NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

# MARKET INQUIRY REPORT

## CONSULTATION DRAFT

Impact of Fixed Charges, The Generation Capacity Charge and Other Associated Charges Levied by Electricity Distributors

2026

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# 1. EXECUTIVE **SUMMARY**

This Market Inquiry was initiated to assess the impact, structure, justification, and implementation of fixed charges levied by electricity distributors, together with Eskom's unbundled Generation Capacity Charge (GCC), Legacy Charge, and Variable Energy Charge introduced following following the National Energy Regulator of South Africa's (NERSA's) approval of the Retail Tariff Plan (RTP) for implementation in the 2025/26 financial year. The Inquiry was prompted by widespread stakeholder concerns that effective electricity price increases experienced by customers materially exceeded the approved average tariff adjustment and that the restructuring of electricity tariffs may have produced unintended consequences across customer categories.

The Inquiry considered documentary evidence, tariff schedules, stakeholder submissions, preliminary quantitative simulations, public hearing inputs, and applicable regulatory principles including cost reflectivity, affordability, transparency, fairness economic efficiency, competition, and the long-term objectives of electricity market reform.

The Inquiry notes that the available quantitative dataset was more representative of industrial and large power user customer segments than residential and small commercial consumers. Although the findings provide valuable insights into tariff impacts on high-consumption users, further work is required to assess the impact on household consumers, especially indigent, low-income and prepaid customer categories. Accordingly, the findings and conclusions of this report should be interpreted within the context of the customer profile represented in the dataset analysed.

Findings reveal that even though the policy rationale for unbundling fixed and variable cost recovery has merit, implementation outcomes appear uneven across customer categories. Certain users with lower consumption profiles, seasonal demand, embedded generation, or high load-factor sensitivity experienced materially higher bill impacts than implied by average approved increases. Similar concerns arose in relation to municipal fixed charges where customers questioned cost basis, transparency, and alignment with approved tariffs.

Findings further reveal that for industrial customers the changes related to the Time-of-Use (TOU) tariff structure had a bigger effect than was expected, especially for those making use of the off-peak and standard rates.

The introduction of fixed charges, particularly the GCC, is intended to improve the stability and predictability of Eskom's revenue base by strengthening the recovery of predominantly fixed generation and network costs. From a revenue recovery perspective, the Inquiry recognises that the restructuring of Eskom's tariff components, including the introduction of the GCC and Legacy Charge, was intended to strengthen the recovery of fixed and capacity-related costs in an environment characterised by declining electricity demand and changing consumption patterns. However, the Inquiry notes that improved revenue stability at aggregate level does not necessarily translate into equitable customer outcomes, as the distribution of costs across customer categories materially affects affordability, competitiveness and consumption behaviour.

Revenue neutrality at aggregate level masks significant distributional shifts, with low-usage residential consumers, agriculture, and energy-efficient customers facing above-average bill increases. Large industrial customers experience greater cost reflectivity but face reduced incentives for load-shifting and embedded generation investment. Stakeholder confidence is weakened by transparency gaps, uneven municipal implementation effects, and legacy cross-subsidies embedded in fixed charges. However, it should be highlighted that one of the key motivations for the splitting out of the capacity charge from the energy charge is to protect the non-solar photovoltaic (PV) customers from subsidising the customers with solar PV and the independent power producer (IPP) generators coming on line. This is still applicable.

The Market Inquiry finds that tariff restructuring can improve long-term pricing efficiency when carefully phased and supported by accurate cost allocation, but poorly calibrated implementation may create affordability stress, discourage efficient consumption behaviour, raise rivals' costs, accelerate grid defection, and undermine confidence in tariff regulation.

Evidence presented during the Inquiry suggests that the cumulative effect of fixed charges, capacity-related charges, and increasing electricity costs may be contributing to reduced electricity demand growth, constrained economic output, accelerated investment in alternative supply options, and declining competitiveness in energy-intensive sectors. Several stakeholders submitted that actual electricity cost increases experienced by customers substantially exceeded approved average tariff adjustments, with some agricultural and industrial users reporting effective increases ranging between 20 and 30 percent.

The Inquiry recognises that tariff design involves balancing multiple regulatory objectives, including cost recovery, affordability, economic efficiency, transparency, and appropriate customer behaviour inducements. While increased fixed cost recovery can support the recovery of infrastructure and capacity-related costs, the resulting allocation of costs across customer categories requires ongoing assessment to ensure that tariff structures remain aligned with efficient market outcomes and do not introduce unintended distortions in consumption, investment or competition.

The Inquiry further identified the need for continued monitoring of Eskom's realised revenue outcomes following the implementation of the RTP. Although the restructuring of tariff components was approved within the broader tariff determination process, including the separation of capacity-related and energy-related charges, the extent to which actual revenue recovery aligns with approved assumptions, demand forecasts and underlying cost drivers requires ongoing assessment. Such assessment is particularly important in a declining demand environment where changes in consumption patterns, customer migration to alternative supply options, and evolving market participation may affect the relationship between approved revenue requirements and realised revenue outcomes. Continued monitoring will assist in determining whether tariff restructuring achieves its intended objectives of improved cost allocation and system sustainability without creating unintended affordability compressions or distortions in future electricity market development.

Of particular significance is the interaction between tariff restructuring and South Africa's ongoing electricity market reforms. The transition towards a competitive electricity market, including the development of the South African Wholesale Electricity Market (SAWEM), will require tariff structures that facilitate efficient competition, transparent cost allocation, and a level playing field among market participants. The Inquiry notes stakeholder concerns that excessive or poorly allocated fixed charges may raise rivals' costs, create margin squeeze risks, distort retail competition, and destabilise future market participation by independent retailers and generators. However, this is not the case as the correct balancing of charges promotes correct economic assessment and true competition.

While no conclusive evidence of anti-competitive conduct was identified within the scope of this Inquiry, the findings suggest that future tariff reforms should be assessed not only against traditional cost-reflectivity principles but also against competition, market development, and consumer welfare objectives. Particular attention should be given to ensuring that fixed charges, legacy cost recovery mechanisms, and vesting contract arrangements do not inadvertently create barriers to entry or distort competitive market outcomes.

The Inquiry concludes that tariff restructuring can improve long-term pricing efficiency when supported by robust cost allocation methodologies, comprehensive impact assessments, transparent stakeholder engagement, and appropriate transition mechanisms. However, poorly calibrated implementation may create affordability pressures, accelerate grid defection, weaken customer trust, suppress economic activity, and compromise the objectives of electricity sector reform.

The report therefore recommends strengthened ex-ante and ex-post impact assessments, enhanced revenue-neutrality verification, customer-class bill simulations, improved municipal cost-of-supply assurance, competition impact screening, affordability safeguards, transitional mitigation measures, and clearer communication obligations. The report further recommends that future tariff reforms be evaluated against their implications for market competition, investment incentives, customer welfare, and the successful implementation of South Africa's evolving competitive electricity market architecture.

Beyond the immediate scope of the Inquiry, several additional matters emerged requiring policy and legislative consideration, including municipal surcharges, levies, taxes and duties, cost-of-supply governance, consumer protection concerns, electricity vending charges, and broader tariff transparency issues. Although these matters fall outside the direct scope of the Inquiry, they warrant engagement with relevant institutions, including the National Treasury, the Department of Cooperative Governance and Traditional Affairs (COGTA), the National Consumer Commission, and other affected authorities as part of a coordinated approach to electricity sector reform.

## 2. MARKET INQUIRY PROCESS

2.1 In accordance with section 4(b)(ii) of the Electricity Regulation Act, 2006 (Act No. 4 of 2006) ('the ERA'), as amended, NERSA initiated a market inquiry to assess the structure, application, and impact of fixed charges levied by municipalities and the unbundled generation charges recently introduced by Eskom.

2.2 The inquiry follows growing concerns from customers and stakeholders regarding the affordability, transparency, and long-term sustainability of these charges. As the custodian of the regulatory framework, NERSA has a statutory duty to safeguard the interests of electricity users, while ensuring that tariffs are fair and cost-reflective, and support the sustainable operation of licensees and the broader electricity supply industry[2]. The Terms of Reference (TOR) identified the following themes as the rationale for initiating a market inquiry:

2.2.1 Whether the changes have been effectively managed;
2.2.2 The extent and adequacy of communication with customers;
2.2.3 Whether any tariffs implemented are unlawful or unauthorised;
2.2.4 The impact of these charges on different customer categories; and
2.2.5 Whether the charges are implemented in a reasonable and justified manner.

2.3 The discussion sets out a summary of the process followed in conducting the market inquiry.

**Launch of the Market Inquiry**

2.4 On 25 September 2025, NERSA officially announced the initiation of the Market Inquiry into the impact of fixed charges levied by municipalities and the unbundled generation charges recently introduced by Eskom and the TOR were published on the NERSA website and various other media platforms, along with Stakeholder Participation Guidelines. The TOR outlined key structured phases and the main activities that would be undertaken under each phase. These included the following:

2.4.1 Evidence gathering;
2.4.2 Data and impact analysis; and
2.4.3 Reporting.

2.5 The Stakeholder Guideline (Appendix 1) contained rules of participation applicable to all stakeholders. The Guideline provided a fair opportunity and a transparent process for all stakeholders to participate in the market inquiry and clearly outlined (i) who could participate in the market inquiry and how they could submit information; (ii) the treatment of confidential information; (iii) the activities and indicative timelines of the market inquiry; and (iv) the powers available to NERSA among others. The market inquiry into electricity charges officially commenced on 25 September 2025.

[2] Section 2(b) of the Electricity Regulation Act, 2006 (Act No. 4 of 2006).

*Phase 1: Evidence Gathering*

2.6 In collecting information for the market inquiry, NERSA issued the TOR, calling for all affected stakeholders, including licensees, industry associations, consumers, and other interested parties, to submit information, evidence or experiences relating to the implementation of fixed charges and restructured generation charges.

2.7 Interactions with stakeholders occurred in different forms, namely: (i) responses to calls for submissions; (ii) information requests; (iii) teleconference meetings; and (iv) public hearings.

2.8 <u>Call for submissions:</u> On 25 September 2025, NERSA officially launched the market inquiry through the publication of the TOR document, calling for all affected stakeholders and other interested parties including Eskom, municipalities, industry associations, and customers to submit information, evidence, or experiences relating to municipal fixed charges and Eskom's restructured generation charges.

2.9 The call for submissions, embedded in the TOR, published on 25 September 2025, provided a list of specific questions related to the issues identified in the TOR, and were detailed in **Appendix 1** of the TOR. Stakeholders were informed that their responses were confined to municipal fixed charges and the split of Eskom's generation charge into a generation capacity charge, legacy charge and variable energy charge. The scope of the market inquiry was intentionally focused to ensure depth and relevance. This approach also sought to prioritise areas of great concern to consumers and stakeholders while avoiding dilution of the inquiry process.

2.10 <u>Written Representations:</u> Since the launch of the market inquiry on 25 September 2025, stakeholder submissions were received via a dedicated e-mail address, outlining issues they have encountered, attributable to Eskom's recently unbundled GCC tariff and other fixed charges imposed by licensees.

2.11 Each of these submissions have been carefully and individually reviewed based on:

2.11.1 the nature of the complaint;
2.11.2 the underlying cause for concern; and
2.11.3 the impact on the affected stakeholders.

2.12 The last day for written submissions was on 28 October 2025. However, certain stakeholders requested an extension to the submission deadline, citing the complexity and the level of detail required from their respective responses as reason.

2.13 Having considered the requests for extension and in recognition of the complexity and significance of the issues under review, along with the need to ensure that all affected parties, including Eskom, municipalities, industry associations and customers can make meaningful contributions, NERSA extended the submission deadline to 23:59 on 8 November 2025.

2.14 Public Hearing: A public hearing was held on 17 November 2025 to gather more information, wherein affected stakeholders provided their oral representations in response to the market inquiry call for submissions. Stakeholders who presented include Elexpert (Pty) Ltd, Manganese Metal Company (MMC), Renew Consulting, and a collective from the Energy Intensive Users Group-Ferro Alloy Producers Association-Minerals Council South Africa (EIUG-FAPA-MSCA).

2.15 Observers of the public hearing proceedings included a variety of stakeholders from SAWEA, ArcelorMittal South Africa, Eskom, NTCSA, PARRA, Senzakahle Youth, Geo Coal and various members of the public.

*Phase 2: Data and Impact Analysis*

2.16 Phase 2 of the market inquiry entailed an extensive data collection and an assessment of the information received from stakeholders. In this regard, a data input template was developed and shared with all stakeholders. The collected data included consumption and tariff structure data for a period of two years, namely the 2024 and 2025 calendar years. The results of this market inquiry are based on 33 datapoints from usable and credible customer data.

2.17 The inquiry considered revenue impacts resultant from tariff restructuring. However, a comprehensive assessment of Eskom's revenue position in the 2024/25 and 2025/26 financial years, its cost recovery requirements and turnaround strategy fall outside the scope of this inquiry and requires separate analysis supported by detailed financial, cost recovery and customer migration information.

2.18 A range of analytical techniques, both qualitative and quantitative, was undertaken to construct patterns, in order to understand the nature of the reported electricity tariff disproportions, as well as the impact of the identified charges.

2.19 Even though the Inquiry sought to assess impacts across the electricity supply industry, the available quantitative dataset predominantly comprised industrial and large power user customers. Residential, prepaid and low-consumption household customers were comparatively underrepresented. Consequently, the quantitative findings are more robust for industrial and commercial customer segments, whereas household impacts are informed primarily through stakeholder submissions, public hearing representations and qualitative assessment.

2.20 For qualitative analysis, submissions were grouped together according to their respective nature, and themes were derived to establish the nature of the emerging issues. For quantitative analysis, the various data inputs received were extracted and consolidated for various analyses.

*Phase 3: Data Synthesis and Reporting*

2.21 The final phase of the market inquiry involved the drafting of the report on the impact of the implementation of the fixed and generation capacity charges on various levels of the economy. A list of key milestones of the inquiry are outlined in Table 1 below.

**Table 1: Key Milestones**

| **KEY MILESTONES** | |
|---|---|
| **INQUIRY ACTIVITY** | **DATE** |
| **Phase 1:** Commencement of the inquiry | |
| Publication of notice and call for written submissions | 25 September 2025 |
| Closing date for written stakeholder representations and submission of relevant information | 25 October 2025, then 8 November 2025 |
| Public hearings | 17 November 2025 |
| **Phase 2:** Draft Market Inquiry Report | |
| Publication of the draft report and invitation for comments | 25 June 2026 |
| Closing date for written stakeholder comments on the draft report | 27 July 2026 |
| **Phase 3:** Finalisation of the Market Inquiry Report | |
| Recommendation of the final Market Inquiry Report by the Electricity Subcommittee to the Energy Regulator | October 2026 |
| Approval of the final Market Inquiry Report and its publication by the Energy Regulator | October 2026 |
| Publication of the Final Report on the NERSA website | December 2026 |

2.22 During the market inquiry process, NERSA posted several documents on its website. These included the TOR with participation guidelines, media statements on both the publication of the TOR and the extension of the submission deadline, a statement of issue and draft recommendations (this report) for public commentary. This was done to ensure that members of the public together with affected stakeholders had ease of access to applicable information and were kept abreast of timelines associated with the Inquiry.

## 3. DATA ANALYTIC FINDINGS AT A GLANCE

3.1 Electricity tariffs have increased by over 1,100% since 2003 (from 16.05 c/kWh to 178.63 c/kWh in 2024/25).

3.2 Industrial electricity demand has declined by approximately 40% from peak levels around July 2025.

3.3 From the analysed data sample, variable charges constitute an approximation of 86% of total electricity costs, whereas fixed charges represent around 14% (Figure 1).

3.4 Significant disparities exist in the application of charges across customer categories.

3.5 Households face compounded pressures from electricity costs and downstream food price inflation.

3.6 Large Power User Groups (agriculture, mining, manufacturing) face threats that could force their businesses into bankruptcy.

3.7 Six out of the eight large customers analysed as part of the sample are not using electricity at a consistently high level throughout the year (i.e., their average demand is below 70% benchmark of their contracted capacity). This implies that they are liable for a capacity charge equivalent to their 100% contracted capacity yet only utilise an average of 50 to 60% of that capacity.

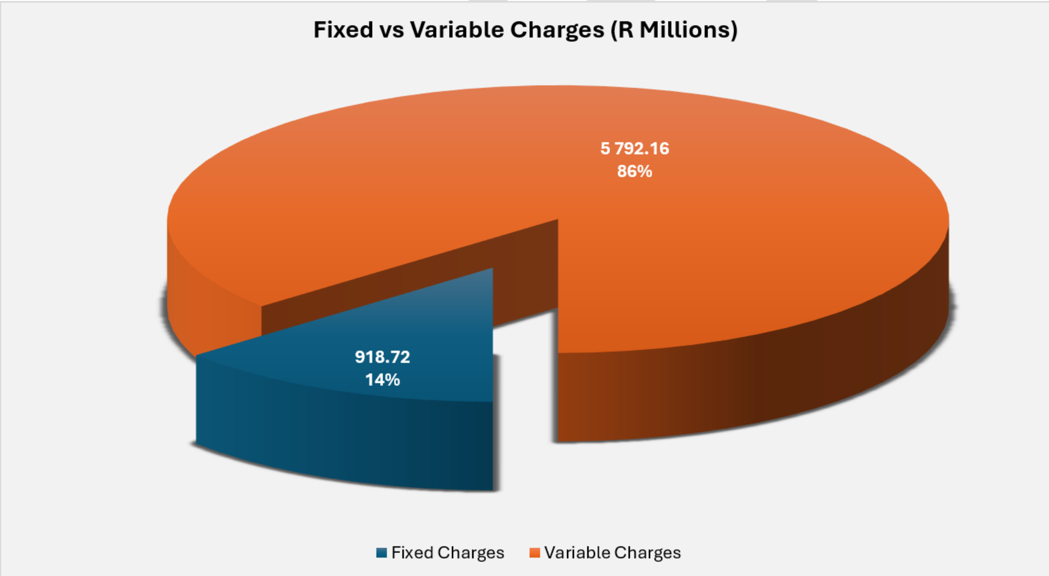



**Figure 1: Fixed vs Variable Charges**

3.8 The variable and fixed charges split of 86%: 14% indicates a tariff structure that is heavily weighted toward consumption-based cost recovery. This should be compared to an actual cost split which is closer to 50/50 between actual fixed costs and variable costs.

3.9 The heavy reliance on volumetric charges places a disproportionate burden on high-consumption users with limited ability to reduce demand, especially in energy-intensive and continuous-process industries. As demonstrated in Section 8 of the report, this drives cost escalation without enabling meaningful consumption adjustment, contributing to declining industrial demand and reduced competitiveness.

3.10 Qualitative analysis of stakeholder submissions identified recurring themes relating to transparency, cost-reflectivity, affordability, and implementation inconsistencies. These themes informed the interpretation of quantitative findings and are summarised in Tables 2 and 3 as follows.

**Table 2: Preliminary Thematic Analysis**

| Theme | Description | Stakeholders | Indicative Impact |
|---|---|---|---|
| **A. Fixed Charges and Cost-reflectivity** | Concerns that fixed charges are being applied above actual cost of service, leading to potential over-recovery. This disproportionately affects low-usage and embedded generation customers. | EIUG-FAPA-MCSA, AgriSA, Agri Letaba and Private Customer (Gillaume). | Residential and agricultural customers experience 20 - 30% higher effective increases than the approved 12.74%. This could compress disposable income & operational margins. |
| **B. Unbundled Tariff Components (Generation Capacity, Legacy, Energy Charges)** | Stakeholders indicate that the restructuring under the MYPD6 and RTP decisions has led to increased total charges, especially for high-demand users. No clarity in the methodology used. | AgriSA, Agri Letaba, Tzaneen Chamber of Commerce. | Reported increases range between 19 - 30% with perceived lack of clarity on methodology. Substantial additional costs impact operational sustainability |
| **C. Non-Compliance with Approved Tariffs** | Alleged breaches of approved tariffs by municipalities (e.g., Ndlambe) where increases of up to 119.8% in capacity charges were applied. | Port Alfred Ratepayers' & Residents' Association (PARRA, Ren), GeoCoal/PARRA (Dawie van Wyk). | Significant deviation from NERSA-approved rates, undermining consumer confidence. Customers face unexpected and excessive charges, placing financial burden on them. |
| **D. Communication and Transparency** | Insufficient disclosure or explanation of tariff drivers to customers; limited stakeholder engagement on tariff reforms. | Transalloys, EIUG-FAPA-MCSA, AgriSA. | Confusion around cost components, raising fairness and transparency concerns. This hampers stakeholders' ability to anticipate and manage electricity costs. |
| **E. Sectorial Financial Harm** | 25 - 30% increase for agriculture & industry. These increases arise from structural changes in approved tariffs, which disproportionately impact energy-intensive operations, such as irrigation, processing, and manufacturing. | Agri Letaba, SA Canegrowers, Tzaneen Chamber of Commerce. | Increased costs may reduce the competitiveness of local produce in national and export markets, potentially affecting revenue streams. Cashflow and sustainability constraints are possible for smaller producers. |

3.11 Table 2 above provides a snapshot of issues raised by stakeholders, highlighting a range of recurring themes and areas of concern. Overall, the issues appear to cluster around key challenges such as capacity constraints, resource limitations, and the need for improved coordination and communication across relevant structures. In addition, several entries in the table suggest gaps in implementation and monitoring, indicating that while policies and frameworks may be in place, their execution remains uneven.

**Table 3: Qualitative Impacts**

| Customer Segment | Approved Average Increase (FY2025/26) | Observed / Reported Increase | Variance | Indicative Concern |
|---|---|---|---|---|
| **Large Power Users** (Eskom LPU – Transalloys) | 12.74% | 14.45% | +1.71% | Possible inclusion of additional capacity/legacy components. |
| **Agricultural Users** (AgriSA, Agri Letaba) | 12.74% | 25 - 30% | +12 - 17% | Unintended effects of unbundled tariffs and high-demand charges. |
| **Municipal Customers (Ndlambe)** (PARRA) | 12.74% | 26.6 - 119.8% | +14 - 107% | Potential non-compliance with NERSA-approved tariffs. |
| **Residential Customers** Through a Reseller | 12.74% | 18 -25% | +6 - 12% | Fixed charge impact under reseller or municipal networks; disproportionate effect on low-usage customers. |

3.12 Preliminary qualitative findings, summarised in Table 3 above, suggest material differences in how distributors apply fixed and capacity charges, with evidence of potential over-recovery in some instances. A quantitative analysis has been carried out to inform the findings within this Market Inquiry Report.

3.13 The interaction with some categories of customers also revealed that changes in the Time-of-Use (TOU) structure had a significant role in the impact, specifically for the agricultural sector. Table 4 below outlines the impacts resulting from the TOU changes.

**Table 4: Cost Impact on Industrial Sector**

| Impact Factor | Change | Direction | Cost Effect |
|---|---|---|---|
| Peak Period Duration | 3 hrs → 5 hrs | ↑ +67% | Higher |
| Off-Peak Opportunity | 10 hrs → 8 hrs | ↓ -20% | Higher |
| Load-Shifting Flexibility | Reduced | ↓ Limited | Higher |
| Peak Energy Rate (c/kWh) | Increased | ↑ +12.7% | Higher |

3.14 The revised TOU structure has materially changed customer cost exposure by extending peak period duration by approximately **67%** and reducing off-peak opportunities by **20%**. This limits customers' ability to shift consumption to lower-cost periods and reduces the effectiveness of demand response strategies that were previously available.

3.15 From an economic perspective, the combination of longer peak exposure, higher peak energy rates (increasing by approximately 12.7%), and limited load-shifting flexibility increases effective electricity costs, even where consumption remains unchanged. This is particularly significant for sectors such as agriculture and other seasonal or process-driven users, where consumption patterns are determined by production cycles, irrigation requirements, and operational constraints rather than discretionary choices.

## 4. SOUTH AFRICA'S ELECTRICITY SUPPLY INDUSTRY – A DECADE IN REVIEW

### 4.1 Historical Price Trajectory (2023 - 2025)

4.1.1 South Africa's electricity prices have increased dramatically over the past two decades. Prior to 2007, South Africa boasted some of the world's lowest electricity prices, a key competitive advantage that attracted energy-intensive industries.

4.1.2 Electricity tariffs increased by 18.7% in 2023 and again by 12.7% in 2024. This compares to Consumer Price Index (CPI) increases of 5.9% and 4.9% over the same two-year period.

4.1.3 Figure 1[3] below shows the Eskom tariffs from 1988 to 2024, plotted against CPI or inflation over the same period. It also shows projections up to 2026, based on inflation expectations and Eskom's tariff application to NERSA under the Multi-Year Price Determination (MYPD) 6 tariff increase in the 2024/25 financial year (FY). For illustrative purposes, the projections assume that approximately half of Eskom's proposed tariff increase of 36.15% in FY2024/25 was approved. This assumption is used to provide a conservative and illustrative projection of tariff trends, as NERSA's approved tariff increases are typically lower than Eskom's initial applications due to affordability, economic impact and regulatory considerations. The actual approved increase for FY2024/25 (12.74%) was significantly below Eskom's requested increase, reflecting this regulatory adjustment process.

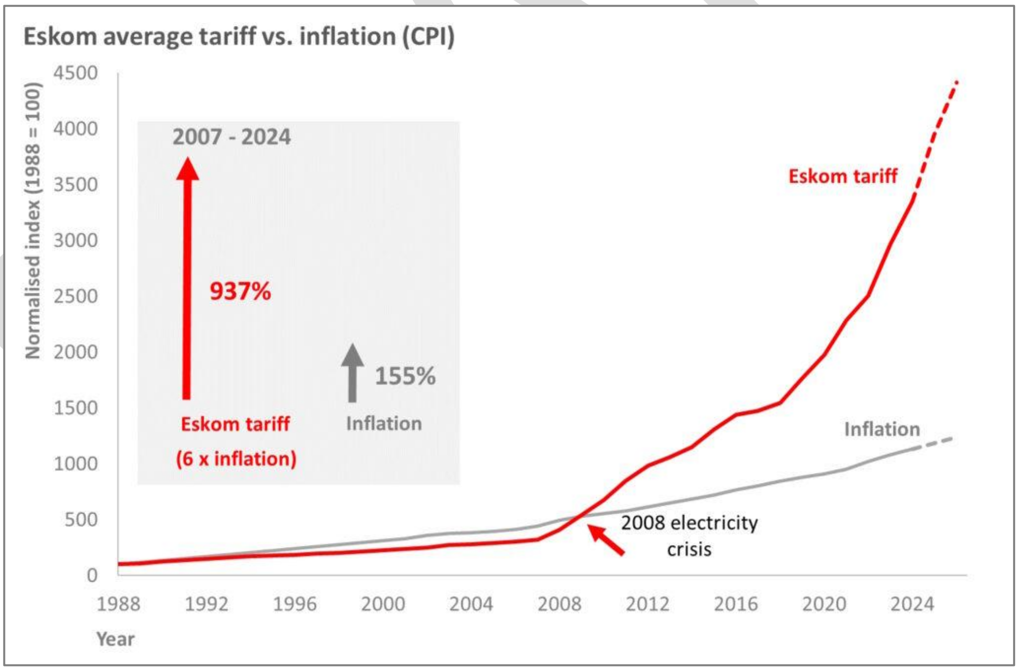



**Figure 2: Electricity Tariffs vs Inflation (CPI)**
*Source: Power Optimal (https://poweroptimal.com/2024-update-eskom-tariff-increases-vs-inflation-since-1988-with-projections-to-2026/)*

[3] The graph depicts overall average increases, actual increases will be different for different types of consumers (residential, commercial and industrial) and will vary between municipalities or distributors.

4.1.4 Looking at the graph, the following observations can be made:

4.1.4.1 In the period from 1988 until the 2008 electricity crisis, electricity tariff increases did not keep tread with inflation. This was partly due to government policy to keep electricity tariffs as low as possible for poor communities, but also due to Eskom having an oversupply of electricity in the 1990's, and not investing in new capacity in the early 2000's.

4.1.4.2 Between 1988 and 2007, electricity tariffs increased by 223%, while inflation over the same period was 335%. In 2008, the new Electricity Pricing Policy (EPP) was published that, among other far-reaching interventions, introduced the use of the modern equivalent asset valuation (MEAV) approach to evaluating Eskom's Regulated Asset Base (RAB).

4.1.4.3 When load-shedding first hit South Africa in 2007, few could have predicted how dramatically electricity costs would rise. By 2008, the electricity crisis was evident and from that point onwards, there is a clear and sharp inflection point for electricity tariffs in South Africa. From 2007 to 2024, electricity tariffs increased by a staggering 937%, while inflation over this period was 155%. Thus, electricity tariffs increased six-fold, or six times faster than inflation, in real money terms over a period of 16 years.

## 4.2 Historical Tariff Evolution by Customer Category (2003/04 to 2024/25)

4.2.1 The focus on specific customer categories is illustrated in detail in Table 5 below.

**Table 5: Historical Tariff Evolution by Customer Category (2003 to 2005)**

| Customer Category | 2003/04 (c/kWh) | 2024/25 (c/kWh) | Total Increase (%) | Total Increase (x) |
|---|---|---|---|---|
| Agriculture | 29.14 | 308.19 | 958% | 10.6x |
| Mining | 15.07 | 193.70 | 1185% | 12.9x |
| Industrial (excl. NPA) | 14.73 | 184.80 | 1155% | 12.5x |
| Overall Average | 16.05 | 178.63 | 1013% | 11.1x |
| Residential | 36.58 | 252.52 | 590% | 6.9x |
| NPA (Smelters) | 11.88 | 112.64 | 848% | 9.5x |

4.2.2 This shows dramatic cumulative tariff increases across all customer categories from 2003 to 2025.

4.2.3 This time series was further marked by a critical 2008 - 2013 period under the MYPD 2 regime, a watershed moment when NERSA approved five consecutive year of double-digit tariff increases ranging from 16% to 31%.

## 4.3 Demand Destruction Evidence

4.3.1 From the consumption data analysis, the inverse relationship between price and volume is stark.

4.3.2 An analysis of the monthly electricity consumption data, as illustrated by the blue bars (actual consumption) and the red dashed trend line (underlying trajectory) in Figure 3, provides clear evidence of emerging demand destruction dynamics within the South African electricity market.

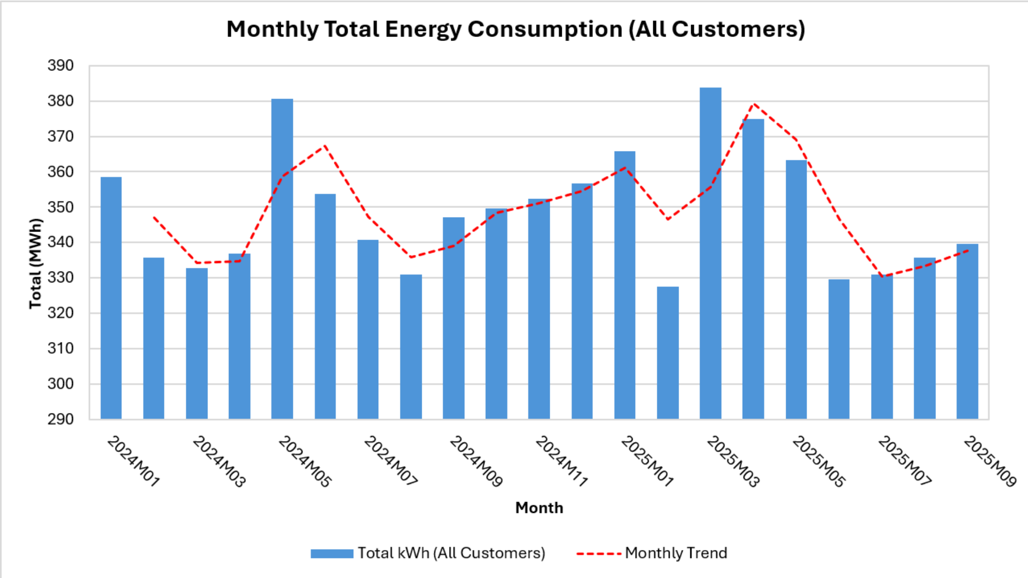



**Figure 3: Demand Reading Trend Over 21 Months**

4.3.3 Monthly consumption fluctuates within a relatively narrow range of approximately 330 to 385 MWh, as shown by the blue bars, indicating that electricity usage has not collapsed outright, but rather exhibits short-term volatility and seasonal variation. However, the inclusion of the trend line reveals a more important underlying pattern: despite periodic increases, there is no sustained upward growth trajectory, and consumption repeatedly returns to lower baseline levels.

4.3.4 Beyond the observed nominal fluctuations in electricity consumption, the trend is more pronounced when considered in real (economic) terms. Despite population growth and underlying economic demand drivers, aggregate electricity consumption appears to be stagnating or declining in real terms, signalling a structural decoupling between economic activity and grid-based electricity usage. This reflects not only supply constraints such as load shedding, but also price-driven behavioural adjustment and substitution effects. In real terms, this implies that economic actors are either producing less output per unit of electricity or shifting away from the grid through embedded generation, energy efficiency, or demand suppression.

4.3.5 When adjusted for inflation and rising tariff levels, the effective cost of electricity per unit of economic output has increased significantly over the period. This means that even where nominal consumption appears relatively stable, the real cost burden on consumers has intensified, forcing both households and firms to adjust behaviour. For large power users, this adjustment often takes the form of production curtailment, load reduction, or investment in self-generation, while for households it manifests as reduced consumption, energy poverty, or fuel switching. The result is a form of demand destruction, where consumption is no longer constrained purely by need, but by affordability and system reliability constraints.

4.3.6 Notably, this real-term contraction in demand has direct implications for the sustainability of the electricity pricing framework. As consumption flattens or declines in real terms, the recovery of predominantly fixed system costs becomes increasingly difficult within a volumetric tariff structure. This places upward pressure on tariffs, including the expansion of fixed charges and the Generation Capacity Charge, thereby reinforcing the feedback loop identified in later sections. In effect, the system is transitioning toward a regime where declining real demand necessitates higher prices to recover fixed costs, further accelerating demand suppression and weakening long-term revenue stability.

4.3.7 Key statistics from analysed data (January 2024 to September 2025) indicate the following:

4.3.7.1 Total Eskom sales volumes dropped from 256,959 GWh at its peak to 189,723 GWh – a loss of over 67,000 GWh.

4.3.7.2 Industrial electricity sales fell from a peak of 71,629 GWh (2004/05) to 43,153 GWh (2024/25) – a decline of approximately 40%.

4.3.7.3 In the ferrochrome sector specifically, only 11 out of 66 smelters remain operational.

4.3.7.4 Demand shows pronounced volatility with two major peaks: May 2024 (approximately 755k) and December 2024 (approximately 750k), and a pronounced trough in July 2025 (in approximation of 645k).

4.3.7.5 There is a seasonal or periodic pattern of rises toward mid-year or year-start followed by declines; the overall range across the period is large (approximately 115k), indicating significant variability in demand.

4.3.7.6 Recent months (August to September 2025) show a rebound from the July 2025 low, but the current level of 695k remains below the earlier peaks, suggesting recovery that is partial.

## 5. THE CURRENT ELECTRICITY LANDSCAPE

### 5.1 Eskom's Legacy Structure in a Monopolistic Environment

5.1.1 For decades, Eskom operated as a vertically integrated monopoly, controlling the generation, transmission, and distribution of electricity. This structure led to the phenomenon set out below:

5.1.2 South Africa's electricity landscape remains dominated by the structural imprint of Eskom's decades-long position as a vertically integrated monopoly that controlled generation, transmission and distribution within a single entity. For most of the post-apartheid period, this model meant that all investment decisions, tariff setting, maintenance schedules and customer categories were managed internally without competitive pressure from independent producers or alternative network operators. The absence of rivals removed the usual market discipline that forces firms to innovate, reduce costs and improve service quality. In practice, Eskom had little incentive to pursue operational efficiency or to experiment with new technologies, because revenue was guaranteed through regulated tariffs and demand was largely captive. This lack of competition also meant that the utility became the sole source of institutional knowledge, which slowed the adoption of decentralised generation, demand-side management and digital grid technologies that were advancing rapidly elsewhere. The result is a system that entered the 2020s with technical and commercial practices still shaped by a command-and-control logic, even as the broader energy sector moves toward liberalisation.

5.1.3 The monopolistic environment enabled cross-subsidisation to be the core feature of South Africa's tariff system, which carried both social and economic consequences. Industrial and commercial users were charged above cost to subsidise residential, agricultural and municipal customers, while wealthier households effectively subsidised low-consumption and indigent households through inclining block tariffs. Although cross-subsidies supported access and affordability objectives, they obscured the true cost of supply and created distortions in demand. Large users faced artificially high prices that encouraged self-generation and defection, reducing the revenue base needed to maintain the network. Meanwhile, subsidised categories had weak incentives to conserve electricity, because prices did not reflect scarcity or the marginal cost of new capacity. For NERSA and for market participants, the bundled tariff made it nearly impossible to determine whether transmission losses, distribution inefficiencies or generation costs were driving price increases. This opacity complicated planning for independent power producers and limited the ability of municipalities to develop financially sustainable distribution businesses, locking the sector into a cycle of hidden transfers rather than transparent, cost-reflective pricing.

5.1.4 The financial consequences of Eskom's monopoly structure are now starkly visible in its balance sheet, where accumulated debt exceeds R400 billion. Because the utility was both the buyer and seller of electricity, it could defer cost-reflective tariffs and finance expansion through borrowing without immediate market penalties. The debt burden grew as large capital projects such as Medupi and Kusile faced cost overruns and delays, while tariff increases lagged behind inflation and operating costs. Servicing this debt consumes a large share of revenue, leaving less funding available for maintenance and new investment. For the South African market, this means that every unit of electricity sold carries a legacy cost component unrelated to current fuel or operational efficiency. The debt overhang also weakens Eskom's credit rating, raises the cost of capital for future projects, and creates uncertainty for IPPs that rely on the utility as the primary off-taker. In a competitive market, financial distress would trigger restructuring or entry by more efficient firms; under the legacy monopoly, the financial strain is transferred to customers through higher tariffs and to the fiscus through government bailouts, perpetuating fiscal risk.

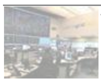
5.1.5 Physical infrastructure has suffered under the same monopolistic conditions, with aging plant and high maintenance backlogs now central to supply insecurity. Eskom's coal-fired fleet, which still provides over 80% of generation, has an average age exceeding 40 years, and deferred maintenance during periods of financial constraint has reduced availability and increased breakdown frequency. The monopoly structure meant there was no competitive pressure to optimise outage planning, adopt predictive maintenance or accelerate refurbishment cycles. Instead, maintenance was often postponed to meet short-term budget targets, leading to a compounding backlog that now requires prolonged unit shutdowns. Transmission and distribution assets face similar issues, with substations, lines and municipal networks deteriorating due to underinvestment. For South Africa, this translates to a system where technical losses are high, resilience to shocks is low, and the margin between available capacity and demand is thin. The infrastructure deficit is not simply a technical problem; it is the physical manifestation of decades without competitive benchmarks or performance incentives that would have forced continuous renewal and efficiency gains.

5.1.6 The most visible manifestation of these legacy dynamics is operational inefficiency that manifests as load shedding and periodic demand reduction. Without competition, Eskom operated as both the planner and executor of capacity adequacy, which weakened accountability when reserve margins eroded. The utility's planning errors, combined with plant unreliability and delayed new build projects, created a structural supply deficit that cannot be resolved by short-term measures alone. Load shedding imposes direct costs on households and businesses, reduces investor confidence, and suppresses economic growth, while also distorting electricity demand as customers invest in diesel generators, solar and storage to avoid outages. This demand-side response, although rational for individual users, further erodes Eskom's revenue and increases the utility's financial strain. South Africa now faces the challenge of transitioning from a monopoly designed for centralised control to a market that requires competition, transparency and coordinated investment across generation, transmission and distribution. Unbundling Eskom into separate entities and opening the market to IPPs and private traders is intended to address these legacy effects, but the transition must confront the accumulated debt, aging assets and cross-subsidy dependencies that the monopoly left behind.

## 5.2 Unbundling into Separate Entities

5.2.1 In December 2024, the electricity minister Dr Kgosientsho Ramokgopa approved Eskom's revised unbundling strategy. The restructuring creates standalone entities as outlined in Table 6 below.

**Table 6: Eskom's Unbundling (Current and Future)**

| | Entity | Function | Status |
|---|---|---|---|
|  | National Transmission Company of South Africa (NTCSA) | Retains ownership, maintenance, and expansion of the physical grid assets as a subsidiary of Eskom Holdings | 2024 (Achieved ) |
|  | Transmission System Operator (TSO) | Functions include market/system operation, grid planning, ancillary services, and acting as the central purchasing agency | 2030 (Target) |
|  | Eskom Generation to become:<br>GenerationCo (GxCo) | Power generation from existing fleet, to become: A standalone generation business that will house Eskom's legacy coal and nuclear power stations | 2025 (Achieved)<br>2030 (Target) |
|  | Eskom Green | A newly conceptualised subsidiary focused solely on renewable and clean energy investments | 2030 (Target) |
|  | National Electricity Distribution Company of South Africa (NEDCSA) | Responsible for the consolidation and operation of national electricity distribution and supply | 2030 (Target) |

5.2.2 Figure 6 below further illustrates Eskom's evolving organisational structure along the electricity value chain, transitioning from a historically vertically integrated utility to functional and legal separation to date.

5.2.3 As shown, Eskom remains under the oversight of the Department of Public Enterprises (DPE), with generation (Gx), transmission (Tx), and distribution (Dx) functions progressively being separated. The first stage reflects a fully vertically integrated structure, where all components operated within a single entity.

5.2.4 This is followed by functional (or accounting) separation, implemented from March 2020, where the generation, transmission, and distribution divisions are delineated operationally but remain within the same corporate structure. The most recent phase introduces legal separation, specifically through the establishment of the transmission entity as a subsidiary (e.g., NTCSA), creating distinct legal entities while still housed under Eskom as a holding company.

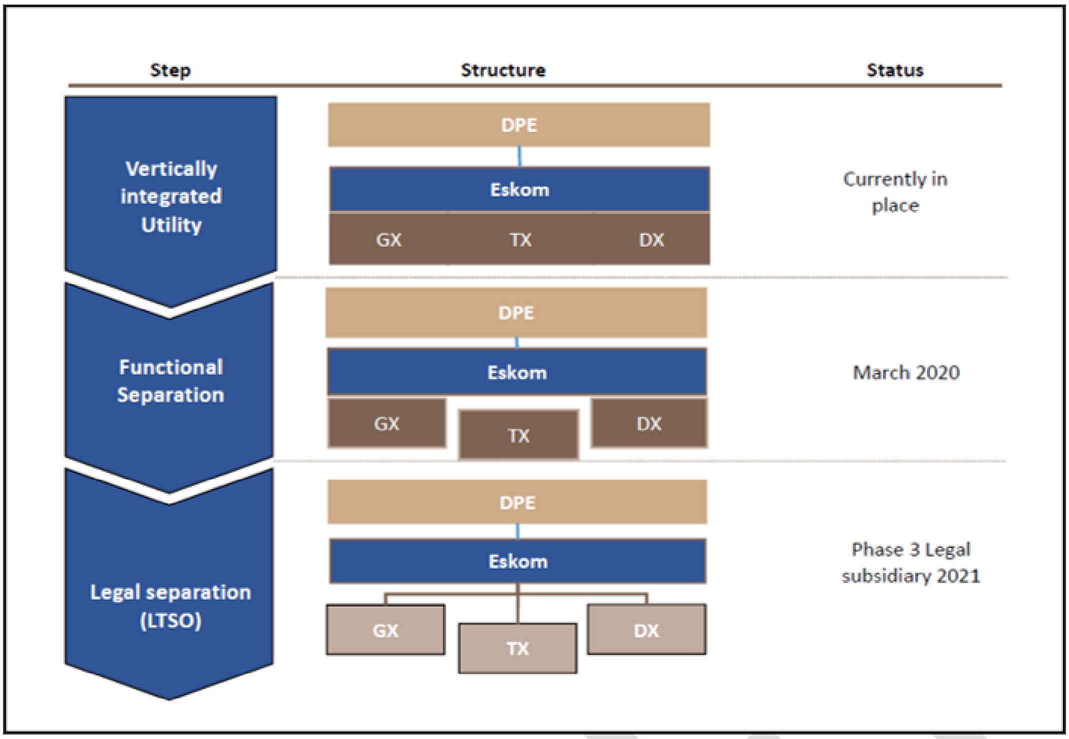



**Figure 4: Eskom Unbundling in Progress**
*Source: DPE's Road Map for Eskom ([https://www.gov.za/sites/default/files/gcis_document/201910/roadmap-eskom.pdf](https://www.gov.za/sites/default/files/gcis_document/201910/roadmap-eskom.pdf))*

5.2.5 Importantly, the diagram highlights that while progress has been made toward legal and functional unbundling, the electricity supply industry has not yet achieved full structural unbundling, where the generation, transmission, and distribution entities operate as entirely independent companies with separate ownership and governance structures. As long as these entities remain under a common holding structure, there may be inherent incentives that limit fully independent decision-making and market behaviour, more so in areas such as pricing and cost allocation.

### 5.3 Implications for Pricing Structure

5.3.1 South Africa's electricity landscape is undergoing a fundamental shift as Eskom's unbundling into separate generation, transmission and distribution entities dismantles the vertically integrated monopoly that defined the sector for decades. This structural separation is not merely administrative; it forces costs that were previously bundled into a single average tariff to be identified, allocated and recovered by each business unit. The transition introduces significant transparency challenges because customers, municipalities and independent power producers must now interpret multiple charge components instead of one aggregated price. For a market accustomed to opacity, this new visibility is disruptive. NERSA as the adjudicator of public hearings, tariff applications and municipal budgets must now account for how much the end-user price reflects actual generation fuel and capital costs, how much they pay for high-voltage transmission, and how much covers local distribution. While this complexity can cause confusion in the short term, it also creates the foundation for a more rational pricing regime where each segment of the value chain is judged on its own efficiency rather than being shielded by cross-subsidies within a single utility.

5.3.2 The most immediate effect of unbundling is that generation costs are now separately identifiable, which fundamentally changes how electricity is priced and procured in South Africa. Under Eskom's legacy structure, inefficiencies in coal plant performance, delays at Medupi and Kusile, and debt service obligations were diffused across all users, making benchmarking impossible. With generation ring-fenced, the National Transmission Company of South Africa buys power from Eskom Generation and from independent producers through transparent power purchase agreements. This allows NERSA and market participants to compare Eskom's cost per MWh against renewables, gas and other IPPs, and to design time-of-use and real-time tariffs that reflect true marginal cost. For demand, this means industrial and commercial customers can now respond to clearer scarcity signals during evening peaks and tight reserve periods. However, it also exposes the extent to which legacy plant costs drive current tariffs, increasing pressure on Eskom Generation to improve availability. In a liberalised market, separately identified generation costs create the basis for competitive wholesale trading, where buyers can choose suppliers and sellers compete in terms of price and reliability rather than operating under a single mandated tariff.

5.3.3 As generation is unbundled, transmission network capacity charges (TNCCs) are becoming more prominent and will shape the emerging price structure. TNCCs are designed to recover the cost of the high-voltage grid and to send locational signals about where new generation and load should connect to avoid congestion and losses. South Africa's transmission network is constrained, especially for wheeling renewable power from the Northern and Eastern Cape to load centres in Gauteng, therefore the TNCC methodology will determine whether the market incentivises efficient siting or creates artificial barriers. In a liberalised structure, transparent TNCC enables bilateral contracts and energy traders to calculate the full cost of wheeling power from an IPP to an end-user. If charges are cost-reflective and stable, they encourage private investment and market participation; if opaque or excessive, they deter competition and keep customers dependent on Eskom's bundled offer. The inquiry and regulatory processes must therefore ensure that the TNCCs follow cost causation principles, distinguish between firm and non-firm access, and adapt as the grid is reinforced. For end-users, prominent transmission charges mean that location and network utilisation become as important as energy consumption in determining the final price.

5.3.4 Distribution network charges are also becoming increasingly material as unbundling forces the future distribution entity and municipalities to recover network costs directly. Historically, distribution was subsidised through surpluses from generation and by overcharging certain customer categories. Once costs are ring-fenced, the financial stress of many municipalities and the need to maintain local wires, transformers and metering become visible in the tariff.

5.3.5 For residential and small business users, rising distribution charges will accelerate the adoption of rooftop solar, storage and energy efficiency, especially where municipal tariffs rise above grid parity. This distributed response changes the planning problem: fewer kilowatt-hours sold over fixed networks threatens to create a 'death spiral' where the remaining customers face higher charges to cover the same infrastructure costs. A liberalised pricing regime must therefore design distribution tariffs that balance cost recovery with efficient price signals, using tools such as capacity charges, time-varying rates and targeted subsidies delivered through the fiscus rather than hidden cross-subsidies.

5.3.6 If done well, transparent distribution pricing can enable aggregators, peer-to-peer trading and smarter local networks; if done poorly, it can fragment the market and undermine universal access.

5.3.7 Finally, unbundling places cross-subsidisation mechanisms under scrutiny and forces South Africa to confront trade-offs between equity and efficiency in its emerging pricing regime. The legacy monopoly relied on industrial and commercial users subsidising residential, agricultural and indigent customers, but cost separation now exposes the magnitude of these transfers. A liberalised market cannot sustain hidden subsidies if it aims to attract competitive investment and allow customers to choose suppliers. The inquiry must therefore assess which subsidies are socially essential and how to deliver them transparently, for example through lifeline tariffs for low-use households or direct fiscal support, rather than embedding them in bulk tariffs. Removing subsidies too quickly risks energy poverty, while retaining them distorts demand and deters IPP entry. The emerging price structure will thus be defined not only by separate charges for generation, transmission and distribution, but also by how South Africa redesigns subsidies to protect vulnerable users without undermining competitive signals. In summary, Eskom's unbundling is pushing the market toward a pricing regime where costs are transparent, risks are allocated, and prices reflect both physical constraints and policy choices, requiring regulators, utilities and customers to adapt to a more market-oriented electricity landscape.

# 6. ESKOM'S RETAIL TARIFF PLAN (RTP) RESTRUCTURING

## 6.1 NERSA's RTP Approval in FY2024/25

6.1.1 In February 2025, NERSA approved Eskom's Retail Tariff Plan (RTP), including revised Time-of-Use (TOU) periods, unbundled energy and network charges, phased capacity and legacy charges, municipal tariff consolidation, removal of inclining block tariffs and service charge adjustments based on points of delivery.

6.1.2 The approval was premised on the following points:

6.1.2.1 *Rationalisation of Municipal Tariffs:* NERSA approved the consolidation of 15 municipal tariffs into three categories: MunicFlex (Large Power User), MunicRate (Small Power User), and Public Lighting. This simplification was aimed at reducing complexity, improving forecasting, and ensuring fairer, more transparent pricing for municipalities.

6.1.2.2 *Introduction of Cost-Reflective Residential Tariffs and Removal of Inclining Block Tariff (IBT):* NERSA approved the introduction of cost-reflective tariffs for HomePower and HomeFlex, with a phased-in generation capacity charge and service charge over three years. The IBT structure for HomePower and HomeLight tariffs was removed, as it was believed it no longer served its intended purpose and has led to unintended cross-subsidies.

6.1.2.3 *Unbundling of Energy Charges and Introduction of Generation Capacity Charge (GCC):* NERSA approved the unbundling of energy charges to introduce a fixed GCC and a separate legacy charge for costs from legacy contracts with IPPs. The GCC would be phased-in at 20% of its proposed level in year 1 and 30% in years 2 and 3 to mitigate the impact on below-average users. This was intended to promote transparency and ensure that customers pay for the specific services they use.

6.1.2.4 *Adjustment of Time-of-Use (TOU) Periods and Rates:* NERSA approved changes to TOU periods and rates to better align with system requirements and customer needs. Key changes included reducing the morning peak to two hours, increasing the evening peak to three hours, and changing the peak-to-off-peak ratio from 1:8 to 1:6. Standard hours have also been introduced on Sunday evenings. These adjustments were made to provide better economic signals and support system optimisation.

6.1.2.5 *Conversion of Service Charges to Per Point of Delivery (POD):* NERSA approved converting service charges to be based on the number of PODs rather than per account. This would ensure equity and fairness among users, as customers with multiple PODs under one account would now pay charges that reflect the true costs incurred. This change was intended to encourage efficient resource allocation and address previous cross-subsidisation issues.

## 6.2 RTP Implementation in FY2025/26

6.2.1 South Africa's electricity landscape is being reshaped by Eskom's Retail Tariff Plan restructuring that is being implemented from FY2025/26, which marks a decisive shift away from the opaque bundled tariffs that characterised the legacy monopoly. The RTP introduces an additional tariff increase of 12.74% effective from 1 April 2025, with

NERSA-approved future increases of 5.36% in FY2026/27 and 6.19% in FY2027/28, pushing the resultant average tariff to 221 c/kWh. This trajectory reflects NERSA's attempt to balance Eskom's reported financial recovery needs against affordability constraints in a market already strained by load-shedding and weak economic growth. More significant than the headline increase is the deliberate restructuring of cost allocation between fixed and variable components; a move that exposes customers to the true cost structure of the system. Historically, Eskom recovered most costs through the energy charge per kWh, which masked fixed network and capacity costs. By shifting more recovery into fixed charges, the RTP makes the economics of network maintenance, debt service and standby capacity visible. For a market transitioning toward liberalisation, this transparency is essential because it creates a common language for pricing between Eskom, independent power producers and municipal distributors as competitive entry expands.

6.2.2 The RTP restructuring directly supports the emergence of a more liberalised market structure by aligning Eskom's pricing with the unbundled architecture of generation, transmission and distribution. As the National Transmission Company of South Africa becomes the central buyer and Eskom Generation competes with IPPs, a tariff that separately identifies fixed and variable costs allows the market to price each segment appropriately. Variable charges can reflect marginal fuel and energy costs, while fixed charges recover capacity, network and sunk costs that do not vary with consumption. This separation is critical for wholesale trading and wheeling, because IPPs and traders must know which portion of the retail price represents energy, and which represents access. In practice, customers considering bilateral contracts can now compare Eskom's energy charge against an IPP's offer without having fixed costs distorting the comparison. The RTP thus acts as a bridge between the old, bundled regime and a competitive pricing regime where buyers choose suppliers and prices reflect cost causation.

6.2.3 However, the transition also creates adjustment costs for customers who previously paid mostly volumetric tariffs, particularly those with low load factors who will now face higher monthly fixed charges regardless of consumption.

6.2.4 A defining feature of the FY2025/26 RTP is the introduction of an Affordability Subsidy Charge set at 25.24%, which explicitly recognises the role of cross-subsidies in South Africa's electricity pricing. Under the legacy monopoly, subsidies were embedded and invisible within the average tariff, with industrial and commercial users overpaying to support residential, agricultural and municipal customers. The RTP makes this transfer transparent by ring-fencing the subsidy charge, forcing policymakers and the public to confront its scale and sustainability. As the market liberalises, hidden cross-subsidies become incompatible with competitive pricing because they distort supplier choice and deter IPP entry if prices are not cost-reflective.

6.2.5 The Affordability Subsidy Charge creates a mechanism to debate and redesign social support, potentially shifting from tariff-based subsidies toward direct fiscal transfers or targeted lifeline rates for indigent households. This is crucial for maintaining access while allowing competitive prices to emerge for the rest of the market. The charge also signals to investors that South Africa is attempting to separate commercial pricing from social policy, a prerequisite for a functional competitive market where prices are not used as a fiscal tool.

6.2.6 The implications of the RTP for the emerging electricity pricing regime are most evident in how demand responds to new price signals. At 221 c/kWh, South Africa's average tariff has reached a level where large users and even residential customers have strong incentives to invest in self-generation, storage and efficiency measures. This demand-side response accelerates under a liberalised structure where customers can choose suppliers, but it also threatens the revenue base needed to cover Eskom's fixed costs and R400 billion debt. The RTP's higher fixed component attempts to mitigate this "utility death spiral" by ensuring some cost recovery even as consumption falls, but it must be calibrated carefully to avoid penalising low-income users and encouraging full defection by large customers. For the market, the restructured tariff creates clearer scarcity signals during peak periods if time-of-use elements are layered on, encouraging load shifting and demand-side management. Over the multi-year trajectory of 5.36% and 6.19% increases, the RTP provides some regulatory certainty, which IPPs and investors require to commit capital. Yet the tariff path also assesses political tolerance, since sustained increases above inflation can erode public support for reforms even when they are economically justified.

6.2.7 Ultimately, Eskom's RTP restructuring positions South Africa at the threshold of an emerging price structure that is more transparent, segmented and market-oriented than the monopoly-era tariff. As the tariff was increased to 221 c/kWh, restructuring fixed versus variable recovery, and making the Affordability Subsidy Charge explicit, the plan forces the electricity sector to confront costs, subsidies and efficiency simultaneously. In a liberalised market, this creates the conditions for competitive procurement, wheeling and retail choice, because each cost component can be priced and contested. The challenge for regulators and policymakers is to ensure that the RTP does not simply shift financial burden onto customers, but also drives efficiency gains in generation, transmission and distribution.

6.2.8 subsidy-related charges are transparent and appropriately targeted, and variable charges reflect underlying cost drivers, the RTP has the potential to improve tariff transparency and strengthen cost allocation signals across the electricity value chain. However, achieving these outcomes requires careful assessment of customer impacts, revenue recovery outcomes and market effects to ensure that tariff structures support affordability, economic efficiency and the transition towards a more competitive electricity market.

6.2.9 The analysis, based on 21 months of customer billing data, provides insight into the composition of charges experienced by customers and the relative contribution of different tariff components. The categorisation of charges into broader cost groups, as depicted in Figure 5 below, assists in assessing transparency, cost allocation and the impact of tariff restructuring on different customer categories.

6.2.10 The analysis below groups the various tariff components into broader categories to provide a clearer understanding of the composition of electricity charges and the relative contribution of different cost elements to customer bills. This categorisation does not imply that each component represents a separate cost driver in isolation, but rather provides a framework for assessing tariff transparency, customer impacts and cost allocation.

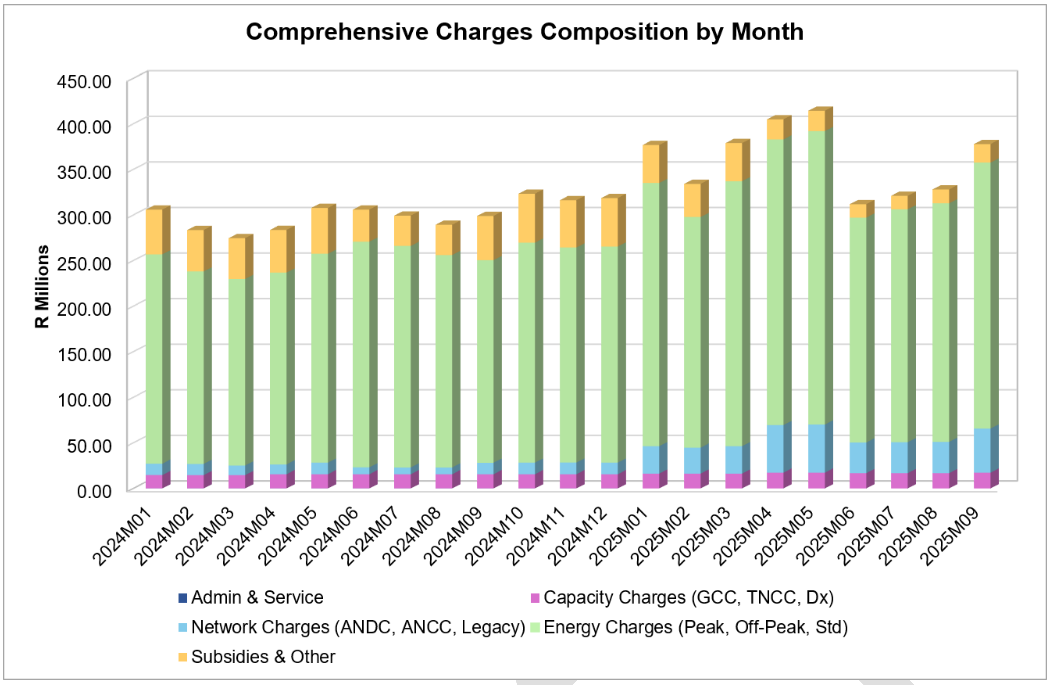



**Figure 5: Charges Composition by Month**

6.2.11 This customer data breaks down 17 individual charge components into five tariff categories namely:

i. Energy Charges, which constitute approximately 76% of the total charges and remain the dominant cost component;
ii. Subsidies & Other represents approximately 11% of the total charges;
iii. Network Charges, accounting for a proximation of 7%;
iv. Capacity Charges, representing approximately 5%; and
v. Admin & Service Charges at the bottom of the band, representing less than 1%.

6.2.12 An analysis of 17 individual charge components reveals that they naturally cluster into five key categories, moving the debate from opaque bundled pricing toward a transparent, segmented view of cost. This clustering is critical as the market liberalises because it allows regulators, customers and independent power producers to see where value is created, where costs are concentrated, and where pricing reform should be targeted. Historically, vertically integrated electricity supply arrangements resulted in many underlying cost categories being recovered through aggregated tariff structures, limiting visibility of the specific cost drivers applicable to different electricity supply activities. The RTP implementation from FY2025/26 represents a move towards greater disaggregation of tariff components that aligns with the unbundled structure of generation, transmission and distribution.

6.2.13 In grounding pricing reform in actual customer billing data, a clearer understanding of individual tariff components enables a more informed assessment of whether charges reflect underlying cost causation principles, while also allowing regulators and stakeholders to evaluate affordability, efficiency and customer impact consideration.

6.2.14 Energy charges dominate the current tariff structure, constituting approximately 76% of total charges analysed. This indicates that the majority of customer billing remains linked to energy consumption-related charges. The dominance of this component highlights the continued importance of generation costs, operational costs and consumption patterns in determining customer electricity expenditure.

6.2.15 As South Africa transitions towards a more competitive electricity market, transparency of energy-related charges becomes increasingly important because it allows market participants to understand the cost drivers influencing electricity prices. Improved visibility of energy charges may support more informed decisions regarding procurement, demand management and alternative supply options. The RTP's restructured allocation between fixed and variable components becomes meaningful here because it allows the energy portion to reflect true marginal cost during peak and off-peak periods. For demand response, this transparency creates stronger incentives for load shifting, efficiency and behind-the-meter solar power, since users can clearly see how much of their bill will decrease if they reduce consumption when generation costs are highest.

6.2.16 Subsidies and other charges represent 11% of total components, making them the second-largest cluster and the most politically sensitive element of the RTP. This category captures the Affordability Subsidy Charge, which constitutes roughly 25% of this component, as well as other social and policy levies that were previously embedded invisibly within the average tariff. Historically, some social and policy-related costs were recovered through broader tariff structures rather than being separately visible to customers. The identification of these components improves transparency and allows policymakers to evaluate whether affordability objectives are best achieved through tariff structures or through alternative policy mechanisms. By clustering subsidies as a distinct component, the RTP makes the scale of transfers explicit and opens them to public scrutiny. In an emerging competitive market, hidden subsidies are unsustainable because they prevent cost-reflective pricing and undermine IPP participation if prices do not reflect actual supply costs. The visibility created by this clustering allows policymakers to debate whether social support should remain tariff-based or shift toward direct fiscal transfers and targeted lifeline rates for indigent households, protecting access without eroding competitive signals for the rest of the market.

6.2.17 Network and capacity charges collectively account for about 12% of the tariff, with network charges at 6.9% and capacity charges at 5.9%, and their prominence will grow as the unbundling process matures. Network charges reflect the cost of transmission and distribution infrastructure, including the high-voltage grid and local wires, while capacity charges recover the cost of maintaining standby generation and network capacity to meet peak demand. In Eskom's legacy structure these costs were buried in the volumetric energy charge, but the RTP and the creation of the National Transmission Company of South Africa make them separately identifiable. This is essential for a liberalised market because locational pricing and wheeling depend on knowing the cost of using the grid. Transparent network charges send signals about where new generation should connect to avoid congestion, especially for renewables in the Northern Cape wheeling power to Gauteng.

6.2.18 Capacity charges similarly expose the cost of security of supply, encouraging customers with flexible load to shift consumption and rewarding investments in storage that reduce peak demand. As demand fragments through self-generation, these charges ensure that fixed infrastructure costs are recovered fairly so that remaining customers do not face a utility death spiral. However, the Inquiry notes that capacity-based recovery mechanisms must be carefully calibrated because customers with limited flexibility to reduce demand may experience higher effective costs without being able to materially change consumption behaviour.

6.2.19 Admin and service charges are the smallest cluster at 0.4%, yet their inclusion in the five-category breakdown highlights the RTP's commitment to full cost transparency. This category covers metering, billing, customer service and other administrative functions that were previously invisible to users. While the percentage is minor, its separation matters in a competitive market because it establishes a baseline for what non-technical service costs should be and allows benchmarking against municipal distributors and future retailers. As South Africa moves toward retail competition, customers will be able to compare not just energy and network prices, but also the efficiency of administrative services. The five-category clustering revealed by customer data therefore a clearer basis for analysing tariff impacts, assessing cost allocation, and identifying areas where further regulatory review may be required. With energy charges dominating, subsidies made explicit, and network, capacity and admin costs ring-fenced, the RTP creates a tariff structure where each component can be regulated, contested and improved independently. This shift from a bundled monopoly tariff to a disaggregated, data-driven price structure is the most important signal that South Africa's electricity market is transitioning from Eskom's legacy control toward a competitive, transparent and sustainable future.

6.2.20 The 21-month cost profile, totaling R6,710 million, summarised in Table 7 below and illustrated in Figure 5 above, reveals a tariff structure that, although still dominated by consumption-based (variable) charges at approximated at 86%, creates a set of structural challenges for large power users (LPUs) across sectors such as smelting, mining, manufacturing, and agriculture. Although the high share of variable costs implies that electricity expenditure remains closely linked to usage, this dependence exposes LPUs to significant cost volatility, particularly in an environment of rising electricity tariffs and shrinking margins. For energy-intensive industries such as smelting and mining, where electricity can account for a substantial share of operating costs, even marginal increases in tariffs directly erode profitability and global competitiveness.

6.2.21 A key challenge for LPUs is that, despite the predominance of variable costs, consumption is not always fully discretionary. In sectors such as smelting and continuous-process manufacturing, operations require stable, baseload electricity supply, limiting the ability to reduce consumption without disrupting production processes or incurring substantial restart costs. This constrains the effectiveness of traditional cost-management responses such as load reduction or interruption, meaning that price increases translate almost directly into higher production costs. Similarly, in agriculture, electricity demand is often seasonal and time-bound (e.g. irrigation cycles), reducing flexibility to shift or curtail usage in response to price signals.

6.2.22 This demonstrates that tariff impacts cannot be assessed solely through the proportion of fixed versus variable charges, but must also consider customer operational characteristics, demand flexibility and the ability to respond to tariff signals.

**Table 7: 21-months Cost Summary**

| FIXED vs VARIABLE COST SUMMARY (Based on 21 Months Data) | | | |
|---|---|---|---|
| **Category** | **Total (R Millions)** | **% of Total** | **Principle** |
| FIXED (Capacity/Demand-Based) | 918.72 | 14% | Pay regardless of usage - reduce by negotiating capacity |
| VARIABLE (Consumption-Based) | 5 792.16 | 86% | Pay based on usage - reduce by efficiency & load shifting |
| **TOTAL** | **6 710.88** | **100%** | |

6.2.23 Although fixed charges account for only an estimate of 14% of total costs, they introduce a non-negotiable cost burden that further compounds these challenges. LPUs must pay these charges regardless of output or consumption, which is particularly problematic for sectors with cyclical output or exposure to commodity price fluctuations, such as mining and agriculture. During periods of reduced production or economic downturn, firms cannot proportionally reduce electricity costs due to these fixed components. This results in cost under-recovery risk at the firm level, where electricity expenses remain elevated even as revenues decline, placing pressure on cash flows and potentially leading to operational cutbacks or closures.

6.2.24 The interaction between high variable costs and rigid fixed charges also creates distorted incentives for investment and operational planning. On one hand, LPUs are encouraged to invest in energy efficiency and embedded generation to manage rising variable costs. On the other hand, the persistence of fixed and capacity-based charges means that the financial returns on such investments are diluted, as a portion of the electricity bill cannot be avoided. For example, even where a smelter or manufacturer installs self-generation (e.g. solar or cogeneration), the obligation to pay for contracted capacity reduces the net savings. This weakens the economic case for decarbonisation and energy diversification in the industrial sector.

6.2.25 Overall, the cost structure reflects a transitional pricing regime that imposes dual pressures on LPUs: exposure to rising consumption-based costs that are difficult to avoid operationally and increasing fixed cost obligations that reduce flexibility and resilience, meaning that firms cannot proportionally reduce costs when output declines. For industries already facing global competition, input cost pressures, and structural economic challenges, this combination may lead to reduced investment, lower output, job losses, and in some cases, accelerated de-industrialisation or grid defection strategies. As tariffs evolve further toward fixed cost recovery under the Retail Tariff Plan, these challenges are expected to intensify unless carefully managed through regulatory safeguards and sector-specific interventions.

6.2.26 The preceding analysis highlights how electricity costs for LPUs are predominantly driven by consumption-based charges, creating both cost volatility and limited flexibility in managing expenditure. Building on this, the analysis of reactive energy, illustrated in Figure 6 below, introduces an additional dimension of cost and operational complexity, as it reflects underlying system inefficiencies and power quality issues that further influence total electricity costs across different user groups.

6.2.27 The chart titled "Reactive Energy by Band Over Time" shows the monthly evolution of reactive energy (measured in MVAR) across three time-of-use bands namely Off-Peak (blue area), Standard (orange), and Peak (green), from January 2024 to September 2025. The stacked area pattern indicates that total reactive energy fluctuates between roughly 17 MVAR and 30 MVAR, with noticeable peaks around late 2024 and early 2025. Peak-period reactive energy constitutes a significant share of total reactive demand, especially during high-demand months, whereas off-peak contributions remain consistently lower but significant.

6.2.28 From an LPU perspective, this pattern highlights a persistent challenge in managing power factor and reactive energy during peak and standard periods, where system demand is highest.

6.2.29 Industries such as smelting, mining, and manufacturing typically operate large loads such as motors, furnaces, and compressors, which inherently generate reactive power.

6.2.30 The observed peaks in reactive energy, mostly during high-demand periods, suggest that LPUs are likely exposed to reactive energy penalties or additional charges, increasing their effective electricity cost beyond active energy consumption. This creates an additional cost layer that is not easily mitigated through simple consumption reduction, as reactive energy is tied to operational processes and equipment characteristics being utilised.

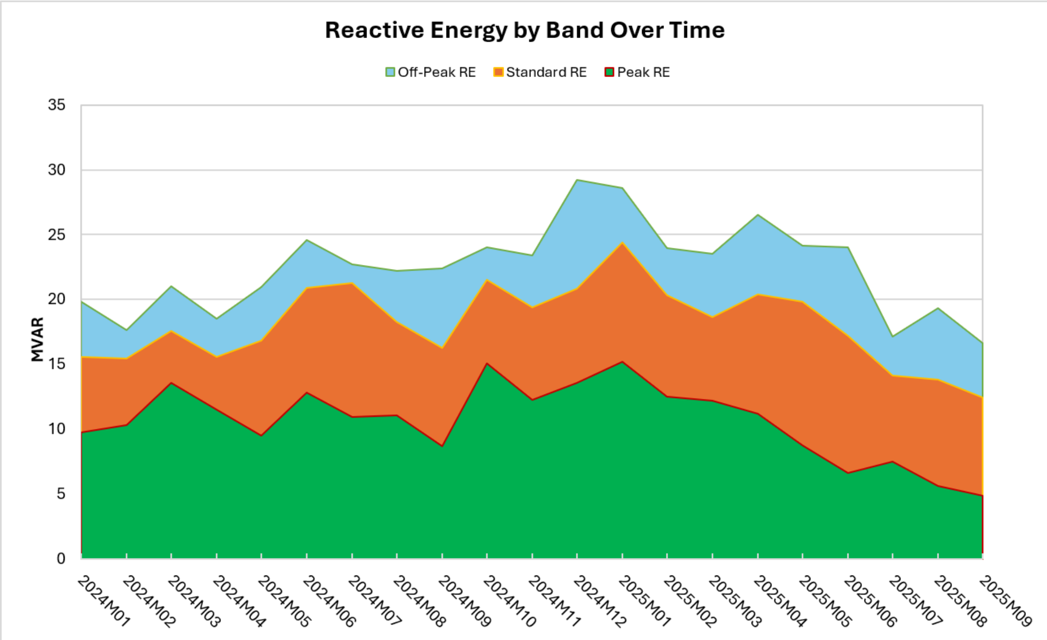


**Figure 6: Reactive Energy Band Over Time**

6.2.31 More broadly, for businesses including small and medium enterprises, the presence of reactive energy charges introduces technical and financial complexity. Unlike variable energy costs (kWh), which can be managed through behavioural or operational adjustments, reactive energy requires capital investment in power factor correction technologies such as capacitors or synchronous condensers. This creates a barrier for smaller businesses that may lack the capital or technical expertise to optimise power quality. Consequently, these users may experience disproportionately higher effective tariffs due to avoidable penalties, further squeezing already constrained operating margins, especially in a rising electricity price environment.

6.2.32 At the household level, even though reactive energy is less directly priced in most residential tariffs, the underlying system inefficiencies reflected in the chart still have indirect cost implications. Poor power factor at the system level increases network losses and reduces overall system efficiency, which ultimately feeds into higher aggregate cost recovery requirements for Eskom and municipalities. These costs are typically passed through to all consumers via higher tariffs over time. Therefore, even if households are not explicitly billed for reactive energy, inefficiencies driven by large users contribute to higher system costs and upward tariff strain, exacerbating affordability challenges.

6.2.33 At a macroeconomic level, persistent and variable reactive energy demand signals underlying inefficiencies in the electricity supply system, particularly in energy-intensive sectors. Elevated reactive energy increases system strain, reduces transmission efficiency, and requires additional grid support investment.

6.2.34 These factors raise the overall cost of supply and contribute to cost-push inflation as higher electricity costs are passed through the economy, in the form of goods and services. For export-oriented industries such as mining and smelting, these added costs weaken international competitiveness and may result in lower output, delayed investment, and potential job losses.

6.2.35 Overall, the data indicates that reactive energy is not merely a technical issue but a significant economic and regulatory concern. For LPUs, it represents an additional cost burden requiring capital investment to manage, whereas for businesses it introduces operational complexity and potential inefficiency costs. At the economy-wide level, it contributes to higher electricity system costs and reduced competitiveness. As tariffs become more cost-reflective, effective management of reactive energy will be increasingly critical for cost optimisation and system efficiency.

## 6.3 Time-of-Use Consumption Patterns and Implications for Fixed Cost Recovery

6.3.1 The Inquiry analysed customer consumption patterns across time-of-use periods to assess whether the current tariff restructuring appropriately aligns cost recovery with actual system utilisation.

6.3.2 The analysis indicates that total energy consumption is predominantly concentrated outside peak periods, with approximately 50% of consumption occurring during off-peak periods, 35% during standard periods and only 15% during peak periods, as illustrated in Figure 7 below.

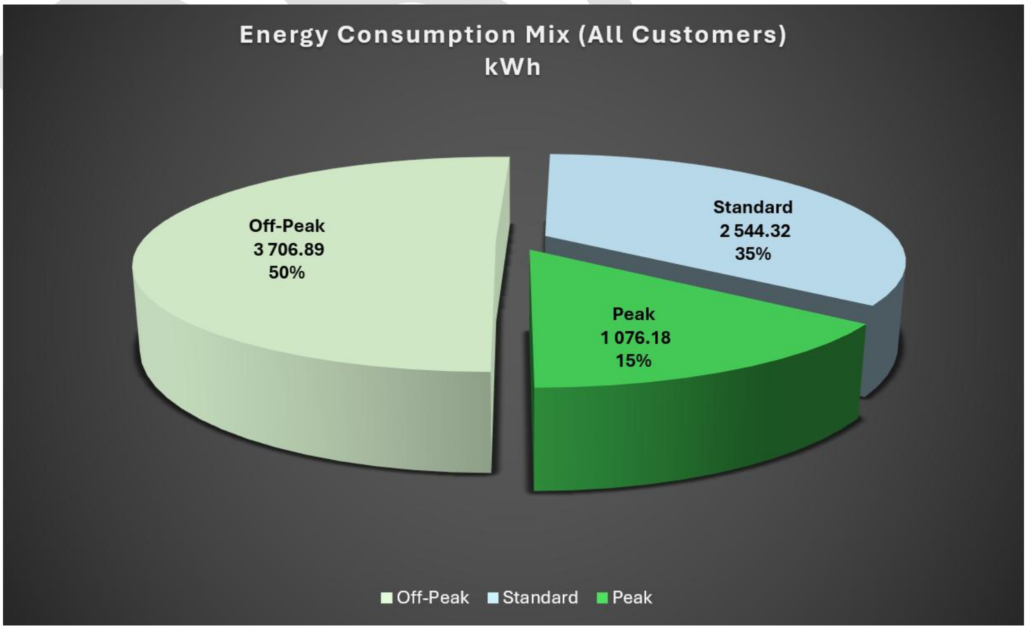



**Figure 7: Energy Mix and Fixed Costs Implications**

6.3.3 Even though the nominal distribution of electricity consumption across off-peak (50%), standard (35%) and peak (15%) periods appears to suggest a system dominated by low-cost usage periods, the implications are significantly more complex when assessed in real (economic and cost-recovery) terms. In practice, the electricity system is not driven by average consumption volumes, but by the need to maintain sufficient generation and network capacity to meet peak demand, regardless of its relatively small share of total energy. This means that the 15% of consumption occurring during peak periods effectively determines the scale of infrastructure investment, system reliability requirements, and standby capacity costs for the entire system.

6.3.4 In real terms, this creates a structural imbalance between how electricity is consumed and how system costs are incurred. Although 85% of electricity is consumed outside peak periods, the cost of maintaining peak capacity, often supplied by high-cost peaking plants such as diesel or gas turbines, is spread across all users. As a result, off-peak and standard consumers, who place relatively limited stress on the system, still bear a portion of these costs through tariff structures that include fixed charges and the GCC. This reflects a shift under the RTP away from purely volumetric pricing toward recovering fixed system costs from the entire user base, regardless of when electricity is consumed.

6.3.5 From a behavioural and investment perspective, this pricing structure has important consequences. Off-peak and standard users, who constitute the majority of consumption, face increasing incentives to reduce grid reliance through self-generation (e.g., solar PV) and energy efficiency, particularly as tariffs rise toward 221 c/kWh. However, as these users reduce consumption, the remaining cost base, predominantly fixed in nature, must be recovered from a shrinking volume of sales. This creates a real risk of cost escalation per unit sold, reinforcing the tariff-demand feedback loop identified elsewhere in the report. In effect, even though consumption patterns are favourable from a system utilisation perspective, the pricing framework may unintentionally accelerate demand erosion rather than efficiency gains.

6.3.6 Stakeholder submissions, specifically from the agricultural sector, indicate that the restructuring of TOU periods and seasonal definitions had a more pronounced impact on customer bills than the introduction of the GCC itself. While the GCC increased fixed cost recovery, changes to peak-period allocation, seasonal categorisation and energy charges altered the timing and cost of electricity consumption, resulting in effective bill increases significantly exceeding the approved average tariff adjustment for certain customer categories.

6.3.7 Evidence submitted by agricultural stakeholders suggests that irrigation-intensive activities are disproportionately exposed to revised TOU structures due to the limited flexibility of irrigation cycles and seasonal production requirements. Consequently, the Inquiry finds that the interaction between TOU restructuring and the GCC warrants further examination as part of future tariff design reviews.

6.3.8 Looking forward, the 2025 consumption mix revealed by the market inquiry provides a critical foundation for reshaping South Africa's electricity pricing regime as Eskom unbundles and competition expands. The fact that standard customers (35%) and off-peak users (50%) together account for 85% of total consumption indicates that the majority of demand is both price-sensitive and has a relatively low-impact on peak system stress.

6.3.9 This segment is therefore most likely to respond to rising tariffs, projected at 221 c/kWh under the RTP, through accelerated adoption of solar PV, storage, and energy efficiency measures, thereby reducing reliance on grid-supplied electricity.

6.3.10 From a cost recovery perspective, however, this creates a structural challenge. In spite of most consumption occurring during off-peak periods, the electricity system must still be designed and maintained to meet the 15% of demand occurring during peak periods, which drives the need for generation capacity and network investment. This implies that capacity and network costs, currently accounting for approximately 13.3% of tariffs, must be recovered from a user base that is increasingly able to reduce volumetric consumption but cannot easily be excluded from fixed cost recovery mechanisms.

6.3.11 This dynamic has important implications for tariff design. As off-peak users reduce grid consumption, the remaining cost base must be recovered over a shrinking volumetric base, placing upward pressure on tariffs and reinforcing the risk of a tariff-demand feedback loop.

6.3.12 In a liberalised market, as contemplated in the SAWEM, improved transparency around when and how electricity is consumed enables more efficient pricing and policy design. This includes the ability to target support to vulnerable households, while ensuring that peak users face prices that reflect the cost of the standby capacity they require. Ultimately, aligning tariffs with this consumption reality will require a rebalancing between volumetric and capacity-based charges, such that off-peak consumption is not unduly penalised, peak demand is appropriately priced and the system remains financially sustainable. Failure to achieve this balance risks accelerating grid defection among the majority of users while increasing cost burdens on those who remain connected.

6.3.13 The Inquiry further observes that the interaction between declining electricity consumption, increasing fixed cost recovery requirements, municipal financial gravities and customer migration towards alternative energy sources creates a potential long-term fiscal sustainability risk for electricity distributors.

6.3.14 As electricity consumption declines, particularly among customers with the ability to adopt embedded generation and energy efficiency measures, distributors may face a shrinking volumetric revenue base though maintaining predominantly fixed network and supply obligations. This may increase upward strain on tariffs as utilities seek to recover the same cost base from fewer units of electricity sold.

6.3.15 At municipal level, this risk is compounded by broader financial burdens, including increasing debt levels, revenue collection challenges, and reliance on electricity surpluses to support municipal finances. Where tariff increases exceed customer affordability thresholds, customers may accelerate migration away from grid-supplied electricity, further reducing revenue recovery and fortifying a potential ‘utility death spiral’.

## 7. IMPACT ON HOUSEHOLDS

### 7.1 Socio-Economic Context

7.1.1 South Africa's socio-economic conditions present a deeply constrained environment in which electricity tariff adjustments and structural pricing reforms unfold. With the standard unemployment rate at 32.1% (expanded[4]: 42.1%), youth unemployment rate at 45.5%, and more than 55% of the population living below the upper-bound poverty line, households operate under severe income limitations. Against this backdrop, electricity is not merely a utility service but a critical determinant of welfare, making any price increase disproportionately impactful. The country's high inequality (Gini coefficient[5] of 0.67) further amplifies the uneven burden of electricity costs, specifically for low- and middle-income households (Statistics SA, 2026).

7.1.2 To illustrate the broader stress environment within which electricity price increases occur, Figure 8 below highlights fundamental socio-economic indicators.

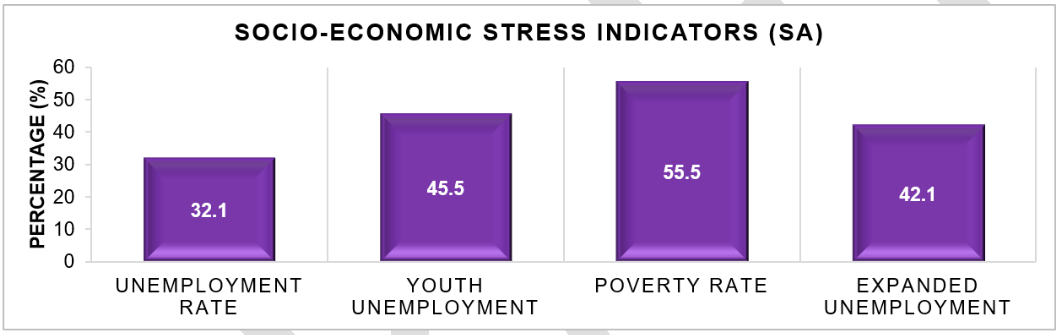



**Figure 8: Socio-Economic Stress Indicators**

7.1.3 The concentration of socio-economic pressures suggests that electricity pricing cannot be assessed in isolation, but rather as part of a broader affordability crisis affecting household welfare and economic participation.

### 7.2 Electricity Price Pressures on Households

7.2.1 The approved 12.74% tariff increase implemented in FY2025/26, together with cumulative increases exceeding 600% since 2008, significantly intensifies affordability difficulties. For an average household consuming 500 kWh, the estimated increase of approximately R120 per month represents a material erosion of disposable income, especially for low-income households, where electricity already accounts for around 10 to 20% of total expenditure.

7.2.2 Furthermore, the burden of electricity costs is not distributed evenly across income groups, as illustrated in Figure 9 below.

[4] Expanded unemployment includes people who are actively searching for work (the standard unemployed), plus those who are available to work but have stopped looking for jobs (discouraged job seekers).
[5] The Gini coefficient is a widely used statistical measure of how income is distributed in the population of a country. It takes a value between 0 and 1. A coefficient of 1 indicates perfect inequality, where one person would earn all the income in that country. Conversely, a coefficient of 0 indicates perfect equality, where the income of the country is distributed perfectly equally among all its citizens.

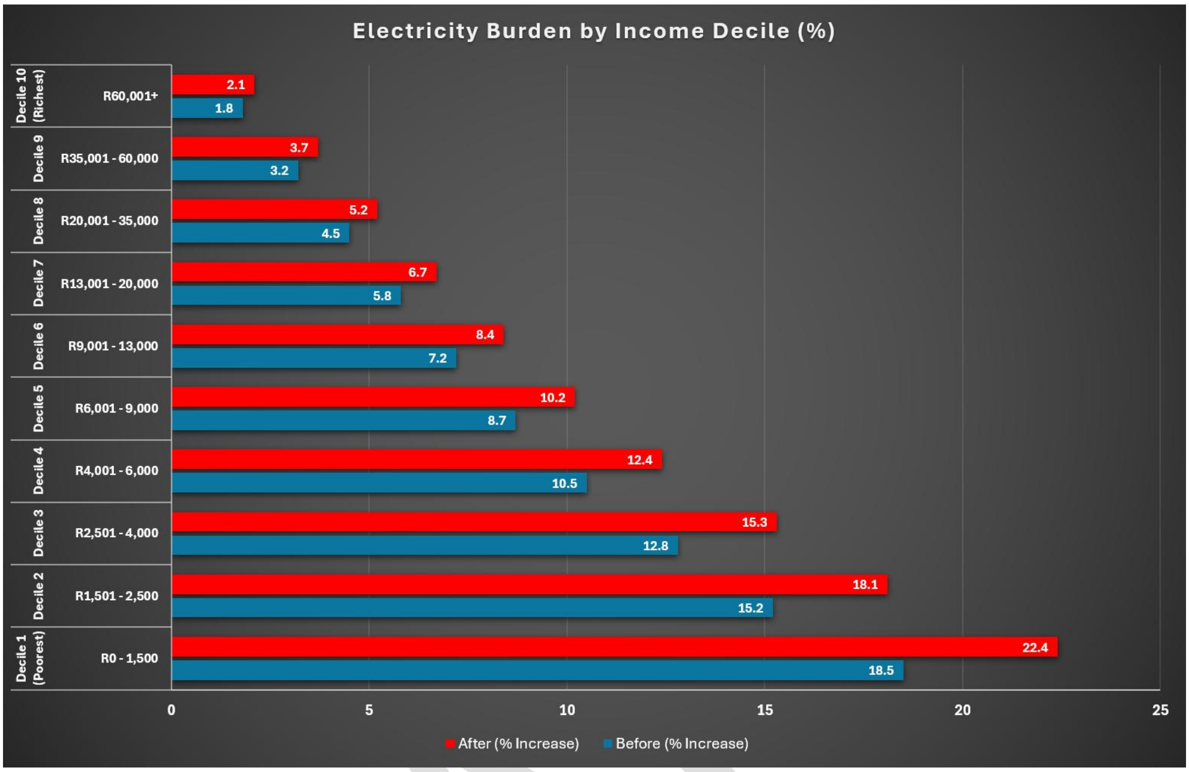



**Figure 9: Electricity Burden by Income Groups**

7.2.3 As shown above, lower-income households spend a significantly larger proportion of their income on electricity compared to middle- and high-income households. This highlights the regressive nature of electricity pricing. Although affordability subsidy adjustments aim to mitigate these impacts, the 25.24% increase in subsidy contributions (already factored in in the tariff structure) is still insufficient to offset the structural imbalance in the evident cost burdens.

## 7.3 Compounding Effects

7.3.1 Households are subject to a compounding 'double burden' effect as follows:

i. Direct electricity costs continue to rise as a share of income
ii. Indirect cost-push inflation increases the cost of essential goods and services such as food (driven up by agricultural electricity costs, which rose by 10.6x since 2003) and transport (increasing due to fuel price linkages)
iii. Consumer goods prices rising as manufacturers pass through costs
iv. Income constraints limit households' ability to absorb these additional pressures.

7.3.2 This dynamic results in a decline in real purchasing power and increases the risk of energy poverty, where households reduce electricity consumption below efficient or safe levels. Over time, such demands may also drive behavioural responses such as reduced formal grid consumption[6], increased reliance on alternative fuels, or the inability to maintain adequate energy access.

[6] Some of the emerging issues identified during the market inquiry include the growing prevalence of illegal electricity connections. This presents a significant regulatory and operational challenge, contributing to increased energy losses, revenue leakage, network strain, and broader concerns relating to the financial sustainability of electricity distributors.

7.3.3 Figure 10 below provides a clear illustration of how electricity costs interact with broader cost-of-living gravities, and highlights the structural affordability challenges faced by low-income households.

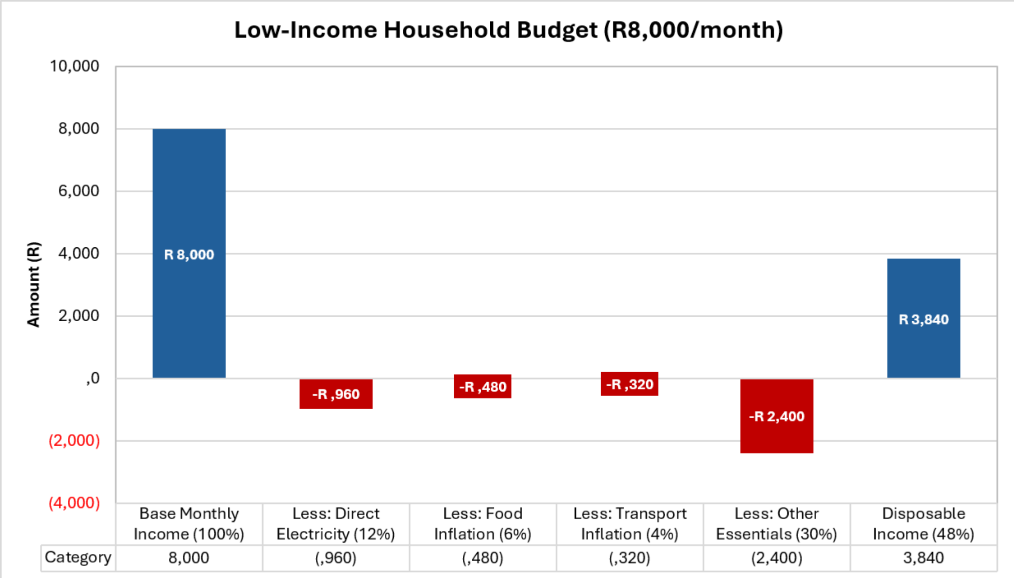



**Figure 10: Low-Income Household Budget Outlook**

7.3.4 Firstly, the chart shows that from a base income of R8,000, essential expenditures rapidly reduce disposable income, leaving only R3,840 or 48% of the base income after accounting for basic cost components. Direct electricity costs alone account for R960 (12%), which is already a significant share of income for a single utility service. When combined with other inflationary goods and services, food (R480 or 6%) and transport (R320 or 4%), electricity costs form part of an all-encompassing pattern of unavoidable expenses that jointly compress household budgets. This indicates that electricity is not an isolated cost but part of a cluster of essential expenditure categories that wear down financial strength.

7.3.5 Secondly, the largest deduction in the budget comes from 'Other Essentials' at R2,400 (30%), suggesting that basic needs such as accommodation, healthcare, education and household goods dominate expenditure. However, when electricity is added to this category of essentials, the total share of income spent on necessary goods and services becomes overwhelming. In effect, more than half of household income is pre-committed, leaving limited flexibility to absorb price shocks such as tariff increases. This intensifies the notion that electricity price increases have a disproportionate marginal impact, even if they appear small in absolute terms.

7.3.6 Finally, the chart features the broader policy implication of the 'double burden' effect, where households face both direct electricity price increases and indirect inflationary demands. Even if electricity accounts for 12% directly, its indirect impact through higher food and transport costs amplifies the overall burden. The resulting 48% residual income is misleadingly high, as it does not fully capture additional informal costs, debt servicing, or unexpected expenses. Overall, the budget structure demonstrates that low-income households operate with very narrow financial margins, making them highly vulnerable to further tariff increases. Such households may resort to coping mechanisms such as reduced consumption, non-payment or illegal connections.

## 8. IMPACT ON LARGE POWER USERS AND ENERGY INTENSIVE USER GROUPS

### 8.1 Demand Concentration and System Dependence

8.1.1 Energy-intensive industries remain central to South Africa's industrial economy, supporting output, employment, exports and downstream value chains despite ongoing structural pressures. The upstream segment that was analysed includes aluminium smelting, ferrochrome production, steel manufacturing, mining operations and agricultural processing, all of which are heavy electricity users with limited fuel-switching flexibility. Key entities include South32's Hillside aluminium smelter, which alone consumes roughly 10.3 TWh per year and accounts for about 5.6% of Eskom's total sales, alongside ferrochrome smelters of which only 11 out of 66 remain operational due to cost pressure and market conditions. Steel production is represented by ArcelorMittal SA's Newcastle plant, currently under care and maintenance, while mining operations such as Sishen, Kolomela and Richards Bay Minerals (RBM) feature prominently in the dataset. Agricultural processing also contributes to the load profile, though at a smaller scale relative to metals and mining. Collectively, these users illustrate how South Africa's industrial base is tightly coupled to reliable, competitively priced electricity supply.

8.1.2 Within the data sample, electricity demand is concentrated among a small number of large power users, increasing exposure for both customers and Eskom to changes in consumption patterns, production decisions and customer migration. An analysis of the 33 customer data points indicates that the largest consumers account for a disproportionate share of total electricity consumption, with RBM alone representing approximately 36% of the analysed consumption at 2.67 TWh per annum, as depicted in Figure 11 below. The remaining demand is distributed among mining houses and industrial facilities, but the concentration of consumption means that operational decisions, production curtailments, plant closures or changes in electricity sourcing strategies by individual customers can materially affect system demand and revenue recovery.

8.1.3 This concentration reflects the capital-intensive structure of South Africa's industrial electricity demand, where a relatively small number of smelters, mines and processing facilities account for a significant share of consumption. From a tariff design perspective, this is important because: as large customers reduce consumption or migrate towards alternative supply arrangements, the recovery of predominantly fixed electricity system costs need to be recovered from a smaller customer base, placing upward pressure on tariffs for remaining users.

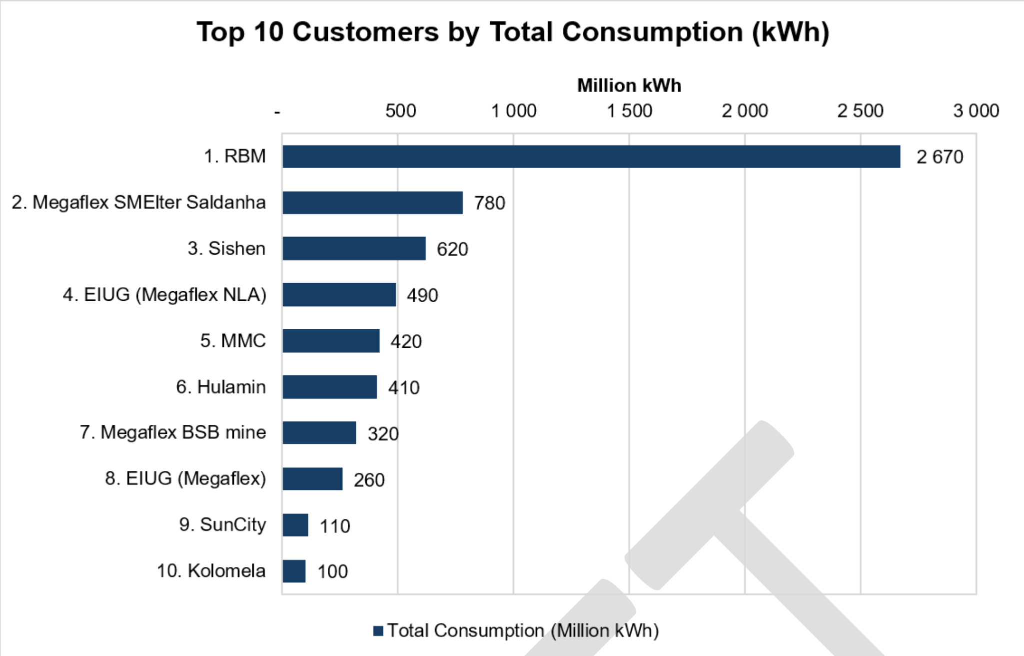



**Figure 11: Top 10 Customers by Total Consumption**

8.1.4 The implications for large power users and energy-intensive groups are therefore twofold. First, their cost competitiveness and operational continuity are directly tied to electricity pricing, availability and quality, making them especially vulnerable to tariff increases, load-shedding and capacity constraints. Second, the concentration of demand places these users in a critical position within South Africa's energy transition, as any shift in their consumption patterns through efficiency measures, demand-side management or relocation affects system stability and Eskom's financial sustainability. With several ferrochrome smelters already idle and steel capacity under care and maintenance, the remaining operational load is both economically vital and systemically significant. This concentration should therefore inform policy design, tariff structuring and any negotiations on special pricing arrangements.

## 8.2 Cost Structure and Financial Sustainability

8.2.1 For energy-intensive industries such as smelting, mining, manufacturing, and agriculture, electricity constitutes a core production input, and consumption is often technically inflexible due to continuous process requirements. Electricity price increases therefore translate directly into higher production costs, with limited scope to reduce demand without affecting output.

8.2.2 The combination of (i) increasing tariffs; (ii) high variable cost exposure (as previously shown); and (iii) growing fixed cost components such as capacity and GCC charges, creates a structural cost burden that reduces operational flexibility. Even where firms invest in efficiency or self-generation, fixed and capacity-related charges limit the extent to which total costs can be reduced, as these remain payable regardless.

8.2.3 From analysed customer data, charge distribution shows a different picture – it reveals that smelter operations bear the highest costs. The top 10 customers by total charges is illustrated in Figure 12 below, with Megaflex Smelter Saldanha in the top position.

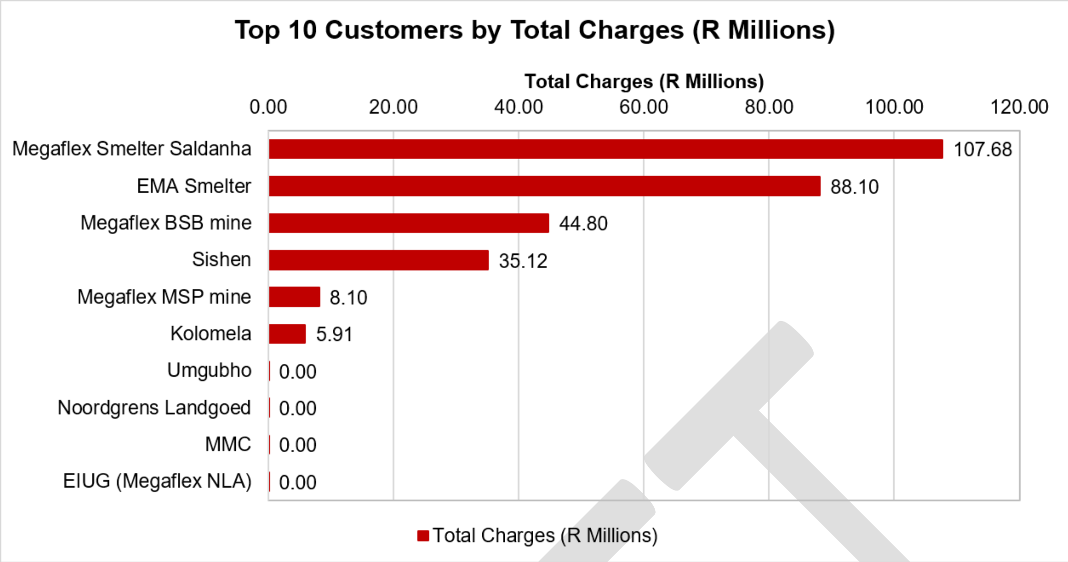



**Figure 12: Top 10 Customers by Total Charges**

8.2.4 Electricity cost structure poses a direct threat to financial sustainability for the sample's energy-intensive industries, where smelting, mining, manufacturing and agriculture depend on power as a non-discretionary production input. These processes operate continuously and are technically inflexible, meaning output cannot be scaled down without shutting entire plants and incurring restart costs. As a result, tariff increases translate almost one-for-one into higher unit production costs, with very limited scope for demand reduction. For sectors already exposed to global commodity price cycles and exchange rate volatility, this linkage between electricity prices and total costs undermines competitiveness and compresses margins, making cost management more a function of tariff outcomes than operational efficiency.

8.2.5 The burden is compounded by the composition of Eskom's charges, which now combine steeply rising volumetric tariffs with growing fixed and capacity-related components such as network access, capacity charges and the generation capacity charge. Analysed customer data shows smelters carry the heaviest cost load, with Megaflex Smelter Saldanha topping the list of the ten largest customers by total the charges. For smelter operations, electricity already accounts for 30 to 40 percent of total production costs. The standard industrial tariff averages about 195.95 c/kWh, roughly three times the estimated breakeven[7] rate of 62 c/kWh required for viability in global metals markets. This implies that firms are operating at electricity cost levels that exceed financial viability thresholds by a substantial margin. Even where firms invest in efficiency retrofits or self-generation to cut energy use, fixed and capacity charges remain payable, so total cost relief is constrained. This structure limits operational flexibility because savings from reduced consumption are offset by charges that are independent of volume.

[7] The breakeven point refers to the level at which a firm's revenues are just sufficient to cover its costs, meaning it neither makes a profit nor incurs a loss. For illustrative purposes, if a firm incurs R100 in operational expenses and generates R100 in revenue, it is considered to be operating at breakeven, having neither realised a profit nor incurred a loss.

8.2.6 Negotiated Pricing Agreements (NPAs), once designed to protect trade-exposed users, have not insulated them from cost pressure. NPA tariffs for smelters increased by 200 percent over four years, rising from 37.65 c/kWh to 112.64 c/kWh, while standard tariffs continued climbing.

8.2.7 The combination of high volumetric rates and expanding fixed cost recovery creates a non-linear cost burden. Firms cannot optimise costs meaningfully through consumption cuts or technological substitution alone, since both variable and fixed charges erode financial sustainability. These dynamics raise long-term concerns about plant closures, reduced investment and deindustrialisation, with direct consequences for employment, exports and Eskom's own revenue base as large users contract or exit the system.

## 8.3 Efficiency and Load Factor Performance

8.3.1 Load factor is a central measure of how effectively electricity capacity is used, and in South Africa's industrial context, it has direct implications for cost recovery, asset utilisation and the competitiveness of energy-intensive sectors. A load factor of around 70 percent is commonly treated as the threshold for efficient system use because it reflects a balance between meeting peak needs and spreading fixed infrastructure costs over a high volume of consumption. When load factor falls below this level, contracted capacity sits idle for extended periods, while capacity-related charges continue to accrue. For Eskom and large power users, this translates to underutilised generation and network assets on the supply side, and higher effective unit costs on the demand side, weakening the financial sustainability of both parties.

8.3.2 The sampled data shows that most large users operate below the 70 percent benchmark. Smelters, ferrochrome producers, steel plants and deep-level mines are designed around continuous, baseload processes that require stable power input 24 hours a day. Yet the measured load factors suggest a pattern of underutilised capacity, not because equipment is idle by choice but because operational, market and regulatory conditions prevent full use of contracted demand. This outcome is widespread rather than isolated, indicating a systemic feature of how industrial load interacts with tariff structures and production cycles. The gap between the 70 percent benchmark and actual performance signals lost value: generation capacity, transmission lines and distribution networks are sized for peak demand but are not fully loaded across the year, reducing the efficiency of capital invested in the system. Figure 13 below depicts the varying bands.

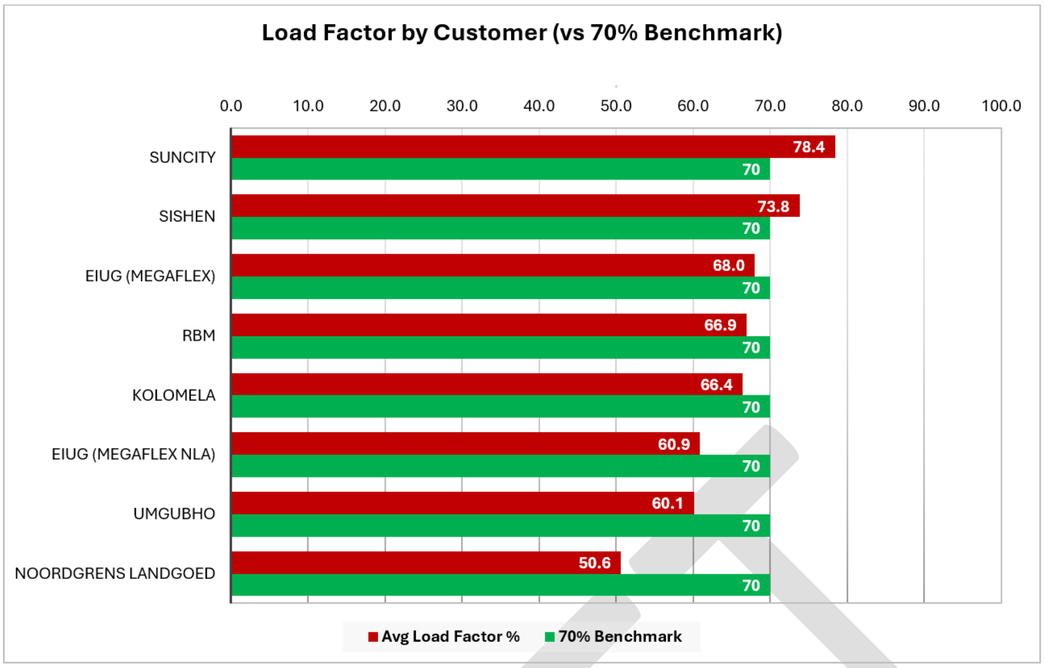



**Figure 13: Load Factor by Customer**

8.3.3 For customers operating below the benchmark, the cost impact is immediate and structural. Capacity charges, network access fees and demand-related components are levied on the level of contracted capacity rather than actual consumption. When load factor is low, those fixed charges are spread over fewer kilowatt hours, pushing up the average cost per unit and eroding competitiveness against international producers facing lower electricity costs. This effect is intensified under South Africa's evolving tariff regime, where the shift toward cost-reflective pricing and time-of-use signals has increased the share of capacity and demand-based charges in the bill. Even if a plant maintains constant total consumption, a lower load factor raises the effective tariff and tightens margins. For smelters where electricity already represents 30 to 40 percent of production costs, and for mines facing declining ore grades, this dynamic adds financial strain without a corresponding operational benefit.

8.3.4 However, low load factors should not be read simply as customer inefficiency. The evidence points to structural factors that constrain how closely industrial demand can align with the assumptions built into tariffs. Continuous-process industries such as aluminium smelting, ferrochrome smelting and deep-level mining cannot rapidly adjust load without risking equipment damage, safety incidents or loss of product. The physical nature of electrolytic cells, furnaces and hoisting systems requires steady baseload operation, limiting responsiveness to time-of-use price signals. This operational reality means that demand flexibility, which tariff design often assumes, is technically limited for these users, regardless of financial incentives.

8.3.5 Production variability adds another layer of constraint. South African commodity exporters face volatile global prices, shifting export demand and operational disruptions ranging from logistics bottlenecks to maintenance outages and, in recent years, load-shedding. When commodity prices fall or export orders decline, plants reduce output but typically retain contracted electrical capacity because recommissioning requires months and substantial cost.

8.3.6 The result is periods of reduced energy throughput against a fixed demand profile, mechanically lowering load factor. This variability is cyclical rather than controllable, and it reflects the exposure of energy-intensive industries to global market forces rather than poor internal energy management.

8.3.7 Finally, the persistent gap between actual load factors and the efficiency benchmark highlights a misalignment between tariff design and industrial reality. Current structures assume a degree of demand responsiveness that is achievable for commercial or light industrial users but not for heavy process industries. By imposing capacity charges that are insensitive to output levels and by designing time-of-use periods around residential and commercial peaks, the tariff framework inadvertently penalises users whose technical and market constraints prevent load shifting. The implication is that underutilised capacity is not purely a function of poor energy management by customers but rather reflects broader design choices. Improving efficiency and load factor performance in South Africa therefore requires coordinated action: tariff reforms that recognise process constraints, incentives for demand-side measures that are technically feasible and industrial policies that support stable output levels so that expensive infrastructure is fully utilised.

8.3.8 As a result, underutilised capacity is not purely a function of customer inefficiency, not solely attributable to customer behaviour, but reflects a broader misalignment between tariff design assumptions and the operational realities of large users.

8.3.9 **The Efficiency vs Cost Tension**

8.3.9.1 The coexistence of low load factors and rising capacity charges reveals a fundamental tension in the current electricity pricing framework. On the one hand, low load factors suggest theoretical cost optimisation opportunities, such as improved demand management, load shifting, or renegotiation of contracted capacity. In practice, these opportunities are often restricted in practice by inflexible production processes, technical requirements, and limited ability to adjust consumption profiles.

8.3.10 **Competitiveness and Cost Burden Effect**

8.3.10.1 Persistent low load factors among South Africa’s energy-intensive industries have immediate consequences for industrial competitiveness because they reshape the cost burden that firms carry regardless of production levels. When capacity charges are levied on contracted demand rather than actual consumption, users that cannot fully utilise their reserved capacity end up paying for infrastructure that sits idle. This raises the average electricity cost per unit and hits high-consumption sectors such as ferrochrome production, steel manufacturing, mining and agricultural processing particularly hard. The effect is mechanical: fixed network access, capacity and demand charges are spread over fewer kilowatt-hours when output drops, so the effective tariff rises even if Eskom’s published rates remain unchanged. For firms operating on thin margins in globally traded commodity markets, this increase in unit cost reduces room to absorb exchange rate volatility, input price swings or transport disruptions.

8.3.10.2 A second competitiveness constraint arises from the limited ability of these industries to manage costs through operational adjustments. Continuous-process plants in mining and heavy manufacturing are designed for stable baseload operation and cannot quickly ramp load up or down without risking equipment integrity, product quality or safety. That technical inflexibility means a significant portion of the electricity bill remains fixed even when commodity cycles force reduced output. Unlike light manufacturing or commercial users that can shift processes to off-peak periods, mines and ferrochrome smelters face physical limits on demand response. Consequently, firms lose a key lever for cost control. When global metal prices fall or export demand weakens, they must still carry capacity charges tied to historical peak demand, which widens losses and discourages short-term production decisions that might otherwise preserve market share.

8.3.10.3 The resulting cost structure directly erodes South Africa's position relative to competing jurisdictions. Export-oriented industries in ferrochrome, steel and mining compete with producers in countries that benefit from lower electricity tariffs, more flexible pricing mechanisms, or targeted industrial electricity support. Where foreign competitors face lower fixed cost recovery and greater scope to align consumption with price signals, South African firms experience a structurally higher cost base that is unrelated to labour productivity or capital efficiency. This disadvantage is magnified for products with low value addition, where electricity forms a large share of total cost. As unit costs climb, South African output becomes less attractive in international markets, contracts shift to alternative suppliers, and domestic plants operate below installed capacity, reinforcing the cycle of low load factor and high average cost.

8.3.10.4 Over time, the barrier to competition created by this cost burden feeds into investment and location decisions. Firms facing sustained margin pressure defer capital upgrades, postpone expansion projects, and reconsider long-term operations within South Africa. In sectors such as ferrochrome and steel, where several plants are already under care and maintenance or operating at reduced throughput, the risk of permanent closure or relocation increases. Deferral of investment not only affects the firms themselves but also weakens upstream and downstream linkages, including suppliers, logistics providers and service industries. The broader risk is therefore deindustrialisation, with job losses, reduced export earnings and diminished demand for locally produced inputs. Because electricity demand from large users underpins a material portion of Eskom's sales, declining industrial load also threatens the utility's revenue base, creating a feedback loop that can pressure tariffs further.

8.3.10.5 The findings from the load factor analysis underscore that the problem is not simply one of customer inefficiency. Low load factors in this context are better understood as an indicator of misalignment between tariff design and the operational realities of process industries. Current structures assume a degree of demand flexibility and responsiveness that is not feasible for continuous operations exposed to global commodity cycles. When tariffs recover fixed costs through capacity and demand charges that do not adjust with output, they impose a cost burden that penalises users for factors beyond their control. Recognising load factor as a signal of this misalignment, rather than solely as a measure of poor energy management, shifts the policy focus toward design improvements that reflect how energy-intensive plants operate.

8.3.10.6 Addressing the competitiveness and cost burden effect therefore requires better alignment between tariff structures and user characteristics. Reforms that distinguish between technically flexible and inflexible loads, adjust the balance between volumetric and fixed charges, or introduce mechanisms that moderate capacity charges during periods of forced low output can reduce the non-linear cost impact. Such adjustments would improve cost efficiency for firms without undermining system revenue recovery, support higher asset utilisation across the network, and enhance industrial competitiveness. In the South African context, where retaining energy-intensive manufacturing and mining is central to employment and export performance, tariff design that acknowledges operational constraints is critical. It allows the electricity system to remain financially sustainable while enabling large users to remain viable participants in global markets.

## 8.4 Demand Patterns and Seasonal Trends

8.4.1 Building on the load factor analysis, an assessment of demand patterns provides further insight into the operational constraints that influence capacity utilisation and cost outcomes. Based on the analysed customer data, the demand trend reveals seasonal patterns with winter peaks (June to August), as illustrated in Figure 14 below.

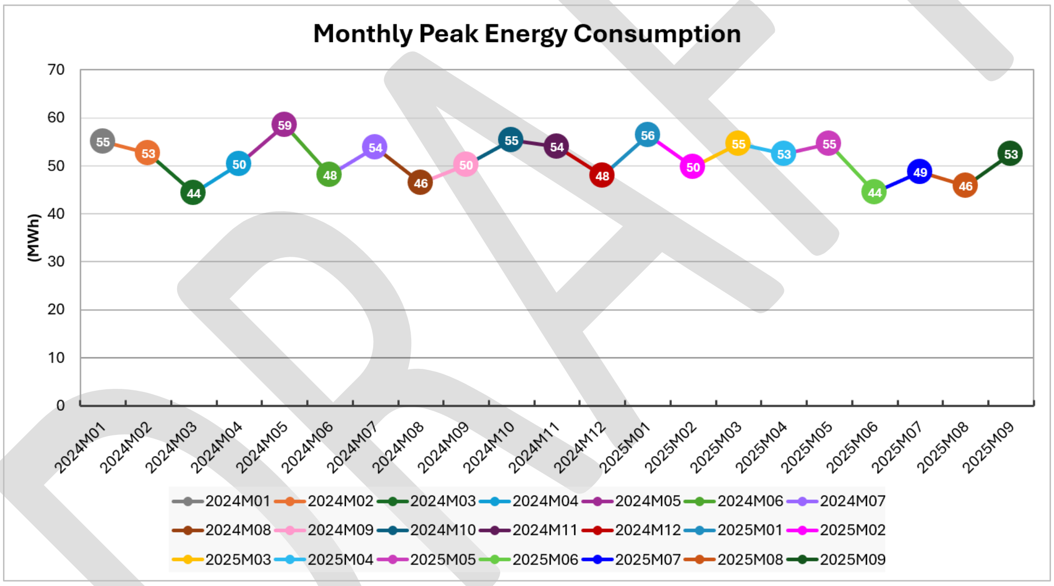



**Figure 14: Demand Analysis**

8.4.2 The customer load data shows a demand profile that is structurally stable but seasonally variable, reflecting South Africa's operational and climatic conditions. Monthly demand over the review period ranged from approximately 44 MVA to 59 MVA, indicating moderate variability rather than erratic swings. This band suggests that large power users, including the mines, smelters and energy-intensive manufacturers that dominate South Africa's industrial load, maintain a consistent baseline requirement.

8.4.3 The relative steadiness of baseline consumption indicates strong continuity in production schedules and contracted capacity use, while the observed seasonal adjustments point to predictable responses to temperature and operational cycles rather than random volatility.

8.4.4 A key feature of the demand curve is the recurring winter peak from June to August, when monthly demand rises to about 55 to 59 MVA. These peaks align with South Africa's High Demand Season and are driven by two main factors. First, colder temperatures across Gauteng, Mpumalanga and other industrial hubs increase heating loads for commercial buildings and residential customers fed from the same networks, raising system-wide stress. Second, several heavy industries adjust input intensity seasonally, with processes such as ferroalloy production and smelting often ramping up during winter months due to production planning and export cycles. The combined effect is a predictable surge that pushes network utilisation higher and influences Eskom's capacity adequacy assessments, outage planning and tariff recovery calculations.

8.4.5 In contrast, shoulder and off-peak months see demand ease to around 44 to 48 MVA, reflecting reduced heating requirements and lower industrial throughput as production schedules normalise. This dip alleviates strain on generation and transmission assets, creating windows for maintenance and improving plant availability ahead of the next winter cycle. For cost outcomes, the pattern implies that capacity utilisation and unit costs are seasonally dependent: higher winter demand spreads fixed costs over more units but also raises exposure to peak energy charges and potential load-shedding risk, while summer and shoulder periods offer cost relief but lower asset utilisation. Recognising these seasonal dynamics is therefore critical for South African large power users and regulators when forecasting demand, negotiating time-of-use tariffs and planning energy efficiency or demand-side management measures to flatten peaks and improve year-round capacity utilisation.

8.4.6 From a tariff and cost perspective, this seasonal variation has important implications. Under time-of-use and demand-based tariff structures, peak demand periods coincide with higher electricity prices and capacity utilisation, meaning that a disproportionate share of total costs is incurred during relatively short periods of elevated demand. This places pressure on customers to manage peak demand; however, as established in the load factor analysis, the ability to adjust demand is often constrained for large industrial users, limiting their responsiveness to price signals.

8.4.7 The relatively narrow demand range (compared to total system capacity) suggests that whereas demand fluctuates seasonally, it does not do so sufficiently to materially improve load factors for many users. This reinforces the earlier finding that underutilised capacity persists even in the presence of seasonal peaks, contributing to inefficient capacity cost recovery and higher average electricity costs.

8.4.8 Overall, the demand profile reflects a structurally stable but operationally inflexible consumption pattern, where seasonal peaks increase exposure to high-cost periods without materially improving overall capacity efficiency. This dynamic confirms the need for tariff structures that better align seasonality, demand variability, and capacity cost recovery, particularly for energy-intensive industries with limited load-shifting capability. The interaction between seasonal demand peaks and capacity-based tariffs amplifies cost pressures for large users, as short-duration demand increases drive disproportionately high charges without corresponding improvements in overall utilisation efficiency.

# 9. BENCHMARKING: INTERNATIONAL PRICE AND AFFORDABILITY

## 9.1 International Benchmarking - Industrial Electricity Prices

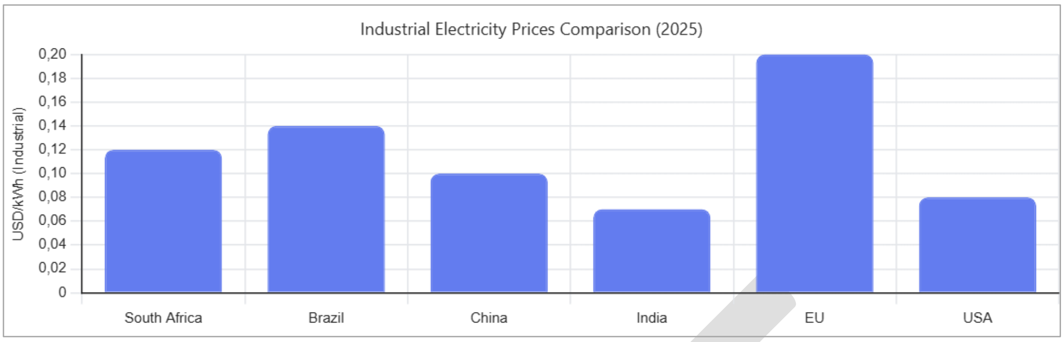



**Figure 15: Industrial Electricity Price Comparison**

9.1.1 Global benchmarking indicates that South Africa's industrial electricity prices are no longer structurally low relative to those of major economies, despite historically having been a competitive advantage. Industrial tariffs in China (approximately $0.10/kWh), India (roughly $0.07/kWh), and the United States (in approximation of $0.08/kWh) remain significantly lower than in South Africa and especially below European benchmarks (www.rhnuttall.co.uk, 2025).

9.1.2 In contrast, the European industry faces the highest electricity costs (estimated at $0.20/kWh), which has already raised concerns about industrial competitiveness within the European Union (EU).

9.1.3 South Africa's position is therefore structurally mid-to-high-cost relative to BRICS peers, weakening its competitiveness, particularly for energy-intensive exports such as mining and smelting.

## 9.2 Household Electricity Price Comparison

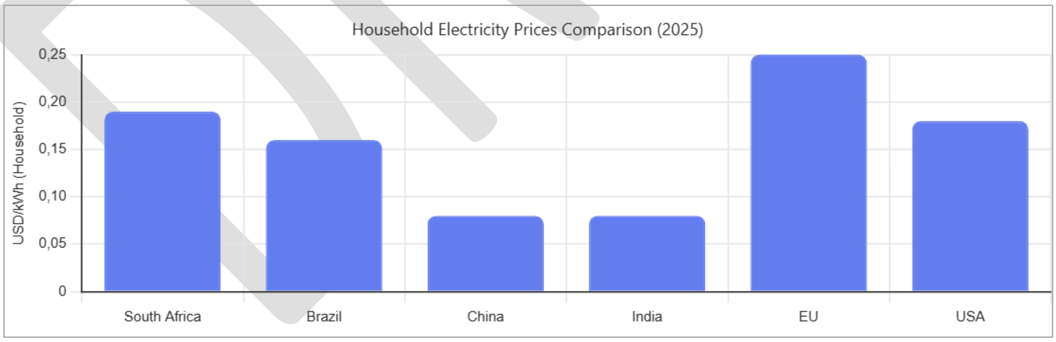



**Figure 16: Household Electricity Price Comparison**

9.2.1 Household electricity prices further highlight the structural affordability challenge. South Africa's average household electricity cost (in approximation of $0.19/kWh) is higher than most BRICS economies and is comparable to developed markets such as the United States (www.businesseurope.eu, 2026).

9.2.2 While European countries exhibit even higher nominal tariffs (around $0.25/kWh), these economies benefit from significantly higher household incomes, meaning the real burden of electricity costs is substantially lower than in South Africa.

9.2.3 This emphasises the conclusion that nominal tariff comparisons alone are insufficient; income-adjusted affordability is the critical metric.

### 9.3 **Electricity Affordability Index (Income-Adjusted Proxy)**

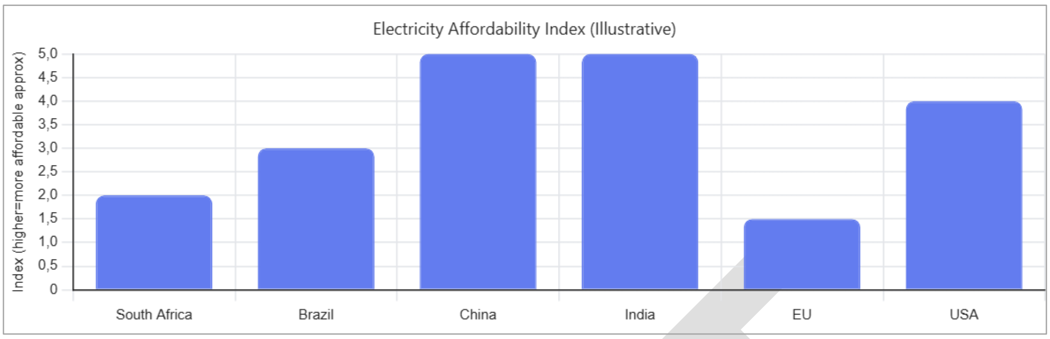



**Figure 17: Electricity Affordability Index Comparison**

9.3.1 The affordability index illustrates the relative burden of electricity costs when adjusted for income levels and economic structure. Although simplified for comparative purposes, the following pattern is clear that:

i. India and China exhibit relatively high affordability due to lower tariffs and lower cost structures

ii. The United States shows strong affordability driven by relatively low industrial tariffs and high household incomes

iii. The European Union, despite high prices, maintains moderate affordability due to income levels and subsidies

iv. South Africa shows comparatively low affordability, reflecting the combined effect of high tariffs and weak income levels.

9.3.2 This aligns with global research showing that energy consumption and affordability are closely linked to income levels, with lower-income economies experiencing higher effective burden even at moderate tariffs (worldpopulationreview.com, 2026).

## 9.4 **Overall Benchmarking Insight**

9.4.1 The benchmarking analysis confirms that South Africa occupies a structurally challenging position within the global electricity pricing landscape, characterised by relatively high tariffs compared to BRICS peers and significantly lower income levels than developed economies. Although industrial electricity prices remain lower than those in the European Union, they are materially higher than in China, India and the United States, reducing South Africa's competitiveness in energy-intensive export sectors. This is particularly concerning for industries such as mining, smelting, and manufacturing, where electricity constitutes a substantial share of production costs and where international price competitiveness is critical.

9.4.2 From a household perspective, the analysis reveals a pronounced affordability gap, where electricity prices that appear moderate in absolute terms translate into a significantly higher burden when adjusted for income. Unlike advanced economies, where higher electricity prices are offset by stronger income levels and social protection mechanisms, South African households face a convergence of high tariffs, high unemployment and constrained income growth, amplifying the financial impact. This places South Africa in a structurally weaker position in terms of energy affordability relative to both BRICS and the member nations of the Organisation for Economic Co-operation and Development (OECD) economies.

9.4.3 At a macroeconomic level, the combination of above-peer tariffs and below-peer income levels creates a dual constraint on economic performance. On the production side, elevated electricity costs undermine industrial competitiveness, discourage investment, and contribute to deindustrialisation risks. On the consumption side, high electricity costs reduce household purchasing power, dampen demand, and increase the risk of energy poverty. This dual impact reinforces a broader cycle of economic fragility, where energy pricing both reflects and exacerbates structural constraints in the economy.

9.4.4 Overall, the international comparison emphasises the importance of balancing cost reflectivity with affordability and competitiveness considerations in tariff design. As South Africa's electricity sector continues to transition toward higher fixed charges and cost-reflective pricing, careful calibration will be required to avoid widening the affordability gap for households while preserving the competitiveness of key industrial sectors.

## 10. DOWNSTREAM ECONOMIC EFFECTS

The impact of rising electricity costs under the evolving RTP extends well beyond direct consumption, transmitting through the economy via multiple interconnected channels. Although increases in energy charges remain a key driver, the introduction and expansion of fixed charges and the GCC have fundamentally altered the cost structure faced by users. Fundamental to this trajectory is the change to the time-of-use schedule, which has had a much greater impact. These changes have shifted electricity pricing from a predominantly consumption-based model toward one that is increasingly driven by capacity and availability costs, thereby amplifying economic challenges across sectors irrespective of actual usage patterns.

### 10.1 **Transmission Mechanisms**

10.1.1 Electricity cost increases propagate through the economy via a multi-stage transmission process, in which both volumetric price increases and fixed cost recovery mechanisms are embedded into production, logistics, and consumption systems. Under the RTP, the growing contribution of GCC and fixed network charges introduces cost rigidity, meaning that even as output declines or consumption is curtailed, a significant portion of electricity costs remains unavoidable. This fundamentally alters cost dynamics across the value chain, shifting the burden from marginal consumption to structural cost recovery.

10.1.2 In the agricultural sector, electricity serves as a critical production input, particularly for irrigation, processing, and storage. The introduction of fixed charges and the GCC has increased the proportion of electricity costs that are independent of output levels, placing farmers under pressure even during low-yield seasons or periods of reduced production. Unlike traditional energy charges, which could be partially managed through reduced usage, these fixed components must be paid regardless, eroding already thin margins and compelling producers to pass costs downstream.

10.1.3 These costs are then transmitted through the food value chain, where electricity is embedded at every stage, from irrigation and primary production through to processing, cold storage, distribution, and retail. The addition of fixed and capacity-based charges compounds this effect by increasing baseline operating costs across all segments. As a result, electricity cost increases become cumulatively embedded, leading to compounded price effects by the time goods reach final consumers. This compounding mechanism transforms electricity price increases into broader cost-push inflation across essential goods.

10.1.4 Transport systems also reflect this dynamic, as electricity-driven cost increases indirectly influence logistics and distribution costs. Refrigerated transport, warehousing, and supply chain operations face rising energy costs not only from electricity tariffs themselves but also from embedded energy costs within system operations. Where electricity tariffs include fixed and capacity-based components, logistics operators face reduced ability to optimise costs, further increasing the pass-through effects on final prices.

10.1.5 At the household level, these interconnected cost pressures form a feedback loop. Direct electricity costs rise due to both higher tariffs and fixed charges; while indirect costs increase through higher food and transport prices. Because fixed charges are largely unavoidable, households cannot fully mitigate these increases through reduced consumption, leading to a sustained erosion of disposable income and reinforcing broader affordability difficulties. The interlinked nature of these transmission channels is illustrated in Figure 18 below, which shows how electricity cost increases propagate through the economy and feed back into the electricity system. Of particular significance is the TOU structure under the RTP model in its current form, which had a negative impact on the agricultural sector in particular.

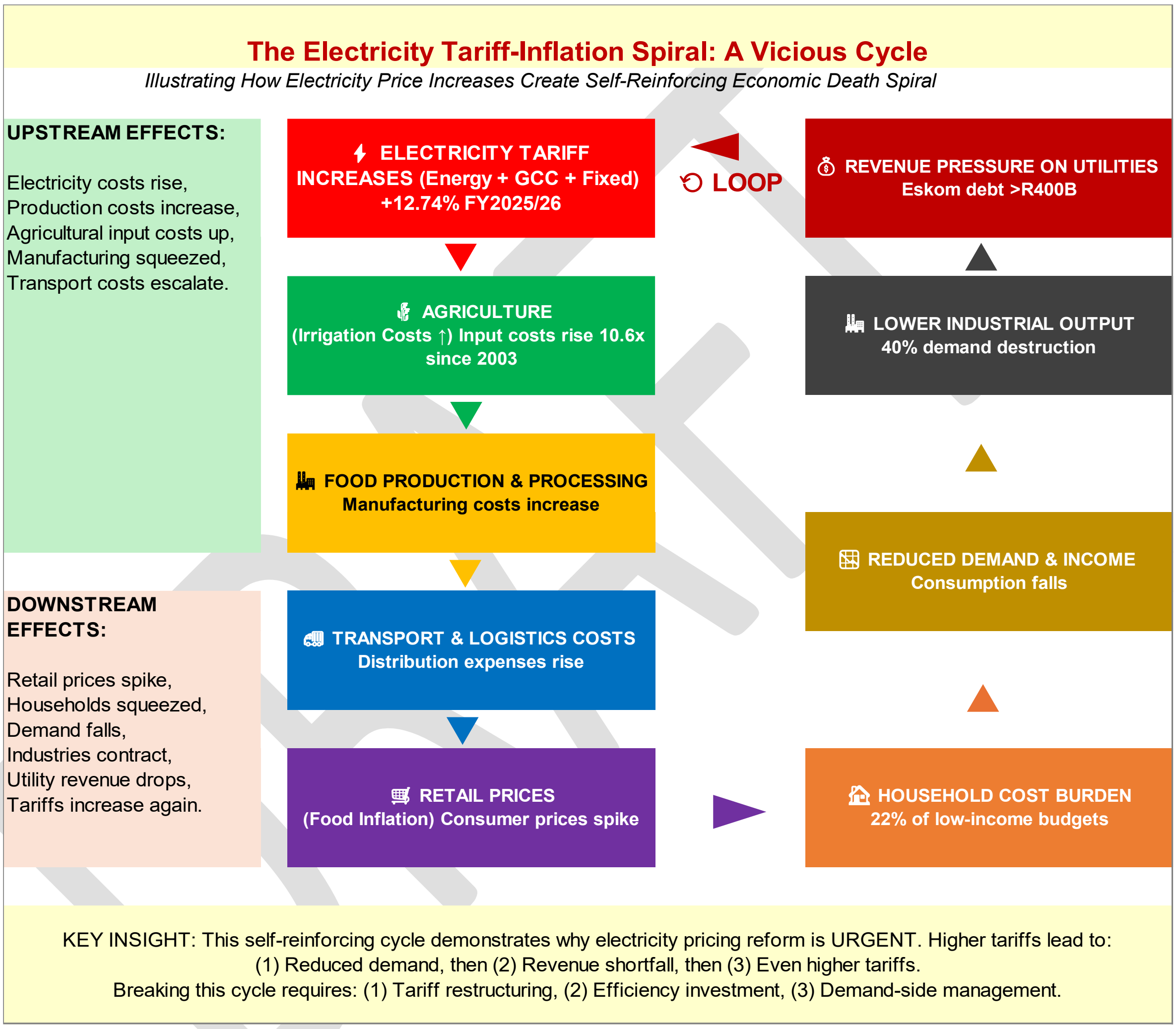



**Figure 18: Tariff Spiral**

## 10.2 Agricultural and Food Price Impact

10.2.1 The agricultural sector has experienced a profound structural shift in its cost base, with electricity tariffs increasing by approximately 10.6 times since 2003. Although this increase reflects broader tariff adjustments, the introduction of fixed charges and the GCC has intensified the impact, as a growing portion of electricity costs is now decoupled from actual consumption. This has raised the baseline cost of agricultural production, regardless of seasonal output or yield variability.

10.2.2 A defining feature of South African agriculture is its dependence on electricity-powered irrigation systems, particularly in high-value crop production. Because irrigation demand is both seasonal and essential, farmers have limited ability to reduce consumption in response to rising tariffs. The addition of fixed and capacity-based charges further constrains flexibility, as producers must maintain sufficient contracted capacity to meet peak irrigation demand, even if that capacity is only fully utilised during limited periods. This, according to the customers' testimony, is exacerbated by the TOU restructuring, which results in structural cost exposure, where users pay for capacity that is not continuously utilised.

10.2.3 The transmission of these cost increases into food prices is both direct and cumulative. Electricity costs influence production, processing, and storage, with each stage passing increases forward. Under the RTP structure, fixed charges exacerbate this process by increasing baseline costs across the entire value chain. Consequently, even modest increases in electricity tariffs result in disproportionate increases in food prices, particularly in energy-intensive segments such as cold storage, milling, and processing.

10.2.4 These dynamics contribute to broader food inflation pressures, which disproportionately affect lower-income households. As electricity costs continue to rise and fixed charges become more prominent, the agricultural sector faces increasing difficulty maintaining cost stability, thereby reinforcing persistent inflationary trends in essential goods.

### 10.3 Industrial and Supply Chain Effects

10.3.1 In the industrial sector, the impact of electricity pricing is intensified by the combination of high energy intensity and limited operational flexibility. Electricity constitutes a significant share of production costs in sectors such as mining, smelting, and manufacturing. Under the RTP, the introduction of fixed charges and the GCC has increased the proportion of costs that are non-discretionary, meaning that firms cannot fully mitigate cost increases through reduced consumption or efficiency improvements.

10.3.2 This has heightened the risk of industrial contraction and deindustrialisation, particularly in energy-intensive industries. Firms facing rising electricity costs, both variable and fixed, are increasingly unable to maintain profitability, resulting in production cutbacks, plant closures, or relocation of operations to jurisdictions with more competitive electricity pricing. The presence of fixed charges further compounds this challenge by maintaining high baseline costs even when production is reduced, thereby accelerating financial pressure during downturns.

10.3.3 Small and medium enterprises (SMEs) are especially vulnerable in this context. Unlike large industrial users, SMEs typically lack access to negotiated pricing agreements, capital for self-generation or advanced energy management systems. The growing share of fixed and capacity-based charges therefore represents a disproportionate burden, as these costs cannot be easily avoided or offset through operational adjustments. This limits SME resilience and increases the likelihood of business closure or informalisation.

10.3.4 Export competitiveness is also significantly affected. South African industries now face electricity costs that are not only higher in absolute terms but increasingly less responsive to production levels due to the expansion of fixed charges. This reduces the ability of firms to compete internationally, as energy costs become less flexible and more structurally embedded within the total production costs. The result is declining export performance, reduced industrial output and weaker economic growth.

### 10.4 **Circular Household Impact**

10.4.1 The combined effects of rising electricity tariffs, expanding fixed charges, and downstream cost transmission mechanisms create a self-reinforcing economic cycle with profound implications for households. At the centre of this cycle is the interaction between electricity pricing, employment, and household income.

10.4.2 Rising electricity costs increase the cost of production across agriculture and industry, leading to reduced output, lower investment and potential job losses. This weakens household income, particularly in vulnerable communities where employment opportunities are already limited. At the same time, households face higher direct electricity costs due to both energy charges and fixed components such as the GCC, as well as higher indirect costs through food and transport inflation.

10.4.3 As disposable income declines, households are increasingly unable to absorb rising electricity costs. Because fixed charges are unavoidable, consumers cannot fully mitigate expenditure through reduced consumption, leading to increased financial strain, payment difficulties and in some cases, non-payment or illegal connections. These responses reduce revenue recovery for the electricity system, placing upward pressure on tariffs and perpetuating the cycle.

10.4.4 Ultimately, this dynamic represents a systemic affordability and sustainability challenge, where electricity pricing both reflects and exacerbates underlying economic constraints. Without targeted intervention, the interaction between fixed cost recovery, declining demand and falling incomes risks entrenching a cycle of rising tariffs, shrinking consumption and weakening economic performance.

## 11. FINDINGS

11.1 Based on the available data and the analysis conducted, the following findings have been established.

**Finding 1: Tariff Restructuring Improves Cost Reflectivity but Requires Better Alignment Between Cost Recovery and Customer Impacts**

11.1.1 The Inquiry finds that the restructuring of electricity tariffs through the RTP, including the introduction of unbundled capacity-related charges, improves transparency regarding the recovery of generation capacity, legacy and energy-related costs. However, the analysis indicates that the allocation of these costs has resulted in differentiated impacts across customer categories.

11.1.2 Even though the tariff restructuring addresses the need to recover predominantly fixed system costs in an environment of declining electricity demand, the resulting customer impacts are not uniform. Customers with lower utilisation patterns, seasonal demand profiles, limited load-shifting capability, or reduced ability to respond to TOU signals experienced proportionally higher increases compared to the approved average tariff adjustment.

11.1.3 The Inquiry therefore finds that future tariff reforms must balance cost reflectivity with affordability, economic efficiency, and customer impact considerations.

**Finding 2: Tariff Implementation Outcomes Require Stronger Ex-Ante Assessment**

11.1.4 The Inquiry finds that certain customer categories experienced effective electricity bill increases materially exceeding the approved average tariff adjustment of 12.74%.

11.1.5 The Inquiry recognises that average tariff increases do not necessarily translate into uniform customer impacts due to differences in consumption patterns, tariff structures and customer profiles. However, the scale of observed increases highlights the need for stronger ex-ante impact assessment before tariff restructuring measures are implemented.

11.1.6 Future tariff determinations should therefore incorporate detailed customer-class bill impact modelling to identify potential affordability, competitiveness and behavioural impacts.

### Finding 3: Time-of-Use Restructuring Had Material Impacts on Seasonal and Load-Insensitive Customers

11.1.7 The Inquiry finds that changes to the TOU tariff structure, particularly the seasonal allocation of peak and standard periods, materially affected customers whose electricity demand is operationally inflexible.

11.1.8 The agricultural sector was particularly impacted due to the limited ability of irrigation-intensive operations to shift consumption away from higher-cost periods without affecting production cycles. Unlike some industrial customers, agricultural customers cannot always adjust consumption timing without direct impacts on output, crop cycles and operational requirements.

11.1.9 The Inquiry therefore finds that TOU tariff design should consider the operational realities of sectors with limited demand flexibility to ensure that efficiency signals do not create unintended economic distortions.

### Finding 4: Electricity Costs Have Become a Material Competitiveness Factor for Energy-Intensive Users

11.1.10 The Inquiry finds that electricity pricing has become an increasingly significant input cost for energy-intensive industries, including mining, smelting, manufacturing and agriculture.

11.1.11 Stakeholder evidence indicates that rising electricity costs, including fixed and capacity-related charges, affect operational flexibility, investment decisions and international competitiveness. However, electricity costs operate alongside other competitiveness factors including logistics, labour costs, market conditions and policy certainty.

11.1.12 The Inquiry therefore finds that tariff design should consider the broader economic impact of electricity pricing on productive sectors.

### Finding 5: Capacity Charge Allocation Requires Consideration of Customer Utilisation Profiles

11.1.13 The Inquiry finds that customer load factors vary significantly across the analysed dataset, indicating different utilisation patterns of contracted capacity.

11.1.14 Where capacity-related charges are applied without sufficient consideration of utilisation profiles, customers with lower load factors may experience higher unit costs despite limited consumption during certain periods.

11.1.15 The Inquiry therefore recommends continued assessment of capacity charge design to ensure that capacity cost recovery remains aligned with cost causation principles.

### Finding 6: Revenue Recovery Outcomes Require Ex-Post Assessment

11.1.16 The Inquiry finds that the implementation of the RTP occurred within a broader context of declining electricity demand, increasing fixed cost recovery requirements and the need to maintain Eskom's financial sustainability.

11.1.17 Although the restructuring of tariff components was intended to improve revenue stability and cost reflectivity, the Inquiry notes that realised revenue outcomes, customer migration effects, and demand responses require further assessment against the assumptions underpinning the approved tariff determination.

11.1.18 NERSA should therefore undertake an ex-post assessment to determine whether actual revenue recovery outcomes remain aligned with approved assumptions under MYPD6 and the 2024/25 financial year Eskom Retail Tariff Structural Adjustment (ERTSA) regime.

### Finding 7: Tariff Design Has Implications for Future Competition

11.1.19 The Inquiry finds that tariff structures will influence the development of future electricity markets, including SAWEM and retail competition.

11.1.20 The allocation of fixed, capacity and legacy costs may affect competitive neutrality between incumbent suppliers and future market participants.

11.1.21 Although the Inquiry did not identify evidence of anti-competitive conduct, future tariff reforms should consider potential impacts relating to barriers to entry, cost allocation neutrality and competition outcomes.

### Finding 8: Emerging Fiscal Sustainability Risks in a Declining Demand Environment

11.1.22 The Inquiry finds evidence of a structural risk resultant from the interaction between declining electricity sales, increasing fixed cost recovery requirements, municipal revenue strains and increasing customer migration towards alternative energy solutions.

11.1.23 If not managed carefully, this dynamic may contribute to increasing tariffs, further demand destruction and additional pressure on utility financial sustainability.

## 12. MATTERS BEYOND THE SCOPE OF THE INQUIRY

### 12.1 Emergent Issues Identified During the Inquiry

12.1.1 Despite the fact that the Inquiry was specifically established to investigate the impact of fixed charges levied by electricity distributors and Eskom's unbundled Generation Capacity Charge, Legacy Charge and Variable Energy Charge, stakeholders raised several additional concerns during written submissions, stakeholder engagements and public hearings.

12.1.2 These matters, although relevant to electricity affordability, pricing transparency and customer welfare, fall outside the scope of the approved Terms of Reference and, in certain instances, outside NERSA's statutory jurisdiction. Accordingly, the Inquiry has not undertaken a detailed assessment of these matters, and no findings are made in relation to them.

### 12.2 Municipal Surcharges, Taxes, Levies and Duties

12.2.1 A significant number of stakeholders raised concerns regarding municipal surcharges, taxes, levies and duties imposed on electricity customers.

12.2.2 The Inquiry notes that, in terms of the Electricity Regulation Act, 2006 (Act No. 4 of 2006), as amended, NERSA regulates electricity tariffs but does not have jurisdiction over surcharges, taxes, levies or duties imposed by municipalities under section 229 of the Constitution of the Republic of South Africa, 1996.

12.2.3 While concerns were raised regarding the magnitude, transparency and affordability implications of these charges, the Inquiry did not assess their lawfulness, cost basis, or appropriateness. These matters fall within the purview of the relevant municipalities and may require consideration by institutions such as the National Treasury, COGTA, the National Consumer Commission and other relevant authorities.

### 12.3 Convenience Fees and Other Ancillary Charges

12.3.1 Stakeholders further raised concerns regarding additional charges levied by third-party electricity vending platforms, payment service providers and other intermediaries, including the reported ‘convenience fees’ associated with the purchase of prepaid electricity.

12.3.2 The Inquiry notes that these charges are not regulated through NERSA-approved electricity tariffs and were therefore not evaluated as part of the Inquiry. However, concerns relating to transparency, consumer protection and disclosure of such charges may warrant consideration by the appropriate consumer protection and competition authorities.

## 12.4 Municipal Revenue Models and Fiscal Dependence on Electricity Sales

12.4.1 The Inquiry received submissions highlighting the growing dependence of some municipalities on electricity-related revenues to support broader municipal operations.

12.4.2 Stakeholders argued that declining electricity sales volumes, increased self-generation, and changing customer consumption patterns may be placing pressure on traditional municipal revenue models.

12.4.3 While these concerns may have implications for future tariff design, municipal finance sustainability and electricity market reform, the Inquiry did not undertake an assessment of municipal fiscal frameworks, cross-subsidisation arrangements, or broader municipal funding mechanisms.

12.4.4 The Inquiry notes that municipal fiscal sustainability risks may require broader coordination with institutions responsible for local government finance and electricity market reform, given the increasing interaction between electricity revenues, municipal financial viability and affordability outcomes.

## 12.5 Electricity Market Reform and Competitive Market Design

12.5.1 Several stakeholders highlighted potential implications of fixed charges and unbundled generation charges for the development of a competitive electricity market, including the SAWEM and future retail competition.

12.5.2 Issues raised included the following:

i. The impact of increasing fixed charges on customer switching behaviour
ii. Potential barriers to entry for independent retailers and traders
iii. The treatment of legacy costs in a competitive market environment
iv. The risk of cost allocation mechanisms distorting competition between incumbent distributors and future market participants
v. The interaction between regulated tariffs and future market-based pricing mechanisms.

12.5.3 While these are important issues for consideration during ongoing electricity market reform, they extend beyond the immediate scope of the Inquiry and may require dedicated regulatory, policy and legislative review processes.

## 12.6 Potential Legislative and Policy Considerations

12.6.1 The Inquiry identified several matters that may require future consideration by policymakers, regulators and other public institutions, including:

i. the development of norms and standards governing municipal surcharges and electricity-related charges
ii. greater transparency and disclosure requirements for non-tariff electricity charges
iii. clarification of institutional roles and responsibilities relating to electricity pricing oversight
iv. alignment between electricity tariff regulation and broader municipal finance frameworks
v. regulatory treatment of legacy costs and fixed cost recovery in the context of electricity market reform.

## 12.7 Referral for Further Consideration

12.7.1 Although these matters fall outside the scope of the current Inquiry, NERSA recognises their potential significance for electricity affordability, consumer protection, municipal sustainability and the future evolution of the electricity supply industry.

12.7.2 The Inquiry therefore recommends that these matters be brought to the attention of the relevant regulatory authorities, government departments and policymakers for further consideration. Where appropriate, NERSA may engage and cooperate with such institutions to share insights arising from the Inquiry and to support the development of coordinated policy and regulatory responses.

## 13. CONCLUSION

13.1 This market inquiry was initiated to assess the impact of fixed charges levied by electricity distributors and Eskom's unbundled Generation Capacity Charge, Legacy Charge and Variable Energy Charge on electricity customers and the broader economy. The evidence gathered through stakeholder submissions, public hearings, documentary reviews and quantitative analysis demonstrates that the impacts of these charges extend beyond individual electricity bills and increasingly influence industrial competitiveness, household affordability, investment decisions and long-term electricity demand trends.

13.2 The Inquiry finds that the policy rationale underpinning the Retail Tariff Plan and the transition towards more cost-reflective tariff structures is generally sound. The unbundling of tariff components improves transparency and provides greater visibility regarding the recovery of generation, network and legacy costs, particularly in an environment symbolised by declining electricity demand, changing consumption patterns and increasing fixed-cost recovery requirements. However, the implementation of these reforms has produced uneven outcomes across customer categories, with certain customers experiencing effective increases significantly above the approved average tariff adjustment.

13.3 The analysis further reveals a growing tension between cost reflectivity and affordability. Even though distributors must recover efficiently incurred costs to maintain financial sustainability, the cumulative impact of increasing fixed charges, capacity-related charges and rising energy costs has materially increased the cost burden borne by households, agriculture, mining, manufacturing and other energy-intensive sectors – a situation further complicated by the lack of transparency inherent in bundled distribution licences currently in operation, where electricity distribution and retail trading activities are undertaken within a vertically integrated framework without separate tariff and licensing treatment.

13.4 Bundled distribution licences are impeding the rigorous approval of transparent and non-discriminatory and cost reflective tariffs. Capital intensive infrastructure for distribution will have a very different financial/risk profile to the high-risk retail trading and therefore must be treated separately as required in terms of section 151B of the ERA, noting that both Eskom and municipalities would be defined as vertically integrated in terms of the ERA.

13.5 The Inquiry finds evidence of a broader structural challenge within the electricity supply industry. Electricity tariffs have increased substantially over the past two decades whereas electricity demand, particularly industrial demand, has declined. This trend suggests the emergence of a negative feedback cycle in which declining sales volumes increase pressure to recover largely fixed system costs from a shrinking consumption base, which may further suppress demand, investment and affordability. The Inquiry therefore emphasises the need for continued monitoring of realised revenue outcomes following implementation of the RTP to assess whether actual revenue recovery remains aligned with approved tariff assumptions, demand forecasts and underlying cost drivers. Such assessment is important to ensure that tariff restructuring achieves its intended objective of sustainable cost recovery and revenue neutrality without creating unintended distortions in affordability, competitiveness or future market development.

13.6 The Inquiry further concludes that electricity pricing has become an increasingly important determinant of industrial competitiveness. For many energy-intensive industries, electricity constitutes a significant share of total production costs. Rising fixed and capacity-related charges reduce operational flexibility, weaken international competitiveness, discourage investment and may contribute to production curtailment, plant closures and deindustrialisation.

13.7 Looking ahead, the findings have important implications for South Africa's electricity market reform agenda. As the industry transitions toward a more competitive market structure, tariff design will play a critical role in ensuring efficient competition, non-discriminatory market access and economically efficient investment outcomes. Cost recovery mechanisms that distort energy prices, raise rivals' costs or create barriers to entry may undermine the objectives of future wholesale and retail electricity market reforms.

13.8 The Inquiry therefore concludes that future tariff reforms should balance the principles of cost reflectivity, affordability, economic efficiency, competition neutrality and long-term sustainability. Achieving this balance will be critical to ensuring that electricity pricing supports, rather than constrains, economic growth, industrial development and the transition toward a competitive electricity market.

13.9 The Inquiry further recognises that the impact of tariff restructuring extends beyond individual customer bills and has implications for the future structure of the electricity market. In particular, as South Africa progresses towards a more competitive electricity market, tariff components that recover fixed, capacity and legacy costs must continue to be assessed to ensure that they do not unintentionally distort competitive outcomes, raise barriers to entry or disadvantage emerging market participants. Future tariff reforms should therefore incorporate competition impact assessments alongside traditional cost-of-supply and affordability considerations.

13.10 The Inquiry further recognises that additional work remains necessary to better understand the impact of tariff restructuring on household consumers, whose representation in the quantitative dataset was limited. Future regulatory work should therefore prioritise a dedicated assessment of residential affordability and consumer welfare impact.

## 14. REGULATORY RECOMMENDATIONS

14.1 The recommendations resulting from the Inquiry are structured in four categories as follows:

14.1.1 **Category A: Immediate Regulatory Actions and Corrective Measures**
(Recommendations requiring direct regulatory intervention based on findings)

14.1.2 **Category B: Tariff Framework and Methodology Improvements**
(Recommendations aimed at improving tariff design and implementation)

14.1.3 **Category C: Strategic Electricity Market Reform Considerations**
(Recommendations supporting future market development and competition)

14.1.4 **Category D: Further Regulatory Assessments and Targeted Inquiries**
(Recommendations requiring additional evidence gathering)

**Category A: Immediate Regulatory Actions and Corrective Measures**

14.2 ✓ **Compliance Investigation and Enforcement Action**

14.2.1 The Inquiry identified *prima facie* evidence of tariff implementation outcomes within Ndlambe Municipality that may be inconsistent with NERSA-approved tariff determinations. It is recommended that NERSA initiate an investigation under its compliance and enforcement framework to determine whether the implemented tariffs complied with approved tariff structures and applicable regulatory requirements.

14.2.2 Where non-compliance is confirmed, NERSA should implement appropriate corrective and remedial measures, including consideration of customer restitution where applicable, and collaborate with relevant institutions where enforcement jurisdiction extends beyond NERSA's mandate.

14.3 ✓ **Eskom Revenue Recovery and Ex-post Implementation Assessment**

14.3.1 NERSA should undertake an ex-post implementation assessment of Eskom's RTP to evaluate whether the restructuring of tariff components achieved the intended objectives of cost reflectivity, transparency and revenue neutrality while maintaining affordability and economic efficiency.

14.3.2 Eskom should provide supporting rationale, detailed revenue recovery information, cost allocation methodologies, sales volumes, demand profiles, customer migration trends and modelling assumptions to enable NERSA to assess whether realised revenue outcomes during implementation align with the approved assumptions under the MYPD6 and the 2024/25 financial year ERTSA process.

14.3.3 Where material divergence between approved tariff assumptions and realised outcomes is identified, NERSA should consider appropriate regulatory interventions, including tariff design adjustments, enhanced monitoring requirements, or other measures necessary to ensure alignment between cost recovery, affordability and long-term electricity market objectives.

**Category B: Tariff Framework and Methodology Enhancements**

### 14.4 ✓ Revenue Neutrality and Customer Impact Assessment

14.4.1 Future tariff restructuring proposals should include mandatory customer impact simulations across representative customer categories prior to implementation to identify potential affordability, competitiveness and behavioural impacts.

14.4.2 Revenue-neutrality assessments should be independently verified through ex-ante and ex-post reviews, including assessment of customer migration, demand response and consumption changes.

### 14.5 ✓ Distribution Licence and Tariff Transparency Reform

14.5.1 NERSA should accelerate the separation of distribution network services (wires) from electricity trading functions to enable transparent cost allocation, ring-fenced revenue assessment and the approval of separate tariffs aligned with the ERA.

### 14.6 ✓ Agricultural and Industrial Customer Impact Assessment

14.6.1 NERSA should undertake sector-specific assessments of electricity-intensive industries, including mining, smelting, manufacturing and agriculture, including demand surveys among consumers that can be compared to the demand profile understood through the supply side lens[8].

14.6.2 NERSA should investigate the extent to which tariff increases exceed improvements in operational efficiency and whether the 'efficient licensee' principle contemplated in section 15 of the ERA is being achieved – once again this may require simulations of revenue caps to instil discipline where market power dominance exists.

14.6.3 Future tariff structures should recognise the operational realities of continuous-process and seasonal industries and avoid unintended cost increases resulting from tariff structures that do not reflect actual demand flexibility.

**Category C: Strategic Electricity Market Reform Considerations**

### 14.7 ✓ Competition Neutrality and SAWEM Alignment

14.7.1 NERSA should assess whether current and future tariff structures support competitive electricity market development, including the establishment of the SAWEM.

[8] Understanding how much power is consumed is important, however in terms of understanding the impact of tariffs, one must know what the primary demand is for the power consumed. For example, in South Africa, a smelter uses large amounts of power on a continuous basis, but thermal energy (arc furnace) is necessary to melt the ore. For that reason, a smelter has a potentially interruptible demand. Whereas a typical SA iron ore to steel manufacturer largely uses the power for mechanical purposes to drive motors. The plant must therefore be running to enable a continuous production process from the blast furnace to the end-product – i.e. there is little potential for interruptibility. Both types of consumers are however very large powers users requiring reliable and competitive power prices, but they use the power for very different purposes, and this affects how tariffs must be structured to address the underlying use of the energy.

14.7.2 Future tariff structures should be assessed for potential competition impacts, including: (i) rising rivals' costs; (ii) margin squeeze risks; (iii) cross-subsidisation; (iv) barriers to entry; and (v) distorted price signals.

14.7.3 NERSA should undertake detailed tariff simulations relating to vesting contracts and wholesale market arrangements to ensure that cost allocations do not create unintended advantages or disadvantages between market participants.

### 14.8 ✓ Fiscal Sustainability and Utility Death Spiral Risk

14.8.1 NERSA should monitor structural risks resulting from declining electricity demand, increasing fixed cost recovery requirements, municipal debt accumulation and customer migration to alternative energy sources.

14.8.2 Future tariff reforms should consider the risk of a negative feedback cycle where declining sales volumes result in increased tariffs, which may further accelerate demand reduction and weaken utility financial sustainability.

## Category D: Further Regulatory Assessments and Targeted Inquiries

### 14.9 ✓ Residential Customer Market Inquiry Phase

14.9.1 Given the limited representation of residential customers in the available dataset, NERSA should consider undertaking a second phase of the market inquiry focused specifically on household consumers.

14.9.2 Such an assessment should consider affordability, distributional impacts and welfare effects emanating from fixed charges, Time-of-Use restructuring, Generation Capacity Charges and evolving tariff structures, including impacts on indigent households, prepaid customers, low-income consumers and customers with embedded generation.

14.9.3 Given the complexity of household affordability analysis, this may require external technical support to ensure that the evidence base adequately represents this customer segment.

### 14.10 ✓ Matters Beyond the Scope of the Inquiry

14.10.1 NERSA should formally communicate the Market Inquiry's observations regarding municipal surcharges, taxes, levies, duties and other electricity-related charges to the relevant authorities, including the Department of Electricity and Energy (DEE), National Treasury, COGTA and the National Consumer Commission.

14.10.2 NERSA should engage relevant institutions regarding the development of appropriate norms, standards and transparency requirements for charges recovered outside regulated electricity tariffs.

14.10.3 NERSA should also consider whether any legislative or policy amendments are required to improve regulatory clarity and consumer protection in relation to electricity-related charges imposed outside NERSA's jurisdiction.