Analysis and Key Findings
Basic Monthly **(R/month)**	2511,53	2662,22	6,00%	2662,22	6,00%	

Low Season Energy Charges						
Peak **(c/kWh)**	493,35	537,75	9,00%	537,75	9,00%	
Standard (**c/kWh)**	221,92	241,90	9,00%	241,90	9,00%	
Off-peak **(c/kWh)**	138,13	150,56	9,00%	150,56	9,00%	
High Season Energy Charges						
Peak **(c/kWh):**	583,13	635,61	9,00%	635,61	9,00%	
Standard (**c/kWh)**	295,73	322,35	9,00%	322,35	9,00%	
Off-peak **(c/kWh)**	166,80	181,82	9,00%	181,82	9,00%	
Demand charge **(R/kVA)**	82,22	89,61	9,00%	89,61	9,00%	
Network capacity charge**(R/kVA)**	61,48	67,02	9,00%	67,02	9,00%	

Scale 5 : Large business and industrial premises (Vacant Stand)	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Analysis and Key Findings**
Basic charge (R/month)	1164,76	1234,65	6,00%	1234,65	6,00%	

Scale 5 : Large business and industrial premises (standard)	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Analysis and Key Findings**
Basic charge (R/month)	4932,93	5228,90	6,00%	5228,90	6,00%	
Energy charges (c/kWh)	148,03	161,35	9,00%	161,35	9,00%	
Network demand charge (R/kVA)	237,92	259,34	9,00%	259,34	9,00%	
Network capacity charge (R/kVA)	210,97	229,96	9,00%	229,96	9,00%	

Scale 5 : Large business and industrial premises (Time of Use)	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Analysis and Key Findings**
Basic Monthly **(R/month)**	4932,93	5228,90	6,00%	5228,90	6,00%	
Low Season Energy Charges						
Peak **(c/kWh)**	296,09	322,74	9,00%	322,74	9,00%	

Standard **(c/kWh)**	188,42	205,37	9,00%	205,37	9,00%	
Off-peak **(c/kWh)**	97,77	106,57	9,00%	106,57	9,00%	
High Season energy charges						
Peak **(c/kWh)**	511,30	557,32	9,00%	557,32	9,00%	
Standard **(c/kWh)**	217,94	237,56	9,00%	237,56	9,00%	
Off-peak **(c/kWh)**	105,90	115,43	9,00%	115,43	9,00%	
Network demand charge**(R/kVA)**	81,71	89,06	9,00%	89,06	9,00%	
Network capacity charge **(R/kVA)**	62,01	67,59	9,00%	67,59	9,00%	

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

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

End.