NIGERIAN ELECTRICITY
REGULATORY COMMISSION

MULTI -YEAR TARIFF ORDER

FOR THE DETERMINATION OF THE COST OF ELECTRICITY SOLD BY DISTRIBUTION/RETAIL COMPANIES FOR THE PERIOD 1 JUNE 2012 TO 31 MAY 2017

Nigerian Electricity Regulatory Commission

1 June, 2012

Table of Contents

List of Tables

Glossary of Terms

ARR	Annual Revenue Requirement
BPE	Bureau of Public Enterprises
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CCGT	Combined Cycle Gas Turbine
CPI	Consumer Price Index
Disco	Distribution company
DUOS	Distribution Use of Service
EPC	Engineering, Procurement and Construction
EPSRA	Electric Power Sector Reform Act
FGN	Federal Government of Nigeria
GENCO	Generator Company
IFC	International Finance Corporation
IMF	International Monetary Fund
IPP	Independent Power Producer
KWh	Kilo Watt hours of electrical energy
LRMC	Long Run Marginal Cost
MAR	Maximum Allowable Revenue
MDAs	Ministries, Departments and Agencies of the (FGN)
MLF	Marginal Loss Factor
MMBTU	Millions of British Thermal Units
MO	Market Operator
MWh	Mega Watt hours of electrical energy

MYTO	Multi Year Tariff Order
N/KWh	Naira per Kilo Watt Hour
NBET	Nigerian Bulk Electricity Trading Company
NELMCO	Nigerian Electricity Liability Management Company
NEPP	National Electric Power Policy
NERA	National Economic Research Associates
NERC	Nigerian Electricity Regulatory Commission
NESI	Nigerian Electricity Supply Industry
NTB	Nigerian Treasury Bonds
NUT	National Uniform Tariff
OCGT	Open Cycle Gas Turbine
ODRC	Optimised Depreciated Replacement Cost
O&M	Operations & Maintenance
Opex	Operating expenditure
PHCN	Power Holding Company Of Nigeria
PI	Price Index
PPA	Power Purchase Agreement
RAB	Regulatory Asset Base
ROE	Return on Equity
ROT	Rehabilitate, Operate and Transfer
SO	System Operator
SPE	Special Purpose Entity
SPV	Special Purpose Vehicle
TCN	Transmission Company Of Nigeria

TSO	Transmission System Operation
TSP	Transmission Service Provider
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital

ORDER NO: NERC/117

<u>ORDER on the Establishment of a Distribution/Retail Tariff</u>

PART ONE

The Nigerian Electricity Regulatory Commission (NERC) is Nigeria's independent regulatory agency for the NESI established by the Electric Power Sector Reform Act (EPSRA) 2005. NERC was officially inaugurated on 31st October 2005.

The Act provides the legal and regulatory framework for the electricity supply industry in Nigeria. It empowers NERC to regulate the Nigerian Electricity Supply Industry (NESI), comprising the Generation, Transmission and Distribution/Retail sectors.

One of the primary functions of NERC as contained in Section 32(1)(d) of the EPSRA is to ensure that the prices charged by licensees are fair to consumers and sufficient to allow the licensees to finance their activities and to allow for reasonable earnings for efficient operation. Section 76 of the EPSRA further empowers NERC to establish one or more tariff methodologies for regulating electricity prices to prevent abuses of market power.

In its effort to provide a viable and robust tariff policy for the Nigerian Electricity Supply Industry (NESI), NERC in 2008 decided to introduce a Multi-Year Tariff Order (MYTO) as the framework for determining the industry pricing structure. The MYTO methodology provides the process to be followed in complying with the statutory obligation in Section 76 of the EPSRA. It provides a fifteen (15)-year tariff path for the electricity industry with minor and major reviews bi-annually and every five years respectively.

In consultation with industry stakeholders and consumers, NERC adopted a holistic and scientific approach to balancing electricity tariffs to ensure a fair and cost-reflective tariff regime capable of sustaining the NESI and at the same time attracting investment into the sector; all of which are non-negotiable enablers for driving socio-economic development across the country. The key principles of cost reflectivity and affordability were taken into consideration in evolving the new tariff regime. The MYTO further assumes a continuous reduction in transmission and distribution/retail loses. Revenue earned by operators which remain unacceptably high, is made dependent on achieving these performance improvements.

The process for adoption of this methodology was transparent as consultations took place with government, customer groups, other major stakeholders and industry practitioners who contributed to the proposed methodology at various public fora and through written representations.

There are three separate Tariff Orders; one for each of the sectors in the NESI namely: generation, transmission and distribution/retail. This Distribution/Retail Tariff Order is divided into two parts – Part One, which is the proclamation of the Order; and Part Two, which presents the basis of the Order. Part Two is further divided into eight sections - the Introduction, Legal and Regulatory Framework, Pricing Methodology, Economic and Financial Assumptions for the 2012 MYTO, Inputs to Distribution Tariff Calculations, Retail Tariff Schedules, Major and Minor Reviews and Dates and Conditions for Effectiveness.

Accordingly, and by virtue of the powers conferred by S. 76 of the Electric Power Sector Reform Act, NERC hereby ORDERS that:

1. The Tables of Fixed and Energy Charges for each of the eleven (11) PHCN Successor Distribution Companies (hereinafter called "Discos") that shall come into effect as from midnight 31st May 2012 and continue in force until midnight 31st May 2017 be as shown herein below, subject to the provisions of this Order.

2. Upon coming into effect, the said Fixed and Energy Charges shall continue in force subject to such minor and major reviews as NERC may conduct from time to time.

3. This Order shall be called the Nigerian Electricity Distribution/Retail Sector Multi-Year Tariff Order, 2012.

PART TWO

1 Introduction

By this Tariff Order, NERC establishes the schedule of tariffs to be paid by each customer in the stated customer classes subject to tariff regulation by NERC. These regulated charges are established for the period 1st June 2012 to 31st May 2017 pursuant to Section 76 of the Electric Power Sector Reform Act (2005).

These retail tariff schedules will be reviewed bi-annually and changes may be made to the Distribution Use of System (DUOS) charge if any or all of the generation wholesale contract price, the Nigerian inflation rate, US$ exchange rate, daily generation capacity and accompanying capex and opex requirements have varied materially from that used in the calculation of the tariff. A material variation for this purpose is defined as a price variation of plus or minus five per cent (+/- 5%) in any of these indices. A review of all inputs to the tariff calculation will commence in 2016 as the basis for a new Multi-Year Tariff Order (MYTO) to commence for 5 years from 1st June 2017.

1.1 Background

NERC is an independent regulatory agency established by the Electric Power Sector Reform (EPSR) Act, 2005. NERC was officially inaugurated on 31st October 2005. The Act provides the legal and regulatory framework for the electricity supply industry in Nigeria. It empowers NERC to undertake technical and economic regulation of the entire NESI.

The various challenges that the Industry must contend with may be summarised as follows:

- Acute shortage of generation capacity;
- Acute shortage of natural gas;
- Transmission constraints and inadequacies;
- Lack of private sector participation;
- Inadequate generation mix e.g. solar, wind, coal, etc;
- Unacceptable technical and non-technical loss levels; and
- Unacceptably high payment or credit risk in the distribution sector.

The establishment of NERC was the direct result of a genuine desire to transform the electricity supply industry into a market-based industry in line with the Federal

Government's reform agenda for the country's economic, industrial and social development. Thus, NERC was established to facilitate the introduction and management of competitive, safe, reliable and fairly-priced electricity in the country. Pursuant to the above, the objects of the Commission include:

- To create, promote, and preserve efficient industry and market structures, and to ensure the optimal utilisation of resources for the provision of electricity services;
- To maximize access to electricity services, by promoting and facilitating consumer connections to distribution systems in both rural and urban areas;
- To ensure that an adequate supply of electricity is available to consumers;
- To ensure that the prices charged by licensees are fair to consumers and are sufficient to allow the licensees to finance their activities and to allow for reasonable earnings for efficient operation;
- To ensure the safety, security, reliability and quality of service in the production and delivery of electricity to consumers;
- To ensure that Regulation is fair and balanced for licensees, consumers, investors and other stakeholders.

In its effort to provide a robust tariff policy to support the long-term viability of the Nigerian Electricity Supply Industry (NESI), NERC in 2008 decided to introduce a Multi Year Tariff Methodology as the framework for determining the industry's pricing structure. The MYTO Methodology provides the process to be followed in meeting the statutory obligation in S.76, EPSRA. It provides a fifteen (15)-year tariff path for the electricity industry with bi-annual minor reviews and major review every five years.

This is the second Tariff Order issued by NERC and it is for the period 1 June 2012 to 31 May 2017. Two other Tariff Orders are being issued concurrently to cover generation prices in wholesale contracts and transmission tariff/institutional charges respectively. The MYTO regulatory model depends on data received from market participants. Institutions within the NESI have supplied estimates and forecasts upon which the industry costs and tariffs developed in the MYTO financial model are based. NERC is conscious that the NESI must evolve to meet the demands placed upon it. The data inputs and estimates underlying the MYTO will be reviewed periodically to ensure they remain up to date.

Following the procedures set out in Section 76 of EPSRA, NERC published the MYTO Methodology upon which both MYTO 1 and 2 are based – see www.nercng.org. In describing its methodology, NERC noted that it had adopted three basic principles. These principles require that a regulatory methodology:

- produces outcomes that are fair;
- encourages outcomes that are efficient in that it involves the lowest possible costs and encourages investment in electricity generation; and
- is simple, transparent and moderate regulatory costs.

In establishing MYTO 2, NERC has sought to apply these principles more precisely in order to produce tariffs that incentivise the NESI to attain standards of performance set by NERC to produce the positive outcomes mandated in Section 32(1), EPSRA.

NERC's recent major review highlighted the need for an amendment to the existing methodology and so a "Notice of Proposed Change to the Multi-Year Tariff Methodology" was published, explaining the need to adjust the existing methodology. There were two (2) major changes to the existing methodology and these were brought about by:

- the need to be more flexible in wholesale generation pricing; and
- the need to consider a number of other variables during the minor reviews.

1.2 Insight into 2008 Multi Year Tariff Order

The 2008 MYTO was based on the new entrant cost profile for generation companies and the building block approach to electricity pricing of transmission and distribution services, all based upon a set of pricing principles and cost assumptions. The ultimate objective is to provide the industry with a stable and cost-reflective pricing structure that provides a modest return on investment to efficient industry operators. At the same time the tariff will protect consumers against excessive pricing, since the price is set at the entry level of the most efficient generation company.

The MYTO provides a fifteen (15) year tariff path and allows for bi-annual minor reviews and a major review no more than five years apart so as to keep the tariffs in line with current realities. The minor reviews only take into consideration four variables, namely:

1. Rate of inflation,
2. Gas prices, and
3. Foreign exchange rates
4. Actual daily generation capacity

The major reviews involve a comprehensive review and overhaul of all the assumptions in the MYTO model. During the minor review of MYTO in May 2009, Successor Discos requested that the major review of MYTO scheduled for 2013 be brought forward in order to take care of the increasing cost of power, the rising cost of O&M expenses and also declining revenue due to the absence of the growth in generation capacity envisaged in the 2008 Tariff Order. NERC considered this request and the MYTO major review was brought forward.

This major review affords stakeholders the opportunity to evaluate the methodology, inputs to the existing model, incorporate Feed-In Tariffs (FITs) for renewable energy (wind, biomass, solar and small hydro) and also develop tariffs for coal-fired generators. Some of the assumptions reviewed include:

- Available generation capacity
- Forecast of electricity demand
- Expansion of the transmission and distribution networks
- Capital expenditure (capex)
- Actual and projected sales
- Operating costs (opex)
- Fuel costs
- Interest rates
- Weighted average cost of capital (WACC)
- Revenue collection efficiencies
- Subsidies

Having concluded that establishing a cost-reflective tariff would ordinarily lead to a general increase in tariffs across all classes; and in other to avoid the effects of a rate shock on more vulnerable consumers, the tariffs paid by certain classes of consumers will be less than cost-reflective values over the first two years, up to June 2014, following the introduction of MYTO 2. In this vein, FGN support will be provided in the form of a subsidy to make up the shortfall between actual and cost-reflective tariffs over this period, while the tariff moves gradually towards viable levels.

Unlike before, this will be enjoyed only by the tariff classes that genuinely need support. The removal of the subsidy over a period of time is expected to lessen the burden on consumers while allowing them to adjust to the new price level. The Federal Government subsidy is intended to exit when power availability increases enough to enable a further rebalancing of tariffs. This rebalancing will be such that the NESI is left with only a cross-subsidy scheme established within the framework of the Power Consumer Assistance Fund (PCAF), as mandated by Part VIII (Sections 83 – 87), EPSRA.

1.3 Electricity Pricing in Nigeria

In Nigeria, the true cost of electricity production is not reflected in the consumer tariff. This new Tariff Order is intended to be cost-reflective and provide financial incentives for immediately-needed increased investments in the industry. These investments, in turn, lead to a significant and continuous improvement in the quantity of energy and quality of service enjoyed by the consumer.

NERC has since September 2010 carried out wide consultations with the industry operators, consumer advocacy groups, the legislature and relevant MDAs on both the MYTO methodology and tariff. (See Appendix 1 for the list of stakeholders consulted).

1.4 Rationale for Tariff Review

Electricity is similar to any other manufactured product. Its costs are made up of the cost of inputs, such as fuel (e.g. natural gas), and capital items, such as turbines, cables, switchyards and switching equipment, communication and data acquisition equipment, transformers and meters. The industry is highly capital intensive and electrical plant and equipment usually have a long technical and economic life but also takes a considerable amount of planning, time and effort to be put in place. Electricity differs from other products in that it cannot yet be economically stored as it is produced. The implication of instantaneous supply and consumption is that price has to be sufficient to cover the cost of production, otherwise supply will be jeopardised.

If electricity is under-priced then supply will not meet demand. At the moment in Nigeria there is a very high level of unsatisfied demand for electricity due in part to the historical under-pricing of electricity. One indicator of this is the extensive use of diesel generators which typically produce electricity at price levels that are much higher than the price of grid electricity.

It is imperative that electricity should be priced such that it covers its supply costs if adequate and reliable electricity is to be produced to meet demand. As with any other product, it needs to cover, at the minimum, operating and capital costs. If the price is at a sufficient level to ensure a reasonable return on investment, it will attract new producers. At present the revenue from electricity tariffs covers about half of the revenue required to achieve a viable and growing electricity sector. In other words, the tariffs currently set for the industry can barely fund routine activities and certainly cannot provide for investment in new generation, transmission and distribution infrastructure.

MYTO 2 is intended purely to facilitate the Industry's successful passage through a period of significant reform, performance improvement and growth. It will:

- Allow for the recovery of an appropriate return on capital invested, depreciation (and replacement) of capital and recovery of fuel, operation, maintenance and overhead costs;
- Provide an incentive for new investment in capital equipment;
- Provide incentives for reducing technical, commercial and collection losses;
- Provide viable and transparent tariff methodology that will allow NESI's progress towards a reformed and market-oriented system in which generation and retail activities are mostly not subject to price regulation while the monopoly activities of transmission and distribution continue to be under price regulation;
- Finally, ensure that the benefits of a reformed NESI are passed through to all consumers in the form of reliable electricity supply at the lowest possible price consistent with the above objectives.

The NESI will, as it grows and evolves during the coming years, move to a market-based system whereby generators and electricity retailers will be free to contract with each other for the supply of electricity. Transmission and distribution, as monopoly wire activities, will remain regulated.

2 Legal and Regulatory Framework

The establishment of NERC was the direct result of a genuine desire to transform the NESI into a market-based industry in line with the government's reform agenda for the country's economic, industrial and social development. Thus, NERC was established to facilitate the introduction and management of competition in the country's electricity supply industry.

Pursuant to the above, the objects of NERC include:

I. To create, promote, and preserve efficient **industry and market structures**, and to ensure the optimal utilization of resources for the provision of electricity services;

II. To maximize **access** to electricity services, by promoting and facilitating consumer connections to distribution systems in both rural and urban areas;

III. To ensure that an **adequate supply of electricity** is available to consumers;

IV. To ensure that the **prices** charged by licensees **are fair** to consumers and are sufficient to allow the licensees to finance their activities and to allow for **reasonable earnings** for efficient operation.

Section 76(1) of EPSRA subjects the following activities to tariff regulation:

(a) Generation and trading, in respect of which licences are required pursuant to this Act, and where NERC considers regulation of prices necessary to prevent abuse of market power; and

(b) Transmission, distribution and system operation, in respect of which licences are required under this Act.

Section 76(2) provides for NERC to adopt appropriate tariff methodology within the general principles established in the Act, which:

- Allows recovery of efficient cost including a reasonable rate of return
- Gives incentives to improve efficiency and quality
- Sends efficient signals to customers on costs they impose on the system
- Phases out or reduces cross subsidies

This Tariff Order (MYTO 2) is based on a set of principles designed to provide tariffs for each of the generation, transmission, and distribution (including retail) sectors (reference Section 1.4 above):

- **Cost recovery/financial viability** – regulated entities should be permitted to recover their (efficient) costs, including a reasonable rate of return on capital.
- **Signals for investment** – prices should encourage an efficient level and nature of investment (e.g., location) in the industry.
- **Certainty and stability** of the pricing framework is also important for private sector investment.
- **Efficient use of the network** – Generally, this requires "efficient" prices that reflect the marginal costs that users impose on the system and the reduction of cross-subsidies.
- **Allocation of risk** – pricing arrangements should allocate risks efficiently (generally to those who are best placed to manage them).
- **Simplicity and cost-effectiveness** – the tariff structure and regulatory system should be easy to understand and not excessively costly to implement (e.g., facilitate metering and billing).
- **Incentives for improving performance** – the way in which prices are regulated should give appropriate incentives for operators to reduce costs and/or increase quality of service.

- **Transparency/fairness** – prices should be non-discriminatory and transparent. Non-discriminatory access to monopoly networks is also a key prerequisite for effective competition in the contestable sectors.
- **Flexibility/robustness** – the pricing framework needs to be able to cater for unforeseen changes in circumstances.
- **Social and political objectives** – the pricing framework needs to provide for the achievement of social policy goals such as universal access, demand-side management and user affordability.

3 Pricing Methodology

3.1 Pricing Principles

The building blocks approach was used as a regulatory method to set Distribution Use of System Charges (DUOS) in the MYTO, as set out in the 2007 Methodology Paper. The building blocks approach is simply a way of bringing together all of the industry's costs in a consistent accounting framework. The standard building blocks used in this approach are:

- **The allowed return on capital** – being the return necessary to achieve a fair (market based) rate of return on the assets necessarily invested in the business;
- **The allowed return of capital** – associated with recovering the actual capital invested during the useful lives of the assets (depreciation); and
- **Efficient operating costs** and overheads.

In order to calculate a projected annual value for each of the building blocks an estimate was required for:

- The initial value of the distribution network asset;
- A particular weighted average cost of capital (WACC) to be achieved each year;
- A capital expenditure program developed from a forecast of feasible growth;
- An appropriate method of depreciation;
- An efficient level of operating expenditure and overheads; and
- A rate of improvement in industry losses.

Using the building block approach, the NESI's overall revenue requirements were established and used as the basis for calculation of the revenue to be collected per unit of sales. The annual revenue requirements for distribution and retailing determined, using the building block approach, was then divided by the forecast level of energy delivered to each of the existing eleven (11) distribution networks to produce a DUOS charge per unit of energy to be sold and collected by the relevant Disco.

3.2 Distribution/Retail Prices

Retail tariffs need to reflect the costs of the entire value chain for the NESI, beginning with natural gas (fuel for generation plant), on to wholesale generation, through to transmission, distribution, metering and billing and finally to the consumer. The components of cost that need to be taken into account in constructing the domestic retail tariff through these steps in the value chain are:

- Electricity supplied through Wholesale Contracts and PPAs for the supply of wholesale electricity injected into the transmission network.
- A Transmission Use of System (TUOS) charge to TCN for each MWh delivered to the distributor/retailer's bulk supply point(s).
- Electricity distribution through the local distribution network owned and operated by the distributor/retailer.
- Marketing, metering, billing and revenue collection (retailing).
- Institutional charges.
- FGN tariff subsidy targeted at vulnerable tariff classes (R1 and R2).

Payments to generators are set out in NERC's Tariff Order on Wholesale Contract Prices. TUOS charges are also set by NERC in the Tariff Order on Transmission Pricing. All other charges applicable to the distribution/retail sector are set within this Tariff Order.

The distribution charges cover the network component of the cost of distribution and are calculated according to the building blocks methodology, including allowances for a return on capital expenditure, depreciation, operation and maintenance of the network, aggregate losses across the distribution networks, meters and metering costs.

Retail costs are brought into the building blocks framework as on-going operation and administrative costs and added to the costs of distribution companies to provide an overall cost of distribution/retailing. The capital expenditure and operation and maintenance allowance included in the tariff calculation includes an allowance for additional meters and improvements in metering, billing and revenue collection. As a consequence, the tariff calculation also includes rates of aggregate loss that reduce each year of the Tariff Order.

The three major losses to distributors/retailers are: technical losses, commercial losses and collection losses. Technical losses result from losses in quantities of energy as they move across the distribution network. They occur naturally but can be minimised through good network management and design. Commercial losses arise from electricity that is stolen or not metered and not paid for. It is the most significant area of loss in Nigeria and a reduction of these losses represents the single most effective strategy for improving distributor/retailer revenues. Collection losses represent sales that have been billed but revenue has not been collected. This is also another significant area of loss. A reduction in aggregate losses, particularly in commercial and collection will improve sales revenues significantly.

3.3 Major changes in the 2012 Distribution/Retail Tariff Order

Most of the cost of the distribution network arises from the capital expenditure needed to build and maintain it. The most useful guide to the future level of necessary capital expenditure comes from the forecast of peak demand for each electricity distributor. Distributors will likely grow at different rates and their capital needs will therefore vary. The Distribution Use of System (DUOS) tariff will cover the cost of distribution and marketing. DUOS charges are calculated according to the building blocks methodology and include allowances for capital expenditure, operation and maintenance of the network, losses across the distribution networks and metering costs.

A major change in the 2012 MYTO model is the recognition that separate revenue requirements will need to be established for each Disco and this will require establishing building blocks for each of the Discos. The Nigerian distribution system currently suffers from high levels of technical and non-technical losses. NERC's preferred approach to tariff regulation for the distribution sector, in tandem with one of the major objectives of the electricity reform, is to provide incentives for reducing these losses.

Losses

The targets set for the reduction of aggregate losses were developed based on available data. For the Discos to improve their performance in loss reduction, they will need to make investments in capital equipment, staff training and change management. The allowances in MYTO 1 for these activities were based on poor quality data on the administration, operation and maintenance costs of the Discos.

Recognising the need for credible data to support efficient target setting and monitoring, NERC has commenced a comprehensive programme to develop an accurate baseline database that will enable distribution companies to determine accurate levels of losses and then build into the model acceptable and realistic levels of improvement in subsequent years of the tariff path.

Customer Service Standards

MYTO 2 makes provision for delivery on customer service standards as part of the index for daily energy allocation. Appropriate indicators have also been developed in discussion with the Discos and are set out in the NERC's KPI and customer service standards regulations. NERC is aware that during the ongoing electricity privatisation programme, preferred bidders for each Disco will be required to execute Performance Agreements that set certain minimum performance standards. Performance to these minimum standards will be very firmly monitored and rewarded or sanctioned by NERC. These service standards are derived from Regulations established by NERC, which are listed at the last page of this Order.

End-user tariffs/retail tariffs

End-user tariffs reflect the costs associated with all the components of the Industry. Until customer choice is introduced, the end-user tariffs will be regulated in order to protect the interests of consumers. NERC, by law, is required to ensure that prices are cost-reflective; but also to ensure that losses are reduced and as little as possible of the costs of such losses are passed on to customers.

MYTO will continue to maintain the policy of unwinding cross-subsidies, which are currently embodied in the tariffs. The end-user tariff covers the cost of electricity (energy & capacity), transmission use of system cost, regulatory and market administration charges, the Discos' distribution charges and costs associated with metering, billing, marketing and revenue collection.

Uniform Tariff/Tariff Equalisation

Uniform tariffs as practiced under the 2008 Tariff Order relied heavily on tariff equalisation principles through the market operator collecting higher payments from distributors with lower costs and redistributing the funds to high cost distributors/retailers. This principle has been very difficult to apply in the market because the technical issues that may have justified equalisation (heavy transmission losses, low voltages and high distribution cost caused by distance from energy suppliers) were exacerbated by commercial issues such as poor revenue collection, poor subsidy disbursement, etc.

NERC also recognises that there is no statutory basis for equalised tariffs at all levels. Indeed, it is clear from the National Electric Power Policy and EPSRA that there is no place in the NESI for uniform national tariffs. Rather, there are clear provisions only for lifeline tariffs for low-income consumers that are to be the same across the country. Thus, a uniform lifeline tariff of =N=4 per kWh, with no fixed charge whatsoever, has been set for the low-income R1 customer class in all eleven Discos.

Aside from this, recognition has been given to the fact that all other tariff classes in each Disco has its tariffs set on the basis of that Discos specific cost profile in serving that customer class.

Return on Working Capital

MYTO 2 allows for working capital to the Discos so that they can continue their operations cash flow sufficient to meet both maturing short-term debts and upcoming operational expenses.

Consumer Class Consolidation

The MYTO 1 tariff schedule had nineteen (19) consumer classes (see table 1). It was inherited from NEPA/PHCN in 2007 and NERC recognised the need to review these classes with a view to merging some of them and having fewer tariff classifications of customers. As the market deepens in capacity and sophistication individual Discos may wish to review their rate classes with the approval of NERC.

In 2009, a report by Omega Systems and Tractebel Engineering (2009) on a "National Load Demand Study" had recommended the need to collapse the existing nineteen rate classes to a smaller number. NERC has, at the instance of the Discos undertaken the current consolidation but hopefully the impetus to review this in future will come from the Discos themselves. For this Tariff Order, NERC has reduced the tariff classes from nineteen customer classes to fourteen as per table 2.

The new customer classification is based on metering capacity i.e. single phase, three-phase, LV, HV maximum demand meters with the exception of R1 customers who are classified on a maximum consumption of 50 KWH. However for R1 consumers to move to the next tariff class (R2), average monthly electricity consumption for the preceding three (3) months must be taken into consideration. The average consumption for three months shall be calculated and if the consumption exceeds 50 KWH, the consumer shall be moved to the next tariff class. However, if the average is below 50kwh, even if it exceeds 50kwh in one or two particular months, the consumer shall remain on R1.

Table 1: Retail Tariff Classes

Old Class	New Class
Residential	
R1	R1
R2	R2
R3	
R4	R3
R5	R4
Commercial	
C1	C1
C2	

<table>
<tr><td>C3</td><td>C2</td></tr>
<tr><td>C4</td><td>C3</td></tr>
<tr><td>Industrial</td><td></td></tr>
<tr><td>D1</td><td rowspan="2">D1</td></tr>
<tr><td>D2</td></tr>
<tr><td>D3</td><td>D2</td></tr>
<tr><td>D4</td><td>D3</td></tr>
<tr><td>Special</td><td></td></tr>
<tr><td>A1</td><td>A1</td></tr>
<tr><td>A2</td><td>A2</td></tr>
<tr><td>A3</td><td>A3</td></tr>
<tr><td>Street Lighting</td><td></td></tr>
<tr><td>S1</td><td>S1</td></tr>
</table>

Table 2: Tariff Class Descriptions

<table>
<tr><th></th><th>Customer Classification</th><th>Description</th><th>Remarks</th></tr>
<tr><td>1</td><td colspan="2">Residential</td><td rowspan="5">A consumer who uses his premises exclusively as a residence - house, flat or multi-storeyed house where people reside.</td></tr>
<tr><td></td><td>R1</td><td>Life-Line (50 kWh)</td></tr>
<tr><td></td><td>R2</td><td>Single and 3-phase</td></tr>
<tr><td></td><td>R3</td><td>LV Maximum Demand</td></tr>
<tr><td></td><td>R4</td><td>HV Maximum Demand (11/33 KV)</td></tr>
<tr><td>2</td><td colspan="2">Commercial</td><td rowspan="4">A consumer who uses his premises for any purpose other than exclusively as a residence or as a factory for manufacturing goods.</td></tr>
<tr><td></td><td>C1</td><td>Single and 3-phase</td></tr>
<tr><td></td><td>C2</td><td>LV Maximum Demand</td></tr>
<tr><td></td><td>C3</td><td>HV Maximum Demand(11/33 KV)</td></tr>
<tr><td>5</td><td colspan="2">Industrial</td><td rowspan="4">A consumer who uses his premises for manufacturing goods including welding and ironmongery.</td></tr>
<tr><td></td><td>D1</td><td>Single and 3-phase</td></tr>
<tr><td></td><td>D2</td><td>LV Maximum Demand</td></tr>
<tr><td></td><td>D3</td><td>HV maximum Demand (11/33 KV)</td></tr>
</table>

4	**Special**		Customers such as agriculture (agro-allied enterprises involving processing are excluded), water boards, religious houses, Government and teaching hospitals, Government research institutes and educational establishments.
	A1	Single and 3 Phase	
	A2	LV Maximum Demand	
	A3	HV Maximum Demand (11/33 KV)	
5	**Street Lighting**		
	S1	Single and 3-phase	

4 Economic and Financial Assumptions for 2012 Tariff Order

4.1 Introduction

To develop the tariffs, NERC developed and took into account a considerable mass of economic and financial assumptions. These include:

4.2 Inflation

An inflation rate of 13% was adopted. This however, is subject to minor review bi-annually. In an event of any material change in inflation rate, this would be reflected and the tariff adjusted accordingly.

In the MYTO, the rate of inflation is used to ensure that investors are well compensated against rising cost of doing business and workers in the industry are paid living wages. To achieve this, NERC escalates the following variables:

- WACC
- Fixed labour cost
- Fixed admin cost
- Variable O&M cost
- Other Fixed O&M cost
- Capital Investment

Table 3: Projected Nigerian Inflation Rate (2012-2016) %

	2012	2013	2014	2015	2016
Inflation	13	13	13	13	13

4.3 Exchange Rate

Being an importer of electricity generation equipment components opens Nigeria to foreign exchange risk. This foreign exchange risk is taken care of in the MYTO model and accommodated on a bi-annual basis during the minor reviews.

Though this is regularly adjusted during the minor reviews to bring it to current realities, investors have informed the Commission that the official CBN rates are not always accessible to them and that they are often charged a commission. NERC therefore recommends a 1% premium above CBN rates. The exchange rate adopted is assumed to increase steadily over the years. This is also subject to review bi-annually.

Table 4: Assumed Naira/US Dollar Exchange Rate (2012-2016)

	2012	2013	2014	2015	2016
Exchange Rate	161	169	178	186	196

4.4 The Weighted Average Cost of Capital (WACC)

The cost of capital included in the MYTO is intended to provide a return on existing assets and appropriate incentives for future investment. The cost of capital is an important component of the tariff and is included in the annual revenue requirement calculation as a return on the value of capital invested. The regulated asset value at the start of a given year is calculated by taking the depreciated replacement cost of capital assets at the start of the immediate proceeding twelve months and adding the investments in new capital assets acquired during the same period.

The Capital Asset Pricing Model (CAPM) is used here to estimate a WACC for the NESI. While this approach gives a method for estimating the average cost of capital in a sector and is widely used by regulators, it requires consideration of volatility of returns in the sector as well as the domestic cost of debt. Even in developed economies the calculation of a WACC frequently requires estimation of a number of inputs. This is the case here and most of the inputs to the WACC calculation are estimates. The WACC is set at the level that attracts investment funds to the industry but is not sufficient to produce super profits.

The CAPM provides estimates of the appropriate return on equity and debt and the returns to equity are measured in relation to the risk premium on the equity market as a whole. Thus:

$$Re = Rf + ße\,(Rm - Rf) \qquad (1)$$

Where:

R_e	is the return on equity
R_f	is the risk free rate observed in the market
$ß_e$	is the correlation between the equity risk and overall market risk
R_m	is the return on the market portfolio
$R_m - R_f$	is the market risk premium

The WACC lies between the cost of equity and the cost of debt. The WACC is calculated as:

$$WACC = Rd \times D/(D + E) + Re \times E/(D + E) \qquad (2)$$

Where:

D	is the total market value of debt
E	is the total market value of equity
R_d	is the nominal cost of debt; and
R_e	is the nominal cost of equity.

This formulation does not include the effects of tax. The formulation of the WACC that allows for the effects of taxation – specifically the corporation tax rate (T_c) – and used extensively by regulators is as follows:

$$\text{Nominal post tax WACC (w)} = Re \times E/V + Rd\,(1 - Tc) \times D/V \qquad (3)$$

Where:

T_C is the company tax rate,

V is the total market value of the business, i.e. debt plus equity

A transformation is applied to derive an estimate of the real pre-tax WACC, as follows:

$$\text{Real pre tax WACC (RW)} = [(1 + w/(1 - Tc)) / (1 + i)] - 1 \qquad (4)$$

Where:

W is the nominal post tax WACC, as given by equation (4)

I is the inflation rate

The company tax rate used is the statutory corporation rate of 30% plus 2% education tax.

4.4.1 Estimating the WACC Components

This section provides NERC's estimates of the various components required to calculate a WACC for the NESI. These estimates are then drawn together in a description of the process used for the first WACC calculation.

The Risk Free Rate

The yield on government bonds is regarded here as the risk free rate and NERC has had regard to relevant yields on Nigerian Treasury bonds and has selected a risk free rate of 18%.

Many regulators use 10-year bond rates or 10-year (indexed linked) bonds or their local equivalent. The longer term also ensures consistency with the risk free rate used to estimate the market risk premium - that is also based on 10-year bonds.

The Cost of Debt

NERC adopted a nominal cost of debt of 24% for generation reflecting current debt levels for business and project. The cost of debt is generally determined by adding a debt premium, and sometimes a transactions cost, to the risk free rate.

$$Rd = Rf + DRP + DIC \qquad (5)$$

Where:

DRP is the debt risk premium

DIC is the debt issuance cost lending in Nigeria

Betas

Beta reflects the risk rating of an asset relative to the market as a whole (usually represented by the stock market). Equity betas will reflect the financial risk carried by shareholders, which is in turn influenced by the level of gearing since high levels of debt increase the risk to shareholders.

Electricity supply is not an area with any history of steady private investment from which to draw information on the relative risk of investments and it is not considered possible to derive statistically significant betas.

Beta is a measure of risk in the electricity supply industry compared to risk in the market as a whole. NERC has decided not to apply any value of beta for the current tariff order and appropriate estimate will be made against the next tariff review when enough data exists for estimates to be made.

Gearing

The ratio of equity and debt is used to weight the equity and debt returns in the WACC calculation.

In the past, independent power producers in developing countries were financed with high gearing ratios, commonly 80:20 debt to equity. However, the World Bank considers that in future greater caution by lenders will result in project sponsors being expected to assume a greater degree of the project risk, by accepting lower debt-equity ratios. The Bank suggested that future ratios would be closer to 60:40. This level would also apply to regulated assets, such as transmission and distribution.

The Commission has selected a gearing ratio of 70:30 in the development of the WACC for the NESI.

WACC estimate

The following are the main assumptions used in the WACC calculations:

Risk free rate	18%
Nominal return on equity	29%
Nominal cost of debt	24%
Gearing level (debt/equity)	70% : 30%
Total Corporate tax rate	32%

These assumptions provide the following WACC estimates:

Nominal before tax WACC	25%
Nominal after tax WACC	17%
Real pre-tax WACC	11%
Real after tax WACC	7%

4.5 Asset Valuation and Rate of Depreciation

NERC has adopted the depreciated optimised replacement cost (DORC) method to determine the value of each Disco's assets. This value is then used to calculate the depreciation charge in the annual revenue requirement. The DORC methodology involves:

- Determining the replacement cost of modern equivalent assets;
- Optimising its capacity (i.e. normalising the asset to the size most appropriate to perform the task it is required to do now and then taking account of the state of maintenance and serviceability); and

- Applying depreciation over the economic life of the individual asset or groups of assets.

The depreciation schedule for regulatory purposes would be applied to each group of assets so that, to the maximum extent that is reasonable, it reflects the remaining economic life of the asset or group of assets. In the case of a regulated monopoly, such as the eleven (11) current distribution networks, technical life will usually approximate economic life as there are no competitive forces that might reduce the economic life of an asset in future. Similarly, the capital expenditure assumed in the tariff calculation has been developed as the appropriate expansion for the sales growth assumed.

Within the life of the Tariff Order, NERC does not envisage that any distribution assets would be further optimised beyond NERC's recent valuation. The rationale for this is that currently there is a severe deficit of reliable infrastructure in the NESI and most infrastructure will be used to the fullest. It is difficult to foresee a time when distribution investments will be surplus to requirements. Nevertheless, the DORC approach is very useful in preventing expenditure on "gold plating" (or over-spending on) assets and thereby unfairly boosting the regulated annual revenue requirement. NERC will continue to examine capital expenditure to make sure that this does not happen. The asset lives used for the purposes of deriving an allowance for depreciation are set out below:

Table 5: Asset lives used in depreciation

Existing assets	Years	New assets	Years
Plant & Machinery	20	Plant & Machinery	35
Land & Buildings	40	Land & Buildings	50
Furniture & Fittings	10	Furniture & Fittings	10
Motor Vehicles	5	Motor Vehicles	5

5 Inputs to the Distribution Tariff Calculation

5.1 Asset Value and Capital Expenditure

At the start of a regulatory period such as this, it is necessary to establish initial values for assets and for methods of calculating additions to assets and depreciation.

NERC has engaged local and international consultants to determine the distributor/retailer's asset values on the basis of optimized replacement value and conditioning principles to arrive at the fair value of assets. This asset base was depreciated using rates shown in Section 4.5.

5.1.1 Valuation methods

The Gross Replacement Cost Method (GRCM) was adopted for the valuation of the regulated distribution assets of the successor companies. The basis for this choice is that it is not only a more robust method for valuation but the electricity services sector is illiquid in Nigeria and the MYTO 1 tariffs are substantially below the actual tariffs. Though the GRCM does not normally take into cognisance the existing condition of the assets, the method was adopted alongside a consideration of asset age. The methodology used covered the following items:

- Valuation of assets
- Establishing a fair value
- Approach to asset expansion and replacement
- Prevention of windfall profits

The table below shows the asset values determined by NERC for the start of the period (beginning of 2012) for each of the distributor/retailers.

Table 6: Conditioned values of regulated asset as at December 2011 (N' 000)

	Plant & Machinery	Land & Buildings	Furniture & Fittings	Motor Vehicles	Total
Abuja	39,762,155.17	3,134,660.72	50,730.00	51,171.75	42,998,717.65
Benin	33,246,331.32	313,358.36	1,920.00	129,468.75	33,691,078.43
Enugu	31,630,459.95	1,194,240.00	55,290.00	125,286.00	33,005,275.95
Ibadan	43,623,802.43	399,795.36	2,100.00	149,493.75	44,175,191.54
Jos	21,064,574.32	244,460.81	756.52	109,836.00	21,419,627.65
Kaduna	41,725,683.26	748,898.48	39,060.00	171,990.00	42,685,631.74
Kano	32,169,305.00	3,117,483.05	370,721.95	72,190.00	35,729,701.00
Eko	35,017,781.59	105,389.70	56,280.00	123,720.00	35,303,171.29
Ikeja	34,324,940.11	71,730.00	567.05	-	34,397,237.16
P/Harcourt	30,307,455.36	2,022,537.82	13,692.00	166,225.50	32,509,910.68
Yola	12,728,559.35	2,673,862.04	23,484.00	94,520.25	15,520,425.64

The table below shows the annual capital expenditure for each Disco in setting the tariff for the period 1st June 2012 to 31st May 2017. These capital expenditures are added to the asset base and annual depreciation is deducted in order to arrive at an annual asset value to which a WACC is applied to derive the return on capital.

Table 7: Regulated asset value and forecast capital expenditures (nominal N '000)

	Asset Value	**Capital Expenditure '000**				
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Abuja	42,998,717.65	5,747,203	5,747,203	5,747,203	5,747,203	5,747,203
Benin	33,691,078.43	3,817,339	3,817,339	3,817,339	3,817,339	3,817,339
Enugu	33,005,275.95	4,275,065	4,275,065	4,275,065	4,275,065	4,275,065
Ibadan	44,175,191.54	6,886,880	6,886,880	6,886,880	6,886,880	6,886,880
Jos	21,419,627.65	3,572,483	3,572,483	3,572,483	3,572,483	3,572,483
Kaduna	42,685,631.74	4,703,660	4,703,660	4,703,660	4,703,660	4,703,660
Kano	35,729,701.42	4,769,432	4,769,432	4,769,432	4,769,432	4,769,432
Eko	35,303,171.29	8,510,036	7,091,697	7,091,697	7,091,697	7,091,697
Ikeja	34,397,237.16	11,066,038	9,221,699	9,221,699	9,221,699	9,221,699
P/ Harcourt	32,509,910.68	4,005,775	4,005,775	4,005,775	4,005,775	4,005,775
Yola	15,520,425.64	2,061,934	2,061,934	2,061,934	2,061,934	2,061,934
TOTAL	371,435,969.14	59,415,846	56,153,167	56,153,167	56,153,167	56,153,167

5.2 Generation Capacity Projections

This is a very significant variable in tariff determination. Under MYTO 1, projected generation capacity was put at 4000 MW for 2008, 6000 MW for 2009, 10,000 MW for 2010 and 16,000 MW for 2011. However, none of these projections were ever achieved, causing additional major disequilibrium in the market and contributing very significantly to the suboptimal performance of MYTO 1. Therefore, having consulted with key generation stakeholders, MYTO 2 is based on the following conservative but realistic gross daily generation capacities:

Table 8: Projected Generation Capacity to National Grid- (2012-2016)

Year	**Projected Gross Generation Capacity(Mwh)**	**Gross Energy sent out to Grid (Gwh)**
2012	5,500	30,715
2013	7,500	41,884
2014	9,061	50,601
2015	10,071	56,242
2016	10,571	59,034

5.3 Losses

The table below shows the allowance made in the MYTO for losses at various stages in the electricity value chain. The technical losses associated with transmission networks are held constant throughout the 5-year period as these appear to be similar to losses experienced by transmission in other countries with comparable networks.

NERC is particularly keen to see significantly reduced levels of commercial and billing losses, reflecting an urgent need to see distributor/retailers increase their revenues not by tariff increases but by reducing unmetered withdrawals from the system and improving the rate of collecting bills. Pending surveys to validate current loss data, NERC has set targets to reduce average commercial losses from 12% (average across all distributor/retailers) in 2012 to 5% in 2016. Revenue collection losses are also expected to improve from 16% in 2012 to 6% in 2016.

Given the urgency of the reform/privatisation agenda and also taking account of the uncertainty about the credibility of some of the data from which aggregate losses are calculated, NERC and BPE have agreed that:

a) Commitments on the reduction of aggregate losses will remain one of the primary determinants for determining successful Disco core investors;

b) NERC has already commenced a study to create a credible industry performance database, particularly as regards aggregate technical, commercial and collection (ATCC) loss data, which will take at least 12 months to undertake;

c) Pending completion of the ATCC database study, the privatisation of the Disco sector may proceed and commitments made on the basis of current data; and

d) At the conclusion of the ATCC database study, any difference in losses will be the subject of separate reduction targets to be agreed between NERC and the relevant Discos; and commensurate cost implications will be the subject of a Minor Review consultative process.

If distributor/retailers can improve on the agreed loss reduction targets then they stand to earn and retain revenues in excess of those provided for in this Tariff Order.

Table 9: Technical and non-technical losses allowed in the Tariff Order

	Units	2012	2013	2014	2015	2016
Sent-out from stations (GWh)	GWh	30,715	41,884	50,601	56,242	59,034
Transmission Losses	% of SO	8.05%	8.05%	8.05%	8.05%	8.05%
Exports	% of Exp	5.0%	5.0%	5.0%	5.0%	5.0%
Delivered to Distribution	GWh	26,830	36,587	44,201	49,128	51,568
Distribution Losses	% of DD	10.0%	9.0%	8.0%	7.0%	7.0%
Delivered to customers	GWh	24,147	33,294	40,665	45,689	47,958
Non-technical losses (non-billed energy)	% of DC	12.0%	10.0%	8.0%	6.0%	5.0%
Billed to Customers	GWh	21,249	29,964	37,412	42,948	45,560
Revenue Collection losses	% of	6.0%	4.0%	2.0%	2.0%	2.0%
Sales where Revenue is collected	GWh	19,975	28,766	36,664	42,089	44,649
Revenue based sales as % of Sent out energy	%	65%	69%	72%	75%	76%
Total technical and non-technical losses	% of SO	35%	31%	28%	25%	24%

5.4 Energy Allocation to the Discos

Given the fact of generation and transmission grid inadequacy that affects all Discos, energy made available into the grid has to be allocated on some fair, transparent and easily understandable basis. Tables 10-13 below show the estimated electrical energy allocation factors for each Disco, estimated energy delivered to the Disco, energy delivered to consumers and the total sales of all the eleven distribution companies projected over the next five (5) years.

Table 10: Estimated Energy Allocation (%)

	2012	2113	2014	2015	2016
Abuja	11.50%	11.50%	11.50%	11.50%	11.50%
Benin	9.00%	9.00%	9.00%	9.00%	9.00%
Enugu	9.00%	9.00%	9.00%	9.00%	9.00%
Ibadan	13.00%	13.00%	13.00%	13.00%	13.00%
Jos	5.50%	5.50%	5.50%	5.50%	5.50%
Kaduna	8.00%	8.00%	8.00%	8.00%	8.00%
Kano	8.00%	8.00%	8.00%	8.00%	8.00%
Eko	11.00%	11.00%	11.00%	11.00%	11.00%
Ikeja	15.00%	15.00%	15.00%	15.00%	15.00%
Port Harcourt	6.50%	6.50%	6.50%	6.50%	6.50%
Yola	3.50%	3.50%	3.50%	3.50%	3.50%
Total	100%	100%	100%	100%	100%

After due consultation with TCN and the Distribution Companies on Load Allocation, it was agreed that the above allocation schedule will be used in executing all Vesting Contracts and will continue to be in use until such a time when the total amount of energy (net of international exports) delivered daily to the distribution companies consistently increases above the 3,200MW mark either through recovery of stranded capacity from existing generators, delivery from NDPHC or other new on-grid generators or via new procurement by Nigerian Bulk Electricity Trading Limited ("NBET" or "the Bulk Trader").

As from 1st June 2012, net daily generation capacity in excess of 3,200 MW will be allocated to the Discos, purely on the basis of individual Disco performance measured against key strategic performance indicators set out below. During each Minor Review, i.e., bi-annually, data on each Discos performance on each of the said indicators would be taken into account and weighed. During the six months following the Minor review, allocations of available daily capacity over 3,200 MW would be made by the System Operator purely on the basis of the results of this performance review.

This will continue until a new formula is determined or a state of generation adequacy is attained sufficient to enable each Disco to contract for and receive the daily amounts of capacity and energy it requires. The strategic performance indicators referred to are stated below and shown in the sample load allocation worksheet (in MS Excel format), with the appropriate formulae for each criterion. The sample worksheet may be found at the NERC website (www.nercng.org)

I. Attainment of metering targets – 30%;
II. Reduction in losses – 35%;
III. Customer service ratings based on biannual customer surveys - 15%; and
IV. Attainment of network expansion targets – 15%.

Table 11: Estimated Energy delivered to Discos (GWh)

	2012	2013	2014	2015	2016
Abuja	3,085	4,207	5,083	5,650	5,930
Benin	2,415	3,293	3,978	4,422	4,641
Enugu	2,415	3,293	3,978	4,422	4,641
Ibadan	3,488	4,756	5,746	6,387	6,704
Jos	1,476	2,012	2,431	2,702	2,836
Kaduna	2,146	2,927	3,536	3,930	4,125
Kano	2,146	2,927	3,536	3,930	4,125

Eko	2,951	4,025	4,862	5,404	5,672
Ikeja	4,025	5,488	6,630	7,369	7,735
Port Harcourt	1,744	2,378	2,873	3,193	3,352
Yola	939	1,281	1,547	1,719	1,805
Total delivered to Discos	**26,830**	**36,587**	**44,201**	**49,128**	**51,568**

Table 12: Delivered to Customers (GWh)

5.4.1	**2012**	**2013**	**2014**	**2015**	**2016**
Abuja	2,777	3,829	4,677	5,254	5,515
Benin	2,173	2,996	3,660	4,112	4,316
Enugu	2,173	2,996	3,660	4,112	4,316
Ibadan	3,139	4,328	5,286	5,940	6,235
Jos	1,328	1,831	2,237	2,513	2,638
Kaduna	1,932	2,664	3,253	3,655	3,837
Kano	1,932	2,664	3,253	3,655	3,837
Eko	2,656	3,662	4,473	5,026	5,275
Ikeja	3,622	4,994	6,100	6,853	7,194
Port Harcourt	1,570	2,164	2,643	2,970	3,117
Yola	845	1,165	1,423	1,599	1,679
Total delivered to Discos	• **24,147**	• **33,294**	• **40,665**	• **45,689**	• **47,958**

Table 13: Collected Sales (GWh)

5.4.2	**2012**	**2013**	**2014**	**2015**	**2016**
Abuja	2,297	3,308	4,216	4,840	5,135
Benin	1,798	2,589	3,300	3,788	4,018
Enugu	1,798	2,589	3,300	3,788	4,018
Ibadan	2,597	3,740	4,766	5,472	5,804
Jos	1,099	1,582	2,017	2,315	2,456
Kaduna	1,598	2,301	2,933	3,367	3,572
Kano	1,598	2,301	2,933	3,367	3,572
Eko	2,197	3,164	4,033	4,630	4,911
Ikeja	2,996	4,315	5,500	6,313	6,697
Port Harcourt	1,298	1,870	2,383	2,736	2,902
Yola	699	1,007	1,283	1,473	1,563
Total Collected Sales	**19,975**	**28,766**	**36,664**	**42,089**	**44,649**

5.5 Distribution/Retail Costs

Tables 14- 24 show the estimated share of power costs, share of transmission costs and distribution/retail cost for individual companies brought together in a building blocks framework, summing the running costs (operation, maintenance, administration and metering and billing) with the return on capital and the return of capital (depreciation).

The operation and maintenance allowance was provided to all the Discos to cover reasonable administrative costs such as salaries and allowances, pension costs workman compensation insurance and staff welfare. It also provides for funds required to carry out both routine and unscheduled maintenance of all sub-stations, transformers, lines and cables (underground and overhead) and ensure regular line tracing and vegetation control.

Capital expenditures are projected and provided to cover the replacement of obsolete equipment, relief of existing overloaded equipment and expansion of the existing network. Provision is also made for procuring retail meters, operational vehicles, ICT and customer care platforms to enhance the level of service to customers.

These opex estimates were arrived at based on submissions by each Disco reviewed by NERC and benchmarked with efficient costs required to run the business. These costs increase sharply over the 5-year regulatory period reflecting the expected huge investment in the distribution infrastructure, in customer care/vending/billing and ICT platforms new meters. These investments will be needed to improve the quality of service to consumers as well, thereby reducing the current high level of commercial and collection losses.

Table 14: Generation & Transmission & Disco Costs (Net Export) – Abuja

Year commencing 1 June	2012	2013	2014	2015	2016
Generation	Nm				
Capacity	12,461	18,559	24,138	28,839	32,443
Opex	14,616	21,808	32,821	39,538	44,627
Sub-Total	27,077	40,367	56,960	68,377	77,070
Transmission					
Opex	3,356	3,596	3,863	3,997	4,299
RO Investment	42	833	1,622	2,485	3,377
Depreciation	1,333	1,603	1,689	2,235	2,542
Sub – Total	4,731	6,032	7,174	8,717	10,217
Distribution/Retail					
Opex	10,433	11,071	11,776	12,557	13,422
RO Investment	5,233	7,502	8,830	10,342	11,663

Depreciation	2,407	2,711	3,042	3,398	3,770
Sub total	18,073	21,284	23,648	26,298	28,854
Total	**101,841**	**138,773**	**178,355**	**210,277**	**235,966**
Subsidy	(5,750)	(5,750)	0	0	0
Net after Subsidy	107,591	114,523	178,355	210,277	235,966

Table 15: Generation & Transmission & Disco Costs (Net Export) – Benin

Year commencing 1 June	2012	2013	2014	2015	2016
Generation	Nm				
Capacity	9,752	14,524	18,891	22,570	25,390
Opex	11,439	17,067	25,686	30,943	34,925
Sub-Total	21,191	31,591	44,577	53,512	60,316
Transmission					
Opex	2,627	2,814	3,024	3,128	3,364
RO Investment	33	652	1,269	1,945	2,643
Depreciation	1,043	1,255	1,322	1,749	1,989
Sub – Total	3,702	4,721	5,614	6,822	7,996
Distribution/Retail					
Opex	9,331	9,758	10,225	10,737	11,299
RO Investment	4,073	5,810	6,750	7,828	8,747
Depreciation	1,980	2,202	2,442	2,701	2,946
Sub total	15,384	17,770	19,417	21,265	22,991
Total	**40,277**	**54,018**	**69,608**	**81,599**	**91,303**
Subsidy	(4,500)	(4,500)	0	0	0
Net after Subsidy	44,777	58,518	69,608	81,599	91,303

Table 16 Generation & Transmission & Disco Costs (Net Export) - Enugu

Year commencing 1 June	2012	2013	2014	2015	2016
Generation	Nm				
Capacity	9,752	14,524	18,891	22,570	25,390
Opex	11,439	17,067	25,686	30,943	34,925
Sub-Total	21,191	31,591	44,577	53,512	60,316
Transmission					
Opex	2,627	2,814	3,024	3,128	3,364
RO Investment	33	652	1,269	1,945	2,643
Depreciation	1,043	1,255	1,322	1,749	1,989
Sub – Total	3,702	4,721	5,614	6,822	7,996
Distribution/Retail					
Opex	9,136	9,590	10,088	10,636	11,240
RO Investment	4,022	5,808	6,811	7,956	8,947
Depreciation	1,917	2,150	2,404	2,677	2,939

Sub total	15,075	17,549	19,303	21,269	23,126
Total	**39,968**	**53,860**	**69,494**	**81,603**	**91,437**
Subsidy	(4,500)	(4,500)	0	0	0
Net after Subsidy	**44,468**	**58,360**	**69,494**	**81,603**	**91,437**

Table 17: Generation & Transmission & Disco Costs (Net Export) - Ibadan

Year commencing 1 June	**2012**	**2013**	**2014**	**2015**	**2016**
Generation	Nm				
Capacity	14,086	20,980	27,287	32,601	36,675
Opex	16,523	24,652	37,102	44,695	50,448
Sub-Total	30,609	45,632	64,389	77,295	87,123
Transmission					
Opex	3,794	4,065	4,367	4,518	4,860
RO Investment	47	941	1,833	2,809	3,817
Depreciation	1,507	1,812	1,909	2,527	2,873
Sub – Total	5,348	6,819	8,109	9,854	11,550
Distribution/Retail					
Opex	17,453	18,433	19,514	20,707	22,026
RO Investment	5,526	8,381	9,938	11,709	13,268
Depreciation	2,680	3,036	3,421	3,838	4,249
Sub total	25,659	29,850	32,873	36,254	39,543
Total	**61,615**	**82,300**	**105,371**	**123,404**	**138,215**
Subsidy	(6,500)	(6,500)	0	0	0
Net after Subsidy	**68,115**	**88,800**	**105,371**	**123,404**	**138,215**

Table 18: Generation & Transmission & Disco Costs (Net Export) - Jos

Year commencing 1 June	**2012**	**2013**	**2014**	**2015**	**2016**
Generation	Nm				
Capacity	5,960	8,876	11,544	13,793	15,516
Opex	6,990	10,430	15,697	18,909	21,343
Sub-Total	12,950	19,306	27,242	32,702	36,860
Transmission					
Opex	1,605	1,720	1,848	1,912	2,056
RO Investment	20	398	776	1,189	1,615
Depreciation	637	767	808	1,069	1,216
Sub – Total	2,263	2,885	3,431	4,169	4,887
Distribution/Retail					
Opex	6,289	6,661	7,073	7,528	8,032
RO Investment	2,660	3,891	4,628	5,459	6,204
Depreciation	1,312	1,493	1,689	1,902	2,102
Sub total	10,261	12,046	13,390	14,889	16,339

Total	**25,473**	**34,236**	**44,062**	**51,759**	**58,085**
Subsidy	(2,750)	(2,750)	0	0	0
Net after Subsidy	**28,223**	**36,986**	**44,062**	**51,759**	**58,085**

Table 19: Generation & Transmission & Disco Costs (Net Export) - Kaduna

Year commencing 1 June	**2012**	**2013**	**2014**	**2015**	**2016**
Generation	Nm				
Capacity	8,669	12,911	16,792	20,062	22,569
Opex	10,168	15,170	22,832	27,505	31,045
Sub-Total	18,836	28,081	39,624	47,566	53,614
Transmission					
Opex	2,335	2,502	2,688	2,780	2,991
RO Investment	29	579	1,128	1,729	2,349
Depreciation	927	1,115	1,175	1,555	1,768
Sub – Total	3,291	4,196	4,990	6,064	7,108
Distribution/Retail					
Opex	7,852	8,276	8,743	9,258	9,827
RO Investment	5,095	6,751	7,744	8,866	9,853
Depreciation	2,485	2,760	3,059	3,381	3,683
Sub total	15,432	17,788	19,546	21,504	23,363
Total	**37,559**	**50,064**	**64,160**	**75,135**	**84,084**
Subsidy	(4,000)	(4,000)	0	0	0
Net after Subsidy	**41,559**	**54,064**	**64,160**	**75,135**	**84,084**

Table 20: Generation & Transmission & Disco Costs (Net Export) - Kano

Year commencing 1 June	2012	2013	2014	2015	2016
Generation	**Nm**				
Capacity	8,669	12,911	16,792	20,062	22,569
Opex	10,168	15,170	22,832	27,505	31,045
Sub-Total	18,836	28,081	39,624	47,566	53,614
Transmission					
Opex	2,335	2,502	2,688	2,780	2,991
RO Investment	29	579	1,128	1,729	2,349
Depreciation	927	1,115	1,175	1,555	1,768
Sub – Total	3,291	4,196	4,990	6,064	7,108
Distribution/Retail					
Opex	5,682	6,025	6,405	6,825	7,291
RO Investment	4,299	5,882	6,886	8,021	9,026
Depreciation	2,133	2,393	2,673	2,976	3,302
Sub total	12,114	14,300	15,963	17,821	19,619
Total	**34,241**	**46,577**	**60,577**	**71,452**	**80,340**
Subsidy	(4,000)	(4,000)	0	0	0
Net after Subsidy	**38,241**	**50,577**	**60,577**	**71,452**	**80,340**

Table 21: Generation & Transmission & Disco Costs (Net Export) - Eko

Year commencing 1 June	2012	2013	2014	2015	2016
Generation	**Nm**				
Capacity	11,919	17,752	23,089	27,585	31,033
Opex	13,981	20,859	31,394	37,819	42,687
Sub-Total	25,900	38,612	54,483	65,404	73,719
Transmission					
Opex	3,210	3,440	3,695	3,823	4,112
RO Investment	40	796	1,551	2,377	3,230
Depreciation	**1,275**	**1,534**	**1,615**	**2,138**	**2,431**
Sub – Total	4,525	5,770	6,862	8,338	9,773
Distribution/Retail					
Opex	11,098	11,752	12,474	13,272	14,156
RO Investment	4,543	7,115	8,586	10,249	11,743
Depreciation	2,293	2,635	3,008	3,411	3,816
Sub total	17,934	21,502	24,068	26,933	29,715
Total	**48,358**	**65,883**	**85,413**	**100,675**	**113,207**
Subsidy	(5,500)	(5,500)	0	0	0
Net after Subsidy	**53,858**	**71,383**	**85,413**	**100,675**	**113,207**

Table 22: Generation & Transmission & Disco Costs (Net Export) - Ikeja

Year commencing 1 June	2012	2013	2014	2015	2016
Generation	Nm				
Capacity	16,254	24,207	31,485	37,616	42,317
Opex	19,065	28,445	42,810	51,571	58,209
Sub-Total	35,318	52,652	74,295	89,187	100,526
Transmission					
Opex	4,378	4,691	5,039	5,213	5,607
RO Investment	54	1,086	2,115	3,242	4,404
Depreciation	1,738	2,091	2,203	2,916	3,315
Sub – Total	6,170	7,868	9,357	11,371	13,327
Distribution/Retail					
Opex	12,286	13,023	13,837	14,737	15,734
RO Investment	4,186	7,529	9,477	11,688	13,669
Depreciation	2,232	2,640	3,083	3,564	4,085
Sub total	18,704	23,192	26,397	29,989	33,488
Total	**60,192**	**83,712**	**110,049**	**130,546**	**147,341**
Subsidy	(7,500)	(7,500)	0	0	0
Net after Subsidy	**67,692**	**91,212**	**110,049**	**130,546**	**147,341**

Table 23: Generation & Transmission & Disco Costs (Net Export) –Port Harcourt

Year commencing 1 June	2012	2013	2014	2015	2016
Generation	Nm				
Capacity	7,043	10,490	13,643	16,300	18,337
Opex	8,261	12,326	18,551	22,347	25,224
Sub-Total	15,305	22,816	32,195	38,648	43,561
Transmission					
Opex	1,897	2,033	2,184	2,259	2,430
RO Investment	24	471	917	1,405	1,909
Depreciation	753	906	955	1,263	1,437
Sub – Total	2,674	3,409	4,055	4,927	5,775
Distribution/Retail					
Opex	5,756	6,085	6,449	6,850	7,294
RO Investment	3,903	5,252	6,087	7,029	7,866
Depreciation	1,839	2,059	2,299	2,558	2,794
Sub total	11,498	13,396	14,835	16,438	17,954
Total	**29,476**	**39,621**	**51,084**	**60,012**	**67,290**
Subsidy	(3,250)	(3,250)	0	0	0
Net after Subsidy	**32,726**	**42,871**	**51,084**	**60,012**	**67,290**

Table 24: Generation & Transmission & Disco Costs (Net Export) –Yola

Year commencing 1 June	2012	2013	2014	2015	2016
Generation	Nm				
Capacity	3,793	5,648	7,346	8,777	9,874
Opex	4,448	6,637	9,989	12,033	13,582
Sub-Total	8,241	12,285	17,336	20,810	23,456
Transmission					
Opex	1,021	1,094	1,176	1,216	1,308
RO Investment	13	253	494	756	1,028
Depreciation	406	488	514	680	774
Sub – Total	1,440	1,836	2,183	2,653	3,110
Distribution/Retail					
Opex	4,217	4,450	4,706	4,989	5,302
RO Investment	1,897	2,669	3,117	3,624	4,074
Depreciation	795	901	1,017	1,142	1,253
Sub total	6,910	8,020	8,841	9,755	10,629
Total	**16,591**	**22,141**	**28,360**	**33,218**	**37,195**
Subsidy	(1,750)	(1,750)	0	0	0
Net after Subsidy	**18,341**	**23,891**	**28,360**	**33,218**	**37,195**

5.6 Institutional charges

Distributors/retailers will be required to pay a number of charges to help meet the costs of running the NESI. These institutions and their charges are:

- The System Operator (SO) serves to dispatch generation according to availability and system requirements (demand) and to allocate available electrical capacity and energy to distributors through their bulk supply points. The SO is also responsible for the procurement and utilisation of ancillary (grid reliability) services.
- The Market Operator (MO), the MO is the NESI commercial clearing house responsible during the pre-Transition Stage for invoicing, settlement of accounts and payments from distributor/retailers to TCN and the generators as well as other market institutions. During the Transition Stage market, the MO will continue to act as commercial settlement/clearing house but will not make payments. Rather payments will be made bilaterally between Discos and their contractual counterparties.
- The Bulk Trader is the entity charged with the responsibility for intermediating between Discos and Gencos and acting as the guarantor of the credit worthiness of Discos. The Bulk Trader's charges will be paid by the Discos.
- The Regulatory Charge covers the cost of the exercise of the licensing, regulatory and industry panel functions of the NESI, which are carried on by

NERC and the various panels established in the Market Rules, Grid Code, Metering Code, etc. These charges are currently set at 1.5% of distribution/retailer revenues.

5.7 Generation Allocation Balancing Mechanism

NERC would expect the Distribution Companies to be supplied power based on the percentage of capacity allocated to each company as stated in this Tariff Order in Section 5.4 above. However, in the event that a Disco cannot absorb its allocated power for whatever reason, such power will be allocated to another Disco or other Discos. The Disco or Discos taking such excess power will be obliged to compensate the constrained Disco.

NERC has developed a mechanism to compensate for these imbalances. In other words Discos can take more or less than their contracted and/or performance-related allocations. Since each Disco's tariff is tied to its load allocations, any diminution in the load supplied to a particular Disco will cause disequilibrium in that Disco's retail tariff. The Disco Balancing Mechanism seeks to redress this risk.

For example, if Disco A receives more than its due share of allocated energy, the excess of which would ordinarily go to Disco B, then the balancing mechanism will operate and funds will be settled by the Market Operator as follows:

A. Full wholesale contract cost of additional power received paid by A to the relevant generator;
B. Full transmission cost and other associated cost (regulatory charge, ancillary service charge) paid by A to TCN
C. A percentage of the distribution cost, covering fixed O & M costs, paid by A to Disco B; while
D. The balance, providing for variable O & M costs, is retained by Disco A.

In Table 25 below, the DUOS charge ordinarily due to Disco B is the "Nominal tariff". Items C – D make up the "compensation" that is payable to Disco B; while Disco A retains only the "variable cost". These values are derived from the Disco tariff worksheet of the MYTO model.

Table 25: Disco Balancing Mechanism Table (NGN/MWh)

		2012	2013	2014	2015	2016
Abuja	Nominal tariff	7,868	6,434	5,609	5,433	5,620
	Compensation	6,256	5,169	4,487	4,329	4,444
	Variable Cost	1,612	1,265	1,121	1,104	1,176
Benin	Nominal tariff	8,558	6,864	5,884	5,614	5,722
	Compensation	7,358	5,923	5,050	4,793	4,847
	Variable Cost	1,199	941	834	821	875
Enugu	Nominal tariff	8,386	6,778	5,850	5,615	5,755
	Compensation	7,050	5,730	4,921	4,700	4,781
	Variable Cost	1,336	1,048	929	915	974
Ibadan	Nominal tariff	9,881	7,982	6,897	6,626	6,813
	Compensation	7,766	6,322	5,425	5,177	5,269
	Variable Cost	2,116	1,660	1,472	1,449	1,543
Jos	Nominal tariff	9,340	7,614	6,640	6,432	6,654
	Compensation	7,375	6,072	5,273	5,086	5,220
	Variable Cost	1,965	1,542	1,367	1,345	1,433
Kaduna	Nominal tariff	9,657	7,729	6,664	6,387	6,541
	Compensation	8,171	6,563	5,630	5,369	5,457
	Variable Cost	1,486	1,166	1,034	1,018	1,084
Kano	Nominal tariff	7,581	6,214	5,442	5,293	5,492
	Compensation	6,308	5,215	4,557	4,421	4,564
	Variable Cost	1,273	999	886	872	929
Eko	Nominal tariff	8,162	6,795	5,968	5,817	6,050
	Compensation	6,460	5,459	4,783	4,652	4,808
	Variable Cost	1,702	1,336	1,184	1,166	1,242
Ikeja	Nominal tariff	6,243	5,375	4,800	4,750	5,000
	Compensation	4,827	4,264	3,815	3,781	3,968
	Variable Cost	1,416	1,111	985	969	1,033
Port Harcourt	Nominal tariff	8,856	7,165	6,225	6,008	6,186
	Compensation	7,422	6,040	5,228	5,027	5,141
	Variable Cost	1,433	1,125	997	982	1,046
Yola	Nominal tariff	9,883	7,966	6,889	6,622	6,801
	Compensation	8,031	6,513	5,601	5,354	5,450
	Variable Cost	1,852	1,453	1,288	1,268	1,351

5.8 FGN Tariff Subsidy

The FGN has provided a subsidy to help introduce a viable tariff for the industry. The tables below show NERC's calculation of the cost of supply for the NESI each year for 2012 and 2013 and the level of FGN subsidy to be paid per unit of energy billed to R1 and R2 customers.

Disco 1 – Abuja Disco

Year 1 -2012

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N'Million

R1	21.72	4.00	17.72	(43.77)
R2	21.72	11.96	9.76	(5,706.23)
Total				(5,750.00)

Year 2- 2013

Tariff Class	Cost of Service-N'Kwh	Recovered from customers-N'Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**20.46**	4.00	16.46	(40.80)
R2	**20.46**	12.58	7.61	(5,709.20)
Total				(5,750.00)

Disco 2- Benin Disco

Year 1 -2012

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**22.40**	4.00	18.40	(8.48)
R2	**22.40**	11.69	10.72	(4,491.52)
Total				(4,500.00)

Year 2 -2013

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**20.89**	4.00	16.89	(8.21)
R2	**20.89**	11.73	9.16	(4,491.79)
Total				(4,500.00)

Disco 3 – Enugu

Year 1 - 2012

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**22.23**	4.00	17.85	(1.13)
R2	**22.23**	13.08	9.15	(4,498.87)
Total				(4,500.00)

Year 2- 2013

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**20.80**	4.00	16.80	(1.01)
R2	**20.80**	15.01	5.79	(4,498.99)
Total				(4,500.00)

Disco 4 – Ibadan Disco

Year 1 - 2012

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**23.73**	4.00	19.73	(39.97)
R2	**23.73**	12.83	10.09	(6,460.03)
Total				(6,500.00)

Year 2- 2013

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**22.01**	4.00	18.01	(39.33)

R2	**22.01**	13.42	8.59	(6,460.67)
Total				(6,500.00)

Disco 5 – Jos Disco

Year 1 - 2012

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy- N/Million
R1	**23.19**	4.00	19.19	(22.31)
R2	**23.19**	16.66	6.53	(2,727.69)
Total				(2,750.00)

Year 2- 2013

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy- N/Million
R1	**21.64**	4.00	17.64	(22.33)
R2	**21.64**	16.65	4.9932	(2,727.67)
Total				(2,750.00)

Disco 6 –Kaduna Disco

Year 1 - 2012

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy- N/Million
R1	**23.50**	4.00	19.76	(1.88)
R2	**23.50**	13.31	10.19	(3,998.12)
Total				(4,000.00)

Year 2- 2013

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy- N/Million
R1	**21.76**	4.00	17.76	(1.70)
R2	**21.76**	14.65	7.10	(3,998.30)
Total				(4,000.00)

Disco 7 –Kano Disco

Year 1 - 2012

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy- N/Million
R1	**21.43**	4.00	17.43	(68.70)
R2	**21.43**	13.04	8.39	(3,931.30)
Total				(4,000.00)

Year 2- 2013

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy- N/Million
R1	**20.24**	4.00	18.94	(65.91)
R2	**20.24**	13.68	6.56	(3,934.09)
Total				(4,000.00)

Disco 8 –Eko Disco

Year 1 - 2012

Tariff Class	Cost of Service-N/Kwh	Recovered from	Subsidy- N/Kwh	Total Subsidy-

		customers-N/Kwh		N/Million
R1	**22.01**	4.00	16.82	(0.01)
R2	**22.01**	13.10	7.69	(5,499.99)
Total				(5,500.00)

Year 2- 2013

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**20.82**	4.00	16.82	(0.01)
R2	**20.82**	13.13	7.69	(5,499.99)
Total				(5,500.00)

Disco 9 –Ikeja Disco

Year 1 - 2012

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**20.09**	4.00	15.40	(0.39)
R2	**10.09**	12.68	7.41	(7,499.59)
Total				(7,500.00)

Year 2- 2013

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**19.40**	4.00	15.40	(0.39)
R2	**19.40**	13.08	6.32	(7,499.61)
Total				(7,500.00)

Disco 10 –Port Harcourt Disco

Year 1 - 2012

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**22.70**	4.00	18.70	(1.28)
R2	**22.70**	16.39	6.31	(3,248.44)
Total				(3,250.00)

Year 2- 2013

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**21.19**	4.00	17.19	(1.37)
R2	**21.19**	16.83	4.36	(3,248.43)
Total				(3,250.00)

Disco 11 –Yola Disco

Year 1 - 2012

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**23.73**	4.00	19.99	(46.35)
R2	**23.73**	11.88	11.86	(1,703.65)
Total				(1,750.00)

Year 2- 2013

Tariff Class	Cost of Service-N/Kwh	Recovered from customers-N/Kwh	Subsidy- N/Kwh	Total Subsidy-N/Million
R1	**21.99**	4.00	17.99	(42.33)
R2	**21.99**	12.80	9.19	(1,707.67)
Total				(1,750.00)

6 Retail Tariffs

6.1 Disco Tariffs

Retail tariffs, as required by Section 76(2), EPSRA, must reflect the costs associated with providing service to each customer, plus a reasonable return. Exceptions are made for lifeline (R1 or low-income) customers. One of NERC's most important functions is to ensure that only prudent costs are passed to customers and a truly reasonable return is earned. Thus, even though NERC is required to ensure a cost-reflective tariff, NERC is in turn obliged to drive licensees to reduce losses and deliver quality service.

In this way, the NERC will ensure that each class of customer pays a tariff that covers for that particular class only. The retail cost of electricity covers generation cost, transmission use of system cost, the Discos' distribution costs and costs associated with metering, billing, marketing and revenue collection. Finally, there are the various regulatory, bulk trader and market administration charges. Therefore, as a natural consequence of the fact that no two Discos have the same set of costs, NERC has set appropriate tariffs for each Disco and for each class of customer that it serves.

The Act accepts this economic reality but also recognises that not every customer can afford the economic cost of being served. In implicitly establishing an obligation to serve EVERY customer that wishes to have electricity supply, irrespective of that customer's economic standing, both the National Electric Power Policy and EPSRA established the concept of a "uniform lifeline tariff" only for those customers unable to pay economic tariffs. Section 85, EPSRA, then went on to establish the Power Consumer Assistance Fund (PCAF) to provide support to these lifeline tariff customers. Accordingly, the administration of any lifeline subsidy scheme in the industry will be done through the PCAF to which, statutorily, any government (Federal, State and Local Government) may contribute.

The retail tariffs for each Disco stated below and represented in the MYTO financial model are applicable for each Disco until a revised tariff is approved by NERC.

DISCO 1 – Abuja Disco

Table 26: Fixed Charges - Abuja Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	702	986	1,384	1,944
R3	37,527	52,696	73,997	103,908	145,909
R4	113,358	136,030	191,016	268,228	376,650
COMMERCIAL					
C1	500	702	986	1,384	1,944
C2	34,020	47,772	67,082	94,197	132,274
C3	102,767	123,321	173,169	243,168	341,461
INDUSTRIAL					
D1	10,000	10,000	14,042	19,718	27,689
D2	101,113	101,113	141,985	199,378	279,970
D3	102,767	123,321	173,169	243,168	341,461
SPECIAL					
A1	500	702	986	1,384	1,944
A2	35,938	43,125	60,557	85,035	119,408
A3	45,313	54,375	76,354	107,218	150,558
STREET LIGHTING					
S1	500	600	843	1,183	1,661

Table 27: Energy Charges - Abuja Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	11.74	12.62	13.25	13.91	14.61
R3	22.62	22.62	23.75	24.94	26.19
R4	22.62	22.62	23.75	24.94	26.19
COMMERCIAL					
C1	16.56	16.56	17.39	18.26	19.17
C2	21.03	21.03	22.08	23.18	24.34
C3	21.03	21.03	22.08	23.18	24.34
INDUSTRIAL					
D1	16.97	16.97	17.81	18.70	19.64
D2	22.04	22.04	23.14	24.30	25.51
D3	22.04	22.04	23.14	24.30	25.51
SPECIAL					
A1	16.24	16.24	17.05	17.90	18.80
A2	16.24	16.24	17.05	17.90	18.80
A3	16.24	16.24	17.05	17.90	18.80
STREET LIGHTING					
S1	12.47	13.41	14.08	14.78	15.52

Disco 2 – Benin Disco

Table 28: Fixed Charges - Benin Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	750	1,500	1,800	1,800
R3	25,018	37,527	49,143	64,355	84,276
R4	101,631	133,091	174,289	228,239	298,889
COMMERCIAL					
C1	500	1,000	1,310	1,715	2,246
C2	22,680	34,020	44,551	58,341	76,401
C3	1,748	141,748	185,625	243,085	318,331
INDUSTRIAL					
D1	500	1,000	1,310	1,715	2,246
D2	139,466	153,413	200,901	263,089	344,527
D3	141,748	155,923	204,188	267,394	350,164
SPECIAL					
A1	500	1,000	1,310	1,715	2,246
A2	34,375	37,813	49,517	64,845	84,918
A3	40,625	44,688	58,520	76,635	100,357
STREET LIGHTING					
S1	500	1,000	1,310	1,715	2,246

Table 29: Energy Charges - Benin Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	11.37	11.37	11.94	12.54	13.16
R3	20.28	20.28	21.29	22.36	23.48
R4	20.28	20.28	21.29	22.36	23.48
COMMERCIAL					
C1	15.84	15.84	16.63	17.46	18.34
C2	18.85	18.85	19.79	20.78	21.82
C3	18.85	18.85	19.79	20.78	21.82
INDUSTRIAL					
D1	15.21	15.21	15.97	16.77	17.61
D2	19.76	19.76	20.75	21.79	22.87
D3	19.76	19.76	20.75	21.79	22.87
SPECIAL					
A1	14.56	14.56	15.29	16.05	16.86
A2	14.56	14.56	15.29	16.05	16.86
A3	14.56	14.56	15.29	16.05	16.86
STREET LIGHTING					
S1	15.00	15.00	15.75	16.54	17.36

Disco 3 – Enugu Disco

Table 30: Fixed Charges - Enugu Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	650	874	1,176	1,581
R3	18,787	24,424	32,847	44,175	59,409
R4	117,416	117,416	157,910	212,369	285,609
COMMERCIAL					
C1	500	650	874	1,176	1,581
C2	17,032	22,141	29,777	40,046	53,857
C3	106,446	106,446	143,157	192,528	258,926
INDUSTRIAL					
D1	1,000	1,300	1,748	2,351	3,162
D2	104,733	104,733	140,852	189,428	254,757
D3	106,446	106,446	143,157	192,528	258,926
SPECIAL					
A1	500	650	874	1,176	1,581
A2	37,500	37,500	50,433	67,826	91,217
A3	46,935	46,935	63,121	84,890	114,166
STREET LIGHTING					
S1	500	650	874	1,176	1,581

Table 31: Energy Charges - Enugu Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	12.89	14.82	15.57	16.34	17.16
R3	23.43	23.43	24.60	25.83	27.12
R4	23.43	23.43	24.60	25.83	27.12
COMMERCIAL					
C1	17.28	17.28	18.14	19.05	20.00
C2	21.78	21.78	22.87	24.01	25.21
C3	21.78	21.78	22.87	24.01	25.21
INDUSTRIAL					
D1	17.57	17.57	18.45	19.37	20.34
D2	22.83	22.83	23.97	25.17	26.43
D3	22.83	22.83	23.97	25.17	26.43
SPECIAL					
A1	16.82	19.34	20.31	21.33	22.39
A2	16.82	19.34	20.31	21.33	22.39
A3	16.82	19.34	20.31	21.33	22.39
STREET LIGHTING					
S1	12.90	14.84	15.58	16.36	17.17

Disco 4 – Ibadan Disco

Table 32: Fixed Charges - Ibadan Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	500	625	781	976
R3	18,764	18,764	23,453	29,314	36,639
R4	117,267	117,267	146,573	183,202	228,985
COMMERCIAL					
C1	500	500	625	781	976
C2	17,010	17,010	21,261	26,574	33,215
C3	106,311	106,311	132,879	166,086	207,592
INDUSTRIAL					
D1	500	500	625	781	976
D2	104,600	104,600	130,740	163,412	204,250
D3	106,311	106,311	132,879	166,086	207,592
SPECIAL					
A1	500	500	625	781	976
A2	33,594	33,594	41,989	52,482	65,598
A3	46,875	46,875	58,589	73,231	91,532
STREET LIGHTING					
S1	500	500	625	781	976

Table 33: Energy Charges - Ibadan Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	12.30	12.91	13.56	14.23	14.95
R3	23.40	24.57	25.80	27.09	28.44
R4	23.40	24.57	25.80	27.09	28.44
COMMERCIAL					
C1	15.48	16.25	17.07	17.92	18.82
C2	21.75	22.84	23.98	25.18	26.44
C3	21.75	22.84	23.98	25.18	26.44
INDUSTRIAL					
D1	17.55	18.43	19.35	20.32	21.33
D2	22.80	23.94	25.14	26.39	27.71
D3	22.80	23.94	25.14	26.39	27.71
SPECIAL					
A1	16.80	17.64	18.52	19.45	20.42
A2	16.80	17.64	18.52	19.45	20.42
A3	16.80	17.64	18.52	19.45	20.42
STREET LIGHTING					
S1	12.90	13.55	14.22	14.93	15.68

Disco 5 – Jos disco

Table 34: Fixed Charges - Jos Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	775	1,163	1,744	2,616
R3	18,764	29,083	43,625	65,438	98,157
R4	117,267	181,764	272,646	408,969	613,453
COMMERCIAL					
C1	500	775	1,163	1,744	2,616
C2	17,010	26,366	39,548	59,322	88,984
C3	106,311	164,782	247,173	370,760	556,139
INDUSTRIAL					
D1	900	1,395	2,093	3,139	4,708
D2	104,600	162,129	243,194	364,791	547,186
D3	106,311	164,782	247,174	370,760	556,139
SPECIAL					
A1	900	1,395	2,093	3,139	4,708
A2	40,625	62,969	94,453	141,680	212,520
A3	46,875	72,656	108,984	163,477	245,215
STREET LIGHTING					
S1	900	1,395	2,093	3,139	4,708

Table 35: Energy Charges - Jos Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	12.99	13.63	14.32	15.03	15.78
R3	23.40	24.57	25.80	27.09	28.44
R4	23.40	24.57	25.80	27.09	28.44
COMMERCIAL					
C1	17.00	17.85	18.74	19.68	20.66
C2	21.75	22.84	23.98	25.18	26.44
C3	21.75	22.84	23.98	25.18	26.44
INDUSTRIAL					
D1	17.00	17.84	18.74	19.68	20.66
D2	22.80	23.94	25.14	26.39	27.71
D3	22.80	23.94	25.14	26.39	27.71
SPECIAL					
A1	16.80	17.64	18.52	19.45	20.42
A2	16.80	17.64	18.52	19.45	20.42
A3	16.80	17.64	18.52	19.45	20.42+
STREET LIGHTING					
S1	17.00	17.00	17.85	18.74	19.68

Disco 6 – Kaduna Disco

Table 36: Fixed Charges - Kaduna Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	800	1,280	2,048	3,277
R3	25,018	40,029	64,046	102,474	163,958
R4	156,356	250,170	400,271	640,434	1,024,695
COMMERCIAL					
C1	500	800	1,280	2,048	3,277
C2	22,680	36,288	58,061	92,897	148,636
C3	141,748	226,797	362,875	580,600	928,960
INDUSTRIAL					
D1	1,000	1,600	2,560	4,096	6,554
D2	139,466	223,146	357,033	571,253	914,004
D3	141,748	226,797	362,875	580,600	928,960
SPECIAL					
A1	500	800	1,280	2,048	3,277
A2	46,728	74,766	119,625	191,400	306,240
A3	62,500	100,000	160,000	256,000	409,600
STREET LIGHTING					
S1	500	800	1,280	2,048	3,277

Table 37: Energy Charges - Kaduna Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	12.69	13.96	15.36	16.90	17.74
R3	23.33	25.66	28.23	31.05	32.60
R4	23.33	25.66	28.23	31.05	32.60
COMMERCIAL					
C1	16.00	17.60	19.36	21.30	22.36
C2	21.68	23.85	26.24	28.86	30.30
C3	21.68	23.85	26.24	28.86	30.30
INDUSTRIAL					
D1	17.50	19.24	21.17	23.29	24.45
D2	22.73	25.00	27.50	30.25	31.76
D3	22.73	25.00	27.50	30.25	31.76
SPECIAL					
A1	16.75	18.42	20.26	22.29	23.41
A2	16.75	18.42	20.26	22.29	23.41
A3	16.75	18.42	20.26	22.29	23.41
STREET LIGHTING					
S1	14.19	15.61	17.17	18.89	19.83

Disco 7 – Kano Disco

Table 38: Fixed Charges - Kano Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	667	889	1,186	1,582
R3	22,516	30,031	40,055	53,424	71,256
R4	117,267	156,407	208,612	278,241	371,110
COMMERCIAL					
C1	500	667	889	1,186	1,582
C2	20,412	27,225	36,312	48,432	64,597
C3	106,311	141,795	189,122	252,245	336,438
INDUSTRIAL					
D1	650	867	1,156	1,542	2,057
D2	104,600	139,512	186,077	248,184	331,022
D3	106,311	141,795	189,122	252,245	336,438
SPECIAL					
A1	500	667	889	1,186	1,582
A2	46,875	62,521	83,388	111,221	148,343
A3	62,500	83,361	111,184	148,294	197,791
STREET LIGHTING					
S1	650	867	1,156	1,542	2,057

Table 39: Energy Charges - Kano Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	12.78	13.42	14.09	14.80	15.54
R3	23.40	24.57	25.80	27.09	28.44
R4	23.40	24.57	25.80	27.09	28.44
COMMERCIAL					
C1	15.84	16.63	17.46	18.34	19.25
C2	21.75	22.84	23.98	25.18	26.44
C3	21.75	22.84	23.98	25.18	26.44
INDUSTRIAL					
D1	17.55	18.43	19.35	20.32	21.33
D2	22.80	23.94	25.14	26.39	27.71
D3	22.80	23.94	25.14	26.39	27.71
SPECIAL					
A1	16.80	17.64	18.52	19.45	20.42
A2	16.80	17.64	18.52	19.45	20.42
A3	16.80	17.64	18.52	19.45	20.42
STREET LIGHTING					
S1	12.90	13.55	14.22	14.93	15.68

Disco 8 – Eko Disco

Table 40: Fixed Charges - Eko Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	750	1,125	1,688	1,688
R3	21,265	31,898	47,847	52,632	57,895
R4	118,831	136,655	150,321	165,353	181,888
COMMERCIAL					
C1	500	750	1,125	1,688	1,688
C2	19,278	22,170	25,495	29,819	33,717
C3	107,728	118,501	130,351	143,387	157,725
INDUSTRIAL					
D1	603	905	1,357	1,628	1,628
D2	105,994	116,594	129,300	142,330	156,453
D3	107,728	118,501	130,351	143,387	157,725
SPECIAL					
A1	500	750	975	1,463	1,463
A2	47,500	52,250	57,475	63,223	69,545
A3	53,125	58,438	64,281	70,709	77,780
STREET LIGHTING					
S1	500	750	1,125	1,688	1,688

Table 41: Energy Charges - Eko Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	12.87	12.87	12.87	12.87	12.87
R3	23.71	23.71	23.71	23.71	23.71
R4	23.71	23.71	23.71	23.71	23.71
COMMERCIAL					
C1	15.84	15.84	15.84	15.84	15.84
C2	22.04	22.04	22.04	22.04	22.04
C3	22.04	22.04	22.04	22.04	22.04
INDUSTRIAL					
D1	17.78	17.78	17.78	17.55	17.55
D2	23.10	22.10	23.10	23.10	23.10
D3	23.10	23.10	23.10	23.10	22.10
SPECIAL					
A1	17.02	16.02	17.02	17.02	17.02
A2	17.02	17.02	17.02	17.02	17.02
A3	17.02	17.02	17.02	17.02	17.02
STREET LIGHTING					
S1	13.07	13.07	13.07	13.07	13.07

Disco 9- Ikeja Disco

Table 42: Fixed Charges - Ikeja Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	750	895	1,067	1,273
R3	17,513	26,269	31,332	37,371	44,575
R4	109,449	164,174	195,818	233,561	278,579
COMMERCIAL					
C1	500	750	895	1,067	1,273
C2	15,876	23,814	28,404	33,879	40,409
C3	99,224	148,835	177,523	211,740	252,552
INDUSTRIAL					
D1	500	1,000	1,193	1,423	1,697
D2	97,626	195,252	232,887	277,775	331,315
D3	99,224	198,447	236,697	282,320	336,736
SPECIAL					
A1	500	750	895	1,067	1,273
A2	35,938	43,125	51,437	61,352	73,177
A3	43,750	65,625	78,274	93,361	111,356
STREET LIGHTING					
S1	500	650	775	925	1,103

Table 43: Energy Charges - Ikeja Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	12.45	12.83	13.21	13.61	14.02
R3	21.84	22.50	23.17	23.87	24.58
R4	21.84	22.50	23.17	23.87	24.58
COMMERCIAL					
C1	16.56	17.06	17.57	18.10	18.64
C2	20.30	20.91	21.54	22.18	22.85
C3	20.30	20.91	21.54	22.18	22.85
INDUSTRIAL					
D1	16.38	16.87	17.38	17.90	18.44
D2	21.28	21.92	22.58	23.25	23.95
D3	21.28	21.92	22.58	23.25	23.95
SPECIAL					
A1	15.68	16.15	16.63	17.13	17.65
A2	15.68	16.15	16.63	17.13	17.65
A3	15.68	16.15	16.63	17.13	17.65
STREET LIGHTING					
S1	12.04	12.40	12.77	13.16	13.55

Disco 10 – Port Harcourt Disco

Table 44: Fixed Charges – Port Harcourt Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	700	1,050	1,575	2,363
R3	25,018	35,025	52,538	78,807	118,210
R4	117,267	164,174	246,261	369,391	554,087
COMMERCIAL					
C1	500	700	1050	1, 575	2,363
C2	22,680	31,752	47,628	71,442	107,163
C3	106,311	148,835	223,253	334,880	502,319
INDUSTRIAL					
D1	700	980	1470	2,205	3,308
D2	104,600	146,439	219,659	329,488	494,233
D3	106,311	148,835	223,253	334,880	502,319
SPECIAL					
A1	700	980	1,470	2,205	3,308
A2	46,875	65,625	98,438	147,656	221,484
A3	62,500	87,500	131,250	196,875	295,313
STREET LIGHTING					
S1	700	980	1,470	2,205	3,308

Table 45: Energy Charges – Port Harcourt Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	12.82	13.21	13.60	14.01	14.43
R3	23.40	24.10	24.83	25.57	26.34
R4	23.40	24.10	24.83	25.57	26.34
COMMERCIAL					
C1	17.20	17.72	18.25	18.79	19.36
C2	21.75	22.40	23.07	23.77	24.48
C3	21.75	22.40	23.07	23.77	24.48
INDUSTRIAL					
D1	23.40	24.10	24.83	25.57	26.34
D2	22.80	23.48	24.19	24.91	25.66
D3	22.80	23.48	24.19	24.91	25.66
SPECIAL					
A1	16.80	17.30	17.82	18.36	18.91
A2	16.80	17.30	17.82	18.36	18.91
A3	22.40	23.07	23.76	24.48	25.21
STREET LIGHTING					
S1	17.20	17.72	18.25	18.79	19.36

Disco 11 – Yola Disco

Table 46: Fixed Charges – Yola Disco

FIXED CHARGES ₦/MONTH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	-	-	-	-	-
R2	500	750	1,250	1,960	2,875
R3	16,137	24,205	40,355	63,244	92,792
R4	100,850	152,274	252,206	395,259	579,927
COMMERCIAL					
C1	500	750	1,250	1,960	2,875
C2	14,629	21,943	36,583	57,334	84,121
C3	91,427	137,141	228,643	358,331	525,746
INDUSTRIAL					
D1	500	750	1,250	1,960	2,875
D2	89,956	134,933	224,962	352,562	517,282
D3	91,427	137,141	228,643	358,331	525,746
SPECIAL					
A1	500	750	1,250	1,960	2,875
A2	34,375	44,688	74,503	116,762	171,314
A3	40,313	60,469	100,814	157,996	231,814
STREET LIGHTING					
S1	500	750	1,250	1,960	2,875

Table 47: Energy Charges – Yola Disco

ENERGY CHARGES ₦/KWH					
TARIFF CODE DETAILS					
	2012	**2013**	**2014**	**2015**	**2016**
RESIDENTIAL					
R1	4.00	4.00	4.00	4.00	4.00
R2	11.32	12.17	12.78	13.42	14.09
R3	20.28	21.63	22.71	23.85	25.04
R4	20.28	21.63	22.71	23.85	25.04
COMMERCIAL					
C1	15.84	17.03	17.88	18.77	19.71
C2	18.71	20.11	21.11	22.17	23.28
C3	18.71	20.11	21.11	22.17	23.28
INDUSTRIAL					
D1	15.09	16.22	17.04	17.89	18.78
D2	19.61	21.08	22.13	23.24	24.40
D3	19.61	21.08	22.13	23.24	24.40
SPECIAL					
A1	14.45	15.53	16.31	17.12	17.98
A2	14.45	15.53	16.31	17.12	17.98
A3	14.45	15.53	16.31	17.12	17.98
STREET LIGHTING					
S1	11.09	11.93	12.52	13.15	13.81

7 Bi-Annual Review

NERC will review the DUOS charges bi-annually as part of the minor review. A Disco wishing NERC to consider varying the DUOS charge must make a submission to NERC supporting its case on the basis stated in the relevant notice of review. NERC will vary the DUOS if there is a material change in the inflation rate, exchange rate and generation capacity used in the calculation of DUOS charges.

NERC considers that a material change would be plus or minus 5% in these index. Other parameters, such as variations in the forecast of capital expenditure on the network or the forecasts for energy transmitted through it, will be considered if requested by a Disco or as part of a comprehensive major review of the MYTO. We also draw attention to provisions on reviewing indices for generation wholesale prices and for the TUOS charge as set out in the other two Tariff Orders.

8 Date and Conditions for Effectiveness

NERC considers that it is proper to balance the increased revenues that the NESI will receive, in the face of a current below average levels of quality of service and minimal increases in energy supply to consumers, with pressure on Discos to rapidly evolve higher standards of customer care and cost-effectiveness. NERC has applied this pressure with some success even before the tariff increase takes effect and will continue to apply such pressure using all regulatory instruments at its disposal.

From 1st June 2012, NERC will begin to review the performance of the Discos in relation to the performance standards stated below. These standards are applicable to all Discos. However, after a specific moratorium period to give time for new owners to arrive, turn management round and start showing signs of a viable business, sanctions will be imposed for failure to conform to these standards of performance. These standards are designed to result in a rapid increase in technical performance, customer care and regulatory compliance.

This Tariff Order, as with the other two, shall take effect as from midnight of 31st May 2012. The standards initially set for the Distribution sector are as follows:

1. Opening of fully-equipped and staffed Forum Offices at locations within the Disco franchise area agreed with NERC

2. Opening of fully-equipped Customer Compliant Units (CCU) by all the Distribution Companies.

3. The submission of information on each Disco's current metering programme funded from its share of the =N=2.9bn Federal Government metering fund provided in 2011;

4. The submission of a Metering Plan for the Commission's approval within two (2) weeks from the date this Tariff Order takes effect. The Plan shall include, amongst other, details of the timelines, milestones, and scope of its implementation.

5. Full implementation of the Customer Metering Plan, as approved by the Commission, within eighteen (18) months from the date this Tariff Order takes effect. Failure to strictly comply with the terms of such Metering Plan will be met with sanctions from the Commission; and

6. The development and implementation of a single standard or set of principles for estimating the consumption of unmetered customers and the strict use of such standards in accordance with the applicable customer service rules already established by NERC (please see the *Customer Service Standards of Performance and Meter Reading Regulations and similar customer care regulations* at www.nercng.org).

DATED AT ABUJA THIS 31st **DAY OF** May **2012**

DR. SAM AMADI
CHAIRMAN/CEO

DR. STEVEN ANDZENGE
COMMISSIONER (LEGAL, LICENSING AND ENFORCEMENT)