



CENTLEC COST OF SUPPLY STUDY REPORT – 2024/25 to 2027/28

Official Endorsement

This Cost of Supply Study Report and accompanying COS Model (MS Excel), covering the financial years 2023/24 to 2027/28, has been formally reviewed and approved by CENTLEC.

Approved by:



Mr MS. Sekoboto,
Chief Executive Officer

Date: 24 / 04 / 2025

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ABBREVIATIONS

ABBREVIATION	DEFINITION
AMR	Automated Meter Reading
BAU	Business As Usual
CAPEX	Capital Expenditure
COS	Cost of Supply
CTS	Cost to Serve
FBE	Free Basic Electricity
IBT	Inclining Block Tariff
kV	Kilo Volts
kVA	Kilo-Volt Amperes
kWh	Kilo-Watt hour
MYPD	Multi-Year Price Determination
NERSA	National Energy Regulator of South Africa
OPEX	Operational Expenditure
POD	Point of Delivery
PODs	Points of Delivery
RAB	Regulated Asset Base
SOC	State-Owned Company
SSEG	Small-Scale Embedded Generation
ToU	Time of Use

Executive Summary

CENTLEC SOC (Ltd.), owned by Mangaung Metropolitan Municipality, has conducted a comprehensive Cost of Supply (COS) study to determine the actual costs of providing electricity services to its diverse customer base across its area of supply. This study follows the methodology established by the National Energy Regulator of South Africa (NERSA) while extending beyond standard requirements to accommodate the evolving business model of electricity distribution.

Key Findings

1. **Revenue Requirement:** The revenue requirement for FY2025/26 (Year 2) is estimated at R5,089,363,348 (excluding subsidies), representing a significant 31.0% increase from the R3,884,136,553 required in FY2024/25 (Year 1).
2. **Cost Structure Analysis:**
 - Retail costs account for 78.1% (R4,006,709,521) of total costs, with Eskom energy purchases representing 70.5% of retail costs
 - Wires business costs constitute 21.9% (R1,120,544,495), dominated by network repairs and maintenance (37.7%), cost of losses (32.6%), OPEX (19.7%), and depreciation (10.1%)
3. **Current Cost-Reflectivity:** Under existing tariffs, CENTLEC achieves only 76.3% cost-reflectivity for FY2025/26, indicating a significant gap between current revenues and the actual cost of service delivery.
4. **Cross-Subsidization:** Substantial cross-subsidization exists within the current tariff structure:
 - Residential and governmental categories (Free Basic Electricity, IBT Indigent, Departmental, IBT Domestic P&C) are heavily subsidized
 - Commercial and industrial users (Elecflex 3, Elecflex 2, Elecflex 1, Homeflex Three Phase) are paying significantly above their cost of service
5. **Tariff Structure Imbalance:** More than 80% of costs are currently recovered through variable energy charges, exposing CENTLEC to volumetric risk, while the cost structure indicates only approximately 55% should be recovered this way.

6. **System Performance:** CENTLEC has demonstrated improved operational efficiency with system losses at 7.74% for FY2023/24, well below NERSA's 12% benchmark, though projected to increase to 11.46% in FY2025/26.
7. **Financial Sustainability Concerns:** Analysis reveals a worsening financial deficit, which increased dramatically from R79.6 million in 2019/20 to R527.8 million in 2023/24, indicating urgent need for financial restructuring.

Recommendations

1. **Phased Tariff Implementation:** The cost of supply study indicates that CENTLEC would need to implement a 31% increase to achieve a cost-reflective tariff. Considering the current economic conditions, CENTLEC suggests adopting a gradual approach to tariff adjustments:
 - Implement a 14.5% average increase for FY2025/26, improving cost-reflectivity to 87.4%
 - Plan for subsequent increases in FY2026/27 (8.0%) and FY2027/28 (8.5%) to close the remaining gap
 - This phased approach aligns with Eskom's approved increases of 12.74%, 5.36%, and 6.19% respectively over the same period
2. **Structural Tariff Reforms:**
 - Gradually rebalance energy, demand, and customer charges to better align with actual cost structure (55% energy, 17% demand, 28% customer)
 - Implement differentiated increases across customer categories to address cross-subsidization while maintaining affordability
3. **Cost Containment:** Develop and implement comprehensive strategies to control operational costs, which have increased by 41.3% over the past five years.
4. **Operational Efficiency:** Continue focus on system loss reduction initiatives to maintain performance below the NERSA benchmark.
5. **Data Enhancement:** Improve asset data collection and analysis to enable more precise capital cost allocations in future COS studies, particularly regarding depreciation rates and asset condition assessments.

This Cost of Supply study provides CENTLEC with a solid foundation for tariff design decisions that balance financial sustainability with socioeconomic considerations while gradually moving toward more cost-reflective tariff structures. The recommended phased implementation approach allows for necessary revenue increases while avoiding tariff shock, supporting long-term planning, and maintaining affordable access to electricity for vulnerable customers.

1. Introduction

A critical first step in understanding the operational performance of an electricity distributor is to conduct a Cost of Supply (COS) study, 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. This allocation is essential for designing tariffs that reflect the true cost of providing electricity services while ensuring the financial sustainability of the distributor.

The COS study for CENTLEC SOC (Ltd.), a Mangaung Metropolitan Municipality entity, follows a standardized methodology to provide insights into the cost drivers behind electricity service delivery. It serves as the foundation for the tariff design process, enabling a balance between competing objectives of cost recovery, affordability, and promoting efficient electricity use.

This report presents the methodology, key findings, and recommendations from CENTLEC's Cost of Supply study for the financial year [Year 2], with projections based on the most recent audited financial data from [Year 0].

2. Study Area Overview

CENTLEC SOC (Ltd.) is owned by Mangaung Metropolitan Municipality, which is located in the Free State province of South Africa. This electricity distributor serves a diverse customer base across residential, commercial, and industrial sectors throughout the municipality's service area.

The total energy sales for CENTLEC were 1,317,819,501 kWh in the 2023/24 financial year. The customer base comprises 187,421 metering points across various customer categories. In 2023/24, the largest proportion of electricity sales came from the Elecflex 2 category (26.09%), followed by domestic customers under the IBT Domestic P&C category (37.22%), and Elecflex 3 (9.31%).

Table 1: CENTLEC Energy Sales per Customer Category (2023/24)

Customer Categories	Number of customers	Energy Sales (kWh)	% Energy Sales
IBT Indigent	39,708	23,824,800	1.81%
IBT Domestic P&C	143,140	490,521,503	37.22%
Homeflex Single Phase	23	298,946	0.02%

Customer Categories	Number of customers	Energy Sales (kWh)	% Energy Sales
Homeflex Three Phase	172	11,318,870	0.86%
Bulk Resell 2	32	31,568,431	2.40%
Bulk Resell 3	182	38,967,648	2.96%
Flat Business P&C	2,690	65,144,956	4.94%
Departmental	30	188,096	0.01%
Departmental ToU	7	740,623	0.06%
Comflex Single Phase	60	673,101	0.05%
Comflex Three Phase	641	35,980,484	2.73%
Elecflex 1	3	63,932,835	4.85%
Elecflex 2	169	343,838,628	26.09%
Elecflex 3	557	122,629,413	9.31%
Streetlights	-	86,405,321	6.56%
SSEG	-	0	0.00%
Sports Stadiums	7	1,785,846	0.14%
Total	187,421	1,317,819,501	100.00%

This customer composition highlights the diverse usage patterns across CENTLEC's service area, with significant contributions from both domestic and commercial/industrial sectors. The data shows a strong residential customer base by count (over 180,000 residential connections), while larger commercial and industrial customers account for a substantial portion of energy consumption.

3. COS Study Methodology

The CENTLEC SOC (Ltd.) cost of supply study follows a comprehensive approach that addresses all requirements of NERSA's current COS framework. This methodology also extends beyond the standard requirements to accommodate electricity distribution businesses transitioning to a more infrastructure availability-based business model.

For revenue requirement determinations, we have applied the NERSA Cost Plus methodology to both the wires and retail business segments. The model incorporates functionality to calculate the wires business revenue requirement using either the allowable return on the regulated asset base or asset values annuitized at selected discount rates.

This COS study is structured as a multi-year model spanning five years, anchored by the most recent audited financial statements. The timeframe is organized as follows:

Table 2: Timeframe for Cost to Serve Study

Reference Year	Applicable Year	Description
Year 0	2023/24	When data sets are last complete
Year 1	2024/25	When the CTS study is carried out
Year 2	2025/26	When new rates are implemented
Year 3	2026/27	Future projection
Year 4	2027/28	Future projection

This multi-year approach, though introducing forecasting complexities, provides several key benefits to the analysis:

1. It allows for a more dynamic view of cost structures over time
2. It accounts for changing customer behavior and usage patterns
3. It enables better planning for infrastructure investments
4. It provides a more stable foundation for tariff design
5. It aligns with NERSA's requirement for forward-looking cost assessments

The methodology follows the standard COS steps of determining the revenue requirement, functionalizing costs, classifying costs by their drivers, allocating costs to customer classes, and designing rates that reflect these costs while adhering to regulatory principles.

4. Overview of COS Study Key Results

The following key results were noted from CENTLEC SOC (Ltd.)'s COS study:

Revenue Requirement

- The revenue requirement in FY2025/26 (Year 2) is estimated as R5,089,363,348 (excluding the impact of subsidy), increasing from R3,884,136,553 in FY2024/25 (Year 1).

This substantial 31.0% increase in the revenue requirement between Year 1 and Year 2 has significant implications for CENTLEC's financial sustainability and tariff strategy. Such a pronounced increase reflects the growing gap between current tariff levels and the actual cost of providing electricity services. Several key factors contribute to this escalation:

1. **Rising Eskom bulk purchase costs:** The wholesale electricity costs from Eskom continue to climb at rates well above inflation, placing immediate pressure on CENTLEC's operating expenses.
2. **Infrastructure investment needs:** Aging distribution infrastructure requires increased maintenance and capital investment, contributing to higher depreciation expenses and capital returns.
3. **Operational cost pressures:** General increases in operational expenses including labor, materials, and contracted services have outpaced revenue growth in recent years.
4. **Declining cross-subsidization capacity:** The traditional model of commercial and industrial customers subsidizing residential users is becoming less sustainable as large consumers implement energy efficiency measures or seek alternative supply options.

This significant revenue requirement increase presents CENTLEC with complex challenges:

- **Tariff shock concerns:** Implementing the full required increase immediately would create financial hardship for many consumers, particularly vulnerable households and businesses still recovering from economic challenges.
- **Regulatory constraints:** NERSA's approval processes may limit the magnitude of allowable tariff increases in a single year.

- **Collection challenges:** Higher tariffs may exacerbate payment delinquency, potentially offsetting revenue gains with increased bad debt.
- **Socioeconomic considerations:** As an essential service provider, CENTLEC must balance financial sustainability with its mandate to provide affordable electricity access.

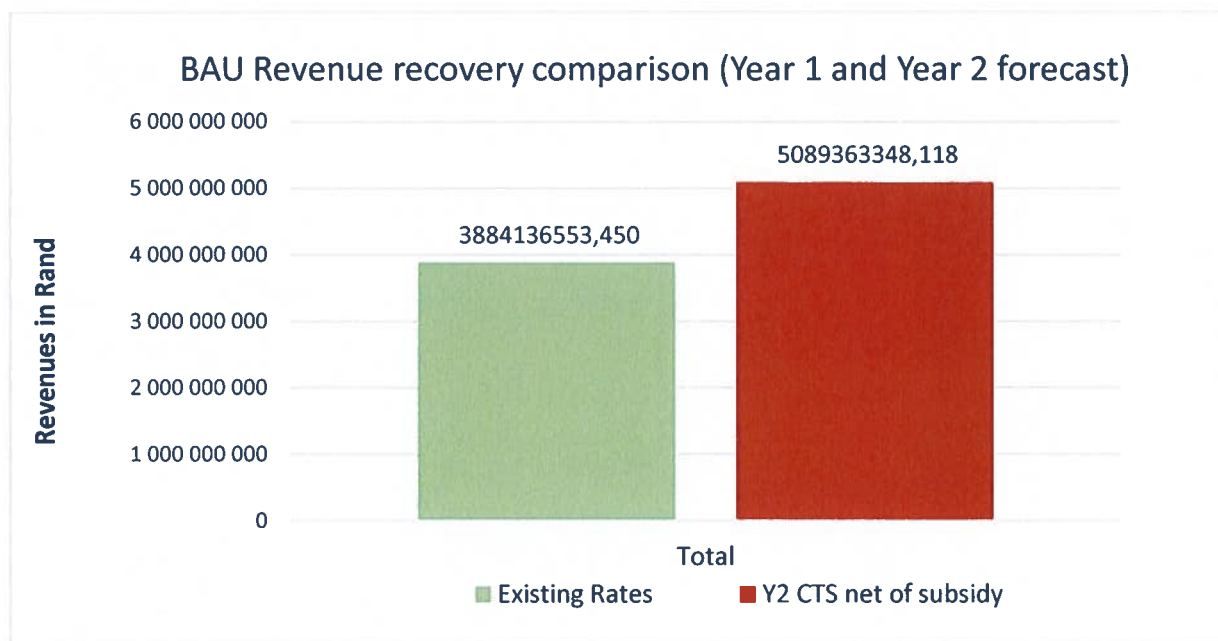


Figure 1: BAU Revenue recovery comparison (Year 1 and Year 2 forecast)

Cost Breakdown by Function

- The wires costs are dominated by network related costs, with network repairs and maintenance representing the largest portion of wires costs, followed by the cost of losses, OPEX, and depreciation. The total wires business costs amount to R1,120,544,495.35.
- With regards to the retail business, the dominant cost is energy purchases from Eskom (excluding losses), represented by the yellow portion of the graph, followed by OPEX (green portion). The retail business costs total R4,006,709,520.77.
- Overall, a greater proportion of total electricity costs are incurred by the retail part of the business (approximately 78.1%) while 21.9% of the cost is related to the wires business, as indicated by the R4,006,709,520.77 for retail versus R1,120,544,495.35 for wires.

This cost structure highlights the significant impact of Eskom energy purchases on CENTLEC's overall cost profile, emphasizing the importance of managing energy purchase costs and losses efficiently. The retail-heavy cost structure also indicates that while network infrastructure costs are substantial, the cost of the energy commodity itself remains the primary driver of CENTLEC's revenue requirement.

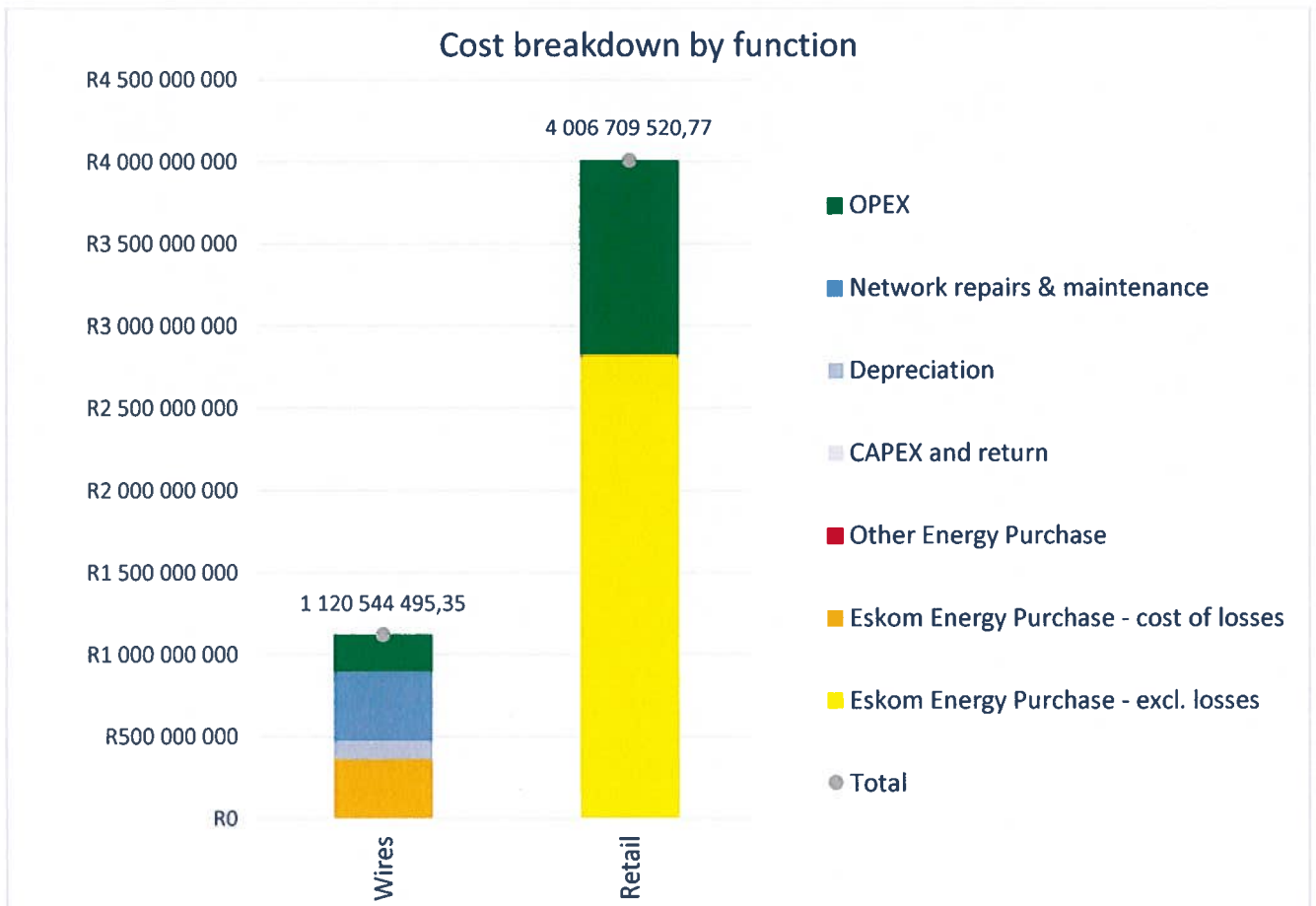


Figure 2: Cost breakdown by function

Cost Functionalisation

- Energy purchases are significant within the cost breakdown and dominate when compared to other costs such as OPEX and surplus.
- Eskom energy purchases (excluding losses) represent the largest portion of costs within the retail business.
- CAPEX costs do not contribute significantly to the overall cost breakdown each year as a 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 component, 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 include depreciation, network repairs and maintenance, along with energy purchase demand-related costs. The period of greatest demand-driven costs is during the Low Season.
- Customer-driven costs are incurred through offering the electricity distribution service to customers, which includes customer service operations and salaries.

Cost Allocation

- The domestic customer category carries the largest proportion of costs, followed by the commercial customers.
- Industrial 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 76.3% cost-reflectivity is achieved for FY2025/26 (Year 2), which represents a significant gap between current revenues and the actual cost of service delivery.
- There is a substantial mismatch between the structure of the revenue breakdown and cost breakdown, as illustrated in Figure 3. Current BAU rates recover over 80% of costs through energy charges, whereas the CTS results indicate that approximately 55% should be recovered through energy charges, with the remainder split between demand (15%) and customer (30%) charges.

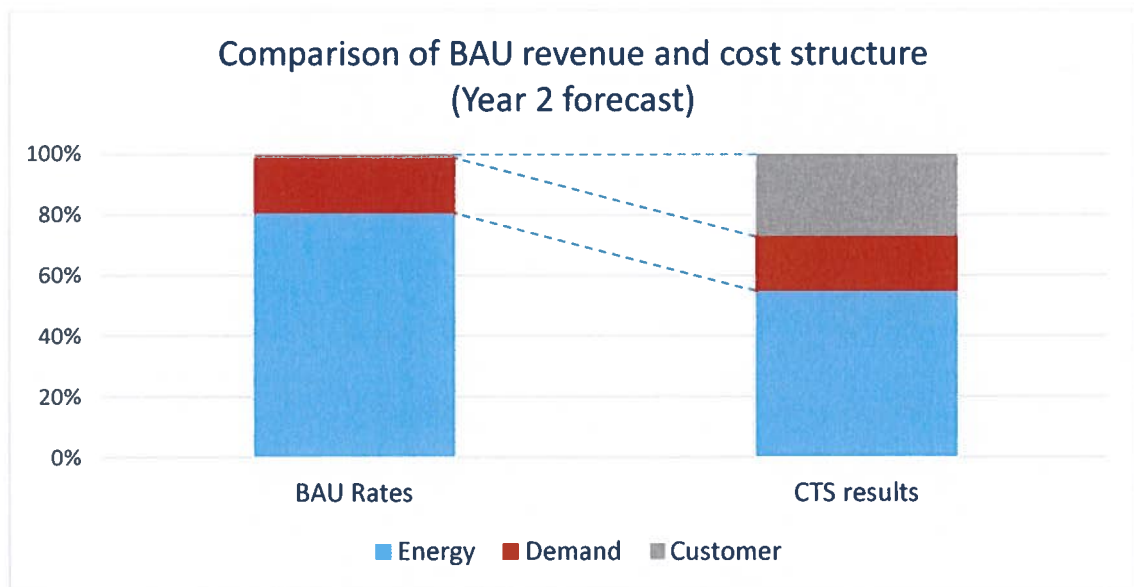


Figure 3: Comparison of BAU revenue and cost structure (Year 2 forecast)

- A 31.0% increase, with rate structure improvements and refined TOU pricing signals would be required to make rates fully cost-reflective in FY2025/26 (Year 2).

This structural imbalance in revenue recovery mechanisms exposes CENTLEC to significant volumetric risk, as energy sales fluctuations directly impact revenue stability. The current tariff structure's heavy reliance on energy charges contrasts with the utility's actual cost drivers, which include substantial fixed infrastructure and customer service components that remain constant regardless of energy consumption volumes.

5. COS Study Analysis

Energy Purchases Analysis

CENTLEC SOC (Ltd.) purchases all electricity supply from Eskom through eight (8) points of delivery (PODs). The COS model comprehensively captures both the unique tariff structures and the volumes purchased at each intake point, allowing for accurate allocation of costs across the distribution network.

The model incorporates detailed information on each POD, including:

- Time-of-use differentiation in purchasing patterns
- Seasonal variations in consumption

- Maximum demand charges at each point
- Network access charges and other fixed costs

This granular approach to energy purchase analysis ensures that the downstream cost allocation accurately reflects the true purchasing profile of CENTLEC and provides a solid foundation for the revenue requirement determination.

COS models and revenue forecasts are always sensitive to sales forecasts. Based on the data from the "Commercial Inputs (Years 1-4)" sheet, the CENTLEC COS model indicates an average increase in sales between Year 0 (2023/24) and Year 1 (2024/25) of 0.2% (from 1,317,819,501 kWh to 1,320,468,919 kWh). For Year 2 (2025/26), the model projects a decrease of 2.3% (to 1,290,515,841 kWh). The forecast continues with small declines of approximately 0.9% and 0.8% for Years 3 and 4 respectively.

This sales forecast reflects a more conservative outlook than previously modeled, showing essentially flat or slightly declining electricity consumption over the forecast period. This pattern may reflect changing customer consumption behaviors, increased energy efficiency, potential economic challenges in the service area, or the impact of distributed generation adoption among certain customer categories.

Operating Expenses Analysis

When analyzing the expenditure over the 6-year period from 2019/20 to 2024/25, indicated on figure 4 below, the following observations can be made:

- **Salaries and allowances** have shown a steady upward trend, increasing from R211,842,651 in 2019/20 to R300,613,957 in 2024/25, representing a 42% growth over the period, with a slight decline from the peak of R312,741,505 in 2023/24.
- **Materials and supplies** have fluctuated significantly, with a consistent increase from R47,655,154 in 2019/20 to a peak of R111,768,750 in 2022/23, followed by a dramatic 65% decline to R38,828,117 in 2023/24, before rebounding to R74,340,340 in 2024/25.
- **Contracted Services** were minimal in earlier years but increased substantially to R116,128,584 in 2023/24 and further to R132,015,972 in 2024/25, indicating a strategic shift toward outsourcing certain functions.

- **Salaries, wages and allowances (excluding repairs and maintenance)** have gradually increased from R159,384,745 in 2019/20 to R204,523,042 in 2024/25, with a noticeable peak of R212,774,033 in 2023/24.
- **Interest** payments have fluctuated considerably, rising from R259,228,846 in 2019/20 to a peak of R283,736,749 in 2022/23, before decreasing significantly to R120,055,645 in 2024/25, suggesting improved debt management or restructuring.
- **Operational Cost** shows high volatility, peaking at R348,786,719 in 2020/21, then declining sharply to R163,105,947 in 2021/22, before stabilizing around R180 million in recent years.

These expenditure patterns reflect CENTLEC's evolving operational strategies, with a clear shift toward increased contracted services in recent years while attempting to control salary costs. The substantial fluctuations in materials and supplies and operational costs suggest periodic capital investments or special projects that impact year-to-year expenses.

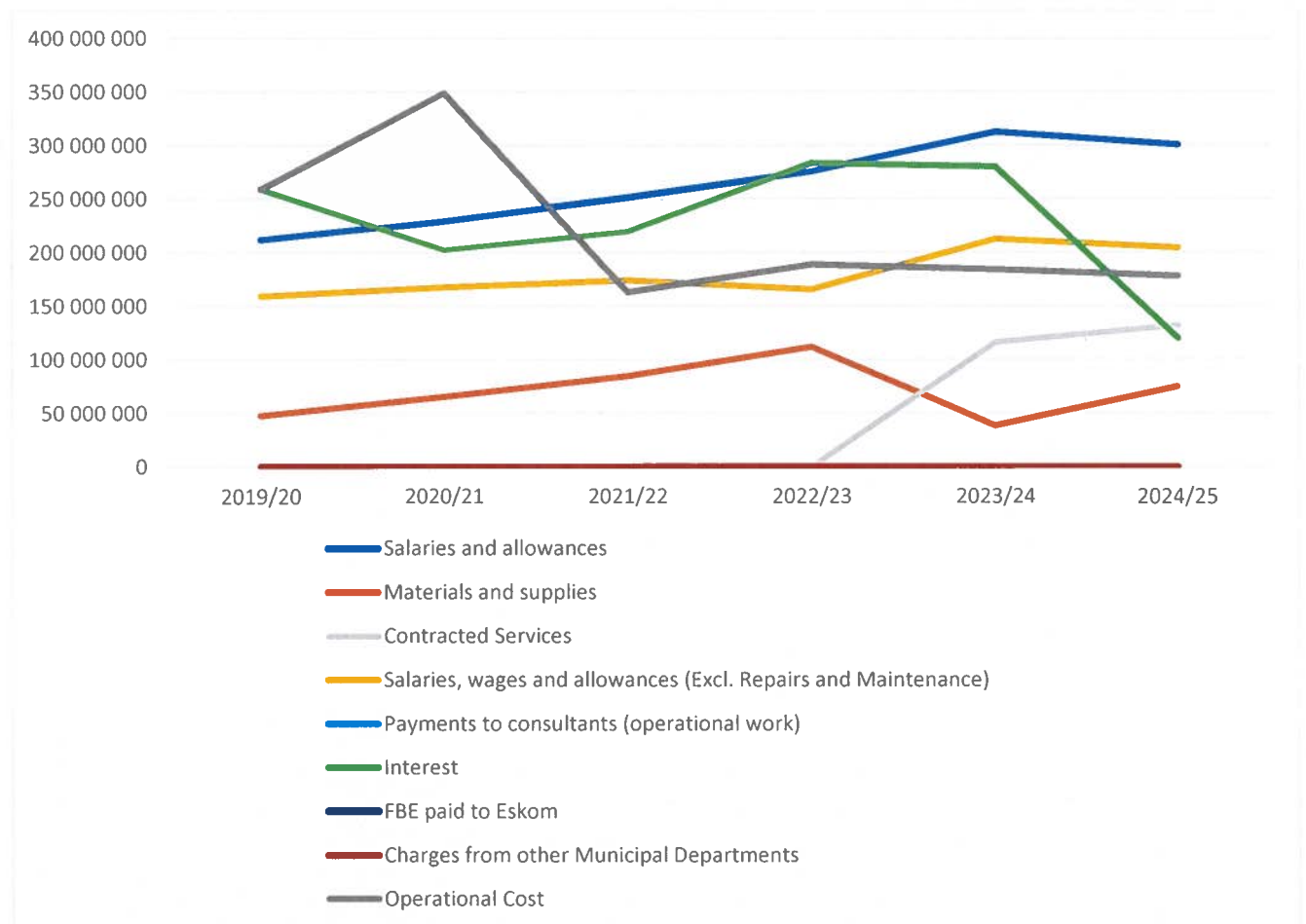


Figure 4: Trend Analysis of CENTLEC D-Form Expenses (2019/20 - 2024/25)

The financial trend analysis from 2019/20 to 2023/24, indicated on figure 5 below, reveals several important patterns:

- **Total Revenue from electricity distribution** has shown consistent growth, increasing from R2.64 billion in 2019/20 to R3.39 billion in 2023/24. This represents a 28.5% increase over the five-year period, reflecting a combination of annual tariff increases and the efforts to curb illegal connections and meter tampering.
- **Energy costs** have risen significantly from R1.69 billion in 2019/20 to R2.47 billion in 2023/24, representing a 45.9% increase over five years. This has substantially outpaced revenue growth, indicating that energy purchase costs have been a major driver of CENTLEC's financial challenges.
- **Operational costs** have increased from R1.02 billion to R1.45 billion (41.3% growth), further contributing to the overall cost pressure.
- Despite revenue growth, **the financial deficit** has worsened dramatically from R79.6 million in 2019/20 to R527.8 million in 2023/24, representing a 563% increase in the shortfall over the five-year period.
- The deficit trajectory shows a temporary improvement in 2020/21 (reducing to R35.2 million) before deteriorating significantly in subsequent years, with the most dramatic worsening occurring between 2021/22 and 2023/24.

This analysis indicates that CENTLEC faces severe and worsening financial challenges, with costs consistently and significantly outpacing revenue growth. The rapidly expanding deficit highlights an urgent need for comprehensive financial restructuring, including:

1. Tariff revisions to better reflect the actual cost of service delivery
2. Cost containment strategies, particularly for operational expenditures
3. Efficiency improvements to reduce technical and non-technical losses
4. Exploration of alternative revenue streams

The persistent and growing deficit suggests that CENTLEC's current financial model is not sustainable. Immediate intervention is required to address these structural issues and establish a path toward financial recovery and long-term sustainability, while balancing affordability considerations for consumers.

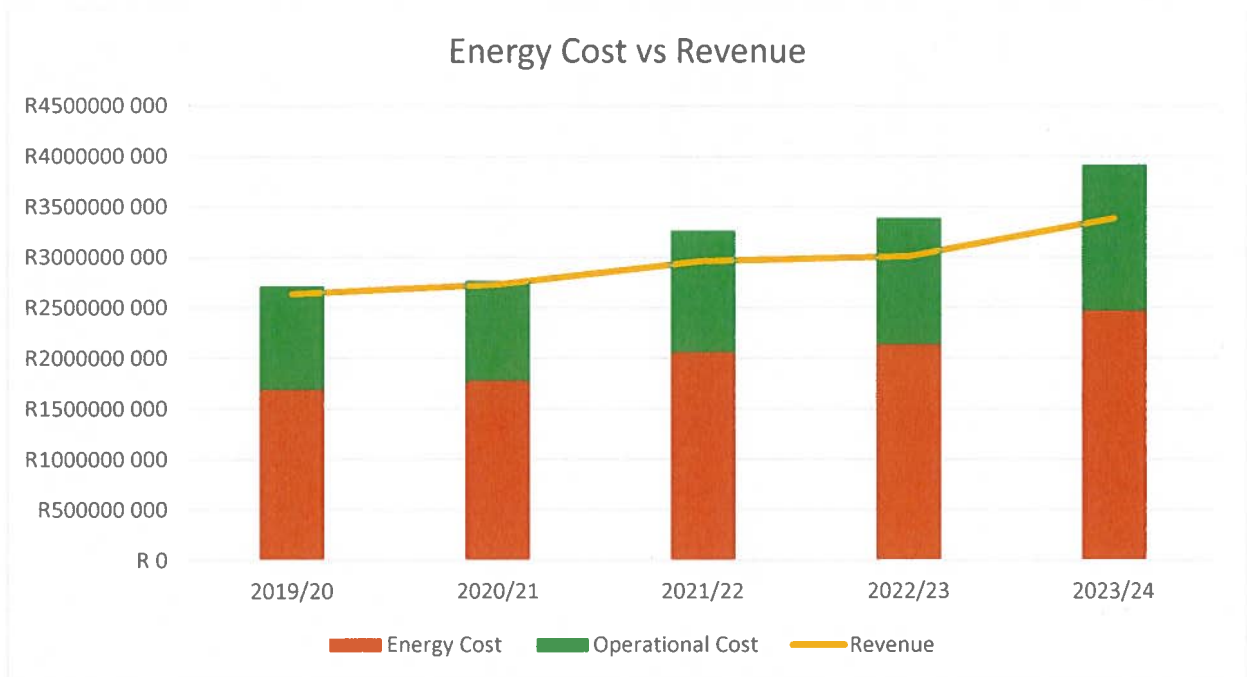


Figure 5: Historic Energy Costs and Revenue Comparison

The energy balance analysis from 2019/20 to 2023/24 reveals important trends in CENTLEC's operational efficiency:

- **Energy purchases** show a consistent declining trend over the five-year period, decreasing from 1,657,119,212 kWh in 2019/20 to 1,428,375,787 kWh in 2023/24. This represents a 13.8% reduction in energy procurement over the period.
- **Energy sales** follow a similar declining pattern, decreasing from 1,453,972,815 kWh in 2019/20 to 1,293,994,701 kWh in 2023/24. This represents a 11.0% reduction in sales over the five-year period.
- **System losses¹** (the difference between purchases and sales) have fluctuated over the period:
 - 2019/20: 203,146,397 kWh (12.26%)
 - 2020/21: 178,817,939 kWh (11.07%)
 - 2021/22: 175,220,019 kWh (10.93%)
 - 2022/23: 180,325,441 kWh (12.38%)
 - 2023/24: 134,381,086 kWh (9.41%)

¹ Note: The losses reported here are taken directly from the D-Forms submitted to NERSA. It should be noted that the D-Forms calculation methodology excludes Free Basic Electricity (FBE) units from the calculation. This means that the actual technical and non-technical losses are slightly lower than the figures reported in the D-Forms.

- The **loss percentage** initially showed improvement from 12.26% in 2019/20 to 10.93% in 2021/22, before temporarily increasing to 12.38% in 2022/23. However, the most recent financial year (2023/24) shows a significant improvement to 9.41%, representing the lowest loss rate in the five-year period.

This analysis indicates that while both energy purchases and sales have decreased over time, CENTLEC has made notable progress in reducing system losses, particularly in the most recent financial year. The substantial improvement in 2023/24 suggests the implementation of effective loss reduction strategies, which may include:

1. Enhanced technical interventions to address infrastructure-related losses
2. Improved metering systems
3. Better detection and resolution of non-technical losses
4. Network optimization initiatives

The current loss rate of 9.41% falls well within acceptable industry standards and below NERSA's benchmark of 12%, indicating improved operational efficiency. Continued focus on loss reduction strategies could further enhance CENTLEC's financial performance by maximizing revenue recovery from purchased energy.

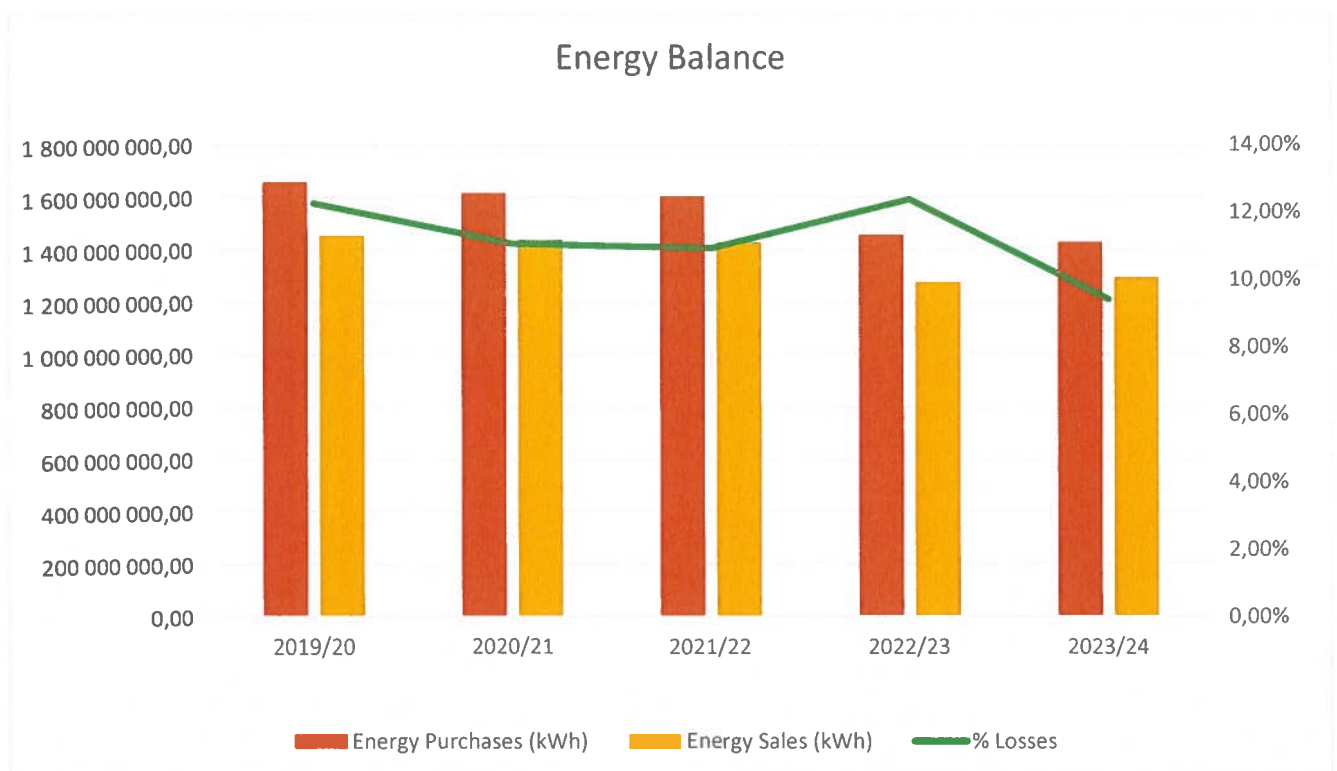


Figure 6: Energy Balance and Losses

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 FY2023/24 [Year 0 in the model]), it is important to adjust these costs for prudence 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 7 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 2025/26 (Year 2).

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

- The revenue requirement in FY2025/26 (Year 2) is estimated as R5,089,363,348 (excluding the impact of subsidy);
- The wires costs are dominated by network related costs, with network repairs and maintenance accounting for R421,988,932 (37.7% of wires costs), cost of losses at R365,532,861 (32.6% of wires costs), depreciation at R113,135,000 (10.1% of wires costs), and OPEX at R221,221,885 (19.7% of wires costs);
- With regards to the retail business, the dominant cost is energy purchases from Eskom at R2,823,661,791, representing 70.5% of total retail costs, followed by OPEX at R1,176,506,551 (29.4% of retail costs);
- Overall, a greater proportion of total electricity costs are incurred by the retail part of the business (R4,006,709,521 or 78.1%) while a smaller portion (R1,120,544,495 or 21.9%) is related to the wires business.

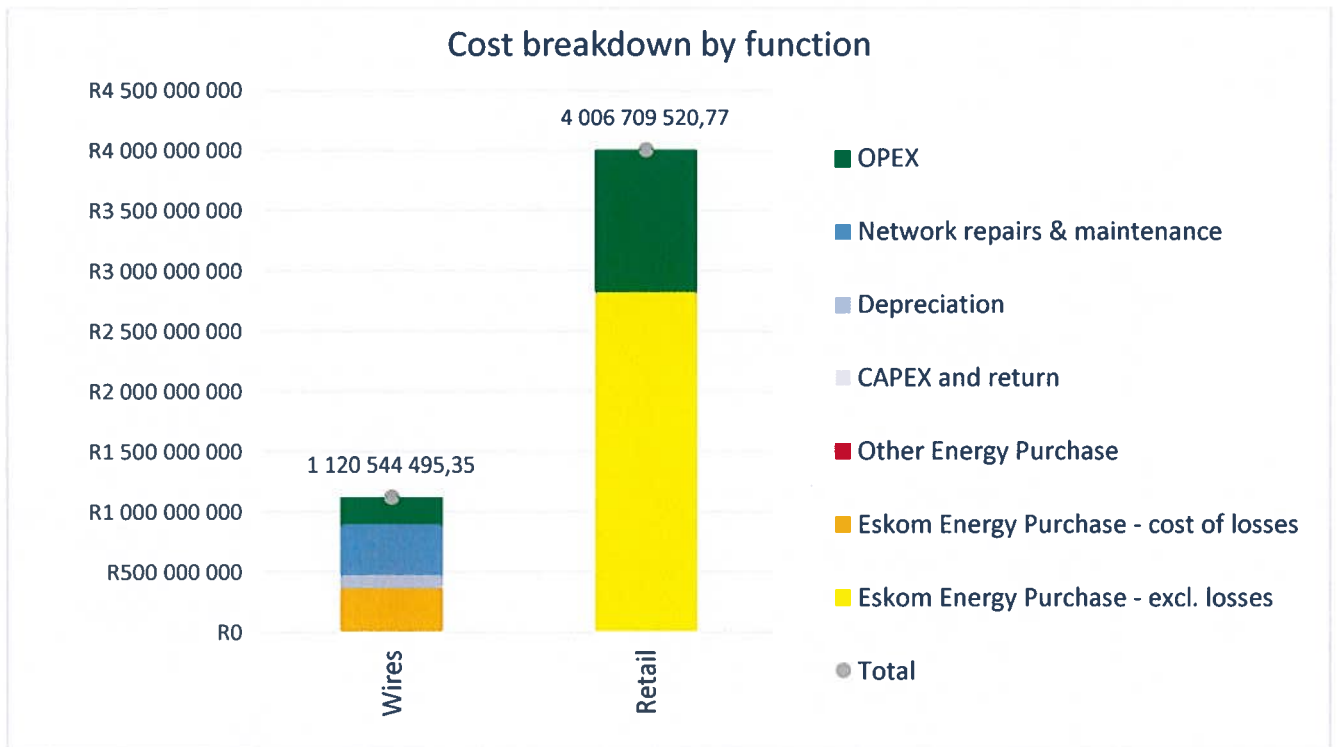


Figure 7: Cost breakdown by function

The cost breakdown visually demonstrates how Eskom energy purchases dominate the overall cost structure, representing 55.5% of the total revenue requirement. OPEX represents the second largest component (27.5%) across both business areas. Within the wires business, network repairs & maintenance forms the most significant cost component (8.3% of total costs), followed by the cost of energy losses (7.2%) and depreciation (2.2%).

Under the current rate regime, it is found that 76.3% cost-reflectivity is achieved for FY2025/26. An average increase of 31.0% in rates would be required to reach overall cost-reflectivity in the target year, representing a significant challenge for tariff design and implementation.

Energy Purchases

CENTLEC SOC (Ltd.) purchases all electricity from Eskom through eight (8) points of delivery (PODs). The COS model captures the tariffs of each POD as well as the volumes purchased at each intake point.

While NERSA's benchmark allows for a maximum of 12% losses, CENTLEC's projected losses for FY2025/26 (Year 2) are 11.46%, which falls within the acceptable benchmark. This demonstrates CENTLEC's operational efficiency in managing system losses.

In FY2025/26, CENTLEC is projected to purchase 1,457,590,161 kWh of electricity from Eskom at a total cost of R3,189,194,652 (comprising R2,823,661,791 for energy excluding losses and R365,532,861 for losses). These energy purchases represent approximately 62.7% of the total revenue requirement, highlighting their significance in the overall cost structure.

The licensee used the purchases for the test period (Year 0) to forecast sales for the financial years covered in the COS study. The forecasted purchases account for all consumption categories including street lighting electricity, own use electricity, and the allowable loss factor.

The total energy requirements show a relatively stable pattern across the forecast period, with a slight decrease from 1,428,375,787 kWh in Year 0 to 1,424,852,503 kWh in Year 1, followed by an increase to 1,457,590,161 kWh in Year 2, and then decreasing gradually to 1,433,466,297 kWh by Year 4. This pattern reflects the complex factors affecting electricity demand, including energy efficiency initiatives, economic conditions, and changing consumption patterns among different customer categories.

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 summarized in the previous section.

COS Results

The key finding is that CENTLEC needs to increase its tariffs by 31.0% to achieve full cost-reflectivity in FY2025/26 (Year 2).

CENTLEC's COS results are shown per tariff category in Figure 8 below. The analysis reveals significant variations in cost-to-serve across different customer categories. The Departmental category shows the highest cost to serve at 1,234 c/kWh, followed by IBT Indigent (non FBE) at 980 c/kWh. Other notable high-cost categories include Flat Business P&C (619 c/kWh) and IBT Domestic P&C (547 c/kWh).

The cost structure across customer categories demonstrates that retail costs (blue portion) generally constitute the larger component of the total cost to serve, though the proportion varies significantly by customer type. Wires costs (red portion) are particularly significant for Departmental and Flat Business P&C customers, forming a substantial portion of their total cost.

Commercial and industrial customers (Elecflex categories) show relatively lower costs to serve, ranging from 223-292 c/kWh, indicating better economies of scale in serving these larger consumers. Bulk Resell 2 shows the lowest commercial cost to serve at 224 c/kWh, while Complex categories range from 328-425 c/kWh.

This cost analysis by customer category provides a critical foundation for designing rates that appropriately reflect the actual cost of service delivery to each customer segment, helping to minimize cross-subsidization and improve overall financial sustainability.

The significant finding that a 31.0% increase would be required to achieve full cost-reflectivity highlights the substantial gap between current tariffs and the actual cost of service provision. This presents a major challenge for tariff design, as implementing such a large increase in a single year would likely create significant economic hardship for customers. As a result, a phased implementation approach will be essential to balance financial sustainability with customer affordability considerations.

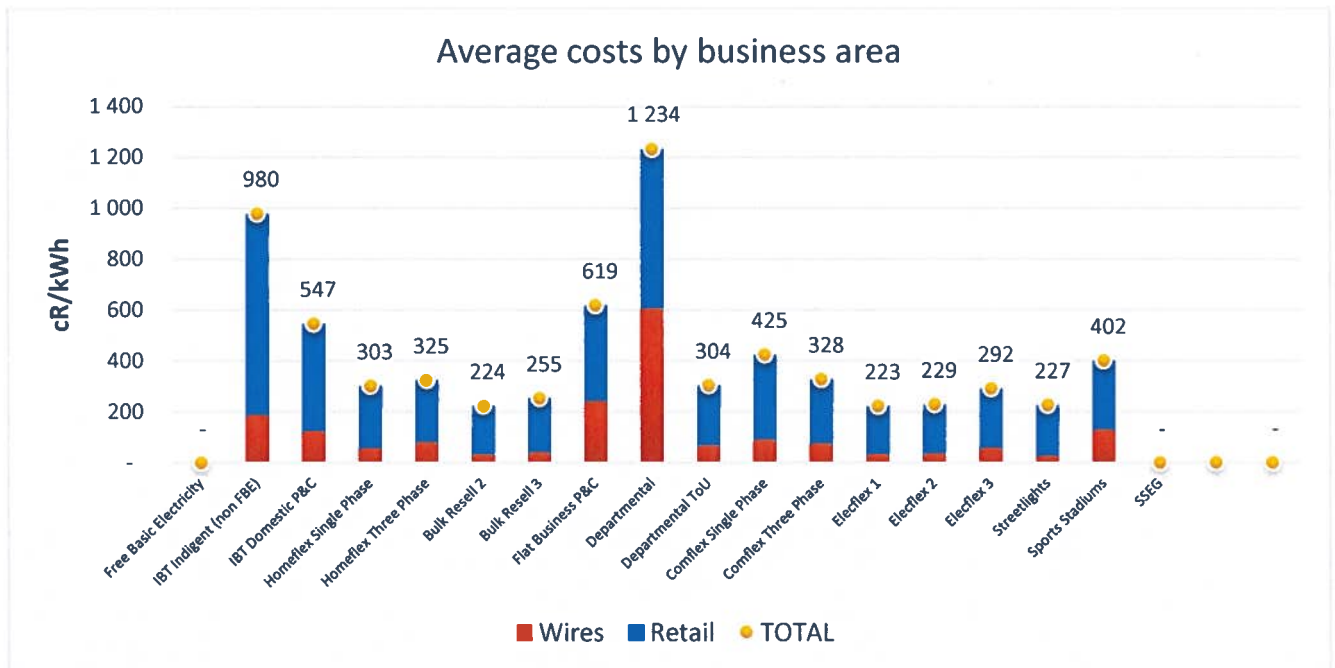


Figure 8: Average costs by business area

Cross-Subsidization Analysis

Comparing these costs to the income per tariff category reveals the over or under recovery per tariff category, as shown in Figure 9. When reading this graph, it is important to note that it is presented in percentage terms and not absolute Rand values.

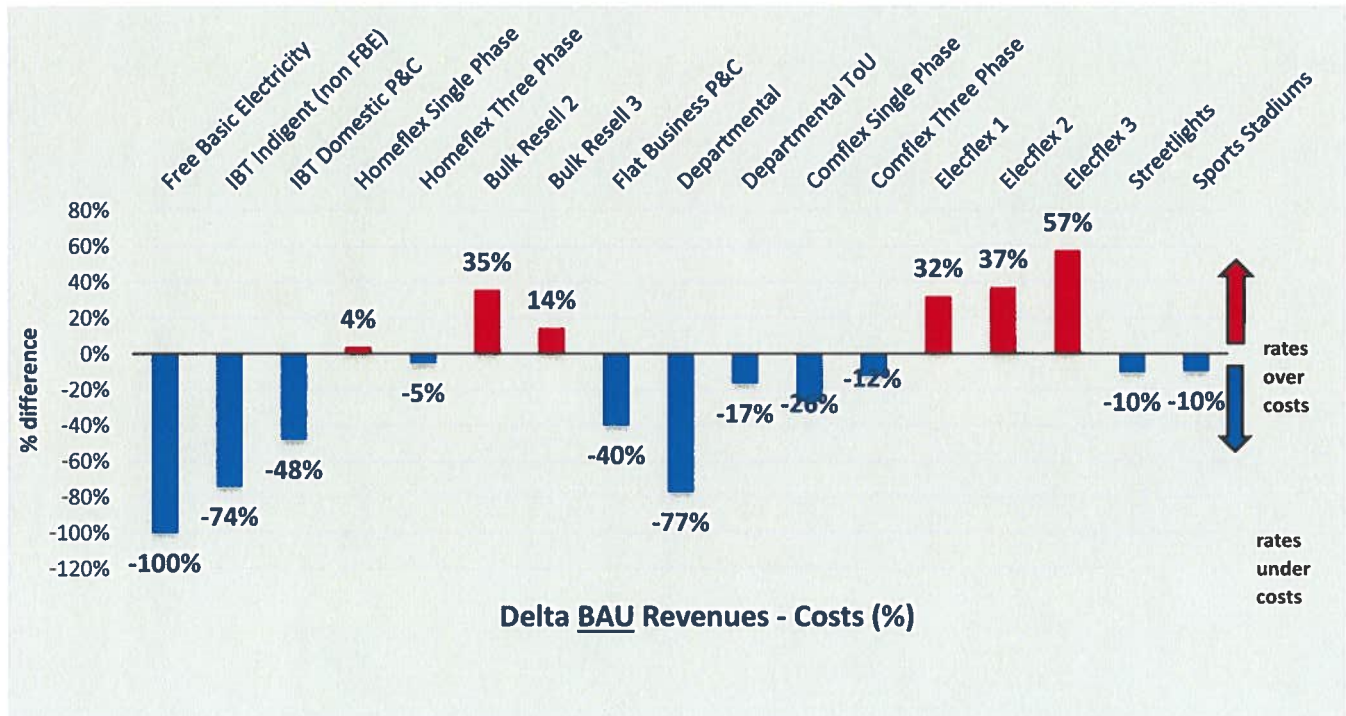


Figure 9: % Over/under recovery of customers

The analysis reveals significant cross-subsidization within CENTLEC's tariff structure. The key insight is that Free Basic Electricity customers show the highest under-recovery at -100%, followed by Departmental (-77%) and IBT Indigent (non FBE) (-74%), indicating these customers are paying substantially less than the cost to serve them. Conversely, Elecflex 3 (+57%), Elecflex 2 (+37%), and Elecflex 1 (+32%) show the highest levels of over-recovery.

Magnitude of Cross-Subsidies

The magnitude of cross-subsidization is substantial, with some customer categories receiving subsidies that cover more than half of their true cost of service. For example, IBT Domestic P&C customers, who represent a significant portion of CENTLEC's customer base, are paying only 52% of their actual cost of service, with the remaining 48% being subsidized.

Commercial categories show varied levels of cross-subsidization, with Flat Business P&C significantly subsidized (-40%), while Complex Three Phase (-12%) and Complex Single Phase (-26%) also receive notable subsidies. This differs from the typical pattern where

commercial customers subsidize residential users, indicating unique characteristics in CENTLEC's service area and customer composition.

This pattern demonstrates that residential, governmental, and certain commercial categories are being cross-subsidized primarily by industrial users (Elecflex categories) and Homeflex Three Phase customers (+35%). While cross-subsidization is common in municipal electricity distribution, the magnitude of these disparities indicates significant structural imbalances in the current tariff design that may not be sustainable in the long term.

Revenue Structure Imbalance

The business as usual (BAU) rates as shown in Figure 10 indicate that existing tariff structures are not cost reflective. The graph clearly illustrates the structural imbalance in CENTLEC's current tariff design, with approximately 80% of costs recovered through variable energy charges (light blue), making the utility highly susceptible to volumetric risk.

In contrast, the Cost of Supply (COS) results demonstrate that a more balanced approach is required, with approximately 55% of costs recovered through energy charges, 17% through demand charges (red), and 28% through customer charges (green). This significant misalignment between the current revenue recovery structure and the actual cost structure represents a fundamental challenge that must be addressed through tariff reform.

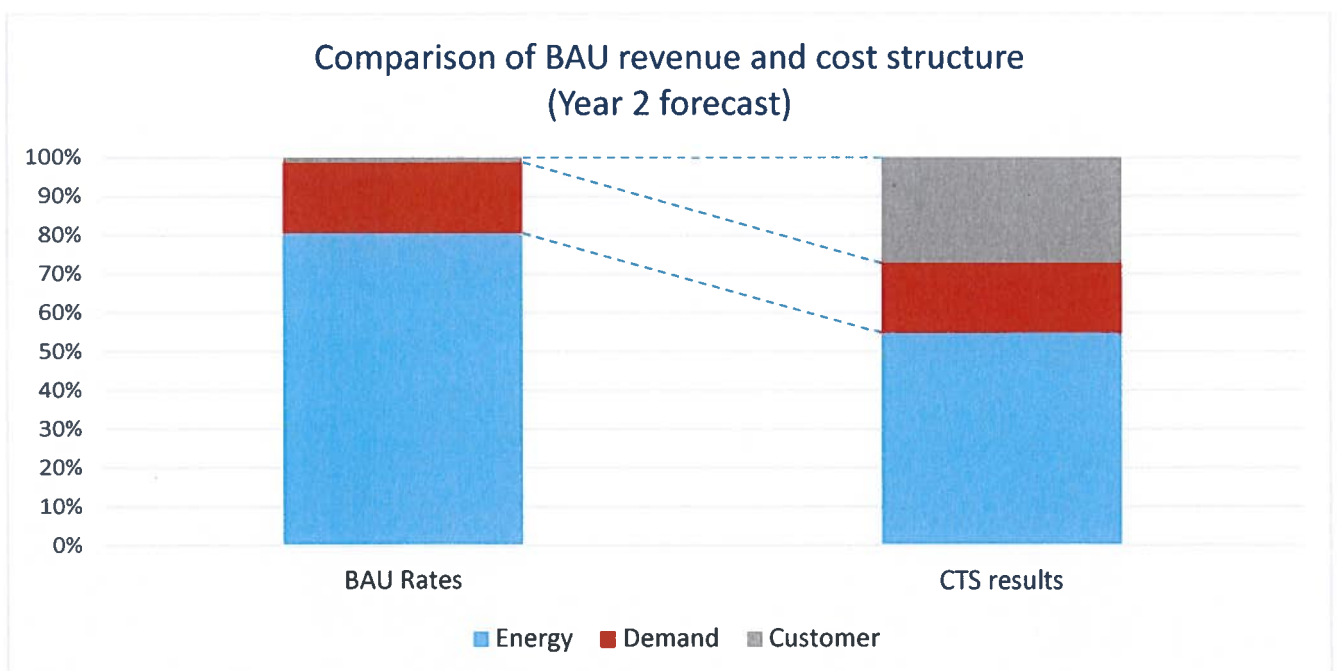


Figure 10: Comparison of revenue and cost structure

As the uptake of distributed generation increases in electricity distribution networks, a more cost-reflective approach to setting tariffs is essential, with greater emphasis on fixed charges to ensure revenue stability and sustainability.

Cost-Reflective Rates

Cost reflective charges are shown in Table 3. These are the result of the cost of supply study and indicate what CENTLEC should be charging customers to recover 100% of their revenue. However, due to South Africa's socio-economic conditions and CENTLEC's revenue recovery strategy, the entity may deviate from these cost-reflective tariffs in the tariff design stage. Rate design is discussed in the next section and may deviate from these results based on CENTLEC's maximum tolerable tariff increase, subsidy policy, price signals, and tariff design choices.

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

	Energy	Demand	Customer
	All	All	All
	c/kWh	R/kVA/month	R/POD/month
Free Basic Electricity	-	87	176
IBT Indigent (non FBE)	224	84	527
IBT Domestic P&C	224	84	527
Homeflex Single Phase	224	92	527
Homeflex Three Phase	224	82	879
Bulk Resell 2	205	68	879
Bulk Resell 3	224	80	1 054
Flat Business P&C	224	90	1 054
Departmental	224	121	1 054
Departmental ToU	224	82	1 054
Complex Single Phase	224	81	1 230
Complex Three Phase	224	89	1 757
Elecflex 1	205	67	1 757
Elecflex 2	205	67	2 636
Elecflex 3	224	75	2 636
Streetlights	224	-	-
Sports Stadiums	224	88	2 636
	c/kWh	R/kVA/month	R/POD/month
	218	69	1 720

The table provides detailed cost-reflective rates across all customer categories. For energy charges, most categories should be charged 224 c/kWh, with some industrial categories at 205 c/kWh. Demand charges vary from 67 to 121 R/kVA/month depending on the customer category, with Departmental customers having the highest demand-related costs. Fixed customer charges show the greatest variation, ranging from 176 R/POD/month for Free Basic Electricity customers to 2,636 R/POD/month for Elecflex 3 and Sports Stadiums customers, reflecting the different customer service costs associated with each category.

The introduction of separate categories for Free Basic Electricity and IBT Indigent (non-FBE) represents an important refinement in the model. This separation ensures that the subsidy is appropriately targeted only to the first block of 50kWh for indigent customers, rather than subsidizing higher consumption blocks which should be cost-reflective. This approach aligns with national policy on Free Basic Electricity while providing a more accurate picture of the true cost of serving different customer segments.

Overall, the weighted average cost-reflective rates across all categories amount to 218 c/kWh for energy charges, 69 R/kVA/month for demand charges, and 1,720 R/POD/month for customer charges. These figures provide the foundation for CENTLEC's tariff redesign efforts, which will need to balance the transition toward cost-reflectivity with socioeconomic considerations and customer impact.

6. Rate Design

Municipal tariff setting is guided by Municipal Tariff Policy, which is developed with reference to various pieces of legislation, particularly Sections 4 and 74 of the Municipal Systems Act (32 of 2000) and the National Electricity Pricing Policy (2008), which 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:

1. Revenue sufficiency of proposed tariffs and the financial sustainability of the utility.

2. 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.
3. 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.
4. Whether environmental objectives are being encouraged; and
5. The transparency of subsidies and surcharges.

Phased Implementation Approach to Cost-Reflective Tariffs

CENTLEC is proposing a 14.5% increase for the 2025/26 financial year, rather than the 31.0% increase indicated by the model to achieve full cost-reflectivity. This approach acknowledges the need to balance financial sustainability with socioeconomic considerations while avoiding tariff shock. With this 14.5% increase, CENTLEC will improve cost-reflectivity in 2025/26 from the current 76.3%.

To address the remaining gap between current and fully cost-reflective tariffs, CENTLEC has developed a multi-year tariff strategy:

1. **Year 1 (2025/26):** Implementation of the 14.5% average increase across customer categories, with strategic structural changes to commercial tariffs. This is designed to align with Eskom's approved 12.74% increase for the same period.
2. **Year 2 (2026/27):** Implementation of an 8.0% increase, which aligns with Eskom's 5.36% increase while providing additional recovery toward cost-reflectivity.
3. **Year 3 (2027/28):** Implementation of an 8.5% increase to complete the path to 100% cost-reflectivity. This rate also aligns with Eskom's approved 6.19% increase for this period while adding the necessary margin to close the remaining gap.

The calculation for this phasing is:

- Starting point: 76.3% cost recovery
- Year 1: 14.5% increase brings recovery to approximately 87.4%
- Remaining gap to 100%: 12.6 percentage points

- Years 2-3: Must close the 12.6% gap through compounded increases

The compound effect of an 8.0% increase in Year 2 followed by an 8.5% increase in Year 3 would yield approximately: $(1.08 \times 1.085 - 1) \times 100\% = 17.2\%$

This compounded increase of 17.2% applied to the Year 1 recovery level of 87.4% would bring CENTLEC to approximately 102.4% cost-reflectivity by the end of the three-year period, providing a small buffer against potential cost increases beyond what's currently projected.

This three-year phased approach balances the need to reach full cost-reflectivity with consideration of Eskom's approved increases while minimizing tariff shock for consumers.

Immediate Impact of 2025/26 Adjustments

After the proposed 14.5% increase is implemented for 2025/26, the revenue recovery for different customer categories will show substantial improvement, though significant cross-subsidies will still exist within the tariff system, as illustrated in Figure 11 below.

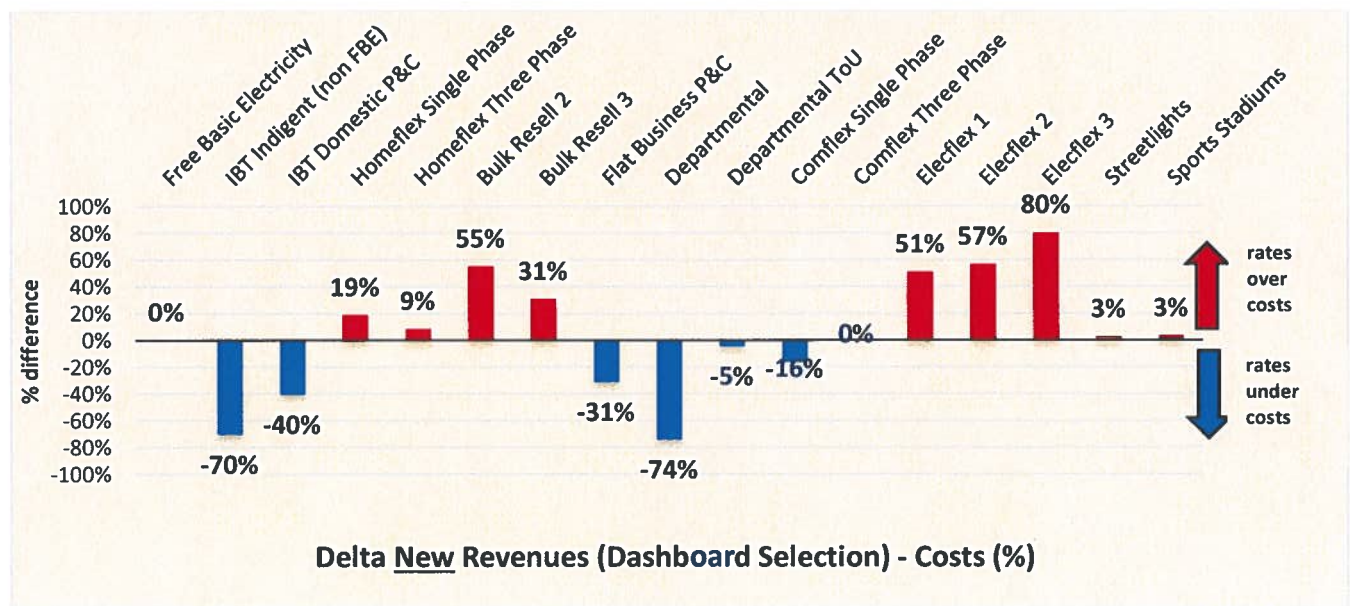


Figure 11: % Over/under recovery after new rates implementation

The chart clearly demonstrates the pattern of cross-subsidization that will exist after implementing the proposed tariff adjustments:

- Free Basic Electricity (0%) customers show no over/under recovery while IBT Indigent (-70%) customers continue to receive significant subsidies, followed by Departmental (-74%) and IBT Domestic P&C (-40%).

This pattern of cross-subsidization strikes a balance between economic efficiency and social welfare objectives. The introduction of the Maximum Demand component for commercial customers in 2025/26 represents an important first step toward more cost-reflective tariff structures that better align with CENTLEC's cost drivers, while maintaining affordable access to electricity for vulnerable residential customers.

7. Key Assumptions

This section outlines key assumptions made in the development of this Cost of Supply study. These assumptions were essential due to data granularity limitations and are as follows:

- **Energy consumption forecasts:** Based on the updated data from the "Commercial Inputs (Years 1-4)" sheet, energy sales are projected to decrease by 0.2% between Year 0 (2023/24) and Year 1 (2024/25). For Year 2 (2025/26), a further decrease of 1.8% is projected. The forecast continues with small declines for Years 3 and 4 of approximately 0.9% and 0.8% respectively. This pattern varies significantly across customer categories, with some (like Complex categories) showing growth while others (particularly residential and certain business categories) show declines.
- **D-Form expenses growth:** Operating expenses are projected to increase at varying rates depending on the expense category:
 - Total expenses are projected to increase from R1,451,676,995 in Year 1 to R1,661,568,242 in Year 4, representing an average annual growth rate of approximately 4.6%.
 - Major expense categories like salaries and materials are projected to increase by around 4.5% annually.
 - Depreciation shows a more significant growth trajectory, increasing from R93,500,000 in Year 1 to R124,448,500 in Year 4, representing a compound annual growth rate of approximately 10%.
- **Total maximum demand:** The total maximum demand of CENTLEC is 163.1 MVA, derived from bottom-up calculations based on customer consumption patterns and coincidence factors.

- **Eskom bulk purchase price increases:** The model assumes Eskom tariff increases of 12.74% for Year 2 (2025/26), 5.36% for Year 3 (2026/27), and 6.19% for Year 4 (2027/28). These projections are based on Eskom's Multi-Year Price Determination (MYPD) application and NERSA's determinations.
- **Inclining block tariff simplification:** For customers with inclining block tariffs, the block 2 tariff was used as the test year input, as the model is unable to accommodate inclining block tariff structures. This approach provides a reasonable approximation of the average tariff paid by these customers.
- **Tariff aggregation:** For customer categories containing multiple tariffs, an average tariff weighted by consumption was calculated and used as input into the model. This approach provides a representative tariff for each customer category while managing the complexity of multiple tariff options within categories.
- **System losses:** The actual municipal energy losses for FY2023/24 (Year 0) were 7.74% according to the COS Model. actual municipal energy losses for FY2023/24 (Year 0) were 7.74% according to the COS Model (as shown in the "High-level CTS projections" sheet, "Energy balance" table, "Total losses (% of total)", row 26). This figure differs slightly from the 9.41% shown in Figure 6: Energy Balance and Losses, which was calculated from previously submitted D-Forms. The difference is because the D-Forms calculation excludes the sales of the FBE Units, whereas the COS Model properly includes FBE Units in the calculation. The COS Model projects losses to increase to 11.46% for FY2025/26 (Year 2) and remain at that level through Year 4. These projected losses remain below NERSA's benchmark of 12%, so no capping of losses was necessary in the model.
- **Rate of return:** A conservative rate of return of 2% has been assumed for the analysis, which explains why CAPEX costs do not contribute significantly to the overall cost breakdown.
- **Cross-subsidization:** The model acknowledges the existing cross-subsidization in the tariff structure, particularly for Free Basic Electricity customers (-100%), followed by Departmental (-74%) and IBT Indigent (non FBE) (-70%), which is expected to be gradually addressed through the proposed three-year phased tariff implementation approach.

8. Data Description and Improvements

Current Data Quality

CENTLEC's electricity sales data (kWh and customer numbers) is derived from multiple integrated systems:

- **Financial System and AMR System:** Provides consumption data for all Time of Use meters and the number of customers per tariff
- **Vending System:** Tracks all prepaid electricity transactions and number of prepaid customers per tariff

The quality of this data can be classified as **excellent**. The data collection and processing methodologies are robust, with proper system integrations ensuring accurate reporting. The data for Year 0 (2023/24) has been reconciled and matches the information submitted in the official D-Forms to NERSA, providing a high level of confidence in the accuracy of the baseline consumption figures used in this COS study.

Similarly, the financial data utilized in this study is of **excellent** quality, as it is derived directly from the audited Financial Statements. This ensures that cost allocations and revenue projections are based on verified financial records that have undergone thorough scrutiny through formal audit processes.

Asset Data Information Following internal review of the initial model, CENTLEC incorporated comprehensive asset data into the COS study. The Asset Register Inputs for Year 0 now include:

- Detailed information on network assets valued at R2,364,308,475, including high-voltage, medium-voltage, and low-voltage infrastructure spanning approximately 2,381 km of lines
- Categorization of 20 other asset groups totalling R5,716,584,324, with information on asset values, wires/retail allocation percentages, and depreciation status
- Allocation percentages for wires and retail business segments across all asset categories

While this asset register information has been incorporated into the COS model, its impact on the current outcomes has been limited. This is primarily due to the conservative 2% rate of

return assumption used in the model, which minimizes the contribution of capital costs to the overall revenue requirement.

Areas for Further Refinement CENTLEC has identified opportunities for further refinement of the existing asset data:

- Updating depreciation rates and annual depreciation calculations that are currently shown as zero in the model
- Enhancing asset condition assessments to better inform maintenance and replacement planning
- Developing more precise allocation methodologies for shared assets

Future Improvement Plan CENTLEC is committed to continuously enhancing data quality for future COS studies through the following initiatives:

1. **Asset Data Enhancement:** Continue refining the asset database by:
 - Completing depreciation rate calculations for all asset categories
 - Implementing a condition-based assessment program for critical network components
 - Enhancing the spatial mapping of assets to customer categories
2. **System Integration:** Work toward further integration of Financial, AMR, and Vending systems to enable more granular analysis of consumption patterns and improve load profiling for different customer categories.
3. **Data Governance:** Establish formal data governance processes to maintain the high quality of existing data while developing new data assets.

These improvements will support more accurate allocation of capital costs across customer categories and enable better infrastructure investment planning, particularly if a higher rate of return is applied in future models.