DRAFT PUBLIC CONSULTATION PAPER ON TARIFF FOR KOGI STATE ELECTRICITY MARKET FOR THE TARIFF PERIOD 2026 TO 2031

1. Introduction

On 13 September 2024, the Nigerian Electricity Regulatory Commission (NERC), acting pursuant to the provisions of the Electricity Act, issued Transition Order No. NERC/2024/125 to Abuja Electricity Distribution Plc ("AEDC" or the "Holding Company"). The Order required AEDC to incorporate and operationalize a subsidiary distribution company to assume responsibility for electricity distribution within its franchise area in Kogi State. A transition period of 180 days was prescribed, after which regulatory oversight of the subsidiary's operations would transfer from NERC to the Kogi State Electricity Regulatory Commission (KERC) in line with the emerging multi-tier electricity market framework.

In compliance with the Transition Order, AEDC applied for and obtained an interim electricity distribution license from KERC on 13 March 2025 for Kogi Electricity Distribution Limited (KEDL), the designated successor distribution company for AEDC's operations within Kogi State. The expiration of the 180-day transition period on 12 March 2025 marked the effective assumption by KERC of full regulatory oversight over electricity distribution, supply, and retail activities within the State.

Subsequently, on 25 July 2025, NERC issued Order No. NERC/2025/074 on the Delineation of Assets and Liabilities of AEDC. The Order established that 7.11 per cent of AEDC's total energy offtake is attributable to consumption within Kogi State and accordingly provided for the transfer of a corresponding 7.11 per cent of AEDC's assets and liabilities to KEDL. This delineation provided regulatory clarity on the scale of KEDL's operations and formed a critical input into tariff and performance assessments within the State electricity market.

Determination of Tariff for KEDL

The Kogi State Electricity Regulatory Commission, established under the Kogi State Electricity Law 2024, is mandated to regulate electricity distribution, supply, and retail activities within Kogi State. In exercising this mandate, KERC is responsible for developing tariff methodologies that strike an appropriate balance between affordability and fairness for consumers, cost-reflectivity, and the assurance of reasonable returns based on efficient operations. These methodologies are designed to support the financial sustainability of licensees while fostering a stable, predictable, and attractive regulatory environment for private sector investment.

Accordingly, the Commission commenced the process of determining end-user tariffs for KEDL through the issuance of applicable tariff regulations and data submission guidelines. During the interim period following the transition, and in order to minimize market disruption and ensure tariff continuity, KERC adopted the NERC-approved tariffs applicable to AEDC, pending the completion of a state-specific tariff review tailored to KEDL's operational and cost structure.

MYTO Framework, Building Blocks, and Principles

KERC's tariff framework is anchored on the principles of the Multi-Year Tariff Order (MYTO), which adopts a building-block methodology for determining the allowed revenue requirement of licensees. Under this methodology, the Commission establishes cost-reflective tariffs by aggregating only those costs that are prudently incurred and efficiently managed. Specifically, the allowed revenue comprises three principal elements:

i. **Return on capital**, designed to provide licensees with a reasonable and fair return on efficiently deployed and approved regulatory assets, thereby promoting investment sustainability;
ii. **Return of capital**, recovered through depreciation charges spread over the economic useful life of the assets, ensuring orderly asset replacement and long-term network integrity; and
iii. **Efficient operating and maintenance expenditure**, including justifiable overheads necessary for the reliable, safe, and continuous provision of electricity services.

The framework promotes transparency, predictability, and regulatory discipline, while carefully balancing investor viability with consumer protection. It establishes a 15-year tariff trajectory, complemented by biannual minor reviews to account for movements in key exogenous variables such as inflation and exchange rates, and quinquennial major reviews during which all assumptions, cost inputs, efficiency parameters, and service obligations are comprehensively reassessed. In view of heightened macroeconomic volatility and KEDL's continued reliance on grid-supplied energy, whose costs fluctuate monthly, a monthly tariff true-up mechanism will be implemented to reflect actual cost variations.

In applying the MYTO framework, the Commission is guided by core regulatory principles, including cost recovery, efficient investment, certainty and stability, transparency, performance-based incentives, flexibility, and social protection through targeted tariff provisions for priority public institutions such as schools and hospitals. The Commission recognizes that the pursuit of these objectives may entail trade-offs, particularly within a nascent state electricity market, and accordingly exercises regulatory judgment to deliver balanced, equitable, and sustainable outcomes.

Tariff Oversight and Performance Regulation

Electricity distribution is recognized as a natural monopoly; accordingly, KEDL's tariffs and operational performance are subject to continuous regulatory oversight in the public interest. The tariff framework incorporates clearly defined technical and non-technical loss reduction trajectories, with performance-based incentives and penalties linked to verified outcomes. In setting tariffs, the Commission applies realistic and evidence-based assumptions, ensuring regulatory credibility while preventing the pass-through of inefficiencies to consumers. End-user tariffs approved by KERC are cost-reflective, covering energy procurement, network operations, metering, billing, and customer service. While cross-subsidies are gradually reduced, lifeline tariffs and consumer protection measures are maintained in line with social policy objectives.

Scope of This Consultation

This consultation paper presents: an overview of the Kogi State electricity market and KEDL's operations; a critical assessment of data submitted by KEDL; proposed technical and cost assumptions; proposed financial assumptions under the MYTO framework; and specific issues for stakeholder comments. Stakeholders are invited to submit comments and alternative proposals to support the development of a cost-reflective, fair, and sustainable tariff regime for electricity supply in Kogi State.

Pursuant to the Commission's tariff regulation and associate guideline, notice is hereby given to interested people to review the public consultation paper, which can be downloaded from the Commission's website, and send comments to the Commission within fourteen **(14)** days, from **12th February, 2026 to 26th February, 2026**. All comments on the proposed tariff should be addressed to:

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KERC PUBLIC CONSULTATION PAPER ON KEDL TARIFF

1. BACKGROUND

1.1. Regulatory and Legal Context

The electricity industry in Nigeria operates within a decentralized regulatory framework established under the Constitution of the Federal Republic of Nigeria (as amended), the Electricity Act, 2023, and various State Electricity Laws enacted pursuant to constitutional authority. This framework represents a fundamental shift from the previously centralized regulatory model and reflects Nigeria's commitment to deepening market reform, improving service delivery, and enhancing sub-national participation in electricity governance.

At the federal level, the Nigerian Electricity Regulatory Commission (NERC) continues to exercise regulatory authority over the national and inter-state electricity market, including electricity generation, transmission, system operations, wholesale trading, and other matters that cut across state boundaries. NERC also retains responsibility for market rules applicable to the national grid and the regulation of entities whose operations are not confined to a single state.

However, with the enactment of the Kogi State Electricity Law, 2024, and the formal establishment of the Kogi State Electricity Regulatory Commission (KERC), regulatory authority over the intra-state electricity market in Kogi State now vests exclusively in KERC. This includes jurisdiction over electricity distribution, retail supply, embedded generation, mini-grids, captive power arrangements (where applicable), and tariff regulation for consumers within the geographical boundaries of Kogi State.

This decentralization of regulatory authority is intended to promote responsiveness to local conditions, enhance accountability, encourage tailored investment solutions, and ensure that regulatory decisions reflect the specific technical, economic, and social realities of the State. Accordingly, KERC is empowered by ***section 12*** of the ***KEL,2024*** to regulate the electricity market within Kogi State in a manner consistent with the overarching principles of fairness, efficiency, transparency, predictability, and sustainability.

Statutory Mandate for Tariff Regulation

Pursuant to **Section 18** of the Kogi State Electricity Law 2024, KERC is statutorily mandated to regulate electricity tariffs and charges applicable within the State. In exercising this mandate, the Commission is required to ensure that tariff outcomes achieve multiple and sometimes competing objectives.

Specifically, KERC is required to regulate tariffs in a manner that:

- Ensures that prices charged by licensees are fair, just, and reasonable to consumers,
- Allow licensees to recover efficiently and prudently incurred costs, including operating expenses, capital investments, and statutory obligations; and
- Provides for a reasonable return on invested capital, sufficient to sustain operations, support maintenance and expansion of infrastructure, and attract new investment into the electricity sector.

In implementing this mandate, KERC is required to strike a careful balance between consumer protection and market sustainability. While consumers must be protected from unjustified or excessive tariffs, the electricity market must also remain financially viable to ensure continuous service delivery, infrastructure development, and long-term reliability.

1.2. Evolution of Cost-Reflective Tariff Regulation

Nigeria's electricity sector has historically faced significant structural and operational challenges. These challenges include inadequate generation capacity, fuel supply constraints (particularly gas availability and pricing), aging and poorly maintained infrastructure, weak institutional capacity, and prolonged underinvestment across the value chain. These factors resulted in unreliable power supply, high system losses, and chronic financial shortfalls.

In response, successive reform efforts sought to transition the sector from a government-dominated model to a market-based framework anchored on private sector participation, commercial discipline, and cost-reflective pricing. A central pillar of this reform agenda was the recognition that sustainable electricity supply cannot be achieved without tariffs that reflect the efficient cost of service delivery.

To operationalize this objective, NERC introduced the Multi-Year Tariff Order (MYTO) framework in 2008 as a transparent, predictable, and rules-based methodology for electricity pricing. MYTO was designed to:

- Ensure full recovery of efficient costs, including a reasonable return on capital;
- Provide incentives for operational efficiency, investment, and service quality improvement;

- Promote certainty and stability for investors and lenders through multi-year tariff paths; and
- Gradually reduce cross-subsidies while incorporating mechanisms to protect vulnerable consumers.

Following the decentralization of electricity regulation under the Electricity Act, 2023, KERC has adopted a tariff regulation approach that is consistent with MYTO principles, while adapting the methodology to reflect the specific characteristics, demand profile, infrastructure condition, and other-peculiarities of the Kogi State electricity market.

1.3. Purpose and Scope of This Consultation

This Consultation Paper is issued by KERC as part of its statutory obligation to conduct transparent and inclusive regulatory processes. The purpose of this Paper is to:

- Explain the principles, assumptions, and components underpinning the proposed electricity tariff review in Kogi State;
- Inform stakeholders of the key technical, financial, and policy issues under consideration by the Commission; and
- Invite evidence-based comments, submissions, and recommendations to support informed, balanced, and credible regulatory decision-making.

The Consultation Paper is intended to provide stakeholders with sufficient information to understand the rationale for the proposed tariff review and to meaningfully participate in the consultation process.

1.4. Distribution Tariff Framework and Cost Structure

Distribution tariffs are designed to recover three broad categories of cost. First is the cost of energy delivered to customers. Second is the cost of installation and operation of the distribution infrastructure such as wires, transformers, substations, meters, and associated systems that enable electricity to be conveyed to end-users. This second component is referred to as the Distribution Use of System (DUOS) charge. Third are other approved statutory charges, including regulatory levies, taxes, and market-related fees.

DUOS is intended to allow a Distribution Company (DisCo) to recover the efficient costs of owning, operating, maintaining, and expanding its distribution network as well as an opportunity to earn a fair return on the investment.

1.5. Performance-Based Zoning Framework and Loss Reduction Incentives

Persistently high levels of technical and non-technical losses continue to place a significant financial and operational burden on the electricity sector and therefore require a regulatory framework that embeds clear, measurable incentives for loss reduction. In Kogi State, the distribution network has been structured into five distribution zones, delineated on the basis of customer density, economic activity, and geographic conditions, to support effective monitoring of operational performance. This zoning approach is designed to foster performance-based competition among zone managers, enhance transparency in operating expenditure, and facilitate measurable improvements in loss reduction and other key performance indicators. Although a uniform retail tariff will apply across the State, this operational modelling is consistent with MYTO principles, which recognize that revenue requirements should reflect the distinct operational conditions, asset base, customer mix, and loss profile of each distribution utility. Loss reduction trajectories are reviewed during major tariff reviews, with KERC balancing ambition and realism to avoid under-recovery risks for licensees while protecting consumers from inefficient cost pass-through.

1.6. Rationale for Cost-Reflective Tariffs

Electricity, much like other manufactured goods, moves through a value chain from generation to final consumption. It all starts at the power station, where electricity is produced using primary inputs like natural gas, hydro, or coal, and major capital assets such as turbines and generators. These facilities require significant investment and ongoing maintenance to ensure reliable operation over long periods.

Once generated, electricity travels through the transmission network, which carries it at high voltages to major urban centers. This minimizes losses and maintains system stability. Finally, in the distribution and retail stage, electricity is stepped down to usable voltages and delivered to homes, businesses, and other end-users.

Because electricity cannot be economically stored on a large scale and must be produced and consumed almost instantaneously, it is crucial that tariffs reflect the true cost of supply. If tariffs fail to cover these costs, investment may decline, maintenance may suffer, and supply could become inadequate.

As electricity networks are natural monopolies, regulators like KERC ensure that costs are recovered efficiently and that consumers are protected from potential monopoly abuse. This involves setting service level benchmarks, defining loss thresholds, and approving tariffs that ensure fair returns on investment while maintaining service quality.

1.7. Determining Energy Cost

Currently, KEDL receives electricity from the national grid at a bulk tariff set by NERC. Looking ahead, local generation sources may also contribute to the energy supply, each potentially at different costs. The energy cost model, therefore, takes into account both grid-supplied and locally generated electricity, adjusting for losses and ensuring that the final energy cost reflects these combined sources.

The energy received is reduced by transmission losses, and any embedded generation is also considered. The final energy available for sale is then adjusted for the total technical, commercial, and collection losses.

1.8. Determination of Annual Distribution Infrastructure Cost

The cost of maintaining distribution infrastructure includes two main components: capital expenditure (CAPEX) and operational expenditure (OPEX).
Capital expenditure is annualized through depreciation, based on the economic life of different asset categories. For example, the cost of buildings are recovered via depreciation over 40 years, plant and machinery over 20 years, furniture and fittings over 10 years, and service vehicles over 5 years. This depreciation reflects the gradual wear and tear of assets.

In addition to depreciation, the return on investment is calculated by applying the Weighted Average Cost of Capital (WACC) to the annual depreciation. This ensures that the utility earns a fair return on its investments.

1.9. Operating Expenditure (OPEX) Breakdown

Operating costs in electricity distribution are divided into three categories:

1. **Administrative OPEX:** This includes corporate and governance expenses, such as management salaries, office utilities, insurance, and regulatory fees. Administrative costs typically make up about 10–20% of total controllable operating costs and are not directly tied to energy volumes.
2. **Fixed OPEX:** These are costs necessary to sustain the network and operations, regardless of changes in energy sales or customer numbers. Fixed OPEX, which typically accounts for 25–35% of controllable costs, includes salaries of technical staff, routine maintenance, and the upkeep of infrastructure.

3. **Variable OPEX:** These costs fluctuate with network activity and energy throughput. Variable OPEX, which often comprises 45–60% of controllable costs, includes expenses related to network operations, fault repairs, metering, billing, and customer services.

This classification ensures transparency and supports a cost-reflective tariff structure.

1.10. Working Capital Allowance

Electricity distribution involves a timing gap between when the utility pays for electricity and when it collects payments from customers. To bridge this gap, a working capital allowance is provided. This allowance covers one (or two) months of operational costs and energy purchase costs.

The total working capital allowance is included in the Regulatory Asset Base and earns a return at the approved Weighted Average Cost of Capital. This approach ensures that the Distribution Licensee remains financially viable and capable of meeting its obligations while maintaining uninterrupted electricity supply to consumers in Kogi State.

The Commission notes that improvements in billing efficiency, metering coverage, and revenue collection are expected to shorten the cash-conversion cycle over time. Accordingly, working capital allowances shall be reviewed periodically and adjusted to reflect actual efficiency gains, in order to protect consumers from unnecessary tariff increases

This approach ensures that the utility remains financially stable and can maintain uninterrupted electricity supply. As billing efficiency improves over time, the working capital requirement will be reviewed and adjusted to reflect these gains, ensuring that consumers are protected from unnecessary tariff increases.

2. KEDL Tariff Data Filing and Analysis for Tariff Determination

In preparation for the development of retail electricity tariffs for consumers in Kogi State, the Commission requested comprehensive data from KEDL through standardized data templates. These templates covered key areas including company assets, human resources, energy flows, billing and sales revenue, customer records, operational expenditures, debt obligations, metering infrastructure, and other relevant information necessary for accurate tariff modeling.

The data provided by KEDL, together with the NERC Asset Delineation Order, served as the primary input for the tariff computation process. The Commission conducted a detailed review of the submitted data, assessing completeness, accuracy, and consistency, and determined which elements would be adopted for the tariff modeling exercise. The following section presents the analysis of the data received from KEDL and outlines the decisions made regarding their inclusion in the tariff modeling process.

2.1. Energy Flow and Loss Analysis

KEDL submitted energy data for the period 2021–2025, indicating that annual energy received from the grid ranged from 257 to 333 GWh, with a mean of 297 ± 28.6 GWh. Reported technical losses over the same period were 1.1–1.6%, with a mean of 1.4 ± 0.2%. The Commission considers this level of technical efficiency to be unrealistic given the condition and configuration of the distribution network. Accordingly, for tariff modeling purposes, the Commission adopted the MYTO technical loss parameters applicable to AEDC, which range from 5.8% to 6.5%, with a mean of 5.9 ± 0.29%.

Commercial losses reported by KEDL ranged between 15% and 21%, with a mean of 19 ± 2.9%, significantly exceeding the MYTO AEDC benchmark range of 7–13.6% (mean 9.49 ± 2.9%). Notwithstanding this divergence, the Commission adopted KEDL's reported commercial loss levels as the baseline, reflecting prevailing operational realities while establishing a reference point for targeted efficiency improvements.

Collection losses were reported at 38.8–47.6%, with a mean of 42.7 ± 3.5%, far above the MYTO AEDC benchmark of 7.8%. Adoption of these values would result in an unrealistically high ATC&C loss level of approximately 56%. This outcome would be inconsistent with sector-wide loss reduction objectives established by NERC, under which capital expenditure support was provided through the Performance Improvement Plan (PIP), targeting ATC&C loss levels of 25.0% in 2024 and 20.6% in 2025 for AEDC. To ensure regulatory coherence, credibility, and alignment with achievable efficiency benchmarks, the Commission adopted a collection loss assumption of 15%, resulting in a baseline ATC&C loss of 30% for 2025.

International benchmarking further validates this approach. Comparable electricity markets record ATC&C losses of 8.8–25.5% in Latin America, 8.8–30.3% in Asia, and 14.3–30.3% in Africa, with regional averages generally below 25%. The adopted baseline therefore provides a realistic and defensible starting point, coupled with a clearly defined loss-reduction trajectory within the tariff framework.

2.2. Energy Sales and Revenue Collection Performance

Kogi Electricity Distribution Limited (KEDL) submitted energy sales, billing, and revenue collection data for the period 2021–2025 for the Commission's regulatory review. The submission shows that annual energy billed during the period ranged from approximately 216–268 GWh, with a period average of about 247 GWh (±22 GWh), reflecting moderate year-to-year variability in billed energy volumes.

In financial terms, the corresponding annual billed revenue ranged from about ₦7.3 billion to ₦15.5 billion, with an average billed amount of approximately ₦11.2 billion (±₦3.3 billion) over the review period. These figures reflect the combined effects of energy billed, applicable tariffs, and customer mix.

Actual revenue collections were substantially lower than billed amounts. Annual collections ranged between approximately ₦4.5 billion and ₦8.7 billion, with an average of about ₦6.5 billion (±₦1.7 billion). A comparison of billed and collected revenues indicates an average collection efficiency of approximately 61 per cent over the period under review. The Commission considers this level of collection performance to be materially below what is required to sustain efficient operations and support cost recovery under a regulated tariff framework.

The persistent gap between billed and collected revenues has significant implications for KEDL's cash flow, liquidity, and capacity to meet market settlement, operational, and investment obligations. Accordingly, the Commission has taken these data into account in assessing revenue adequacy, setting realistic performance assumptions, and establishing efficiency benchmarks for tariff determination. Stakeholders are invited to review the submitted data and provide comments on the reasonableness of the reported energy sales and collection performance, as well as on appropriate regulatory and operational measures to improve billing effectiveness and revenue collection efficiency going forward.

2.3. Electricity Subsidy in the State Electricity Market

The Nigerian electricity market operates a regulated tariff framework under which end-user tariffs approved by the Nigerian Electricity Regulatory Commission (NERC) may, in defined periods, be set below the efficient cost of electricity supply. The difference between the cost-reflective tariff and the approved allowed tariff constitutes an electricity subsidy, which is funded by the Federal Government. This subsidy regime is intended to safeguard the financial viability of the electricity supply industry while ensuring affordability for consumers and supporting broader macroeconomic and social stability.

Under the Multi-Year Tariff Order (MYTO) methodology, NERC first determines the Weighted Average Cost-Reflective Tariff (CRT) for each Distribution Company based on prudent and efficient cost assumptions. These assumptions cover generation costs, transmission and system operation charges, distribution operating and capital expenditure, approved loss targets, collection efficiency, and relevant macroeconomic parameters. The CRT represents the tariff level required to fully recover efficient costs across the electricity value chain.

Having established the CRT and taking into account the level of subsidy committed by the Federal Government primarily in respect of generation costs, NERC approves a Weighted Average Allowed Tariff (AT) that may be lower than the cost-reflective level. The difference between the CRT and the Allowed Tariff constitutes the tariff shortfall, which defines the quantum of subsidy applicable for the period. This approach ensures that affordability considerations are reflected in end-user tariffs, while the subsidy component remains explicitly quantified and transparent within the tariff framework.

The electricity subsidy is applied implicitly through regulated tariff setting, rather than through direct financial transfers to electricity consumers. Customers are billed strictly at the approved allowed tariff, while Distribution Companies apply these tariffs in accordance with the applicable tariff order. The unrecovered portion of efficient supply costs arising from the tariff shortfall is recognized as a subsidy obligation within the Nigerian Electricity Supply Industry. In practice, the subsidy is predominantly embedded in the generation cost component of the tariff, which accounts for the largest share of total electricity supply costs.

To operationalize the subsidy, the Federal Government makes budgetary provisions to cover part or all of the tariff shortfall. These funds are applied to settle upstream market obligations, including payments to Generation Companies and other market participants. Where subsidy releases are delayed or inadequate, liquidity constraints may arise across the electricity value chain.

2.3.1. Application of the Subsidy at the State Level

In setting tariffs for the Kogi State electricity market, the Commission applied the inherited Federal Government electricity subsidy framework by adopting net-of-subsidy generation costs in the tariff model, while maintaining consumer tariffs at the approved allowed levels. This approach ensures that electricity customers within the

State fully benefit from the Federal Government subsidy, with the resulting tariff shortfall transparently recognized within the market settlement framework.

Evidence from the applicable MYTO Orders for Abuja Electricity Distribution Company (AEDC) covering January 2024 to December 2025 indicates an average cost-reflective tariff of approximately ₦180/kWh, driven largely by an average generation price of about ₦101.5/kWh. Against an allowed tariff of roughly ₦110.5/kWh, the implied subsidized generation price is estimated at ₦62.3/kWh, significantly lowering the effective cost of electricity supply relative to a fully unsubsidized tariff regime.

Consistent with this framework, the bulk energy cost applied in this tariff review is derived from subsidy-adjusted invoices issued by the Nigerian Bulk Electricity Trading Plc (NBET) and the Zungeru Hydropower Plant (ZHEPP), divided by an average monthly energy sent out of 446 GWh. On this basis, the simple average bulk energy cost over the period July 2024 to November 2025 is estimated at ₦55.1 per kilowatt-hour. This represents the pure cost of electricity generation, exclusive of transmission wheeling and market administration charges, distribution operating expenses, statutory deductions such as NEMSF and MAF, as well as technical and commercial losses.

Applying this subsidized generation cost, the average annual cost of grid electricity supplied to Kogi Electricity Distribution Limited (KEDL) in 2025, based on approximately 324 GWh of energy received, is estimated at about ₦21.3 billion, compared to approximately ₦35.9 billion if computed at the full, unsubsidized generation price. This implies an annual Federal Government subsidy of about ₦14.6 billion, equivalent to roughly ₦1.2 billion per month. Accordingly, the approved tariff for the Kogi State electricity market is computed on a net-of-subsidy generation cost basis, ensuring affordability for consumers, transparency in subsidy treatment, and consistency with established regulatory principles of passing through to consumers the subsidy from Federal electricity market.

2.4 KEDL Baseline Operating Expenditure (Opex)

2.4.1 Scale Validation, Data Reliability Assessment, and Benchmark-Based Opex Determination

As a preliminary step in the prudency and efficiency review of KEDL's operating expenditure (Opex), the Commission conducted a scale validation and sanity assessment of the utility's reported operating parameters. This assessment focused on customer numbers, energy throughput, and average consumption per customer, which collectively provide the contextual basis for evaluating the reasonableness of operating costs.

KEDL reported an installed customer base of approximately 215,019 registered accounts, comprising about 110,508 suspended accounts and 38,715 closed accounts. Closed accounts were excluded from the tariff analysis, while suspended accounts were retained for scale assessment purposes given their continued presence on the network. KEDL further reported annual energy throughput of approximately 256 GWh and an average annual consumption of about 1.19 MWh per registered customer.

The reported scale of operations falls within the range observed in several emerging-market distribution utilities. In particular, average per-customer consumption levels of 1–2 MWh per annum are consistent with those observed among Indian State Distribution Companies, selected service areas of Indonesia's Perusahaan Listrik Negara (PLN), Philippine private distribution utilities, and Nigerian DisCos operating under the MYTO framework. On this basis, the Commission considers KEDL's declared operating scale to be prima facie plausible and suitable for comparative efficiency assessment.

Data Reliability and Prudency Assessment

Notwithstanding the plausibility of the reported operating scale, the Commission's detailed review of KEDL's Opex submission identified material deficiencies in data completeness, internal consistency, and cost disaggregation across multiple expenditure categories. These weaknesses significantly constrained the Commission's ability to rely on the submitted Opex data as a robust basis for prudency assessment.

In particular, the absence of sufficiently granular, verifiable, and internally consistent cost information limited the Commission's capacity to establish clear causal links between reported expenditure levels and underlying operational drivers such as customer growth, network expansion, inflationary pressures, asset base evolution, or measurable service improvements. In the absence of credible explanatory evidence, reliance on the submitted Opex figures would pose a material risk of inefficient or unsubstantiated costs being passed through to electricity consumers.

Accordingly, the Commission determined that KEDL's submitted Opex data could not be relied upon as the primary basis for tariff determination and that an alternative, structured analytical approach consistent with established regulatory practice was required.

Benchmark-Based Reasonableness Assessment

In light of the foregoing data limitations, the Commission applied comparative efficiency benchmarking as a proxy basis for determining a reasonable Opex envelope. Benchmarking is a well-established regulatory tool used where submitted cost data fails basic reliability or prudence tests. The approach normalizes operating costs by scale variables such as energy throughput and customer numbers, enabling an objective assessment of cost reasonableness for an efficiently operated utility.

As part of this assessment, the Commission observed pronounced non-economic volatility in KEDL's reported Opex profile. Several cost line items exhibited year-on-year fluctuations in excess of 300 percent, and in some cases exceeding 1,000 percent, without corresponding changes in operational scale, asset base, inflation, or service delivery outcomes. Such patterns are inconsistent with the stability expected in core operating cost categories and fail basic prudence, consistency, and causality tests.

Particular concern was noted with respect to "Miscellaneous Distribution Expenses," which dominated total Opex in certain years, reaching levels of ₦5.78 billion and ₦5.67 billion. This concentration indicates weak cost classification, inadequate internal expenditure controls, and the potential aggregation of unrelated or non-routine costs. Similarly, Meter Reading, Metering, and Billing costs displayed erratic movements despite a largely stable customer base and stated progress toward digitalization. The sharp reported decline in Salaries and Wages in the final year—from ₦584 million to ₦89 million—is operationally implausible and inconsistent with the staffing requirements of a distribution utility of KEDL's scale.

These observations reinforce the conclusion that KEDL's submitted Opex data does not provide a reliable foundation for direct regulatory approval.

MYTO 2024 Opex Benchmarks and Kogi-Specific Adjustments

The Nigerian Electricity Regulatory Commission (NERC) conducted a comprehensive tariff reset culminating in the issuance of the MYTO 2024 Tariff Orders, effective from 1 January 2024 for all eleven Distribution Companies. This reset followed extensive rate-case proceedings and stakeholder consultations and marked a transition from the prolonged period of mutual non-performance under the Performance Agreements.

MYTO 2024 recalibrated key tariff assumptions, realigned allowed revenues with cost-reflective benchmarks, and introduced a regime of monthly minor reviews to improve responsiveness to macroeconomic variables such as inflation and exchange-rate movements. Arising from this reset and a comparative assessment of peer Nigerian DisCos and selected emerging-market utilities, an industry-wide benchmark operating cost of approximately ₦10.00/kWh was established as representative of efficient distribution network operations under normal operating conditions.

The Commission recognizes, however, that distribution systems characterized by dispersed load centers, low customer density, challenging terrain, elevated logistics costs, and heightened security requirements such as those within Kogi State are structurally more expensive to operate. Taking these factors into account and applying conservative structural cost adjustment of approximately 10 percent, the Commission adopted an escalated benchmark of ₦11.00/kWh for application within the Kogi State electricity market.

For regulatory benchmarking purposes, the Commission applied this benchmark to an adjusted energy throughput of 256 GWh, representing estimated net billable energy after accounting for technical and commercial losses. On this basis, the benchmark-derived Opex requirement for the 2024 tariff year is approximately ₦2.82 billion.

Triangulation and Efficiency Envelope

For additional context, the Commission undertook a supplementary plausibility check by reference to KEDL's proportional share of Abuja Electricity Distribution Company's approved Opex under the MYTO framework for the 2020–2024 period, as indicated in the NERC Asset Delineation Order (2025). Applying an allocation factor of 7.11 percent yields an indicative Opex range of approximately ₦1.3 billion to ₦3.7 billion**,** with a five-year average of about ₦2.19 billion**.**

The Commission emphasizes that this proportional reference is used strictly as an external plausibility indicator and does not constitute a scaling or allocation rule for Opex determination. Differences in customer density, network configuration, and operating environment limit the direct comparability of proportional Opex allocations.

Taken together, the benchmark-based assessment and the proportional plausibility check define a broadly consistent efficiency envelope. Within this envelope, an indicative annual Opex allowance of ₦2.34 billion is assessed as reasonable and reflective of an efficiently operated distribution utility of comparable scale and operating conditions. This value is adopted for regulatory purposes, reflecting a balanced consideration of data uncertainty, structural cost factors, and consumer protection objectives.

Sensitivity Analysis and Data Integrity Considerations

For completeness, the Commission examined an alternative scenario based on KEDL's reported active customer base of approximately 104,000 customers. Under this assumption, benchmark-derived Opex estimates on a per-customer basis yield a range of approximately ₦0.93 billion to ₦2.33 billion.

The Commission considers this multiple check necessary for regulatory determination given persistent challenges with customer enumeration and the high fixed-cost nature of distribution operations. This sensitivity analysis underscores the importance of improved customer data integrity, enhanced cost disaggregation, and more robust internal validation processes in future tariff submissions.

2.4.2 Line-by-Line Opex Vetting and Cost Allocation Benchmarks

The Commission notes that the effectiveness of operating expenditure depends not only on the total approved amount, but also on the allocation of expenditure across specific cost categories. Under-spending on critical operational activities or excessive expenditure on non-essential items may undermine service delivery and efficiency outcomes.

Accordingly, based on the indicative total Opex envelope of ₦2.34 billion per annum, the Commission derived benchmark ranges for individual cost components using typical proportional shares observed in efficiently operated electricity distribution utilities, as established in the regulatory and industry literature. These proportional benchmarks are applied to guide line-by-line vetting of KEDL's Opex submission and to support the identification of inefficient, misclassified, or non-essential expenditures.

The table below presents the standard Opex component shares and the corresponding benchmark ranges applied for regulatory assessment purposes.

Table 1: Typical opex components of the OPEX with their share.

Item	Typical Share (%)	Range (Nmillion)
Routine network maintenance (non-capital)	4 – 6	93.6 – 140.4
Vegetation management	2 – 4	46.8 – 93.6
Overhead line supplies & expenses	3 – 5	70.2 – 117
Meter reading	2 – 3	46.8 – 70.2
Billing and collection	3 – 5	70.2 – 117
Meter expenses (repairs, testing, small replacements)	2 – 4	46.8 – 93.6
Station/Substation equipment supplies	2 – 4	46.8 – 93.6
Station/Substation buildings & fixtures	1 – 2	23.4 – 46.8
Load dispatch center operations	0.5 – 1.5	11.7 – 35.1
Call centers & complaint handling	1 – 2	23.4 – 46.8
Salaries & wages	30 – 40	702 – 936
Security services (network-related)	2 – 3	46.8 – 70.2
Insurance premiums	1 – 2	23.4 – 46.8
Office rent & utilities	2 – 3	46.8 – 70.2
Miscellaneous distribution expenses	1 – 2	23.4 – 46.8
ICT expenses	2 – 4	46.8 – 93.6
License fees & regulatory levies	0.5 – 1.5	11.7 – 35.1
Maintenance of station/sub-station equipment	4 – 6	93.6 – 140.4
Maintenance of overhead lines	5 – 7	117 – 163.8
Maintenance of underground lines	0.5 – 1.5	11.7 – 35.1
Maintenance of distribution/line transformers	4 – 6	93.6 – 140.4
Maintenance of Street Lighting and Signal System	0.5 – 1	11.7 – 23.4
Maintenance labor (technical crews)	5 – 7	117 – 163.8
Maintenance of buildings & structures – plant	1 – 2	23.4 – 46.8
Maintenance of buildings & structures – office & others	0.5 – 1	11.7 – 23.4
Maintenance of meters	2 – 3	46.8 – 70.2
Maintenance of billing & collection equipment	0.5 – 1	11.7 – 23.4
Maintenance of equipment on customers' premises	0.5 – 1	11.7 – 23.4
Total		**1930.5 – 3006.9**

OPEX ASSESSMENT AND REGULATORY DETERMINATIONS

a. Distribution Network Routine Maintenance

KEDL's filing shows significant variability in routine distribution network maintenance expenditure over the review period, ranging from ₦0.62 million to ₦13.21 million, with an average annual outturn of ₦3.51 million. This level of expenditure is materially below the indicative benchmark range of ₦93.6 million to ₦140.4 million for distribution utilities of comparable scale.

The expenditure profile is characterized by intermittent spikes followed by reversion to minimal spending levels, which is inconsistent with a structured and continuous preventive maintenance framework. While low expenditure does not, in itself, indicate inefficiency, the absence of a stable expenditure pattern and supporting maintenance documentation limits the Commission's ability to validate the scope, adequacy, and sustainability of the reported activities.

Accordingly, the Commission allows routine maintenance costs at the historical average level of ₦3.51 million. Any upward adjustment shall be contingent on the submission of credible asset condition assessments, clearly defined and time-bound maintenance programmes, and verifiable supporting documentation, including job cards, work orders, completion certificates, vendor invoices, payment records, and asset maintenance logs directly linked to reported expenditure.

b. Vegetation Management

Vegetation management expenditure over the review period ranged from ₦3.27 million to ₦20.39 million, with an average annual outturn of ₦11.00 million, compared to an indicative benchmark range of ₦46.8 million to ₦93.6 million. Given Kogi State's location within the Guinea savannah vegetation belt—where seasonal vegetation regrowth along feeders and rights-of-way typically necessitates regular clearing—the reported expenditure profile appears inconsistent with expected maintenance requirements.

Actual expenditure remains materially below benchmark levels and exhibits notable year-to-year variability, suggesting intermittent interventions rather than a systematic, feeder-based vegetation management programme. In the absence of evidence demonstrating sustained coverage or defined clearing cycles, the Commission is unable to support normalization to benchmark levels.

The Commission therefore allows vegetation management expenditure at the historical average level of ₦11.00 million and disallows benchmark headroom. For future tariff reviews, KEDL shall submit feeder-specific vegetation management plans, BoQ-based contracts, feeder coverage reports, GIS or route maps, and comprehensive supporting documentation linking activities to reported costs.

c. Station and Substation Buildings and Fixtures
Expenditure on station and substation buildings and fixtures ranged from ₦6.18 million to ₦13.61 million over the review period, with an average annual outturn of ₦8.30 million, compared to a benchmark range of ₦23.4 million to ₦46.8 million. Spending levels are relatively stable year-on-year, indicating predictable cost behavior.

While the reported expenditure does not raise efficiency concerns, it remains materially below benchmark levels for a network of comparable scales, raising questions regarding the adequacy of asset upkeep over time. In the absence of asset condition evidence demonstrating limited maintenance needs, the Commission allows expenditure at the historical average level. Any future upward adjustment shall be supported by asset condition assessments and defined maintenance plans.

d. Station and Substation Equipment Supplies
Expenditure on station and substation equipment supplies ranged from ₦1.53 million to ₦4.56 million, with a five-year average outturn of approximately ₦3.0 million. Year-on-year movements are modest and consistent with routine procurement of consumables and minor spares required for day-to-day operations.

The average outturn is materially below the benchmark range of ₦46.8 million to ₦93.6 million. While this does not indicate inefficiency or imprudence, it provides no basis for normalizing costs to benchmark levels in the absence of evidence of expanded asset scope or revised maintenance standards.

Accordingly, the Commission allows station and substation equipment supplies at the historical average level of ₦3.0 million and disallows benchmark headroom.

e. Meter Reading
Meter reading expenditure was highly variable over the review period, ranging from ₦448 to ₦8.80 million, with a five-year average outturn of approximately ₦2.06 million. This expenditure pattern is inconsistent with a comprehensive meter reading programme and reflects low meter penetration, partial outsourcing, and reliance on estimated billing.

Actual expenditure remains materially below the benchmark range of ₦46.8 million to ₦70.2 million. While this does not give rise to efficiency concerns, the volatility and periods of negligible expenditure limit the Commission's ability to validate cost adequacy.

The Commission therefore allows meter reading costs at the historical average level of ₦2.06 million. Any future increase shall be subject to demonstrated expansion in metered customer coverage and submission of meter reading methodologies, service contracts, monthly read volumes, and cost-per-meter benchmarks.

f. Billing and Collection

Billing and collection expenditure ranged from ₦67.46 million to ₦93.30 million, with an average annual outturn of ₦77.91 million. Expenditure exhibits moderate growth and relatively low volatility, consistent with routine billing, revenue collection, and payment processing activities.

However, the Commission notes KEDL's reported collection efficiency of approximately 56 percent, indicating material revenue leakage. While average expenditure falls within efficient bounds and below the benchmark range of ₦70.2 million to ₦117 million, the sharp reduction to ₦10.8 million in one year is not aligned with revenue volumes or customer numbers and raises concerns regarding cost consistency and completeness of disclosure.

Accordingly, the Commission allows billing and collection costs at the historical average level of ₦77.91 million and disallows benchmark headroom. KEDL shall submit a detailed breakdown of billing versus collection costs, collection agent contracts, commission structures, and reconciliations to reported revenue collections in subsequent reviews.

g. Meter Expenses

Meter-related expenditure ranged from ₦4.84 million to ₦28.77 million, with an average annual outturn of ₦16.92 million. The observed volatility reflects episodic meter repairs, testing, and limited replacement activity rather than a sustained metering rollout programme.

Given persistently low metering coverage, the historical average remains materially below the benchmark range of ₦46.8 million to ₦93.6 million. The Commission therefore allows meter expenses at the historical average level of ₦16.92 million and disallows benchmark headroom, pending submission of a comprehensive metering rollout plan and reconciliation of the meter asset register.

h. Salaries and Wages

Salaries and wages ranged from ₦584.29 million to ₦806.83 million over the review period, with a five-year average outturn of ₦740.14 million. Expenditure has remained relatively stable and reflects the core workforce cost of the utility.

Relative to the benchmark range of ₦702 million to ₦936 million, reported expenditure remains within efficient limits. Accordingly, the Commission allows salaries and wages at the historical average level of ₦740.14 million, subject to submission of detailed payroll and emolument schedules.

i. Insurance Premiums

Insurance expenditure ranged from ₦7.32 million to ₦27.57 million, with an average annual outturn of ₦19.02 million. Reported costs remain below the benchmark range of ₦23.4 million to ₦46.8 million and are indicative of prudent coverage levels.

The Commission therefore allows insurance premiums at the historical average level, subject to confirmation of statutory and asset-related insurance policies.

j. Office Rent and Utilities

Office rent and utilities expenditure increased from ₦38.93 million to ₦146.58 million over the review period, with an average annual outturn of ₦93.53 million. This exceeds the upper bound of the benchmark range of ₦46.8 million to ₦70.2 million.

In the absence of evidence of office footprint expansion, regulatory mandates, or exceptional cost drivers, the Commission allows expenditure at the historical average level and disallows excess costs pending adequate justification.

k. Security Services

Security services expenditure ranged from ₦6.98 million to ₦54.23 million, with an average annual outturn of ₦36.52 million, below the benchmark range of ₦46.8 million to ₦70.2 million.

The Commission allows security services expenditure at the historical average level, subject to periodic review against vandalism and theft incidence data.

l. ICT Expenses

ICT expenditure ranged from ₦14.94 million to ₦75.50 million, with an average annual outturn of ₦29.55 million. Spending remains below the benchmark range of ₦46.8 million to ₦93.6 million and reflects modest system investment.

Accordingly, the Commission allows ICT costs at the historical average level, with future increases contingent upon demonstrated improvements in digital service delivery and system capability.

m. Maintenance of Station and Substation Equipment

Expenditure ranged from ₦1.46 million to ₦18.17 million, with an average annual outturn of ₦11.55 million, materially below the benchmark range of ₦93.6 million to ₦140.4 million. This indicates constrained maintenance activity rather than inefficiency.

The Commission therefore allows expenditure at the historical average level and disallows benchmark headroom pending submission of asset condition reports and maintenance schedules.

n. Maintenance of Overhead Lines

Expenditure ranged from ₦8.76 million to ₦46.64 million, with an average annual outturn of ₦27.48 million, compared to a benchmark range of ₦117 million to ₦163.8 million. For an overhead-dominated network, reported expenditure remains materially below expected levels.

The Commission allows expenditure at the historical average level and requires outage statistics and vegetation-interaction data to support any future upward adjustment.

o. Maintenance of Underground Lines

Underground maintenance expenditure ranged from ₦2.71 million to ₦16.33 million, with an average annual outturn of ₦8.70 million. Given KEDL's limited underground network footprint, this level of expenditure appears reasonable.

However, expenditure volatility suggests a predominance of corrective or capital-type interventions rather than routine maintenance. Accordingly, the Commission allows the historical average level and disallows benchmark normalization. Future reviews shall require evidence of maintained line length, fault incidence, and a clear distinction between preventive and corrective activities.

p. Maintenance of Distribution and Line Transformers

Expenditure on transformer maintenance ranged from ₦6.19 million to ₦74.31 million, with an average annual outturn of ₦26.36 million, materially below the benchmark range of ₦93.6 million to ₦140.4 million. The high volatility observed is not clearly correlated with transformer population size, age profile, or reported failure rates.

Accordingly, the Commission allows transformer maintenance costs at the historical average level, subject to future validation against asset performance indicators. KEDL shall submit transformer population data, age profiles, failure statistics, and repair-versus-replacement cost breakdowns in subsequent reviews.

q. Maintenance of Street Lighting and Signal Systems

No expenditure was reported during the review period. In the absence of evidence establishing asset ownership or maintenance responsibility, the Commission disallows this cost entirely pending submission of supporting documentation.

r. Maintenance Labor

No explicit maintenance labor costs were reported. These costs are presumed embedded within salaries and service contracts. To avoid double recovery, the Commission disallows a separate maintenance labor allowance.

s. Maintenance of Buildings & Structures – Plant

Expenditure on plant buildings and structures was negligible, ranging from ₦0.003 million to ₦0.15 million, with an average annual outturn of ₦0.06 million, compared to a benchmark range of ₦23.4 million to ₦46.8 million. Reported spending is materially below benchmark levels, reflecting minimal maintenance activity. The Commission allows actual costs incurred at the historical average level and disallows any benchmark headroom until credible asset condition assessments and maintenance plans are submitted.

t. Maintenance of Buildings & Structures – Office and Other Facilities

Expenditure on office buildings and other structures ranged from ₦0.33 million to ₦3.51 million, with an average annual outturn of ₦1.38 million, well below the benchmark range of ₦11.7 million to ₦23.4 million. The Commission allows costs at the historical average level, pending submission of supporting maintenance documentation and work plans for future review.

u. Maintenance of Meters

Meter maintenance expenditure ranged from ₦0.82 million to ₦10.67 million, with a five-year average outturn of ₦4.15 million, materially below the benchmark range of ₦46.8 million to ₦70.2 million. The Commission allows costs at the historical average level and disallows benchmark headroom, pending submission of a comprehensive metering maintenance plan, including meter repair, testing, replacement schedules, and supporting asset logs.

v. Maintenance of Billing and Collection Equipment

Expenditure on billing and collection equipment ranged from ₦0.76 million to ₦1.43 million, with an average annual outturn of ₦1.14 million, compared to a benchmark range of ₦11.7 million to ₦23.4 million. Reported costs are below expected levels for routine upkeep. The Commission allows expenditure at the historical average, with future increases subject to evidence of expanded or enhanced billing infrastructure.

w. Maintenance of Equipment on Customers' Premises

Expenditure for maintenance of equipment on customer premises ranged from ₦0.63 million to ₦3.82 million, with an average outturn of ₦1.98 million, below the benchmark range of ₦11.7 million to ₦23.4 million. The Commission allows costs at the historical average level and requires documented maintenance plans and asset logs for any future upward adjustments.

x. Miscellaneous Distribution Expenses

Miscellaneous distribution expenses ranged from ₦473.59 million to ₦5.78 billion, with an average annual outturn of ₦3.42 billion. The Commission notes the absence of detailed constituents and significant volatility in this category. The magnitude of expenditure exceeds the benchmark range of ₦23.4 million to ₦46.8 million by an order of magnitude, inconsistent with prudent Opex management. Accordingly, the Commission caps this cost at the benchmark level and disallows excess amounts. Any future allowance above this cap will require submission of a detailed cost breakdown, reclassification of expenditures, and audit verification.

y. Total Maintenance Expenses

Total operations and maintenance expenditure averaged approximately ₦1,418.86 million, compared to a benchmark range of ₦1,930.5 million to ₦3,006.9 million. The observed gap reflects systemic under-execution of maintenance activities rather than efficiency gains. Accordingly, the Commission approves maintenance Opex at historical average levels only. Any upward adjustment in subsequent reviews shall be conditional upon submission of a network-wide maintenance plan, comprehensive asset condition assessments, and verifiable supporting documentation.

The above analysis are summarized in the table   2 below:

Table 2:Analysis of KEDL Filling for Opex

Line Item	Range Filed by KEDL (₦ m)	Average (₦ m)	Benchmark Range (₦ m)	Approved Value (₦ m)	Remark
a. Distribution network routine maintenance	0.62 – 13.21	3.51	93.6 – 140.4	3.51	Approved at historical average due to volatility, lumpy spending, and absence of structured preventive maintenance; benchmark disallowed pending asset-condition evidence.
b. Vegetation management	3.27 – 20.39	11.00	46.8 – 93.6	11.00	Approved at historical average; benchmark headroom disallowed pending feeder-specific vegetation management plan and supporting documentation.
c. Station & substation buildings and fixtures	6.18 – 13.61	8.30	23.4 – 46.8	8.30	Approved at historical average; low spend raises adequacy concerns, future increases subject to asset-condition assessments.
d. Station & substation equipment supplies	1.53 – 4.56	3.00	46.8 – 93.6	3.00	Approved at historical average; benchmark headroom disallowed due to lack of evidence of expanded asset scope.
e. Meter reading	~0.00 – 8.80	2.06	46.8 – 70.2	2.06	Approved at historical average; volatility reflects low metering penetration; benchmark disallowed pending metering expansion evidence.
f. Billing and collection	10.80 – 93.30	77.91	70.2 – 117.0	77.91	Approved at historical average; benchmark headroom disallowed pending substantiated cost drivers and detailed cost breakdown.
g. Meter expenses	4.84 – 28.77	16.92	46.8 – 93.6	16.92	Approved at historical average; benchmark disallowed pending comprehensive metering rollout plan and asset reconciliation.
h. Salaries & wages	584.29 – 806.83	740.14	702 – 936	740.14	Approved at historical average; within benchmark range, subject to payroll verification.

i. Insurance premiums	7.32 – 27.57	19.02	23.4 – 46.8	19.02	Approved at historical average; subject to confirmation of statutory and asset-related insurance coverage.
j. Office rent & utilities	38.93 – 146.58	93.53	46.8 – 70.2	93.53	Approved at historical average; excess above benchmark disallowed pending justification for footprint or energy cost shocks.
k. Security services	6.98 – 54.23	36.52	46.8 – 70.2	36.52	Approved at historical average; subject to periodic review against vandalism and theft data.
l. ICT expenses	14.94 – 75.50	29.55	46.8 – 93.6	29.55	Approved at historical average; future increases contingent on demonstrated digital service improvements.
m. Maintenance of station / substation equipment	1.46 – 18.17	11.55	93.6 – 140.4	11.55	Approved at historical average; benchmark disallowed pending asset-condition reports and maintenance schedules.
n. Maintenance of overhead lines	8.76 – 46.64	27.48	117.0 – 163.8	27.48	Approved at historical average; future increases subject to outage and vegetation-interaction data.
o. Maintenance of underground lines	2.71 – 16.33	8.70	11.7 – 35.1	8.70	Approved at historical average; benchmark disallowed given limited underground network and volatile spend.
p. Maintenance of distribution / line transformers	6.19 – 74.31	26.36	93.6 – 140.4	26.36	Approved at historical average; volatility noted, future validation tied to asset performance indicators.
q. Maintenance of street lighting & signal systems	0.00	0.00	11.7 – 23.4	0.00	Disallowed entirely due to absence of expenditure and lack of evidence of asset ownership or responsibility.
r. Maintenance labour	0.00	0.00	117.0 – 163.8	0.00	Disallowed to avoid double recovery; costs presumed embedded in salaries or service contracts.
s. Maintenance of buildings & structures – plant	0.003 – 0.15	0.06	23.4 – 46.8	0.06	Approved at actual outturn only; benchmark headroom disallowed.

t. Maintenance of buildings & structures – office & others	0.33 – 3.51	1.38	11.7 – 23.4	1.38	Approved at historical average; benchmark disallowed.
u. Maintenance of meters	0.82 – 10.67	4.15	46.8 – 70.2	4.15	Approved at historical average; pending comprehensive metering maintenance plan.
v. Maintenance of billing & collection equipment	0.76 – 1.43	1.14	11.7 – 23.4	1.14	Approved at historical average; benchmark disallowed.
w. Maintenance of equipment on customers' premises	0.63 – 3.82	1.98	11.7 – 23.4	1.98	Approved at historical average; benchmark disallowed.
x. Miscellaneous distribution expenses	473.59 – 5,780.00	3,420.00	23.4 – 46.8	46.80	Capped at benchmark due to extreme magnitude and opacity; excess disallowed pending detailed breakdown and audit.
y. Total Operation & maintenance expenses	**—**	**4,544.26**	**1,930.5 – 3,006.9**	**1,418.86**	**Approved at historical average with a f; under-execution noted, future increases subject to network-wide maintenance plan.**

2.3.2. Overall Conclusion on the Opex Data Filed by KEDL

The Commission finds that, while the benchmark-derived headline operating and expenditure of approximately ₦2.3 billion is reasonable for a distribution utility of KEDL's scale operating at the desired level, the internal cost allocation is materially distorted. Expenditure on critical service-delivery functions, particularly network operations and maintenance, metering, billing, and collection is significantly understated, while administrative and general costs account for a disproportionately large share of total Opex. This expenditure structure is inconsistent with the requirements of a utility expected to deliver safe, reliable, and adequately metered electricity services.

Although KEDL's aggregate operating scale, measured by registered customers and energy throughput, is broadly credible, material inconsistencies between registered and active customer figures undermine the robustness of cost normalization and efficiency assessment. In addition, wide year-on-year volatility in core operating costs, weak disaggregation, and limited reconciliation with audited financial statements indicate deficiencies in cost classification, budgeting discipline, and internal validation processes. Consequently, the Commission is unable to place full regulatory reliance on the submitted Opex values.

In light of these limitations, the Commission adopts a benchmark-based approach to Opex determination. Applying Nigerian MYTO parameters and emerging market comparators, the Commission determines an efficient Opex range of ₦1.3 billion to ₦3.7 billion per annum and adopts a midpoint allowance of approximately ₦2.3 billion as the OPEX cap for tariff-setting purposes. Applying this headline cap and benchmark restructuring of the proposed expenditure profile the Commission proposes an efficient OOPEX of 1.34 billion. However, approval is subject to structural rebalancing of costs in line with efficiency benchmarks, including allocating approximately 27–30 percent to network operations and maintenance and 20–30 percent to customer service functions, while enforcing strict separation between capital and operating expenditures. Where this structural rebalancing is not done the Commission may claw back costs that are inefficiently deployed in the subsequent tariff reviews.

Accordingly, the Commission rejects cost line items that fail basic sanity and benchmark tests and conditions final Opex approval on measurable improvements in service delivery indicators, including meter reading coverage, outage frequency, and vegetation management cycles. Until data quality, customer enumeration, and cost disaggregation materially improve, the Commission will continue to rely primarily on comparative benchmarks in future regulatory reviews.

2.4. Capital Expenditure (CAPEX) and Regulatory Asset Base (RAB)

The Commission's determination of KEDL's allowable capital expenditure (CAPEX) and Regulatory Asset Base (RAB) for tariff purposes is grounded in a harmonized, evidence-based assessment of available asset records. This assessment draws on KEDL's fixed asset register, the NERC Asset Delineation Order, and MYTO-approved capitalization principles. Comparative benchmarking against distribution utilities of similar scale is applied strictly as a plausibility and reasonableness check, and not as a valuation substitute.

The Commission reiterates that the NERC Asset Delineation exercise was undertaken primarily to establish asset ownership and allocation at the point of sector privatization and subsequent restructuring. It was not intended to constitute a comprehensive asset valuation exercise, nor to replace asset-level verification required for tariff resets at sub-national, state, or franchise levels. Accordingly, asset values implied by proportional allocation or energy-offtake proxies are treated as indicative only and are not adopted as regulatory valuations.

For tariff determination, the Commission's overriding considerations are the verifiability, prudence, serviceability, and historic acquisition cost of assets, rather than notional or revalued figures.

2.4.1. Harmonized Asset Mapping and Regulatory Treatment

To establish a defensible historic-cost RAB consistent with MYTO principles and international best practice in incentive-based utility regulation, the Commission reconciled two parallel asset records:

i. the NERC Asset Delineation Record; and

ii. KEDL's fixed asset register as reflected in its tariff filing document.

This reconciliation process eliminated double counting, corrected distortions arising from legacy revaluations conducted during privatization and subsequent sub-company delineation, and excluded assets that are non-operational, redundant, or imprudently incurred. The outcome is a single, harmonized asset position based on historic acquisition cost net of accumulated depreciation, applied on an asset-specific basis in accordance with applicable accounting standards.

In the absence of a comprehensive, independently verified asset-level valuation, the Commission considers it inappropriate to upscale or revalue the RAB through proportional allocation, benchmarking, or notional adjustments. Accordingly, where asset records overlap, KEDL's verified historic-cost netbook values prevail for tariff purposes, while the NERC Asset Delineation Record is relied upon strictly to confirm asset existence, serviceability, and ownership.

The resulting harmonized position constitutes a verified, serviceable, historic-cost Regulatory Asset Base, forming the basis for allowable depreciation and return on capital within the tariff framework.

2.4.2. Asset-Class Treatment

a. Distribution Network Assets (MV/LV)

The NERC Asset Delineation Record assigns a combined distribution network value of approximately ₦6.27 billion, reflecting legacy revaluations undertaken during privatization and subsequent restructuring. By contrast, KEDL reported an original acquisition cost of ₦4.84 billion and a net book value (NBV) of ₦3.82 billion for its MV and LV network assets.

In line with MYTO methodology, tariff determination is based on verified historic acquisition cost and serviceability rather than revalued or notional figures. Accordingly, the Commission adopts KEDL's verified NBV of ₦3.82 billion as the regulatory valuation for tariff purposes.

As a plausibility check, the Commission reviewed the physical network extent using the reported feeder route length of 2,010.85 km from the NERC record, which implies an average unit network cost of approximately ₦1.9 million per kilometer. This figure is consistent with sector benchmarks for legacy distribution infrastructure and supports the reasonableness of the adopted historic-cost valuation. Benchmarking is applied solely as a validation tool and does not constitute a basis for asset revaluation.

Accordingly, KEDL's distribution network assets are admissible into the **RAB** at ₦3.82 billion, subject to confirmation of physical existence, commissioning dates, and continued serviceability.

b. Metering and Revenue Assurance Assets

KEDL reported metering and revenue assurance assets with an original cost of ₦1.83 billion and an NBV of ₦1.51 billion. The relatively low level of accumulated depreciation reflects recent investment associated with metering expansion initiatives.

However, the submission does not clearly distinguish assets funded directly by the distribution company from those financed through customer contributions (including CAPMI) or donor-supported programmes and other initiatives that are being recovered through rates or tax. To prevent double recovery from electricity consumers, only DisCo-funded metering assets are admissible into the RAB for depreciation and return on capital.

Pending verification of funding sources through procurement records, funding declarations, and installation documentation, the Commission provisionally admits ₦0.90 billion as DisCo-funded metering and revenue assurance assets for tariff purposes. Any additional assets shall be considered for inclusion upon satisfactory verification in subsequent regulatory reviews.

c. Land, Buildings, and Civil Infrastructure

The Commission notes that the NERC Asset Delineation Record assigns an aggregate value of approximately ₦6.46 billion to land and buildings, which exceeds KEDL's reported historic acquisition cost and NBV. The fixed asset register further indicates instances where netbook values exceed original cost, suggesting the application of revaluation adjustments or asset misclassification.

Land, by its nature, is non-depreciable and does not require capital recovery through tariff-based depreciation. Accordingly, land is excluded from depreciation and return on capital allowances.

Buildings and civil infrastructure may be admissible where they are demonstrably operational, prudently incurred, and efficiently sized to support regulated distribution activities. In the absence of verifiable documentation demonstrating these criteria, the Commission has excluded buildings and civil infrastructure from the RAB for the current tariff period. KEDL may resubmit such assets for consideration upon providing satisfactory evidence of operational necessity, prudence, and historic acquisition cost.

d. Tools, Workshop Assets, Furniture, and Equipment

These asset classes are fully or near-fully depreciated and exhibit minimal remaining economic life. As depreciation serves as the mechanism for capital recovery, assets that have reached the end of their depreciable life are deemed to have fully recovered their capital cost through prior tariffs.

Accordingly, these assets do not qualify for continued recovery through the RAB. Any residual costs associated with their use are more appropriately treated as operating expenditure. Replacement of such assets is addressed through new, prudently reviewed CAPEX submissions in subsequent regulatory periods, which—if approved—are admitted into the RAB for depreciation and return on capital.

e. ICT Assets

Legacy ICT assets are recorded at ₦53.75 million in the NERC Asset Delineation Record, while KEDL reports an NBV of ₦1.53 million. Given the short economic life of ICT assets, only systems that are operational and directly support regulated activities—such as billing, energy accounting, and network control (including SCADA)—are potentially admissible.

In the absence of verifiable evidence demonstrating operational relevance and funding source, ICT assets are excluded from the RAB for the current tariff period. KEDL may resubmit qualifying ICT investments for consideration under future CAPEX approvals.

f. Vehicles and Inventory

Vehicles, (except operational trucks, Hiab, etc) are not considered core distribution network assets for the purpose of RAB determination in the current tariff period and are therefore excluded from capital recovery through depreciation and return on capital. Costs associated with vehicle usage may be recovered through efficient operating expenditure allowances where appropriate.

Inventory represents working capital rather than fixed capital investment and is accordingly excluded from CAPEX and the RAB.

2.5.3 Resulting Regulatory Asset Base and Forward-Looking CAPEX Treatment

Following the foregoing adjustments, the harmonized historic-cost Regulatory Asset Base for KEDL is estimated at approximately ₦4.7 billion, comprising:

₦3.82 billion in admissible distribution network assets; and

₦0.90 billion in provisionally admissible, DisCo-funded metering and revenue assurance assets.

These legacy assets continue to earn allowed depreciation and return on capital strictly on a historic-cost basis, without revaluation uplift or notional adjustments.

Consistent with MYTO methodology, only incremental, forward-looking capital investments that are prudently incurred, efficiently procured, verifiable, and demonstrably funded by the distribution company are eligible for recovery through future tariffs.

2.5.4 Interim Treatment of Baseline CAPEX

Pending the commissioning of an independent, comprehensive asset enumeration and verification exercise, the Commission has adopted a conservative interim approach to establishing a forward-looking CAPEX baseline for KEDL.

For this limited purpose, and without conferring any recognition of historical asset value, the Commission provisionally references KEDL's proportional share (7.11 per cent, as specified in the 2025 Asset Delineation Order) of AEDC's MYTO-approved capital expenditure. Applying this proportion yields an indicative forward-looking baseline CAPEX of ₦209.02 million as at 2024, which is adopted solely as a temporary planning reference for tariff determination.

This interim measure does not alter the historic-cost RAB adopted for the current tariff period and shall be replaced upon completion of asset-level verification and confirmation of funding sources. The approach preserves MYTO integrity, enhances regulatory credibility, and mitigates the risk of tariff inflation arising from unverified legacy asset revaluations.

2.5. Customer Classification and Tariff Structure

The Commission reviewed the applicability of the national Band A–E customer classification framework within the Kogi State electricity market. Following this assessment, the Commission determined that the adoption of the Band A, B, C, and D structure would be impracticable under prevailing market conditions. This determination is informed by two principal considerations: first, the significant monitoring and enforcement challenges associated with ensuring compliance with service-hour commitments at feeder level; and second, the limited number of Band A feeders and customers within the State.

At the national level, the Band A tariff framework has been effective largely because approximately 15 percent of customers classified as Band A account for nearly 40 percent of total energy consumption, thereby enabling cross-subsidisation without excessive tariff distortion. In contrast, within Kogi State, customers that would qualify as Band A account for only about 9 percent of total energy offtake. Consequently, requiring this small customer segment to absorb the subsidy burden of lower-service bands would necessitate disproportionately high tariff increases, potentially resulting in economic inefficiency, affordability concerns, and demand erosion.

In light of the foregoing, the Commission has approved a revised customer classification and tariff structure tailored to the State's consumption profile and administrative capacity. Under this framework, former Band A customers shall be reclassified as **Premium Customers**, reflecting their higher quality of supply and willingness to pay for enhanced service levels. All other customers shall be reclassified broadly in line with the legacy PHCN customer categories, as follows:

- **Residential Customers**:
    - Residential - Basic (Small Residential)
    - Residential- Standard (Large Residential/MD)
- **Commercial Customers**:
    - Commercial Basic (Small Commercial)
    - Commercial Standard (Large Commercial/MD)
- **Industrial Customers**:
    - Industrial - small
    - Industrial -Large
- **Public and Special Customers**:
    - Public Buildings
    - Educational Institutions (Schools)
    - Healthcare Institutions (Hospitals)
    - Agricultural Institutions
    - Lifeline Customers

The Premium Customer tariff shall apply to eligible customers previously classified under Band A and selected high-consumption commercial and industrial customers, subject to clearly defined eligibility criteria and service standards.

Furthermore, the Commission notes that this revised classification enhances transparency and facilitates targeted subsidy administration. Accordingly, subsidy policies shall be explicitly directed at socially sensitive and priority customer classes, notably lifeline customers, public schools, and hospitals, in line with the State's social and economic policy objectives. This approach ensures a more equitable allocation of subsidies while preserving cost reflectivity and financial sustainability of the electricity market

2.6. Aggregate Technical, Commercial and Collection (ATC&C) Losses

Aggregate Technical, Commercial and Collection (ATC&C) losses represent a comprehensive measure of inefficiencies within an electricity distribution system. They reflect the gap between the quantum of energy delivered into a distribution network and the portion of that energy for which revenue is ultimately realized by the utility. ATC&C losses therefore capture both physical energy losses and commercial revenue leakages inherent in distribution operations.

ATC&C losses comprise three distinct components. Technical losses arise from the physical characteristics of the distribution network, including energy dissipation in conductors, transformers, and other network elements due to resistance and equipment limitations. Commercial losses result from non-technical factors such as energy theft, illegal connections, meter bypasses, meter tampering, and inaccuracies in customer enumeration and billing. Collection losses occur when billed revenues are not fully recovered, reflecting payment defaults and weaknesses in revenue collection processes. Collectively, these components provide a holistic assessment of distribution efficiency and revenue integrity.

High ATC&C losses have a direct and material impact on electricity tariffs. Where losses are elevated, Distribution Companies (DisCos) are required to procure energy that does not translate into collectible revenue. In order to satisfy revenue sufficiency and cost recovery requirements, tariffs must rise to compensate for the reduced volume of paid energy. Consequently, the effective cost per kilowatt-hour borne by paying customers increases, even where the underlying cost of energy supply remains unchanged.

Beyond tariff impacts, persistently high loss levels erode the financial viability of utilities, limiting their capacity to invest in network rehabilitation, metering infrastructure, and system modernization. This dynamic creates a self-reinforcing cycle in which underinvestment perpetuates inefficiency, further elevating loss levels and tariff pressure.

Recognizing these dynamics, tariff frameworks make explicit provision for an allowed level of ATC&C losses**.** Such allowances are incorporated into tariffs as part of prudently incurred operating costs. Where a utility's actual losses exceed the allowed level, the resulting shortfall is borne by the utility and not passed through to customers. This regulatory treatment establishes a clear efficiency incentive, encouraging loss reduction while protecting consumers from the cost of avoidable inefficiencies. At the same time, regulators are required to set loss targets that are realistic and achievable, reflecting prevailing operational constraints and the financial sustainability of the utility.

Under the Multi-Year Tariff Order (MYTO**)** methodology, the Nigerian Electricity Regulatory Commission establishes assumed ATC&C loss levels for each DisCo during tariff determination. These assumptions inform allowed energy purchases, revenue forecasts, and overall cost recovery. MYTO further defines both a base-year loss level and a target loss trajectory, requiring DisCos to progressively reduce losses over the tariff period.

The divergence between actual and target loss performance has direct revenue implications. DisCos that fail to achieve approved loss targets may experience reduced cost recovery or other regulatory adjustments. Conversely, where a DisCo outperforms its loss reduction targets, the resulting improvement in collected revenue accrues to the utility as a performance gain, effectively serving as an efficiency incentive. MYTO also provides for revenue true-ups where loss outcomes deviate materially from approved assumptions. Collectively, these mechanisms send a strong regulatory signal for utilities to prioritize metering acceleration, network upgrades, enhanced billing systems, and robust anti-theft enforcement.

2.6.1. Benchmark ATC&C Loss Levels for Kogi State

In establishing benchmark Aggregate Technical, Commercial and Collection (ATC&C) loss levels for Kogi State, the Commission sought to balance regulatory ambition with operational realism. The benchmarking exercise was informed by a combination of national ATC&C loss averages, the performance of comparable distribution companies, and state-specific conditions, including network topology, customer density, metering penetration, and the incidence of energy theft. Due consideration was also given to the current stage of market development and the capacity of the utility to implement loss-reduction measures within a defined regulatory period.

In determining the appropriate target loss levels, the Commission further recognized the existence of supportive state institutions established to strengthen electricity supply operations. These include a dedicated electricity theft task force and a specialized court for the prosecution of electricity-related offences. The presence of these institutions is expected to enhance enforcement, improve collection discipline, and accelerate the reduction of commercial and collection losses over time.

Against this background, the Commission proposes an initial benchmark ATC&C loss level of 30 percent for Year 1. This level broadly reflects historical national DisCo averages prior to intensified reform efforts, while providing a realistic and credible baseline from which performance improvements can be measured. Over the medium term, a progressive reduction to a target range of 20–22 percent within three to five years is considered achievable, subject to sustained investment in metering, network reinforcement, and robust enforcement actions.

The proposed loss trajectory provides a transparent framework for performance monitoring, investment planning, and incentive alignment under the MYTO framework, while safeguarding the financial viability of the utility and supporting improved service delivery to customers in Kogi State.

2.7. Inflation and Macroeconomic Assumptions

In developing the proposed tariff, the Commission has adopted the macroeconomic indices applied under the Nigerian Electricity Regulatory Commission (NERC) Multi Year Tariff Order (MYTO) framework. This approach reflects the fact that the SubCo, Kogi Electricity Distribution Limited (KEDL), operates within the same national macroeconomic environment as other electricity distribution licensees in Nigeria.

Accordingly, key macroeconomic parameters including the inflation rate, exchange rate, and weighted average cost of capital (WACC) have been adopted from the prevailing MYTO model. The Commission considers the use of these standardized assumptions to be appropriate, as they provide consistency with national tariff-setting practices, enhance regulatory certainty, and ensure comparability of tariffs across jurisdictions.

Stakeholders are invited to review these assumptions and provide comments on their continued applicability to the Kogi State electricity market, including any state-specific considerations that may warrant adjustment within the bounds of regulatory prudence and consumer protection.

3. Invitation for Stakeholder Submissions

The Kogi State Electricity Regulatory Commission (KERC) hereby invites written submissions from all interested stakeholders on the proposed tariff framework for the Kogi State electricity market. The Commission seeks informed, constructive, and evidence-based comments that will assist in refining the tariff to achieve cost reflectivity, service improvement, investment sustainability, and consumer protection.

To ensure that submissions received are focused and capable of informing regulatory determinations, stakeholders are requested to structure their responses in line with the issues outlined below. Where practicable, comments should be supported by data, operational experience, or reasoned analytical arguments.

i. Cost of Service and Cost Reflectivity

Stakeholders are invited to review the assumptions underpinning the proposed tariff and comment on their accuracy, consistency, and reasonableness. In particular, respondents should assess whether costs associated with distribution activities, technical and non-technical losses, operating expenditures, and capital investments have been appropriately identified, quantified, and reflected in the tariff.

The Commission welcomes comments on the transparency and realism of key assumptions, including load forecasts, energy sales projections, and other critical inputs used in the tariff model.

ii. Tariff Design and Structure

Respondents should examine the proposed tariff design and its application across customer categories, including residential, commercial, industrial, public institutions, and other classes. Comments are invited on the appropriateness of the customer classification, the use of block or flat tariffs, and the balance between single-part and multi-part tariff structures.

Stakeholders are also encouraged to comment on whether the proposed structure is fair, simple to understand, and reflective of cost causation. Particular attention should be paid to the adequacy of lifeline or subsidized tariffs for schools and hospitals, in view of the broader social and economic impact of electricity costs on essential public services.

iii. Rate of Return and Utility Profitability

Stakeholders should assess the reasonableness of the proposed rate of return for distribution utilities and comment on whether it is sufficient to attract and retain investment while remaining consistent with consumer protection and value for money.

Submissions may also address whether the rate of return should be fixed or linked to defined performance outcomes, and how such an approach could incentivize efficiency, service improvement, and prudent investment.

iv. Technical and Non-Technical Loss Assumptions

Given the significant influence of losses on tariff outcomes, stakeholders are requested to review the assumed levels of technical, commercial, and collection losses, as well as the proposed loss reduction trajectories. Comments should address the realism and achievability of these targets, taking into account local network conditions, metering penetration, and enforcement arrangements.

Stakeholders may further comment on whether the costs associated with loss reduction have been efficiently allocated and whether improvements in utility performance should result in measurable benefits for consumers.

v. Quality of Service and Performance Incentives

Respondents are encouraged to comment on how the proposed tariff framework addresses service quality and performance incentives. This includes views on the introduction of a premium tariff class in place of the Band A framework, the discontinuation of band-based tariffs, and the merits or otherwise of the proposed tariff structure in improving reliability, transparency, and customer experience.

vi. Inflation and Macroeconomic Assumptions

Stakeholders should review and comment on the macroeconomic assumptions underlying the tariff, including inflation, exchange rates, interest rates, and other relevant economic variables. Submissions should assess whether these assumptions are realistic and adequately reflected in the tariff design.

Comments are also invited on the adequacy of mechanisms for managing macroeconomic volatility, including the use of periodic tariff reviews or automatic adjustment mechanisms to balance utility sustainability with consumer protection.

vii. Social Protection and Supporting Policies

Stakeholders are requested to assess the effectiveness of social protection measures embedded in the proposed tariff, including lifeline tariffs, cross-subsidies, and targeted support for vulnerable customers, particularly through hospital and school tariff arrangements.

Respondents may also comment on complementary policies such as energy efficiency initiatives, demand management measures, and targeted interventions that could mitigate tariff pressures while improving access, affordability, and service delivery.

viii. Transparency and Data Disclosure

Finally, stakeholders are invited to comment on whether the consultation document provides sufficient data, methodological clarity, and explanatory detail to support informed participation. Submissions should identify any information gaps, unclear assumptions, or areas where additional disclosure would enhance transparency, credibility, and regulatory confidence.

Thank you
Kogi State Electricity Regulatory Commission
Lokoja