NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

Decision and Reasons for Decision (RfD)

In the matter regarding the

Private Distributor Tariff Application for the 2026/27 Financial Year

by

Ithala Development Finance Corporation LTD: Ezakheni

THE DECISION

At its meeting held on 9 May 2026, the Regulator Executive Committee (REC) considered Ithala Development Finance Corporation LTD's (Ezakheni) application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year (FY) the decision is set out on the tariff analysis section 8 on page 21 of the RFD.

Based on the information submitted and the analysis conducted, the REC decided to:

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

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ABBREVIATIONS AND ACRONYMS

COS	Cost of Supply
D-form	Distribution form
ERTSA	Eskom Retail Tariff Structural Adjustments
FBE	Free Basic Electricity
IBT	Inclining Block Tariff
IPP	Independent Power Producer
Ithala	Ithala Development Finance Corporation LTD
MFMA	Municipal Finance Management Act
NERA	National Electricity Regulation Act
NERSA	National Energy Regulator of South Africa
OPEX	Operating Expenditure

1. INTRODUCTION

1.1. The National Energy Regulator of South Africa (NERSA) receives and considers tariff applications on a yearly basis, in accordance with its mandate to regulate prices and tariffs. Municipal tariffs must be approved by NERSA to be implemented on 1 July of each financial year.

1.2. Ithala Development Finance Corporation LTD (Ezakheni) is a private corporation located in KwaZulu-Natal. It supplies electricity to three areas namely, Isithebe, Ezakheni and Madadeni. Isithebe has its own set of tariffs while Ezakheni and Madadeni share the same set. This submission will be assessing Ezakheni.

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

Consumer classification	Sales (MWh)	%MWh	Number of consumers
Manufacturing/Industrial	34388	96,56%	62
Street lighting and Own use	1225	3,44%	N/A
Totals	**35 613**	**100%**	**62**

1.3. The licensee's manufacturing/industrial customers account for 95.56% of its sales, while the remaining 3.44% is for its own use and street lighting.

1.4. NERSA received Ezakheni's tariff application together with its Cost of Supply (COS) study on 31 March 2026.

1.5. Ezakheni implemented a 12.74% average price increase in 2025/26FY and is applying for an average price increase of 8.76% for the 2026/27FY.

1.6. The licensee has indicated to NERSA that its Board approved the tariff application, and the resolution and proof of customer consultation was submitted.

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

1.8. NERSA's decision was made on 9 May 2026, considering the written comments received from the affected stakeholders and the analysis performed by NERSA.

2. LEGAL AND REGULATORY FRAMEWORK

2.1. Background

2.1.1. The approval of municipal electricity tariffs constitutes a core regulatory function of NERSA and must be exercised in accordance with the applicable legislative framework, national policy directives and court orders. The principal legal

instruments governing the exercise of this regulatory authority include the National Energy Regulator Act, 2004 (Act No. 40 of 2004) ('NERA'), the Electricity Regulation Act, 2006 (Act No. 4 of 2006) as amended ('ERA'), the Promotion of Administrative Justice Act, 2000 (Act No. 3 of 2000) ('PAJA'), and the Electricity Pricing Policy for the South African Electricity Supply Industry, 2008 ('EPP').

2.1.2. The approval of private electricity distributor tariffs follows the Eskom Multi-Year Price Determination and Eskom Retail Tariff and Structural Adjustment decision.

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.

2.1.5. The inclusion of surpluses by private electricity distributors raises issues of statutory authority, tariff regulation, administrative legality, competition law, and constitutional compliance in the South African electricity sector. A private distributor has no inherent taxing or revenue-raising power. Unlike municipalities, private distributors do not possess constitutional fiscal powers and cannot cross-subsidise unrelated services unless lawfully authorised. If a private distributor includes a surplus solely to generate profit outside approved tariff structures, the charge may be *ultra vires*, unlawful.

2.1.6. Some of the key distinctions between municipal surplus and private distributor profit can be summarised as follows

Table 2: Distinction between municipal surplus and private distributor surplus

Municipal Surplus	Private Distributor Surplus
Permitted under the municipal fiscal framework	Requires explicit legal authorisation
Used for public services and cross-subsidisation	Usually private commercial gain
Subject to constitutional accountability	Subject to licensing, incorporation and contract law
Approved via municipal budgeting processes	

2.2. NERSA's Statutory Mandate

2.2.1. NERSA is established as a juristic person in terms of section 3 of the NERA. In terms of section 4 of NERA, the Energy Regulator, as the decision-making body, must regulate the electricity industry and execute the functions set out in the ERA. The Energy Regulator's electricity regulatory mandate 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.
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 that sought to vary the timelines that had been were set by the Court on 4 December 2025, considering the practical difficulties that arose in terms of NERSA's compliance with the court order. The Court, having heard NERSA's application, granted the variation application in respect of the fixed deadlines for the 2026/27 municipal tariff approvals.

2.8. Court-Directed Timelines

2.8.1. The following timelines are applicable in respect of the 2026/27 municipal tariff approvals:

a) Written notice of bulk tariffs by 6 March 2026
b) Municipal tariff applications must be submitted by 31 March 2026
c) Public participation processes must be concluded by 21 April 2026
d) The publication of NERSA decisions by 11 May 2026.

2.8.2. Municipal tariff approvals from 2027/28 must comply with the following timelines:

a) Written notice of bulk electricity tariffs must be communicated by 31 January each year
b) Municipal tariff applications must be submitted to NERSA by 20 March each year

c) Municipal tariff approvals and the Tariff Reasons for Decision Document must be approved and published by 5 May of each year.

2.9. Conclusion

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

2.9.2. The reasons that follow in this Reasons for Decision Document demonstrate how NERSA complied with the legislative, policy and judicial framework in determining the municipal electricity tariff for the 2026/27 municipal financial year.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In evaluating the financial and technical performance of Ezakheni, the assessment relied on the Distribution forms (D-forms) for the 2024/25 financial year submitted as part of the licensee's tariff application. The information contained in the D-forms was verified against the supporting source documents provided by the municipality, including the trial balance and annual financial statements. As a result, the data captured in the D-forms is considered reliable for the purposes of the tariff analysis.

3.2. Ezakheni recorded a percentage surplus of 8.58%% in the 2023/24 financial year; this has improved to 10.5% in the 2024/25 financial year.

3.3. Table 3 below shows Ezakheni's recorded energy losses of 3.31% in the 2023/24 financial year and 3.07% in the 2024/25 financial year.

Table 3: Performance Indicators

Outputs:	2024/25	2023/24
Percentage Surplus:	10,50%	8,58%
Percentage Energy Losses:	3,07	3,31

3.4. The private distributor's performance is satisfactory as evidenced by the surplus and low energy losses.

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

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

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

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

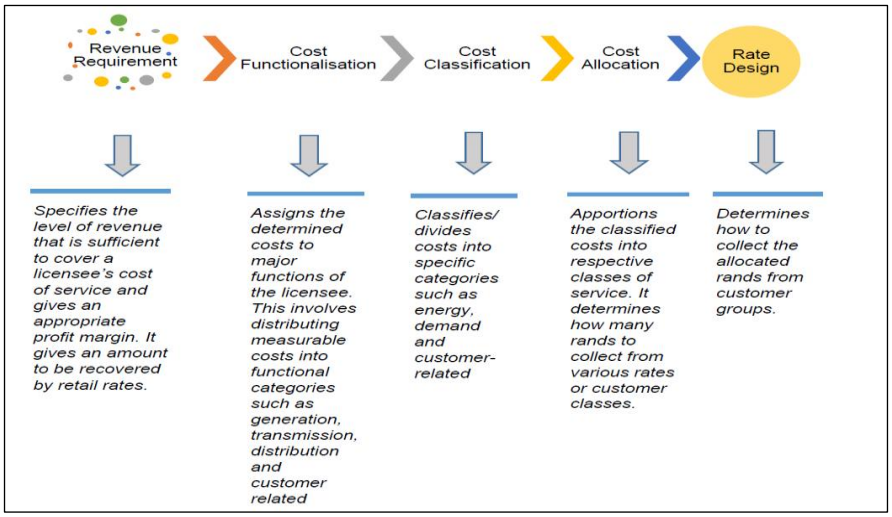


Figure 1: Five Steps of COS

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 the 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 Operating Expenditure (OPEX) costs were 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 cost of supply 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 indicates 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. Ezakheni submitted a COS study detailing revenue requirements of R153 406 154 million for the 2026/27 financial year. As shown in Table 4 below, this revenue requirement is predominantly Eskom purchases, accounting for 85%, including an energy losses allowance. Operational expenditure accounts for 13%.

Table 4: Ezakheni Revenue Requirement[1]

	Total cost (R)					
Revenue Requirement components	Wires	Retail	Applied for 2026/27	NERSA Adjustments	NERSA Decision 2026/27	% of Total
Allowable costs	7 995 253	145 410 900	153 406 154	-	153 406 154	100%
Energy purchases from Eskom - net of cost of losses	-	116 881 372	116 881 372	-	116 881 372	76%
Energy purchases from Eskom - cost of losses	2 716 913	11 737 420	14 454 333	-	14 454 333	9%
Other energy purchases	-	-	-	-		0%
Capital expenditure	-	-	-	-		0%
Operational expenditure (incl. Depreciation)	4 798 491	15 265 554	20 064 045	-	20 064 045	13%
Other revenues	-	-	-	-	-	0%
Surplus	479 849	1 526 555	2 006 404	-	2 006 404	1%
Not allowable costs	-	-	-	-	-	
Cost of losses disallowed	-	-	-	-	-	
TOTAL COSTS	7 995 253	145 410 900	153 406 154	-	153 406 154	
	5%	95%				

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.

[1] Section 4.2 of the COS Framework states that a profit margin is added to determine a licensee's revenue requirement after all costs have been ascertained. The margin is represented by the surplus to be earned by the licensee.

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. Ezakheni's COS study projects a bulk purchase expenditure of R131 335 705, which accounts for 85% of total costs when including the 12% energy losses allowance. Bulk purchases were verified against Eskom invoices in the 2024/25 financial year.

4.7.6. The licensee projected its bulk purchases for the 2026/27 financial year using the 2025/26 financial year Eskom tariffs as a base and made the following assumptions: sales growth of 0%, and a bulk purchase cost increase of 8.76% for the 2026/27 financial year, which is in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

Operational Expenditure

4.7.7. Ezakheni's COS study projects operational expenditure totalling R20 064 045, representing 13% of overall costs. Table 5 below provides a breakdown of this expenditure.

Table 5: Operational Expenditure[2]

Cost Drivers	Actual 2024/25	Budget 2025/26	Applied for 2026/27	NERSA Adjustments	NERSA Decision 2026/27
General & Other	R 15 666 000	R 18 448 000	R 20 064 045	R -	R20 064 045
Salaries and allowances	R 2 985 000	R 3 148 000	R 3 423 765	R -	R 3 423 765
Materials and supplies	R -	R -	R -	R -	R -
Contracted Services	R -	R -	R -	R -	R -
Salaries, wages and allowances (exclu. Repairs an	R -	R -	R -	R -	R -
Payments to consultants (operational work)	R 1 569 000	R 2 528 000	R 2 749 453	R -	R 2 749 453
Eskom debts' interests	R -	R -	R -	R -	R -
Other creditors interests	R -	R -	R -	R -	R -
Current year depreciation	R -	R -	R -	R -	R -
NMD exceedance penalties	R -	R -	R -	R -	R -
Current year depreciation	R 11 112 000	R 12 772 000	R 13 890 827	R -	R 13 890 827
Total	**R 15 666 000**	**R 18 448 000**	**R 20 064 045**		**R20 064 045**

4.7.8. The operating expenditure comprises the following:

4.7.8.1. Depreciation, as a proxy for asset consumption and future asset replacement of R13 890 827;

4.7.8.2. Salaries and allowances of R3 423 765; and

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

4.7.8.3. Payments to consultants of R2 749 453.

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

Surplus

4.7.10. Ezakheni's revenue requirement includes a surplus of R2 006 404, calculated using a margin of 10% applied to operating expenditure, exclusive of bulk purchases, for both the wires and retail components of the electricity business.

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

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

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

4.7.12. Risk factors considered include the following:

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

4.7.12.2. Operational risk, including energy losses of approximately 3.3%, signifying a well-maintained network infrastructure.

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

4.7.12.4. The surplus makes up 1% of allowable costs.

4.7.13. Based on the above, the applied 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.

4.7.14. Furthermore, in recommending the margin, 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'.

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

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

Cost Functionalisation

4.7.17. The licensee has categorised its revenue requirement of R153.4 million into two primary functional components, namely the wires business (5%) and the retail business (95%), in accordance with the NERSA COS Framework, as illustrated in Figure 2 below. On verification, the allocation of costs to these functional components is consistent with the stated revenue requirement.

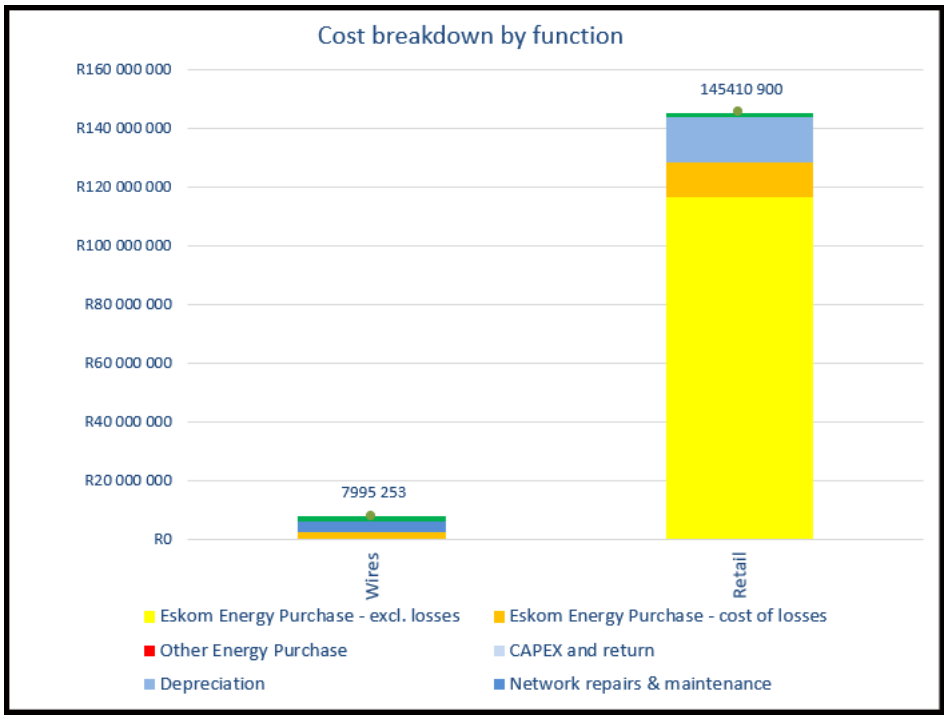


Figure 2: Cost Breakdown by Functions

4.7.18. 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

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

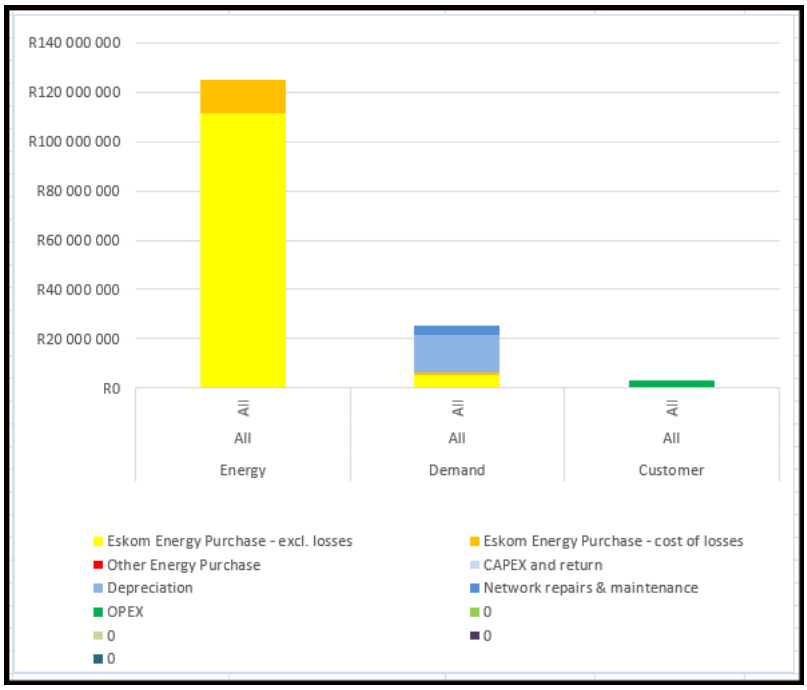


Figure 3*:* Cost Breakdown by Cost Structure (Classification)

4.7.20. Energy purchases are energy-driven costs, with the highest expenditure incurred during the summer period under the standard time-of-use structure, largely due to the longer 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 providing electricity distribution services to customers.

Cost Allocation

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

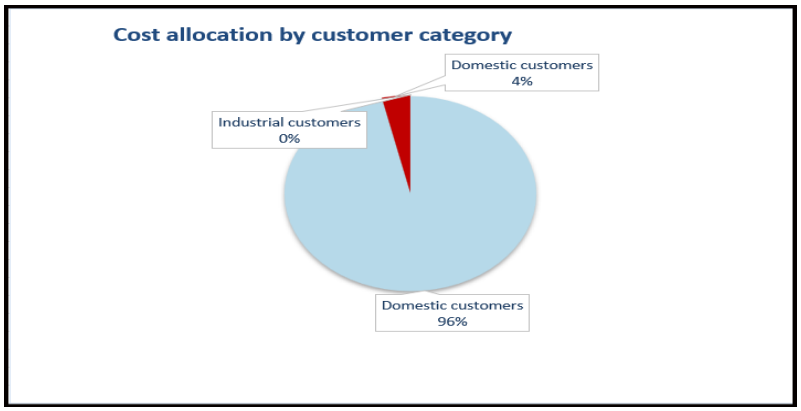


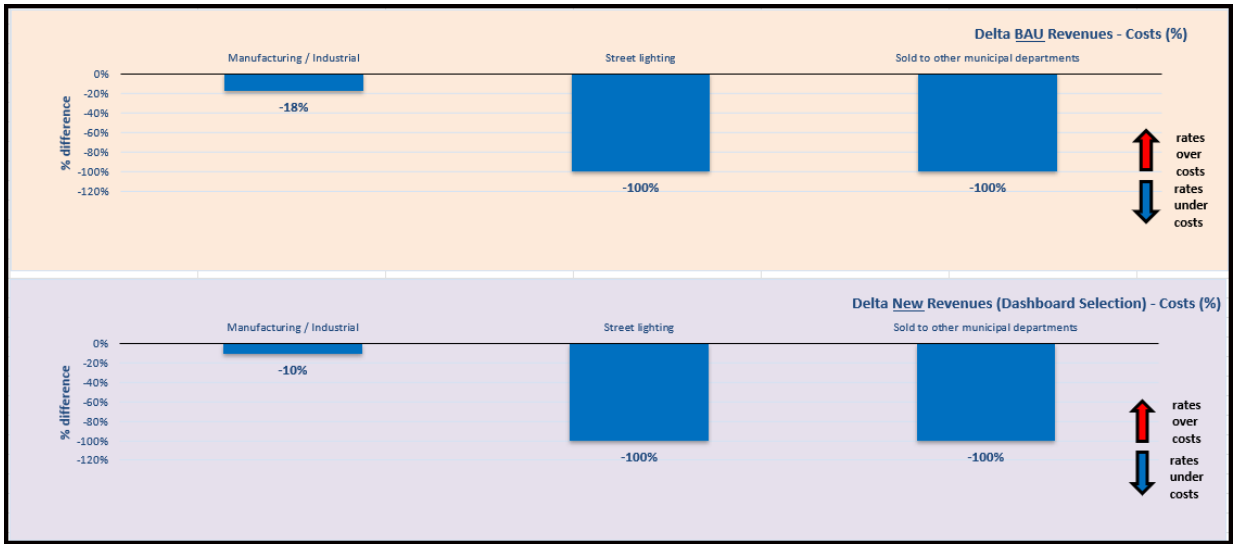
Figure 4: Costs Allocated

Rate Design

4.7.22. Table 4 below presents the COS study results, indicating that certain customer categories require upward adjustments, while others warrant downward adjustments. 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.

4.7.23. To achieve full cost reflectivity, the municipality would be required to implement differentiated tariff adjustments across customer categories. However, the municipality has adopted a less aggressive approach, opting instead for a uniform 13.9% tariff increase across all customer categories.

Table 4: Revenue Recovery by Customer Category



5. CONCLUSION ON THE COS

5.1.1. While the outcome of the COS study may indicate an average tariff adjustment of a certain percentage for a licensee to achieve full cost reflectivity, a

municipality may elect to implement such adjustments on a phased basis, including applying an increase below the COS-derived level.

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

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

5.1.4. 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.

5.1.6. The COS study results indicate a required increase of 25.9%, as illustrated in Figure 4 below. However, to mitigate the impact on customers, the licensee has proposed a lower increase of 8.76%.

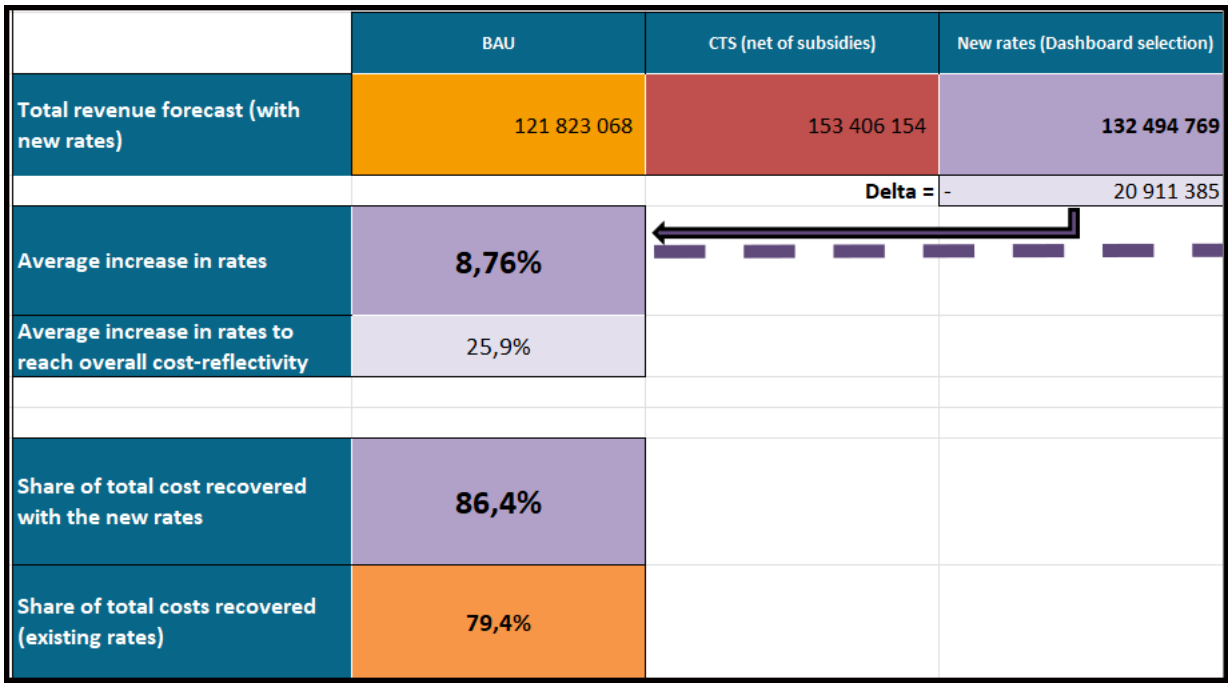


Figure 4: Rate Design

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9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

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

End.