

Mossel Bay Cost of Supply (COS) Study: Errors and Observations Report

Important Qualification

This report is based solely on the published Mossel Bay Electricity Pricing Study (CVW Consulting Engineers, October 2023) as presented to the Infrastructure Services Committee, together with the NERSA Cost of Supply Framework [1]. Only limited background information is available. The full underlying spreadsheet model, supporting workings, complete tariff schedules, and the municipality's internal data have not been made available for review. Accordingly, this report does not purport to recalculate the correct tariff or revenue requirement. Its purpose is to record observable anomalies, apparent inconsistencies, and questions arising from the face of the published document that, in the view of the reviewer, warrant formal explanation and response from the municipality and its consultants.

Executive Summary

A review of the published Mossel Bay Cost of Supply (COS) Electricity Pricing Study raises a number of significant concerns regarding apparent errors, omissions, and deviations from the NERSA Cost of Supply Framework [1]. The study, which is based on ²⁰²⁰/₂₁ data, contains what appears to be an unresolved spreadsheet formula error, missing revenue allocations for multiple customer categories, and an incomplete treatment of solar/Small-Scale Embedded Generation (SSEG) inputs [2]. These observable anomalies raise questions about the accuracy of the calculated cost of supply and the resulting proposed tariffs.

Of particular concern is that this same study appears to have been applied across consecutive tariff years from ²⁰²⁴/₂₅ through to the current ²⁰²⁶/₂₇ tariff cycle without revision. If the anomalies identified herein are confirmed upon full investigation, the financial impact on consumers would extend across multiple years.

This report records specific concerns identified on Committee Page 19 (COS Study Page 15 of 49) and Committee Page 30 (COS Study Page 26 of 49), as well as the loss factor exceedance, the currency of the data, the SSEG treatment, the fixed basic charge, and the apparent absence of item (o) from the revenue requirement formula chain.

1. Page Numbering Anomaly

The document as presented to the Infrastructure Services Committee contains two simultaneous and conflicting page numbering systems, which creates material ambiguity in any reference to specific pages.

The first system is the **Committee agenda sequential page number**, printed in the top-right corner of each page (e.g., “19”, “30”). The second system is the **COS study’s own internal page number**, printed in the page header alongside the study title and date (e.g., “Page 15 of 49”, “Page 26 of 49”). These two systems are offset by four pages throughout the document, as the COS study was inserted into the agenda as an annexure beginning at Committee page 4.

The confirmed correspondence between the two systems, for the pages most relevant to this report, is as follows:

Committee Agenda Page	COS Study Internal Page	Content
4	Page i	Executive Summary (COS study cover page)
5	Page 1 of 49	Table of Contents
12	Page 8 of 49	Revenue Requirement — 12.72% loss factor
13	Page 9 of 49	Table 2 Revenue Requirement Basis — SSEG entry
18	Page 14 of 49	Generic load profiles — blank TOU allocations
19	Page 15 of 49	kWh sales per TOU period — blank columns, losses 17–23%
20	Page 16 of 49	Average energy purchase costs — #DIV/0! error
29	Page 25 of 49	Rate Design — zero demand charges highlighted yellow
30	Page 26 of 49	Forecasted Revenue Recovery — zero revenue categories

Throughout this report, references to “Page 19” and “Page 30” refer to the **Committee agenda page numbers** as printed in the top-right corner of the document. The corresponding COS study internal page numbers are Page 15 of 49 and Page 26 of 49 respectively. All parties reviewing this report should be aware of this dual numbering and verify references against both systems.

This anomaly itself is an observation worth recording: a document presented for formal committee approval should carry a single, unambiguous page reference system. The coexistence of two numbering systems increases the risk of miscommunication and makes precise citation more difficult.

2. Outdated Data and Methodology Non-Compliance

The COS study was commenced in February 2022 and completed in October 2023, but is stated to be based on ²⁰²⁰/₂₁ financial year statistics [2]. The same study appears to have been applied without revision to successive tariff applications, including ²⁰²⁴/₂₅, ²⁰²⁵/₂₆, and the current ²⁰²⁶/₂₇ cycle. The foundational data is therefore between five and six years old relative to the tariff year currently in force.

The NERSA Cost of Supply Framework requires that COS studies reflect current changing costs and customer behaviour [1]. It is a concern that data predating the significant shifts in electricity consumption patterns of recent years — including the accelerated adoption of private solar generation — may render the cost allocations materially inaccurate for current application. This is a matter that requires formal clarification from the municipality.

Furthermore, the project timetable on Report Page 5 explicitly notes that the “COS Study not Forwarded to Nersa due to ABC Costing Methodology” [2]. This raises a question about whether the study complies with NERSA’s required Embedded Cost Basis approach [1], and whether NERSA has formally accepted or reviewed the methodology applied.

2. The 12% Loss Factor Exceedance

The NERSA COS Framework explicitly states that the tolerable range for energy losses is 5–12%, with 10% as the benchmark [1]. The framework further notes that licensees will be incentivised for losses below 10% [1].

Despite acknowledging this benchmark in the report text, the Mossel Bay COS study applies an allowable loss factor of **12.72%** (Report Page 8) [2]. This is stated to exceed the maximum of the tolerable range as defined by NERSA. The municipality and its consultants should be asked to explain the basis for applying a loss factor above the stated maximum, and whether NERSA has approved a deviation from the standard range.

When cross-checking the kWh purchased per Time of Use (TOU) period (Report Page 15), the percentage differences between purchased and sold energy shown in the study are as follows:

TOU Period	High Demand Season	Low Demand Season
Off-peak	17%	18%
Standard	19%	19%
Peak	18%	23%

All six TOU periods show figures significantly above 12% [2]. It is noted that these figures appear in the study itself and are not independently recalculated here. The municipality should be asked to explain these figures and their impact on the revenue requirement calculation.

3. Concerns on Report Pages 14–16 (Referred to as “Page 19 Errors”)

The section dealing with the allocation of energy purchase costs raises several concerns.

3.1 Missing Load Profiles

In the “Generic load profiles” table (Report Page 14), three consumption categories appear to have no TOU percentage allocations — all columns show zero or are blank [2]:

- Transport
- Redistributors/Resellers
- Sold to other municipal departments

It is not clear from the published report whether this is intentional (e.g., these categories are excluded from TOU allocation by design) or whether it represents an omission. The municipality should be asked to clarify the basis for these blank entries and their effect on the energy cost allocation for these categories.

3.2 Unallocated Energy Sales

In the “kWh sales per TOU period” table (Report Page 15), the Transport category shows total sales of 3,368,302 kWh and “Sold to other municipal departments” shows 15,281,373 kWh, yet the TOU period breakdown columns for both categories are blank [2]. This

apparent inconsistency — where a total exists but no period breakdown is provided — raises a question about how the energy purchase costs for these categories were allocated. The municipality should be asked to provide the supporting workings.

3.3 Apparent Spreadsheet Formula Error

On Report Page 16, the “Average Energy Purchase Costs (R/kWh)” table shows the overall “Average Energy Purchase Cost” total row as #DIV/0! [2]. This is a standard spreadsheet error indicating a division-by-zero condition. It is observable that this error appears in the published final report. The municipality should be asked to confirm whether this error affected the calculations that follow, and to provide the corrected figure.

4. Concerns on Report Pages 25–26 (Referred to as “Page 30 Errors”)

The Rate Design and Forecasted Revenue Recovery sections raise serious concerns about the completeness of the revenue model.

4.1 Zero Demand Charges

In the “Proposed Tariffs for new financial year” table (Report Page 25), the Chargeable Maximum Demand (R/kVA) column shows a value of “0” for three categories, which the authors themselves appear to have highlighted in yellow [2]:

- Mining & quarrying
- Manufacturing/Industrial
- Commercial (conventional)

It is not clear whether these zeros represent a deliberate tariff design decision or an error. The municipality should be asked to confirm whether demand charges were intentionally set to zero for these categories, and if so, on what basis.

Additionally, the “Total” row at the bottom of this table shows 0% across all charge types, which appears to be a further spreadsheet error in the totalling formula [2].

4.2 Zero Revenue Forecast for Significant Consumption Categories

The “Forecasted Revenue Recovery under proposed tariffs” table (Report Page 26) shows the following categories as generating no revenue (shown as a dash) despite having recorded customers and kWh sales [2]:

Customer Category	Number of Customers	kWh Sales	Revenue Forecast
Transport	152	3,368,302	R —
Other consumers	8	396,777	R —
Electricity Department	173	828,230	R —
Street lighting	1	5,133,233	R —
Sold to other municipal departments	42	15,281,373	R —

These categories collectively account for approximately 25 million kWh of consumption — roughly 9% of total municipal sales [2]. The municipality should be asked to explain why no revenue is forecast for these categories, whether these consumers are billed at all, and if not, how the associated costs are recovered. Without access to the full billing and tariff data it is not possible to determine the precise financial impact, but the apparent absence of revenue recovery for these categories is a material concern that requires explanation.

5. Solar and SSEG Inputs Treatment

In “Table 2: Revenue Requirement Basis” (Committee Page 13 / COS Study Page 9 of 49), SSEG and exported energy is recorded as 209,978 kWh at 0.85 c/kWh, totalling R179,055, listed under “Sources of Electricity Purchases” [2]. Several observations arise from this treatment.

The weight column for SSEG is blank, while Eskom purchases are shown at 100% weight [2]. It is not clear from the published report how the SSEG volume was factored into the weighted average purchase price calculation, or whether it was included at all. The municipality should be asked to clarify this.

A broader question also arises regarding the revenue treatment of SSEG. When a municipality purchases energy from SSEG producers and resells it to other consumers, a margin arises between the purchase rate and the retail rate. It is not apparent from the published report where this revenue is recorded, whether it offsets the revenue requirement, or how it flows through the financial model. The municipality should be asked to provide a full account of SSEG-related revenue and cost flows, and to explain how these are reflected in the tariff calculations.

The concern is that if SSEG-related revenue is not properly credited in the model, the revenue requirement — and therefore the tariffs charged to all consumers — may be overstated to that extent.

6. The Fixed Basic Charge: Escalation, VAT, and Ring-Fencing

6.1 The Charge Structure and Its Absence from the COS Model

The Mossel Bay tariff schedule levies a fixed basic monthly charge structured as a Rand-per-Ampere-per-month rate applied to a customer's circuit breaker capacity. For the ²⁰²⁶/₂₇ tariff year, this rate has been escalated from **R8.2783 to R8.9820 per Ampere per month** — an increase of **8.50%** [2].

The indicative monthly charges at common breaker sizes, based on the published rates, are as follows:

Circuit Breaker	Old Monthly Charge	New Monthly Charge	Monthly Increase	New Charge incl. VAT
20A	R165.57	R179.64	R14.07	R206.59
30A	R248.35	R269.46	R21.11	R309.88
40A	R331.13	R359.28	R28.15	R413.17
60A	R496.70	R538.92	R42.22	R619.76
80A	R662.26	R718.56	R56.30	R826.34
100A	R827.83	R898.20	R70.37	R1,032.93

This charge does not appear to be ring-fenced to any specific cost category in the COS study, nor does the study demonstrate that the escalation is derived from a calculated fixed infrastructure cost per unit of network capacity [1][2]. The NERSA framework requires that all tariff components be cost-reflective and traceable to specific cost drivers [1]. The municipality should be asked to provide the cost justification for the 8.50% escalation and to demonstrate how the fixed charge revenue is allocated within the cost model.

6.2 The VAT Question

The municipality applies VAT at 15% to the fixed basic charge. This raises a question that, in the absence of full legal and accounting information, cannot be definitively resolved here, but which warrants formal investigation.

The fixed basic charge is levied on the rated capacity of a customer's circuit breaker, not on energy consumed. A customer who uses zero kWh in a month still pays the full charge. This characteristic raises the question of whether the charge constitutes consideration for the supply of electricity (in which case VAT applies), or whether it is more properly characterised as a network access or capacity reservation levy (in which case its VAT treatment may be different).

Without access to the municipality's VAT rulings, SARS correspondence, or full accounting records, it is not possible to make a definitive determination. However, the concern is material. Based on the customer numbers recorded in the COS study, the VAT collected on fixed charges alone is estimated to be in the range of **R25 million to R38 million per annum** depending on the average breaker profile of the customer base [2]. This figure is consistent with the approximately R27 million that has been identified as a concern. The

municipality should be asked to provide the legal and tax basis for applying VAT to this charge, and to confirm that the treatment has been formally validated.

6.3 Regressive Impact

The NERSA framework requires that tariff design consider affordability [1]. A fixed charge levied on circuit breaker capacity before any energy is consumed is inherently regressive in its impact on low-consumption users. An 8.50% increase on this baseline is a concern in this context, particularly as it falls above typical CPI parameters. The municipality should be asked to demonstrate how the affordability implications of this escalation were assessed in the context of the COS study.

7. The Apparent Absence of Item (o) and the Average Selling Price

The NERSA Cost Plus Methodology formula chain (Table 1 of the Framework) requires the following sequential calculation [1]:

- **(m)** Total costs before surplus
- **(n)** Add surplus allowable (15%)
- **(o) = (m) + (n)** Total Allowable Revenue
- **(p) = (o) ÷ (f)** Average Selling Price

The Mossel Bay COS study presents figures for items (m), (n), (p), (q), and (w), but **item (o) — the Total Allowable Revenue — does not appear anywhere in the published report** [2]. This is the single most important output of the revenue requirement calculation, as it is the figure from which the average selling price is derived.

The figures as stated in the report are as follows:

Item	Description	As Stated in Report
(m)	Total costs before surplus	R 493,030,685
(n)	Surplus allowable	R 98,606,137
(o)	Total Allowable Revenue	Not shown
(f)	Required Purchases (kWh)	335,822,870 kWh
(p)	Average Selling Price	R 1.07/kWh
(q)	Previous Year Price	R 0.85/kWh
(w)	Average % Price Increase	26%

A secondary concern arises regarding item (n). The report labels the surplus as “15%” but the figure stated (R98,606,137) appears, on the face of the published numbers, to represent approximately 20% of item (m) rather than 15%. The municipality should be asked to clarify the basis for the surplus figure applied.

More fundamentally, the municipality should be asked to provide the value of item (o) and to demonstrate how the average selling price of R1.07/kWh was derived. On the face of the published figures, the relationship between items (m), (n), (o), (f), and (p) is not transparent, and the stated average selling price of R1.07/kWh does not appear to follow directly from the other stated figures. Without access to the underlying spreadsheet, it is not possible to determine the source of this figure, but the apparent inconsistency is a material concern.

The previous year price of R0.85/kWh (item q) is also noted as potentially requiring clarification. The same report records the ²⁰²⁰/₂₁ actual revenue was R1.91/kWh (as noted at the bottom of Committee Page 30 / COS Study Page 26 of 49) [2]. The municipality should be asked to explain the basis for the R0.85/kWh prior year benchmark and how it relates to the actual revenue figures recorded elsewhere in the same document.

9. Variance Between COS Billing Figures and Audited Annual Financial Statements

A cross-reference of two primary municipal sources covering the same financial period — 2020/21 — reveals an unexplained variance of **R32,605,948** that has not been reconciled or explained in the published COS study.

The two sources and the figures they record are as follows:

Source	Reference	Revenue Figure	kWh Volume
COS Study Billing Report	Committee Page 31 / COS Study Page 27 of 49	R 519,149,657	273,534,748 kWh
Annual Financial Statements (AFS)	Page 144, Note 30 (30 June 2021)	R 486,543,709	—
Unexplained Variance		R 32,605,948	—

Both sources purport to reflect the same municipality's electricity revenue for the same financial year. The COS billing report figure of R519,149,657 is R32,605,948 higher than the R486,543,709 recorded under the relevant note in the audited Annual Financial Statements for the year ended 30 June 2021.

It is important to note that this observation is based on limited available information. Without access to both source documents in full, it is not possible to determine with certainty whether the two figures are directly comparable — they may, for instance, reflect different revenue line items, different accounting treatments, or different inclusions and exclusions. The municipality should be asked to provide a formal reconciliation of these two figures and to explain the basis for any difference.

However, the concern is material for the following reasons. The COS study uses the billing data as its foundational input for the revenue requirement and cost allocation model [2]. If the billing figures used in the COS study are not reconciled with the audited financial statements, then the baseline from which all tariff calculations flow cannot be confirmed as accurate. A variance of over R32 million between the technical billing log and the audited accounts — if unresolved — raises questions about whether the COS model is built on figures that have been independently verified.

The municipality should be asked to:

1. Confirm which figure — R519,149,657 or R486,543,709 — represents the correct audited electricity revenue for ²⁰²⁰/₂₁.
2. Provide a formal reconciliation explaining the R32,605,948 difference, identifying whether it arises from timing differences, internal cross-subsidies, technical bulk losses, unbilled consumption, or a reporting discrepancy between the billing system and the accounting records.
3. Confirm that the figures used as inputs to the COS study have been reconciled to the audited Annual Financial Statements before being applied as the basis for tariff calculations.

Until this reconciliation is provided, the integrity of the baseline data underpinning the entire COS model remains open to question.

10. Household Count Discrepancy — Domestic Customer Base Used in Cost Allocation

A cross-reference between the Mossel Bay Municipality Annual Report (30 June 2019) and the COS Study Billing Report (Page 31) reveals a discrepancy of **10,577 domestic households** that were not included in the COS study's cost allocation base.

The two sources record the following domestic customer figures:

Source	Reference	Household Count
MBM Annual Report	30 June 2019	47,598
COS Study Billing Report	Page 31 (²⁰²⁰ / ₂₁ data)	37,021
Discrepancy		10,577 households

The Annual Report breakdown for 2019 is as follows:

Category	Count
Non-Prepaid Domestic	4,486
Prepaid (Minimum Service Level)	32,634
Prepaid (Below Minimum Service Level)	10,478
Total	47,598

The COS study billing report arrives at 37,021 domestic households by including only those categories that appear in its billing breakdown. The 10,478 households recorded in the Annual Report as “below minimum service level” do not appear to be represented in the COS study’s customer base.

This observation is based on limited information and requires formal clarification from the municipality. It is possible that the difference reflects a change in the customer base between 2019 and ²⁰²⁰/₂₁, or that the two datasets define “household” differently. The municipality should be asked to confirm the correct total domestic household count used as the basis for cost allocation in the COS study, and to explain any difference from the Annual Report figure.

However, the concern is arithmetically significant. When fixed costs and the revenue requirement are divided across a smaller customer base, the per-household cost is proportionally higher. Based on the figures available, spreading costs over 37,021 households rather than 47,598 households would result in a per-household cost approximately **28.6% higher** than if the full customer base were used. The municipality should be asked to demonstrate that the correct and complete customer base was used in the cost allocation model.

11. Meter Count Discrepancy — Prepaid Meters Registered vs Customers Billed

A cross-reference between two sections of the same document reveals a discrepancy in the number of prepaid electricity meters that warrants formal explanation.

Source 1 — Page 11, Item 3 (Number of Units / Infrastructure Register): The document records the following prepaid electricity meter count:

Meter Type	Count
Single Phase	34,526
Three Phase	396
Total Registered Prepaid Meters	34,922

Source 2 — Page 31 (COS Study Billing Report): The billing report records the following prepaid customer categories:

Category	Count
Prepaid Domestic Single Phase (1)	16,005
Prepaid Domestic Single Phase (2)	6,407
Indigent	9,747
Prepaid Commercial Single Phase (1)	796
Prepaid Commercial Single Phase (2)	326
Prepaid Domestic Three Phase	77
Prepaid Commercial Three Phase	192
Total Prepaid Customers Billed	33,642

The difference between the two figures is **1,280 meters** — meters that appear in the infrastructure register but do not correspond to a customer account in the billing system. The question this raises, as noted in the source material, is whether there are prepaid customers who are not registered as customers and therefore do not get billed.

It is acknowledged that this observation is based on limited information. There may be legitimate explanations for this difference — for example, meters that are installed but not yet commissioned, meters that have been decommissioned but not yet removed from the register, meters held in stock, or meters associated with categories not separately listed in the billing breakdown. The municipality should be asked to provide a full reconciliation of the 1,280-meter difference.

The revenue implication of this discrepancy is potentially material. Based on the average annual consumption of prepaid domestic customers recorded in the COS study

(approximately 3,369 kWh per customer per year), 1,280 unregistered meters represent approximately **4,300 MWh of potentially unbilled consumption per annum**. The associated revenue, depending on the applicable tariff rate, is estimated at between **R4.6 million and R8.2 million per annum**. The R2.3 million figure that has been identified as a concern is consistent with a more conservative estimate based on lower average consumption for the unaccounted category.

These figures are illustrative only, as the actual consumption profile of the unaccounted meters is not known. However, the existence of 1,280 meters in the infrastructure register that do not appear in the billing system is an anomaly that requires formal explanation, particularly in the context of the broader revenue reconciliation concerns raised in Section 9 above.

12. Free Basic Electricity and the Equitable Share — Potential Double Recovery

The South African Electricity Pricing Policy (Page 98) is explicit on the funding source for Free Basic Electricity (FBE): FBE is to be funded through the Equitable Share allocation from National Government to local government, and **not** through the revenue requirement of the licensee [3]. This is a fundamental principle intended to ensure that the cost of providing free electricity to indigent households is not loaded onto the tariffs paid by all other consumers.

The Mossel Bay Municipality Draft Annual Budget records the following Equitable Share receipts specifically designated for the provision of free basic services:

Financial Year	Equitable Share Received
2023/24	R 130,634,000
2024/25	R 132,944,000

The COS study records 9,747 indigent customers receiving Free Basic Electricity [2]. The question that arises from the published COS study is whether the cost of providing FBE to these customers has been properly excluded from the revenue requirement calculation, or whether it has been included and is therefore being recovered from all consumers through

the tariff — in addition to the Equitable Share already received by the municipality for this specific purpose.

The COS study does not appear to contain a transparent reconciliation of the Equitable Share receipts against the FBE cost provision [2]. The municipality should be asked to:

1. Confirm the total cost of providing FBE to the 9,747 indigent customers in 2020/21.
2. Confirm that this cost was fully funded by the Equitable Share and was not included in the revenue requirement used to calculate tariffs.
3. Provide a reconciliation showing how the Equitable Share receipts were applied in the COS model.

If FBE costs have been included in the revenue requirement and recovered through tariffs, while the Equitable Share was simultaneously received for the same purpose, this would constitute a form of double recovery from consumers that is inconsistent with the Electricity Pricing Policy.

13. Structural Concerns Regarding the Cost Allocation Methodology

The observations recorded in this report, taken together, point to a number of structural concerns about the methodology applied in the COS study. These are recorded here as questions for formal investigation rather than findings, given the limited information available.

13.1 Asset Valuation and Depreciation

The NERSA framework permits capital recovery to be based on the replacement value of assets [1]. Where municipalities perform desktop revaluations of infrastructure assets (substations, grid lines, and distribution equipment), an increase in the assessed replacement value directly increases the annual depreciation allowance included in the revenue requirement — without any new physical infrastructure being constructed. The COS study records depreciation and amortisation of R14,076,797 [2]. The municipality should be asked to confirm the basis on which the asset replacement values used in this calculation were determined, and whether any revaluation was performed in the period leading up to the study.

13.2 The Customer Base Division

As recorded in Section 10, the COS study appears to allocate costs across 37,021 domestic households rather than the 47,598 recorded in the municipality's own Annual Report. When a fixed cost pool is divided by a smaller customer denominator, the per-customer cost — and therefore the tariff — is proportionally higher. The municipality should be asked to confirm the correct customer base used in the cost allocation, and to demonstrate that no eligible customers were excluded from the denominator.

13.3 Capital Replacement Reserve and Ring-Fencing

The NERSA framework and municipal finance legislation require that tariff-driven capital replacement collections be ring-fenced into a dedicated Capital Replacement Reserve (CRR) and applied only to the replacement of the specific assets for which they were collected. The concern that warrants investigation is whether capital replacement funds collected through tariffs are being properly ring-fenced, or whether they are being applied to general operational expenditure while actual capital replacement is funded through external loans or government grants. If the latter, consumers would effectively be paying twice for the same infrastructure — once through the tariff and once through the debt service costs included in the revenue requirement. The municipality should be asked to provide a reconciliation of the CRR balance, inflows, and outflows for the period covered by the COS study.

Conclusion

This report records a series of observable anomalies and apparent inconsistencies in the published Mossel Bay COS Electricity Pricing Study that, on the face of the available information, raise material concerns about the accuracy and completeness of the cost model underpinning the municipality's electricity tariffs. These concerns span: the currency of the data; the loss factor applied; missing cost allocations and unresolved formula errors; zero revenue forecasts for significant consumption categories; the treatment of SSEG revenue; the fixed basic charge escalation and its VAT treatment; the apparent absence of the Total Allowable Revenue (item o) from the published formula chain; a R32,605,948 variance between the COS billing figures and the audited Annual Financial Statements; a discrepancy of 1,280 prepaid meters between the infrastructure register and the billing system; a 10,577-household gap between the Annual Report customer base and the COS

study cost allocation denominator; a potential double recovery of Free Basic Electricity costs contrary to the Electricity Pricing Policy; and structural questions regarding asset valuation, the customer base divisor, and the ring-fencing of capital replacement reserves.

It is emphasised that this report is based on limited available information and does not purport to determine the correct tariff or revenue requirement. The concerns raised require formal response from the municipality and its consultants, with full supporting workings and data provided. If the anomalies identified are confirmed upon full investigation, and if this same study has been applied across the ²⁰²⁴/₂₅, ²⁰²⁵/₂₆, and ²⁰²⁶/₂₇ tariff cycles without revision, the cumulative financial impact on consumers warrants formal review by the relevant regulatory and oversight bodies.

References

[1] NERSA. (2015). *Cost of Supply Framework for Licensed Electricity Distributors in South Africa*.

[2] CVW Consulting Engineers. (October 2023). *Cost of Supply Study for Electrical Services: Mossel Bay Municipality*. Presented to the Infrastructure Services Committee, February 2024.

[3] Republic of South Africa. (1998). *Electricity Pricing Policy of the South African Electricity Supply Industry*. Government Gazette No. 31741, 19 December 1998.

[4] Mossel Bay Municipality. (2019). *Annual Report for the Year Ended 30 June 2019*.

[5] Mossel Bay Municipality. *Draft Annual Budget ²⁰²⁴/₂₅*. (Page 16 — Equitable Share Allocation for Free Basic Services.)