# Initial Draft of Performance Improvement Plan

# Enugu Electricity Distribution Plc

**September 2019**

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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

Enugu Electricity Distribution company is a utility that covers five states in Nigeria. It took over the PHCN in the south-eastern region in 2013 as a majority shareholder with the Nigerian government.

EEDC has a network of 33/11 kV feeders spanning 10,252 km with 18 business units and 151 service centres to ensure proximity to customers and improve customer access and satisfaction. We currently serve 1,036,655 customers with our staff strength of 5,087 serving these customers at different levels. There is expectation that these staff numbers will increase to meet the increasing customer numbers.

The outputs of this plan have been decided by the Disco team after a rigorous process of listing and prioritising. The targets project that over the five years covered in this plan, the ATCC loss would be 30% under the Full CAPEX scenario and 34% under the minimal CAPEX scenario with 1.8 million customers. In order to meet the expected loss reduction thresholds as set out in this plan, EEDC would need a CAPEX of N 40bn over the 5-year period and OPEX of N 118bn in the same period to be able to meet these targets and the levels of reliability and availability as proposed.

It is intended to use these funds for network reinforcements and upgrades to increase the capacity of the network to meet the growing demand in our franchise area. It is our target to have availability of over 80% on our network at the end of the period planned and to serve 25.8% more customers as well as increase the reliability so as to reintroduce some of the large industrial customers who have gone off-grid. It is expected that the funding for this plan would be raised from shareholder loans as well as the Siemens intervention of the Federal Government. In the event that there are none of these interventions, there will only be the possibility of funding through IGR.

The financing plan is important as this will impact the tariffs and would determine the rate of increase in coming years. Based on the scenarios in this report, the average tariff could go from the present rate of 35N/kWh to as high as 91N/kWh.

# 2 Overview

According to NERC's requirements and guidelines for the Performance Improvement Plan, EEDC has prepared this document which sets out the operational plans of the Disco for the years 2020 – 2024. This plan is a result of internal consulting, engagement with a cross section of stakeholders as well as internal planning.

The purpose of this plan is to improve power supply and increase customer satisfaction in our franchise area. We aim to do this by the following:

- Increasing reliability and customer satisfaction;
- Deploying an effective metering plan;
- Increasing resource capability;
- Ensuring safety standards; and
- Increasing stakeholder engagement

Our strategy is to increase efficiency by improving our processes and making them more efficient and improve company culture to ensure that staff are motivated to make the changes that are needed for the company's improvement.

The scenarios in this document include:

- A "full CAPEX" scenario that includes full CAPEX;
- A "partial intervention" scenario that includes a minimised CAPEX

In order to meet the targets, set by EEDC, there is need to ensure that the conditions that are laid out in this document are met. This is especially important in the area of tariffs; as the tariffs have to give the right indicators to incentivise financing of the plan by any prospective investors.

There is also the need to address the important regulatory risks inherent in this market as the last few years have been fraught with regulatory risks that have hampered the ability of EEDC to meet its targets and perform its obligatory market roles.

## 2.1 Summary of process

EEDC has followed a robust process to prepare this plan and justify our planned expenditure.

We have set up a team to review our expected performance outputs and develop target outputs from those by taking audits of our departments and assessing the contribution of each to the attainment of these goals; including the resources and the measures that must be put in place.

The process is described in more detail in Section 3.

## 2.2 Scenarios

This PIP considers two scenarios – one “minimal CAPEX” and one “full CAPEX” scenario.

The key characteristics of the two scenarios are:

- A business as usual scenario called “minimal CAPEX” based on NERC tariff assumptions from the latest minor review (June 2019), which treated the end of 2020 as year 4 of ATC&C loss reduction;
- A “full CAPEX” scenario 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 the Disco’s ambitious loss reduction and other output targets.

The “minimal CAPEX” scenario is currently the most probable, as it is consistent with NERC’s public statements to date. However, the “full CAPEX” scenario allows EEDC to achieve their most ambitious output goals.

The scenarios are described in more detail in Section 4.3.

## 2.3 Outputs with intervention

Over five years, the ambitious “full CAPEX” scenario will allow EEDC to:

- Reduce ATC&C losses from the current level of 53% to 22%, which will allow our business to be sustainable;
- Reduce the number of customer interruptions from the current level of 14036 to 4000, increasing reliability for our customers;
- Increase the number of new meters installed from the current level of 70,000 per year to 207,000 per year, 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 from the current average level of 58,000 per year to 70,000 per year.

These outputs are discussed in Section 4.4.

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

## 2.4 Navigating this report

For ease of flow, the map below is helpful to navigate 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 4.4: 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<br>Section 6.9 |
| Criterion 4 - Financing | Are the proposed financing arrangements efficient? | Section 7.5: Funding Plans |
| | Detail of individual financing areas. | Section 7.5: Funding Plans |
| 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

EEDC has designed a stakeholder engagement process that attempts to include all stakeholders in a way that is appropriate for any focus group and receive feedback from them that can be used to serve them better.

This process would be used in the navigation of stakeholder engagement for this PIP. The process includes:

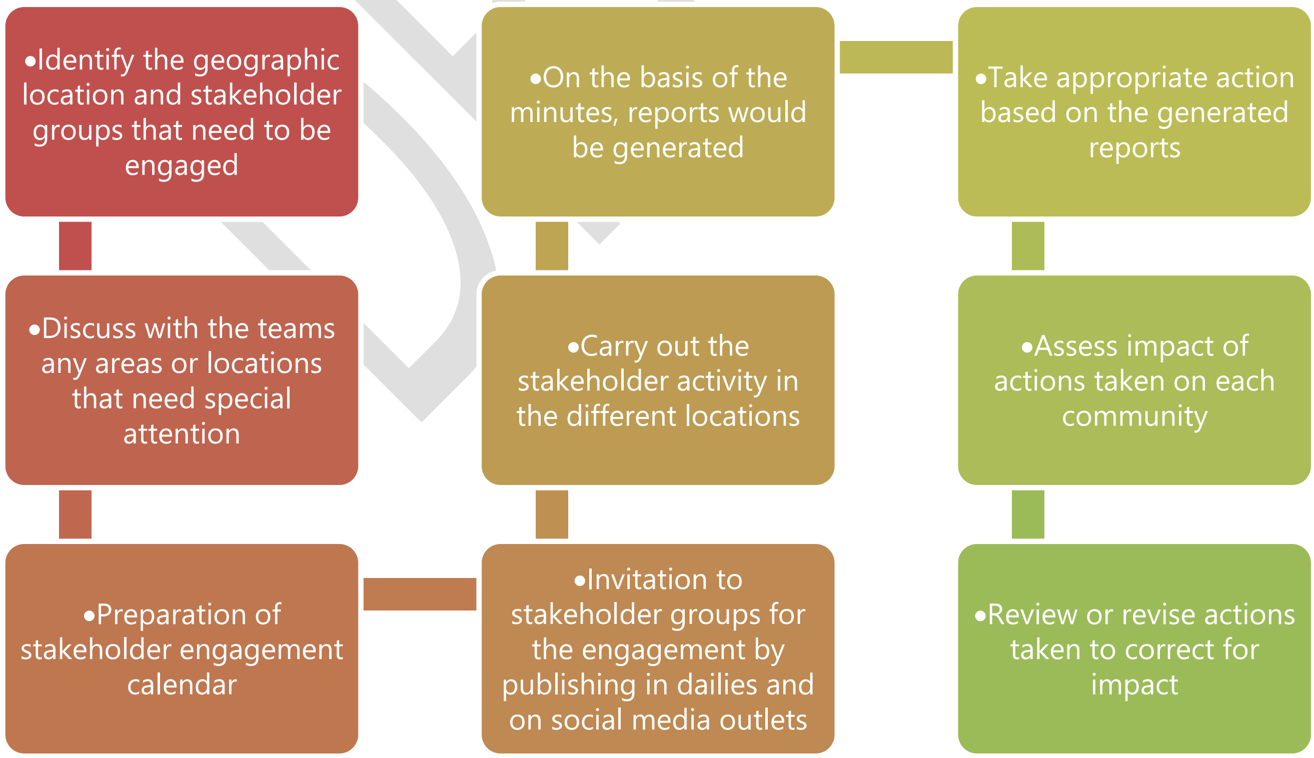


**Figure 1: Stakeholder Engagement Process for EEDC**

## 3.3 Process for demand forecast

In 2018, EEDC commissioned Energy Market and Rates Consultants (EMRC) to carry out a demand forecast.

The demand analysis was conducted using an econometric analysis.

The analysis employed for the 2018 hourly load data received from EEDC comprises two main models, a structural and dynamic regression model. The structural model is applied to consistently energized feeders to develop and reconstruct unsuppressed demand data based on the historical observations (recorded data) of suppressed demand on the feeder data set.

For poorly energized and sparsely populated feeders, the dynamic regression model is applied to develop the hourly demand timeseries using the influence of customer behaviour and seasonal pattern on demand consumption, observed on well energized feeders.

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

## 3.4 Process for setting output goals

EEDC has come up with the output goals in this document by setting up in-house teams in every area of the business who are tasked with assessing the strengths and weaknesses of the current structure and coming up with action plans to leverage on the strengths and improve on areas of weakness.

The basis of assessment is the Performance Agreement and the parameters agreed therein. The outputs of the company are aligned with the PA and then the KPIs for the achievement of these outputs are designed for every department and cascaded to all tiers.

In determining the rate of success or otherwise in the pursuit of these goals, EEDC holds frequent community and stakeholder engagements to enable the assessment of the results of the efforts put in and also enable the community understand and buy into the policies and processes that are put in place for the improvement of services. The results of these stakeholder engagements are then analysed and then the processes and policies are reviewed or redesigned or revisited as necessary.

This will enable the Disco to meet its target output whilst ensuring that customer satisfaction is improved to further increase chances of meeting these targets.

## 3.5 Process for investment planning

In order to ensure that the investments made are the least cost for the greatest returns, EEDC has planning processes in place. These processes are initiated by assessments through studies and from departmental assessments of the team managers. Once the assessments have been carried out, projects are prioritised based on criteria such as importance, safety implications, available funding, revenue projections and customer satisfaction.

### 3.5.1 Process for electricity distribution planning

Electricity distribution investment will help EEDC achieve the following targets:

- Reduce ATC&C losses from the current level of 53% to 22%, which will allow our business to be sustainable;
- Reduce the number of customer interruptions from the current level of 14036 to 4000, increasing reliability for our customers;
- Increase the number of new customer connections from the current average level of 58,000 per year to 70,000 per year.

The electricity distribution planning process has been carried out by initiating assessment of the network and its constraints on a feeder by feeder basis across the EEDC franchise area and this information has been collated and all the necessary investments listed. Based on criteria such as those outlined in this section, the investments have been ranked and prioritised.

Refer to Section 5 and Section 6.

### 3.5.2 Process for commercial operation planning

NERC has set out expectations for several software applications to support commercial operations. EEDC has already been operating with some of these applications for ease of operations. The consideration for the employment of the systems was important as due to the paucity of funds, it is the most important functions of the system to EEDC that have been employed and any missing modules and/or applications would be employed over time as the liquidity situation improves.

These systems and monitoring them will enable accurate assessments of the customer base, improve billing accuracy, reduce theft, improve reliability and overall efficiency of the company. The NERC requirements for the systems were the consideration when choosing the applications that were to be employed. Also, the peculiarities of the needs in the EEDC franchise area were considered and at this point, the Enterprise Resource Planning system and the Commercial Management system are up and running with plans already in place to incorporate the Works Management system by the end of 2019.

The table below shows the systems required by NERC and the status of deployment of these systems:

| No. | Required Management Systems | Status of Deployment |
|---|---|---|
| 1 | Commercial Management System | Deployed[1] |
| 2 | Enterprise Resource Planning | Fully deployed |
| 3 | Revenue Protection Project | Deployed[2] |

### 3.5.3 Process for meter investment planning

Meter investment via Meter Asset Providers will help EEDC achieve the following target:

- Increase the number of new meters installed from the current level of 70,000 per year to 207,000 per year, allowing customers to trust the bills they receive;

EEDC has been working on plans to meter the entirety of its customer base. To this end, it had designed a meter deployment plan and had begun a zone by zone deployment of meters. In 2018 alone, the newly designed deployment plan meant that EEDC was able to meter over 90,000 customers in a 10-month window.

The NERC MAP regulation stipulated that the Discos engage the Meter Asset Providers and EEDC initiated the process by putting out an EOI and then carry out a bidding process and at the end of that process, 2 bidders have been successful and are currently engaged to roll-out meters to our customers.

The actual MAP plans will be in section 6.

[1] No module for service anomalies

[2] No Meter Data Management module included

### 3.5.4 Process for safety investment planning

Health and Safety investment will help EEDC achieve the following target:

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

The Health and Safety department has carried out an assessment on the current state of safety in the Disco amongst the staff and in the communities and has pinpointed the problem areas especially in the matter of safety for the community. To this end, a number of trainings for staff and engagements and knowledge dissemination sessions for the community have been planned to ensure that we meet our target outputs.

The actual H&S plans will be in Section 6.

# 4 Introducing the Context for this PIP

## 4.1 Overview

This section covers:

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

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

## 4.2 Introduction to EEDC

Enugu Electricity Distribution company provides service to 5 states in the South-eastern zone of Nigeria. The company took over operations of the distribution utility in November 2013. At the time, the assumed losses of the network were assumed at 21% and were later updated to 35%. However, the Disco carried out a baseline loss level study in 2014 and the loss level was established to be Y%. This necessitated the review of tariffs to reflect the actual loss levels and this review was carried out by the regulator at different times.

EEDC has been able increase its base of customers from 342,209 in 2014 to 1,036,655 in August 2019. The company commenced its enumeration exercise in accordance to regulatory requirements. It has been able to map all assets and buildings and is in the process of enumerating customers after which there would be an indication of the number of registered customers on the Disco network; enabling the utility to improve its services to customers.

### 4.2.1 Vision

EEDC has a vision to be the number one African integrated utility company in fifteen years. This vision is backed by strategy that the company believes would enable the achievement of the vision in the allotted time.

### 4.2.2 Mission

The mission of the company is to improve the lives of the customers it serves by effectively offering products and services that improve their socioeconomic state thereby enabling their attainment of their economic potential and bringing an improvement in the quality of life.

### 4.2.3 Overall strategy

The initial strategy when the Interstate Electric took over the utility was to introduce measures to increase collections and reduce ATC losses by investing in the network and accounting for all energy users. The strategy included:

- ATC&C loss reduction;
- Supply of adequate, quality and reliable power on a sustainable basis at reasonable costs;
- Closing the metering gap;
- Increase of electricity access to unserved and underserved areas through the network expansion program;
- Enhancement of customer satisfaction;
- Increased safety and discharge of social responsibility.

However, the issues of NESI characterised by the huge gap in demand and supply as well as the lack of capital due to the liquidity issues that have plagued the market have made progress slow in these areas. The issues that faced the utility at inception, such as vandalization of assets, electricity theft, lack of skilled manpower and estimated billing disputes, are still prevalent.

Therefore, given the persistent issues, the current strategy that the Disco has adopted includes the following in order to enable EEDC meet its obligations.

#### 4.2.3.1 *Creation of "Think Tank' Group*

EEDC is in the process of forming a Think Tank Group. This team would seek to define the strategies for EEDC business considering all the sector challenges and the availability of the resources vital for enabling a turnaround in the Disco.

#### 4.2.3.2 *ATC&C Loss Reduction Measures*

The EEDC strategy here is to prioritise supply to high revenue potential areas. Before this is done, there will be a replacement of all faulty meters in the given areas and so EEDC would put in place an adequate inventory of these meters. Although all these measures are capital intensive, EEDC also plans to reduce its technical loss by the reduction of the lengths of the medium voltage feeders.

#### 4.2.3.3 *Increased Billing Efficiency*

Cash flow is most important in the utility business and EEDC has a strategy to maintain this flow by arresting the revenue loss currently suffered due to inefficient billing. An increase in billing efficiency would lead to higher collections and increased revenue. Currently, only about 40% of EEDC customers who number almost a million, are paying for the electricity that they use. EEDC is tackling this by undertaking a customer sensitisation programme; launching campaigns on television and radio. It has already been observed that the radio jingles are helping create awareness amongst customers and other stakeholders. To also support more efficient billing, there is also the network sanitisation programme; a key initiative for the ATC&C loss reduction programme.

#### 4.2.3.4 *Identification of System Constraints*

EEDC has identified some constraints in its system but the remedial actions need to be fast tracked. Some of these actions include; augmentation of the existing conductors, power transformation, creation of additional bays at TCN as well as Disco injection substations. These initiatives, some of which have been undertaken already, are bringing good results in terms of customer satisfaction and additional revenue to EEDC.

#### 4.2.3.5 *Increased Reliability and Customer Satisfaction*

In order to ensure reliable power supply to customers and to enhance customer satisfaction, EEDC has changed its maintenance approach from breakdown to the preventive by making use of advanced tools available in the market. Among the more prominent exercises under the preventive maintenance schedule are overhauling of the aged power transformers, distribution T/Fs, circuit breakers, and replacement of the aged cables and conductors. EEDC is investing huge sums in order to increase the service availability and quality on a sustainable basis. The task is highly challenging and requires lots of resources but EEDC is working hard to optimise the resources in order to remain in the business.

#### 4.2.3.6 *Effective Metering Plan*

In order to address the issue of estimated billing, EEDC recently concluded its MAP procurement process and deployed two MAPs for undertaking the deployment of massive metering. This will help to meet the demand for meters and issuance of the bills to customers as per their actual consumption and not on estimates. Furthermore, the metering would also help in determining the actual ATC&C losses.

#### 4.2.3.7 *Resource Capacity Building*

EEDC appreciates that human resource is capital and therefore is taking a systematic approach like imparting onboard training, conducting workshops for culture transformational programme, and giving staff the required exposure by deputising them to better developed utilities. A new appraisal system has also been introduced so that proper performance evaluation of individuals is done in a scientific manner to retain and promote exceptional staff in EEDC as well as to root out bad elements without any fear or favour.

#### 4.2.3.8 *Incorporation of Customer Care Centre*

Customers are very important to EEDC and resolving the issues they face are uppermost in the mind of the Disco. In order to address this, EEDC has started a 24x7 customer service centre to ensure the fast tracking of issues the customers face.

#### 4.2.3.9 *Increased Ease of Payment*

EEDC appreciates the valued time of the customers and therefore, has opened several payment outlets and platforms to facilitate ease of bill payment and energy purchase.

#### 4.2.3.10 *E-Governance*

EEDC formerly had three discrete billing platforms that made billing and reconciliations quite difficult. In order make use of the advanced but proven technology in the governance of the EEDC business, an ERP system has been launched which has solved the problems created by multiple platforms. All platforms were merged into a singular Customer Information System (database) and made operational from August 1, 2019. This will help to maintain a `single source of truth` across the business and avoid many irregularities/ ambiguities.

### 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 that mean tariffs have not been cost reflective. Table 34 in Annex D 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. |
| 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.<br>– 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.<br>– In April 2015, tariffs are amended to strip out collection losses. The removal of collection loss led the majority of the Discos to issue notice of Force Majeure under their Performance Agreements in 2015.<br>– Minor reviews not implemented. |
| 2016 | No. MDA debts still not resolved.<br>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.<br>– From March 2016, generation dropped dramatically as a result of insurgency, Discos revenue decreased dramatically as a result of less power to sell. |

| Year | Tariff cost reflective? | Events |
| --- | --- | --- |
| | | – From May 2016, foreign exchange weakens considerably, and PPA indexation means cost of generation jumps from 12 N/kWh to 18 N/kWh.<br>– 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.<br>– MDA payments have still not been resolved. |
| 2018 | No. | – Tariff freeze in January 2018, when NERC instructed the Discos to freeze their tariff at the 2017 level.<br>– Six monthly minor reviews in June and December were not implemented.<br>– MDA payments have 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.<br>– 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.

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.

EEDC has already had one customer migrate on this regulation; albeit without regulatory approval; with the possibility of five more customers who might be leaving our network for eligible status. The impact of the company (Inner Galaxy Steel Company) that has left means that EEDC has lost N 3.3bn/yr of securitised revenue and our collection loss has increased by 5%. 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 others. 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 have unintended consequences, such as worsening the ability of market participants to raise capital or reducing the liquidity of the sector.

### 4.2.5 Description of achievements 2013-2019

Regardless of the operational environment, EEDC has been able to record some successes in

| Year | Events |
|---|---|
| 2017 | – Construction of 33kv feeders which improved power supply in the capital of Enugu state.<br>– Commencement of enumeration exercise |
| 2018 | – Increased hours of supply to customers<br>– Improvement of revenue collection from high yield 11kV feeders.<br>– Construction of Injections substations to relieve load<br>– Reduced ATCC in Districts where projects were located |
| 2019 | – Deployment of ERP system<br>– Network reinforcements- provided relief to over loaded transformers in Umuguma, Owerri etc.<br>– Network reinforcements- provided relief to over loaded feeders in Ifite &Enugu Agidi, Owerri etc.<br>– Improved hours of supply to mixed customer population of over 3,544 customers<br>– Increased hours of supply to MD customers in Enugu, Awka, Owerri & Onitsha town.<br>– Improvement of revenue collection in districts where network reinforcements were carried out.<br>– Implementation of Business Process Reengineering. |

## 4.3 Scenarios in this PIP

There are two scenarios considered in this PIP:

- A lean operations scenario called the "minimal CAPEX" based on EEDC's current loss levels and our inability to finance the required CAPEX, with the possible loss reduction from the current reality of EEDC;
- The second scenario is based on a "full CAPEX" as allowed in MYTO. It assumes that EEDC is able to reduce losses considerably and that the cost reflective tariffs based on current realities are allowed.

Both scenarios assume that EEDC is able to take its set energy allocation from the available energy.

In the "minimal CAPEX" scenario, it will not be possible to achieve the full ATC&C loss reduction improvement. The "full 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 these scenarios are summarised in Table 3.

**Table 3: Summary of the two scenarios**

| Assumption | "Minimal CAPEX" inability to raise CAPEX | "Full CAPEX" scenario with cost-reflective tariff and full CAPEX | Detailed description |
|---|---|---|---|
| **Demand** | Full load allocation of energy delivered by TCN | | Section 4.3.1 |
| **Generation levels** | Stable at 2019 levels | | 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** | Tariff is cost reflective and assumes losses to be as they are in reality | Cost reflective tariff with ATC&C assumptions in reality | Section H. 3 |
| **Market shortfall** | Historic shortfall written off based on NERC Minor Review only; new shortfall may be accrued | All historic shortfall written off based on 2020 as year 1 of ATC&C loss reduction; no new shortfall accrued | Section H. 4 |

| Assumption | "Minimal CAPEX" inability to raise CAPEX | "Full CAPEX" scenario with cost-reflective tariff and full CAPEX | Detailed description |
|---|---|---|---|
| **Allowed CAPEX** | EEDC proposed levels for 2020 - 2024 | EEDC proposed levels in 2020-2024 | Section |
| **Access to capital** | Unable to raise capital | Funding is assumed from EEDC shareholders | Section H. 6 |
| **Actual ATC&C** | Actual ATC&C with a slow trajectory to reduce over the period | Actual ATC&C with a more aggressive trajectory | Section H. 7 |

### 4.3.1 Demand forecast

From the supplied demand data for 2018, EEDC had a simultaneous peak demand of 433 MW, non-simultaneous peak demand of 994 MW.

The problem faced by Discos in Nigeria is that due to the chronic shortages of power and in some cases unreliability of equipment, feeders are not always energised, and consequently only parts of the network are energised at any point in time. Consequently, the underlying *total* load is difficult to determine. To combat this issue of sparseness in the data, we modelled the time series of load of EEDC's feeders 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.

The application of a combination of a structural and a dynamic forecasting model to the hourly load data for EEDC, and the customer population was used to determine the current and projected demand for EEDC. Over the forecast period, the customer population is projected to increase by 820,125 customers to 1,802,280 customers by 2024, representing an increase of 84% over the forecast period. This translates to an unsuppressed energy consumption increase of 72% from 7.5 TWh in 2018 to 12.8 TWh in 2024 – see Table 4.

Drawing these analyses together gives a peak load projection for Total Demand (Unsuppressed Demand plus Unconnected Demand) in the EEDC franchise zone. Load for Total Demand is expected to grow from 1,119 MW to 1,793 MW by 2024 representing a growth of 60%, as shown in Figure 4. The network infrastructure analysis presented here is based on this demand projection for customers served by EEDC.

**Table 4: EEDC Demand Projection 2019-2024**

| Year | Increase in Load | EEDC Total Coincident Peak Load (MW) | EEDC Total Non-Coincident Peak Load (MW) |
|---|---|---|---|
| Base Year | | 416 | 747 |
| FY-2020 | 97 | 513 | 921 |
| FY-2021 | 94 | 608 | 1,091 |
| FY-2022 | 58 | 665 | 1,195 |
| FY-2023 | 64 | 729 | 1,309 |
| FY-2024 | 70 | 799 | 1,435 |

**Figure 2: EEDC projected non-simultaneous peak demand (MW) 2019-2024**

### 4.3.2 Generation

#### 4.3.2.1 *Energy Generation*

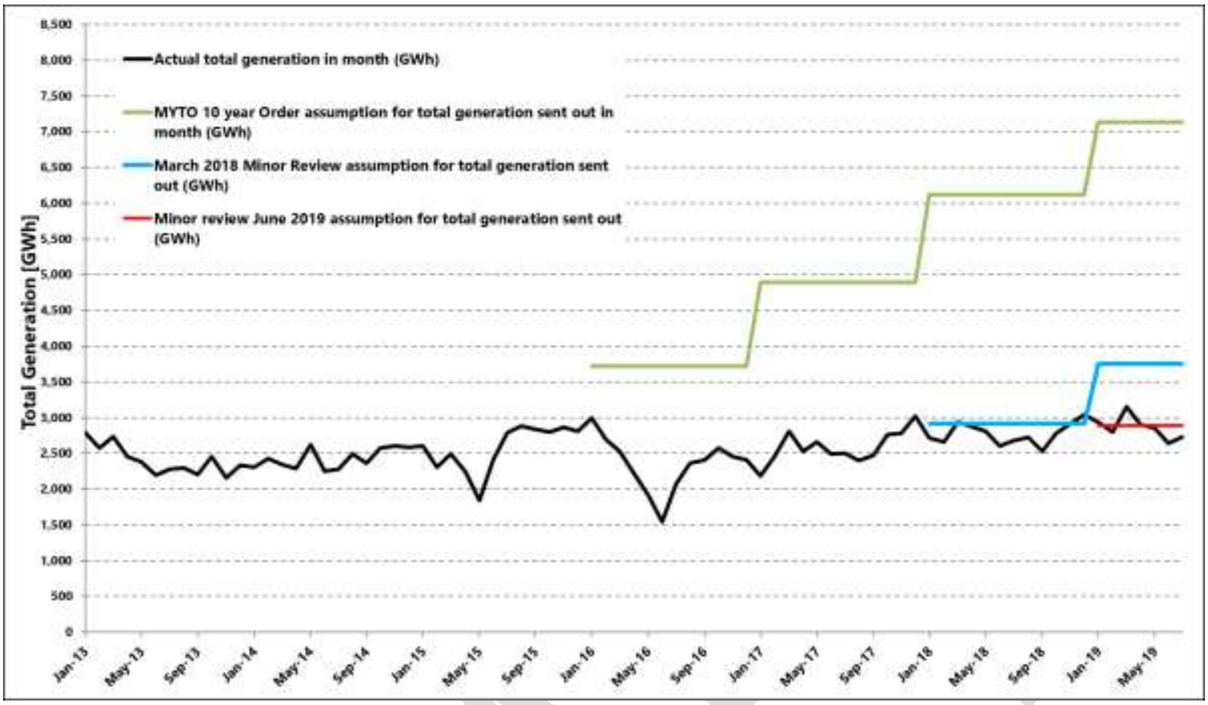
Power generation is assumed to gradually improve as the EEDC network improves to allow the Disco to receive more power or according to the growth of the Disco load demand as shown in the table below.

**Table 5: EEDC, TCN energy delivered forecast**

| (GWh/month) | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| Current level | 199.5 | | | | | |
| **Minimal CAPEX scenario** (less than half of MYTO projection) | | 199.5 | 210 | 220 | 231 | 243 |
| **Full CAPEX scenario** (MYTO projection) | | 225 | 244 | 257 | 271 | 286 |

Energy received is assumed to grow to 9% of the national availability in all scenarios. For EEDC this means an average of 201,757 MWh/month. A flat generation projection is valid given that the average monthly generation levels since 2013 have fluctuated but have not significantly improved (see Figure 3).

**Figure 3: Energy sent out by Gencos from January 2013 to July 2019**




If future generation rises above this level, it can be taken into account in future minor tariff reviews. However, it seems more appropriate to base this performance improvement plan on historic expectation, rather than MYTO projections that have proven overly optimistic in the past (see Figure 3).

#### 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.

- **Generation capacity charges for those Gencos with active PPA's 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% was used to project the capacity charges expected from the remaining Gencos once their PPAs are activated in 2020.

The expected energy and capacity levels to be borne by Discos are shown in Table 36.

## 4.4 Outputs: strategic objectives

### 4.4.1 Performance Agreement

As set out in the Performance Agreement, EEDC based on the knowledge available to it at the time, had set out the target goals to be met. These targets outlined are as below.

**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 (%) | 59.1% | 58.7% | 43.9% | 31.4% | 20.0% | 11.3% |
| 2 | Reliability/ availability | Number of customer Interruptions (#) | Not available | 80 | 72 | 50.4 | 35 | 25 |
| 3 | Metering | Number of new consumer meters installed | 320593 | 261112 | - | - | - | - |
| 4 | New connection/ network expansion | Number of new customer connections | Not available | 50,513 | 57,080 | 62,239 | 67,867 | 74,000 |



### 4.4.2 Current service deficits

The target outputs as outlined in the Performance Agreement have not been met due to the factors as outlined in the issues that the Discos have faced in general and EEDC in particular. EEDC has made submissions to NERC on these indices every month as required by regulation.

As at handover in 2013, the ATC&C losses in EEDC were calculated to be 59.1% and EEDC has been able to reduce these losses by over 5% to 53% in 2019. However, this is still far off from the target in the Performance Agreement of 43% and the even lower NERC reviewed figure of 28%. The status of the other indices is as in the table below.

**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 (%) | 59.1% | 54.6% | 53.1% |
| 2 | Reliability/availability | Number of customer Interruptions (#) | Not available | 664 | 246 |
| 3 | Metering | Number of consumer meters installed | 6,288 | 95,936 | 29,545 |
| 4 | New connection/ network expansion | Number of new customer connections | Not available | 64,782 | 42,861 |
| 5 | Customer satisfaction | Customer complaint resolution | Not available | | |
| 6 | Safety | Number of H&S reports | 12 | 24 | 12 |
| 7 | Social responsibility | Number of community outreaches | Not available | | |
| 8 | Remittance | Market remittance to NBET and MO | Not available | | |

### 4.4.3 Goals 2020-2024

Target outputs are dependent on the modelling scenario, in particular on tariff levels and allowed CAPEX. The target outputs assume all the allowed CAPEX is spent in each scenario. In the event that  (see Annex A).

#### 4.4.3.1 *Target outputs in "minimal CAPEX" scenario*

A business as usual scenario called "minimal CAPEX" based on NERC tariff assumptions from the latest minor review (June 2019), which treated the end of 2020 as year 4 of ATC&C loss reduction.

**Table 8: Target service levels ("outputs") in "minimal 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 (%) | 51% | 47% | 44% | 41% | 37% | 34% |

| No. | Key performance index | Measurement criteria defined in privatisation | Annual Performance | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Base line | 2020 | 2021 | 2022 | 2023 | 2024 |
| 2 | Reliability/ availability | Number of customer Interruptions (#) | 492 | 400 | 400 | 360 | 320 | 300 |
| 3 | Metering | Number of consumer meters installed | | 70,000 | 317,800 | 233,545 | | |
| 4 | New connection/ network expansion | Number of new customer connections | 64,782 | 67,225 | 78,115 | 82,052 | 86,190 | 88,000 |
| 5 | Customer satisfaction | Not defined – propose composite of 1, 2 and 3[3] | | | | | | |
| 6 | Safety | Not defined – propose number of deaths and number of accidents | 24 | 20 | 15 | 10 | 5 | 5 |

#### 4.4.3.2 *Target outputs in "full CAPEX" scenario*

The "full CAPEX" scenario 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 the Disco's ambitious loss reduction and other output targets.

**Table 9: Target service levels ("outputs") in "full 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 (%) | 51% | 46.0% | 43.0% | 39.2% | 35.4% | 29.8% |

[3] Loss reduction demonstrates customer willingness to pay, reliability measures their access to electricity and metering reduces the number of estimated bills (a key factor in complaints).

| No. | Key performance index | Measurement criteria defined in privatisation | Annual Performance | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Base line | 2020 | 2021 | 2022 | 2023 | 2024 |
| 2 | Reliability/ availability | Number of customer Interruptions (#) | 492 | 400 | 350 | 300 | 200 | 150 |
| 3 | Metering | Number of new consumer meters installed | | 70,000 | 317,800 | 233,545 | | |
| 4 | New connection/ network expansion | Number of new customer connections | 64,782 | 67,225 | 78,115 | 82,052 | 86,190 | 88,000 |
| 5 | Customer satisfaction | Not defined – propose composite of 1, 2 and 3[4] | | | | | | |
| 6 | Safety | Not defined – propose number of deaths and number of accidents | 24 | 20 | 15 | 10 | 5 | 5 |

It is important to note the target outputs shown here would be possible if all conditions as laid out are met. However, the issues concerning tariffs, generation, ATC&C loss levels would have to be resolved for this to be possible.

### 4.4.4 Projected investment

EEDC proposes a CAPEX of N 40.4bn to invest in the network and other related operations in order to meet the proposed ATC&C targets as set by this plan. The CAPEX in the MYTYO comes to this figure; however, the figure includes the cost of metering which is not accounted for in the CAPEX that we have accepted as MAP is financing the customer meters.

**Table 10: Assumed CAPEX constraints in MYTO**

| Naira billion | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Allowed in MYTO Minor Review (June19) | 7,027 | 7,027 | 8,783 | 8,783 | 8,783 |

[4] Loss reduction demonstrates customer willingness to pay, reliability measures their access to electricity and metering reduces the number of estimated bills (a key factor in complaints).

| | | | | | |
|---|---|---|---|---|---|
| Minimised CAPEX | 4,236 | 1,101 | 3,275 | 848 | 3,169 |
| Full CAPEX | 7,027 | 7,027 | 8,783 | 8,783 | 8,783 |

### 4.4.5 Justification for EEDC's goals

In this plan, EEDC has tried to align our goals with the economic objectives of the state and federal government to ensure that we support and make available supply that promotes economic activity. We have made decisions based on the needs of our customers gathered from the engagements that we have carried out with all the different customer groups including the local state governments.

Our ability to deliver these outputs are dependent on the validity of our projections at a particularly volatile time in the market and also our ability to raise finance which is a challenge for every utility in the Nigerian market at this time.

Refer to the process in section 3.

# 5 Infrastructure Review

## 5.1 Overview

This section covers:

- Current state of infrastructure;
- Review of current limitations;
- Need for area strategies;
- Recent and ongoing projects; and
- Implications of the infrastructure review.

Each section of the plan should have an overview and contents page.

## 5.2 Current state of infrastructure

EEDC serves 82 Local Governments Areas, in 5 states of Nigeria. The distribution network, operates at three voltage levels, serves major residential, commercial and industrial hubs within the state, covering 18 business units within its network. There are 73 33kV feeders, 206 11kV feeders, and 16,485 distribution transformers – see Table 11.

**Table 11: EEDC Distribution Network**

| s/n | Distribution Network | Number |
| --- | --- | --- |
| 1. | Business Units (BU) | 18 |
| 2. | 33kV feeders | 73 |
| 3. | 11kV feeders | 206 |
| 4. | Distribution Transformers | 16,485 |

The EEDC 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.

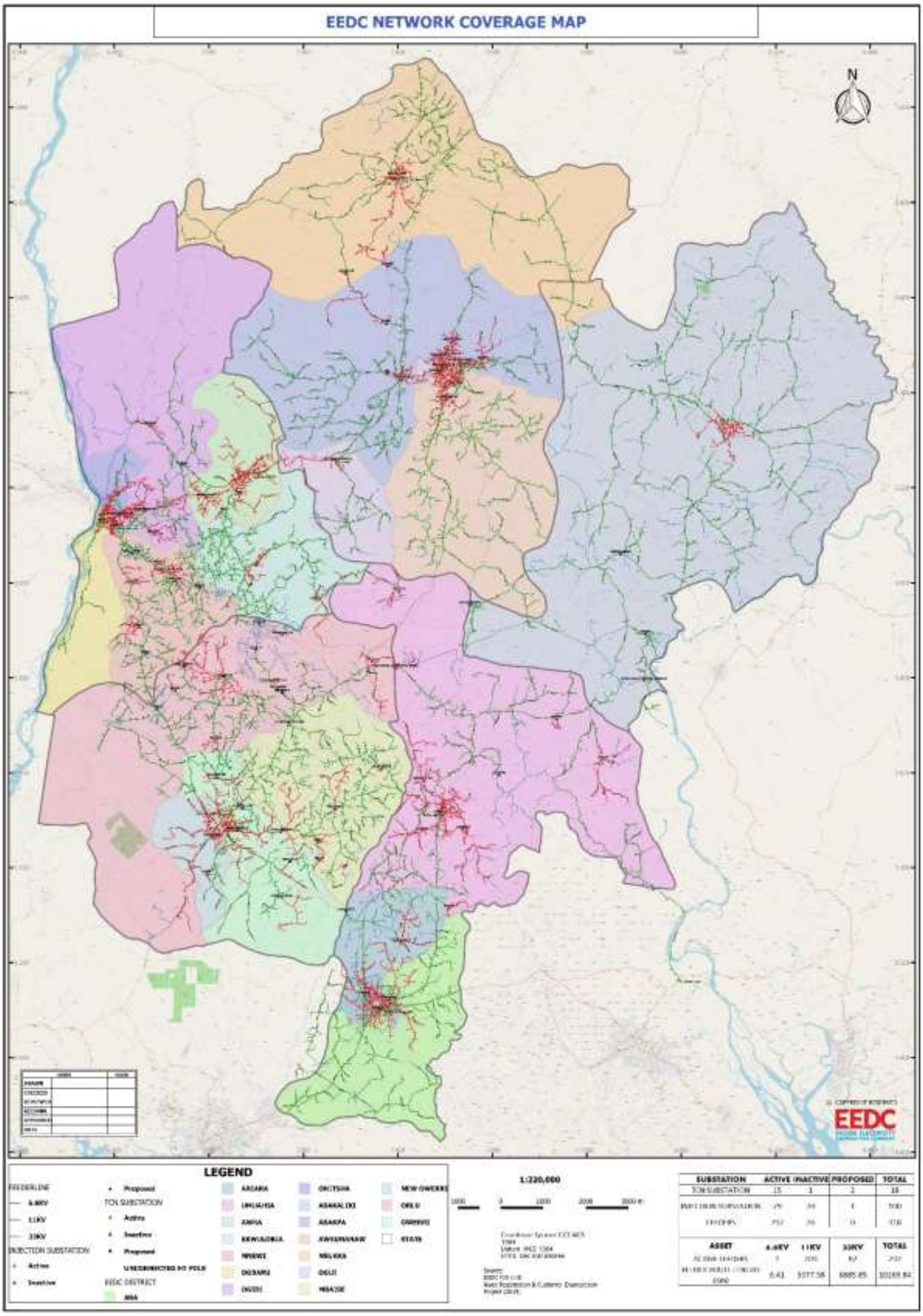
The EEDC network is supplied from 15 TCN transmission stations with a combined nameplate capacity of 5,203 MVA. The 71 33kV feeders, which are all overhead feeders, supply 33/11kV power transformers across 90 injection substations. With a total 33/11kV power transformer transformation capacity of 1,132 MVA, 206 11kV feeders are energized for onward downstream power distribution.

There are 10,137 11/0.415kV distribution transformers and 6,345 33/0.415 kV distribution transformers served by EEDC. The total transformational capacity of the 11/0.415kV and the 33/0.415kV distribution transformers are 2,880 MVA and 1,990 MVA respectively – see Table 12. The route length for the 33kV and 11kV feeders are 5,877 km, 3,071 km, respectively, resulting in a total route length of 8,950 km.

**Table 12: EEDC Network Configuration**

| S/N | Network Parameters | Unit | Total |
|---|---|---|---|
| 1. | Transmission Substations | No | 15 |
| 2. | 132/33kV transformers | No | 30 |
| 3. | 132/6.6kV transformers | No | 1 |
| 4. | Injection Substations | No | 85 |
| 5. | 33/11KV Transformers | No | 95 |
| 6. | 33/0.415kV Transformers | No | 6348 |
| 7. | 11/0.415kV Transformers | No | 10,137 |
| 8. | Installed Transmission Capacity | MVA | 1452.5 |
| 9. | Installed Transformer Capacity (33/11kV) | MVA | 1102.5 |
| 10. | Installed Transformer Capacity (33/0.415kV) | MVA | 1990.185 |
| 11. | Installed Transformer Capacity (11/0.415 kV) | MVA | 2880.809 |
| 12. | Route Length 33KV Feeders | ckt km | 6,019 |
| 13. | Route Length 11KV Feeders | ckt km | 4,233 |

## Figure 4: EEDC Geographical Single Line Diagram



EEDC has carried out GIS mapping of all assets and the SLD for the network have been developed and some samples can be seen in Appendix

From the handover in November 2013, EEDC has added to the regulatory assets such as is needed for the growth and efficiency of the business. The inventory includes the equipment needed to set up the offices and the plant and machinery that are needed for the optimal operation of the network. EEDC has a number of assets around the franchise area that are aged but are considered in the MYTO to have a lifespan starting at acquisition. This meant that there was need to upgrade and replace some of these assets earlier than was expected or provision was made for.

The breakdown of all assets in the EEDC franchise area can be found in the Annex J.

The regulatory assets of EEDC as recorded are the assets that have been obtained since handover in 2013. There has been considerable investment by EEDC into all areas of the business and this means that the asset base has grown substantially. There has also been asset mapping carried out by the GIS department and the information gathered is being included into the asset records. It is important to EEDC to ensure that the assets are audited and classified to indicate the true status of the equipment. To this end, EEDC is currently in the process of carrying out an audit and subsequent update of the status of the condition of assets.

This register is located in Annex J of this report and there is an associated Excel file of the data as recorded by the Disco.

## 5.3 Review of current limitations

Infrastructure links primarily to the following targets:

- Reduce ATC&C losses from the current level of 51% to 30%, which will allow our business to be sustainable;
- Reduce the number of customer interruptions from the current level of 14036 to 4000, increasing reliability for our customers;
- Increase the number of new customer connections from the current average level of 58,000 per year to 70,000 per year.

### 5.3.1 Technical network constraints

There are identifiable infrastructure limitations impacting service delivery in EEDC network formation most of which present as overloaded conditions of the existing power transformers, 33kV and 11kV lines, distribution transformers and at the interface with some existing transmission bulk power equipment. The lack of capacity to handle power demands and power flows leaves a widening gap between demand and supply. The immediate consequence is increasing suppressed loads and reduced hours of supply available to affected customers.

The effects of TCN related system constraints are felt across all the states in EEDC franchise area notably at Oji in Enugu, Egbu in Owerri, Aba in Abia state, Abakiliki and Nkalagu in Ebonyi state, Awada Onitsha and Nru Nsukka. In these areas, installed equipment have been estimated to be operating at near full load capacities as demand remains on the rise.

At present, the Disco has 19 number of overloaded (above 95%) power transformers, 10 number of overloaded 33kV lines and 57 number of overloaded 11kV lines, 32 number of injection substations and 384 distribution substations requiring relief substations across all districts. The company's overall performance in meeting revenue targets will receive a boost following a systematic resolution of these bottlenecks.

However, projects that guarantee elimination of these constraints have been carefully articulated and form part of a robust 5-year system improvement plan. Furthermore, the company's demonstration of commitment to tackling these challenges is evidenced in the recent upgrade of Agu Awka 7.5MVA Power transformer, construction of two new injection substations at Nike Lake, Enugu and ABS Awka; all completed between 2018 and 2019 financial year.

### 5.3.2 Aging infrastructure

The infrastructure that EEDC inherited after handover were already aging and some of this was unaccounted for until the Disco was handed over. This meant that a lot of the old equipment had to be replaced. Even customers who were considered metered had old and obsolete meters which had to be replaced further reducing the number of metered customers. There was also the need for reinforcements and increase of capacity in areas where the population had grown without the commensurate upgrade of the equipment in those areas.

The asset register shows the assets that EEDC purchased after acquisition and the plants and machinery in this register are aged 0-5 years with a purchase value of N3.2bn and a net book value of N2.76bn. The assets before acquisition are as contained in asset register.

EEDC has been in the process of replacing this old and outdated equipment; however, due to its shortage of funds, the process has been slow. This has a direct impact on the reliability of the system and contributes to the down times. It also has increased the cost of operating and maintaining the system as the aged infrastructure needs attention more often that newer and more sophisticated equipment would.

### 5.3.3 Customer enumeration analysis

It is important to EEDC to know all our customers in their different locations and their classification to enable accurate planning for their needs. To enable this, EEDC is carrying out a comprehensive and thorough customer enumeration analysis which is employing GIS mapping technology for more accurate results.

The exercise increased our customer base from 342,209 in 2014 to 982,155 at the close of 2018. The numbers are still growing and are forecast to rise to over 1.8 million customers in the next 5 years.

**Table 13: Projected Customer Numbers**

| Year | Total Customer Numbers |
|---|---|
| 2019 | 1,131,843 |
| 2020 | 1,338,698 |
| 2021 | 1,555,923 |
| 2022 | 1,634,038 |
| 2023 | 1,716,090 |
| 2024 | 1,802,280 |

The implication of this is a reduction in the commercial and collection losses as many more customers have been captured on our database and can be billed accordingly. We have also been able to regularise a lot of connections that were carried out without the accompanying paperwork that would include those customers on the Disco database.

### 5.3.4 Metering gaps

Table 14 provides a metering gap analysis, including both meters to be provided by EEDC and those to be provided by MAPs. This includes the customer meters as well as the network meters.

**Table 14: Customer metering and MAP intervention**

| Customer Number Breakdown | Total | Prepaid | Postpaid |
|---|---|---|---|
| Residential | **849,545** | **185,001** | **664,544** |
| Commercial | **135,685** | **36,651** | **99,034** |

| Customer Number Breakdown | Total | Prepaid | Postpaid |
|---|---|---|---|
| Industrial | **26,653** | **19,811** | **6,842** |
| Special | **59,343** | **19,621** | **39,722** |
| MDAs | **1,783** | **178** | **1,605** |
| | | | |
| **Classification by Demand** | | | |
| MD Customers | **7,659** | **4,225** | **3,434** |
| Non-MD Customers | **1,063,565** | **256,857** | **806,708** |
| | | | |
| **Metered Customers** | | | |
| Residential | **282,668** | **185,001** | **97,667** |
| Commercial | **56,262** | **36,651** | **19,611** |
| Industrial | **20,617** | **19,811** | **806** |
| Special | **35,121** | **19,621** | **15,500** |
| MDAs | **1,234** | **178** | **1,056** |
| | | | |
| **Metered Customers by Demand** | | | |
| MD Customers | **5,926** | **4,225** | **1,701** |
| Non-MD Customers | **388,742** | **256,857** | **131,885** |
| | | | |
| **MAP Metering** | | | |
| | | ***MAP 1*** | ***MAP 2*** |
| | **MAP Name** | ***Mojec Int. Ltd*** | ***Protegy Global Services Ltd*** |
| Total contractual number of meters from MAPs | No. contracted meters | **372,927** | **248,618** |
| Total MAP Metering period | Metering period | **July 2019 to October, 2021** | **July 2019 to October, 2021** |
| | | | |
| Expected average number of meters installed monthly | | **13,320** | **8,879** |
| | Annual Target | | |
| | 2019 | **42,000** | **28,000** |
| | 2020 | **190,800** | **127,000** |
| | 2021 | **140,127** | **93,418** |
| | 2022 | | |
| | 2023 | | |
| | 2024 | | |

The network meters are priority for EEDC to stop leakages in the network and ensure credible interfaces with TCN.

**Table 15: Metering gaps for bulk metering**

| Metering | Priority assigned by NERC in PIP Guidelines | Current situation | EEDC desired implementation date |
|---|---|---|---|
| MDA metering | Very high priority | 70% metered | 2018 - 2021 |
| Network (feeder) metering | Not assigned | 100% metered | |
| DT metering | Not assigned | 900 out of 16,485 | 2019 - 2022 |

### 5.3.5 IT Gaps

Table 16 provides the status of all the management systems required by NERC and those identified by EEDC.

**Table 16: Review of management system gaps**

| Management system | Priority assigned by NERC in PIP Guidelines | Current situation | EEDC desired implementation date |
|---|---|---|---|
| Incidents Recording and Management System (IRMS) | Very high priority | Not available yet | 2020 |
| Commercial Management System (CMS) | High priority | Available and deployed | Already implemented |
| Enterprise Resource Planning (ERP) information system | High priority | Available and deployed | Already implemented |
| Geographical Information System (GIS) mapping of customers and network assets | High priority | Available and deployed | Already implemented |

| Management system | Priority assigned by NERC in PIP Guidelines | Current situation | EEDC desired implementation date |
|---|---|---|---|
| Supervisory Control and Data Acquisition System (SCADA) | High priority | Not available yet | 2020 – 2022 (to be deployed in stages) |
| Works Management System (WMS)" | Medium priority | Not available yet | December 2019 |

EEDC is working on the deployment of its WMS as it currently uses a manual system for this purpose. This slows down the time to clear faults and makes it important to automate the system in a way that increases the overall efficiency.

## 5.4 Recent and ongoing projects

### 5.4.1 Completed Projects

There are projects completed by EEDC to increase network capacity and reduce technical losses in the system. A detailed breakdown of these projects and the benefits can be found in Annex G.

### 5.4.2 Ongoing Projects

EEDC is currently undertaking a number of projects seen below to reduce the losses in the network including rehabilitation and construction of some feeders as well as the construction of new lines.

- Dualization of industrial 11kV in Ariaria
- Rehabilitation of Ukwa 33kV Ariaria
- Rehabilitation of Owerrinta 33kV Ariaria
- Rehabilitation of Guinness 33kV Ariaria
- Proposed construction of Aba - Owerri II 33kV feeder injection substation, Ariaria
- Proposed ATC&C loss reduction on IGI 33kV feeder, Aba
- Construction of double circuit 33kV overhead line for Oguta from Egbu TCN to Onitsha road injection substation, New Owerri

- Dualization of 3-3, 33kV feeder for the creation of Fegge 33kV feeder
- Nowas industrial 11kV feeder
- Okpara Avenue 11kV feeder
- Dualization of Thinkers' Corner 33kV line
- Rehabilitation of NNPC 33kV feeder

Most of these ongoing projects would be online by the end of 2019.

## 5.5 Implications of the infrastructure review

There has been a prolonged period of underinvestment in the distribution networks in Nigeria. In November 2013, EEDC 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 EEDC into a modern distribution company.

In developing this PIP, EEDC has prioritised investment 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 **Error! Reference source not found.** in section 4.4.

Resulting infrastructure investment plan is in section 6.

# 6 Detailed Program Plans

## 6.1 Overview

This section covers:

- Delivering outputs efficiently;
- Electricity distribution investments;
- Working with Meter Asset Providers (MAP);
- Commercial operations investments;
- Health and safety plans;
- Resourcing plans; and
- Overall investment plan.

## 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.

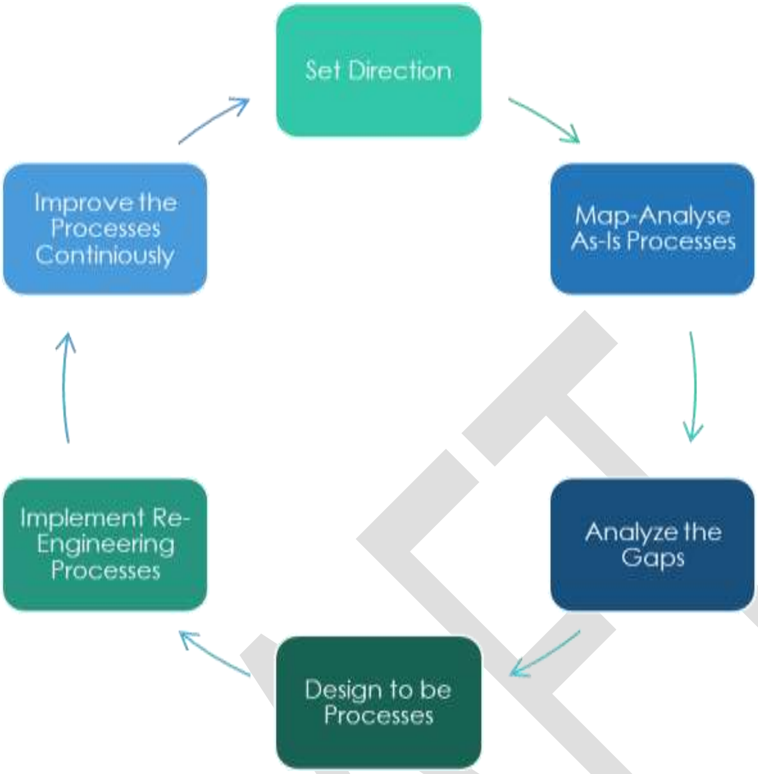
Investing in metering of our customers as well as network assets (DTs and Feeders) is top priority for EKEDC as we believe that it will greatly reduce commercial and collection losses within our network and help us to better ascertain technical losses with time.

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

## 6.3 Business Process Engineering

EEDC has undertaken Business Processes Engineering to streamline our processes and make it more efficient.

### 6.3.1 Approach and Methodology




#### 6.3.1.1 *Get Direction*

**"***If you fail to plan, you plan to fail"*. Planning and Preparation are vital factors for any activity or event to be successful, and reengineering is no exception. So, for us this activity begins with the development of executive consensus on the importance of reengineering and the co-dependency of the breakthrough business goals and reengineering projects. A mandate for change is produced and a cross-functional team is established with a game plan for the process of reengineering.

Our objective of these few last few days of our primary research was to understand the interdependencies between the different departments and the process alignment in the functional performance of the districts. For our better understanding, we first initiated with our discussion with all the Head of the Departments and then visited and interacted with various operational teams of districts like Onitsha, Owerri, New Owerri, Ogui & Aba.

After our visits and interactions, we identified the vision of EEDC to be able to,

*"Provide a reliable power supply & the best of services to Customers in their area and become one of the best performing Electricity Distribution Company in Nigeria."*

#### 6.3.1.2 *Map-Analyse As-Is Process*

The main objective of this phase is to identify disconnects (anything that prevents the process from achieving desired results and in particular information transfer between organizations or people) and value adding processes.

This is initiated by first creation and documentation of Activity and Process models by studying the existing SOPs and also through interviews from various process initiators and Owners. Then, the amount of time that each activity is taking and the cost that each activity requires in terms of resources is calculated on basis of available information.

Before innovation can begin within an organization, we tried to identify need for improvement expressed by an employee, manager, business owner, regulatory agency and customers.

#### 6.3.1.3 *Analyse the Gaps*

*"Improved financial performance, customer satisfaction, operational efficiency, reliability, and agility are often key internal motivators for a change program".*

Once a need for process improvement has been identified, the change requirement is documented and its justification brought to the attention of senior management.

Our Gap Analysis of all the existing As-Is Process is done on the basis of 3 parameters:

1. Effectiveness.
2. Efficiency.
3. Economically.

In this step we perform the following activities:

1. Insight into areas that need improvement, such as efficiency, products, profitability, processes, customer satisfaction, performance, participation, adherence to NERC Regulations and competitive advantage.
2. Finding areas of weakness and shortcomings to address.
3. Providing information to guide decision makers, which can lead to better decisions.
4. Finding the best places to deploy resources and focus energy
5. Prioritization of needs.

#### 6.3.1.4 *Design To-be Processes*

The objective of this phase is to produce one or more alternatives to the current situation, which satisfy the strategic goals of the enterprise.

The first step in this phase is benchmarking. "*Benchmarking is the comparing of both the performance of the organization's processes and the way those processes are conducted with those relevant peer organizations to obtain ideas for improvement.*" The peer organizations need not be competitors or even from the same industry. Innovative practices can be adopted from anywhere, no matter what their source. Having identified the potential improvements to the existing processes, the development of the To-Be models is done using the various modelling methods available, bearing in mind the principles of process design. Then, similar to the As-Is model, we analyse factors like the time and cost involved. It should be noted that this activity is an iterative process and cannot be done overnight. The several To-Be models that are finally arrived at are validated. By performing Trade off Analysis, the best possible To-Be scenarios are selected for implementation.

Our To-Be Process will include following things:

1. **Trigger:** For every main activity the trigger process will be defined.
2. **Responsibility:** To-Be Process will assign the Responsibility of each activity in the process.
3. **Activity:** In Process there will be description of each the activity in the details.
4. **Output/Records:** There will be details of all the Output and Records if generating against any activity. Even we will provide the format of all the records for the reference purpose and to avoid any confusion.
5. **Risk:** We will also explain the Risk involved against each activity as we have classified Risk under various category like: Financial Risk, Operational Risk, Strategy Risk etc.
6. **Control/SLA:** SLA against each activity will be clearly defined along with the details of instructions and reference related to that activity.

#### 6.3.1.5 *Implement Re-Engineering Process*

The implementation stage is where reengineering efforts meet the most resistance and hence it is by far the most difficult one. If we expect that the environment would be conducive to the reengineering effort, we are sadly mistaken.

The question that confronts us would be,' If BPR promises such breath-taking results then why it wasn't adopted much earlier?' We could expect to face all kinds of opposition - from blatantly hostile antagonists to passive adversaries: all of them determined to kill the effort. When so much time and effort is spent on analyzing the current processes, redesigning them and planning the migration, it would indeed be prudent to run a culture change program simultaneously with all the planning and preparation. This would enable the organization to undergo a much more facile transition. But whatever may be the juncture in time that the culture change program may be initiated, it should be rooted in our minds that 'winning the hearts and minds of everyone involved in the BPR effort is most vital for the success of the effort.

Once this has been done, the next step is to develop a transition plan from the As-Is to the redesigned process. This plan must align the organizational structure, information systems, and the business policies and procedures with the redesigned processes. Rapid implementation of the information system that is required to support a reengineered business process is critical to the success of the BPR project.

#### 6.3.1.6 *Improve Process Continuously*

A process cannot be reengineered overnight. A very vital part in the success of every reengineering effort lies in improving the reengineered process continuously. The first step in this activity is monitoring. Two things have to be monitored – the progress of action and the results. The progress of action is measured by seeing how much more informed the people feel, how much more commitment the management shows and how well the change teams are accepted in the broader perspective of the organization. This can be achieved by conducting attitude surveys and discrete 'fireside chats' with those initially not directly involved with the change. As for monitoring the results, the monitoring should include such measures as employee attitudes, customer perceptions, supplier responsiveness etc. Communication is strengthened throughout the organization, ongoing measurement is initiated, team reviewing of performance against clearly defined targets is done and a feedback loop is set up 5 wherein the process is remapped, reanalysed and redesigned. Thereby continuous improvement of performance is ensured through a performance tracking system and application of problem-solving skills.

## 6.4 Electricity distribution investments

EEDC has outlined the investments that would need to be made in order to meet the targeted loss and service levels and it is determined that the updated CAPEX figures in the MYTO will suffice. The assumption made is that the CAPEX has no metering component as the entire amount will be spent on other investments with the consideration that metering will be undertaken by the MAPs.

### 6.4.1 Network Investment Summary

This is a summary of the proposed full CAPEX needed by EEDC to meet the set targets in this PIP.

| | Capex (N million) | | | | |
|---|---|---|---|---|---|
| **Network Investment Type** | **2020** | **2021** | **2022** | **2023** | **2024** |
| Reliability, Distribution Automation | 522 | 432 | 809 | 733 | 485 |
| Planning and Construction (P&C) | 4,922 | 5,237 | 6,376 | 6,873 | 6,816 |
| Loss Reduction | 73 | 154 | 453 | 111 | 199 |
| Protection, Control & Metering (PC&M) | 118 | 173 | 260 | 211 | 84 |
| Energy Efficiency | 217 | 218 | 245 | 243 | 325 |
| GIS Mapping Projects | 612 | 257 | 249 | - | - |
| HSE Projects | 127 | 142 | 189 | 221 | 217 |
| Fleet, Security, Facility and Tools | 132 | 55 | 102 | 8 | 58 |
| IT projects | 304 | 357 | 209 | 230 | 240 |
| **Total** | **7,027** | **7,027** | **8,783** | **8,783** | **8,783** |

### 6.4.2 Incident Reporting System

An incident reporting system is planned to support quick and accurate identification of location and the causes and extent of any interruption to power supply to customers. This will enable EEDC with faster response times for the clearing of faults. Currently, this is done through manual monitoring and recording of customer complaints.

It is important that the system be able to track all complaints and classify them as well as show the status of follow-up and resolution and support management with reports to enable decision making.

### 6.4.3 Network metering plans

EEDC is already in the process of metering the entire network. However, this is capital intensive and the paucity of funds have slowed the execution. This notwithstanding, EEDC intends to meter the entirety of its network by the end of 2020.

This will support our loss reduction strategy as it will enable the detection of discrepancies in the network. It will also give us a more accurate interface with TCN and ensure that the bills we receive can be properly verified.

### 6.4.4 New connections plans

There is currently no application for a management system being employed for new connections; however, EEDC has an approach outlined below:

- The customer obtains new service connection form from the district office or from the website; fills the form as required and approaches a licenced electrical contractor for clearance and certification of his connection.
- The customer returns the form to the customer service officer, who verifies the submission, and generates an NSC application number in the NSC register.
- The feeder manager undertakes a feasibility study and sends the report to the billing manager to confirm commercial feasibility.
- When feasibility and commercial study have been completed and a decision made, the customer is informed and advised on statutory fees and payment mode.
- Meter installation advice is prepared and forwarded alongside the NSC file to the metering department for meter installation.
- Meter is installed and protocol form generated with a copy forwarded to the customer service officer to inform network and feeder managers for commissioning.
- The customer service officer updates the NSC register and sends an SMS/email to or calls the customer; welcoming them to EEDC and giving information regarding his/her unique account number.

In addition, the EEDC approach to handling existing supply address is the same as above. When the customer service officer has received the form and generated an NSC application number, a check is done by the feeder manager and the customer is informed of the requirements for the line separation and other fees.

Whilst the above method might have worked some time ago, as the customer base grows, it becomes less and less feasible. Therefore, EEDC is in the process of adopting a process backed by technology for the management of its new customers. We plan to adopt an integrated system that will incorporate all parts of our operation in one system; ranging from bill payment, disconnections, reconnections and complaint management.

We plan to develop a New Service Connection application for a seamless NSC process and also to enable us to meet our target of over 1.8 million customers over this 5-year period. This system would come online in 2019 and would be fully deployed in 202.

## 6.5 Working with Meter Asset Providers (MAP)

It is important to EEDC that there is proper accountability for the energy expended on its network and also that it completely eradicates estimated billing for its customers. Therefore, EEDC is committed to the workability of the MAP program in its franchise area.

It is on record that the current number of customers in the EEDC network is 1,036,655 and it is estimated that 60% of these customers are unmetered and would be serviced by the MAPs that have been signed on by EEDC.

EEDC have contracted 2 MAPs; Mojec International Limited and Protogy Global Services Limited and these MAPs are to provide 621,545 meters within a 3-year period. This would close the gap by 97% and in the event that the customer number grows, EEDC would be looking to increase the number of MAPs that serve its franchise area.

The MAP program kicked off in August 2019 and would run for 3 years. Currently, these MAPs are about to enter their deployment stage. The plan is as shown below:

**Table 17: Status of MAP meter deployment**

| Meter Asset Provider | Mojec | Protogy | Total |
|---|---|---|---|
| **No. contracted meters** | 372,927 | 248,618 | **621,545** |
| **Metering period (months)** | 36 | 36 | 36 |
| **Monthly target (meters/month)** | 13,320 | 8,879 | **22,199** |
| **2019** | 42,000 | 28,000 | 70,000 |
| **2020** | 190,800 | 127,000 | 317,800 |
| **2021** | 140,127 | 93,418 | 233,545 |

On execution of the above plan, 98% of the EEDC network would be metered with 1,017,445 meters in the network and that would bring down the number of estimated bills that are distributed by the Disco. It is also estimated that there would be a reduction in the commercial losses by 2% on the average each year with the implementation of the plan.

## 6.6 Commercial operations investments

EEDC targets a reduction in the commercial losses of the company and an increase in the billing efficiency currently estimated at 70% to 80% and this would bring about an overall reduction of 21% in the ATC&C losses. It is important to do this not only to meet our performance targets, but more importantly to increase our quality of service and the number of customers willing to pay for this service.

### 6.6.1 Revenue protection plans

EEDC has developed policies and implemented processes to insure its revenue. These policies cover issues such as disconnection and reconnection, meter provision, and vigilance methods.

#### 6.6.1.1 *Revenue Protection Project & Advanced Metering Infrastructure*

There is currently a project being implemented that is supported by Advanced Metering Infrastructure (AMI). This targets all customers at all voltage levels with high monthly consumption. The system is programmed to flag sudden drops in this volume and alert the vigilance task force to ensure that there is no loss to the Disco.

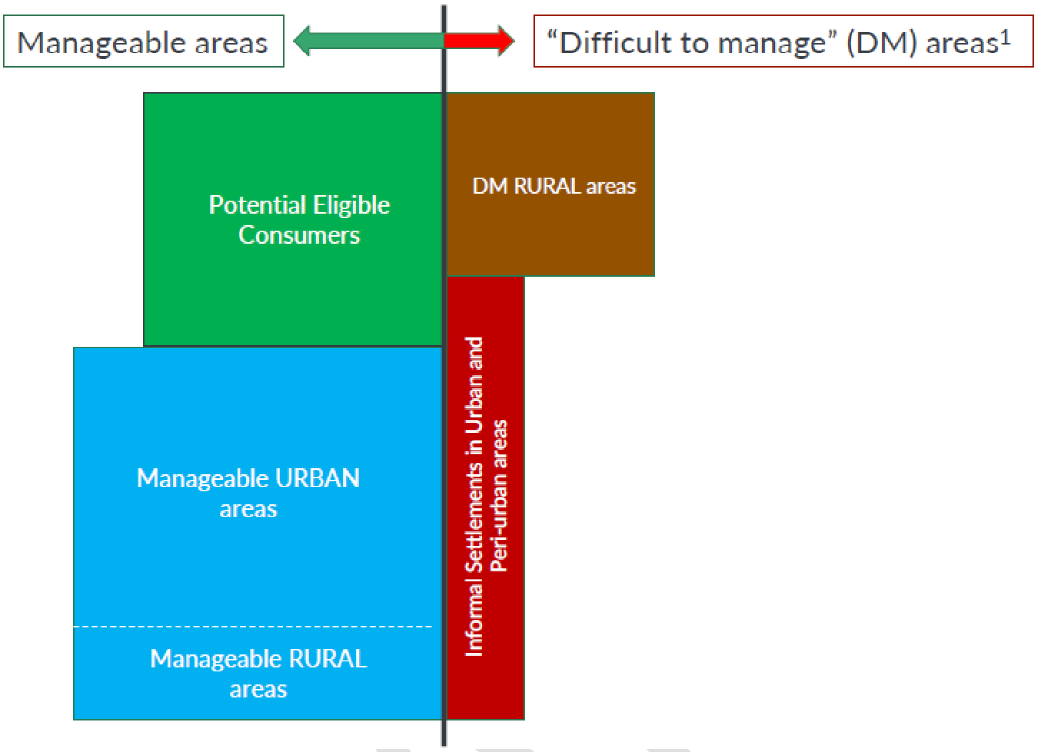
EEDC's revenue protection program records and monitors the consumption of large customers using the AMI technology and takes corrective action speedily when there are any irregularities detected. There are plans to incorporate Meter Data Management systems that would support this project and ensure that any anomalies are spotted and the lead time to resolving them are shortened for a higher all-round efficiency.

#### 6.6.1.2 *Loss reduction strategies for manageable and difficult to manage areas*

Due to the customer segmentation at EEDC, it is important for the company to tailor its loss reduction strategies to the environment and types of customers it serves. There is a large rural population in the EEDC franchise area with most states having urban capitals and largely rural towns.

It is important that we segment these customers and come up with strategies for how best to serve them.

**Figure 5: Four market segments defined by CaBTAP**[5]




EEDC has ensured that the losses in its rural areas are minimised by engaging its rural communities and having agreements with them on metering their use as a unit and selling power to them as some type of a cooperative. There is the need for NERC to support this process as the metering schemes might not be quite viable in some of the rural areas and this would enable the Disco provide service to areas that would be otherwise difficult to manage.

Some further proposed measures for 'hard to manage' customers include:

- Supply based on performance
- Introduction of energy efficiency measures
- State and LG involvement
- Franchising of areas to local utilities

In addition to all these, the ongoing enumeration program has increased the number of customers by over 100%. This has increased the revenue base for EEDC and has improved

[5] Capacity Building and Technical Assistance Programme (CaBTAP) presentation 18-19 June 2019. NERC has divided the market in manageable and unmanageable areas. We don´t think is appropriate the terminology and we prefer to call it "difficult to manage" areas as we believe there is an opportunity to manage those areas with different business proposals

billing accuracy. EEDC has a detailed map of its assets and is building the same accurate mapping of its customers. Customers have been regularised leading to more accountability for energy received.

EEDC is also working with the State and LGAs in our franchise area to fashion out payment plans for the energy that these agencies receive.

### 6.6.2 Management system plans

EEDC has deployed a number of systems to automate operations for a seamless efficiency. The status of the various systems as required by NERC are as below.

- Commercial Management System: The CMS deployed by EEDC provides functionalities such as billing and billing adjustments, payment processing, service application, customer assistance and complaints, meter management system, meter information system, and energy sales to dealers. It is in the process of incorporating a module that takes care of any service anomalies as required by regulation and this would be available by the end of 2019.
- Enterprise Resource Planning System: EEDC deployed its ERP in August 2019 and it has modules that cover the financial, logistics, human resources and procurement needs of the company.
- Geographic Information System: EEDC GIS is currently in use in the enumeration exercise to geo-reference all assets and customers and would be a single source of truth for all the company's assets. We have used the system to drive efficiency through reduction of energy theft and ATCC losses. It has also supported the expansion of the customer base through the regularisation of all unregistered energy consumers.
- Supervisory Control and Data Acquisition System: The SCADA will provide remote monitoring and control of the 33/11 kV network to bring better visibility of the network and reduce outage detection time to improve reliability in the network. EEDC intends to deploy a SCADA system in modules from 2020 and the plan is to have a fully deployed system by 2022. The total cost for this system is N1.87bn; this is apart from the work that would have to be done to prepare the network.
- Works Management System: EEDC currently uses a manual system that incorporates close monitoring, customer complaint data and regular scheduled checks to ensure that we have a system that enable efficient execution of works in our network. However, in order to increase our efficiency, we are deploying a WMS by the end of 2019 with the features that mirror the regulatory requirements.

### 6.6.3 Customer services

EEDC seeks to improve services to its customers and reduce the lead times to resolution of customer complaints.

The improvement of our customer services is linked to the following targets:

- Reduce ATC&C losses from the current level of 51% to 29%, which will allow our business to be sustainable;
- Increasing the customer resolution and satisfaction percentage to 98% over the next 3 years.

One of the most important measures for EEDC to increase customer satisfaction is to make available meters for unmetered customers so as to eliminate estimated billing. Payment response to for these customers is very low and due to the inability of EEDC to meter them, their complaints (of being unmetered) are unresolved for longer than the regulated time. It is believed that the MAP deployment would be able to take care of this issues. Other measures that EEDC is putting in place include:

- Adequate and comprehensive enumeration immediate onboarding of all identified illegal consumers in the network;
- Proper segmentation of customers for easy of management;
- Expansion of contact channels for ease of payments and prompt conflict resolution;
- Provision of service kiosks in clusters and shopping malls to make our services readily available at all times/places;
- Expansion of call centre to have a robust call centre to accommodate 60 agents.

## 6.7 Health and safety plans

EEDC's approach to health and safety has greatly improved and there are plans to ensure that they improve even further. The target for the Health and Safety department is to reduce number of accidents, injuries and deaths of employees and non-employees to zero.

There is an internal Health and Safety Committee made up of managers who review the health and safety reports and advise on any changes that can be made to our processes to reduce incidents and make the workplace safer for all our staff and ensure the safety of our customers.

It can be seen from a preliminary analysis of the incidents and fatalities in our network that an increase in the safety knowledge of the staff causes a reduction of these incidents.

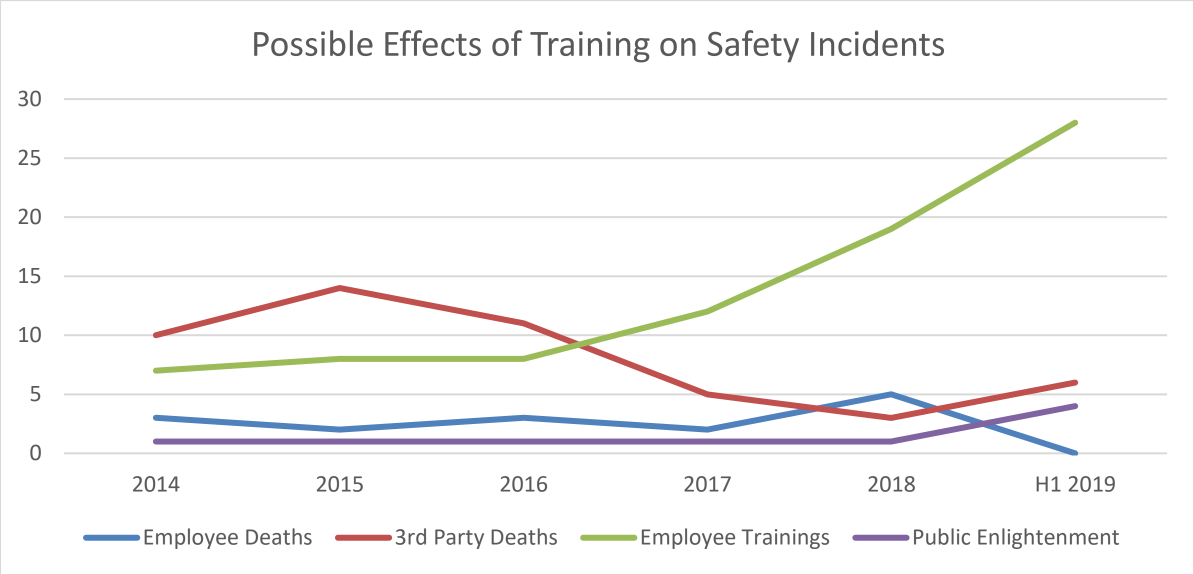



**Figure 6: Effects of training and awareness on death and accidents**

EEDC aims to reduce the number of deaths and accidents in our area to zero and the approach taken is to geometrically increase the number of trainings to staff and annual public enlightenment campaigns.

Due to the correlation above, the Health and Safety department has increased its training requirements both for employees and the public to ensure that there in a proliferation of knowledge and a corresponding reduction in the incidents that have occurred since Handover. To this end, the proposed schedule of training for the years 2020 – 2024 are as below:

**Table 18: Number of planned HSE trainings and community safety engagements**

| | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Number of planned annual safety trainings | 28 | 28 | 28 | 28 | 28 |
| Number of planned community engagements | 4 | 8 | 12 | 12 | 12 |

The costs for a plan of this magnitude have been assessed and are included in the OPEX budget for the years concerned.

The planned trainings and pubic enlightenment campaigns are as below.

**Table 19: Planned annual HSE trainings**

| Year | Name of Training | Details of Training |
|---|---|---|
| 2019-2024 | Accident Investigation and Reporting | To recognize Visible & Non-Visible causes of accident and take remedial actions. To ensure that designated workers are knowledgeable. |
| 2019-2024 | General HSE | To enable participant gain basic knowledge in HSE |

| Year | Name of Training | Details of Training |
| --- | --- | --- |
| 2019-2024 | Application of Occupational Health and Safety Principles in Line Construction | This course will enable the participants to create safety culture from the credo of their job assignment. |
| 2019-2024 | Fire Safety Training/Fire Demonstration | This course will enable the participants to have skills for fighting fire especially from incipient stage. |
| 2019-2024 | Unsafe Act/Unsafe condition Auditing | The participants will be able to assess injuries and accident. And also manage emergencies in the workplace. |
| 2019-2024 | Accident Causes/Prevention and Permit to Work System through the use of Protection guarantee. | Good knowledge of this course will enable our operation personnel to avoid all electrical accident |
| 2019-2024 | Basic First Aid/CPR | This course will enable the participants learn basic first aid information's and treatment procedures and instructions. It will also help them to understand the basic function of all the materials in the First Aid kits. |
| 2019-2024 | Environmental/Waste Management | To achieve sustainable development in the environment. |
| 2019-2024 | Journey Mgt/Defensive Driving Course | This course will enhance the capabilities of our drivers to drive safely and manage the company's vehicle. |
| 2019-2024 | Good Housekeeping | Effective good housekeeping can eliminate some workplace hazards and help job done safely and properly. |
| 2019-2024 | Ladder Safety Disconnection and Reconnection Process. | This course will enable the Technicians understand the Factors contributing to fall from ladders, have overview of Disconnecting and Reconnecting procedures. |
| 2019-2024 | Risk Management | This will help the participants know how to manage risk when new work is planned and at regular intervals appropriate to the nature of the workplace and the health Hazards present. |
| 2019-2024 | Job Hazard Analysis (Field Staff) | This will help the participants understand the observations to make when embarking on any assigned Job |
| 2019-2024 | Occupational Health and Hygiene | This will help the participants understand their working environment better and the health hazards inherent in it. |
| 2019-2024 | Hearts and Minds | This will help teach the participants fundamentals of safety culture change, focusing on the various stages of a culture change program from design to implementation and review. |
| 2019-2024 | Health Risk Assessment | This course will enable the participants assess the risk involve in any assigned Job. It will help the employee with a snapshot of their current health status. |
| 2019-2024 | Effective Pest /Weed Control | This course is to enable technical staff to adequately control pest/weed that encroaches EEDC installations. |

| Year | Name of Training | Details of Training |
|---|---|---|
| 2019-2024 | Safe Work Practice for Revenue Cycle Service | This course will enable RCS team to achieve incident free operations. |
| 2019-2024 | Risk Assessment for GIS Enumerators | Application of proactive measures for enumeration processes. |
| 2019-2024 | JHA for Network/Feeder Managers | Identifying Unsafe acts and conditions that must be addressed in their districts. |
| 2019-2024 | Linesman General Safety | Achieving zero incidents. |
| 2019-2024 | Understanding NERC Health & Safety code | Complying with HSE Standards as indicated by the regulators |
| 2019-2024 | EEDC's 21 Safety Rules | Achieving a positive Safety culture in the company |
| 2019-2024 | ISO 14001 Environmental Management Systems | Build customer confidence in your commitment to managing environmental impact as a vital aspect of business success. (For HSE Staff). |
| 2019-2024 | Managing Safely (IOSH) | Gain the knowledge, skills and confidence to manage health and safety within the organization. (For HSE Staff) |
| 2019-2024 | Working safely. (IOSH) | Identifies everyone's responsibility in relation to health safety and well-being in the workplace. (For HSE Staff) |
| 2019-2024 | ISO 45001 Occupational Health and Safety Management System | OHSMS Promotes a safe and healthy work environment to : Reduce Occupational Health and safety risks, prevent work related incidents and improve legislative compliance. (For HSE Staff). |
| 2019-2024 | ISO 9001:2015 Quality Management System | Provides senior management with an efficient management process, sets out areas of responsibility across the organisation. Mandatory if you want to tender for some public sector work, communicates a positive message to staff and customers, Identifies and encourages more efficient and time saving processes. (For HSE Staff). |

The expectation while there is an increase in the costs, there would be a commensurate reduction in the number of accidents and deaths and the costs that would be incurred from these deaths/accidents and any resulting enforcement actions that the regulator might take.

## 6.8 Resourcing plans

In order to meet the targeted outputs, it is important that EEDC allocates resources adequately and to the right areas to maximise the effects. This section breaks down the allocation of our resources in a manner that enables the acquisition of the targets set.

### 6.8.1 Human Resources plans

EEDC currently employs a workforce with a staff strength of 5,087 (H1 2019). 24% of this workforce is female and there is a concerted effort by the Disco to increase the female percentage of the workforce to ensure equal opportunities at our offices. In the first half of 2019, we have employed 234 staff and have an internship program that caters to interns who come in the National Youth Service program.

The average annual cost of this workforce is currently at about N 6bn and with the expansion expected over the next few years, these costs are projected to go up to an annual average of N7.9bn over the 5-year period.

**Table 20: Projections for labour costs 2020 - 2024**

| Year | Labour Costs, Nm |
|---|---|
| 2020 | 6,500 |
| 2021 | 7,150 |
| 2022 | 7,865 |
| 2023 | 8,652 |
| 2024 | 9,517 |

Staff training is an integral part of the HR operations at EEDC and there are trainings planned companywide. This is important, as EEDC has sometimes suffered lapses in its service due to staff misunderstanding of duties or regulations. Therefore, there is a budget to handle staff training which would cost an average of N 70m annually.

**Table 21: Projected cost of staff training 2020 - 2024**

| Year | Training Costs, Nm |
|---|---|
| 2020 | 58.04 |
| 2021 | 63.85 |
| 2022 | 70.23 |
| 2023 | 77.26 |
| 2024 | 84.98 |

There are also costs involved in the recruitment process and these costs are currently an annual average of N 36m. This cost would be considered in our OPEX costs of Labour and Admin.

In order to deliver the PIP, there is the need recruit skilled labour, train and retrain staff and improve customer service delivery through culture change advocacy. The HR department has also pinpointed the need for an annual recruitment of 20% in the areas of network expansion and maintenance, meter installation and customer service. There must also be annual competency-based training for all staff.

The CAPEX needs for the HR department are tabled below.

**Table 22: CAPEX needs for HR department**

| Year | CAPEX, Nm |
|---|---|
| 2020 | 150 |
| 2021 | 200 |
| 2022 | 250 |
| 2023 | 300 |
| 2024 | 350 |

EEDC has managed to ensure cost efficiency in these plans by ensuring the following:

- Effective salary negotiation;
- Reduction in staff redundancy;
- Establishment of company training centre to facilitate in-house staff training

### 6.8.2 Other resource requirements

There is the need to provide different resources for the smooth running of the business and logistics is an important part of our business. The provision and maintenance of motor vehicles will ease movement during routine vigilance checks, maintenance runs, routine hazard hunting, etc.

In order to meet the requirements for the boost in services that would increase revenues and reduce losses, EEDC would need to acquire new corporate offices especially service centres and cash offices. These would have to be in line with the projected expansion and the growing needs of the customers.

The CAPEX and OPEX needs for the buildings and facilities are as below.

**Table 23: CAPEX and OPEX for buildings and facilities 2020 - 2024**

| Year | CAPEX, Nm | OPEX, Nm | Total, Nm |
|---|---|---|---|
| 2020 | 190.70 | 25 | 215.70 |
| 2021 | 209.77 | 30 | 239.77 |
| 2022 | 230.75 | 35 | 265.75 |
| 2023 | 253.82 | 40 | 293.82 |
| 2024 | 279.20 | 40 | 319.20 |

EEDC has ensured cost efficiency by:

- Cost effective rent negotiation; and
- Purchase of high-quality materials

## 6.9 Overall investment plan

EEDC investment needs over the next five years to achieve the targeted outputs in this plan is N 158bn; with CAPEX of N 40bn and OPEX of N 118bn during the period. The funding plan is captured in the next section.

# 7 Financial plan

## 7.1 Overview

This section covers:

- Minimal CAPEX Scenario;
- Full CAPEX Scenario;
- Funding plans; and
- Financial analysis.

## 7.2 Minimal CAPEX Scenario

This scenario supposes that EEDC is only able to invest minimally in its CAPEX. The other assumptions include:

- Energy levels at 9% of national availability;
- ATC&C losses at EEDC's current reality;
- Tariffs allowed to be cost-reflective of actual losses

Due to the CAPEX being minimal, losses would reduce slowly.

**Table 24: Assumptions for "minimal CAPEX" scenario**

| Assumptions | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| **Energy Received (GWh/month)** | 199.5 | 214 | 214 | 214 | 214 |
| **CAPEX** | 4,237 | 4,665 | 3,607 | 2,778 | 2,688 |
| **OPEX** | 19,328 | 21,261 | 23,387 | 25,726 | 28,299 |
| **ATC&C Trajectory** | 47% | 44% | 41% | 37% | 34% |

## 7.3 Full CAPEX Scenario

This scenario supposes that EEDC is only able to invest in the MYTO allowed CAPEX for the period. The other assumptions include:

- Energy levels at 9% of national availability;

- ATC&C losses at EEDC's current reality;
- Tariffs allowed to be cost-reflective of actual losses

Due to the CAPEX being higher, losses would reduce to more aggressive levels over the period.

**Table 25: Assumptions for "full CAPEX" scenario**

| Assumptions | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| **Energy Received (GWh/month)** | 199.5 | 214 | 214 | 214 | 214 |
| **CAPEX** | 7,027 | 7,027 | 8,783 | 8,783 | 8,783 |
| **OPEX** | 19,328 | 21,261 | 23,387 | 25,726 | 28,299 |
| **ATC&C Trajectory** | 46% | 43% | 39% | 35% | 30% |

## 7.4 Planned expenditure

### 7.4.1 Capital expenditure

Without access to finance to source the planned capital expenditure as outlined in Section 4.3.5, Enugu is unable to make these investments in full in the minimal CAPEX scenario.

**Table 26: Realised CAPEX investments in "minimal CAPEX" scenario against the expected investments**

| Naira million | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Expected CAPEX | 4,237 | 4,665 | 3,607 | 2,778 | 2,688 |
| Realised CAPEX | 0 | 0 | 0 | 0 | 0 |

In the "full CAPEX" scenario, Enugu is able to make some of the capital investments defined in Section 4.3.5, based on the allowed CAPEX in the MYTO.

**Table 27: Realised CAPEX investments in "full CAPEX" scenario against the expected investments**

| Naira million | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Expected CAPEX | 7,027 | 7,027 | 8,783 | 8,783 | 8,783 |
| Realised CAPEX | 7,027 | 7,027 | 8,783 | 8,783 | 8,783 |

## 7.5 Funding plans

In both scenarios it is assumed that the Disco does not have access to additional financing. In both scenarios we assume:

- There is no Siemen's investment/loan
- No access to commercial debt,
- And no incremental funding supplied by shareholders (through equity or SHLs).

The funding gap in the two scenarios is shown in Table 28.

**Table 28: Funding gaps in the scenarios**

| Naira million | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| **Minimal CAPEX** | | | | | |
| CAPEX | 4,237 | 4,665 | 3,607 | 2,778 | 2,688 |
| Achieved investment | - | - | - | - | - |
| Funding gap | 4,237 | 4,665 | 3,607 | 2,778 | 2,688 |
| **Full CAPEX** | | | | | |
| CAPEX | 7,027 | 7,027 | 8,783 | 8,783 | 8,783 |
| Achieved investment | 7,027 | 7,027 | 8,783 | 8,783 | 8,783 |
| Funding gap | 100% | 100% | 100% | 100% | 100% |

## 7.6 Financial analysis

### 7.6.1 Assumptions

Assumptions for the modelling have been detailed in section 4.3 and further assumptions are outlined in Annex Y.

A summary of the key assumptions for the two scenarios are shown in Tables 31 and 32.

**Table 29: Key assumptions in the 'no intervention' scenario**

| | Units | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| Customer tariff | ₦/kWh | 45.82 | 41.57 | 40.93 | 40.94 | 41.29 |

| | Units | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| Current market liability offset by historic tariff shortfall | ₦m | 140,001 | | | | |
| CAPEX | ₦m | 4,237 | 4,665 | 3,607 | 2,778 | 2,688 |
| Achievable ATC&C - CAPEX reflective (without cash restrictions) | % | 47% | 44% | 41% | 37% | 34% |
| Tariff included ATC&C losses - | % | 47% | 44% | 41% | 37% | 34% |

**Table 30: Key assumptions in the 'with intervention' scenario**

| | Units | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| Customer tariff | ₦/kWh | output | | | | |
| Current market liability offset by historic tariff shortfall | ₦m | 195,496 | | | | |
| CAPEX | ₦m | 7,027 | 7,027 | 8,783 | 8,783 | 8,783 |
| Achievable ATC&C - CAPEX reflective (without cash restrictions) | % | 46% | 43% | 39% | 35% | 30% |
| Tariff included ATC&C losses - (permitted in the customer tariff) | % | 46% | 43% | 39% | 35% | 30% |

### 7.6.2 Results

**<u>Minimal CAPEX</u>**

**In this scenario:**

- **Tariffs increase to cost reflective levels;**
- **Internally generated revenue is sufficient to meet OPEX but not CAPEX;**
- **ATC&C losses are at current levels**
- **No distribution to shareholders is made.**

| | Units | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| **CAPEX** | | | | | | |
| CAPEX submitted | ₦m | 4,237 | 4,665 | 3,607 | 2,778 | 2,688 |
| CAPEX used | ₦m | - | - | - | - | - |
| CAPEX used vs Allowed CAPEX (%) | % | 0% | 0% | 0% | 0% | 0% |
| Funding gap | ₦m | 4,237 | 4,665 | 3,607 | 2,778 | 2,688 |
| **Tariffs** | | | | | | |
| Customer tariff | ₦/kWh | 91.17 | 86.21 | 83.25 | 79.60 | 77.62 |
| Cost-reflective tariff if full CAPEX spent | ₦/kWh | 91.17 | 86.21 | 83.25 | 79.60 | 77.62 |
| Cost-reflective tariff given cash constraints | ₦/kWh | 91.17 | 90.92 | 92.24 | 93.85 | 95.76 |
| Tariff - Difference | ₦/kWh | 0.00 | -4.71 | -8.99 | -14.24 | -18.15 |
| **ATC&C losses** | | | | | | |
| ATC&C losses (full CAPEX) | % | 47% | 44% | 41% | 37% | 34% |
| ATC&C losses achieved (given cash restrictions) | % | 47% | 47% | 47% | 47% | 47% |
| ATC&C losses Difference | % | 0% | -3% | -6% | -10% | -13% |
| **Payment waterfall based on NBET and MO paid before disco OPEX** | | | | | | |
| % of Disco's operational costs paid | % | 0% | 0% | 74% | 95% | 81% |
| Market payment | % | 151% | 132% | 100% | 100% | 100% |
| **Payment waterfall based on disco OPEX met before NBET and MO payment** | | | | | | |
| % of Disco's operational costs paid | % | 100% | 100% | 100% | 100% | 100% |
| Market payment | % | 120% | 112% | 109% | 111% | 107% |

**Full CAPEX scenario**

**In this scenario:**

- **Tariffs increase to as high as N81/kWh;**
- **Internally generated revenue is sufficient to meet OPEX and CAPEX as in MYTO;**
- **ATC&C losses reduce to 29.8%.**
- **No distribution to shareholders is made.**

| | Units | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| **CAPEX** | | | | | | |
| CAPEX submitted | ₦m | 7,027 | 7,027 | 8,783 | 8,783 | 8,783 |
| CAPEX used | ₦m | 7,027 | 7,027 | 8,783 | 8,783 | 8,783 |
| CAPEX used vs Allowed CAPEX (%) | % | 100% | 100% | 100% | 100% | 100% |
| Funding gap | ₦m | - | - | - | - | - |
| **Tariffs** | | | | | | |
| Customer tariff | ₦/kWh | 89.51 | 85.20 | 81.46 | 78.75 | 74.55 |
| Cost-reflective tariff if full CAPEX spent | ₦/kWh | 89.51 | 85.20 | 81.46 | 78.75 | 74.55 |
| Cost-reflective tariff given cash constraints | ₦/kWh | 89.51 | 85.20 | 81.46 | 78.75 | 74.55 |
| Tariff - Difference | ₦/kWh | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **ATC&C losses** | | | | | | |
| ATC&C losses (full CAPEX) | % | 46% | 43% | 39% | 35% | 30% |
| ATC&C losses achieved (given cash restrictions) | % | 46% | 43% | 39% | 35% | 30% |
| ATC&C losses Difference | % | 0% | 0% | 0% | 0% | 0% |
| | | | | | | |
| Market payment | % | 100% | 100% | 100% | 100% | 100% |

Cash flows for the two scenarios can be seen in Annex H.

We acknowledge that both of these scenarios have relatively high tariffs and understand that our customers are unable to pay such high rates. However, this is the reality of what we would need to be able to function optimally as required by NERC and meet our market obligations.

# 8 Risk assessment and management

## 8.1 Overview

This section covers:

- Approach to managing risk; and
- Risk analysis.

## 8.2 Approach to managing risk

EEDC 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 31 provides a risk assessment for this performance improvement plan.

**Table 31 – 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)*<br>*Reduction (optimize – mitigate)*<br>*Sharing (e.g. insure, transfer)*<br>*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).*<br>The decision on tariffs is outside the direct control of the Discos.<br>Within the different scenarios modelled in section 0, 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.<br>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 | High | High | **Retention** *(accept and budget).*<br>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 |

| Risk title | Risk description | Risk likelihood | Risk impact | Risk management strategy |
|---|---|---|---|---|
| | currently being accrued at the state level. | | | section 0, we have considered different possible scenarios for MDA payment.<br>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.<br>BPE has indicated that 2017 and 2018 will be treated as non-performance years.[6] 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.<br>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).*<br>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.<br>This risk is not possible to manage, unless BPE amend the performance agreement targets to reflect an achievable trajectory.<br>**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 | High | High | **Avoidance** *(eliminate, withdraw).*<br>Failure to implement a minor review could qualify as a "change of law" force majeure event under the |

[6] 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 |
|---|---|---|---|---|
| | to meet their obligations. | | | performance agreement, since the regulation is not being enforced.<br>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 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.<br>Once PPAs are activated, generation | High | Low (providing minor reviews implemented) | **Retention** *(accept and budget)*.<br>The scenarios in this report assume that generation tariffs are consistent with NBET current tariffs in real 2019 terms.<br>This is addressed retrospectively when NERC use actual NBET invoices in minor reviews but will have an impact in short term cashflow and |

| Risk title | Risk description | Risk likelihood | Risk impact | Risk management strategy |
|---|---|---|---|---|
| | costs will deviate further from MYTO assumptions as capacity factors will be considerably higher once successor and NIPP generators can charge for available capacity. | | | ability to meet market remittances.<br>**Regulatory need.**<br>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.<br>When there are generation shocks (such as in 2016), there is a disproportionate impact on payment, due to customer dissatisfaction and the fact that fixed costs are spread over fewer kWhs. | High | High | **Retention** *(accept and budget).*<br>The scenarios in this report assume that generation levels remain at 2019 levels, with no increase.<br>**Regulatory need.**<br>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. EEDC has experienced a loss of one of its major | High | Low to medium | **Avoidance** *(eliminate, withdraw).*<br>If the market issue is not resolved, and tariff levels are not adjusted to compensate, the only option for some Discos may be |

| Risk title | Risk description | Risk likelihood | Risk impact | Risk management strategy |
|---|---|---|---|---|
| | customers without payment of accrued energy bills. 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. | | | withdrawal via force majeure.<br>**Regulatory need.**<br>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)*<br>EEDC has managed their MAP contracts to ensure best possible service.<br>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 financing by the customers themselves. Many of our customers may not be able to finance the CAPEX. This is important to EEDC as a large number of our customers are in rural and semi—urban areas where economic power is relatively low.<br>**Regulatory need.** |

| Risk title | Risk description | Risk likelihood | Risk impact | Risk management strategy |
|---|---|---|---|---|
| | | | | 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. |
| **Allowed CAPEX in MYTO model.** | If allowed CAPEX is not consistent with assumptions, it will restrict the ability of EEDC to make the required investment and may prevent the planned Outputs being achieved. | High | Medium | **Retention** *(accept and budget)*<br>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)*<br>In our financial planning, we have considered known sources of finance. We have considered cases where investment is financed out of free cashflow rather than 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 EEDC's, as discussed in section H. 4. | [Client risk assessment] | Medium | **Retention** *(accept and budget)*<br>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. |

| Risk title | Risk description | Risk likelihood | Risk impact | Risk management strategy |
|---|---|---|---|---|
| **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 | |
| **Insurgency activities damage EEDC assets (or other extreme events beyond EEDC's control e.g. extreme weather).** | In recent years, insurgency and civil unrest has caused damage to electricity infrastructure in Nigeria. There is a risk of recurrence.<br>Other extreme events could include (for example) extreme weather or seismic events. | Medium | High | **Sharing** *(e.g. insure, transfer)*<br>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.<br>**Avoidance** *(eliminate, withdraw).*<br>The Performance Agreement allows for withdrawal in the case of severe or prolonged insurgency and other specific force majeure events. |

# Annexes

# Annex A Achievable outputs in modelled scenarios

assume all the allowed CAPEX is spent in each scenario. In some scenarios, finance may not be available to meet the required CAPEX, in which case the achievable outputs may differ from the target outputs.

Unless additional sources of finance are found (for example, shareholder loans via BPE or other FGN sources), the achievable outputs are expected to be as follows in each of the scenarios.

## A. 1 Achievable outputs in "minimal CAPEX" scenario

A "minimal CAPEX" scenario based on current realities and the inability to raise CAPEX.

**Table 32: Achievable service levels ("outputs") in "minimal 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 (%) | 51% | 47% | 44% | 41% | 37% | 34% |
| 2 | Reliability/ availability | Number of customer Interruptions (#) | 492 | 400 | 400 | 360 | 320 | 300 |
| 3 | Metering | Number of consumer meters installed | | 70,000 | 317,800 | 233,545 | | |
| 4 | New connection/ network expansion | Number of new customer connections | 64,782 | 67,225 | 78,115 | 82,052 | 86,190 | 88,000 |
| 5 | Customer satisfaction | Not defined – propose composite of 1, 2 and 3[7] | | | | | | |
| 6 | Safety | Not defined – propose number of deaths and number of accidents | 24 | 20 | 15 | 10 | 5 | 5 |

[7] Loss reduction demonstrates customer willingness to pay, reliability measures their access to electricity and metering reduces the number of estimated bills (a key factor in complaints).

## A. 2 Achievable outputs in "full CAPEX" full CAPEX allowance scenario

The "full CAPEX" scenario based on a cost-reflective tariff, which assumes that tariffs have not permitted loss reduction to date and so losses are high; whilst allowing full required CAPEX to achieve the Disco's ambitious loss reduction and other output targets.

**Table 33: Achievable service levels ("outputs") in "full 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 (%) | 51% | 46.0% | 43.0% | 39.2% | 35.4% | 29.8% |
| 2 | Reliability/ availability | Number of customer Interruptions (#) | 492 | 400 | 350 | 300 | 200 | 150 |
| 3 | Metering | Number of new consumer meters installed | | 70,000 | 317,800 | 233,545 | | |
| 4 | New connection/ network expansion | Number of new customer connections | 64,782 | 67,225 | 78,115 | 82,052 | 86,190 | 88,000 |
| 5 | Customer satisfaction | Not defined – propose composite of 1, 2 and 3[8] | | | | | | |
| 6 | Safety | Not defined – propose number of deaths and number of accidents | 24 | 20 | 15 | 10 | 5 | 5 |



[8] Loss reduction demonstrates customer willingness to pay, reliability measures their access to electricity and metering reduces the number of estimated bills (a key factor in complaints).

# Annex B Financial Modelling Assumptions

The following items detail assumptions or simplifications made outside of the detailed descriptions given in the main body of the report.

## B. 1 Depreciation

The depreciation calculation has been simplified to only consider one kind of depreciation in the model across all asset classes – the same depreciation rates are used for accounting, taxation and MYTO allowable revenue purposes.

An average rate of depreciation (3.9% weighted average based on MYTO defined asset base, decreasing balance) has been used to model the depreciation. This figure will be slightly different to what the figure in the MYTO model which considers different asset classes separately.

## B. 2 NEMSF I CBN Loan

It has been assumed that the MYTO reported annual principal and interest repayments from the June 2019 minor review for the NEMSF I loan are correct.

## B. 3 Outstanding liabilities and assets

The following changes to the balance sheet figures received from the Disco's have been made and the changes have been reflected in the value of the reserves.

- Any applicable MO/NBET liability is written-off by the 31st December 2019 according to the scenario assumptions. If there are any tax implications from this for the Disco, this needs to be discussed with accountants.
- Historic MO and NBET liability is based on latest balance sheet data. Additional MO and NBET liability to end 2019 is added based on most recent remittance data from NERC and an estimate of MO and NBET bills for the remaining months of 2019.
- 90% of the current receivables due from customers has been written off as bad debt by the 31st December 2019.

## B. 4 Customers

As a required simplification due to the lack of available data, no customer disaggregation has been applied. As discussed in the body of the report, in the major tariff review it will be imperative that the MYTO load allocation are revised so that the MYTO tariff model is reflective of reality.

## B. 5 Achieved ATC&C loss reductions

In a scenario where cashflow is not sufficient to cover desired CAPEX investments and funding from a loan is not available, the realised ATC&C pathway is adjusted to align with the actual CAPEX which can be funded. The adjustment to ATC&C to pathway is directly proportional to the amount of CAPEX available relative to the full CAPEX required to meet the ATC&C pathway.

## B. 6 Achieved CAPEX

Achieved CAPEX may differ from planned CAPEX based on available funding. We assume funding is available based on [Enugu's funding plans discussed in section 7. Funding is not available in years when operational costs exceed revenues (when tariffs are not cost reflective).

CAPEX is linked to specific investment programs.

We assume funding is only available to cover CAPEX (not OPEX).

## B. 7 VAT

VAT is not considered in the collections or cost-reflective tariffs presented. Since VAT is a passthrough tax on customer bills, this should not make a difference to business performance.

## B. 8 Macroeconomic parameters

Assumptions for foreign exchange and inflation are based on the latest June 2019 minor review.

## B. 9 Payment Waterfall

The payment waterfall assumes Disco own operational costs (excluding CAPEX and new OPEX linked to CAPEX) are met before paying MO and NBET. The MO is paid before NBET. Proportion of payment to MO and NBET is an output of the model for each year.

# Annex C Results of stakeholder consultation

# Annex D Timeline

**Table 34: 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 | | | 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 | | | | | | | | | 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).<br>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 of |

| 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 | |
| | | | | | | | | | | 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 | 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 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Market** | | | **MYTO Model in Use** | | | | | |
| | 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 E Outstanding issues in tariff shortfall calculation

Prepared in response to NERC letter dated 2 August 2019.

**Table 35: Outstanding issues in shortfall calculation**

| No. | EEDC comments on MYTO 2019 in letter to NERC dated [date] | NERC response dated 2 August 2019 | EEDC clarifications in response to NERC letter |
|---|---|---|---|
| 1 | Shortfall calculation assumed 2015, 2016 and 2019 were loss reduction years, whereas, we believe these years should be treated as years of mutual non-performance for the reasons discussed in section 4.2.4.1. | 2014 was made whole by NEMSF. | See discussion of legacy issues for the interim rules period below. |
| | | 2015 first year of baseline losses being applied. | Collection losses were stripped from tariffs in April 2015, just 2 months after tariffs were implemented. Therefore, baseline losses were not applied in tariffs in 2015. EEDC declared force majeure to BPE. |
| | | Deferred revenue allowed for in 2015-2016. | Underpayment was provided for in the 2015 MYTO Order (MYTO 2.1) for 2015 and 2016, which would be recovered with return on investment from overpayments in 2017 and 2018.<br>However, the actual under provision against allowed revenue for these years was [Y]% in 2015 and [Z]% in 2016 according to NERC's own June 2019 minor review[9]. This is beyond the ability of EEDC to manage deferred revenue between years. The deferred revenue has still not been recovered. The prevision for return on investment on the shortfall has been removed from the MYTO shortfall calculation. |
| | | Expectation that Discos would borrow to settle upstream market invoices. | The failure of NERC to implement minor reviews, and successive tariff reversal in April 2015 has meant that banks are now unwilling to lend to Discos until there is greater security over forward revenue streams. Most Discos are now effectively insolvent. The ability to borrow will depend on regulatory stability and cost reflective tariffs for a number of years to build the confidence of the financial sector. |

[9] Our figures are higher, as we consider 2015 and 2016 non-performance years.

| No. | EEDC comments on MYTO 2019 in letter to NERC dated [date] | NERC response dated 2 August 2019 | EEDC clarifications in response to NERC letter |
|---|---|---|---|
| 2 | MDA debt repayment has still not been resolved, which was a condition for MDA loss removal in the MYTO 2015 model. | NERC view is that the responsibility for revenue collection from MDAs rests with Discos. | MDA debts were stripped from Disco ATC&C losses from February 2016 on the expectation that FGN would be responsible for payment. If this decision no longer holds, then the initial baseline losses should be in line with the 2014 Baseline Loss Study, with no deduction for MDAs. |
| 3 | [Legacy issues affecting the interim rules period shortfall should be resolved. | Will be resolved in extraordinary tariff review in the next couple of months. | NERC developed a MYTO Shortfall model to calculate the shortfall in the allowable revenue requirement experienced by the industry during the Interim Rules Period. The results fed into the Central Bank of Nigeria Capital Model for the Nigerian Electricity Market Stabilisation Facility (NEMSF) of ₦214bn (full amount, including transaction costs). NERC calculated that the share of this amount due to EEDC after payment of market debts would be N Xbn.<br>There were issues with the shortfall computation at the time which meant that EEDC was unable to meet all liabilities. The difference that was not covered by the fund was N Ybn. The breakdown of this figure is provided in **Error! Reference source not found.**.<br>We propose that the difference of N Y bn should be reconciled with NERC and subsequently netted off the payment due to the market by EEDC. |
| 4 | CAPEX actually spent in non-compliance years should be included in the model. | NERC is not averse to allowing the CAPEX allowance on the provision that loss reduction will apply in that period. | The limited CAPEX expenditure has been on emergency repairs rather than ATC&C loss reduction. EEDC requests that NERC reviews the CAPEX actually spent in the relevant years to determine that it is appropriate expenditure. [Ideally add1 or 2 examples of actual CAPEX in 2017/2018 from client] |
| 5 | Customer enumeration and energy consumed by | Will be resolved in extraordinary tariff | |

| No. | EEDC comments on MYTO 2019 in letter to NERC dated [date] | NERC response dated 2 August 2019 | EEDC clarifications in response to NERC letter |
|---|---|---|---|
| | customer tariff class should be updated in the model. | review in the next couple of months.<br>Discos are required to submit customer enumeration data and load demand study in line with approved methodologies. | |
| 6 | Inclusion of MDA loss in the MYTO and inclusion of the unverified bills into the loss level | | |

## Annex F   Sample Single Line Diagrams


Figure 7: Sample SLD of LV


**Figure 8: Sample SLD of 33kV feeder**

# Annex G  Demand forecast

# Annex H Financial Analysis Assumptions

## H. 1Energy 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.

## H. 2Input data

The expected energy and capacity levels to be borne by Discos are shown in 2019 real terms in Table 36.

**Table 36: Expected generation costs for the industry and EEDC in nominal terms**

| | Current[10] | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| National generation capacity (MWh/month) | 3,180,313 | 4,516,503 | 4,516,503 | 4,516,503 | 4,516,503 | 4,516,503 |
| National energy delivered to Discos (MWh/month) | 2,380,223 | 2,380,223 | 2,380,223 | 2,380,223 | 2,380,223 | 2,380,223 |
| Load allocation for Enugu (%) | 8.4% | 8.4% | 9% | 9% | 9% | 9% |
| Capacity allocated to Disco (MWh/month) | 266,664 | 266,664 | 266,664 | 266,664 | 266,664 | 266,664 |
| Energy received at Disco (MWh/month) | 199,578 | 199,578 | 214,220 | 214,220 | 214,220 | 214,220 |
| Overall charge for delivered energy (N/kWh delivered) | 22.43 | 27.45 | 27.54 | 27.71 | 27.88 | 28.07 |
| Average energy tariff (N/kWh delivered) | 11.05 | 10.41 | 10.48 | 10.56 | 10.65 | 10.73 |

[10] NBET invoices for 2019

| | Current[10] | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| Average capacity tariff (N/kWh available) | 8.50 | 8.98 | 8.99 | 9.04 | 9.08 | 9.14 |

## H. 3Retail tariff levels

Two different scenarios for tariffs are considered, as summarised in Table 37.

**Table 37: Summary of two tariff scenarios**

| Assumption | "minimal CAPEX" scenario | "full CAPEX" scenario Cost-reflective tariff and full CAPEX |
|---|---|---|
| **Tariffs** | "Cost reflective" tariff from Jan 2020 with variable assumptions for allowed ATC&C losses and allowed CAPEX. | |
| **ATC&C losses allowed in tariffs** | End of 2020 as year 4 of ATC&C loss reduction | End of 2020 as year 1 of ATC&C loss reduction |
| **Allowed CAPEX** | Proposed minimal levels for 2020 – 2024 | Full MYTO CAPEX |
| **Tariff level as an input or output of financial modelling?** | **Output** | **Output** |

As a result, tariff levels are an output in the "minimal CAPEX" scenario and "full CAPEX" scenario.

Tariff levels are an output of the "full CAPEX" scenarios based on a cost-reflective tariff with full CAPEX. Cost-reflective tariffs are an output of the financial model (see section 0).

For EEDC this results in the following allowed tariffs in each scenario (Table 38).

**Table 38: Allowed average tariffs in each scenario (N/kWh)**

| Scenarios | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| "Minimal CAPEX" scenario (output) | 91.17 | 86.21 | 83.25 | 79.60 | 77.62 |
| "Full CAPEX" scenario (output) | 89.51 | 86.53 | 84.21 | 81.93 | 77.74 |

In both scenarios, we assume that minor reviews are conducted and implemented in tariffs every six months without delay.

If tariff levels are not consistent with assumptions, it will jeopardise the ability of EEDC to implement the outputs expected in each scenario.

## H. 4Load allocation in tariffs

In both scenarios, we assume that the MYTO model is amended to reflect current load allocation for future tariffs.

Based on the assumed load allocation in the June 2019 Minor Review, the 2020 tariffs would result in an average overall tariff of [XX] N/kWh. If the actual load allocation is used, the 2020 tariffs would result in an average overall tariff of [YY] N/kWh. The underlying data for this calculation is provided in **Error! Reference source not found.** in Annex H.

If the load allocations in MYTO are not amended, there will be a significant shortfall in revenue for EEDC.

## H. 5Market shortfall

Table 39 summarises the historic and projected market shortfall assumptions across the modelled scenarios.

**Table 39: Summary of both market shortfall scenarios**

| Assumption | "minimal CAPEX" scenario NERC tariff assumptions for ATC&C | "full CAPEX" scenario Cost-reflective tariff and full CAPEX |
|---|---|---|
| **Actual historic market shortfall** | Actual shortfall to (invoices received minus invoices paid) to [date, e.g. July 2019]<br>Projection from [date, e.g. July 2019] to December 2019, based on 2019 remittance to date and projected market invoices | |
| **Market shortfall permitted in MYTO tariffs** | Historic shortfall written off based on NERC ATC&C assumptions only (June 2019 minor review figure) | All historic shortfall written off based on 2020 as year 1 of ATC&C loss reduction |
| **Future market shortfall as an input or output of** | **Output** (new shortfall may be accrued) | **Input** (no new shortfall accrued) |

| Assumption | "minimal CAPEX" scenario NERC tariff assumptions for ATC&C | "full CAPEX" scenario Cost-reflective tariff and full CAPEX |
|---|---|---|
| **financial modelling?** | | |

Market shortfalls 2020-2025 are an output in the "minimal CAPEX" scenario with NERC tariff assumptions for ATC&C. Market shortfalls are an output of the financial model (see section 0).

Market shortfalls 2020-2025 of 0% (full market remittance) are an input to the "full CAPEX" scenario based on a cost-reflective tariff with full CAPEX.

Actual historic market shortfalls (which must be repaid) are an input to all scenarios and are consistent in all four scenarios.

Historic market shortfalls allowed in tariffs are based on three different assumptions:

- In the "minimal CAPEX" scenario: we assume that the historic shortfall written off is only the level allowed by NERC in the June 2019 minor review. In the case of EEDC, this is [insert amount] Naira as defined in the *2016-2018 Minor Review of MYTO 2015 and Minimum Remittance Order for the Year 2019*. Therefore, there is an overall shortfall.
- In the "full CAPEX" scenarios based on a cost-reflective tariff with full CAPEX: we assume that the full shortfall agreed at least covers remittance shortfall (no remaining debt to NBET or to MO). In EEDC's letter to NERC dated 26th June, 2019 we highlighted the following reasons why the shortfall calculated by NERC was inconsistent with our own expectations, see Table 35.

In the NERC response dated 2nd August 2019, NERC requested that any outstanding issues, including legacy issues, should be clearly articulated in this PIP. Table 35 in Annex E provides this summary of outstanding issues.

EEDC welcomes NERC's willingness to consider the tariff and shortfall assumptions ahead of the extraordinary tariff review and is very happy to discuss the outstanding issues in Table 35 at NERC's convenience.

## H. 6Access to capital

In both scenarios there will be no access to new capital, with Disco expenditure from internally generated revenue only. The lack of funding is discussed in Section 7..

In both scenarios, dividends are distributed to shareholders if internally generated revenue is sufficient to meet internal OPEX and CAPEX needs.

The efficient funding sources selected by EEDC are discussed in Section 7.5.

## H. 7ATC&C

In the "minimal CAPEX" scenario, actual ATC&C losses experienced by the Disco do not fully reduce in line with the expectations in the MYTO.

In the "full CAPEX" scenario, we assume ATC&C losses are reduced from 2019 levels to meet the loss reduction trajectory set by EEDC. The achieved trajectory is also influenced by the availability to fund CAPEX plans.

**Table 40: ATC&C trajectory in both scenarios**

| ATC&C % | | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| "minimal CAPEX" scenario | Target in MYTO tariffs | 47% | 44% | 41% | 37% | 34% |
| | Achieved based on CAPEX | 39% | 39% | 39% | 39% | 39% |
| "full CAPEX" scenario | Target in MYTO tariffs | 46% | 43% | 39% | 35% | 30% |
| | Achieved based on CAPEX | 42% | 35% | 30% | 25% | 25% |

## H. 8OPEX

In both scenarios OPEX costs incurred by the Disco are as shown in Table 43. The OPEX grows as a result of the business growth and

A further increase in OPEX costs is expected in the "full CAPEX" scenario ´to account for an increase in OPEX costs as a result of CAPEX investments.

**Table 41: Projected OPEX costs incurred by EEDC**

| Naira million/year | current | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| MYTO Minor Review (June19) | 14,962 | 16,535 | 18,280 | 20,218 | 22,369 | 24,757 |
| "minimal CAPEX" | 12,498 | 15,771 | 15,652 | 17,520 | 19,613 | 21,959 |

| Naira million/year | current | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| "Intervention" | 12,498 | 15,771 | 15,652 | 17,520 | 19,613 | 21,959 |

## H. 9Inflation 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 I Distribution Network Investments

### Table 42:Completed Projects (2017-2019)

| S/N | Project Description | Project Benefits | Year of Completion |
|---|---|---|---|
| **2017** | | | |
| 1 | CONSTRUCTION OF UGWUAJI TRANSEKULU 33KV FEEDER FROM UGWUAJI TRANSMISSION | - For power Evacuation from Ugwuaji TCN - Improvement of supply in the capital territory | 2017 |
| 2 | CONSTRUCTION OF UGWUAJI GARRIKI 33KV FEEDER FROM UGWUAJI TRANSMISSION | - For power Evacuation from Ugwuaji TCN - Improvement of supply in the capital territory | 2017 |
| **2018** | | | |
| 3 | DEDICATED 11KV FEEDER FOR WILLSON INDUSTRIES NSUKKA | - Improvement of supply within Nsukka town - Increase in revenue collection from high yield 11kv feeders - Improved services to our teeming customers | 2018 |
| 4 | CONSTRUCTION of 1 x 7.5MVA 33/11kv INJECTION SUBSTATION AT NIKE LAKE ENUGU | - Improvement of supply in the capital territory - Increase in revenue collection from high yield 11kv feeders - Improved services to our teeming customers | 2018 |
| 5 | PROPOSAL TO DELOAD ABA TOWNSHIP WITH OGBOR INJECTION SUB STN | - Increased hours of supply to high energy demand customers - Increased revenue collection for benefitting district. | 2018 |
| 6 | PROPOSAL TO DELOAD UMUDIKE 11KV FEEDER | - Increased hours of supply to high energy demand customers - Increased revenue collection for benefitting district. | 2018 |

| S/N | Project Description | Project Benefits | Year of Completion |
|---|---|---|---|
| 7 | PROPOSAL TO DELOAD TOWNSHIP 11KV FEEDER USING NDUME 11KV FEEDER | - Increased hours of supply to high energy demand customers<br>- Increased revenue collection for benefitting district. | 2018 |
| 8 | FENCING ANDCOMPLETION OF BAKASSI 300KVA TRANSFORMER AND REHABILITATION ON 1NO LT CIRCUIT | - Increased hours of supply to high energy demand customers<br>- Increased revenue collection for benefitting district. | 2018 |
| 9 | REINFOREMENTOF WATERSIDE SECTION OF ABA-UMUAHIA AND IGI 33KV FEEDERS WITH STEEL LATTICE TOWERS AND EROSION CONTROL | - Increased hours of supply to high energy demand customers<br>- Increased revenue collection for benefitting district. | 2018 |
| 10 | CREATION OF NKWELLE 11KV FEEDER TO FACILITATE LOAD TRANSFER FROM TOLL GATE 11KV FEEDER | Loss reduction and improvement in revenue collection | 2018 |
| **2019** | | | |
| 11 | CONSTRUCTION OF ABS 1X7.5MVA 33/11KV INJECTION SUBSTATION | - Provide much needed relief to existing overloaded 11kv feeders, e.g Ifite & Enugu Agidi.<br>- Accommodation of suppressed loads<br>- Improve hours of supply availability to a mixed customer population of over 3,544.<br>- Improve cash collection for benefitting district. | 2019 |
| 12 | UPGRADE OF AGU-AWKA 2X7.5MVA SUBSTATION TO 1X15MVA & 1X7.5MVA 33/11KV INJECTION SUBSTATION | - Improvement of supply in the capital territory<br>- Increase in revenue collection from high yield 11kv feeders e.g Unizik and Industrial feeders.<br>- Improved services to our teeming customers | 2019 |

| S/N | Project Description | Project Benefits | Year of Completion |
|---|---|---|---|
| 13 | CONSTRUCTION OF 6KM 11KV O/H LINE FOR CREATION OF ALBEN DEDICATED FEEDER FOR MD CUSTOMERS | - Increased hours of supply to high energy demand customers<br>- Increased revenue collection for benefitting district. | 2019 |
| 14 | DE-LOADING OF AZUIYIOKWU 11KV FEEDER FROM CENTENARY INJECTION SS | - Increased hours of supply to high energy demand customers<br>- Increased revenue collection for benefitting district. | 2019 |
| 15 | INSTALLATION OF 33KV AUTO RECLOSER ON ABA-UMUAHIA 33KV FEEDER | - Increased hours of supply to high energy demand customers<br>- Increased revenue collection for benefitting district. | 2019 |
| 16 | ALEX DEDICATED 33KV FEEDER INYISHI MBAISE | increase the supply of energy to a demand customer | 2019 |
| 17 | CONSTRUCTION OF OGUTA DOUBLE CCT FROM EGBU TCN TO ONITSHA ROAD INJECTION SUBSTATION | Network reinforcement | 2019 |
| 18 | APUCHE/GOLDEN GATE 2 X 300KVA SS, OWERRI | network reinforcement | 2019 |
| 19 | COMPLETION OF IMO HOUSING ESTATE SS, UMUGUMA | Network reinforcement | 2019 |
| 20 | DE-LOADING OF AZUIYIOKWU 11KV FEEDER FROM CENTENARY INJECTION SS | - Increased hours of supply to high energy demand customers<br>- Increased revenue collection for benefitting district. | 2019 |
| 21 | INSTALLATION OF 33KV AUTO RECLOSER ON ABA-UMUAHIA 33KV FEEDER | - Increased hours of supply to high energy demand customers<br>- Increased revenue collection for benefitting district. | 2019 |
| 22 | COMPLETION OF 60X50KVA NIPP CSP TRANSFORMERS IN ENUGU METROPOLIS | - Increased hours of supply to high energy demand customers<br>- Increased revenue collection for benefitting district. | 2019 |

| S/N | Project Description | Project Benefits | Year of Completion |
|---|---|---|---|
| 23 | REHABILITATION OF ITIGIDI 33KV FEEDER | - Increased hours of supply to high energy demand customers - Increased revenue collection for benefitting district. | 2019 |
| 24 | RENOVATION OF ABOMEGE SWITCH YARD | - Increased hours of supply to high energy demand customers - Increased revenue collection for benefitting district. | 2019 |
| 25 | construction of new UNN 33kv feeder from 1 x 40MVA Nru TCN nsukka | loss reduction and load growth - Increased hours of supply to high energy demand customers - Increased revenue collection for benefitting district. | 2019 |
| 26 | Proposed Uwani Ugwu 1 x 300KVA 11/0.415KVA relief Substation at Nsukka | loss reduction and load growth - Increased hours of supply to high energy demand customers - Increased revenue collection for benefitting district. | 2019 |
| 27 | Construction of Emene Ind. II 33kv feeder | loss reduction and load growth - Increased hours of supply to high energy demand customers - Increased revenue collection for benefitting district. | 2019 |
| 28 | Alo Aluminium 33kv tee-off | loss reduction and load growth - Increased hours of supply to high energy demand customers - Increased revenue collection for benefitting district. | 2019 |
| 29 | REHABILITATION OF HILTOP 11KV FEEDER IN OGUI DISTRICT | loss reduction and load growth - Increased hours of supply to high energy demand customers - Increased revenue collection for benefitting district. | 2019 |
| 30 | Load transfer from Coal Camp 11kv feeder to Hilltop 11kv feeder | loss reduction and load growth - Increased hours of supply to high energy demand customers | 2019 |

| S/N | Project Description | Project Benefits | Year of Completion |
|---|---|---|---|
| | | - Increased revenue collection for benefitting district. | |
| 31 | UPGRADE OF TUNNEL 1 X 7.5MVA 33/11KV TO 1 X 15MVA 33/11KV | - Improvement of supply in the capital territory<br>- Increase in revenue collection from high yield 11kv feeders<br>- Improved services to our teeming customers | 2019 |
| 32 | CONSTRUCTION OF NDIAGU AMECHI 1 X 300KVA 33/0.415KV RELIEF SUBSTATION AWKUNANAW ENUGU | - Increased hours of supply to customers<br>- Increased revenue collection for benefitting district. - Improve supply quality | 2019 |
| 33 | LOAD TRANSFER BETWEEN EZEIWEKA AND NWAZIKI 11KV FEEDER, OGIGI DISTRICT | Loss reduction | 2019 |

### Feeder Investments

### Table 43: A. 1 List of Proposed Dedicated Feeders and Load Demand

| District | Project Title | Project Cost | No. of Beneficiary MD Customers | Current Average Daily Availability | Current Energy Import (kWh) | Installed capacity (MVA) | Present Load Demand (MW) | Minimum Expected Energy Import after project completion |
|---|---|---|---|---|---|---|---|---|
| | | NAIRA | POPULATION | | CURRENT KWH | INSTALLED MVA | DEMAND MW | EXPECTED KWH |
| Ariaria | Construction of 12.45km Industrial feeder to feed MD customers in Ariaria | 73,255,879.07 | 57 | 6.2 | 217,409 | 9.8 | 4.40 | 1,716,000 |
| Ariaria | Dualization of osisioma 11kv feeder in ariaria to provide a dedicated feeder to all md customers along the route | 40,478,056.29 | 9 | 4.7 | 8,459 | 2.1 | 0.08 | 31,906 |
| Ariaria | Polema 11kV feeder | | 13 | 13.6 | 945,150 | 10.5 | 3.16 | 1,478,376 |
| Umuahia | Construction of 4.55 km of 11kV lines to feed Shoprite Umuahia and some MD customers | 30,025,500.79 | 22 | 11.0 | 202,667 | 6.0 | 0.84 | 452,231 |
| Awka | Construction of Awka Business Line 11kV feeder | 15,313,137.50 | 13 | 9.6 | 31,098 | 3.1 | 0.15 | 58,309 |

| District | Project Title | Project Cost | No. of Beneficiary MD Customers | Current Average Daily Availability | Current Energy Import (kWh) | Installed capacity (MVA) | Present Load Demand (MW) | Minimum Expected Energy Import after project completion |
|---|---|---|---|---|---|---|---|---|
| Awka | Transfer of 10Nos MD Customers from Okpuno 11kv to Secretariat 11kv fdr. from ABS Inj. SS | 3,391,728.50 | 10 | 14.2 | 1,357,590 | 4.5 | 4.36 | 1,699,602 |
| Awka | Proposed extension of supply via Unizik 11kv feeder to Bryan Vegetable Oil | 8,610,973.50 | 1 | 7.4 | 64,877 | 1.5 | 1 | 390,000 |
| Awka | Proposed dualization of Enugu-Agidi 11kv feeder | 45,307,835.74 | 84 | 9.8 | 149,431 | 17.1 | 0.69 | 323,706 |
| Onitsha | Reconfiguration of Inland 11kV and GRA 11kV feeders at Onitsha District | 6,208,793.88 | 81 | 8.7 | 799,933 | 21.9 | 4.18 | 1,955,950 |
| Ogbaru | Harbour 11kV feeder | | 33 | 13.8 | 306,271 | 24.8 | 1.01 | 472,117 |
| Ogbaru | Intafact 11kV | | 1 | 21.3 | 1,464,676 | | 3.13 | 1,950,401 |
| Ogbaru | Golden Oil 33kV | | 1 | 21.3 | 772,290 | 7.5 | 1.65 | 1,028,402 |
| Nnewi | Reconfiguration of Nnewi Industrial | | 37 | 16.1 | 192,570 | 30.1 | 0.54 | 254,440 |

| District | Project Title | Project Cost | No. of Beneficiary MD Customers | Current Average Daily Availability | Current Energy Import (kWh) | Installed capacity (MVA) | Present Load Demand (MW) | Minimum Expected Energy Import after project completion |
|---|---|---|---|---|---|---|---|---|
| | 33kV feeder | | | | | | | |
| Abakaliki | Dualization of Township 11kV feeder | 51,409,520.50 | 92 | 11.0 | 338,346 | 16.8 | 1.40 | 581,620 |
| Abakpa | Emene Industrial 2, 33kV feeder | 22,141,499.00 | 9 | 21.5 | 637,321 | 3.3 | 2.64 | 1,235,520 |
| Abakpa | 9th Mile 11kV feeder | | 58 | 6.9 | 228,107 | 15.2 | 1.50 | 703,254 |
| Abakpa | Coca cola | | | 11.8 | 12,120 | 2.5 | 0.05 | 21,850 |
| Abakpa | New NNPC 33kV feeder | | 40 | 21.0 | 977,157 | 33.5 | 3.12 | 1,460,160 |
| Owerri | Reconfiguration of GRA 11kV feeder | 9,413,940.00 | 83 | 15.0 | 424,637 | 35.7 | 1.29 | 772,067 |
| Owerri | Dualization of FUT 11kv feeder to create a dedicated feeder to all MD customers on the feeder. | 79,449,729.29 | 32 | 8.6 | 155,556 | 5.5 | 0.82 | 319,165 |
| New Owerri | Construction of 5.25 km of 11kV lines to feed MD customers in New Owerri | 29,527,161.24 | 41 | 14.0 | 911,240 | 14.7 | 2.96 | 1,597,628 |
| New Owerri | Construction of 9.15 km of 3kV lines to | 79,047,746.73 | 154 | 8.5 | 1,719,640 | 15.0 | 8.9 | 3,471,000 |

| District | Project Title | Project Cost | No. of Beneficiary MD Customers | Current Average Daily Availability | Current Energy Import (kWh) | Installed capacity (MVA) | Present Load Demand (MW) | Minimum Expected Energy Import after project completion |
|---|---|---|---|---|---|---|---|---|
| | feed New Owerri Injection Substation | | | | | | | |
| New Owerri | Construction of Dedicated feeder to feed Irete industrial | 11,556,250.00 | 19 | 8.5 | 55,662 | 5.8 | 1 | 390,000 |

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# Annex J Regulatory asset inventory

# Annex K Network constraint analysis

### 11kV Voltage Level Analysis

The network constraint analysis is discussed in Section 5.3.1.

**Table 44: 11kV Feeders Constrained Analysis (Text highlighted in RED indicate a constrained feeder)**

| 11KV FEEDER | Transformation Capacity (MW) | Feeder Loading (MW) | Max Load (MW) | Max Load (%) |
|---|---|---|---|---|
| AZUIYIOKWU FEEDER 2 | 12.8 | 5.97 | 11.80 | 93 |
| INDUSTRIAL FEEDER 3 | | 5.83 | | |
| TOWNSHIP FEEDER 1 | 12.8 | 6.83 | 12.85 | 101 |
| UDEMEZUE FEEDER 4 | | 6.02 | | |
| ABAKALIKI ROAD | 12.8 | 4.33 | 8.70 | 68 |
| ARTISAN | | 4.36 | | |
| NEW HAVEN | 12.8 | 3.79 | 9.39 | 74 |
| PRESIDENTIAL | | 5.61 | | |
| MARY-LAND | 12.8 | 4.62 | 11.44 | 90 |
| UNEC | | 6.82 | | |
| POWERHOUSE | 12.8 | 4.36 | 14.52 | 114 |
| COAL CAMP | | 5.15 | | |
| HILL TOP | | 5.00 | | |
| GOLF COURSE | 12.8 | 4.64 | 12.36 | 97 |
| ONITSHA ROAD | | 3.73 | | |
| PRISONS | | 4.00 | | |
| CHIME AVENUE | 6.4 | 4.91 | 4.91 | 77 |
| ACHARA LAYOUT | 6.4 | 3.33 | 3.33 | 52 |
| OJI-RIVER URBAN | 12.8 | 3.30 | 3.30 | 26 |
| EMENE 2 | 6.4 | 3.17 | 3.17 | 50 |
| EMENE 3 | 6.4 | 3.77 | 3.77 | 59 |
| AKPOGA 33KV T-OFF | | | | |
| ABAKPA 1 | 12.8 | 5.76 | 8.79 | 69 |
| G.R.A | | 3.03 | | |
| UGWOGO 33KV | | 0.00 | 0.00 | |
| ABAKPA 2 | 12.8 | 5.97 | 10.82 | 85 |
| EMENE 1 | | 4.85 | | |
| NIKE LAKE 11KV | 6.4 | 0.89 | 6.86 | 108 |
| AMORJI 11KV | | 3.27 | | |
| ABAKPA 3, 11KV | | 2.70 | | |
| NTA | 12.8 | 2.88 | 10.30 | 81 |
| OKWE | | 3.64 | | |
| INDUSTRIAL | | 3.79 | | |

| 11KV FEEDER | Transformation Capacity (MW) | Feeder Loading (MW) | Max Load (MW) | Max Load (%) |
|---|---|---|---|---|
| PHASE 6 | 6.4 | 3.18 | 6.27 | 98 |
| DAHMIJA | | 3.09 | | |
| NOWAS | 6.4 | 5.00 | 5.00 | 78 |
| TOP-LAND | 6.4 | 1.27 | 2.62 | 41 |
| AMECHI-UWANI | | 1.35 | | |
| SATELLITE | 12.8 | 3.73 | 3.73 | 29 |
| GARIKI | 12.8 | 5.89 | 10.20 | 80 |
| ARMY | | 4.30 | | |
| ONU IYI 11KV | 12.8 | 4.20 | 9.55 | 75 |
| UNN 11KV | | 3.23 | | |
| WILSON 11KV | | 2.12 | | |
| TOWNSHIP | 6.4 | 1.68 | 7.73 | 121 |
| CAMPUS | | 1.50 | | |
| UGWUOYE | | 2.05 | | |
| AKU | | 2.50 | | |
| MBUTU /NGOR-OKPALA | 12.8 | 0.71 | 0.71 | 6 |
| | | 0.00 | 0.00 | |
| UMUIHI | 6.4 | 0.00 | 0.00 | 0 |
| NKWOALA | 12.8 | 2.68 | 4.62 | 36 |
| EGBEREDE 11KV | | 1.94 | | |
| PORT HARCOURT ROAD | 12.8 | 6.89 | 12.61 | 99 |
| IRETE/ INDUSTRIAL | | 5.71 | | |
| WORLD BANK | 12.8 | 7.89 | 14.59 | 114 |
| EGBEADA | | 6.70 | | |
| CONCORDE | 12.8 | 6.17 | 11.47 | 90 |
| OBINZE | | 5.30 | | |
| OWERRI ROAD | 12.8 | 3.94 | 7.27 | 57 |
| AMAIGBO ROAD | | 3.33 | | |
| IHIOMA | 6.4 | 3.79 | 3.79 | 59 |
| LIMCA | 6.4 | 0.18 | 1.39 | 22 |
| TOWNSHIP | | 1.21 | | |
| AWOIDEMMILI 2, 11KV | 6.4 | 0.00 | 0.00 | 0 |
| AWOIDEMMILI 1, 11KV | | 0.00 | | |
| AKOKWA 1 | 6.4 | 0.00 | 0.00 | 0 |
| AKOKWA 2 | | 0.00 | | |
| IKENEGBU | 12.8 | 5.38 | 11.15 | 87 |
| EGBU | | 5.77 | | |
| FUT | 12.8 | 8.44 | 8.44 | 66 |
| NEW OWERRI | 12.8 | 6.61 | 12.09 | 95 |
| NAZE | | 5.48 | | |
| G.R.A. | 12.8 | 6.14 | 10.98 | 86 |
| TOWNSHIP | | 4.85 | | |

| 11KV FEEDER | Transformation Capacity (MW) | Feeder Loading (MW) | Max Load (MW) | Max Load (%) |
|---|---|---|---|---|
| IFAKALA | 12.8 | 5.38 | 11.30 | 89 |
| MBIERI | | 5.30 | | |
| SHANGAI | | 0.62 | | |
| ORLU 33KV T-OFF | | 14.73 | 14.73 | |
| UMUNEKE | 12.8 | 1.44 | 0.95 | 7 |
| EMEKUKU | 6.4 | 3.39 | 7.08 | 111 |
| AVUVU | | 3.68 | | |
| HOUSING EBH | 12.8 | 2.52 | 9.85 | 77 |
| IWEKA | | 3.00 | | |
| WATER WORKS | | 4.33 | | |
| IYIOWA (INDUSTRIAL) | 12.8 | 3.91 | 7.74 | 61 |
| WOLRF | | 1.08 | | |
| PREMIER | | 2.76 | | |
| BIDA | 6.4 | 3.82 | 6.61 | 104 |
| UGA | | 2.79 | | |
| MARKET | 12.8 | 6.02 | 9.11 | 71 |
| FEGGE | | 3.09 | | |
| DOZZY | 12.8 | 4.50 | 12.20 | 96 |
| HARBOUR | | 3.58 | | |
| INTERFACT | | 3.03 | | |
| GCM 1&2 11KV | | 1.09 | | |
| NSUGBE | 6.4 | 4.70 | 9.47 | 149 |
| NKWELLE | | 4.77 | | |
| HOUSING | 6.4 | 5.73 | 5.73 | 90 |
| INLAND | 6.4 | 5.68 | 5.68 | 89 |
| G.R.A. | 12.8 | 4.76 | 12.85 | 101 |
| OMAGBA | | 4.09 | | |
| MINAJ 1 | | 4.00 | | |
| ARMY | 12.8 | 1.82 | 12.42 | 97 |
| MGBUKA | | 4.85 | | |
| MINAJ 2 | | 5.76 | | |
| OGIDI | 12.8 | 5.06 | 14.30 | 112 |
| NKPOR | | 4.76 | | |
| TOLL-GATE | | 3.55 | | |
| ALBEN 11KV | | 0.94 | | |
| WOLIWO | | 5.61 | | |
| NWAZIKI | | 5.91 | | |
| PPI | 12.8 | 1.91 | 11.13 | 87 |
| IUNT | | 2.42 | | |
| EZEIWEKA | | 6.80 | | |
| Mgbemena/Ugwuagba 11KV | 12.8 | 5.97 | 11.49 | 90 |
| AWADA | | 5.52 | | |

| 11KV FEEDER | Transformation Capacity (MW) | Feeder Loading (MW) | Max Load (MW) | Max Load (%) |
|---|---|---|---|---|
| OKPOKO | 12.8 | 6.06 | 6.06 | 48 |
| AVENCO | 6.4 | 1.97 | 4.85 | 76 |
| OJOTO | | 2.88 | | |
| IDEMILI 33KV T-OFF | | | | |
| MBANAGU | 12.8 | 2.70 | 7.06 | 55 |
| NNEWICHI | | 4.36 | | |
| OTOLO | 6.4 | 4.45 | 4.45 | 70 |
| IBOLO | 6.4 | 1.71 | 3.44 | 54 |
| NKWOEDO | | 1.73 | | |
| FEEDER 1 | 6.4 | 0.00 | 4.70 | 74 |
| URUAGU | | 4.70 | | |
| UMUOFOR 11KV | 12.8 | 3.50 | 8.55 | 67 |
| UBAHU 11KV | | 5.05 | | |
| ENUGU AGIDI | 12.8 | 7.80 | 12.35 | 97 |
| NIBO | | 4.55 | | |
| UDOKA | 12.8 | 4.91 | 11.51 | 90 |
| AWKA MAIN | | 6.60 | | |
| ABAGANA | 6.4 | 3.33 | 5.15 | 81 |
| UKPO | | 1.82 | | |
| ENUGU UKWU | 6.4 | 4.65 | 6.27 | 98 |
| NIMO | | 1.62 | | |
| OKPUNO 11KV | 6.4 | 4.53 | 7.45 | 117 |
| SECRETERIATE 11KV | | 2.92 | | |
| INDUSTRIAL | 12.8 | 5.14 | 10.26 | 80 |
| UNIZIK | | 5.12 | | |
| AMANSEA | 6.4 | 4.32 | 9.26 | 145 |
| IFITE | | 4.94 | | |
| URU NRI | 6.4 | 0.24 | 0.83 | 13 |
| EKE MARKET | | 0.59 | | |
| MAIN OFFICE | 6.4 | 2.06 | 5.03 | 79 |
| AGULUEZECHUKWU | | 2.97 | | |
| OKO POLY | 6.4 | 2.79 | 3.89 | 61 |
| EZIOKO | | 1.11 | | |
| **AMUDO 11KV** | 6.4 | 0.91 | 0.91 | 14 |
| **FEEDER 2, 11KV** | | 0.00 | | |
| **UMUNZE LGA** | 6.4 | 2.76 | 5.45 | 86 |
| **OGBUNKA** | | 2.70 | | |
| EHI ROAD | 6.4 | 3.85 | 6.36 | 100 |
| NGWA | 12.8 | 6.45 | 12.56 | 98 |
| OBOHIA | | 6.11 | | |
| PORT HARCOURT | 12.8 | 6.11 | 12.12 | 95 |
| OMUMA | | 6.02 | | |

| 11KV FEEDER | Transformation Capacity (MW) | Feeder Loading (MW) | Max Load (MW) | Max Load (%) |
|---|---|---|---|---|
| BARRACKS | 12.8 | 5.41 | 16.23 | 127 |
| TOWNSHIP | | 5.21 | | |
| INDUSTRIAL | | 5.61 | | |
| ABA EAST | 12.8 | 4.00 | 9.71 | 76 |
| GRA | | 5.71 | | |
| 7UP | 6.4 | 4.05 | 8.38 | 131 |
| WATER SIDE 11KV | | 4.33 | | |
| OVOM ROAD | 6.4 | 2.29 | 2.29 | 36 |
| OMOBA | 6.4 | 1.74 | 1.32 | 21 |
| WORLD BANK | 12.8 | 6.14 | 16.00 | 125 |
| POLEMA | | 4.18 | | |
| ARIARIA | | 5.68 | | |
| ABAYI | 12.8 | 5.91 | 11.59 | 91 |
| OSISIOMA | | 5.68 | | |
| GUINESS 33KV T-OFF | | 2.95 | 2.77 | |
| OWERRINTA 33KV T-OFF | | 3.18 | 3.18 | |
| URATTA | 12.8 | 6.24 | 12.14 | 95 |
| ASA-OKPUAJA | | 5.89 | | |
| CBN 33KV T-OFF | 12.8 | 0.53 | 15.14 | 119 |
| AZIKIWE | | 3.33 | | |
| WORLD BANK | | 4.45 | | |
| ABA ROAD | | 5.45 | | |
| GOLDEN GUINEA | | 1.36 | | |
| TOWNSHIP | 12.8 | 5.76 | 11.27 | 88 |
| GRA | | 5.52 | | |
| UBAKALA | 6.4 | 3.62 | 7.97 | 125 |
| OLD UMUAHIA | | 4.35 | | |
| ABIRIBA | 6.4 | 2.58 | 2.47 | 39 |
| NKWOEGWU | 6.4 | 2.29 | 3.38 | 53 |
| AMAOGWUGWU | | 1.09 | | |
| RESEARCH | 12.8 | 3.06 | 11.67 | 92 |
| NDUME | | 4.18 | | |
| UMUDIKE | | 4.42 | | |
| OLOKORO | 12.8 | 2.89 | 2.79 | 22 |
| AMACHARA | 6.4 | 3.41 | 5.74 | 90 |
| EKENOBIZI | | 2.33 | | |
| ASAGA | 6.4 | 2.20 | 4.02 | 63 |
| BARRACKS | | 1.82 | | |

### 33kV Voltage Level Analysis

**Table 45: 33 Feeders Constrained Analysis (Text highlighted in RED indicate a constrained feeder)**

| TRANSMISSION STATION | TRANSFORMER | 33kV FEEDER | Transformation Capacity (MW) | Max Load (MW) | % Loading (%) |
|---|---|---|---|---|---|
| AWADA (ONITSHA) | MOB 40MVA 132KV/33KV | ARMY BARRACKS 33KV | 32 | 31.80 | 99.38 |
| | | AWADA 2, 33KV | | | |
| | TR 13, 60MVA 132KV/33KV | NNEWI INDUSTRIAL 33KV | 48 | 46.30 | 96.46 |
| | | NNEWI 33KV | | | |
| | | NICCUS 33KV | | | |
| | TR 13, 60MVA 132KV/33KV | 3-3, 33KV | 48 | 36.20 | 75.42 |
| | | OSAMALA 33KV | | | |
| | | OBOSI 33KV | | | |
| | MOB 45MVA 132KV/33KV/11KV | UMUNYA 33KV | 0 | 33.39 | 92.75 |
| | | OGIDI 33KV | | | |
| | | WOLIWO 11KV | | | |
| | | NWAZIKI 11KV | | | |
| | TR 12, 15MVA 132KV/11KV | PPI, 11KV | 12 | 11.92 | 99.33 |
| | | IUNT 11KV | | | |
| | | EZEIWEKA 11KV | | | |
| **SUB-TOTAL** | **160MVA** | | **140** | **159.61** | **90.69** |
| GENERAL COTTON MILL, GCM | 60MVA 132KV/33KV | GOLDEN OIL 33KV | 48 | 34.90 | 72.71 |
| | | ATANI 33KV | | | |

| TRANSMISSION STATION | TRANSFORMER | 33kV FEEDER | Transformation Capacity (MW) | Max Load (MW) | % Loading (%) |
|---|---|---|---|---|---|
| | | TR1, 15MVA, 33KV/11KV | | | |
| | | E-AMOBI 33KV | | | |
| **SUB-TOTAL** | **60MVA** | | **48** | **34.90** | **72.71** |
| NIBO (AWKA) | TR1, 30MVA 132KV/33KV | TR2, 15MVA, 33KV/11KV | 24 | 18.20 | 75.83 |
| | | TR4, 15MVA, 33KV/11KV | | | |
| | TR3, 60MVA, 132KV/33KV | NENI 33KV | 48 | 28.00 | 58.33 |
| | | AGULU 33KV | | | |
| SUB-TOTAL | 90MVA | | 72 | 46.20 | 64.17 |
| AGU-AWKA | MOB 40MVA, 132KV/33KV | AGU-AWKA 33KV | 32 | 42.70 | 133.44 |
| | | AGULERI 33KV | | | |
| | | ENGUGU UKWU 33KV | | | |
| **SUB-TOTAL** | **40MVA** | | **32** | **42.70** | **133.44** |
| New Haven | TR1 60MVA, 132KV/33KV | NEW HAVEN 33KV | 48 | 34.30 | 71.46 |
| | | INDEPENDENCE L/O 33KV | | | |
| | | NEW NNPC 33KV | | | |
| | TR2, 60MVA, 132KV/33KV | KINGWAY LINE 1, 33KV | 48 | 41.20 | 85.83 |
| | | KINGSWAY LINE 2, 33KV | | | |
| | | GOVERNMENT HOUSE 33KV | | | |
| | | TRANS EKULU 33KV | 48 | 33.90 | 70.63 |

| TRANSMISSION STATION | TRANSFORMER | 33kV FEEDER | Transformation Capacity (MW) | Max Load (MW) | % Loading (%) |
|---|---|---|---|---|---|
| | TR3, 60MVA 132KV/33KV | ITUKU-OZALLA 33KV | | | |
| | | THINKERS CORNER 33KV | | | |
| | TR4, 60MVA 132KV/33KV | EMENE INDUSTRIAL 33KV | 48 | 14.50 | 30.21 |
| | | EMENE INDUSTRIAL 2, 33KV | | | |
| **SUB-TOTAL** | **240MVA** | | **192** | **123.90** | |
| UGWUAJI 132/33KV | TRI 60MVA 132/33KV | GARIKI 33KV | 48 | 33.50 | 69.79 |
| | | AMECHI 33KV | | | |
| | | UGWUAJI AUXILIARY TXF | | | |
| ABAKALIKI | TR1, 30MVA 132KV/33KV | ITIGIDI 33KV | 24 | 26.90 | 112.08 |
| | | TR3, 15MVA, 33KV/11KV | | | |
| | TR2, 60MVA 132KV/33KV | YAHE 33KV | 48 | 38.93 | 81.10 |
| | | AFIKPO 33KV | | | |
| | | ISHEKE 33KV | | | |
| | | TR4, 15MVA, 33KV/11KV | | | |
| **SUB-TOTAL** | **90MVA** | | **72** | **65.83** | |
| NKALAGU | T1A, 30MVA, 132KV/33KV | EHA-AMUFU 33KV | 24 | 24 | 100 |
| | T2A, 30MVA, 132KV/33KV | EZILLO 33KV | 24 | 24 | 100 |
| **SUB-TOTAL** | **60MVA** | | **48** | **48** | |

| TRANSMISSION STATION | TRANSFORMER | 33kV FEEDER | Transformation Capacity (MW) | Max Load (MW) | % Loading (%) |
|---|---|---|---|---|---|
| OJI-RIVER | T1A, 30MVA 132KV/33KV | WATER WORKS 33KV | 24 | 21.63 | 90.13 |
| | | UDI 33KV | | | |
| | | ACHI 33KV | | | |
| | | OJI-URBAN 33KV | | | |
| | | COCA-COLA 11KV | | | |
| | | ORUMBA 33KV | | | |
| **SUB-TOTAL** | **30MVA** | | **24** | **21.63** | **90.125** |
| NSUKKA | T1A, 7.5MVA 66KV/33KV | IBAGWA 33KV | 6 | 4.69 | 78.17 |
| | T1B, 7.5MVA, 66KV/33KV | T2, 7.5MVA, 33KV/11KV | 6 | 4.85 | 80.83 |
| **SUB-TOTAL** | **15MVA** | | **12** | **9.54** | |
| NRU TS | TR1, 30MVA, 132KV/33KV | OBA 33KV | 24 | 22.48 | 93.67 |
| | | UNN 33KV | | | |
| **SUB-TOTAL** | **30MVA** | | **24.00** | **22.48** | **93.67** |
| ABA CONTROL | T1A, 7.5MVA, 132KV/6.6KV | EHI ROAD 6.6KV | 6 | 4.2 | 70 |
| | T1B, 60MVA 132KV/33KV | ABA OVERHEAD 33KV | 48 | 28.87 | 60.15 |
| | | T3B, 15MVA, 33/11KV | | | |
| | T2A, 60MVA 132KV/33KV | ABA - OWERRI 33KV | 48 | 52.03 | 108.40 |
| | | UKWA 33K | | | |
| | | T3A, 15MVA, 33/11KV | | | |
| | | IGI 33KV | 24 | 23.80 | 99.17 |

| TRANSMISSION STATION | TRANSFORMER | 33kV FEEDER | Transformation Capacity (MW) | Max Load (MW) | % Loading (%) |
|---|---|---|---|---|---|
| | MOB 30MVA 132KV/33KV | ABA - UMUAHIA | | | |
| **SUB-TOTAL** | **157.5MVA** | | **126** | **108.9** | |
| OHIYA, UMUAHIA | TR1, 40MVA 132KV/33KV | AFARA 33KV | 32 | 29.90 | 93.44 |
| | | NKWOEGWU 33KV | | | |
| | TR1, 40MVA 132KV/33KV | UBAKALA 33KV | 32 | 36.60 | 114.38 |
| | | NTIGHA 33KV | | | |
| | | OBOWO 33KV | | | |
| **SUB-TOTAL** | **80MVA** | | **64** | **66.50** | |
| ITU, CROSS RIVER | TR1, 60MVA 132KV/33KV | AROCHUKWU 33KV | 48 | 8.64 | 18 |
| **SUB-TOTAL** | **60MVA** | | **48** | **8.64** | **18** |
| EGBU, OWERRI | TR1, 60MVA 132KV/33KV | AIRPORT 33KV | 48 | 42.72 | 89.00 |
| | | OWERRI 3, 33KV | | | |
| | TR2, 60MVA 132KV/33KV | OGUTA 33KV | 48 | 69.25 | 144.27 |
| | | ORLU 33KV | | | |
| | | OKIGWE 33KV | | | |
| | MOB 40MVA, 132KV/33KV | MBAISE 33KV | 32 | 30.27 | 94.59 |
| | | Alex 33kV | | | |
| **SUB-TOTAL** | **160MVA** | | **128** | **142.24** | |