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 FY2026/27

By

Drakenstein Local Municipality

THE DECISION

1. At its meeting held on 6 May 2026, the Regulator Executive Committee (REC) considered Drakenstein Local Municipality's (DLM) tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for FY2026/27 as set out on the tariff analysis section 8 on page 22 of the RfD.

2. Based on the information submitted and the analysis conducted, the REC decided:
   2.1. 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;
   2.2. to note the COS study submitted by the municipality; and
   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 (NERSA) to perform its independent verification audit commencing 31 January 2027.

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ABBREVIATIONS

AFS	Annual Financial Statements
COS	Cost of Supply
D-form	Distribution form
DLM	Drakenstein Local Municipality
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. NERSA receives and considers tariff applications annually, in accordance with the mandate of the Energy Regulator to regulate prices and tariffs. Municipal tariffs must be approved by the Energy Regulator for implementation on 1 July of each financial year.

1.2. DLM is located in the Western Cape. The Municipality is made up mostly of manufacturing customers, which consume 42.25% of the total electricity sales. The municipality provides 85 kWh per month for Category A and B consumers (Customers with income from R6 500- R7 500 per month) and 50 kWh per month for Category C and D consumers (Customers with income from R7 5001- R9 000 per month) of Free Basic Electricity (FBE) per month. The Municipality further reports that it maintains an indigent register. The details regarding customer statistics are highlighted in Table 1 below.

Table 1: Customer Statistics (Data obtained from the latest D-forms – FY2024/25)

Customer categories	***MWh***	***% MWh***	***Customer numbers***
Domestic Prepaid	162,080	26.00	42,003
Domestic Conventional	51,807	8.31	6,331
Agriculture	28,783	4.62	774
Manufacturing	263,342	42.25	654
Commercial Pre	5,450	0.87	783
Commercial Conventional	90,179	14.47	2,188
Own Use	21,674	3.48	523
TOTAL	**623,315**	**100**	**53,256**
FBE[1]	17,134	8.01[2]	17,505

1.3. NERSA received DLM's tariff application together with its revised COS study, which is based on the cost-plus methodology on 31 March 2026. The Municipality indicated that the reason for the revision is that the Municipality is introducing a new small domestic time of use (TOU) tariff which will provide residential customers with the opportunity to proactively manage their consumption patterns and costs. The revised COS study aims to balance revenue recovery needs with affordability concerns.

[1] This information is already included in the customer statistics table above under domestic prepaid/conventional category.

[2] Percentage of Domestic MWh.

1.4. DLM implemented a 10.31% average price increase in FY2025/26 and is applying for an average price increase of 6.30% for the FY2026/27.

1.5. The municipality submitted its Council resolution and evidence of customer consultation as part of the tariff application submitted to NERSA on 31 March 2026.

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

1.7. NERSA's decision was taken on 6 May 2026, following consideration of 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 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 in order to align with the municipal budgeting process contemplated in the Municipal Finance Management Act, 2003 (Act No. 56 of 2003) (MFMA).

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 FY2026/2027.

2.2. NERSA's Statutory Mandate

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

a) must enable an efficient Licensee to recover the full cost of the licensed activity;
b) must allow for a reasonable return commensurate with the risk of the licensed activity;
c) may provide incentives for continued improvement of technical and economic efficiency;
d) must avoid undue discrimination between customer categories;
e) may permit cross-subsidies of tariffs to certain classes of customers; and

f) may have regard to the need to ensure security of supply, diversity of supply and the promotion of renewable energy.

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

2.4. Administrative Law Requirements

2.4.1. The approval of municipal electricity tariffs constitutes administrative action as defined in section 1 of the PAJA. Accordingly, the Energy Regulator must ensure that its tariff determinations are lawful, reasonable and procedurally fair as required by sections 3 and 6 of the 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 (RR) for a regulated Licensee must be set at a level that covers the full cost of production, including a reasonable risk-adjusted margin or return on appropriate asset values.

2.5.3. Policy Position 2 of the EPP states that electricity tariffs must reflect the efficient cost of rendering electricity services accurately and that the average level of tariffs must be set to recover the approved RR.

2.6. COS Studies

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

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

2.6.3. Policy Position 23 of the EPP requires electricity distributors to undertake COS studies at least every five years, or when significant structural changes occur in the customer base or cost structure.

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

2.7. Judicial Oversight of the Tariff Approval Process

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

2.7.2. In its final judgment delivered on 4 December 2025, the Court held that NERSA's public-participation process relating to FY2025/26 municipal tariff approvals did not comply with the procedural requirements of section 4 of the PAJA and was therefore unlawful.

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

2.7.4. NERSA subsequently launched a variation application that sought to amend the timelines set by the Court on 4 December 2025, in view of the practical difficulties encountered in complying with the Court order. The Court having heard NERSA's application, granted the variation application in respect of the fixed deadlines for FY2026/27 municipal-tariff approvals.

2.8. Court-Directed Timelines

2.8.1. The timelines below are applicable in respect of the FY2026/27 municipal-tariff approvals:

a) written notice of bulk tariffs by 6 March 2026;
b) municipal tariff applications to be submitted by 31 March 2026;
c) public participation processes to be concluded by 21 April 2026; and

d) publication of NERSA decisions by 11 May 2026.

2.8.2. Municipal-tariff approvals from FY2027/28 are to comply with the following timelines:

a) written notice of bulk electricity tariffs to be communicated by 31 January each year;
b) municipal-tariff applications to be submitted to NERSA by 20 March each year; and
c) municipal-tariff approvals and the tariff RfD document to 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 RfD document demonstrate how the Energy Regulator complied with the legislative, policy and judicial framework in determining the municipal electricity tariff for FY2026/27.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. In evaluating the financial and technical performance of DLM, the assessment relied on the Distribution forms (D-forms) for FY2024/25 submitted as part of the Municipality's tariff application. The information contained in the D forms was verified against the supporting source documents provided by the Municipality, including the Trial Balance and Annual Financial Statements. As a result, the data captured in the D forms is considered reliable for the purposes of the tariff analysis.

3.2. Table 2 below shows that DLM's electricity business's percentage surplus declined from 18.47% in FY2023/24 to 17.91% in the FY2024/25.

3.3. The energy losses slightly increased from 7.09% in FY2023/24 to 7.77% in the FY2024/25 as highlighted in table 2 below. The Municipality is encouraged to keep energy losses at low levels.

Table 2: Performance Indicators

Performance indicators	***Municipality FY2024/25 D-forms Information***	***Municipality FY2023/24 D-forms Information***
Percentage surplus: (%)	17.91	18.47[3]
Energy Losses: (%)	7.77	7.09

3.4. Based on the above information, the Municipality's electricity department demonstrates satisfactory financial and operational performance, as evidenced by the recorded surplus and relatively low energy losses. The surplus indicates prudent financial management and cost recovery, while the low level of energy losses suggests effective network maintenance and operational efficiency. Collectively, these factors indicate a stable and sustainable electricity service function.

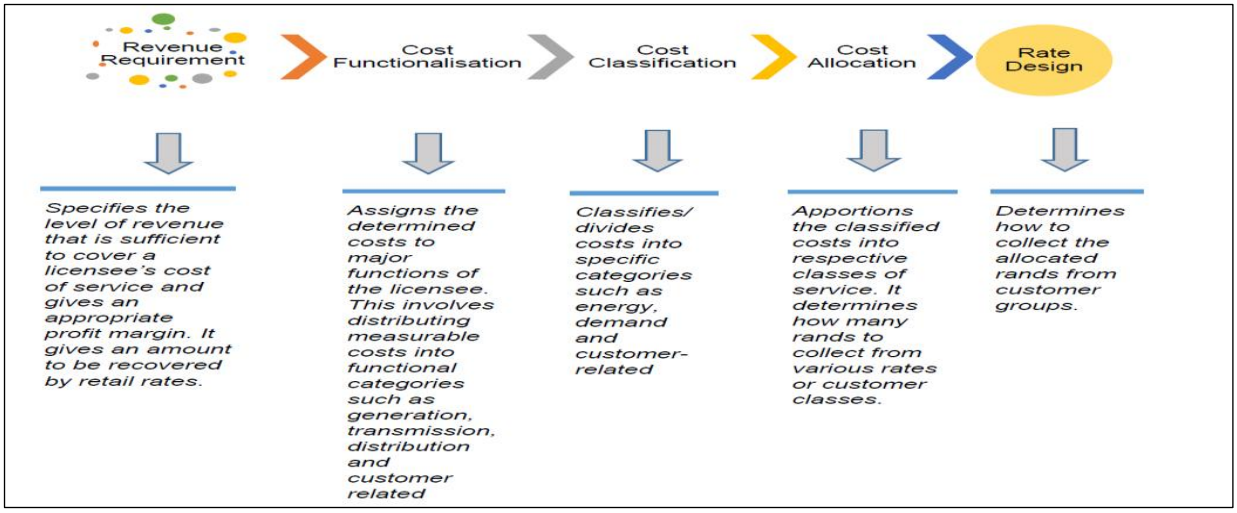
4. DETERMINATION OF DRAKENSTEIN'S LOCAL MUNICIPALITY TARIFFS BASED ON THE COST OF SUPPLY STUDY

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

4.2. DLM utilised the COS study model developed by Sustainable Energy Africa (SEA) to determine its Revenue Requirement (RR) for FY2026/27 and to apportion costs required to service each customer's class in a fair and equitable manner. The study follows the NERSA COS study Framework and utilises the latest available audited data which is based on FY2024/25.

4.3.

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



[3] Total Electricity Purchases divided by Total Expenditure

Figure 1: Five 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 rather than a rate of return (ROR) approach. Under the cost-plus methodology, the allowable revenue is derived as follows:

a) efficient and prudent Operating Expenditure (OPEX);
b) depreciation (as a proxy for asset consumption and future replacement); and
c) a reasonable surplus margin.

4.5.1.2. To be fully cost reflective, the Municipality's RR is R2.15 billion for the FY2026/27. This amount is primarily driven by Eskom purchases, which account for 76%, while operational expenditure (including the surplus) accounts for the remaining 24%, as highlighted in Table 3 below.

Table 3: Revenue Requirement Components

	Total cost (R)			
Revenue Requirement components	Wires	Retail	Total	% of Total
Allowable costs	536 256 239	1 901 231 132	2 156 476 814	100%
Energy purchases from Eskom - net of cost of losses	-	1 483 358 417	1 483 358 417	69%
Energy purchases from Eskom - cost of losses	148 306 548	-	148 306 548	7%
Other energy purchases	-	-	-	0%
Capital expenditure	-	-	-	0%
Operational expenditure (incl. Depreciation)	173 635 578	107 374 980	281 010 558	13%
Other revenues	**- 1 038 886**	**- 3 250 076**	**- 4 288 962**	**0%**
Surplus	41 717 421	206 372 832	248 090 253	12%
Not allowable costs	134 947	-	134 947	
Cost of losses disallowed	134 947	-	134 947	
TOTAL COSTS	536 391 186	1 901 231 132	2 156 611 761	

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

4.5.1.4. All expenses included in the RR were assessed to ensure they relate solely to the Municipality's electricity function. Where costs were found to be overstated or inadequately supported, appropriate adjustments were made, as outlined below.

Bulk purchases

4.5.1.5. DLM applied for bulk purchase expenditure amounting to R1.6 billion, representing 76% of total costs. The bulk purchase figures were verified against Eskom invoices for the FY2024/25.

4.5.1.6. To get to the FY2026/27 estimate, the Municipality projected the year-to-date amount for FY2025/26 since complete financial year data is unavailable, then made an estimate that this cost item would increase by 9.01% in line with the approved Eskom Retail Tariff Structural Adjustments (ERTSA).

4.5.1.7. The Eskom bills were analysed and there are no Notified Maximum Demand (NMD) exceedance penalties charged. Furthermore, the Municipality remains current on its Eskom bulk account and therefore does not incur interest charges.

4.5.1.8. The methodology applied by DLM in forecasting bulk purchase costs is found to be reasonable. Accordingly, the bulk purchase expenditure is recommended for approval as applied for.

Operational Expenditure

4.5.1.9. DLM has applied for operational expenditure totaling R281 million, representing 13% of overall costs, as reflected in Table 3 above.

Depreciation

4.5.1.10. Depreciation is a key component of operational expenditure, as it enables the recovery of electricity infrastructure costs over the useful life of the assets. An adequate provision for depreciation is essential to ensure the long-term sustainability of the electricity undertaking and to facilitate the future refurbishment and replacement of aging network infrastructure.

4.5.1.11. The Municipality reported an asset value of R2,680,656.002, as reflected in it submitted audited D-forms for the FY2024/25. This amount was verified against the audited AFS, the trial balance and supporting financial information.

4.5.1.12. Depreciation amounted to R38,215,779 in FY2024/25 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 2024/25FY AFS. The projected depreciation for FY2025/26 is R49,449,458, reflecting a growth of approximately 29%.

Surplus

4.5.1.13. The municipality applied for a surplus of R248 million which is based on a 12% return on OPEX including bulk purchases. The applied surplus was assessed

against the municipality's financial performance, operational requirements, cost-reflectivity principles and the affordability impact on consumers.

4.5.1.14. The Energy Regulator notes that maintaining an appropriate level of surplus is necessary to mitigate financial and operational risks associated with the electricity business. An inadequate surplus may expose the municipality to risks such as:

4.5.1.14.1. insufficient cash flow to fund operations and maintenance activities;

4.5.1.14.2. deterioration of network infrastructure due to underinvestment;

4.5.1.14.3. increased reliance on borrowing or cross-subsidisation from other municipal functions;

4.5.1.14.4. inability to respond effectively to network failures and emergency repairs;

4.5.1.14.5. and weakening of the long-term financial sustainability of the electricity undertaking.

4.5.1.15. To ensure that the surplus is not excessive or detrimental to consumers, NERSA relied on section 15(1)(a) of 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. In applying this provision, together with the COS methodology, NERSA is required to ensure that Swartland recovers efficiently and prudently incurred costs, including a reasonable return, while preventing excessive compensation.

4.5.1.16. NERSA is satisfied that the surplus applied for by DLM is reasonable and supports the financial sustainability of the electricity business, as it falls within the approved target range of 10% to 20% prescribed in the NERSA Cost of Supply (COS) Framework.

4.5.1.17. The applied surplus is considered proportionate to the risks associated with an inadequate surplus, particularly within the context of a municipal distributor that is not profit-maximising but is required to remain financially sustainable. Accordingly, NERSA has decided to approve the revenue requirement as applied for.

4.5.1.18. The decision to approve the RR 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 RR. Further details on these stages are provided below.

4.5.2. Cost Functionalisation

4.5.2.1. The Municipality has categorised its RR of R2.1 billion into two primary functional components, namely the wires business (17%) and the retail business (83%), in accordance with the NERSA COS study Framework, as illustrated in Table 4 below. Upon verification, the allocation of costs to these functional components is found to be consistent with the stated RR.

Table 4: Costs Breakdown by Functions

	Total Functionalised Costs (R)		
Functions	**Wires**	**Retail**	**Total**
Eskom Energy Purchase - excl. losses	-	1 483 358 417	1 483 358 417
Eskom Energy Purchase - cost of losses	148 306 548	-	148 306 548
Other Energy Purchase	-	-	-
CAPEX and return	-	-	-
Depreciation	24 541 135	19 496 826	44 037 962
Network repairs & maintenance	152 948 006	-	152 948 006
OPEX	36 824 972	291 000 909	327 825 882
Total	**362 620 661**	**1 793 856 152**	**2 156 476 814**
	17%	83%	

4.5.2.2. These costs, upon verification, are consistent with the approved RR. 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 Municipality has classified its costs into energy, demand and customer-related cost components, in accordance with the NERSA COS study Framework as highlighted in Figure 2 below. The costs align with RR and Cost Functionalisation upon verification.

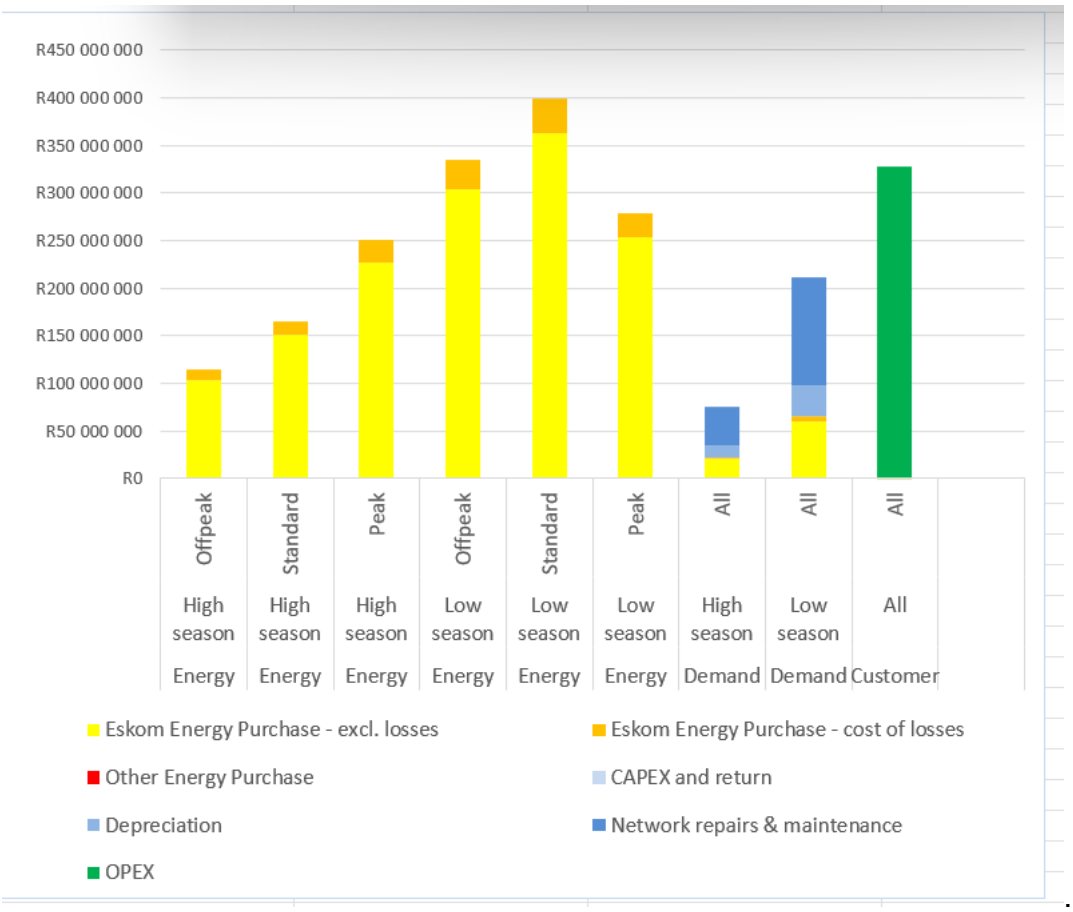


Figure 2: Costs Breakdown by Cost Structure (Classification)

4.5.3.2. Energy purchases constitute energy-driven costs, with the highest expenditure incurred during the summer period under the standard time-of-use (TOU) 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 RR is allocated across customer categories, in accordance with the NERSA COS study Framework. Upon verification, the allocation is found to be consistent with the stated RR and aligned with the principles of cost allocation.

Table 5: 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				
Domestic (pre-paid)	373 624 046	80 914 277	175 906 045	630 444 368
Domestic (conventional)	133 539 758	28 920 176	51 839 585	214 299 519
Agriculture	74 193 882	13 638 804	11 063 813	98 896 500
TOU-LV	101 267 948	18 615 736	8 781 484	128 665 168
TOU-MV	422 978 622	66 938 493	7 242 461	497 159 577
Commercial (pre-paid)	14 048 409	2 582 470	9 327 051	25 957 931
Commercial (conventional)	85 085 122	15 640 903	20 641 015	121 367 040
Large Bulk	196 598 092	31 112 636	7 161 460	234 872 188
Small Bulk	42 076 367	6 658 797	7 633 173	56 368 337
Municipal Domestic	4 520 836	979 060	1 400 845	6 900 740
Municipal Street Lights	13 748 375	3 025 203	3 114 973	19 888 551
FBE	44 165 617	9 564 772	20 851 856	74 582 246
Municipal TOU-LV	27 454 032	5 046 780	1 471 125	33 971 937
Municipal Bulk	9 872 707	1 814 866	1 415 139	13 102 712
Total	**1543173814**	**285452974**	**327850026**	**2 156 476 814**

4.5.4.2. The Domestic Customer Category carries the largest proportion of costs, followed by the TOU Customer Category. Municipal own-use and Street Lighting result 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 certain customer categories require upward adjustments, while others warrant decreases. A comparison between the COS study and the revenue generated per tariff category highlights the extent of over- or under-recovery within each category, as illustrated in Figure 3 below.

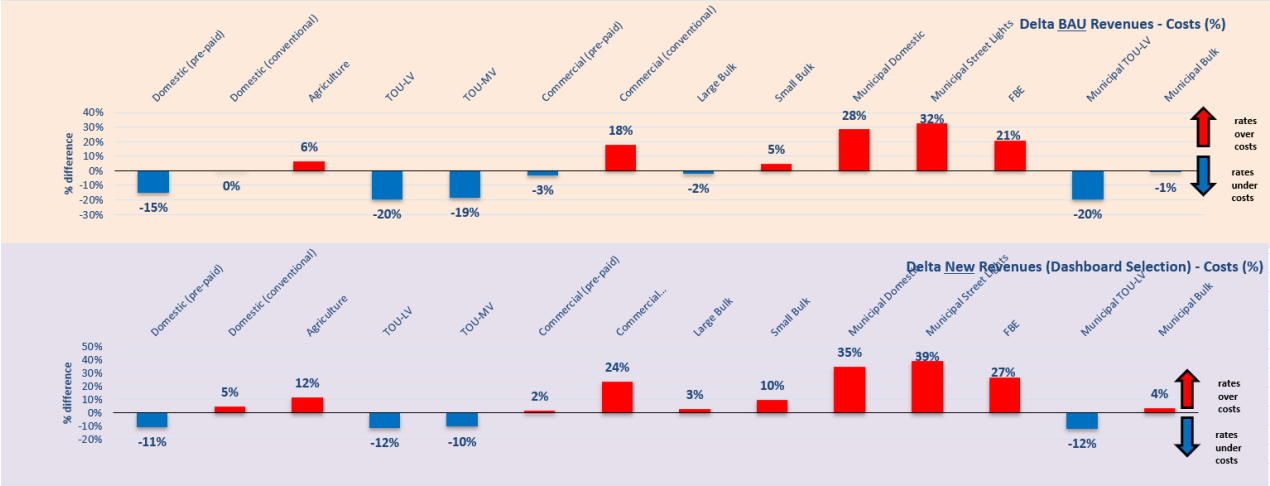


Figure 3: Revenue Recovery by Customer Category

4.5.5.2. To achieve full cost-reflectivity, the Municipality would be required to implement differentiated tariff adjustments across customer categories.

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 municipality 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 RR 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 8.60% for the municipality 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 6.30% in consumption charges and 2% in fixed, demand and notified demand charges. The municipality has applied for these differentiated increases in its tariff structure to balance revenue recovery with affordability concerns.

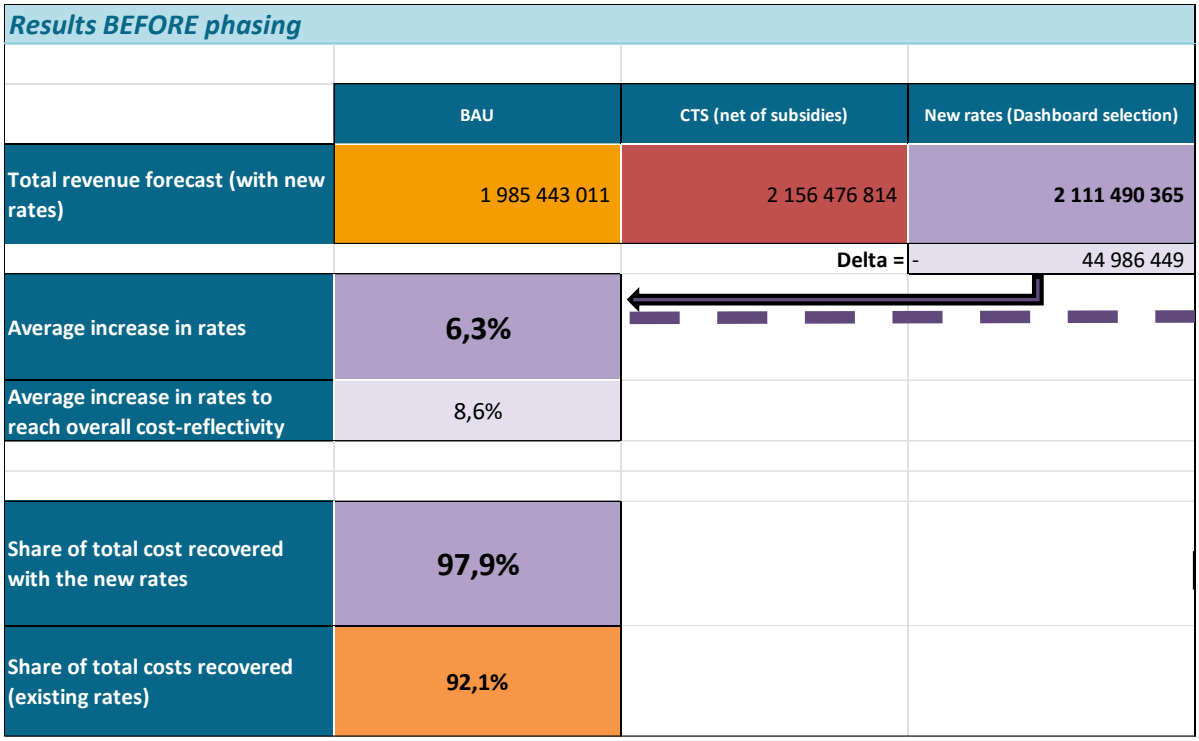


Figure 4: Rate Design

5.7. The assessment confirms that the study is generally aligned with the prescribed COS Study Framework and applies an appropriate methodological approach, including cost functionalisation, classification and allocation. The overall RR and cost build-up are considered reasonable.

5.8. The COS study indicates that the existing tariffs will result in an estimated revenue recovery of approximately 92.1% of the RR, thereby giving rise to a material under-recovery as highlighted in Figure 4 above. Furthermore, the analysis reveals the presence of significant cross-subsidisation between customer categories, with certain tariffs being priced below cost while others are above cost.

5.9. Figure 4 further highlights that the implementation of the proposed new rates is projected to increase the share of total cost recovery to 97.9%. This significant improvement demonstrates the Municipality's commitment to narrowing the under-recovery gap and moving toward a more cost-reflective and financially sustainable tariff structure.

5.10. The municipality has adopted a phased approach that balances financial sustainability with current socio-economic realities and for FY2026/27, the

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The whole decision is on NERSA's website:
https://www.nersa.org.za/file/9153/DrakensteinMunicipality-ReasonsforDecisiononTariffApplicationI

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https://www.nersa.org.za/file/9153/DrakensteinMunicipality-ReasonsforDecisiononTariffApplicationI

DETAILS OF TARIFFS APPLIED FOR						
2. Single Phase Conventional/Prepaid 30A	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge (R/Amp)	9.29	9.48	2%	9.48	2%	The proposed 2% increase in the basic charge is modest and remains below prevailing cost pressures, thereby limiting the impact on domestic consumers. This conservative adjustment is appropriate in the context of affordability considerations. However, the COS study indicates that domestic customers are under-recovering by approximately 15%. The proposed increase, while not sufficient to fully address the under-recovery, represents a gradual step towards improved cost-reflectivity without imposing significant tariff shocks. The tariff structure remains unchanged, ensuring stability and predictability for customers. Overall, the proposed tariff balances affordability and cost-recovery considerations and it is therefore recommended that the proposed tariff be approved.
Basic Charge (R/month)	278.70/30A	284.40/30A		284.40/30A		
Energy charge (c/kWh)	289.10	303.56	5%	303.56	5%	

DETAILS OF TARIFFS APPLIED FOR						
3. All Other Domestic Single Phase Conventional / Prepaid	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge (R/Amp)	11.89	12.13	2%	12.13	2%	The proposed 2% increase in the basic charge is modest and remains below prevailing cost pressures, thereby limiting the impact on domestic consumers. This conservative adjustment is appropriate in the context of affordability considerations. However, the COS study indicates that domestic customers are under-recovering by approximately 15%. The proposed increase, while not sufficient to fully address the under-recovery, represents a gradual step towards improved cost-reflectivity without imposing significant tariff shocks. The tariff structure remains unchanged, ensuring stability and predictability for customers. Overall, the proposed tariff balances affordability and cost-recovery considerations and it is therefore recommended that the proposed tariff be approved.
Basic Charge (R/month)	535.05/45A	545.85/45A		545.85/45A		
Energy charge (c/kWh)	289.10	303.56	5%	303.56	5%	

4. All Domestic Three Phase Conventional / Prepaid	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge (R/Amp)	10.20	10.40	2%	10.40	2%	The proposed 2% increase in the basic charge is modest and remains below prevailing cost pressures, thereby limiting the impact on domestic consumers. This conservative adjustment is appropriate in the context of affordability considerations. However, the COS study indicates that domestic customers are under-recovering by approximately 15%. The proposed increase, while not sufficient to fully address the under-recovery, represents a gradual step towards improved cost-reflectivity without imposing significant tariff shocks. The tariff structure remains unchanged, ensuring stability and predictability for customers. Overall, the proposed tariff balances affordability and cost-recovery considerations and it is therefore recommended that the proposed tariff be approved.
Basic Charge (R/month)	1530/50A	1 560/50A		1 560/50A		
Energy charge (c/kWh)	306.85	322.19	5%	322.19	5%	

DETAILS OF TARIFFS APPLIED FOR						
5. Commercial Single Phase Prepaid 20A	**FY2025/26 approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Energy charge (c/kWh)	411.85	432.44	5%	432.44	5%	The proposed 5% increase in the energy charge reflects a moderate adjustment and is broadly aligned with prevailing cost pressures, particularly bulk-electricity cost increases. As a consumption-based tariff, the increase appropriately targets variable-cost recovery without introducing additional fixed-cost burdens on customers. While the COS study indicates that commercial customers are under-recovering by approximately 15%, the proposed increase for this commercial category remains reasonable and does not suggest excessive cross-subsidisation. The adjustment supports gradual movement towards improved cost reflectivity while maintaining price stability. Overall, the proposed tariff is considered appropriate, and it is therefore recommended that the proposed tariff be approved.

6. All Other Commercial Single Phase	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge (R/Amp)	11.86	12.10	2%	12.10	2%	The proposed tariff reflects differentiated increases across components, with a 2% adjustment in the basic charge and a 5% increase in the energy charge. This approach indicates a measured rebalancing between fixed and variable cost recovery. The COS study findings show that commercial conventional customers are over-recovering by approximately 18%, while prepaid customers are under-recovering by 15%. In this context, the relatively lower increase in the basic charge is appropriate, as it limits further over-recovery from conventional customers. The moderate increase in the energy charge supports alignment with underlying bulk supply cost pressures while avoiding significant pricing distortions. Overall, the proposed adjustments reflect a cautious approach to addressing cost imbalances and it is recommended that the proposed adjustments be approved, noting that further tariff restructuring may be required to fully address cross-subsidisation between customer segments.
Basic Charge (R/month)	711.60/60A	726/60A		726/60A		
Energy charge (c/kWh)	339.26	356.22	5%	356.22	5%	

7. All Commercial Three Phase connections	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge (R/Amp)	9.08	9.26	2%	9.26	2%	The proposed tariff reflects differentiated increases across components, with a 2% adjustment in the basic charge and a 5% increase in the energy charge. This approach indicates a measured rebalancing between fixed and variable cost-recovery. The COS study findings show that commercial conventional customers are over-recovering by approximately 18%, while prepaid customers are under-recovering by 15%. In this context, the relatively lower increase in the basic charge is appropriate, as it limits further over-recovery from conventional customers. The moderate increase in the energy charge supports alignment with underlying bulk-supply cost pressures while avoiding significant pricing distortions. Overall, the proposed adjustments reflect a cautious approach to addressing cost imbalances and it is recommended that the proposed adjustments be approved, noting that further tariff restructuring may be required to fully address cross-subsidisation between customer segments.
Basic Charge (R/month)	1634.40/60 A	1 666.80/60 A		1 666.80/60A		
Energy charge (c/kWh)	315.55	331.33	5%	331.33	5%	

DETAILS OF TARIFFS APPLIED FOR						
8. Rural 16 kVA and less	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge (R/month)	1,845.05	1,881.95	2%	1,881.95	2%	The proposed tariff reflects a differentiated increase, with a 2% adjustment in the basic charge and a 5% increase in the energy charge. This indicates a measured approach to balancing fixed and variable cost-recovery. The COS study indicates that this customer category is over-recovering by approximately 6%. In this context, the limited increase in the basic charge is appropriate, as it avoids further exacerbating over-recovery. The moderate increase in the energy charge is aligned with prevailing bulk supply cost pressures while remaining within reasonable limits. Overall, the proposed adjustments are considered reasonable, and it is recommended that the proposed adjustments be approved, noting that future tariff downwards adjustments may be required to address the identified over-recovery.
Energy charge (c/kWh)	255.33	268.10	5%	268.10	5%	

DETAILS OF TARIFFS APPLIED FOR						
9. Rural >16kVA up to 25KVA	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge (R/month)	2,109.92	2,152.12	2%	2,152.12	2%	The proposed tariff reflects a differentiated increase, with a 2% adjustment in the basic charge and a 5% increase in the energy charge. This indicates a measured approach to balancing fixed and variable cost recovery. The COS study indicates that this customer category is over-recovering by approximately 6%. In this context, the limited increase in the basic charge is appropriate, as it avoids further exacerbating over-recovery. The moderate increase in the energy charge is aligned with prevailing bulk supply cost pressures while remaining within reasonable limits. Overall, the proposed adjustments are considered reasonable, and it is recommended that the proposed adjustments be approved, noting that future tariff downwards adjustments may be required to address the identified over-recovery.
Energy charge (c/kWh)	259.35	272.32	5%	272.32	5%	

DETAILS OF TARIFFS APPLIED FOR						
10. Rural >25kVA up to 50 kVA	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge (R/month)	2,977.39	3,036.94	2%	3,036.94	2%	The proposed tariff reflects a differentiated increase, with a 2% adjustment in the basic charge and a 5% increase in the energy charge. This indicates a measured approach to balancing fixed and variable cost recovery. The COS study indicates that this customer category is over-recovering by approximately 6%. In this context, the limited increase in the basic charge is appropriate, as it avoids further exacerbating over-recovery. The moderate increase in the energy charge is aligned with prevailing bulk supply cost pressures while remaining within reasonable limits. Overall, the proposed adjustments are considered reasonable, and it is recommended that the proposed adjustments be approved, noting that future tariff downwards adjustments may be required to address the identified over-recovery.
Energy charge (c/kWh)	259.35	272.32	5%	272.32	5%	

DETAILS OF TARIFFS APPLIED FOR						
11. Rural >50 kVA up to 100kVA	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge (R/month)	3,922.22	4,000.66	2%	4,000.66	2%	The proposed tariff reflects a differentiated increase, with a 2% adjustment in the basic charge and a 5% increase in the energy charge. This indicates a measured approach to balancing fixed and variable cost recovery. The COS study indicates that this customer category is over-recovering by approximately 6%. In this context, the limited increase in the basic charge is appropriate, as it avoids further exacerbating over-recovery. The moderate increase in the energy charge is aligned with prevailing bulk supply cost pressures while remaining within reasonable limits. Overall, the proposed adjustments are considered reasonable, and it is recommended that the proposed adjustments be approved, noting that future tariff downwards adjustments may be required to address the identified over-recovery.
Energy charge (c/kWh)	259.35	272.32	5%	272.32	5%	

12. Bulk Urban MV	***FY2025/26 Approved***	***FY2026/27 Proposed***	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Monthly: R/month	3,105.27	3,167.38	2%	3,167.38	2%	The proposed tariff reflects differentiated increases across components, with a 2% adjustment in fixed charges (basic, access and demand charges) and higher increases in energy charges, particularly a 10% increase in peak energy. This indicates a deliberate shift towards strengthening variable cost recovery in line with cost drivers, while limiting increases in fixed charges. The COS study indicates that this customer category is under-recovering by approximately 19%. In this context, the higher increases in energy charges are justified, as they support improved cost reflectivity and align with rising bulk supply costs, particularly TOU energy costs. The relatively modest increases in fixed and demand-related charges help to avoid excessive cost burdens on capacity while maintaining tariff stability. The TOU structure remains intact, preserving appropriate price signals that encourage efficient consumption and load shifting, particularly during peak periods. Overall, the proposed tariff demonstrates a balanced approach to addressing under-recovery while maintaining economic efficiency and it is recommended that the proposed adjustments be approved.
Access Charge-R/kVA						
12 months	102.68	104.73		104.73		
6 months	51.33	52.36		52.36		
4 months	34.23	34.91		34.91		
2 months	17.10	17.44		17.44		
Low Season Energy Charges:						
Peak (c/kWh)	318.28	350.11	10%	350.11	10%	
Standard (c/kWh)	173.34	190.67		190.67		
Off-peak (c/kWh)	107.62	118.38		118.38		
High Season Energy Charges:						
Peak (c/kWh)	628.88	691.77		691.77		
Standard (c/kWh)	214.17	235.59		235.59		
Off-peak(c/kWh)	119.52	131.47		131.47		
Reactive energy charge (c/kVArh)	10.67	13.50		13.50		
Demand charge R/kVA	122.08	124.52	2%	124.52	2%	

13. Bulk Urban LV	***FY2025/26 Approved***	***FY2026/27 Proposed***	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Monthly: R/month	3,105.27	3,167.38	2%	3,167.38	2%	The proposed tariff reflects differentiated increases across components, with a 2% adjustment in fixed charges (basic, access and demand charges) and higher increases in energy charges, particularly a 10% increase in peak energy. This indicates a deliberate shift towards strengthening variable cost recovery in line with cost drivers, while limiting increases in fixed charges. The COS study indicates that this customer category is under-recovering by approximately 20%. In this context, the higher increases in energy charges are justified, as they support improved cost reflectivity and align with rising bulk supply costs, particularly TOU energy costs. The relatively modest increases in fixed and demand-related charges help to avoid excessive cost burdens on capacity while maintaining tariff stability. The TOU structure remains intact, preserving appropriate price signals that encourage efficient consumption and load shifting, particularly during peak periods. Overall, the proposed tariff demonstrates a balanced approach to addressing under-recovery while maintaining economic efficiency and it is recommended that the proposed adjustments be approved.
Access Charge- R/kVA						
12 months	112.04	114.28		114.28		
6 months	56.01	57.13		57.13		
4 months	37.34	38.09		38.09		
2 months	18.66	19.03		19.03		
Low Season Energy Charges:						
Peak (c/kWh)	318.28	350.11	10%	350.11	10%	
Standard (c/kWh)	173.34	190.67		190.67		
Off-peak(c/kWh)	123.67	136.04		136.04		
High Season Energy Charges:						
Peak(c/kWh)	628.88	691.77		691.77		
Standard (c/kWh)	225.01	247.51		247.51		
Off-peak(c/kWh)	126.45	139.10		139.10		
Reactive energy charge (c/kVArh)	10.67	13.50		13.50		
Demand charge R/kVA	128.57	131.14	2%	131.14	2%	

14. Special Customer-Stellenbosch municipality TOU MV						
	FY2025/26 Approved	**FY2026/27 Proposed**	**% increase**	**Recommended Tariffs**	**Recommended % increase**	***Analysis and Key findings***
Service Charge: R/day	201.62	219.11	9.01%	219.11	9.01%	The proposed tariff reflects a 9.01% increase in the service charge, with corresponding upward adjustments across energy, capacity, demand and ancillary charge components. The increases are applied consistently across the tariff structure, indicating a systematic response to underlying cost pressures. The COS indicates that this customer category is under-recovering by approximately 20%. In this context, the proposed increases are justified as they support a meaningful movement towards cost reflectivity. The adjustments to both capacity- and demand-related charges appropriately align revenue recovery with network and generation cost drivers, while the TOU energy charges continue to reflect the temporal variation in supply costs. The TOU structure remains intact, preserving efficient price signals that incentivise load shifting away from peak periods. Furthermore, the inclusion and adjustment of ancillary, network and legacy charges contribute to a more comprehensive recovery of system-related costs. Overall, the proposed tariff demonstrates a structured and cost-aligned approach to addressing under-recovery while maintaining economic efficiency and it is recommended that the proposed adjustments be approved.
Low Season Energy charges:						
Peak(c/kWh)	289.98	316.11		316.11		
Standard c/kWh	163.04	177.73		177.73		
Off-peak(c/kWh)	116.47	126.96		126.96		
High Season Energy charges:						
Peak c/kWh	698.76	762.72		762.72		
Standard c/kWh	174.68	190.42		190.42		
Off-peak c/kWh	116.47	126.96		126.96		
capacity charge R/kVA	36.97	40.30		40.30		
Demand charge R/kVA	24.67	26.89		26.89		
Administration charge (R/once off)	19.67	21.44		21.44		
Ancillary service charge(c/kWh)	0.40	0.44		0.44		
Network charges R/month	10.75	11.72		11.72		
Subsidy charge(R/kWh)	0.0502	0.0547		0.0547		
Reactive Power Charge (c/kVArh)	32.20	35.10		35.10		
Legacy Charge (c/kWh)	22.59	24.63		24.63		
Generation Capacity Charge (R/kVA/m)	7.71	8.40		8.40		

DETAILS OF TARIFFS APPLIED FOR						
15. Bulk: Small bulk users (40kVA to	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge(R/month)	1,969.72	2,009.11	2%	2,009.11	2%	The proposed tariff reflects a differentiated adjustment, with a 2% increase in the basic charge and demand charge and a 5% increase in the energy charge. This approach indicates a controlled shift towards strengthening variable cost recovery while limiting increases in fixed and capacity-related charges. The COS study indicates that this customer category is over-recovering by approximately 5%. In this context, the relatively low increases in the basic and demand charges are appropriate, as this avoids further exacerbating over-recovery from fixed components. The moderate increase in the energy charge aligns with prevailing rising bulk supply costs while remaining within reasonable bounds. Overall, the proposed adjustments are considered reasonable, and it is recommended that the proposed adjustments be approved, noting that future tariff adjustments may be required to address the identified over-recovery.
Demand charge(R/kVA)	393.35	401.22		401.22		
Energy charge (c/kWh)	196.70	206.54	5%	206.54	5%	

DETAILS OF TARIFFS APPLIED FOR						
16. Bulk: Large bulk users (> 100kVA)	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge (R/month)	2,873.92	2,931.40	2%	2,931.40	2%	The proposed tariff reflects moderate and differentiated increases, with a 2% adjustment in the basic and demand charges and a 5% increase in the energy charge. This indicates a balanced approach to revenue recovery across fixed, capacity and variable cost components. The COS indicates that this customer category is under-recovering by approximately 2%. In this context, the proposed increases are appropriate, as they support a gradual move towards cost-reflectivity without imposing excessive tariff adjustments. The higher increase in the energy charge aligns with prevailing bulk supply cost pressures, while the modest adjustments to fixed and demand charges maintain tariff stability. Overall, the proposed tariff is considered reasonable, and it is recommended that the proposed adjustments be approved.
Demand charge (R/kVA)	487.04	496.78		496.78		
Energy charge (c/kWh)	159.23	167.19	5%	167.19	5%	

DETAILS OF TARIFFS APPLIED FOR						
17. Small Domestic TOU-Single Phase ≥ 30 Amp	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge/A/month	New	13.19	*N/A*	13.19	*N/A*	The proposed tariff introduces a new TOU structure, comprising a basic charge and differentiated energy charges across peak, standard and weekend periods. This represents a positive shift towards improved cost-reflectivity, as pricing is aligned with the temporal variation in electricity supply costs. The Municipality has indicated that the tariff is intended to enable residential customers to actively manage their consumption patterns and associated costs. The significant differentiation between peak and off-peak periods provides appropriate price signals to incentivise load shifting and demand-side management. Although no direct percentage increase is applicable, the tariff design reflects a balanced approach between financial sustainability and customer affordability. The structure remains transparent and consistent with TOU principles. Overall, the introduction of this tariff is considered appropriate, and it is recommended that the proposed adjustments be approved.
Peak (c/kWh)	New	625.95		625.95		
Standard (c/kWh)	New	236.21		236.21		
Weekend (c/kWh)	New	215.29		215.29		

18.Small Domestic TOU – Three Phase ≥ 20 Amp	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Basic Charge/A/month	New	11.16	***N/A***	11.16	***N/A***	The proposed tariff introduces a new TOU structure, comprising a basic charge and differentiated energy charges across peak, standard and weekend periods. This represents a positive shift towards improved cost-reflectivity, as pricing is aligned with the temporal variation in electricity supply costs. The Municipality has indicated that the tariff is intended to enable residential customers to actively manage their consumption patterns and associated costs. The significant differentiation between peak and off-peak periods provides appropriate price signals to incentivise load shifting and demand-side management. Although no direct percentage increase is applicable, the tariff design reflects a balanced approach between financial sustainability and customer affordability. The structure remains transparent and consistent with TOU principles. Overall, the introduction of this tariff is considered appropriate, and it is recommended that the proposed adjustments be approved.
Peak (c/kWh)	New	625.95		625.95		
Standard (c/kWh)	New	236.21		236.21		
Weekend (c/kWh)	New	215.29		215.29		

19. Domestic, Commercial, Rural, Bulk Users and Bulk Time of use customers (excluding small domestic time of use) **Feed in tariff**	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Feed in tariff-energy charge (c/kWh)-	(95.06)	(103.62)	9.01%	(103.62)	9.01%	The proposed feed-in tariff reflects a 9.01% increase in the energy credit provided to customers. This adjustment is broadly aligned with prevailing bulk electricity cost increases, which is appropriate to ensure that compensation for exported energy remains reflective of avoided energy costs. The upward revision enhances the attractiveness of embedded generation, particularly for customers investing in renewable energy solutions, while maintaining a controlled and sustainable level of compensation that does not place undue financial pressure on the Municipality. Furthermore, the tariff remains structured as an energy-based credit, ensuring simplicity and transparency in its application. Overall, the proposed adjustment is considered reasonable, supports the integration of distributed generation and it is recommended that the proposed adjustments be approved.

20. Co-generation feed-in for small domestic time of use: Domestic Co-generation (1 and 3 Phase) **Feed in tariff**	**FY2025/26 Approved**	**FY2026/27 Proposed**	***% increase***	***Recommended Tariff***	***Recommended % increase***	***Analysis and Key findings***
Feed-in tariff: Peak (R/kWh)	New	(292.35)	**N/A**	(292.35)	**N/A**	The proposed tariff introduces a TOU-differentiated feed-in structure for domestic co-generation customers, with distinct rates for peak, standard and weekend periods. This represents a positive development, as it aligns compensation for exported energy with the temporal value of electricity. The higher (negative) credit during peak periods appropriately reflects the increased value of energy supplied to the grid during high-demand periods, while lower credits during standard and weekend periods are consistent with lower system demand. This structure provides efficient price signals to encourage customers to export energy when it is most needed. Although no direct percentage increase is applicable due to the tariff being newly introduced, the design is consistent with TOU principles and supports the integration of distributed generation in a controlled and cost-reflective manner. Overall, the proposed tariff is transparent, economically efficient and it is recommended that the proposed adjustments be approved.
Feed-in tariff: Standard (R/kWh)	New	(154.40)		(154.40)		
Feed-in tariff: Weekend (R/kWh)	New	(133.01)		(133.01)		

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

10.1. From a conspectus of the facts and evidence presented to the REC, supporting information, stakeholder inputs and applicable legal framework, it is appropriate to consider and approve DLM's tariff application as set out in this RfD for FY2026/27.

End