NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

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Decision and Reasons for Decision (RfD)

In the matter regarding the

Municipal Tariff Application for the 2026/27 Financial Year

By

Great Kei Local Municipality

THE DECISION

At its meeting held on 8 May 2026, the Regulator Executive Committee (REC) considered the Great Kei Local Municipality's tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2026/27 financial year, as set out in in section 8 of this document.

Based on the available information and the analysis performed, the REC decided:

1. to approve the tariffs 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. to note the COS study submitted by the municipality;
3. that the municipality must submit a report accounting for all the costs identified in its COS study, to enable the National Energy Regulator of South Africa (NERSA) to perform its independent verification or audit process by 31 January 2027; and
4. that the municipality must submit quarterly progress reports on the efficiency improvement measures taken to reduce high energy losses and deficits to enable NERSA to monitor the implementation 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
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 annually, in accordance with its mandate to regulate prices and tariffs. Municipal tariffs must be approved by the Energy Regulator to be implemented on 1 July of each financial year.

1.2. The Great Kei Local Municipality (Great Kei) is located in the Eastern Cape. The majority population of the municipality resides in the rural areas. The municipality accounts for 5 419 MWh of total electricity sales. The details regarding customer statistics are highlighted in Table 1 below. Great Kei offers 50 kWh of Free Basic Electricity (FBE) per month to all registered Indigent consumers.

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

CONSUMER STATISTICS (OBTAINED FROM 2024-2025 DISTRIBUTION FORMS)			
Consumer Classification	**Sales (KWh)**	**%KWh**	**Number of Consumers**
Domestic (Prepaid)	3 136 136	57,88%	2 176
Domestic (Conventional)	91 442	1,69%	16
Manufacturing/Industrial	54 251	1,00%	1
Commercial (Prepaid)	350 568	6,47%	43
Commercail (Conventional)	1 781 451	32,88%	30
StreetLighting	788	0,01%	
Municipal Consumption	4 060	0,07%	8
TOTAL SALES	**5 418 695**	**100%**	**2 274**
Free Basic Electricity (FBE)	**492 354**	**15,25%**	**286**

1.3. NERSA received Great Kei's tariff application and its revised cost of supply (COS) study on 30 March 2026 with align to Eskom's revised tariff structure for the 2025/26 financial year, which introduced new cost components and reallocation of existing charges across energy, network and service-related elements. This revision was also due to the introduction of new winter tariffs.

1.4. Greak Kei is applying for an average price increase of 9.01% for the 2026/27 financial year (FY).

1.5. In accordance with NERSA requirements, all tariff applications must include confirmation that the proposed tariffs have been approved by the municipal council and have undergone customer consultation. The municipality indicated that it undertook its own consultation process and submitted an advert, and that one comment was received during the consultation process, which mainly concerned affordability issues.

1.6. NERSA published Great Kei's application on its website, social media platforms (Facebook, X and LinkedIn) and in national and local newspapers, along with an invitation to stakeholders to submit written comments by 21 April 2026.

1.7. The Energy Regulator's decision was made on 8 May 2026, considering the written comments received from the affected stakeholders and the analysis performed by NERSA.

2. LEGAL AND REGULATORY FRAMEWORK

Background

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

2.2. The approval of municipal electricity tariffs follows the Eskom Multi-Year Price Determination and Eskom Retail Tariff and Structural Adjustment decision and is undertaken annually to align with the municipal budgeting process contemplated in the Municipal Finance Management Act, 2003 (Act No. 56 of 2003).

2.3. 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.

2.4. 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.

NERSA's Statutory Mandate

2.5. NERSA is established as a juristic person in terms of section 3 of NERA. In terms of section 4 of NERA, the Energy Regulator, as the decision-making body, must regulate the electricity industry and execute the functions set out in the ERA. The electricity regulatory mandate of the Energy Regulator is therefore primarily governed by the ERA. Section 3 of the ERA 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.

2.6. 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.

2.7. 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.

Tariff Determination Principles under the ERA

2.8. When determining or approving electricity tariffs, the Energy Regulator must apply the principles contained in section 15(1) of the ERA.

2.9. 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.

2.10. These statutory requirements form the core legal principles guiding the determination of electricity tariffs within the South African electricity supply industry.

Administrative Law Requirements

2.11. The approval of municipal electricity tariffs constitutes administrative action as defined in section 1 of PAJA. Accordingly, the Energy Regulator must ensure that its tariff determinations are lawful, reasonable and procedurally fair as required by sections 3 and 6 of PAJA. Procedural fairness requires that affected parties and the public be afforded a reasonable opportunity to make representations before a final decision is taken.

2.12. Therefore, public participation processes conducted by the Energy Regulator form an essential component of the municipal tariff approval process and are intended to ensure transparency, accountability and fairness in regulatory decision-making.

Policy Framework: Electricity Pricing Policy (2008)

2.13. 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.

2.14. 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.

2.15. 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.

Cost of Supply Studies

2.16. The EPP recognises that cost-reflective tariff structures require a sound understanding of the underlying cost drivers associated with electricity distribution.

2.17. Paragraph 8.1 of the EPP notes that COS methodologies have historically not been consistently applied across the electricity distribution industry.

2.18. Policy Position 23 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.

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

Judicial Oversight of the Tariff Approval Process

2.20. 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.

2.21. 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.

2.22. 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.

2.23. NERSA subsequently launched a variation application seeking to vary the timelines set by the Court on 4 December 2025, in light of practical difficulties that arose regarding 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.

Court-Directed Timelines

2.24. The timelines below are applicable in respect of the 2026/27 municipal tariff approvals
   a) Written notice of bulk tariffs must be communicated by 6 March 2026.
   b) Municipal tariff applications must be submitted by 31 March 2026.
   c) Public participation processes must be concluded by 21 April 2026.
   d) NERSA decisions must be published by 11 May 2026.

2.25. 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 tariffs and the tariff reasons for decision documents must be approved and published by 5 May of each year.

Conclusion

2.26. The determination of municipal electricity tariffs by the Energy Regulator must 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).

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

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In assessing the financial and technical performance, NERSA relied on the 2024/25 Distribution forms' (D-forms) information provided in analysing the licensee's tariff application. The D-forms' information was validated by NERSA against the relevant

source documents submitted by the municipality (i.e. the trial balance/annual financial statement). Hence, the information provided in the D-forms is considered reasonable for the analysis of the tariffs.

3.2. Great Kei operated at a deficit of 39.10% in the 2024/25 financial year, a deterioration from a 4.20% surplus in the 2023/24 financial year. The high deficit level is primarily attributed to a 93% decrease in grant revenue allocation in the 2024/25 financial year. Based on the sales (revenue from electricity) and cost of sales (bulk purchases) figures, the municipality is operating at a gross profit of -3.96% (deficit). This subjects the municipality to budget constraints to address other operational costs, as it is already operating at a financial loss. Total revenue reduced by 18%, while total expenditure increased by 16%.

3.3. The energy losses reduced from 33.31% in the 2023/24 financial year to 21.04% in the current financial year. This improvement reflects enhanced technical and commercial efficiency, contributing directly to revenue protection and improved cost recovery.

Table 2: Performance indicators

PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS		
INDICATORS	**2024-25FY (Actuals)**	**2023-24 FY (Approved)**
Percentage Surplus (Deficit)	-39,10%	4,20%
Percentage Energy Losses	21,04%	33,31%

3.4. Current losses of 21.04% are far above acceptable norms and materially erode financial sustainability. If losses were capped at 12%, the municipal deficit would have decreased from 39.10% to 27.92%, resulting in an additional revenue of R1.319 million. Furthermore, reducing energy losses to 6% would improve the deficit to 21.44%, translating into an additional revenue of R2.195 million as shown in Table 3 below.

Table 3: Energy loss analysis

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	212,65		
Sales kWh	5 418 695,00	6 039 366,08	6 451 141,04
Purchases kWh	6 862 916,00	6 862 916,00	6 862 916,00
Losses kWh	1 444 221,00	823 549,92	411 774,96
Losses percentage	**21,04%**	**12,00%**	**6,00%**
Additional Energy (kWh)		620 671,08	1 032 446,04
Additional Revenue (Rands)		1 319 857,05	2 195 496,50
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 15 099 458,00	R 16 419 315,05	R 17 294 954,50
Total Expenses (Rands)	R 21 003 204,00	R 21 003 204,00	R 21 003 204,00
Net Profit (Loss)	R -5 903 746,00	R -4 583 888,95	R -3 708 249,50
Percentage Surplus/Deficit	**-39,10%**	**-27,92%**	**-21,44%**

3.5. Based on the above information, while the utility is on a positive recovery trajectory, maintaining financial sustainability will depend on disciplined cost management, continued efficiency gains and careful regulatory oversight.

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

4.1. The process that the Energy Regulator followed in considering and approving Great Kei's tariff application was supported by a COS study.

4.2. Great Kei utilised the COS study model developed by Sustainable Energy Africa (SEA) and various other stakeholders 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 diligently follows the NERSA COS Framework and utilises the latest available audited data, which is based on the 2024/25 financial year

4.3.

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

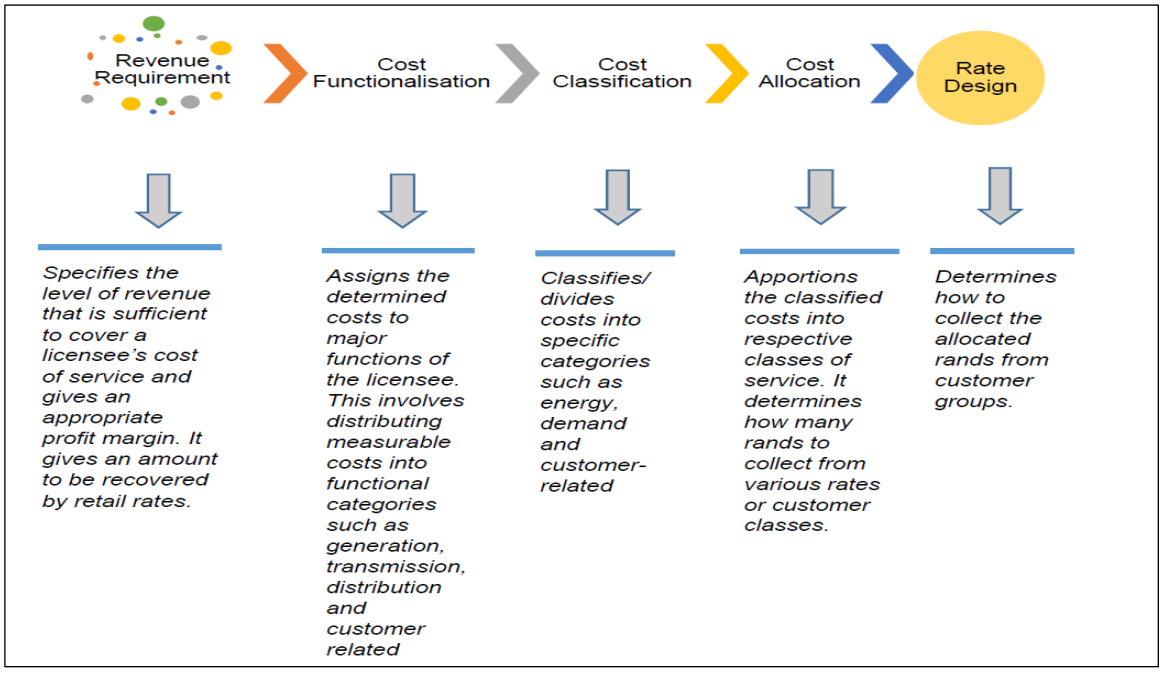


Figure 1: Five steps of COS study

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

Revenue Requirement

4.5.1. In order to be fully cost-reflective, the licensee's revenue requirements are R28. 294m for the 2026/27 financial year. This revenue requirement is predominantly Eskom purchases, accounting for 68%, including an energy loss allowance. Operational expenditure accounts for 28%.

Table 4: Revenue requirement components

	Total cost (R)			
Revenue Requirement components	Wires	Retail	Total	% of Total
Allowable costs	9 561 226	18 732 962	28 294 189	100%
Energy purchases from Eskom - net of cost of losses	-	16 677 334	16 677 334	59%
Energy purchases from Eskom - cost of losses	2 178 485	346 871	2 525 356	9%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	6 526 879	1 500 375	8 027 254	28%
Other revenues	- 13 340	- 1 494 614	- 1 507 955	-5%
Surplus	869 202	1 702 997	2 572 199	9%

4.5.2. The efficiency of costs in the 2024/25 financial year has been assessed, as this is the most recent set of actual audited data. This assessment forms the basis for projecting costs for the 2026/27 financial year using assumptions to calculate revenue requirements for that year.

4.5.3. 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. Where expenses are deemed inflated or unjustified, they have been adjusted accordingly and expanded below.

Bulk Purchases

4.5.4. The licensee applied for a bulk purchase expenditure of R19. 203 million which accounts for 68% of the total costs. Bulk purchases were verified against the 2024/25 Eskom invoices.

4.5.5. In order to get to the 2026/27 estimation, the 2025/26 COS amount was adjusted by 9.01% in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

4.5.6. NERSA is satisfied that the approach taken by the licensee to forecast bulk purchases is reasonable. As a result, this cost has been recommended for approval as applied for.

Operational Expenditure

4.5.7. The licensee applied for operational expenditure of R8. 027 million. Following the prudency assessment undertaken by the Energy Regulator, adjustments amounting to R1.044000 were made, resulting in recommended operational expenditure of R6 983 254, as shown in Table 5 below.

Table 5: Operating expenditures

Cost Drivers	2024/25FY Actuals	2025/26FY Budgeted	2026/27FY Applied	NERSA Adjustment	2026/27FY Recommended
General Costs and Other	**R5 259 294**	**R6 104 659**	**R6 373 264**	**R0**	**R6 373 264**
Salaries and Allowances	R2 591 756	R1 965 197	R2 051 666		R2 051 666
Materials and supplies	R127 102	R1 210 000	R1 263 240		R1 263 240
Contracted services	R144 329	R261 979	R273 506		R273 506
Salaries, wages and allowances (exclu. R&M)					
Payments to consultants	R1 240 779	R290 000	R302 760		R302 760
Eskom debts interest					
Current year Depreciation	R1 155 328	R2 377 483	R2 482 092		R2 482 092
NMD exceedance penalties					
Shared OPEX	**R1 195 961**	**R1 584 282**	**R1 653 990**	**-R1 044 000**	**R609 990**
Bad debts written off	R0	R0	R0		
FBE paid to Eskom	R548 458	R1 000 000	R1 044 000	-R1 044 000	
General expenses	R647 503	R584 282	R609 990		R609 990
Total OPEX	**R6 455 254**	**R7 688 941**	**R8 027 254**	**-R1 044 000**	**R6 983 254**

4.5.8. The difference between contracted services and consultants is mainly based on the nature and purpose of the service provided.

4.5.9. Contracted services (payments) refer to services outsourced to external service providers to perform operational or technical functions on behalf of the municipality. These are usually ongoing or project-based services, e.g. meter reading, security services, maintenance work, revenue collection, information technology (IT) support and grass-cutting to name a few.

4.5.10. Payments to consultants (operational work) refer to payments made to professional experts or specialists who provide advisory, technical, analytical, or professional support services. Consultants usually provide expertise rather than performing routine operational functions, e.g. engineers, financial advisers, legal consultants, tariff or COS specialists, auditors and project management consultants.

Shared Operating Expenditure

4.5.11. The municipality applied for shared operating expenditure of R1 653 990. Following an assessment of the allocation methodology and the supporting information provided, the Energy Regulator made adjustments totalling R1 044 000, resulting in a recommended shared operating expenditure of R609 990.

4.5.12. The adjustment primarily relates to FBE grants, amounting to R1 044 000. NERSA noted that the FBE costs are funded through government grants and should therefore not be recovered from electricity tariffs. Consequently, the amount was disallowed from the allowable cost base.

Surplus

4.5.13. The licensee applied for a surplus of R2 572 million, representing 9% of the allowable revenue requirement., The applied surplus margin as reflected in Table 4 of the revenue requirement, was benchmarked against the target range of 10% to 20% in the approved NERSA COS Framework

4.5.14. To ensure that the surplus is not excessive or detrimental to consumers and it commensurate with risk, NERSA relied on section 15(1)(a) of the ERA, which provides that tariffs must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return.

4.5.15. In applying this provision and the COS methodology, NERSA is required to ensure that the municipality recovers efficiently and prudently incurred costs, including a reasonable return, while preventing excessive compensation.

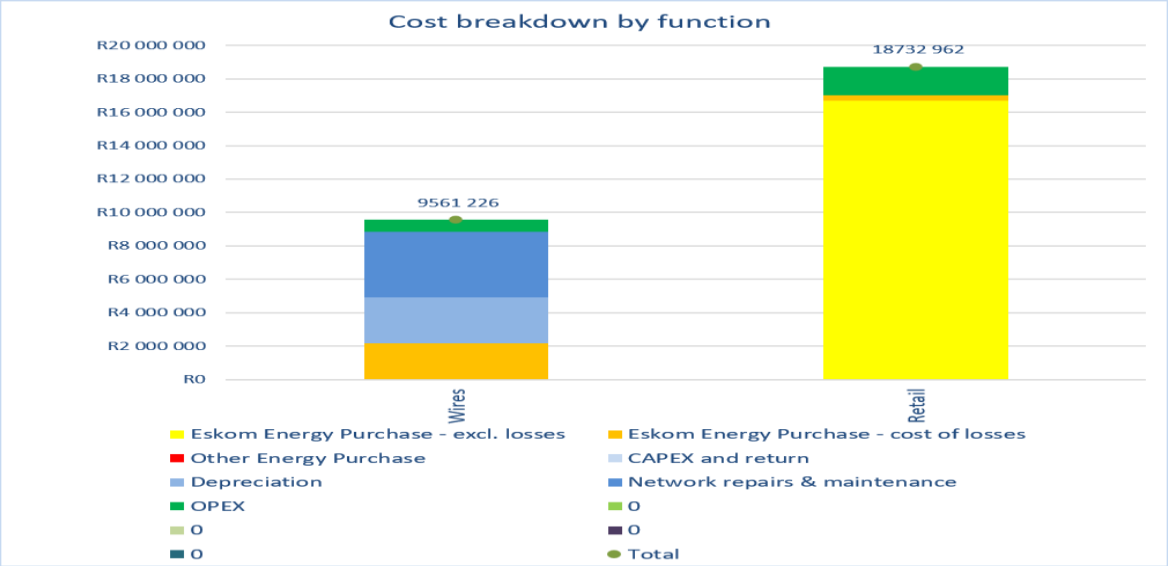
4.5.16. NERSA is satisfied that the surplus applied for is reasonable and supports the financial sustainability of the electricity business, Therefore, the applied surplus is considered modest and reasonable having regard to the relevant risk factors, including ageing infrastructure, financial stability requirements, and customer affordability constraints. This is particularly so in the context of a municipal electricity distributor, which, while not operating on a profit-maximising basis, is nonetheless required to maintain financial sustainability and operational viability.

4.5.17. It is therefore recommended that the Energy Regulator approve the allowable revenue as set out in Table 4 above. This revenue is then used in the subsequent steps of cost functionalisation, classification, allocation, and rate design. These steps were verified to be consistent with the approved revenue requirement and are discussed belowhas therefore approved the revenue requirement as submitted.

Cost Functionalisation

4.5.18. The licensee has categorised its revenue requirements of R28 294 188 before adjustments into two main functions: wires (35%) and retail business (65%), in line

with the NERSA COS Framework, as demonstrated in



4.5.19. Figure **2** below. These costs align with revenue requirements upon verification.

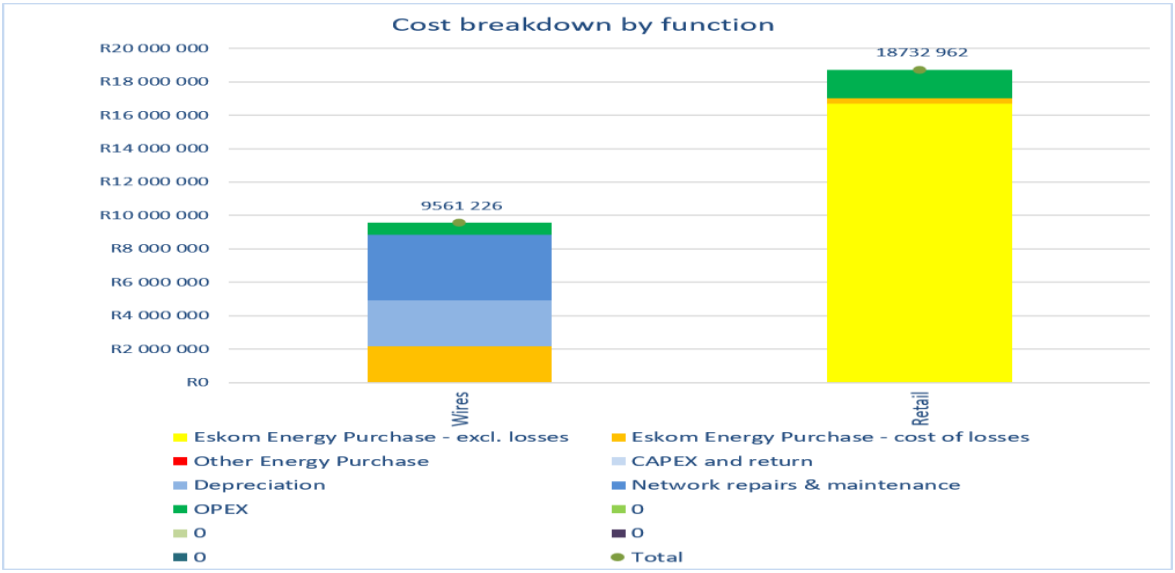


Figure 2: Cost breakdown by functions

4.5.20. These costs align with revenue requirements upon verification. Network repairs and maintenance dominate the wires business while the energy purchases are the primary cost driver for the retail business.

Cost Classification

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

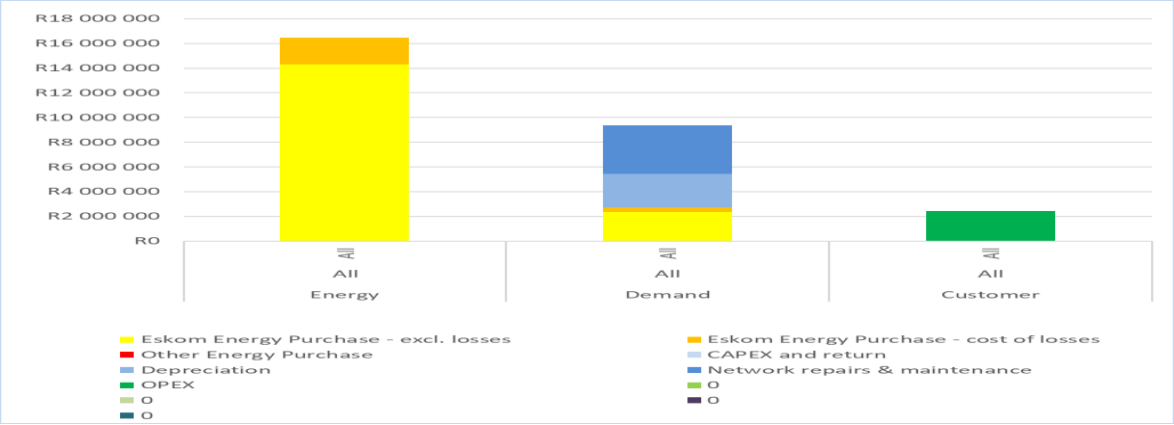


Figure 3: Cost breakdown by cost structure (classification)

4.5.22. Energy purchases constitute energy-driven costs, with the highest expenses occurring during summer under standard time of use, mainly because summer spans a larger portion of the year. Demand-driven costs are also predominantly incurred in summer. Customer-driven costs are primarily attributed to 'Other OPEX', which includes expenses associated with providing electricity distribution services to customers.

Cost Allocation

4.5.23. In this step, the licensee's revenue requirements are allocated between customer categories, in line with the NERSA COS Framework. The costs align with revenue requirements, cost functionalisation and cost classification upon verification.

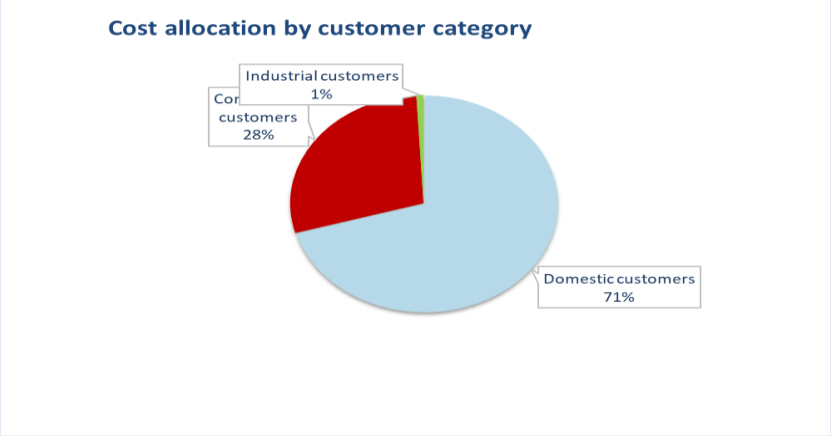


Figure 4: Costs allocated

Rate Design

4.5.24. Figure 5 below indicates the outcome of the COS study, showing that certain customer categories should increase while others should decrease. Comparing these

costs to the income per tariff category reveals the over- or under-recovery per tariff category, as shown in Figure 5 below.

4.5.25. To achieve full cost reflectivity, the municipality is required to increase tariffs across customer categories, as demonstrated below. In doing so, it will increase some categories more than others to manage the cross-subsidies in the system. However, the municipality has opted for a uniform tariff increase of 9.01%. The second graph of Figure 5 shows the under- and over-recoveries per tariff category after the proposed changes are implemented.

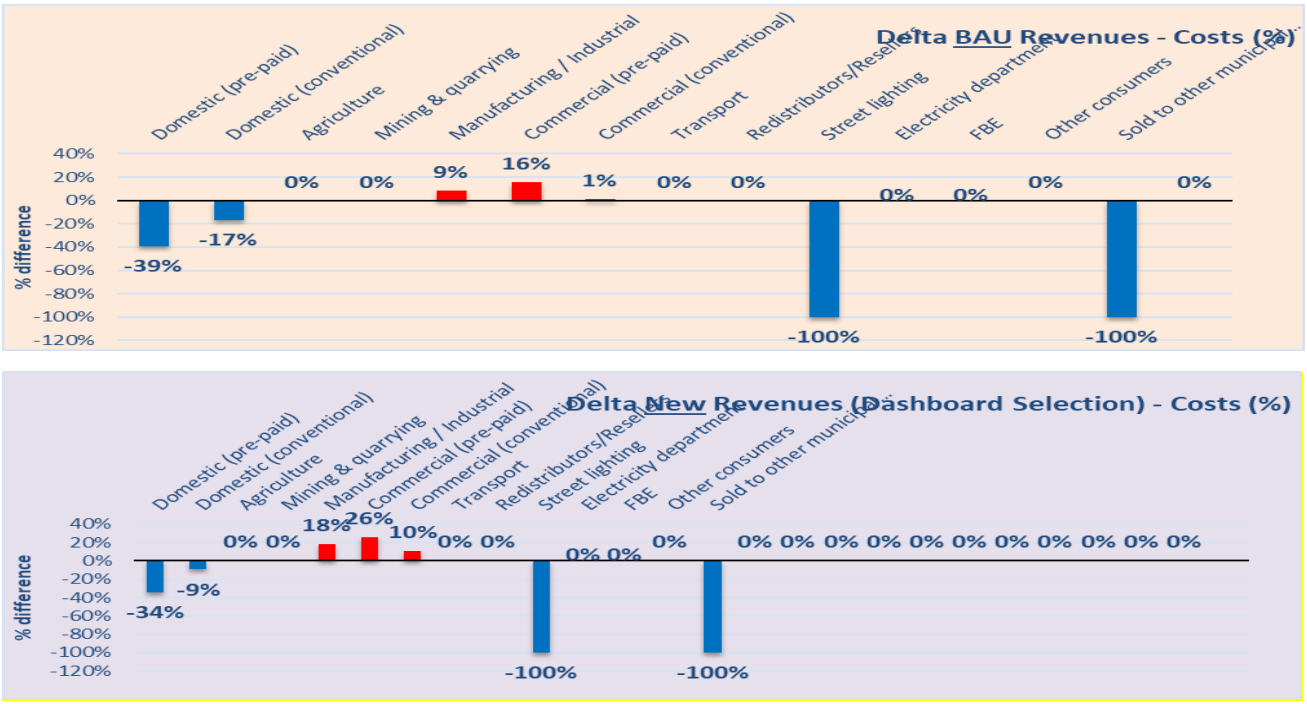


Figure 5: Revenue recovery by customer category

5. CONCLUSION ON THE COS STUDY

5.1. The COS outcome indicates that achieving full cost reflectivity would require a tariff increase of approximately 35.8% (R28 294 188). However, the municipality proposes a lower increase of 9.01% (R22 714 000), adopting a phased approach to mitigate the potential negative impacts of higher tariffs on customer affordability and electricity demand.

5.2. The analysis recognises that excessively high tariff increases may reduce consumption, weaken revenue collection and affect the municipality's ability to meet its financial obligations, including payments to Eskom. Furthermore, as the COS study is based on forecasts, there is inherent uncertainty regarding the realisation of projected costs and revenues.

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This page is part of the decision's record of public participation,
objections or comments, which names members of the public.
We do not republish it.

The whole decision is on NERSA's website:
https://www.nersa.org.za/file/9231/GreatKeiLocalMunicipality_ReasonsforDecisionTariffapplication

2. Domestic Indigent (*Winter*)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***
Tariff Blocks	*c/kWh*	*n/a*	c/kWh	*c/kWh*	*n/a*
Block 1 (0 - 50kWh)	*New*	*New*	*219,11*	*219,11*	*New*
Block 2 (51 - 350 kWh)	*New*	*New*	*275,11*	*275,11*	*New*
Block 3 (351 -600kWh)	*New*	*New*	*345,09*	*345,09*	*New*
Block 4 (>600 kWh)	*New*	*New*	*402,63*	*402,63*	*New*
Basic Charge (R/month)	*New*	*New*	*294,00*	*294,00*	*New*

3. Domestic Conventional	***Approved***	***Increase***	***Proposed***	***Recommended***	***% Increase***
Tariff Blocks	*c/kWh*	*9,01%*	c/kWh	*c/kWh*	*9,01%*
Block 1 (0 - 50kWh)	*191,43*	*9,01%*	*208,68*	*208,68*	*9,01%*
Block 2 (51 - 350 kWh)	*240,35*	*9,01%*	*262,01*	*262,01*	*9,01%*
Block 3 (351 -600kWh)	*301,49*	*9,01%*	*328,65*	*328,65*	*9,01%*
Block 4 (>600 kWh)	*351,76*	*9,01%*	*383,45*	*383,45*	*9,01%*
Basic Charge (R/month)	*347,30*	*9,01%*	*378,59*	*378,59*	*9,01%*

4. Domestic Conventional (Winter)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***
Tariff Blocks	*c/kWh*	*n/a*	c/kWh	*c/kWh*	*n/a*
Block 1 (0 - 50kWh)	*New*	*New*	*219,11*	*219,11*	*New*
Block 2 (51 - 350 kWh)	*New*	*New*	*275,11*	*275,11*	*New*
Block 3 (351 -600kWh)	*New*	*New*	*345,09*	*345,09*	*New*
Block 4 (>600 kWh)	*New*	*New*	*402,63*	*402,63*	*New*
Basic Charge (R/month)	*New*	*New*	*397,52*	*397,52*	*New*

5. Domestic Prepaid	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***
Tariff Blocks	*c/kWh*	*9,01%*	c/kWh	c/kWh	*9,01%*
Block 1 (0 - 50kWh)	*191,43*	*9,01%*	*208,68*	*208,68*	*9,01%*
Block 2 (51 - 350 kWh)	*245,80*	*9,01%*	*267,95*	*267,95*	*9,01%*
Block 3 (351 -600kWh)	*302,13*	*9,01%*	*329,35*	*329,35*	*9,01%*
Block 4 (>600 kWh)	*352,42*	*9,01%*	*384,17*	*384,17*	*9,01%*

6. Domestic Prepaid (*Winter*)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***
Tariff Blocks	*c/kWh*	*n/a*	c/kWh	c/kWh	*n/a*
Block 1 (0 - 50kWh)	*New*	*New*	*219,11*	*219,11*	*New*
Block 2 (51 - 350 kWh)	*New*	*New*	*281,34*	*281,34*	*New*
Block 3 (351 -600kWh)	*New*	*New*	*345,82*	*345,82*	*New*
Block 4 (>600 kWh)	*New*	*New*	*403,38*	*403,38*	*New*

7. Commercial Prepaid	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***
Tariff Blocks	*c/kWh*	*9,01%*	c/kWh	c/kWh	*9,01%*
Energy Charge: c/kWh	*409,67*	*9,01%*	*446,58*	*446,58*	*9,01%*

8. Commercial Prepaid (*Winter*)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***
Tariff Blocks	*c/kWh*	*n/a*	c/kWh	c/kWh	*n/a*
Energy Charge: c/kWh	*New*	*New*	*468,91*	*468,91*	*New*

9. Business Credit Meters 1&3Phase	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***
Tariff Blocks	*c/kWh*	*9,01%*	c/kWh	c/kWh	*9,01%*
Energy Charge: c/kWh					
1000kWh	*326,27*	*9,01%*	*355,67*	*355,67*	*9,01%*
>1000kWh	*351,76*	*9,01%*	*383,45*	*383,45*	*9,01%*
Basic Charge (R/month)	*438,62*	*9,01%*	*478,14*	*478,14*	*9,01%*

10. Business Credit Meters 1Phase (Winter)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***
Tariff Blocks	*c/kWh*	*n/a*	c/kWh	c/kWh	*n/a*
Energy Charge: c/kWh					
1000kWh	*New*	*New*	*373,45*	*373,45*	*New*
>1000kWh	*New*	*New*	*383,45*	*383,45*	*New*
Basic Charge (R/month)	*New*	*New*	*502,05*	*502,05*	*New*

11. Business Credit Meters 3Phase (Winter)	***2025/26 Approved***	***Proposed % Increase***	***2026/27 Proposed***	***2026/27 Recommended***	***Recommended % Increase***
Tariff Blocks	*c/kWh*	*n/a*	c/kWh	c/kWh	*n/a*
Energy Charge: c/kWh					
1000kWh	*New*	*New*	*373,45*	*373,45*	*New*
>1000kWh	*New*	*New*	*383,45*	*383,45*	*New*
Basic Charge (R/month)	*New*	*New*	*502,05*	*502,05*	*New*
Demand Charge (R/kVA)	*New*	*New*	465,00	465,00	*New*

12. Bulk Power Users	*2025/26 Approved*	*Proposed % Increase*	*2026/27 Proposed*	*2026/27 Recommended*	*Recommended % Increase*
Tariff Blocks	*c/kWh*	*9,01%*	c/kWh	c/kWh	*9,01%*
Energy Charge: c/kWh					
<=1000kWh	*183,26*	*9,01%*	*199,77*	*199,77*	*9,01%*
>1000kWh	*192,09*	*9,01%*	*209,40*	*209,40*	*9,01%*
Basic Charge (R/month)	*454,79*	*9,01%*	*495,77*	*495,77*	*9,01%*
Demand Charge (R/kVA)	*406,30*	*9,01%*	*442,91*	*442,91*	*9,01%*

13. Bulk Power Users (*Winter*)	*2025/26 Approved*	*Proposed % Increase*	*2026/27 Proposed*	*2026/27 Recommended*	*Recommended % Increase*
Tariff Blocks	*c/kWh*	*n/a*	c/kWh	c/kWh	*n/a*
Energy Charge: c/kWh					
<=1000kWh	*New*	*New*	*209,76*	*209,76*	*New*
>1000kWh	*New*	*New*	*219,87*	*219,87*	*New*
Basic Charge (R/month)	*New*	*New*	*520,55*	*520,55*	*New*
Demand Charge (R/kVA)	*New*	*New*	*465,05*	*465,05*	*New*

Analysis and Key Findings

8.1. The municipality has introduced a winter tariff for all its customers to send an appropriate price signal that reflects the higher cost of electricity supply during the high-demand winter season, when consumption typically increases significantly due to heating and other usage patterns. This targeted tariff structure is intended to encourage more efficient energy use during peak periods while aligning tariffs more closely with cost drivers. The proposed winter tariff has been adjusted by an inflationary increase relative to the standard tariff to ensure revenue adequacy without imposing a disproportionate burden on consumers. As a result, the measure is expected to support improved cost recovery, stabilise municipal revenue streams during periods of elevated demand and reduce the risk of revenue shortfalls associated with seasonal consumption fluctuations.

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

10.1. The Energy Regulator, having considered Great Kei's application, supporting information, stakeholder inputs and applicable legal framework, approves the tariff adjustments, as set out in these reasons for decision document.

End.