Kgatelopele Local Municipality Cost of Supply Study Report

1. Introduction

A critical first step in understanding the operational performance of an electricity distributor is to conduct a Cost of Service (COS) study and sometimes referred to as a Cost to Serve (CTS) study. The objective of this study is to fairly and equitably allocate all costs associated with servicing customers among different customer classes. To support this objective, the National Energy Regulator of South Africa (NERSA) has developed a COS Framework for all licensed electricity distributors ('licensees'), in the country. This framework will serve as a guideline for licensees when conducting their own COS studies.

2. Study Area Overview

Kgatelopele Municipality is a Category B municipality found in the South African province of Northern Cape, and it has a population of 19 854. The total energy sales of the municipality were 12,737,069 kWh in the 2024/25 financial year. In 2024/25, the majority of the electricity sales (64%) came from domestic customers, while 36% came from industrial and commercial customers.

Table 1 Municipal energy sales per customer category

	Sales (kWh)		Number of customers
	Actual		Actual
Consumer classification	2024/25	% Sales	2024/25
Free Basic Electricity	865 450	7%	1 567
Domestic (pre-paid)	6 973 073	55%	3 526
Domestic (conventional)	1 199 351	9%	204
Manufacturing / Industrial	2 221 949	17%	12
Commercial (pre-paid)	862 111	7%	78
Commercial (conventional)	510 003	4%	80
Street lighting	105 132	1%	0
Total	12 737 069	100%	5 487

3. COS Study Methodology

The Kgatelopele Local Municipality cost of supply study is a sophisticated study that is inclusive of all requirements of NERSA's current COS framework and also goes beyond it to accommodate electricity distribution businesses transitioning to a more infrastructure availability-based business.

The NERSA Cost Plus methodology has been used for both the wires and retail business revenue requirement determinations. The model has functionality to use the allowable return on the regulated asset base or asset values annuitized at selected discount rates to calculate the revenue requirement of the wires business.

The COS study is a multi-year model spanning across 3 years, namely, the most recent audited financial statement. The years are described as follows:

- Year 0 (FY 24/25) - The data input test year with the recently audited financial statements
- Year 1 (FY 25/26) - The current year in which the study is taking place
- Year 2 (FY 26/27) - The following year for which tariffs are being designed

This multi-year approach introduces several complexities and requires forecasting of costs across years, but it does bring a range of benefits to the analysis.

4. Overview of COS Study Key Results

The following key results were noted from X Municipality's COS study:

Revenue requirement

- The revenue requirement in FY26/FY27 is estimated as R64.42 million (excluding the impact of subsidy), increasing from R7.3 million in FY24/25
- The wires costs are dominated by network related costs, namely network repairs and maintenance, depreciation, cost of losses and other OPEX costs;
- With regards to the retail business, the dominant cost in this regard is energy purchases from Eskom; and
- Overall, a greater proportion of total electricity costs are incurred by the retail part of the business (around 74%) whilst 26% of the cost is related to the wires business.

Cost functionalisation

- Energy purchases are significant within the cost breakdown and dominate when compared to other costs such as OPEX and Surplus
- CAPEX costs do not contribute significantly to the overall cost breakdown each year as result of the rate of return for the analysis assumed at 2%.

Cost classification

- 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 TOU – mostly due to the low season covering a greater proportion of the year.
- Demand driven costs are depreciation, network repairs and maintenance, along with 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 the customers, which includes salaries.

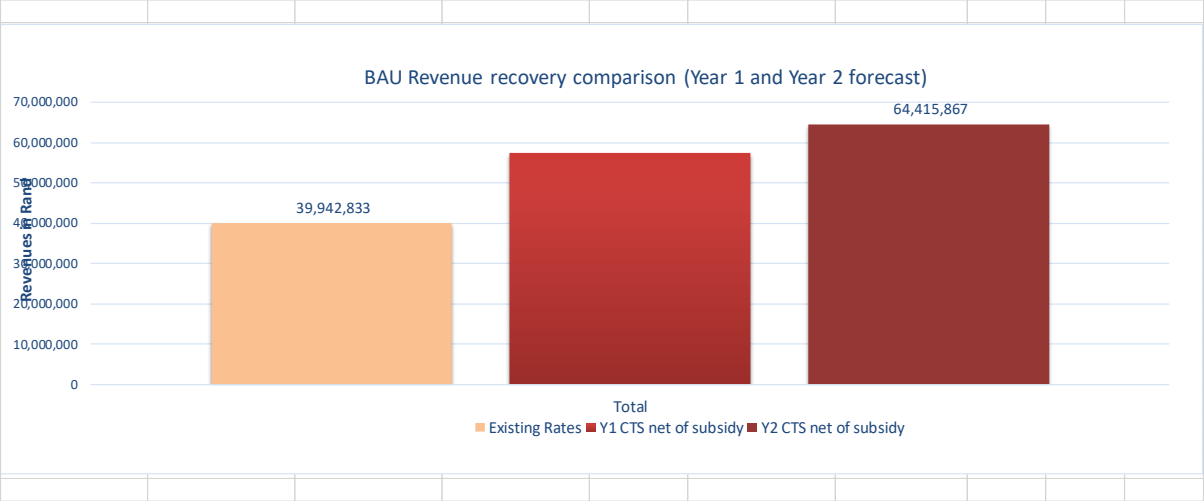
Cost allocation

- The domestic customer category carries the largest proportion of costs, followed by the industrial customers.
- Commercial customers and internal electricity requirements result in the lowest proportion of costs
- Differences in results between customer classes are mainly driven by differences in voltage of connection point, load factors, coincidence factors, and average specific consumption.

COS results

- Under the current rate regime, it is found that 62% cost-reflectivity is achieved for FY25/26
- There is a mismatch between the structure of the revenue breakdown and cost breakdown
- A 10.00% increase, with rate structure improvements and refined TOU - pricing signals would make rates cost-reflective in FY2025/26.

Table 2 BAU revenue comparison (FY25/26 forecast)



5. COS Study Analysis

Energy purchases analysis

The municipality purchases all their energy from Eskom via 1 point of delivery (PODs). The COS model captures the tariffs of each POD as well as the volumes purchased at each intake point.

COS models and revenue forecasts are sensitive to sales forecasts. The Kgatelopele Local Municipality COS model assumes an increase in sales between Year 0 and Year 1 of 5%. Thereafter, sales are assumed to keep increasing, at 5% per year.

Operating expenses analysis

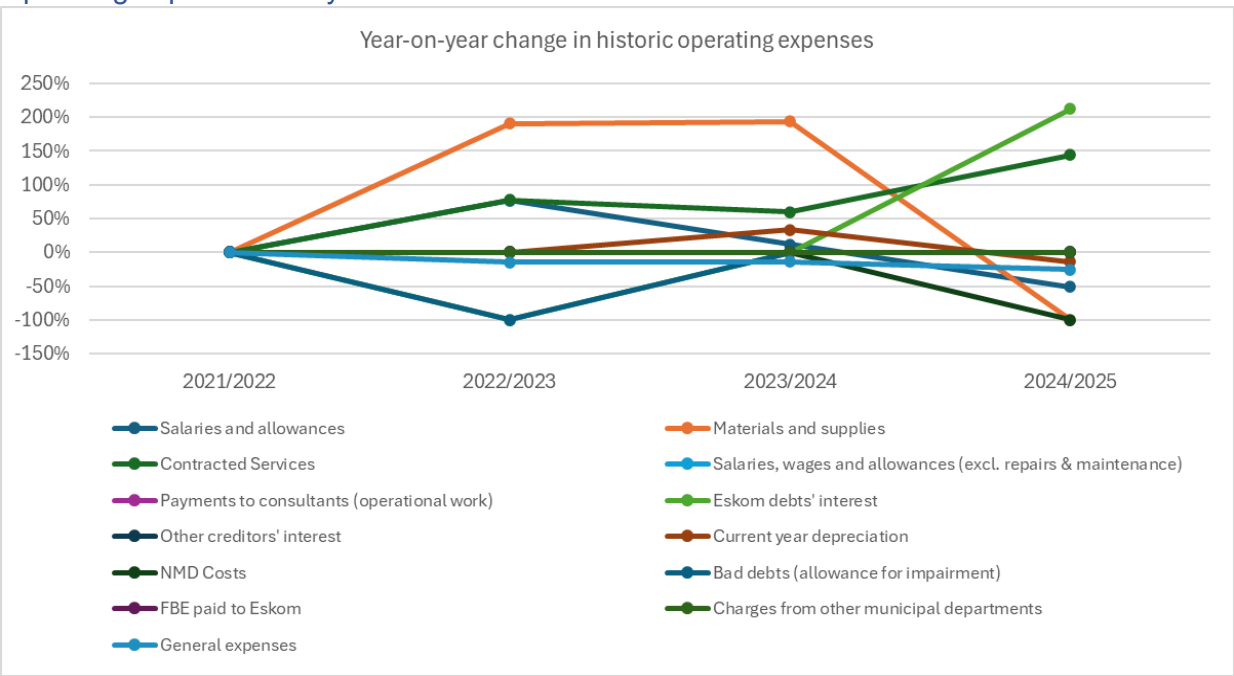


Figure 1 Trend Analysis of D-Form Expenses

When analysing the expenditure over the 5 years, the following observations were made:

- Salaries and allowances have increased over the years, but at a slower pace compared to electricity purchases.
- Materials and supplies have remained relatively constant until 2024/25, where it has seen a significant increase.
- Contracted services have fluctuated over the years, but have been consistently high.
- Payments to consultants have decreased steadily over the years, possibly indicating an increased in-house expertise.
- Depreciation and impairment have also increased over the years, indicating the aging of the infrastructure.

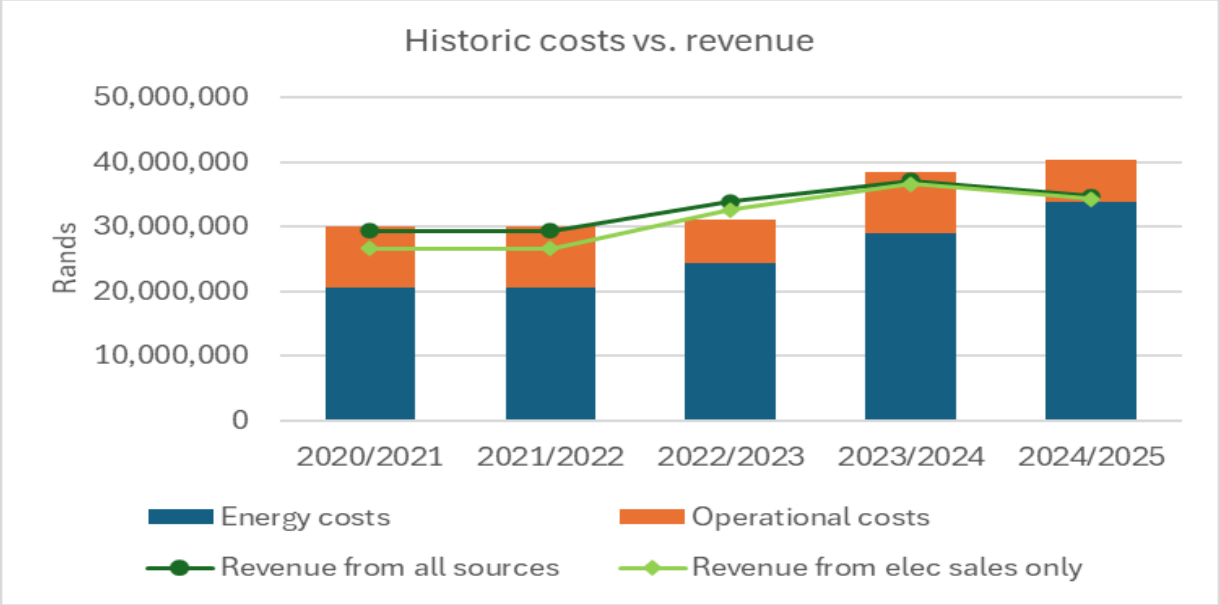


Figure 2 Historic energy costs and revenue comparison

Overall, the analysis suggests that the cost of electricity purchases has been the main driver of the increase in expenses, while revenue from electricity sales has been steadily increasing, resulting in an unregulated profit in the electricity sales of the municipality. There are also other areas of concern, such as the significant increase in bad debts in 2020/21 and the aging infrastructure, which may require attention to ensure the sustainability of the municipality.

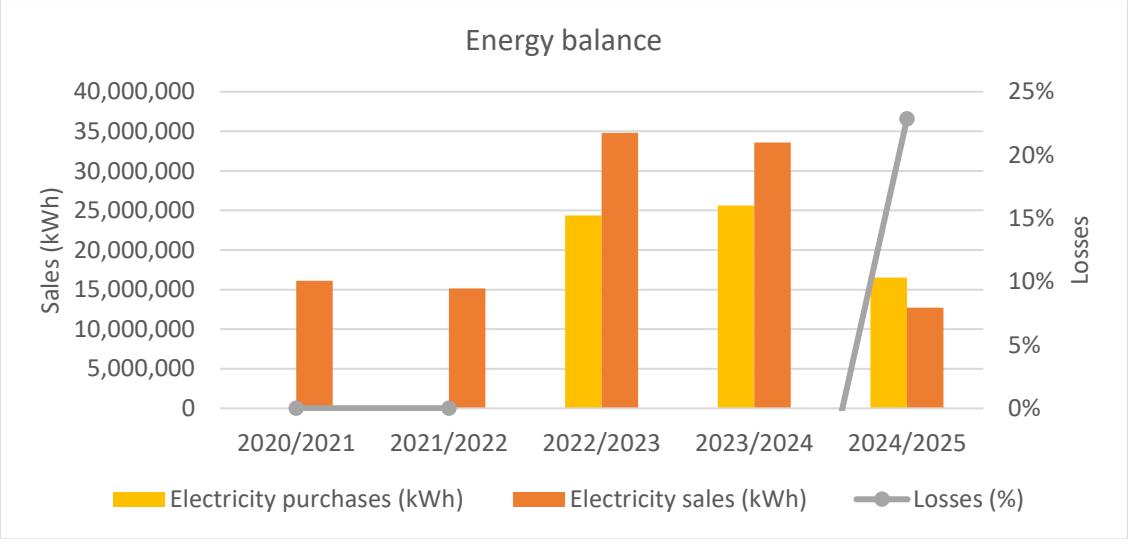


Figure 3 Energy balance and losses

Revenue requirement analysis

Section 3.2.1.1 of the NERSA COS framework deals with the revenue requirement and states that NERSA adopted the Cost-Plus Methodology 'as an interim methodology for implementation by licensees, including small licensees with limited capacity and database challenges. This is because other regulatory methodologies such as the rate of return, price cap, revenue cap, yard stick regulation, will be difficult to implement for a number of reasons, including the fact that licensees might struggle to keep proper accounting and property records, among other reasons. Even though these are historical costs (since the test year for the study was FY24/FY25), it is important to adjust these costs for prudency and efficiency so that when they are allocated to different customers, the allocation results reflect the proper costs. The framework covers the key elements of the revenue requirement including purchases, operating costs, repairs and maintenance, and depreciation and return on assets or interest on loans.

Figure 4 below offers a breakdown of the revenue requirement based on the various functions that have been established and split between the wires and retail/trading parts of the electricity value chain. The data below is determined based on a forecast for the financial year 2026/27 or Year 2.

Various aspects can be ascertained from the figure. These include:

- The revenue requirement in FY26/27 is estimated as R62,415,867(excluding the impact of subsidy)
- The wires costs are dominated by network related costs, namely network repairs and maintenance, depreciation and cost of losses;

- With regards to the retail business, the dominant cost in this regard is energy purchases from Eskom; and
- Overall, a greater proportion of total electricity costs are incurred by the retail part of the business R48 269 741(74%) whilst the costs related to the wires business is R16 645 560 (26%).

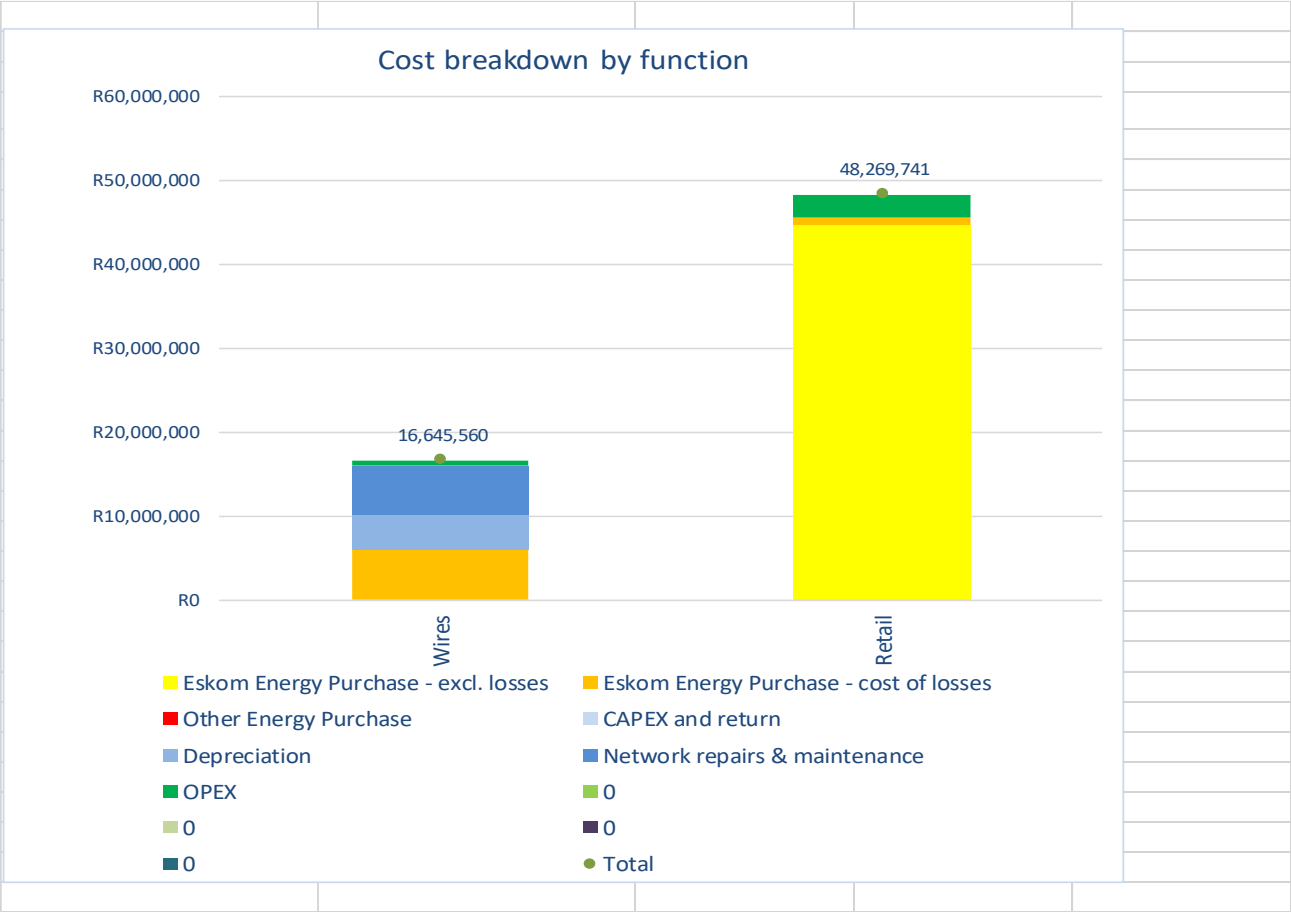


Figure 4 Cost breakdown by function

Energy Purchases

Kgatelopele Local Municipality has one incoming electricity supplies from Eskom that it uses for distribution, namely DANIELSKUIL BULKFED 5000 KVA.

The municipal energy purchases have been adjusted for losses since the COS framework only allows for only 12% of losses as per the benchmark. The municipality's projected losses for (FY26/27) are 23%. The municipality buys electricity from Eskom and the total energy purchases were projected to be R44 716 822 in (FY26/27).

The licensee used the purchases for the test period to forecast sales for the financial year that it is applying for. The forecasted purchases include street lighting electricity, own use electricity and the allowable loss factor.

Cost functionalisation, classification, and allocation

The model follows the NERSA COS framework methodology for these methodological steps. Costs are first split into their function, and then classified according to their cost drivers, and finally allocated to the customer categories according to usage. These methodological steps are sound and the key results have been summarised in the previous section.

COS results

The key finding is that the municipality needs to increase its tariffs by 61.3% to achieve full cost-reflectivity in FY2026/27.

The municipality's COS results are shown per tariff category in the figure below. The prepaid customers are the costliest to service.

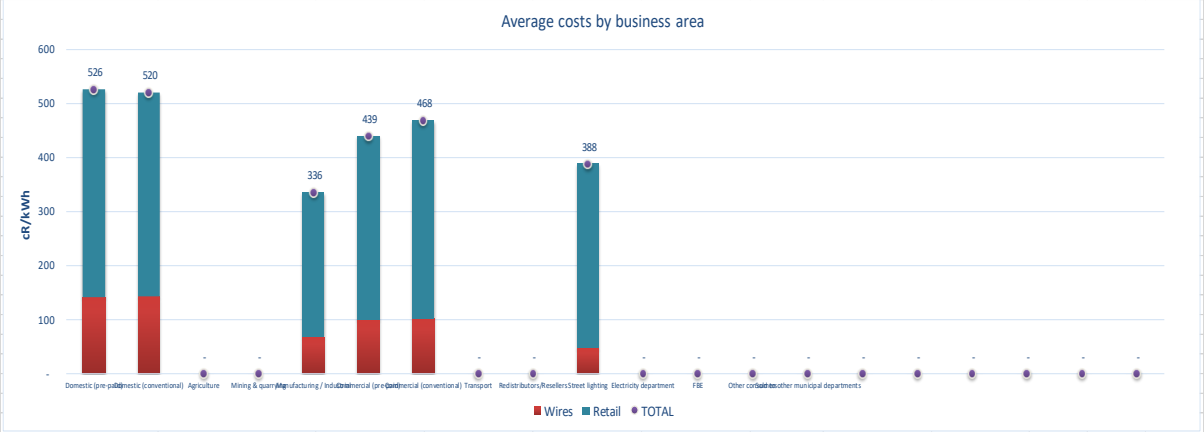


Figure 5 average costs by business area

Comparing these costs to the income per tariff category reveals the over or under recovery per tariff category, as shown in the figure below. When reading this graph, it is important to note that it is presented in % terms and not absolute Rand terms.

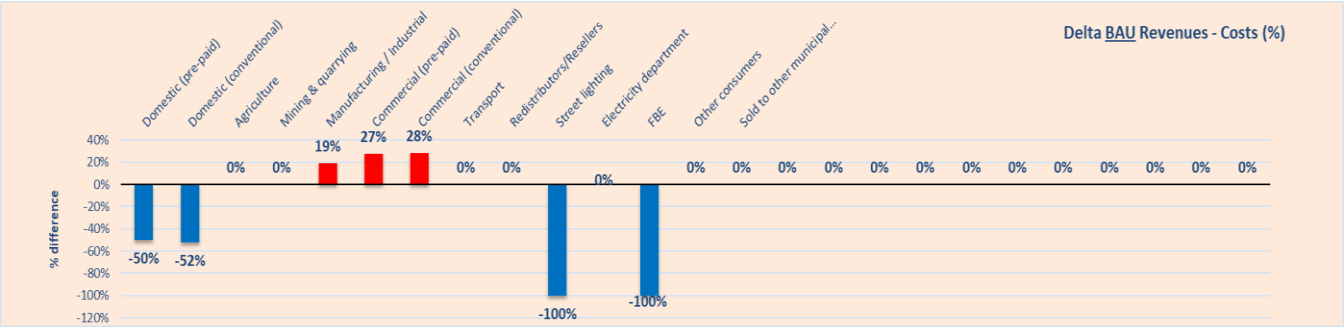


Figure 6 % Over/under recovery of customers

The key insight is that domestic customers are currently receiving electricity services at a price below cost (i.e., being cross-subsidized) while business scale customers are paying above cost for electricity.

The business as usual (BAU) rates as shown in the graph below indicate that existing tariff structures are not cost reflective. More than 85% of costs are recovered through a variable energy charge and this makes the municipality susceptible to volumetric risk. The cost of supply (CTS) results indicates that to achieve cost reflectivity, the municipality must recover less than 65% of their costs through variable energy charges, the remainder of costs through stable or fixed demand and customer charges. As the uptake of distributed generation increases in electricity distribution networks, a more cost reflective approach to setting tariffs is proposed.

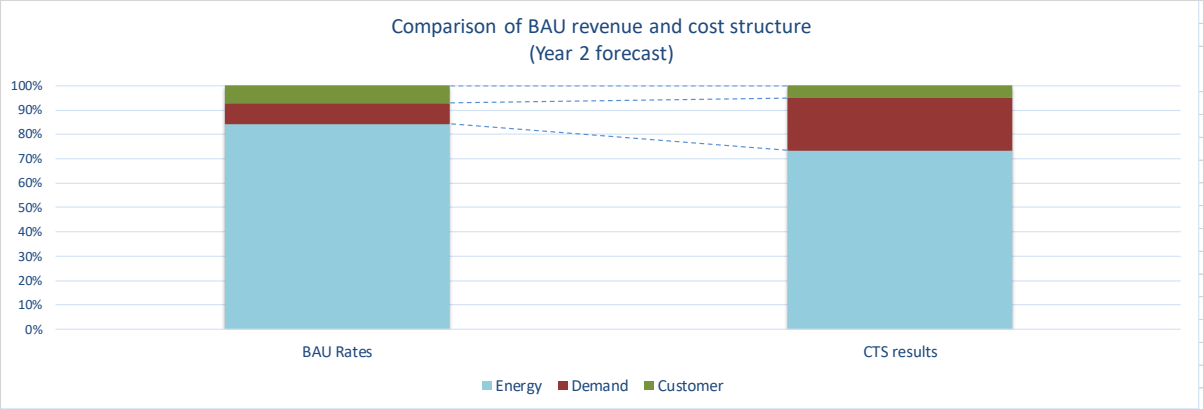


Figure 7 Comparison of revenue and cost structure

Cost reflective charges are shown in the table below. These are the result of the cost of supply study and indicate what the municipality should be charging customers to recover 100% of their revenue. However, due South Africa's socio-economic conditions and the municipality's revenue recovery strategy, the municipality may deviate from these cost reflective tariffs in the tariff design stage of the cost of supply study. Rate design is discussed in the next section and may deviate from these results based on the municipality's maximum tolerable tariff increase, subsidy policy, price signals, tariff design choices, etc.

Table 3 Cost reflective results by business area, class, season, TOU

Business area:			
Cost class:	Total	Total	Total
Season:	Energy	Demand	Customer
TOU:	All	All	All
Unit:	All	All	All
	c/kWh	R/kVA/month	R/POD/month
Customer Categories			
Domestic (pre-paid)	384	285	27
Domestic (conventional)	384	277	27
Agriculture	-	-	-
Mining & quarrying	-	-	-
Manufacturing / Industrial	280	162	2,124
Commercial (pre-paid)	297	172	531
Commercial (conventional)	297	175	531
Transport	-	-	-
Redistributors/Resellers	-	-	-
Street lighting	384	-	-
	-	-	-
	-	287	27

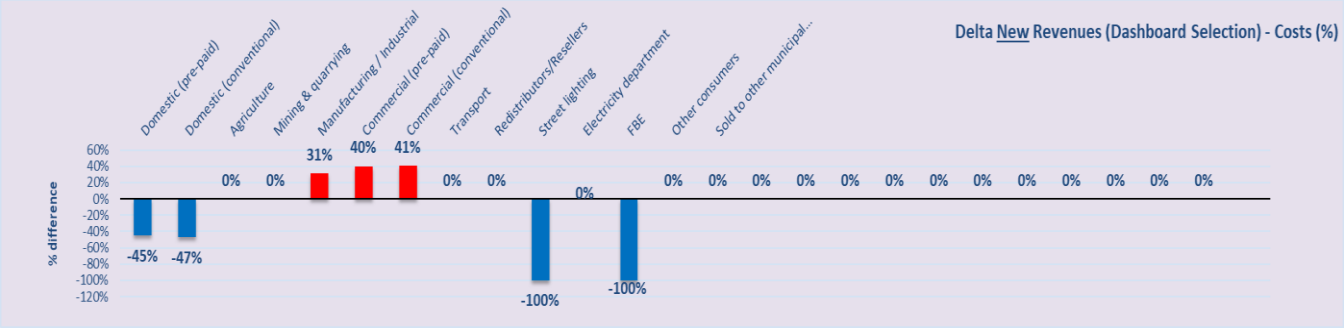
5. Rate design

Municipal tariff setting is guided by Municipal Tariff Policy, which is developed with reference to various pieces of legislation, but in particular Sections 4 and 74 of the Municipal Systems Act (32 of 2000) and the National Electricity Pricing Policy (2008), which also outlines the General Tariff Principles as set out in S16 of the Electricity Regulation Act of 2006. The regulatory framework on tariffs seeks to balance the often competing or contradictory tariff principles of revenue sufficiency, economic efficiency, equity, fairness and simplicity.

The COS is an important, but not deterministic, input to tariff design. It enables a municipality (and the Regulator) to assess:

a. Revenue sufficiency of proposed tariffs and the financial sustainability of the utility.
b. That tariffs reflect the costs associated with rendering the services and those customers are treated equitably and pay in general proportion to use of services.
c. The reasonableness of the low-income tariff determination in line with guiding policy: including access to a free basic service plus lifeline tariff based on operation and maintenance only.
d. Whether environmental objectives are being encouraged; and
e. The transparency of subsidies and surcharges.

The municipality is proposing increasing its tariffs by 10.5% to achieve cost-reflectivity. In doing so, it will increase some categories more than others to manage the cross-subsidies in the system. After the proposed changes are implemented, the under and over recovery per tariff category presents as follows:



The key takeaway from the proposed tariffs is that the time-of-use tariffs have moved above cost-reflectivity and are now able to subsidise the smaller prepaid customers.

The only structural change the municipality is proposing is an introduction of seasonal tariffs for domestic customers. Low season tariffs are decreased by 9% and the three months of high season are increased by 49% in order match Eskom's seasonal billing and achieve the proposed overall 10% increase.

Furthermore, a high increase on basic charges is proposed for commercial and industrial customers in order to cover the cost to deliver electricity.

The new proposed tariff schedule is included as Annexure A in this report and the tariffs will be phased in over 1 year.

6. Key Assumptions

This section of the report outlines key assumptions that were made in the development of this Cost of Supply study. These assumptions were essential due to granular data unavailability and lack of clear planning approaches in the municipality. These assumptions are as follows:

- The energy forecasts will increase year on year by 5%
- The D-Form expenses will increase year on year by 10%
- The total maximum demand of the municipality is 6.8 MVA.
- The Eskom bulk purchase energy price was assumed to increase by year on year by 12.70%.
- For customers with an inclining block tariff, the block 2 tariff was used as the test year input. The model is unable to cater for inclining block tariff inputs.
- The actual municipal energy losses for FY2024/25 were 23% however, energy losses were capped at 12% as per the COS framework.

7. Data description and improvements

The municipality relies on its information systems for all the information used. The data collated can be relied upon for accuracy.

The municipality is constantly implementing data cleansing process in order to guarantee integrity.

ELECTRICITY	Low Season			High Season		
Domestic Households (Prepaid)	**Current rates**	**New Rates**	**Increase**	**Current rates**	**New Rates**	**Increase**
Tariffs Applied for:						
Block 1 (0-50 kWh)	1.88	1.71	-9.16%	1.88	2.80	48.65%
Block 2 (51-350 kWh)	2.42	2.20	-9.16%	2.42	3.60	48.65%
Block 3 (351-600 kWh)	3.43	3.12	-9.16%	3.43	5.10	48.65%
Block 4 (>600 kWh)	4.03	3.66	-9.16%	4.03	5.99	48.65%
Basic Charges	34.27	39.14	14.20%	34.27	39.14	14.20%
Basic Charges (Indigent) - Only for first prepaid meter	FREE			FREE		
Basic Charges (Indigent) - Second, third ,etc. prepaid meter	34.27	39.14	14.20%	34.27	39.14	14.20%
Domestic Households (Conventional)						
Tariffs Applied for:						
Block 1 (0-50 kWh)	1.88	1.71	-9.16%	1.88	2.80	48.65%
Block 2 (51-350 kWh)	2.42	2.20	-9.16%	2.42	3.60	48.65%
Block 3 (351-600 kWh)	3.43	3.12	-9.16%	3.43	5.10	48.65%
Block 4 (>600 kWh)	4.03	3.66	-9.16%	4.03	5.99	48.65%
Basic Charge	34.27	39.14	14.20%	34.27	39.14	14.20%
Basic Charge on Vacant Stands	741.35	815.48	10.00%	741.35	815.48	10.00%
Business (Commercial)						
Business Prepaid Single Phase	3.73	4.19	12.22%	3.73	4.19	12.22%
Business Prepaid Three Phase	3.73	4.19	12.22%	3.73	4.19	12.22%
Business Conventional Single Phase	3.94	4.15	5.42%	3.94	4.15	5.42%
Business Conventional Three Phase	3.94	4.15	5.42%	3.94	4.15	5.42%
Demand KVA Meters (per KVA)	292.02	235.66	-19.30%	292.02	235.66	-19.30%
Basic charge Conventional	487.19	752.05	54.36%	487.19	752.05	54.36%
Basic charge Prepaid	487.19	743.34	52.58%	487.19	743.34	52.58%
Basic Charge on Vacant Stands	487.19	743.34	52.58%	487.19	743.34	52.58%
Industrial						
Energy	3.17	3.64	15.06%	3.17	3.64	15.06%
Demand KVA Meters (per KVA)	292.02	319.69	9.47%	292.02	319.69	9.47%
Basic Charge Conventional & Prepaid	1,006.89	1,422.62	41.29%	1,006.89	1,422.62	41.29%
Basic Charge on Vacant Stands	1,006.89	1,422.62	41.29%	1,006.89	1,422.62	41.29%
Schools, Public Benefit Organisation, Own use						
Energy	3.73	4.10	10.00%	3.73	4.10	10.00%
Demand KVA Meters (per KVA)	292.02	321.23	10.00%	292.02	321.23	10.00%
Basic Charge Conventional	439.23	483.15	10.00%	439.23	483.15	10.00%
Basic Charge Prepaid	439.23	483.15	10.00%	439.23	483.15	10.00%