NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

## Decision and Reasons for Decision (RfD)

In the matter regarding the

**Municipal Tariff Application for the 2026/27 Financial Year**

By

**Elundini Local Municipality**

## THE DECISION

At its meeting held on 4 May 2026, the Regulator Executive Committee (REC) considered the Elundini 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 Table 1 below.

**Table 1: Summary of the REC decision**

| Tariff Category | 2026/27 Approved % Increase |
|---|---|
| Domestic Prepaid Residential 20A (Low) | 12.2% |
| Domestic Prepaid Residential 60A (High) | 12.2% |
| Residential Three Phase 25KVA | 12.2% |
| Business Prepaid single phase 60A | 12.2% |
| Business Prepaid single phase 80A (Medium) | 12.2% |
| Business Prepaid Three phase 40A Low | 12.2% |
| Business Three Phase 80A (Medium) | 12.2% |
| Business Conventional 150A (High) | 12.2% |
| Business Conventional 200kVA (High) | 12.2% |
| Business Conventional 315 kVA (Medium) | 12.2% |
| Commercial Conventional 500kVA (medium) | 12.2% |

| | |
|---|---|
| Municipal Own Use | 12.2% |
| Conversional Prepaid Single Phase 40A (Low) | 12.2% |
| Business Conventional 315 kVA (High) | 12.2% |
| Conversional Three phase 80A (medium) | |
| Municipal Own use (50kVA) | 12.2% |
| Municipal Own use (315 kVA) | 12.2% |
| TOU Conventional Single Phase 60A (High) | |
| Small scale embedded generation (SSEG) | 12.2% |

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

1. to approve the tariffs that are based on the cost of supply (COS) study, as recommended in the tariff analysis section, for implementation by the 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 by 31 January 2027 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; and
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 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 on a yearly basis, in accordance with its mandate to regulate prices and tariffs. Municipal tariffs must be approved by the Energy Regulator to be implemented on 1 July of each financial year.

1.2. The Elundini Local Municipality (Elundini) is located in the Eastern Cape. The municipality is made up mostly of domestic customers, who consume 51.85% of the total electricity sales. The municipality provides its indigent customers with 50kWh of Free Basic Electricity (FBE) per month. The municipality further reported that it maintains an indigent register. The details regarding customer statistics are highlighted in Table 2 below.

**Table 2: Customer statistics**

| CUSTOMER STATISTICS (OBTAINED FROM 2024-2025 DISTRIBUTION FORMS) | | | |
|---|---|---|---|
| **Consumer Classification** | **Sales (KWh)** | **%KWh** | **Number of Consumers** |
| Domestic (Prepaid) | 6 377 793 | 51,85% | 3 272 |
| Commercial (Prepaid) | 1 582 773 | 12,87% | 250 |
| Commercial (Conventional) | 3 974 768 | 32,31% | 49 |
| Municipal Consumption & Street Lighting | 365 182 | 2,97% | 13 |
| **TOTAL SALES** | **12 300 516** | **100%** | **3 584** |
| **Free Basic Electricity (FBE)** | **721 002** | **11,30%** | **1 182** |

1.3. NERSA received Elundini's tariff application and its cost of supply (COS) study on 16 March 2026.

1.4. For the 2025/26 financial year, Elundini implemented an average price increase of 15%. Although the initial tariff application published on the NERSA website projected a further 16% increase for the 2026/27 period, this figure was subsequently revised. Following a rigorous analysis of the COS study to identify and eliminate inefficient costs, the projected increase for 2026/27 was adjusted to 12.2% in line with the COS results. This revised adjustment ensures that the proposed tariffs accurately reflect the actual cost of service delivery, promoting both fiscal responsibility and fairness for consumers.

1.5. This adjustment was formally discussed and agreed upon with the municipality to ensure the new rates accurately reflect the underlying costs.

1.6. The municipality submitted all requested supporting documentation required for the comprehensive analysis of the tariff application.

1.7. NERSA followed the notice and comment consultation process. Elundini's tariff application was published on the NERSA website on 19 March 2026, and notices were published on social media platforms and in national and local newspapers to solicit written comments from affected parties.

1.8. NERSA's decision was made on 4 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 No. 3 of 2000) (PAJA) and the Electricity Pricing Policy for the South African Electricity Supply Industry, 2008 (EPP).

2.1.2. The approval of 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).

2.1.3. In addition, the municipal tariff approval process has recently been the subject of judicial scrutiny in the High Court of South Africa (Gauteng Division, Pretoria) in AfriForum NPC v National Energy Regulator of South Africa and Others (Case No. 2025/137620), which resulted in structural directives governing the timing and conduct of NERSA's tariff approval process.

2.1.4. This section provides the legal and policy context within which the Energy Regulator evaluated and determined the municipal electricity tariff application for the 2026/27 municipal financial year.

### 2.2. NERSA's Statutory Mandate

2.2.1. NERSA is established as a juristic person in terms of section 3 of NERA. In terms of section 4 of NERA, the Energy Regulator, as the decision-making body, must regulate the electricity industry and execute the functions set out in the ERA. 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 an administrative action as defined in section 1 of PAJA. Accordingly, the Energy Regulator must ensure that its tariff determinations are lawful, reasonable and procedurally fair as

required by sections 3 and 6 of PAJA. Procedural fairness requires that affected parties and the public be afforded a reasonable opportunity to make representations before a final decision is taken.

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

## 2.5. Policy Framework: Electricity Pricing Policy (2008)

2.5.1. In addition to the statutory framework, the Energy Regulator must have regard to the EPP. The EPP establishes national policy principles for electricity tariff setting, including cost reflectivity, transparency, economic efficiency and equity.

2.5.2. Policy Position 1 of the EPP provides that the revenue requirement for a regulated licensee must be set at a level that covers the full cost of production, including a reasonable risk-adjusted margin or return on appropriate asset values.

2.5.3. Policy Position 2 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 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 NERSA.

## 2.7. Judicial Oversight of the Tariff Approval Process

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

2.7.2. In its final judgment delivered on 4 December 2025, the Court held that NERSA's public participation process relating to the 2025/26 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 seeking to vary the timelines set by the Court on 4 December 2025, in light of practical difficulties that arose in relation 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 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.

2.8.2. 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 tariffs and the tariff reasons for decision documents 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 be undertaken within a comprehensive regulatory framework consisting of the NERA, ERA, PAJA, EPP and the binding judicial directives issued by the High Court in AfriForum NPC v NERSA (Case No. 2025/137620).

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

# 3. FINANCIAL AND TECHNICAL PERFORMANCE

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

3.2. During the 2024/25 financial year, Elundini's electricity business experienced a significant decline in financial performance, with its deficit widening to 38.66% from 9.46% in the 2023/24 financial year. This downturn was driven by a 9% decrease in total revenue – compounded by a 43% reduction in grant allocations – and a 15% surge in total expenditure.

3.3. Operational inefficiencies also played a critical role; high energy losses alone accounted for over R12 million (R12,080,695) in lost revenue. Additional factors contributing to the deficit include high levels of bad debt and ongoing energy distribution challenges.

3.4. Table 4 below shows that during the 2024/25 financial year, energy losses rose to 32.93%, up from 30.22% the 2023/24 financial year. This upward trend is driven by a combination of persistent illegal connections and underlying technical and administrative inefficiencies. The municipality's losses generally fall into two categories:

a) Technical losses: These are unavoidable physical losses within the infrastructure, such as energy dissipating through conductors, transformer cores and metering equipment coils.

b) Administrative losses: These stem from the energy required by the utility to manage and operate the distribution network effectively.

3.5. To reduce high energy losses and improve operational efficiency, the municipality has implemented the following strategic measures:

a) Energy theft prevention: To minimise non-technical losses, the municipality is introducing regular, rigorous meter inspections alongside enhanced security protocols.

b) Smart metering initiative: The completion of the ongoing smart meter project will provide precise, real-time consumption data, significantly reducing manual billing discrepancies.

c) Scheduled maintenance: Routine maintenance checks ensure all metering infrastructure functions accurately, preventing small technical errors from compounding into significant losses.

d) Data concentrator units (DCUs): The installation of DCUs enables real-time monitoring of the distribution network, allowing technical teams to quickly identify and resolve localised loss issues.

e) Vending system data cleansing: By rigorously auditing and updating municipal vending records, the utility ensures accurate data for more reliable billing and tracking of energy usage.

**Table 3:Energy loss analysis**

| | D-Form Input | Energy Loss@12% | Energy Loss@6% |
|---|---|---|---|
| Average Selling Price | 311,54 | | |
| Sales kWh | 12 300 516,00 | 16 139 960,32 | 17 240 412,16 |
| Purchases kWh | 18 340 864,00 | 18 340 864,00 | 18 340 864,00 |
| Losses kWh | 6 040 348,00 | 2 200 903,68 | 1 100 451,84 |
| Losses percentage | **32,93%** | **12,00%** | **6,00%** |
| Additional Energy (kWh) | | 3 839 444,32 | 4 939 896,16 |
| Additional Revenue (Rands) | | 11 961 404,83 | 15 389 752,50 |
| | D-Form Input | Energy Loss@12% | Energy Loss@6% |
| Total Revenue (Rands) | R 7 732 582,00 | R 19 693 986,83 | R 23 122 334,50 |
| Total Expenses (Rands) | R 16 712 932,00 | R 16 712 932,00 | R 16 712 932,00 |
| Net Profit (Loss) | R -8 980 350,00 | R 2 981 054,83 | R 6 409 402,50 |
| Percentage Surplus/Deficit | **-116,14%** | **15,14%** | **27,72%** |

3.6. The municipality has high energy losses of 32.93%, which significantly undermines its financial sustainability

3.6.1. If losses were capped at 12%, the municipality would:

a) improve net revenue by approximately R1.4 million; and

b) operate at a surplus of 15.14%.

3.6.2. If losses were capped at 6%, the municipality would:

a) improve net revenue by approximately R15 million; and

b) operate at a surplus of 27.72%.

**Table 4: Performance indicators**

| PERFORMANCE INDICATORS: OBTAINED FROM D-FORMS | | |
|---|---|---|
| **INDICATORS** | **2024-25FY (Actuals)** | **2023-24 FY (Approved)** |
| Percentage Surplus (Deficit) | -38,66% | -9,46% |
| Percentage Energy Losses | 32,93% | 30,22% |

3.7. The municipality's electricity business is currently underperforming, characterised by significant energy losses and a substantial percentage deficit. Addressing these core issues can transform the electricity business from a financial liability into a self-sustaining, efficient service.

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

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

4.2. The municipality revised its COS study to support the introduction of new tariffs, namely the Conventional Single Phase 60A High, SSEG and municipal own use tariffs.

4.3. Elundini 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 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.

4.4. Figure 1 below illustrates the five steps considered in the determination of the COS study.

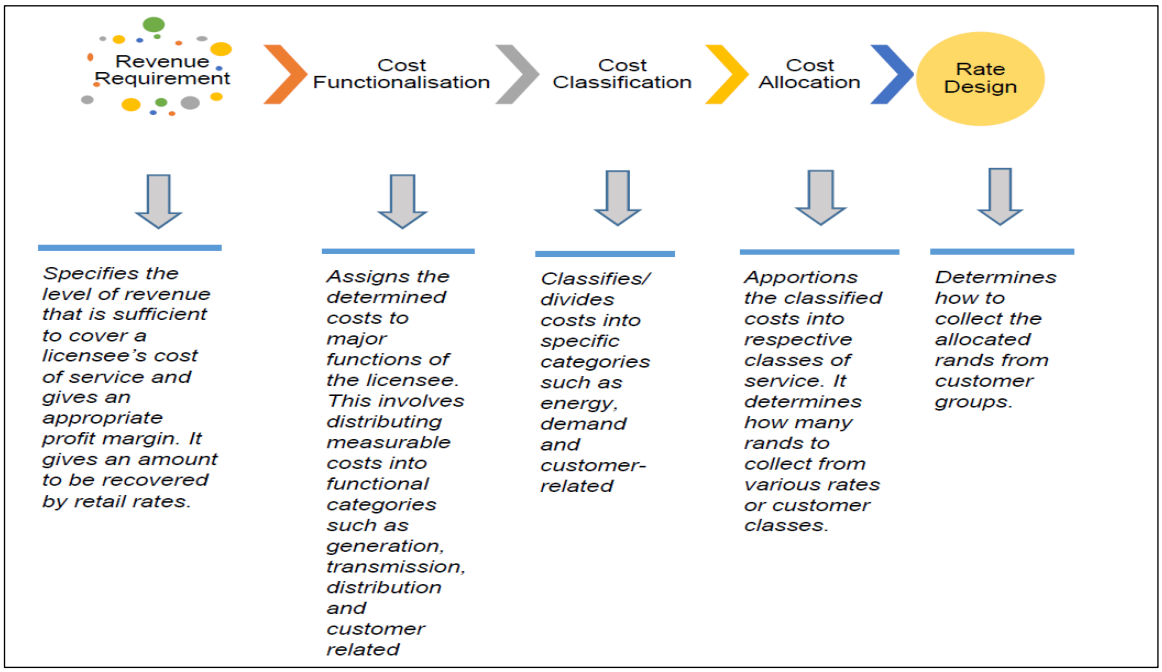



**Figure 1: Five steps of COS study**

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

## Revenue Requirement

4.5.1 The efficiency of costs for the 2024/25 financial year has been assessed, as this is 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.

**Table 5: Revenue requirement components**

| | Total cost (R) | | | |
|---|---|---|---|---|
| Revenue Requirement components | Wires | Retail | Total | % of Total |
| Allowable costs | 48 638 432 | 56 775 087 | 67 920 180 | 100% |
| Energy purchases from Eskom - net of cost of losses | - | 31 445 656 | 31 445 656 | 46% |
| Energy purchases from Eskom - cost of losses | 1 360 118 | 3 946 360 | 5 306 479 | 8% |
| Other energy purchases | - | - | - | 0% |
| Capital expenditure | - | - | - | 0% |
| Operational expenditure (incl. Depreciation) | 22 519 374 | 14 973 966 | 37 493 340 | 55% |
| **Other revenues** | **- 11 246** | **- 9 147 506** | **- 9 158 753** | **-13%** |
| Surplus | 2 250 813 | 582 646 | 2 833 459 | 4% |
| Not allowable costs | 795 153 | 6 673 370 | 7 468 522 | |
| Cost of losses disallowed | 795 153 | 6 673 370 | 7 468 522 | |
| TOTAL COSTS | 49 433 585 | 63 448 457 | 75 388 703 | |

4.5.2 All expenses included in the revenue requirement have been examined to confirm that they pertain exclusively to the licensee's electricity function. Where any

amounts were found to be inflated or insufficiently substantiated, adjustments have been effected accordingly, as detailed below.

**Bulk Purchases**

4.5.3 Elundini submitted an application for bulk purchase expenditure amounting to R31million, representing 54% of total costs. The bulk purchase figures were verified against Eskom invoices for the 2024/25 financial year.

4.5.4 To derive the 2026/27 bulk purchase estimate, the 2025/26 COS amount was escalated by 9.01%, consistent with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

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

**Operational Expenditure**

4.5.6 Elundini has applied for operational expenditure, totalling R37 million, representing 55% of overall costs, as reflected in Table 4 above.

4.5.7 The approach adopted by Elundini in forecasting operational expenditure is considered reasonable, and the amount has therefore been approved as requested. However, inefficient cost components – such as Notified Maximum Demand exceedance penalties and interest incurred on Eskom-related debt – have been excluded from the total, as these items fall within the control of the municipality.

**Surplus**

4.5.8 Elundini has requested a surplus of R2 million, calculated using a surplus factor of 4% applied to operating expenditure, inclusive of bulk purchases, for both the wires and retail components of the business.

4.5.9 The return proposed by Elundini is considered reasonable, as it falls within the established target range of 10–20%. Consequently, the requested amount has been approved as applied for.

4.5.10 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.

## Cost Functionalisation

4.5.11 The licensee has categorised its revenue requirement of R67 million into two primary functional components, namely the wires business (61.5%) and the retail business (38.5%). This categorisation is in accordance with the NERSA COS Framework, as illustrated in Figure 2 below. Upon verification, the allocation of costs to these functional components is consistent with the stated revenue requirement.

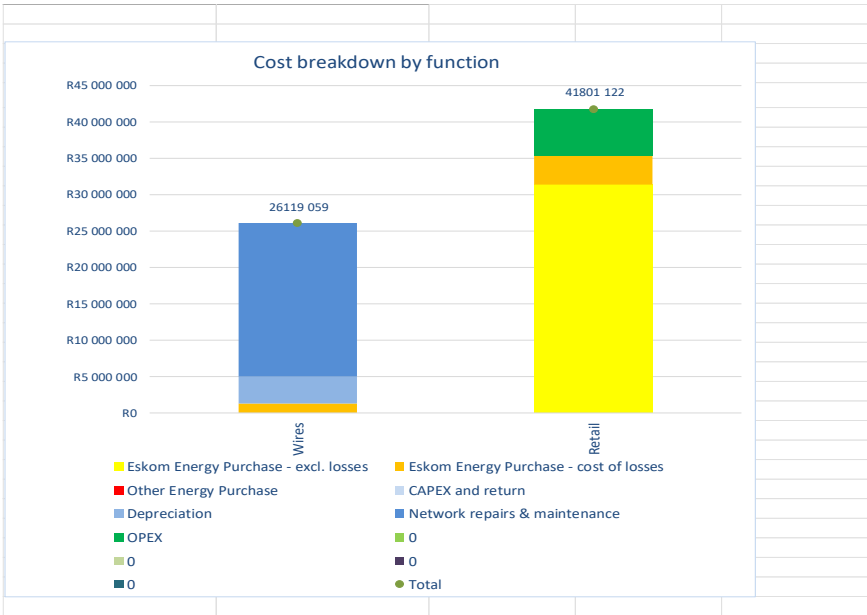



**Figure 2: Cost breakdown by functions**

4.5.12 Energy purchases are significant within the cost breakdown and dominate when compared to other costs, such as the operating expenditure (OPEX) and surplus. Capital expenditure (CAPEX) does not contribute significantly to the overall cost breakdown each year because of the rate of return.

## Cost Classification

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

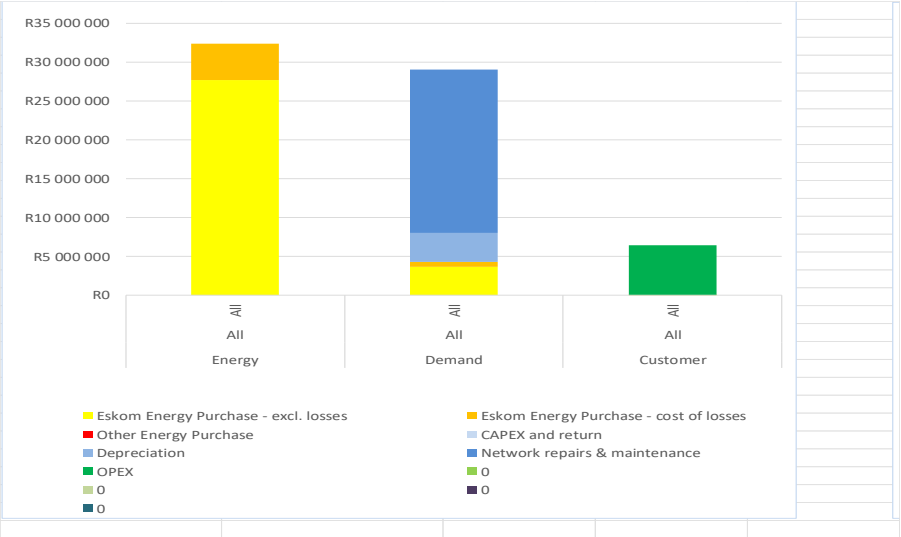



**Figure 3: Costs breakdown by cost structure (classification)**

4.5.1.2. Energy purchases and the cost of losses make up the energy-driven cost, with the highest amount of costs incurred during the low season and standard on time of use – mostly due to the low season covering a greater proportion of the year. Demand-driven costs include depreciation, network repairs and maintenance and energy purchase demand-related costs. The period of greatest demand-driven costs is during the low season. Finally, customer-driven costs are incurred through offering the electricity distribution service to customers, including salaries.

## Cost Allocation

4.5.1.3. 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 consistent with the stated revenue requirement and aligned with cost allocation principles.

4.5.1.4. The domestic (prepaid) customer category carries the largest proportion of costs, followed by commercial (conventional) customers. Other municipal departments and FBE customers account for the lowest portion of costs. Differences in results between customer classes are mainly driven by variations in connection-point voltage, load factors, coincidence factors and average specific consumption.

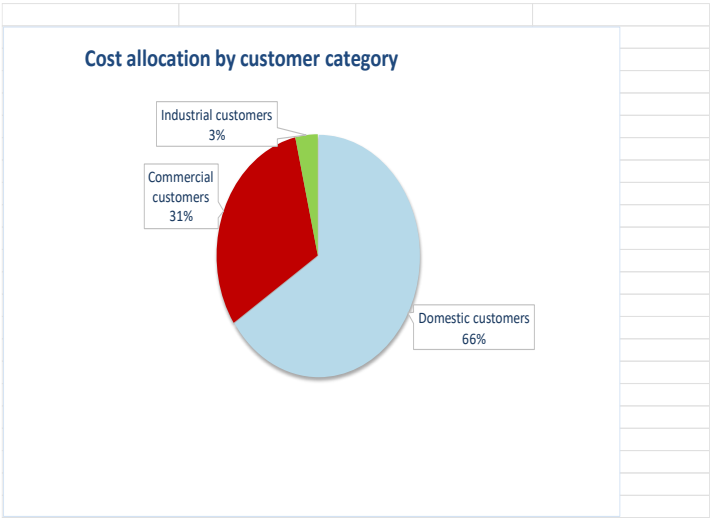
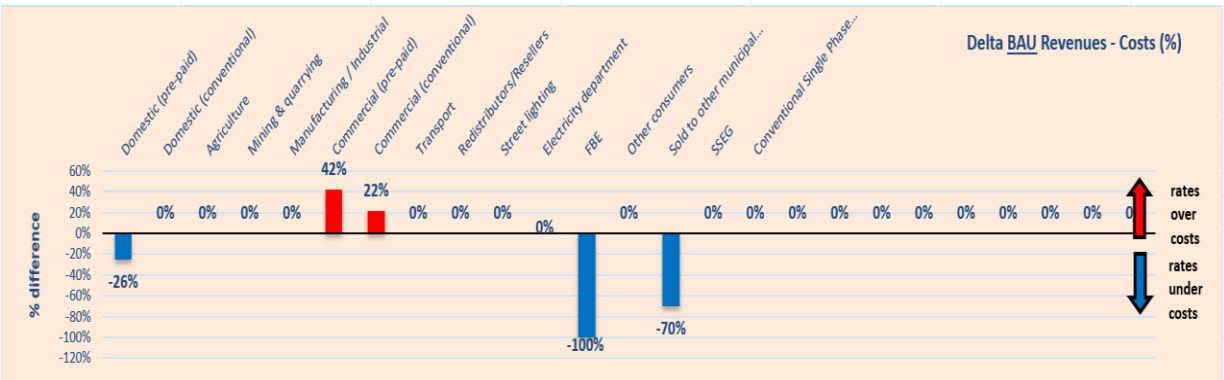



**Figure 4: Cost allocation**

### 4.5.2. Rate Design

4.5.2.1. **Error! Reference source not found.** reflects the outcome of the COS study, indicating that certain customer categories require upward adjustments, while others require downward adjustments. A comparison between the COS and the revenue generated per tariff category highlights the extent of over- or under-recovery within each category.

4.5.2.2. To ensure that electricity services remain sustainable and fair, the municipality is adjusting tariffs by 12.2% across all categories. The average increase was guided by COS results, which provide a technical basis for ensuring that the rates accurately reflect the true cost of providing reliable electricity to every household and business.



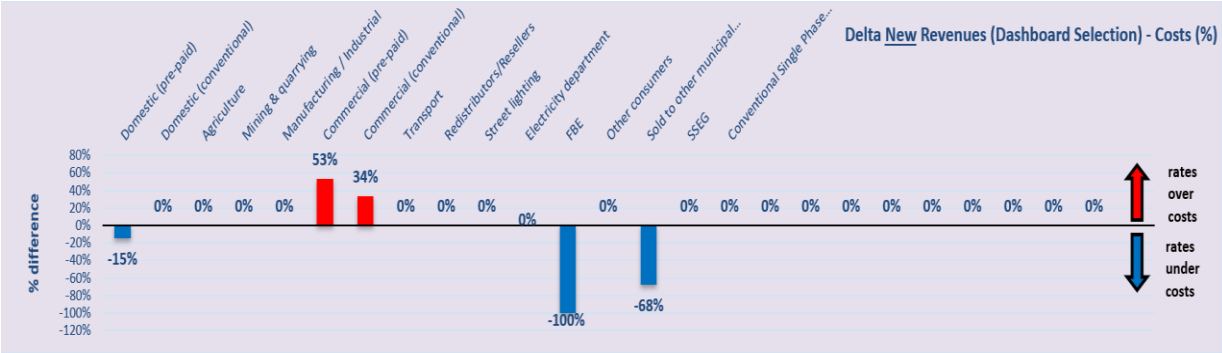



**Figure 5: Rate design**

## 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 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 municipality'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 municipality is projected to maintain long-term financial stability following the implementation of a 12.2% tariff increase. This adjustment is a strategic necessity to address a historical under-recovery of electricity-related costs, which has previously strained the city's fiscal health.

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| Domestic Prepaid Residential 60A (High) | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Block 1 (0-50) kWh | 241.43 | 270.88 | 12.2% | 270.88 | 12.2% | According to the COS study, prepaid electricity customers are currently paying less than the actual cost of providing the service, a situation known as cross-subsidisation. To address this and ensure that the price of electricity reflects its true production and delivery costs, a proposed increase of 12.2% is recommended to establish a uniform and sustainable tariff structure across all customer categories. |
| Block 2 (51-350) kWh | 349.23 | 391.83 | 12.2% | 391.83 | 12.2% | |
| Basic Charge (R/month) | 288.25 | 323.41 | 12.2% | 323.41 | 12.2% | |

| Residential Three Phase 25KVA | 2025/26 Approved Tariff | 2026/27 Recommended Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 1 439.10 | 1 614 .67 | 12.2% | 1 614.67 | 12.2% | The proposed 12.2% increase is a strategic step toward creating a uniform and sustainable tariff structure for all electricity users. |
| Energy Charge (c/kWh) | 338.50 | 379.79 | 12.2% | 379.79 | 12.2% | |

**Commercial Tariffs**

| Business Prepaid 60A Single Phase | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 588.00 | 659.73 | 12.2% | 659.73 | 12.2% | The COS study highlights a significant imbalance in electricity pricing. Commercial customers are currently paying rates above the actual cost of service, effectively subsidising domestic customers. To move toward a fairer structure, a proposed 12.2% increase is recommended. This move is designed as a strategic balance, ensuring the financial sustainability of the municipality while carefully managing affordability for all customer base. |
| Energy Charge (c/kWh) | 393.42 | 441.41 | 12.2% | 441.41 | 12.2% | |

| Business Prepaid Single Phase 80A (medium) | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 735.00 | 824.67 | 12.2% | 824.67 | 12.2% | The COS study highlights a significant imbalance in electricity pricing. Commercial customers are currently paying rates above the actual cost of service, effectively subsidising domestic customers. To move toward a fairer structure, the proposed 12.2% increase is recommended. This move is designed as a strategic balance, ensuring the financial sustainability of the municipality while carefully managing affordability for all customer base. |
| Energy Charge(c/kWh) | 393.42 | 441.41 | 12.2% | 441.41 | 12.2% | |

| Business Prepaid Three Phase 40A Low | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 1 439.11 | 1 614.68 | 12.2% | 1 614.68 | 12.2% | The COS study highlights a significant imbalance in electricity pricing. Commercial customers are currently paying rates above the actual cost of service, effectively subsidising domestic customers. To move toward a fairer structure, the proposed 12.2% increase is recommended. This move is designed as a strategic balance, ensuring the financial sustainability of the municipality while carefully managing affordability for all customer base. |
| Energy Charge(c/kWh) | 420.84 | 472.18 | 12.2% | 472.18 | 12.2% | |

| Business Three Phase 80A medium | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 1 510.00 | 1694.22 | 12.2% | 1 694.22 | 12.2% | The COS study demonstrates that all time-of-use (TOU) tariffs are nearing cost-reflectivity.<br>The 12.2% average increase is recommended as it will enhance the municipality's financial sustainability by improving revenue collection and ensuring service costs are fully recovered. |
| Energy Charge (c/kWh)<br>Off-peak<br>standard<br>peak | <br>323.74<br>340.88<br>358.04 | <br>363.23<br>382.46<br>401.72 | <br><br><br>12.2% | <br>363.23<br>382.46<br>401.72 | <br><br><br>12.2% | |
| Demand Charge (R/kVA) | 265.12 | 297.46 | 12.2% | 297.46 | 12.2% | |

| Business Conventional 150A (High) | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 2 357.03 | 2 644.58 | 12.2% | 2 644.58 | 12.2% | The COS study demonstrates that all TOU tariffs are nearing cost-reflectivity.<br>The proposed 12.2% increase is recommended as it will enhance the municipality's financial sustainability by improving revenue collection and ensuring service costs are fully recovered. |
| Energy Charge (c/kWh)<br>Off-peak<br>standard<br>peak | <br>352.35<br>398.04<br>418.99 | <br>395.33<br>446.60<br>470.10 | <br><br><br>12.2% | <br>395.33<br>446.60<br>470.10 | <br><br><br>12.2% | |
| Demand Charge (R/kVA) | 265.12 | 297.46 | 12.2% | 297.46 | 12.2% | |

| Business Conventional 200kVA (High) | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 2 357.03 | 2 644.58 | 12.2% | 2 644.58 | 12.2% | The COS study demonstrates that all TOU tariffs are nearing cost-reflectivity.<br>The proposed 12.2% increase is recommended as it will enhance the municipality's financial sustainability by improving revenue collection and ensuring service costs are fully recovered. |
| Energy Charge (c/kWh)<br>Off-peak<br>standard<br>peak | <br>352.35<br>398.04<br>418.99 | <br>395.33<br>446.60<br>470.10 | <br><br><br>12.2% | <br>395.33<br>446.60<br>470.10 | <br><br><br>12.2% | |
| Demand Charge (R/kVA) | 265.12 | 297.46 | 12.2% | 297.46 | 12.2% | |

| Business Conventional 315kVA (Medium)-d0ne | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 2 036.24 | 2 284.66 | 12.2% | 2 284.66 | 12.2% | The COS study demonstrates that all TOU tariffs are nearing cost-reflectivity.<br>The proposed 12.2% increase is recommended as it will enhance the municipality's financial sustainability by improving revenue collection and ensuring service costs are fully recovered. |
| Energy Charge (c/kWh)<br>Off-peak<br>standard<br>peak | <br>147.45<br>237.83<br>461.36 | <br>165.44<br>266.85<br>517.64 | <br><br><br>12.2% | <br>165.44<br>266.85<br>517.64 | <br><br><br>12.2% | |
| Demand Charge (R/kVA) | 193.80 | 222.49 | 12.2% | 222.49 | 12.2% | |

| Commercial Conventional 500kVA (Medium) | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 2 491.37 | 2 795.31 | 12.2% | 2 795.31 | 12.2% | The COS study demonstrates that all TOU tariffs are nearing cost-reflectivity.<br>The proposed 12.2% increase is recommended as it will enhance the municipality's financial sustainability by improving revenue collection and ensuring service costs are fully recovered. |
| Energy Charge (c/kWh)<br>Off-peak<br>standard<br>peak | <br>243.68<br>333.08<br>762.45 | <br>273.40<br>373.71<br>855.46 | <br><br><br>12.2% | <br>273.40<br>373.71<br>855.46 | <br><br><br>12.2% | |
| Demand Charge (R/kVA) | 265.12 | 297.46 | 12.2% | 297.46 | 12.2% | |

| Municipal Own Use | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 157.50 | 176.71 | 12.2% | 176.71 | 176.71 | An average increase of 12.2% will sustain the financial sustainability of the municipality. |
| Energy Charge (c/kWh) | 181.20 | 203.30 | 12.2% | 203.30 | 203.30 | |

| Conversional Prepaid Single Phase 40A Low | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 1076.40 | 1 207.72 | 12.2% | 1 207.72 | 12.2% | The proposed increase of 12.2% will sustain the financial sustainability of the municipality |
| Energy Charge (c/kWh) | 218.90 | 245.60 | 12.2% | 245.60 | 12.2% | |

| Business Conventional 315 kVA (High) | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 2 722.44 | 3 054.58 | 12.2% | 3 054.58 | 12.2% | The COS study demonstrates that all TOU tariffs are nearing cost-reflectivity. The proposed 12.2% increase is recommended as it will enhance the municipality's financial sustainability by improving revenue collection and ensuring service costs are fully recovered. |
| Energy Charge (c/kWh)<br>Off-peak<br>standard<br>peak | <br>318.07<br>337.00<br>354.25 | <br>356.87<br>378.11<br>397.47 | <br><br><br>12.2% | <br>356.87<br>378.11<br>397.47 | <br><br><br>12.2% | |
| Demand Charge (R/kVA) | 265.12 | 297.46 | 12.2% | 297.46 | 12.2% | |

| Conversional Prepaid 80A Medium Three Phase | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | 1 129.40 | 1 267.18 | 12.2% | 1 267.18 | 12.2% | The proposed increase of 12.2% will sustain the financial sustainability of the municipality. |
| Energy Charge (c/kWh) | 241.10 | 270.51 | 12.2% | 270.51 | 12.2% | |

**New Tariffs**

| 50 KVA Municipal Own use | 2025/26 Approved | 2026/27 Proposed | % Increase | Recommended Tariff | Recommended % Increase | Analysis and key findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | New | 1496.86 | New | 1496.86 | New | This is a new tariff that will gradually align with the proposed 12.2% increase. |
| Energy Charge (c/kWh)<br>Off-peak<br>standard<br>Peak | New | <br>320.91<br>337.89<br>354.88 | New | <br>320.91<br>337.89<br>354.88 | New | |
| Demand Charge (R/kVA) | New | 262.81 | New | 262.81 | New | |

| 315 KVA Municipal Own Use | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and key findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | New | 2 698.76 | New | 2 698.76 | New | This is a new tariff that will gradually align with the proposed 12.2% increase. |
| Energy Charge (c/kWh)<br>Off-peak<br>Standard<br>Peak | New | <br>315.30<br>334.06<br>351.16 | 12.2% | <br>315.30<br>334.06<br>351.16 | New | |
| Demand Charge (R/kVA) | New | 262.81 | 12.2% | 262.81 | New | |

| SSEG | 2025/26 Approved Tariff | 2026/27 Proposed Tariff | % Increase | Recommended Tariff | Recommended % Increase | Analysis and Key Findings |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | New | 1 248.62 | 12.2% | 1 248.62 | New | This is a new tariff that will gradually align with the proposed 12.2% increase. |
| Energy Charge(c/kWh) | New | 253.92 | 12.2% | 253.92 | New | |

| **TOU -Conventional Single Phase 60A High** | **2025/26 Approved Tariff** | **2026/27 Proposed Tariff** | **% Increase** | **Recommended Tariff** | **Recommended % Increase** | **Analysis and Key Findings** |
|---|---|---|---|---|---|---|
| Basic Charge (R/month) | New | 2 036.24 | New | 2 036.24 | New | This is a new tariff that will gradually align with. The proposed 12.2% increase. |
| Energy Charge (c/kWh)<br>Off-peak<br>standard<br>peak | <br><br><br>New | <br>147.45<br>237.83<br>461.26 | <br><br><br>New | <br>147.45<br>237.83<br>461.26 | <br><br><br>New | |
| Demand Charge (c/kWh) | New | 198.30 | New | 198.30 | New | |

## 9. CONFIDENTIALITY

9.1. None.

## 10. CONCLUSION

10.1. From a conspectus of the facts and evidence presented to the REC, it is appropriate to approve Elundini's tariff application for the 2026/27 financial year.

***End.***