Performance Improvement Plan

For Eko Electricity Distribution Company Plc (EKEDC)

September 2019

Hyperlinked Contents

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Acronyms

Acronym	Definition
AMI	Advanced Metering Infrastructure
ATC&C	Aggregate Technical, Commercial and Collection Losses
BPE	Bureau of Public Enterprises
CAPEX	Capital Expenditure
CMS	Commercial Management System
Disco	Distribution Company
ERP	Enterprise Resource Planning
GIS	Geographical Information System
IRMS	Incidents Recording and Management System
IT	Information Technology
MAP	Meter Asset Provider
MDA	Ministries, Departments and Agencies
MO	Market Operator
MYTO	Multi-Year Tariff Order
NBET	Nigerian Bulk Electricity Trading Plc.
PHCN	Power Holding Company of Nigeria
PIP	Performance Improvement Plan
RPP	Revenue Protection Project
SCADA	Supervisory Control and Data Acquisition System
WACC	Weighted Average Cost of Capital
WMS	Works Management System

1 One-page Summary for Stakeholders

Eko Electricity Distribution Company (EKEDC) covers the license area of the southern part of Lagos state and Agbara in Ogun state. The southern Lagos State comprises Ojo, Festac, Ijora, Mushin, Orile, Apapa, Lekki, and Ibeju while the Lagos Island covers Ajele areas. The distribution network, operated at three voltage levels, serves major residential, commercial and industrial hubs within the state, covering 10 Districts within its network.

There are 387 feeders in the EKEDC Network; 300 - 11kV feeders and 87 - 33kV feeders. There are 104 - 33/11kV transformers and 42 - 132/33kV transformers. There are 9,079 - 11/0.415kV distribution transformers and 1601 - 33/0.415kV distribution transformers served by EKEDC.

As at June 2019, there are 501,028 customers in the EKEDC network.

After receiving feedback from our customer engagement sessions in the different parts of our franchise areas, we have aligned our investment priorities to those of our customers as majority of our customers wish to see more focus on metering and improving the reliability of power supply.

To fully invest and achieve our customers' service level expectations, we will need to spend more than the Regulatory Allowed capital expenditure, and this will imply that we will need to charge our customers a higher tariff to fully recover the cost of investment. Without charging cost-reflective tariffs, lenders/investors will not provide us with the needed capital to invest in power supply and service improvement to our customers.

2 Overview

- In line with NERC's guideline for the PIP, EKEDC held customer engagements in the different circles of the Disco and obtained key feedback which confirmed that metering and network reliability were as important to our customers as they are to us.
- To improve supply and customer satisfaction, we focused our investments on initiatives categorized by five (5) pillars namely: (1) Reliable Power and Quality Services, (2) Organizational Capability, (3) Operational Excellence, (4) Safety Standards, and (5) Proactive Stakeholder Engagement.
- As part of our innovative strategies, we plan to segment our network into manageable and difficult-to-manage areas and allow third-party players to partner with us in improving supply in difficult to manage areas.
- We have looked at two (2) possible scenarios: (1) Regulatory Allowed Capex Scenario and (2) EKEDC Required Capex Scenario.
- If we must be able to sustainably and fully pay our market bills, cover our costs (Opex & Capex), we must be to allowed charge a truly cost-reflective tariff that can achieve a realistic ATC&C loss reduction trajectory (from 26.63% in 2020 to 18.63% in 2024) thereby sending the right pricing signal to investors/lenders.
- This we can only achieve if the different risks and challenges we have continued to face in the Nigerian power sector are addressed.

2.1 Summary of process

EKEDC has followed a robust process to prepare this plan and we have justified our planned expenditure.

The process involved liaising with our customers for feedback needed to guide our prioritization of EKEDC's future investments.

The process is described in more detail in Section 3.

2.2 Scenarios

This PIP considers two scenarios – (1) "Regulatory Allowed Capex" and (2) "EKEDC Required Capex" scenario.

The key characteristics of the two scenarios are:

- **"Regulatory Allowed Capex" Scenario** – The Capex and Opex requirements as well as end-user tariffs are as stipulated in the June 2019 Minor Review MYTO Model. In this scenario, EKEDC's achievable loss reduction trajectory from 2020 to 2024 is not as aggressive as NERC envisages in the Minor Review Model;
- **"EKEDC Required Capex" Scenario** – The Capex and Opex requirement are higher and reflect what is needed, at cost-reflective tariffs, to achieve loss reduction (more than in the "Regulatory Allowed Capex" scenario) which will still not be as aggressive as NERC envisages in the Minor Review Model.

The "Regulatory Allowed Capex" scenario is currently the most probable, as it is consistent with NERC's public statements to date. However, the "EKEDC Required Capex" scenario allows EKEDC to achieve their most ambitious output goals.

The scenarios are described in more detail in Section 4.3.

2.3 Outputs EKEDC Required Capex

Over five years, the ambitious "EKEDC Required Capex" scenario will allow EKEDC to:

- Reduce ATC&C losses from the current level of 26.63% (2020) to 18.63% (2024), which will allow our business to be sustainable;
- Reduce the number of customer interruptions from 11622 in 2020 to 8712 by 2024, thus increasing reliability for our customers;
- Increase the number of new meters installed by 204,000 by 2021, allowing customers to trust the bills they receive;
- Reduce the number of deaths and accidents in our service area to zero; and
- Increase the number of new customer connections per year.

These outputs are discussed in Section ▪.

The justified investment plan to achieve these objectives is captured in Section 6.

2.4 Navigating this report

Table 1: Mapping the structure of this report to NERC criteria

NERC criteria for evaluating the PIP	NERC questions for the PIP	Hyperlinks
Criterion 1 - Process	Has the Disco followed a robust process?	Section 3: Process
Criterion 2 - Outputs	Detail of individual outputs.	Section ▪: Outputs: strategic objectives
	Does the Plan deliver the required outputs?	Section 6: Detailed Program Plans
Criterion 3 - Expenditure	Are the costs of delivering the outputs efficient?	Section 6.2: Delivering outputs efficiently
	Detail of individual cost items.	Section 6: Detailed Program Plans
Criterion 4 - Financing	Are the proposed financing arrangements efficient?	Section 7.4: Funding Strategy
	Detail of individual financing areas.	Section 7.4: Funding Strategy
Criterion 5 - Uncertainty and Risk	How well does the Plan deal with uncertainty and risk?	Section 8.2: Approach to managing risk
	Detail of individual uncertainty area.	Section 8.3: Risk analysis

3 Process

3.1 Overview

This section covers:

- Process for stakeholder consultation and engagement;
- Process for demand forecast;
- Process for setting output goals; and
- Process for investment planning.

3.2 Process for stakeholder consultation and engagement

EKEDC held stakeholder consultation meetings in the three different Circles (East, Central, and West) that make up Eko Disco.

Figure 1: EKEDC team engaging with Customers in Central Circle

Figure 2: Customer in Central Circle proving feedback to EKEDC team

3.2.1 East Circle

The Districts that make up the East Circle are Island, Lekki and Ibeju. We met with customers from these Districts on September 6th, 2019 at Virginrose Resorts, Victoria Island, Lagos. The purpose of the stakeholder engagement was to engage customers to ascertain the key priority areas based on their expectations and also get their views on which areas of our services they believe need urgent attention.

The main issues identified by our customers were billing, metering, poor supply, and faulty transformers. The list of issues is highlighted in Annex A.

3.2.2 Central Circle

The Districts that make up the Central Circle are Ijora, Mushin, Orile and Apapa. We met with customers from these Districts on September 12th, 2019 at the Auditorium of the Nigerian Institute of Medical Research in Yaba, Lagos. The purpose of the stakeholder engagement was to engage customers to ascertain the key priority areas based on their expectations and also get their views on which areas of our services they believe need urgent attention.

The main issues identified by our customers were billing, metering and safety. The list of issues is highlighted in Annex A.

3.2.3 West Circle

The Districts that make up the West Circle are Agbara, Ojo, and Festac. We met with customers from these Districts on September 20th, 2019 at Sunfit Hotel in Festac Town, Lagos. The purpose of the stakeholder engagement was to engage customers to ascertain the key priority areas based on their expectations and also get their views on which areas of our services they believe need urgent attention.

The main issues identified by our customers were on billing and pre-paid meters. The list of issues is highlighted in Annex A.

3.3 Process for demand forecast

In 2018, EKEDC has commissioned Energy Market and Rates Consultants (EMRC) to:

- Review the MYTO % customer load allocations; and
- Compute detailed load demand projections over a 5-year period from 2019 to 2023.

As a basis for projecting load demand through to 2023, we established the simultaneous demand and the non-simultaneous demand at present.

We used hourly feeder time series data at 33 kV to estimate the simultaneous (coincidental) peak load currently met. Non-simultaneous peak estimates unconstrained demand which is the demand that would have occurred if all feeders were permanently energised.

In order to forecast the demand for EKEDC, a population projection analysis was carried out to determine the customer growth trajectory over the next 5 years. This projection was based on the average feeder population growth per tariff class over 2018. These potential customers per tariff class were applied to both 11 kV and 33 kV feeders over the 5-year forecast resulting in customer growth projection.

Furthermore, a dynamic regression model was applied to each feeder on the EKEDC's network to generate its hourly demand using the hourly regression coefficients for each customer tariff category in the baseline year (2018). The dynamic regression model is a linear regression model expressing how demand depends on the number of customers connected in each hour of the dataset. The model is dynamic because the regression coefficients vary over time.

3.4 Process for setting output goals

A four-stage approach was implemented to enable EKEDC arrive at setting its output goals, the goals of which are further elaborated in different sections of the PIP.

Stakeholder Engagement
- Brainstorming
- Receiving feedback from customers in the 3 different circles on priority areas for investment (metering and reliablity)

Bottom-up Gap Analysis
- Assessing Achievements & Challenges on Performance Agreement targets since takeover
- Understanding the demand-supply Gap and infrastructure needs
- Collating Capex and Opex projections for achieving planned initiatives from the different departments

Alignment
- Prioritizing investments in line with feedback from stakeholders
- Projecting ATC&C loss reduction trajectories based on 2 scenarios: MYTO Minor Review Capex and Full Capex

Validation
- Circulating draft PIP for feedback
- Incorporating feedback and finalizing PIP

3.5 Process for investment planning

3.5.1 Process for electricity distribution planning

Our process for planning the expansion of our electricity distribution network was informed by the results of our energy demand study which identified areas where demand-supply gaps existed in our network.

The process involved using an Optimization Model for Network Investments (OMNI) to prioritize the different technical initiatives to ensure that those projects that rank highest in payback potential and impact on loss reduction are given higher priority for implementation.

Refer to Section 5 and Section 6 for further details.

3.5.2 Process for commercial operation planning

EKEDC's process for planning commercial operations involved identifying initiatives that will directly or indirectly reduce commercial and collection losses while allowing us to achieve improved commercial performance.

In terms of process improvement initiatives, the process for selecting software applications for supporting commercial operations and making our work more efficient involves implementing rigorous bid tender and selection processes (for Technical and Commercial evaluation). We will ensure that selected vendors have a track record of successful implementation of the required initiative while also following industry requirements and standards.

3.5.3 Process for meter investment planning

EKEDC's process for meter investment planning involved carrying out a bidding process for potential MAPs which involved evaluating the technical and financial capabilities of the MAPs before selecting the preferred MAPs.

The actual MAP plans are discussed in section 6.

3.5.4 Process for safety investment planning

Health and Safety investment will help EKEDC achieve the following targets:

- Reduce the number of deaths and accidents in our service area to zero.

At Eko Disco, our overall target is zero occupational fatality, injuries and reduction in third-party accidents to As-Low-As-Reasonably-Practicable. Our internal processes to achieving these are as follows:

- Monthly Safety Trainings (simultaneously across the 10 Districts)
- Daily Toolbox talks with all technical staff
- Knowledge Sharing Sessions on key health and safety related issues
- Health and Safety meetings: Quarterly for Safety Committee, Monthly for Safety Officers, Monthly for Safety Champions.
- Robust Risk Assessment for our operational activities
- Hazard Identification (HAZID) -unsafe installations, equipment, powerline right of way encroachment, etc. (Network Monitoring)
- Facility Inspections
- Provision of fit-for-purpose Personal Protective Equipment (PPE) are provided to staff and compliance to its right use.

Adequate supervision has always been a key instrument to achieving our targets, which include spot-checks/unscheduled visitations to Injection Substations, Distribution operations - fault clearing, disconnection activities, new construction (projects), etc.

The actual H&S plans are discussed in section 6.

4 Introducing the Context for this PIP

4.1 Overview

This section covers:

- Introduction to EKEDC;
- Scenarios in this PIP; and
- Strategic objectives.

This chapter provides the information required by NERC in an "introductory chapter".

4.2 Introduction to EKEDC

4.2.1 Vision

To be the leading and customer centric utility in Africa, and to be the preferred choice of all stakeholders.

4.2.2 Mission

Our mission is to empower the quality of lives of our customers, employees, community and other stakeholders through:

1. Reliable power and quality services
2. Work culture of learning and high performance
3. Best technologies, processes and practices
4. High standards of ethics and safety
5. Advocacy of policies for sustainability of sector
6. Responsibility towards community and environment

4.2.3 Overall strategy

In order to achieve our vision and mission, five (5) strategic pillars have been identified to help enhance customer experience and maximize shareholder benefits. They are:

- Reliable power & quality services
- Organizational capability
- Operational excellence
- Safety standards and
- Proactive stakeholder engagement

These strategic pillars are detailed in Section 6.

4.2.4 Business environment 2013-2019

Following the privatization of the distribution companies in November 2013, the Discos have continued to operate in an adverse business environment which has led to limited progress in the performance improvement of the Discos. Some of the factors that have made the business environment very challenging are discussed below.

4.2.4.1 *Lack of cost reflective tariff*

At the time of privatization of the Discos, the Multi Year Tariff Order II (MYTO II) was in effect. However, it became clear during the privatisation process that the key assumptions of the MYTO II (including generation levels, ATC&C losses and customer numbers) were inaccurate and resulted in tariffs that were not cost reflective. Since the true PHCN performance was not known, NERC and BPE agreed that the new owners of the Discos should carry out a study to determine their baseline losses and real customer numbers at the time of privatization, and this would be the basis of a tariff reset.

Despite this commitment, the full cost of the electricity value chain has never been allowed to pass-through to tariffs since privatisation. Table 2 shows a summary of the major events depicting that tariffs have not been cost reflective. Table 25 in Annex B provides a more detailed timeline.

Table 2: Summary timeline of key tariff challenges

Year	Tariff cost reflective?	Events
2013	No.	– Privatisation process recognised that tariff review would be required once true level of ATC&C losses were understood. Interim Rules Period (IRP) introduced to recognise Disco's inability to pay the market until tariffs were cost reflective.

Year	Tariff cost reflective?	Events
2014	No.	– Discos conducted Baseline Losses Studies to determine true levels of ATC&C losses.
2015	No. Only 2 months (February and April) where tariffs were close to cost reflective.	– Commencement of TEM in February 2015. Discos were expected to pay full market invoices from this date. – February 2015 was the start of revised tariffs based on a new tariff model known as MYTO 2.1 which recalculated tariffs based on the results of the Disco's baseline losses study. However, MYTO 2.1 assumed that the Discos has started their loss reduction path in January 2013. This meant that tariffs were not truly cost reflective. – In April 2015, tariffs were amended to strip out collection losses. The removal of collection losses from the ATC&C loss profile led the majority of the Discos to issue notice of Force Majeure under their Performance Agreements in 2015. – Minor reviews not implemented.
2016	No. MDA debts still not resolved. Minor reviews not implemented.	– New MYTO 10-year tariff order from February 2016, reinstated most collection losses but reduced allowed losses by removing Ministries, Departments & Agencies (MDA) debt. The intention was for FGN to pay these historic liabilities and introduce a mechanism to meet future bills. Addresses one of the flaws of MYTO 2.1 by adjusting the assumed first year of loss reduction from 2013 to 2015. – From March 2016, generation dropped dramatically as a result of insurgency, Discos revenue decreased dramatically as a result of less power to sell. – From May 2016, foreign exchange weakened considerably, and PPA indexation meant cost of generation jumped from 12 N/kWh to 18 N/kWh. – Six monthly minor reviews in June and December were not implemented, these should have incorporated the impact of the generation level and foreign exchange in retail tariffs.
2017	No.	– Six monthly minor reviews in June and December were not implemented in tariffs. – MDA payments were still not been resolved.
2018	No.	– Tariff freeze in January 2018, when NERC instructed the Discos to freeze their tariff at the 2017 level. – Six monthly minor reviews in June and December were not implemented. – MDA payments were still not been resolved.
2019	No.	– Six monthly minor review in June was implemented, but revised tariffs were delayed until January 2020, so tariff remains not cost-reflective. – MDA payments have still not been resolved.

The NERC tariff review process was designed with the intent to undertake major reviews every five years, in addition to minor reviews every six months to adjust tariffs for changes to the gas price, the foreign exchange rate, generation output, and inflation. The minor reviews have not been implemented since the release of MYTO 2015 and as a result, tariffs continue to slide further below cost-reflective levels, undermining the Discos ability to fulfil their obligations under the Performance Agreements and Vesting Contract(s).

There is inadequate CAPEX provision in the MYTO model for the ambitious performance improvement required. It is hoped that this PIP will form the basis for revised CAPEX.

The lack of a cost reflective tariff has resulted in accrued liabilities to NBET and MO and means that Discos are unable to raise finance for performance improvement.

4.2.4.2 *Eligible Customers*

The eligible customer regulations will allow large ("eligible") customers to purchase power directly from generating companies. Large customers are a major source of revenue for Discos due to their ability and willingness to pay, and heavy cross subsidies between tariff classes. Although a Competition Transition Charge and Distribution Use of System Charges were intended to address the financial impact of losing these customers, they have not yet been put in place.

Under the regulations, eligible customers are required to apply to NERC for eligible customer status, with their proposed supplier. NERC has not officially granted eligible customer status to any customers yet, but eligible customers are still taking advantage of this new policy. Since 2018, Discos have been reporting that some transmission-connected customers are defecting without approval from NERC. We are aware of at least six cases across different Discos in which these customers are refusing access to the Disco to read meters and invoice them for demand. If the customers do have a PPA with a provider to supply them power, the Market Operator would need to be aware of it and account for it in Settlement Statements.

4.2.4.3 *Customer perceptions*

The lack of liquidity has resulted in an adversarial public discussion, with various participants blaming one another. This has reinforced negative customer perceptions, and together with a perception of electricity as a public good that should be consumed freely, has led to low willingness to pay, energy theft, meter bypass and vandalization of power assets. This is exacerbated by insecurity in some areas of operations.

The sector should try to present a more unified vision in the future, to support customer confidence and encourage customers to pay their bills.

4.2.4.4 Policy and regulatory uncertainty

The regulatory framework in Nigeria has changed very rapidly since 2013. There is a need for regulatory stability, and for regulations to be applied consistently. We recommend:

- The MYTO minor reviews should be implemented in tariffs every six months, without delay;
- Conditions precedent should be met – the conditions for the TEM were not met before it was declared. This materially contributed to the failure of participants to meet their obligations;
- New regulations such as Eligible Customers and Meter Asset Providers (and in the future potentially Franchising) have increased the number of players in the sector, but it is not yet clear that they will increase investment unless the resulting risks are reduced;
- Proposed regulations, in particular the Business Continuity Regulations, may make it impossible to raise finance in the sector;
- Transparency is essential – instructions by NERC to specific market players (such as the MO or NBET) should be made public and consulted on – as they may result in changes to market charges that are not reflected in retail tariffs; and
- The pace of regulatory change should be slowed, and full regulatory impact assessment conducted, so that new regulations do not conflict with existing regulations or result in unintended consequences, such as worsening the ability of market participants to raise capital or reducing the liquidity of the sector.

4.2.4.5 Other issues

The Other issues/challenges we face include:

- Absence of load forecast by the Transmission Service Provider.
- NERC's position on the years of loss reduction trajectory. We believe that 2015 and 2016 should be classified as Force Majeure years in addition to 2017 and 2018 that NERC have already agreed to.
- Power procurement initiatives – Regulatory discrimination in allowable energy Tariff outside MYTO for new projects.
- NBET's Punitive Interest charges.
- Political agitations resulting in gas pipeline vandalization in the Niger-Delta.

- Litigations.
- Market Illiquidity: Revenue shortfall and Difficulty in attracting local & foreign investment.
- Legacy Issues: dilapidated infrastructure; inaccurate data used for computing revenue requirement for NEMSF

4.2.5 Description of achievements 2013-2019

Despite the challenging business environment, EKEDC has recorded several achievements from inception to date.

4.2.5.1 *2013 Achievements*

100% satisfactory customer complaint resolution.

4.2.5.2 *2014 Achievements*

100% satisfactory customer complaint resolution

Organized and paid for 13 staff capacity development programmes both local and foreign with 461 participants.

4.2.5.3 *2015 Achievements*

Successfully conducted embedded generation tender process in 2015, producing 10 projects for the generation of 458MW.

92% satisfactory customer resolution complaint in a force majeure year

Organized and paid for 58 staff capacity development programmes both local and foreign with 259 participants.

4.2.5.4 *2016 Achievements*

Successfully entered bilateral power procurement agreement with Egbin Power Plc and Paras Generation Ltd for 100MW & 60MW power supply respectively.

94.7% satisfactory customer complaint resolution in a force majeure year.

Funded 21 staff capacity development programmes both local and foreign with 1812 participants.

4.2.5.5 *2017 Achievements*

96.9% Satisfactory customer complaint resolution

Organized and paid for 76 staff capacity development programmes both local and foreign with 1390 participants.

4.2.5.6 *2018 Achievements*

The Human Resource Integrated Software (HRIS) became fully operational in 2018

92.2% Satisfactory customer complaint resolution despite 84% increase in customer complaints.

Organized and paid for 129 staff capacity development programmes, both local and foreign with 1852 participants.

4.2.5.7 *2019 Achievements*

Partial implementation of the Supervisory Control and Data Acquisition (SCADA) system.

Full implementation of the Work Force Management (WFM) software for process automation.

Organized and paid for 83 staff capacity development programmes, both local and foreign with 1332 participants till date.

4.3 Scenarios in this PIP

There are two scenarios considered in this PIP:

- **"Regulatory Allowed Capex" Scenario** – The Capex and Opex requirements as well as end-user tariffs are as stipulated in the June 2019 Minor Review MYTO Model. In this scenario, EKEDC's achievable loss reduction trajectory from 2020 to 2024 is not as aggressive as NERC envisages in the Minor Review Model;
- **"EKEDC Required Capex" Scenario** – The Capex and Opex requirement are higher and reflect what is needed, at cost-reflective tariffs, to achieve loss reduction (more than in the "Regulatory Allowed Capex scenario") which will still not be as aggressive as NERC envisages in the Minor Review Model.

In the "Regulatory Allowed Capex" scenario, it will not be possible to achieve the full ATC&C loss reduction improvement. The "EKEDC Required Capex" scenario allows more ambitious levels of loss reduction and performance against other outputs.

Cost-reflective average tariffs and payments to the market (expected % payment to MO and NBET) are outputs of both scenarios.

The differences between the two scenarios are summarised in Table 3.

Table 3: Summary of the two scenarios

Assumption	"Regulatory Allowed Capex" scenario	"EKEDC Required Capex" scenario	Detailed description
Demand	Consistent demand scenario		Section 4.3.1
Generation levels	Dependent on scenario		Section 4.3.2
Generation tariffs	Increasing with foreign exchange; increasing due to additional capacity charges once PPAs are activated		Section 4.3.2
Tariffs	MYTO tariffs from Jan 2020 with 2020 as year 1 of ATC&C loss reduction	Cost reflective tariff from Jan 2020 with 2020 as year 1 of ATC&C loss reduction	Section 7
Allowed CAPEX	MYTO levels	EKEDC proposed levels in 2020-2024	Section 7
Access to capital	70% debt; 30% from free cash flow	70% debt; 30% from free cash flow	Section 7
Actual ATC&C	ATC&C loss reduction trajectory achievable within the limits of NERC's Capex	ATC&C loss reduction trajectory achievable within the limits of Full Capex	Section 7

4.3.1 Demand forecast

One of problems faced by EKEDC is that grid power supply shortages result in load management or shedding and the disconnection of feeder supply. This consequently means only parts of the network are energised at any point in time – which makes the underlying total load difficult to determine. The total load recorded from energized feeders can thus be described as the constrained demand due to load shedding. To combat this issue of sparseness in the recorded demand data, EKEDC modelled the time series of feeder loads using a "structural model". The Structural Model approach calculates the Unsuppressed Demand by forecasting the demand that would otherwise exist on the disconnected feeders if they were connected, which can be described as the unconstrained demand.

In 2018, the constrained simultaneous peak demand (highest recorded summation of concurrent readings on feeders) for EKEDC was 527MW, with a total constrained energy supply of 2.2TWh. This consumption was driven by a customer population of 490,802 customers. The unconstrained simultaneous peak demand was 870MW, with an expected unconstrained total energy supplied of 5.4TWh. The suppressed simultaneous demand of 343MW was due to network and supply constraints described above.

The 2019 to 2024 demand projections are based on the 2018 base year data. The application of a combination of a structural and a dynamic forecasting model to the hourly load data for EKEDC, and the customer population was used to determine the current and projected unconstrained demand for EKEDC. Over the forecast period (2019 to 2024), the customer population is projected to increase by 103,060 customers to 593,862 customers by 2024, representing an increase of 21% over the forecast period.

The demand projections for 2019 reveals a non-simultaneous peak demand of 1,139MW with energy supplied of 5.0TWh. In 2024, the non-simultaneous peak demand is expected to increase to 1,346MW with a supplied energy of 6.5TWh – see Table 4. This gives a non-simultaneous demand increase of 207MW (a percentage increase of 18.17%) over the forecast period. This translates to an unsuppressed energy consumption increase of 19.51%, from 5,442GWh/year in 2019 to 6,502GWh/year in 2024 - see Table 4. The network infrastructure analysis presented here is based on this demand projection for customers served by EKEDC.

Table 4: EKEDC Demand Projection 2019-2024

Year	Simultaneous Peak Demand (MW)	Non-Simultaneous Peak Demand (MW)	Energy (GWh)
2019	870	1139	5,442
2020	838	1174	5,656
2021	868	1210	5,855
2022	899	1251	6,062
2023	931	1297	6,277
2024	964	1346	6,502

The estimate of demand forecast 2019-2024 is linked to how quickly EKEDC can connect the currently unsuppressed demand and projected demand growth. The expected total demand is shown in Figure 3.

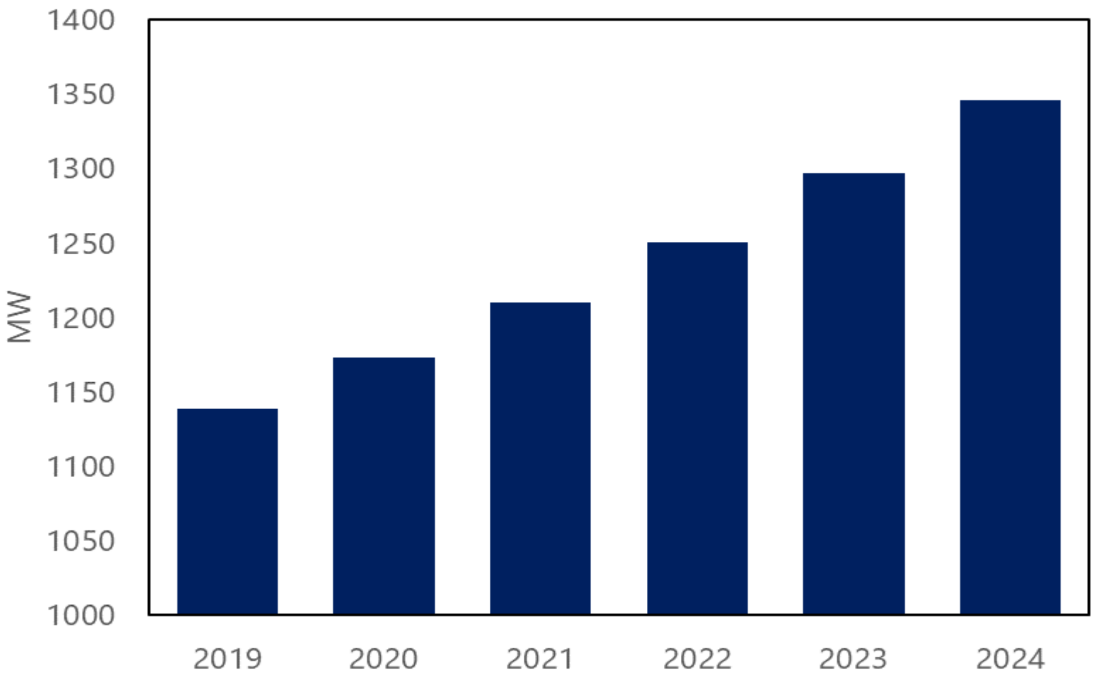


Figure 3: Expected peak load demand (MW) in EKEDC franchise zone 2019-2024

4.3.2 Generation

4.3.2.1 Energy generation

Energy generation is assumed to gradually improve in line with MYTO projections as shown below Table 5.

Table 5: Eko Disco forecast of Energy Received from TCN

(GWh)	2019	2020	2021	2022	2023	2024
Current level	3,050	3,050	3,050	3,050	3,050	3,050
Regulatory Allowed Capex Scenario (MYTO projection)		4,294	4,684	5,216	5,628	5,950
EKEDC Required Capex Scenario (Higher-than-MYTO projection)		4,294	4,730	5,168	5,606	6,044

4.3.2.2 Generation capacity

Although energy generation is assumed to be constant, generation capacity is assumed to increase from January 2020, as PPAs will be activated. This means that Gencos who currently do not have active PPAs will be able to charge for their capacity that is available but not used. This could potentially increase the cost of energy received by EKEDC.

- Generation capacity charges for those Gencos with active PPAs in 2019: Omotosho, Olorunsogo, Agip, Shell and Azura): Capacity charges were calculated based on the average capacity factor for each Genco in the months January to May 2019. These are 66%, 84%, 28%, 43% and 64% respectively
- Generation capacity charges for those Gencos without active PPA's in 2019: Using data on the daily energy sent out from stations and the daily available capacity from the TCN daily operational reports from the start of 2013 to the end of May 2019, an average capacity factor of 54% was calculated. The average monthly energy in MWhs and the capacity factor of 54% were used to project the capacity charges expected from the remaining Gencos once their PPAs are activated in 2020.

4.4 Outputs: strategic objectives

4.4.1 Performance Agreement

Table 6: Performance Agreement metrics

No.	Key performance index	Measurement criteria defined in privatisation	Annual Performance					
			Base line	Y1	Y2	Y3	Y4	Y5
1	Loss reduction	ATC&C (%)	35.0	25.5	22.4	17.1	14.3	13.4
2	Reliability/ availability	Number of customer Interruptions (#)		155	155	155	155	155
3	Metering	Number of new consumer meters installed	69753	124398	124398	124398	124398	124398
4	New connection/ network expansion	Number of new customer connections	49864	87916	87916	87916	87916	87916

4.4.2 Current service deficits

Despite earlier challenges with data, the table below highlights our performance now compared to handover.

Table 7: Current service levels

No.	Key performance index	Measurement criteria defined in privatisation	Annual Performance		
			2013 (handover)	2018	Six months to June 2019
1	Loss reduction	ATC&C (%)	35.17 (as at 2015)	28.22	29.34
2	Reliability/availability	Number of customer Interruptions (#)	12181 (as at 2016)	11622	9129
3	Metering	Number of new consumer meters installed	2887	16599	12905
4	New connection/ network expansion	Number of new customer connections	2506	42638	5089
5	Customer satisfaction	Customer complaint resolution		92.2%	98%
6	Safety	Number of Health and Safety reports	13	9	1
7	Social responsibility	Not defined – propose safety is the key index in near term			
8	Remittance	Market remittance to NBET and MO (%)	83 (in 2015)	43	

4.4.3 Goals 2020-2024

Target outputs are dependent on the modelling scenario, on tariff levels and allowed CAPEX. The target outputs assume all the allowed CAPEX is funded and spent in each scenario.

However, if actual financing achieved is insufficient to meet the required CAPEX in either scenario, the achievable outputs will defer from the target outputs.

4.4.3.1 *Target outputs in "Regulatory Allowed Capex" scenario*

The outputs here are based on a "Regulatory Allowed Capex" scenario whereby tariff assumptions are based on the latest minor review (June 2019).

Table 8: Target service levels ("outputs") in "Regulatory Allowed Capex"

No.	Key performance index	Measurement criteria defined in privatisation	Annual Performance					
			Base line	2020	2021	2022	2023	2024
1	Loss reduction	ATC&C (%)		26.63%	25.63%	24.63%	23.63%	22.63%
2	Remittance	Market remittance to NBET and MO	<100%	<100%	<100%	<100%	<100%	<100%

4.4.3.2 *Target outputs in "EKEDC Required Capex" scenario*

The "EKEDC Required Capex" scenario is based on a cost-reflective tariff, which recognises that tariffs have not permitted loss reduction to date (end of 2020 is treated as year 1 of ATC&C loss reduction) and allowing full required CAPEX to achieve EKEDC's proposed loss reduction and other output targets.

Table 9: Target service levels ("outputs") in "EKEDC Required Capex" scenario

No.	Key performance index	Measurement criteria defined in privatisation	Annual Performance					
			Base line	2020	2021	2022	2023	2024
1	Loss reduction	ATC&C (%)	26.63	26.63	24.63	22.63	20.63	18.63
2	Reliability/ availability	Number of customer Interruptions (#)	11622	11040	10459	9878	9298	8717
3	Metering	Number of new consumer meters installed	45,000	107,000	52,000	As needed	As needed	As needed
4	New connection/ network expansion	Number of new customer connections	45,000	107,000	52,000	As needed	As needed	As needed
5	Customer satisfaction	Customer complaint resolution	98%	98%	98%	98%	98%	98%
6	Safety	Proposed number of deaths and number of accidents	0	0	0	0	0	0
7	Social responsibility	Number of CSR initiatives	>1	>1	>1	>1	>1	>1
8	Remittance	Market remittance to NBET and MO (%)		100	100	100	100	100

4.4.4 Projected investment

In the "Regulatory Allowed Capex" scenario, we assume EKEDC's CAPEX is limited by levels allowed in MYTO.

In the "EKEDC Required Capex" scenario (cost reflective tariff with higher than MYTO CAPEX), we assume NERC will allow the full CAPEX levels we propose for 2020-2024.

Table 10: Assumed CAPEX constraints

Naira million	2020	2021	2022	2023	2024
Allowed in MYTO Minor Review (June19)	11,656	11,656	14,570	14,570	14,570
Projected in this PIP (full proposed CAPEX above NERC limit)	21,650	13,240	14,570	14,570	14,570

4.4.5 Justification for EKEDC's goals

We have aligned our goals with both the federal and state governments' objective of economic recovery tied to measurable improvements in the power sector. By taking in the feedback from our customers and reviewing our ATC&C loss reduction projections, we believe we have been better positioned to deliver more reliable power while satisfying our customers. However, our ability to deliver our goals may be affected by the challenges of raising the necessary finance to invest in improving our aging infrastructure. Coupled with obvious impact of unresolved MDA debt and recovery mechanism for future energy bills as a going concern as well as unforeseeable constraint in implementation of major corrective and infrastructural project targeted towards ATC & C loss reduction arising from force majeure situation could constitute a draw back in achieving beyond expectation.

Refer to the process in Section 3

5 Infrastructure Review

5.1 Overview

This section covers:

- Current state of infrastructure;
- Review of current limitations; and
- Implications of the infrastructure review.

5.2 Current state of infrastructure

Eko Electricity Distribution Company (EKEDC) covers the license area of southern part of Lagos state and Agbara in Ogun state. The southern Lagos State comprises Ojo, Festac, Ijora, Mushin, Orile, Apapa, Lekki, and Ibeju while the Lagos Island covers Ajele areas. The distribution network, operated at three voltage levels, serves major residential, commercial and industrial hubs within the state, covering 10 Districts within its network.

There are 387 feeders in the EKEDC Network; 300 - 11kV feeders and 87 - 33kV feeders (see Table 11). There are 104 - 33/11kV transformers and 42 - 132/33kV transformers.

Table 11: EKEDC Distribution Network

s/n	Distribution Network	Number
1.	Districts	10
2.	33kV feeders	87
3.	11kV feeders	300
4.	132/33kV transformers	42
5.	33/11kV transformers	104

The EKEDC's single line diagram (SLD) shows the network configuration and the flow of energy from Transmission Company of Nigeria (TCN) stations to 33kV feeders, to injection substations and then to 11kV feeders as shown in Figure 4 below.

The EKEDC network is supplied from 12 TCN transmission stations with a combined nameplate capacity of 2500MVA. The 87 - 33kV feeders, comprising 50 underground and 37 overhead feeders, supply 104 - 33/11kV power transformers across 40 injection substations. With a total

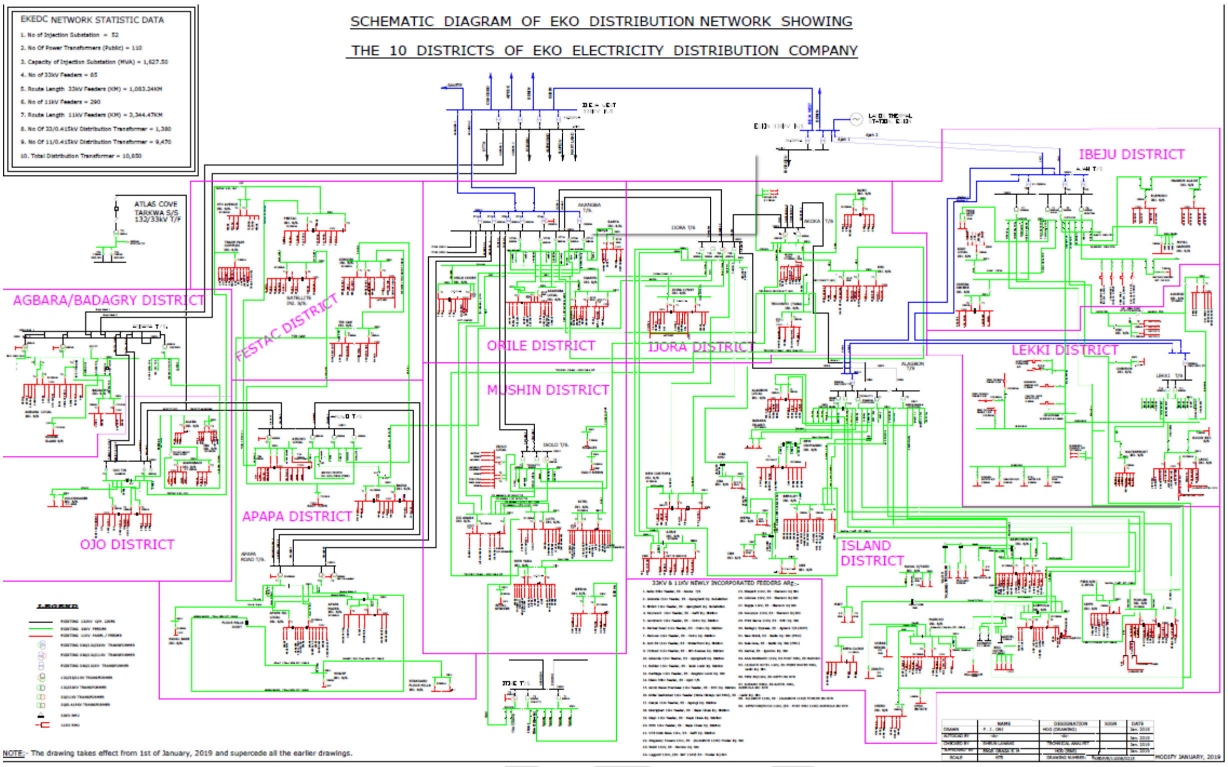
33/11kV power transformer transformation capacity of 1537.5MVA, 300 11kV feeders are energized for onward downstream power distribution.

There are 9,079 - 11/0.415kV distribution transformers and 1601 - 33/0.415kV distribution transformers served by EKEDC. The total transformational capacity of the 11/0.415kV and the 33/0.415kV distribution transformers are 3363.3MVA and 662.3MVA respectively. The route length for the 33kV and 11kV feeders are 948.7km, and 3,067.8km respectively, resulting in a total route length of 4,016.5km – see Table 12.

Table 12: EKEDC Network Configuration

S/N	Network Parameters	Unit	Total
1.	Transmission Substations	Count	12
2.	132/33kV transformers	Count	42
3.	Injection Substation	Count	40
4.	33/11KV Transformers	Count	104
5.	33/0.415kV Transformers	Count	1,601
6.	11/0.415kV Transformers	Count	9,079
7.	Installed Transmission Capacity	MVA	1137.5
8.	Installed Transformer Capacity (33/11kV)	MVA	2,500
9.	Installed Transformer Capacity (33/0.415kV)	MVA	1,537.5
10.	Installed Transformer Capacity (11/0.415 kV)	MVA	662.3
11.	Route Length 33KV Feeders	MVA	3,363.3
12.	Route Length 11KV Feeders	ckt km	948.7
13.	Route Length 415V Feeders	ckt km	3,067.8

Figure 4: EKEDC Single Line Diagram



Information on our asset inventory is provided in Annex F.

5.3 Review of current limitations

5.3.1 Technical network constraints

This analysis uses the demand forecast discussed in section 4.3.1.

Tables of the network constraints analysis are provided in Annex D.

5.3.1.1 *11kV Feeders Load Analysis*

Table 26 shows the 11kV transformation capacity analysis and highlights the feeders where additional transformation capacity is required to prevent overloads on the network's distribution transformers. EKEDC has a combined transformation capacity of 4,025.4MVA. The 2019 base year reveals additional transformation capacity of 413MVA and rising to 522MVA in 2024 if no investments are made. The five most constrained feeders with limited transformation capacity include National Hall Local, Babalola Express, Akarigberi, Psychatric, and Palm Shopping Mall.

5.3.1.2 *33kV Backbone System Unconstrained Analysis*

The loading analysis of the injection substations (ISS) supplied by EKEDC are captured in Table 27 for the base year, 2019 and final year, 2024. In the 2019 demand analysis, 34 transformers are recorded in the network to be overloaded (at 80% loading tolerance). The five most constrained 33/11kV transformers include Ojo Local T1 15MVA, Anifowoshe T3A 15MVA, NRC T2 15MVA, Alagbon Local T2 15MVA, and Ojo Local T3 15MVA. In the 2024 loading analysis, it is observed that the demand growth to be experienced in the network will result in overloads in 46 transformers across EKEDC injection substations if no investments are made.

5.3.1.3 *33kV Feeders Load Analysis*

Table 28 shows the loading analysis of the 33kV feeders and the amount in MVA each feeder is overloaded by. With an assumed capacity of 26.2MVA for each feeder, in the 2019 load analysis, 10 of the 87 33kV (11%) feeders are overloaded, the most significant of which is Oko Afo 33kV feeder by 35MVA. Other highly constrained feeders include Badagry 33, Festac 1 (Ojo), and Agbara 33. The total feeder exceedance in 2019 is 109MVA.

By 2024, it is expected that the number of overloaded feeders increases to 15 (50%), if no investments are made, with a total feeder exceedance of 191MVA. In 2024, the most constrained feeders are expected to be Oko Afo, Badagry 33, Festac 1 (Ojo), Ibeju and Waterfront.

5.3.1.4 *Projected Load by TCN Station*

The forecasting methodology applied in this study was performed at the 11kV and 33kV feeder level, thereby generating a demand forecast for each feeder. A summary of the 33kV demand forecast and the TCN substation demand forecast are presented in this report – see Figure 5. The projected load summarised at TCN substation level is presented in Table 29.

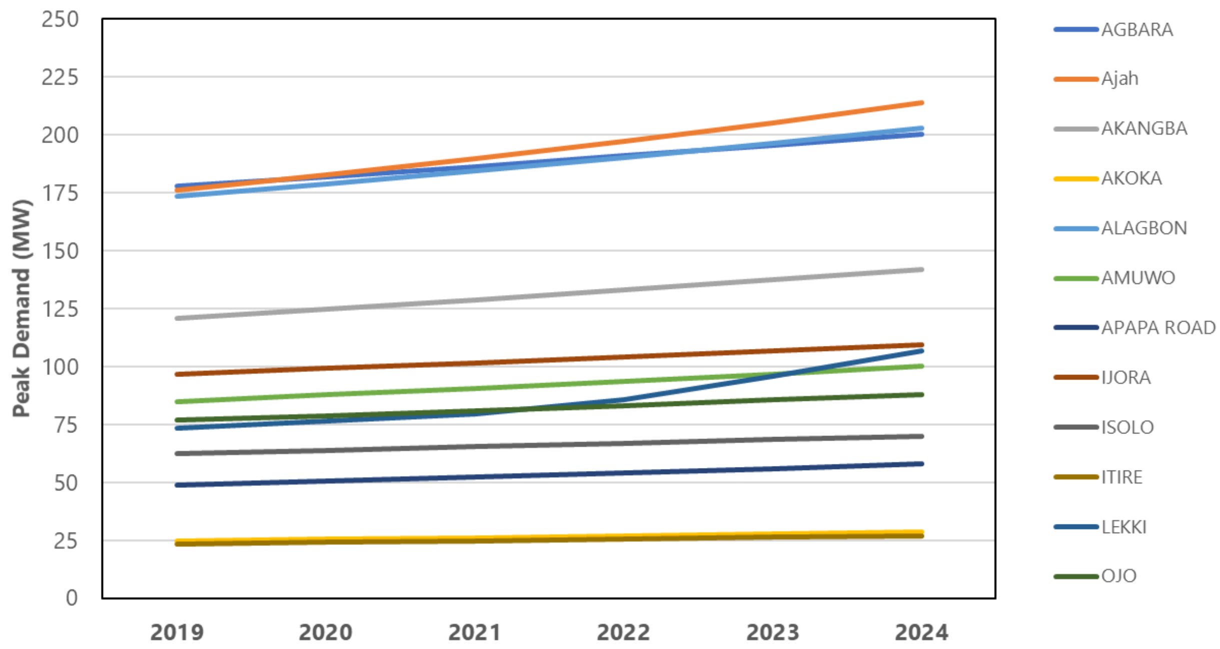


Figure 5: Load Forecast by TCN Stations

While the total nameplate capacity across the TCN stations supplying EKEDC is 2,525MVA, however, the total operational capacity, i.e., the total loading allowed on the transformers, is 1,819MW.

With the 2019 peak demand of 1,139MW, the current TCN operational capacity is adequate to supply EKEDC power, however, the disaggregate values of peak demand downstream in the TCN stations reveal this operational capacity is insufficient. Across the 12 TCN stations that supply the EKEDC franchise, by nameplate capacity (2,525MVA) there is adequate capacity to meet the peak demand in 2019 and 2024 in 9 stations.

However, by operational capacity (1,819MW), there is capacity to meet demand in 9 stations in 2019, and this reduces to 8 by 2024 if no TCN investments are made. Ajah, Akoka, Ijora and Itire TCN stations with a capacities 690MVA, 105MVA, 190MVA and 120MVA respectively have more capacities than their downstream connected distribution transformation capacities.

Across the substations, Agbara substation has the current highest peak demand of 178MW and is expected to increase to 200MW by 2024. While EKEDC has a distribution transformer capacity of 187MVA to serve this demand, the Agbara TCN station with a nameplate capacity of 100MVA, is operationally limited to 65MW. The operational limit of 65MW at the Agbara TCN station causes downstream supply constraints as 113MW of current peak demand cannot be served. The largest percentage increase in demand over the period occurs at the Lekki TCN station, with a 46% increase from 73MW to 107MW.

The total current distribution transformation capacity connected to Lekki TCN station is 340MVA, comprising 811 11kV/415V transformers, however, the Lekki TCN station with a nameplate capacity of 165MVA, is operated at just 119MW.

The projected constrained TCN stations using transformer operational capacity in 2019 and 2024 are Ajah, Akangba, Akoka, Alagbon, Ijora, Itire, Lekki, and Ojo if no investments are made – see Figure 6. The demand projection impact on these TCN stations are limited to EKEDC load only. The analysis does not include the 132kV eligible customer demand.

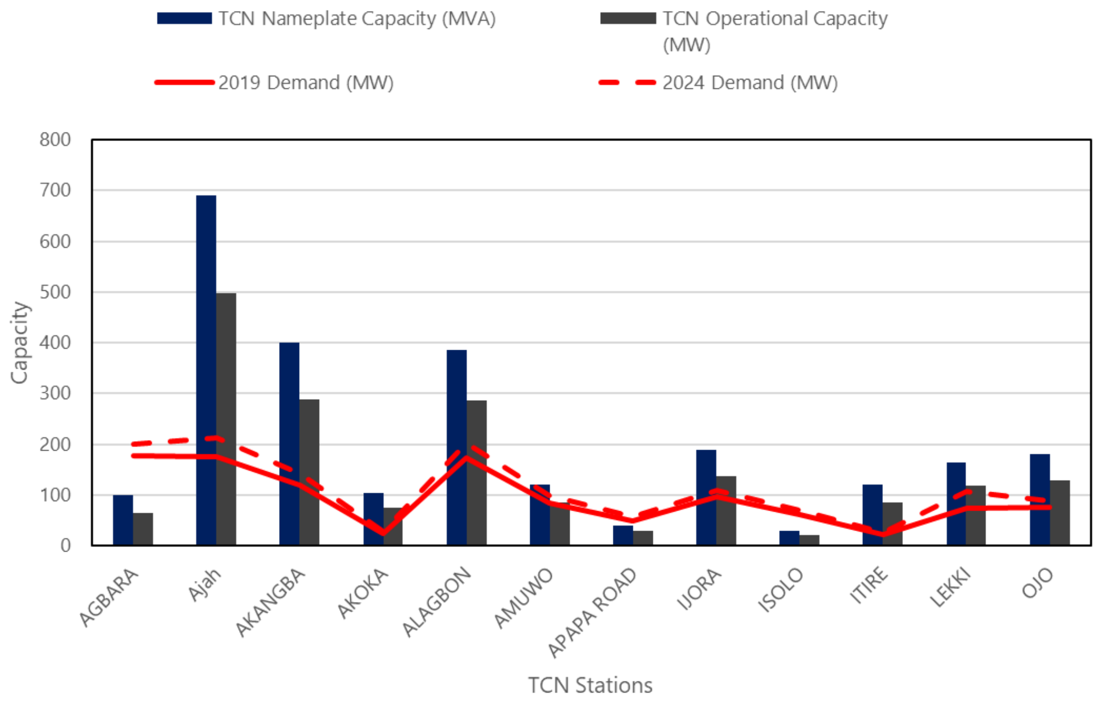


Figure 6: Demand Forecast (2019 & 2024) and TCN Station Capacity

5.3.2 Aging infrastructure

The reliability of electrical power supply is amongst the conditions that inform aging analysis at EKEDC. Reliability depends in part on the conditions of the distribution infrastructure involved, and in part on its source of supply of energy. Its value to customers may be capitalised into the value of the company.

We use an aging analysis approach, comparing initial cost of purchase to its net book value to test the reliability offered by distribution infrastructure. An estimate of the remaining useful life of the infrastructure against the initial cost is computed, therefore showing the reliability.

Below is a summary showing the total cost of purchase of our plant and machinery (in red) with the present state as at today (in blue). Looking at the aging analysis, we categorized the plant and machinery into the useful life remaining (in years), their initial cost on purchase and its book value as at today.

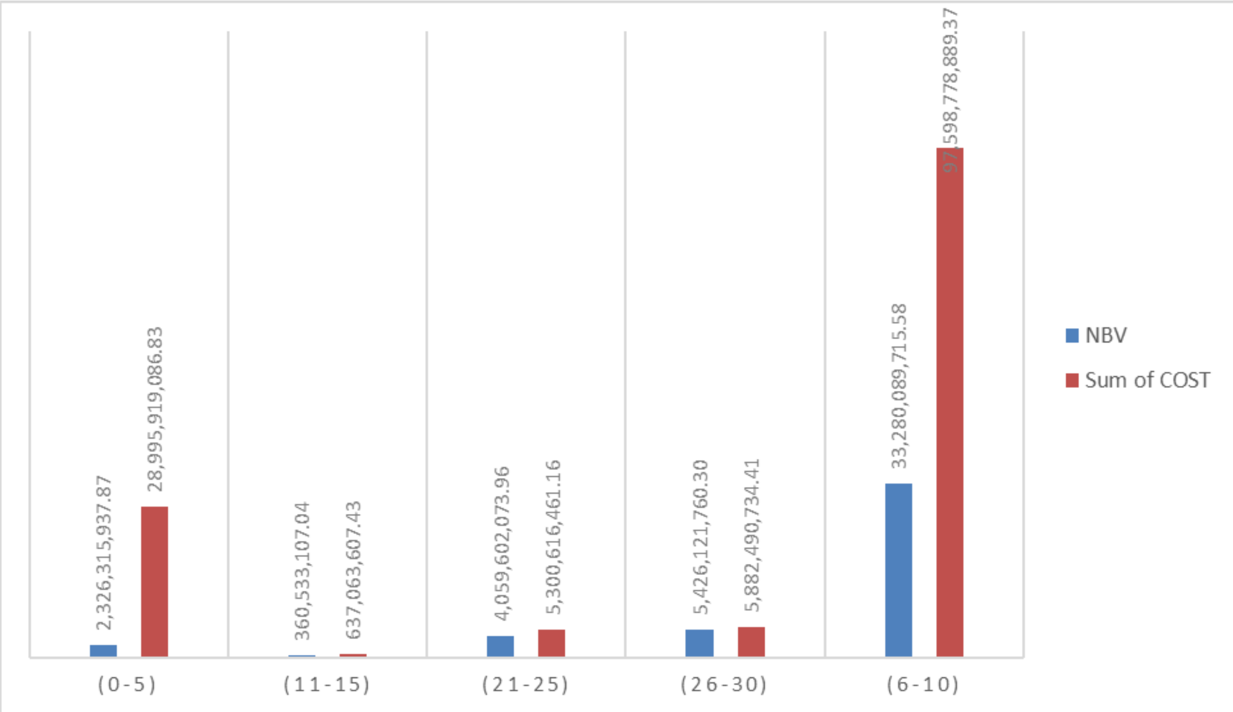


Figure 7: Aging infrastructure analysis

In the graph above, the plant with remaining useful life of 5years and below were purchased at ₦28.9bn but has a net book value of ₦2.34bn. The aging categorized between 11-15 years were purchased at ₦637m, but its net book value is ₦360m, 21-25 years cost ₦5.3bn now has a net book value of ₦4.05bn, 26-30 years present lifespan worth ₦5.4bn from an initial purchase cost of ₦5.8bn. The Plant and Machinery with a remaining lifespan of 6-10 years and a net book value of ₦33.2bn was initially purchased at ₦97.5bn.

5.3.3 Customer enumeration

To support efforts in regularizing illegal connections, EKEDC engaged 4 different consultants to assist with customer enumeration in different districts. The enumeration efforts have been yielding results as we have been able to grow our customer base by 51,600 customers as at August 30th, 2019. We have presently achieved 82% of our kick-off enumeration target.

Table 13: EKEDC Network Configuration

EKO ELECTRICITY DISTRIBUTION PLC

SUMMARY OF UPLOADED ENUMERATED DATA

S/N	DISTRICT (Coverage Area)	CONSULTANT	POPULATION			ACCEPTED DATA		WORK ORDER			TOTAL	% Done Against KICKOFF	Rating
			EKO CUSTOMER BASE AS AT KICKOFF	CURRENT CUSTOMER BASE	CUSTOMER GROWTH DUE TO ENUMERATION EXERCISE	ENUMERATED	ENUMERATED + TREATED WORK ORDER	OPEN WORK ORDER	Submited	Treated			
1	MUSHIN	POWERCAP	52,757	55,265	2,508	33,600	47,622	6,621	20,643	14,022	54,243	102.8%	1st
2	OJO	HAFMANI	50,277	56,518	6,241	30,773	44,018	6,532	19,777	13,245	50,550	100.5%	2nd
3	AGBARA	POLARIS DIGITECH	59,078	72,754	13,676	32,808	49,608	8,559	25,359	16,800	58,167	98.5%	3rd
4	ORILE	TURBO	31,178	33,133	1,955	29,969	30,862	0	893	893	30,862	99.0%	4th
5	IBEJU	HAFMANI	54,821	65,398	10,577	31,527	36,982	12,959	18,414	5,455	49,941	91.1%	5th
6	LEKKI	HAFMANI	24,043	35,992	11,949	15,168	18,619	2,037	5,488	3,451	20,656	85.9%	6th
7	ISLANDS	POLARIS DIGITECH	38,875	38,019	-856	26,599	31,156	1,232	5,789	4,557	32,388	83.3%	7th
8	APAPA	POWERCAP	43,108	41,330	-1,778	26,904	27,605	187	888	701	27,792	64.5%	8th
9	FESTAC	POWERCAP	50,449	53,236	2,787	23,740	24,037	-9	288	297	24,028	47.6%	9th
10	IJORA	TURBO	45,346	49,887	4,541	20,462	20,903	0	441	441	20,903	46.1%	10th
			449,932	501,532	51,600	271,550	331,412	38,118	97,980	59,862	369,530	82%	

5.3.4 Customer metering gaps

As at June 2019, there are 501,028 customers in EKEDC network. The table below summarizes the current status of metering.

Table 14: Breakdown of metered customers

Customer Number Breakdown	**Total**	**Prepaid**	**Postpaid**
Residential	415,088	202,730	212,358
Commercial	84,972	24,571	60,401
Industrial	468	-	468
Street Light	66	11	55
MDAs	434	-	434
Classification by Demand			
MD Customers	8,307		8,307
Non-MD Customers	492,721	227,312	265,409
Metered Customers			
Residential	214,081	202,730	11,351
Commercial	33,952	24,571	9,381
Industrial	193	-	193
Street Light	49	11	38
MDAs	57	-	57
Metered Customers by Demand			
MD Customers	7,537		7,537
Non-MD Customers	240,795	227,312	13,483

Table 15: EKEDC MAP Metering Plan

	MAP 1	MAP 2	MAP 3	MAP 4	MAP 5	MAP 6	MAP 7
MAP Name	*Mojec Int*	*IRL*	*Tubor*	*Bendoriks*	*Gospell*	*Armese*	*CIG*
No. contracted meters	140,000	10,000	10,000	10,000	14,000	10,000	10,000
Metering period	24	24	24	24	24	24	24
Annual Target							
2019	29000	2,500	2,500	2,500	3,000	2,500	2,500
2020	70,000	6,000	6,000	6,000	7,200	6,000	6,000
2021	41,000	1,500	1,500	1,500	3,800	1,500	1,500

As at September 2019, there are 7 MAPs as highlighted in the table above. The total contracted number of meters to be provided by these MAPs in 24 months is 204,000. The expected average number of meters to be installed by each MAP is 8,500 meters a month.

5.3.5 Network metering gaps

Table 16 provides a network metering gap analysis for Feeders, DTs, etc.

Table 16: Review of metering gaps

Metering	Priority assigned by NERC in PIP Guidelines	Current situation	EKEDC desired implementation date
Bulk metering (market interface)	Very high priority	Completely metered	2020 – 2024
MDA metering	Very high priority	MDA KCG, 95% metered	2020
Network (feeder) metering	Not assigned	274 metered out of 286	2020
DT Metering	Not assigned	1232 metered out of 5015	2022

5.3.6 IT management gaps

Table 17provides the status of all the management systems required by NERC and those identified by EKEDC.

Table 17: Review of IT management system gaps

Management system	Priority assigned by NERC in PIP Guidelines	Current situation	EKEDC desired implementation date
Incidents Recording and Management System (IRMS)	Very high priority	In place	N/A
Commercial Management System (CMS)	High priority	In place	N/A
Enterprise Resource Planning (ERP) information system	High priority	Implementation underway	2020
Geographical Information System (GIS) mapping of customers and network assets	High priority	In place	N/A
Supervisory Control and Data Acquisition System (SCADA)	High priority	In place. SCADA has been implemented for 14 out of 52 substations. Remaining 38 will be implemented by 2020 Priority is HIGH.	Remaining 38 will be implemented by 2020
Works Management System (WMS)	Medium priority	In place	N/A

5.4 Ongoing Programs

As part of efforts to improve the quality of power supply and satisfy our customers, we have embarked on several ongoing programs. Majority of them are targeted at ensuring reliability and automation of distribution.

The list of some of our ongoing programs is in Annex H.

5.5 Implications of the infrastructure review

There has been a prolonged period of underinvestment in the distribution networks in Nigeria. In November 2013, EKEDC inherited networks from PHCN that had received minimal investment for many decades. In some cases, this was simply emergency investment to maintain supply, or expansion based on political rather than economic drivers.

Much investment is needed to turn EKEDC into a modern distribution company.

In developing this PIP, EKEDC has prioritised investments that are aligned with our customer desires to best deliver the outputs given current liquidity constraints. The process for investment planning was discussed in section 3.5. The output goals are defined in section ▪.

Resulting infrastructure investment plan is in section 6.

6 Detailed Program Plans

6.1 Overview

This section covers:

- Delivering outputs efficiently;
- Reliable Power and Quality Services;
- Organizational Capability;
- Operating Excellence;
- Safety Standards;
- Proactive Stakeholder Engagement; and
- Innovative Strategies for Different Areas.

6.2 Delivering outputs efficiently

In order to efficiently deliver outputs in the PIP, we had to ensure that our internally prioritized initiatives were aligned with the feedback received from our stakeholders. The issues that were priority for our stakeholders bothered on metering and power supply availability/reliability which both coincide with our priority initiatives for investment.

Investing in metering of our customers as well as network assets (DTs and Feeders) is top priority for EKEDC as we believe that it will greatly reduce commercial and collection losses within our network and help us to better ascertain technical losses with time.

Investing in improving the availability/reliability of power supply allows us to earn more revenue needed to cover our costs.

6.3 Reliable Power and Quality Services

This includes efforts and initiatives towards increasing quantity of energy supplied and improving quality of the service. We believe these efforts will reduce ATC&C losses (especially technical losses) and in addition include system improvement, system augmentation, and embedded generation initiatives.

6.3.1 Technical Loss Reduction

The technical loss reduction strategies cover the following areas:

a) **LT Reticulation:** This involves the replacement of existing overhead conductors with LT aerial bunched cables in theft prone areas. This cable is insulated and would make it difficult for customers to directly hook on the LT feeder, which is very common in the case of bare overhead feeder. There will be a reconstruction of 15km of LV lines quarterly and rehabilitation of 15 distribution transformers/ substations quarterly.

b) **Construction of Capacitor Banks:** Three capacitor banks will be constructed quarterly within the 8 business units to reduce to the barest minimum the low voltage at the customers end due to the continuous overloaded state of the network.

c) **Replacement of Undersized Cable (HV):** This involves the reconstruction of 12km of undersized cables (HV) monthly as undersized cables create a voltage drop that shorten the life of equipment and waste energy.

d) **Replacement of Sick Cables:** The sick cables pose a serious issue since most of EKEDC's network is radially connected, implying that a breakdown of one feeder leads to the complete outage of the customer. 12km of 33kv lines and 24km of 11kv lines will be reconstructed every quarter, this will optimize the CAPEX as faulty sections of the feeders will be replaced instead of laying of new feeders.

6.3.2 Commercial Loss Reduction

Different metering strategies will be deployed to provide accurate billing to EKEDC customers while minimizing commercial losses within the network. The planned initiatives to reduce commercial losses include:

a) **Metering all feeders up to the substations:** This initiative allows EKEDC to keep track of energy flow within customer clusters within the network, and bill customers appropriately.

b) **Rollout of smart Automatic Meter Reading (AMR) enabled meters to maximum demand customers (KCG):** AMR enabled meters create an automated environment for the purpose of meter readings and eliminate human error. The meters produce accurate records of energy consumed and allow accurate download of data and minimizes errors. This ensures accurate billing and reduces customers' incessant complaints, errors and delay in billing.

c) **Rollout of smart prepaid meters:** There is a reasonable amount of commercial losses within EKEDC area due to the existence of unbilled customers, obsolete meters and faulty or burnt meters. The rollout of smart prepaid meters allows EKEDC's customers to migrate from post-paid to prepaid smart meters, thereby reducing energy theft and eliminating wrong or estimated billing and minimizes customers' complaints with respect to billing.

d) **Capturing, certification and recertification of meters:** This initiative will help improve monitoring of energy usage and improve revenue collection.

e) **Enumeration of customers:** This initiative provides accurate data on customers, captures illegal and unregistered consumers and helps identify incorrect customers' tariffs to enable adequate reclassification.

f) **Deployment of Statistical Meters to all Distribution Transformers:** This will help in energy tracking and accountability and also help localize losses and improve monitoring of energy losses which will result in improved estimated billing of unmetered customers pending when these customers are metered.

g) **Active Power Management:** This involves energy scheduling for better tracking and monitoring of energy delivery to the customers using colour coding and automatic load scheduling.

6.3.3 Collection Loss Reduction

The ability to drive collection and reduce collection losses is critical to EKEDC's capacity to embark on its planned capital expenditure projects. Therefore, the following initiatives and action plans have been identified to help reduce collection losses:

a) **Well empowered disconnection and enforcement group:** This initiative involves empowering a group to drive collection of debts across all districts which will increase overall collection efficiency of EKEDC. It will also increase monitoring of prepaid meters for by-passes and other forms of tampering.

b) **Outsourcing of cash collection of debts more than three months:** This initiative will be outsourced to a consultant who will drive collection of debt longer than three months and will be paid 10% commission on all recovered debts which will increase revenue to EKEDC through improved collection efficiency.

c) **Deployment of different payment channels:** To enable customer 24/7 vending, access to energy supply and quick and secured collection, different payment channels such as cash collection online, POS, direct debit, and payment through the district office will be deployed.

d) **Active implementation of Credit Management Process:** The standard credit management strategies will help to manage new connections, reduce late payments, recover existing debts, and curb electricity thefts. EKEDC shall carry out credit check on all prospective customers and such customers shall be mandated to pay security deposits before connecting to EKEDC network.

e) Energy Audit & Tariff Reclassifications: Continuous energy audit of customers (especially the Maximum demand customers) through equipment (meter, CTs VTs etc) revalidation/recalibration which helps to validate the accuracy of metering facilities and reduce losses arising from inaccurate metering equipment. The process also involves reclassification of wrongly classified customers' tariffs.

6.3.4 System Improvement

EKEDC's existing electrical networks and systems are obsolete. The following planned projects will be executed as part of efforts to ensure system improvement and improve quality of energy supplied.

a) Rehabilitation of substations: Complete rehabilitation of 16 distribution substations quarterly to standardize them and ensure compliance with all safety standards.

b) Automation of network: Implementation of automation within the network to incorporate SCADA systems in the entire network (Injection S/S, feeders, distribution transformers, poles). As part of EKEDC's plan to provide reliable power and quality services, the SCADA system will give real time visibility of operating conditions of the distribution network. This will improve the reliability of operations, improve record keeping, cost control, analysis, effectiveness and quality of customer service.

Figure 8: SCADA room showing real-time network monitoring

The SCADA system will deliver key benefits in the area of safety to DISCO personnel and the general public. The Data Acquisition and Alarm processing functions will alert distribution system operators when equipment is operating beyond safe limits, overloaded and in danger of fire or explosion.

In addition, it provides tools for the improvement of reliability of power supply. SCADA programs such as fault isolation and service restoration will reduce the time taken to restore supply following a fault on the primary thereby improving the reliability of supply to the customers. Voltage monitoring will make EKEDC personnel aware of high/low voltage situations throughout the service area and enable EKEDC to prioritize remediation projects to improve customer satisfaction.

c) **Reconstruction of HV Network:** Reconstruction of 15km of problematic lines with sagged conductors, aged and broken poles, cross arms insulators, etc. quarterly.

d) **Reconstruction of LV Network:** Reconstruction of 15km of LV lines with sagged conductors, aged and broken poles, insulators, etc quarterly.

e) Upgrade of Switchgear: Upgrade of 10 HV switchgear to modern switchgears that are SCADA complaint quarterly.

6.3.5 System Augmentation

Due to the projected network expansion, the following initiatives will be implemented:

a) Installation of distribution transformers: A distribution transformer provides the final voltage transformation in the electric power distribution system, stepping down the voltage used in the distribution lines to the level used by the customer. We plan to install 45 distribution transformers quarterly, which will result in additional 15MVA 11/0.415KV and 7.5MVA 33/0.415KV distribution to the network.

b) Construction of new 33KV and 11KV lines: Primary distribution lines carry medium voltage power to distribution transformers located near the customers' premises. We plan to construct 6km of new 33KV and 11KV lines quarterly.

c) Construction of new interconnectors: Interconnectors improve the reliability of a system. We plan to construct 6km of 33KV interconnectors and 12km of 11KV interconnectors quarterly.

d) Installation of power transformers: It is generally used in transmission network for stepping up or down the voltage level. We plan to install additional 45MVA 33/11 KV power transformers annually.

6.4 Organizational Capability

In order to position EKEDC as a leader in electricity distribution in Africa, this strategic pillar is focused on employing world class talents, promoting a work culture of learning and stimulating high performance. The recruitment, learning and development, performance management and compensation management plans have been articulated below.

6.4.1 Recruitment

In order to build a world class organization, EKEDC will engage a pool of passionate employees who are competent, motivated and highly skilled with relevant experience (for experienced hires) to drive growth of the company. To attract and retain this group of outstanding talents, EKEDC is rolling out the following initiatives:

a) Re-launching the career website and commence advert of vacancies on the site for a more diverse workforce and quality new hires.

b) Continuously employing strategic approach to manpower planning across the different departments to enable the company to determine optimum workforce mix, anticipate vacant positions and fill roles when required

c) Continuously aligning recruitment process to planned demand from business units and performance expectations.

d) As part of the Eko Distribution Training Program (EDTP), we are developing an Engineering Graduate Trainee programme for the technical roles to be conducted every two years to develop talent for succession planning. First batch of the premiere EDTP program 2019 has been successfully integrated into the system.

e) As part of the EDTP, we are developing a Non-Engineering Graduate Trainee Framework for non-technical roles to be conducted every three years. First batch of the premiere EDTP program 2019 has been successfully integrated into the system.

f) Engage in specialized recruitment fairs in related areas of energy and engineering to attract good talent and improve company brand to create a positive brand in the minds of young graduates.

g) Conduct employee engagement surveys every two years to assess employee satisfaction levels, and work on identified improvement areas.

h) Establish computer-based aptitude test for candidates with less than three years work experience along key areas including electrical engineering, mechanical engineering, and civil engineering.

i) Establish general aptitude test for other graduates.

j) Establish wellness initiatives (gym facilities etc) to promote work life balance, increase staff engagement and improve staff productivity levels and staff welfare.

k) Set up an aptitude test room with at least twelve computers to allow for in-house testing.

l) Conduct regular interviews to ensure availability of pool of qualified staff when there are vacancies in EKEDC.

Already, we have launched the new employee handbook to increase awareness of company expectations and ensure compliance with company policies and procedures among staff.

6.4.2 Learning and Development

As part of the organizational capability development plan, initiatives to drive learning and development within EKEDC have been articulated. This is to ensure that employees are empowered with the technical, behavioural and leadership trainings needed to meet business objectives and deliver excellent service.

The initiatives to be deployed are clustered around six key areas including training infrastructure, training content, training delivery, training monitoring, training support and workplace culture enrichment. The detailed action plans under each of the six key areas are detailed below:

6.4.2.1 *Training Infrastructure*

• We have refurbished and commenced use of in-house training centres to eliminate costs from the use of external training facilities.

• Establish Leadership Development Centre at Islands District.

• Establish the Hands-on Technical Training (HOTT) centre at Islands district and equip the centre with required dummy equipment to enable employees have good practical knowledge of the job.

• We have established an e-learning centre at the Head Office and plan to roll out more at all business districts to promote research and development.

6.4.2.2 *Training Content*

• Conduct Training Needs Assessment (TNA) to identify training gaps based on performance gaps and requirements of job roles.

• Develop an established Training Plan, which details the industry-specific and relevant training programs needed to be implemented based on the knowledge and skills gaps required to achieve the competencies that support the strategic objectives of EKEDC.

6.4.2.3 *Training Delivery*

• Ensure every employee attends at least one relevant soft skills and technical skills training annually.

• Currently collaborating with National Power Trainings Institute of Nigeria (NAPTIN) - We will continue to collaborate with the Institute to conduct orientation programs for newly engaged Engineers equipping them with the technical know-how of the power industry. This training will run for 1 month.

• Develop HSE (Health, Safety and equipment) trainings.

- Conduct Strategic Customer Service Training: A mindset change/ transformational program for all employees to align staff to the vision of the company- driving customer service excellence in all of our operations.

- Roll-out 'Train-the-Trainer' training programs to strengthen internal competencies and reduce training cost.

- We regularly implement an orientation program for entry level staff to facilitate onboarding in the company.

- We regularly organize cost-effective Internal Knowledge Sharing Sessions monthly to upscale soft skills in the company.

6.4.2.4 *Training Monitoring*

- We regularly conduct training evaluations to assess the relevance and impact of trainings while ensuring accurate and complete training records are kept.

6.4.2.5 *Training Support*

- We have implemented a mentor-mentee model to enable employees have role models to guide career paths and progression.

- We have developed a succession planning framework, including design of departmental leadership framework to guide identification and management of future managers and leaders.

- Provide support to employees pursuing advanced educational programmes or professional certifications to ensure access to highly skilled workforce.

- We periodically inculcate the values of EKEDC on existing staff in all induction and training interventions to ease the challenges of the process of change from the old PHCN into the new EKEDC culture.

- Optimize efficiencies through best technology processes and practices

6.4.2.6 *Workplace culture enrichment*

- Develop culture enrichment programmes and ensure buy-in of the executive management

- Build a network of Change Ambassadors

6.4.3 Performance Management

Instituting high performance culture is a journey involving several foundational steps. The schematic below is an integrated framework that depicts linkage between EKEDC's overall strategic objectives and key performance indicators.

We will undertake the following action plans to institute a high-performance culture within EKEDC.

- We have worked with stakeholders to develop a new performance management framework including Key Result Areas (KRAs)/Key Performance Indicators (KPIs) for departments and individual employees to ensure alignment of departmental and individual goals to the company's strategic goals and objectives.
- We have already procured Performance Management System (PMS) software to improve and standardize the present performance management framework.
- We regularly organize workshop/training of all EKEDC staff on the use of the PMS software to effectively carry out appraisal exercises.
- Ensure continuous performance monitoring to eliminate complacency & maximize productivity based on performance reviews.

6.4.4 Compensation Management

This includes all the activities involved in developing and implementing appropriate workforce compensation strategies, in order to attract and retain the necessary human resources and talent required to implement and execute EKEDC's strategy and support its ongoing operations.

- We have developed a competitive but sustainable reward policy to ensure increased staff motivation, engagement and productivity. This will include linking performance to reward system.
- Conduct benchmark assessment of peer competitors' compensation structure and review current compensation structure to ensure competitiveness.
- In terms of conditions of service, we have created, managed and administered retirement programs and services by providing appropriate proactive corporate support to assist employees' transit successfully to this next stage of their life.

6.5 Operational Excellence

EKEDC realizes its revenue through the metering, billing and collection processes. The extent to which EKEDC can integrate and secure its metering, billing and collection processes determines the likelihood of business sustainability. Many inefficiencies exist in these processes currently which can be effectively and adequately reduced through IT initiatives and process improvement. Hence, this segment focuses on strategic initiatives covering processes and technology for efficient operations.

6.5.1 Information and Communication Technology (ICT)

Technology is the backbone of the business. In order to deliver excellent service and operate effectively, the following initiatives will be deployed:

- We have procured servers, laptops, desktops for staff and projects to increase efficiency and productivity.
- Obtain relational database (Oracle Enterprise, SQL Server Data Centre Version, Mongo DB) licenses to avoid interruptions of all applications.
- We have procured communication facilities (RF, Fibre Optics and Microwave) to ensure smooth running of the business operations.
- Develop and roll out disaster recovery plan to ensure seamless business continuity and zero down time in case of disasters.
- We are currently installing AMR/AMI for KCG and NON-KCG metered customers to reduce energy theft, allow remote meter monitoring and provide accurate and up-to-date meter readings.
- We have obtained licenses for all applications (office 365, EMS2000, Eclipse, SAP B1, GIS, SCADA, Biometrics, Cyberoam) to avoid disruptions to business operations.

6.5.2 Process Improvement

One of the critical levers of operational excellence is process efficiency and effectiveness. Hence, there is a constant need to review and improve existing processes. The various initiatives to drive process improvement are articulated below:

6.5.2.1 *Deployment of Revenue Cycle Management System*

The RCM system effectively follows the flow of money in EKEDC from order to cash, which optimizes revenue collection on electricity distributed. It reduces fraud both internally and externally, reduces technical losses and promotes excellent customer service delivery.

- **Workforce Management Systems (WMS):** This is a continuous integration system fully integrated to the Business and Operation Support system for managing the reported faults and allocating resources to fix the faults. The Customer Care Centre may use this to report faults. Also, faults reported by customers directly from EKEDC's website, mobile app and via SMS will also be routed directly to the system. WMS also provides databases, tools, and applications that can be used to plan construction. Construction is required to provide feeder extensions for supplying new housing subdivisions, to supply service to newly constructed premises, or to support a system improvement project. The system also includes other features including Fault Lifecycle Management, Resource Allocation & Management, Location Management, and Reports
- **Unified Collections Gateway:** This is a management information dashboard that provides an integrated view from all collection channels including collection online, POS, direct debit, and payment through the district office. The district office shall use the Crown Interactive Convergence on Demand (CICOD) terminal for transaction handling in order to provide real-time visibility of transactions. The finance/treasury team will have real-time access to funds available in cash or in EKEDC's bank accounts.
- **Online/Mobile/SMS Customer Self-Service:** Both pre-paid and post-paid customers will be able to engage with EKEDC via the website and mobile application for order fulfilment, billing/usage enquiry and fault reporting. The registered customers will also be able to report faults and get billing alerts / payment confirmation via SMS.
- **Inventory Management System (IMS):** The IMS will be seamlessly integrated, so that order fulfilment through to the provisioning of meters and other utility assets are managed. The IMS also stores the location of the asset (meter) when provisioned. The features in the IMS include, Stock Management, Provisioning, Inventory Lifecycle (Track & Trace), Alerts, and Reports.
- **Voucher Management System:** This system provides the capability for the organisation to produce and manage pre-paid pin for mass-market distribution of power credits. Customers may use vouchers to pay their bills at any time. Prepaid meter customers who have registered their meters shall have tokens generated and sent back to them or automatically loaded to their meters. The key features in the VMS include

Voucher Lifecycle Management, Dealer & Commissions Management, Virtual Distribution Service and Reports

- **Energy Management Control Centre (EMCC):** This is the dashboard for the technical operations team. It serves as the unified meter data management system which integrates the Advanced Metering Infrastructure's (AMI's) of different providers into one single view. The key features of the EMCC include forecast, bulk purchase & distribution management, asset provisioning, manage power, consumption measurement, outage management, power on-demand scheduler, energy audit, unified advanced metering infrastructure interface and reports and analytics/dashboard

6.5.2.2 *Outsourced customer call centres*

EKEDC's customer call centres have been outsourced. The centres were set up to receive customer complaints 24/7 through telephone and transfer complaints to the appropriate departments for action. This will facilitate speedy resolution of customers' issues and complaints in a timely and prompt manner

6.5.2.3 *Set up of customer care centres*

The customer care centre would be established in all districts and at the headquarter equipped with facilities to receive calls, emails and letters and other facilities such as TV, DSTV etc. that make customers comfortable. The centres will be manned with well-trained customer care officers that will attend to customers promptly and ensure excellent customer care services.

6.5.2.4 *Meter rollout management office within New Service department*

The office will be responsible for meter rollout plans and management, identifying customers for different phases of the rollout. It will also be a contact point for issues related to meter rollout; installations and capturing.

6.6 Safety Standards

6.6.1 Incident Reporting System

EKEDC has a documented laid out process for incident reporting. From 2013 to 2018, there have been 67 Health and Safety reports of including 1 fire incident happening only in 2015 and another in 2016. There have been 7 employee deaths from 2014 to 2018 with 36 third-party deaths in the same period. There were 22 injuries reported in the period.

We have been continuously working to address health and safety issues by sponsoring at least 50 either through technical workshops or health and safety training sessions in our various Districts. These touched on areas such as public enlightenment on public safety and protection on electricity equipment; safety workshop on use of Permit-to-Work system and Ladder safety; accident prevention and emergency response management; fire safety & fire-related medical emergency management, etc.

From 2020 to 2024, we plan to carry out 40 annual safety trainings and 60 community engagement activities.

In the provision of services to its network, EKEDC realizes that the health and safety of its environment, staff and third parties is of utmost importance to the company. In view of this, health and safety initiatives have been identified to ensure hazard prevention, safety awareness, adequate emergency response and monitoring and review. Details of action plans under each of the objectives are provided below.

6.6.2 Hazard Prevention

- **Provision of Personal Protective Equipment (PPE):** This will be provided to reduce employee exposure to hazards when conducting engineering tasks as administrative controls are not feasible or effective in reducing these risks to acceptable levels.
- **Provision of Other Protective Equipment:** This category of equipment falls under the Engineering Controls and they guaranty workmen safety locally at the point of work. They include Grounding Sticks, Operating Rods/Hot Sticks etc.
- **Provision of motor vehicles:** This will ease movement of staff during routine hazard hunting, audit of injection substations, collation of PTW, toolbox talks, preparation of reports, etc.

6.6.3 Health and Safety Awareness

- **Provision of Safety Equipment/ Materials and Vehicle:** This will ensure protection and safety of employees and staff. This for the purpose of continuous safety enlightenment.
- **Provision of Information Aid Equipment:** The objective is to aid the dissemination of information using safety statistical boards, projectors/ mobile screens, printing of fliers, handbills and posters.
- **Safety Enlightenment/ Awareness Programme:** To maintain our commitment to safe work practices, and to ensure that we continue to meet regulatory standards, we will conduct regular, thorough inspections of associated work areas and continually check for unsafe conditions and practices

6.6.4 Adequate Emergency Response

- **Regular and proactive maintenance of firefighting equipment:** This includes installation of fire extinguishers and the fire hydrant system at the headquarter building, injection substations, business units and service units. Proactive maintenance measures will be taken to ensure their effective functionality when there is an emergency.

- **First Aid Boxes:** We will provide first aid boxes to ensure our staff have adequate access to first aid in emergency situations. Also, we will refresh first aiders' training and display first aiders' names at prominent places. In addition, we will inspect first aid kits available at worksite, office, vehicle, stores, etc.

6.6.5 Monitoring and Review

- **Regular and proactive maintenance of firefighting equipment:** To ensure consistency with our set goals, we shall continuously monitor our performance and periodically review our safety management system, so that we can close identified gaps and improve on the system.

6.7 Proactive Stakeholder Engagement

EKEDC plans to collaborate and innovate with key stakeholders across the value chain including National Electricity Regulatory Commission (NERC), Nigerian Electricity Management Services Agency (NEMSA), Transmission Company of Nigeria (TCN), Central Bank of Nigeria (CBN), and the Federal Government. Planned engagements with some of the stakeholder are detailed below:

6.7.1 National Electricity Regulatory Commission

EKEDC plans to engage the regulator, NERC, on the following:

a) Creation and implementation of regulatory asset: Regulatory asset consists of specific costs or revenues that the Commission will permit EKEDC to defer in its balance sheet. These costs would otherwise be required to appear on the company's income statement and would be charged against current expenses or revenues.

b) Proactively engage the regulators and other relevant stakeholders to resolve the following discrepancies in MYTO:

I. Increase in Capital Expenditure Investment.

   - Development of a cost-benefit analysis.

- Development of a communication plan for customers to understand the benefits of additional CAPEX.
- Compilation of judicious expenditure of CAPEX allocated to EKEDC in the MYTO.

II. Recognition of Accurate Aggregate Technical Commercial & Collection (ATC&C) Losses.

III. Foreign Exchange Rate.

IV. Available Generation.

V. Energy Allocation.

VI. Customer Numbers.

c) Implementation of late payment surcharge and security deposit: Engage NERC to ensure establishment of credit management controls/debt management policy to cover EKEDC's customers.

d) Metering (estimated billing): Communicate the methodology used for estimated billing by EKEDC to NERC in line with regulatory requirements.

e) Engage retired judges to assist with presiding over Mobile Courts for energy offences (across the country): Mobile courts to be available in all parts of Nigeria to deal with only energy issues brought up by the Disco or the customer. This will include penalties ranging from fines to imprisonment. EKEDC plans to engage retired judges to assist with hearing cases.

The Power Consumer Assistance Fund, if fully kicked off by NERC will assist underprivileged power consumers who are mostly in those areas classified as Difficult-to-Manage areas.

6.7.2 Transmission Company of Nigeria (TCN)

EKEDC plans to engage TCN in order to unravel TCN bottleneck. Key action plans include:

I. Establishment of a Joint Planning Task Force between TCN, NERC and EKEDC.

II. Identification of projects to enhance grid network emanating to EKEDC's network.

III. Entering into repayment agreements with TCN.

6.7.3 Central Bank of Nigeria

EKEDC plans to engage CBN on existing rules against borrowing foreign currency. This is essential as the availability of various options to cover EKEDC's financing needs will be critical to EKEDC's success going forward. More specifically, borrowing USD or other hard currency will allow EKEDC to make investments that will lower diesel usage which will in turn lower the amount of foreign currency that is used to purchase diesel fuel from importers in USD.

6.7.4 Federal Government

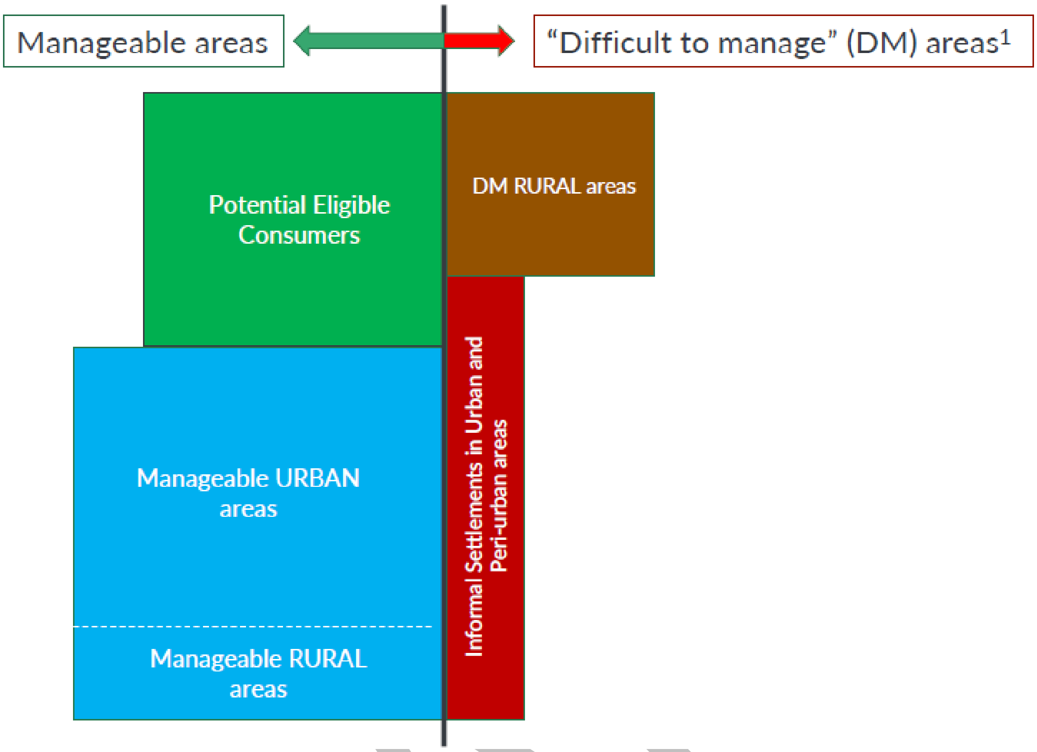
EKEDC will engage the Federal Government to ensure that payment of MDA debt and bills are deducted at source by the Ministry of Finance.

6.8 Innovative Strategies for Different Areas

Our plan is to segment our customers and the feeders by which they are served into different market segments (manageable and difficult-to-manage) as shown below and then address the different customer market segments identified below in Figure 9 with different strategies.

Our Optimization Model for Network Investments (OMNI) developed by EMRC already helps us rank our feeders to be classified into the different market segments.

Figure 9: Four market segments defined by CaBTAP[1]



6.8.1 Manageable areas

6.8.1.1 *Manageable URBAN area*

This area will be our highest priority for ring-fencing communities and providing reliable power supply at cost-reflective tariffs. We will identify communities in this area of our network who are willing to pay for cost-reflective power supply to cover the cost of embedded generation sources as well as our investment in improving our ability to reliably distribute power in such areas. EKEDC will prioritize investments in feeders and associated distribution infrastructure in these areas.

6.8.1.2 *Manageable RURAL areas*

This area will be the next highest priority for ring-fencing communities and providing reliable power supply at cost-reflective tariffs. We will identify communities in this area of our network who are willing to pay for cost-reflective power supply to cover the cost of embedded

[1] Capacity Building and Technical Assistance Programme (CaBTAP) presentation 18-19 June 2019. NERC has divided the market in manageable and unmanageable areas.

generation sources as well as our investment in improving our ability to reliably distribute power in such areas.

6.8.1.3 *Potential Eligible Customers*

We are happy to allow potential eligible customers who are willing to pay the Distribution Use of System (DUoS) charge and compensate us via Competition Transition Charge (CTC) to use our distribution assets in line with regulatory provisions.

6.8.2 Difficult-to-manage areas

6.8.2.1 *Difficult-to-Manage RURAL areas*

The difficult-to-manage rural areas will be our priority for franchising. We are willing to work with distribution sub-franchisees that can provide services in the following areas:

- Metering, Billing, and Collection
- Total management of part of our distribution network
- Supply power and manage part of our distribution network

Mini-grid developers will also be able to participate in this space.

6.8.2.2 *Informal Settlements in Urban and Peri-urban areas (ISPUAs)*

Identified community settlements in urban and peri-urban areas will be engaged to determine affordable tariffs and energy requirements. Based on agreed commercial commitments from the settlements, proposed strategies include:

- Bulk metering for the community
- Distribution of bulk bills for the community
- Supply based on payment performance from the community
- Engagements with the state and local governments to determine energy subsidies and network investment support for poorer settlements.

7 Financial plan

7.1 Overview

This section covers:

- Zero Capex Scenario;
- Regulatory Allowed Capex Scenario;
- EKEDC Required Capex Scenario; and
- Financing Plan.

In each scenario, it is assumed that the Capex amount stated is the Capex amount that will be funded, ceteris paribus.

Each scenario is organized by inputs (assumptions) and outputs (cash flow waterfall).

7.1 Zero Capex Scenario

7.1.1 Inputs

This is a scenario that assumes that EKEDC will not be able to raise any funds needed for Capex investments.

The tariffs used at MYTO Minor Review tariffs for 2020 to 2024. The energy received from 2020 till 2024 is assumed to be the same with 2019 projected levels till year end. The 2019 ATC&C loss levels remain till 2024, although without any Capex investment, losses will likely increase.

Table 18: Zero Capex Scenario - Inputs

Assumptions	2020	2021	2022	2023	2024
Energy Received (GWh)	3,050	3,050	3,050	3,050	3,050
Av. Power Received (MW)	348	348	348	348	348
Capex	0	0	0	0	0
Opex	20,681	22,828	25,209	27,851	30,783
ATC&C Projection	26.63%	26.63%	26.63%	26.63%	26.63%
% of CAPEX from IGR	30%	30%	30%	30%	30%
% from Debt	70%	70%	70%	70%	70%

Equity Rate	27%	27%	27%	27%	27%
Debt Rate	22%	22%	22%	22%	22%
Tenor – Debt (years)	5	5	5	5	5

7.1.2 Outputs

Without any Capex investments, EKEDC will not be able to fully remit to the market (as expected by NERC) as shown in the table below.

Table 19: Zero Capex Scenario - Outputs

		2020	2021	2022	2023	2024
Cost-reflective tariff		62.89	64.16	65.02	66.23	67.71
Allowed tariff		45.97	39.77	39.19	38.77	38.94
Opening cash flow	₦m	8,436	-	-	-	-
Receipts						
Cash Collection from Credit customers	₦m	106,504	89,008	87,692	86,756	87,146
Equity Injection	₦m	-	-	-	-	-
Bank loan drawdown	₦m	-	-	-	-	-
Shareholder Loan	₦m	-	-	-	-	-
Payments						
Payment to NBET	₦m	84,077	68,405	67,819	67,112	67,428
Payment to MO	₦m	20,717	19,572	18,843	18,613	18,687
% of NBET Bill Paid	%	100%	80%	76%	72%	68%
% of MO Bill Paid	%	100%	100%	100%	100%	100%
Loan Payment	₦m	1,031	1,031	1,031	1,031	1,031
Loan Default	₦m	-	-	-	-	-
Staff Cost	₦m	2,116	-	-	-	-
% of staff cost paid	%	33%	0%	0%	0%	0%
Accounts Payable	₦m	6,971	-	-	-	-
Taxation and VAT	₦m	28	-	-	-	-
Capex	₦m	-	-	-	-	-
Cash available for distribution	₦m	-	-	-	-	-
Dividends	₦m	-	-	-	-	-
Cash available after dividends	₦m	-	-	-	-	-
Closing cash flow	₦m	-	-	-	-	-

7.2 Regulatory Allowed Capex Scenario

7.2.1 Inputs

This is a scenario that assumes that EKEDC will be able to raise the Regulatory Allowed Capex needed for Capex investments.

The tariffs used at MYTO Minor Review tariffs for 2020 to 2024. The energy received from 2020 till 2024 is same as assumed in the MYTO Minor Review model. The ATC&C loss reduction projection is a trajectory that EKEDC can achieve given the limited Regulatory Allowed Capex for 2020 to 2024.

Table 20: Regulatory Allowed Capex Scenario - Inputs

Assumptions	**2020**	**2021**	**2022**	**2023**	**2024**
Energy Received (GWh)	4,294	4,684	5,216	5,628	5,950
Av. Power Received (MW)	490	535	595	642	679
Capex	11,656	11,656	14,570	14,570	14,570
Opex	20,681	22,828	25,209	27.851	30,783
ATC&C Projection	26.63%	25.63%	24.63%	23.63%	22.63%
% of CAPEX from IGR	30%	30%	30%	30%	30%
% from Debt	70%	70%	70%	70%	70%
Equity Rate	27%	27%	27%	27%	27%
Debt Rate	22%	22%	22%	22%	22%
Tenor – Debt (years)	5	5	5	5	5

7.2.2 Outputs

Without the Regulatory Allowed Capex investments, EKEDC will not be able to fully remit to the market (as expected by NERC) as shown in the Table 21 below.

Table 21: Regulatory Allowed Capex Scenario - Outputs

		2020	2021	2022	2023	2024
Cost-reflective tariff		58.10	57.88	56.74	56.31	56.21
Allowed tariff		45.97	39.77	39.19	38.77	38.94
Opening cash flow	₦m	8,436	-	-	-	-
Receipts						

Cash Collection from Credit customers	₦m	148,461	138,094	152,951	165,016	176,880
Equity Injection	₦m	-	-	-	-	-
Bank loan drawdown	₦m	-	-	-	-	-
Loan	₦m	8,159	8,159	10,199	10,199	10,199
Payments						
Payment to NBET	₦m	118,231	107,005	119,696	129,640	139,394
Payment to MO	₦m	28,872	30,058	32,224	34,346	36,456
% of NBET Bill Paid	%	100%	82%	80%	77%	75%
% of MO Bill Paid	%	100%	100%	100%	100%	100%
Loan Payment	₦m	1,031	1,031	1,031	1,031	1,031
Loan Default	₦m	-	2,851	5,703	9,267	12,832
Staff Cost	₦m	2,035	-	-	-	-
% of staff cost paid	%	31%	0%	0%	0%	0%
Accounts Payable	₦m	6,703	-	-	-	-
Taxation and VAT	₦m	27	-	-	-	-
Capex	₦m	8,159	8,159	10,199	10,199	10,199
Capex used (%)	%	70%	70%	70%	70%	70%
Cash available for distribution	₦m	-	-	-	-	-
Dividends	₦m	-	-	-	-	-
Cash available after dividends	₦m	-	-	-	-	-
Closing cash flow	₦m	-	-	-	-	-

There is a chance that we will default on our loan by 2021 and this can affect our chances of raising finance in the subsequent years.

7.3 EKEDC Required Capex Scenario

7.3.1 Inputs

In the EKEDC Required Capex scenario, it is assumed that EKEDC will be allowed to invest a higher Capex than the Regulatory Allowed Capex. Also, it is assumed that EKEDC could charge a truly cost-reflective tariff which will cover this higher investment level and will make it much easier for us to source and spend above the MYTO Capex limit especially in years 2020 and 2021. EKEDC will be able to achieve losses that are more aggressive than in the Regulatory Allowed Scenario.

Table 22: EKEDC Required Capex Scenario - Inputs

Assumptions	**2020**	**2021**	**2022**	**2023**	**2024**
Energy Received (GWh)	4,294	4,730	5,168	5,606	6,044
Av. Power Received (MW)	490	540	590	640	690
Capex	21,650	13,240	14,570	14,570	14,570
Opex	27,836	29,107	32,142	35,547	39,354
ATC&C Projection	26.63%	24.63%	22.63%	20.63%	18.63%
% of CAPEX from IGR	30%	30%	30%	30%	30%
% from Debt	70%	70%	70%	70%	70%
Equity Rate	27%	27%	27%	27%	27%
Debt Rate	22%	22%	22%	22%	22%
Tenor – Debt (years)	5	5	5	5	5

7.3.2 Outputs

With EKEDC's Required Capex, EKEDC will be able to fully remit to the market (as expected by NERC) as shown in the table below.

Table 23: EKEDC Required Capex - Outputs

		2020	2021	2022	2023	2024
Cost-reflective tariff		60.37	59.86	58.54	57.60	60.37
Opening cash flow	₦m	8,436	-	-	-	-
Receipts						
Cash Collection from Credit customers	₦m	193,828	213,412	234,051	256,282	279,593
Equity Injection	₦m	-	-	-	-	-
Bank loan	₦m	-	-	-	-	-
Shareholder Loan	₦m	15,155	9,268	10,199	10,199	10,199
Payments						
Payment to NBET	₦m	117,891	130,241	143,192	156,319	169,629
Payment to MO	₦m	28,149	30,353	31,928	34,212	37,032
% of NBET Bill Paid	%	100%	100%	100%	100%	100%
% of MO Bill Paid	%	100%	100%	100%	100%	100%
Loan Payment	₦m	1,031	6,327	9,566	13,130	16,694
Loan Default	₦m	-	-	-	-	-
Staff Cost	₦m	6,224	6,979	7,826	8,776	9,841
% of staff cost paid	%	100%	100%	100%	100%	100%
Accounts Payable	₦m	20,500	20,988	23,190	25,644	28,383
Taxation and VAT	₦m	82	4,283	5,580	5,881	6,326

Capex	₦m	21,650	13,240	14,570	14,570	14,570
Capex (%)	%	100%	100%	100%	100%	100%
Cash available for distribution	₦m	21,894	23,063	19,605	15,058	8,931
Dividends	₦m	9,101	11,857	12,497	13,444	8,931
Cash available after dividends	₦m	12,793	11,206	7,109	1,614	-
Closing cash flow	₦m	12,793	11,206	7,109	1,614	-

7.4 Funding Strategy

EKEDC plans to fund its capex plans 30% via Internally Generated Revenue (IGR) as equity with rate of return of 27% (in line with the MYTO Minor Review assumptions) and 70% from debt at debt interest rate of 22% (in line with the MYTO Minor Review assumptions.

Our funding strategy is hinged on prioritizing cheaper sources of funds over more expensive sources.

8 Risk assessment and management

8.1 Overview

This section covers:

- Approach to managing risk;
- Risk analysis; and
- EKEDC's approach to regulatory risk.

8.2 Approach to managing risk

EKEDC has carried out a risk analysis of the business environment in the coming years. The following four step approach to risk management was followed:

- A series of risk identification sessions were held in which the major technical and commercial risks to the Performance Improvement Plan were identified and listed;
- A subjectively assessed risk likelihood was assigned to each identified risk according to the following ranges:
  - High: 67% - 100% probability of occurring
  - Medium: 34% - 66% probability of occurring
  - Low: 0% - 33% probability of occurring
- Similar subjectively assessed impacts (high, medium, low) were attached to each identified risk.
- For risks assessed as being high/medium or above the following risk management strategies were formulated:
  - Avoidance (eliminate, withdraw)
  - Reduction (optimize – mitigate)
  - Sharing (e.g. insure, transfer)
  - Retention (accept and budget)

The risk analysis is summarised in the next section.

8.3 Risk analysis

Table 24 provides a risk assessment for this performance improvement plan.

Table 24 – Risk assessment and management

Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
Brief title	*Description*	*e.g. High, medium, low*	*e.g. High, medium, low*	*Avoidance (eliminate, withdraw)* *Reduction (optimize – mitigate)* *Sharing (e.g. insure, transfer)* *Retention (accept and budget)*
Loss reduction pathway in tariffs.	Discos have argued that NERC should recognize the actual loss position of the Discos. Discos have been unable to reduce losses due to non-cost reflective tariffs, low CAPEX allowance in the MYTO which doesn't reflect reality, high energy charges from NBET, and MDA collection loss is yet to be addressed. The timeline of non-cost reflective tariffs is provided in Section 4.2.4.1 in Table 2.	High	High	**Retention** *(accept and budget).* The decision on tariffs is outside the direct control of the Discos. Within the different scenarios modelled in section 7, we have considered different possible scenarios for allowed ATC&C losses. We have considered the impact this will have on Disco performance during the tariff period. It will be important to **negotiate with NERC** to avoid the worst tariff scenarios.
MDA payment.	MDA debts are not paid to date, current deliberations between the Discos and FGN only focuses on federal MDAs and not state. Discos need to engage with state MDAs to address the debt currently being accrued at the state level.	High	High	**Retention** *(accept and budget).* The decision on tariffs and the solution to MDA debt payment is outside the direct control of the Discos. Within the different scenarios modelled in section 7, we have considered different possible scenarios for MDA payment.

Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
				It will be important to **negotiate with FGN** to avoid the worst MDA scenarios.
Performance agreement timescales.	The performance agreements end date was originally December 2019. BPE has indicated that 2017 and 2018 will be treated as non-performance years.[2] However, they are treating 2015, 2016 and 2019 as loss reduction years. None of the Discos have achieved the first three years of loss reduction, and even with cost reflective tariffs, it is unlikely they will achieve their full loss reduction commitment by the end of 2021. Based on the current performance of the Discos, the call option to buy back the Discos at $1 if they fail to meet their commitments.	High	High	**Avoidance** *(eliminate, withdraw).* Under the current treatment of the loss reduction targets, Discos can use their businesses without compensation. This makes it very challenging to finance improvements unless the targets are made more achievable. This risk is not possible to manage, unless BPE amend the performance agreement targets to reflect an achievable trajectory. **Negotiating with BPE is essential.** If this is not resolved, the business may not be viable.
Minor review.	No minor review has been implemented in tariffs since 2015 to date leaving the Discos operating under impossible economic conditions, and unable to meet their obligations.	High	High	**Avoidance** *(eliminate, withdraw).* Failure to implement a minor review could qualify as a “change of law” force majeure event under the performance agreement, since the regulation is not being enforced. By declaring force majeure within the timescales, Discos would protect themselves from the performance targets and make themselves eligible to receive full compensation if the situation is not rectified in performance

[2] BPE - Presentation on the Review of Performance Target Dates of the DISCOS (21st February 2019)

Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
				agreement timescales. To date, Discos have been reluctant to declare force majeure because of political implications. Once new performance agreements and tariffs have been implemented, Discos should enforce their entitlement to a cost-reflective tariff.
NBET charges for generation inconsistent with Disco tariffs.	The NBET invoices issued to the Discos have remained significantly higher than MYTO projections, largely because NBET has been charging the Discos using the actual economic indices i.e. forex etc. However, the tariffs used by NBET remain higher than the generation tariff in the June 2019 MYTO minor review model. Once PPAs are activated, generation costs will deviate further from MYTO assumptions as capacity factors will be considerably higher once successor and NIPP generators can charge for available capacity.	High	Low (providing minor reviews implemented)	**Retention** *(accept and budget).* The scenarios in this report assume that generation tariffs are consistent with NBET current tariffs in real 2019 terms. This is addressed retrospectively when NERC use actual NBET invoices in minor reviews but will have an impact in short term cashflow and ability to meet market remittances. **Regulatory need.** NERC are requested to ensure their generation tariff formulae are consistent with those being applied by NBET, and that the capacity factor assumptions are consistent with SO declarations for all generation, so that the MYTO model provides a realistic tariff base.
Generation levels.	In past MYTO models, forecast generation levels have been significantly in excess of reality. Actual generation levels have changed very little since 2013. When there are generation shocks (such as in 2016), there is a disproportionate impact on	High	High	**Retention** *(accept and budget).* The scenarios in this report assume that generation levels remain at 2019 levels, with no increase. **Regulatory need.**

Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
	payment, due to customer dissatisfaction and the fact that fixed costs are spread over fewer kWhs.			MYTO minor reviews will be essential for tariffs to keep pace with generation levels.
Eligible Customers.	Some transmission connected customers of the Discos have self-declared themselves eligible customers and are currently receiving power illegally through TCN. Customers who self-declare themselves without due process create a risk to Disco revenue, financial performance, energy received and customer numbers. At present, TCN is refusing to Disconnect illegally defaulting customers as required under the Supplementary Order on the Commencement of TEM.	High	High	**Avoidance** *(eliminate, withdraw).* If the market issue is not resolved, and tariff levels are not adjusted to compensate, the only option for some Discos may be withdrawal via force majeure. **Regulatory need.** It is important that any Eligible Customers pay the Competition Transition Charge (CTC) and that their status is legal.
Meter Assets Providers (MAP).	The MAP regulation has been in effect for over a year now, however there has been limited progress by the MAP's in commencing metering. Recent reports indicate that a number of MAP's currently do not have the necessary finance to commence metering within the set timelines. Metering is likely to be based only on those customers who can afford to pay. Discos are not permitted to use regulated CAPEX for metering.	High	High	**Reduction** *(optimize – mitigate)* EKEDC has managed its MAP contracts to ensure best possible service. However, a residual risk remains because the metering allowance by NERC is not adequate to allow financing of metering, therefore all meters will initially be financed by the customers themselves. Many of our customers may not be able to finance the CAPEX. **Regulatory need.** It is important that NERC reviews the metering CAPEX allowance to enable third party financing of meters and to ensure that metering can reach all our customers.

Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
Allowed CAPEX in MYTO model.	If allowed CAPEX is not consistent with assumptions, it will restrict the ability of EKEDC to make the required investment and may prevent the planned Outputs being achieved.	High	Medium	**Retention** *(accept and budget)* We have prepared this PIP for a range of allowed CAPEX scenarios, and the projected outputs will differ depending on the allowed CAPEX.
Limited or no access to finance.	The regulatory uncertainty, non-cost reflective tariffs since privatisation in 2013, and the fact that most Discos are effectively insolvent mean that commercial lenders are unwilling to lend to Discos. Investors have not received dividends.	High	Medium	**Retention** *(accept and budget)* In our financial planning, we have considered known sources of finance. We have considered cases where investment is financed both from free cashflow and commercial lending.
Acknowledged tariff shortfall covers liability.	NERC anticipated that liability to MO and NBET will be reduced by the tariff shortfall. However, NERC's calculation of the tariff shortfall differs from EKEDC's.	Medium	Medium	**Retention** *(accept and budget)* We have considered a range of tariff scenarios based on a range of acknowledged tariff shortfall scenarios, and the projected outputs will differ depending on NERC's acknowledged tariff shortfall.
Project delivery timescales.	We have planned this PIP based on expected delivery timescales. However, there is a risk that external contractors may not deliver the work to time.	Medium	Medium	**Reduction** *(optimize – mitigate)* We will continually monitor contract performance to ensure that contracts adhere to agreed service levels.
Insurgency activities damage EKEDC assets (or other extreme events beyond EKEDC's	In recent years, insurgency and civil unrest has caused damage to electricity infrastructure in Nigeria. There is a risk of recurrence. Other extreme events could include (for example) extreme weather or seismic events.	High	High	**Sharing** *(e.g. insure, transfer)* It is possible that specific investment to address short-term insurgency activities could be allowed for in tariffs as additional CAPEX, and outputs and/or allowed CAPEX could be reviewed in an extraordinary tariff review following these or similar extreme events.

Risk title	Risk description	Risk likelihood	Risk impact	Risk management strategy
control e.g. extreme weather).				**Avoidance** *(eliminate, withdraw).* The Performance Agreement allows for withdrawal in the case of severe or prolonged insurgency and other specific force majeure events.

8.4 EKEDC's approach to regulatory risk

The approach of the company to regulatory risk rests on how well the company, in its activities can remain consistent and compliant with all the necessary regulations and regulatory obligations.

Our model is simple, perform an analysis of the company's performance as it relates to several regulations. The key is to ensure that all staff members are aware of all the regulations and the specific regulations that concern the activities of the various departments.

The risk regulatory model hinges on these components:

- Risk evaluation and Tolerance
- Compliance and performance evaluation
- Crisis management and avoidance.

A departmental risk assessment registry has been created to help with performance evaluation to ensure compliance. Assessments are done on a monthly basis.

The key goal of the regulatory risk framework is minimizing the company's risk exposure as it concerns its obligations and ensure that the enterprise risk management culture is held in high regard.

Annexes

Annex A Results of stakeholder consultation

A. 1 East Circle

STAKEHOLDER ENGAGEMENT MEETING FOR ISLANDS, LEKKI AND IBEJU DISTRICT CUSTOMERS

DATE: 6TH September

VENUE: VIRGINROSE RESORTS VICTORIA ISLAND LAGOS

PURPOSE: To engage customers on the areas of our services that they believe require urgent attention.

The following were the issues raised at the stakeholder engagement:

AREA	CHALLENGES/OBSERVATIONS
LEKKI GARDENS AJAH	• BILLING
IBEJU	• BILLING
IBEJU	• TRANSFORMER • NEED PPM
AGUNGI	• NEED PPM • BILLING
VGC	• POOR SUPPLY • UNABLE TO LOAD TOKEN
BADORE	• METERS • FAULTY METER REPLACEMENT • FAULTY FEEDER • POOR SUPPLY
SANGOTEDO	• BILLING
OMIDIDUN	• UNSTABLE CURRENT
LEKKI COUNTY HOMES	• NEED FOR A QUARTERLY NETWORK MAINTENANCE. •
ELEMEROH	• SAFETY – WEEDS GROWING AROUND TRANSFORMER, TREE AFFECTING HT IN FRONT OF FACILITY [AUTONATION] • POOR SUPPLY • SLOW RESPONSE TO FAULT
IDUMAGBO	• POOR SUPPLY • FAULTY FEEDER • OVERLOADED TRANSFORMERS
LAFIAGI	• BILLING • SAFETY – DILAPIDATED WOODEN POLLS
AJAH – MERRY HILLS ESTATE	• RELIEF TRANSFORMERS NEEDED

	• POOR SUPPLY • WRONGFUL CONNECTION WITHIN THE ESTATE • POOR CUSTOMER RELATION [FROM EFRS]
SHELL TRUSTEE ESTATE	• FAULTY TRANSFORMER

A. 2 Central Circle

STAKEHOLDER ENGAGEMENT MEETING FOR MUSHIN, ORILE, IJORA AND APAPA DISTRICT CUSTOMERS

DATE: 12TH September 2019

VENUE: THE AUDITORIUM, NIGERIAN INSTITUTE OF MEDICAL RESEARCH [NIRM], 6 EDMOND CRESCENT YABA, LAGOS

PURPOSE: To engage customers on the areas of our services that they believe require urgent attention.

The following were the issues raised at the stakeholder engagement:

AREA	CHALLENGES/ OBSERVATION
MASHA	• Safety- poles need to be relocated to a safe distance.
OWOSENI	• Supply/meters
EBUTE METTA	• Safety: Pole mounted transformer broken, slow response to resolving the issue. • Billing: although distribution transformers are metered, billing is still not accurate. • Metering: steps to acquiring meters, shouldn't just be online only but also offline.
ANIMASHAUN	• Billing • Metering
ITIRE/IKATE	• Billing
ODUDUWA	• Billing • Metering • Fault resolution takes time
AJEGUNLE	• Safety: sagging line
SAM SHONIBARE	• Supply • Billing
MUSHIN	• Billing • Metering

A. 3 West Circle

STAKEHOLDER ENGAGEMENT MEETING FOR FESTAC, OJO AND AGBARA DISTRICT CUSTOMERS

DATE: 20TH September 2019

VENUE: SUNFIT INTERNATIONAL LTD. HOTEL, PLOT 327/329 RABIU BABATUNDE TINU ROAD, FESTAC TOWN, LAGOS.

PURPOSE: To engage customers on the areas of our services that they believe need the most attention.

The following were the issues raised at the stakeholder engagement:

AREA	**CHALLENGES/ OBSERVATION**
BADAGRY	• BILLING • PPM
FESTAC	• BILLING • SUPPLY • ILLEGAL CONNECTION
ABOJU - FESTAC	• CUSTOMER RELATIONS • BILLING • NO METERS ON DTs
OJO	• BILLING
KIRIKIRI COMMUNITY	• ILLEGAL STRUCTURES • BILLING
FESTAC	• PPM
AGBARA	• ABANDONED TRANSFORMERS • BILLING
IBA - OJO	• BILLING • PPM • ILLEGAL CONNECTION
OLAOLUWA COMMUNITY	• BILLING • PPM

Annex B Timeline

Table 25: Nigerian Electricity Supply Industry Timeline of Transaction and Regulatory Events

		Market			MYTO Model in Use					
Year	Month	Interim Rules - initial period	Interim Rules - Amended	TEM declared but CPs not satisfied	MYTO II Order and Model	MYTO 2.1 Model	MYTO 2.1 Model for TEM (not released)	MYTO 2.1 Model for TEM - 2016 year	MYTO 10 Year Tariff Plan Model	
2012	J									01/06/2012 - start of MYTO II.
	J									31/7/2012 - Privatisation bids submitted.
	A									
	S									
	O									Privatisation bids opened.
	N									
	D									6 Month MYTO Minor Review - no evidence it took place.
2013	J									Privatisation bidder negotiations commenced.
	F									17/02/2013 - signature of Industry documents and payment of 25% of price.
	M									
	A									
	M									
	J									6-month MYTO Review - took place but looked backwards so no tariff change despite huge generation shortfall.
	J									
	A									Signature of Transaction documents & payment of 75% of price.
	S									
	O									
	N									1/11/2013 - Handover.
	D									6-month MYTO Review - no evidence it took place. 04/12/2013 Interim Rules signed.
2014	J									
	F									NERC Letter (17/2/2014) restating Capacity and Energy tariffs and setting Capacity in MWh units.
	M									
	A									
	M									14/05/14 - Revised Interim Rules signed/ 01/05/2014 Fixed Charges Order restricting fixed charges if no power.

Year	Month	Market: Interim Rules - initial period	Market: Interim Rules - Amended	Market: TEM declared but CPs not satisfied	MYTO Model in Use: MYTO II Order and Model	MYTO Model in Use: MYTO 2.1 Model	MYTO Model in Use: MYTO 2.1 Model for TEM (not released)	MYTO Model in Use: MYTO 2.1 Model for TEM - 2016 year	MYTO Model in Use: MYTO 10 Year Tariff Plan Model	
	J									6-month MYTO Minor Review - wholesale generation prices reduced (and basis changed, consumer tariffs increased for generation).
	J									
	A									
	S									
	O									
	N									CBN in collaboration with the Ministry of Petroleum Resources, Ministry of Power and NERC, signed a MoU for CBN-NEMSF.
	D									6-month MYTO Minor Review - incorporated into the Major Review in Jan 2015.
2015	J									MYTO Major Tariff Review, known as MYTO 2.1. It was assumed in the model that Discos started the Loss Reduction path on 1 January 2013 and were in the third year of their loss reduction path on 1st January 2015.
	F									01/02/2015 Commencement of TEM (Order dated 29/1/2015 and Supplementary Order dated 18th March 2015). CBN-NEMSF disbursement commences.
	M									
	A									01/04/2015 Amended MYTO Tariff Order removing Collection Losses from ATC&C (dated 24/3/2015) - MO/NBET to use PPA prices from MYTO model.
	M									
	J									MYTO Minor Review - did not take place.
	J									Interim Order abolishing Balancing Mechanism (dated 30/07/2015).
	A									
	S									
	O									
	N									
	D									NERC Commissioners 5-year tenure ends and Acting Chairman Appointed.
2016	J									Start of 2016 year in MYTO 2.1 Model, new gas prices and indexation.
	F									Tariff Order and commencement of 10-year Tariff Plan and Model. Model assumed that the first year

Year	Month	Market			MYTO Model in Use					
		Interim Rules - initial period	Interim Rules - Amended	TEM declared but CPs not satisfied	MYTO II Order and Model	MYTO 2.1 Model	MYTO 2.1 Model for TEM (not released)	MYTO 2.1 Model for TEM - 2016 year	MYTO 10 Year Tariff Plan Model	
										of loss reduction was 2015, but reduced allowed losses by removing Ministries, Departments and Agencies (MDA) debts.
	M									Dramatic drop in generation as a result of gas pipeline attacks, the drop in delivered power means tariffs no longer cover costs.
	A									
	M									Naira weakens and PPA FX indexing means cost of generation jumps from 12 N/kWh to 18 N/kWh with no corresponding increase in end-user tariffs, thus exacerbating the liquidity crisis in the sector.
	J									Minor Review undertaken but results not implemented.
	J									Barrister Toluwani judgement issued against NERC.
	A									Discos begin to lose trust of the sector due to declining performance in % remittances to the market.
	S									CBN constitutes two committees to look at means to address the liquidity problems - proposals for an "NBET Bond" to solve the liquidity crisis are tabled.
	O									Senate instructs that the proposal for the NBET Bond be put on hold until a comprehensive fix developed.
	N									Government turns to World Bank for support in solving the sector liquidity crisis - WB visit Abuja for discussions.
	D									MYTO Minor Review - the 7th since Handover - NERC requests Discos proposals for tariffs but results not implemented. FGN reportedly not wanting tariff increase before 2019 elections.
2017	J									2017 MYTO 10 Year tariffs are implemented by Discos but it is not enough to offset the continued rise in the cost of grid generation - now over 20 N/kWh. CBN Issues a new Foreign Exchange Policy in attempt to close gap between the official rate and parallel market. FGN approves ₦701bn Power Assurance Guarantee for NBET.
	F									
	M									Power Sector Recovery Program – jointly developed by FGN and World Bank. Plan has approved in principle by the FEC but gaps remain.

Year	Month	Market			MYTO Model in Use					
		Interim Rules - initial period	Interim Rules - Amended	TEM declared but CPs not satisfied	MYTO II Order and Model	MYTO 2.1 Model	MYTO 2.1 Model for TEM (not released)	MYTO 2.1 Model for TEM - 2016 year	MYTO 10 Year Tariff Plan Model	
	A									
	M									Under section 27 of EPSRA the Minister of Power declares 4 categories of Eligible Customers who will be able to purchase power directly from Successor Gencos and IPPs.
	J									NERC release a Consultation Paper for the Review of MYTO Methodology asking if reviews should become more regular and whether a RDM should be introduced for TCN. MYTO Minor Review - did not take place.
	J									NERC enact the Regulation setting out permit and tariff approval procedures for Mini-Grid Operators.
	A									NERC releases a consultation on Eligible Customers.
	S									
	O									NERC publishes the Eligible Customer Regulations 2017 and 7 Discos declare Force Majeure on grounds of lack of cost reflective tariffs and presence of cross subsidy and in some instances, change of law.
	N									Further details of the ₦701bn PAG facility emerge. Will make up some of the shortfall from Discos remittances to Gencos such that Gencos receive 80% of amounts invoiced.
	D									MYTO Minor Review - undertaken but results delayed.
2018	J									NERC orders tariffs to be frozen at 2017 levels - 2018 change not implemented. Publishes Draft Meter Asset Providers (MAP) Regulations 2017 in attempt to close metering gap.
	F									Assisted by World Bank. NERC prepares and circulates guidelines for Performance Improvement Plan an apparent requirement of the "reset" of the NESI.
	M									MYTO Minor Review - NERC presents outcomes of December 2017 Minor Review to Industry but results not implemented.
	A									A Bill to Amend the EPSR Act of 2005 to proscribe and criminalise Estimated Billing proceeds to its 2nd reading in the National Assembly.
	M									Permanent NERC Chairman - James Adeche Momoh - finally appointed, 29 months after previous.

Year	Month	Market			MYTO Model in Use					
		Interim Rules - initial period	Interim Rules - Amended	TEM declared but CPs not satisfied	MYTO II Order and Model	MYTO 2.1 Model	MYTO 2.1 Model for TEM (not released)	MYTO 2.1 Model for TEM - 2016 year	MYTO 10 Year Tariff Plan Model	
	J									MYTO Minor Review - did not take place.
	J									
	A									
	S									
	O									BPE issued a press statement in October 2018, which clarified that the target date in the Performance Agreements signed with Discos is 31 December 2019.
	N									
	D									MYTO Minor Review - did not take place.
2019	**J**									
	F									
	M									
	A									
	M									NERC issues amended Performance Improvement Plan Guidelines.
	J									MYTO Minor review undertaken but results not implemented in tariffs. Only 2017 and 2018 treated as FM years.
	J									
	A									June minor review tariff orders and minimum remittance percentages published. Tariffs not scheduled to change until January 2020, by which point NERC expects an extraordinary tariff review to have been completed.

Annex C Financial Analysis Assumptions

C. 1 Energy and capacity costs

The capacity and energy charges for the period 2020-2024 are based on the June 2019 MYTO Minor Review Model in nominal terms.

C. 2 Inflation in cost base

In all scenarios, we have applied inflation to operational costs consistent with NERC's June 2019 Minor Review.

The regulatory asset base and CAPEX are inflated in the MYTO model by foreign exchange only. Since the June 2019 Minor Review assumed no change in foreign exchange, this means that the regulatory asset base only increases by CAPEX minus depreciation.

Note that this is an issue with the MYTO model, as US inflation should also be applied to the regulatory asset base to keep the investor whole in real terms.

Annex D Network constraint analysis

The network constraint analysis is discussed in Section 5.3.1.

D. 1 11kV Voltage Level Analysis

Table 26: 11kV Transformation Capacity Analysis

Feeder Name	Transformation Capacity MVA	2019 Maximum Load MVA	2019 Loading (%)	2019 Additional Transformation Capacity MVA	2024 Maximum Load MVA	2024 Loading (%)	2024 Additional Transformation Capacity MVA
BEECHAM	1.5	0.1	6%		0.1	6%	
ESTATE (AGBARA)	0.0	6.6	-	6.62	8.1	-	8.11
EVANS	3.0	0.1	3%		0.1	3%	
SHAGAMU	0.0	8.9	-	8.89	10.8	-	10.84
IJURI	0.2	5.4	3624%	5.32	6.4	4293%	6.32
NESTLE	0.0	0.1	-	0.09	0.1	-	0.09
OPIC	1.3	8.4	645%	7.35	9.5	729%	8.44
OTTO AWORI	0.0	6.6	-	6.56	7.6	-	7.58
AJEAST	0.5	0.1	18%		0.1	18%	
LEVER BROTHERS	10.1	0.1	1%		0.1	1%	
P&G	6.2	5.1	82%	0.15	5.1	82%	0.15
AJARA	0.0	8.3	-	8.34	9.1	-	9.10
BADAGRY	22.3	5.9	27%		7.0	32%	
DEDICATED LINE	0.0	0.0	-	0.00	0.0	-	0.00
ADDO ROAD	23.5	6.0	26%		7.8	33%	
BADORE	2.6	5.1	197%	3.01	6.8	263%	4.71
GOLDEN SWAM	0.0	5.6	-	5.56	7.1	-	7.10
LANGBASA	15.1	6.6	43%		8.6	57%	
AJIWE	0.5	5.2	1039%	4.80	6.6	1328%	6.24
ESTATE (AJAH)	0.0	5.5	-	5.53	7.0	-	7.03
OGOMBO	26.1	6.4	25%		8.2	32%	
VGC IKOTA	22.4	4.3	19%		5.2	23%	
VGC ROAD 4	21.7	6.8	31%		6.8	31%	
VGC ROAD 2	15.6	4.4	28%		4.4	28%	
VGC ROAD 3	22.7	4.1	18%		4.2	18%	
AWOYAYA	0.0	0.0	-	0.00	0.0	-	0.00

Feeder Name	Transformation Capacity MVA	2019 Maximum Load MVA	2019 Loading (%)	2019 Additional Transformation Capacity MVA	2024 Maximum Load MVA	2024 Loading (%)	2024 Additional Transformation Capacity MVA
BOGIJE	0.0	0.0	-	0.00	0.0	-	0.00
LAKOWE	0.0	0.0	-	0.00	0.0	-	0.00
SHAPATI	0.0	0.0	-	0.00	0.0	-	0.00
ABOYADE COLE	32.2	4.0	12%		4.9	15%	
ANNEX	30.3	5.9	20%		7.4	25%	
CANTI TOWER	0.0	0.1	-	0.09	0.1	-	0.09
DIDEOLU	23.8	2.8	12%		7.2	30%	
MOBIL (MAROKO)	0.0	0.0	-	0.00	0.0	-	0.00
PALACE ROAD	22.0	4.4	20%		5.7	26%	
ROCKY ESTATE	1.7	6.8	401%	5.46	6.8	401%	5.46
ETIM INYANG	1.0	5.9	591%	5.11	7.5	747%	6.67
MAROKO LOCAL	0.0	0.0	-	0.00	0.0	-	0.00
ONIRU	49.9	3.8	8%		4.9	10%	
PALM SHOPPING MALL	0.1	5.0	4984 %	4.90	5.0	4984 %	4.90
AMUWO EXPRESS	2.0	5.6	285%	4.00	6.0	308%	4.45
TEXLON	22.3	2.4	11%		2.8	13%	
IMAM MEMUDU	12.2	4.7	38%		5.4	44%	
SANYA	6.9	4.0	58%		4.8	69%	
ADELABU	39.9	5.6	14%		6.8	17%	
AGUDA	0.0	5.7	-	5.69	6.8	-	6.79
AKINYELE	1.1	5.2	475%	4.34	6.0	546%	5.12
ADISA BASHUA	30.1	4.7	16%		5.7	19%	
CENSUS	5.8	9.8	168%	5.12	11.7	202%	7.05
ODUTAYO AGBOYIN	14.9	5.6	37%		6.7	45%	
ADETOLA	27.3	6.3	23%		7.4	27%	
BABALOLA EXPRESS	0.1	5.6	11111 %	5.52	5.6	11111 %	5.52
IKATE	6.9	3.3	49%		3.9	57%	
LUTH COMPLEX	11.4	0.1	1%		0.1	1%	
OKOH	77.1	4.6	6%		5.4	7%	
ATUNRASHE	65.1	5.1	8%		6.2	9%	
ISHAGA	82.8	4.4	5%		5.1	6%	
OGUNLANA	95.3	7.3	8%		8.8	9%	
MONTGOMERY 2	5.3	5.1	96%	0.86	6.3	119%	2.04
OJUELEGBA	19.5	4.0	20%		4.7	24%	

Feeder Name	Transformation Capacity MVA	2019 Maximum Load MVA	2019 Loading (%)	2019 Additional Transformation Capacity MVA	2024 Maximum Load MVA	2024 Loading (%)	2024 Additional Transformation Capacity MVA
TEJUOSHO MARKET	0.0	2.6	-	2.62	2.6	-	2.62
EB LOCAL	15.5	6.8	44%		8.1	53%	
JACOB MEWS	1.5	0.0	0%		0.0	0%	
PRINT SERVE	0.0	0.0	-	0.00	0.0	-	0.00
ABEOKUTA EXPRESS	15.2	5.3	35%		6.2	41%	
BORNU WAY	13.2	5.6	42%		6.6	50%	
CAPITAL WORKS	1.7	8.9	539%	7.57	10.1	612%	8.77
FREEMAN (NRC)	0.0	4.0	-	4.00	4.7	-	4.71
HERBERT MACAULAY	4.0	2.8	70%		3.5	87%	0.30
MURITALA MUHAMMED	23.0	3.8	17%		4.8	21%	
SABO EXPRESS	12.0	4.1	34%		4.7	39%	
COKER	8.3	3.4	41%		4.4	53%	
MOSAFEJO	0.0	0.4	-	0.44	0.4	-	0.44
ORILE	3.3	3.6	109%	0.94	4.0	122%	1.39
DEDICATED	0.0	0.0	-	0.00	0.0	-	0.00
BAGCO	15.6	3.4	22%		4.4	28%	
KERNEL	0.0	0.0	-	0.00	0.0	-	0.00
NOVELTY	5.0	1.9	39%		2.4	48%	
NITEL DOMSAT	28.6	5.6	20%		6.9	24%	
PASSAT	4.8	5.1	107%	1.28	5.7	119%	1.89
JIBOWU	0.0	0.0	-	0.00	0.0	-	0.00
MONTGOMERY 1	5.0	4.7	94%	0.72	6.3	126%	2.28
MUSHIN 2	0.0	5.7	-	5.68	5.7	-	5.68
BIRREL	10.2	8.9	87%	0.72	10.6	104%	2.40
FADEYI	0.0	0.0	-	0.00	0.0	-	0.00
NATHAN	0.8	3.7	446%	3.02	4.5	540%	3.80
NIMR	0.1	2.4	1941 %	2.33	2.4	1941 %	2.33
AGEGE MOTOR ROAD	0.0	0.0	-	0.00	0.0	-	0.00
NAFDAC (NEW YABA)	0.0	0.1	-	0.09	0.1	-	0.09
PSYCHATRIC	0.1	3.3	6666 %	3.29	3.3	6666 %	3.29
ONIKE 2	19.5	7.8	40%		9.1	47%	
OYADIRAN	25.5	5.0	20%		5.7	22%	
ONIKE	0.0	0.0	-	0.00	0.0	-	0.00

Feeder Name	Transformation Capacity MVA	2019 Maximum Load MVA	2019 Loading (%)	2019 Additional Transformation Capacity MVA	2024 Maximum Load MVA	2024 Loading (%)	2024 Additional Transformation Capacity MVA
UNILAG 1	46.8	6.3	14%		6.3	14%	
UNILAG 2	0.0	0.0	-	0.00	0.0	-	0.00
1004 1	28.1	3.0	11%		3.7	13%	
ADEOLA HOPEWELL	20.7	6.4	31%		7.8	38%	
RMU LOCAL	24.8	7.5	30%		9.4	38%	
UPDC	0.0	3.5	-	3.49	3.5	-	3.49
1004 EXPRESS	0.0	4.4	-	4.40	4.4	-	4.40
ROAD 12	39.0	5.8	15%		7.2	18%	
AKARIGBERI	0.1	4.4	8889 %	4.40	4.4	8889 %	4.40
IDEJO	0.0	3.5	-	3.55	3.5	-	3.55
MRS	2.3	4.6	202%	2.76	4.7	210%	2.93
KINGSWAY	10.8	3.7	34%		4.9	45%	
MOORE ROAD	38.9	4.7	12%		6.7	17%	
SHAW ROAD	67.8	4.5	7%		6.1	9%	
WHEAT BAKER HOTEL	0.0	0.1	-	0.09	0.1	-	0.09
FALOMO	22.9	3.9	17%		5.0	22%	
IKOYI HOTEL	0.3	0.0	0%		0.0	0%	
MTN	0.5	0.3	53%		0.3	53%	
MULLINER	11.2	4.1	36%		4.9	43%	
STATE HOUSE	50.0	4.2	8%		4.9	10%	
STATION FEEDER	8.9	3.3	37%		3.3	37%	
ALAGBON 11KV	2.7	3.0	112%	0.87	3.7	136%	1.52
BRITISH AMERICA TOBACCO	0.0	4.7	-	4.73	4.7	-	4.73
FOWLER LOCAL	16.8	5.0	30%		6.7	40%	
GLOVER	0.0	4.3	-	4.34	5.2	-	5.17
RUMENS	29.7	5.2	18%		13.1	44%	
OBA	26.3	6.0	23%		7.3	28%	
ADENIJI ADELE	15.8	5.8	37%		6.6	42%	
DOLPHIN	12.2	5.3	43%		5.8	48%	
NTDA	11.5	4.5	39%		5.6	48%	
POSTE RMU	0.7	0.3	37%		0.3	37%	
BAR BEACH	24.6	4.4	18%		5.6	23%	
FEDERAL PALACE EXPRESS	9.1	4.1	45%		4.3	47%	

Feeder Name	Transformation Capacity MVA	2019 Maximum Load MVA	2019 Loading (%)	2019 Additional Transformation Capacity MVA	2024 Maximum Load MVA	2024 Loading (%)	2024 Additional Transformation Capacity MVA
IDOWU MARTINS	0.0	2.4	-	2.38	2.8	-	2.83
MAROKO OVERHEAD	23.2	5.3	23%		6.7	29%	
INDEPENDENCE	2.8	5.3	189%	3.05	6.4	228%	4.15
MACARTHY	0.0	5.3	-	5.28	6.2	-	6.23
MOLONEY	0.0	3.1	-	3.11	3.7	-	3.70
NATIONAL HALL LOCAL	0.0	10.5	41882 %	10.45	10.7	42944 %	10.72
ONIKAN 1	8.3	2.4	29%		2.4	29%	
SUPREME COURT	0.0	0.0	-	0.00	0.0	-	0.00
LAPAL	3.3	2.6	80%		3.6	109%	0.96
AWOLOWO ROAD	1.9	5.6	300%	4.08	7.0	377%	5.50
GTB	0.0	2.2	-	2.22	2.2	-	2.22
OBALENDE	2.7	0.1	3%		0.1	3%	
RAYMOND NJOKU	20.8	6.5	31%		8.3	40%	
ST. GREGORY	15.9	5.3	33%		5.9	37%	
CORPORATION DRIVE	16.8	5.6	33%		6.9	41%	
HERITAGE	0.1	3.9	3871 %	3.79	3.9	3871 %	3.79
OSBORNE	18.3	4.3	23%		5.3	29%	
PARKVIEW	39.2	6.1	16%		8.4	21%	
2ND AVENUE	47.0	5.8	12%		7.6	16%	
FEDERAL SECRETARIAT	0.9	10.0	1111 %	9.28	11.1	1234 %	10.39
FORESHORE	14.7	3.2	22%		8.4	57%	
MOBOLAJI JOHNSON	0.0	4.6	-	4.64	4.7	-	4.72
FEDERAL PALACE 2	5.4	3.0	56%		3.8	72%	
ICON	0.0	3.2	-	3.17	3.7	-	3.74
OLOGUN AGBAJE	22.2	2.2	10%		2.8	12%	
OZUMBA MBADIWE	7.2	3.3	46%		3.5	48%	
ADELEKE ADEDOYIN	17.6	10.0	57%		12.7	73%	
ELEKE CRESCENT	4.8	5.4	112%	1.54	7.0	145%	3.14
MEGA PLAZA	0.0	4.0	-	4.02	4.0	-	4.02
NEST OIL	0.0	2.0	-	1.95	2.0	-	1.95
NIPOST	0.0	0.9	-	0.87	0.9	-	0.87
PARLIAMENTRY	7.6	5.4	72%		6.8	91%	0.81
ALABA (AMUWO)	0.0	5.2	-	5.22	6.4	-	6.38

Feeder Name	Transformation Capacity MVA	2019 Maximum Load MVA	2019 Loading (%)	2019 Additional Transformation Capacity MVA	2024 Maximum Load MVA	2024 Loading (%)	2024 Additional Transformation Capacity MVA
ARMY SIGNAL	7.0	5.5	78%		6.6	95%	1.02
CARDOSO	12.1	5.0	41%		5.6	46%	
MBA	5.8	4.2	73%		5.1	88%	0.48
OBA PALACE	10.8	7.1	66%		8.3	77%	
71 ROAD	12.1	5.9	49%		6.9	57%	
72 ROAD	0.0	0.1	-	0.09	0.1	-	0.09
4TH AVENUE	0.0	0.0	-	0.00	0.0	-	0.00
6TH AVENUE	14.9	5.3	36%		6.3	42%	
22 ROAD	0.7	1.5	213%	0.93	1.9	276%	1.37
512 ROAD	12.4	5.0	40%		6.1	49%	
AGBOJU	2.1	5.3	254%	3.65	6.4	307%	4.76
311 ROAD	24.1	7.2	30%		9.0	37%	
321 ROAD	5.3	1.5	29%		1.8	34%	
5TH AVENUE	2.1	2.6	125%	0.92	3.4	164%	1.72
7TH AVENUE	9.7	5.0	52%		6.0	61%	
BEACHLAND	26.5	4.7	18%		5.7	21%	
VANGUARD	6.0	0.7	12%		0.7	12%	
KIRIKIRI INDUSTRIAL	21.0	5.1	24%		6.1	29%	
OLODI	18.0	5.4	30%		6.2	35%	
COMFORT OBOH	11.0	5.2	47%		5.7	52%	
ALAKIJA	15.6	6.4	41%		7.7	49%	
CHEVRON	11.4	6.1	54%		7.5	66%	
ABULE OSHUN	2.6	0.0	0%		0.0	0%	
COMMUNITY	7.9	5.1	65%		6.4	81%	0.08
IJEGUN	13.4	9.2	69%		11.1	83%	0.38
PROMENADE	0.0	0.0	-	0.00	0.0	-	0.00
COMMERCIAL	8.6	3.2	38%		3.9	46%	
PLAZA	2.7	10.0	377%	7.88	12.3	464%	10.19
HANDICRAFT	3.7	1.1	29%		1.1	30%	
OLOFIN	12.4	5.6	45%		7.0	56%	
WAREHOUSE	44.0	4.8	11%		6.0	14%	
WHARF ROAD	49.3	3.9	8%		4.7	10%	
AJEGUNLE EXPRESS	9.2	6.8	74%		7.5	81%	0.10
BOUNDARY	14.4	5.9	41%		7.0	49%	

Feeder Name	Transformation Capacity MVA	2019 Maximum Load MVA	2019 Loading (%)	2019 Additional Transformation Capacity MVA	2024 Maximum Load MVA	2024 Loading (%)	2024 Additional Transformation Capacity MVA
BROSETTE	18.2	4.4	24%		5.8	32%	
VANLEER	23.5	2.7	11%		3.2	14%	
CENTRAL AVENUE	18.7	5.0	27%		6.4	34%	
MOBIL (APAPA)	0.0	9.6	-	9.56	11.0	-	10.99
SHELL TANK	21.8	6.7	31%		6.7	31%	
CROWN FLOUR MILLS	7.1	0.8	11%		0.8	11%	
TINCAN PORT	0.0	0.2	-	0.18	0.2	-	0.18
FREEMAN (AJELE)	0.0	8.1	-	8.06	10.3	-	10.29
NEPA 2	1.3	5.5	432%	4.49	7.0	550%	6.00
TOKUNBOH	13.3	7.8	58%		8.8	66%	
AJELE LOCAL	13.4	4.4	33%		4.8	36%	
NEPA 1	0.4	5.3	1424 %	5.04	5.3	1424 %	5.04
ODUNFA	4.7	4.7	102%	1.02	5.4	117%	1.71
CSS	26.5	8.3	32%		9.9	37%	
NEW CUSTOMS	0.9	3.0	324%	2.26	3.6	392%	2.88
TBS	12.1	4.7	39%		5.6	46%	
ABEOKUTA XI	0.5	6.7	1333 %	6.27	7.5	1491 %	7.06
APAPA 2	6.2	4.4	72%		4.8	77%	
CAUSEWAY 2	0.0	5.6	-	5.56	5.6	-	5.65
EB1	23.3	5.0	22%		5.9	25%	
CAUSEWAY 1	3.4	1.3	39%		1.3	39%	
IGANMU 11KV	0.0	4.0	-	4.00	4.9	-	4.91
N.B.L	0.6	10.0	1667 %	9.52	10.0	1667 %	9.52
NATIONAL ART THEATRE	0.2	1.2	543%	1.04	1.2	543%	1.04
NEPA 11KV	0.9	6.1	679%	5.39	7.5	837%	6.82
OTTO PALACE	0.0	0.6	-	0.62	0.6	-	0.63
ZAIN	0.0	0.1	-	0.09	0.1	-	0.09
AUTOTELEX	0.0	0.0	-	0.00	0.0	-	0.00
EKO BRIDGE	3.1	8.6	277%	6.11	9.8	317%	7.36
M&K EXPRESS	8.4	6.7	79%		8.3	98%	1.55
OLD NIGER	1.7	3.3	196%	1.97	4.4	261%	3.07
PZ	14.3	4.8	33%		5.5	39%	
UNITY (CUSTOM)	0.0	0.8	-	0.79	0.8	-	0.79

Feeder Name	Transformation Capacity MVA	2019 Maximum Load MVA	2019 Loading (%)	2019 Additional Transformation Capacity MVA	2024 Maximum Load MVA	2024 Loading (%)	2024 Additional Transformation Capacity MVA
GBO	0.0	4.5	-	4.48	5.9	-	5.90
M&K LOCAL	9.3	5.7	61%		6.9	74%	
PLANK MARKET	2.5	5.5	226%	3.56	6.3	256%	4.30
SARI	2.7	4.0	150%	1.86	4.5	170%	2.40
ADELEYE	1.9	5.0	263%	3.47	5.6	296%	4.11
AMUKOKO	5.8	4.0	70%		4.5	78%	
BADIA	1.0	4.3	444%	3.55	4.9	500%	4.10
ODOFIN	9.5	5.0	53%		5.6	59%	
SULE	0.0	0.0	-	0.00	0.0	-	0.00
NAFDAC (ISOLO)	0.0	0.1	-	0.09	0.1	-	0.09
ILASAMAJA	18.2	5.7	31%		6.7	37%	
FIVE STAR	12.9	4.4	34%		5.2	40%	
PAPA AJAO	12.9	7.6	59%		8.8	68%	
BABALOLA	2.2	5.0	230%	3.26	5.8	269%	4.11
IDI ARABA	0.0	5.1	-	5.13	6.1	-	6.10
DANIYAN	1.7	8.0	469%	6.61	8.6	506%	7.24
LUTH EXPRESS	6.7	6.7	100%	1.31	7.9	118%	2.55
LADIPO	0.0	4.4	-	4.44	5.5	-	5.50
OSHODI EXPRESS	11.4	3.6	32%		3.6	32%	
ARMY RESETTLEMENT	2.4	4.0	169%	2.09	5.1	215%	3.18
CHALLENGE	8.6	9.8	114%	2.93	11.0	128%	4.13
FATAI ATERE	11.4	6.2	55%		7.5	66%	
FEDERAL MEDICAL STORE	0.0	0.3	-	0.26	0.3	-	0.26
NITEL	3.9	3.3	86%	0.23	4.0	104%	0.92
FIRRO	0.0	0.1	-	0.09	0.1	-	0.09
NAFDAC (NITEL)	0.0	0.7	-	0.70	0.7	-	0.70
CELE	6.7	5.6	83%	0.20	6.6	98%	1.23
OLOWU	12.8	7.8	61%		9.3	73%	
SMITH	18.9	5.1	27%		6.1	32%	
ADESHINA	32.6	5.0	15%		5.9	18%	
ODO ERAN	5.7	7.2	127%	2.66	8.0	140%	3.44
ONITIRE	12.6	4.8	38%		5.3	42%	
AJIRAN	34.5	6.0	17%		7.8	23%	
OSAPA	7.9	5.8	73%		7.2	91%	0.84

Feeder Name	Transformation Capacity MVA	2019 Maximum Load MVA	2019 Loading (%)	2019 Additional Transformation Capacity MVA	2024 Maximum Load MVA	2024 Loading (%)	2024 Additional Transformation Capacity MVA
SPG	27.7	5.4	20%		7.1	26%	
ADMIRALTY	41.0	4.7	12%		6.4	16%	
LADI ALAKIJA	2.2	6.1	284%	4.39	34.5	1606 %	32.80
PRIME WATER VIEW	0.8	5.4	654%	4.74	5.4	654%	4.74
JAZZ 38	3.8	3.8	100%	0.75	3.8	100%	0.75
JUBRIL AYINLA	25.0	4.9	20%		11.9	48%	
WATER CORPORATION	48.5	5.5	11%		7.1	15%	
WOLE OLATEJU	24.8	4.6	19%		5.8	23%	
BASHORUN OGUNSANYA	32.9	6.8	21%		8.8	27%	
FOLA OSHIBO	20.8	5.4	26%		6.8	33%	
VICTORIA AROBIEKE	18.8	3.6	19%		4.4	23%	
LANDBRIDGE	0.0	3.9	-	3.89	4.0	-	3.98
MARKET ROAD	31.6	3.9	12%		4.0	13%	
MARWA	19.6	3.7	19%		5.2	27%	
ILOGBO	9.0	6.4	72%		7.3	81%	0.06
SABO	7.0	6.1	87%	0.51	7.2	102%	1.56
SHIBIRI	31.1	7.0	23%		8.0	26%	
AKA	0.3	4.4	1460 %	4.14	4.4	1460 %	4.14
IGBEDE	9.8	5.6	57%		6.3	64%	
JAKANDE	6.5	7.8	121%	2.64	8.9	137%	3.69
ALABA (ALABA)	39.7	0.0	0%		0.0	0%	
ILUFE	21.4	3.8	18%		4.2	20%	
ESTATE (IBA)	0.0	4.2	-	4.22	4.8	-	4.82
UNITY (IBA)	52.9	6.1	12%		7.0	13%	
LASU	1.4	5.9	421%	4.77	5.9	421%	4.77
OBA GORIOLA	0.0	0.0	-	0.00	0.0	-	0.00
ASPANDA	0.0	0.1	-	0.09	0.1	-	0.09
AULIC	0.0	0.1	-	0.09	0.1	-	0.09
BALOGUN	0.0	0.2	-	0.18	0.2	-	0.18
LAKEVIEW	0.0	0.1	-	0.09	0.1	-	0.09
PROGRESSIVE	0.0	0.1	-	0.09	0.1	-	0.09
TRADE FAIR MOTEL	0.0	0.1	-	0.09	0.1	-	0.09
IJANIKIN	13.1	6.4	49%		7.4	56%	

Feeder Name	Transformation Capacity MVA	2019 Maximum Load MVA	2019 Loading (%)	2019 Additional Transformation Capacity MVA	2024 Maximum Load MVA	2024 Loading (%)	2024 Additional Transformation Capacity MVA
OKOKOMAIKO	8.1	8.1	100%	1.63	9.1	113%	2.65
SATELITE 2	23.5	6.0	26%		7.1	30%	
ARMY CANTONMENT	7.6	5.4	72%		5.7	76%	
IBA	24.2	6.7	28%		8.2	34%	
OJO	9.7	7.0	72%		8.5	87%	0.72
SATELITE 1	27.2	5.9	22%		7.0	26%	
DEDICATED LINE	0.0	0.0	-	0.00	0.0	-	0.00

D. 2 33kV Voltage Level Analysis

Table 27: EKEDC 33/11kV Power Transformers Loading Analysis in 2019 and 2024

			2019			2024		
Injection Substation	Transformer	Nameplate Capacity MVA	Maximum Demand MVA	Capacity Ratio %	N-0 Relief	Maximum Demand MVA	Capacity Ratio %	N-0 Relief
AGBARA	AGBARA T4 15MVA	15.00	11.4	76%		13.9	93%	1 x 15 MVA
AGBARA	AGBARA T5 15MVA	15.00	16.0	106%	1 x 15 MVA	18.4	123%	1 x 15 MVA
AGBARA	AGBARA T6 15MVA	15.00	5.2	35%		5.2	35%	
BADAGRY	BADAGRY T2 15MVA	15.00	11.6	78%		12.6	84%	1 x 15 MVA
BADAGRY	BADAGRY T2 15MVA	15.00	3.3	22%		3.5	23%	
OKE IRA	OKE IRA T1 15MVA	15.00	10.7	71%		14.1	94%	1 x 15 MVA
OKE IRA	OKE IRA T2 15MVA	15.00	11.3	75%		14.6	97%	1 x 15 MVA
AJAH LOCAL	AJAH LOCAL T1 15MVA	15.00	15.0	100%	1 x 15 MVA	19.1	127%	1 x 15 MVA
VGC	VGC T1 15MVA	15.00	9.2	61%		9.6	64%	
VGC	VGC T2 15MVA	15.00	5.9	40%		6.0	40%	
MAROKO	MAROKO T1 15MVA	15.00	14.7	98%	1 x 15 MVA	17.6	117%	1 x 15 MVA
MAROKO	MAROKO T2 15MVA	15.00	9.2	61%		11.1	74%	
ELEMORO	ELEMORO T1 15MVA	15.00	0.0			0.0		

			2019			2024		
Injection Substation	Transformer	Nameplate Capacity MVA	Maximum Demand MVA	Capacity Ratio %	N-0 Relief	Maximum Demand MVA	Capacity Ratio %	N-0 Relief
SANYA	SANYA T1 15MVA	15.00	7.5	50%		8.3	55%	
SANYA	SANYA T2 15MVA	15.00	8.1	54%		9.5	63%	
ADELABU	ADELABU T1 15MVA	15.00	14.5	97%	1 x 15 MVA	17.1	114%	1 x 15 MVA
ADELABU	ADELABU T2 15MVA	15.00	17.5	117%	1 x 15 MVA	21.0	140%	1 x 15 MVA
ADELABU	ADELABU T3 15MVA	15.00	14.3	95%	1 x 15 MVA	15.9	106%	1 x 15 MVA
LUTH	LUTH T1 15MVA	15.00	4.7	31%		5.5	37%	
LUTH	LUTH T2 15MVA	15.00	12.1	81%	1 x 15 MVA	14.5	97%	1 x 15 MVA
TEJUOSHO	TEJUOSHO T1 15MVA	15.00	8.8	59%		10.6	70%	
NRC	NRC T1 15MVA	15.00	6.8	46%		8.1	54%	
NRC	NRC T2 15MVA	15.00	18.4	123%	1 x 15 MVA	21.2	142%	1 x 15 MVA
NRC	NRC T3 15MVA	15.00	9.0	60%		10.9	73%	
ORILE COKER	ORILE COKER T1 15MVA	15.00	6.5	44%		7.6	51%	
IGANMU	IGANMU T1 15MVA	15.00	0.0			0.0		
IGANMU	IGANMU T2 15MVA	15.00	4.9	32%		6.1	41%	
IGANMU	IGANMU T3 15MVA	15.00	8.7	58%		10.3	69%	
NEW YABA	NEW YABA T1 15MVA	15.00	9.3	62%		10.8	72%	
NEW YABA	NEW YABA T2 15MVA	15.00	11.1	74%		13.1	87%	1 x 15 MVA
NEW YABA	NEW YABA T3 15MVA	15.00	3.4	23%		3.4	23%	
SABO	SABO T1 15MVA	15.00	11.7	78%		13.6	91%	1 x 15 MVA
AKOKA LOCAL	AKOKA LOCAL T3 15MVA	15.00	6.3	42%		6.3	42%	
ADEMOLA	ADEMOLA T2 15MVA	15.00	15.2	102%	1 x 15 MVA	18.5	124%	1 x 15 MVA
ADEMOLA	ADEMOLA T3 15MVA	15.00	8.0	53%		8.8	59%	
NEPA CLOSE	NEPA CLOSE T1 15MVA	15.00	11.0	73%		11.1	74%	
FOWLER	FOWLER T2 15MVA	15.00	10.9	72%		15.0	100%	1 x 15 MVA
FOWLER	FOWLER T3 15MVA	15.00	10.1	67%		11.9	79%	
FOWLER	FOWLER T1 15MVA	15.00	16.6	111%	1 x 15 MVA	19.5	130%	1 x 15 MVA
NEW IDUMAGBO	NEW IDUMAGBO T1 15MVA	15.00	6.0	40%		7.3	48%	

			2019			2024		
Injection Substation	Transformer	Nameplate Capacity MVA	Maximum Demand MVA	Capacity Ratio %	N-0 Relief	Maximum Demand MVA	Capacity Ratio %	N-0 Relief
NEW IDUMAGBO	NEW IDUMAGBO T2 15MVA	15.00	10.3	69%		11.5	77%	
ADEMOLA	ADEMOLA T1 15MVA	15.00	0.1	1%		0.1	1%	
ANIFOWOSHE	ANIFOWOSHE T1 15MVA	15.00	12.6	84%	1 x 15 MVA	15.0	100%	1 x 15 MVA
ADEMOLA	ADEMOLA T1 15MVA	15.00	4.5	30%		5.6	37%	
BERKLEY	BERKLEY T1 15MVA	15.00	8.6	58%		10.4	70%	
BERKLEY	BERKLEY T2 15MVA	15.00	10.6	71%		10.9	72%	
BERKLEY	BERKLEY T3 15MVA	15.00	2.6	18%		3.6	24%	
BERKLEY	BERKLEY T2 15MVA	15.00	0.0			0.0		1 x 2.5 MVA
KEFFI	KEFFI T1 15MVA	15.00	13.7	92%	1 x 15 MVA	16.5	110%	1 x 15 MVA
ALAGBON LOCAL	ALAGBON LOCAL T1 15MVA	15.00	15.4	103%	1 x 15 MVA	16.6	110%	1 x 15 MVA
ALAGBON LOCAL	ALAGBON LOCAL T2 15MVA	15.00	18.3	122%	1 x 15 MVA	16.3	109%	1 x 15 MVA
ANIFOWOSHE	ANIFOWOSHE T2 15MVA	15.00	8.7	58%		10.2	68%	
ANIFOWOSHE	ANIFOWOSHE T3A 15MVA	15.00	18.9	126%	1 x 15 MVA	23.0	154%	1 x 15 MVA
AMUWO LOCAL	AMUWO LOCAL T1 15MVA	15.00	16.9	113%	1 x 15 MVA	20.1	134%	1 x 15 MVA
AMUWO LOCAL	AMUWO LOCAL T2 15MVA	15.00	7.1	47%		8.3	55%	
4TH AVENUE	4TH AVENUE T1 15MVA	15.00	6.0	40%		6.9	46%	
4TH AVENUE	4TH AVENUE T2 15MVA	15.00	5.3	36%		6.3	42%	
FESTAC	FESTAC T1 15MVA	15.00	9.1	61%		11.1	74%	
FESTAC	FESTAC T2 15MVA	15.00	12.1	81%	1 x 15 MVA	14.6	98%	1 x 15 MVA
KIRIKIRI	KIRIKIRI T1 15MVA	15.00	5.2	35%		6.2	41%	
KIRIKIRI	KIRIKIRI T2 15MVA	15.00	9.6	64%		11.3	75%	
KIRIKIRI	KIRIKIRI T3 15MVA	15.00	5.2	35%		5.7	38%	
SATELLITE	SATELLITE T1 15MVA	15.00	11.7	78%		14.1	94%	1 x 15 MVA
SATELLITE	SATELLITE T3 15MVA	15.00	10.9	73%		13.2	88%	1 x 15 MVA
APAPA MAINS	APAPA MAINS T2 15MVA	15.00	11.0	73%		13.5	90%	1 x 15 MVA
APAPA MAINS	APAPA MAINS T3 15MVA	15.00	13.9	93%	1 x 15 MVA	17.1	114%	1 x 15 MVA
APAPA ROAD LOCAL	APAPA ROAD LOCAL T1 15MVA	15.00	14.9	99%	1 x 15 MVA	17.5	117%	1 x 15 MVA

			2019			2024		
Injection Substation	Transformer	Nameplate Capacity MVA	Maximum Demand MVA	Capacity Ratio %	N-0 Relief	Maximum Demand MVA	Capacity Ratio %	N-0 Relief
APAPA ROAD LOCAL	APAPA ROAD LOCAL T2 15MVA	15.00	12.7	84%	1 x 15 MVA	14.2	94%	1 x 15 MVA
TIN CAN	TIN CAN T1 15MVA	15.00	0.8	5%		0.8	5%	
TIN CAN	TIN CAN T2 15MVA	15.00	0.2	1%		0.2	1%	
AJELE	AJELE T2 15MVA	15.00	11.3	75%		14.1	94%	1 x 15 MVA
AJELE	AJELE T3 15MVA	15.00	9.4	62%		10.1	67%	
AJELE	AJELE T1 15MVA	15.00	9.3	62%		11.1	74%	
IJORA CAUSEWAY	IJORA CAUSEWAY T1 15MVA	15.00	14.1	94%	1 x 15 MVA	15.4	103%	1 x 15 MVA
IJORA CAUSEWAY	IJORA CAUSEWAY T2 15MVA	15.00	15.5	103%	1 x 15 MVA	16.5	110%	1 x 15 MVA
IJORA CAUSEWAY	IJORA CAUSEWAY T3 15MVA	15.00	0.1	1%		0.1	1%	
NEW CUSTOM	NEW CUSTOM T1 15MVA	15.00	11.3	75%		13.2	88%	1 x 15 MVA
NEW CUSTOM	NEW CUSTOM T2 15MVA	15.00	4.5	30%		5.9	39%	
NEW CUSTOM	NEW CUSTOM T3 15MVA	15.00	5.7	38%		6.9	46%	
BADIA	BADIA T1 15MVA	15.00	8.6	58%		9.8	66%	
BADIA	BADIA T2 15MVA	15.00	15.0	100%	1 x 15 MVA	16.9	112%	1 x 15 MVA
ISOLO LOCAL	ISOLO LOCAL T1 15MVA	15.00	0.1	1%		0.1	1%	
ISOLO LOCAL	ISOLO LOCAL T2 15MVA	15.00	5.7	38%		6.7	45%	
ISOLO LOCAL	ISOLO LOCAL T3 15MVA	15.00	9.9	66%		11.5	77%	
IDI ARABA	IDI ARABA T1 15MVA	15.00	9.0	60%		10.6	71%	
IDI ARABA	IDI ARABA T2 15MVA	15.00	9.1	61%		10.0	67%	
NITEL	NITEL T1 15MVA	15.00	5.9	39%		7.0	46%	
NITEL	NITEL T2 15MVA	15.00	14.8	99%	1 x 15 MVA	17.8	119%	1 x 15 MVA
NITEL	NITEL T3 15MVA	15.00	0.8	5%		0.8	5%	
IJESHA	IJESHA T1 15MVA	15.00	14.3	95%	1 x 15 MVA	17.1	114%	1 x 15 MVA
IJESHA	IJESHA T2 15MVA	15.00	14.1	94%	1 x 15 MVA	15.9	106%	1 x 15 MVA
AGUNGI	AGUNGI T1 15MVA	15.00	12.2	81%	1 x 15 MVA	15.8	105%	1 x 15 MVA
LEKKI	LEKKI T1 15MVA	15.00	12.9	86%	1 x 15 MVA	38.1	254%	1 x 15 MVA
WATERFRONT	WATERFRONT T1 15MVA	15.00	3.8	25%		3.8	25%	

			2019			2024		
Injection Substation	Transformer	Nameplate Capacity MVA	Maximum Demand MVA	Capacity Ratio %	N-0 Relief	Maximum Demand MVA	Capacity Ratio %	N-0 Relief
LEKKI	LEKKI T2 15MVA	15.00	13.9	93%	1 x 15 MVA	17.2	115%	1 x 15 MVA
LEKKI	LEKKI T3 15MVA	15.00	14.7	98%	1 x 15 MVA	18.6	124%	1 x 15 MVA
ONIRU	ONIRU T1 15MVA	15.00	9.9	66%		11.1	74%	
AJANGBADI	AJANGBADI T1 15MVA	15.00	17.1	114%	1 x 15 MVA	19.6	130%	1 x 15 MVA
AJANGBADI	AJANGBADI T2 15MVA	15.00	13.7	91%	1 x 15 MVA	15.1	101%	1 x 15 MVA
ALABA	ALABA T1 15MVA	15.00	3.8	25%		4.2	28%	
IBA	IBA T1 15MVA	15.00	8.8	59%		10.1	67%	
IBA	IBA T2 15MVA	15.00	5.9	39%		5.9	39%	
TRADE FAIR	TRADE FAIR T1 7.5MVA	7.50	0.6	8%		0.6	8%	
OJO LOCAL	OJO LOCAL T3 15MVA	15.00	18.2	121%	1 x 15 MVA	20.9	140%	1 x 15 MVA
OJO LOCAL	OJO LOCAL T1 15MVA	15.00	20.5	136%	1 x 15 MVA	24.1	161%	1 x 15 MVA
OJO LOCAL	OJO LOCAL T2 15MVA	15.00	0.0			0.0		

D. 3 33kV Feeder Load Analysis

Table 28: 33kV Feeders Overloading Analysis

33kV Feeders	2019 Overloading (MVA)	2024 Overloading (MVA)
AGBARA LOCAL T4	-	-
AGBARA LOCAL T5	-	-
AGBARA LOCAL T6	-	-
BADAGRY 33	35	43
GUINEA (BETA) GLASS	-	-
AGBARA 33	7	11
OKO AFO	35	43
RYDER GLASS	-	-
BADAGRY EXPRESS	-	-
MAIN ONE	-	-

33kV Feeders	2019 Overloading (MVA)	2024 Overloading (MVA)
ELEKO	-	-
OKE-IRA	-	2
IBEJU	6	15
ILASAN	-	-
ROYAL GARDEN CITY	-	-
AJAH LOCAL T1	-	-
IKATE EXPRESS	-	-
MAROKO	-	2
ELEMORO	-	-
CHEVRON 33	-	-
TWINLAKE	-	-
SANYA 33	-	-
ADELABU 1	4	10
ADELABU 2	-	-
LUTH	-	-
NEW YABA (AKANGBA)	-	-
NRC (AKANGBA)	-	-
NRC (AKOKA)	-	-
AMUWO	-	-
IGANMU 1	-	-
IGANMU 2	-	-
NEW YABA (AKOKA)	-	-
SABO 33	-	-
AKOKA LOCAL T3A	-	-
UNILAG 33	-	-
ADEMOLA 2	1	5
BANANA ISLAND 1	-	-
FOWLER 1	-	-
FOWLER 2	-	-
NEW IDUMAGBO	-	-
ADEMOLA 1	-	-
ANIFOWOSHE 2	-	-
ADEMOLA 1	-	-
BANANA ISLAND 2	-	-
BERKLEY EXPRESS	-	-
FEDERAL SECRETARIAT 33	-	-
FOWLER 3	-	-

33kV Feeders	2019 Overloading (MVA)	2024 Overloading (MVA)
ALAGBON LOCAL T1	-	-
ALAGBON LOCAL T2	-	-
ANIFOWOSHE 1	-	4
AMUWO LOCAL T3	-	0.12
FESTAC 1 (AMUWO)	4	10
SNAKE ISLAND	-	-
KIRIKIRI EXPRESS	-	-
SATELLITE 1 33	-	-
SATELLITE 2 33	-	-
APAPA MAINS 1	-	-
APAPA MAINS 2	-	-
FLOUR MILLS	-	-
NAVAL BASE	-	-
APAPA ROAD LOCAL T1	-	-
APAPA ROAD LOCAL T2	-	-
TINCAN	-	-
UBA/UBN	-	-
AJELE 1	-	-
AJELE 2	-	-
CAUSEWAY 1 33	-	-
CAUSEWAY 2 33	-	-
CUSTOM 1	-	-
CUSTOM 2	-	-
BADIA 33	-	-
PTC	-	-
ISOLO LOCAL	-	-
IDI ARABA 33	-	-
NITEL 33	-	-
IJESHA	0.1	4
AGUNGI	-	-
IGBO EFON	-	-
WATER FRONT	-	12
ELEGUSHI	-	-
LEKKI	2	9
ONIRU 33	-	-
FESTAC 1 (OJO)	15	20
FESTAC 2	-	-

33kV Feeders	2019 Overloading (MVA)	2024 Overloading (MVA)
OJO LOCAL T3	-	-
OJO LOCAL T1	-	-
OJO LOCAL T2	-	-
VOLKSWAGEN	-	-
Count	**10**	**15**
Total Exceedance (MVA)	**109**	**191**

Annex E TCN Station Analysis

Table 29: TCN Station Analysis

TCN	TCN Nameplate Capacity (MVA)	TCN Operational Capacity (MW)	Connected DTR Capacity (MVA)	Demand MW					
Substation	Current	Current	Current	2019	2020	2021	2022	2023	2024
AGBARA	100	65	187	178	182	186	191	196	200
AJAH	690	497	605	176	183	190	197	205	214
AKANGBA	400	288	670	121	125	129	133	137	142
AKOKA	105	76	61	25	25	26	27	28	29
ALAGBON	385	286	765	174	179	184	190	196	203
AMUWO	120	86	251	85	88	91	94	97	100
APAPA ROAD	40	29	231	49	51	52	54	56	58
IJORA	190	137	185	97	99	101	104	107	109
ISOLO	30	22	92	62	64	65	67	68	70
ITIRE	120	86	89	23	24	25	25	26	27
LEKKI	165	119	340	73	76	80	86	96	107

Annex F Asset Registry

EKEDC’s asset registry will be submitted as softcopy.

Annex G List of MDAs

EKEDC's MDA customer list will be submitted as softcopy.

Annex H List of Ongoing Programs

Table 30: List of some of our ongoing programs.

Project	Project Description	Project Type	Unit Cost (Naira Mill)	Quantity	Cost (Naira Mill)	Expected Completion Date (Year)	Upstream Constraints e.g. TCN (Yes/No?)	Upstream Constraints Notes
1	Removal & Replacement of Hazardous Shocking Iron Poles with Concrete Pole at Island Business Unit	HSE	22.04	1	22.04	2019	No	
2	Construction of 15 Relief Transformer Substations within Eko Electricity Distribution PLC's Network - Turbo	Reliability, Distribution Automation	12.54	1	12.54	2019	No	
3		Reliability, Distribution Automation	26.00	1	26.00	2019	No	
4		Reliability, Distribution Automation	17.77	1	17.77	2019	No	
5		Reliability, Distribution Automation	11.03	1	11.03	2019	No	
6		Reliability, Distribution Automation	14.27	1	14.27	2019	No	
7		Reliability, Distribution Automation	13.52	1	13.52	2019	No	
8		Reliability, Distribution Automation	10.43	1	10.43	2019	No	
9		Reliability, Distribution Automation	11.70	1	11.70	2019	No	
10		Reliability, Distribution Automation	11.79	1	11.79	2019	No	
11		Reliability, Distribution Automation	10.17	1	10.17	2019	No	
12		Reliability, Distribution Automation	10.73	1	10.73	2019	No	
13		Reliability, Distribution Automation	11.78	1	11.78	2019	No	
14		Reliability, Distribution Automation	11.78	1	11.78	2019	No	
15		Reliability, Distribution Automation	10.43	1	10.43	2019	No	
16		Reliability, Distribution Automation	11.03	1	11.03	2019	No	
17	Reliability Improvement of 33KV Network	Reliability, Distribution Automation	220.94	1	220.94	2019	Yes	Outage for safe work, loss of revenue as result of shuntdown of the line
18	Construction of 19 Relief Transformer Substations within Eko Electricity Distribution PLC's Network - Kenol	Reliability, Distribution Automation	15.88	1	15.88	2019	No	
19		Reliability, Distribution Automation	15.15	1	15.15	2019	No	
20		Reliability, Distribution Automation	12.36	1	12.36	2019	No	
21		Reliability, Distribution Automation	14.95	1	14.95	2019	No	
22		Reliability, Distribution Automation	16.20	1	16.20	2019	No	
23		Reliability, Distribution Automation	19.00	1	19.00	2019	No	
24		Reliability, Distribution Automation	14.96	1	14.96	2019	No	
25		Reliability, Distribution Automation	14.66	1	14.66	2019	No	
26		Reliability, Distribution Automation	15.78	1	15.78	2019	No	
27		Reliability, Distribution Automation	14.96	1	14.96	2019	No	
28		Reliability, Distribution Automation	15.85	1	15.85	2019	No	
29		Reliability, Distribution Automation	14.92	1	14.92	2019	No	

30		Reliability, Distribution Automation	16.49	1	16.49	2019	No	
31		Reliability, Distribution Automation	15.20	1	15.20	2019	No	
32		Reliability, Distribution Automation	7.99	1	7.99	2019	No	
33		Reliability, Distribution Automation	8.36	1	8.36	2019	No	
34		Reliability, Distribution Automation	6.57	1	6.57	2019	No	
35		Reliability, Distribution Automation	9.95	1	9.95	2019	No	
36		Reliability, Distribution Automation	10.84	1	10.84	2019	No	
37	Proposed Mbu Close 500KVA 11/0.415KV Relief S/S	Reliability, Distribution Automation	1.35	1	1.35	2019	No	
38	Rehabilitation of Alpha Beach Tee-Off on Agungi 33KV Feeder	Reliability, Distribution Automation	23.78	1	23.78	2019	No	
39	Installation of 52 Units of Automated Load Scheduling Device (ALSD) on some selected Feeders and Distribution Transformers within Eko Electricity Distribution PLC's Network	Loss Reduction	3.68	52	191.10	2019	No	
40	Rehabilitation Work on the Lekki TCN and Alagbon TCN Underground Basement	HSE	10.00	1	10.00		Yes	Outage for safe work, loss of revenue as result of shuntdown of the station
41	Proposed Alara II to relieve Alara I 500KVA; 33/0.415KV	Reliability, Distribution Automation	5.85	1	5.85	2019	No	
42	Construction 200KVA; 11/0.415KV at Okotie Eboh Street	Reliability, Distribution Automation	5.66	1	5.66	2019	No	
43	Rehabilitation of Rumens 11KV Feeder covering Bourdillion, Ipewu Junction and Mekwuen Street within Island Business District	Reliability, Distribution Automation	7.07	1	7.07	2019	No	
44	Proposed Rehabilitation of Rumens 11KV Feeder within EKEDP's Island Business Unit	Reliability, Distribution Automation	6.05	1	6.05	2019	No	