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

AECI Property Services

THE DECISION

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1. At its meeting held on 11 May 2026, the Regulator Executive Committee (REC) considered AECI Property Services' tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year (FY) set out in section 8 of the RFD.

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

   2.1. 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;
   2.2. noted the COS report submitted by the licensee; and
   2.3. that the licensee must submit a report accounting for all the costs that have been noted in its COS study to enable the National Energy Regulator of South Africa to perform its independent verification/audit process by 30 September 2026.

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ABBREVIATIONS

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
AECI	AECI Property Services
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. AECI Property Services (AECI) is a private distributor located in KwaZulu-Natal. The private distributor purchases electricity from the eThekwini Metropolitan Municipality (eThekwini). AECI has its own set of tariffs and shares the same set of tariffs with eThekwini.

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

CUSTOMER STATISTICS			
Consumer classification	**Sales (MWh)**	**%MWh**	**Number of consumers**
Manufacturing/Industrial	99052	95,58%	93
Own Use	4581	4,42%	N/A
Totals	**103 633**	**100%**	**93**
Free Basic Electricity	**-**	**0,00%**	**0**

1.3. The licensee's manufacturing/industrial customers account for 95.58% of its sales, while the remaining 4.42% is for its own use and street lighting.

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

1.5. AECI implemented a 12.74% average price increase in FY2025/26 and is applying for an average price increase of 9.50% for the FY2026/27.

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

1.7. NERSA followed the notice and comment consultation process. On 31 March 2026, NERSA published AECI's tariff application on its NERSA 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 11 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 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 merely 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:

Municipal Surplus	**Private Distributor Surplus**
Permitted under 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	Approval via Board of Directors

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 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 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. Policy Position 23 of the EPP, 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 2025/26 municipal tariff approvals did not comply with the procedural requirements of section 4 of PAJA and was therefore unlawful.

2.7.3. However, recognising the potentially disruptive consequences of setting aside tariff determinations already implemented by municipalities, the Court declined to invalidate the tariffs. Instead, to assist in the timeous and lawful approval of

municipal tariffs, the Court issued a structural interdict regulating the municipal tariff approval process going forward.

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

2.8. Court-Directed Timelines

2.8.1. The timelines below are applicable with respect to the 2026/27 municipal tariff approvals:

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

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

a) Written notice of bulk electricity tariffs must be communicated by 31 January each year.
b) Municipal tariff applications must be submitted to NERSA by 20 March each year.
c) Municipal tariff approvals and the tariff reasons for decision document, must be approved and published by 5 May of each year.

2.9. Conclusion

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

2.9.2. The reasons contained in this document demonstrate how the Energy Regulator complied with the legislative, policy and judicial framework in determining the municipal electricity tariff for the 2026/27 municipal financial year.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In evaluating the financial and technical performance of AECI, the assessment relied on the Distribution Forms (D-forms) for FY2024/25 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 private electricity distributor, 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. Table 2: Performance indicators below shows that AECI's recorded energy losses improved from 1.08% in FY2023/24 to 1.06% in FY2024/25. The licensee recorded an improvement in the surplus from 8.90% in FY2023/24 to 11.08 in FY2024/25, mainly due to a significant increase in the revenue from the sale of electricity, with the sales driven mainly by the industrial/manufacturing customer category. The licensee further maintained a slight increase in operating expenditure, with repairs and maintenance, general expenses being the key cost driver.

Table 2: Performance indicators

Outputs	2023/24	2024/25
Percentage Surplus	8,90%	11,08%
Percentage Energy Losses	1.08%	1.06%

3.3. The private distributor's performance is satisfactory, as evidenced by a surplus and below the NERSA threshold energy losses.

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

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

4.2. AECI utilised the COS study model developed by Sustainable Energy Africa (SEA) to determine its revenue requirements for the FY2026/27 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 FY2024/25.

4.3.

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

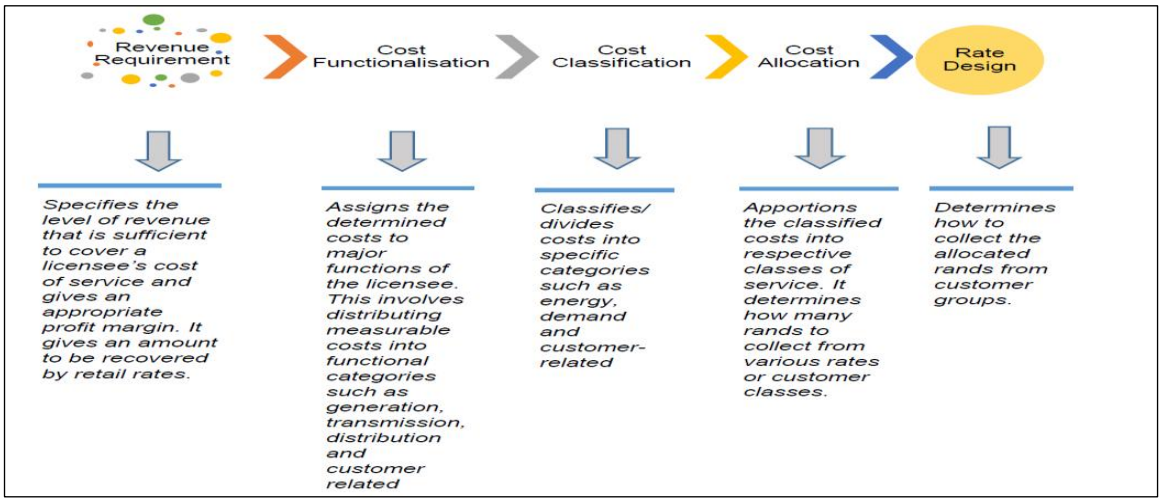


Figure 1: Five steps of COS study

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

4.5.1. be informed by COS outcomes;

4.5.2. progressively move tariffs towards cost reflectivity; and

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

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

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

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

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

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

4.7. This ensures that tariff adjustments are grounded in a cost-reflective manner.

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

Revenue Requirement

4.8.1. The revenue requirement step specifies the level of revenue that is sufficient to cover a licensee's cost of service and appropriate margin. It is an indication of the amount to be recovered from the approved tariffs.

4.8.2. The licensee applied a cost-plus methodology in the determination of its revenue requirement and did not utilise a Rate of Return (ROR) approach. Accordingly, no return based on a Regulatory Asset Base (RAB) was determined or applied.

4.8.3. AECI submitted a COS study detailing revenue requirements of R325.91 million for FY2026/27. As shown in Table 4 below, this revenue requirement is largely driven by Eskom bulk purchases, accounting for 76%, excluding the energy losses allowance of 10%. Operational expenditure accounts for 13% of the allowable costs.

Table 3: Revenue requirement

	Total cost (R)			
Revenue Requirement components	**Wires**	**Retail**	**Total**	**% of Total**
Allowable costs	39 139 758	304 895 234	325 914 892	100%
Energy purchases from Eskom - net of cost of losses	-	247 137 255	247 137 255	76%
Energy purchases from Eskom - cost of losses	11 436 991	19 591 919	31 028 910	10%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	12 647 175	5 472 925	18 120 100	6%
Other revenues	-	-	-	0%
Surplus	2 408 417	27 220 210	29 628 627	9%

4.8.3.1. The efficiency of costs for FY2024/25 has been assessed, as this constitutes the most recent set of actual data. This assessment serves as the baseline for projecting costs for FY2026/27, applying stated assumptions to determine the revenue requirement for that period.

4.8.4. Furthermore, NERSA has verified all expense items included in the revenue 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

4.8.5. AECI's COS study projects a bulk purchase expenditure of R 278.17 million, which accounts for 76% of total costs when including the 10% energy losses allowance. Bulk purchases were verified against Eskom invoices in FY2024/25.

4.8.6. The licensee projected its bulk purchases for FY2026/27 using FY2025/26 Eskom tariffs as a base and made the following assumptions: sales growth of 2% and a bulk purchase cost increase of 9.01% for FY2026/27, which is in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

Operational Expenditure

4.8.7. AECI's revised COS projects operational expenditure totals R18.12 million, representing 6% of overall costs. Table 5 below provides a breakdown of this expenditure.

Table 4: Operational expenditure

Function	Total Opex	Wires	Retail
Depreciation	R511 750	R511 750	-
Network and repairs	R6 662 500	R6 662 500	
Opex	R10 945 850	R5 472 925	R5 472 925
Total	**R18 120 100**	**R12 647 175**	**R5 472 925**

4.8.8. The operating expenditure comprises the following:

4.8.8.1. Depreciation of R511 750 which was calculated on a straight-line basis and the base has been calculated from FY2024/25 audited AFS.

4.8.8.2. Network and repairs of R6.66 million as evidenced by low energy losses.

4.8.8.3. All the other efficient expenses of R10.95 million have been grouped under 'OPEX'. This includes bad debts, which have been tested to ensure that they are below the NERSA 5% threshold.

4.8.9. The approach adopted by AECI 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

4.8.10. AECI's revenue requirement includes a surplus of R29.63 million, calculated using a margin of 9% applied to operating expenditure, exclusive of bulk purchases, for both the wires and retail components of the electricity business.

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

4.8.11.1. The applied margin of 9% was benchmarked against the 10–20% range prescribed in the approved NERSA COS Framework, as supported by the EPP Policy Position 1.

4.8.11.2. The margin was further assessed against the private electricity distributors risk profile to ensure alignment with the principle of cost reflectivity and financial sustainability.

4.8.12. Risk factors considered include the following:

4.8.12.1. Revenue collection risk, with current collection levels above 95%, reflecting minimum exposure to non-payment, indigent and bad debts.

4.8.12.2. Operational risk, including low energy losses of approximately 10%, signifying a well-maintained network infrastructure.

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

4.8.13. Based on the above, the applied surplus margin of 9% is considered conservative, justified and commensurate with the licensee's risk profile, while remaining within the acceptable parameters of the NERSA COS Framework. This approach supports the financial viability of the electricity distribution function without imposing undue burden on consumers.

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

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

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

Cost Functionalisation

4.8.17. The licensee has categorised its revenue requirement of R325.91 million into two primary functional components, namely the **wires business** (**8%**) and the **retail business** (**92%**), in accordance with the NERSA COS Framework, as illustrated in Figure 2 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

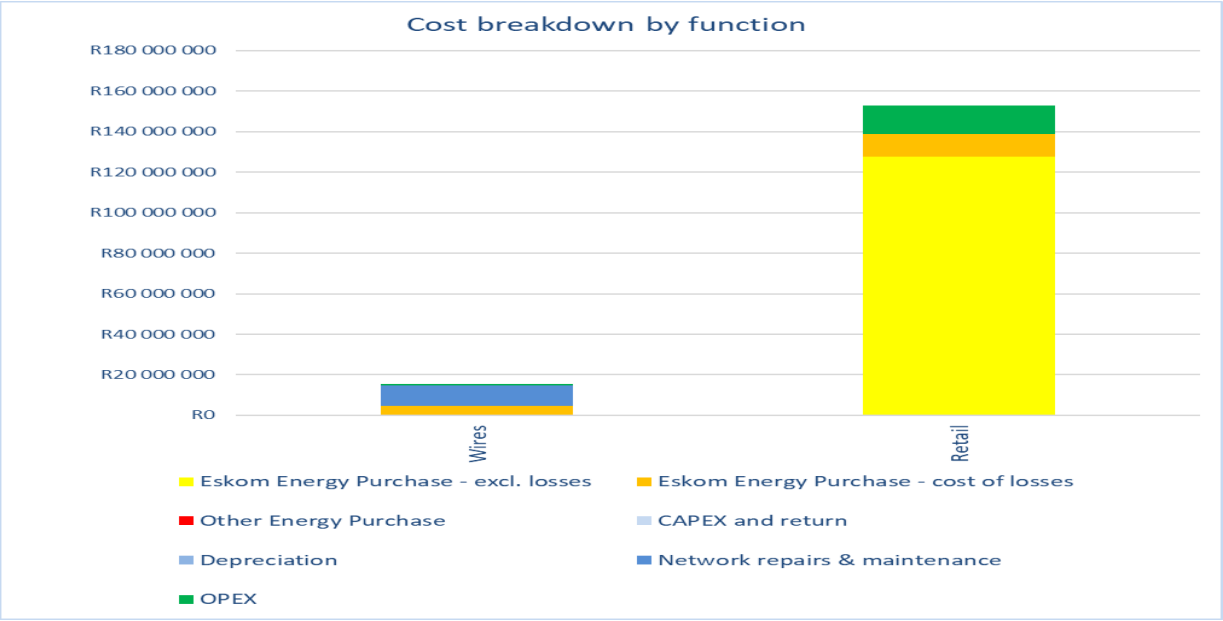


Figure 2: Cost breakdown by functions

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

Cost Classification

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

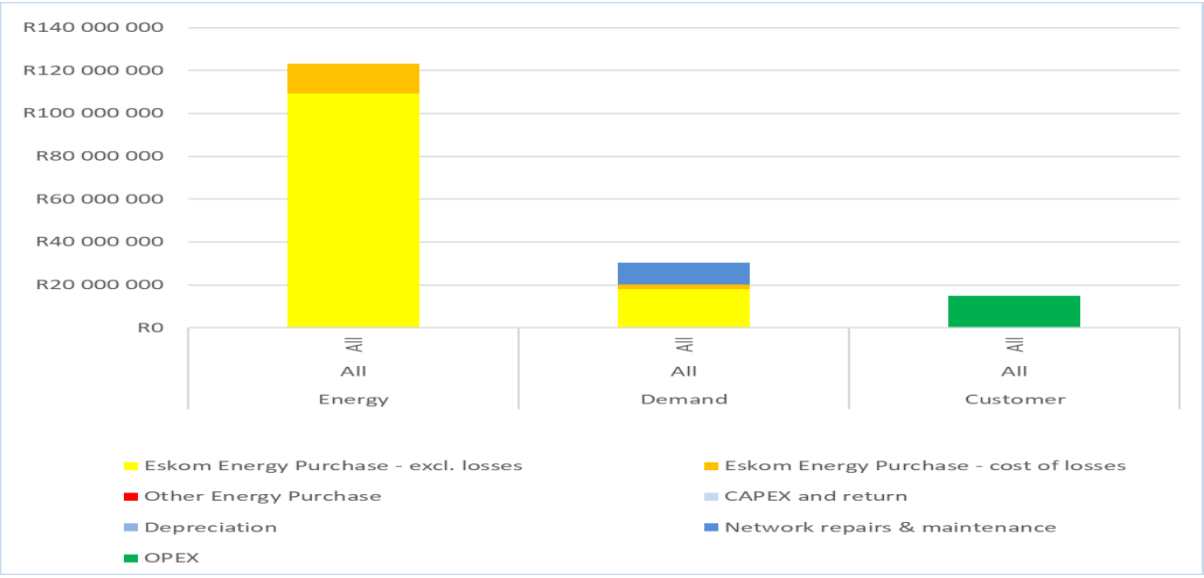


Figure 3: Cost breakdown by cost structure (classification)

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

Cost Allocation

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

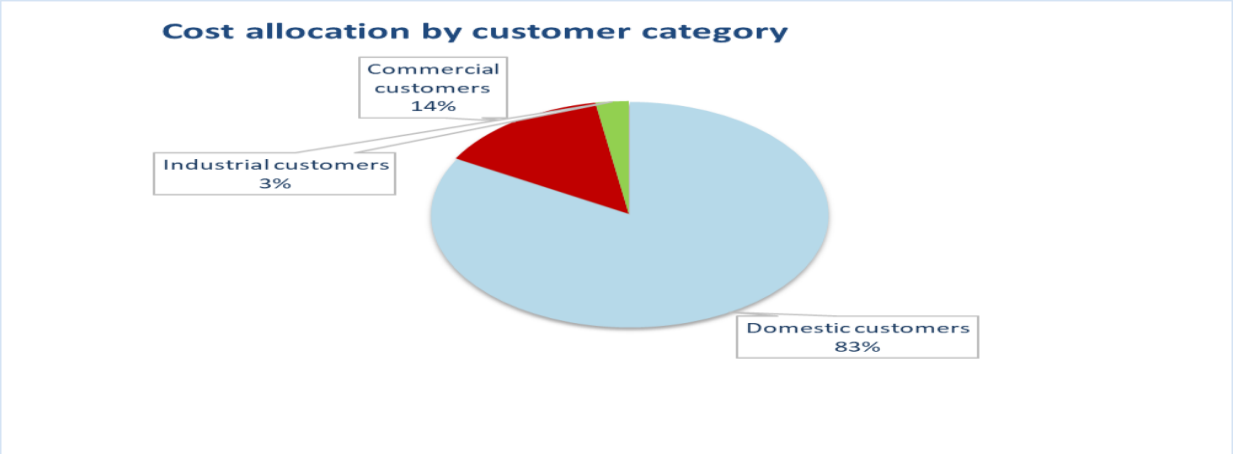


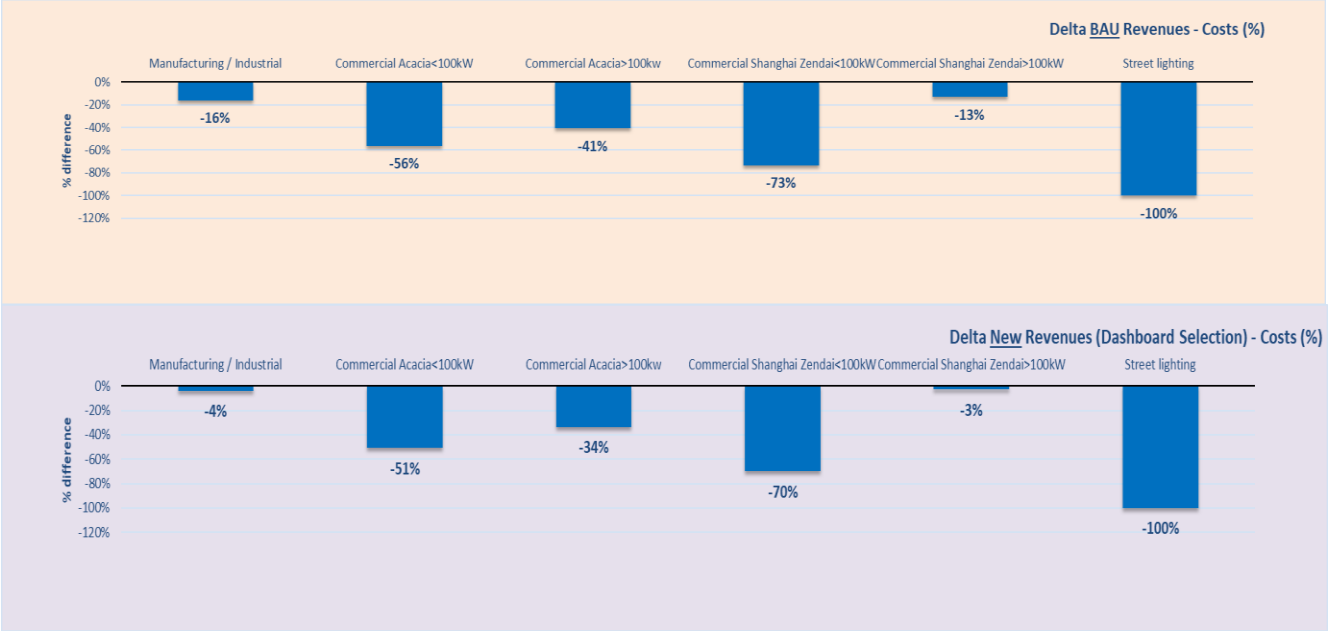
Figure 4: Costs allocated

Rate Design

4.8.22. Table 6 below reflects the outcome of the COS study, indicating that certain customer categories require upward adjustments, while others warrant a decrease. A comparison between the cost of supply and the revenue generated per tariff category highlights the extent of over- or under-recovery within each category, as illustrated in Table 6 below.

4.8.23. To achieve full cost reflectivity, the licensee would be required to implement standard average tariff adjustments of 9.50% across customer categories. However, the licensee has adopted a less aggressive approach, opting instead for a uniform tariff increase of 9.50% across all customer categories.

Table 5: Revenue recovery by customer category



5. CONCLUSION ON THE COS STUDY

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

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

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

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

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

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