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

The Mpumalanga Economic Growth Agency (MEGA)

THE DECISION

1. At its meeting held on 11 May 2026, the Regulator Executive Committee (REC) considered the MEGA Local Municipality tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year set out in Section 8(Page 24) below.

2. Based on the available information and the analysis performed thus far, the Regulator Executive Committee decided to:

   2.1. approve the tariffs that are based on the Cost of Supply (COS) Study as recommended in the tariff analysis section for implementation by the municipality with effect from 1 July 2026;

   2.2. note the COS study submitted by the municipality;

   2.3. that the municipality 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 31 January 2027; and

   2.4. that the municipality must submit a quarterly smart efficiency plan with

improvement measures identified in reducing high energy losses and submit by 30 September 2026

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ABBREVIATIONS

COS	Cost of Supply
D-form	Distribution form
ERTSA	Eskom's Retail Tariff Structural Adjustments
FBE	Free Basic Electricity
IBT	Inclining Block Tariff
IPP	Independent Power Producer
MEGA	Mpumalanga Economic Growth Agency
MFMA	Municipal Finance Management Act
NERA	National Electricity Regulation Act
NERSA	National Energy Regulator of South Africa
OPEX	Operating Expenditure

1. INTRODUCTION

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

1.2. The Mpumalanga Economic Growth Agency (MEGA) is a licensed electricity distributor supplying electricity to the Ekandustria Industrial Town near Bronkhorstspruit. Electricity is purchased in bulk from the City Of Tshwane (CoT) and distributed and sold to a predominantly industrial consumer base. In effect, MEGA performs municipality electricity distribution function within the Ekandustria Industrial Park, which necessitates the submission of its own electricity tariff application to the Regulator.

1.3. MEGA implemented an 18.40% average price increase in 2025/26 FY and in the current cycle, it is applying for an average price increase of 16%.

1.4. The details regarding consumer statistics are highlighted in Table 1 below. MEGA is implementing Inclining Block Tariffs (IBTs) fully and is offering 50kWh of Free Basic Electricity per month to all registered indigent consumers.

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

Customer categories	***MWh***	***% MWh***	***Customer numbers***
Manufacturing/ Industrial	46	100.00%	488
TOTAL	**46**	**100%**	**488**

1.5. NERSA received MEGA's tariff application together with its revised Cost of Supply (COS) on 31 March 2026.

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

1.7. 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 ("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 2026/2027 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, 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 distinction between municipal surplus and private distributor profit can be summarised as follows:

Table 2: Municipalities and Private Distributor surplus distinction

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	

2.2. Statutory Mandate of the Energy Regulator

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:

- Section 4(a)(i) of the ERA provides that the Energy Regulator must consider applications for licensees and may issue licenses subject to conditions.
- Section 4(a)(ii) of the ERA provides that the Energy Regulator must regulate prices and tariffs.
- Section 14(1)(d) of the ERA authorises the Energy Regulator to impose license 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 licenses 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:

- must enable an efficient licensee to recover the full cost of the licensed activity;
- must allow for a reasonable return commensurate with the risk of the licensed activity;
- may provide incentives for continued improvement of technical and economic efficiency;
- must avoid undue discrimination between customer categories;
- may permit cross-subsidies of tariffs to certain classes of customers; and
- 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 Cost of Supply methodologies have historically not been consistently applied across the electricity distribution industry.

2.6.3. 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 the Energy Regulator.

2.7. Judicial Oversight of the Tariff Approval Process

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

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

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

2.7.4. NERSA subsequently launched a variation application which sought to vary the timelines which were set by the Court on 4 December 2025, considering the practical difficulties which arose as it relates to the 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

- written notice of bulk tariffs by 6 March 2026;
- municipal tariff applications to be submitted by 31 March 2026;
- public participation processes to be concluded by 21 April 2026
- the publication of NERSA decisions by 11 May 2026.

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

- written notice of bulk electricity tariffs be communicated by 31 January each year;
- municipal tariff applications be submitted to NERSA by 20 March each year;
- municipal tariff approvals and the tariff reasons for decision document, 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 Reasons for Decision document demonstrate how the Energy Regulator complied with the legislative, policy and judicial framework in determining the municipal electricity tariff for the 2026/2027FY municipal financial year.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In evaluating the financial and technical performance of MEGA, the assessment relied on the Distribution forms (D-forms) for the 2024/25FY 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 MEGA, 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. Table 3 below indicates that MEGA electricity business recorded a declined in the percentage deficit from 0.92% in the 2023/24FY to 1.47% in the 2024/25FY.

3.3. MEGA's collection rate is 73%, which is below NERSA's acceptable level of 95%. This low collection rate may be contributing to the poor financial performance of the electricity business, as it limits the ability to recover revenue required to sustainably operate and maintain the electricity service.

3.4. The energy losses declined from 34.31% in the 2023/24 financial year to 19.41% in the 2024/25 financial year, as highlighted in table 3 below. The distributor indicated that the reduction in energy losses is attributable to the implementation of corrective measures, including the replacement of faulty meters and the correction of billing errors. The distributor will be required to continue implementing energy loss reduction initiatives to further improve operational efficiency and reduce energy losses.

Table 3: Performance indicators

Performance indicators	***2024/25 D-forms Information***	***2023/24 D-forms Information***
Percentage surplus: (%)	-1.47	-0.92[1]
Energy Losses: (%)	19.41	34.31

[1] Total Electricity Purchases divided by Total Expenditure

3.5. Based on the above information, the licensee's electricity department reflects unsatisfactory financial and operational performance, as evidenced by the reported deficit. This deficit suggests weaknesses in financial management and cost recovery and indicates that the electricity service function is neither stable nor financially sustainable. The municipality is, however, encouraged to maintain its current efforts in keeping energy losses at low levels.

3.6. Table 4 below provides a revenue impact analysis under three energy loss scenarios: actual (19.41%), when reduced to 12% and at 6%.

Table 4 : Energy Losses Analysis (Data obtained from D-forms FY2024/25)

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	143,27		
Sales kWh	46 880 990,00	51 192 667,68	54 683 076,84
Purchases kWh	58 173 486,00	58 173 486,00	58 173 486,00
Losses kWh	11 292 496,00	6 980 818,32	3 490 409,16
Losses percentage	**19,41%**	**12,00%**	**6,00%**
Additional Energy (kWh)		4 311 677,68	7 802 086,84
Additional Revenue (Rands)		6 177 340,61	11 178 049,82
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 133 260 042,38	R 139 437 382,99	R 144 438 092,20
Total Expenses (Rands)	R 135 215 776,47	R 135 215 776,47	R 135 215 776,47
Net Profit (Loss)	R -1 955 734,09	R 4 221 606,52	R 9 222 315,73
Percentage Surplus/Deficit	**-1,47%**	**3,03%**	**6,38%**

3.7. Under the current scenario, with actual electricity losses of 19.41%, the licensee records an operating deficit of approximately R1.9 million, which translates to a deficit level of 1.47%, based on approved D-form inputs. The revenue deficit of R1.9 million (-1.47%), indicates that current tariffs are not cost-reflective under prevailing inefficiencies. This negative surplus margin indicates that elevated energy losses continue to place pressure on the financial sustainability of the electricity business.

3.8. Based on the scenario analysis, should electricity losses be reduced to 12%, and assuming constant electricity purchases, operating costs, and tariff structures, the estimated revenue that could be recovered through loss reduction is estimated to increase by approximately R4.2 million, reflecting improved revenue retention relative to the current position and a move from a deficit to a surplus of 3.03%. Further reductions in energy losses are expected to strengthen the surplus position, subject to the sustainability and effectiveness of the implemented loss-reduction measures.

3.9. If loses were to further be reduced to 6% and assuming constant electricity purchases, operating costs, and tariff structures, the estimated revenue that could be recovered through loss reduction is estimated to increase by approximately

R9.2 million, reflecting improved revenue retention relative to the current position and a surplus of 6.38%

3.10. The above demonstrates that a reduction in energy losses would improve the municipality's surplus position, subject to the sustainability and effectiveness of the loss-reduction measures implemented. The municipality is therefore encouraged to further strengthen its energy loss mitigation mechanisms in order to enhance its overall financial performance.

4. DETERMINATION OF MEGA TARIFFS BASED ON THE COST OF SUPPLY STUDY

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

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

4.3.

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

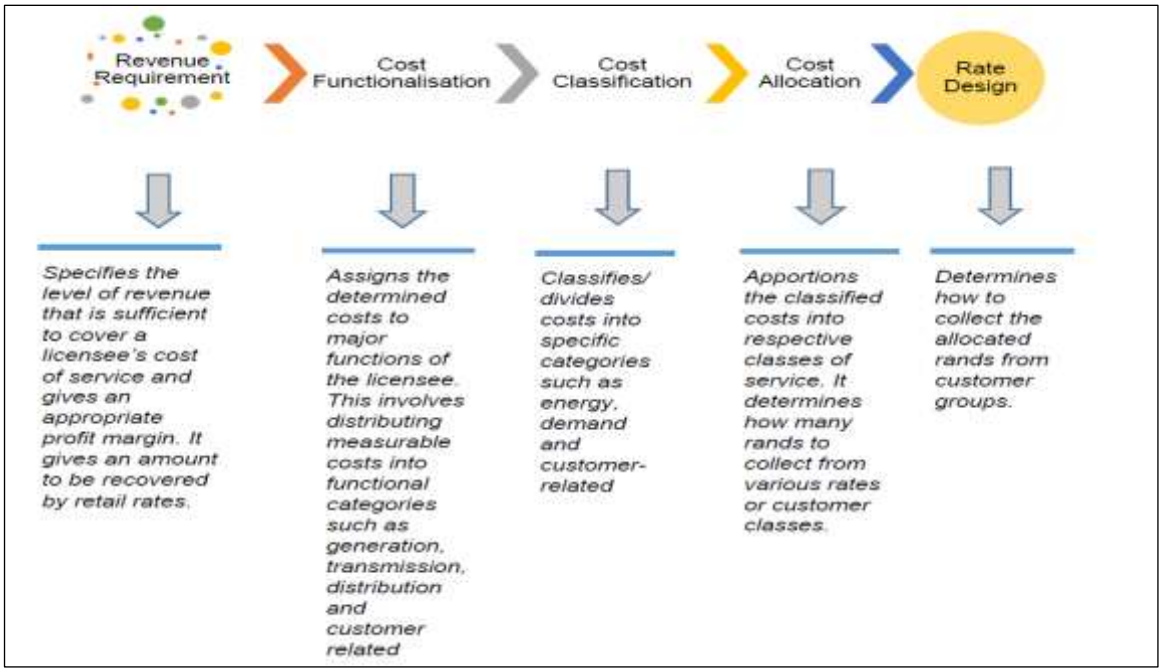


Figure 1: Fives steps of COS

4.5. The following steps are undertaken to analyse the cost of supply study:

4.5.1. Revenue Requirement

4.5.1.1. The municipality applied a cost-plus methodology and not a rate of return (ROR) approach. Under the cost-plus methodology, the allowable revenue is derived as follows:

- Efficient and prudent operating expenditure (OPEX)
- Plus, depreciation (as a proxy for asset consumption and future replacement)
- Plus, a reasonable surplus margin.

4.5.1.2. To be fully cost reflective, the licensee's revenue requirement is R251 million for the 2026/27 financial year. This amount is primarily driven by Eskom purchases, which account for 47%, while operational expenditure (including the surplus) makes up the remaining 53%, as highlighted in Table 5 below.

Table 5*:* Revenue Requirement components

	Total cost (R)			
Revenue Requirement components	Wires	Retail	Total	% of Total
Allowable costs	50 866 130	200 876 387	251 742 517	100%
Energy purchases from Eskom - net of cost of losses	-	104 893 487	104 893 487	42%
Energy purchases from Eskom - cost of losses	- 2 781 117	15 603 716	12 822 599	5%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	49 023 053	62 117 695	111 140 748	44%
Other revenues	-	-	-	0%
Surplus	4 624 194	18 261 490	22 885 683	9%
TOTAL COSTS	50 866 130	200 876 387	251 742 517	

4.5.1.3. The efficiency of costs for the 2024/25 financial year has been assessed, as this constitutes the most recent set of actual data. This assessment serves as the baseline for projecting costs for the 2026/27 financial year, applying stated assumptions to determine the revenue requirement for that period.

4.5.1.4. All expenses included in the revenue requirement were assessed to ensure they relate solely to the licensee's electricity function.

Bulk purchases

4.5.1.5. MEGA applied for a bulk purchase expenditure of R117 million which accounts for 47% of total costs. Bulk purchases were verified against Eskom invoices in the 2024/25FY.

4.5.1.6. To derive the 2026/27FY bulk purchase estimate, the licensee projected the year-to-date costs for 2025/26FY and increased this cost by 9.01% in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

4.5.1.7. The methodology applied by MEGA in forecasting bulk purchase costs is deemed reasonable. Accordingly, the bulk purchase expenditure has been recommended for approval as submitted.

Operational Expenditure

4.5.1.8. NERSA applied for operational expenditure (including depreciation) of R111 million, which accounts for 44% of total costs. Table 6 below provides a breakdown of this expenditure, including depreciation.

Table 6: Operational expenditure[2]

OPEX Cost Drivers	2025/26FY Costs as per submitted COS	2026/27FY budgeted costs as perlicensee
General & Other	R 62 076 622	R 65 658 453
Materials and supplies	R 43 000	R 45 150
Contracted Services	R 10 500 000	R 11 025 000
Salaries, wages and allowances	R 23 900 000	R 25 573 000
Payments to consultants (operational work)	R 13 400 000	R 14 070 000
Eskom debts' interests	R -	R -
Other creditors interests	R -	R -
Current year depreciation	R 14 233 622	R 14 945 303
NMD exceedance penalties	R -	R -
Shared OPEX	R 43 316 471	R 45 482 295
Bad debts written-off	12892470,96	13537094,51
FBE paid to Eskom	0	0
Charges from other Municipal Departments	0	0
General Expenses	30424000	31945200
Total	**R 105 393 093**	**R 111 140 748**

4.5.1.9. Only the portion of shared costs directly attributable to the electricity service was allocated to the revenue requirement. This ensures that electricity consumption is charged solely for costs associated with the provision of electricity services.

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

4.5.1.10. The approach adopted by MEGA 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.

4.5.1.11. The municipality reported an asset value of R80 934 551 as reflected in its submitted audited D-Forms for the 2024/25FY.

4.5.1.12. Depreciation amounted to R14 233 622 in the 2024/25FY calculated using the straight-line method over the useful lives of the respective assets. This amount was extracted from the submitted 2024/25FY D-Form and verified against the audited 2024/25 Annual Financial Statements. The projected depreciation for 2026/27FY is R14 945 303.

4.5.1.13. The depreciation values were verified against the D forms, trial balance and the audited financial statements

Surplus

4.5.1.14. MEGA's revenue requirement includes a surplus of R22 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.

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

- The applied surplus 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.
- The margin was further assessed against MEGA's risk profile to ensure alignment with the principle of cost reflectivity and financial sustainability.

4.5.1.16. Risk factors considered include the following:

- Revenue collection risk, with current collection levels above 73%, reflects minimum exposure to non-payment.
- Operational risk, including energy losses of approximately 19.41%, signifying a network infrastructure that is not well maintained; and
- Financial sustainability requirements, including the need to maintain adequate cash flows for ongoing operations and infrastructure investment.

4.5.1.17. Based on the above, the applied surplus margin of 9% is considered conservative, justified, and commensurate with the licensee's risk profile, notwithstanding that it falls below the established target range of 10–20% the COS framework. This approach supports the financial viability of the electricity distribution function without imposing undue burden on consumers.

4.5.1.18. 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.

4.5.1.19. In applying the act, NERSA is required to ensure that MEGA recovers efficient costs and a reasonable return, while preventing excessive compensation. The return proposed by MEGA 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.

4.5.1.20. The decision to approve the revenue requirement as submitted will be applied in the subsequent stages, namely Cost Functionalisation, Cost Classification, Cost Allocation, and Rate Setting. These stages have been verified and confirmed to align with the approved revenue requirement. Further detail on these stages is provided below.

4.5.2. **Cost Functionalisation**

4.5.2.1. The licensee has categorised its revenue requirement of R251 million 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 Table 7 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated revenue requirement.

Table 7: Costs breakdown by Functions

		Total Functionalised Costs (R)		
Functions	Included in Surplus baseline	Wires	Retail	Total
Eskom Energy Purchase - excl. losses	FALSE	-	104 893 487	104 893 487
Eskom Energy Purchase - cost of losses	FALSE	- 2 781 117	15 603 716	12 822 599
Other Energy Purchase	FALSE	-	-	-
CAPEX and return	FALSE	-	-	-
Depreciation	TRUE	16 439 833	-	16 439 833
Network repairs & maintenance	TRUE	12 177 165	-	12 177 165
OPEX	TRUE	25 030 248	80 379 184	105 409 433
		50 866 130	200 876 387	251 742 517
		20%	80%	TRUE

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

4.5.3. Cost Classification

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

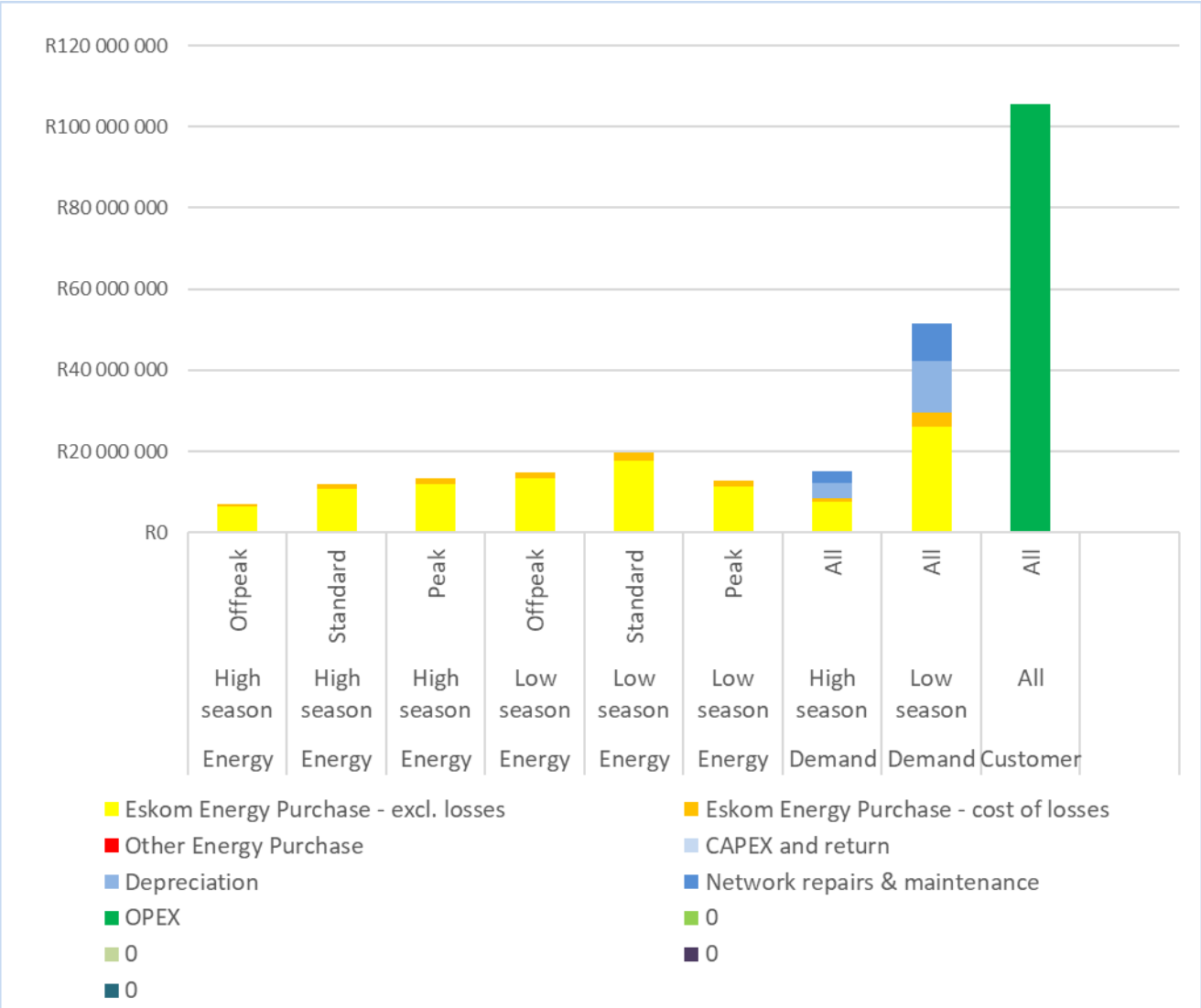


Figure 2*: Costs breakdown by cost structure (Classification)*

4.5.3.2. The cost breakdown by component indicates that the energy-related costs constitute the largest portion of the total revenue requirement, significantly outweighing both demand- and customer-related costs.

4.5.3.3. The energy cost component is dominated by bulk energy purchases from Eskom (excluding losses), with an additional contribution from the cost of losses. This confirms that the municipality's cost structure is highly energy-intensive and largely variable in nature, making it sensitive to changes in bulk tariffs and consumption levels.

4.5.3.4. The demand-related costs are comparatively smaller and mainly consist of network repairs and maintenance, depreciation, and limited capital-related costs (CAPEX and return).

4.5.3.5. The overall cost structure reflects a strong reliance on volumetric (energy-based) cost recovery, with relatively low contributions from demand and customer charges. This imbalance suggests that the current tariff structure may not fully align with cost causation principles.

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

4.5.4. Cost Allocation

4.5.4.1. In this step, the licensee’s revenue requirement is allocated across customer categories, in accordance with the NERSA COS framework as shown in Table 8 below. Upon verification, the allocation is found to be consistent with the stated revenue requirement and aligned with the principles of cost allocation.

Table 8: Costs Allocated

Business area:	Total	Total	Total	Total
Cost class:	Energy	Demand	Customer	All
Season:	All	All	All	All
TOU:	All	All	All	All
Customer Categories				
Manufacturing / Industrial-MV Connection	21 407 114	17 881 796	28 304 385	67 593 294
Manufacturing / Industrial - LV Connection > 25KVA	39 566 252	33 071 265	52 314 311	124 951 828
Manufacturing / Industria - ILV Connection < 25KVA	18 749 679	15 656 979	24 790 737	59 197 395
Electricity department	-	-	-	-
	79 723 045	66 610 039	105 409 433	251 742 517

4.5.4.2. The manufacturing/Industrial LV connection >25KVA carries the largest proportion of costs, followed by the manufacturing/Industrial MV connection. manufacturing/Industrial LV connection <25KVA results in the lowest proportion of costs.

4.5.4.3. Differences in the results between the customer categories are mainly driven by differences in voltage of connection point, load factors, coincidence factors and average specific consumption

4.5.5. Rate Design

4.5.5.1. Figure 3 below reflects the outcome of the COS study, indicating that the manufacturing/Industrial tariffs are under- recovering.

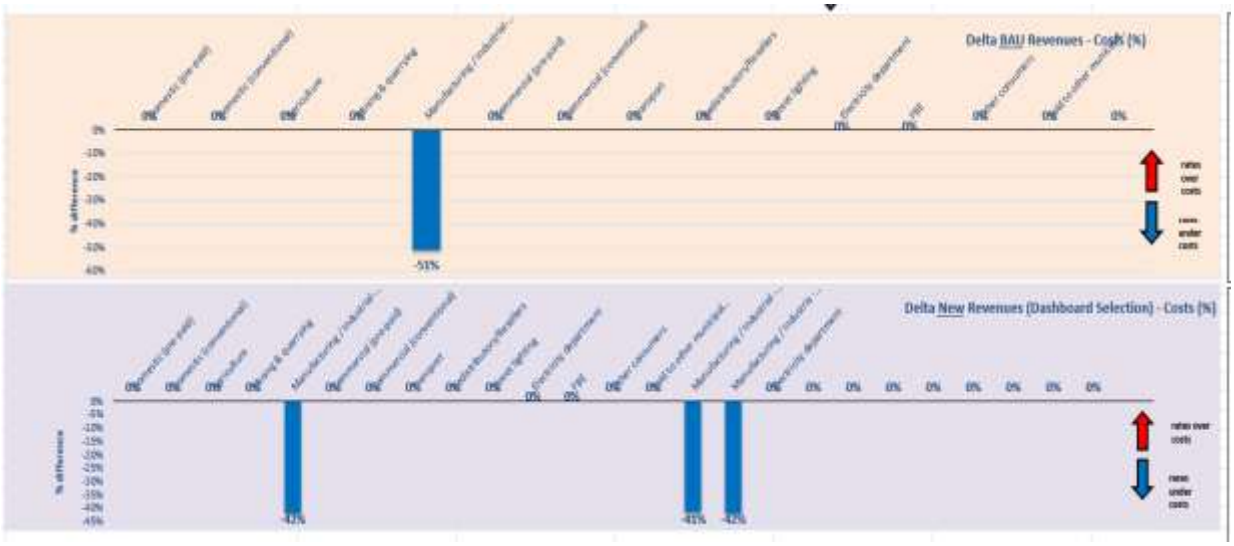


Figure 3: Revenue Recovery by customer category

5. CONCLUSION ON THE COS

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

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

5.3. In addition, the licensee may 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 MEGA's revenue base and support its financial sustainability, in line with applicable legislative requirements.

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

5.6. The COS study results indicate a required increase of 102.60% for the private distributor to reach cost reflectivity, as illustrated in Figure 4 below. The municipality opted for a conservative approach, considering the local community's socio-economic context and has applied for an average increase of 16%

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Table 9 Tariff analysis

DETAILS OF TARIFFS APPLIED FOR					
1. Commercial <=25kVA	**2025/26 Approved**	**2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***
Winter Energy Rate (c/kWh)	431.50	500.60	16%	500.60	16%
Summer Energy Rate (c/kWh)	431.50	500.60	16%	500.60	16%

DETAILS OF TARIFFS APPLIED FOR					
2.Industrial >25kVA and Low Tension	**2025/26 Approved**	**2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***
Fixed Charge (R/month)	4 699.30	5 451.20	16%	5 451.20	16%
Winter Energy Rate (c/kWh)	216.80	251.50	16%	251.50	16%
Summer Energy Rate (c/kWh)	154.60	179.40	16%	179.40	16%
Maximum Demand Charge (R/kVA)	520.40	603.70	16%	603.70	16%

DETAILS OF TARIFFS APPLIED FOR					
3.Industrial >25kVA and Medium Tension	**2025/26 Approved**	**2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***
Fixed Charge (R/month)	4 829.30	5 602.00	16%	5 602.00	16%
Winter Energy Rate (c/kWh)	212.20	246.20	16%	246.20	16%
Summer Energy Rate (c/kWh)	153.50	178.10	16%	178.10	16%
Maximum Demand Charge (R/kVA)	507.00	588.20	16%	588.20	16%

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

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

End.