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

KwaDukuza Local Municipality

THE DECISION

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

1. to approve the tariffs that are based on the Cost of Supply (COS) report as recommended in the tariff analysis section for implementation by the licensee with effect from 1 July 2026;
2. to 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 Cost of Supply study to enable the National Energy Regulator of South Africa to perform its independent verification/audit process by 30 September 2026.

TABLE OF CONTENTS

THE DECISION 1

ABBREVIATIONS AND ACRONYMS 5

1. INTRODUCTION 6

2. LEGAL AND REGULATORY FRAMEWORK 7

3. FINANCIAL AND TECHNICAL PERFORMANCE 10

4. DETERMINATION OF KWADUKUZA'S TARIFFS BASED ON THE COS STUDY 11

5. CONCLUSION ON THE COS STUDY 19

6. PUBLIC PARTICIPATION 20

7. THE OBJECTORS AND OTHER INTERVENING PARTIES 20

8. TARIFF ANALYSIS 29

9. CONFIDENTIALITY 36

10. CONCLUSION 36

TABLE OF TABLES

Table 1: Customer statistics (data obtained from the latest D-forms – 2024/25) 6
Table 2: Performance indicators 11
Table 3: Energy losses recovery potential impact 11
Table 4: KwaDukuza revenue requirement 13
Table 5: Operational expenditure 14

TABLE OF FIGURES

Figure 1: Five steps of COS study 12
Figure 2: Cost breakdown by functions 16
Figure 3: Cost breakdown by cost structure (classification) 17
Figure 4: Costs allocated 18
Figure 5: Revenue recovery by customer category 19

ABBREVIATIONS ACRONYMS

COS	Cost of Supply
D-form	Distribution form
ERTSA	Eskom Retail Tariff Structural Adjustments
FBE	Free Basic Electricity
IBT	Inclining Block Tariff
IPP	Independent Power Producer
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 KwaDukuza Local Municipality (KwaDukuza) is in KwaZulu-Natal.

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)	65 705	12,48%	55 256
Domestic (Conventional)	112 592	21,39%	10 293
Commercial (Pre-paid)	8 062	1,53%	792
Comercial (Converntional)	336 029	63,84%	478
Own Use,street lighting and other Departments	3993	0,76%	N/A
Totals	526 381	100%	66 819
Free Basic Electricity	7 008	3,93%	11680

1.3. Industrial customers account for 63.84% of the total electricity sales, followed by domestic customers accounting for 33.87%.

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

1.5. KwaDukuza implemented a 10% average price increase in the 2025/26 financial year (FY) and is applying for an average price increase of 11% for FY2026/27.

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 comments received.

1.7. NERSA followed the notice and comment consultation process. On 31 March 2026, NERSA published KwaDukuza'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

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 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 2026/27 municipal financial year.

2.2. NERSA's Statutory Mandate

2.2.1. NERSA is established as a juristic person in terms of section 3 of 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. Therefore, the electricity regulatory mandate of the Energy Regulator is 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. Therefore, public participation processes conducted by the Energy Regulator 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 of the EPP 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. EPP Policy Position 23, therefore, requires electricity distributors to undertake Cost-of-Supply studies at least every five years, or when significant structural changes occur in the customer base or cost structure.

2.6.4. Such studies must be conducted in accordance with the methodology approved by NERSA and must accompany tariff structure applications submitted to 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, given 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 that follow 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 KwaDukuza, 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. KwaDukuza recorded a percentage deficit of 6.56% in the 2023/24 financial year and 11.52% in the 2024/25 financial year.

3.3. Table 2 below shows that KwaDukuza recorded energy losses of 25.57% in the 2023/24 financial year and 26.73% in the 2024/25 financial year.

Table 2: Performance indicators

Outputs:	2024/25	2023/24
Percentage Surplus	-11,52%	-6,56%
Percentage Energy Losses:	26,73	25,57

3.4. Based on the above information, the municipality's performance is satisfactory as it is able to generate a surplus, and the energy losses are low.

Table 3: Energy losses recovery potential impact

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	260,17		
Sales kWh	526 381 640,00	632 193 336,72	675 297 427,86
Purchases kWh	718 401 519,00	718 401 519,00	718 401 519,00
Losses kWh	192 019 879,00	86 208 182,28	43 104 091,14
Losses percentage	26,73%	12,00%	6,00%
Additional Energy (kWh)		105 811 696,72	148 915 787,86
Additional Revenue (Rands)		275 288 258,92	387 431 344,89
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 1 483 786 982,00	R 1 759 075 240,92	R 1 871 218 326,89
Total Expenses (Rands)	R 1 654 766 951,00	R 1 654 766 951,00	R 1 654 766 951,00
Net Profit (Loss)	R -170 979 969,00	R 104 308 289,92	R 216 451 375,89
Percentage Surplus/Deficit	-11,52%	5,93%	11,57%

3.5. The licensee has the potential to improve the surplus from a deficit of 11,52% to a surplus of 5.93% if energy losses are limited to 12%, and the surplus could potentially increase to 11.57% if the energy losses are reduced to 6%.

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

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

4.2. KwaDukuza 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 uses the latest available audited data, which is based on the 2024/25 financial year.

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

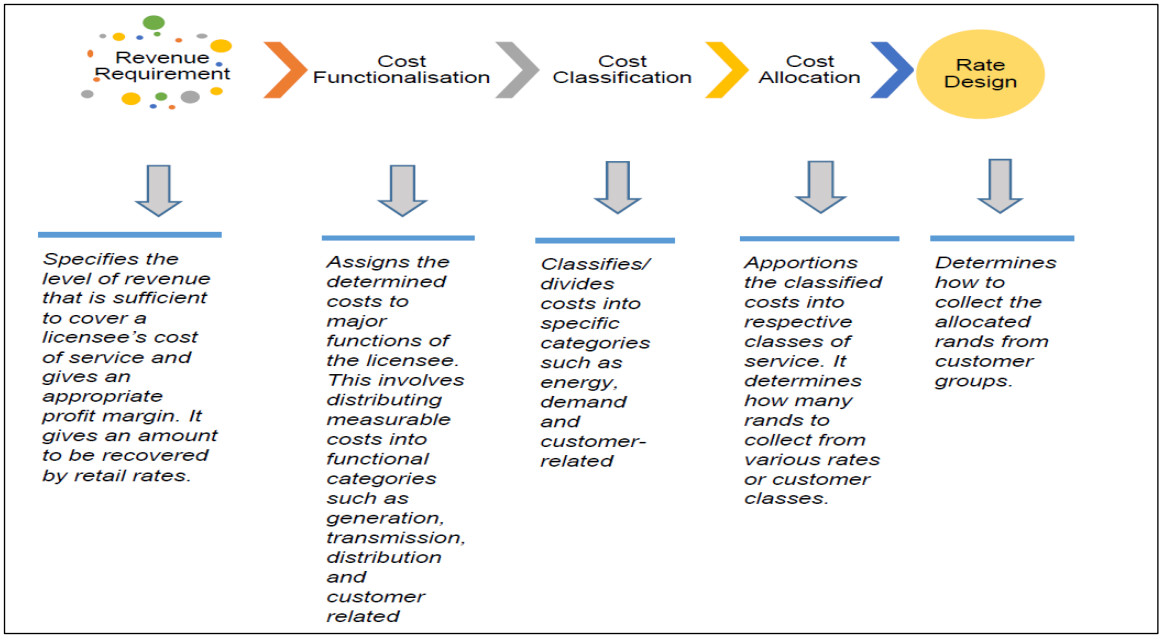


Figure 1: Five steps of COS study

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

4.4.1. be informed by cost-of-supply outcomes;

4.4.2. progressively move tariffs towards cost reflectivity; and

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

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

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

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

4.5.3. Controllable electricity OPEX was adjusted using CPI-linked assumptions.

4.5.4. Adjustments were supported by source documents and reasonability checks (D-forms, trial balance and AFS).

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

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

Revenue Requirement

4.7.1. 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.

4.7.2. 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.

4.7.3. KwaDukuza submitted a COS study detailing revenue requirements of R2 504 614 831 for the 2026/27 financial year. As shown in Table 4 below, this revenue requirement is dominantly Eskom purchases accounting for 88%, including an energy losses allowance. Operational expenditure accounts for 13%.

Table 4: KwaDukuza revenue requirement

	Total cost (R)					
Revenue Requirement components	**Wires**	**Retail**	**Applied for 2026/27**	**NERSA Adjustments**	**NERSA Decision 2026/27**	**% of Total**
Allowable costs	456 581 277	2 048 033 554	2 504 614 831	- 95 979 820	2 408 635 011	100%
Energy purchases from Eskom - net of cost of losses	-	1 896 633 357	1 896 633 357	-	1 896 633 357	76%
Energy purchases from Eskom - cost of losses	237 191 573	66 326 446	303 518 019	-	303 518 019	12%
Other energy purchases	-	-	-			0%
Capital expenditure	-	-	-			0%
Operational expenditure (incl. Depreciation)	201 899 265	130 452 668	332 351 934	- 87 254 382	245 097 552	13%
Other revenues	**- 2 454 080**	**- 53 112 895**	**- 55 566 975**	-	**- 55 566 975**	**-2%**
Surplus	19 944 519	7 733 977	27 678 496	- 8 725 438	18 953 058	1%
Not allowable costs	123 403 368	205 762 083	329 165 451	-	329 165 451	
Cost of losses disallowed	123 403 368	205 762 083	329 165 451		329 165 451	
TOTAL COSTS	**579 984 645**	**2 253 795 637**	**2 833 780 282**	**-95 979 820**	**2 737 800 461**	
	20%	80%				

4.7.3.1. 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.

4.7.4. Furthermore, NERSA has verified all expense items included in the revenue requirements to ensure that they relate only to the electricity function of the licensee. In instances where expenses are deemed inflated or unjustified, these have been adjusted accordingly and expanded on below.

Bulk Purchases

4.7.5. KwaDukuza's COS study projects a bulk purchase expenditure of R2 200 million, which accounts for 88% of total costs when including the 12%

energy losses allowance. Bulk purchases were verified against the 2024/25 Eskom invoices.

4.7.6. 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

4.7.7. KwaDukuza's COS study projects operational expenditure totalling R332 351 934, representing 13% of overall costs. Table 5 below provides a breakdown of this expenditure.

Table 5: Operational expenditure[1]

Cost Drivers	Actual 2024/25	Budget 2025/26	Applied for 2026/27	NERSA Adjustments	NERSA Decision 2026/27
General & Other	R 186 006 320	R 240 695 755	R 255 137 500	-R 60 661 128	R 194 476 372
Materials and supplies	R 7 996 948	R 56 112 653	R 59 479 412	-R 50 829 913	R 8 649 499
Contracted Services	R 63 295 964	R 57 896 123	R 61 369 890	R 7 091 024	R 68 460 915
Salaries, wages and allowances (exclu. Repairs	R 76 262 456	R 83 991 043	R 89 030 506	-R 6 545 033	R 82 485 472
Eskom debts' interests	R -	R -	R -	R -	R -
Other creditors interests	R -	R -	R -	R -	R -
Current year depreciation	R 35 435 325	R 42 695 936	R 45 257 692	-R 10 377 206	R 34 880 486
NMD exceedance penalties	R 3 015 627	R -	R -	R -	R -
Shared OPEX	R 46 829 896	R 73 099 371	R 77 214 433	-R 26 593 254	R 50 621 180
Bad debts written-off	R 722 017	R 4 515 000	R 4 515 000	-R 3 764 102	R 750 898
FBE paid to Eskom	R 1 492 333	R 1 051 785	R 1 114 892	R 499 215	R 1 614 107
Charges from other Municipal Departments	R -	R -	R -	R -	R -
General Expenses	R 44 615 546	R 67 532 586	R 71 584 541	-R 23 328 367	R 48 256 175
Total	**R 232 836 216**	**R 313 795 126**	**R 332 351 934**	**-R 87 254 382**	**R 245 097 552**

4.7.8. NERSA recommends an operational expenditure of R245 097 552 in line with the adjustments in Table 6 above, which are a result of the following:

4.7.8.1. The audited 2024/25 figures have been escalated in line with the expected inflation of 4% when compared to the licensee's projected 6%.

4.7.8.2. Materials and supplies were projected by the municipality to initially grow by 602% and 6% for the 2025/26 and 2026/27 financial years, respectively. These amounts have been limited to the projected inflation of 4% after considering stakeholder concerns around a

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

consistent pattern of underspending on upgrade and capital programmes. The principle has been applied to the other expenses.

4.7.8.3. The licensee is not incurring inefficient costs such as Notified Maximum Demand (NMD) exceedance penalties and interest incurred on Eskom-related debt.

4.7.8.4. Bad debts are on 0.3% of operational expenditure, below the NERSA threshold of 5%.

Surplus

4.7.9. KwaDukuza's revenue requirement includes a surplus of R27 678 496, 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. The surplus as depicted is a result of implementing a reasonable margin of 9% on efficient operating expenditure in line with the ERA, section 15(1)(a), i.e. (R332.351 million – R55.556 million) X 10% = R27.678 million. This represents 1% of total expenditure. This has been adjusted in line with the recommended operational expenditure.

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

4.7.10.1. 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.

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

4.7.11. Risk factors considered include the following:

4.7.11.1. Revenue collection risk, with current collection levels above 95%, reflecting minimum exposure to non-payment.

4.7.11.2. Operational risk, including energy.

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

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

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

4.7.14. In applying the Act, NERSA is required to ensure that KwaDukuza recovers efficient costs and a reasonable return, while preventing excessive compensation.

4.7.15. The recommended revenue requirement will be applied in the subsequent COS steps, namely cost functionalisation, cost classification, cost allocation, and rate setting. These steps have been verified and confirmed to align with the approved revenue requirement. Further details on these steps are provided below.

Cost Functionalisation

4.7.16. The licensee has categorised its revenue requirement into two primary functional components, namely the wires business (20%) and the retail business (80%), in accordance with the NERSA COS Framework, as illustrated in Figure 2 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

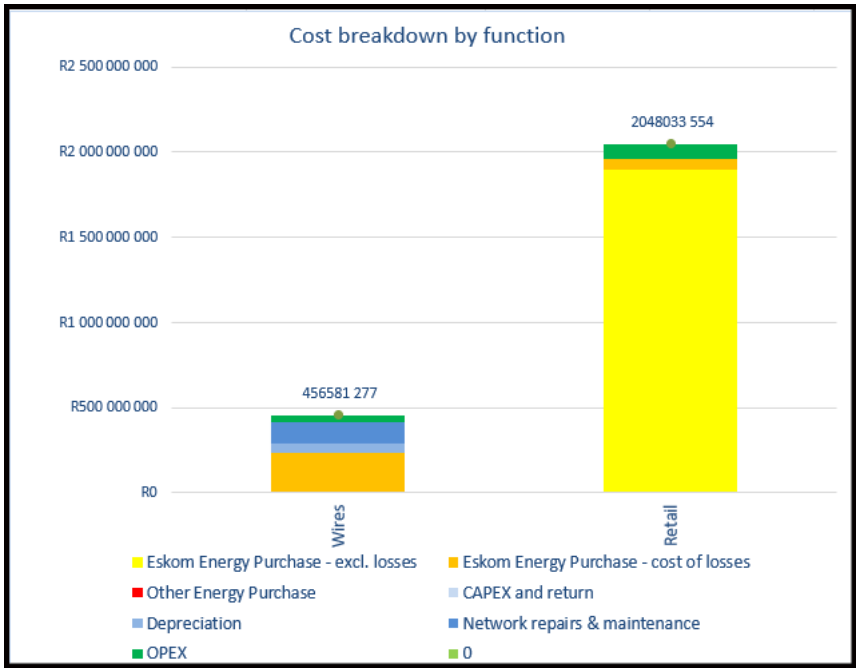


Figure 2*:* Cost breakdown by functions

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

Cost Classification

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

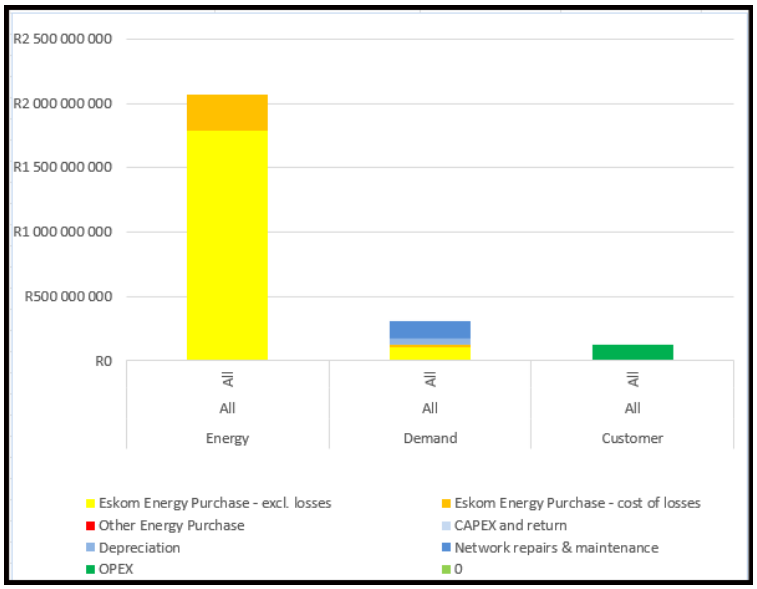


Figure 3*:* Cost breakdown by cost structure (classification)

4.7.19. Energy purchases constitute energy-driven costs, with the highest expenditure incurred during the summer period under the standard time-of-use structure, largely due to the longer duration of the summer season, as shown in Figure 3 above. Demand-driven costs are similarly concentrated in the summer period. Customer-driven costs are primarily associated with 'Other OPEX', which includes expenses related to the provision of electricity distribution services to customers.

Cost Allocation

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

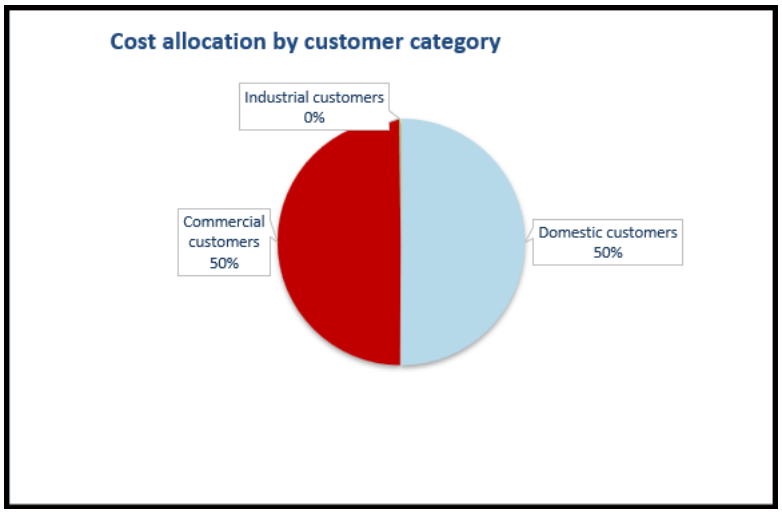


Figure 4: Costs allocated

Rate Design

4.7.21. Table 7 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 7 below.

4.7.22. To achieve full cost reflectivity, the municipality would be required to implement differentiated tariff adjustments across customer categories. However, the municipality has adopted a less aggressive approach, opting 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.

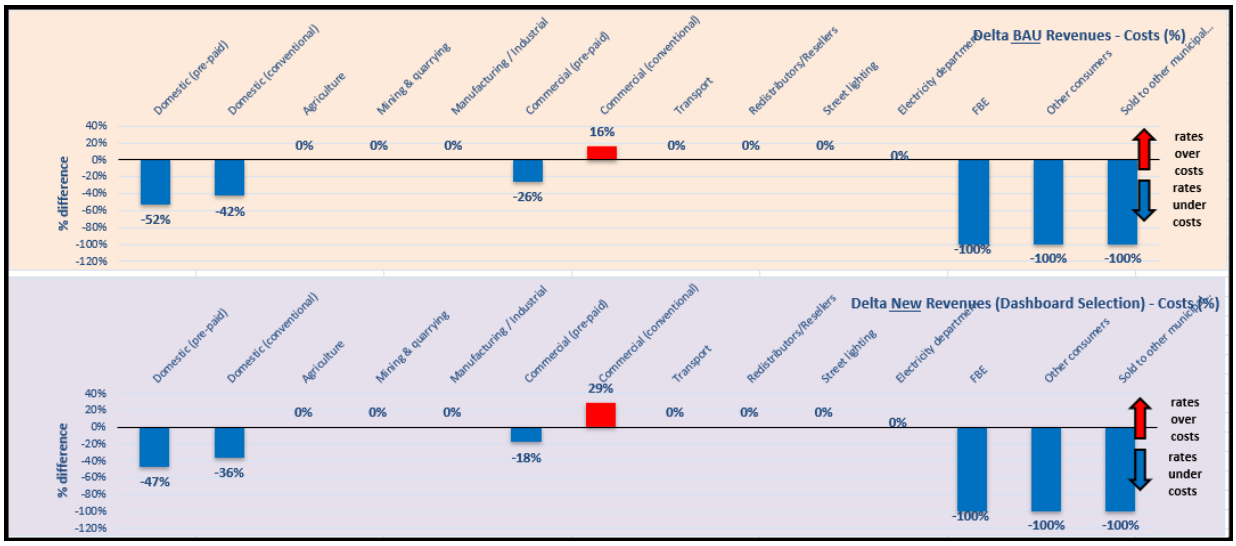


Figure 5: Revenue recovery by customer category

5. CONCLUSION ON THE COS STUDY

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

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

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

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

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

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T5 (1B) Religious organizations with an NMD of 65KVA-1000KVA	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Demand charge (R/kVA)	181,65	201,63	11,00%	201,63	11,00%	
Energy charge (c/kWh)	284,26	315,53	11,00%	315,53	11,00%	

2. COMMERCIAL TARIFFS						
T8(iv) Commercial Prepaid	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended tariff**	**% Increase**	**Key analysis and Findings**
Energy charge (c/kWh)	390,68	433,66	11,00%	433,66	11,00%	

T3 Commercial Conventional – Single Phase connection not exceeding 60 Ampere & Three-phase connection not exceeding 3 X 80 Ampere	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Basic charge (R/month)	395,04	418,74	6,00%	418,74	6,00%	
Energy charge (c/kWh)	357,98	397,36	11,00%	397,36	11,00%	

3. INDUSTRIAL TARIFFS						
T1 Industrial low voltage – notified maximum demand of 65KVA or more, but not exceeding 1000KVA	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic Charge (R/month)	1690,79	1792,24	6,00%	1792,24	6,00%	
Energy charge (c/kWh)	284,26	315,52	11,00%	315,52	11,00%	
Demand charge (R/kVA)	181,34	201,29	11,00%	201,29	11,00%	

T7 (bb) Industrial Medium Voltage – large consumers exceeding 1 000 kVA	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Basic Charge (R/month)	1690,79	1792,24	6,00%	1792,24	6,00%	
Energy charge (c/kWh)	274,04	304,19	11,00%	304,19	11,00%	
Demand charge (R/kVA)	157,81	175,17	11,00%	175,17	11,00%	

~~T9(1A): Maximum Demand of 65kVA~~	~~2025/26 Approved~~	~~2026/27 Proposed~~	~~% Increase~~	~~Recommended Tariff~~	~~% Increase~~	~~Key Analysis and Findings~~
~~Basic Monthly: R/month~~	~~1 690,79~~	~~1792,24~~	~~6,00%~~	~~1792,24~~	~~6,00%~~	Tariff deleted in 2025/26
~~**Energy charges:**~~	-	-	-	-	-	
~~Peak(c/kWh)~~	~~781,8146825~~	~~867,81~~	~~11,00%~~	~~867,81~~	~~11,00%~~	
~~Standard c/kWh~~	~~321,0604499~~	~~356,38~~	~~11,00%~~	~~356,38~~	~~11,00%~~	
~~Off-peak(c/kWh)~~	~~173,945085~~	~~193,08~~	~~11,00%~~	~~193,08~~	~~11,00%~~	
~~**Demand charge R/kVA**~~	~~138,349496~~	~~153,57~~	~~11,00%~~	~~153,57~~	~~11,00%~~	

T9(1B): Maximum Demand > 65kVA	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Basic Monthly: R/month	1 690,79	1792,24	6,00%	1792,24	6,00%	
Low Season						
Energy charges:						
Peak(c/kWh)	320,6403604	355,91	11,00%	355,91	11,00%	
Standard c/kWh	210,5768949	233,74	11,00%	233,74	11,00%	
Off-peak(c/kWh)	138,405508	153,63	11,00%	153,63	11,00%	
High Season						
Energy charges:						
Peak c/kWh	781,83	867,83	11,00%	867,83	11,00%	
Standard c/kWh	321,06	356,38	11,00%	356,38	11,00%	
Off-peak c/kWh	173,95	193,08	11,00%	193,08	11,00%	
Demand charge R/kVA	138,35	153,57	11,00%	153,57	11,00%	

T10: Maximum Demand < 65kVA	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Basic Monthly: R/month	1 690,79	1792,24	6,00%	1792,24	6,00%	
Energy charges:						
Peak(c/kWh)	674,52	748,72	11,00%	748,72	11,00%	
Standard c/kWh	212,85	236,26	11,00%	236,26	11,00%	
Off-peak(c/kWh)	105,02	116,57	11,00%	116,57	11,00%	
Demand charge R/kVA	181,34	201,29	11,00%	201,29	11,00%	

T11: Residential TOU	2025/26 Approved	2026/27 Proposed	% Increase	Recommended Tariff	% Increase	Key Analysis and Findings
Basic Monthly: R/month	103,50	109,71	6,00%	109,71	6,00%	
Energy charges:						
Peak(c/kWh)	489,12	542,93	11,00%	542,93	11,00%	
Standard c/kWh	244,55	271,45	11,00%	271,45	11,00%	
Off-peak(c/kWh)	181,06	200,98	11,00%	200,98	11,00%	

~~T7: Sappi Fine Paper Agreement~~	~~2025/26 Approved~~	~~2026/27 Proposed~~	~~% Increase~~	~~Recommended Tariff~~	~~% Increase~~	~~Key Analysis and Findings~~
~~Basic Monthly: R/month~~	~~68,15~~	~~75,65~~	~~11,00%~~	~~75,65~~	~~11,00%~~	Migrated to Tariff T13 in 2025/2026
~~***Low Season***~~	-	-	-	-	-	
~~**Energy charges:**~~	-	-	-	-	-	
~~Peak(c/kWh)~~	~~228,92958~~	~~254,11~~	~~11,00%~~	~~254,11~~	~~11,00%~~	
~~Standard c/kWh~~	~~157,540064~~	~~174,87~~	~~11,00%~~	~~174,87~~	~~11,00%~~	
~~Off-peak(c/kWh)~~	~~99,931964~~	~~110,92~~	~~11,00%~~	~~110,92~~	~~11,00%~~	
~~***High Season***~~	-	-	-	-	-	
~~Energy charges:~~	-	-	-	-	-	
~~Peak c/kWh~~	~~701,65~~	~~778,83~~	~~11,00%~~	~~778,83~~	~~11,00%~~	
~~Standard c/kWh~~	~~212,55~~	~~235,94~~	~~11,00%~~	~~235,94~~	~~11,00%~~	
~~Off-peak c/kWh~~	~~115,42~~	~~128,11~~	~~11,00%~~	~~128,11~~	~~11,00%~~	
~~Demand charge R/kVA~~	~~68,15~~	~~75,65~~	~~11,00%~~	~~75,65~~	~~11,00%~~	

~~Network capacity charge (R/kVA)~~	~~35,95~~	~~39,90~~	~~11,00%~~	~~39,90~~	~~11,00%~~	
~~Transmission Network Charge (R/kVA)~~	~~18,16~~	~~20,15~~	~~11,00%~~	~~20,15~~	~~11,00%~~	
~~Reactive energy charge [c/kVArh]~~	~~0,32~~	~~0,35~~	~~11,00%~~	~~0,35~~	~~11,00%~~	
~~Ancillary Charge~~	~~0,01~~	~~0,01~~	~~11,00%~~	~~0,01~~	~~11,00%~~	
~~Electrification~~	~~0,01~~	~~0,01~~	~~11,00%~~	~~0,01~~	~~11,00%~~	

Tariff 6(i): Street Lighting – Installation maintained by customer	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Energy charge (c/kWh)	383,68	425,89	11,00%	425,89	11,00%	
Per pole new	143,76	159,57		159,57	11,00%	
Per pole up to 200 kW	517,05	573,92	11,00%	573,92	11,00%	
Per pole up greater than 200 kW	605,24	671,81	11,00%	671,81	11,00%	
Per Traffic Controller per signal head	605,24	671,81	11,00%	671,81	11,00%	
Charge per flood gate, tele booth lighting & street lighting	605,24	671,81	11,00%	671,81	11,00%	
Charge per traffic control installation	605,24	671,81	11,00%	671,81	11,00%	

Tariff 6(ii): Street Lighting – Installation maintained by municipality	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Energy charge (c/kWh)	383,68	425,89	11,00%	425,89	11,00%	
Per pole up to 200 kW	517,05	573,92	11,00%	573,92	11,00%	
Per pole up greater than 200 kW	605,24	671,81	11,00%	671,81	11,00%	

Per Traffic Controller per signal head	605,24	671,81	11,00%	671,81	11,00%	
Charge per flood gate, tele booth lighting & street lighting	605,24	671,81	11,00%	671,81	11,00%	
Charge per traffic control installation	605,24	671,81	11,00%	671,81	11,00%	

T6: Illuminated Advertising	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic Monthly: R/month	404,97	429,27	6,00%	429,27	6,00%	
Energy charge (c/kWh)	354,09	393,03	11,00%	393,03	11,00%	

T12 NMD >1000kVA up to 5000kVA	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic Monthly: R/month	1 739,10	1843,45	6,00%	1843,45	6,00%	
Demand charge R/kVA	134,98	149,83	11,00%	149,83	11,00%	
Low Season						
Energy charges:						
Peak(c/kWh)	312,82	347,23	11,00%	347,23	11,00%	
Standard c/kWh	205,44	228,04	11,00%	228,04	11,00%	
Off-peak(c/kWh)	135,03	149,88	11,00%	149,88	11,00%	
High Season						
Energy charges:		N/A	N/A	N/A	N/A	
Peak c/kWh	762,76	846,66	11,00%	846,66	11,00%	
Standard c/kWh	313,23	347,69	11,00%	347,69	11,00%	
Off-peak c/kWh	169,70	188,37	11,00%	188,37	11,00%	

T13 NMD >5000kVA	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic Monthly: R/month	1 702,07	1804,19	6,00%	1804,19	6,00%	
Demand charge R/kVA	132,10	146,63	11,00%	146,63	11,00%	

Low Season						
Energy charges:						
Peak(c/kWh)	306,16	339,84	9,01%	339,84	11,00%	
Standard c/kWh	201,06	223,18	9,01%	223,18	11,00%	
Off-peak(c/kWh)	132,16	146,70	9,01%	146,70	11,00%	
High Season						
Energy charges:						
Peak c/kWh	746,52	828,64	9,01%	828,64	11,00%	
Standard c/kWh	306,56	340,28	9,01%	340,28	11,00%	
Off-peak c/kWh	166,09	184,36	9,01%	184,36	11,00%	

Tariff 14b: Residential EG generation	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic Monthly: R/month	404,80	429,09	6,00%	429,09	6,00%	
Feed in energy charge (c/kWh)	155,00	172,05	11,00%	172,05	11,00%	

Tariff 14c: Non-Residential EG generation	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Feed in energy charge (c/kWh)	155,00	172,05	11,00%	172,05	11,00%	

Tariff 14d: Wheeling and system charges	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Basic Monthly: R/month	288,87	306,20	6,00%	306,20	6,00%	
Service charge (R/day)	301,25	334,39	11,00%	334,39	11,00%	
Tariff 14e: Wheeling energy charges	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Low Season						
Energy charges						
Peak(c/kWh)	109,42	121,46	11,00%	121,46	11,00%	

Standard c/kWh	108,29	120,20	11,00%	120,20	11,00%	
Off-peak(c/kWh)	50,28	55,81	11,00%	55,81	11,00%	
High Season						
Energy charges:						
Peak c/kWh	89,94	99,83	11,00%	99,83	11,00%	
Standard c/kWh	47,25	52,45	11,00%	52,45	11,00%	
Off-peak c/kWh	28,50	31,64	11,00%	31,64	11,00%	

Tariff 14f: Wheeling excess energy feed-in	**2025/26 Approved**	**2026/27 Proposed**	**% Increase**	**Recommended Tariff**	**% Increase**	**Key Analysis and Findings**
Low Season						
Energy charges:						
Peak(c/kWh)	160,00	177,60	11,00%	177,60	11,00%	
Standard c/kWh	110,00	122,10	11,00%	122,10	11,00%	
Off-peak(c/kWh)	70,00	77,70	11,00%	77,70	11,00%	
High Season						
Energy charges:						
Peak c/kWh	389,65	432,51	11,00%	432,51	11,00%	
Standard c/kWh	122,65	136,14	11,00%	136,14	11,00%	
Off-peak c/kWh	120,00	133,20	11,00%	133,20	11,00%	

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

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

End.