NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

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Decision and Reasons for Decision (RfD)

In the matter regarding the

Tariff Application for the 2026/27 Financial Year

By

City of Ekurhuleni Metropolitan Municipality

THE DECISION

At its meeting held on 22 May 2026, the Regulator Executive Committee (REC) considered the tariff application submitted by the City of Ekurhuleni Metropolitan Municipality for the 2026/27 financial year. Having considered the facts, information and evidence presented, the REC approved the tariff increases as set out below.

1. approve the tariffs that are based on the Cost of Supply (COS Study) as recommended in the tariff analysis section for implementation by the municipality with effect from 1 July 2026;
2. note the COS study submitted by the municipality;
3. that the municipality must submit a report accounting for all the costs that have been noted in its COS study by 31 January 2027 to enable the National Energy Regulator of South Africa (NERSA) to perform its independent verification/audit process; and
4. that the municipality must submit quarterly progress reports on the efficiency improvement measures taken to reduce high energy losses and deficits to enable NERSA to monitor the implementation thereof by 30 September 2026.

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ABBREVIATIONS

COS	Cost of Supply
D-form	Distribution form
ERTSA	Eskom Retail Tariff Structural Adjustments
FBE	Free Basic Electricity
IBT	Inclining Block Tariff
IPP	Independent Power Producer
COE	City of Ekurhuleni Metropolitan 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 the mandate of the Energy Regulator to regulate prices and tariffs. Municipal tariffs must be approved by the Energy Regulator to be implemented on 1 July of each financial year.

1.2. The City of Ekurhuleni Metropolitan Municipality (COE) is situated in Gauteng. The 2024/25 customer profile indicates that the electricity business is highly dependent on the manufacturing customer category, which accounts for 63,02% of total energy sales (5 312 330 MWh) while representing only 5 427 customers. The municipality further reports that it maintains an indigent register. The details regarding customer statistics are highlighted in Table 1 below.

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

	2024/25		
Customer categories	***MWh***	***% MWh***	***Customer numbers***
Domestic (Prepaid)	1 461 177	17,33%	258 126
Domestic (Conventional)	374 435	4,44%	46 801
Manufacturing	5 312 330	63,02%	5 427
Commercial Prepaid	65 451	0,78%	5 927
Commercial Conventional	349 956	4,15%	9 730
Street Lighting	335 650	3,98%	
Sold to other departments	197 387	2,34%	547
Other Consumers	332 893	3,95%	2 120
TOTAL	**8 429 279**	**100%**	**328 678**
Free Basic Electricity	**27 689**	**1,51%**	**117 791**

1.3. NERSA received the COE's tariff application together with its Cost of Supply (COS) study on 20 April 2026.

1.4. COE implemented an 11% average price increase in FY2025/26 and is applying for an average price increase of 9.01% for FY2026/27.

1.5. In accordance with NERSA requirements, all tariff applications must include confirmation that the municipal council has approved the proposed tariffs and has undergone customer consultation.

1.6. NERSA followed the notice and comment consultation process. On 20 April 2026, NERSA published the COE'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.

1.7. NERSA's decision was made on 22 May 2026, considering the written comments received from the affected stakeholders and the analysis performed by NERSA.

2. LEGAL AND REGULATORY FRAMEWORK

2.1. Background

2.1.1. The approval of Municipal electricity tariffs constitutes a core regulatory function of the Energy Regulator and must be exercised in accordance with the applicable legislative framework, national policy directives and court orders. The principal legal instruments governing the exercise of this regulatory authority include the National Energy Regulator Act, 2004 (Act No. 40 of 2004) (NERA), the Electricity Regulation Act, 2006 (Act No. 4 of 2006) as amended ('the ERA'), the Promotion of Administrative Justice Act, 2000 (Act No. 3 of 2000) (PAJA), and the Electricity Pricing Policy for the South African Electricity Supply Industry, 2008 (EPP).

2.1.2. The approval of municipal electricity tariffs follows the Eskom Multi-Year Price Determination (MYPD) 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. 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 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 COS methodologies have historically not been consistently applied across the electricity distribution industry.

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

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

2.7. **Judicial Oversight of the Tariff Approval Process**

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

2.7.2. In its final judgment delivered on 4 December 2025, the Court held that NERSA's public participation process relating to the 2025/2026 municipal tariff approvals did not comply with the procedural requirements of section 4 of PAJA and was therefore unlawful.

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

2.7.4. NERSA subsequently launched a variation application which sought to vary the timelines which were set by the Court on 4 December 2025, considering the practical difficulties which arose as it relates to NERSA's compliance with the Court order. 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 set out in Table 2 below are applicable to the approval process for the 2026/27 City of Ekurhuleni electricity tariffs.

Table 2: Court-directed timelines

Activity	Proposed dates
Submission of tariff application	20 April 2026
NERSA publication of the application	20 April 2026
Closing date for public participation	10 May 2026
NERSA submits comments received for reply by COE	11 May 2026
COE submits replies to comments to NERSA	14 May 2026
Finalisation of the public participation process	15 May 2026
Consideration of the application and decision	23 May 2026
Communication of the decision and publishing of the reasons for decision	24 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 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 COE, 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 audited 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 COE's electricity business operated at a deficit in both financial years under review, with the percentage deficit increasing from 2,31% in 2023/24 to 2,73% in 2024/25. This indicates a deterioration in the financial performance of the electricity

business and suggests that current tariff revenues are insufficient to fully recover the cost-of-supplying electricity.

3.3. Table 3 below shows that the COE's energy losses increased from 13,86% in 2023/24 to 15,54% in 2024/25, above the prudent level generally applied by NERSA. The increasing trend in energy losses places additional financial pressure on the electricity business, as the municipality is required to recover the cost of lost energy through its tariff structure and operational efficiencies.

Table 3: Performance indicators

Indicators	**Perfornance indicators obtained from D-forms**	
	2023/24	**2024/25**
Percentage Surplus (%):	**-2,31%**	**-2,73%**
Percentage Energy Losses:	**13,86**	**15,54**

3.4. Based on the above information provided, the continued increase in both the operating deficit and energy losses indicates weaknesses in revenue management, network maintenance, metering accuracy, and loss control measures. Unless corrective interventions are implemented, the sustainability of the electricity business may be adversely affected.

3.5. Table 4 below shows that the licensee's financial and technical performance is significantly influenced by high energy losses, which remain above the allowable levels.

Table 4: Revenues foregone due to high energy losses

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	266,55		
Sales kWh	8 429 278 589,28	8 782 932 407,91	9 381 768 708,45
Purchases kWh	9 980 605 008,99	9 980 605 008,99	9 980 605 008,99
Losses kWh	1 551 326 419,71	1 197 672 601,08	598 836 300,54
Losses percentage	**15,54%**	**12,00%**	**6,00%**
Additional Energy (kWh)		353 653 818,63	952 490 119,17
Additional Revenue (Rands)		942 661 375,12	2 538 854 660,21
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	23 991 120 752	R 24 933 782 127,06	R 26 529 975 412,15
Total Expenses (Rands)	24 645 752 717	R 24 645 752 716,54	R 24 645 752 716,54
Net Profit (Loss)	R -654 631 964,60	R 288 029 410,52	R 1 884 222 695,61
Percentage Surplus/Deficit	**-2,73%**	**1,16%**	**7,10%**

3.6. The D-Form information submitted by the municipality reflects energy purchases of approximately 9 980 605 009 kWh against sales of approximately 8 429 278 589 kWh, resulting in total energy losses of approximately 1 551 326 420 kWh or 15.54%. Based on the reported average selling price of

266.55 c/kWh, the electricity business recorded a deficit of approximately R654 631 965, representing a deficit margin of 2.73%.

3.7. The analysis further demonstrates that, had the municipality reduced losses to the 12% level, additional recoverable energy of approximately 353 653819 kWh could have been realised. This would have generated additional revenue of approximately R942 661 375, increasing total revenue to approximately R24 933 782 127 and resulting in a surplus of approximately R288 029 411 or 1.16%.

3.8. Furthermore, the analysis indicates that a reduction in losses to 6% would have yielded additional recoverable energy of approximately 952 490 119 kWh and additional revenue of approximately R2 538 854 660. Under this scenario, total revenue would increase to approximately R26 529 975 412, resulting in a surplus of approximately R1 884 222 696 or 7.10%.

3.9. The analysis therefore demonstrates that excessive energy losses are materially contributing to the municipality's financial challenges and placing additional pressure on tariff increases. The results further indicate that improved operational efficiency and effective loss-reduction initiatives could substantially improve the financial sustainability of the electricity business without relying solely on higher tariffs to recover revenue shortfalls.

3.10. NERSA notes that a significant portion of the reported losses may be attributable to non-technical losses, including electricity theft, illegal connections, metering inaccuracies, billing inefficiencies, and weak revenue management controls. In this regard, the Regulator emphasises that customers should not be unduly burdened with the cost of avoidable operational inefficiencies through increased tariffs.

3.11. Accordingly, the analysis supports the need for the municipality to prioritise:

a) implementation of credible loss-reduction strategies;
b) strengthening of revenue protection measures;
c) improvement of metering and billing systems;
d) enhancement of network maintenance and monitoring; and
e) acceleration of smart metering and infrastructure modernisation programmes.

3.12. The COE has submitted an energy loss reduction plan, which NERSA will monitor to assess the implementation and effectiveness thereof.

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

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

4.2. COE 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 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.

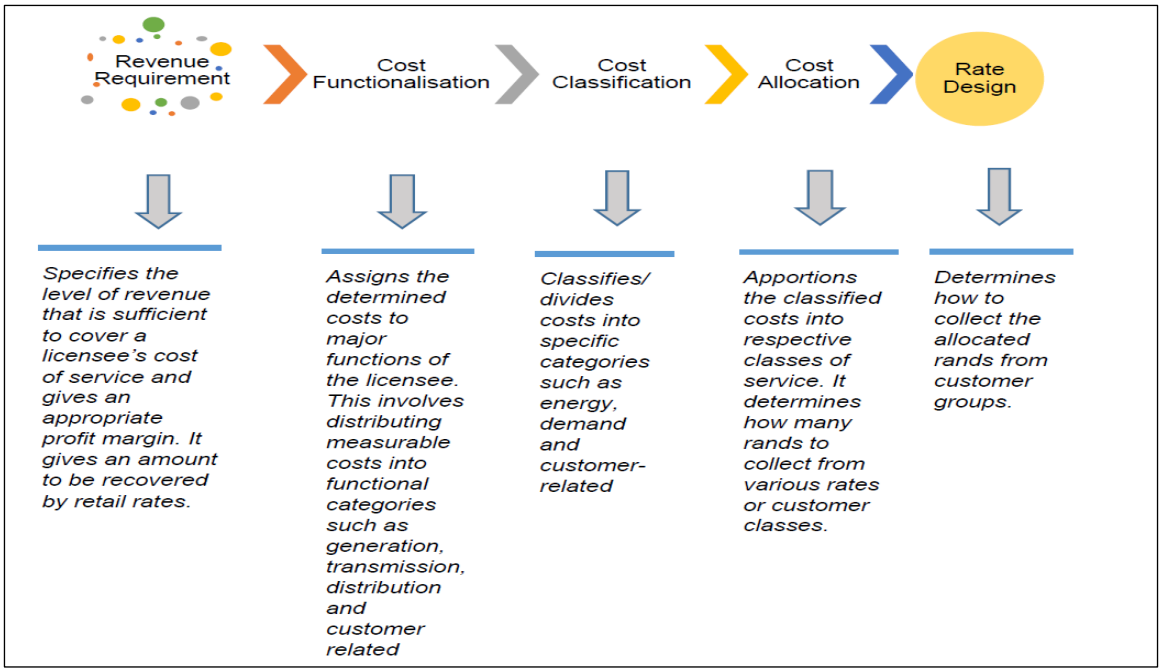


Figure 1: Five steps of COS study

4.5. The following steps are undertaken to analyse the COS study:

4.5.1. Revenue Requirement

4.5.1.1. 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.

4.5.1.2. The analysis of the revenue requirement components indicates that the electricity business remains predominantly driven by bulk electricity purchase costs from Eskom. Energy purchases from Eskom, net of the cost of losses, amount to R16 828 202 159 and constitute approximately 68,41% of the total

allowable revenue requirement. This confirms that the municipality's cost structure is highly dependent on external bulk supply costs and remains vulnerable to increases in Eskom tariffs as shown in Table 5

Table 5: Revenue requirement components

Revenue Requirement components	Wires	Retail	Total Applied	NERSA Adjustment	NERSA Recommended	% of Total
Allowable costs	5 301 571 108	19 451 542 102	24 753 113 210	(155 622 053)	24 597 491 156	100,00%
Energy purchases from Eskom - net of cost of losses	-	16 828 202 159	16 828 202 159		16 828 202 159	68,41%
Energy purchases from Eskom - cost of losses	1 633 595 546	763 980 134	2 397 575 680		2 397 575 680	9,75%
Other energy purchases	-	4 763 553	4 763 553		4 763 553	0,02%
Operational expenditure (incl. Depreciation)	3 193 137 605	2 040 950 784	5 234 088 389	(135 323 525)	5 098 764 864	20,73%
Other revenues	**- 3 593 638**	**- 428 258 388**	**- 431 852 025**		**- 431 852 025**	**-1,76%**
Surplus	478 431 595	241 903 859	720 335 454	(20 298 528)	700 036 926	2,85%
Not allowable costs	387 739 693	358 442 344	746 182 038			
Cost of losses disallowed	387 739 693	358 442 344	746 182 038			
TOTAL COSTS	5 689 310 801	19 809 984 446	25 499 295 248			
	22%	78%				

4.5.1.3. In addition, the municipality applied for recovery of R2 397 575 680 relating to the cost of losses. A further amount of R746 182 038 associated with disallowed losses was reflected under non-allowable costs. The magnitude of these loss-related costs suggests persistent technical and non-technical losses within the distribution network, including possible electricity theft, metering inaccuracies, and network inefficiencies. Excessive losses continue to place significant financial pressure on the electricity business and negatively impact overall cost-reflectivity.

4.5.1.4. Operational expenditure, including depreciation, was applied for at R5 234 088 389. Following the assessment, NERSA adjusted this amount downward by R135 323 525, resulting in a recommended allowable operational expenditure of R5 098 764 864. Operational expenditure constitutes approximately 20,73% of the total allowable revenue requirement. The adjustment reflects the removal of costs considered inefficient or not fully prudent for tariff recovery purposes.

4.5.1.5. The municipality further applied for a surplus of R720 335 454. Following the assessment, NERSA reduced the surplus by R20 298 528 to a recommended amount of R700 036 926, representing approximately 2,85% of the total

allowable revenue requirement. The approved surplus is considered moderate relative to the overall cost base and is intended to contribute toward the sustainability of the electricity business, including future infrastructure refurbishment and replacement requirements.

4.5.1.6. Overall, the municipality applied for total allowable costs of R24 753 113 210. After assessment and adjustments amounting to R155 622 053, NERSA recommended an allowable revenue requirement of R24 597 491 156. The relatively limited adjustment indicates that the majority of the municipality's submitted costs were accepted as reasonable and prudent, subject to the exclusion of identified inefficiencies and non-allowable costs.

4.5.1.7. The results suggest that the financial challenges experienced by the electricity business are primarily driven by high bulk electricity purchase costs, excessive energy losses and elevated operating expenditure, rather than excessive surplus generation. Accordingly, in addition to tariff adjustments, the municipality may need to intensify initiatives aimed at reducing technical and non-technical losses, improving revenue collection, enhancing operational efficiencies and strengthening cost containment measures to improve the long-term financial sustainability of the electricity business.

Bulk purchases

4.5.1.8. Bulk electricity purchases from Eskom amount to R16,828 billion, excluding the cost of losses, and constitute 67,98% of the municipality's total allowable revenue requirement. When the cost of energy losses amounting to R2,398 billion is included, the total cost associated with bulk electricity purchases increases to approximately R19,226 billion, representing the dominant cost-driver within the electricity business.

4.5.1.9. The high proportion of bulk purchase costs indicates that the municipality's electricity tariffs are heavily influenced by Eskom tariff increases and changes in energy consumption patterns. This level of dependence limits the municipality's ability to absorb cost increases without passing them on to consumers through tariff adjustments.

4.5.1.10. The municipality purchased approximately 9,981 GWh of electricity during the 2023/24 financial year, while only 8,429 GWh was sold to customers, resulting in significant energy losses of 1,551 GWh. Consequently, a substantial portion of bulk electricity purchases does not generate corresponding revenue, thereby placing additional pressure on the financial sustainability of the electricity business.

4.5.1.11. The cost of losses associated with bulk purchases amounts to R2,398 billion, of which R746,182 million was disallowed by NERSA for exceeding the allowable loss benchmark. This indicates that a portion of the municipality's bulk purchase costs is attributable to excessive and inefficient losses that may not be recovered through tariffs.

4.5.1.12. Overall, the bulk purchase analysis highlights:

a) significant reliance on Eskom as the primary electricity supplier;
b) bulk energy costs as the largest contributor to the revenue requirement;
c) high exposure to Eskom tariff increases;

d) material financial pressure arising from energy losses; and
e) the need for stronger energy loss management and network efficiency improvements.

4.5.1.13. Therefore, the municipality should prioritise interventions aimed at reducing technical and non-technical losses to minimise the unrecoverable portion of bulk electricity purchase costs and improve the overall sustainability of the electricity business.

Operational Expenditure

4.5.1.14. The municipality applied for a total operating expenditure amounting to R5 234 088 389 for the 2026/27 financial year. Following the prudency and efficiency assessment, NERSA identified certain costs that were considered inefficient and therefore not allowable for tariff determination purposes as shown in Table 6 below.

Table 6: Operational expenditure breakdown

Cost Drivers	2024/25 Actuals	2025/26 Budget	2026/27 Applied for	NERSA Adjustments	2026/27 Recommended Opex
General & Other	**2 974 802 905**	**3 183 273 624**	**3 310 604 569**	**(135 210 225)**	**3 175 394 344**
Salaries and allowances	285 897 502	266 382 925	277 038 242		277 038 242
Materials and supplies	676 078 185	718 832 329	747 585 622		747 585 622
Contracted Services	734 844 248	967 269 475	1 005 960 254		1 005 960 254
Salaries, wages and allowances (exclu. Repairs)	568 760 876	572 764 731	595 675 320		595 675 320
Payments to consultants (operational work)	-	-	-	-	-
Eskom debts' interests	115 635 205	113 797 813	118 349 726	(118 349 726)	-
Other creditors interests	-	-	-	-	-
Current year depreciation	553 946 571	528 014 332	549 134 906		549 134 906
NMD exceedance penalties	39 640 318	16 212 018	16 860 499	(16 860 499)	-
Shared OPEX	**2 191 963 678**	**1 849 503 672**	**1 923 483 819**	**(113 300)**	**1 923 370 520**
Bad debts written-off	999 952 282	669 743 615	696 533 359		696 533 359
FBE paid to Eskom	32 088 666	108 942	113 300	(113 300)	-
Charges from other Municipal Departments	1 132 164 030	1 162 476 364	1 208 975 418		1 208 975 418
General Expenses	27 758 700	17 174 752	17 861 742		17 861 742
Total	**5 166 766 583**	**5 032 777 297**	**5 234 088 389**	**(135 323 525)**	**5 098 764 864**

4.5.1.15. The disallowed costs relate primarily to Eskom debt interest amounting to R118 349 726, Notified Maximum Demand (NMD) exceedance penalties amounting to R16 860 499, and FBE paid to Eskom amounting to R113 300. These costs were excluded from the allowable revenue determination as they do not constitute efficient operating expenditure recoverable from electricity consumers.

4.5.1.16. After applying the adjustments totalling R135 323 525, the recommended operating expenditure for the 2026/27 financial year amounts to R5 098 764 864.

4.5.1.17. The assessment indicates that contracted services, interdepartmental charges and bad debt provisions continue to constitute a significant portion of the

municipality's operating cost structure and should therefore be continuously monitored to ensure operational efficiency and long-term financial sustainability of the electricity business.

Surplus

4.5.1.18. The COE applied for a surplus amounting to R720 335 454 for the 2026/27 financial year. Following the assessment of the allowable revenue requirement, NERSA adjusted the surplus downward by R20 298 528, resulting in a recommended surplus of R700 036 926.

4.5.1.19. In recommending a surplus, NERSA relied on section 15(1)(a) of the ERA, which provides that tariffs must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return. In applying this provision, together with the COS methodology, NERSA is required to ensure that the COE recovers efficiently and prudently incurred costs, including a reasonable return, while preventing excessive compensation.

4.5.1.20. The recommended surplus represents approximately 2,85% of the total allowable revenue of R24 597 491 156. This indicates that the municipality is not generating an excessive margin from electricity tariffs but rather maintaining a relatively modest operating buffer within the electricity business.

4.5.1.21. The surplus forms an important component of the municipality's electricity business sustainability as it contributes towards:

a) funding future infrastructure refurbishment and replacement;

b) strengthening cash flow and working capital requirements;

c) mitigating financial risks associated with bulk electricity price increases and revenue under-collection;

d) supporting the long-term financial viability of the electricity undertaking.

4.5.1.22. However, the municipality's ability to realise the approved surplus remains dependent on several operational and financial factors, including:

a) the effectiveness of revenue collection;

b) the management of technical and non-technical energy losses;

c) the containment of operating expenditure; and

d) the municipality's ability to manage Eskom-related debt obligations and avoid additional interest charges and penalties.

4.5.1.23. The assessment further indicates that, despite the approved surplus, the electricity business remains under significant financial pressure due to the high proportion of bulk electricity purchase costs and elevated energy losses. As a result, the approved surplus should not be interpreted as excessive profitability, but rather as a necessary provision to support the sustainability and resilience of the electricity business.

4.5.1.24. There is also a regulatory risk associated with insufficient surplus margins. Where the electricity business generates an inadequate surplus over a sustained period, the municipality may face challenges in funding asset maintenance, network expansion, and capital replacement programmes,

which could ultimately compromise service reliability and infrastructure performance.

4.5.1.25. Conversely, excessively high surplus levels may place undue tariff pressure on consumers and raise concerns regarding affordability and cost-reflectivity. NERSA therefore seeks to balance the financial sustainability of the licensee with the protection of customer interests through the assessment of prudent and reasonable surplus levels.

4.5.2. Cost Functionalisation

4.5.2.1. The licensee has categorised its revenue requirement of R24,753 billion into two primary functional components, namely the **wires business (22%)** and the **retail business (78%)**, 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.

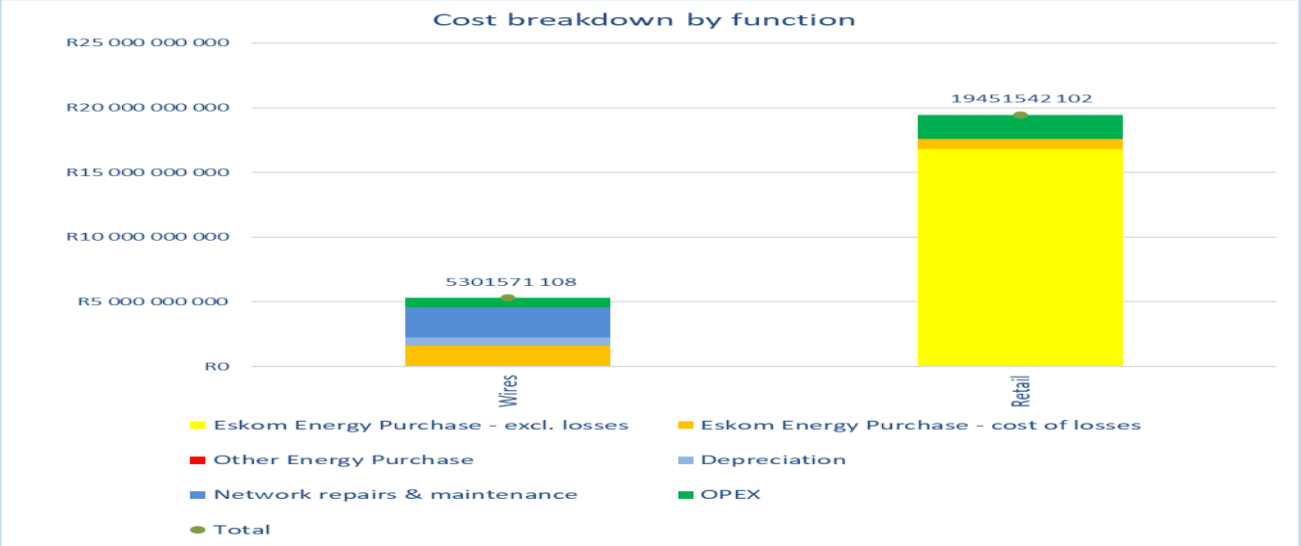


Figure 2: Cost breakdown by functions

4.5.2.2. The cost breakdown by function indicates that the retail function constitutes the largest portion of the municipality's electricity revenue requirement, amounting to R19,452 billion or approximately 78% of total allowable costs, while the wires function accounts for R5,302 billion or 22% of total allowable costs.

4.5.2.3. The retail function is predominantly driven by Eskom bulk electricity purchases, excluding losses, which represent the most significant cost component within the electricity business. This demonstrates that the municipality's electricity operations are heavily dependent on energy procurement costs and are therefore highly sensitive to Eskom tariff increases.

4.5.2.4. The wires function mainly comprises network-related costs, including network repairs and maintenance, depreciation, operational expenditure, and the cost associated with energy losses. The relatively high contribution of wires costs

reflects the importance of maintaining and operating the electricity distribution infrastructure to ensure reliable supply and service delivery.

4.5.2.5. Figure 2 above further indicates that:

a) bulk energy purchases are concentrated within the retail function;
b) network repairs, maintenance, and depreciation are largely attributable to the wires function;
c) operational expenditure contributes significantly to both functions; and
d) the cost of energy losses remains a material component across the electricity business.

4.5.2.6. The significant difference between the retail and wires cost allocations suggests that the municipality's revenue requirement is primarily influenced by electricity procurement rather than network operations alone. However, the continued increase in network-related costs and energy losses may place additional pressure on future tariff adjustments if not effectively managed.

4.5.2.7. The municipality should therefore ensure that:

a) retail tariffs adequately recover bulk purchase costs;
b) network maintenance expenditure is prioritised to improve system reliability and reduce technical losses;
c) operational efficiencies are strengthened across both functions;
d) cost allocation methodologies remain transparent, reasonable, and aligned with the approved COS study.

4.5.2.8. Effective management of both the retail and wires functions will be essential to improving the long-term financial sustainability and operational performance of the electricity business.

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

4.5.3. Cost Classification

4.5.3.1. 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 upon verification.

4.5.3.2. The cost allocation by tariff component indicates that the municipality's electricity revenue requirement is predominantly driven by energy-related costs. The energy component constitutes the largest share of the total revenue requirement, mainly attributable to Eskom bulk electricity purchases excluding losses, with additional contributions from the cost of losses and other energy purchases.

4.5.3.3. The demand component represents the second-largest cost category and is primarily associated with network-related expenditure, including network repairs and maintenance, depreciation, and CAPEX-related costs and returns.

This reflects the infrastructure-intensive nature of the electricity distribution business and the need to maintain, refurbish, and expand the distribution network to ensure a reliable supply.

4.5.3.4. The customer component is comparatively smaller and mainly consists of operational expenditure (OPEX) associated with customer-related services such as billing, metering, vending, customer administration, and revenue management activities.

4.5.3.5. Figure 3 below demonstrates the following key observations:

a) Energy costs are the dominant driver of the municipality's electricity tariffs.
b) Eskom bulk purchases constitute the largest single cost element within the revenue requirement.
c) Demand-related costs are significantly influenced by infrastructure maintenance and depreciation requirements.
d) Customer-related costs represent a relatively smaller portion of total costs.
e) Energy losses continue to contribute materially to the overall cost structure.

4.5.3.6. The high concentration of costs within the energy component indicates that the municipality's tariff structure remains highly sensitive to Eskom tariff increases and energy consumption levels. In addition, the sizeable demand-related costs highlight the importance of sustained investment in network infrastructure and maintenance to improve reliability and reduce technical losses.

4.5.3.7. The municipality should therefore ensure that:

a) cost classification between energy, demand, and customer components is cost reflective and aligned with the approved Cost-of-Supply study;
b) demand charges appropriately recover network-related costs;
c) customer charges are reasonable and equitable across customer categories;
d) network maintenance and refurbishment programmes are adequately funded; and
e) measures to reduce technical and non-technical losses are prioritised to limit pressure on future tariffs.

4.5.3.8. A balanced and cost-reflective allocation of costs across tariff components is essential to support the long-term financial sustainability and operational efficiency of the electricity business.

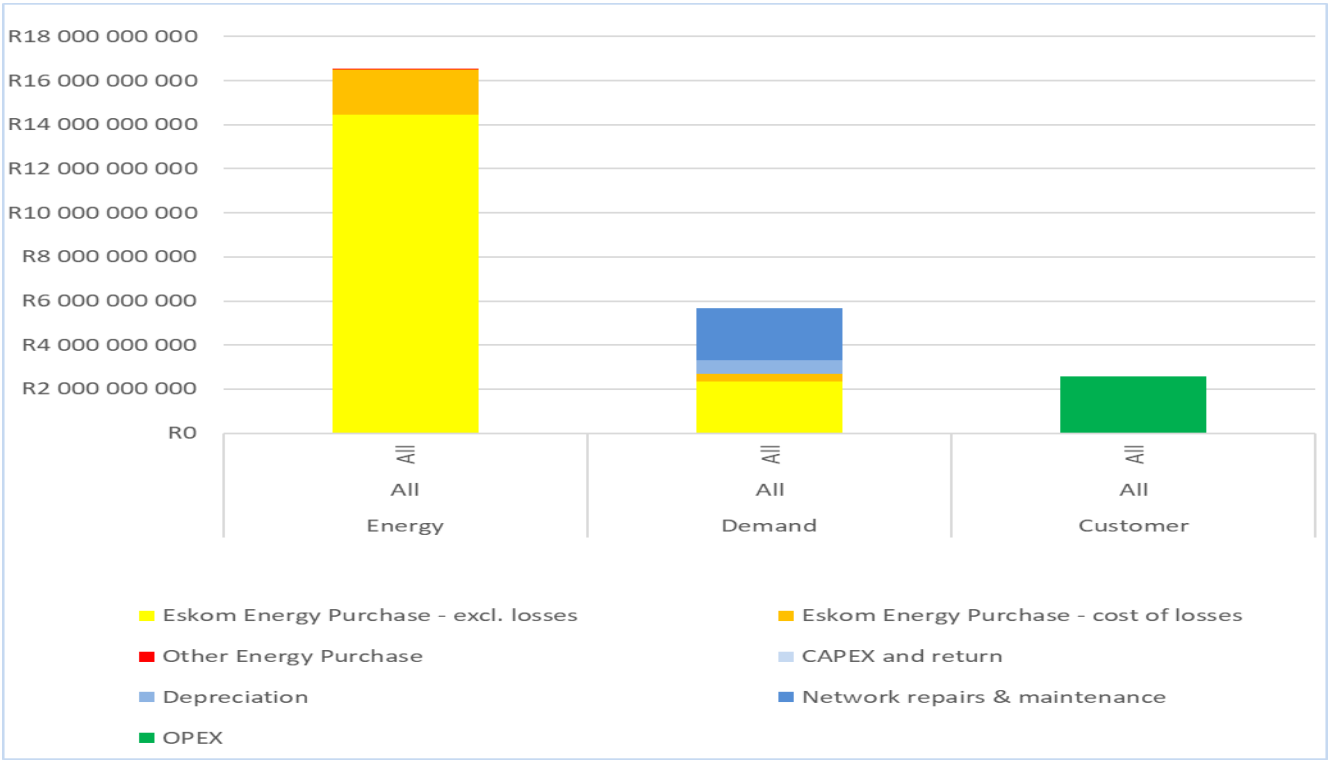


Figure 3*:* Cost breakdown by cost structure (classification)

4.5.3.9. 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.

4.5.4. Cost Allocation

4.5.4.1. 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.

4.5.4.2. The cost allocation by customer category indicates that domestic customers account for the largest share of allocated electricity costs at 48%, followed closely by commercial customers at 45%, while industrial customers account for only 7% of total allocated costs.

4.5.4.3. The significant allocation of costs to domestic customers suggests that a substantial portion of the municipality's network, customer service, and retail-related expenditure is incurred in servicing the residential sector. This is expected given the large number of domestic customers connected to the network, the widespread use of prepaid metering, and the costs associated with customer management, vending, billing, and maintenance of low-voltage distribution infrastructure.

4.5.4.4. Commercial customers also constitute a substantial portion of allocated costs at 45%, indicating that this customer category makes extensive use of the electricity network and contributes significantly toward the recovery of operational and infrastructure-related costs. Commercial customers are generally important contributors to municipal revenue stability due to their relatively consistent consumption profiles and payment reliability.

4.5.4.5. Industrial customers account for only 7% of allocated costs despite contributing a significant share of total electricity consumption. This may indicate that industrial customers benefit from economies of scale, higher load factors, and more efficient network utilisation, resulting in lower relative cost allocation per unit of energy consumed.

4.5.4.6. The allocation profile demonstrates that:

a) Domestic and commercial customers collectively bear the majority of the municipality's electricity cost burden;
b) Industrial customers consume large volumes of electricity but attract proportionally lower allocated costs;
c) Customer density, service requirements, and network utilisation significantly influence cost allocation outcomes; and
d) The municipality's tariff structure should carefully balance affordability, cost-reflectivity, and revenue sustainability across customer categories.

4.5.4.7. The municipality should ensure that the allocation of costs to customer categories is fully supported by the approved COS methodology and that tariffs remain:

a) Cost-reflective and equitable;
b) Free from undue cross-subsidisation beyond approved policy objectives;
c) Supportive of economic activity and industrial competitiveness; and
d) Affordable for domestic consumers, particularly indigent households.

4.5.4.8. Appropriate cost allocation is essential to ensure that each customer category contributes fairly toward the recovery of electricity supply costs while maintaining the long-term sustainability of the electricity business.

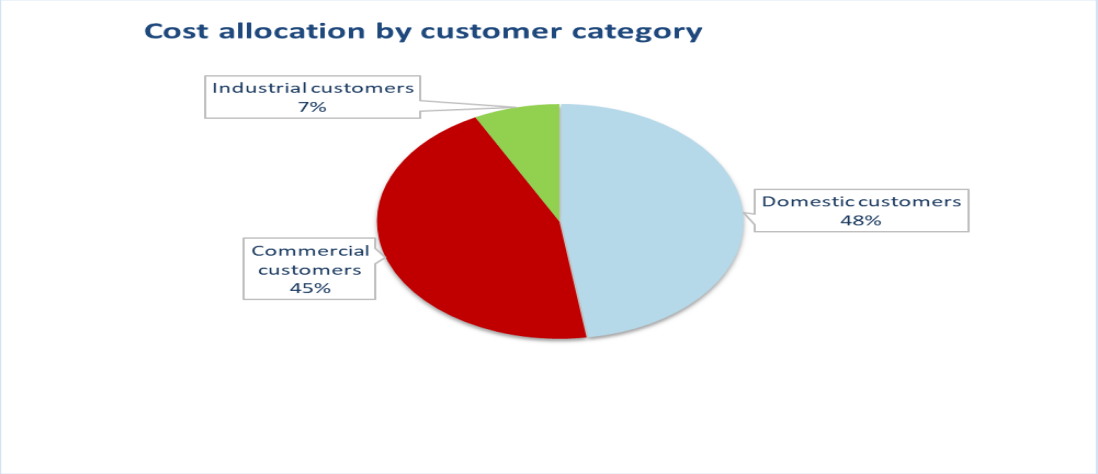


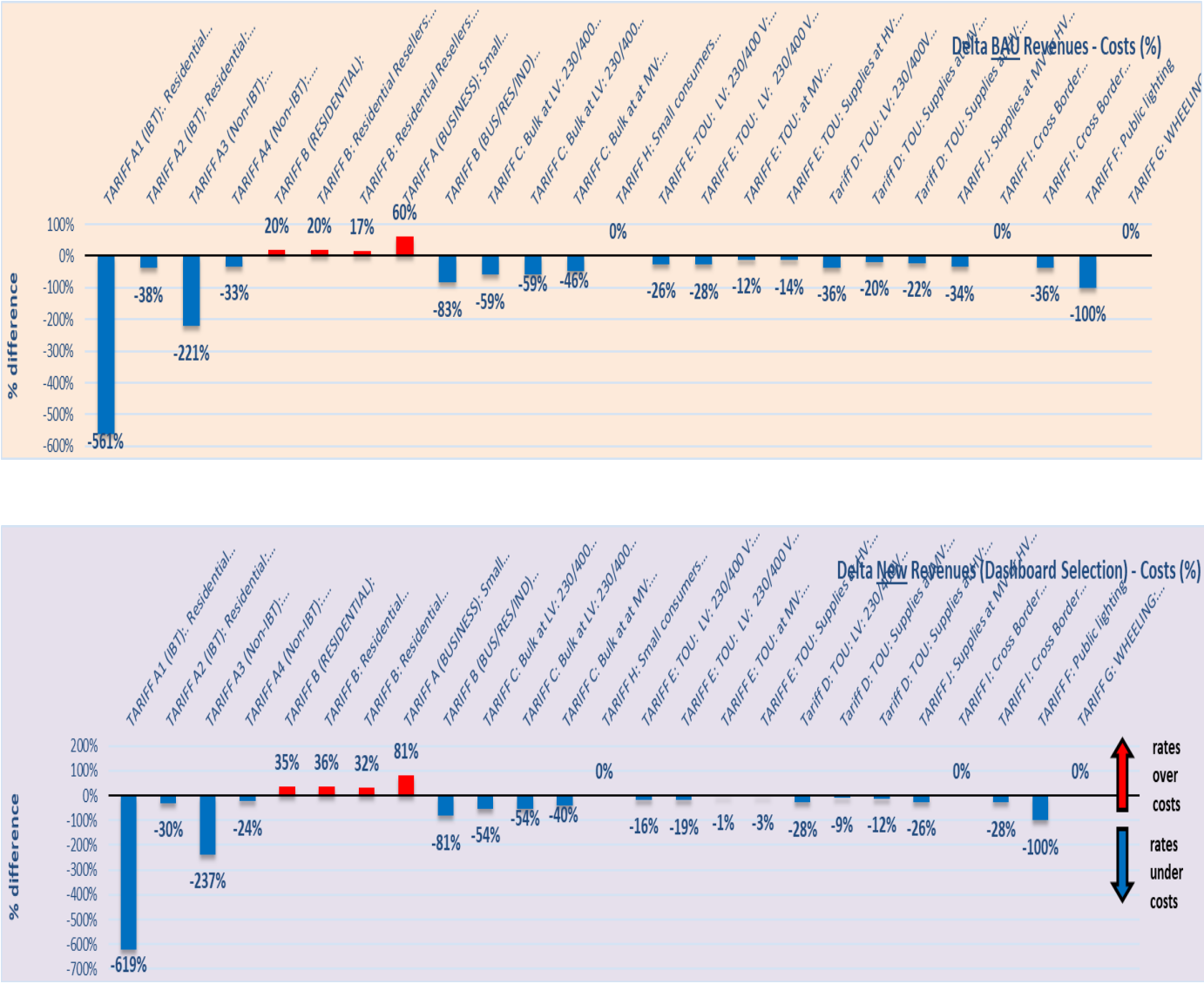
Figure 4: Costs allocated

4.5.5. Rate Design

4.5.5.1. Table 4 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.

4.5.5.2. 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 19.1% across all customer categories.

Figure 5: **Revenue recovery by customer category**



4.5.5.3. The delta between revenues and costs per tariff category indicates significant levels of under-recovery and over-recovery across several customer categories, suggesting that the current tariff structure is not fully cost-reflective.

4.5.5.4. A number of tariff categories reflect substantial negative variances, indicating that the revenues generated from those tariffs are insufficient to recover the associated cost-of-supply. These significant negative variances suggest the presence of substantial cross-subsidisation within the tariff structure, where certain customer categories are charged below their cost-of-supply and are effectively subsidised by other customer groups or by the overall electricity business.

4.5.5.5. Conversely, a limited number of tariff categories reflect positive variances, indicating over-recovery relative to the cost-of-supply. These include:

a) certain residential tariffs at approximately 17% to 20%; and
b) residential reseller tariffs reflecting over-recovery of up to 60%.

4.5.5.6. The existence of both significant under-recoveries and over-recoveries demonstrates that the tariff structure remains materially misaligned with the approved COS study. While some degree of cross-subsidisation may be permissible to support social and policy objectives, excessive deviations from cost-reflectivity may undermine tariff fairness, economic efficiency, and long-term sustainability.

4.5.5.7. The results further indicate that:

a) domestic tariff categories appear to be heavily subsidised in certain instances;
b) some reseller and residential categories may be over-recovering costs;
c) industrial, business, and bulk supply customers are experiencing material under-recovery;
d) TOU tariffs are not fully aligned with the associated cost-drivers; and
e) certain tariff categories reflect a 0% variance, suggesting alignment between revenues and allocated costs.

4.5.5.8. Persistent under-recovery in high-consumption customer categories may negatively affect revenue adequacy and could create pricing distortions that discourage efficient electricity usage and investment. Similarly, excessive over-recovery from certain customer groups may raise affordability and equity concerns.

4.5.5.9. The municipality should therefore:

a) gradually migrate tariffs toward full cost-reflectivity in line with the approved COS study;
b) reduce excessive cross-subsidisation between customer categories;
c) ensure that social subsidies are transparent and appropriately funded;
d) review TOU tariff structures to better reflect network and energy cost-drivers; and
e) implement phased tariff restructuring to minimise tariff shock while improving revenue sustainability.

4.5.5.10. NERSA may require the municipality to provide a detailed tariff rationalisation and migration plan demonstrating how the identified revenue-to-cost

disparities will be addressed over time to achieve a more equitable and cost-reflective tariff structure.

5. CONCLUSION ON THE COS STUDY

5.1. While the outcome of the COS study may indicate an average tariff adjustment of 19.1% 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. 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.

5.5. The results before tariff phasing indicate that the municipality's proposed tariff adjustments improve cost recovery levels but do not yet achieve full cost-reflectivity.

5.6. The Cost-to-Serve (CTS) analysis, net of subsidies, indicates that the municipality requires total revenue of approximately R23,672 billion to achieve full cost recovery. However, the proposed new tariffs are projected to generate revenue of approximately R22,399 billion, resulting in a revenue shortfall of approximately R1,273 billion below the fully cost-reflective level.

5.7. The municipality proposed an average tariff increase of 12,7%, whereas an average increase of approximately 19,1% would be required to achieve full overall cost-reflectivity. This demonstrates that the municipality elected to phase in tariff adjustments rather than immediately implement the full cost-reflective tariffs, likely to mitigate tariff shock and affordability pressures on consumers.

5.8. The proposed new tariffs are expected to recover approximately 94,6% of total costs, representing a substantial improvement from the existing tariff structure, which only recovers approximately 83,9% of total costs. This indicates that the tariff restructuring significantly improves revenue adequacy and financial sustainability, although a funding gap remains.

5.9. The analysis demonstrates the following:

a) Existing tariffs are materially under-recovering the cost of supply.
b) The proposed tariff increases improve alignment with the COS study.
c) Full cost reflectivity has not yet been achieved.
d) The municipality is applying a phased migration approach toward cost-reflective tariffs.
e) A residual revenue gap of approximately R1,273 billion remains after the proposed tariff adjustments.

5.10. The phased approach may be reasonable from an affordability and socio-economic perspective, particularly where immediate implementation of fully cost-reflective tariffs would result in excessive tariff increases for certain customer categories. However, continued under-recovery of costs may place pressure on the financial sustainability of the electricity business if not progressively addressed over time.

5.11. The municipality should therefore:

a) develop a clear multi-year tariff migration strategy toward full cost-reflectivity;
b) ensure that future tariff increases progressively close the remaining revenue gap;
c) minimise excessive cross-subsidisation between customer categories;
d) strengthen loss reduction and revenue management interventions to reduce cost pressures; and
e) balance financial sustainability objectives with customer affordability considerations.

5.12. NERSA requires the municipality to submit a phased tariff rationalisation plan demonstrating how the remaining cost recovery gap will be addressed over future financial years while limiting undue tariff shock to consumers.

5.13. The COS study results indicate a required increase of 19.1%, as illustrated in Figure 5 below. However, in an effort to mitigate the impact on customers, the licensee has proposed a lower increase of 12.7%. Based on the available information, the municipality is expected to remain financially sustainable under the proposed tariff increase of 12.7%.

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9. TARIFF COMPONENTS

Table 8: Approved tariffs

Tariff Name	2025/26 NERSA-Approved Tariff	2025/26 CEO-Implemented Tariff	Proposed % Increase	Proposed 2026/27 Tariff Increase	Recommended % Increase	2026/27 Approved Tariff
TARIFF A Residential						
TARIFF A1: Residential Indigents:						
A0.1 Energy: Block (0 to 50 kWh)/month: R/kWh	2,5861	R0,0000	**0,00%**	R0,0000	,	**0,0000**
A1.1 Energy: Block (>50 to <= 600)/month: R/kWh	2,5861	R2,5861	**15,54%**	R2,9879	15,54%	**2,9879**
A2.1 Energy: Block (>600 to <= 700)/month: R/kWh	4,3956	R4,3956	**-32,03%**	R2,9879	-32,03%	**2,9879**
A3.1 Energy: Block (>700 kWh) /month: R/kWh	12,3889	R12,3839	**-75,87%**	R2,9879	-75,87%	**2,9879**
A4.1 Single rate in the case of a billing system that cannot accommodate the IBT	2,7356	R2,7356	**9,22%**	R2,9879	9,22%	**2,9879**
TARIFF A2-Residential (non-Indigents)	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
A.0.2.1 Basic charge:1 ph:R/POS/Month	142,5084	R0,00	**-100,00%**	R0,00	-100,00%	**0,0000**
A.0.22 Basic charge:3 ph:R/POS/Month	269,8286	R0,00	**-100,00%**	R0,00	-100,00%	**0,0000**
A.2.2 Energy: Block (0 to <=600kWh)/month: R/kWh	2,8287	R2,5865	**18,44%**	R3,0635	18,44%	**3,0635**
A.3.2 Energy:Block (>600 to <700kWh)/month:R/kWh	4,4182	R4,0341	**-24,06%**	R3,0635	-24,06%	**3,0635**
A.4.2 Energy:Block (>600 to <700kWh)/month:R/kWh	11,4398	R10,4287	**-70,62%**	R3,0635	-70,62%	**3,0635**
A4.1 Single rate in the case of a billing system that cannot accommodate the IBT	2,96	R2,7061	**13,21%**	R3,0635	13,21%	**3,0635**

TARIFF B: RESIDENTIAL	2025/26 NERSA-Approved Tariff	2025/26 COE-Implemented Tariff	Proposed % Increase	Proposed 2026/27 Tariff Increase	Recommended % Increase	2026/27 Approved Tariff
BR1.1 Basic charge:1 Ph:R/POS/month	142,5084	R109,78	**9,01%**	R119,67	**-22,97%**	109,78
BR1.2 Basic charge:3 Ph:R/POS/month	269,8286	R203,89	**9,01%**	R222,26	**-24,44%**	203,89
BR3 Energy charge: High Demand Season: R/kWh	3,5683	R3,3722	**9,01%**	R3,6760	**-5,50%**	3,37
BR4 Energy charge: Low Demand Season: R/kWh	3,5683	R3,3722	**9,01%**	R3,6760	**-5,50%**	3,37
		R313,80				
TARIFF B: (BULK RESIDENTIAL RESELLERS)	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
TARIFF B: (BULK RESIDENTIAL RESELLERS) 230/400 Volt						
RR.1 Basic charge: 230/400 V- R/month	656,4874	R636,10	**112,62%**	1352,50	9,01%	715,64
RR1.1 Demand charge: High/Low Demand season: R/Kva	36,3697	R35,78	**-100,00%**	0,00	-100,00%	**0,00**
RR.2.2.Network Access charge (NAC): R/kVA	42,3261	R35,78	**-100,00%**	R0,0000	-100,00%	**0,00**
RR.3.1.1. Energy charge: High Demand: Peak: R/kWh	3,6362	R4,2772	**-14,51%**	R3,6565	0,56%	3,6565
RR.3.1.3. Energy charge: High Demand: Standard: R/kWh	3,5729	R3,3024	**10,72%**	R3,6565	2,34%	3,6565
RR.3.1.5. Energy charge: High Demand: Off-Peak: R/kWh	3,5198	R3,1941	**14,48%**	R3,6565	3,88%	3,6565
RR.3.2.1. Energy charge: Low Demand: Peak: R/kWh	3,6362	R3,5169	**3,97%**	R3,6565	0,56%	3,6565
RR.3.2.3. Energy charge: Low Demand: Standard: R/kWh	3,5729	R3,2807	**11,45%**	R3,6565	2,34%	3,6565
RR.3.2.5. Energy charge: Low Demand: Off-Peak: R/kWh	3,5198	R3,1941	**14,48%**	R3,6565	3,88%	3,6565
TARIFF B: (BULK RESIDENTIAL RESELLERS > 400 Volt	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
RR.2 Basic charge: >400V - R/month	7327,985	R6 705,87	**0,00%**	R6 705,87	-8,49%	6 705,87
RR.1.3.Demand charge: High/Low Demand Season: R/kVA	34,3583	R35,78	**-100,00%**	R0,00	-100,00%	R0,00

RR.2.3. Network Access charge (NAC): R/kVA	42,3261	R35,78	**-100,00%**	R0,00	-100,00%	R0,00
RR.3.1.2. Energy charge: High Demand: Peak: R/kWh	3,4463	R4,1013	**-11,53%**	R3,6283	5,28%	3,6283
RR.3.1.4. Energy charge: High Demand: Standard: R/kWh	3,3864	R3,1265	**16,05%**	R3,6283	7,14%	3,6283
RR.3.1.6. Energy charge: High Demand: Off-Peak: R/kWh	3,336	R3,0182	**20,21%**	R3,6283	8,76%	3,6283
RR.3.2.2. Energy charge: Low Demand: Peak: R/kWh	3,4463	R3,3409	**8,60%**	R3,6283	5,28%	3,6283
RR.3.2.4. Energy charge: Low Demand: Standard: R/kWh	3,3864	R3,1048	**16,86%**	R3,6283	7,14%	3,6283
RR.3.2.6. Energy charge: Low Demand: Off-Peak: R/kWh	3,336	R3,0182	**20,21%**	R3,6283	8,76%	3,6283
TARIFF A: BUSINESS						
BR1.1 Basic charge:1 Ph:R/POS/month	77,8	R138,22	**9,01%**	R150,67	9,01%	**84,81**
BR1.2 Basic charge:3 Ph:R/POS/month	34,98	R269,75	**9,01%**	R294,05	9,01%	**38,13**
BR3 Energy charge: High Demand Season: R/kWh	4,0925	R3,7705	**9,01%**	R4,1102	9,01%	**4,46**
BR4 Energy charge: Low Demand Season: R/kWh	4,0925	R3,7705	**9,01%**	R4,1102	9,01%	**4,46**
TARIFF B (BUSINESS MIXED BUSINESS and RESIDENTIAL COMMERCIAL or INDUSTRIAL)	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
BBR.1.1 Basic charge: 1 ph R/month	33,8969	R58,22	**9,01%**	R63,47	9,01%	**36,95**
BBR.1.2 Basic charge: 3 ph R/month	76,065	R91,95	**9,01%**	R100,23	9,01%	**82,92**
B.BR.2. Capacity charge (Rand/Ampere/phase)	25,6593	R26,57	**9,01%**	R28,96	9,01%	**27,97**
B.BR.3. Energy charge: High Demand Season: R/kWh	3,0737	R3,4843	**9,01%**	R3,7982	9,01%	**3,35**
B.BR.4. Energy charge: Low Demand Season: R/kWh	3,8787	R2,8391	**9,01%**	R3,0949	9,01%	**4,23**
TARIFF C	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
TARIFF C - 230/400V						
C1.1. Basic charge: 230/400V - R/month	3979,8125	R3 389,73	**9,01%**	R3 695,14	9,01%	**4338,39**

C.2.1.1. Demand charge: High Demand Season: R/kVA	245,7278	242,19	**9,01%**	R264,01	9,01%	**267,87**
C.2.2.1. Demand charge: Low Demand Season: R/kVA	294,8867	242,19	**9,01%**	R264,01	9,01%	**321,46**
C.2.3.1. Network Access Charge (NAC): R/kVA (highest of max / notified)	85,5049	R99,1500	**9,01%**	R108,08	9,01%	**93,21**
C.3.1.1 Energy charge: High Demand Season: R/kWh		R4,6143	**9,01%**	R5,0300	new	**5,03**
C.3.2.1. Energy charge: Low Demand Season: R/kWh		R2,2641	**9,01%**	R2,4681	new	**2,47**
TARIFF C - 230/400V DIRECT FROM SUBSTATION	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
C1.2. Basic charge: 230/400V(DIRECT FROM SUB) - R/month	3979,8125	R3 389,73	**9,01%**	R3 695,14	9,01%	**4338,394**
C.2.1.2. Demand charge: High Demand Season: R/kVA	241,3752	R236,54	**9,01%**	R257,85	9,01%	**263,123**
C.2.2.2. Demand charge: Low Demand Season: R/kVA	289,599	R236,54	**9,01%**	R257,85	9,01%	**315,692**
C.2.3.2. Network Access Charge (NAC): R/kVA (highest of max / notified)	83,9909	R96,2300	**9,01%**	R104,90	9,01%	**91,558**
C.3.1.2. Energy charge: High Demand Season: R/kWh		R4,5266	**9,01%**	R4,9344	new	**4,9344**
C.3.2.2. Energy charge: Low Demand Season: R/kWh		R2,2017	**9,01%**	R2,4001	new	**2,4001**
TARIFF C - >230/400V&<= 11KV	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
C1.3. Basic charge: >230/400V&<= 11KV- R/month	5648,4325	R5 179,21	**9,01%**	R5 645,86	9,01%	**6157,356**
C.2.1.3. Demand charge: High Demand Season: R/kVA	236,9335	R227,16	**9,01%**	R247,63	9,01%	**258,281**
C.2.2.3. Demand charge: Low Demand Season: R/kVA	284,3113	R227,16	**9,01%**	R247,63	9,01%	**309,928**
C.2.3.3. Network Access Charge (NAC): R/kVA (highest of max / notified)	82,4659	R90,09	**9,01%**	R98,21	9,01%	**89,896**
C.3.1.3. Energy charge: High Demand Season: R/kWh		R4,4522	**9,01%**	R4,8533	new	**4,8533**
C.3.2.3. Energy charge: Low Demand Season: R/kWh		R2,1520	**9,01%**	R2,3459	new	**2,3459**
TARIFF D1 - REVERTING TO TARIFF E.1						

230/400V	2025/26 NERSA-Approved Tariff	2025/26 COE-Implemented Tariff	Proposed % Increase	Proposed 2026/27 Tariff Increase	Recommended % Increase	2026/27 Approved Tariff
D.1.1.1. Basic charge: R/month	3351,26	R3 069,24	**9,01%**	R3 345,78	-0,16%	**3345,779**
D.1.2.3. Demand charge: High Demand Season: R/kVA	175,69	R158,13	**9,01%**	R172,38	-1,89%	**172,378**
D.1.2.4. Demand charge: Low Demand Season: R/kVA	175,69	R158,13	**9,01%**	R172,38	-1,89%	**172,378**
D.1.4. Network Access Charge (NAC): R/kVA (highest of max / notified)	118,24	R105,86	**9,01%**	R115,40	-2,40%	**115,398**
D.1.5.2. Energy charge: High Demand: Peak: R/kWh	11,835	R10,8679	**9,01%**	R11,8471		**11,8471**
D.1.5.3. Energy charge: High Demand: Standard: R/kWh	3,4523	R3,1774	**9,01%**	R3,4637	0,33%	**3,4637**
D.1.5.4. Energy charge: High Demand: Off-Peak: R/kWh	2,1292	R1,9636	**9,01%**	R2,1405	0,53%	**2,1405**
D.1.6.2. Energy charge: Low Demand: Peak: R/kWh	3,8704	R3,5610	**9,01%**	R3,8818	0,30%	**3,8818**
D.1.6.3. Energy charge: Low Demand: Standard: R/kWh	2,5424	R2,3426	**9,01%**	R2,5537	0,44%	**2,5537**
D.1.6.4. Energy charge: Low Demand: Off-Peak: R/kWh	1,6143	R1,7876	**9,01%**	R1,9487	20,71%	**1,949**
D.1.7. Reactive Energy charge: P&S (<085PF): R/kvarh		R0,3220	**9,01%**	R0,3510	R0,3510	**0,351**
TARIFF D2						
230/400V(DIRECT FROM SUB)	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
D.1.1.1. Basic charge: R/month	5645,98342	R1 029,41	**9,01%**	R1 122,16	9,01%	**6154,687**
D.1.2.3. Demand charge: High Demand Season: R/kVA	139,37	R168,95	**9,01%**	R184,18	9,01%	**151,927**
D.1.2.4. Demand charge: Low Demand Season: R/kVA	139,37	R168,95	**9,01%**	R184,18	9,01%	**151,927**
D.1.4. Network Access Charge (NAC): R/kVA (highest of max / notified)	83,62	R145,20	**9,01%**	R158,29	9,01%	**91,154**
D.2.5.1.1. Energy charge: High Demand: Peak: R/kWh	8,7742	R7,1622	**9,01%**	R7,8075	9,01%	**9,5648**
D.2.5.1.2. Energy charge: High Demand: Standard: R/kWh	3,0248	R2,2882	**9,01%**	R2,4944	9,01%	**3,2973**
D.2.5.1.3. Energy charge: High Demand: Off-Peak: R/kWh	1,797	R1,7466	**9,01%**	R1,9040	9,01%	**1,9589**
D.2.5.2.1 Energy charge: Low Demand: Peak: R/kWh	3,262	R3,3606	**9,01%**	R3,6634	9,01%	**3,5559**

D.2.5.2.2. Energy charge: Low Demand: Standard: R/kWh	2,1027	R2,1800	**9,01%**	R2,3764	9,01%	**2,2922**
D.2.5.2.3. Energy charge: Low Demand: Off-Peak: R/kWh	1,6345	R1,7466	**9,01%**	R1,9040	9,01%	**1,782**
D.2.6. Reactive Energy charge: P&S (<0.85PF): R/kvarh		R0,3220	**9,01%**	R0,3510		**0,351**
TARIFF D3						
>230/400V&<= 11KV	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
D.3.1. Basic charge: R/month	5645,98	R3 302,34	**9,01%**	R3 599,88	9,01%	**6154,683**
D.3.2.1.1. Demand charge: High Demand Season: R/kVA	136,85	R140,68	**9,01%**	R153,36	9,01%	**149,180**
D.3.2.2.1. Demand charge: Low Demand Season: R/kVA	136,85	R140,68	**9,01%**	R153,36	9,01%	**149,175**
D.3.3.1. Network Access Charge (NAC): R/kVA (highest of max / notified)	82,11	R120,57	**9,01%**	R131,43	9,01%	**89,508**
D.3.4.1.1. Energy charge: High Demand: Peak: R/kWh	8,3358	R7,0829	**9,01%**	R7,7211	9,01%	**9,0869**
D.3.4.1.2. Energy charge: High Demand: Standard: R/kWh	2,9326	R2,2089	**9,01%**	R2,4079	9,01%	**3,1968**
D.3.4.1.3. Energy charge: High Demand: Off-Peak: R/kWh	1,7646	R1,6674	**9,01%**	R1,8176	9,01%	**1,9236**
D.3.4.2.1. Energy charge: Low Demand: Peak: R/kWh	3,1009	R3,2813	**9,01%**	R3,5769	9,01%	**3,3803**
D.3.4.2.2. Energy charge: Low Demand: Standard: R/kWh	2,0338	R2,1007	**9,01%**	R2,2900	9,01%	**2,2170**
D.3.4.2.3. Energy charge: Low Demand: Off-Peak: R/kWh	1,6038	R1,6674	**9,01%**	R1,8176	9,01%	**1,748**
D.3.5. Reactive Energy charge: P&S (<0.85PF): R/kvarh		R0,3220	**9,01%**	R0,3510	R0,00	**0,351**
TARIFF D4						
> 11KV	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
D.4.1. Basic charge: R/month	862,77	R11 822,44	**9,01%**	R12 887,64	R940,51	**940,506**
D.4.2.1.1. Demand charge: High Demand Season: R/kVA	126,73	R120,82	**9,01%**	R131,71	R138,15	**138,148**
D.4.2.1.2. Demand charge: Low Demand Season: R/kVA	126,73	R120,82	**9,01%**	R131,71	R138,15	**138,148**

D.4.3.1. Network Access Charge (NAC): R/kVA (highest of max / notified)	75,98	R103,41	**9,01%**	R112,73	R82,83	**82,826**
D.4.4.1.1. Energy charge: High Demand: Peak: R/kWh	7,7261	R7,0294	**9,01%**	R7,6627	R8,42	**8,4222**
D.4.4.1.2. Energy charge: High Demand: Standard: R/kWh	2,7008	R2,1551	**9,01%**	R2,3493	R2,94	**2,9441**
D.4.4.1.3. Energy charge: High Demand: Off-Peak: R/kWh	1,6345	R1,6135	**9,01%**	R1,7589	R1,78	**1,7818**
D.4.4.2.1. Energy charge: Low Demand: Peak: R/kWh	2,8711	R3,2275	**9,01%**	R3,5183	R3,13	**3,1298**
D.4.4.2.2. Energy charge: Low Demand: Standard: R/kWh	1,885	R2,0468	**9,01%**	R2,2312	R2,05	**2,0548**
D.4.4.2.3. Energy charge: Low Demand: Off-Peak: R/kWh	1,4847	R1,6135	**9,01%**	R1,7589	R1,62	**1,618**
D.4.5. Reactive Energy charge: P&S (<0.85PF): R/kvarh		R0,3220	**9,01%**	R0,3510	R0,00	**0,351**
TARIFF E						
Tariff E 230/400V directly from substation: NAC of < 1 MVA.	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
E1.1. Basic charge: R/month	3579,19	R3 069,24	**9,01%**	R3 345,78	**9,01%**	**3901,675**
E.2.1.2. Demand charge: High Demand Season: R/kVA	150,37	R154,09	**9,01%**	R167,97	**9,01%**	**163,918**
E.2.2.2. Demand charge: Low Demand Season: R/kVA	150,37	R154,09	**9,01%**	R167,97	**9,01%**	**163,918**
E.2.3.2. Network Access charge (NAC): R/kVA (highest of max / notified)	92,41	R102,97	**9,01%**	R112,25	**9,01%**	**100,736**
E.3.1.1. Energy charge: High Demand: Peak: R/kWh	11,5481	R10,6709	**9,01%**	R11,6323	**9,01%**	**12,5886**
E.3.1.4. Energy charge: High Demand: Standard: R/kWh	3,3006	R3,0981	**9,01%**	R3,3772	**9,01%**	**3,5980**
E.3.1.7. Energy charge: High Demand: Off-Peak: R/kWh	1,945	R1,9053	**9,01%**	R2,0770	**9,01%**	**2,1202**
E.3.2.1. Energy charge: Low Demand: Peak: R/kWh	3,514	R3,4833	**9,01%**	R3,7971	**9,01%**	**3,8306**
E.3.2.4. Energy charge: Low Demand: Standard: R/kWh	2,3072	R2,2818	**9,01%**	R2,4874	**9,01%**	**2,5151**
E.3.2.7. Energy charge: Low Demand: Off-Peak: R/kWh	1,7318	R1,7348	**9,01%**	R1,8911	**9,01%**	**1,888**
E.4. Reactive Energy charge: P&S (<0.85PF): R/kvarh		R0,3220	**9,01%**	R0,3510	**9,01%**	**0,351**
Tariff E MV: > 230/400 V: NAC of < 1 MVA.	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**

E1.2. Basic charge: R/month	5683,28	R5 207,09	**9,01%**	R5 676,25	9,01%	**6195,344**
E.2.1.3. Demand charge: High Demand Season: R/kVA	147,45	R146,09	**9,01%**	R159,25	9,01%	**160,735**
E.2.2.3. Demand charge: Low Demand Season: R/kVA	147,45	R146,09	**9,01%**	R159,25	9,01%	**160,735**
E.2.3.3. Network Access charge (NAC): R/kVA (highest of max / notified)	90,63	R96,62	**9,01%**	R105,33	9,01%	**98,7958**
E.3.1.2. Energy charge: High Demand: Peak: R/kWh	3,4484	R10,4902	**9,01%**	R11,4354	9,01%	**3,7591**
E.3.1.5. Energy charge: High Demand: Standard: R/kWh	,2,2639	R3,0403	**9,01%**	R3,3142	9,01%	**2,4678**
E.3.1.8. Energy charge: High Demand: Off-Peak: R/kWh	1,6988	R1,8609	**9,01%**	R2,0286	9,01%	**1,8519**
E.3.2.2. Energy charge: Low Demand: Peak: R/kWh	11,342	R3,4150	**9,01%**	R3,7227	9,01%	**12,3639**
E.3.2.5. Energy charge: Low Demand: Standard: R/kWh	3.2480	R2,2314	**9,01%**	R2,4324	9,01%	**3,541**
E.3.2.8. Energy charge: Low Demand: Off-Peak: R/kWh	1,9092	R1,6926	**9,01%**	R1,8451	9,01%	**2,081**
E.4. Reactive Energy charge: P&S (<0.85PF): R/kvarh		R0,3220	**9,01%**	R0,3510	9,01%	**0,351**
Tariff E HV: > 11 kV: NAC of < 1 MVA.	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
E1.3. Basic charge: >R/month	5683,29	R6 911,12	**9,01%**	R7 533,81	9,01%	**6195,354**
E.2.1.4. Demand charge: High Demand Season: R/kVA	136,58	R133,43	**9,01%**	R145,45	9,01%	**148,886**
E.2.2.4. Demand charge: Low Demand Season: R/kVA	136,58	R133,43	**9,01%**	R145,45	9,01%	**148,886**
E.2.3.4. Network Access Charge (NAC): R/kVA (highest of max / notified)	83,89	R87,79	**9,01%**	R95,70	9,01%	**91,448**
E.3.1.3. Energy charge: High Demand: Peak: R/kWh	10,501	R9,8066	**9,01%**	R10,6902	9,01%	**11,4471**
E.3.1.6. Energy charge: High Demand: Standard: R/kWh	3,0063	R2,8361	**9,01%**	R3,0916	9,01%	**3,2772**
E.3.1.9. Energy charge: High Demand: Off-Peak: R/kWh	1,768	R1,7371	**9,01%**	R1,8936	9,01%	**1,9273**
E.3.2.3. Energy charge: Low Demand: Peak: R/kWh	3,1928	R3,1997	**9,01%**	R3,4880	9,01%	**3,4805**
E.3.2.6. Energy charge: Low Demand: Standard: R/kWh	2,0964	R2,0865	**9,01%**	R2,2745	9,01%	**2,2853**
E.3.2.9. Energy charge: Low Demand: Off-Peak: R/kWh	1,5734	R1,5814	**9,01%**	R1,7239	9,01%	**1,715**
E.4. Reactive Energy charge: P&S (<0.85PF): R/kvarh		R0,3220	**9,01%**	R0,3510	9,01%	**0,351**

TARIFF F Public lighting	2025/26 NERSA-Approved Tariff	2025/26 COE-Implemented Tariff	Proposed % Increase	Proposed 2026/27 Tariff Increase	Recommended % Increase	2026/27 Approved Tariff
F.1. A fixed charge: Per luminaire /. Traffic light/month		R67,36	**9,01%**	R73,43	new	**73,4291**
F.2. Streetlight: Energy charge: High Demand Season: R/kWh	3,4225	R2,9932	**9,01%**	R3,2629	**9,01%**	**3,7309**
F.3. Streetlight: Energy charge: Low Demand Season: R/kWh	3,4225	R2,9932	**9,01%**	R3,2629	**9,01%**	**3,7309**
F.4. Traffic Light: Energy charge: High Demand Season: R/kWh	3,4225	R2,9932	**9,01%**	R3,2629	**9,01%**	**3,7309**
F.5. Traffic Light: Energy charge: Low Demand Season: R/kWh	3,4225	R2,9932	**0,00%**	R3,2629	**9,01%**	**3,4225**
TARIFF G WHEELING	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
Eskom connected generator						
G.1.1. Eskom Wheeling Basic: R/month	10842,9	R7 583,65	**397,18%**	R37 704,59	**9,01%**	**73,4291**
G.2.1. Energy Credit: High Demand: Peak: R/kWh	6,2733	R6,2733	**-4,76%**	R5,9744	**9,01%**	**5,9744**
G.2.2.Energy Credit: High Demand: Standard: R/kWh	1,9003	R1,9003	**-21,41%**	R1,4935	**9,01%**	**1,4935**
G.2.3 Energy Credit: High Demand: Off-Peak: R/kWh	1,0319	R1,0319	**-3,50%**	R0,9958	**9,01%**	**0,9958**
G.2.1. Energy Credit: Low Demand: Peak: R/kWh	2,0463	R2,0463	**21,16%**	R2,4793	**9,01%**	**2,4793**
G.2.2. Energy Credit: Low Demand: Standard: R/kWh	1,4084	R1,4084	**-1,02%**	R1,3940	**9,01%**	**1,5353**
G.2.3. Energy Credit: Low Demand: Off-Peak: R/kWh	0,8935	R0,8935	**11,45%**	R0,9958	**9,01%**	**0,9740**
TARIFF G: WHEELING: within the City's distribution networks: Off-taker ≥MV	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
G.1.1. Municipal Wheeling Basic: R/month	10842,9	R7 583,65	**397,18%**	R37 704,59	9,01%	**11819,85**
G.2.1. Energy Credit: High Demand: Peak: R/kWh	6,7149	R6,7149	**12,07%**	R7,5251	9,01%	**7,3199**

G.2.2.Energy Credit: High Demand: Standard: R/kWh	2,0748	R2,0748	**-9,33%**	R1,8812	9,01%	**2,2617**
G.2.3 Energy Credit: High Demand: Off-Peak: R/kWh	1,1534	R1,1534	**8,74%**	R1,2542	9,01%	**1,2573**
G.3.1. Energy Credit: Low Demand: Peak: R/kWh	2,2168	R2,2168	**40,88%**	R3,1230	9,01%	**2,4165**
G.3.2. Energy Credit: Low Demand: Standard: R/kWh	1,5399	R1,5399	**14,02%**	R1,7558	9,01%	**1,6786**
G.3.3. Energy Credit: Low Demand: Off-Peak: R/kWh	0,9936	R0,9936	**26,23%**	R1,2542	9,01%	**1,0831**
G.4.1. DUoS rates	0,1348	R0,1211	**8,76%**	R0,1317	9,01%	**0,1469**
Tariff H RESIDENTIAL TOU: LV: <=100 kVA / 150 Amp 3 phase	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
Tariff H Single-phase. <=80Amp.						
H1.1. Basic charge: Single-phase. <=80Amp. R/month	580,48	R548,89	**9,01%**	R598,34	9,01%	**632,78**
H2.1.1. Energy charge: High Demand: Peak: R/kWh	10,1297	R6,7690	**9,01%**	R7,3789	9,01%	**11,0424**
H2.1.2.Energy charge: High Demand: Standard: R/kWh	2,7497	R1,8950	**9,01%**	R2,0657	9,01%	**2,9974**
H2.1.3. Energy charge: High Demand: Off-Peak: R/kWh	1,7122	R1,3534	**9,01%**	R1,4753	9,01%	**1,8665**
H3.1.1. Energy charge: Low Demand: Peak: R/kWh	3,5453	R2,9674	**9,01%**	R3,2348	9,01%	**3,8647**
H3.1.2. Energy charge: Low Demand: Standard: R/kWh	2,5326	R1,7868	**9,01%**	R1,9478	9,01%	**2,7608**
H3.1.3. Energy charge: Low Demand: Off-Peak: R/kWh	1,5193	R1,3534	**9,01%**	R1,4753	9,01%	**1,6562**
Tariff H Single-phase. Three-phase, <=80Amp.	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
H1.2. Basic charge: Three-phase, <=80Amp. R/month	1451,06	R1 019,44	**9,01%**	R1 111,29	9,01%	**1581,80**
H2.1.1. Energy charge: High Demand: Peak: R/kWh	10,1297	R6,7690	**9,01%**	R7,3789	9,01%	**11,0424**
H2.1.2.Energy charge: High Demand: Standard: R/kWh	2,7497	R1,8950	**9,01%**	R2,0657	9,01%	**2,9974**
H2.1.3. Energy charge: High Demand: Off-Peak: R/kWh	1,7122	R1,3534	**9,01%**	R1,4753	9,01%	**1,8665**
H3.1.1. Energy charge: Low Demand: Peak: R/kWh	3,5453	R2,9674	**9,01%**	R3,2348	9,01%	**3,8647**
H3.1.2. Energy charge: Low Demand: Standard: R/kWh	2,5326	R1,7868	**9,01%**	R1,9478	9,01%	**2,7608**
H3.1.3. Energy charge: Low Demand: Off-Peak: R/kWh	1,5193	R1,3534	**9,01%**	R1,4753	9,01%	**1,6562**

Tariff H Single-phase. Three-phase, >80Amp.	2025/26 NERSA-Approved Tariff	2025/26 COE-Implemented Tariff	Proposed % Increase	Proposed 2026/27 Tariff Increase	Recommended % Increase	2026/27 Approved Tariff
H1.3. Basic charge: Three-phase, >80Amp: R/month	1451,06	R1 019,44	**9,01%**	R1 111,29	9,01%	**1581,80**
H2.1.1. Energy charge: High Demand: Peak: R/kWh	10,1297	R6,7690	**9,01%**	R7,3789	9,01%	**11,0424**
H2.1.2.Energy charge: High Demand: Standard: R/kWh	2,7497	R1,8950	**9,01%**	R2,0657	9,01%	**2,9974**
H2.1.3. Energy charge: High Demand: Off-Peak: R/kWh	1,7122	R1,3534	**9,01%**	R1,4753	9,01%	**1,8665**
H3.1.1. Energy charge: Low Demand: Peak: R/kWh	3,5453	R2,9674	**9,01%**	R3,2348	9,01%	**3,8647**
H3.1.2. Energy charge: Low Demand: Standard: R/kWh	2,5326	R1,7868	**9,01%**	R1,9478	9,01%	**2,7608**
H3.1.3. Energy charge: Low Demand: Off-Peak: R/kWh	1,5193	R1,3534	**9,01%**	R1,4753	9,01%	**1,6562**
TARIFF I						
Tariff I Cross Border between Cities: Municfelx +10%. Supply at LV: 230/400V	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
ICP.1.1. Basic charge: R/month	9066,33	R8 242,13	**8,76%**	R8 964,14	8,76%	**9860,54**
ICP.2.2.1. Demand charge: High Demand Season: R/kVA	33,22	R30,21	**8,76%**	R32,86	8,76%	**36,1301**
ICP.2.1.2. Demand charge: Low Demand Season: R/kVA	33,22	R30,21	**8,76%**	R32,86	8,76%	**36,1301**
ICP.2.3.1. Network Access Charge (NAC): R/kVA (highest of max / notified)	74,2	R67,46	**8,76%**	R73,37	8,76%	**80,6999**
ICP.3.1.1. Energy charge: High Demand: Peak: R/kWh	9,501	R8,6373	**8,76%**	R9,3939	8,76%	**10,3333**
ICP.3.1.2.Energy charge: High Demand: Standard: R/kWh	2,6577	R2,4161	**8,76%**	R2,6278	8,76%	**2,8905**
ICP.3.1.3 Energy charge: High Demand: Off-Peak: R/kWh	1,8975	R1,7250	**8,76%**	R1,8761	8,76%	**2,0637**
ICP.3.2.1. Energy charge: Low Demand: Peak: R/kWh	4,1634	R3,7849	**8,76%**	R4,1165	8,76%	**4,53**
ICP.3.2.2. Energy charge: Low Demand: Standard: R/kWh	2,5056	R2,2779	**8,76%**	R2,4774	8,76%	**2,7251**
ICP.3.2.3. Energy charge: Low Demand: Off-Peak: R/kWh	1,8975	R1,7250	**8,76%**	R1,8761	8,76%	**2,0637**

Tariff I Cross Border between Cities: Megaflex +10%. Supply at MV or HV: >230/400V and <=66kV	2025/26 NERSA-Approved Tariff	2025/26 COE-Implemented Tariff	Proposed % Increase	Proposed 2026/27 Tariff Increase	Recommended % Increase	2026/27 Approved Tariff
ICP.1.2. Basic charge: R/month	47344,98	R19 528,90	**8,76%**	R21 239,63	8,76%	**51492,40**
ICP.2.1.1. Demand charge: High Demand Season: R/kVA	48,37	R67,35	**8,76%**	R73,25	8,76%	**52,6072**
ICP.2.2.2. Demand charge: Low Demand Season: R/kVA	48,37	R67,35	**8,76%**	R73,25	8,76%	**52,6072**
ICP.2.3.1. Network Access Charge (NAC): R/kVA (highest of max / notified)	12,93	R53,24	**8,76%**	R57,90	8,76%	**14,0627**
ICP.3.1.4. Energy charge: High Demand: Peak: R/kWh	8,8212	R8,0193	**8,76%**	R8,7218	8,76%	**9,5939**
ICP.3.1.5.Energy charge: High Demand: Standard: R/kWh	2,4712	R2,2465	**8,76%**	R2,4433	8,76%	**2,6877**
ICP.3.1.6 Energy charge: High Demand: Off-Peak: R/kWh	1,7655	R1,6050	**8,76%**	R1,7456	8,76%	**1,9202**
ICP.3.2.4. Energy charge: Low Demand: Peak: R/kWh	3,8684	R3,5167	**8,76%**	R3,8248	8,76%	**4,21**
ICP.3.2.5. Energy charge: Low Demand: Standard: R/kWh	2,3303	R2,1184	**8,76%**	R2,3040	8,76%	**2,5344**
ICP.3.2.6. Energy charge: Low Demand: Off-Peak: R/kWh	1,7655	R1,6050	**8,76%**	R1,7456	8,76%	**1,9202**
TARIFF J Supplies at MV or HV close-coupled to the Eskom grid	**2025/26 NERSA-Approved Tariff**	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
J.1.1. Basic charge: R/month	280431,02	R11 822,44	**8,76%**	R12 858,09	-95,41%	**12858,09**
J.2.1.4. Demand charge: High Demand Season: R/kVA	85,31	R80,56	**8,76%**	R87,62	8,76%	**92,7832**
J.2.1.2. Demand charge: Low Demand Season: R/kVA	85,31	R80,56	**8,76%**	R87,62	8,76%	**92,7832**
J.2.2.1. Network Access Charge (NAC): R/kVA (highest of max / notified)	58,5	R68,10	**8,76%**	R74,07	8,76%	**63,6246**
J.3.1.1. Energy charge: High Demand: Peak: R/kWh	8,4472	R6,9967	**8,76%**	R7,6096	8,76%	**9,1872**
J.3.1.2.Energy charge: High Demand: Standard: R/kWh	2,6856	R2,1227	**8,76%**	R2,3086	8,76%	**2,9209**
J.3.1.3 Energy charge: High Demand: Off-Peak: R/kWh	1,6278	R1,5811	**8,76%**	R1,7196	8,76%	**1,7704**
J.3.2.1. Energy charge: Low Demand: Peak: R/kWh	3,079	R3,1951	**8,76%**	R3,4750	8,76%	**3,35**
J.3.2.2. Energy charge: Low Demand: Standard: R/kWh	2,1301	R2,0145	**8,76%**	R2,1910	8,76%	**2,3167**
J.3.2.3. Energy charge: Low Demand: Off-Peak: R/kWh	1,468	R1,5811	**8,76%**	R1,7196	8,76%	**1,5966**

D4.5. Reactive Energy charge: P&S (<0.85PF): R/kvarh		R0,3220	**8,76%**	R0,3502	8,76%	**0,35**
	2025/26 NERSA-Approved Tariff	**2025/26 COE-Implemented Tariff**	**Proposed % Increase**	**Proposed 2026/27 Tariff Increase**	**Recommended % Increase**	**2026/27 Approved Tariff**
SSEG export credit						
SSEG for Non-TOU	1,0538	R1,0538	**8,76%**	R1,1461	**8,76%**	**1,1461**
SSEG for TOU High Season	1,4054	R1,4054	**8,76%**	R1,5285	**8,76%**	**1,5285**
SSEG for TOU Low Season	0,9611	R0,9611	**8,76%**	R1,0453	**8,76%**	**1,0453**

10. CONFIDENTIALITY

10.1. None.

11. CONCLUSION

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

End.